AN INTERVAL MATHEMATICS APPROACH TO ECONOMIC EVALUATION OF POWER DISTRIBUTION SYSTEMS

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(ABSTRACT)

Electric utilities are constantly seeking ways to reduce costs, and one way is to defer the construction of major new facilities. Such a deferal can be instituted by automating the power distribution system in an effort to make the system operate more efficiently and effectively. Increased efficiency on the distribution level improves the use of existing facilities on the distribution, transmission, and generation levels. The stumbling block for justifying distribution automation is often at the economic evaluation stage. This is due to the difficulty of incorporating the effects of technologies which have not been implemented in the past.

In this research, a new method of economic analysis of utility distribution systems is proposed. The method will utilize interval analysis to determine the effects of uncertainty in data in utility revenue requirement studies. One of the frequently encountered problems in applying interval analysis is the resulting overly large bounds which in turn reduce the usefulness of results. Therefore, a method of obtaining sharp bounds is presented.

The economic calculations will incorporate results from reliability analysis as well as reconfiguration studies. Thus, an explicit consideration of engineering design aspects is included. In addition, a cost/effectiveness analysis of distribution automation is presented in terms of several proposed economic indices associated with system cost, reliability, efficiency, and peak. A method of incorporating value of service

considerations into revenue requirement studies is also presented. The capability to analyze automation expansion plans as well as conventional expansion plans will be discussed. Accordingly, utility distribution planning can be more precise with regard to potential economic benefits.

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CHAPTER 1

Introduction

1.1 Distribution System Design

Approximately half of capital investment in electric power supply systems is at the distribution level. In addition, more than half of the losses associated with the electric supply system are related to distribution. Nevertheless, very little research is performed at the distribution level regarding a comprehensive approach to the relevant problems.

Electric utilities are constantly seeking ways to reduce costs. One way is to defer the construction of new facilities, and one way to institute such a deferral is to automate the power distribution system in an effort to make the overall system operate more efficiently and effectively. Increased efficiency on the distribution level improves the use of existing facilities on the distribution, transmission, and generation levels [1].

Recently, the availability of distribution automation equipment has given utility planners more choices in the design of distribution systems. Thus, distribution automation is now a big part of upgrading existing systems and designing new ones. Economic evaluation of distribution automation is therefore especially important because it facilitates examining potential costs and benefits of technologies which have not been implemented in the past. Therefore, a computer aided approach can potentially allow utilities to evaluate distribution automation functions before actually implementing them.

Although all utilities are not the same, examples of common utility objectives in considering distribution automation include:

1. Minimize revenue requirement through capital deferments and reduction in operation and maintenance costs
2. Meet regulatory requirements
3. Provide improved system operation

4. Provide improved engineering and planning decisions.

Automation can be thought of as doing a repetitive task with minimal human intervention. Distribution automation refers to automation of repetitive tasks on the electric utility's distribution system. To understand distribution automation, one must first look at the manual tasks the utility performs [2]. These tasks involve communicating and performing operations. For the electric distribution system, these tasks include the following:

a. Reading kilowatt-hour and kilowatt-demand meters

b. Reading temperatures

c. Taking load checks at distribution substations and along the feeders

d. Opening and closing feeder circuit switching devices

e. Operating capacitor banks

f. Raising and lowering taps on voltage regulators.

Most electric utilities already have automation of some type. Automation may range from time clocks for turning street lights on and off, to a computerized energy management system for economic dispatch of the generation and transmission of bulk power. Distribution automation usually refers to a fully integrated system that includes all of the functional data flow and control that pertains to the distribution system. A fully automated system can be a natural extension and enhancement of the level of automation that already exists in individual utilities [2].

Distribution automation requires the installation of equipment at substations, along the feeders, and even in the customers' residences for the purpose of automating the distribution system. This provides a tool to achieve maximum utilization of the utility's physical plant, and to provide the highest quality of service to its customers [2]. Obviously, both the utility and its customers are beneficiaries of successful distribution automation.

The technology required to implement distribution automation is available today. The challenge for utilities is to identify and evaluate potential automation functions and determine those appropriate for implementation. In the average utility, implementing distribution automation will cross almost all corporate organizational lines to provide support for the design, construction, operation and maintenance of the program. Therefore, successful implementation of distribution automation will affect and benefit the company as a whole.

Distribution automation functions provide a means to more effectively manage the continuous operation of a distribution system. This involves collecting and analyzing information from which to make decisions, implementing the appropriate decision, and then verifying that the desired result is achieved. Distribution automation encompasses load control, volt/var control, and system reconfiguration; it also includes the associated computer hardware and software.

Load control gives utilities the capability to turn off or to cycle appliances in customers' homes. This process will reduce the electric load that must be satisfied by the utility at the time of the daily system peak load. The reduced load results in less use of costly peaking generation units and facilities which in turn defers the construction of new plant facilities. Appliances subject to such control include water heaters, central air conditioners, central space heaters, and heat pumps.

With load control, a utility must pay attention to the load "payback effect". It refers to the fact that after control of customers' appliances is removed, the appliances may all want to come on at the same time. The result may be a greater system peak load than that before installation of a load control system [1].

Volt/var control gives utilities the ability to remotely control capacitors, regulators, and load-tap-changing transformers. This combined control provides a way to obtain a balanced distribution system by optimizing feeder losses and feeder voltage profiles.

Capacitor control is performed to improve the power factor and to reduce feeder losses through voltage control as well. Reduced feeder losses result in a lesser demand for generation. Furthermore, for every kilowatt saved on the distribution level, additional kilowatts are saved on the transmission and generation levels due to the losses along those levels. This allows a utility to defer construction of additional generation and transmission facilities until a later date.

Voltage regulators and load-tap-changing transformers are used for voltage control. Voltage can be lowered during peak periods of system peak to reduce peak load. Twenty-four-hour load conservation voltage regulation is also possible [1].

System reconfiguration implies that distribution switches are allowed to change status in order to improve the paths of power flow to better serve varying location and time dependent factors of distribution load. This can be achieved through the use of automatic switches.

Reconfiguration can also improve service reliability and restoration. Faults can be isolated by the operator using remote feeder switching while a repair crew is en route, and service can be restored to unfaulted feeder sections. The result is a much faster overall restoration time for a large number of customers. Additional benefits include increased revenue to the utility and greater customer goodwill.

Load transfers between feeders and between substations may prevent overloading conditions by balancing loads among the lightly and heavily loaded feeders and substations. This can permit deferring the construction of additional distribution facilities. Load transfers may also allow feeder losses to be reduced, thereby saving fuel and increasing the efficiency of distribution systems [1].

Distribution automation should be evaluated for benefits from both operational and economic viewpoints, and the cost should be compared accordingly. One of the major stumbling blocks facing distribution automation projects is the economic justification. It is mainly due to the difficulty of incorporating the effects of technologies which have not yet been fully implemented.

1.2 Current Economic Analysis Practices

The revenue requirement method provides utilities with the ability to choose the most attractive economic alternative in addition to assessing the impact of that alternative on customers. Revenue requirement is traditionally calculated as the sum of capital expenses and operating costs associated with each alternative. However, there is no explicit consideration of engineering design aspects such as system reliability, efficiency, and peak.

Value of service is another consideration which is not normally incorporated into revenue requirement studies. Value of service considers the cost of power outages to the customer. Despite its importance, quantifying value of service is not an easy task. The monetary and nonmonetary value of various degrees of reliability have not been accurately known. While some of the cost of unreliability to some users are quantifiable, such as production losses, other costs, such as the value of personal comfort or safety, are difficult to assess and quantify.

Value of service is closely related to reliability. Reliability of service has always been a major factor in planning, design, and operation of electric power systems. Reliability has received increasing attention as systems have grown in size and complexity [3]. In general, the higher the level of reliability, the greater the cost of building and operating an electric power system.

Sensitivity analysis is needed in economic studies to assess the effects of variations in input parameters such as minimum acceptable return, inflation, and carrying charges on the revenue requirements. Sensitivity studies are often performed by varying a single parameter at a time. This results in the need to perform many sensitivity simulations. Furthermore, it does not represent real world situations since there is no simultaneous variation of parameters.

Clearly, there is a need for a new method of economic evaluation which utilizes sensitivity analysis to determine the effects of uncertainty in data. In addition, the new method should have the capability to perform cost/effectiveness analysis of distribution automation. Finally, the new method should be an integrated approach which incorporates the economic impacts of the various engineering performance aspects of distribution system design.

1.3 Scope of Dissertation

The present work focuses on developing an economic evaluation algorithm for distribution systems which utilizes interval calculations for sensitivity analysis. Standard revenue requirement theory calculations will be placed in interval form to evaluate the economic impacts associated with alternative distribution system designs. The bounds on the interval parameters used here are well defined. In other words, it is a valid assumption to consider that these parameters vary within the defined bounds. This is discussed in further detail in Chapter 4.

The important design aspects of system reliability, efficiency, and peak demand will be considered. In addition, value of service considerations will also be incorporated. In general, the approach used by utilities to estimate value of service is to conduct customer surveys. An alternative approach is proposed here which places an interval dollar amount on value of service by customer type when such information is unavailable.

A problem which is often encountered in applying interval analysis is very wide bounds. Interval bounds can be so wide that the result may not be useful. It is shown for economic analysis that a simple rearrangement of the calculations produces sharp bounds.

This research attempts to develop a new approach to economic evaluation of utility distribution systems which takes into consideration several aspects that have not been incorporated in the past. A computer-aided approach will be utilized to evaluate alternative system designs. These alternatives are evaluated in terms of system effectiveness and cost. This represents a multi-objective problem which is not easy to evaluate. Decision evaluation is therefore facilitated by several evaluation displays showing both cost and performance measures.

The new approach gives utility planners the ability to assess the impact of alternative distribution plans from different perspectives. In other words, planners can conduct cost/effectiveness analysis from either reliability, efficiency, or system peak perspective in addition to a combination of them. Accordingly, utility distribution planning can be more precise with regard to potential economic benefits.

An overview of the remaining chapters is as follows. Chapter 2 presents a review of previous work on utility economics, electric outage costs, and interval mathematics. It also includes a background discussion of the recent history of the utility industry environment along with the revenue requirement method which is commonly used by utilities.

Chapter 3 deals with interval mathematics and its application to sensitivity analysis. Ways of getting sharp interval bounds are discussed in relation to economic analysis. A discussion of statistical concepts and their relevance to interval mathematics is also included.

Chapter 4 presents the design evaluation methodology and concepts of dealing with uncertainty in input parameters. Design evaluation displays are also presented to illustrate the methodology application.

Chapter 5 presents a methodology for economic evaluation and cost/effectiveness analysis of distribution system design in terms of several proposed economic indices. In addition, a method of incorporating value of service considerations is presented along with a method of back-calculating the value of service. Finally, an economic decision evaluation display is developed.

Chapter 6 presents the economic analysis algorithm along with related software aspects. In addition, a brief description of reconfiguration and reliability algorithms is provided.

Chapter 7 presents the solution of several example problems and the results are used to illustrate the concepts involved in this research.

Finally, Chapter 8 states the research conclusions and future recommendations.

CHAPTER 2

Literature Review

2.1 Economics of Distribution Systems

The design and operation of distribution systems are of vital importance to the overall performance of a power system. Recognizing the concern for service reliability and the increasingly high cost of electric distribution, some attempts have been made to develop a unique criterion for quantitatively comparing the performance of distribution systems and evaluating alternative designs in terms of reliability and cost. However, these attempts have focused mainly on specific distribution automation functions based on one or two reliability indices.

Horton, et. al [4] presented a computer based method for predicting the cost/benefit ratios associated with distribution feeder reliability improvement projects. The cost/benefit analysis was applied to the study of an upgrade of a Pacific Gas and Electric Company feeder.

Chang [5] examined the effects of manual and automatic sectionalizing schemes on system reliability indices. A cost reliability index was defined as the inverse of the product of system cost per customer and system average interruption duration index. A cost effectiveness ratio was defined as the ratio of change in cost per customer to change in average interruption duration index.

Lee and Brooks [6] described a method developed and applied by Advanced Systems Technology, a division of Westinghouse Electric Corporation, for the Pennsylvania Power & Light Company (PP&L). The method examined the effects of continuous system reconfiguration of switches and capacitors with Automated Distribution Control (ADC) on a portion of the PP&L service territory. The results showed that the application of ADC techniques provided potential distribution system loss reductions which could not otherwise be achieved.

A bibliography of 161 articles on distribution automation was compiled by a task group of the IEEE transmission and distribution committee [7]. The articles cover the period from 1969 through 1982 and represent publications in North America. Much of the work prior to 1969 concentrated on automatic meter reading schemes.

A report published by the Electric Power Research Institute (EPRI) described a methodology for the economic feasibility of automating electric utility distribution systems [8]. Approximately 40 distribution automation functions for the distribution substation, feeder primary, and secondary levels were included.

The EPRI approach is based on first analyzing the distribution system over a period of future years assuming growth of the distribution system is satisfied without automation. Next, implementation of selected distribution automation functions is assumed by the utility. The present value and annual revenue requirements of the alternative expansion plans are then determined. Selection of the most beneficial functions for a specific electric utility will depend on the distribution system characteristics for that utility.

The EPRI report concluded that a large number of equipments, system characteristics, and economic parameters are involved in using the methodology. Therefore, digital computer programs are desirable to facilitate the evaluation process and to guide the user in an orderly fashion [8].

New techniques are being investigated as a result of distribution automation capabilities. Therefore, distribution automation pilot projects are becoming more prominent in the electric utility industry. The economic evaluation of such projects plays a major part in the decisions made by utilities.

The most comprehensive distribution automation project was the Athens Automation and Control Experiment (AACE), which involved research and development of both hardware and software [9]. Equipment for the project was installed on the electric distribution system of the Athens Utilities Board in Athens, Tennessee. The purpose of the AACE was to develop and test various load control options, voltage and reactive power control options, and distribution system reconfiguration capabilities on an electric distribution system from the transmission substation to individual residential appliances.

More recently, EPRI is sponsoring an ambitious test of distribution automation with Carolina Power & Light as host Utility [10]. The test aims at demonstrating a system providing several automation functions, operating on a scale large enough to provide meaningful projection to utility-wide operation.

A recently published paper described experiences of pilot distribution automation projects at Kansas City Power & Light Co. and Midwest Energy Inc. [11]. Eight functions were identified as potentially beneficial to these Kansas utilities and were selected for evaluation. The main objective of the research was to test the effectiveness and reliability of commercially available distribution automation equipment. The authors concluded that some of the equipment did not function as well as expected. On the other hand, the authors predicted that improved reliability and reduction in the cost of equipment will make them more economically attractive in the future.

Several other utilities across the U.S. have undertaken experimental studies in distribution automation. Information on many of these studies is available in an EPRI report [12]. Through these projects, a wealth of information has been gathered which can be used by utilities planning to automate their distribution systems. However, the most difficult task for a utility contemplating distribution automation is to identify the functions to be automated [2]. The needs of every utility are different and depend on geographic location, type of customers, and financial situation.

As with any other utility projects, distribution automation is unacceptable if the costs are greater than the sum of the benefits. Therefore, distribution automation projects must survive economic evaluation to justify implementation.

2.2 Electric Utility Economics

2.2.1 Classical Economic Analysis

The utility industry is frequently faced with the need to make informed decisions regarding alternatives involving money. These alternatives may involve the implementation of a distribution automation function or the replacement of old equipment. The problem is made more complex because expenditures associated with a given project may occur at different times in the life of the project. Since money has a time varying value, these amounts cannot be directly compared. Moreover, competing projects may have different life spans.

Several analysis techniques have evolved over the years to address these needs and each has found application. It must be recognized that each industry may possess unique concerns and constraints. These, in turn, shape the nature of the economic analysis technique which is appropriate for that particular industry. Thus, one industry may focus primarily on return on investment, while others may be concerned with the cost/benefit ratio or payback period. The utility industry focuses heavily on a technique referred to as the revenue requirement method [13].

Almost all economic analysis techniques have either evolved from or utilized aspects of present worth analysis. As mentioned above, money has a time value and hence a monetary amount today cannot be directly compared to a similar amount at some other point in time. This is due to the fact that both inflation and the cost of money will determine the value of an amount at given points in time.

In present worth analysis, techniques are developed to reflect monetary amounts occurring at different points in time to some common point in time. This time is frequently the present. By bringing these amounts to a common point in time, they may be summed to determine the present worth of the total investment. In this way, competing alternatives may be placed on equal footing and the appropriate economic choices can be made.

A key concept in present worth analysis is the cost of money. This cost could represent the cost of borrowing funds from banks or other lending institutions. It could also represent the cost associated with the sale of stocks and bonds. In either case, present worth analysis recognizes that monetary amounts occurring at different points in time would have different present worths due to the time value of money. It is recognized that these amounts may occur as single amounts occurring at various times or as a periodic series of amounts. The present worth factor and annuity factor allow straightforward movement of these dollar amounts through time.

The present worth factor allows the movement of a single sum of money occurring at one point in time to another point in time. Similarly, the annuity factor may be used to determine the present worth of a series of costs which are equal and periodic in nature.

Many utilities use the revenue requirement method for choosing the most economic alternative. This method reduces all costs associated with each alternative to the revenue required from the utility's customers to support that alternative [13].

The costs associated with a plan are expressed as capital expense and operating expense. The capital expense is the cost associated with the original placement of the plant item including its purchase price and installation cost. The operating expense is associated with the on-going operation of the plant item such as personnel costs.

The carrying charge factor is used to reduce capital expenses to a yearly amount. The yearly costs associated with capital expense is referred to as a carrying charge. The carrying charge factor is multiplied by the capital expense to reduce the capital expense to an annuity over the lifetime of the project. Thus, the revenue requirement for each year is the sum of carrying charges and operating expenses for that given year. The revenue requirement method is discussed in more details in Section 2.3.

2.2.2 Utility Industry Economics

The utility industry is unique in the American industry for several reasons including the following [13].

a. It is capital intensive. Over half the revenue is frequently spent on capital items such as generation plants or transmission lines.

b. The plant items usually have long lives, which are in the 15 to 30 year range.

c. The utility has relatively uniform annual revenues.

d. The utility exists to supply energy to a specified service area. The area is established by regulatory agencies and is not generally determined by the utility itself.

e. The utility is heavily regulated and is literally mandated to provide reliable, low cost service to its customers.

f. Many utilities are investor owned by means of common or preferred stock. Therefore, in addition to the above considerations, the utility must maintain an adequate rate of return to attract investment funds.

g. The utility exists in an atmosphere of public concern for the depletion of natural resources and the impact of its generation by-products on the environment. This atmosphere is unpredictable, and changes in federal regulations can severely impact the utility during the life of a project. The most obvious example has been the changing nuclear plant regulations even as funded and approved plants were being constructed.

From the above discussion it can be seen that utility industry economics revolve around the revenue it receives from its customers. These customers pay for all expenses associated with the production and distribution of electrical power through the utility rate structure. The expenses include capital costs for plant items as well as operation and maintenance costs. The rate structure is determined by regulatory agencies. Therefore, it would be natural for utilities to view economic analysis with utmost attention to the impact that such decisions have on the revenue required from customers [13].

2.2.3 Utility Industry Environment

The current economic, social, and political climate in which the electric power industry operates has changed considerably in the last 30 years. Prior to the end of the 1950's, planning for the construction of plant facilities was basically straightforward because it could be assumed that the load would at least double every 10 years [14]. Therefore, past trends provided a relatively simple guide for the future. During the 1960's, generation unit sizes increased and high voltage transmission and interconnections between utilities expanded rapidly to take advantage of the economics of scale.

The utility industry economic environment was relatively stable prior to the 1970's. Both inflation and interest rates were predictable, and consequently costs did not change rapidly. Therefore, the uncertainties associated with most aspects of utility finance were minimal, and economic studies could be performed with some degree of certainty [13].

The oil embargo of the early 1970's disrupted the economic stability of the utility industry. The industry was faced with escalating fuel costs in addition to the possibility of supply interruptions. Furthermore, the United States was experiencing rapid increases in interest rates. These factors represented a reversal of long-standing trends.

Public concern for depleting the earth's limited resources along with concern for the environmental impact added to the challenges confronting the utility industry. In addition, the cost of nuclear power was escalating due to new Federal regulations, which made it evident that nuclear power was not going to be a universal supply for our energy needs.

Looking into the future, the issues facing utilities will be driven by the fundamental need for additional generating capacity, new transmission systems, and more efficient use of existing resources [15]. The retirement of older units coupled with load growth that has been higher than expected in some cases indicates that substantial construction will be required. Proposed stricter environmental legislation will probably accelerate the retirement of older plants.

As a result, there are now many uncertainties associated with utility economic decisions. It is no longer valid to assume that the input parameters of economic studies are known with certainty. Utilities need to understand the potential effects of variations in these parameters on the final outcome of economic studies.

2.3 The Revenue Requirement Method

2.3.1 Components of Revenue Requirement

The revenue requirement method seeks to identify all costs related to a particular decision involving money and to reflect these costs into the revenue that must be collected from customers to support that decision. These costs may be divided into two broad categories of expenses and carrying charges. The yearly revenue requirement to support a certain decision is then the sum of the expenses and carrying charges for that particular year [13].

1. Expenses are all costs associated with the normal operation and maintenance of the equipment after it is placed in service. Expenses consist of salaries for personnel, fuel

costs, plant maintenance, and repair costs, etc. These costs are typically associated with items or services used within a period of one year. It is common practice to view expenses as costs to be recovered directly from revenues.

2. Carrying charges are related to the costs associated with the initial placement of the plant. As such, these costs are not normally paid directly from operating revenue. The reason is that the cost impact on the customer would be enormous and present customers would be paying for plant items which would be used by customers many years in the future. It is common practice to purchase such items through some form of debt or equity financing and pass the yearly costs of this financing on to the customer in the form of a carrying charge.

The carrying charge actually consists of at least six components, and many utilities add other factors as well [13]. The primary components of the carrying charge are as follows.

a. Book depreciation (BD), which repays the original amount obtained from investors.

b. Return on Equity (RE), which repays investors for the use of their money in the form of preferred and common stock.

c. Return on Debt (RD), which repays lenders for the use of their money in the form of mortgages and debentures.

d. Taxes (TX), which represents Federal and state taxes on taxable income.

e. Property Taxes and Insurance (PTI), which represent the state property taxes and insurance premiums.

f. Deferred Taxes (DT), which are taxes deferred from previous years.

The total carrying charge is then the sum of these factors, which is given by the following equation:

$$CC = BD + RE + RD + TX + PTI + DT. \tag{2.1}$$

Therefore, the resulting Revenue Requirement (RR) is

$$RR = CC + \text{Expenses.} \tag{2.2}$$

A brief description of the components of carrying charge is given in the following section.

2.3.2 Aspects of Utility Finance

Utility funding is secured in much the same way as in other industries. It is derived form either debt financing or equity financing [13].

Debt financing is secured by either mortgaging a portion of the utilities' physical assets, or by use of an IOU without using physical assets as collateral, referred to as debentures. Debt financing carries an obligation to pay the investor a stated fixed return for the use of his money.

Equity financing comes from the selling of ownership in the utility by means of preferred or common stock. Unlike the case of debt financing there is no fixed rate of return on common stock. The actual rate of return depends in some measure on the financial success of the utility.

It is common practice to speak in terms of weighted cost of capital when referring to the aggregate cost of debt and equity financing. The weighted cost of capital is simply the sum of the capitalization ratio of debt, preferred stock, and common stock multiplied by their respective costs. Utilities commonly try to limit the ratio of debt financing to equity financing. This ratio varies from utility to utility, but it is frequently in the 50 percent range.

It is increasingly important to consider the effects of escalation and inflation on the outcome of economic studies. Escalation may be viewed as the annual rate of increase of an expenditure due to either resource depletion or increased demand. Inflation may be viewed as the annual rate of increase due to an increase in available currency and credit without a proportionate increase in available goods and services of equal quality. It is important to realize that escalation is independent and exclusive of inflation [13].

With the introduction of escalation and inflation it is appropriate to discuss the concept of levelization. Several of the revenue requirement analysis techniques present their final data in the form of an array of numbers. These numbers can sometimes be difficult to follow, especially due to the fact that the data may be subject to some uniform escalation. It is therefore frequently desirable to reduce such an array to a single levelized annual amount in order to facilitate comparison.

Depreciation may be defined in several ways including the following [13].

a. The decline in market value of an asset.

b. The decline in the value of an asset to its owner.

c. The systematic allocation of the cost of an asset divided by its book life.

The last definition is the one normally used by accountants and as such is the way the utility industry normally views depreciation. Tax laws permit depreciation in order to allow for the gradual wearing out of plant items. It is worth noting that all items depreciate except land, which is assumed to maintain its purchase value. The tax codes allow depreciation for personal property. Since a utility corporation is viewed as a "person," it is allowed deductions for depreciation.

Tax codes have historically evolved through several modifications culminating in the Tax Reform Act of 1986. This tax code recognizes several types of items to be depreciated. It groups these types into several classes, each of which is assumed to possess the same tax depreciation life, and are referred to as tax depreciation classes. The utility industry recognizes the 5, 7, 15, and 20 year classes because most of its equipment falls into these groups [13].

2.3.3 Types of Revenue Requirement Analysis

There are several forms of revenue requirement analysis in common use. Each type exists and has application because it responds to a particular need. Each type will now be discussed as follows [13].

1. Book Life Analysis: This type of analysis focuses on the entire book life of the project. Essentially, the yearly costs associated with the project, including carrying charges and expenses, are reduced to present worth value. The sum of these present values gives the total present value of the project throughout its projected life. It is also common practice to reduce the final answer to a levelized form using the appropriate levelization factor. This levelized number can then be readily compared with a similar number derived for a competing alternative. The alternative with the lowest present value or levelized cost would be the proper economic choice.

In this method it is not possible to get meaningful information regarding the actual costs associated with the selected alternative. It is important to realize this since the selected alternative might require annual costs which are beyond the means of the utility. In many cases it is important to have a better understanding of the actual cash flow requirements. The Year-by-Year analysis method provides this insight.

2. Year-by-Year Analysis: In this form of analysis the actual yearly cash requirements are generated. The requirements for any given year would be the sum of the carrying charges for that particular year plus the necessary expenses. This form of analysis provides the necessary information for the utilities' financial planners to assess the potential cost impact of an alternative on the financial condition of the utility. However, it presents data in the form of a large array of numbers which may be difficult to grasp.

3. Continuing Plant Analysis: In many cases the alternatives under consideration have different book lifes which adds complexity to the analysis. Continuing plant analysis provides a useful way to deal with this problem. The costs associated with the alternatives under consideration are projected to perpetuity. When the plant item reaches its book life it is assumed to be replaced with identical equipment at escalated cost. Expenses are likewise projected to perpetuity. The result is the cost of maintaining the investment indefinitely. This eliminates the need to account for the differences in book lives because the lives of all alternatives are carried to infinity.

4. Short Term Analysis: This form of analysis is carried out in exactly the same manner as the book life analysis with the exception of the study period. Here the attention is focused on the short term impact on the utility. This period is frequently the first twenty-five to thirty percent of the book life of the project. Due to the changing regulatory climate, projects which show economic advantage only after this initial period may be unacceptable.

5. Break Even Analysis: In this form of analysis the year is determined in which the cumulative present worth of the total costs are equal for the alternatives under consideration. This is usually an iterative process. The break even point is quite important for several reasons. Utilities are becoming less inclined to spend substantial amounts on projects which promise benefits many years in the future. Break even analysis determines when the alternatives have exactly the same cumulative present worth and hence the point at which one alternative shows an advantage over the other.

In conclusion, it may be seen that each form of revenue requirement analysis has its appropriate application. As a matter of fact, many problems require the application of more than one of these techniques in order to gain as much insight as possible into the consequences of a particular decision. Furthermore, it is apparent that each form of revenue requirement analysis depends on essentially the same mathematical techniques and, all of these in turn depend heavily on present worth analysis.

From the above discussion it is clear that the results of any economic analysis will depend largely on the accuracy of the data used in the computations. It is therefore apparent that variations in any of several economic parameters might significantly alter the results of a study. In fact it is not inconceivable that the wrong course of action could be selected [13].

2.4 Electric Outage Costs

One factor which is not normally considered in revenue requirement studies is the value of service. Value of service represents the cost to the customer of loosing electric power. Quantifying value of service is not an easy task due to its qualitative nature.

The cost of interruption to customers cannot be easily estimated because of the intangibles involved that are not always amenable to direct costing. These intangibles vary from one area to another and from one customer type to another. They also depend on the time of interruption, the customer's product and its dependence on electric supply [16].

Electric supply to customers involves three stages: generation, transmission and distribution. All these stages contribute to customer interruptions, but their share in supply interruptions are different from one country to another and from one customer type to another. In developed countries, the biggest share of faults that cause interruptions occur in the distribution network. It has been stated that distribution system facilities contribute approximately 80 percent of the outages seen by the average customer in the United States [17].

Few countries have estimated the cost of electric outage to the individual customer, to classes of consumers or to the national economy. Sweden was a pioneer in this field. Its report, published in 1969, was the most comprehensive of its type. The Swedish approach involved comprehensive questioning of consumers, particularly industrial consumers, in order to obtain their own evaluation of the cost of interruption. Their method of estimating costs is to have ranges for the time of each interruption with each range having its respective cost, thus recognizing the importance of interruption duration and frequency on the total cost [16].

More recently, there have been some attempts to predict costs of outages related to distribution systems in Norway and Finland. Kjolle et. al [18] described a planning procedure to handle reliability not only as an important design parameter but as an integrated part of the cost minimization problem. The reliability is described as an operating cost by evaluating cost of non-delivered power. The reported case studies show that the economic assessment of reliability is of great importance in distribution system automation and design.

Makinen et. al [19] described a computer-aided method for the reliability analysis of a distribution system. Using the reliability calculation program, the magnitude of the customer cost of interruptions can be evaluated quantitatively. The optimum reliability level can be reached by minimizing the total costs, including cost of investment, losses and outages.

Billinton et al [20] provided a comprehensive list of 93 publications relating to the customer cost of electric service interruption. In addition, Billinton and Wacker [21] grouped the methods utilized to evaluate electric outage costs into three broad categories. These categories are indirect analytical evaluations, case studies of blackouts, and customer surveys.

Indirect analytical methods infer interruption cost values from associated indices or variables. The advantages of these methods are that they are reasonably easy to apply, make use of readily available data, and are therefore inexpensive to implement. Their disadvantages are that most are based on numerous and severely limiting assumptions.

The second category of outage cost assessment is to conduct an after-the-fact case study of a particular outage. This approach has been limited to major blackouts such as the study of the 1977 New York blackout [22]. The study attempted to assess both direct and indirect short-term costs. Direct costs included food spoilage, wage loss, loss of sales, loss of taxes, etc. Indirect costs included emergency costs, losses due to civil disorder, and losses of governments and insurance companies from social disorder. The study also considered a wide range of societal and organizational impacts. Such impacts are significant but difficult to evaluate in monetary terms. While specific data were based on assumptions and were incomplete in many aspects, some important conclusions resulted. In particular, the results indicated that indirect costs were much higher than direct costs.

The third approach to assess customer interruption costs is customer surveys. This method is based on asking customers to estimate their costs or losses due to electric outages of varying duration and frequency, and at different times of the day and year. The advantage of this method lies in the fact that the customer is probably in the best position to assess the losses.

Direct costs are relatively easy to determine for industrial customers. However, residential customers' opinions are particularly important in assessing less tangible losses such as inconvenience. Obviously, this method is subject to all the problems of questionnaire surveys. In addition, the cost and effort of undertaking surveys is significantly higher than using the other approaches outlined earlier.

While no single approach has been universally adopted, utilities seem to favor customer surveys. Skof [3] reported a study based on 172 responses by large industrial customers with individual peak demands of 5 MW or greater. The purpose of the study was to examine the customers' estimate of the cost and other effects of service interruptions. The study showed a big variation in the cost to the user due to interruptions of electric service. These types of studies generally show that value of service costs vary over a wide range, although trends are similar in virtually all cases. Furthermore, costs depend on the country of origin and type of consumer [23]. An approach is developed in Chapter 5 to place a dollar amount on value of service by customer type when such information is unavailable.

2.5 Interval Analysis

Interval analysis is a relatively new field which has developed during the past three decades. Interest in interval analysis nowadays is based on the fact that numerical computations are carried out using parameters which may contain significant levels of uncertainty. The uncertainty can be treated as an interval whose bounds contain the expected range of values.

One of the earliest and most prominent workers in this field is Ramon Moore. Moore's book "Interval Analysis" was published in 1966 and provided the basis for much of the work that followed [24]. Assem Deif published "Sensitivity Analysis in Linear Systems" in 1986 which provided a survey of sensitivity analysis techniques including interval analysis [25]. Matthews extended interval analysis techniques to the revenue requirement method of utility economic analysis [26]. This was the first application of interval analysis to the sensitivity concerns of utility economic analysis.

Wang and Alvarado used interval arithmetic to solve the power flow problem, which is fundamental to the study of power systems [27]. It was found that if input data vary within relatively small ranges, good results that contain all possible solutions are obtained. Therefore, the authors concluded that interval methods can deal with uncertain input data in power flow problems. Clearly, interval analysis has many useful applications in various fields.

One of the biggest disadvantages of interval analysis is the overly large bounds that may result from interval computations. In Matthews' work, the accuracy of bounds predicted by interval computations was investigated by means of an exhaustive search algorithm. His investigation revealed that bounds predicted by several computations were almost exact while others produced larger than desirable bounds [13].

It was also found that implementing interval mathematics required careful evaluation of the numerical steps involved. This is due to the fact that the mathematical behavior of each computational step can expose the potential for larger than desired bounds. Therefore, Matthews concluded that there was a need for developing bound conserving algorithms. The present work includes a method to derive sharp interval bounds in economic calculations [28].

CHAPTER 3

Interval Mathematics And Sensitivity Analysis

3.1 Introduction

A great deal of engineering effort is often devoted to testing systems' sensitivities to changes in design parameters. As a rule, sensitive elements are those which should be designed with utmost care. On the other hand, the mathematical model used in the design process is usually idealized and often inaccurately formulated. Therefore, some unforeseen changes may cause the system to behave in a different manner. Sensitivity analysis can help the engineer innovate ways to minimize such system discrepancies since the analysis takes into consideration assumptions concerning discrepancies between the ideal and the actual system [25].

Methods of mathematical optimization rely in one way or another on relative sensitivities. Even the simple task of fitting data to a curve usually involves sensitivity calculations. As for social scientists, economists, and others, sensitivity and perturbation techniques can provide valuable information about the amount of inaccuracy in the behavior of a model regarding the inaccuracies in the system's data.

If the data gathered by field study or experimental testing falls within certain tolerance limits, the tolerances may well be amplified and widened in the results obtained. The question may then arise as to how uncertain the results are due to the uncertainties of the data [25].

Sensitivity analysis is usually carried out by determining which parameters have significant effects on the results of a study. An attempt is then made to increase the precision of these parameters in order to reduce the danger of serious error. Furthermore, sensitivity analysis techniques have generally relied on either a-priori or a-posteriori techniques. A-priori techniques attempt to predict the sensitivity of the solution based on analytical methods applied to the input data. A-posteriori techniques seek to achieve the same goal based on analysis of the final results of the computations [25].

Traditionally, all parameters are set to nominal values and each parameter is varied independently to determine its effect on the outcome. Those parameters which have significant effect are viewed as sensitive. In most cases sensitivity analysis does not deal with the possibility that several parameters varying simultaneously can cause significant variations in the output. Simultaneous variations of parameters more accurately models the real world situation [13].

During the 1960's a new approach, known as interval analysis, emerged as an alternative way of dealing with uncertainty in data [24]. The uncertainties associated with utility economic analysis could be more effectively understood if the input parameters were treated as interval numbers whose ranges contain the uncertainties in those parameters. The resulting computations, carried out entirely in interval form, would then literally carry the uncertainties associated with the data through the analysis. Likewise, the final outcome in interval form would contain all possible solutions due to the variations in input parameters.

Thus it is possible to perform sensitivity analysis by assigning interval bounds to any or all of the input parameters and observing the effects on the final interval outcome.

3.2 Interval Mathematics

Interval mathematics provides a useful tool in determining the effects of uncertainty in parameters used in a computation. In this form of mathematics, interval numbers are used instead of ordinary single point numbers. An interval number is defined as an ordered pair of real numbers representing the lower and upper bounds of the parameter range [24]. For instance, assume that the cost of a particular piece of equipment will be in the range of 600 to 800 dollars. The corresponding interval number would then be as follows: cost = [600 , 800]. An interval number can then be formally defined as follows: [a, b], where $a \leq b$.

In the special case where the upper and lower bounds of an interval number are equal, the interval is referred to as a point or degenerate interval. In this case, interval mathematics is reduced to ordinary single point arithmetic.

Given two interval numbers, [a, b] and [c, d], the rules for interval addition, subtraction, multiplication, and division are as follows:

$$[a, b] + [c, d] = [a+c, b+d],$$

$$[a, b] - [c, d] = [a-d, b-c],$$

$$[a, b] * [c, d] = [\min(ac,ad,bc,bd), \max(ac,ad,bc,bd)],$$

$$[a, b] / [c, d] = [a, b] * [1/d, 1/c], \text{ where } 0 \notin [c, d].$$

A brief review of some basic interval relationships and interval arithmetic is given below.

Two intervals are considered equal if and only if their corresponding end points are equal. Therefore, given two interval numbers X = [a, b] and Y = [c, d], X = Y if and only if a = c and b = d.

The intersection of two intervals X = [a,b] and Y = [c, d] is empty if either a > d or c > b. If the intersection is not empty, then the result is an interval given by

$$X \cap Y = [a, b] \cap [c, d] = [\max\{a, c\}, \min\{b, d\}]. \quad (3.1)$$

If the intersection of the above two intervals is not empty, then the union of X and Y is an interval given by

$$X \cup Y = [a, b] \cup [c, d] = [\min\{a, c\}, \max\{b, d\}]. \tag{3.2}$$

Another useful relation for intervals is set inclusion. This can be stated as [a, b] [c,d] if and only if $c \leq a$ and $b \leq d$.

The midpoint of an interval X = [a, b] is defined as

$$m(X) = m([a, b]) = (a + b)/2 \tag{3.3}$$

Similarly, the width of an interval is given by

$$w(X) = w([a, b]) = (b - a) \tag{3.4}$$

The negative of an interval Y = [c, d] is defined as

$$-Y = -[c, d] = [-d, -c] \tag{3.5}$$

The reciprocal of an interval X = [a, b] is given by

$$1/X = 1/[a, b] = [1/b, 1/a] \tag{3.6}$$

if X does not contain zero. If X contains zero then the set is unbounded and cannot be represented as an interval whose end points are real numbers.

Based on these mathematical properties, powers of intervals may be given by

$$X^y = [a^y, b^y] \text{ if } a > 0 \text{ or if } y \text{ is odd,}$$
$$= [b^y, a^y] \text{ if } b < 0 \text{ and } y \text{ is even,}$$

$$= [0\ ,\ |X|^{y}] \text{ if } 0 \quad X \text{ and y is even, where } |X| = \max\{|a|, |b|\}. \tag{3.7}$$

Given the interval numbers X, Y, and Z, the following properties hold

$$X + (Y + Z) = (X + Y) + Z \tag{3.8}$$

$$X * (Y * Z) = (X * Y) * Z \tag{3.9}$$

$$X + Y = Y + X \tag{3.10}$$

$$X * Y = Y * X \tag{3.11}$$

It can be seen that interval addition and multiplication are both associative and commutative. Unfortunately, the distributive law does not always hold. In other words,

$$X * (Y + Z) = X * Y + X * Z \tag{3.12}$$

is not always true. However, it is always true that

$$X * (Y + Z) \subseteq X * Y + X * Z. \tag{3.13}$$

This useful property is referred to as subdistributivity. However, there are special cases in which subdistributivity holds. For example,

$$x * (Y + Z) = x * Y + x * Z \tag{3.14}$$

where x is a real number and Y and Z are interval numbers. In addition, if $Y * Z >$ zero, then

$$X * (Y + Z) = X * Y + X * Z \tag{3.15}$$

It is also worth noting that

$$X - X = 0, \text{ and } X/X = 1$$

only when X is a degenerate interval. Otherwise,

$$\begin{aligned} X - X &= [a, b] - [a, b] \\ &= [a, b] + [-b, -a] \\ &= [a-b, b-a] \end{aligned} \tag{3.16}$$

and

$$\begin{aligned} &X/X = [a/b, b/a] \text{ if } a > 0, \text{ or} \\ &X/X = [b/a, a/b] \text{ if } b < 0. \end{aligned} \tag{3.17}$$

The cancellation law holds for interval addition. In this case, the following implies that $X = Y$

$$X + Z = Y + Z. \tag{3.18}$$

The metric distance between a pair of intervals is defined by the following nonnegative function [24]:

$$d([a,b], [c,d]) = \max(|a-c|, |b-d|). \tag{3.19}$$

It is easy to see that

$$d(I, J) = d(J, I)$$

for any pair of intervals I, J. It is also easy to see that

$$d(I, J) = 0$$

if and only if I = J.

It is interesting to note that

$$d([x,x], [y,y]) = |x-y|$$

and therefore the metric distance reduces to ordinary distance between two real numbers for degenerate intervals. This is consistent with the identification of a degenerate interval [x,x] with the real number x.

The following example is used to illustrate the above concepts. Assume that $1000 is invested for one year at an interest rate varying between 8% and 10%, which is represented by the interval [0.08 , 0.1]. The resulting interval will be [1080 , 1100], which means that the minimum future worth of the $1000 investment would be $1080, while the maximum amount would be $1100.

Implementing interval analysis techniques confronts some obstacles because its algebraic structure is unlike that of common single point arithmetic. Accordingly, interval computations may produce extremely conservative bounds [26].

3.3 Interval Bounds

Some interval computations produce narrow bounds while others result in overly wide bounds. Normally, the approach to producing better bounds has been to rearrange the expression so that each interval parameter appears only once [24]. For example, assume that A is an interval variable in the following equation

$$Y = A/(A-2), \tag{3.20}$$

where Y is the interval output. The equation can be rearranged so that it has fewer occurrences of the variable A

$$Y = 1 + 2/(A-2). \tag{3.21}$$

Equation (3.21) yields a narrower interval result since it has only one occurrence of the variable A as opposed to two occurrences in Equation (3.20). The reason for this is that when the substitution of the numerical interval is made for the variable A, the identity of the variable in its two occurrences in Equation (3.20) is lost. From the viewpoint of interval calculations alone, the interval computation in Equation (3.20) is equivalent to finding the range of values of a function of two independent variables. That is, Equation (3.20) can be rewritten as

$$Y = A1/(A2-2) = [a1,b1]/([a2,b2]-[2,2]). \tag{3.22}$$

In evaluating Equation (3.22), the interval A1 can be at its maximum value while A2 is at its minimum value.

The following example will be used to illustrate the above observation. The present worth of an annual expense of \$1000 over 2 years will be found using two different approaches to the calculation. A Minimum Acceptable Return (MAR) in the range of eleven to twelve percent, which is represented by the interval [0.11 , 0.12], will be assumed. The present worth annuity factor [38] is as follows

$$P/A(i,n) = [1 - (1/(1+i)^{n})]/i, \tag{3.23}$$

where i = MAR = [0.11, 0.12],

n = number of years = [2, 2].

The present worth is given by

$$\begin{aligned} \text{Present worth} &= 1000 * P/A(i,n) \\ &= [1000 , 1000] * [1.57 , 1.844] \\ &= [1570 , 1844]. \end{aligned} \tag{3.24}$$

Exact bounds can be obtained by rearranging the manner in which the calculations are performed [28]. This can be achieved by carrying out the calculations one year at a time. This is performed by setting n to 1 in Equation (3.23) to obtain

$$P/A = 1/(1+i) \tag{3.25}$$

and then repeatedly applying Equation (3.25) year-by-year. Here the calculations are rearranged such that the interval parameter appears only once per calculation. Thus, the analysis is performed one year at a time such that i appears only once in each operation as given by

Step 1 (year 2 to year 1) :

[1000,1000] * 1/(1+i) = [893, 901]

Step 2 (year 1 to present) :

([893,901] + [1000,1000]) * 1/(1+i) = [1690,1713].

The result is [1690, 1713], which has a width of 23 as compared to the width of 274 obtained using Equation (3.24). It is clear that the resulting interval bounds are drastically improved by using year-by-year calculations. This concept can be used to carry out any economic calculation to get exact bounds on the resulting interval.

3.4 Statistical Aspects Of Interval Analysis

Formal statistical reasoning is based on the laws of probability [39]. Implicit in the treatment of statistical inference problems is the assumption that random samples of observations can be obtained. A random sample can be defined as consisting of statistically independent, identically distributed random variables [40].

A random variable may represent the occurrence or non occurrence of an event under a given set of conditions. However, if an event always occurs under a given set of conditions then it is called a certain or deterministic event [41].

In certain cases, a point estimate of a parameter may be obtained based on a random sample of observations from a population with known distribution function. However, the point estimate is a random variable distributed around the true value of the parameter. Therefore, an interval is needed which will actually include the true value of the parameter with reasonable confidence [40].

The generally accepted method of handling this problem is to construct what are known as confidence intervals. The computed confidence interval covers the true parameter with a specified probability such as 0.95, or in other words with 95%

confidence. However, it cannot be said that the probability is 95% that the true value falls within the computed interval; it either does or does not. What can be said is that the computed interval covers the true value in 95% of all possible samples [39].

There are problems which can be properly posed in terms of intervals and solved correctly by interval analysis. In this view, interval analysis is a branch of mathematics which has its own theory, techniques, and problems to which it is applicable [42].

Interval analysis deals with transformations of one interval into another. The central theory of numerical interval analysis is that the resulting interval contains the answer [42]. It means that if the input interval represents a parameter range, then the computed output interval contains all values resulting from the transformation of input data.

It is important to optimize interval computations as much as possible with respect to accuracy. However, there is a difference between having confidence in the accuracy of a computed result and knowing the exactness of the resulting interval bounds.

The assessment of confidence in the result of an interval computation depends mainly on the level of confidence in the input parameters. Therefore, if input parameters are known to be accurate, then there is high confidence in the results. However, if there is little confidence in input parameters, then it follows that there is a proportionally limited confidence in the result. In other words, the confidence in the computed results depends on the level of confidence in input parameters and not on the computational procedure.

As mentioned earlier, there is a distinction between having confidence in the computed result and knowing the exactness of the resulting interval bounds. The width of the resulting interval bounds may sometimes be so large that the result's usefulness is greatly diminished. Therefore, an effort has to be made to reduce the width of the resulting interval bounds.

Given a set of interval input parameters, the bounds of the resulting interval computations may depend on the calculational procedure as well as the input parameters. Therefore, the same set of input parameters may produce different interval bounds depending on the calculational procedure used. Authors like Hansen [43] have used the term 'sharp bounds' to denote the narrowest resulting bounds. Others have used the term 'exact bounds' to indicate the same meaning [26].

Based on the above discussion, it can be argued that the concept of statistical confidence intervals does not apply in the technical sense to this research. The empirical fact is that most of the input parameters used are either arbitrary or deterministic in nature. Therefore, the fundamental concepts of probability theory is not applicable in this situation. This conclusion is supported by the lack of published research in the field of statistics as it relates to interval analysis.

It should be noted that a bibliography on interval mathematics, which contains about 760 titles, was listed in Reference [44]. None of these titles addressed the subject of statistical confidence intervals in relation to interval mathematics. Review of more recent literature have also revealed the same observation.

It is important to mention that input parameters which are modeled as intervals are not described by a normal distribution. This is based on the fact that the normal distribution would emphasize the middle section of a parameter range. By contrast, the uniform distribution is more appropriate since it does not emphasize any given point [41]. In other words, the probability of any given value is the same throughout the entire interval range.

The uniform distribution is formally defined as follows [41]. A random variable x has a continuous uniform distribution on [a,b] if it has the following density function:

$$f(x) = 0 \qquad x \notin [a,b]$$
$$= 1/(b-a) \quad x \in [a,b].$$

Figure 3.1 shows a graph of the density function which indicates why this distribution is also referred to as a rectangular distribution. The mean of this distribution is easily found to be $(b+a)/\sqrt{2}$. The variance can also be found to be $(b-a)^2/12$, which means that the standard deviation is equal to $(b-a)/\sqrt{12}$.

Based on the above discussion, it is only possible to come up with what can be called probability intervals on certain results. The situation here can be described as follows. There is a set of variables $X_1, X_2, \ldots, X_k$ where one or more of them can be considered a random variable. A transformation is then applied to produce a new variable Y from the X variables. If the distribution of $X_1, X_2, \ldots, X_k$ is known, then the problem is to find the distribution of Y.

A simple example is as follows. Suppose that $k=1$, which means there is only one X variable. Let $Y = X^2$ and assume that X is described by a continuous uniform distribution. Let $x \in [2, 3]$ for instance, where x is described by a uniform distribution. Thus, $f(x) = 1$ for $x \in [2,3]$. Let $g(y)$ denote the density function of y, which leads to

$$g(y)\, dy = f(x)\, dx,$$

since the probabilities of these two events must be equal [40]. Then

$$g(y) = f(x)\, dx/dy. \tag{3.25}$$

In other words, the probability density function for y equals the probability density for x multiplied by the derivative of x with respect to y. The foregoing discussion assumed that

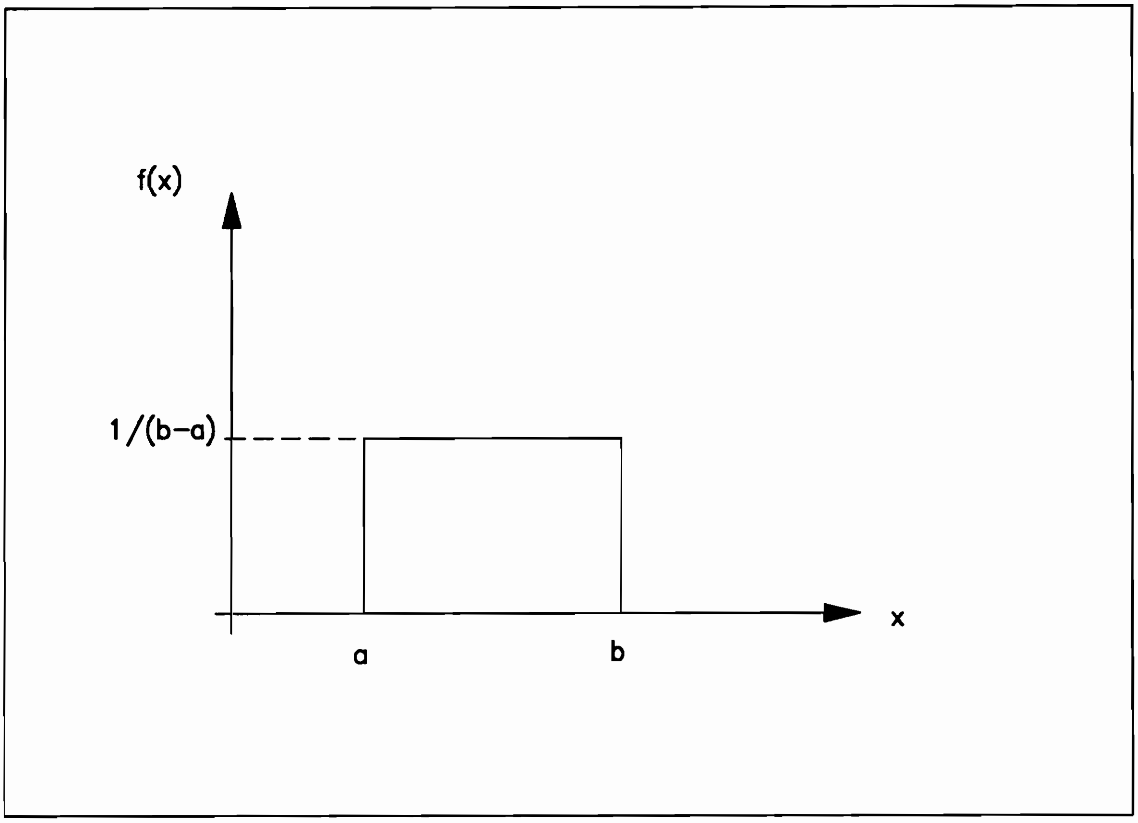

Figure 3.1. Density function of uniform distribution

y was a strictly increasing function of x everywhere. The same result is readily obtained if y is a strictly decreasing function of x everywhere [40]. The only difference is that the absolute value of dx/dy appears in place of dx/dy in Equation 3.25. But since $x = \sqrt{y}$, then

$$dx/dy = 0.5\ y^{-1/2}.$$

Finally, proper substitutions in Equation 3.25 provide

$$g(y) = f(x)\ dx/dy$$
$$= (1) * (0.5\ y^{-1/2})$$

or $$g(y) = 0.5\ y^{-1/2}\ ,\ \text{where } y \in [4,9].$$

The middle 95% of this distribution can now be found to obtain an interval that covers 95% of the range of y. The cumulative distribution function is as follows:

$$G(y) = \int_4^y g(y)\ dy = \int_4^y (0.5\ y^{-1/2})\ dy$$
$$= \sqrt{y} - 2\ ,\ y \in [4,9].$$

Figure 3.2 shows a graph of G(y) along with the 95% probability interval. Therefore, y is between 4.1006 and 8.8506 with 95% probability. Obviously, different levels of probability can be found using the same procedure with the appropriate choice of numbers.

The above concepts are explained in the context of economic analysis as follows. Suppose there are two alternative system designs to be considered. The annual total cost associated with each alternative is represented by:

$$RR = MC + ccf * CC \text{ , where} \quad (3.26)$$

RR = Revenue Requirement

MC = Maintenance Cost

ccf = carrying charge factor

CC = Capital Cost.

The carrying charge factor is determined by utilities based on equipment type. Note that all elements of Equation 3.26 are either arbitrary or deterministic in nature.

The present value of annual revenue requirements associated with each alternative is needed to compare alternatives on equal footing with respect to the time value of money. As a result, the present worth factor has to be used in the following manner [38]:

Present Value = (future amount) * P/F(i,n)

where P/F = present worth factor = $1/(1+i)^n$

i = interest rate

n = number of years.

As shown in the previous section, this type of calculation is performed one year at a time to obtain sharp interval bounds. Therefore, the above equation simplifies to using $1/(1+i)$ year by year.

Based on material discussed earlier, it is now possible to develop probability intervals for the present value of future costs. Suppose that K represents the total cost associated with a certain alternative one year from now. Then P/F = $1/(1+i)$, and the present worth of K is $K/(1+i)$. Let y be a transformation of the variable x defined as follows: $y = K/(1+x)$, where x is the interest rate. Suppose that x is between 11% and

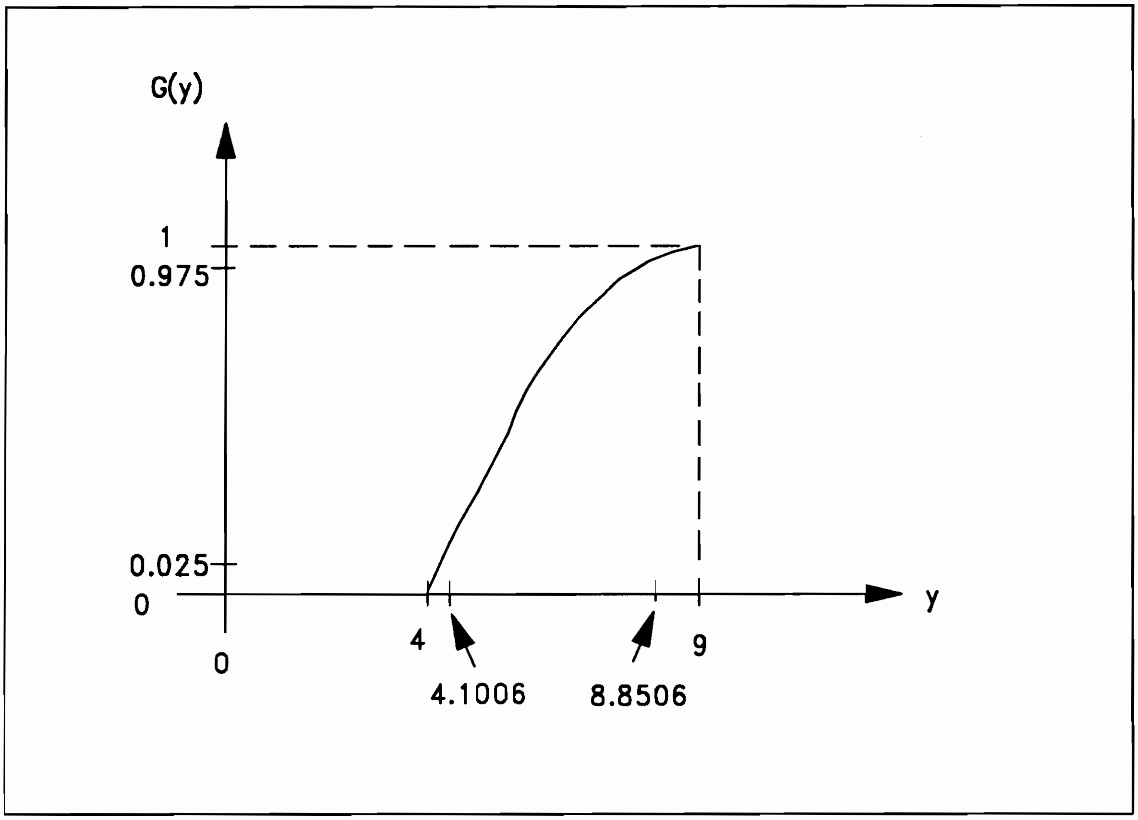

Figure 3.2. Cumulative distribution function

12% and is described by a uniform distribution. Then it follows that $x \in [0.11 , 0.12]$ and $f(x) = 1/0.01 = 100$ for that range of x.

Let g(y) denote the density function of y, then Equation 3.25 can be used as follows:

$$g(y) = f(x)\ dx/dy$$

but $y = k/(1+x) \Rightarrow x = (k - y)/y$

$$\Rightarrow dx/dy = -k/y^2.$$

Then $g(y) = f(x)\ |dx/dy|$

$= (100)(k/y^2)$, where $y \in [0.8928, 0.9009]K$.

Figure 3.3 shows a graph of g(y). The cumulative distribution function can now be found as follows:

$$G(y) = \int_{.893}^{y} g(y)\ dy = \int_{.893}^{y} 100K/y^2\ dy$$

$= (112 - 100/y) * K$, $y \in [0.8928, 0.9009]K$.

Figure 3.4 shows a graph of G(y) along with the 95% probability interval. Therefore, the present worth is between 0.893K and 0.9006K with a probability of 95%.

In conclusion, This research will concentrate on sensitivity analysis with interval mathematics. Sensitivity of the resulting interval bounds can be assessed based on the variation in one or all input parameters. This form of sensitivity analysis is not normally possible without the use of interval mathematics. Since the input parameters are not obtained through sampling, the concept of statistical confidence intervals does not apply. However, probability intervals may be obtained for the present value of a future amount.

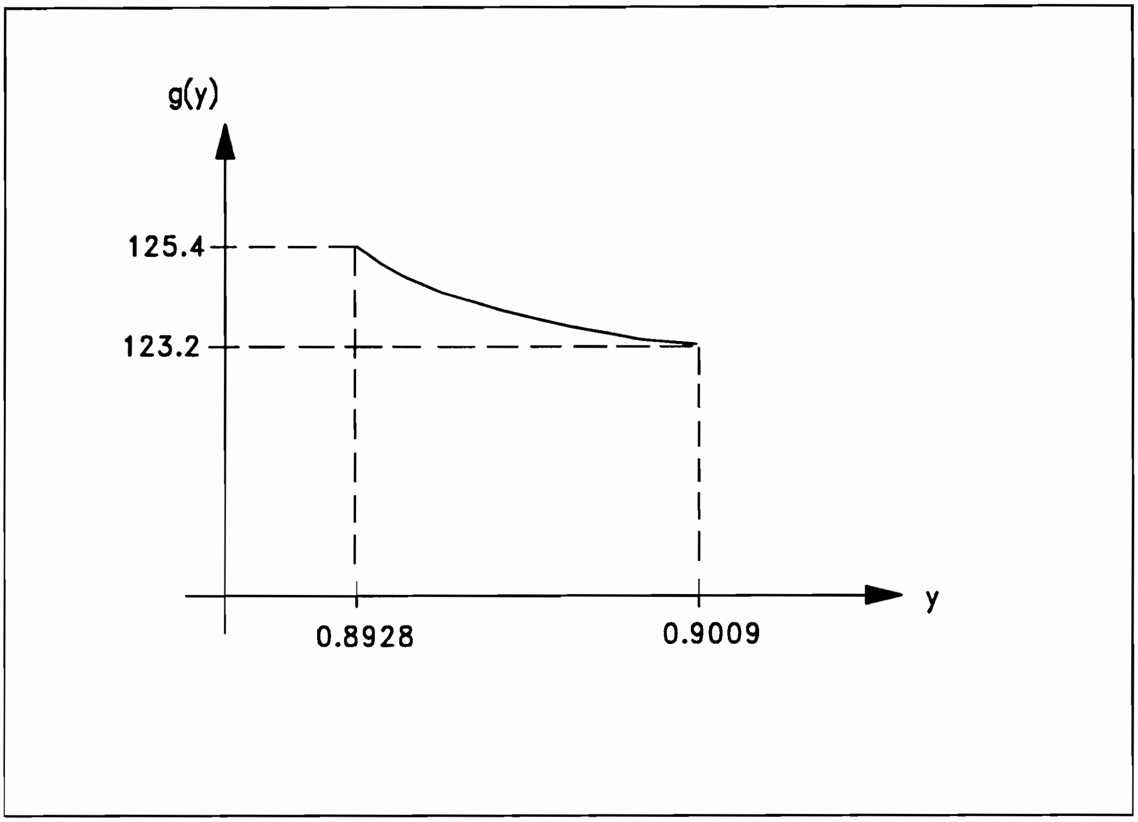

Figure 3.3. Density Function of y

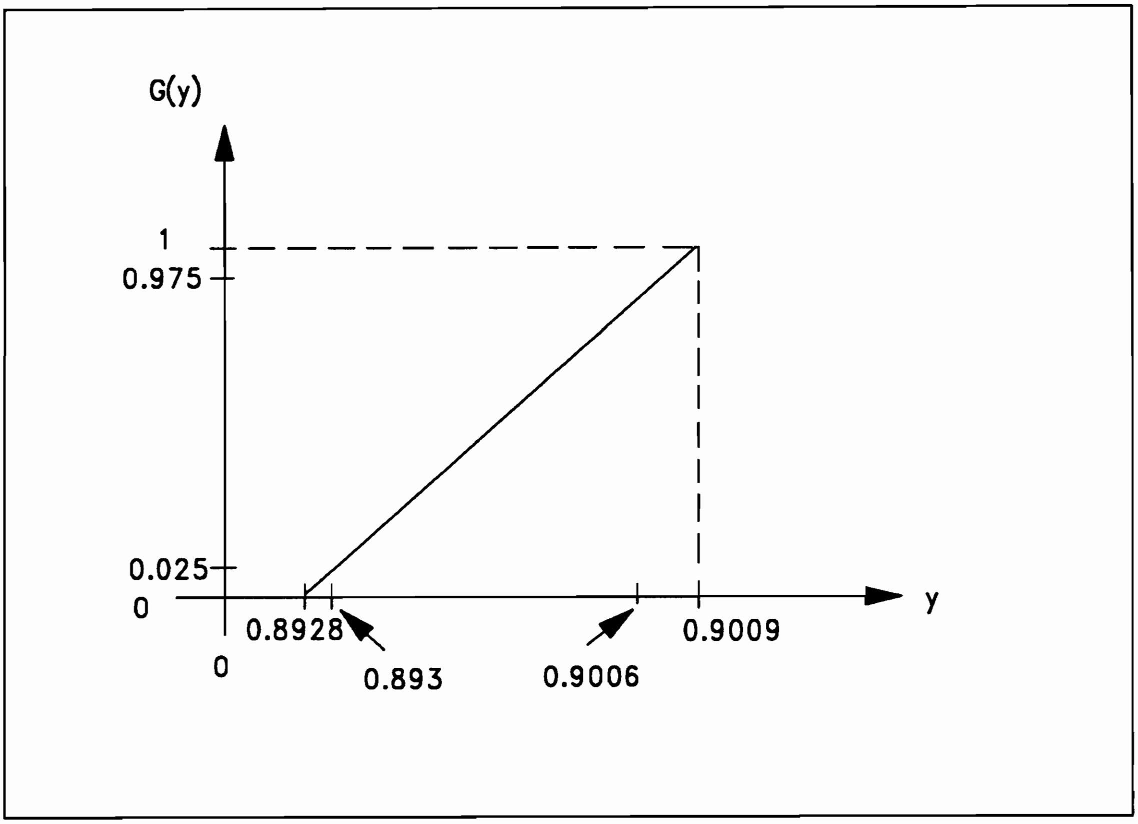

Figure 3.4. Cumulative Distribution Function

CHAPTER 4

Design Evaluation Methodology

4.1 Introduction

Sweeping changes under way in the utility industry are continually presenting new challenges to utility power system planning. Today's utility planner is responsible for planning the reliable and efficient operation of a multi-billion-dollar, high technology power system. Therefore, the utility industry is becoming more cost-conscious and cost competitive, as well as more innovative in its methods of addressing the issues [29].

Life-cycle engineering is suggested as an integration approach to build competitive products or systems in a way that minimizes their deficiencies and life-cycle costs [30]. This emerging methodology has great promise for assuring the competitiveness of new products, structures, and systems. Furthermore, the life-cycle approach is applicable to both small and large-scale products and systems.

Engineering economics has always been associated with the time value of money. The time value of money relative to an interest rate is an important aspect in decisions involving money flow over time. Since money can earn at a certain interest rate, it is clear that a dollar in hand at present is worth more than a dollar to be received at a future time [31]. Accordingly, engineering economics and the system life-cycle have the same dimension of time.

Cost/effectiveness is an evaluation methodology for decisions involving multiple criteria. Cost/effectiveness analysis originated in the economic evaluation of complex defense and space systems [31]. Its predecessor, cost/benefit analysis, had its origin in the civilian sector of the economy. Much of the philosophy and methodology of the cost/effectiveness approach was derived from cost/benefit analysis. The basic concepts inherent in cost/effectiveness analysis are now being applied to a broad range of problems in both defense and civilian sectors of public activities [31].

In applying cost/effectiveness analysis to systems, three requirements must be satisfied. First, the systems being evaluated must have common goals or purposes. Second, alternative means for meeting the goal must exist. Finally, most details of the systems being evaluated must be available or estimated so that the cost and effectiveness of each system can be estimated [31].

4.2 Design Evaluation Functions

Decision evaluation is needed as a basis for choice among alternative system designs. An economic equivalence function, such as the present worth, provides a common economic evaluation measure. However, a performance evaluation measure is also needed along with economic evaluation so that an informed choice can be made.

Fabrycky and Blanchard stated that an evaluation measure, E, may be derived from a decision evaluation function [31]. The evaluation function is a mathematical model that formally links E with controllable decision variables, X, and system parameters Y which may not be under the control of a decision maker. An extension of this model involves the identification and isolation of decision-dependent system parameters, Y_d, from decision-independent system parameters, Y_i. The functional relationship is expressed as follows:

$$E = f(X, Y_d, Y_i). \tag{4.1}$$

It is important to evaluate both the cost and effectiveness of alternative designs. Therefore, the above concepts can be adapted such that two evaluation functions are defined to account for both considerations. The focus here is on electric utility distribution systems as a special case. However, it should be noted that the theory and principles defined are general enough be applied, with some modifications, to generation and transmission systems as well.

Relative to distribution system design, a cost evaluation vector can be defined as a measure of the cost of each system design as follows:

$$\underline{C} = \underline{h}(\underline{U}, \underline{Y}_d, Y_i), \text{ where} \tag{4.2}$$

$\underline{C}$ = the present value of revenue requirements of actual and planned system;

$\underline{U}$ = choice, placement, and operation of distribution equipment;

$\underline{Y}_d = \underline{f}(\underline{x})$ = system efficiency, reliability, and peak demand;

$\underline{x}$ = system currents, voltages, and downtimes;

Yi = interest rate, inflation rates, equipment and maintenance costs, and carrying charge factors;

The decision evaluation vector can then be defined as follows:

$$\underline{D} = \underline{e}(\underline{C}, \underline{Y}_d). \tag{4.3}$$

It is important to note that the decision evaluation vector is a function of C and Yd, which indicates that decision evaluation is based on both cost and effectiveness measures. This is because there is a cost associated with system efficiency, reliability, and peak. Therefore, changes in these performance measures will affect the overall cost of the system. Both the cost and decision evaluation vectors are subject to power flow and reliability equations represented by the following equality:

$$\underline{g}(\ \underline{x}, \underline{U}, \underline{S}\ ) = 0, \text{ where} \tag{4.4}$$

$\underline{S}(\ \underline{t}, \underline{x}\ )$ = customer loads

$\underline{t}$ = time point.

The parameter $\underline{U}$ represents design variables such as the choice and placement of automatic switches, switched capacitors, controllable loads, regulating transformers, and instrumentation in the distribution network. These variables affect power flows, down times, and system losses. The Y_d parameters are in turn affected because system efficiency, reliability, and peak are defined in terms of system losses, down times, and loading, respectively.

It should be mentioned that in some cases there may be limits on the Y_d parameters set by the decision maker. On the other hand, in some other cases these parameters may not have limits on them. The existence of these limits depends on the particular case and objectives of the decision maker. A more detailed definition of the above vectors will be given in Chapter 5 in conjunction with the definition of several economic indices.

4.3 Modeling of Uncertainty

The past decade has seen a growing recognition that policies that ignore uncertainty often lead in the long run to unsatisfactory technical, social, and political outcomes. As a result, many large corporations and federal agencies now routinely employ decision analytic techniques that incorporate explicit treatment of uncertainty [32].

Uncertainty is a major issue facing electric utilities in planning and decision making. Substantial uncertainties exist concerning future load growth, construction times and costs, performance of new resources, and the regulatory and economic environment in which utilities operate.

During the past few years, utilities have begun to use a variety of analytical approaches to deal with these uncertainties. These methods include sensitivity, scenario, portfolio, and probabilistic analyses. As typically applied, these methods involve the use of a computer model that simulates utility operations over 20 or 30 years [33].

Modeling uncertainty in utility economic evaluation can be based on two general approaches [34]. The first is a probabilistic approach where probability distributions for all of the uncertainties are assumed. The second approach is called "Unknown but Bounded" in which upper and lower limits on the uncertainties are assumed without a probability structure. The two approaches are explained as follows.

Probability distributions may not be available for some variables in economic evaluations because sampled data is unavailable. Examples of such variables would be the carrying charge factor and minimum acceptable return for an electric utility. An opinion sampling of people who work in the field could be performed along with an evaluation of historical data. However, this process may be highly unreliable since it is based on opinions of economic situations which are changing both drastically and rapidly.

A probability distribution may be assumed in some cases. Since no particular distribution is known, all values are assumed to be equally likely between given limits. In this type of situation a uniform distribution is the most appropriate. This distribution is also referred to as the rectangular distribution because of its shape. Based on a known distribution, confidence intervals can be defined. In addition, the way in which confidence intervals vary with transformations can be determined.

Another approach to modeling uncertainty is referred to as unknown but bounded. In this case upper and lower bounds on the uncertainties are assumed without probability distributions. In Schweppe's last published paper, the concept was defined in general without providing any worked out examples [34]. The concept was previously mentioned in Schweppe's book titled "Uncertain Dynamic Systems" [35]. However, the book covered dynamic systems driven by a white unknown-but-bounded process.

Interval mathematics provides a tool for the practical implementation and extension of the unknown but bounded concept. Confidence intervals cannot be calculated in this case because there are no probability distributions.

The unknown but bounded concept as presented by Schweppe does not directly address sensitivity analysis [34]. He addressed that problem separately in the context of strategic planning for a utility as a whole [36-37]. Schweppe's method was based on running simulations repeatedly for a range of input variables. Results of these runs are integrated into functions which yield nonlinear relationships between input and output variables. These functions are then used to evaluate the effects of uncertainties and sensitivities of particular decisions [36].

In contrast to Schweppe's approach, an interval analysis solution with sharp bounds immediately provides the complete sensitivity analysis for the problem. There is no need for many simulation runs because the total variation in the output is known given the total variation in input parameters.

4.4 Design Evaluation Displays

If the goal of performing analysis is insight, not numbers, then clearly an important challenge to analysts is communicating the insights to those who need them. Such insights should include an appreciation of the overall degree of uncertainty about the conclusions [32].

The insights obtained will ultimately be qualitative in nature, even if the model they derive from are quantitative. This means analysts need to find ways to present quantitative results in a manner that communicates the information and aid users in making appropriate decisions. However, the use of graphics to communicate uncertain information has been the focus of remarkably little attention [32].

Considerations of multiple criteria in electric utility economic analysis arise when both economic and noneconomic elements are included in the evaluation. In this research, decision evaluation is facilitated by the use of design evaluation displays showing both cost and effectiveness measures [30].

Figure 4.1 shows a display combining three engineering design aspects; namely: efficiency, reliability, and peak. The effectiveness and performance measures are shown on the perpendicular axis of the display, whereas the present value of annual costs is shown on the horizontal axis. The maximum allowed values are also shown on the display. These represent the case in which the maximum allowed peak demand, system losses, and power outages are specified. The cost of the two alternative designs are shown as intervals. The width of each rectangle represents the interval bounds, whereas the height represents the performance measure.

In some cases there may be a cost overlap between the two designs, which is represented by the cross-hatched areas in Figure 4.1. The objective in certain cases may be to choose the alternative which satisfies the effectiveness measures at the lowest cost. However, in some other cases the objective may be reaching a particular level of effectiveness regardless of the cost. Therefore, a more elaborate economic decision evaluation display will be developed in the next chapter.

It is important to note that there are significant calculations required to come up with these results for each alternative. These values are calculated independently using economics, reconfiguration, power flow, and reliability analysis algorithms. These algorithms will be described in more detail in Chapter 6. However, the decision

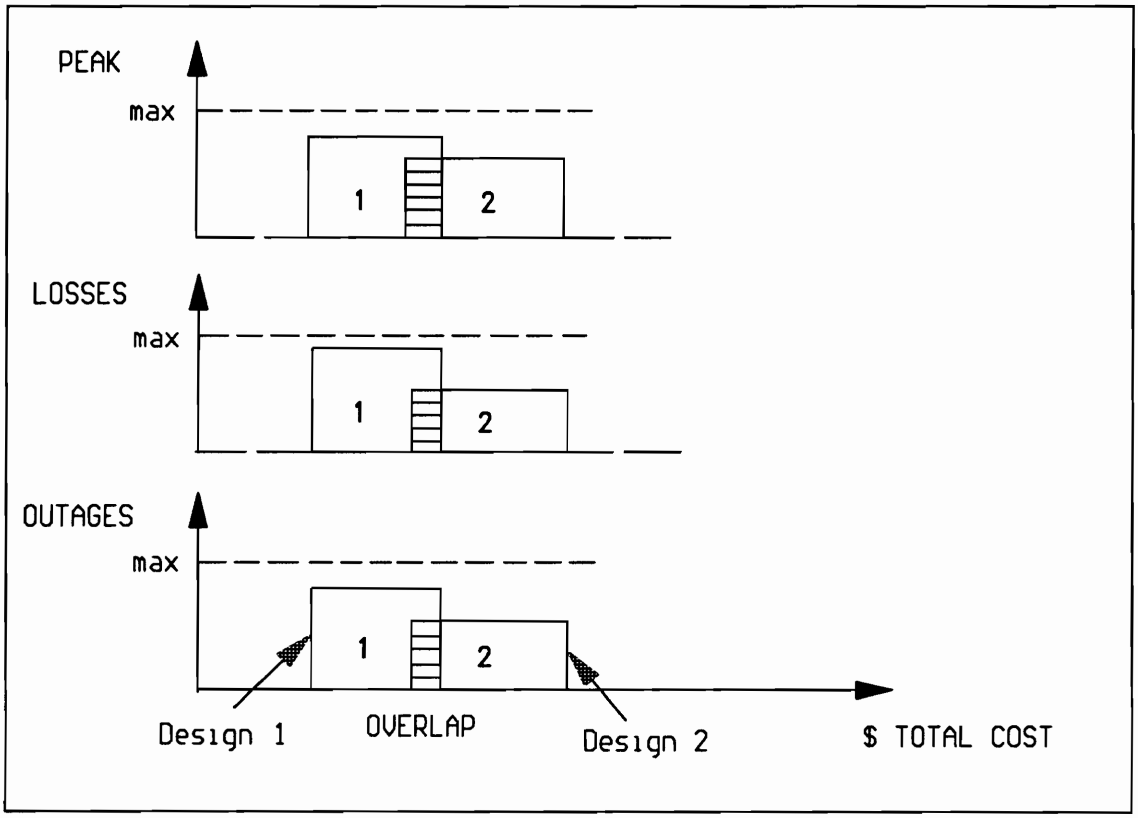

Figure 4.1. Design Evaluation Display

evaluation display integrates the engineering design factors to give the decision maker an overview of the cost and performance measures.

In conclusion, this research will utilize a computer-aided approach to evaluate alternative system designs in terms of effectiveness and cost. Each decision alternative has calculated performance measures as well as an associated present value of annual costs. Thus, a pairwise comparison of design alternatives may be performed to evaluate alternatives in terms of performance and cost.

CHAPTER 5

Economic Evaluation Of Distribution Systems

5.1 Introduction

A distribution system project should be treated no differently than any other project proposed by a utility. Such a project must survive cost/effectiveness scrutiny to justify implementation whether the electric utility is investor owned, a rural electric cooperative, or a municipal system. Utility management is not so much interested in the number of remote terminal units as in the answer to such questions as "What will it cost? How much will it save? Will revenue requirements be satisfied?" [1].

To warrant implementation, the benefits of a distribution system design must exceed the costs. Tangible savings (such as the cost of fuel saved) and tangible costs (such as expenditures for a remote-controlled capacitor bank) can be calculated with little difficulty. However, there are also intangible benefits such as improved customer relations that, although difficult to quantify, may receive much emphasis from some utilities.

The quick restoration of electric service to customers on unfaulted sections of a faulted feeder following an outage may be deemed highly desirable by a utility searching for means to improve customer relations. Each utility performing a cost/effectiveness analysis of distribution system design must decide the value it will assign to each such intangible benefit.

For instance, ascertaining anticipated benefits from distribution automation must include an evaluation of the costs. The costs of equipment, installation, maintenance, and repair must all be documented to give an accurate accounting of the costs of distribution automation.

A cost evaluation should recognize that many costs can be shared among different distribution automation functions. For example, the communication system, such as power line carrier, can be utilized for load control, volt/var control, and system reconfiguration commands by the operator. Thus, individual distribution automation functions should not be evaluated in isolation. Costs can be shared among such functions where possible, and it is even advisable to search for ways to share costs [8].

5.2 Value of Service Reliability

There is a growing feeling among utilities that investments related to electric service reliability should be carefully evaluated as regards their cost and benefit implications. The essence of this approach is the explicit recognition that from the customer's perspective, the total cost of electric service consists of two components. The first component is the cost of service received, and the second is the cost of service interruptions. Thus, customers are best served when this total cost is minimized [45].

Service interruptions cause customers inconvenience, irritation and loss. Research has shown that this is a function of the frequency, duration and time of day in which the interruption occurs [16]. It is also a function of the dependence of customers on electricity and their expectations of its reliability. Estimating the cost of interruptions in monetary terms is not an easy task. Research in this area is necessary for this purpose.

The costs consumers incur may be either direct or indirect outage costs. The direct costs occur when an outage actually takes place. Indirect costs arise if consumers adapt their activities by paying more to become less susceptible to outages, or if they resort to standby energy resources. Therefore, the relative importance of direct and indirect components in total outage costs depends on consumers' expectations about the reliability of future supply and the extent of behavior changes to avoid outages [46].

Some outages are deterministic in nature, such as the time of day in which they occur, while other outages are of random occurrence. Therefore, optimization of investment in different sectors of the power system, and within each sector, should be weighted with respect to the time of day and effect of the outage [16].

There is a broad variation in the value of service estimates reported in the literature. One source of this variation is embedded in the measurement approach and how it is implemented. This encompasses aspects such as the methodological approach, sampling, and model specification and estimation. A second source centers around how respondents perceive and answer key questions if the study is based on a survey. The third source of variation is due to the inherent diversity of customers' reliability preferences, which is responsible for the bulk of observed variation and will always be present [45].

Although the literature of the economic costs of electric interruptions dates back to the early 1960's, systematic and precise attempts at developing theoretically correct methods are limited and have been made only recently. With few exceptions, most utilities have virtually no individual customer data on the value of service measured by either the cost of outages or willingness to pay for service continuity [45].

In this research, it will be assumed that value of service is dependent on customer type. The three customer types considered here will be industrial, commercial, and residential. Additional customer types could be considered such as agricultural or further industrial classifications.

An approach is proposed here to back-calculate value of service when a utility does not have the necessary information. The approach is based on considering the difference in costs of alternative expansion plans. The first plan, called the base case, represents a typical expansion plan without automation. The second plan, called the automated case, represents an expansion plan utilizing some automation functions.

In order to place a dollar amount on the value of service, the following key question is posed: What would the value of service have to be for the two cases to be of equal cost? This implies that the value of service is the amount added to the less costly case to make it cost as much as the other case. Hence, the value of service is assigned to the increase in reliability of one case over the other.

Of course, this is not necessarily the cost of service, but it is a cost expressed in interval form that can be used to evaluate the improved reliability. If this increase in reliability is worth the investment, this value of service calculation provides the cost of obtaining the improved reliability.

It is important to distinguish between the concepts of value of service and cost of service. For any product or service, the only connection between the two is that value of service is greater than cost of service. In other words, most consumers buy a product or service only if the benefit they derive from it exceeds its cost [45].

The value of service can be found as described earlier by comparing the costs associated with both cases. The value of service will be calculated on a per customer basis. A value of service weighting factor will be assigned for each customer type. All customer types can be assigned an equal weighing factor if they are to be treated equally regarding value of service considerations. On the other hand, different customer types can be assigned different weighting factors as well.

For example, suppose economic studies revealed that value of service was $1000 per hour. The weighting factors for the three customer types may be assigned as follows:

Residential Weighting Factor (RWF) = 1

Commercial Weighting Factor (CWF) = 4

Industrial Weighting Factor (IWF) = 5

The sum of all weighting factors is ten. Therefore, ten equivalent customers are considered, and the value of service per equivalent customer will be as follows: $1000/10 = $100. The Value Of Service (VOS) per customer type can then be found as follows:

VOS/Residential Customer = $100 * 1 = $100

VOS/Commercial Customer = $100 * 4 = $400

VOS/Industrial Customer = $100 * 5 = $500.

The weighting factor could even be set to zero for some customer types if so desired. The value of service calculation would not be affected by customer types with a zero weighting factor.

In recent years, the notion of customer based value of service has been increasingly associated with reliability studies. This terminology is perhaps motivated by the increasing interest in marketing electricity services tailored to best match the unique reliability preferences of different customer types. In this context, value of service refers to the price that consumers are willing to pay for the benefit they derive from it. Thus, a customer can select a service option that offers inferior reliability at a discounted rate [45].

Some have raised the issue that lower reliability standards are in conflict with a utility's obligation to serve customers. However, use of traditional engineering design standards presumes that all customers are willing to pay the cost of providing the utility selected level of reliability. But growing empirical evidence suggest that this is not the case for all customers, and certainly not for all end-uses. In addition, some customers desire higher levels of reliability than is offered today. Therefore, customers will be best served by providing service options that best match their preferences [45].

Electric utilities may use individual customer data on the value of service if available. However, if utilities do not have such data available, the above described method can be utilized to obtain an estimate on value of service by customer type.

5.3 Economic Analysis Method

This section describes the economic analysis method used to implement the economics algorithm. As mentioned earlier, the revenue requirement method is used to identify all costs related to a particular decision involving money and to reflect these costs into the revenue that must be collected from customers to support that decision. These costs are divided into two broad categories of expenses and carrying charges. The yearly revenue requirement to support a certain decision is then the sum of the expenses and carrying charges for that particular year.

Expenses are all costs associated with the normal operation and maintenance of the equipment after it is placed in service. Expenses in this research will consist of the following components: maintenance cost, KWh losses cost, peak cost, and value of service cost. These costs are typically associated with items or services used within a period of one year.

Carrying charges are related to the costs associated with the initial placement of a plant item. As such, these costs are not normally paid directly from operating revenue. The reason is that the cost impact on the customer would be enormous and present customers would be paying for plant items which would be used by customers in the future. It is common practice to purchase such items through some form of debt or equity financing and pass the yearly costs of this financing to the customer in the form of a carrying charge. Therefore, the annual carrying charges are calculated by multiplying a carrying charge factor by the sum of capital and installation costs of a plant item.

There are several forms of revenue requirement analysis in common use. Each type exists because it responds to a particular need and has its appropriate application. As a matter of fact, many problems require the application of more than one technique in order to gain as much insight as possible into the consequences of a particular decision. Therefore, a combination of the year-by-year and short term analysis methods will be used here.

In the year-by-year form of analysis the actual yearly cash requirements are generated. The requirements for any given year would be the sum of the carrying charges for that particular year plus the necessary expenses. This form of analysis provides the necessary information for the utilities' financial planners to assess the potential cost impact of an alternative on the financial condition of the utility. In addition, the short term analysis focuses the attention on the short term impact on the utility. This is due to the changing regulatory climate and the uncertain economic environment in which utilities operate nowadays.

5.4 Economic Indices

The cost/effectiveness analysis of distribution system design can be facilitated by using several proposed indices. Among these, three indices can be used in cost/effectiveness analysis. The first is associated with reliability, the second with efficiency, and the third with system peak. However, all the indices can be used for economic comparisons of alternative designs.

For all the indices, there are two alternative designs to be considered. Let

A = Interval present value of revenue requirement of actual design = [a1, a2],

P = Interval present value of revenue requirement of planned design = [p1, p2],

then dC = Distance between A and P = $\max\{ |a1-p1|, |a2-p2| \}$. (5.1)

The distance between the two intervals is a measure of difference in present value of revenue requirements of the two designs. This value will be used in the definition of the following economic indices which represent cost comparison and cost/effectiveness ratios.

5.4.1 Relative Cost Index (RCI)

There is a need for a measure of difference in cost between the alternative system designs. In this case, the present value of revenue requirement is used as an economic equivalence measure. The Relative Cost Index (RCI) is defined as follows:

$$\mathrm{RCI} = \mathrm{sign}(p2-a2) * dC/NC, \tag{5.2}$$

where NC = Normalizing Cost = $\min(a2, p2)$.

This index represents a normalized difference in present value of revenue requirements of the two designs. For example, suppose that A = [3, 5] and P = [4, 7]. The RCI can then be found to be +2/5 or 0.4, which means that the planned system costs 40% more than the actual. This can be shown by multiplying the upper bound of the interval A by 1.4 to get the upper bound of the interval P. The sign of the RCI may turn out to be negative in the case where the actual costs more than the planned system.

5.4.2 Probability of Overlap (PO)

In some cases there may be a cost overlap between the two designs, which is represented by the cross-hatched area in Figure 5-1. It is useful for the decision maker to know the chances of this occurring to indicate the probability of the perceived lower cost being higher than the perceived higher cost. This probability can be calculated using the fractions of overlap areas as a portion of each interval range. For example, suppose the overlap area represents a 0.3 fraction of the interval A and a 0.2 fraction of interval P. The probability of overlap can then be defined as follows:

$$PO = Pr(A \cap P) \tag{5.3}$$

$$= (0.3) * (0.2) = 0.06,$$

which means that there is a 6% chance that the cost of the two designs will be in the same range. It is important to note that this probability does not mean there is a 6% chance of the cost being the same, but rather it means there is a 6% chance of both costs falling in the overlap region.

5.4.3 Economic Index for Reliability (EIR)

A distribution system is made up of distribution substations, primary feeders, laterals, protective devices, switches, distribution transformers, and customers' connections. Distribution system reliability evaluation therefore consists of assessing how adequately the different parts are able to perform their intended function [47].

The distribution system is an important part of the total electric system since it provides the final link between the bulk system and the customer. It has been stated that 80% of all customer interruptions occur due to failures in the distribution system [48].

An absolutely uninterruptable electric supply is impossible to attain. The incremental cost of improving reliability increases considerably with each incremental improvement in continuity of service. Therefore, what is the optimum reliability for the electric supply of a utility? Khatib defined this optimum reliability to be attained when the marginal benefit of an increment of reliability is equal to the marginal cost of achieving it [16].

Any level of reliability above the optimum represents over-spending and waste of limited resources, while a lower level represents negligence and misallocation of resources. However, as in many other optimum resource-allocation concepts in economics, the optimum level is easier to define than compute. Such a computation

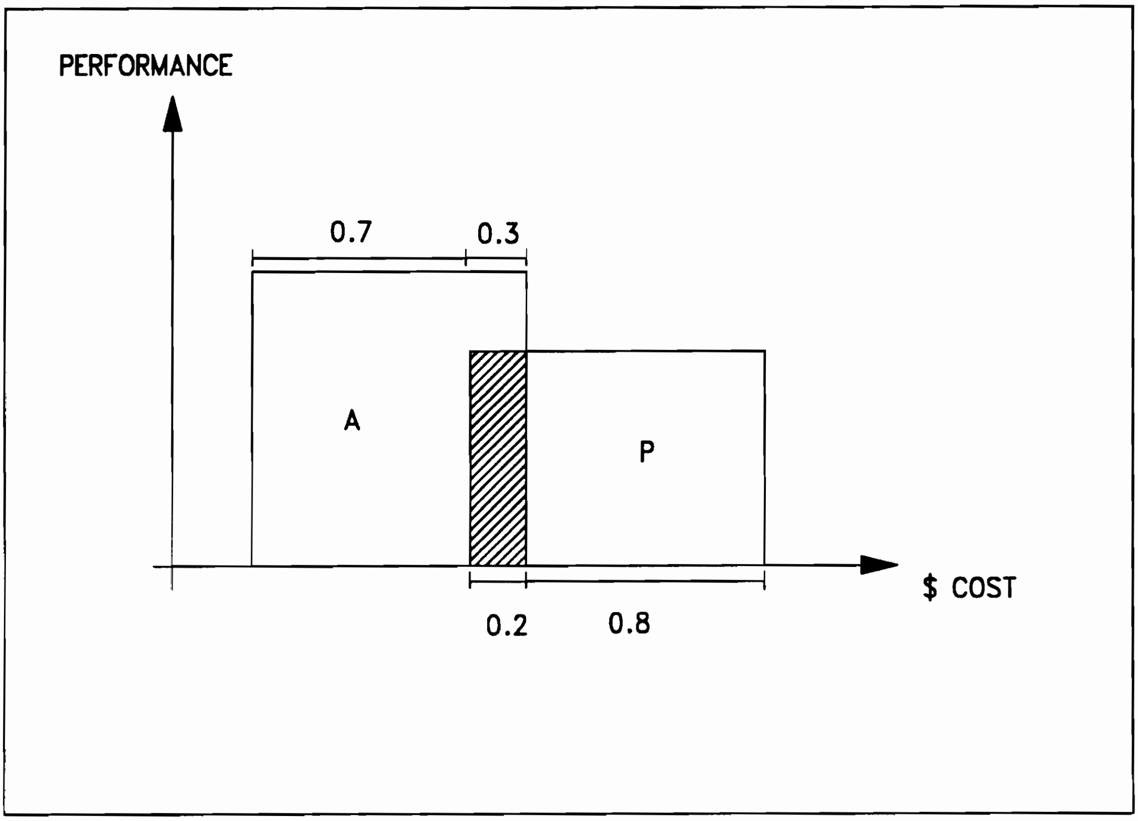

Figure 5.1. Illustration of Probability of Overlap

requires two sets of data. First, a set which shows how the reliability of supply responds to extra incremental investment. Second, a set of data showing to what extent the customer interruption of service is alleviated through increased reliability.

The value of service of one design can be higher if it is more reliable. The more reliable design provides better service to customers. Therefore, the additional cost of that design can be passed on to customers in the form of higher rates in exchange for better service.

Two comprehensive studies have been conducted to determine North American utility practices regarding service reliability data and its utilization in system management [45]. Both studies show that the System Average Interruption Duration Index (SAIDI) is one of the popular indices in both the U.S. and Canada. The SAIDI is defined as

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

Let SAIDI_1 = Average annual SAIDI of actual design

SAIDI_2 = Average annual SAIDI of planned design

$$\text{then } \%\Delta\text{SAIDI}_{12} = \frac{\text{SAIDI}_1 - \text{SAIDI}_2}{\min(\text{SAIDI}_1, \text{SAIDI}_2)} * 100 \tag{5.4}$$

which is the normalized percentage change in reliability. The EIR for the overall system is then defined as follows:

$$\text{EIR} = \frac{dC}{\%\Delta\text{SAIDI}_{12}} \tag{5.5}$$

which is a cost/effectiveness ratio associated with the difference in reliability between planned and actual designs. EIR gives utilities a measure of how much of the difference in revenue requirement is associated with the percentage change in reliability based on an index such as SAIDI. Furthermore, the EIR can be defined for a single load point in the system as follows: EIR = dC/(downtime/year), which can be used for high priority customers who are willing to pay more for improved reliability. This concept is discussed in more details in Section 5.3.

5.4.4 Economic Index for Efficiency (EIE)

There are three basic ways to reduce system losses on a distribution system [6]. The first is to improve the physical plant by replacing small conductors with larger ones or by changing equipment for voltage upgrading. The second is to change the way the system serves the load by reconfiguring the switches. The third way is to alter the load itself to reduce the compounding effects of the I-squared-R losses on the delivery system components by adding capacitors or load management.

In the reconfiguration approach, distribution switches are allowed to change status to improve the paths of power flow to better serve varying location and time dependent factors of distribution load. Switching will distribute load in a better way which will reduce the system I-squared-R delivery losses. This research addresses the economic impact of reduced system losses.

The Economic Index for Efficiency is associated with the improved efficiency of one design over another in terms of reduced system losses. Let

$LOSS_1$ = Total annual KWh losses of actual design, and

$LOSS_2$ = Total annual KWh losses of planned design.

Then define $$\%\Delta LS_{12} = \frac{LOSS_1 - LOSS_2}{\min(LOSS_1, LOSS_2)} * 100 \qquad (5.6)$$

which is the normalized percentage change in efficiency. Therefore, the EIE can be defined as

$$\mathrm{EIE} = \frac{dC}{\%\Delta LS_{12}}. \tag{5.7}$$

which is a cost/effectiveness ratio associated with the difference in efficiency between planned and actual designs. EIE gives utilities a measure of how much of the difference in revenue requirement is associated with the percentage change in efficiency based on KWh losses. Furthermore, it may be possible to compare this index with the cost of building new generation to supply one KWh. Let CG = \$ cost of new generation to supply one KWh, then the investment is economic if EIE < CG. However, this comparison is valid only if the reduced losses are the only benefit from the investment. Other factors have to be considered such as improved system reliability and reduction in peak load demand.

5.4.5 Economic Index for reduced Peak (EIP)

Reducing the system load at peak times can have the potential of delaying or deferring the construction of new generation plants or reducing the use of power plants that use extensive fuel and are required or used only for peaking purposes.

A load control program can be implemented to reduce system peaks by transferring demand from the peak period to a time of day when the demand is lower. To effectively accomplish this, information is needed to determine when to control the load and how much load is to be controlled [9]. Voltage reduction can also be used to control peak. In addition, rate structures can be used to reduce peak demand. This is achieved by charging customers higher rates during peak demand periods. Consequently, customers are encouraged to reduce their electric usage during the high rate periods.

The Economic Index for reduced Peak is associated with reduced peak load demand of one design compared to the other. Let

PEAK1 = KW peak demand associated with actual design, and

PEAK2 = KW peak demand associated with planned design.

$$\text{Then } \%\Delta PK_{12} = \frac{PEAK_1 - PEAK_2}{\min(PEAK_1, PEAK_2)} * 100 \tag{5.8}$$

which is the normalized percentage change in system peak. Therefore, EIP can be defined as

$$EIP = \frac{dC}{\%\Delta PK_{12}} \tag{5.9}$$

which is a cost/effectiveness ratio associated with the difference in system peak between planned and actual designs. EIP gives utilities a measure of how much of the difference in revenue requirement is associated with the percentage change in peak KW demand. This reduction in peak represents displaced generation, which means that the utility does not have to build additional capacity corresponding to the reduction in peak.

In considering the alternative designs, one design may represent an automated plan while the other may represent a conventional expansion plan. Similarly, one design may represent keeping the system as it is while the other design may represent implementing certain improvements on the system. In conclusion, no index should be viewed individually, but rather in the context of overall system improvement of one design over another.

5.5 Economic Decision Evaluation Display

The design evaluation functions defined in Section 4.2 can now be defined in more details based on the economic indices defined above. The cost evaluation vector of Equation 4.2 is defined as a 2x1 vector

$$\underline{C} = \begin{matrix} C_a \\ C_p \end{matrix} \tag{5.10}$$

where C_a = present value of revenue requirement of actual system, and

C_p = present value of revenue requirement of planned system.

The decision evaluation vector of Equation 4.3 is defined as a 9x1 vector

$$\underline{D} = \begin{matrix} dC \\ RCI \\ PO \\ \%\Delta LS_{12} \\ \%\Delta SAIDI_{12} \\ \%\Delta PK_{12} \\ EIE \\ EIR \\ EIP \end{matrix} \tag{5.11}$$

The nine elements in the $\underline{D}$ vector can be placed into three groups. The first group consists of the first three elements which relate to interval cost evaluations between alternative designs. These elements are defined in terms of the components of the vector $\underline{C}$ as shown by Equation 5.1 through 5.3. The second group consists of the forth, fifth, and sixth elements, which represent normalized percent difference in performance. These elements are defined in Equations 5.4, 5.6, and 5.8 in terms of the components of $\underline{Y}_d$, which was defined in Section 4.2 to include system efficiency, reliability, and peak. The last group consists of the last three elements, which represent cost/effectiveness ratios.

These elements are defined in terms of dC and the three elements of the second group as shown by Equations 5.5, 5.7, and 5.9.

The economic results pertaining to cost/effectiveness analysis will fall into one the following four categories:

1. Cost/Benefit
2. Cost/Deficit
3. Savings/Benefit
4. Savings/Deficit.

In these categories, the term 'cost' indicates a cost increase, whereas the term 'savings' indicates a cost decrease. Similarly, the term 'benefit' indicates an improvement in performance, whereas the term 'deficit' indicates worse performance. Clearly, category 2 represents a worst case scenario, while category 3 represents a best case scenario.

A decision evaluation display can now be developed to include all elements of the vector $\underline{D}$. An example of the Economic Decision Evaluation Display is shown in Figure 5.2. The RCI is shown on the bar graph on the left side of the display, which also shows its sign. The other graph shows the normalized percent difference in performance between the two designs on the horizontal axis. The positive side of the horizontal axis represents an improvement of the planned over actual design, whereas the negative side represents a performance decline. The vertical axis shows the cost/effectiveness ratios of the planned design over the actual. The positive side of the vertical axis represents a cost increase, whereas the negative side represents a cost saving. Finally, the important parameters of PO, dC, and NC are also written on the display.

The placement of each of the cost/effectivenes indices EIR, EIE, and EIP depends on which of the four scenarios mentioned above it represents. Therefore, that a cost/benefit case is placed in the first quadrant, which is identified when both RCI and the index are positive. A cost/deficit case is placed in the second quadrant, which is identified when RCI is positive but the index is negative. A cost saved/deficit is placed in the third quadrant, which is identified when both RCI and the index are negative. Finally, a cost saved/benefit is placed in the fourth quadrant, which is identified when RCI is negative but the index is positive.

In conclusion, this chapter presents the specific methodology of economic evaluation of distribution systems, which was presented in less details in Chapter 4. The next chapter presents the implementation of the economic analysis algorithm.

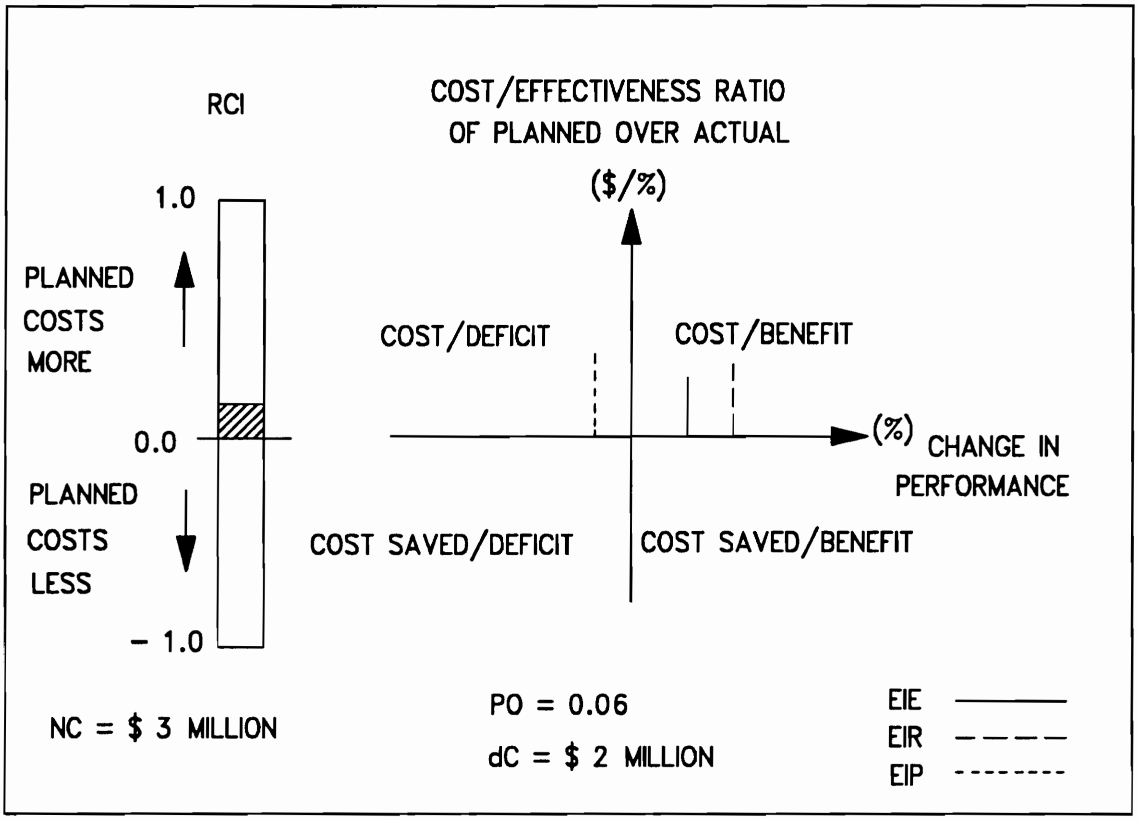

Figure 5.2. Sample Economic Decision Evaluation Display

CHAPTER 6

Economic Analysis Implementation

This chapter describes the computer implementation of economic evaluation. The economic evaluation algorithm runs as part of a distribution engineering workstation. Therefore, descriptions of the database and workstation environments are provided. In addition, this chapter briefly describes the two main algorithms which provide the reliability, efficiency, and peak results needed to carry out the economic calculations.

6.1 Database And Workstation Environments

6.1.1 Introduction

As distribution automation has evolved from a research topic into reality, many pilot projects have been undertaken [9-11]. However, many of these projects are focused on the hardware aspects of distribution automation such as remote control, monitoring of devices, and the communication system [49]. As the basic hardware problems are dealt with and the systems mature, more emphasis will need to be placed on the computer software required to improve system performance and increase the return of the hardware investment [50].

Data generated by distribution automation systems has the potential to provide important feedback for distribution operation and planning. Currently, the collected data is being used for a limited number of real-time operations and tracking load trends. Unfortunately, because of the volume of data and minimal processing presently taking place, this data is not being used effectively for further analysis. Automated strategies for the analysis of data will lead to more effective utilization of information for improving upon operating, planning, and design practices [49].

Clearly, information management is a basic function in distribution automation systems. The basic element in such an information system is a descriptive distribution system database. A database may be defined as a large, organized collection of information that is accessed via software and is an integral part of a system function. The database must be initialized accurately and designed for continuous update to track all changes in the system [2].

The required database attributes include the following: the database must always be a complete and accurate record; must be easily updated by the automation system or the operator; must be readily expandable as the distribution system expands; contents should be readily accessible to the user as well as the system for verification purposes [2].

Distribution automation software will probably evolve gradually over many years from the work of several programmers. Each program is typically designed to have its own data files. Thus, data may be duplicated in several files, and routines for accessing data may be duplicated in several different programs. Furthermore, files are restructured as the system model evolves over time, which requires programs to be rewritten. Therefore, managing multiple data files can be a formidable task [51].

Complex data sets can be easier to control, however, if all information is stored in a common database. All programs would access this common database for their input and output. And a set of common routines could be supplied for efficiently storing and retrieving information. An integrated system for handling complex databases is called a database management system [52].

Databases typically involve two types of information: entities and relationships. An entity is a thing, such as a transformer. Entities have properties called attributes. For example, a transformer has a model type, a voltage rating, and a capital cost. In addition to entities and their attributes, a user may wish to represent relationships among two or more entities [51].

The relational database was proposed by Codd in the late 1960's to implement this entity-relationship model [53]. In a relational database, data is stored in tables. A separate table is used for each type of entity. The columns of the table represent the entity's attributes. The rows represent individual entities of that type.

Data must not only be stored efficiently, but also must be easy to retrieve. Data can be retrieved from the database through the use of a high-level query language. The leading query language for relational databases is the Structured Query Language or SQL [54]. SQL is an industry standard originally developed by IBM for its System R, but it has since been adopted by many other relational systems. Basically, a query language allows users to retrieve any subset of the rows and columns of a group of tables [51].

6.1.2 Workstation Description

The Virginia Tech Distribution Analysis and Economic Evaluation Workstation (DANE) has been developed to provide a standardized programming environment to perform studies and develop algorithms for electrical distribution systems [55]. DANE uses a Standardized Distribution Database, illustrated in Figure 1, which contains utility supplied data. DANE also provides a graphical interface for rapidly incorporating this data into systems of substations and circuits. Once a system has been graphically built, any available algorithm may be used for analysis.

As illustrated in Figure 1, DANE provides an application programming interface consisting of a standardized database interface, standardized data structures and linked lists, a library of graphical functions, an error handling methodology, and defined interfaces to any analysis, design, or operational algorithm in the system.

DANE integrates data management, graphical input/output, analysis, design, and operational algorithms associated with electrical distribution. A relational database stores the data needed by all functions. Once a data item is created in the database to support a function, it is available to all existing and future functions.

DANE is being developed in the C language under the Extended Version of OS/2. The SQL database system that is supplied with extended OS/2 is used [56]. Standard embedded SQL statements are used to access the database directly from the C code.

An illustration of the DANE workstation screen is shown in Figure 2. At the top of the screen is a dual row menu bar with 22 different selections. Many of the selections from this menu bar lead to pulldown menus. At the bottom of the screen is a boxed-in two line message area. Help, error, and algorithm generated messages are displayed in this area. A help message is always generated to inform the user of the next expected actions.

When errors occur, the bottom message area is back-highlighted in red and the mouse pointer is automatically placed in this area. The user must then acknowledge the error with a mouse pick. Messages from analysis, design, and operation algorithms are also written to the bottom message area. The drawing area is between the top menu and bottom message areas. A variable message area exists to the right of the bottom message area. The system of circuits which is currently in memory is indicated here along with the variables being displayed on the circuit schematic.

The first page of the Analysis and Design pulldown menu for DANE is also illustrated in Figure 6.2. Depending upon the number of functions implemented on a pulldown menu, a menu may consist of multiple pages. The Enter function is implemented if more than one choice may be made before exiting the menu. At any point in the operation of the workstation, any of the top menu bar selections may be chosen to go directly to the selected function.

When analysis and design studies are performed, the student selects the circuits to be studied. All circuits are displayed on a pageable, pulldown menu. Algorithms to be

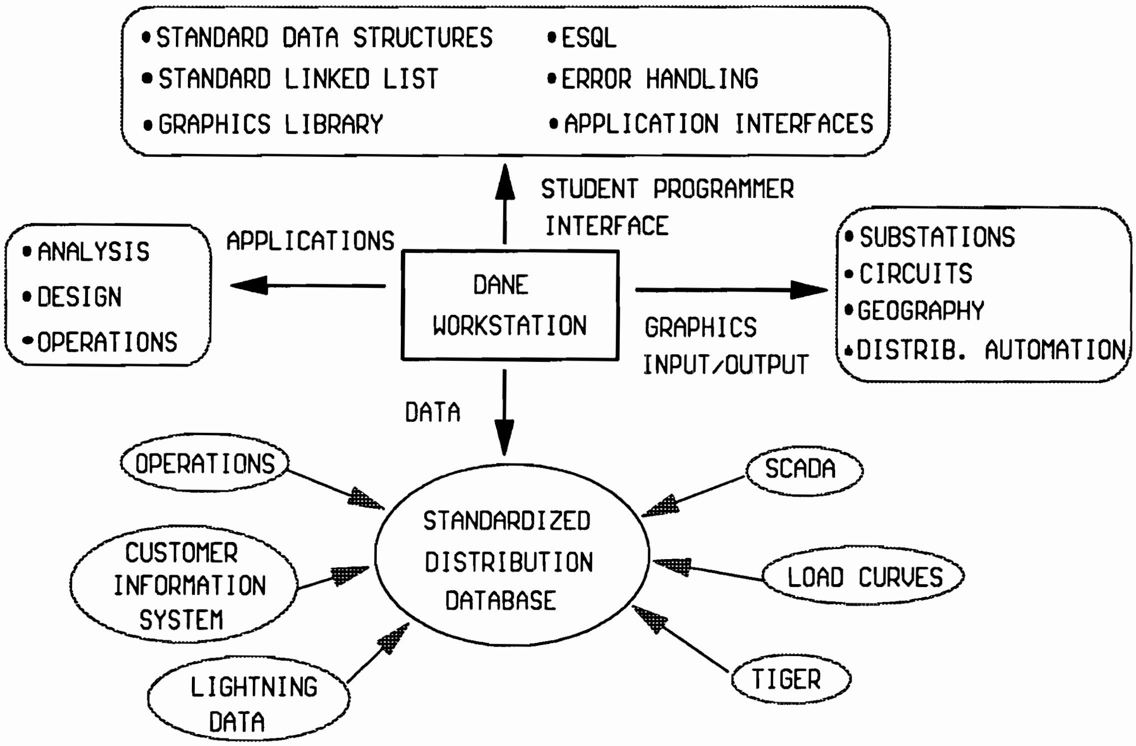

Figure 6.1. Dane Workstation Environment

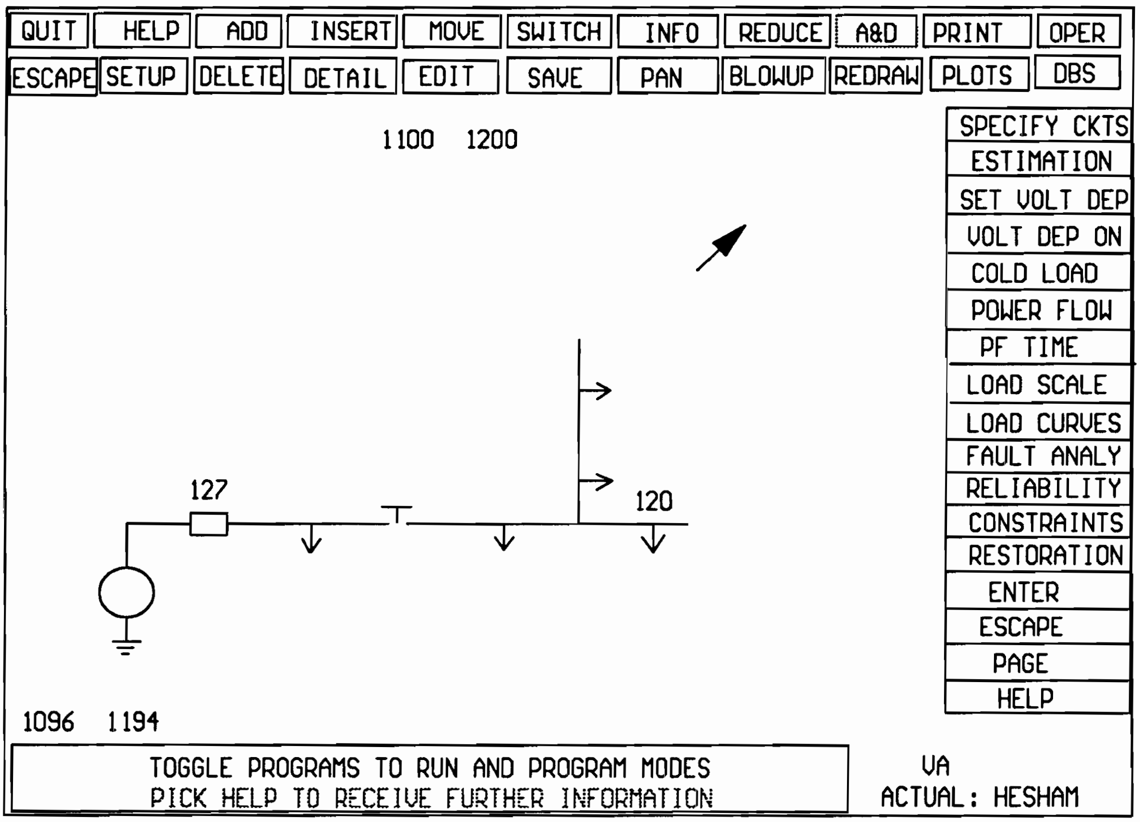

Figure 6.2. DANE Workstation Screen Display

run are then selected. Multiple algorithms may be set to run sequentially - that is, analysis and design studies may be concatenated, with the results from one study being used as input to the next. Once the analysis and design studies to be run have been selected, Enter is picked to cause the algorithms selected to begin execution.

Automatic analysis of a series of points from a time-varying load pattern is made possible with concatenation of studies. Studies may be performed based upon season, type of day, and time of day. The concatenation of studies also allows interactions among design algorithms do be studied.

6.1.3 Database And Data Structures

DANE is built around a relational database that interfaces to data from other sources as illustrated in Figure 6.1. The tables in the database are grouped into what are referred to as libraries of data. There are eight such groupings of tables as follows: Parts, Engineering, System Data, Measurement, Operations, Application, Geographical, and Dane System [55].

When DANE is active, some of the tables are stored in their entirety in data structures in memory. These tables are the ones which are accessed most frequently by algorithms. The large majority of these tables belong either to the Parts or Engineering libraries. The Parts Library tables contain data associated with components used in building substations and circuits. The Engineering tables store data for a set of actual circuits, a set of planned circuits, and data related to operations. Pointers are used to access the in-memory data [55].

Storing the most commonly used data in memory provides efficiency in programmer man-hours, reduces code size, and increases algorithm execution speed. These advantages are in large part due to the multi-thread capability of OS/2. The main function in the DANE software starts analysis and design functions as threads. A major feature of a thread is that it can share data with the main function. Hence, the graphics and power flow calculations can run simultaneously out of the same data in memory.

Two systems of circuits are stored to the database, referred to as Actual and Planned systems. Only one system of circuits is brought into memory at a time. The variable message area indicates the system of circuits which is currently active. The user can interactively cause the system of circuits in memory to be switched. The user can also cause circuits to be copied from the system of circuits in memory to its counterpart on the hard disk. Hence, if the Actual system of circuits is in memory, an Actual circuit can be copied to the Planned system on hard disk. The user can then switch to the Planned system to make design modifications to the circuit and to analyze it.

A data structure can be defined as a collection of one or more variables, possibly of different types, grouped together under a single name for convenient handling. Data structures help to organize complicated data operations because they permit the treating of a number of variables as a unit instead of as separate entities. A data structure consists of two parts, which are the data of interest and pointers that may be used to manipulate data structures [57]. Pointers are well suited for handling the sparsity of distribution system topology.

Two data structures that are used in every algorithm in DANE are the Substation/Circuit and Component. These data structures are used to hold data from their corresponding database tables of either the Actual or Planned system. The Substation/Circuit and Component data structures also store additional data that is not stored to the database tables on hard disk. In general, this additional data is involved with system analysis, and includes pointers to analysis data structures. For instance, the complex voltage for phase A for the component represented by pointer p is

```
p->pf->complex_volts[0].
```
(6.1)

The Substation/Circuit data structure is a doubly linked list used for storing substation and circuit data. Each Substation/Circuit data structure contains pointers to the starting and ending component for a linked list in the Component data structure.

The Component data structure contains several pointers that are available to the analyst. Many of these pointers are used to implement a linked list, or circuit trace [55]. Pseudocode for implementing a forward circuit trace, FT, is given by

```
    p = sp
While( p not equal NULL )                                  (6.2)
  { ...
    p = p->f  }.
```

As indicated by the logic test of the While statement, all linked lists are set to end with the NULL pointer. Various calculations may be performed or circuit information developed as the forward trace is performed.

Traces may also be performed using segments. A segment represents a group of components that all have the same sectionalizing device. A segment's entry component in the forward trace direction is a switch or protective device, and each segment only contains one switch or protective device. Segment traces are useful in reliability and protection system calculations [55].

The Component data structure also contains offsets into other linked lists. The offset is an integer and is added to the start of the appropriate linked list to locate the desired data structure [55]. For instance, suppose the component represented by pointer p is of type breaker and it is desired to determine the interruption rating. This particular breaker may occur many times as a component throughout the distribution system, but all information associated with the breaker is stored at one place in memory. The integer offset stored in the Component data structure pointed to by p may be used to access the interrupting rating by

$$(\text{sbrk} + (\text{p->ord}))\text{->interrupting\_rating}. \tag{6.3}$$

Some components can have other equipment associated with them, such as relays associated with breakers. Such components will have multiple order numbers that may be used to access information.

6.2 Efficiency And Peak Calculations

6.2.1 General Background

The power flow algorithm is an independent module that may either be run as a stand alone analysis program or as an integral part of other analysis programs, such as reconfiguration. When run over multiple points in time, the algorithm executes on only one time point at a time generating a complete profile for voltages, currents, line power flows, and power factors. These results include the elements of Equation 4.4 and the vector $\underline{x}$ which were defined in Section 4.2.

The power flow algorithm is designed to model essentially all types of electrical distribution components such as substations, tap changing transformers, fixed transformers, voltage regulators, switched capacitors, fixed capacitors, line sections, automatic and manual switches, and several types of protective devices such as breakers.

The power flow algorithm also incorporates a controller algorithm which is used to control voltages and power factors at a given bus. For example, when the power flow is run on a given circuit which contains a voltage regulator at a given bus, the voltage regulator tap may increase or decrease by a predefined tap step size depending upon the voltage value at the given bus. The tap takes continuous values until the required voltage is obtained at the given bus. Once the algorithm converges, the voltage regulator tap is set to the closest discrete value. This tap value is then stored in a database table. The same controller procedure applies to tap changing transformers and switched capacitors present in any circuit.

Distribution systems consist of groups of interconnected radial circuits. Their configurations may be varied with manual or automatic switching operations to transfer loads among the circuits. Ideally, the system configuration should produce minimum losses. Starting with a given set of switch positions, the reconfiguration algorithm searches for a revised combination of switch positions to reduce losses. The algorithm converges when the search procedure cannot locate a switch pair operation that further reduces losses [58].

Distribution system load varies seasonally by time and type of day. Manual switching to reduce losses satisfies the utility's need to accommodate seasonal load variations. The emergence of distribution automation technology and equipment allows automatic switches to take advantage of daily and time of day switching patterns to reduce losses.

The load profile for a circuit is a function of customer types. Load profiles vary from circuit to circuit due to the mix and dispersion of customers served. In distribution systems, circuit peaks are noncoincident due to the diversity of load resulting from the categories of customer classes served. This variation in circuit load profile makes reconfiguration possible to reduce losses. Thus, a circuit's load diversity is established by the daily electrical power demands of the various customer types which are served by the circuit.

Seasonal, daily, and hourly time variations of load provide analysis points for the reconfiguration algorithm. Using this load data the algorithm develops switching patterns to reduce losses, where time may vary over a daily cycle and/or a seasonal cycle. Benefits from seasonal loss reduction can be accomplished through manual switching, whereas benefits from the daily loss reduction requires automatic switching [58].

The reconfiguration of an electrical distribution system to reduce losses has a natural tendency to balance loading among circuits. This balancing process places the system in a better position to respond to emergency load transfers [58].

Estimation of load distribution along a feeder is critical to successful reconfiguration analysis. The algorithm can use available system measurements, load statistics based on customer class, and/or load estimates. If available, the algorithm takes the following into account: feeder circuit measurements; the number of customers by customer class throughout the circuit; diversified customer load curves.

If none of the preceding load information is readily available, traditional load estimates may be used. Diversified load curves may be developed from load research data or experiments such as those performed in the Athens distribution automation project [9].

6.2.2 Reconfiguration Computer Algorithm

The reconfiguration algorithm which analyzes distribution systems for loss reduction is part of the DANE Workstation [55]. The reconfiguration algorithm generates switching patterns corresponding to the reduced loss configuration of the distribution system. Therefore, the results of reconfiguration algorithm affect the elements of vector $\underline{Y}_d$ defined in Section 4.2. This in turn affects the results of the vector $\underline{D}$ as shown in Equation 5.11.

The variation in time may be considered by time of day, type of day, and season. The time variation is considered across seasons given the time of day or across a day given a season. The reconfiguration algorithm analyzes these data points automatically.

The outputs of the algorithm are switching patterns as a function of time, where time may vary over a daily cycle or a seasonal cycle.

The reconfiguration algorithm is an engineering tool which may be utilized to improve the operational efficiency of the distribution system. It can also be utilized as an on-line aid to distribution system operators since its execution time is in the order of seconds. The energy saved due to distribution reconfiguration may result in substantial amounts of money savings over several years. Thus, it can be used for distribution system planning purposes as well.

Load information used for load estimation is stored in two data structures. The Diversified Customer Load Data Structure stores information associated with diversified time-varying customer load characteristics. Elements of this data structure include customer class, season, type of day, time of day, hourly diversified KW usage, power factor, and cold load pickup factor.

The Circuit Measurements Data Structure stores information about feeder power flows at the substation. Elements of this data structure include feeder name, feeder loss factor, season, type of day, time of day, hourly KW and power factor measurements for each phase.

Reconfiguration algorithm results are stored mainly in two data structures. The Switching Configuration Data Structure stores switch status for each switch in the system. The set of switch positions stored in each data structure is unique, and is given a unique identifier referred to as a Configuration Identification.

The Operations Data Structure stores season, type of day, time of day, and the Configuration Identification for the associated point in time. Two-hundred and seventeen data structures of type Operations Data are utilized. Of these two-hundred and seventeen structures, two-hundred and sixteen correspond to the twenty-four hours in a day, three types of days, and three seasons. The remaining structure corresponds to the base case system configuration that exists at the start of the solution.

Using available information from the Diversified Customer Load and Circuit Measurements data structures, the loading condition for the given time point is evaluated. A power flow calculation is then performed for each circuit. If constraint violations occur on the first iteration, those violations are flagged and the algorithm proceeds to the next time point to be analyzed. Otherwise, the loss functions are calculated [58].

The real losses are evaluated for the base case and for each possible switch pair operation. A direct search method then determines the switch pair operation that produces the maximum decrease in system losses. This switch pair operation is performed and power flow calculations are re-run on the circuits that changed. If no constraint violations occur, the real losses of the modified circuits are updated [58].

A new base case at this time point has now been created, and further comparisons are made against this base case. When switch pair operations produce no further loss reduction, the algorithm has converged for this time point. If a new switching pattern has been generated, results are stored to the Switching Configuration Data Structure. The Configuration Identification, system losses, and load level for the time point are stored in the Operations Data Structure. This procedure is repeated for all time points under study [58].

6.3 Reliability Calculations

6.3.1 General Background

Emergency power restoration and reliability are important considerations in electric distribution systems. The Electric Utility survey indicates that most outages are at the distribution level [59]. Simultaneous outages may be located in widely separated geographical areas due to weather conditions, such as storms.

Emergency power restoration involves isolation of failed equipment and restoration of service to customers such as hospitals or cold storage units, whereas reliability studies calculate load point performance indices and circuit performance indices.

The load point performance indices include average downtime per year and average restoration time per outage. The average restoration time per outage is equal to the total downtime per year divided by the number of outages. The circuit performance indices include Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Duration Index (SAIDI). The system downtimes are calculated based on SAIDI. Therefore, the results of reliability algorithm affect the elements of vector $\underline{Y}_d$ defined in Section 4.2. This in turn affects the results of the vector $\underline{D}$ as shown in Equation 5.11.

Reliability analysis is considered here as a tool to be used in predicting the performance of a given distribution system design. Generally, restoration analysis is considered as a tool to be used during operations for outaged situations. However, restoration analysis should also be applied during system design deliberations.

Most algorithms presented for reliability analysis have focused on generation and transmission systems. Since most outages occur at the distribution system level, emergency power restoration and reliability algorithms are needed to improve distribution system performance [59].

Reliability analysis calculates load point performance indices and circuit performance indices. It should be noted that as a subset of its calculations, reliability analysis must predict restoration times. Emergency power restoration analysis is used to minimize restoration times during outage conditions.

The Electric Power Research Institute sponsored a project on distribution system reliability analysis which defined sets needed for calculating the reliability of a given load point. Two additional sets have been added to those defined by EPRI to account for system constraint violations [59].

EPRI's reliability analysis calculates load point reliability indices at each bus. A load point represents a set of individual loads that have been grouped together at each bus for the reliability analysis. For a given circuit, EPRI's distribution system reliability algorithm selects a load point whose reliability indices are desired. This load point will be referred to here as the "down load point".

Associated with the down load point, the reliability algorithm builds several unique sets of circuit components. The set of components whose failure can cause loss of power to the selected down load point are grouped together. EPRI has used the average component failure rates and the average component repair times to predict the downtime and the restoration time of each load point in a given circuit.

Reliability and restoration time analysis algorithms utilize field and statistical data to determine load point performance indices. Successful implementation of the algorithms depend upon having field data and associated statistics.

The component failure rates are a function of weather conditions. That is, component failure rates are often higher during lightning conditions than during fair weather conditions. The duration of the fair weather periods and lightning weather conditions is considered to be a random phenomenon and can be described by an expected value. For each individual failure, the weather condition at the time of failure should be defined. Some utilities currently have programs in place which gather field data that is needed to calculate failure rates and repair times [59].

Reliability and restoration time analysis also require switch operation times to determine service restoration time during outage conditions. The distribution system contains a number of manual and automatic switches. A number for the operation of automatic switches may be readily assumed, such as one minute.

During outage conditions with manual switches, the distribution system crew physically locates the manual switch that needs to be operated to restore the power. The manual switch operation time varies with the weather condition and geographic location of the switch. In general, utilities do not currently maintain switch operation times.

Electrical utilities currently have programs in place which gather field data that is needed to calculate failure rates and repair times. Utilities generate outage reports for each failure in the system [59]. The outage report includes a short description of a restoration scheme and the date and time stamp for each step taken during the restoration of power. The date and time stamps may be used in failure rate and repair time calculations. The outage reports can be easily generated in an engineering workstation environment.

6.3.2 Reliability Computer Algorithm

A computer algorithm for reliability analysis of distribution systems is part of the DANE Workstation [55]. The workstation is used to edit/modify the reliability algorithm's data inputs. The data inputs include failure rates and repair times of each component and switch operation times. The Workstation allows interactive modification of switch placement and operation times so that the effect of automatic switches may be readily studied. The reliability algorithm then calculates reliability indices using these data inputs.

For the reliability analysis algorithm, circuit components are placed in groups called segments [59]. The components within a segment are electrically connected to each other, and cannot be switched away from one another. Each segment may be considered to consist of boundary components and interior components.

A segment's entry boundary component is either a switch, recloser, breaker, fuse, or source [59]. Furthermore, each segment has only one switch, recloser, breaker, or fuse. A segment's remaining interior and boundary components consist of such components as line sections, transformers, voltage regulators, and capacitor banks.

All of the load within a segment is lumped into a single equivalent load, which is referred to as a load point. Segments that do not contain any loads are not considered to be load points. The reliability algorithm calculates load point performance indices and circuit performance indices.

The average downtime and restoration time are calculated for the average customer and also for each customer type for all segments in a given circuit. The average restoration time is equal to the total downtime per year divided by the number of outages. Note that the reliability algorithm extrapolates CAIDI and SAIDI using downtimes, whereas utilities calculate the CAIDI and SAIDI using the real field data.

The load point performance indices and circuit performance indices are determined using circuit traces and set operations. The reliability algorithm employs circuit traces to develop several unique sets of segments. Linked-list circuit traces are used to identify the reliability sets for the radial distribution system. The linked lists are facilitated by using pointers inside the C language structures. These pointers are used as the links which join C language structures together [57].

6.4 Economic Evaluation

6.4.1 General Background

The general approach to evaluating distribution systems used in this research is to develop and compare alternative plans for meeting the needs of a specified portion of a utility's service area over a given period. Some of these plans would employ customary circuit designs, while others would incorporate automated distribution functions. All plans should meet the basic planning objectives of providing service at desired voltage and reliability levels to all customers in a safe and efficient manner [2].

For each year, the total requirements for new equipment are determined. From these requirements, the capital expenditures along with operating and maintenance costs are determined. These costs along with expenses and benefits associated with maintaining efficient and reliable service are used to calculate the year-by-year revenue requirements for each plan. The economic comparison of alternative plans is based on comparing respective present value of revenue requirements.

A large amount of equipment and financial accounting, data manipulations, and calculations are required in evaluating detailed alternative distribution plans. The requirements for new equipment to implement the desired distribution automation functions in each year must be considered. The annual capital carrying charges as well as maintenance cost for this equipment must be calculated. In addition, the operational savings due to distribution automation should be accounted for.

To relieve the computational burden, software may be developed to perform many of the equipment and cost accounting functions, the calculation of costs and benefits of automated functions, and the evaluation of total revenue requirements discounted to the present. Furthermore, computer software is used to establish a database containing all necessary input parameters. The analysis would be guided by the configuration of the existing system, the load and capacity situation, and the specified policy regarding the level of automation.

A report published by the Electric Power Research Institute (EPRI) described a methodology for the economic feasibility of automating electric utility distribution systems [8]. Approximately 40 distribution automation functions for the distribution substation, feeder primary, and secondary levels were included. The report concluded that a large number of equipments, system characteristics, and economic parameters are involved in using the methodology. Therefore, digital computer programs are desirable to facilitate the evaluation process and to guide the user in an orderly fashion [60].

Computer programs were developed by Public Service Electric & Gas (PSE&G) as part of the economic evaluation methodology described in the EPRI report [8]. These programs were used to analyze part of the PSE&G distribution system. The basic purpose was to determine the revenue requirements for a base case distribution system expansion as opposed to an automated case expansion. The results allow the user to compare cases and determine if distribution automation is cost effective. Input requirements and typical output results were described in a published paper [61].

The use of a structured approach supported by computer software can significantly expand the capability for analyzing a wide range of alternative plans. Furthermore, a structured approach coupled with the computational aids of interval mathematics provide an excellent format for sensitivity analysis. Thus, attention can be focused on the critical aspects of alternative designs and their economic impacts, which in turn improves confidence in the results.

A computer algorithm for economic analysis of distribution systems is presented in the next section. The algorithm runs in an engineering workstation environment which gives the user the capability to modify input parameters for all available algorithms. The engineering workstation is used as a design or an operational tool to improve the performance of the system. The workstation performs reliability, restoration, power flow, reconfiguration, and economic analysis calculations. These analyses can be used in either planning studies or during actual operations.

The engineering workstation retrieves data from the distribution database and builds network topology using circuit traces. The workstation then displays distribution networks on the workstation screen. Once the set of circuits are displayed, the system designer or operator can select any number of circuits for the system analysis [55].

It should be noted that the entire system's data is retrieved into the workstation memory. Since the entire data is stored in the random access memory, the workstation hard disk is not accessed during design or operational studies. This process saves computer time which is better utilized for studying the distribution system. In addition, the workstation is facilitated with an interactive graphical display of the distribution system. The user can interactively edit or modify the system using a mouse, which is used as a pointing device for each system device displayed on the workstation screen.

6.4.2 Database Aspects

This section first presents the data structures used by the economics algorithm along with interval mathematics functions. The linked lists of data structures are then presented along with pointers that are utilized in the economic calculations.

As mentioned earlier, the DANE workstation uses a relational database management system to maintain necessary data in tables [55]. Relational databases have many advantages in flexibility and data integrity, but they suffer from slow performance [62]. DANE improves the performance by loading the data into liked lists of data structures. The algorithms can then access data through pointers to memory locations, rather than by reading from the hard disk.

A data structure can be viewed as a group of data describing some item. To form a linked list of data structures, at least one pointer is required. Pointers in the C language specify the location of data in computer memory [57]. A pointer is used to locate a desired data structure within the linked list and then retrieve a data item from that data structure [62]. Each data structure has at least one pointer which points to another data structure. Thus, the pointers allow various algorithms in DANE to work in a coordinated fashion.

There is a parallel relationship that exists between database rows and tables to data structures and linked lists. This parallelism implies that a database row is the equivalent of a data structure. When all the data structures have been processed the linked list is formed, which is equivalent to a database table [62].

The economics algorithm does not have access to the database tables directly. The information in the database tables is brought into computer memory by database access algorithms. This information is stored in memory in the form of linked lists of data structures. These lists are a chain of data structures linked together using pointers and are available to the algorithm.

Pointers are one of the most useful features of the C programming language. A pointer provides an indirect means of accessing the value of a particular data item. A linked list has a starting pointer and is terminated by NULL. Table 6.1 shows the correspondence between database tables and data structures used by the economics algorithm. It should be noted that data items in database tables and data structures do not have a one-to-one correspondence. The data structures used to implement the economics algorithm are described as follows.

Interval Data Structure:

The Ival data structure is defined in terms of two elements l and u representing the lower and upper bounds of an interval number. It is formally defined as follows:

```
Struct ival
        {
         double l;
         double u;
        }.
```

Therefore, each parameter declared as an interval number contains two real numbers representing the lower and upper bounds. For example, if a parameter X is an interval in the range of 1.0 to 2.0, then X.l = 1.0 and X.u = 2.0.

Table 6.1. Correspondence Between Database Tables And Data Structures

Database Table	Data Structure
-	Ival
-	Sys_econ
Economics	Tab_econ
Circuit	Ckts
Components	Component Trace
Substation	Tab_sour
Capacitor	Tab_caps
Controller	Tab_Cont
Transformer	Tab_xform
Line_Cable	Tab_lines
Switches	Tab_swt
Breaker	Tab_brk
Configurations	Swt_conf
Operations	Oper

System Economics Data Structure:

The system economics data structure is defined for the actual and planned system of circuits. This data structure stores the results of the economics algorithm for every system it runs for. Table 6.2 illustrates the definition of data items in the data structure. As seen from Table 6.2, the data items include the present value of revenue requirement along with its annual components. In addition, it contains the relevant results used in calculating these revenue requirement components. Finally, it contains the elements of the vector $\underline{D}$ as shown in Equation 5.11 which was defined in Chapter 5.

Economics Data Structure:

The data structure Tab_econ corresponds to the Economics database table. The economics table contains the general economic input parameters which are used by the economics algorithm. Table 6.3 illustrates the definition of data items in the Tab_econ data structure. Some of these parameters can be chosen interactively from the DANE workstation menu. These parameters are as follows: mar, econ_peak, and inflation rates.

Circuit Data Structure:

The Circuit Data Structure is defined for every circuit in the system. This data structure stores items pertinent to a specific circuit. Some prominent data items in the Circuit Data Structure are Circuit Order, Circuit Name, Circuit KW Peak, and Circuit Voltage Dependency Factor. Table 6.4 illustrates the definition of data items in the Circuit Data Structure which are relevant to the economics algorithm.

If there are several circuits in the system, then there is a linked list of Circuit Data Structures, where each data structure contains information about a single circuit in the system. This data structure also contains a pointer which is pointing to the first component present in the linked list of Component Trace Data Structures for that particular circuit.

Table 6.2. Description of Data Items in System Economics Data Structure

Data Item	Description
pvrr[sys]	interval present value of revenue requirement (0 = actual system, and 1 = planned system)
ann_rev_req[0][yr][sys]	interval annual system revenue requirement
ann_rev_req[1][yr][sys]	interval annual system carrying charges
ann_rev_req[2][yr][sys]	interval annual system maintenance cost
ann_rev_req[3][yr][sys]	interval annual system capital plus maintenance cost
ann_rev_req[4][yr][sys]	interval annual system cost of losses
ann_rev_req[5][yr][sys]	interval annual system peak cost
ann_rev_req[6][yr][sys]	interval annual system value of service cost
vos_per_cus[3][yr][sys]	interval annual system value of service per customer type (0 = residential, 1 = commercial and 2 = Industrial)
ann_kwh_loss[yr][sys]	annual system KWh losses
kwh_loss[sys]	total system KWh losses
ann_peak_kw[yr][sys]	annual system peak KW demand
peak_kw[sys]	system peak KW demand
season_for_peak[yr][sys]	season when system peak occurred
type_of_day_peak[yr][sys]	type of day when system peak occurred
hour_of_day_peak[yr][sys]	hour of day when system peak occurred

Table 6.2. Description of Data Items in System Economics Data Structure Continued

Data Item	Description
cus[yr][3]	number of system customer by customer type (0 = residential, 1 = commercial & 2 = Industrial)
ann_caidi[yr][sys]	annual system caidi
average_caidi[sys]	average system caidi over all years analyzed
ann_saidi[yr][sys]	annual system saidi
average_saidi[sys]	average system saidi over all years analyzed
dC	distance between the intervals pvrr[0] and pvrr[1]
RCI	fractional difference between pvrr[0].u and pvrr[1].u
PO	probability of overlap between the intervals pvrr[0] and pvrr[1]
$\%\Delta LS_{12}$	percent change in system losses between two alternative designs (kwh_loss[0] and kwh_loss[1])
$\%\Delta SAIDI_{12}$	percent change in average SAIDI between two alternative designs (average_saidi[0] and average_saidi[1])
$\%\Delta PK_{12}$	percent change in peak between two alternative designs (peak_kw[0] and peak_kw[1])
EIR	Economic Index for Reliability ($dC/\%\Delta SAIDI_{12}$)
EIE	Economic Index for Efficiency ($dC/\%\Delta LS_{12}$)
EIP	Economic Index for Peak ($dC/\%\Delta PK_{12}$)

Table 6.3. Description of Data Items in Tab_econ Data Structure

Data Item	Description
mar	interval minimum acceptable return
inflation[2]	interval inflation rate (0 = capital and 1 = labor)
carry_charge_factor[47]	interval carrying charge factor by equipment type (up to 47)
instal_cost[47]	installation cost by equipment type (up to 47)
inc_kwh_gen_cost[3][3]	incremental KWh generation cost by season and type of day (0 = summer, 1 = winter & 2 = fall/spring; 0 = weekday, 1 = weekend & 2 = holiday)
econ_peak	peak KW level beyond which an additional cost is added

Table 6.4. Description of Data Items in Circuit Data Structure

Data Item	Description
ckt_nam	circuit name
ckt_num	circuit number
ckt_ord	order in which the circuit appears in the linked list
num_cmps	total number of components in the circuit
q_ckt_analy	variable used to indicate whether circuit is to be analyzed or not
cus[j][p]	number of customers attached to circuit based on customer type & phase
load_scal[j]	load scaling factor based on customer type
year	year for analysis
sea	season (0 = summer, 1 = winter, and 2 = fall)
hod	hour of day to be analyzed (ranges from 0 to 23)
tyd	type of day (0 = weekday, 1 = weekend, and 2 = holiday)
kw_loss	kilowatt losses in circuit corresponding to year, season, type of day, and hour of day
circuit_peak	circuit kilowatt peak
year_for_peak	year for circuit peak
season_for_peak	season for circuit peak

Table 6.4. Description of Data Items in Circuit Data Structure Continued

Data Item	Description
type_of_day_peak	type of day for circuit peak
hour_of_day_peak	hour of day for circuit peak
*sckt	pointer which is pointing to the first component present in the linked list of Component Trace Data Structures for a particular circuit
*eckt	pointer which is pointing to the last component present in the linked list of Component Trace Data Structures for a particular circuit
*ptr_ckts	pointer which is pointing to the next Circuit Data Structure in linked list

Component Trace Data Structure:

The Component Trace Data Structure is defined for every component in the circuit. This data structure contains engineering, topological, and graphical data for each component. In addition, it stores the output of analysis programs such as power flow analysis, fault analysis, and reliability analysis. There are many components in a circuit and each component is represented by a Component Trace Data Structure. Thus, several such data structures are linked together using pointers to form a list of components in a circuit.

The Component Trace Data Structure includes data items such as Component Order, Component Type, Component Code, Circuit Order, Voltages, Currents, Power Flow, year installed, and so on. The data items in this Data Structure relevant to the economics algorithm are defined in Table 6.5.

Source Data Structure:

This data structure obtains the information from the Substation Table which is a member of the Parts Library. If there is more than one source in the Substation Table, then there is a linked list of the Source Data Structures. Some of the prominent data items are source code, source type, primary kilovolts magnitude, customer voltage, and capital and maintenance costs. Table 6.6 shows the data items in this data structure.

Transformer Data Structure:

This data structure acquires the information from the Transformer Table which is a member of the Parts Library. There is a linked list of Transformer Data Structures if there is more than one transformer in the Transformer Table. Some important data items are primary voltage, secondary voltage, kva rating, winding impedance and, and capital and maintenance costs. Relevant data items in the Transformer Data Structure are shown in Table 6.7.

Capacitor Data Structure:

The Capacitor Data Structure stores information regarding switched or fixed capacitors. The information in this data structure is derived from the Capacitor Table. If there is more than one capacitor in the Capacitor Table, then a linked list of Capacitor Data Structures is formed. Table 6.8 shows the definition of relevant data items in the Capacitor Data Structure.

Controller Data Structure:

This data structure stores the information regarding the controllers present in the Parts Library. A linked list of Controller Data Structures is also defined which is comprised of various types of controllers. Some of the data items pertinent to the economics algorithm are controller code, controller type, controller order, and capital maintenance costs. Table 6.9 shows the definition of relevant data items in this data structure.

Breaker Data Structure:

The Breaker Data Structure stores information regarding different types of breakers. The information in this data structure is derived from the Breaker Table. If there is more than one breaker in the Breaker Table, then a linked list of Breaker Data Structures is formed. Table 6.10 shows the definition of relevant data items in the Breaker Data Structure.

Lines Data Structure:

The Lines Data Structure stores information regarding different line types. The information in this data structure is derived from the Line_Cable Table. If there is more than one line in the Line_Cable Table, then a linked list of Lines Data Structures is formed. Table 6.11 shows the definition of relevant data items in the Lines Data Structure.

Table 6.5. Description of Data Items in Component Trace Data Structure

Data Item	Description
tra_ord	order in which component appears in circuit
cmp_type	component type
type_num	code number associated with component type
yr_instal	component installation year
ckt_ord	order of the circuit as it appears in linked list of Circuit Data Structures
adj_ckt	circuit number for the circuit which is physically adjacent to the circuit under study. The two circuits are separated by an open switch
adj_cmp	number of the component in the adjacent circuit which is connected to the circuit under study via an open switch
f_cmp	forward component
*f_ptr	pointer which is pointing to the forward component
cmp_code	code assigned to each component
ord	order in which component appears in linked list associated with the PARTS LIBRARY
phase	phase present (0 = A, 1 = B, and 2 = C)
fdrlngth	distance between component and the source (in miles)
cmplngth	component length (in miles)

Table 6.5. Description of Data Items in Component Trace Data Structure Continued

Data Item	Description
tap_cmp	component that tap is associated with
tap[p]	transformer or capacitor tap for phase p
nom_kw[p]	kw value calculated at nominal voltage for each phase (includes both spot and customer loads)
nom_kvar[p]	kvar value calculated at nominal voltage for each phase (includes both spot and customer loads)
spot_kw[P]	constant kw load attached at a load point for each phase

Table 6.6. Description of Data Items in Source Data Structure

Data Item	Descriptions
Source_Code	user specified code
Source_type	substation or cogenerator
Source_Ord	order in which source appears in the Substation Table (order number is added to the start of the linked list in order to access a particular source in the linked list)
cap_cst	substation capital cost
main_cst	substation maintenance cost
Pri_Kv_Mag	primary side voltage magnitude in kilovolts
Cust_Vol	customer side voltage in volts
Phase_Ang[p]	phases A, B, and C voltage angle in degrees
*ptr_sour	pointer which points to the next data structure of type Source in the linked list

Table 6.7. Description of Data Items in Transformer Data Structure

Data Item	Description
Transformer_Code	user specified code for transformer
Transformer_Type	regulating transformer or fixed transformer
Transformer_Ord	order in which transformer appears in linked list (order number is added to the start of a linked list to access a particular transformer)
cap_cst	capital cost
main_cst	maintenance cost
Pri_Vol	primary side voltage rating
Sec_Vol	secondary side voltage rating
KVA_Rating	KVA rating
Z	winding impedance
*ptr_xform	pointer which points to the next data structure of type Transformer in the linked list

Table 6.8. Description of Data Items in Capacitor Data Structure

Data Item	Description
Capacitor Code	user specified code
Capacitor Type	switched capacitor or fixed capacitor
Capacitor_Ord	order in which capacitor appears in the linked list (added to the start of linked list to access a particular capacitor)
cap_cst	capital cost
main_cst	maintenance cost
Nominal Kvar	nominal kvar value
Vol_Rating	voltage rating in volts
*ptr_caps	pointer which points to the next data structure of type Capacitor

Table 6.9. Description of Data Items in Controllers Data Structure

Data Item	Description
Controller_Code	user specified code for controller
Controller_Ord	order in which controller appears in linked list
Controller_Type	switched capacitor, regulating transformer, or voltage regulator
cap_cst	capital cost
main_cst	maintenance cost
min_cont_set	minimum controller setting in terms of transformer's tap or capacitor's kvar
max_cont_set	maximum controller setting in terms of transformer's tap or capacitor's kvar
Step Size	steps by which tap or kvar may increase or decrease
Min_Setpoint	minimum setting in terms of voltage or power factor
Max_Setpoint	maximum setting in terms of voltage or power factor
*ptr_cont	pointer to next data structure of type Controller in the linked list

Table 6.10. Description of Data Items in Breaker Data Structure

Data Item	Description
Breaker Code	user specified code
Breaker Type	type of breaker
Breaker_Ord	order in which breaker appears in the linked list (added to start of linked list to access a particular breaker)
cap_cst	capital cost
main_cst	maintenance cost
*ptr_brk	pointer which points to the next data structure of type breaker

Table 6.11. Description of Data Items in Lines Data Structure

Data Item	Description
Line Code	user specified code
Line Type	type of line
Line_Ord	order in which line appears in the linked list (added to start of linked list to access a particular line)
Amps_rat	Amps rating of line
cap_cst	capital cost
main_cst	maintenance cost
*ptr_lines	pointer which points to the next data structure of type line

Switch Data Structure:

The Switch Data Structure stores information regarding switch types. The information in this data structure is derived from the Switch Table. If there is more than one switch in the Switch Table, then a linked list of Switch Data Structures is formed. Table 6.12 shows the definition of data items in the Switch Data Structure.

Swt_Conf Data Structure:

This is one of the output data structures used by the reconfiguration algorithm. This in turn is used as an input for the economics algorithm. The Swt_Conf Data Structure stores switch status (i.e. open or closed) for each switch in the system. It can store up to two-hundred and fifty switch statuses for each system configuration. An identification number is also assigned for each system configuration. A given set of switch statuses is only stored once. The definition of the data items in the Swt_Conf Data Structure is shown in Table 6.13.

Operations Data Structure:

The Operations Data Structure serves as one of the output data structures for the reconfiguration algorithm. It is in turn used as an input for the economics algorithm. This data structure stores season, type of day, hour of day, and configuration identification number. This structure also stores the kilowatt loss for that particular system configuration. Table 6.14 illustrates the definition of data items in the Operations Data Structure.

6.4.3 Economics Computer Algorithm

This section describes the economics algorithm in terms of the information presented so far. The main features of the economics algorithm are as follows. The economic analysis algorithm will interface with results obtained from an existing reliability analysis algorithm which calculates reliability indices such as CAIDI and SAIDI. Existing power flow and reconfiguration algorithms will be used to evaluate

Table 6.12. Description of Data Items in Switch Data Structure

Data Item	Description
Switch Code	user specified code
Switch Type	type of switch
Switch_Ord	order in which switch appears in the linked list (This is added to the start of a linked list to access a particular switch)
cap_cst	capital cost
main_cst	maintenance cost
*ptr_swt	pointer which points to the next data structure of type switch

Table 6.13. Description of Data Items in Swt_Conf Data Structure

Data Items	Description
conf_id	system configuration identification
swt_status[250]	switch status, open or closed
*ptr_swt_conf	pointer which points to the next data structure of type Swt_Configuration in the linked list

Table 6.14. Description of Data Items in Operations Data Structure

Data Item	Description
sea	season (0 = summer, 1 = winter, and 2 = fall/spring)
tyd	type of day (0 = weekday, 1 = weekend, and 2 = holiday)
hod	hour of day (ranges from 0 = 12 midnight, ..., 23 = 11 p.m.
conf_id	configuration identification
kw_loss	system kw loss for particular system configuration
caidi	system caidi
saidi	system saidi
*ptr_oper	pointer which points to the next data structure of type Operations in the linked list

system losses and system peak loads. Several economic indices associated with system cost, reliability, efficiency, and system peak will be used in cost/effectiveness analysis of alternative distribution systems. The analysis can incorporate traditional expansion plans as well as plans that implement distribution automation.

The economics algorithm utilizes both power flow and estimation algorithms to obtain certain results. The estimation algorithm calculates loads at the chosen time points based on time of day, type of day, and season. A load growth factor is also incorporated in the estimation algorithm, which means that loads are updated for future years by multiplying by a customer type dependent scaling factor. These updated loads are then utilized to study the effect of load growth on future planning.

Before running the economics program, several choices must be made interactively from the DANE menu to identify which options to run. The first choice is to specify the circuits to be analyzed. The time points to be analyzed must then be chosen. The next choice is to specify whether to run reconfiguration studies or not. Similarly, a choice is needed to specify whether to run reliability or not. The next choice pertains to whether two systems need to analyzed or just one. Typically, one system represents an actual or base case while the other represents a planned case. Finally, the economic parameters of minimum acceptable return and inflation rates need to be specified along with the analysis period in years.

A description of the economics algorithm steps can now be given as follows:

1. Initialize all the variables of data structure sys_econ for all chosen analysis years.
2. Check whether one system or two need to be analyzed.
3. Start the analysis for the first year.
4. Run reconfiguration on chosen circuits if needed to obtain KWh losses and peak KW. These results are used to obtain $\%\Delta LS_{12}$ and $\%\Delta PK_{12}$ as defined by Equations 5.6 and 5.8, respectively. These in turn are used to obtain EIE and EIP as defined by Equations

5.7 and 5.9, respectively. All of these results are elements of the vector $\underline{D}$ as shown by Equation 5.11.

5. Run reliability on chosen circuits if needed to obtain reliability indices such as SAIDI. The SAIDI is used to obtain $\%\Delta SAIDI_{12}$ and EIR as defined by Equations 5.4 and 5.5, respectively. These in turn are elements of the $\underline{D}$ vector as shown by Equation 5.11.

6. Analyze chosen time points by season, type of day, and hour of day.

7. Run estimation and power flow for current time point if reconfiguration was not run. This is because reconfiguration runs power flow and estimation as part of its calculations. The results of these two algorithms include voltages, currents, and line power flows. These results are elements of the vector Y_d which affects both the $\underline{C}$ and $\underline{D}$ vectors as shown by Equations 4.2 and 4.3, respectively. The estimation algorithm calculates loads at chosen time points, which provides the results of Equation 4.4.

8. If all chosen circuits and time points were analyzed, store results in sys_econ data structure. These results include KWh losses, Peak KW and time it occurred, and SAIDI.

9. Use forward pointer to trace through all circuit components to obtain capital, installation, and maintenance costs as well as carrying charge factor. These are the elements of Y_i as defined in Section 4.2, which affect the $\underline{C}$ vector as shown by Equation 4.2. These parameters are obtained using procedures outlined in Section 6.1.3 and described by Equations 6.1 through 6.3. If a components has been installed in a previous year, then get its maintenance cost only. The carrying charge factors are used to calculate annual carrying charges based on capital and installation costs.

10. Apply inflation factors to capital and maintenance costs based on analysis year.

11. Calculate value of service cost based on the values in the Economics Table.

12. Add revenue requirement components for current analysis year. These components include cost of losses, peak cost if applicable, value of service cost, maintenance cost, and carrying charges.

13. Analyze the next year by repeating steps 4 through 12.

14. Calculate present value of revenue requirement after all chosen years are analyzed.

15. Analyze the other system if needed by repeating steps 3 through 14.

16. If all chosen systems and years have been analyzed, then the economic indices are calculated, which would be the final step. These indices comprise the elements of the $\underline{D}$ vector as shown in Equation 5.11.

A flow diagram of the algorithm steps is shown in Figure 6.3.

In conclusion, this chapter presented the relevant aspects of database and workstation environments along with the implementation of economic evaluation. The next chapter presents the application of the economics algorithm and the obtained results.

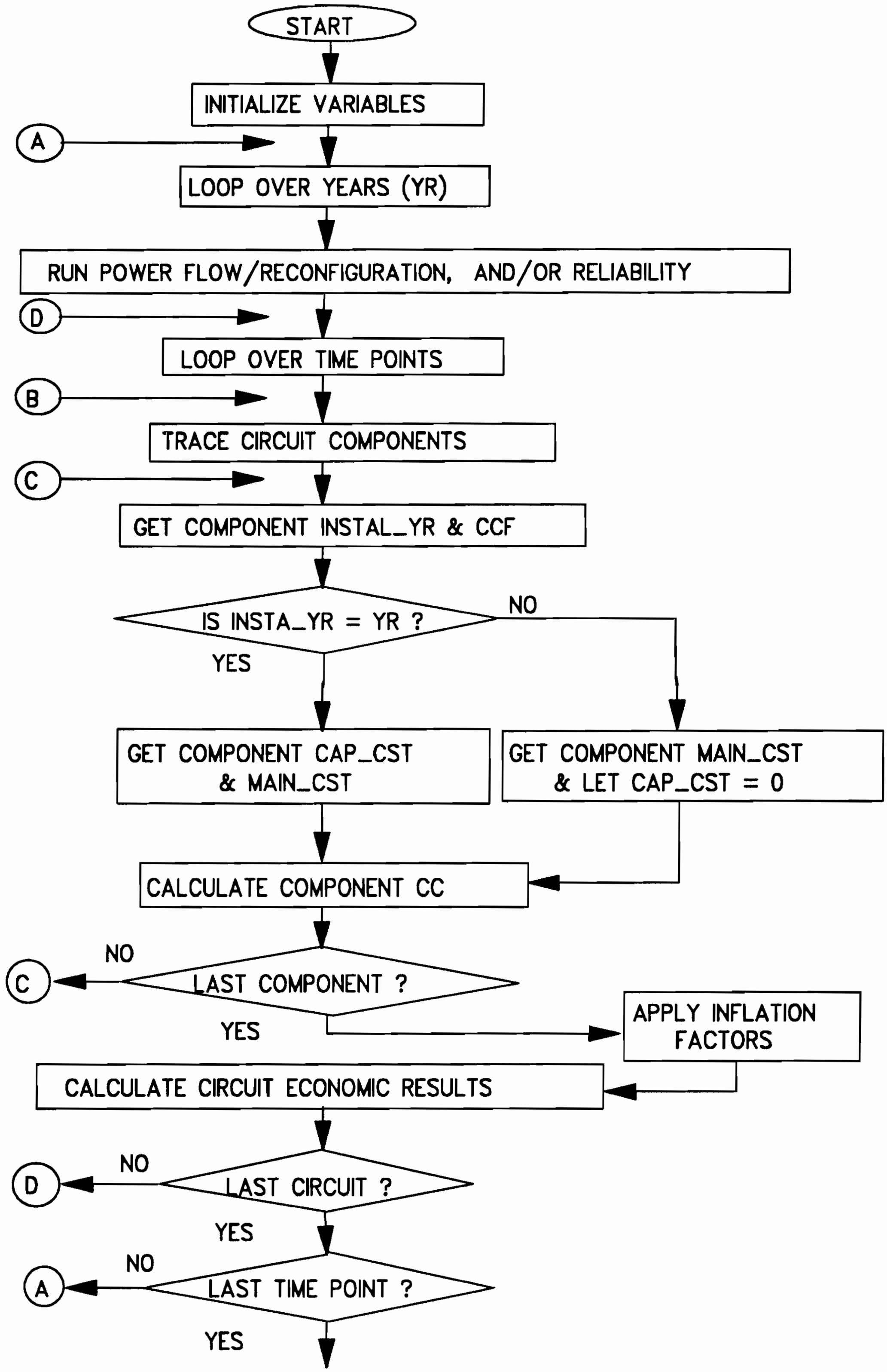

Figure 6.3. Flow Diagram of Economics Algorithm

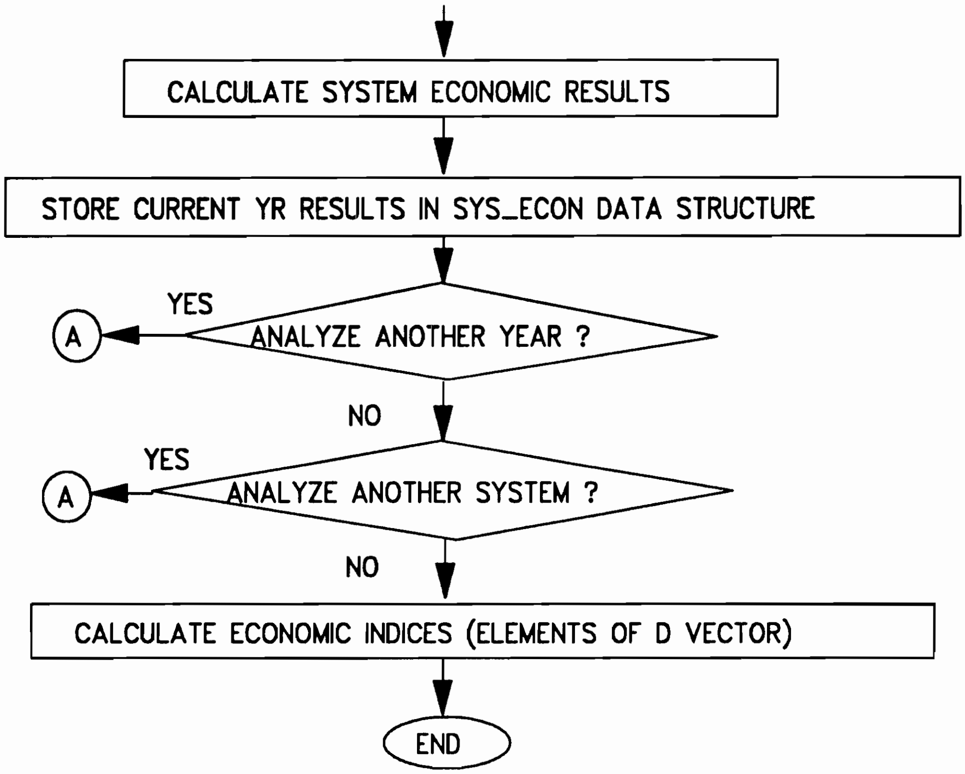

Figure 6.3. Continued Flow Diagram of Economics Algorithm

CHAPTER 7

Sample Applications And Results

7.1 Introduction

This chapter presents several case studies for a sample distribution system. These examples are intended to illustrate the use of the economics algorithm as part of the DANE workstation. The results which are presented apply particularly to the system of circuits used here as an example. Therefore, it may be incorrect to generalize these results on all distribution systems. However, some important insights are obtained which may be applicable to distribution system design in general.

7.2 Description Of Case Studies

The sample distribution system which is used in the following case studies is shown in Figure 7.1. The system consists of two circuits attached to an existing distribution substation. Circuit 1 supplies 3000 residential all electric customers, whereas Circuit 2 supplies 341 small commercial customers. In addition, there is a constant load of 300 KW in the middle which may be supplied by either circuit. It is assumed that these loads have stabilized and are no longer growing. However, there are ten new industrial customers in the area indicated by the dotted line in Figure 7.1. These industrial loads have a 3% annual growth rate.

The base case considered here represents building a new substation to supply the load growth as shown in Figure 7.2. The alternative design cases represent implementing other measures to defer the construction of the new substation without overloading the existing circuits. These different choices represent the elements of the vector $\underline{U}$ which affects both the $\underline{C}$ and $\underline{g}$ vectors as shown in Equations 4.2 and 4.4, respectively. In addition, these choices affect the $\underline{Y}_d$ vector as well, which in turn affects both the $\underline{C}$ and

D vectors as shown in Equations 4.2 and 4.3, respectively. The alternative case studies are described as follows:

1. Reconductoring: Upgrading line sections to avoid overloading and improve system efficiency

2. Reconfiguration: Replace manual switches with automatic switches to perform daily reconfiguration in order to improve system efficiency and reliability

3. Power factor control: Adding switched capacitors to improve the power factor in order to improve system efficiency

4. Voltage control: Adding regulating transformers to control the voltage level in order to reduce system peak

5. Load management without storage: Implementing load management to reduce system peak and improve efficiency

6. Load management with storage: Implementing load management with storage to reduce system peak and improve efficiency

7. Combination: Implementing all cases in order to improve system efficiency and reliability and reduce peak.

It should be mentioned that in all cases the new substation will eventually be built.

The load curves for residential all electric customers as well as small commercial customers are shown in Figure 7.3 for a Summer Weekday. The load curve for industrial customers is shown in Figure 7.4 for a Summer Weekday. The analysis period for all cases is ten years, but only for Summer Weekdays and Weekends for 24 hours a day. Other seasons are not considered since no good data is readily available. Furthermore, the same trends in the results can apply to other seasons. The cost information on equipment needed for each case is shown in Table 7.1. The equipment ratings are shown in Table 7.2. The economic input parameters are presented in Table 7.3. The information presented in these tables is based on realistic estimates from several electric utilities.

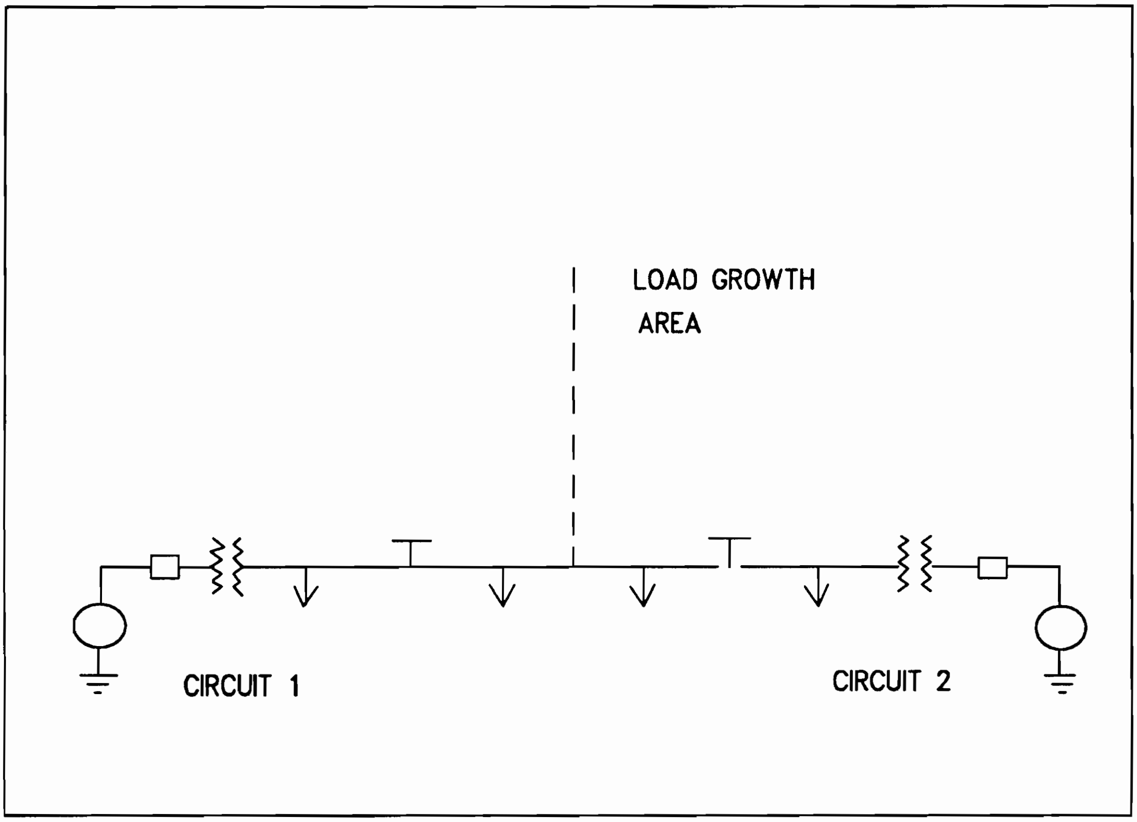

Figure 7.1. Existing System of Circuits

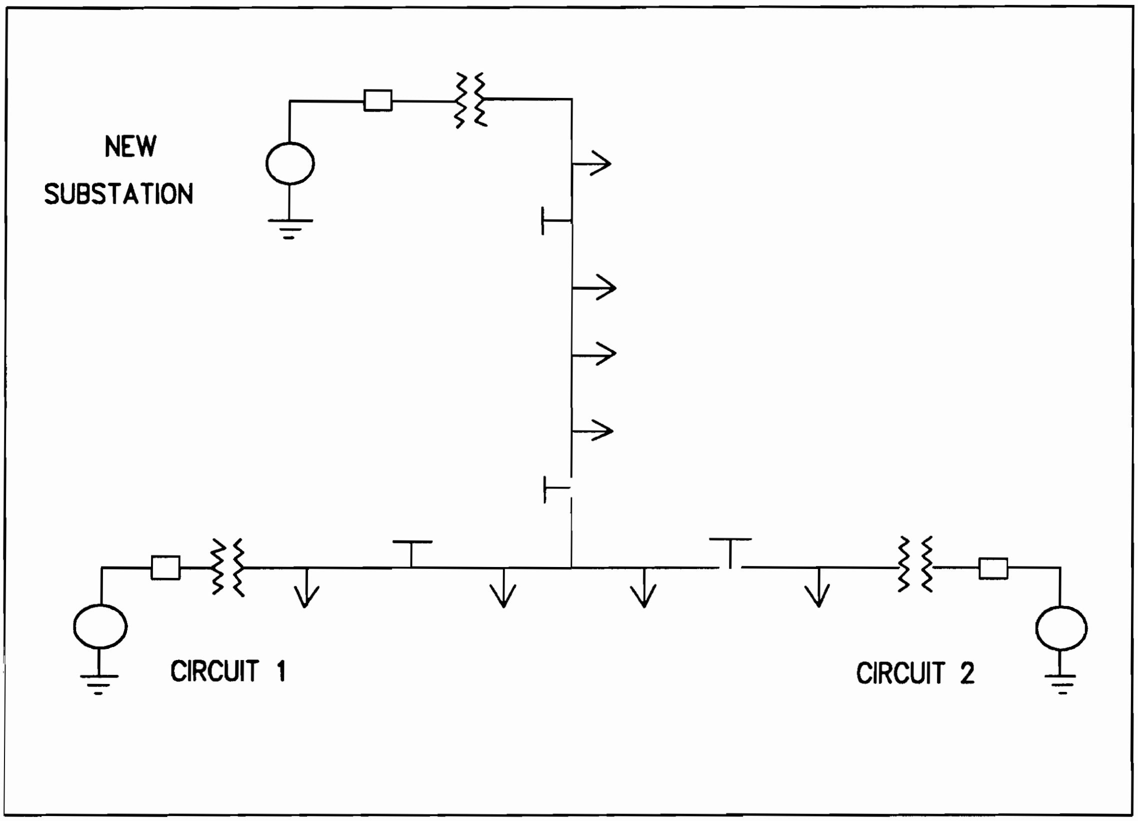

Figure 7.2. Base Case System

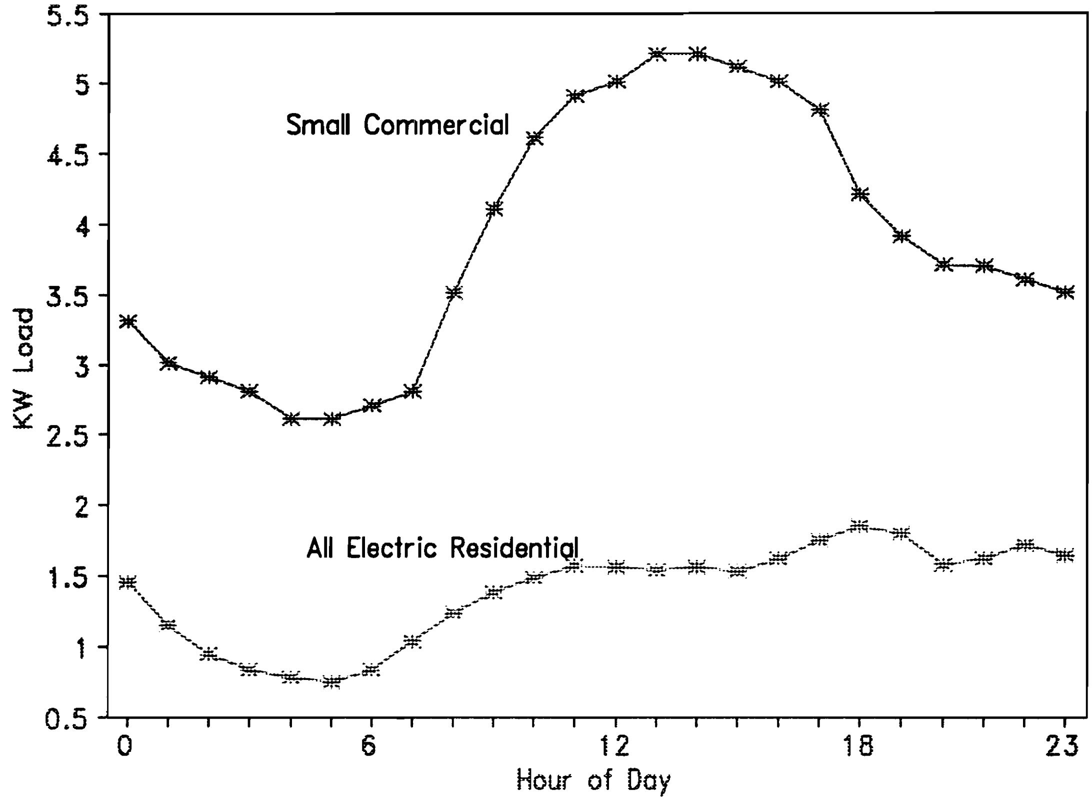

Figure 7.3. Load Curves For Residential All Electric And Small Commercial Customers

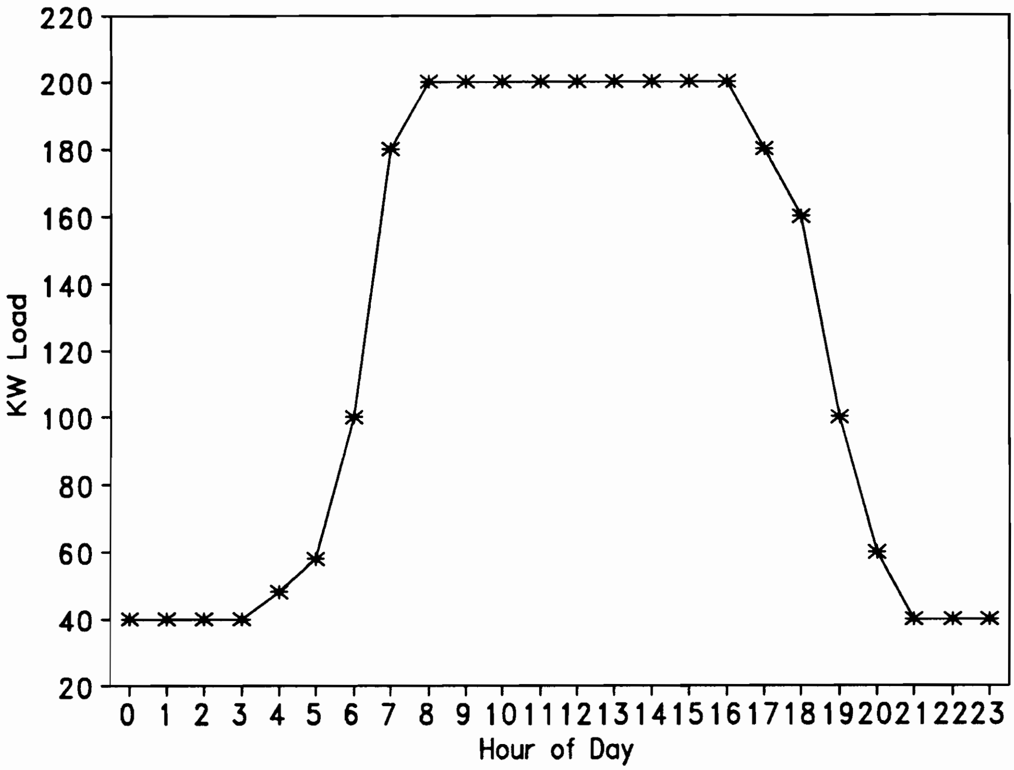

Figure 7.4. Load Curve For Industrial Customers

Table 7.1. Cost information on equipment added for each case

Case	Equipment Needed	Capital cost ($)	Installation cost ($)
Base Case	New substation	500000	250000
	Transformer	225000	112500
	Breaker	14000	7000
	Manual switch	5900	2950
Case 1	477 Al line	118000/mile	59000/mile
Case 2	Automatic switch	6000	3000
	Leased telephone line	100/month	-
Case 3	Switched capacitor	4800	2400
	Capacitor bank switch	1200	600
	Watt transducer	800	400
	Var transducer	500	250
	Power Factor controller	4000	2000
Case 4	Regulating transformer	275000	137500
	Watt transducer	800	400
	Var transducer	500	250
	Volt transducer	100	50
	Leased telephone line	100/month	-
Case 5	Load controller	100	50
	Radio controller	150	75
Case 6	Load controller	100	50
	Radio controller	150	75
	Storage equipment	200	100
Case 7	Equipment of all the above cases		

Table 7.2. Equipment Ratings

Equipment	Max Amp rating	Volt rating	Power rating
336 ACS line	450	13.2 KV	-
477 Al line	600	13.2 KV	-
Breaker	800	13.2 KV	-
Fixed Transformer	600	13.2 KV	14000 KVA
Regulating Transformer	600	13.2 KV	14000 KVA
Manual Switch	600	13.2 KV	-
Automatic switch	600	13.2 KV	-
Switched Capacitor	-	13.2 KV	300 KVAR
Power Factor Controller	-	-	0 - 10000 KVAR
			500 KVAR step
			0.94 - 0.98 pf

Table 7.3. General Economic Input Parameters

Parameter		Value
Minimum Acceptable Return		[0.10, 0.12]
Incremental KWh generation cost ($):		
	Fall morning	0.05
	Fall afternoon	0.04
	Fall night	0.02
	Winter morning	0.05
	Winter afternoon	0.04
	Winter night	0.02
	Summer morning	0.05
	Summer afternoon	0.05
	Summer night	0.03
Additional generation cost per peak KW ($)		2000
Inflation Rate (capital expenses)		[0.04, 0.05]
Inflation Rate (labor expenses)		[0.05, 0.06]
Equipment Carrying Charge Factor		[0.18, 0.20]
Value of Service by customer type ($/hr):		
	Residential	[2, 5]
	Commercial	[50, 100]
	Industrial	[1000, 1500]
Installation cost (% of capital cost)		50
Maintenance Cost (% of capital cost)		10

7.3 Results Of Case Studies

7.3.1 Base Case Results: Building New Substation

The results of the base case are summarized in Table 7.4. The range of present value of revenue requirements over ten years is equal to $ [2481821, 3381029]. The average SAIDI over ten years is 1.41. The sum of KWh losses over ten years is 1433423, and the peak KW in 1992 is 16335. The same relevant information for all cases is summarized in Table 7.5. The KWh losses increase every year due to the industrial load growth, which is indicated by the annual increase in cost of KWh losses. The carrying charges increase every year as well due to inflation. A plot of annual revenue requirement is shown in Figure 7.5. It should be noted that there is a widening trend of the interval range due to the inflation factor being multiplied more times as the number of years increases. This is a normal unavoidable situation due to the nature of inflation calculations.

7.3.2 Case 1 Results: Reconductoring

The results of case 1 are summarized in Table 7.6. Comparative information on all cases is presented in Table 7.5. A plot of annual revenue requirement is shown in Figure 7.6 for both Case 1 and the base Case. A Design Evaluation Display (DED) is shown in Figure 7.7 for losses since efficiency is an important aspect here. It should be noted that % losses are considerably higher in this case compared to the base case as shown by the last columns of Table 7.6 and Table 7.4.

It can be seen that reconductoring results in a deferment of building the new substation for nine years. However, a current overload occurs in the tenth year which requires building the new substation. In addition, it is obvious that the KWh losses are much larger than the base case losses because the industrial loads were being supplied by the existing two circuits. The reliability in this case becomes worse as well since SAIDI is higher. The present value of revenue requirement is 2.6% less than the base case.

Table 7.4. Base Case Results (New Substation)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[46606, 90392]	3975	[376976, 399500]	[427557, 493867]	1.61
1993	[46606, 90392]	4111	[383946, 408213]	[434663, 502716]	1.67
1994	[46606, 90392]	4481	[389453, 419104]	[440540, 513977]	1.77
1995	[46606, 90392]	4887	[393350, 432352]	[444843, 527631]	1.87
1996	[46606, 90392]	5330	[395482, 448148]	[447418, 543870]	1.98
1997	[46606, 90392]	5808	[395682, 466693]	[448096, 562893]	2.10
1998	[46606, 90392]	6323	[393771, 488204]	[446700, 584919]	2.21
1999	[46606, 90392]	6874	[389560, 512911]	[443040, 610177]	2.34
2000	[46606, 90392]	7461	[382846, 541058]	[436913, 638911]	2.46
2001	[46606, 90392]	8084	[373411, 572906]	[428101, 671382]	2.60

Table 7.5. Summary Of Relevant Information For All Cases

	Present Value Of Revenue Requirement ($)	Average SAIDI (Hours)	Sum of Losses (KWh)	Peak (KW)
Base Case	[2481821, 3381029]	1.41	1433423	16335
Case 1	[2465406, 3296655]	1.67	3292751	16327
Case 2	[1963655, 2591816]	1.074	1715419	16329
Case 3	[1706736, 2321988]	1.576	2434974	16330
Case 4	[2432655, 3214671]	1.486	1986734	15904
Case 5	[2731957, 3769271]	1.497	2266912	15861
Case 6	[3338848, 4506434]	1.497	2261080	15821
Case 7	[6087735, 7694218]	1.06	1047397	15381

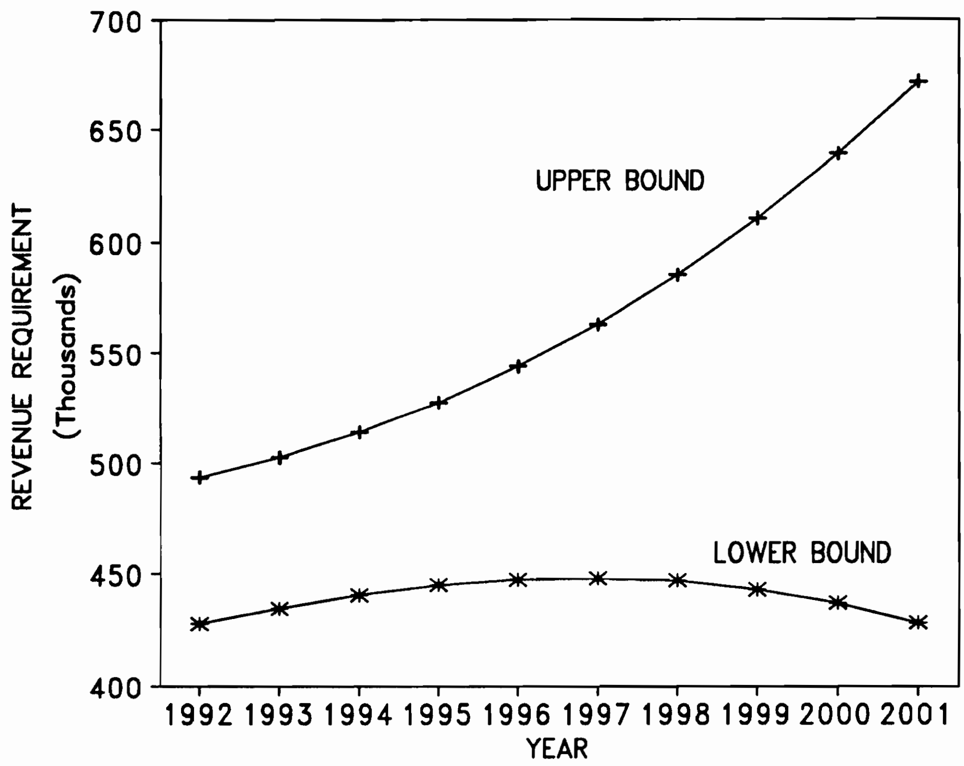

Figure 7.5. Annual Revenue Requirements For Base Case (New Substation)

Table 7.6. Case 1 Results (Reconductoring)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[56342, 109274]	10177	[353860, 382180]	[420378, 501631]	4.12
1993	[56342, 109274]	10658	[357819, 387129]	[424818, 507061]	4.33
1994	[56342, 109274]	11697	[360947, 393315]	[428985, 514286]	4.62
1995	[56342, 109274]	12794	[363161, 400840]	[432296, 522908]	4.90
1996	[56342, 109274]	13951	[364371, 409812]	[434663, 533037]	5.18
1997	[56342, 109274]	15166	[364485, 420346]	[435992, 544786]	5.48
1998	[56342, 109274]	16440	[363400, 432564]	[436181, 558278]	5.75
1999	[56342, 109274]	17772	[361008, 446598]	[435121, 573644]	6.05
2000	[56342, 109274]	19164	[357194, 462585]	[432699, 591023]	6.32
2001	[46606, 90392]	3887	[492176, 514700]	[542669, 608979]	1.57

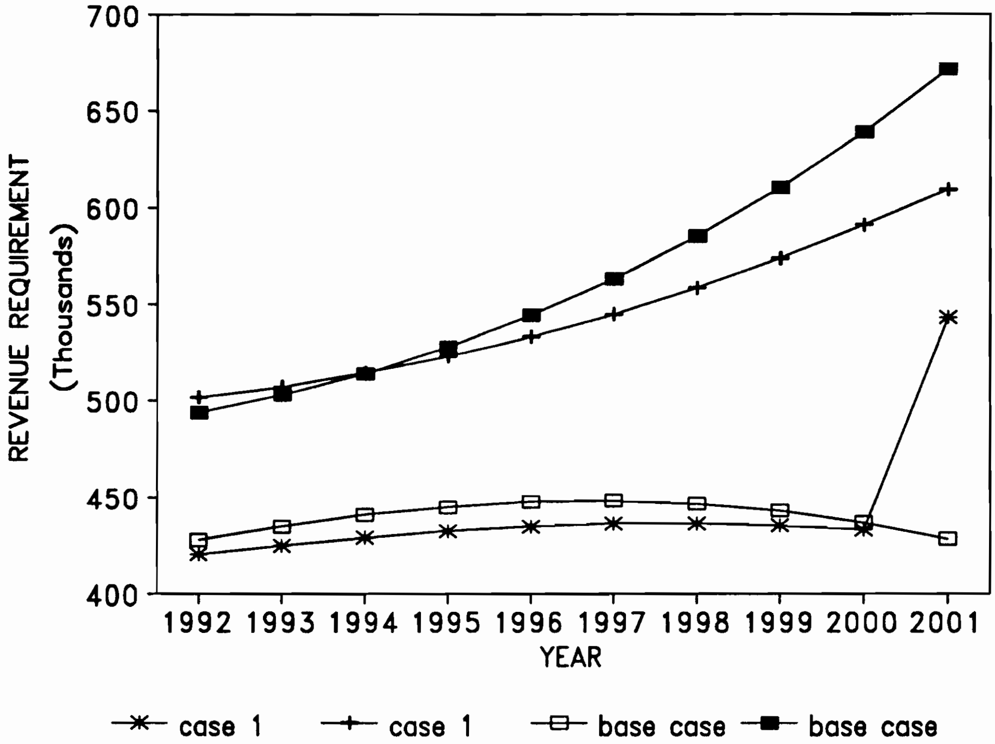

Figure 7.6. Annual Revenue Requirements For Case 1 (Reconductoring) Vs. Base Case

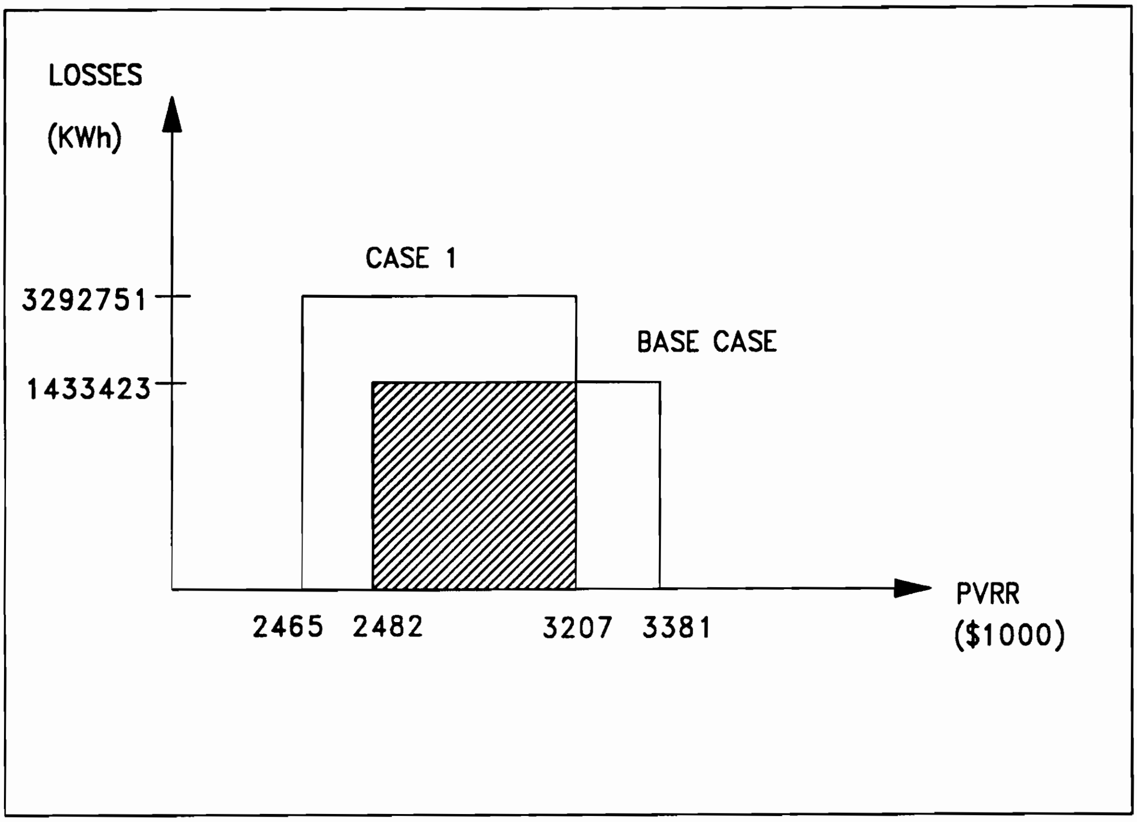

Figure 7.7. DED For Case 1 (Reconductoring)

However, the probability of overlap is 89%. The EDED for this case is shown in Figure 7.8. The EIP is not shown in Figure 7.8 since there is no significant change in Peak KW from the base case.

7.3.3 Case 2 Results: Reconfiguration

The results of Case 2 are summarized in Table 7.7. A plot of annual revenue requirement for both Case 2 and the base case is shown in Figure 7.9. The DED for losses is shown in Figure 7.10.

The results in this case indicate that building the new substation can be deferred for two years without overloading the existing circuits. It is clear from Figure 7.9 that the revenue requirements increase significantly in the year in which the new substation is built due to higher carrying charges. In addition, the installation of automatic switches results in improving reliability by 31% over the base case. Meanwhile, there is an overall increase in KWh losses due to the higher losses in the first two years. But there is also a reduction in % losses in the year 1994 as shown by the last column of Table 7.7. Since efficiency is measured over the total annual losses, there is an overall decrease in efficiency by 20%. However, Case 2 has 30% less present value of revenue requirement compared to the base case with a relatively low probability of overlap. Therefore, this represents a best case scenario from at least a reliability perspective. The EDED for this case is shown in Figure 7.11. The EIP is not shown in Figure 7.11 since there is no significant change in Peak KW from the base case.

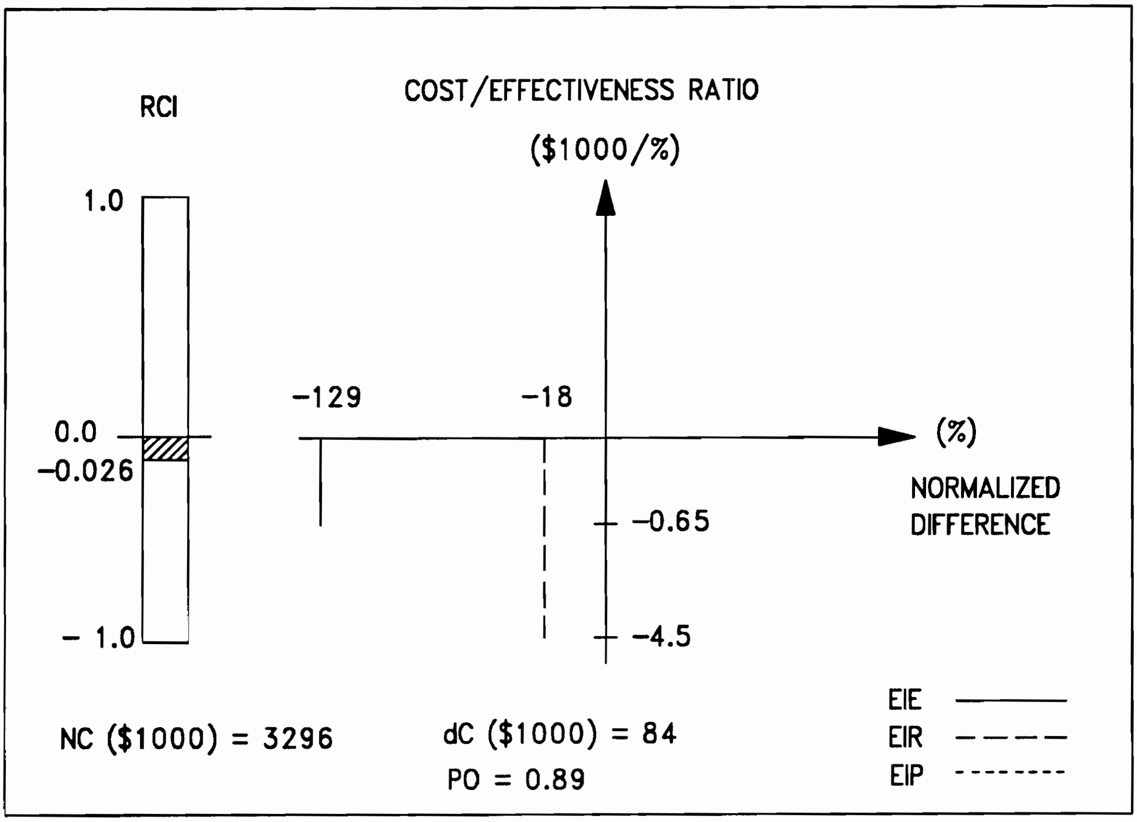

Figure 7.8. EDED For Case 1 (Reconductoring)

Table 7.7. Case 2 Results (Reconfiguration)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[35932, 69690]	14583	[103350, 103800]	[153865, 188072]	5.91
1993	[35932, 69690]	15270	[107322, 108765]	[158524, 193724]	6.20
1994	[35244, 68355]	4240	[377296, 399820]	[416780, 472415]	1.72
1995	[35244, 68355]	4392	[386728, 409816]	[426364, 482563]	1.74
1996	[35244, 68355]	4553	[389773, 420061]	[429570, 492969]	1.79
1997	[35244, 68355]	4726	[393670, 432672]	[433640, 505753]	1.82
1998	[35244, 68355]	4910	[395802, 448468]	[435956, 521733]	1.87
1999	[35244, 68355]	5104	[396002, 467000]	[436350, 540459]	1.92
2000	[35244, 68355]	5310	[394102, 488524]	[434656, 562189]	1.97
2001	[35244, 68355]	5528	[389880, 513205]	[430652, 587088]	2.03

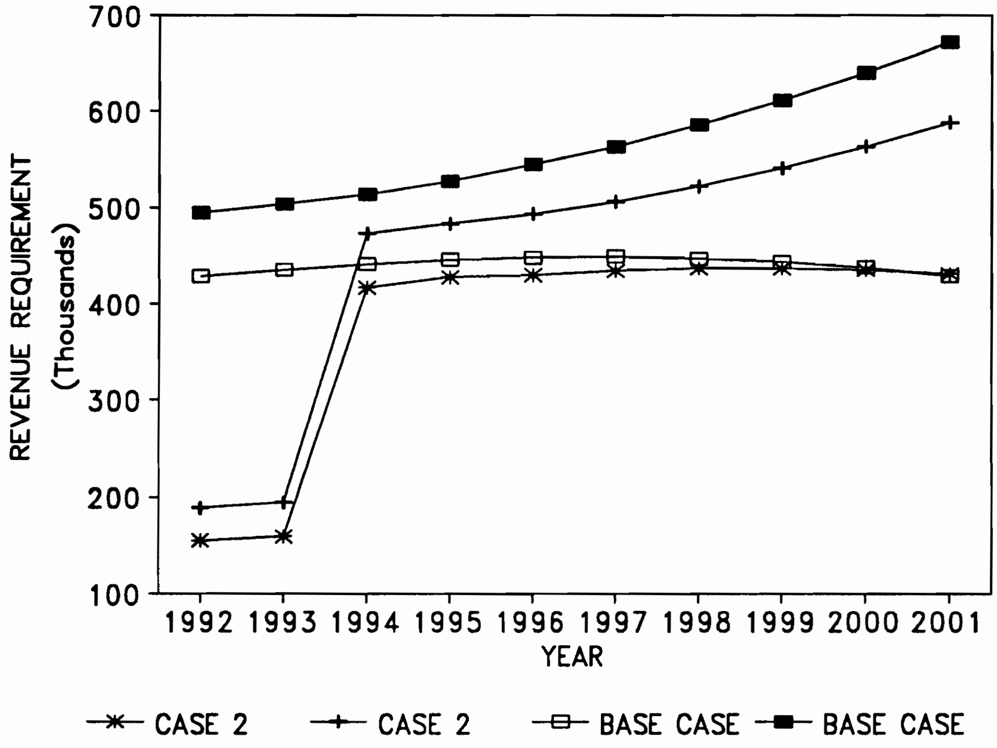

Figure 7.9. Annual Revenue Requirements For Case 2 (Reconfiguration) Vs. Base Case

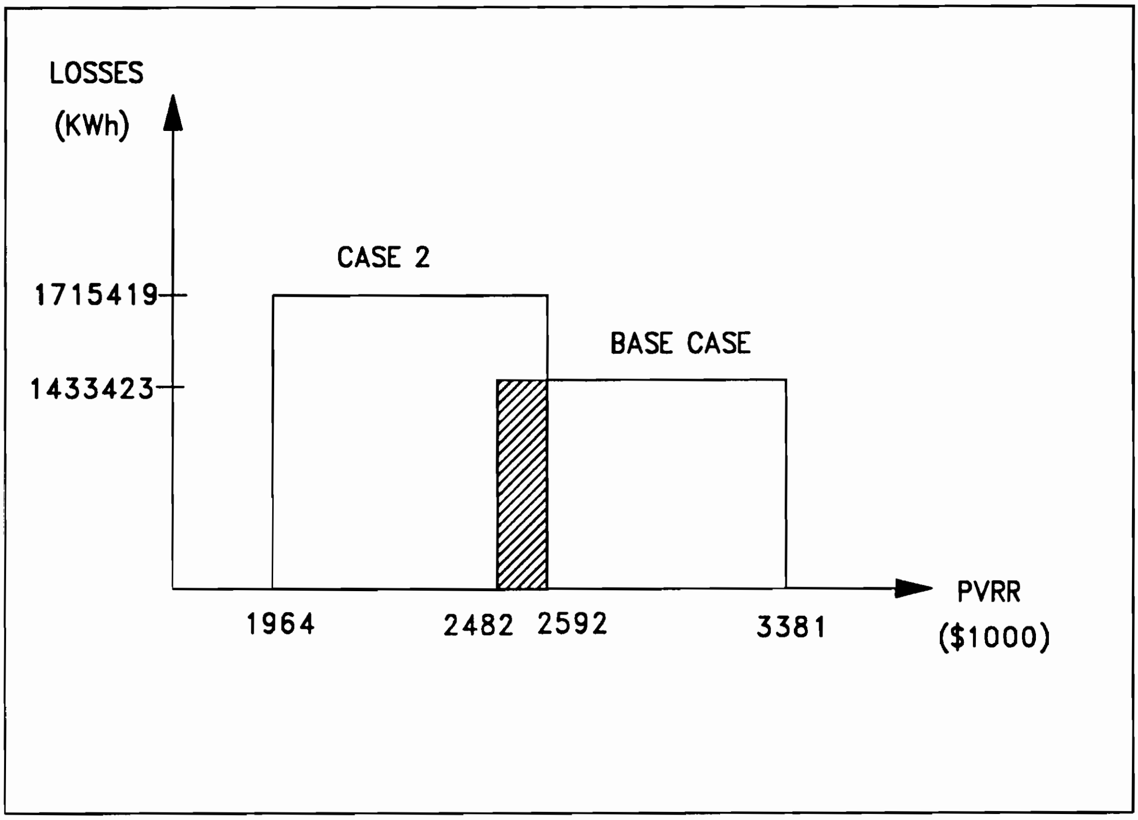

Figure 7.10. DED for Case 2 (Reconfiguration)

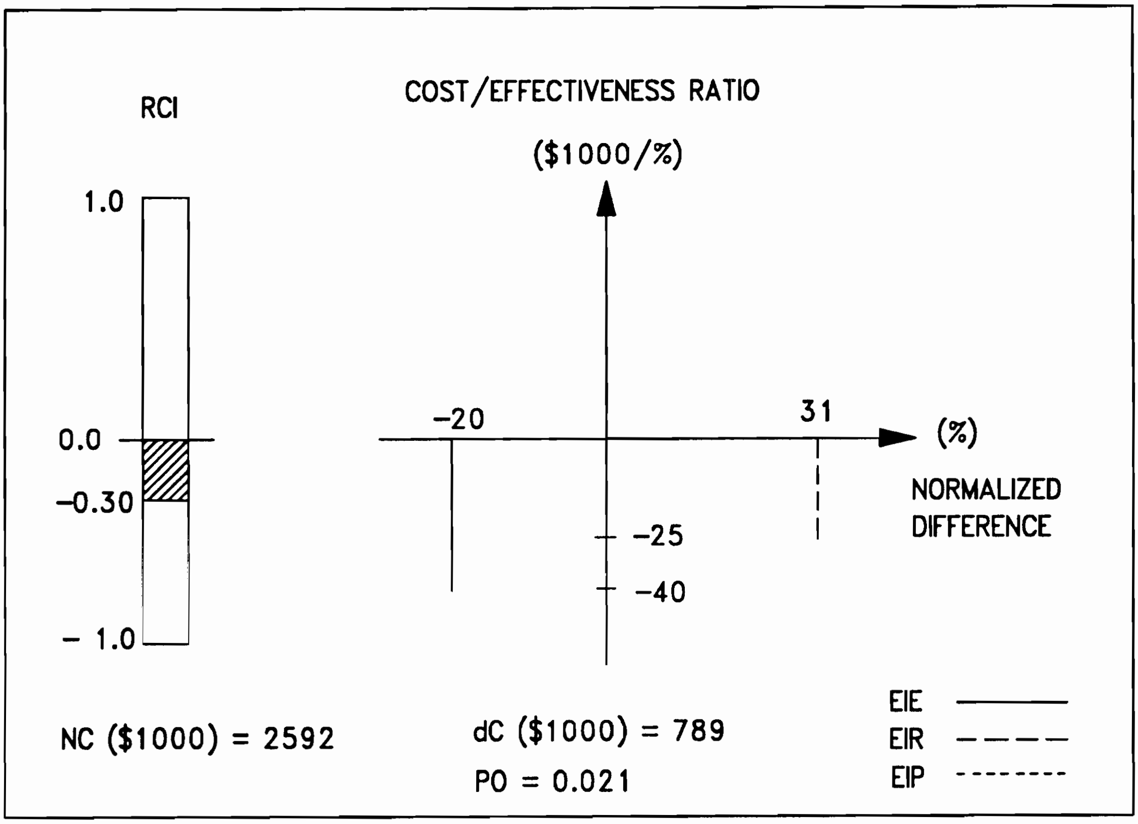

Figure 7.11. EDED For Case 2 (Reconfiguration)

7.3.4 Case 3 Results: Power Factor Control

The results of Case 3 are summarized in Table 7.8. A plot of annual revenue requirement for both Case 3 and the base case is shown in Figure 7.12. The DED for losses is shown in Figure 7.13.

The results in this case indicate that building the new substation can be deferred for four years without overloading the existing circuits. It is clear from Figure 7.12 that the revenue requirements increase significantly in the year in which the new substation is built due to higher carrying charges. The main objective in this case is to improve system efficiency through power factor control. However, the increase in losses during the first four years without a new substation results in an overall decrease in efficiency by 70%. This is also shown by the reduction in % losses in the year 1996 as shown by the last column of Table 7.8. Furthermore, the reliability also decreases by 12% due to the deferment. However, there is large decrease in present value of revenue requirement of 46% with no probability of overlap due to the deferment. Therefore, this represents a case where costs can be drastically reduced at the expense of worse performance. The EDED for this case is shown in Figure 7.14. The EIP is not shown in Figure 7.14 since there is no significant change in peak KW from the base case.

Table 7.8. Case 3 Results (Power Factor Control)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[57962, 112416]	13377	[103162, 103501]	[174500, 229293]	5.42
1993	[57962, 112416]	13952	[107167, 108507]	[179080, 234874]	5.67
1994	[57962, 112416]	14615	[110330, 114764]	[182906, 241794]	5.77
1995	[57962, 112416]	15310	[122375, 122375]	[185840, 250100]	5.86
1996	[48204, 93491]	6219	[378107, 400631]	[432529, 500340]	2.25
1997	[48204, 93491]	6395	[385123, 409401]	[439721, 509286]	2.28
1998	[48204, 93491]	6579	[390665, 420362]	[445447, 520431]	2.32
1999	[48204, 93491]	6773	[394587, 433697]	[449563, 533960]	2.36
2000	[48204, 93491]	6978	[396733, 449594]	[451914, 550062]	2.41
2001	[48204, 93491]	7197	[396934, 468260]	[452334, 568947]	2.47

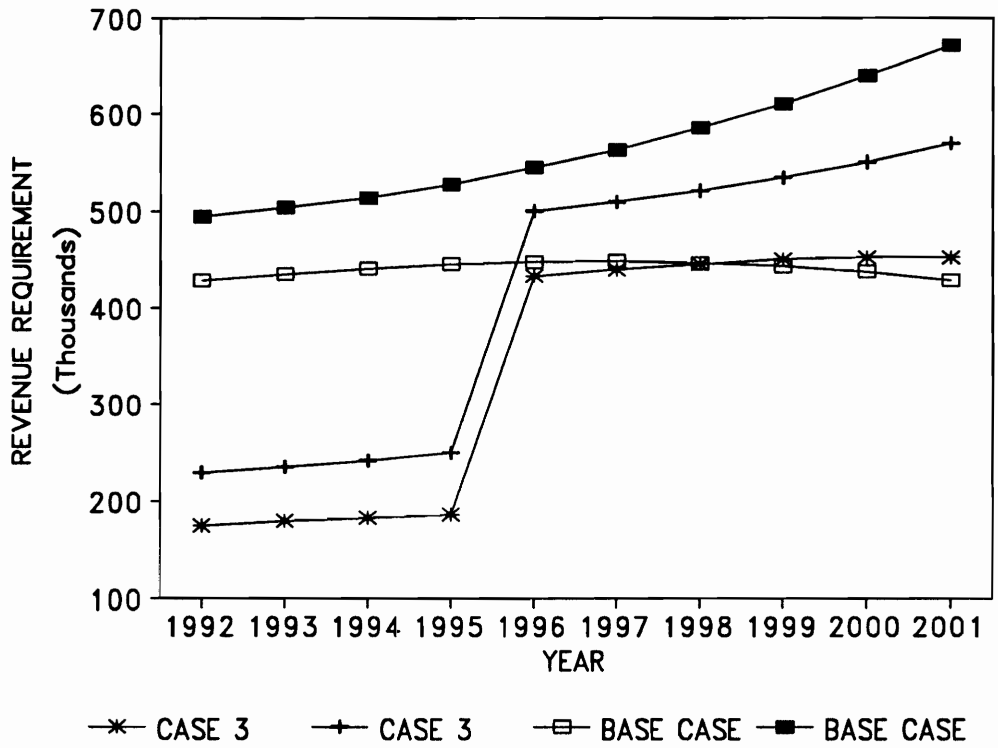

Figure 7.12. Annual Revenue Requirements For Case 3 (Power Factor Control)

Vs. Base Case

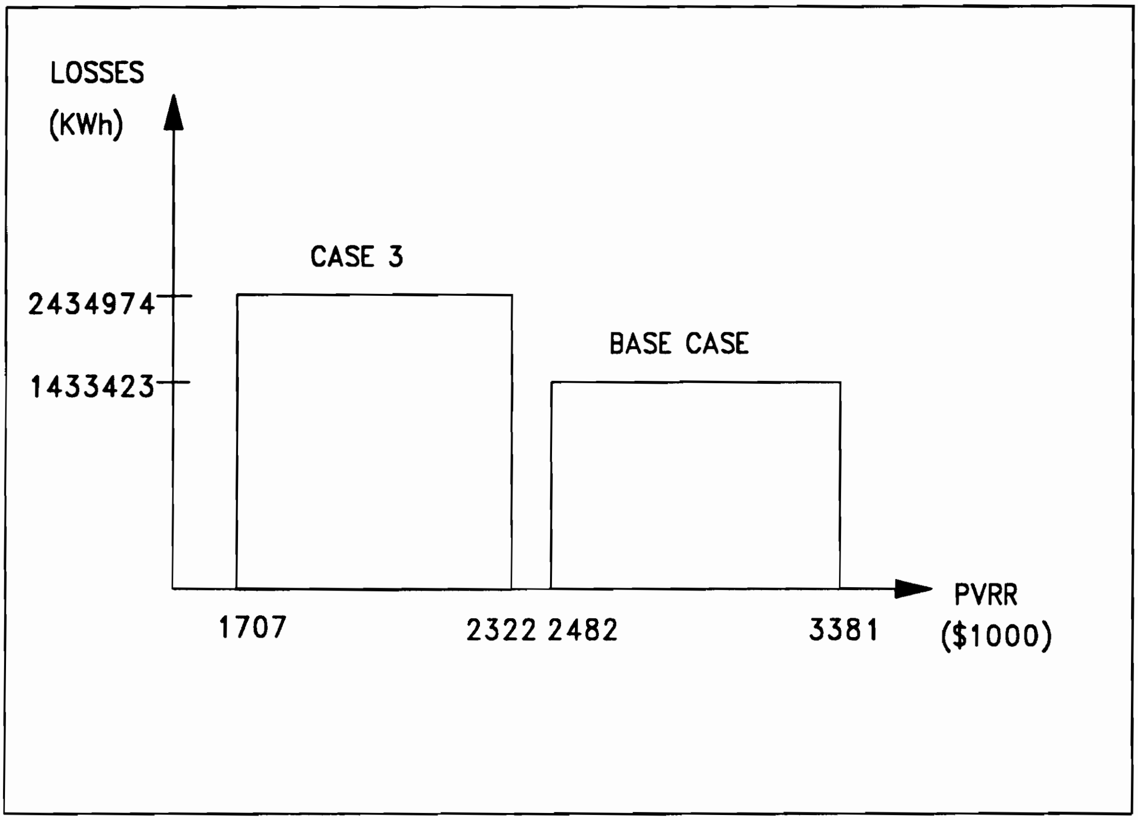

Figure 7.13. DED For Case 3 (Power Factor Control)

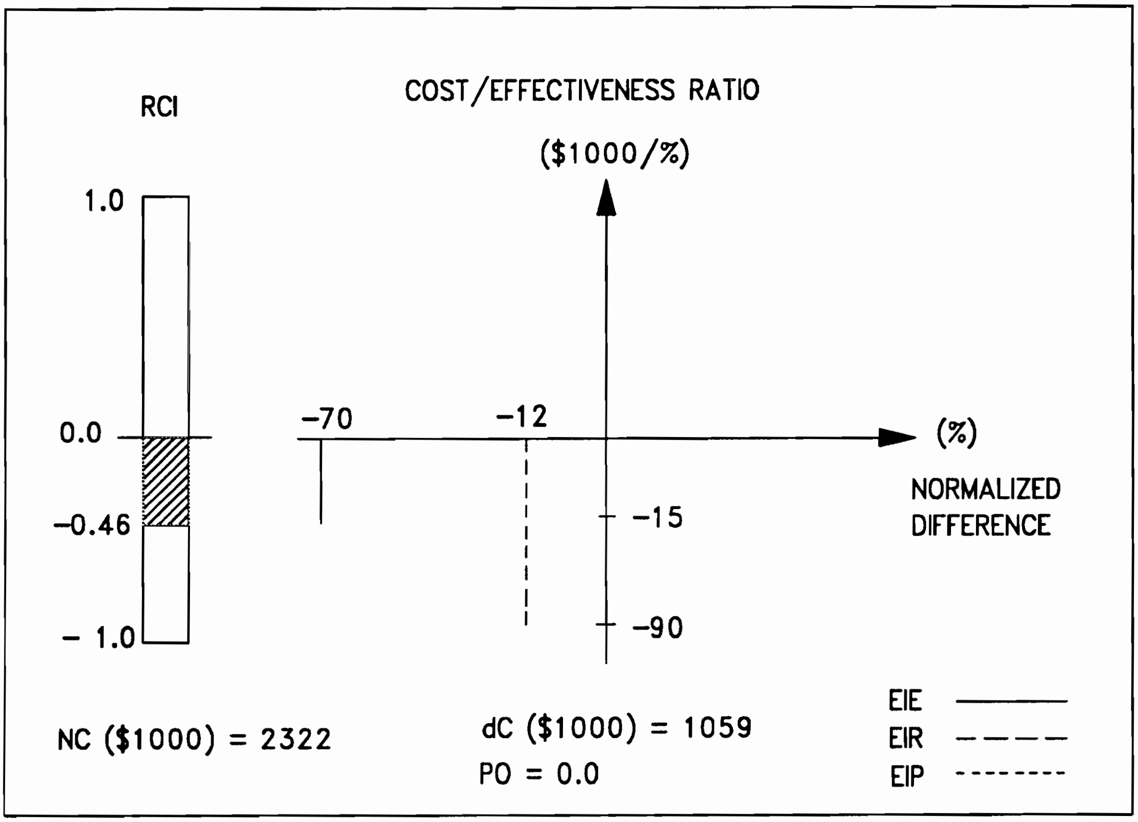

Figure 7.14. EDED For Case 3 (Power Factor Control)

7.3.5 Case 4 Results: Voltage Control

The results of Case 4 are summarized in Table 7.9. A plot of annual revenue requirement for both Case 4 and the base case is shown in Figure 7.15. The DED for losses is shown in Figure 7.16.

The results in this case indicate that building the new substation can be deferred for two years without overloading the existing circuits. A voltage dependency factor of 3% was used. This indicates that loads are simulated as constant impedance type loads. The main objective in this case is to reduce the voltage at the source in order to reduce system peak. The assumption made here and in the remaining cases is that the overall peak of the utility system coincides with the peak of the circuits under consideration. Furthermore, the assumption is that the utility is near its generation capacity, which means higher peaks require building new generation. Therefore, the reduction in peak represents displaced generation, and a $2000 value is placed on each KW reduced.

The results show that a 795 KW reduction in peak was achieved by the year 2001 compared to the base case. This means that an additional capital cost of $1591280 is added to the base case, which is accounted for using carrying charges over the ten year period. The result is a reduction in present value of revenue requirements by 66% compared to the base case with no probability of overlap. However, the higher losses during the first two years without a new substation results in an overall decrease in efficiency by 39%. However, the large reduction in revenue requirements certainly makes this an attractive economic alternative. The EDED for this case is shown in Figure 7.17.

Table 7.9. Case 4 Results (Voltage Control)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[56253, 109102]	14807	[261705, 278643]	[332765, 402552]	6.04
1993	[56253, 109102]	15505	[266075, 284106]	[337833, 408713]	6.34
1994	[46517, 90219]	4508	[406277, 430343]	[457302, 525070]	1.74
1995	[46517, 90219]	4909	[413865, 439827]	[465291, 534955]	1.85
1996	[46517, 90219]	5346	[419859, 451683]	[471722, 547248]	1.96
1997	[46517, 90219]	5817	[424101, 466103]	[476435, 562139]	2.09
1998	[46517, 90219]	6323	[426421, 483297]	[479261, 579839]	2.20
1999	[46517, 90219]	6863	[426639, 503483]	[480019, 600565]	2.33
2000	[46517, 90219]	7438	[424559, 526898]	[478514, 624555]	2.45
2001	[46517, 90219]	7953	[419976, 553792]	[474446, 651964]	2.59

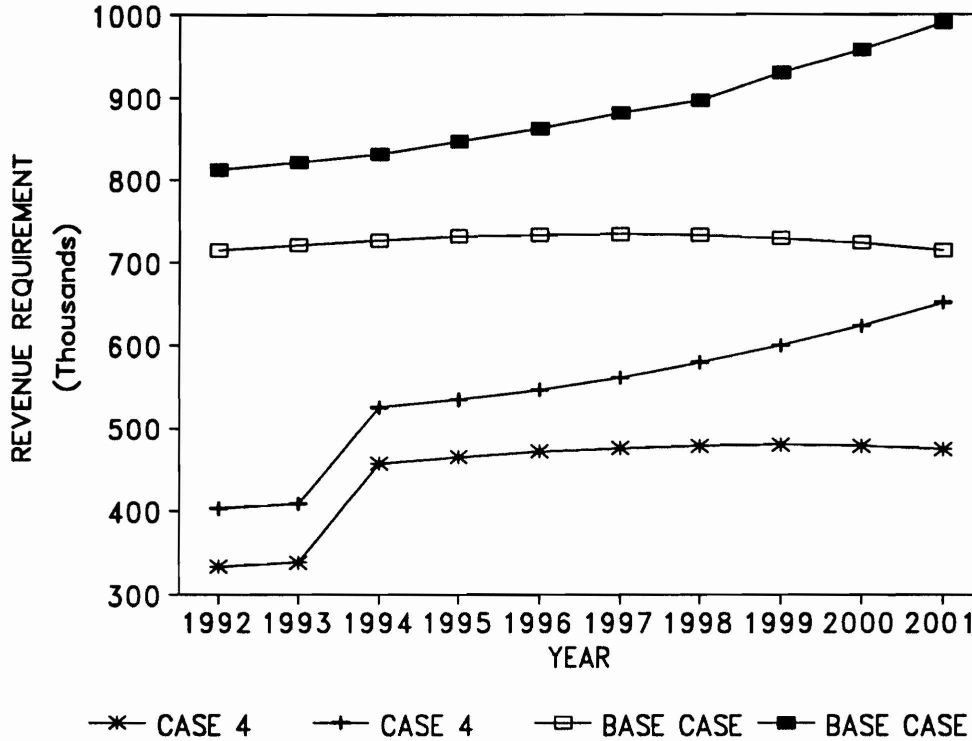

Figure 7.15. Annual Revenue Requirements For Case 4 (Voltage Control) Vs. Base Case

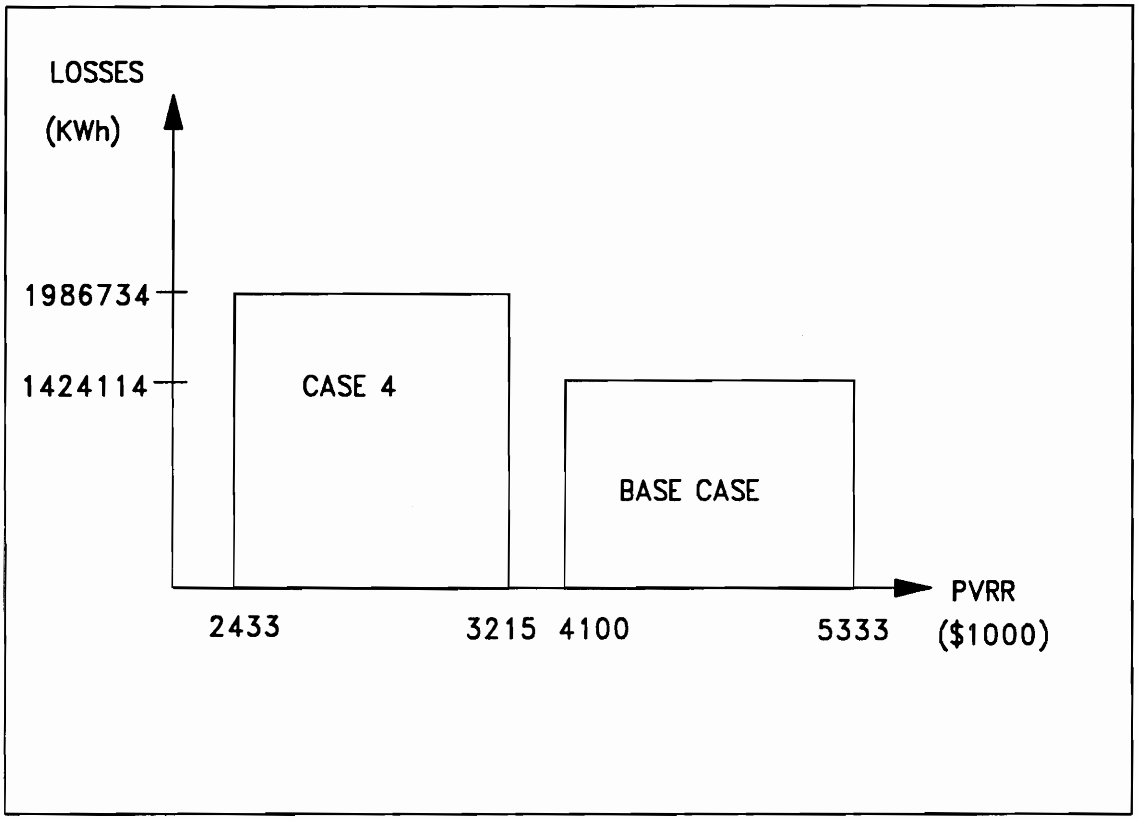

Figure 7.16. DED For Case 4 (Voltage Control)

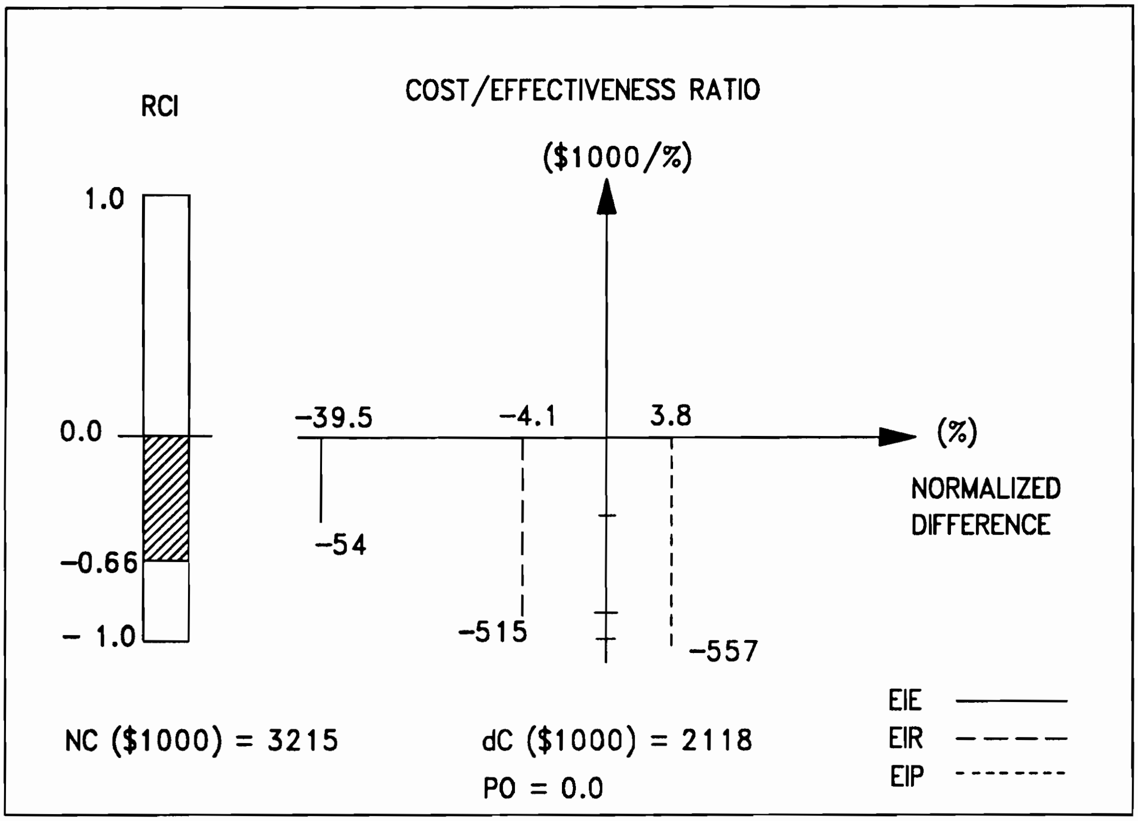

Figure 7.17. EDED For Case 4 (Voltage Control)

7.3.6 Case 5 Results: Load Management

The results of Case 5 are summarized in Table 7.10. A plot of annual revenue requirement for both Case 5 and the base case is shown in Figure 7.18. The DED for losses is shown in Figure 7.19.

The results in this case indicate that building the new substation can be deferred for three years without overloading the existing circuits. It is clear from Figure 7.18 that the revenue requirements increase significantly in the year in which the new substation is built. The main objective in this case is to control all 3000 residential water heaters in order to reduce system peak. The load control strategy reduces the residential load by 0.1875 KW during the period from 2-5 P.M. which then increases the load by 0.1875 KW during 6-9 P.M. The load curves with and without load control are shown in Figure 7.20. It is also shown in Figure 7.20 that the area under the curve does not change, which means the energy delivered is unchanged. The results show that a 537 KW reduction in peak was achieved compared to the base case. This means that an additional capital cost of $1074920 is added to the base case, which is accounted for using carrying charges over the ten year period. However, the higher losses during the first three years without a new substation results in an overall decrease in efficiency by 58%. But there is significant reduction in % losses in the year 1995 as shown by the last column of Table 7.10. Furthermore, there is a 25% reduction in revenue requirements compared to the base case with very low probability of overlap. The EDED for this case is shown in Figure 7.21.

Table 7.10. Case 5 Results (Load Control)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[56342, 109274]	14388	[233980, 248980]	[304710, 372642]	5.83
1993	[56342, 109274]	15069	[237939, 253929]	[309350, 378272]	6.12
1994	[56342, 109274]	16540	[241067, 260115]	[313949, 385929]	6.53
1995	[46606, 90392]	4878	[562623, 623057]	[614107,718327]	1.86
1996	[46606, 90392]	5319	[564755, 638852]	[616680, 734563]	1.97
1997	[46606, 90392]	5796	[564955, 657397]	[617357, 753585]	2.08
1998	[46606, 90392]	6310	[563044, 678908]	[615960, 775610]	2.20
1999	[46606, 90392]	6860	[558833, 703615]	[612299, 800867]	2.33
2000	[46606, 90392]	7446	[552119, 731762]	[606171, 829600]	2.45
2001	[46606, 90392]	8068	[542684, 763610]	[597358, 862070]	2.59

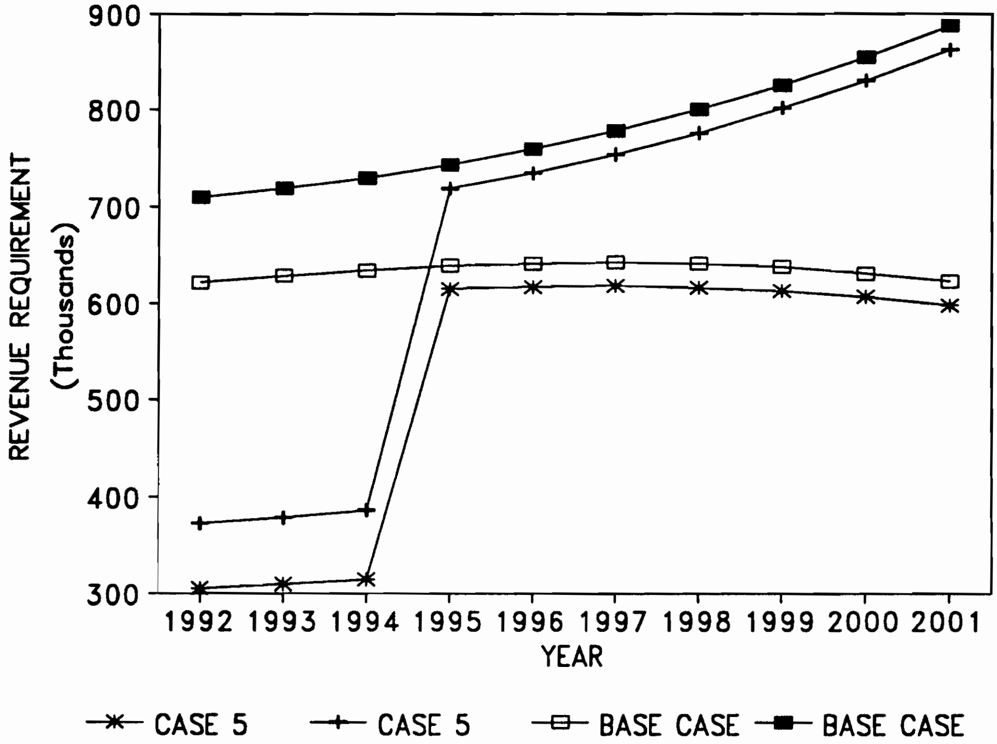

Figure 7.18. Annual Revenue Requirements For Case 5 (Load Control) Vs. Base Case

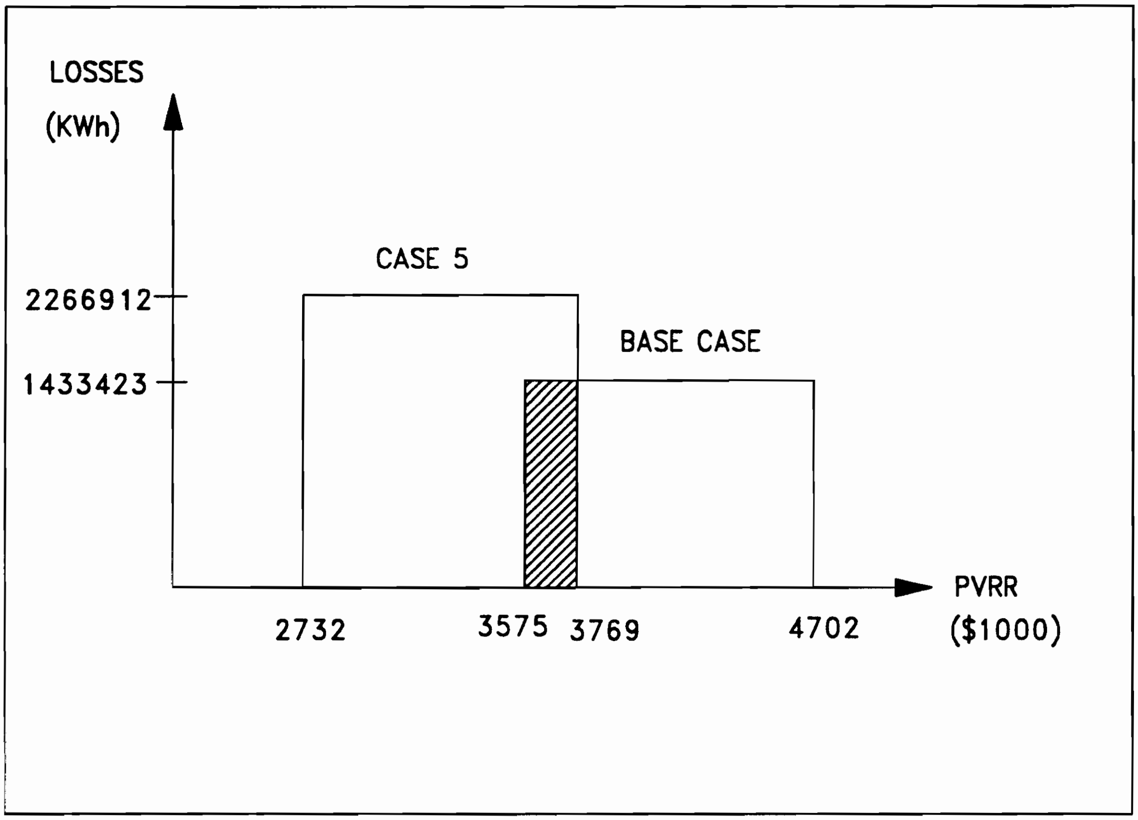

Figure 7.19. DED For Case 5 (Load Control)

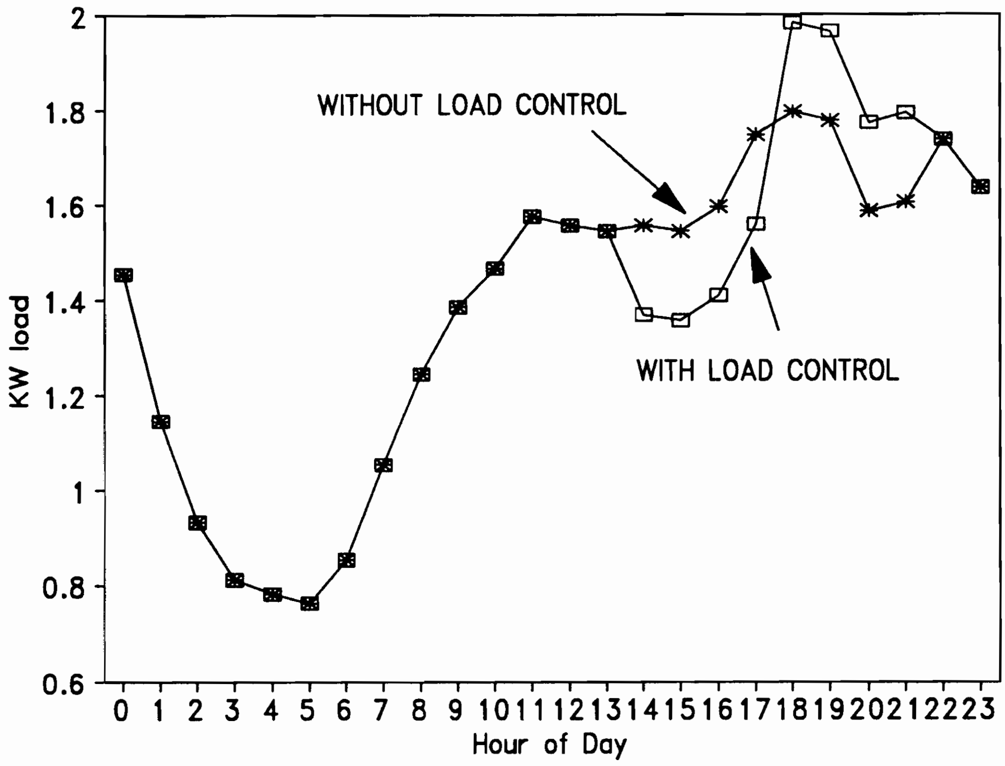

Figure 7.20. Residential Load Curves With And Without Load Control

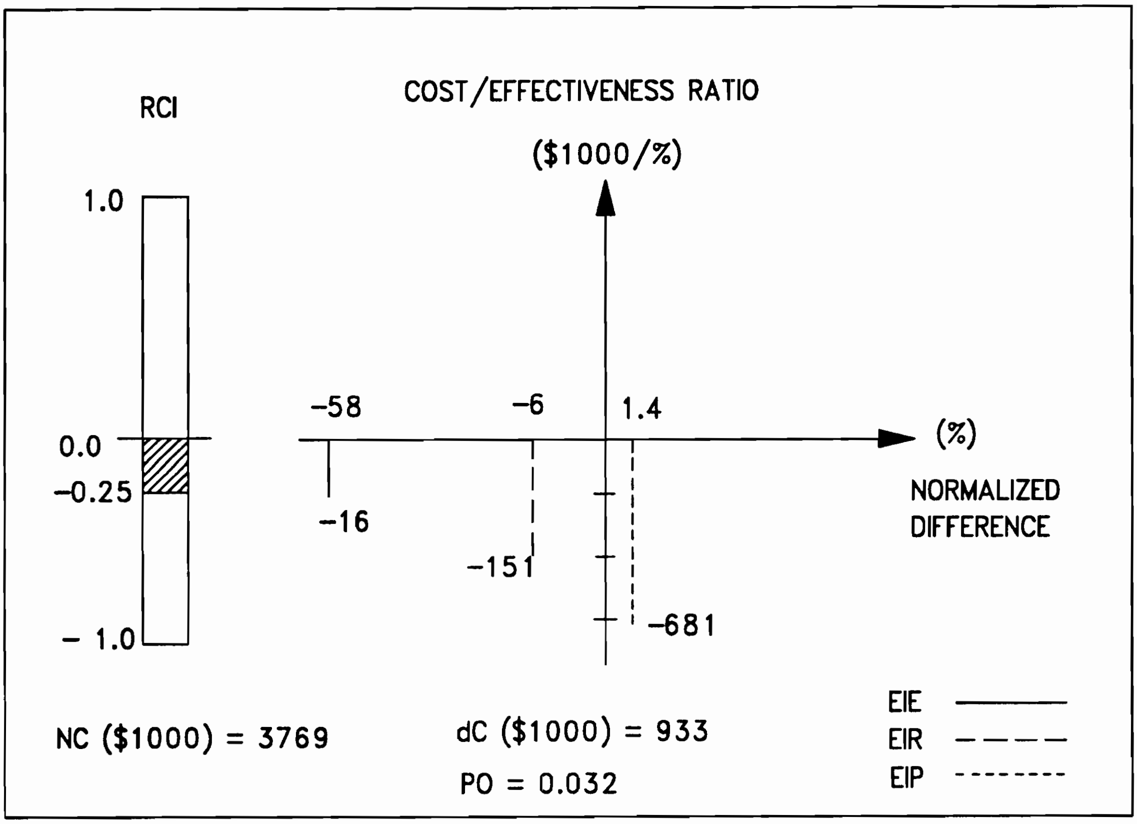

Figure 7.21. EDED For Case 5 (Load Control)

7.3.7 Case 6 Results: Load Management With Storage

The results of Case 6 are summarized in Table 7.11. A plot of annual revenue requirement for both Case 6 and the base case is shown in Figure 7.22. The DED for losses is shown in Figure 7.23.

The results in this case indicate that building the new substation can be deferred for three years without overloading the existing circuits. It is clear from Figure 7.22 that the revenue requirements increase significantly in the year in which the new substation is built. This case is also similar to case 5 with the addition of storage units in order to store heated water to be used during load control periods. The load control strategy reduces the residential load by 0.25 KW during the period from 2-7 P.M., which then increases the load by 0.1875 KW during 1-6 A.M. The load curves with and without load control are shown in Figure 7.20. It is also shown in Figure 7.24 that the area under the curve does not change, which means the energy delivered is unchanged.

The results show that a 561 KW reduction in peak was achieved compared to the base case. This means that an additional capital cost of $1122200 is added to the base case, which is accounted for using carrying charges over the ten year period. However, due to the capital and installation costs of 3000 load controllers and storage units, the present value of revenue requirement was only 6.3% higher than the base case with a relatively high probability of overlap. Furthermore, the higher losses during the first three years without a new substation result in an overall decrease in efficiency by 58%. But there is significant reduction in % losses in the year 1995 as shown by the last column of Table 7.11. The EDED for this case is shown in Figure 7.25.

Table 7.11. Case 6 Results (Load Control With Storage)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[56342, 109274]	14324	[341980, 368980]	[412646, 492578]	5.80
1993	[56342, 109274]	15003	[345939, 373929]	[413325, 498206]	6.09
1994	[56342, 109274]	16475	[349067, 380115]	[421884, 505864]	6.51
1995	[46606, 90392]	4869	[670623, 743957]	[722098, 838318]	1.86
1996	[46606, 90392]	5311	[672755, 758852]	[724672, 854555]	1.97
1997	[46606, 90392]	5790	[672955, 777397]	[725351, 873579]	2.08
1998	[46606, 90392]	6304	[671044, 798908]	[723954, 895604]	2.20
1999	[46606, 90392]	6855	[666833, 823615]	[720294, 920862]	2.33
2000	[46606, 90392]	7442	[660119, 851762]	[714167, 949596]	2.45
2001	[46606, 90392]	8065	[650684, 883610]	[705355, 982067]	2.59

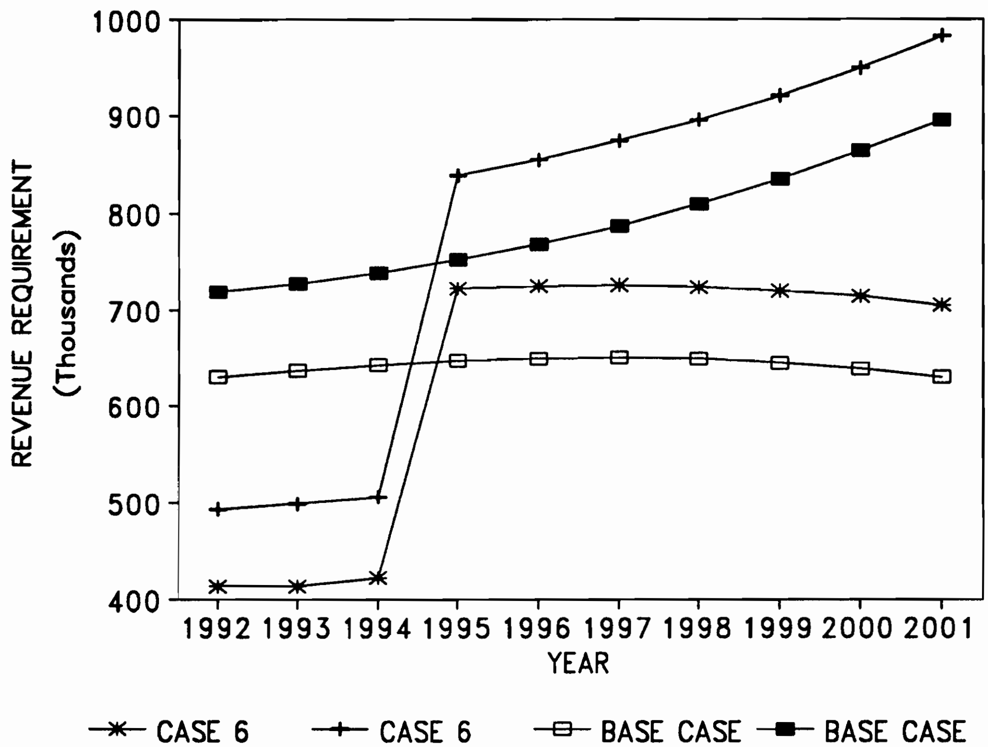

Figure 7.22. Annual Revenue Requirements For Case 6 (Load Control With Storage) Vs. Base Case

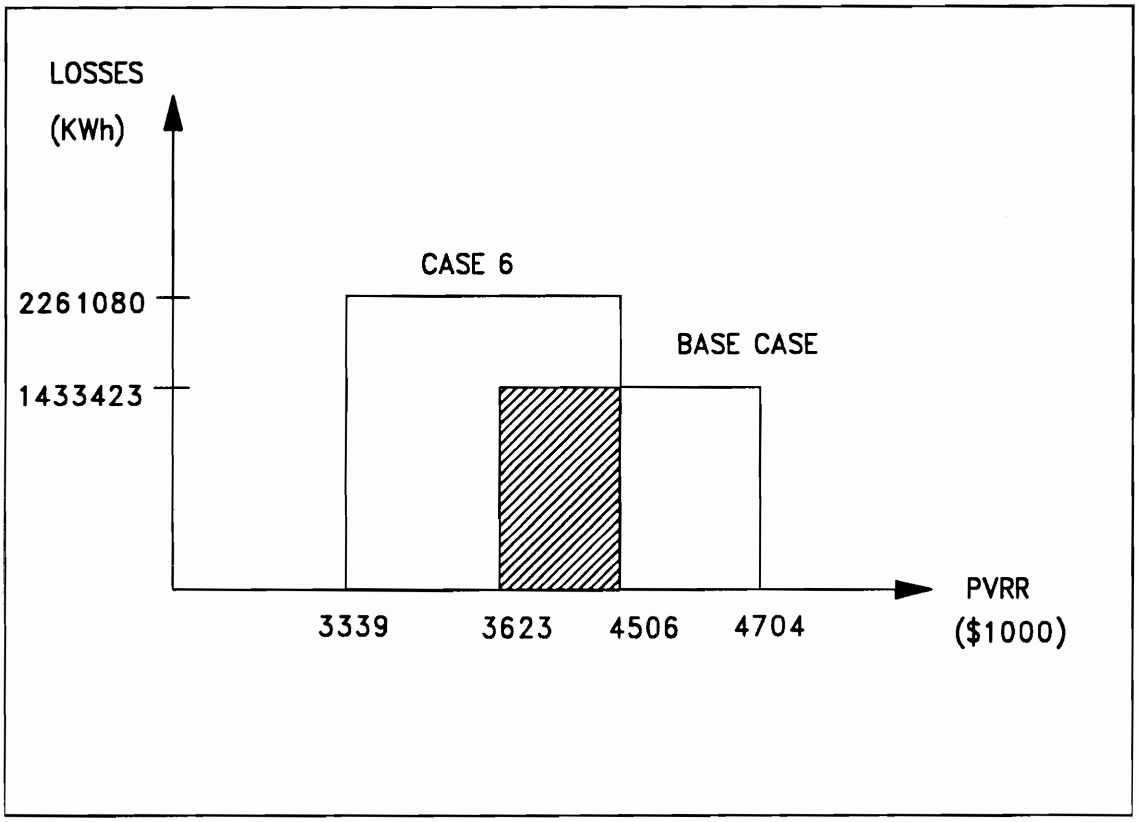

Figure 7.23. DED For Case 6 (Load Control With Storage)

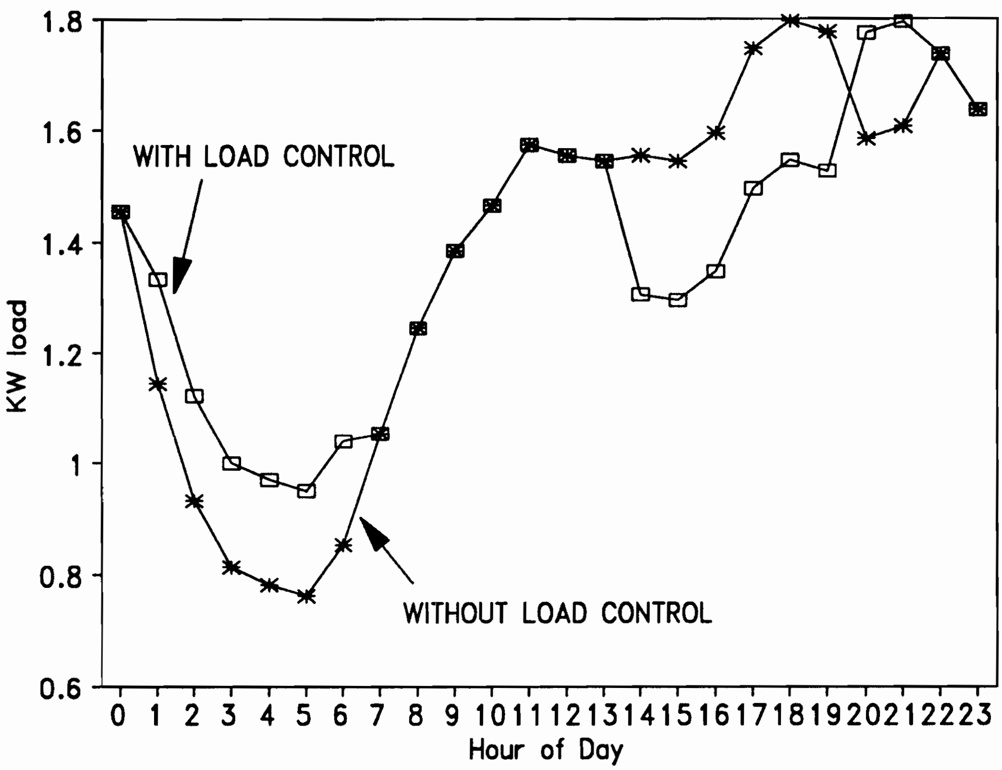

Figure 7.24. Residential Load Curves With And Without Load Control Plus Storage

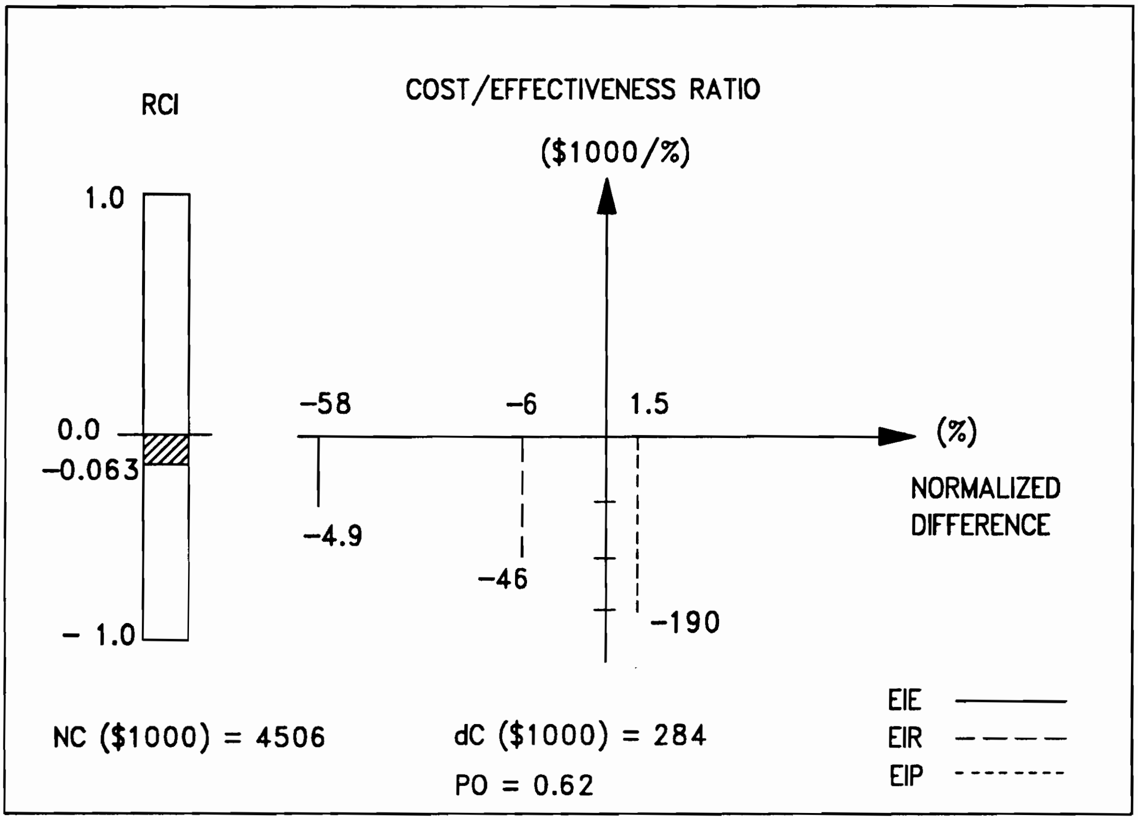

Figure 7.25. EDED For Case 6 (Load Control With Storage)

7.3.8 Case 7 Results: Combination Of All Choices

The results of Case 7 are summarized in Table 7.12. A plot of annual revenue requirement for both Case 7 and the base case is shown in Figure 7.26. The DED for losses is shown in Figure 7.27.

It is clear that this is the most costly alternative since it implements all previous choices. However, this case obviously has the best performance with respect to all aspects of reliability, efficiency, and peak. The results show that a 1114 KW reduction in peak was achieved by the year 2001 compared to the base case. This means that an additional capital cost of $2228020 is added to the base case, which is accounted for using carrying charges over the ten year period. The EDED for this case is shown in Figure 7.28.

7.4 Summary of Results

Based on the results of the previous section, the following observations can be made. The deferment of building a new substation for a few years may be beneficial from the economic point of view but not from a performance perspective. This is due to the fact that there are higher losses and downtimes without the new substation. But the savings achieved from deferment reduce the overall revenue requirements even with higher costs of losses and value of service. Therefore, it may be more appropriate to build the new substation at the same time other measures are implemented in Cases 1 through 6 if reducing revenue requirements is not an important factor.

As regards which case would be more attractive, the summary of results presented in Table 7.13 should be helpful. The information presented in Table 7.13 is sufficient to indicate which case is attractive from which perspective. For example, the same case may be attractive from the reliability point of view even though it may not be attractive from the efficiency point of view.

As a general rule, when RCI is positive and % change in performance is negative, then it represents a worst case scenario because there is cost increase for worse performance. On the other hand, when RCI is negative and % change in performance is positive, then it represents a best case scenario because there is cost reduction and performance improvement. The other two possibilities represent less cost for less performance or more cost for better performance.

Based on the information in Table 7.13, it is obvious that Case 1 comes closest to representing a worst case scenario since there is insignificant reduction in cost while performance is worse. Case 2 is clearly an attractive alternative since it has 31% better reliability than the base case while at the same time costing 30% less. Case 3 is attractive from a cost reduction perspective, but it has much worse performance. Case 4 is attractive only from the peak perspective because of the 3.8% reduction in peak. Case 5 is attractive from peak reduction perspective as well as cost since it costs 25% less. However, it has worse reliability and efficiency while reducing peak by only 1.4%. Similarly, Case 6 is attractive only from peak reduction perspective since it reduces peak by only 1.5%. However, it has worse reliability and efficiency, and has only 6.3% less costs. Finally, it is clear that Case 7 has the best performance improvement from all perspectives with 26% higher cost. It should be noted that Case 7 is the only one showing an improvement in efficiency. This is due to the fact that the new substation is built in the first year without deferment as in other cases.

Another view of which alternative is attractive or not depends on which performance factor is considered the most important. For example, if reliability is the most important factor, then Case 2 is the most attractive. Similarly, if efficiency is the most important factor, then Case 2 is also the most attractive since it has the least increase in losses. Finally, if peak concerns are the most important, then Case 6 is the most attractive. All the above choices are valid only if Case 7 is not considered since it has the best performance in all aspects.

Table 7.12. Case 7 Results (Combination)

Year	VOS cost ($)	Loss cost ($)	Carrying Charges ($)	Revenue Requirement ($)	% Loss
1992	[35127, 68128]	2946	[1027108, 1120084]	[1065181, 1191158]	1.19
1993	[35127, 68128]	3051	[1034721, 1129600]	[1072899, 1200779]	1.24
1994	[35127, 68128]	3314	[1040735, 1141495]	[1079176, 1212937]	1.31
1995	[35127, 68128]	3603	[1044991, 1155965]	[1083721, 1227696]	1.38
1996	[35127, 68128]	3919	[1047320, 1173216]	[1086366, 1245263]	1.46
1997	[35127, 68128]	4261	[1047538, 1193471]	[1086926, 1265860]	1.54
1998	[35127, 68128]	4630	[1045451, 1216965]	[1085208, 1289723]	1.62
1999	[35127, 68128]	4982	[1040853, 1243949]	[1080962, 1317059]	1.70
2000	[35127, 68128]	5372	[1033519, 1274691]	[1074018, 1348191]	1.77
2001	[35127, 68128]	5817	[1023214, 1309474]	[1064158, 1383419]	1.87

Table 7.13. Summary Of Results

	RCI	%ΔLOSS	%ΔSAIDI	%ΔPEAK
Case 1 (Reconductoring)	-0.026	-129	-18	-
Case 2 (Reconfiguration)	-0.30	-20	31	-
Case 3 (Power Factor Control)	-0.456	-70	-12	-
Case 4 (Voltage Control)	-0.058	-39	-4	3.8
Case 5 (Load Control)	-0.25	-58	-6	1.4
Case 6 (Load Control & Storage)	-0.063	-58	-6	1.5
Case 7 (Combination)	0.26	36	33	5.4

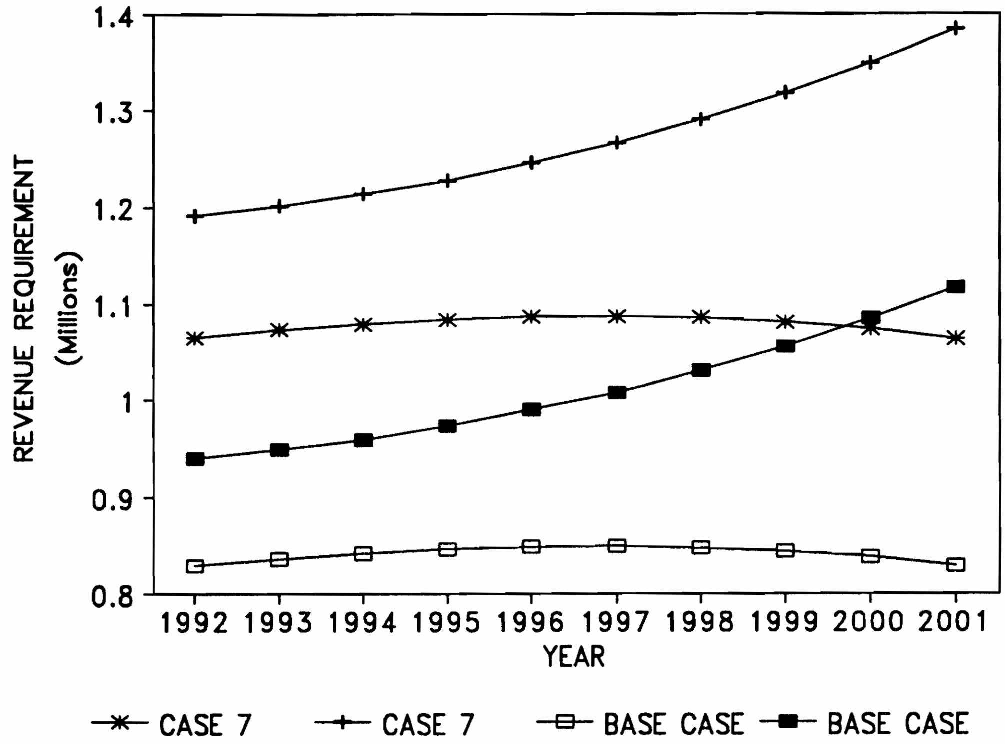

Figure 7.26. Annual Revenue Requirements For Case 7 (Combination) Vs. Base Case

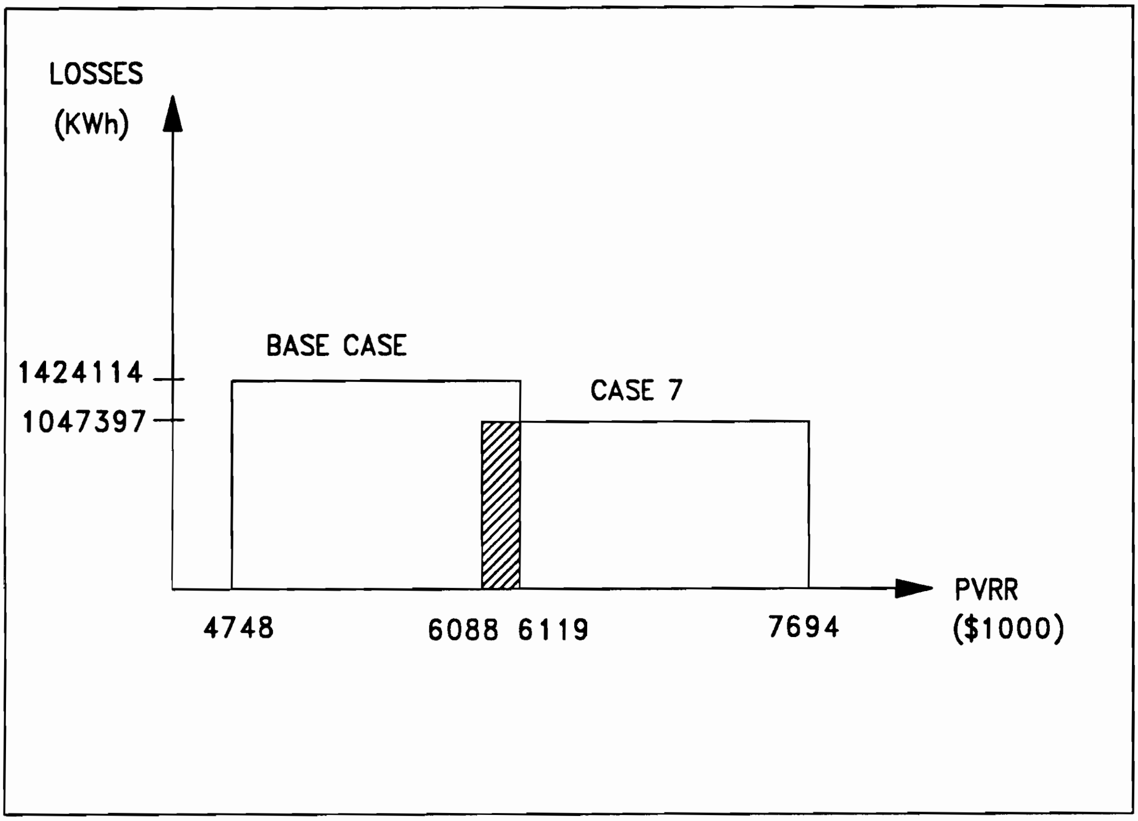

Figure 7.27. DED For Case 7 (Combination)

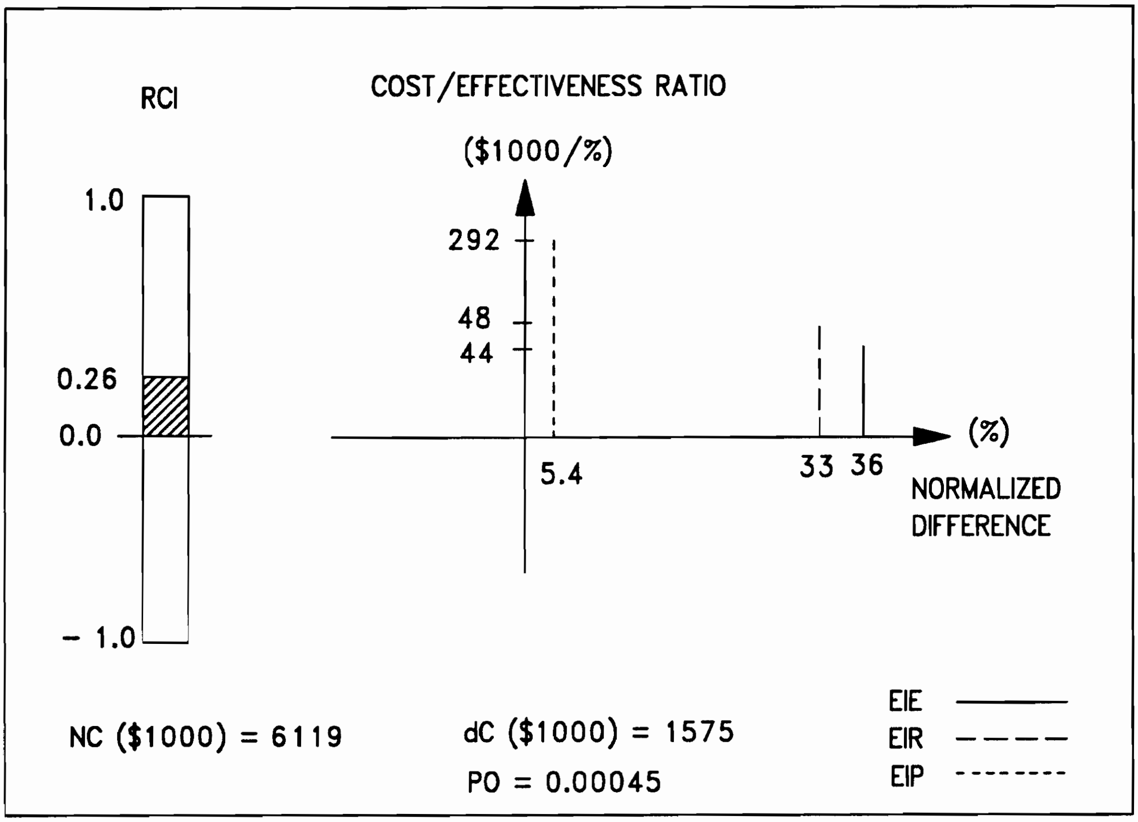

Figure 7.28. EDED For Case 7 (Combination)

CHAPTER 8

Conclusions And Recommendations

In this research a new method of economic analysis of utility distribution systems is presented. The method utilizes interval analysis to determine the effects of uncertainty in data in utility revenue requirement studies. This chapter presents the conclusions and future recommendations on the research reported in this dissertation. The following section provides the contributions of this research. Section 8.2 provides recommendations for future work.

8.1 Contributions

The focus of this research is to develop a new approach to economic evaluation of utility distribution systems. The approach takes into consideration several aspects that have not been incorporated in the past. A computer-aided approach is utilized to evaluate alternative system designs. These alternatives are evaluated in terms of system effectiveness and cost.

The new approach gives utility planners the ability to assess the impact of alternative distribution plans from different perspectives. Accordingly, utility distribution planning can be more precise with regard to potential economic benefits. The approach is particularly useful in evaluating distribution automation since it provides the capability to examine costs and potential benefits before actual implementation.

The main contributions of this research can be summarized as follows:

1. An economic evaluation algorithm for distribution systems has been developed which utilizes interval calculations for sensitivity analysis. Standard revenue requirement theory calculations are placed in interval form to evaluate the economic impacts associated with

alternative distribution system designs. There is a capability to analyze automation expansion plans as well as conventional expansion plans.

2. A problem which is often encountered in applying interval analysis is the resulting wide bounds. A calculational procedure which produces sharp bounds is presented.

3. The important design aspects of system reliability, efficiency, and peak demand are incorporated in the economic evaluation. In addition, value of service considerations is also incorporated.

4. The economic calculations incorporate results from reliability analysis as well as reconfiguration studies. Thus, an explicit consideration of engineering design aspects is included.

5. Cost/effectiveness analysis of distribution system design is presented in terms of several economic indices associated with system cost, reliability, efficiency, and system peak. Therefore, utility distribution planning can be more precise with regard to potential economic benefits.

6. Decision evaluation is facilitated by several evaluation displays showing both cost and performance measures.

8.2 Future Recommendations

Recommendations for future work include the following:

1. The focus of this research is on the distribution portion of power systems. Therefore, the concepts presented may be generalized to be used for generation and transmission systems as well.

2. More distribution system design aspects may be identified to be incorporated in the economic evaluation.

3. A method to back calculate value of service has been proposed, but it was not implemented in the results. The application of the method can be demonstrated in future work.

4. In the use of economic decision evaluation displays, decision rules may be devised to recommend a particular alternative. When the choice among alternatives is not clear, it may also indicate so.

5. Certain input parameters may be identified which can be set by the decision maker to serve as guidelines in choosing among alternatives.

6. The rule based decision may be incorporated in the display itself so that a decision maker can readily see it.

7. In addition to pairwise comparison of alternatives, decision trees may be developed for the decision analysis process.

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