DISTRIBUTION NETWORK DEVELOPMENT PLANNING WITH QUALITY OF SUPPLY (QOS) COSTING

by

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Acknowledgements

The basic theory of network planning presented in this project report was established from the IEEE publications, various technical journals, standards and Eskom documents. The author therefore wishes to acknowledge diverse efforts of previous research in network planning. The author acknowledges research attempts in project related topics such as power quality and the risk concept. The efforts of previous research provided the basis for the development of this thesis. My grateful thanks are due to **Associate Professor C. Trevor Gaunt** for his invaluable assistance and guidance throughout the research project.

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- **My wife, Nokwanda Fipaza** for moral support and sustaining my family whilst grappling with the project challenges at the University of Cape Town.

Mmeli Fipaza
March 2002

Terms of reference

The dissertation document describes the research completed by the author under the mentorship of Associate Professor C. Trevor Gaunt of the University of Cape Town in 99/ 00. The area of research is network development planning with quality of supply (QOS) costing.

The research mentor's requirements were as follows:

- To understand current practices in distribution network planning,
- To highlight problems and risks in network plans,
- To evaluate various network risk handling approaches,
- To develop distribution line cost optimisation mechanisms,
- To propose quality costing model and establish the link with planning, and
- To present the research findings such that they can be incorporated into TIPS.

Abstract

The report outlines details of research in distribution network development with consideration of costs due to quality. Network planning methods are diverse with the common objective of establishing minimum cost options without violating network constraints. The selected network alternative is directed to meet customer requirements. Network planning models have evolved from consideration of simplistic models to multi variable and more realistic approaches. It is not always possible to achieve the desired outcome because planning is a difficult and complex task. There are usually uncertainties due to vague or no information available about the long-term (15-20 years) planning. The uncertainties generally result in risks, which have to be sufficiently analysed before reaching planning decisions. The recently proposed Minimum Risk Criterion is not a preferred risk resolution approach because it suggests that utilities should not establish expensive networks due to cost risk. Uncertainty modeling approaches based on fuzzy logic are proposed as the solution for analysis of uncertain conditions where very limited information is available.

Costs in distribution lines are usually due to capital investment and operating costs. Distribution capital costs are primarily due to cost of conductor, structure and insulator. The cost of conductor and structure varies with size and type. Insulator costs do not vary significantly with variations in insulator type and properties. Quality related costs are a relatively new concept in distribution costing and are developed in the research. They are primarily due to mitigation, condition monitoring and interruptions. Quality mitigation costs are defined in the mitigation cost models in Figure 4- 8 and Figure 4- 9. The impact cost values in the models were established on the basis of assumptions, which require further research. According to CTLab [12], quality-monitoring equipment costs could vary from R50, 000 to R250, 000. Interruption costs are incurred through penalty cost and revenue losses. The penalty cost is similar to the revenue loss cost in many respects but is incurred when the standard limits are violated. Revenue loss costs are applicable whenever the frequency or voltage deviates from the nominal. It may be preferred to accept revenue losses where mitigation is expensive.

The Wang and McDonald's [69] heuristic planning method is evaluated and modified. The modified method is called **'The Modified Heuristic Planning Approach'**. Additions made to the original heuristic method include the following:

- Initial investment costs are a summation of line capital and mitigation costs.
- Incorporation of risk analysis techniques.
- Addition of the N-1 principle when one of the lines is faulted.

It is proposed that quality opex evaluation tool (test.xls) is incorporated into the TIPS subsystem. The research directs all network plans to achieve the objectives of the value based planning approach as described in Chapter 5.

It uses an Eskom based case study to demonstrate the theory developed and obtain results. The first case has a special outage condition twice a year. The current arrangement requires a dedicated line to supply Koeberg Nuclear Power Station when the 132 kV busbars at the Koeberg substation are stripped. Currently, a transmission 400 kV line between Koeberg and Accacia is operated at 132 kV and used for emergency supply on special outage conditions. The load forecast in the region indicates growth and another line is required to meet demand at Westwood, Blouberg and Vissershoek areas. The second study is similar to the first case but the special condition is removed. The contribution of the research to the network development plan is to demonstrate quality costing in planning and apply the proposed heuristic method.

The research identifies quality related topics that require research beyond the scope of this thesis. Finally, it draws conclusions and makes recommendations.

Declaration

I, Mmeli Fipaza hereby declare that the work contained in this thesis document is my own original work with proper referencing where necessary and has not previously been submitted to any university for the purpose of obtaining a degree.

M. Fipaza

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Signature

March 2002

This thesis is dedicated to my daughter, Silindile Fipaza.

Acronyms and Abbreviations

%	Percentage
A	Amps
AIDS	Acquired Immunodeficiency Syndrome [73]
capex	Capital Expenditure
CCM	Capital Cost of Mitigation
CCQ	Capital Cost of Quality
CME	Cost of Monitoring Equipment
h	Hour
HIV	Human Immunodeficiency Virus [73]
HVPCC	Higher Voltage at Point of Common Coupling
IRR	Internal Rate of Return [64]
LR	Loss of Renevue
M	Mega (10^6)
m	milli (10^{-3})
MIRR	Modified Internal Rate of Return
NDP	Network Development Plan
NER	National Electricity Regulator
NNR	National Nuclear Regulator
opex	Operating Expenditure
PCC	Point of Common Coupling
PCQ	Penalty Cost of Quality
QOS	Quality of Supply
s	seconds
SVC	Static Var Compensator
TIPS	The Integrated Planning Solution
TRFR	Power Transformer
UCT	University of Cape Town
US$	Currency for the United States of America
V	Volts
W	Watts

Definitions

Capital Risk:	The probability of a slower return on established network investment due to poor economic performance, competition, load growth, power quality related costs, etc [26].
Constant Current:	Mid range type of loads between constant impedance and constant power loads. They represent an even spread of lightly loaded and heavily loaded motors.
Constant Impedance:	Low impedance loads such as lightly loaded motors, heaters, lights, etc.
Constant Power:	Loads in which there is less or no variability in power factor and speed as the supply voltage is varied.
Demand:	The magnitude of power requirement from the network [62].
Design Risk:	The probability of exceeding some percentile voltage drop at the system maximum demand due to the stochastic nature of consumer load currents [26].
Investment:	The process of incurring costs with the expectation and indication to achieve more monetary returns.
Network Planning:	According to this research, network planning is a systematic and/ or continuous process of seeking a set of optimal solutions to supply future electrical loads.
Optimal Solution:	Minimum cost network alternative that does not violate the stated technical constraints and statutory requirements.
QOS Parameters:	Deviation of voltage and/ or frequency of supply from the nominal in exceedance of the standard limits. In South Africa, the standard limits are defined in the NRS 048: 1-5.
QOS Risk:	The probability of a feeder not to comply with the quality statutory requirements during a predefined period of time as a result of stochastic nature of customer load currents [26].
Quality of Supply:	There is no generally accepted definition of power quality but to most engineers it would mean a measure of the faithfulness of the bus voltage to maintain a sinusoidal waveform at rated voltage and frequency [27].
Reliability:	Ability of the network to meet the required technical performance over a defined period.
Risk:	An uncertain condition with a likelihood to have negative impact to the planning investment.

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CHAPTER 1

1. BACKGROUND OF NETWORK PLANNING

1. INTRODUCTION

Due to the increasing requirement for electricity power utilities to operate their systems more efficiently and economically, the network planning process is a crucial factor in determining the performance and design of power networks. As a result, network planners must understand and use optimal network planning techniques to facilitate the achievement of these objectives. Improvements in planning methodology can have significant implications for the commercial success of the power distribution company by meeting stated technical and financial goals. Therefore, this thesis project report sets out the results of research into various possible techniques of electrical distribution network development planning with consideration of costs associated with quality of supply. As utilities change from fully regulated entities to participants in a competitive process, understanding and sustaining optimum costs becomes a challenge. The purpose of this report is to contribute towards the understanding of optimal network planning methods by utilities, so that their profits may be maximised through electricity sales. To achieve this objective, the utility must sustain continuous and reliable electricity supply to its customers. The objectives of this thesis research report therefore are:

- To highlight current distribution network planning problems.
- To identify various network planning techniques.
- To establish a link between network planning and cost of quality of supply.
- To optimise costs associated with operation of distribution lines.
- To verify proposed network risk handling models.
- To present the research findings such that they can be incorporated into TIPS.

2. NETWORK CHANGES

Electricity demand or customer base would normally grow over a period and distribution networks would have to be reinforced or newer ones established. According to Fipaza and Gaunt [20], the decision whether to built a new network or reinforce would normally be based on whether a network existed in the area and its performance. The network performance would be measured in terms of the following parameters:

- operating costs,
- voltage profile,
- thermal constraints [63],
- loadflow performance, and
- environmental factors.

Partenan [47] stated that network load factors are time variant and as a result, network planning is a time variant problem. Krishans et al [34] defined the aim of electricity distribution network planning as seeking a solution (or a set of solutions) which would satisfy a changing and growing power system load demand during the planning period within quality, operational, economical and safety constraints. The term used to refer to most acceptable (cost and technical effective) solution for the chosen planning solution is '**optimal**'. Optimal describes an option that would satisfy all or most network and load constraints with limited risk of exceeding the set regulatory guidelines. Such a solution may be obtained by an analysis of all options using available tools for loadflows, Internal Rate of Return on investment, etc. However, there are some difficulties in dealing with the network-planning problem, which pose challenges to the distribution network planners. According to Krishans et al, network-planning challenges can be summarised as:

- multiple planning criteria (cost, losses, etc),
- non linearity of planning models,
- large size of networks,
- dynamic nature, and
- risk and uncertainties (cost, load, economic indices, etc).

These complexities or challenges make the planning task very difficult to optimise. Over the last four decades, network-planning researchers established a variety of planning methods, from simplified models to the multiple criteria planning methods. According to Krishans et al these techniques have evolved and benefited from developments in scientific knowledge and computational capacities or tools. They stated that the history of the methods is the history of conflict between the precision of the model and the computation efficiency of the solution for the model. The attributes of distribution network planning models are as shown in Figure 1- 1.

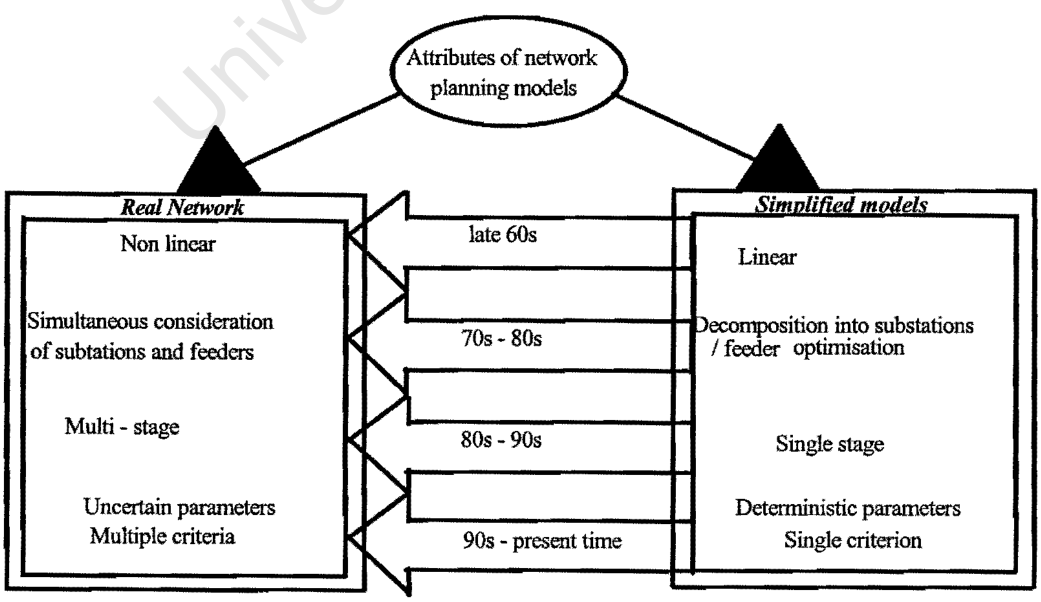

Figure 1- 1: Attributes of network planning models [34]

It has not been until recently that most models shifted from consideration of single stage to multi stage planning with the so called **'horizon year'** which according to Krishans et al highlights the time consideration in planning. Dynamic planning models on the other hand were introduced to expand the planning period to several time stages with dynamic programming applied to handle such complex problems.

3. OBJECTIVES OF NETWORK PLANNING

The planning objectives discussed in this section are highlighted in the planning definition developed in this thesis. Generally, there is no standard definition of planning but this research defines it as **a systematic and/ or continuous process of seeking optimal solution/s to supply future electrical loads.** Planning is important because utilities need to have appropriate quality capacity available to sustain national load growth and serve as a key input to economic advancement. The establishment of newer networks, rebuilding and reinforcement of existing ones are the main categories of planning, with common objectives at times. Network planning objectives include:

- Provision of minimum cost solution/ s to supply electrical power to as many customers as possible within the statutory and utility limits.
- Network capacity building to satisfy the expected or projected demand growth in accordance with the regional or national load forecasts. However, Partenan [47] stated that demand growth could not be guaranteed due to uncertainties in long-term load forecasts, in which case some network developments would either be postponed or cancelled. According to Nara et al [46], it is normal engineering practice to design distribution lines for both winter and summer demands to sustain capacity whilst not violating thermal constraints.
- Network planning ensures that technical and statutory constraints are not exceeded. The objective ensures minimal supply interruptions to customers due to non-fault conditions. Adherence to technical and statutory requirements ensures safety of humans and plant equipment on fault conditions.
- Network planning usually gives preference to simple, functional and reliable designs because the primary objective is to reduce initial costs whilst satisfying most technical constraints.

4. PROBLEMS OF NETWORK PLANNING

Desired network plans may not always be realised due the costs associated with choosing a particular network option with regard to network operational cost, rate of return on investment and cost of redesign in a case of poor performing network/ s. Problems of network planning include the following:

- The requirement for semi-governmental utilities such as Eskom to improve the cost knowledge as a result of business transformation. The current costing approaches used by utilities generally ignore certain parameters; result in gross approximations, large cumulative error and eventually unnecessary expensive networks.

- The current planning methods used in Eskom do not account for network reliability improvements in initial investment cost. This results in unquantified trade off between supply availability and cost.
- The models used for distribution planning are normally far from ideal and may have already included gross approximations in the originally proposed function, which they intend to represent. The approximations could be the use of d.c. load flow equation to represent an a.c. power system to alleviate computing restrictions and timing. It is not yet possible to develop a planning program that includes as many interrelationships as cost, time, voltage drop, etc without dramatically increasing the required computational time and integrate the intuitive developments of a skilled engineer.
- The planning task is complex in that no generalisation can be made in the specification of the model without some loss of accuracy because each element must be clearly defined for the purpose of optimisation. Planners have to strive to reach the balance between simplicity and realism, which are conflicting requirements but both basic for the definition of the model.
- There are uncertainties in dealing with the network-planning problem. These uncertainties represent an element of chance, which can be disastrous and costly if incorrect or uncalculated decisions to a degree of confidence are made. However, correct planning decisions based on the same opportunity result in benefits. The uncertainties represent risks because the outcome cannot be guaranteed. Utilities such as Eskom currently have no accepted scientific mechanism to resolve network risks. Methods for mitigating risks were known since the late seventies but exist in isolation from network planning.
- The Integrated Planning Solution (TIPS) for distribution planning may be a sound idea but the lacking interface between this system and external planning tools introduces other planning challenges.
- There is no standard or benchmark planning process in Eskom. This means that variations in planner decisions are possible between Eskom branches given the same set of circumstances.
- Load growth patterns are not known with certainty. This usually results in difficulties in accurate sizing of distribution lines and/ or possible network redesign in the short term.

The problems are the root of many planning difficulties so far described relating to design of electrical networks and are not a lack of a successful mathematical application.

5. INCORPORATION OF QUALITY CONCEPTS INTO PLANNING

Very little planning incorporates power quality aspects. Power quality consideration in planning is important to ensure minimal future costs due to supply interruptions. Unplanned supply interruptions usually result in revenue losses to both the customers and utility. Power quality may be regarded as customer desire for a perfect service from the supply utility. In South Africa, it could mean adherence to statutory requirements outlined in the NRS 048 [52] standard. The perfect service of electricity supply is measured in terms of the smoothness of the supply voltage signal of 1 per unit at a rated voltage and frequency. It is important to note that electrical distribution systems are not immune to interruptions. However, the effects of interruptions may be reduced through mitigation methods such as:

- installation of line compensators,
- taking insurance against catastrophic events,
- minimum fault restoration time,
- even loading of networks, and
- provision of alternative feeders.

Power quality is measured and monitored in terms of network performance with regard to the occurrence of voltage dips, harmonics, voltage unbalance, transients and flicker. These parameters are currently quantified as measures of voltage distortion and time or frequency variations. The quality related costs to network investment are not established but utilities generally perceive the cost to be quite high.

Due to the uncertainty about quantification and impact of quality related costs on the overall network investment, there are difficulties and inaccuracies in concluding that any chosen network alternative provides an optimal solution. Network investment costs are normally determined during the planning phase but quality related costs are future operating costs that are usually not quantified. The unquantified future costs derail return on capital investment. It would be reasonable to develop mechanisms to quantify quality related costs and incorporate quality into planning to ensure informed investment decision-making at network development stage. The voltage and frequency behavior of most quality related parameters are known and it is the requirement of this thesis report to discuss the impact of quality related costs and incorporation of power quality into planning.

6. RESEARCH PROBLEM STATEMENT

Utilitilies, such as Eskom, realised that current planning tools lacked interface with each other and are insufficient to resolve network difficulties to the distant future (20-30 years). As a result, research was initiated into a number of network development areas including the costing of power quality. The author's survey in Eskom revealed that TIPS was proposed some years ago as the possible solution to the network planning problems but to date, it has achieved very limited success. Power quality effects on electrical equipment are an established area, but the quantification of related costs presently cannot be predicted. This research project was launched to propose power quality costing methods in distribution networks, and define the link between quality and planning through TIPS.

7. RESEARCH METHODOLOGY

Distribution network research was initiated due to network problems that could be associated with planning. The problems relate to not thoroughly understanding total costs and the risk concept in planning. The research for this project commenced with a literature survey and review of what is published in the planning field. The planning and design departments at Eskom (Brackenfell) were regularly consulted to establish current practices, problems, and objectives of network planning. Analysis of the literature and Eskom planning information identified a planning knowledge gap. The concept of risk was introduced and developed with particular reference to quality costing. Fuzzy theory approach has been proposed as a novel approach to analyse long-term uncertainties in planning. Power quality cost relationships were defined and an Excel spreadsheet (test.xls) was developed and proposed as a tool to evaluate the quality operating costs in distribution systems. Parameters influencing the capital cost of distribution lines were studied and the quality related capital cost was evaluated. The quality impact cost models were developed for 22 and 132 kV systems. The costing models assumed that the impact cost for voltages in the range (22 - 132 kV) would be within the corresponding cost range for evaluated voltages. Planning algorithms were evaluated, and improved through the inclusion of quality costs and a practical case study was undertaken to demonstrate research results.

8. RESEARCH PROJECT SCOPE

The scope of this research project is limited to sub-transmission and distribution networks (22–132 kV) of Eskom in Southern Africa, but the solution provided could well suit the requirements of transmission networks. The costing dimensions of this research are limited to distribution lines and violation of the standard quality requirements.

9. REPORT STRUCTURE

Chapter 1 is an introductory section to network planning with emphasis on the current challenges, objective and problems of distribution network planning. The chapter describes the problem of incorporating power quality into planning. It defines the research problem statement, and describes the research methodology and development of this report.

Chapter 2 reviews literature on published research in distribution network development completed over the last three decades. A detailed description of the planning approaches; from heuristic exchanges to modern mathematical modeling methods is given in this chapter. Although emphasis is given to the known traditional planning methods, literature on the risk concepts and quality of supply aspects are covered in the chapter.

Chapter 3 develops the risk concept described in Chapter 2. It classifies and describes risks into planner resolvable and unresolvable risks. The chapter discusses uncertainty models for long range network planning.

Chapter 4 discusses the key elements of capital costs in distribution lines and how costs relate to planning. It describes how the cost elements relate or influence line power quality. The chapter proposes operating quality cost and mitigation assessment methods.

Chapter 5 proposes modifications to existing network-planning algorithms to include quality considerations. It provides recommendations to link TIPS and quality related costs into planning. It proposes an algorithm for quality costing in distribution networks.

Chapter 6 discusses an Eskom practical case study to illustrate the results of the theory developed in earlier chapters. The study is a planned network in the Western Cape region and has a special outage condition twice a year. The study is first conducted with the outage condition and subsequently the special outage condition is removed.

Chapter 7 is a final chapter, which uses the outcome of the theory and case studies as a guide to understanding the relationship between planning and QOS challenges. It highlights possible topics for further research in network planning and power quality. It draws research conclusion and makes recommendations.

10. CHAPTER SUMMARY

This chapter introduced the topic of this thesis by highlighting some of the changes that are taking place in the electricity-planning environment. It pointed out that planning has evolved from simplistic to complex planning models. The challenges of network planning nowadays include:

- multiple planning criteria (cost, losses, etc),
- non linearity of planning models,
- large size of networks,
- dynamic nature, and
- risk and uncertainties (cost, load, economic indices, etc).

The chapter pointed out that planning is a complex task such that no generalisation could be made in the application of a specific model without loss of accuracy. It stated that planning risks were due to uncertainties, which must be resolved, as much as possible. The primary objective of the research is to optimise costs in distribution lines. To achieve research objectives, the chapter outlined the scope and developed theory of various planning concepts that will be applied in the practical case studies in Chapter 6.

The next chapter discusses the literature of planning methods and related topics.

CHAPTER 2

2. REVIEW OF PLANNING LITERATURE

1. INTRODUCTION

This chapter identifies and reviews published research work in network planning. The chapter discusses network issues such as planning methods, quality of supply and the risk concept. Network planning methods are divided into approaches and models. There is however a special case of a planning method that is applicable to reinforcement planning. Network planning approaches may be classified as ranging between judgemental and mathematical. Judgemental approaches are scientific methods that use mathematical evaluation but allow planner discretion to reach a planning solution. Mathematical approaches on the other hand only use comprehensive mathematical analysis techniques to reach a decision.

2. PLANNING MODELS

Planning models have evolved from simplistic networks to the simultaneous consideration of many network parameters. The non-linear nature and uncertainty of network parameters complicates the planning problem. There are four basic planning models, namely:

- The Heuristic Approach,
- Planning with Faults Considered,
- A Branch and Bound Formulation, and
- Mathematical Models.

The planning models are discussed in the order of decreasing planner judgement as follows:

2.1 THE HEURISTIC APPROACH

One of the most popularly used approaches is the heuristic planning method. The heuristic approach is based on intuitive analysis, sound experience and knowledge. It requires less computational time than more advanced mathematical models and can be associated to the way engineers think. Wang and McDonald [69] suggested that heuristic planning techniques were the most preferred due to their flexibility, practicability, straight forwardness and high degree of manipulation offered to network planners. Network loading is one but not the only constraint in distribution planning, even though most heuristic methods place emphasis on it. The stages of a heuristic planning method include overload checking, sensitivity analysis and scheme formation. The three stages are described in the following subsections.

2.1.1 Overload Checking

This stage is primarily concerned with whether there is sufficient transmission capacity available in the network i.e. it checks for overloads in distribution lines. The overload requirement is usually tested by simulation under both normal power system conditions and contingency situations (when one of the lines is faulted). The principle of evaluating network loading with one line faulted is normally referred to as the N–1 checking principle. The load flow studies are usually performed to determine load distribution in the network and identify overloading. It is normally preferred to use a.c. load flow equations for accuracy of results. The a.c. load flow equations are however cumbersome and generally require a lot of computation. Network parameters that are determined from the load flow evaluation include active and reactive power, voltage magnitude and phase angle. Due to large computational requirements for resolving a problem of this nature, Wang and McDonald [69] suggested that the a.c. equations be approximated with the d.c. load flow equations to provide simplification of the problem and enhance speed of power system analysis. The technique only ensures node power balance by using Kirchorff's first law, resulting in a big computational error. A blind application of this method could result into such decisions as unquantified trade off between incremental network costs and quality requirements.

2.1.2 Sensitivity Analysis

When the results of the load flow indicate a line is overloaded, sensitivity analysis method/ s are used to remove the overload by introducing network changes that eliminate network disconnection or overloading. The line that eliminates overloading is heuristically referred to as an effective line. The process of eliminating overloading may entail addition of other lines, opting for a bigger sized conductor/s, changing network configuration, etc until the overload is removed. Planners are responsible for making network choices on the basis of the most effective solution. In the late eighties, Gonen [22] highlighted that it was insufficient to consider only network disconnection and/ or line overload as the criteria for determining network effectiveness. He suggested the incorporation of the cost element into the mechanism to determine effective solution. According to his proposals, removing overloads to achieve effectiveness would come short in meeting overall network optimality. Wang and Mc Donald [69] supported Gonen's idea in 1994 and proposed the effectiveness index approach. The subject of effectiveness is however still debatable, as some of the constituents of effectiveness are not yet well understood. The effectiveness approach heuristically has no consideration of possible risks, line overrating, reliability and quality related costs. Using this technique, it is possible to obtain varying decisions between different network planners.

2.1.3 Scheme Formation

Scheme formation uses sensitivity analysis to add effective lines to the network. Load flow analysis guides the planner to generate effective lines. Addition of one or a group of effective lines is a comparatively simple way of expanding the network, at this stage. A possible combination of effective lines may be added on an ad hoc basis to improve the system. The scheme formation is more of a manual process and so network planners may terminate or commence it any time.

Gonen and Ramirez-Rosado [21] stated that it was most often heuristically considered cheaper to build radial feeders with line way tap offs to supply certain customer loads. They developed a set of mathematical rules for radiality. The approach assumed that the original network was radial. It did not consider a number of diverse factors such as whether the network was for rural or urban distribution and cost of additional protection equipment. They did not explain the heuristic rules used to differentiate rural from urban feeders, but in the context of South Africa, these would include:

- difficulty in establishing load forecast for rural areas,
- fewer or no networks in rural areas,
- rural loads are mainly due to electrification demand and farming.
- less revenues involved in building and operating rural lines, and
- power quality and network performance not critical in rural networks.

Gonen and Ramirez-Rosado heuristically defined a distinctive criterion of when to establish radial or ring feeders. Although ring feeders built using this method would provide higher system fault levels and alternative feed routes on contingency, the approach did not provide quality costs information.

2.2 PLANNING WITH FAULTS CONSIDERED

The random nature of occurrence of severe electrical faults complicates the network-planning problem. The problem with the occurrence of faults is the ability of the network to achieve fault restoration within minimal time, and without affecting a large number of customers. In the early nineties, Nara et al [44] suggested a method by which network planning could still be achieved but under conditions of severe faults. The proposal entailed running meshed networks as the so-called '**radial open loop**' system, just as it is done in urban areas of Japan. According to Eskom [17], Nara et al's approach is to some extent applicable in certain urban areas of South Africa as well but merely for improved supply availability. It however presents an uneven trade off between quality and costs, due to possible unnecessary duplication.

According to Nara et al [44], a number of predetermined faults are simultaneously considered with caution not to violate any network operational constraints. The objective is to ensure that all network loads are supplied but the faulted node. The approach presents difficulties to obtain optimal solution/ s with minimum redundancy. Design redundancy is critical in fault planning to ensure alternative supply routes in cases of faults. It is virtually impossible to eliminate design redundancy in fault planning and so the designs are generally costly than alternative methods.

2.2.1 Fault Planning Model

Nara et al [44] developed a model in which linear mixed integer programming is used to establish solution/ s to the objective function and related facility constraints.

According to his planning model, a solution is obtained by performing branch exchange iterations until the final expansion plan is reached. His fault-planning model is shown in Figure 2- 1 as follows:

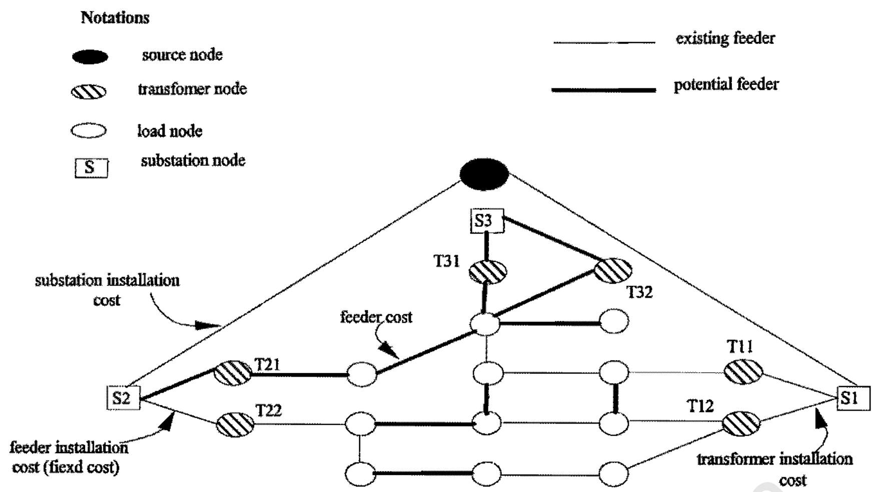

Figure 2- 1: Distribution network fault planning model [44]

2.2.2 Formulation of the problem

Nodes in Figure 2- 1 represent substations, transformers and load points. The branches represent electrical connections between nodes. Each branch has its impedance, current capacity and installation cost. The model does not consider all quality related problems but is primarily concerned with contingency. The cost of installed capacity represents the main cost in the fault model. According to Nara et al [44], the mixed integer-programming problem for planning with faults can be formulated on the basis of the following assumptions:

- candidates for the facility to be installed are known before hand,
- load is a lumped constant current load of which the power factor is 1, and
- only predetermined fault cases are considered.

Nara et al defined the objective function as the minimum weighted cost, within the constraints regarding current flow, radial configuration, current capacity, voltage drop and positive integer branches.

2.2.3 Solution algorithm

Nara et al [44] proposed a six-step solution algorithm to the fault-planning problem. The first step entails determination of the primary supply branches in order to construct the initial tree configuration. Branch exchange is then applied for each fault case, in step two. Next, the sum of constraint violations of all fault cases is reduced into a single and multi facility expansion (steps 3 & 4). Then, using all candidate facilities performs reduction of the sum of constraint violations. Finally, the algorithm performs reduction of the installation cost by removing the unnecessarily installed capacity. Nara et al did not show the mechanism of removing design redundancy and the degree of acceptance of redundancy in any proposed design. The aspects of the fault-planning model are applied and incorporated into the development of the contingency analysis method for the proposed planning algorithms in Chapter 6.

2.3 THE BRANCH AND BOUND ALGORITHM

A branch and bound formulation is a method that, like dynamic programming, is particularly suited for multi stage single variable problems, with definite decisions to be made at each stage. In the mid 80s, Boardman and Meckiff [7] stated that they were only aware of two references that explicitly applied the branch and bound technique in a practical problem. They reported the references to be Lee et al who exploited the simplicity of the basic structure to reduce the search for an optimum single circuit addition in 1984, and Meliopoulos et al who developed an original approach to a long range planning problem in 1976. Benchakroun [6] again used the same approach in the early 90s to solve the non-linearity of the proposed objective function using mixed integer linear problem. According to Boardman and Meckiff, the branch and bound method depends on recognition that in general only a small percentage of the solutions need actually be enumerated in a search for the optimum. Many of the solutions may be eliminated by application of bounds that will show that the solution cannot in any way be optimal or fall within the required margin of optimality. The success of the method relies on early identification of those courses that would be unproductive, and reduce the number of solutions to be examined before an optimal solution is reached. In the late eighties, Boardman and Meckiff performed a simple heuristic circuit exchange principle to check for overloads for a range of credible outage conditions. This was the original combination of optimisation technique and contingency analysis that ensured the feasibility of outline solutions from the standpoints of supply continuity and thermal ratings. The method recorded savings in the overall network cost for every topologically feasible exchange and updated them as exchanges were implemented in the course of the algorithm execution. There was however, nothing in the highest cost saving selection criterion or procedure that suggested that the solution produced by the method would definitely be optimal. Using the Synthesis Optimality Assessment Program (SOAP) algorithm as shown in Figure 2- 2, the multi stage decision process had a number of solutions including the optimum that could be identified using tree search procedures.

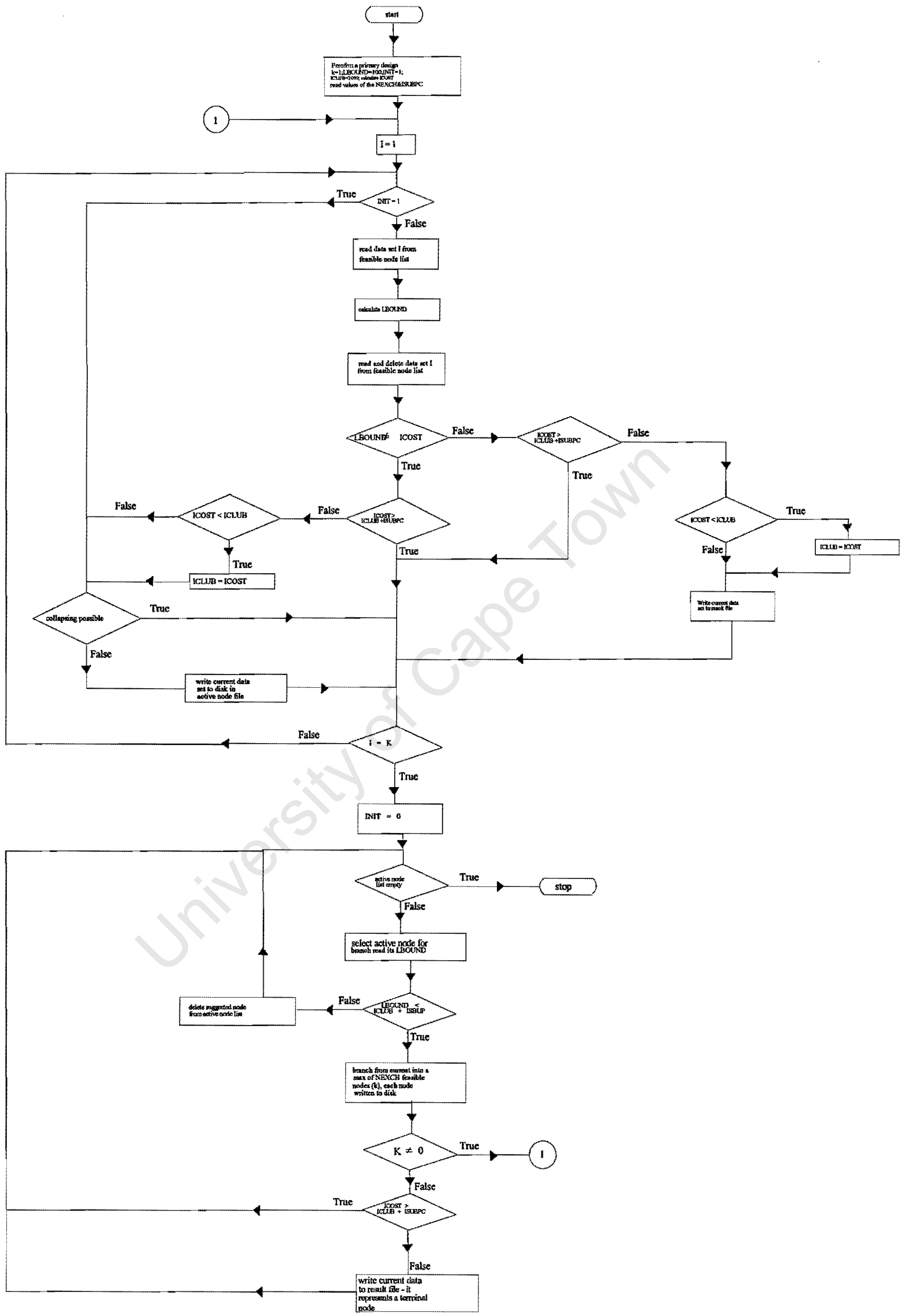

Figure 2- 2:Synthesis Optimality Assessment Program (SOAP) [7]

Boardman and Meckiff [7] identified the four main components of any branch and bound method to include the following:

- tree structure,
- branching policy,
- formulae for the bounds, and
- the terminating rule.

The following subsections provide a detailed description of the Boardman and Meckiff's SOAP algorithm.

2.3.1 Tree Structure

The initial node of the tree represents all solutions that may be obtained with the definition and restrictions of the algorithm. It is important to realise from the outset that the SOAP algorithm is an essential subset of any branch and bound algorithm. According to Boardman and Meckiff [7], the restrictions of the proposed SOAP algorithm equally represent an ideal solution in the branch and bound technique. Any network configuration represented by a feasible node may or may not be feasible, subject to satisfying all load flow security constraints. Branching may only take place from a feasible node since it is impossible for a circuit exchange to produce a feasible network from an infeasible node. The maximum number of branches that may emanate from any feasible node is equal to the number of circuit exchanges that could (regardless of load flow constraints) be applied to the network it represents. The number of branches from a node affects the overall improvement of the objective function (reduction of network costs).

2.3.2 Branching Policy

The computation time of the SOAP algorithm is generally higher than other algorithms and branching is restricted by the amount of computer storage space available. The minimum number of network branches is established using this policy, with the choice of a branch with the least lower bound taken first.

2.3.3 Formulae for Bounds

Ashirifnia and Aashtiani [3] proposed that the lower bound of any node could only be an estimate. If the lower bound were to be calculated as a precise value, then the network with an objective function equal to the lower bound would constitute an optimum solution. As a result, the overall branch and bound solution would be trivial. Thus, according to Ashirifnia and Aashtiani, for any active node, the requirement is that the least possible value of the objective function of any of the solutions be calculated.

2.3.3.1 Terminating Rule

According to Boardman and Meckiff [7], a node that may support no further branching is known as a terminal node. For this to happen, one of the following four situations must arise:

- Node may represent a feasible network to which no further profitable circuit exchanges may be applied.

- Node may represent an infeasible network.
- Lower bound that is calculated for that node may itself represent a node that is feasible within the load flow constraints.
- The lower bound on the node may be greater than the current least upper bound.

Although Boardman and Meckiff used the method to obtain the most optimum network option, the method could not guarantee optimality of the final option. This is because a few other options could possibly be within 5% of the chosen alternative. Due to the rigid mathematical nature of the branch and bound algorithm, it is not possible to identify the exact minimum cost solution and the approach is least preferred.

2.4 MATHEMATICAL MODELING

Mathematical modeling is another significant network planning approach established in the early seventies. It is strictly defined and does not allow planner judgement in the search for a network solution. Adams and Laughton [1] were amongst the first people to develop mathematical modeling methods. The first methods however were based on the assumption that networks were linear. Gonen and Ramirez-Rasado [21] later introduced non-linear mathematical models. Several research efforts to improve network mathematical modeling have since been forth coming. Gonen [22] later proposed that distribution models be divided into the subsystems of substations and feeders. Gonen's approach entailed resolving the subsystem of substations first and subsequently that of feeders. His proposal produced solutions that were not necessarily optimal. Eskom [19] reported in the late nineties that there were good mathematical models that combined both substations and feeders in one optimisation problem. Gonen and Ramirez-Rosado criticised earlier models for lack of reality and representation due to limitations imposed by the single stage planning approach. The single stage approach was improved to accommodate multi stage time based planning into the future between the 80s and 90s.

Crawford and Holt [11] proposed special algorithms, e.g. a branch and bound algorithm, sometimes coupled with the transshipment technique to resolve practical problems in mathematical modeling approaches.

Gonen and Ramirez Rosado [21] developed the mixed integer dynamic programming model in 1987. The model provided an improvement over the mixed integer linear programming mathematical models developed some two years earlier by Ashirifnia and Aashtiana [3]. The shortcoming of earlier models was the negligence of the voltage drop constraint in the optimisation. According to Gonen [22] however, when such constraint was not considered in the planning model and the radiality of the network was not a requirement, it could happen that the optimal solution represented a demand supplied from two or more substations or paths. This would lead to two or more different voltage levels to be associated with the same node, causing unrealistic solutions. Gonen and Ramirez–Rosado's approach was applicable in the multiple-stage network expansion throughout the planning period.

2.4.1 Basic Model Description

According to Gonen and Ramirez-Rosado [21], the model was presented to solve the optimal sizing, timing, and location of distribution substations and feeder expansion problems, simultaneously. The developed model allowed the inclusion of constraints defined to guarantee achievement of design requirements. The constraints included the logical mathematical constraints, voltage drop limitations and radiality restrictions. The distribution expansion problem involved a cost function that represented the present worth of the "**building decisions**" of the substation and feeders throughout the planning period. Gonen and Ramirez-Rosado proposed the objective function as a mixed integer dynamic programming model to minimize feeder and substation installation costs. The proposed model included investment cost, operational and maintenance expenses. The mathematical relationships accounted for network book depreciation, cost of energy and demand losses that would normally take place in the distribution system.

Gonen and Ramirez-Rosado [21] linked the logical mathematical constraints to the planning decision variables for building a substation or feeders throughout the planning period. The limitations guaranteed that only one substation of a given size could be built at any given location over the planning period. They defined constraints to guarantee feeder routes and included reconductoring variables for feeders and size increasing decisions.

Ramirez-Rosado [21] proposed the voltage drop constraints over the entire feeder length based on the following cases:

- nodes that receive and transfer power without necessarily consuming it,
- reconductoring of distribution lines,
- feeder power flow studies for newly established load demand, and
- substation power flow studies.

Ramirez-Rosado [21] proposed a set of mathematical rules for radial feeders. The scientific basis for the derivation of the mathematical relationships was however not explicitly stated.

2.4.2 Reliability Modeling and Optimisation

Tang [66] described reliability modeling and optimisation of distribution systems in the mid 90s using mathematical representation of networks. He stated that an improvement in system reliability levels or the decreasing of outage costs would usually demand an increase in investment cost. According to him, the goal of any reliability optimisation problem is to search for the minimum equilibrium. Figure 2- 3 is a graphical representation of the reliability and optimisation concepts described in his publication.

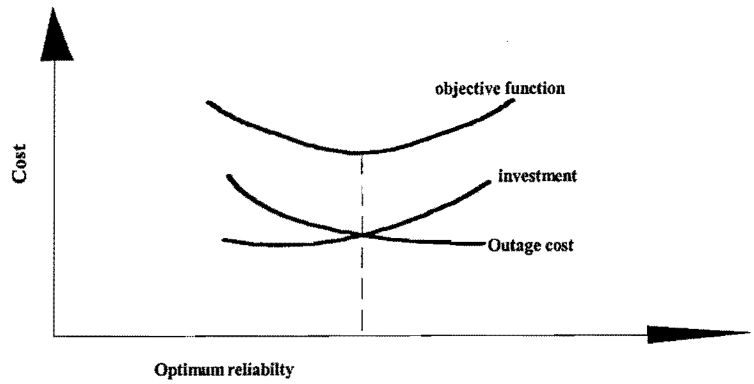

Figure 2- 3:Reliability Optimisation [66]

Tang [66] considered the static planning approach first and then the mixed integer dynamic optimisation model. Outage costs in the latter model were represented as a function of outage frequency, outage duration, average outage power and energy. For each branch or feeder, outage cost was not only related to its individual outage but outages of adjacent branches as well. Tang proposed that the factors influencing feeder outage costs included the network configuration, network element reliabilities, location and reliability of switches, lost load and its capital value.

Tang [66] also proposed the multi stage interlacing approach in which the cost optimisation model would be decomposed into several stage optimisation problems and the sub-problems are coordinated throughout the iteration solution process.

3. SPECIAL PLANNING MODEL

3.1 NETWORK REINFORCEMENTS

Planning of distribution networks can be classified according to the particular task under consideration. According to Partenan [47] and Krishans et al [34], sometimes one deals with new system expansion planning, so called **'greenfields planning'**, or the problem of strengthening an existing feeder **'reinforcements'**, or restoring an existing network to its original design state known as **'refurbishment planning'**. Krishans et al stated, 'the basis of the distribution network reinforcement design task is an existing distribution feeder'. Feeders may be strengthened or reinforced due to poor performance, quality related problems and/ or to cater for growth in customer load demand. The information required for reinforcements would usually include data of existing line section/ s, type of customer loads, feeder records of QOS data and load forecasts over the study period under consideration. Partenan suggested that network reinforcement plans should answer the questions: **what kind of an investment is to be made, where and when?** The intention of answering these questions according to Fipaza and Gaunt [20] would be to ensure that the sum of investment and operational costs (mainly due to losses) would be minimised over the study period within technical and safety constraints.

According to Partenan [47], reinforcements could be based on two criteria i.e. losses and voltage drop. Partenan described that reinforcement based on losses would be effective when the annual savings on losses and investment annuity were in equilibrium. Voltage drop based reinforcements are usually due to whether the design voltage drop levels are exceeded. The challenge of the voltage drop approach is the difficulty to ensure that no voltage drop limits are exceeded in any one feeder in obtaining an acceptable reinforcement solution/ s in cases of interconnected networks. The process would require backward checks whenever network changes are made. Possible distribution network reinforcement strategies are represented in the network theoretical problem as shown in Figure 2- 4. The figure shows possible feeder reinforcements in the vertical axis and time (years) in the horizontal.

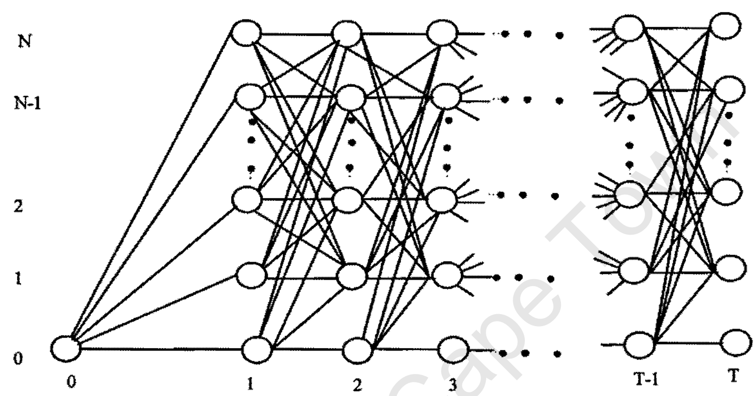

Figure 2- 4: Chart of possible reinforcement strategies [47]

The possible network reinforcement strategies shown in Figure 2- 4 were first proposed by Partenan [47] in 1990 and Krishans et al [34] supported the proposal in 1997. According to Partanen and Krishans et al, the reinforcement strategy considerations possible using the figure include:

- replacing the conductor of each line section with one of bigger cross sectional area, or
- the loads of the feeder can be decreased by building new line sections so that the feeder is divided into two feeders, and/ or
- the loads of the feeder can be decreased by building new primary substations.

Decreasing the feeder load using the suggested methods would effectively increase the system fault level. Each column in Figure 2- 4 depicts a certain time stage and each row represents one possible action. The lines between the states in the figure represent transfer costs.

The problem is formulated as a dynamic programming function and provides improvements to the linear programming reinforcement methods proposed by Masud [38] in the mid 70s. According to the figure, the decision for the t^{th} planning phase is obtained from the decision made at stage (t–1). The method minimises the transfer cost of moving from the starting point to any required stage.

The state (0, 0) means the existing feeder at present time. Figure 2- 4 suggests that moving, for example, from state (2, 2) to (2, 3) requires no reinforcement and moving from (2, 2) to (3, 3) means that reinforcement alternative 3 is realised in year 3. There are many reinforcement strategies that are feasible using Figure 2- 4 up to the end of the planning period (year T).

Partenan [47] defined the network optimisation function as the minimum sum of operational and initial investment costs over the planning period. Partenan's optimisation function differed from Nara et al's [44] proposal because it considered time based operational costs. Both proposals had a shortcoming because they neglected quality related costs in the cost relationships.

Partenan [47] proposed the main functions of the reinforcement optimisation program as shown in the flow diagram in Figure 2- 5.

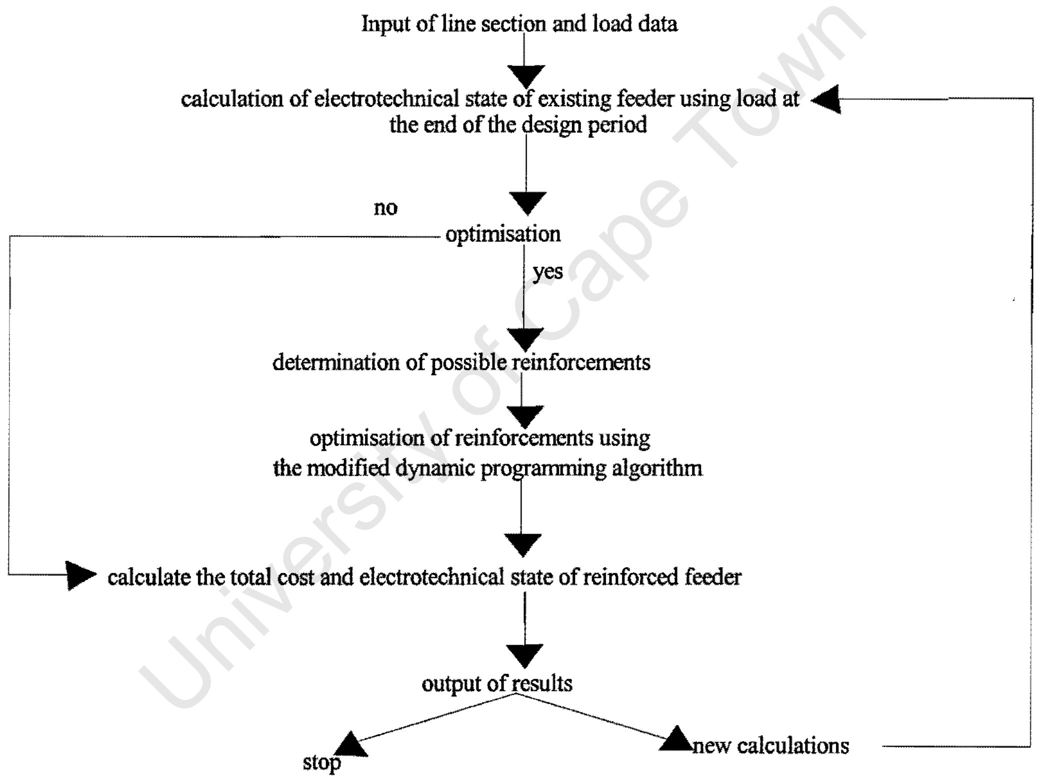

Figure 2- 5: Reinforcement optimisation program model [47]

Nahman and Strbac [43] acknowledged in the mid 90s that most research efforts had been concentrated on minimising real power losses whilst avoiding inadequate voltages, feeder and transformer overloads. According to the proposal, an alternative strategy to deal with the reinforcement issue would be to balance load amongst feeders and transformers in order to possibly postpone the new network investment. Nahman and Strbac stressed that reinforcements should mainly be based on network reliability improvements. The load sharing strategy of Nahman and Strbac [42] was a sound approach, as it would ensure improved utilisation of network equipment.

The approach however neglected possible poor performance of lines when certain load limits were exceeded. Moreover, the load-sharing proposal seems to neglect the possibility of rapid demand changes. The feeder reliability approaches of Nahman and Strbac could be manipulated and used with Strbac and Djapic's [65] planning algorithms to resolve quality performance problems in distribution networks. The approach would possibly achieve a system that addresses most problems and provide significant benefits in postponing network reinforcement.

4. QUALITY OF SUPPLY IN NETWORK PLANS

4.1 DEFINITION

There is currently no single universal agreed and accepted definition of power quality of supply. Koch [33] and Heydt [27] stated that power quality to most engineers would generally mean sufficiently high-grade electrical service that would be measured by the faithfulness of load bus voltage to maintain a sinusoidal waveform of 1 per unit at a rated voltage and frequency. All quality definitions covered thus far highlight difficulties relating to the distortion of a voltage wave shape in an alternating current power system. According to CIGRE [9], the Electrical Power Research Institute (EPRI) and National Scientific Forum (NSF) have done considerable research in the subject of power quality. Heydt [27] stated that other research efforts in books are those of United Nations Development Program, which has presented short courses on quality of supply. According to the NER [72], in South Africa, legislation outlines the statutory requirements for the Electricity Supply Industry (ESI) in accordance with government policy and law.

4.2 THE NATIONAL ELECTRICITY REGULATOR

The National Electricity Regulator (NER) is a statutory body established in terms of the Electricity Act, No. 41 of 1987 as amended in the Act of 1994 and 1995. Established in 1995, to take over the Electricity Control Board, the Minister of Minerals and Energy [72] appoints two members to the NER but once appointed act independently and report directly to parliament. The NER [72] is financed from the levy on electricity generators, which eventually is passed onto electricity customers. The NER has four sub committees amongst which there is Customer Service Committee. This committee is responsible for drawing up policy, procedures and monitoring of power quality in selected networks. The South African Bureau of Standards approved the NRS 048 (1-5), which provides guidelines for the equitable handling of quality in distribution networks.

4.3 THE NRS STANDARD FOR POWER QUALITY

The NRS 048–3 [52] provides for certain site categories (i.e. 1, 2 and 3) to be monitored for specified type interruptions and reported to the NER as shown in Table 2- 1.

catergory site	Voltage	sample size	Harmonics	Unbalance	Dips	Interrup.	Voltage Reg.
3	22kV(R)	0.01%				x	x
2	22 kV	2%		x	x	x	x
1	66 kV	10%	x	x	x	x	x
1	88 kV	10%	x	x	x	x	x
1	132 kV	10%	x	x	x	x	x

Table 2- 1:NRS 048-3 Site category monitoring requirements [52]

The optimality of the NRS 048 [52] limits could not be verified due to lack of test results and/ or description of mechanism to derive limits. It is assumed that the statutory quality limits were established with due consideration to plant equipment and human safety. It would probably be reasonable to conclude that the NRS 048 limits were absolute and have no quality impact consideration. The NRS standard indicates that voltage dips are the most common causes of customer complaints on quality. Some causes of dips are beyond the control of utilities. It states that the rate of occurrence of dips is geographically dependent due to different environmental conditions such as lightning, ground resistivity, pollution, birds, etc. It represents voltage dips graphically in terms of duration and magnitude on a dip window graph as shown in Figure 2- 6.

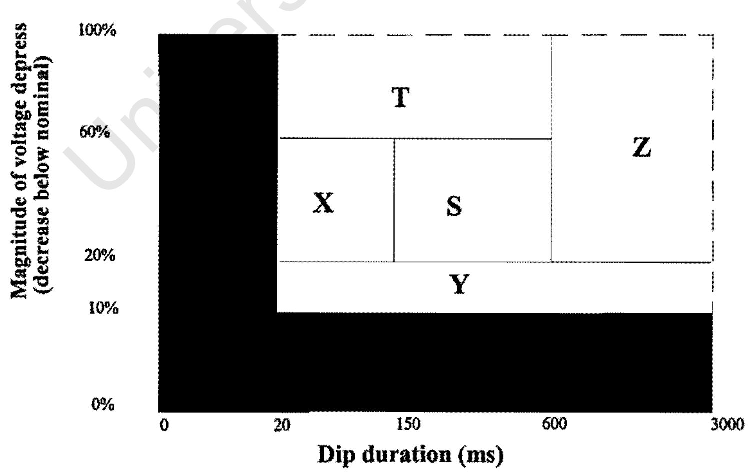

Figure 2- 6: Voltage dip window [52]

The XYZST voltage dip window in Figure 2- 6 provides insufficient dip representation because it does not quantify or even comment about the impact of dips to utilities and customers.

The NRS 048–1 [52] provides the requirements for the relative disturbances levels as indicated in Figure 2- 7.

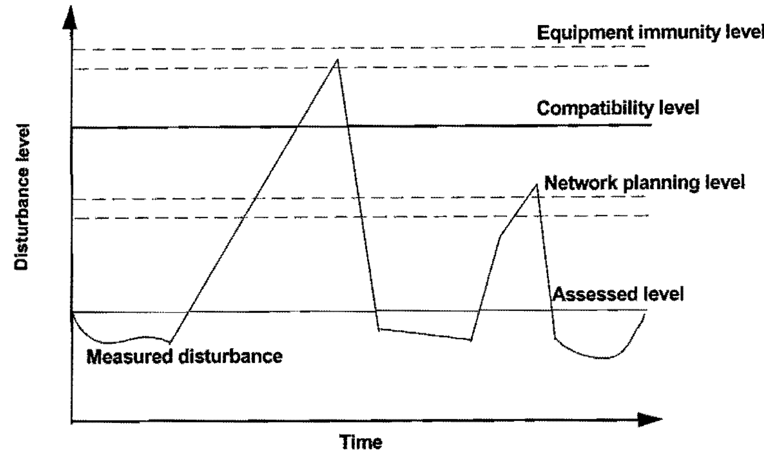

Figure 2- 7: Assessed and compatibility QOS levels [52]

According to Figure 2- 7 the NRS 048 [52] outlines the quality limits in terms of what would be the expected utility planning, compatibility and assessed levels. The different levels are defined per parameter category. The assessed level is compared with the compatibility level, which is the required minimum standard. Customers are expected to have their equipment with immunity levels higher than the compatibility levels, with mitigation where necessary. The NRS 048–4 was established for quality apportioning and acceptance techniques based on the International Electrotechnical Commission (IEC) standards. The NRS 048-4 however does not indicate or provide reference for the technical basis for the derivation of the IEC standard.

4.4 POWER QUALITY EFFECTS ON UTILITIES

Bad power quality in the network impacts on the network design through mitigation and costs.

4.4.1 Power Quality Mitigation

The NRS 048 [52] only provides the minimum quality requirements for utilities. Where utilities violate the required limits, they are responsible for corrective action to ensure network operation within statutory quality limits. Mitigation is the most common practice used to reduce or eliminate quality problems in networks. Power quality mitigation may be achieved through line reconductoring, installation of line compensators, line shielding, and so forth.

4.4.2 Utility Costs

The utility costs of quality may be due to the following:

- power quality mitigation,
- network condition monitoring,
- network repairs,
- loss of revenue due to interruptions,
- operation cost, and
- penalty cost for exceedance of standard limits or breach of supply contracts.

4.4.3 Utility Approaches to the Quality Problem

In 1985, Aspens et al [4] described various methods of improving electrical power quality based on the network data collected in the rural Alaska. The areas monitored were supplied from diesel generators with capacities ranging form 100 to 1000 kVA. The selected rural areas had numerous incidents of supply interruptions due to equipment malfunctioning but these were always blamed on **"power quality"**. Aspens et al reviewed a number of power availability reports and selected circuits supplying villages with frequent interruptions. All selected sites had a single phase supply voltage of 120 V (line to neutral) and the wiring was in accordance to the National Electrical Code (Alaska). They used a disturbance analyser to record outages, voltage dips and transients. Aspens et al [4] assumed that the user had no control over the source of quality problems. The study concluded that alternatives to resolve power quality problems varied in both cost and effectiveness. The alternatives ranged from the simple and cheapest compressors to expensive uninterruptible power supply units. The research provides a relevant basis for the development of quality costing mechanisms in chapter 4.

Late in 1993, Hughes and Chan [30] conducted a power quality survey in response to customer complaints received by B.C. Hydro. The study monitored customer exposure to voltage incidents of disturbances and harmonic levels. The results indicated that power quality problems originated from both the customer and supplier sides. The research did not indicate what proportions of quality related incidents were due to each source. The conclusions of the study may have been logically correct but the mechanism of identifying the sources of quality related problems requires clarification.

In 1995, BCM Consulting Engineers in collaboration with Lentz et al [35] identified the most common causes of quality problems to be grounding, wiring methods, load configurations, surge protection and employee practices. Lentz et al designed an implementation plan to mitigate the causes of identified quality problems. The study concluded that some of the disturbances may be locally generated by the customers i.e. impulses may be produced from local load switching over which the utility has no control. It further highlighted that high system impedance would accentuate locally generated quality problems. The project addressed most quality related issues but the cost impact of quality.

In 1998, San Roman [49] published that Argentina made a breakthrough in the development of explicit power quality regulation. San Roman stated that such developments were implemented in the early 90s, during privatisation of public utilities. He reported that the country was first to develop a quality standard for measurement of emissions, and control of flicker and harmonics. He proposed economic penalties for violations of set quality limits. No other research efforts have been forthcoming to cost power quality since his reports.

In 1999, Townsend [67] reported progress made by Yorkshire Electricity in power quality performance during the financial year 1998/ 99. The report attributed the success of his organisation to such factors as the best use of new equipment, reducing effect of network faults, and investigation of computer control and information systems. Townsend highlighted that they used 13 mobile generators, which could be connected at certain points in the network during maintenance so that customers would not be interrupted. A device known as REZAP, which switched the power back on after incidents of intermittent faults would restore customer supply within minutes. He emphasised the effect of the quality management systems implemented at Yorkshire Electricity to reduce the customer minutes lost (CML) due to interruptions. The statistics reflected an overall savings of 7.48 CML in 1998/ 99, which was a significant improvement compared to previous years. The study is relevant to the topic and highlights the element of minimum supply restoration time to reduce the inconvenience to customers and possibly costs. The report contributes to the development of quality-costing relationships in chapter 4.

4.5 POWER QUALITY EFFECTS ON CUSTOMERS

Supply interruptions to customers result in loss of productivity, cost and disruptions.

4.5.1 Loss of Productivity

Certain processes require continuous operation in the Chemical and Food industry and result in spoilt bulk materials if interrupted. Supply interruptions in such cases result in loss of man-hours and shortfalls in production volumes. Although some customers are equipped with emergency standby generators, these are usually sized to mainly cater for essential loads. The disadvantage of emergency generators is generally higher operating costs due to high cost of fuel. Industrial customer operating costs would be generally higher where production is interrupted without notice due to loss of raw material, downtime and startup costs.

4.5.2 Domestic Costs

The effect of interruptions to households may include:

- spoilt food in the refrigerator,
- inconvenience not to watch a favorable television program,
- appliance fuse blown, and
- general appliance damage.

4.5.3 Customer Approaches to the Quality Problem

In the early 90's, Ward [70] introduced the concept of power quality sensitive loads. Ward reported that minicomputers, electronic cash registers and data terminals often fell victims of their own complexities. Figure 2- 8 illustrates typical computer tolerance limits for various power disturbances as analysed in his research. In the figure, the voltage envelope between the two curves represents the limits in which a typical computer can withstand voltage disturbance without malfunctioning or damage. He established that in addition to the indicated voltage limits, quality sensitive loads typically required the following:

- frequency to be within +/- 0.5 Hz of the rated,
- the rate of change of frequency to be less than 1 Hz/ sec,
- voltage waveform distortion to be under 5%, and
- voltage unbalance to be less than 3%.

His experiment indicated how sensitive equipment would react to supply frequency fluctuations but did not quantify the impact of frequency fluctuations.

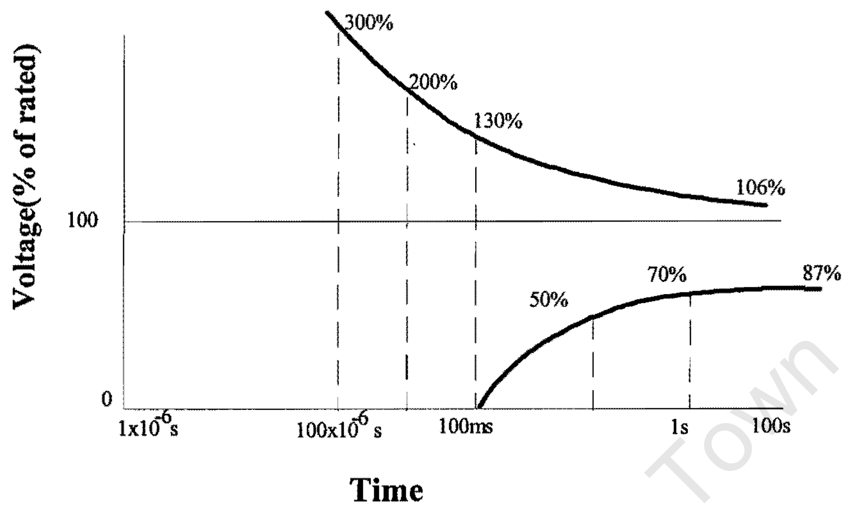

Figure 2- 8: Computer sensitivity to QOS [70]

Similar experimental findings to Ward [70] were reported by Wagner et al [68] later in the same year. Wagner et al stated that industrial plant power electronic equipment operated under unusually harsh electrical environment with high density of motors, switching devices and special equipment. They analysed results obtained from 3.5-month period of monitoring a variety of industrial processes using a sag generator. They found that the most sensitive electrical equipment required the voltage during the sag to drop below 80–86% of rated voltage to malfunction. The least sensitive malfunctioned when the voltage dropped below 30% of the rated. Results obtained indicated that 65 % of the interruptions were due to voltage dips. Production interruption levels occurred at 87% of the nominal voltage for more than 8.3 ms (0.5 cycle at 60 Hz) and these were the only interruptions directly causing loss of plant production. Wagner et al attributed voltage dips to faults that occurred a far distance in a transmission system, storms, etc. They suggested installation of on load tap changers to mitigate against system voltage dips. However, according to Eskom [17], tap changers in South Africa are usually used for voltage regulation. Voltage dips are usually mitigated by control stabilisation, improved protection settings and higher voltage at the point of common coupling. Wagner et al's research made no specific reference to possible cost implications of voltage dips. However, the report is relevant to this thesis as it indicated the need to define optimal approaches to quality mitigation.

In 1997, Willis [71] evaluated customer supply interruptions in an attempt to cost quality. Willis monitored quality of service for a pipe rolling plant in the United States.

He found that an interruption of shorter duration (ms) would cost approximately five thousand US dollars (US$ 5000) in lost wages and operating costs to unload materials in the process. The results obtained established a linear interruption relationship and suggested that cost was independent of interruption duration. The results of his survey are indicated in the cost-duration relationship in Figure 2- 9. The findings however do not express the specific costs of concerned quality parameters (i.e. dips, harmonics) but operational costs due to seemly combined interruption incidents in the specific plant. It is difficult to establish general mathematical cost representation for quality incidents on the basis of his report. The graphical representation in Figure 2- 9 could be interpreted to mean that interruptions of zero duration would cost US$ 5000. The figure provides limited scientific sense because it allows for many interpretations than the intended. It is acknowledged that the zero duration in Figure 2- 9 could be a representation of incidents of relatively short duration i.e. transients, but it is recommended the figure be revised to indicate its intended meaning.

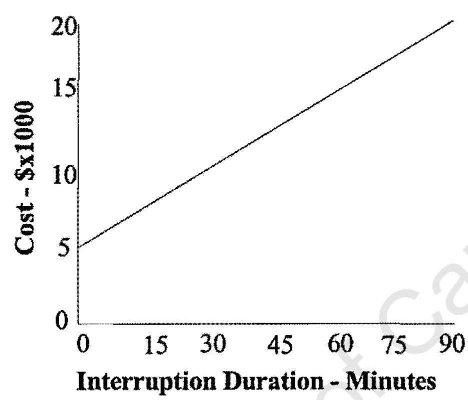

Figure 2- 9: Cost–duration relationship for interruptions [71]

In year 2000, Bollen [8] suggested that the occurrence of interruptions in low voltage networks could be predicted using the probability distribution curve as shown in Figure 2- 10. The curve suggests that probability of any system disturbance occurring in the network increases parabolically from 0 to 0.8 and hyperbolically from 0.8 to 1 whilst the voltage increases from 0.8 to 0.95 pu and from 0.95 to 1 pu, respectively. Bollen did not indicate the mechanism followed to establish the findings of probability distribution function in the figure.

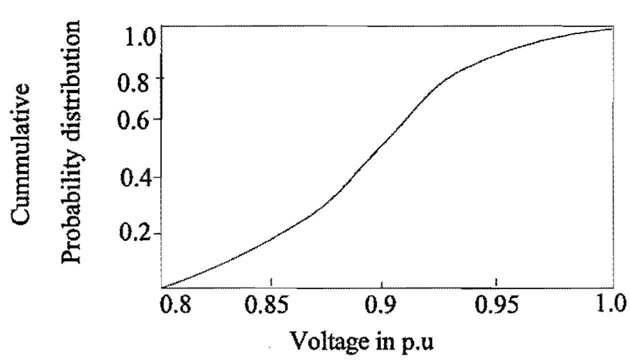

Figure 2- 10: Probability distribution of disturbance in networks [8]

The cumulative probability distribution curve in Figure 2- 10 indicates the tendency for dips to be smaller (<10% of nominal) or large (>30% of nominal) for different system disturbances. The function in the figure is a generic representation and does not indicate to which networks (rural or urban) dips of small or higher magnitude would be predominant.

5. NETWORK PLANNING RISK

5.1 DEFINITION OF RISK

According to Lister [36], risk may be well defined as an element of chance, which is characterised by an uncertainty condition. Risk usually has adverse effects on humans or plant and eventually catastrophic financial consequences. Lister stated, "the key to risk resolution is an improvement in the understanding of uncertain parameters that constitute a particular risk". Hsu [28] stated that most often, some information about the uncertain condition is not easily available and in such cases, uncertainty-modeling techniques are used.

5.2 UNCERTAINTY MODELS

Uncertain modeling techniques consist of:

- Fuzzy set theory,
- Pareto Concept, and
- Minimum Risk Criterion.

Heunis and Herman [26] stated that fuzzy sets were first introduced by Zadeh and later developed through the research efforts of Dhar [16] and Speltzer et al [59]. According to them, fuzzy set theory provide tools to represent and manipulate inexact concepts of ambiguity prevalent in human interpretation and thought process. Dhar was first to attempt the fuzzy approach in electrical engineering as early as 1979. A number of applications have since been increasing, including two literature surveys by Momoh and Tomsovic [40], and Srinivasan et al [61]. Dhar commented that he sought the fuzzy approach because decisions at network planning and design levels were always made without good data or a logical scientific approach. He added that making appropriate decisions through formal decision analysis would increase the likelihood of desirable outcome. He further suggested that those human factors, such as feelings, opinions, judgement, etc. were not to be disregarded in the formal decision making process. His proposal however did not clarify/ specify the degree of consideration to be allowed for human factors to influence the planning decision. Later, Gupta et al [23] acknowledged the first attempt by Dhar to use fuzzy logic in power system planning, but expressed concern that it was an oversimplification of real life situation that overlooked many complexities. He acknowledged that the approach might have been successfully used to evaluate long-range feasibility of interconnecting Detroit Edison Company with Ontario Hydro by submarine under Lake Huron, for which a total of sixteen alternatives were evaluated. In the mid 90's, Satoh and Serizawa [55] reported success in performing the expansion planning of generation capacity using fuzzy linear programming.

Srinivasan et al [60] recently attempted the fuzzy logic to forecast demand on a public holiday. His study reported success of the fuzzy forecasting method but the results were not verified.

Fuzzy logic may be considered as a super set of classical Boolean logic, which uses multiple truth-values to handle the concept of partial truth. According to Srinivasan et al [61], fuzzy logic uses linguistic variables with membership functions. It should be noted that the concept of fuzzy sets was introduced in order to develop a theory for incompletely or vaguely defined phenomena. It departs from classical methods of coping with difficulties of assumptions of randomness. In 1991, David and Zhao [13] reported a fuzzy dynamic programming method for long range expansion planning of power systems where decision variables were expressed qualitatively and fuzzy decision making under many conflicting objectives was sought by Huang et al [29] and Saraiva et al [54]. Srinivasan et al later suggested that fuzzification offered superior expressive power, greater generality and an improved capability to model complex problems at low solution cost.

In 1995, Strbac and Djapic [65] used the fuzzy coordinated technique to define a distribution optimisation problem with a number of objectives. The technique was used to find an ideal solution for minimum service interruption costs, load imbalance amongst feeders and transformers as well as real power losses. Strbac and Djapic found it rather difficult to reach an optimal solution and introduced the concept known as the **"Pareto Concept"** which would look at the efficiency of the solution rather than simply looking at optimality. According to Allan and Billiton [2], the Pareto Concept improves the objective function by looking at minimisation of multiple parameters at once, but one parameter achieves the minimum at the expense of the other. Pareto decision-making is not uniquely defined as a final solution, which requires that one must select from a set of optimal solutions. Due to the shortcoming of the Pareto Concept, Nahman and Strbac [43] proposed the fuzzy mapping approach to obtain the least outage cost and real power losses whilst maintaining radiality in distribution feeders as Sakawa [53] reported some two years earlier.

In 1997, Krishans et al [34] proposed that the Minimum Risk Criterion be used to resolve long-range uncertainties in planning. The approach, however, may present difficulties to network planners because it seemly rules out the possibility of establishing expensive network due the to cost risk. Although a recent publication in network planning, it focuses on minimum cost with no consideration of such constraints as network performance and power quality.

5.3 APPLICATION OF THE RISK MODELS IN PLANNING

There has been no application of uncertainty models to resolve risk in network planning with the incorporation of power quality, hence the subject of this dissertation. Mechanisms for the application of the risk models in planning are discussed in chapter 3.

6. CHAPTER SUMMARY

This chapter discussed network-planning techniques with emphasis on minimum cost planning methods, risk and quality of supply. Network planning approaches are classified into judgemental and mathematical.

Judgemental (heuristic) methods involve mathematical analysis but allow planner discretion in reaching a solution. Heuristic planning models are found to be flexible, practicable and straightforward, but lack the cost consideration since the key criterion in their application revolves around checking for network overloads. The choice of a suitable network option is up to the planner as long as the chosen alternative will not result in network overloads or line disconnection.

Mathematical methods on the other hand involve detailed mathematical analysis in reaching a decision. Earlier mathematical models discussed in this chapter assumed that networks were linear but later developments could deal with the non-linearity of the planning problem. Mathematical models were later improved to solve multi stage planning problems but these were broken down into substations and feeders with substations resolved first and feeders subsequently. Tang [66] proposed mathematical models for reliability modeling and optimisation. His approaches were based on the mixed integer mathematical modeling. He further suggested an integrated approach to evaluate outage costs where outage of one network branch influenced other branches. He also proposed a multi stage interlacing approach to decompose complex reliability problems into simple logical stages.

The chapter described the branch and bound technique as a dynamic programming approach with various planning decision stages. Boardman and Meckiff [7] first proposed the approach as early as 1985. The method relies on recognizing that only a small percentage of solutions need be evaluated and entails a simple heuristic branch exchange technique until a minimal cost solution is obtained. Boardman and Meckiff developed the SOAP algorithm to perform the branch exchanges but the process could not guarantee an optimal solution because there could be it a number of alternatives within 5% the optimum. The chapter identified the shortcoming of the branch and bound models as negligence of the voltage drop constraint, which could result in inaccurate solutions. In addition, where voltage drop constraint was neglected and radiality was not a requirement, it could well happen that the optimal solution represented demand supplied from two or more paths, which could lead to two or more voltage levels.

There is however a special method applicable only to reinforcement planning. The method uses possible reinforcement strategies proposed by Partenan [47] and is limited to areas where networks exist. The chapter highlighted Nahman and Strbac's [43] criticism of Krishans et al [34] and Partenan's time based reinforcement approach. Nahman and Strbac proposed that reinforcement investments could be postponed or cancelled as a result of balancing the load between feeders. The chapter discussed Nara et al's [44] proposal that network planning should consider possible combination of severe faults. The concept of planning with fault consideration can be related to the meshed networks in urban areas of South Africa. This approach does not guarantee optimal solution/ s due to the unquantified trade off between capital costs and power quality. It is primarily intended for good supply availability and is characterised by design redundancy that is very difficult to eliminate.

Various power quality studies conducted in different research efforts were discussed in the chapter but lacked appropriate representation of power quality related costs. The chapter described the Yorkshire Electricity's quality management strategy for 1998/ 99 to reduce customer supply interruptions and restoration time in case of outage/ s as one of the methods to improve quality. The quality surveys discussed in the chapter form the basis of the quality costing proposals in Chapter 4.

Finally, this chapter introduced the concept of risk where there is insufficient data and logic. It discussed proposals by Heunis and Herman [26] to analyse uncertainty using fuzzy numbers. The chapter highlighted an antagonistic view raised to the approach by Gupta et al [23] that it was an oversimplification of reality and that Dhar [16] had overlooked a number of complex issues in the uncertainty problem. It is also evident from the studies that fuzzy logic may not always produce an optimal solution but Strbac and Djapic [65] proposed the Pareto Concept to reach a solution in such circumstances. The Pareto Concept emphasised the importance of efficiency rather than optimality. The Minimal Risk Criterion as proposed by Krishans et al [34] is mentioned but not the most preferred approach as it limits planners not to choose expensive networks.

The theory of the risk concept and analysis techniques is further developed in chapter 3.

CHAPTER 3

3. RISK IN PLANNING

1. BACKGROUND OF THE RISK CONCEPT

This chapter outlines the fundamentals of risk in network development plans. It describes risk as identification, likelihood, impact and expected value. The chapter classifies risk into two categories and develops into the theory of mitigation and uncertainty models. Although some risks are difficult to understand due to limited or no information available, Heunis and Herman [26] proposed that probabilistic and possibilistic approaches could be used to resolve the uncertainty. It is important that electricity utilities understand planning risks, due to the threat they impose which could have adverse effects in the long-term investment. The benefits of understanding network risk include:

- reduced exposure to risk through better information,
- sound management actions,
- appropriate financial decisions that give confidence to stakeholders, and
- reduced waste.

2. UNDERSTANDING RISK

Risk may be evaluated by applying a process that provides the planner with future information on possible incidents that have negative effects to networks. The key principles in understanding uncertain conditions include identification, likelihood, impact and expected value.

2.1 RISK IDENTIFICATION

Identification of risk involves analysis of available network information, i.e. load profiles and network stability studies to identify all negative incidents that can occur and affect the investment. Quantitative methods such as load flows, fault analysis and network performance data are analysed to identify areas that could deviate from the limits adopted in the network design and performance. The degree of certainty varies, based on how much information is available on the incident of concern. Certain risks are subtle and their identification may depend on an unusual combination of factors. Subtle risks are commonly referred to as unforeseen risks. These risks require planner brainstorming sessions and detailed analysis of information from other participants, such as environmentalists. As an example of unforeseen risk, equipment malfunctioning on commissioning may be due to late delivery of cheaper equipment, purchased from a new supplier with no track record, no factory test certificates and possibly with damage during transportation. This could result in network performance and power quality problems that could be costly to the utility with no benefit of purchasing less expensive equipment without guarantees. It is proposed that network planners collect as much information as possible about the network and planning area so that all risks are identified. The information can be collected from such entities as environmentalists, city and rural planners, civic organisations, statisticians, weather forecasting institutes, etc. Technical risks are usually obvious and easy to resolve but subtle risks are mostly non-technical, costly and difficult to resolve.

2.2 LIKELIHOOD

The next principle of network risk analysis is its likelihood to occur, expressed in percentage form in the range of 0% to 100%, for the minimum occurrence and definite occurrence chances, respectively. The approach constitutes a continuous scale of measurement from 0 % to 100% expressing the likelihood that an event will happen. The likelihood of occurrence or non-occurrence of an event in network plans would depend largely on the occurrence of the underlying causes. In such cases, it would be easier for the planner to identify related risks if a similar setup had been experienced before, otherwise comprehensive risk modeling methods are used. Therefore, it is often more appropriate to concentrate the analysis of likelihood on the underlying causes, rather than the risk itself. The likelihood of a risk event is sometimes estimated and whenever this happens, credible assumptions must also be evaluated to test for the response of the likelihood to different set of assumptions. In cases where there is insufficient information to assess the likelihood with a tolerable degree of confidence, (where uncertainty is predominant) it may be possible only to say the likelihood is within a certain range. However, if the event could have significant consequences if it occurred, the result could well be that utilities would be unable to make decisions about the future. In such cases, it is worth considering all possibilities in a defined alternative range.

2.3 IMPACT OR CONSEQUENCE

Impact is concerned with possible consequences if a certain event does occur. These possible consequences may vary from delays in certain project completion, direct and indirect financial consequences, damage of customer electrical machinery or equipment (in the cases of some interruptions), etc. For example, a 5% likelihood of loosing a R1 000 000 is far more serious than a 5% impact of loosing a R100. Therefore, it is crucial to establish impact in network planning since the magnitude of monies involved may range in hundred of thousands to multi million rands.

2.4 EXPECTED VALUE

Expected value of a network event may be expressed as the product of its likelihood and impact. Statistically, it is the product of the product of the probability of an event and the amount of money in question. As an example, the expected value of 5% likelihood of loosing R1 000 000 would be R50 000. Often, a certain network risk event will not have a single unique impact, but there may be a range of possible impacts each with different probabilities. In such cases, a financial value would be attached to each impact and ranking would be applied in order of importance. For example, it would not be worth spending R 1000 000 for a non-catastrophic event with an expected value of only R 10000. However, considering that in networks the concern is about plant (capital), safety of people and environment, expected value is used to determine the insurance cost of identified risk/s. Generally, the cost of mitigating each risk will not exceed the expected value. It is important that costing of the network be accurate for expected value to correctly define the risk concerned.

3. CLASSIFICATION OF RISK

Network risk can be divided into planner resolvable and unresolvable risks.

3.1 PLANNER RESOLVABLE RISKS

Resolvable risks are those uncertain conditions for which network planners have knowledge of occurrence. The impact of resolvable risks is usually known from analysis of available information, past experience, etc. Accurate network costing usually makes it possible for the expected value of the resolvable risks to be quantified. It is possible to eliminate resolvable risk using analytical methods. The methods may entail varying certain network parameters whilst keeping within stated design constraints and in the process remove the unwanted effect (risk). The following are examples of network planning resolvable risks.

3.1.1 Initial Investment Costs

Initial cost risk is possible in network plans due to inaccurate costing which result in over or under utilisation of capital. Inaccurate costing is usually due to a combination of such factors as inadequacies in costing tools, incorrect load forecasts or economic downturn. These shortcomings in initial costing of networks normally result in poor rate of return on the investment made and/ or poor technical performance. The current practice in Eskom is that management decides on the amounts to be invested in network developments. Planners however are required to make planning proposals to the investment committee. It is the responsibility of planners to clearly identify all planning issues, risks and recommend actions or mitigation. There is however uncertainty about future economic performance. It is therefore advantageous to develop networks step by step because with accurate costing and short-term forecasting (1-5 years), the risk of initial investment cost can be resolved. It is important to evaluate existing network capacity prior to reinforcement because load sharing between feeders may result in the postponement of a network investment as Nahman and Strbac [43] proposed.

3.1.2 Internal Rate of Return

Utilities usually invest large amounts of money in network capital (fixed assets) over a period. Further, network expansion is fundamentally dependent on expected future electricity sales. As a result, a decision to buy network capital that is expected to last for 10 years involves an implicit 10-year sales forecast. An erroneous forecast of the asset requirements can have bad and undesired consequences. If a utility invests too much on the fixed assets (without an equivalent growth in load demand), it will incur unnecessary heavy expenses and will be saddled with excess capacity. The abnormally high costs in such situations can even lead to bankruptcy. It is therefore important to establish capital investment strategies to improve both the quality and timing of the assets purchased.

The Internal Rate of Return (IRR) is a financial modeling tool used in utilities in Eskom to measure network investment returns. This tool measures the rate at which the money invested in developing the network will be recovered. However, because the feature is uncertain, IRR needs to be reviewed and updated (preferable annually). Eskom [17] states that the internal rate of return long-term risk due to uncertainty can better be resolved by use of the Modified Internal Rate of Return (MIRR). The MIRR provides for flexibility in the IRR and allows for changes to be made in the return forecasts on the basis of risk data availability and analysis. However, Eskom is incorrect to assume that the proposed MIRR resolves long term uncertainties in investment returns without confidence on its existing and used risk analysis methods/ models.

3.1.3 Operating Cost

Optimal cost of network designs is a problem that presents difficulties to planners. The process of cost optimisation involves striving to obtain minimal cost (not cheap) that will satisfy the investment whilst not violating statutory and technical constraints. The planning constraints are of essence because they determine the overall costs of a distribution line. Higher operating cost than originally projected may be due to inadequate revenue forecasts, network fraud, technical and managerial incompetence. The causes of higher operating costs could result in failure to sufficiently recover all network costs and ultimately bankruptcy. A number of network parameters (voltage drop, cost, capacity, spans, etc) need to be coordinated to ensure optimised network operating costs. The optimisation of network parameters is difficult to achieve due to variations in a combination of influencing factors such as network configuration, distribution area, load profiles, environmental and human factors. However, bench marking of operating costs of distribution lines of different voltage levels provides a guide to the operating cost difficulties.

3.1.4 Quality of Supply Penalty

The power quality standard provides the minimum limits that the NER expects electricity utilities to comply with in supplying electricity to the customers. The penalty cost of violations of the standard requirement is however not specified. As a result, utilities like Eskom are often subject to unscientifically derived contractual claims from the customers. These claims usually involve large amounts of money. It is proposed in this report that planners perform QOS cost analysis and indicate results to the investment committee. The development of costing model taking into account supply quality is the objective of this thesis, and is described in Chapter 4.

3.2 PLANNER UNRESOLVABLE RISKS

Unresolvable risks are those uncertain conditions for which planners have very little or no information of occurrence. They are normal due to a combination of various unrelated factors and are not necessarily known from the past. These risks are vaguely understood and are very difficult or impossible to mitigate. Unresolvable risks have catastrophic consequences and can lead to bankruptcy. Allowance is usually made to reduce unresolvable risk or even shift them somewhere else by the way of insurance premiums. The following are example of network unresovable risks.

3.2.1 Non Technical Losses

These are losses not directly related to the technical nature or parameters of the electrical network i.e. conductors, voltage levels, transformers and other switchgear. Non-technical looses are mainly due to the chaotic behavior of humans to the distribution system. Cable theft and unauthorised supply connections constitute a considerable portion of these losses to the electricity utility. The chaotic behavior often results in loss of life and/ or damage to property. The unauthorised connections have no consideration of statutory regulations and cause supply interruptions. It is very difficult for planners to mitigate against non-technical losses.

3.2.2 Load Growth

According to Jones and Charlton [32], network planning traditionally deals with capacity problems, where the planner attempts to balance supply to the growing load demand. Network plans are realised provided there are sufficient funds available and the network development does not result in performance difficulties. This report proposes that network developments consider resolution of network power quality difficulties as part of planning. The capacity based network planning approach is problematic due to limitations in the availability of monthly metering data. The unavailability of metering data can be resolved by considering annual maximum demand forecasts as a suitable load demand representation. Jones and Charlton stated that time series were also applied in load modeling to obtain load forecast requirements using monthly values of energy and demand. The major setback of modeling using time series was found to be inaccuracies when dealing with clustered customers and lack of predictability in the long term. Consumers would typically experience rapid load growth in the beginning (during plant commissioning) and load growth would thereafter decrease to a stable level. Depending on the area of economic growth i.e. Cape Town (Urban and developed) versus Transkei (Rural and greenfields), the S curve approach can be used to indicate the expected growth for the first few years with confidence. Jones and Charlton proposed a method of improving load forecasting in 1991. The method provided no clear distinction between spatial and densely populated loads. It raised concerns that the quality and accuracy of the geographical data it presented could not be verified. It is a risk because there are no mechanisms used to verify the accuracy/ validity of geographical load forecasts.

3.2.3 HIV/ AIDS

The HIV/AIDS impacts negatively on economic growth as productivity is retarded due to high employee work absenteeism rate, cost of sick leave, increase in medical aid premiums, cost of death benefits, training cost, etc. Envisaged networks as the consequence are either postponed, plans cancelled or utilities have to carry the burden of excess network capacity due to unexpected decline in electricity demand. Although it is not entirely for planners to resolve the HIV/AIDS problem, it affects network planning. According to Planetrx [73], the impact of this deadly disease is not known with certainty because some people live longer than others whilst carrying the virus.

3.2.4 Natural Disaster

Natural disasters are uncertain conditions that result in loss of human lives and/ or destruction of networks. They are subtle risks which are difficult or impossible to mitigate. It is difficult to clearly define the behavior of natural disasters and thus even building robust networks at a higher cost is not an ideal solution. Moreover, robust networks at a higher cost are in conflict with the cost minimisation objective of network development. Generally, expensive networks are undesirable because the expense will be passed to the customer, in which case, network development will not provide economic growth to the country.

4. RISK MITIGATION TECHNIQUES

Mitigation is the process concerned with replacement of an uncertain and volatile future with one where there is less exposure to adverse conditions and so less variability in investment return. Risk mitigation is difficult where the uncertain condition is vaguely defined. Mitigating risks is costly and increases the network costs through an increase in capital expenditure or payment of insurance premiums. Network risk can be mitigated in the following ways:

- eliminating or reducing,
- transferred to a third party,
- avoidance, and
- absorption or pooling.

4.1 ELIMINATING OR REDUCING RISKS

The impact of certain risks may be eliminated or reduced through network redesign, use of different materials and mitigation by means of line compensators. Table 3- 1 tabulates various power quality consequences and possible mitigation to eliminate or reduce the effects due to quality risks on networks. Power quality parameters in Table 3- 1 are examples of planner resolvable risks.

Quality Parameter	Consequence	Mitigation
Voltage Dips	Damage to contactors, drives, computers, motors and processes.	Higher voltage at busbars, protection setting method and energy storage .
Voltage Flicker	Visual irritation, television screen damage and on line fan balancing.	Series reactors, SVCs, Higher wattage lamps, fault levels and furnace charge sizing.
Voltage Harmonics	Transformer, capacitor, neutral conductor and motor overheating. Capacitor over voltages, insulation damage and control circuit mal - operation	(Static/ Active) Filters, Tuned capacitors, Series reactors and increasing fault level.
Voltage Regulation	Undervoltage trips, motor overheating, insulation damage and light bulb life reduction.	Local generation, SVCs, voltage regulators, tap changers (onload), and capacitor banks.
Transients	Overcurrents and switching surges	Surge arrestors, current limiting reactors and capacitor tuning.
Voltage Unbalance	Motor tripping and overheating	Line transpositioning, SVC's, and motor derating.

Table 3- 1: Consequences of power quality and mitigation techniques

Risk of higher operating costs can be reduced through the costing practices discussed in Chapter 4. The costing methods define relationships that allow cost optimisation of such network parameters as voltage, capacity, spans, etc. The principle is that the selected network alternative shall be minimum cost option without sacrificing network performance and statutory quality requirements. Comprehensive analysis and modeling is sometimes used to improve understanding of uncertainty conditions and/ or possibly reducing the imposed risks.

4.2 TRANSFERRING RISKS

Utilities normally transfer risks to the third party when they find it impossible and costly to resolve. This happens when the network net present value (NPV) is equal to or less than zero. Network risks are normally transferred by the way of contractual or financial agreements. For example, utilities may cover their networks for financial loss in cases of natural disasters by taking an insurance policy. An insurance premium payable would ideally be linked to the capital covered and probability of occurrence **(expected value)** for catastrophic incidents. Utilities may insure for loss of revenue during natural disasters to minimise the impact but customers will bear the inconvenience of possible prolonged supply outage/ or no production for that period. Risk of loss or physical damage to equipment (mechanical or electrical works) during the network construction phase may also be insured. Although there is a direct relationship between insurance premiums payable and the expected value of an incident, it is possible to have low premiums for low probability incidents even if higher capital amounts are involved. In the case of power quality related risk, contractual agreements may be such that those customers who introduce quality difficulties into the network and affect other customers are made liable for penalty cost. This penalty fee would be charged when statutory quality standard limits were exceeded. Such customers would in addition to the penalty cost be responsible for mitigation of bad power quality within their plants.

4.3 AVOIDING RISKS

This is the most obvious way of dealing with network risk but least preferred because it would mean that networks would never develop because risks are generally present in every investment. For example, it makes business sense to avoid using less established contractors for distribution line construction because they might become bankrupt and no compensation would be available should contractual obligations not be met. Some power quality risks can be avoided if electrical loads are grouped and allocated to networks in accordance with their ability to generate non-standard voltage and/ or frequency signals.

4.4 ABSORBING AND POOLING RISKS

Network risks that cannot be reduced, transferred or avoided are simply absorbed. The cost (expected value) for these risks may be shared between the utility and the supplier of equipment (services rendered). As an example, the utility may contract with a consulting firm to establish load forecast for an area and if the forecasts were inaccurate beyond a certain degree or over conservative, the consulting firm would be liable for a certain penalty fee, according to the upfront agreement. For existing networks, the utility might have to reconductor the lines or reinforce the network. This would cause delays in supplying the area and the utility would lose the expected revenue. Based on the agreed formulae for penalty fee, imbalances between the penalty fee and the utility revenue loss are possible. Although risks can be shared, uncertainties about the impact of certain unresolvable risks to utilities and customers usually result in conservative cost sharing formulae.

5. UNCERTAINTY MODELS

5.1 BACKGROUND

One of the challenges that pose difficulties to network planners is the uncertainty associated with some network planning parameters. The uncertainty concepts reviewed in Chapter 2 are combined and developed further in this chapter based on the research work completed by Dhar [16], Heunis and Herman [26], Srinivasan et al [61], and Strbac and Djapic [65]. Uncertainties normally contain vast and varying information about unknown parameters and so Heunis and Herman proposed uncertainty models that are able to represent both probabilistic and possibilitic information. As early as 1972, Dhar identified and tested the fuzzy probability approach as the most suitable model in electrical engineering problems. Twenty-five years later, Srinivasan et al repeated Dhar's findings. Uncertainty tools establish the most probable and possible solution/ s even with very little data or ambiguous terms available. There are four basic models used in electrical engineering and other applications to analyse uncertainties that are vaguely defined. The models include the following:

- possibility known,
- probability known,
- scenarios, and
- probability and possibility unknown, but defined limits.

5.2 DESCRIPTION OF MODELS

5.2.1 Possibility Known

Most of the decisions in long range system planning take place in an environment where the objectives, constraints and consequences of certain decisions are not sharply defined. This often happens when the network parameters involved are fuzzy in nature. However, Heunis and Herman [26] proposed that if the upper and lower limits are well defined, the uncertainty could be modeled as a fuzzy set or possibilistic distribution. The most common application of a fuzzy set is a fuzzy number, which can be described as a trapezoidal membership function shown in Figure 3- 1. The trapezoidal membership function can be expressed as a quadruplet; a1,a2,a3,a4.

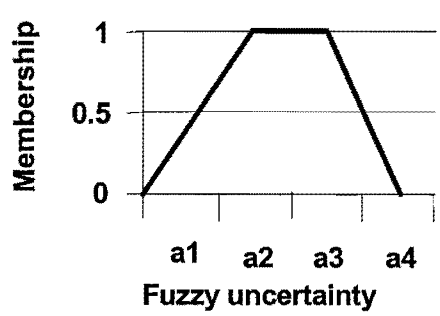

Figure 3- 1: A trapezoidal membership function [26]

Uncertainties that are not easily quantified probabilistically may be modeled using the membership function approach in Figure 3- 1. The approach is however not useful if the confidence intervals are not known as unrealistically extreme estimates of likelihood of an uncertainty can be easily made.

Since the long range planning decision problem cannot be adequately represented by a statistical decision model, it is important that all possible attributes are considered for optimal decision. Some of the attributes of alternatives are not possible to define in the planning stage because of unavailability of exact design configuration, as suggested by Srinivasan et al [61]. Statistical decision approach for determination of a planning decision is of doubtful value without consideration of attributes of all other alternatives. As possibilitic alternatives are not always quantifiable because of incomplete data, unavailability of statistical information or fuzziness of the system, the states may be represented by quantitative semantics or linguistic variables such as ***very high, high, medium, low, very low,*** etc.

A fuzzy set may be easily defined as a set of ordered pairs of objects (or points) and grades of membership which associate with each of the points of the universe of discourse U, where $U \rightarrow [0, 1]$. If the set X denotes the objects (or points) then the fuzzy set, S^f in X is given by,

$S^f = (x, \omega S(x)), x \in X$ where $\omega S(x)$ characterises the grades of membership of x in S^f of a membership space U. If $\omega S(x)$ is either 0 or 1 then it does not belong to the fuzzy set S^f. The values of $\omega S(x)$ close to 0 or 1 indicate the lowest and highest degrees of membership in S^f, respectively. For example if X = (1, 2, 3, 4) is a set of non negative numbers, then

$S^f = (1, 0.32), (2, 0.65), (3, 0.25), (4, 0.01)$

5.2.2 Probability Known

Models for uncertainty are chosen based on the amount of information that is available. A probabilistic model can be used if statistical data related to probability of different outcomes is known. Dhar [16] proposed a power system long-range decision analysis in a three dimensional morphological box as indicated in Figure 3- 2 and statistical decision approaches have been used in conjunction with the decision model. The model uses a set of feasible alternatives for a set of given system states, for which the probabilities of occurrence and costs or benefits for each alternative are known. The product of probability and utility (cost or benefit) give the expected value. The decision rule is to select an alternative that offers the highest expected value. This approach however neglects some of the criteria of merit because of unavailability of data.

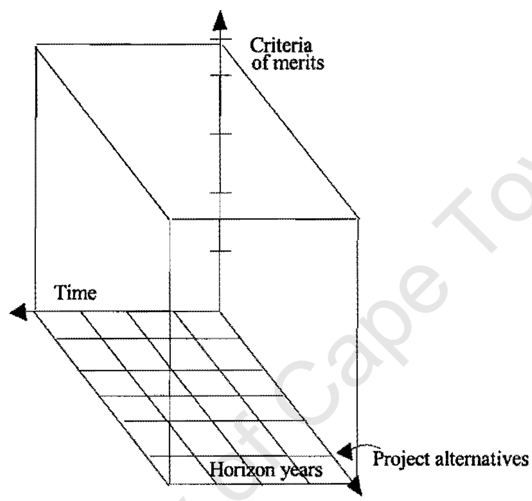

Figure 3- 2:Dimensions of long–range decision making [16]

Time dimension in Figure 3- 2 indicates the fuzziness of system states and criteria of merits of alternatives are shown. The criterion of merits in the proposed method includes both quantitative and linguistic measures. Possible quantitative measures may include capital costs, annual operating cost, network reliability, quality targets, etc. Other criteria of merits, which are impossible to calculate, would be expressed with such linguistically terms as high, low, etc.

Heunis and Herman [26] proposed other examples of probabilistic models that include probability distribution functions (pdf) and random variables. Mathematically, probability distribution functions describe the probability associated with each value an uncertainty can assume. Probability models derived with insufficient information could give misleading results due to the inaccuracies about confidence intervals.

5.2.3 Scenarios

Scenario modeling entails definition of different possible states for each uncertainty. These possible states can be weighted if their probabilities are known. Weighting of uncertainty possibilities result in discrete state or uncertainties that can be modeled with discrete states.

This technique is disadvantageous because of the amount of computation power required to evaluate continuous distributions and even with high number of repetitive calculations with inaccurate results.

5.2.4 Probability and Possibility Unknown

An uncertainty may be represented by an interval if the range of values it can assume have finite upper and lower bounds. Probability and possibility information are not necessary and the defined range does not have to be continuous in this type of an uncertainty model. This model can be analysed efficiently using interval mathematics. However, if the lower and upper bounds are estimated in a biased manner, the model results could lead to an over or under design.

5.3 APPLICATION OF FUZZY SET THEORY

Network planning areas that relate to fuzzy set theory include network expansion, scheduling and reliability. When the fuzzy theory is used to solve network problems, the following steps must be followed:

- Mathematical or linguistic description of the problem to be solved.
- Definition of the threshold for the planning variables. For each variable there is a specific value that defines the degree of satisfaction evaluated from empirical knowledge and a certain deviation is acceptable with a decreasing degree of satisfaction, until the value reaches an unacceptable value. The two values corresponding to the greatest and least degree of satisfaction are termed the threshold or lower and upper bounds. An example of the threshold is the power quality standard limits that are defined in terms of percentage of voltage magnitude or percentage voltage magnitude and time for some parameters.
- Construction of the membership functions based on the defined thresholds. Forms of membership functions are available, i.e. trapezoidal, parabolic, etc. The membership function should reflect the change in the degree of satisfaction with the change in the variable concern.
- Selection of fuzzy operations based on the domain fuzzy expert's reasoning. To remove ambiguity, the commonly used operations are those established by David and Zhao [13].

6. CHAPTER SUMMARY

The chapter covered the development of risk theory that is mainly due to uncertainty. Risk is defined in terms of likelihood (probability) of an incident to occur, impact and the expected value, which is usually expressed in financial terms. The expected value of an incident expresses the consequential costs to be incurred by the utility if the uncertainty incident occurred. The understanding developed in this chapter suggests that risks are common in the long term due to limited information available. The unavailability of information causes uncertainty about the future, hence long-term network plans cannot be guaranteed. Network risks discussed in the chapter are classified into planner resolvable and unresolvable risks.

Resolvable planner risks are considered to be those risks for which network planners have knowledge of occurrence either from past experience or scientific analysis. Unresolvable risks on the other hand are those risks that are difficult to analyse because they are vaguely defined and difficult or impossible to mitigate. Uncertainty models are discussed and proposed as a way to analyse long-term uncertainties within a degree of accuracy.

Chapter 4 discusses costs in distribution lines and makes proposals to cost evaluate quality risks.

CHAPTER 4

4. DISTRIBUTION COSTING

1. OVERVIEW

Traditionally, a distribution system's initial investment capital comprises of substation equipment and the distribution line itself. This chapter discusses costing of distribution lines and how it relates to quality. It presents quality-costing proposals for both utilities and customers. Quality related costs are usually not considered as primary to the initial investment costs of a distribution system. According to Eskom [17], it is common for utilities to include quality related costs in the operating cost budget. It is important to quantify costs due to quality to improve understanding of its impact in distribution networks.

2. CAPITAL EXPENDITURE IN DISTRIBUTION LINES

Eskom [17] estimates the capital expenditure (capex) in distribution lines on the basis of an approximation that total project costs are approximately five times the conductor cost (**conductor cost ≤ 0.18*total project cost**). The line cost estimates data used in Barei's [5] report in 1999 suggested that for a 22 kV mink line, the cost of conductor was 26.71 % of the total project cost. The following year, the research repeated the exercise and found that conductor cost would be 20% of the total line cost. Makhathini [37] later reported that for the same type of a line, conductor cost would be approximately 21.27 % of the total line cost. According to CIGRE 22.09 [10], total line cost is usually 3-5 times the conductor cost. The research evaluates line costing on the basis of the outcome of various survey reports. The approximate costing method does not completely account for quality related costs as it only includes voltage regulation. It is rather difficult to establish a generic approach of evaluating quality capital expenditure as quality related costs are unique and case specific. Distribution line capex is primarily due to the cost of three most significant materials, namely poles structures, insulators and conductors. Figure 4- 1 shows the typical capital cost structure of high voltage distribution lines. An allowance is usually made for planting the poles to depth, and the rest of the costs would cover for overheads, labour, transport, etc. The combined cost of poles, crossarms, insulator and planting depth constitute the line structure cost.

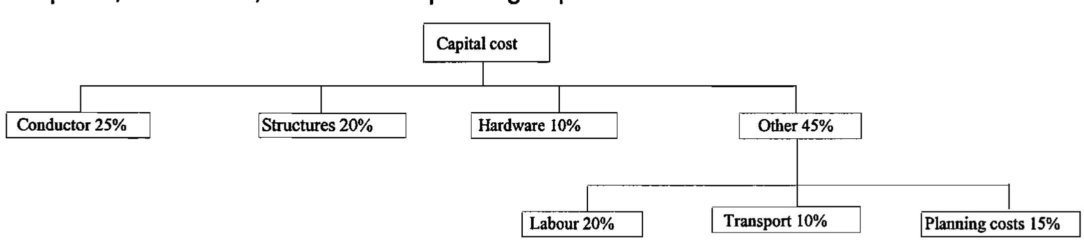

Figure 4- 1: Capital cost structure of HV distribution lines [17]

A detailed description of distribution line cost constituents is given in the following subsections.

2.1 POLE STRUCTURES

Poles that are commonly used in distribution lines include:

- wooden poles,
- steel poles,
- steel lattice poles,
- concrete poles, and
- aluminium poles.

Wooden poles are most preferred in Southern Africa because of ease of handling, abundance of materials and affordable cost. The height of a pole required for a particular location is mainly determined by such factors as:

- length of vertical pole required for wires and equipment,
- sag of conductors,
- clearance required above ground or obstructions for wires, and equipment, and
- planting depth into the ground.

Generally, pole costs can be related to the physical characteristics, affordability and availability of materials in the area. Certain pole structures require extensions or modification to provide for support of shield wire/ s. The design decision determines whether or not to extent the structures. Where the nature of structure is not suitable for shielding, the network would be exposed to the risk of lightning flashovers causing transients and possibly supply interruptions. Structural modifications made to provide for shielding may require additional support structures per line length due to additional mass of shield conductor/ s.

2.1.1 Wooden Poles

Wooden poles can be materially extended by impregnation with wood preservatives. According to Gonen [22] and Makhathini [37], once the wood is properly treated for the environment in which it will be used, it will to a certain extent resist decay and maintain its life strength to a minimum life expectancy of 35 years. Wooden poles are suited for use in the distribution industry in varying climatic conditions. Environmental conditions and strength requirements determine the wooden pole properties and these may vary for different species of trees. Gonen suggested that wooden pole structural design is based on an ultimate stress for the species used and its inherent flexibility adds a certain degree of cushion when severe loadings are imposed. He stated that wooden construction was capable of absorbing shock loads and had longitudinal load capability not found in rigid structures. The shortcoming of wooden poles is the inability to withstand fires. Fires could easily result in supply interruptions in a wooden pole distribution system due to sensitive earth faults as a result of destruction of line supports. The poles are considered to be less expensive than other pole types but sacrifice quality performance in cases of fires and ground rot.

2.1.2 Steel Poles

Steel pole designs can be optimised to produce light steel which is more flexible than wood. In South Africa, steel poles are normally used to support overhead lines that are heavily loaded and where wind speed is of concern. According to Makhathini [37], wind speed consideration is important to ensure that required clearances are maintained even on conditions of storms or winds. The violation of clearance requirements can cause faults between phases and result in unnecessary supply interruptions. According to Eskom [17], steel poles are considered to be amongst the expensive support structures but low maintenance gives them the competitive life cycle costs. The light steel pole technology, which includes the lattice steel, has been used in distribution systems for decades and gives steel an added advantage in terms of its weight, amount of material used and subsequently its cost. They are easier to handle than wood and can be modified in the field during line construction.

2.1.3 Concrete Poles

Gonen [22] reported that concrete poles (normally reinforced with steel) have been used in street lighting because of their neat appearances. These poles have an average life span of approximately 60 years and their greatest advantage is the immunity to ground rot. The use of concrete poles in distribution systems is limited because of high cost. Due to heavier mass of concrete in comparison to wood and light steel poles, transportation costs are generally higher. Cost effectiveness in distribution line construction projects may therefore be achieved if the manufacturing site for concrete poles is located closer to the line construction site. The approach would eliminate the cost difficulty due to transportation.

2.2 INSULATORS

Distribution overhead lines are provided with insulators to prevent current from leaking out of the distribution system. Insulators are classified into shackle, bobbin, pin, post, suspension, long rod and strain type insulators. The basic requirement of any insulator is to provide mechanical strength sufficient to support the conductor under both normal and worst load conditions. The selection criteria for insulators usually include insulator strength (Cantilever Strength) and pollution levels in the area of use. Cantilever Strength is important for quality performance because appropriately selected insulator will not break on windy conditions and result in interruptions. The measure of an insulator to withstand pollution is usually expressed as its creepage distance (mm/ kV). Eskom [17] would normally use insulators with a creepage distance less than 25 and above 31 mm/kV for lightly and very heavily polluted areas, respectively. Insulator properties are important for quality performance in regions with varying pollution levels. Polluted insulators result in bad quality performance due to flashovers from dirt deposits. The price difference between insulator types is insignificant.

The geographical map in Appendix E indicates pollution levels in different parts of South Africa. According to the map, coastal areas are very heavily polluted. Insulators normally used in these areas would have creepage distances of above 31 mm/ kV. Coastal areas are polluted because they are exposed to the sea spray or very strong pollution winds from the coast. Polluted winds along the coast are due to sand from the beaches and salts from the sea. Insulators in heavily polluted areas should be frequently cleaned (once in 3 months) to prevent bad quality performance. The bad quality performance causes supply interruptions, customer inconveniences and loss of revenue. The next most polluted regions are the inland areas within hundreds of kilometers from the coast. The regions would normally have pollution levels for which Eskom [17] would use insulators with creepage distances of approximately 25 mm/ kV. There is a relatively high degree of exposure to pollution from the sea but the primary source of pollution is local industrial plants. The most inland areas of South Africa are all medium polluted. Medium polluted areas are not subjected to the sea winds and/ or pollution because of the distance from the coast. Pollution in such areas could be due to high density of industries and/ or houses. The northern west region is classified as lightly polluted area with pollution levels for which Eskom would use insulators with creepage distances of between 16 and 21 mm/ kV. Winds in these areas are relatively clean and the density of houses and/ or industrial plants is relatively low. Lightly polluted areas have a relatively low risk of bad quality performance due to dirt-accumulated insulators. Insulators used in these areas should require less frequent maintenance than in heavily polluted areas.

Table 4- 1 lists creepage distances for insulators commonly used in Eskom.

Geographical Area	**Eskom insulator creepage distance (mm/kV)**
Coastal	≥ 31 mm/kV
≤ 100 km from Coast	~ 25 mm/kV
Inland	16 ≤creepage≤ 21 mm/kV

Table 4- 1: Creepage distance for line insulators [17]

2.3 CONDUCTORS

The most known types of conductor materials in distribution systems comprise of Steel, Copper and Aluminum. The selection criteria for which conductor to use is based on:

- cost,
- mechanical strength,
- weight, and
- conductivity.

The conductivity parameters used for conductor selection include:

- cross sectional area (mm^2), and
- resistance (Ω).

According to the selection criteria, copper is the most preferred conductor type in terms of its conductivity and availability whereas aluminum gets the second preference. According to Gonen [22] however, aluminum has the advantage of 70% less weight than copper of the same size but its conductivity is 61% that of annealed copper. Gonen identified copper as much stronger than aluminum as the breaking strength of aluminum is rated at 43% of hard drawn copper. It is important that conductor properties are such that there will be no excessive sag, voltage drop and power losses. Conductors with higher tensile strength are usually used in rural distribution (lower load densities and longer spans) without excessively increasing the pole height. It is possible in such arrangement to maintain the required clearances. Conductor current carrying capacity and minimum voltage drops are more important in urban distribution because greater capacity is essential to serve fast growing and high-density loads.

Conductor sizes are an important measure of capacity (MVA.km) that is variable with voltage. Quality limits conductor selection by the way of voltage regulation consideration. Material resistivity, which is the limiting factor for heat losses, I^2R however reduces power transfer capability of conductors. The relationship between conductor resistance and size is expressed as:

$$R = \frac{\ell\rho}{A}[\Omega] \qquad (4-1)$$

where:

R	:	resistance of conductor (Ω)
ℓ	:	length of conductor (m)
A	:	conductor cross sectional area (mm^2)
ρ	:	resistivity of conductor material (Ωm)

Equation (4-1) may be re-arranged to show the inverse relationship between conductor resistance per kilometer of a line and size.

Figure 4- 2 shows the relationship between conductor cost per kilometer and its size.

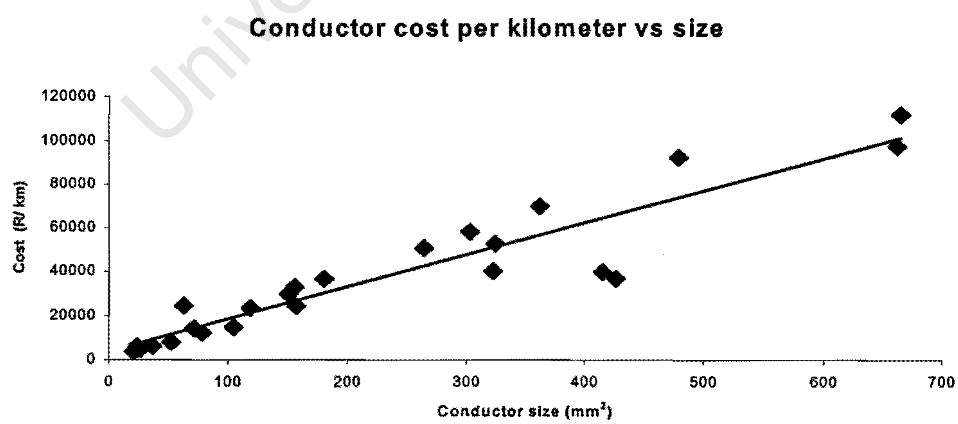

Figure 4- 2: Conductor cost per kilometer versus size

The curve in Figure 4- 2 was established on the basis of conductor data obtained from Eskom - Brackenfell in July 2000. The conductor data is listed in Appendix F. The curve suggests a direct relationship between conductor cost per unit length and size.

The gradient of the linear graph, m can be calculated from the co-ordinates (400, 60000) and (260, 40000) as:

$$m = \frac{\Delta y}{\Delta x} = \frac{200}{14} = 142.8 \qquad (4-2)$$

The relationship between the conductor cost per kilometer and size may be expressed as:

$$\left[R/_{km} \right] = m * size \qquad (4-3)$$

Substituting for m in Equation (4-3), conductor cost-size relationship may be expressed as:

$$Conductor\left[R/_{km} \right] = 142.8 * size \qquad (4-4)$$

Figure 4- 3 presents the cost per capacity against conductor size for varying distribution voltages. The curves in the figure were established from estimate data presented in the final year project of Barei [5] at UCT in November 1999. The calculated line parameters and cost data are in Appendix G**1-4**.

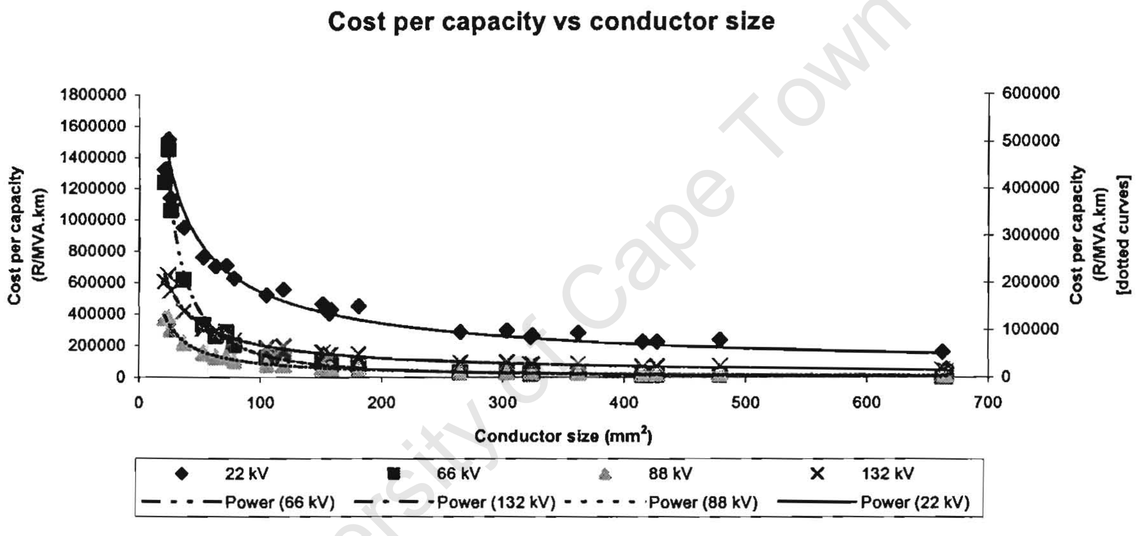

Figure 4- 3:Cost per line capacity versus conductor size

In 2000, the research revised Barei's estimates for 22, 66, 88 and 132 kV distribution systems. The cost of line shielding was added to indicate cost of mitigation for lightning. The given line parameters, assumptions and recalculated network parameters used to develop the curves in Figure 4- 3 are listed in the following subsections.

2.3.1 Given line parameters

- Conductor cost.
- Conductor impedance per kilometer.
- Distribution voltage levels: 22, 66, 88 and 132 kV.

2.3.2 Assumptions

- Sending voltage, V_s is set at 105% of V_r.
- Voltage drop, ΔV is 10% of V_r.

- The line cost estimate for the smallest conductor size per kilometer at 22kV is assumed to be R53000.
- The calculation of cost estimates for different voltages is evaluated on the basis of similar type or sized conductors.
- Network power factor is 0.9.
- Total line cost is 5 times conductor cost.
- One half sized shield wire is used for 22 kV systems and two half sized shield wires are used in 132 kV systems.
- The 22 and 132 kV shielding costs define the cost range limits for shielding distribution networks in the voltage range (22 -132 kV).

2.3.3 Calculated Parameters

- Power transfer capability and current flows.
- Line capacity in MVA.km.
- The next 22kV system line cost estimate per kilometer is obtained by adding R7700 onto the previous cost estimate of the smaller sized conductor. The mechanism is repeated up to the cost estimate for largest sized conductor.
- The line cost estimates for 66 kVsystem are derived based on the approximation: Cost(66kV)[R/km] ={64000+5%[60700+5%Cost(22kV)]+7700}.
- The line cost estimates for 88 kV systems are derived on the basis of the approximation: Cost(88kV)[R/km]= [75000+5%Cost(66kV)+7700].
- The line cost estimates for 132 kV systems are based on the approximation: Cost(132kV)[R/km] = [8600+5%Cost(88kV)+7700]

The inverse relationships in Figure 4- 3 indicate that conductors of smaller size have minimal capacity and result in higher cost per capacity. The cost per capacity decreases as the system voltage increases. The figure indicates that 66 and 88 kV systems provide minimum cost per capacity at approximately 200 mm^2 and above. In practice however, 132 kV systems are preferred for large conductors because of higher power transfer capability (V^2/X_L). There is small variation in the cost per capacity of 132 kV systems between conductor sizes of 100-300 mm^2. The 132 kV system cost per capacity reaches a constant minimum for conductor sizes above 400 mm^2. The 66 and 132 kV systems provide an equal cost per capacity at approximately 80 mm^2, but 88 kV is the minimum cost voltage at the point. Table 4- 2 shows the proposed conductor sizes on various voltages for optimum capacity in accordance with Figure 4- 3.

Conductor Size (mm^2)	Proposed System Voltage (kV)
0-100	22
100-300	66, 88
300-700	132

Table 4- 2: Proposed conductor-voltage selection criteria

Differentiation between the 66 and 88 kV systems can be achieved on the basis of capacity and quality requirements.

Quality related costs were not completely included in the costing model. This is because network quality depends on such factors as network loading, design configuration, line materials, environmental conditions and available mitigation. It would therefore be unrepresentative to make generalisation about quality costs on every distribution line. The line cost estimates used to develop Figure 4- 3 were manipulated to include the cost of line shielding.

Figure 4- 4 shows the cost effect of shielding 22 and 132 kV systems.

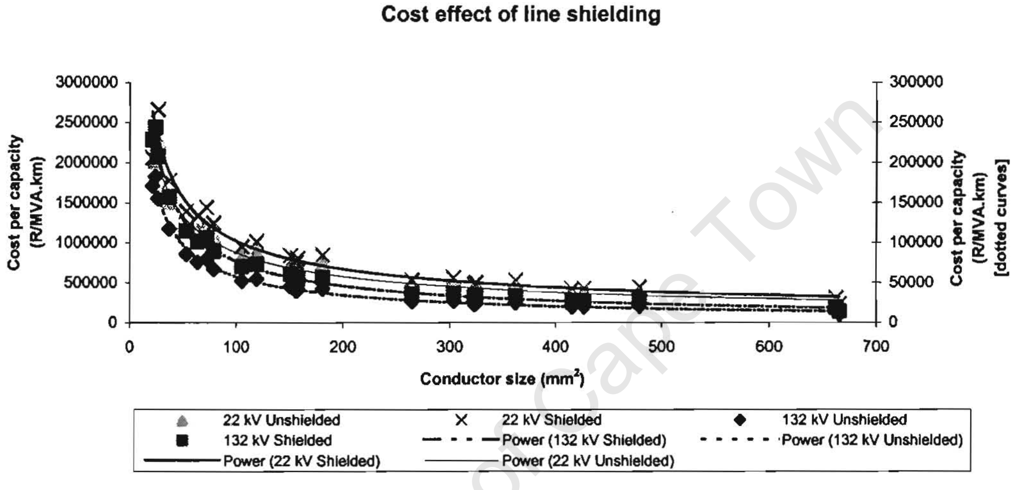

Figure 4- 4: Cost effect of shielding

Shielding costs for 22 and 132 kV systems increased the total line costs by 16% and 33%, respectively. Line shielding does not affect distribution capacity and as a result, the cost per capacity increased by the same proportion.

Copper conductors are generally not preferred in South Africa due to the sag problem. To overcome the sag difficulties due to conductor weight, it is normal practice to shorten spans with higher support structures. The shortening of spans and provision of higher poles increases line capex.

The use of steel material in distribution conductors is also not preferred due to high resistivity of the meterial. Steel conductors result in exceptional high voltage drop and losses.

According to Stephen et al [62], aluminum conductors are the most used and preferred in South Africa. Gonen [22] stated that the conductivity and strength of aluminum could be changed to the desired requirements by combining it with other materials (alloying). The alloying makes aluminum to be available in two types, which include:

- *Aluminum Cable Steel Reinforced (ACSR)*, which is steel core, stranded aluminum sized to provide the required strength for common use in rural overhead lines, and
- *All-Aluminum Alloy Conductor (AAAC)*, which is aluminum alloy conductor, produced as a result of developments in high tensile strength and conductivity aluminum alloying.

According to Gonen, aluminum alloys provide acceptable balance between strength, conductivity and cost when compared with steel and copper. They are good for voltage regulation (quality), and provide minimum voltage drop and losses.

2.4 OTHER CAPITAL COST FACTORS

There are other secondary factors to the investment of capital materials that influence capex in distribution lines. The factors largely relate to the technical design and construction of the line itself. This subsection discusses only those factors that influence capex and network quality performance.

2.4.1 Line Route

Distribution line routes are normally selected across the country and sometimes on private right of way in order to obtain the most direct route with proper spacing of towers to the customers. The most direct route criteria is intended to optimise the line initial capital costs. Line routes are selected with the intent to avoid buildings, highways and low voltage lines. The general character of the country in which the line is located affects the design as judgement and skill is needed in terms of conductor selection and support structures that will result in minimum cost. The choice of routes in which no foreign objects interfere with the power line contributes to good quality performance of a line. It is important to consider line maintenance and operation when choosing routes. Line maintenance may reduce some causes of faults that could result in supply interruptions. Egornomics in the chosen route should be such that it is possible for certain equipment to be operated manually during maintenance and testing.

2.4.2 Line Spans

The distance between any two adjacent structures in a distribution line is commonly known as span length (spans). Spans determine the number of support structures required per unit length to satisfy statutory clearance requirements. They are determined on the basis of such factors as:

- character of the route,
- required clearance between conductors,
- excessive tension under maximum load, and
- adequacy of structures to carry additional load.

Although the primary criterion in route selection is the option of direct route, it is not always possible to go direct in a mountainous terrain or in developed areas. In mountainous areas, more structures may be required to maintain the ground clearances. According to the NRS 033 [50], the required conductor clearances and spans in different distribution areas are stipulated for spans of 80 to 120 m. The standard makes it possible for certain types of structures to be used in certain areas to maintain statutory clearance requirements at longer spans. Longer spans ensure minimum number of support structures and cost. The effect of statutory clearance requirements on quality performance is not clarified and is a possible topic for further research.

Early in 2000, Makhathini [37] defined the inverse relationships between cost per unit length of a line and the varying spans as shown in Figure 4- 5. The data used to establish the curves is in the CD-ROM Excel spreadsheet (MKHSIM004FPZ.xls).

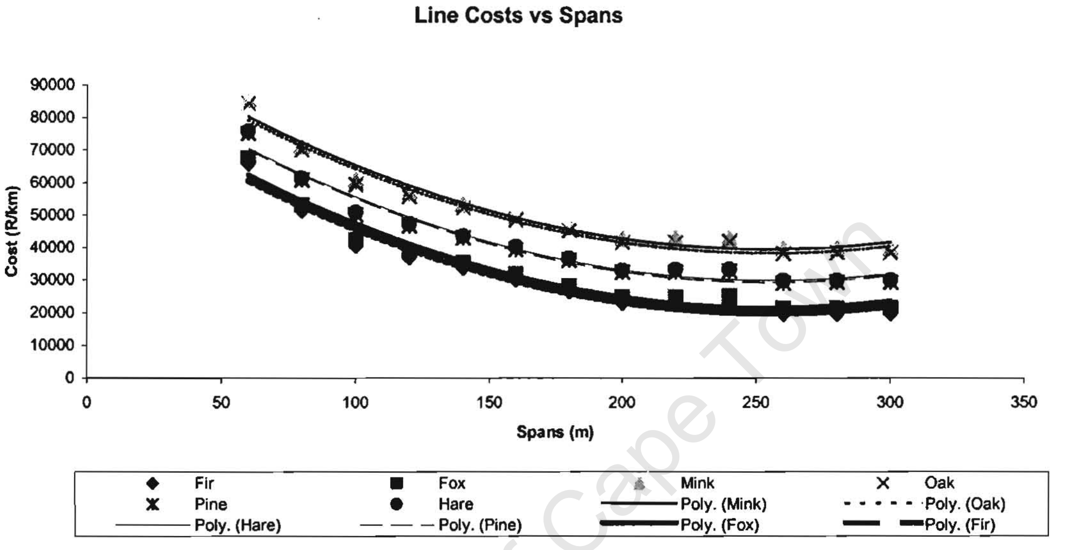

Figure 4- 5: Relationship between capital cost and line spans [37]

According to the figure, mink is the most expensive conductor and fir is the least expensive. The figure indicates that the total cost of a line per kilometer is generally higher and varies rapidly for shorter spans (<200m). Shorter spans increase line capital costs due to the requirement for more support structures per kilometer. Figure 4- 5 shows that the cost per kilometer is relatively constant between spans of 200-250 m, but gradually increases for spans in excess of 250 m. The figure suggests that optimal spans for the sampled conductors are in the range of 200-250 m. Longer spans (>250 m) increase capital costs due to the combination of requirements that may include tensioning, stronger and taller structures, etc. Makhathini's findings are valid for varying conductor types on a constant terrain. It is expected that the results would be different if different conductors were used in areas with uneven terrains. His calculations neglected possible conductor loading variations relative to spans. Elongation of conductors is possible at maximum conductor loading and could result in the violation of sag requirements in cases of longer spans. Sag violations could cause external initiated faults that would result in poor quality performance and higher costs.

2.4.3 Wind Loading

According to Gonen [22], the pressure exerted by wind on the conductor results in line vibrations and could possibly cause line insulator failures. The consequences of insulation failure would be current leakages in the system and/ or possibly phase faults. Faults negatively affect the quality performance of distribution lines due to unplanned outages, damage to equipment, loss of revenue, etc. It is important that selected insulators have appropriate Cantilever Strength ratings to withstand wind pressure.

The aspects of line design such as statutory limits, right of way and temperature or weather conditions do not affect the cost of achieving a quality standard.

3. QUALITY RELATED COSTS

This section describes proposals to quantify quality costs and assess mitigation. Costs related to quality may be grouped into operating and capital costs. Quality operating costs are generally incurred as a result of violation of the standard operating limits whereas capital quality costs are due to mitigation and quality monitoring equipment.

3.1 QUALITY OPERATING COSTS

The NRS 048 [52] describes the standard quality requirements that the NER expects utilities to comply with in supplying electricity to customers. The standard however does not provide any penalty for the violation of the quality requirements. Utilities such as Eskom usually depend on customer claims for indications of quality operating costs and implications. Customer claims vary in magnitude because they would usually be due to loss of productivity and damage to plant equipment. There is no existing quality costing mechanism that defines the relationships between quality incidents and costs.

The quality operating expenditure (opex) evaluation approaches proposed in this subsection are divided into utility and customer costing.

3.1.1 Proposed Quality Costing Methods for Utilities

It is proposed that quality opex is grouped into the Loss of Revenue (LR) and Penalty Cost of Quality (PCQ). Loss of Revenue applies whenever there is a deviation from rated voltage and/ or frequency, whereas the Penalty Cost of Quality comes into effect when the standard requirements are violated. It is proposed that the penalty cost for violation of quality standard be based on the NRS limits because the NRS 048 [52] is currently the only existing quality standard in South Africa. Loss of Revenue can be evaluated from the lost sales due to power not delivered. It is proposed that the percentage voltage or harmonic distortion ($\%Q_n$) for constant power and constant current loads over a period be used to derive Loss of Revenue on the basis that: P_D=**VI*pf**, and for interruptions, **V'** = $\%Q_n$**V**
Therefore, the interrupted power may be represented as $P_D=\%Q_n$**VI*pf**. For three phase systems a multiplication factor of √3 is included. Loss of Revenue can be evaluated from the of interrupted power and network tariff (R/kWh) over the interruption period.

Equation (4-1) represents the relationship between Loss of Revenue and interrupted power as:

$$LR = k\sum_{n=1}^{N}\frac{\%Q_n}{100}t_n P_D \qquad (4-1)$$

The proposal for Loss of Revenue in the case of constant impedance loads is on the basis that P_D=**V^2 *pf/Z**, and for interruptions, **V'=%Q_nV**. The interrupted power for constant impedance loads is represented as: P_D=%Q^2_n**V^2 pf/Z**.

Equation (4-2) represents the proposed Loss of Revenue for constant impedance loads as:

$$LR = \frac{k}{10000}\sum_{n=1}^{N}\%Q_n^2 t_n P_D \qquad (4-2)$$

where:

%	:	percentage
I	:	system rated current
k	:	R/ KWh constant (7.87c/kWh -urban and 8.49c/kWh-rural)
n	:	1,2,3...N – are integers representing the n^{th} quality parameter
P_D	:	power delivered by the network (losses neglected)
pf	:	system power factor
Q_n	:	magnitude of the n^{th} quality parameter
t_n	:	time elapsed by the n^{th} quality parameter in seconds
V	:	rated network voltage
V'	:	interruption voltage
Z	:	system impedance

The NRS standard quantifies voltage deviations as a percentage of the rated voltage and time limits. Frequency distortions are quantified as percentage of total harmonic distortion only. Voltage unbalance is defined only as the ratio of the presence of negative phase to positive phase sequence voltage. It is important to define costing proposals for different quality parameters in a manner that is consistent with the standard. This would avoid generic-costing relationships with poor representation of quality costs. As a result, the current costing proposals differentiate between those parameters with no standard time limit and those with both voltage and time limits. The Penalty Cost of Quality is similar in many respects to the Loss of Revenue but does not apply where the standard limits are not exceeded. It is therefore important to consider only the difference between the standard limits and the actual quality parameter when evaluating the penalty cost. In constant current and power networks, the proposed PCQ for flicker, voltage dips and voltage regulation is expressed as:

$$PCQ = \frac{k}{100}\sum_{n=1}^{N}[\%Q_n t_n - \%Q_{n(NRS)}t_{n(NRS)}]P_D \qquad (4-3)$$

The standard time limit in Equation (4-3) can be eliminated and the same proposal used for PCQ due to harmonics and voltage unbalance as:

$$PCQ = \frac{k}{100}\sum_{n=1}^{N}[\%Q_n - Q_{n(NRS)}]t_n * P_D \qquad (4-4)$$

The proposed PCQ for voltage dips, flicker and voltage regulation in constant impedance networks may be represented as:

$$PCQ = \frac{k}{10000}\sum_{n=1}^{N}[\%Q_n^2 t_n - \%Q_{n(NRS)}^2 t_{n(NRS)}]P_D \qquad (4-5)$$

The proposed costing mechanism for harmonics and unbalance in constant impedance networks becomes:

$$PCQ = \frac{k}{10000}[\sum_{n=1}^{N}\%Q_n^2 - \%Q_{n(NRS)}^2]t_n * P_D \qquad (4-6)$$

where:

$Q_{n(NRS)}$: standard magnitude of the specific quality incident

$t_{n(NRS)}$: standard minimum duration for the specific quality incident

The proposed quality penalty cost formulae, PCQ has the following mathematical limits:

= 0	if $Q_n t_n = Q_{n(NRS)} t_{n(NRS)}$	NRS margin
> 0	if $Q_n t_n > Q_{n(NRS)} t_{n(NRS)}$	NRS limits exceeded
< 0	if $Q_n t_n < Q_{n(NRS)} t_{n(NRS)}$	NRS limits not reached

The negative penalty cost generally indicates a cost benefit to the utility, except in the case of over voltage, which is not clearly defined in the standard. The following practical example indicates the relationship between Revenue Loss and interruption duration.

3.1.1.1 Practical Example

Evaluate 15% voltage depreciation from duration of 20 ms to 3 s in a constant current load network with a capacity of 80 MVA.

Loss of Revenue is evaluated on the basis of Equation (4-1). The data used to develop the revenue loss curve is in Appendix **G5**. The quality-costing tool for revenue loss calculations at different time intervals is in the CD-ROM Excel spreadsheet (test.xls).

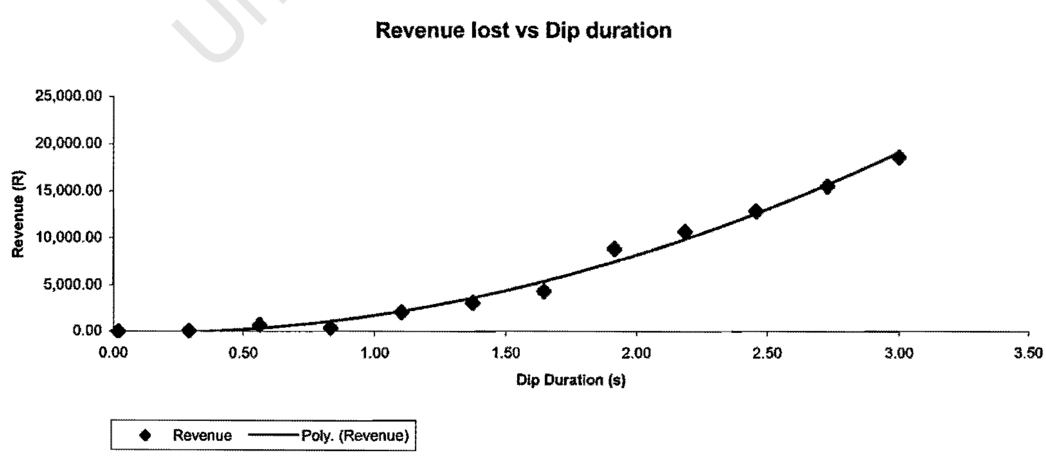

Figure 4- 6: Revenue loss for a 132 kV network with 80 MVA load

Figure 4- 6 suggests a parabolic increase of the utility revenue loss cost with respect to interruption duration. The figure shows that revenue loss for a voltage depreciation of shorter

duration (< 0.5 s) is insignificant. The cost is insignificant when the interruption duration is within the standard time requirements. It would generally be cheaper to accept dips with duration of 1.5 s or less because mitigation might be expensive (>R5000) due to lower revenue loss. The revenue loss due to medium duration dips (1.5 - 3 s) increases at an approximate rate of R1000/ s, which is triple the rate of increase at durations shorter than 1.5 s. It is important to note that the minimum cost mitigation option for all interruptions may be achieved provided mitigation cost does not exceed expected value of revenue lost. Based on the indicated trend (figure and data), it would be reasonable to conclude that the curve in Figure 4- 6 would have a sharper increase for dips longer than 3 s. This would have revenue loss implications (>R20000) to the utility and mitigation would be necessary. It is proposed that network design should be such that revenue losses due to interruptions are kept to the minimum possible.

3.1.2 Proposed Quality Costing Methods for Customers

Consideration of supply interruptions in network design and operation requires that violation of quality requirements be quantified in one way or another. Quality quantification with no indication of the interruption impact to the customers or utility might as well be considered useless and ineffective due to lacking information to evaluate the expected value of the quality incident. The expected value of the quality incident is required to assess mitigation and make appropriate investment decisions. It is preferred that quality inconveniences are translated into monetary terms to facilitate identification of optimal mitigation. This subsection therefore discusses proposals to cost quantify the impact of interruptions to a variety of customers.

To evaluate customer costs due to interruptions, an inventory of all direct and indirect costs may be drawn for use in the system design and operation. The approach is commonly adopted for large industrial and commercial customers to evaluate mitigation options. It may be applied to networks with a group of domestic customers who experience interruptions in violation of the statutory requirements. However, for domestic customers, it is often a non-material inconvenience, which has a larger influence on the decision than direct and indirect costs. Bollen [8] and Willis [71] proposed an approach in which a survey was conducted to a group of customers by asking a number of questions and an average cost was taken based on responses. The approach acknowledged that customer responses to questions might differ due to different questions asked or questions too specific or even depending on customer perceptions about the specific questions. According to Bollen, interruption costs to customers may be grouped into the following three classes:

- cost per interruption,
- cost per interrupted kW, and
- cost per kWh not delivered.

3.1.2.1 Cost per Interruption

The cost per interruption for duration t, with one customer affected may be expressed in South Africa Rands (R). The cost per interruption depends on the duration of supply disturbance and/ or combination of other factors. However, such factors are for simplicity neglected. The costs per interruption can be determined by summation of all inventory direct and indirect costs.

3.1.2.2 Cost per Interrupted kW

Generally, interruptions are a function of duration t. Supposed the cost of interruption for customer, i is denoted by $C_i(t)$, and the interrupted load is L_i, the cost per interrupted kW may be expressed as:

$$\frac{C_i(t)}{L_i} \qquad (4-7)$$

in R/ kW.

Similarly, for a group of customers who are affected by the same interruption, the cost may be expressed as:

$$\frac{\sum_i C_i(t)}{\sum_i L_i} \qquad (4-8)$$

in R/kW.

3.1.2.3 Cost per kWh not Delivered

It is assumed in this exercise that the cost of interruptions is large related to the interruption duration. From Equation (4-7), it can be seen that the cost per kWh not delivered for one customer can be expressed as:

$$\frac{C_i(t)}{tL_i} \qquad (4-9)$$

in R/kWh.

For a group of customers, the relationship in Equation (4-9) becomes:

$$\frac{\sum_i C_i(t)}{t\sum_i L_i} \qquad (4-10)$$

in R/ kWh.

Utilities however establish this average figure for all their customers and use it for system operation. The cost is usually known as the value of lost load.

3.1.2.4 Practical Example 1

A group of twelve small and medium industrial customers with a total demand of 10 MW are interrupted for 2.5 hours at a total cost of R53, 000. If the South African Breweries is one of the customers affected with a load of 7.7 MW but incurred a cost of R27, 200 for the same interruption, evaluate the different customer costs due to the interruption. Using Equations 4-7 to 4-10, one obtains the answers as shown in Table 4- 3.

Customer	Cost per interrupted kW (R/ kW)	Cost for undelivered energy (R/ kWh)	Total Cost (R'000)
SA Breweries	3.53	1.41	27.20
All Other Customers	11.22	4.49	25.80

Table 4- 3: Customer interruption costs

Table 4- 3 suggests that for grouped customers, there is no direct relationship between the amount of power demanded by any one customer and the interruption cost portion due to that customer. The value of lost load for grouped customers does not provide sufficient information about interruption cost of individual customers. The relationship between customer interrupted load and cost impact may be determined from a combination of other factors such as availability of emergency supply facilities, type of industry, etc.

3.1.2.5 Practical Example 2

In 1994, the author collected quality data from different customers in the Eastern Cape. The quality survey was requested by the Technology Research Group of Eskom to identify customers that experienced quality problems. There were complications in retrieving the data from Eskom for the research and new estimates were developed to indicate the ideal interruption costs that customers would incur. The survey estimate grouped customers into Agricultural, Chemical, Domestic, Food and Textile Industries in the cost estimate exercise. Different supply interruption durations used for the exercise include:

- 1 minute,
- 1 hour,
- 5 hours, and
- 10 hours.

Assumptions and Calculations

- The initial cost estimate for a 1-minute interruption to a Domestic Industry is assumed to be 4 R/kW.
- The 1-hour cost estimate is two times the initial estimate.
- For 5-hours, the cost estimate is five times the initial estimate.
- The cost estimate for 10-hours is twelve times the initial estimate.
- The cost estimates for the same interruption durations in other industries were calculated from the Domestic Industry estimates based on the following assumptions:
  a) Cost estimates for Chemical Industry are four times the Domestic Industry estimates.
  b) Agricultural Industry cost estimates are six times the Domestic Industry estimates.
  c) For Food Industry, the cost estimates are eight times the Domestic Industry estimates.
  d) Textile Industry cost estimates are ten times the Domestic Industry estimates.

The customer interruption cost curves are shown in Figure 4- 7 and the data used to develop the curves is in Appendix H.

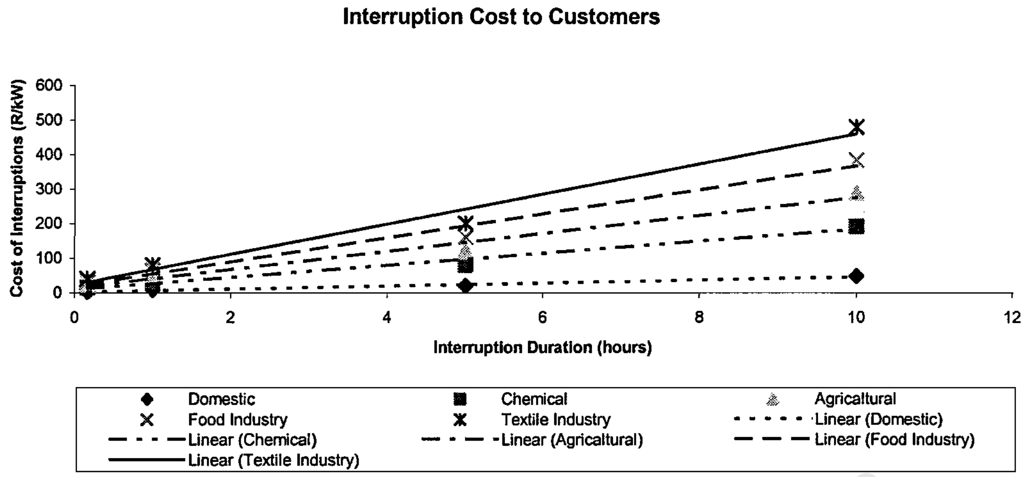

Figure 4- 7: Customer cost of supply interruptions (Eastern Cape–1994)

Figure 4- 7 suggests a linear relationship between customer interruption costs and duration. The figure shows that interruption costs are higher for the Textile Industry and lower for the Domestic Industry. The costs for the Chemical, Agricultural, and Food Industries are between the lowest and the highest interruption costs for the industries considered in the study but follow the same trend.

3.2 CAPITAL COSTS OF POWER QUALITY

Capital costs of power quality are mainly due to mitigation and/ or network quality monitoring equipment costs. No mechanism exists to quantify capital quality costs in distribution systems and as a result, these costs are often neglected when assessing the network investment. It is proposed that quality capital costs be represented as:

$$CCQ = \sum_{n=1}^{N} CCE_n + \sum_{j=1}^{J} CME_j \qquad (4-11)$$

Costs of quality mitigation are important in planning because where quality risk is identified and mitigation is sought, the cost of risk alleviation constitutes the network initial costs. The cost per mitigation component is used to estimate the cost per impact on quality improvement. The impact costs are evaluated on the basis of empirical assumptions and the results compose the mitigation-cost models in Figure 4- 8 and Figure 4- 9. The mitigation cost models were developed for 22 and 132 kV systems and it is assumed that mitigation costs for voltages in the range, (22-132 kV) are within the assessed cost interval. The costs for mitigation components are derived in the following subsection.

3.2.1 Cost per Component of Mitigation

3.2.1.1 Static Var Compensators

It is distribution practice to use Static Var Compensation in networks where there is excessive flicker and/ or voltage unbalance. The research had difficulty to obtain practical data for SVC's at voltage levels of 22 and 132 kV. It only obtained the cost for a 400 kV SVC but the cost for the 22 and/ or 132 kV SVC's could not be determined due to only one data point available. As a result, the cost of SVC components at 22 and 132 kV could not be quantified.

3.2.1.2 Tower Transpositioning

Eskom usually exchanges the position of phase conductors to minimise voltage unbalance. According to Eskom [17], transposition is applicable on longer lines (>100km) and at voltages of 66 kV or higher. As a result, it is assumed that transpositioning is not applicable in 22 kV systems. According to Muftic [41], a 132 kV line transpositioning project may be estimated at R400, 000. Since the actual cost of the tower is not known, it is estimated that only 70% of the total project cost is actual tower costs. The proposed cost per 132 kV transpositioning tower is expressed as:

$$\frac{Cost(Tower)}{132kV} = 0.7\frac{R400,000}{132kV} = R2121\Big/_{kV} \qquad (4-12)$$

3.2.1.3 Line Reconductoring

Reconductoring of lines to bigger sized conductors is normally done on refurbishment or reinforcement planning where there is sufficient load growth and capacity increase is required. It often increases system fault level and improves voltage regulation. It is a common quality approach to mitigate for excessive voltage flicker in distribution networks. It is applicable in all distribution voltage levels. The exercise assumes that reconductoring costs are mainly due to cost of conductor replacement. According to CIGRE 22.09 [10], total line costs are 3–5 times the conductor costs. Based on outcome of various research reports, the exercise assumes the average total line costs to be 4 times the conductor cost. The estimate costs for the 22 and 132 kV distribution lines are R50, 000/ km and R120, 000/ km, respectively. The proposed cost of reconductoring a kilometer of a line is expressed as:

$$\frac{Cost(reconductor22kV)}{22kV} = 0.25\frac{R50,000}{22km.kV} = R568.2\Big/_{km.kV} \qquad (4-13)$$

$$\frac{Cost(reconductor132kV)}{132kV} = 0.25\frac{R120,000}{132km.kV} = R227.3\Big/_{km.kV} \qquad (4-14)$$

3.2.1.4 Fault Level Increase

System fault level increase may be achieved through the paralleling of lines or introduction of parallel transformers in a substation. The parallel circuit effectively reduces the equivalent system impedance and raises the fault level capability of the distribution system. Increased fault level inhibits occurrence of power quality incidents such as flicker and harmonics. It is applicable to all distribution voltage levels. The exercise uses mid range sized transformers for both 22 and 132 kV systems, which are 1 MVA and 60 MVA, respectively. According to Meyer [39], the estimate cost for a 1 MVA transformer is R200, 000 and for a 60 MVA transformer, the cost is R3, 200,000. The proposed cost per component for fault level increase is expressed as:

$$\frac{Cost}{TRFR@(22kV)} = \frac{R200{,}000}{1MVA} = kR200\Big/_{MVA} \qquad (4-15)$$

$$\frac{Cost}{TRFR@(132kV)} = \frac{R3{,}200{,}000}{60MVA} = kR53.33\Big/_{MVA} \qquad (4-16)$$

3.2.1.5 Voltage Regulators

Voltage regulators are a special type of equipment used in networks mainly to limit voltage drop. According to de Castro [14], voltage regulators are applicable in 22 kV systems only. It is normal practice to build substations when voltage regulation problems are experienced in 132 kV networks. According to de Castro, the estimate cost of a 22 kV voltage regulator is R140, 000. The proposed cost per component of a voltage regulator is expressed as:

$$\frac{Cost(regulator)}{22kV} = \frac{R140{,}000}{22kV} = kR6.36\Big/_{kV} \qquad (4-17)$$

3.2.1.6 Surge Arrestors

Surge arrestors are equipment used to divert surge currents to ground to avoid damage to substation equipment, typically transformers. The surge currents are usually a multiple of the system rated current and are of high magnitude. They are mainly due to transients as a result of lightning flashovers. Surge arrestors operate once and are not re-useable after operation. They are applicable in all distribution voltage levels. According to de Kok [15], surge arrestors rated for 22 and 132 kV systems can be estimated at costs of R300 and R3, 500, respectively. The proposed cost per component of a surge arrestor is expressed as:

$$\frac{Cost(Arrestor)}{22kV} = \frac{R300}{22kV} = R13.64\Big/_{kV} \qquad (4-18)$$

$$\frac{Cost(Arrestor)}{132kV} = \frac{R3500}{132kV} = R26.52\Big/_{kV} \qquad (4-19)$$

3.2.1.7 Tap Changers

Tap changers are installed in transformers for improved voltage regulation in feeders. They come as on load or off load tap changers. They are applicable in all distribution voltage levels. The number of taps in any transformer depends on the required voltage improvement and transformer size. According to de Kok [15], 22 kV transformers rated at 10 MVA usually have tap changers with cost a estimate of R600, 000.

The cost is the same for 132 kV transformers rated at 60 MVA. The proposed cost per tap changer component may be expressed as:

$$\frac{Cost(TapChanger)}{TRFR\,@(22kV)} = \frac{R600{,}000}{10MVA} = kR60\Big/_{MVA} \qquad (4-20)$$

$$\frac{Cost(TapChanger)}{TFRF\,@(132kV)} = \frac{R600{,}000}{60MVA} = kR10\Big/_{MVA} \qquad (4-21)$$

3.2.1.8 Protection Setting

Protection setting approach is used to counter voltage dips in distribution systems in order to reduce supply outages. Improvements in protection setting can be achieved in various ways i.e. introduction of a trip-reclose system instead of fuses which completely isolate the line on faults. The cost of implementation of a protection setting option varies with the method used and cannot be quantified.

3.2.1.9 Energy Storage Systems

Energy storage systems, such as the flywheel are rarely ever used in distribution systems in South Africa. However, according to Hennessey [24][25], the systems provide sound mitigation for voltage dips. Where applicable, they would normally be used in 22 kV systems and are not used in 132 kV distribution voltage systems. According to Hennessey, the estimate cost of a 1 MW energy storage system is R5, 000, 000. The proposed cost per component of energy storage is expressed as:

$$\frac{Cost(EnergyStorage)}{@\,22kV} = MR5\Big/_{MW} \qquad (4-22)$$

3.2.1.10 Local Generation

Local Generation in distribution systems can be achieved through distributed generation. Distributed generation is a relatively novel concept in distribution. As a result, very limited costing knowledge and data is available. It is important for voltage regulation improvement in distribution. It is only applicable in 22 kV distribution voltages. According to Scott [57], the estimate cost of distributed generation for a 100 MW unit is R100, 000, 000. The proposed cost per component of local generation unit is expressed as:

$$\frac{Cost(LocalGen.)}{100MW\,@(22kV)} = \frac{MR100}{100MW} = MR1\Big/_{MW} \qquad (4-23)$$

3.2.1.11 Higher Voltage at PCC

Higher voltage at the point of common coupling (busbars) is required to counter voltage dips and flicker. It is usually achieved through the use of step up transformers. The amount of power to be transferred determines the transformer size. The approach is applicable across the distribution voltages. According to Ramsbottom [48], an 11/22 kV transformer rated at 1 MVA can be used for a higher voltage at the busbars of the 22 kV system and it is estimated at a cost of R200, 000. Similarly, the estimate for a 22/ 132 kV transformer rated at 60 MVA is R3, 200, 000. The proposed cost per transformer component to obtain higher voltages on the 22 and 132 kV busbars is expressed as:

$$\frac{Cost(HVPCC)}{TRFR@(22kV)} = \frac{R200,000}{1MVA} = kR200\Big/_{MVA} \qquad (4-24)$$

$$\frac{Cost(HVPCC)}{TRFR@(132kV)} = \frac{R3,200,000}{60MVA} = kR53.333\Big/_{MVA} \qquad (4-25)$$

3.2.1.12 Shield Wires

Line shielding entails provision of dummy conductor/ s at highest position on the line structures. This ensures that lightning only strikes the dummy conductor/ s and does not affect power distribution. Shielding serves as mitigation to transients due to lightning. It is applicable across the distribution voltages in areas where the average lightning flash density is greater than 5 flashes/km^2/year. On the basis of CIGRE 22.09 [10] and other reports, it is assumed that total line costs are 4 times the conductor costs. The costs for the 22 and 132 kV distribution lines are estimated at R50, 000/ km and R120, 000/ km, respectively. The exercise assumes that 22 kV systems are shielded with one half sized wire and 132 kV systems are shielded with two half sized wires. The shield wires are also assumed to be of the same type as the power carrying conductors. Table 4- 4 provides the summary of distribution line costs and includes shielding.

Cost categories [R/km]	**22 kV Distribution Systems**		**132 kV Distribution Systems**	
	Unshielded	***Shielded***	***Unshielded***	***Shielded***
Conductor	12,500	12,500	30,000	30,000
E/W	-	2,083.33	-	10,000
Rest	37,500	35416.67	90,000	80,000
Shielding Cost (incl. E/W)	-	***8,333,33***	-	***40,000***
Total	**50,000**	**58,333.33**	**120,000**	**160,000**

Table 4- 4: Cost of shielding 22 and 132 kV systems

The estimates in Table 4- 4 suggest that the proposed cost of shielding for 22 kV and 132 kV systems may be expressed as:

$$\frac{Cost(Shielding)}{22kV} = \frac{R8,333.33}{km(22kV)} = R378.79\Big/_{km.kV} \qquad (4-26)$$

$$\frac{Cost(Shielding)}{132kV} = \frac{R40,000}{km(132kV)} = R303.03\Big/_{km.kV} \qquad (4-27)$$

The shielding costs include the cost of structural modification, and so forth.

3.2.1.13 Line Reactors

Line reactors in distribution are usually used to mitigate for harmonics. They are applicable to all distribution voltages. There were difficulties in obtaining practical cost data for the equipment. The cost per component of a line reactor is therefore unquantified.

3.2.2 Cost per Quality Impact

The section derives the impact cost of quality from the cost per component of mitigation on the basis of empirical assumptions. The verification of the assumptions is outside the scope of the report and is proposed as a possible topic for further research. Due to limited application of certain mitigation components at some voltages or lack of component data, it is impossible to quantify impact costs for every mitigation method. General assumptions made in the evaluation of impact costs include the following:

- Power delivered by 22 kV systems is limited to a maximum of 2 MVA.
- Power delivered by 132 kV systems is limited to a maximum of 80 MVA.
- Distribution systems are always delivering power at maximum capacity.

Assumptions specific to any quality parameter are described in the relevant subsections. The impact cost quantification provides indication of the cost benefit of quality mitigation. The following impact costs are evaluated for quality parameters defined in the NRS standard.

3.2.2.1 Harmonics (kR/ %THD)

Strategies to mitigate for harmonics in distribution systems include:

- fault level increase,
- installation of line reactors,
- installation of tuned capacitors, and
- installation of static/ active filters.

According to Equations (4-15) and (4-16), the cost per component for fault level increase in 22 and 132 kV systems is kR 200/ MVA and kR 53.33/ MVA, respectively.

Assumptions and Calculations

It is assumed that the percentage total harmonic distortion (%THD) is expressed as power delivered (MVA_{system}) in the system over the system fault power (MVA_f) due to additional component. The proposed mathematical relationship is:

$$\%THD = \frac{MVA_{system}}{MVA_f} \Rightarrow MVA_f = \frac{MVA_{system})}{\%THD} \qquad (4-28)$$

The impact cost of increasing the fault level to improve harmonic distortion is obtained from manipulation of Equations (4-15) and (4-16). The cost per impact equations are related to the fault power due to additional component as follows:

For 22 kV systems

$$\frac{R}{\%THD} = MVA_f * \frac{kR200}{MVA} = \frac{MVA_{system}}{\%THD} * \frac{kR200}{MVA}$$

$$\Rightarrow \quad \frac{2MVA}{\%THD} * \frac{kR200}{MVA} = kR400/_{\%THD} \qquad (4-29)$$

For 132 kV systems

$$\frac{R}{\%THD} = MVA_f * \frac{kR53.33}{MVA} = \frac{MVA_{system}}{\%THD} * \frac{kR53.33}{MVA}$$

$$\Rightarrow \quad \frac{80MVA}{\%THD} * \frac{kR53.33}{MVA} = MR4.27 / _{\%THD} \qquad (4-30)$$

The impact costs of filters, reactors and tuned capacitors are unquantified.

3.2.2.2 Voltage Unbalance (kR/ %kV)

Mitigation of voltage unbalance in distribution systems is achieved through the following:

- transpositioning of phase conductors,
- installation of static var compensators (SVCs),and
- motor derating.

The transpositioning of power conductors is applicable to 132 kV distribution systems. Equation (4-12) expresses the proposed cost per transposition tower as R2121/ kV.

Assumptions and Calculations

- Voltage unbalance is limited to 2%.
- It is assumed that the NRS 048 [52] standard limit for unbalance is given by the actual negative phase voltage magnitude over the system voltage i.e. (ΔkV/ kV_{system}). The proposed mathematical representation of percentage voltage unbalance is:

$$\%kV = \frac{\Delta kV}{kV_{system}} \Rightarrow \quad kV_{system} = \frac{\Delta kV}{\%kV} \qquad (4-31)$$

The cost per tower in Equation (4-12) is related to the voltage improvement as follows:

For 132 kV systems

The unbalance, ΔkV=2.64 kV.

$$\frac{R}{\%kV} = kV_{system} * \frac{R2121}{kV}$$

$$\Rightarrow \quad \frac{\Delta kV}{\%kV} * \frac{R2121}{kV} = \frac{2.64kV}{\%kV} * \frac{R2121}{kV} = kR5.6 / _{\%kV} \qquad (4-32)$$

The impact costs for motor derating and static var compensators are unquantified.

3.2.2.3 Voltage Regulation (kR/ %kV)

The following usually mitigate voltage regulation in distribution systems:

- reconductoring of distribution line,
- local generation,
- installation of transformer tap changers,
- installation of voltage regulators,

- installation of static var compensators, and
- installation of capacitor banks.

Line reconductoring and installation of tap changers in transformers are applicable to all distribution voltages. Application of voltage regulators and local generation are common at 22 kV voltage systems. Equations (4-17) and (4-23), express the cost per component of voltage regulators and local generation as kR 6.36/ kV and MR 1/ MW. Reconductoring and tap changer component costs are expressed in accordance with Equations (4-13) and 4-20) as R568.2/ km.KV and kR60/ MVA, respectively.

Assumptions and Calculations

- Voltage regulation is limited to 10% of the system voltage.
- The distribution line is assumed to be 1 km long.
- It is assumed that the percentage change in voltage due to action of the voltage regulator is in accordance with Equation (4-31).
- Distributed generation power (MW_{DG}) over the system rated power (MVA_{sytem}) is equal to the voltage regulation capability due to distributed generation, i.e.

$$\%kV = \frac{MW_{DG}}{MVA_{system}} \Rightarrow MVA_{system} = \frac{MW_{DG}}{\%kV} \qquad (4-33)$$

- The system rated power (MVA_{system}) over the rating of the on load tap changer transformer (MVA_{TRFR}) is equal to the voltage regulation capacity due to the transformer taps, i.e.

$$\%kV = \frac{MVA_{system}}{MVA_{TRFR}} \Rightarrow MVA_{TRFR} = \frac{MVA_{system}}{\%kV} \qquad (4-34)$$

The proposed impact cost for regulators, local generation, tap changers and reconductoring are expressed as follows:

For 22 kV systems

- Voltage regulation capacity of 10% (ΔkV=2.2 kV) with regulators would give:

$$\frac{R}{\%kV} = kV_{system} * \frac{kR6.36}{kV}$$

$$\Rightarrow \quad \frac{\Delta kV}{\%kV} * \frac{kR6.36}{kV} = \frac{2.2kV}{\%kV} * \frac{kR6.36}{kV} = kR14 \Big/ \%kV \qquad (4-35)$$

- Applying Equations (4-23) and (4-33), local generation of 100 MW would give:

$$\frac{R}{\%kV} = MVA_{system} * \frac{MR1}{MW} = \frac{MW_{DG}}{\%kV} * \frac{MR1}{MW}$$

$$\Rightarrow \quad \frac{100MW}{\%kV} * \frac{MR1}{MW} = MR100 \Big/ \%kV \qquad (4-36)$$

- Applying Equations (4-20) and (4-34), the impact cost of on load tap changers in transformers becomes:

$$\frac{R}{\%kV} = MVA_{TRFR} * \frac{kR60}{MVA} = \frac{MVA_{system}}{\%kV}$$

$$\Rightarrow \quad \frac{2MVA}{\%kV} * \frac{kR60}{MVA} = kR120/_{\%kV} \qquad (4-37)$$

- Using similar assumptions as in the case of voltage regulators with ΔkV=2.2 kV and applying Equation (4-13) for reconductoring, the impact cost becomes:

$$\frac{R}{\%kV} = kV_{system} * \frac{R568.2}{km.kV} * 1km$$

$$\Rightarrow \quad \frac{\Delta kV}{\%kV} * \frac{R568.2}{kV} = \frac{2.2kV}{\%kV} * \frac{R568.2}{kV} = kR1.25/_{\%kV} \qquad (4-38)$$

For 132 kV systems

- Applying Equations (4-21) and (4-34) for transformer tap changers, the impact cost becomes:

$$\frac{R}{\%kV} = \frac{80MVA}{\%kV} * \frac{kR10}{MVA} = kR800/_{\%kV} \qquad (4-39)$$

- Using similar assumptions as in 22 kV systems with ΔkV=13.2 kV and applying Equation (4-14), the impact cost due to reconductoring becomes:

$$\frac{R}{\%kV} = \frac{\Delta kV}{\%kV} * \frac{R227.3}{kV} = \frac{13.2kV}{\%kV} * \frac{R227.3}{kV} = kR3/_{\%kV} \qquad (4-40)$$

The impact costs for application of capacitor banks and static var compensators are unquantified.

3.2.2.4 Voltage Dips (kR/ %kV)

Common approaches to mitigate for voltage dips in distribution systems include:

- high voltage at the point of common coupling (busbars),
- installation of energy storage systems, and
- improvement of protection setting method.

Energy storage is limited to 22 kV systems, whereas high voltage at the busbars is applicable across distribution voltages. According to Equations (4-24) and (4-22) the costs per component of high voltage at the busbars and energy storage are kR 200/ MVA and MR5/ MW. According to Equation (4-25), the component cost of high voltage at the busbars in 132 kV systems is kR 53. 33/ MVA.

Assumptions and Calculations

- Assumptions expressed in Equation (4-33) are applicable in energy storage systems.

- The transformer (MVA_{TRFR}) over the system power (MVA_{system}) is equal to the percentage reduction in voltage dip. The dip reduction is expressed as:

$$\%kV = \frac{MVA_{TRFR}}{MVA_{system}} \Rightarrow MVA_{system} = \frac{MVA_{TRFR}}{\%kV} \qquad (4-41)$$

The proposed impact cost for energy storage and high voltage at the busbars may be evaluated as follows:

For 22 kV systems

- Voltage dip impact cost due to energy storage system is evaluated in accordance with Equation (4-36), but the energy stored and cost per component are replaced with 1 MW and MR 5/ MW:

$$\frac{R}{\%kV} = \frac{1MW}{\%kV} * \frac{MR5}{MW} = MR5/_{MW} \qquad (4-42)$$

- Voltage dip impact cost due to high voltage at the busbars is evaluated in accordance with Equations (4-24) and (4-41), as:

$$\frac{R}{\%kV} = \frac{MVA_{TRFR}}{\%kV} * \frac{kR200}{MVA} = \frac{1MVA}{\%kV} * \frac{kR200}{MVA} = kR200/_{\%kVA} \qquad (4-43)$$

For 132 kV systems

Equation (4-43) is applied to evaluate impact cost of high voltage at busbars, but with the substitution of cost per component in accordance with Equation (4-25). The transformer rating in Equation (4-43) is replaced with 60 MVA for 132 kV systems. The proposed impact cost becomes:

$$\frac{R}{\%kV} = \frac{MVA_{TRFR}}{\%kV} * \frac{kR53.33}{MVA} = \frac{60MVA}{\%kV} * \frac{kR53.33}{MVA} = MR3.2/_{\%kV} \qquad (4-44)$$

The impact cost of improving protection setting method is unquantified.

3.2.2.5 Flicker (kR/ %kV)

Mitigation of flicker in distribution systems is achieved through the following:

- increasing fault level,
- high voltage at the point of common coupling (busbars),
- installation of series reactors, and
- installation of static var compensators.

Equations (4-15) and (4-16) express the cost per component of increasing the fault level as kR 200/ MVA for 22 kV systems and kR 53.33 for 132 kV systems. The impact cost of increasing fault level to mitigate for flicker is evaluated as follows:

Assumptions and Calculations

- It is assumed that system power (MVA_{system}) over fault power (MVA_f) provide an indication of percentage flicker improvement due to fault level increase. The proposed mathematical representation of flicker is expressed as:

$$\%kV = \frac{MVA_{system}}{MVA_f} \Rightarrow MVA_f = \frac{MVA_{system}}{\%kV} \qquad (4-45)$$

For 22 kV systems

Applying equations (4-15) and (4-45), the proposed impact cost due to fault level increase becomes:

$$\frac{R}{\%kV} = \frac{kR200}{MVA} * \frac{MVA_{system}}{\%kV} = \frac{kR200}{MVA} * \frac{2MVA}{\%kV} = kR400 / \%kV \qquad (4-46)$$

For 132 kV systems

Substituting the system power with 80 MVA for 132 kV networks and the cost per component with kR 53.33/ MVA in Equation (4-46), the impact cost due to fault level increase becomes:

$$\frac{R}{\%kV} = \frac{kR53.33}{MVA} * \frac{MVA_{system}}{\%kV} = \frac{kR53.33}{MVA} * \frac{80MVA}{\%kV} = MR4.27 / \%kV \qquad (4-47)$$

The proposed impact cost of high voltage at the common point of coupling (busbars) is expressed using Equations (4-43) and (4-44). The impact costs of static var compensators and series reactors are unquantified.

3.2.2.6 Transients (kR/ %kV)

Mitigation of transients is usually achieved through the following:

- installation of surge arrestors,
- line shielding, and
- installation of capacitor tuning.

Surge arrestors and line shielding are applicable to all distribution voltages. According to Equation (4-18), the cost per surge arrestor in 22 kV systems is R 13.64/ kV. In 132 kV systems, Equation (4-19) shows that the surge arrestor cost is R 26.52/ kV. According to Equations (4-26) and (4-27), shielding cost per component in 22 kV is R378.79/ km.kV and R303.03/ km.kV in 132 kV systems. The proposed impact costs for shielding and surge arresters are evaluated as follows:

Assumptions and Calculations

- Transient voltage (ΔkV) is limited to 5% of the system voltage.
- The distribution line is assumed to be 1 km long.
- The magnitude of transient voltage over system voltage gives transient percentage as:

$$\frac{\Delta kV}{kV} = \%kV \Rightarrow kV = \frac{\Delta kV}{\%kV} \qquad (4-48)$$

For 22 kV systems

The transient voltage, ΔkV =1.1 kV.

- Substituting Equation (4-26) into Equation (4-38), the impact cost of shielding becomes:

$$\frac{R}{\%kV}=\frac{\Delta kV}{\%kV}*\frac{R378.79}{km.kV}*km=\frac{1.1kV}{\%kV}*\frac{R378.79}{kV}=R416.67/_{\%kV} \qquad (4-49)$$

- For surge arrestors, the impact cost becomes:

$$\frac{R}{\%kV}=\frac{\Delta kV}{\%kV}*\frac{R13.64}{kV}=\frac{1.1kV}{\%kV}*\frac{R13.64}{kV}=R15/_{\%kV} \qquad (4-50)$$

For 132 kV systems

The transient voltage, ΔkV =6.6 kV. The relationships applied in 22 kV systems are used to evaluate 132 kV system impact cost. The transient voltages and cost per components in Equations (4-49) and (4-50) are replaced with corresponding values for 132 kV systems.

- Impact cost due to shielding becomes:

$$\frac{R}{\%kV}=\frac{\Delta kV}{\%kV}*\frac{R303.03}{km.kV}*km=\frac{6.6kV}{\%kV}*\frac{R303.03}{kV}=kR2/_{\%kV} \qquad (4-51)$$

- The surge arrestor impact cost is:

$$\frac{R}{\%kV}=\frac{\Delta kV}{\%kV}*\frac{R26.52}{kV}=\frac{6.6kV}{\%kV}*\frac{R26.52}{kV}=R175.03/_{\%kV} \qquad (4-52)$$

The impact cost of capacitor tuning is unquantified.

3.2.3 Mitigation Cost Models

The subsection discusses mitigation cost models for 22 and 132 kV systems as shown in Figure 4- 8 and Figure 4- 9. The costing models are in a matrix format and were developed from the impact cost values in Equations (4-28) to (4-52). In the models, for each quality parameter there are corresponding mitigation strategies. Each value indicates the cost of quality improvement due to application of corresponding mitigation. The blank spaces indicate that mitigation has no effect to the quality parameter. The geometric shape, ▼ means the cost of improving quality is unquantified for the specific mitigation.

Mitigation

Quality Parameters	SVC	Energy Storage	Reactors	HVPCC	Fault Level	Capacitors	Local Generation	Tap Changers	Motor Derating	Surge Arrestors	Transpositioning	Protection Setting	Voltage Regulators	Reconductoring	Filters	Shielding
Dips(kR/ %kV)		5000		200								▼				
Flicker (kR/ %kV)	▼		▼	200	400											
Harmonics(kR/ %THD)			▼		400	▼									▼	
Regulation (kR/%kV)	▼					▼	10^5	120					14	1.25		
Unbalance (kR/ %kV)	▼								▼							
Transients (kR/ %kV)						▼				.01						.42

Figure 4- 8: Mitigation cost model for 22 kV systems

Mitigation

Quality Parameters	SVC	Energy Storage	Reactors	HVPCC	Fault Level	Capacitors	Local Generation	Tap Changers	Motor Derating	Surge Arrestors	Transpositioning	Protection Setting	Voltage Regulators	Reconductoring	Filters	Shielding
Dips(kR/ %kV)		▼		3200								▼				
Flicker (kR/ %kV)	▼		▼	3200	4270											
Harmonics(kR/ %THD)			▼		4270	▼									▼	
Regulation (kR/%kV)	▼					▼	▼	800					▼	3		
Unbalance (kR/ %kV)	▼										5.6					
Transients (kR/ %kV)						▼				.18						2

Figure 4- 9: Mitigation cost model for 132 kV systems

For example, in Figure 4- 8, mitigating flicker by HVPCC would cost R 200, 000/ %kV and mitigating harmonics by application of capacitors is unquantified. It is obvious from the models that regulation mitigation through the installation of reactors is not applicable or has no effect, hence blank spaces in the models. The status of mitigation impact costs varies between voltage levels depending on the utility practice at the specific distribution voltage (i.e. impact cost to mitigate dips by energy storage would be R 5, 000,000/ %kV at 22 kV, but the same is unquantified at 132 kV). It is reasonable to conclude that mitigation applicable to all voltages is generally more costly at higher voltages (≤132kV) than at lower voltages (≥22 kV). The conclusion is based on the following assumptions:

- impact cost values in the cost model are correct,
- cost of mitigation is known and quantified,
- quantification of mitigation is consistent in all distribution voltages, and
- there is a defined cost trend in the distribution voltage range (22 - 132 kV).

3.2.4 Cost of Monitoring Equipment

According to the NRS 048 [52], the NER may select specific networks for power quality monitoring by the utility. The data collected from the network would be submitted to the NER for analysis and reporting at the utility's cost. It is important that utilities monitor distribution networks out of their own to ensure compliance with the standard and avoid penalty costs. There is a variety of on line monitoring equipment available in the South African market. The equipment differs in capabilities, make and cost. Commonly known types of quality monitoring equipment include:

- voltage dip recorders,
- qualimeters, and
- vectographs.

According to CTLab [12], there is a price difference between various makes and models of quality monitoring equipment. The price range of the listed monitoring equipment varies from R50, 000 to R250, 000.

3.2.5 Benefits of Quality Costing

It is important to note that improvement of quality performance may not necessarily need installation of line compensators if the selected network option complies with the quality standard requirements. The most trivial advantage of establishing mechanisms of power quality quantification is that a costing framework and parameters to observe are clearly defined to the electricity utility. Based on this knowledge, risks associated with power quality can be identified with a degree of confidence. Cost of quality mitigation to achieve pre-defined network objectives helps to eliminate design redundancy and optimises network investment costs. The proposed quality costing method provides utilities with competitive economics. It reduces the risk of exposure to customer claims for violation of standard requirements and/ or contractual agreements. Quality costing contributes to an improvement of the utility cost structure. To discourage the negligence of utilities or customers in violating the standard quality emission levels, it is proposed that a penalty fee is charged for exceeding the standard limits.

4. CHAPTER SUMMARY

Chapter 4 highlighted that costs in distribution lines are due to initial capital investment and quality related costs.

The chapter stated that capital expenditure (capex) in any distribution line is due to the cost of the following three key line constituents:

- conductor,
- structure, and
- insulator.

The choice of conductors is limited by cost, weight and conductivity. Conductor capacity, which is voltage depended, limits conductor cost. According to Cirge 22.09 [10] and other reports, conductor costs range between 20 to 30 % of the total project costs. Availability of materials, ease of handling and maintenance requirements of poles limit structural costs over the entire life. The cost of insulator does not vary significantly with variations in the type of insulator.

There are however, other secondary elements or combinations of elements that influence distribution line costs. The chapter discussed only those elements that influence network quality performance. The elements include line route, spans and wind loading. It defined relationships between conductor cost/ km and area, and cost per capacity and area. It analysed Makhathini's [37] findings on the relationship between line costs and spans. The relationships were analysed to establish the effect of varying capex parameters to quality performance and cost.

The chapter developed mechanisms to quantify quality related costs. It proposed that quality costs consist of quality capex (due to mitigation) and operating expenditure (opex). The opex is attributed to cost of violation of statutory limits and loss of revenue. The proposed quality costs for customers are grouped into cost per interruption, cost per interrupted kW and cost per kWh not delivered. The cost per interruption is not explicitly defined because for some customers certain interruptions may result in an unquantifiable inconvenience, etc. The chapter evaluated cost of mitigation components for 22 and 132 kV systems. Distribution voltages in the range (22-132 kV) are assumed to be within the corresponding cost range. On the basis of empirical assumptions, the cost per component is used to derive the impact cost for each mitigation component. The defined impact costs are put into the cost model to assess mitigation options. Benefits of quality costing are discussed against the background of avoiding additional costs and/ or promoting network investment.

Chapter 5 discusses planning proposals and the incorporation of quality into planning.

CHAPTER 5

5. PROPOSED PLANNING APPROACH

1. INTRODUCTION

This chapter discusses recommendations to incorporate QOS into planning with consideration of The Integrated Planning Solution that is explored in Eskom [18]. It describes various TIPS modules and the integration of the proposed quality penalty-costing tool into the program. It proposes a planning approach that incorporates the three elements of this research that include planning, power quality costing and risk. The literature review in Chapter 2 revealed that planning methods could be grouped into mathematical and judgemental. Mathematical methods involved comprehensive mathematical analysis and allow no planner intervention in a search for optimal solution/ s. They are inflexible and less preferred because reaching optimal solutions cannot be guaranteed. Judgemental methods involve mathematical analysis but allow planner discretion to reach a solution. The integration of risk concepts into planning requires scientific analysis and planner judgement. It is therefore important that the planning approach proposed in this chapter allows for planner discretion, hence a judgemental planning method.

The Heuristic Method described in chapter 2 is updated and proposed in this chapter as **The Modified Heuristic Planning Approach**.

The following section describes QOS aspects and incorporation into planning.

2. QUALITY OF SUPPLY RECOMMENDATION

The recommendation for the incorporation of quality into planning is discussed in terms of:

- the value based planning,
- reliability aspects of power quality, and
- The Integrated Planning Solution.

2.1 THE VALUE BASED PLANNING APPROACH

The impact of imperfect power quality to customers may be understood by evaluating what poor service quality creates for the customer. Such an impact is an indication of customer value of electricity supply. Electricity provides value, and supply interruptions or violation of customer expected quality requirements decrease that value. Value reduction occurs for a variety of reasons, usually with costs that are often difficult to quantify. It is important to determine real customer value of electricity and incorporate such value/ s into the network quality assessment mechanism/ s used in the utility in order to determine the real value of the network. Power quality is linked into planning to balance quality against costs.

It is proposed that the value based planning approach be used because it combines customer value data with distribution design data. The data is analysed for various levels of reliability, and quality and at varying cost to the utility. The objective of the approach is to obtain a minimum cost balance between customer desire for quality and utility aversion to costs.

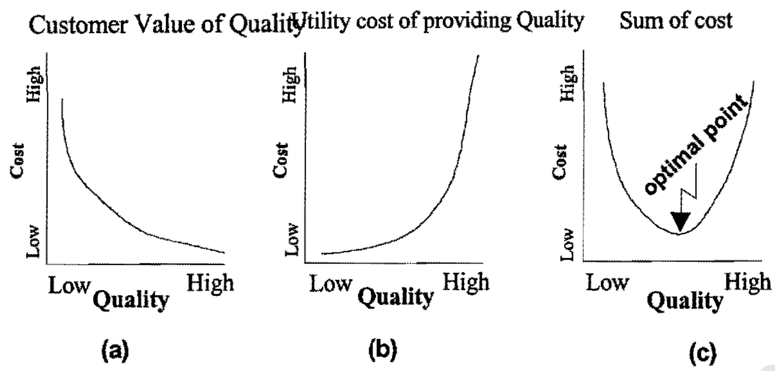

Figure 5- 1: Value based planning approach [71]

Figure 5- 1 illustrates the concept of value based planning with the customer costs due to poor quality (a) and the cost of various power delivery designs with varying levels of quality of supply (b). The cost of quality and that of building a system with various reliability levels are summated to obtain the balance between customer desire for reliability and aversion to cost (c). The bottom point of the total quality curve represents the optimum distribution design. It is recommended that value based planning approach be used to benefit both the utility and customers. The approach reduces the risk of penalty cost of quality to utilities and loss customer revenue due to electrical energy (kWh) not delivered. The statutory requirements state the minimum quality limits to be adhered to in the design and operation of networks. In practice, it is possible to apply the value based planning approach and meet statutory requirements. It is sometimes difficult to reach the optimal point due to varying QOS performance of networks. When such difficulties occur, it is proposed to consider the minimum cost option between network redesign and mitigation as the optimum.

2.2 RELIABILITY ASPECTS OF QOS

Power quality reliability entails the ability of network to meet QOS constraints within a defined period. Reliability is important in a market driven industry to achieve, and sustain quality improvements and distribution efficiency. Different customers have varying needs at different times. It is important for utilities to note differing quality demands from customers and provide acceptable solution/ s. Nahman and Strbac [43] proposed that urban distribution systems that were arranged into a number of feasible radial structures that would supply their customers through several different paths. The approach is similar to the fault-planning model discussed in Chapter 2. The radial structures would be of different lengths with equipment of varying makes and reliabilities. The chosen network configuration would affect supply restoration time due to time spent locating, isolating and restoring supply to the out of service network section. The reliability indices of network components can be linked to quality performance because unreliable components could often result in failures that cause supply interruptions or faults. Distribution network supply interruptions are sometimes due to the influence of environmental factors. It is good practice to limit the number of network components, such as insulators, that are affected by environmental factors. For example, the number of insulators in polluted areas directly influences the chances of supply interruptions because of possibility of flashovers. As a result, it is recommended that for enhanced reliability, SWER systems be used in areas where customer loads are mostly single-phase electrification loads. The SWER systems are minimal cost because fewer structures are required for conductor support per kilometer. Longer spans in these systems are possible at a lower cost per kilometer as indicated in Figure 4- 5. Insulator costs are lower because there is only one insulator required per structure and the likelihood of insulator flashovers which result in supply interruptions is minimal. The other additional advantage of these systems is that occurrence of multiple phase faults that would normally be found in multi-phase distribution systems are not possible. This reduces the chances of supply interruptions due to faults and promotes good quality performance.

2.3 THE INTEGRATED PLANNING SOLUTION

Eskom [18] proposed The Integrated Planning Solution in 1997 as the new approach to resolve the network planning problems. The approach was preferred because of the suggested features that included offering planners the ability to handle large quantities of planning information (network, census, demographics, land use, etc) on one simplistic geographic view for analysis. The system was expected to integrate well with existing planning tools. Expected results from TIPS included:

- future network plans,
- load forecasts, and
- preliminary and detailed designs that could be viewed at once against the geographical backdrop.

According to Jones and Charlton [32], TIPS application is based on three major subsystems namely; planning needs register (PNR), Geobased Load Forecasting and Power System Analysis as shown in Figure 5-2.

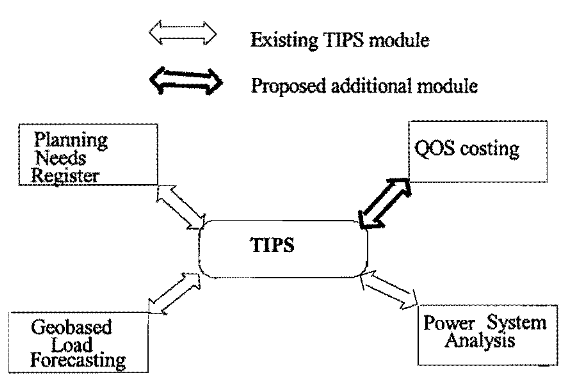

Figure 5- 2: TIPS subsystem

2.3.1 The Planning Needs Register

The Planning Needs Register is used to map the identified needs for the network plan. Mapping ensures that electricity needs are captured in appropriate time and space. These electricity needs are also used to review and fine tune load forecasts for the envisaged network developments. Jones and Charlton [32] suggested that planners could use this module for prioritisation of network planning projects.

2.3.2 Geobased Load Forecasting

The module allows planners to integrate utility planning with other spatial services such as roads, gas, water and land development zones. Data sources for this forecasting approach would include national census, municipality planning departments, statistical metering for existing networks and geological futures which limit land use and identify possible future activities such as mining, residential, etc. Land use classes are established for possible future loads taking into account the correlation of load to customer type for classification.

2.3.3 Power System Analysis

Jones and Charlton [32] stated that the Power System Analysis module would serve as an interface between the load forecast, planned and existing (if any) networks. The module allows planners to simulate the power network under different load growth scenarios and network topologies with time progression. The use of tools such as Retic Master, Power System Simulator for Engineers, etc, facilitates simulation of network performance on various loading conditions. According to Eskom [18], Power System Analysis tools cater for evaluation of network capacity planning, losses and energy planning as well as performance planning to allow planners to quickly note any network technical constraint violations such as voltage drop and power quality limits.

2.3.4 QOS Costing Module

This thesis proposed an Excel spreadsheet, test.xls as an additional subsystem to be integrated into TIPS modules as shown in Figure 5- 2. The subsystem is required to cost evaluate penalty cost of violating power quality statutory requirements. Mitigation equipment costs at the planning stage are added with the capital cost of a distribution line to provide the initial investment cost. Costs due to power quality incidents that occur during network operation are considered as quality operating costs and are evaluated using the proposed tool. Where mitigation is necessary, cost of mitigation is evaluated using capital cost models in Figure 4- 8 and Figure 4- 9.

2.4 THE PROPOSED PLANNING APPROACH

This section describes proposed modifications to the heuristic planning method and gives result to the new planning approach named **"The Modified Heuristic Planning Approach"**. The heuristic planning method as first reported by Wang and McDonald [69] is described in chapter 2. It is usually based on intuitive analysis and could give good designs based on experience. The constraints in the method are derived from a combination of judgemental and scientific analysis. The approach offers great flexibility and involves relatively simple manipulation to obtain good results. However, it requires improvements to overcome quality costing and risk analysis difficulties in planning. The proposed additions or modifications to the traditional heuristic approach of Wang and McDonald include the following:

- The derivation of initial investment cost from the summation of capex and cost of mitigation equipment. The initial investment cost is used in Equation (5-38) to evaluate line/ network effectiveness index. Wang and McDonald [69] neglected costs associated with quality mitigation in the representation of the initial investment cost. In practice, all quality related costs are generally included in the opex. This generalisation is a gross misrepresentation of network capital costs. It is proposed that capital costs due to equipment purchased to improve supply quality and continuity be included in the investment costs.
- The introduction of the risk identification and analysis technique to minimise the negative impact to utility and customers. It is proposed that the risk analysis technique that was first established by the Institute of Civil Engineers and Faculty of Actuaries [31] be used. The description of the proposed risk analysis technique is in Appendix A to Appendix D. It is a preferred approach because it defines risk seriousness, severity of occurrence and provides guidelines for acceptance. The expected value for every risk is evaluated using risk concepts described in chapter 3. The proposed risk analysis approach neglects incidents that are classified to be extremely unlikely to occur and would result in marginal or negligible consequences due to insignificant expected value.
- Addition of the N-1 principle for contingency analysis when there is a faulted line. The principle ensures that when one line fails, network operational requirements (i.e. distribution capacity) are sustained. It accounts for fault planning consideration similar to Nara et al's [44] proposals in Chapter 2. Nara et al however suggested that networks be designed as rings but operated as radial open loops. It the proposed approach prior to reinforcement, load balancing between feeders should be achieved as Nahman and Strbac [43] suggested.

2.4.1 Load Flow Equations

According to Wang and McDonald [69], load flow equations used in distribution systems are derived as follows.

A set of power system AC flow equations is:

$$P_i = V_i \sum_{j \in 1} V_j (G_{ij} Cos\theta_{ij} + B_{ij} Sin\theta_{ij}) \qquad i = 1,2,...N \qquad (5-1)$$

The branch active power may be given as:

$$P_{ij} = V_i V_j (G_{ij} Cos\theta_{ij} + B_{ij} Sin\theta_{ij}) - t_{ij} G_{ij} V_i^2 \qquad (5-2)$$

where:

N: number of nodes

P_i: active injection power at node I

V_i: voltage magnitude at node I

$j \in i$: nodes that are directly connected to i, including j = I

θ_{ij}: phase angle difference across branch ij, i.e. $\theta_{ij} = \theta_i - \theta_j$ (5-3)

G_{ij}: real part of corresponding element of node admittance matrix

B_{ij}: imaginary part of corresponding element of node admittance matrix

t_{ij}: circuit transformer ratio per unit

Therefore:

$$G_{ij} + B_{ij} = \frac{1}{r_{ij} + x_{ij}} = \frac{r}{r_{ij}^2 + x_{ij}^2} - j\frac{x}{r_{ij}^2 + x_{ij}^2} \qquad (5-4)$$

where r_{ij} and x_{ij} are resistive and reactance parts of the distribution line ij, respectively. The above power A.C. system flow equations can be simplified to give the d.c. load flow equations.

2.4.1.1 Assumptions

The following assumptions are applicable to distribution networks and within the high voltage range consideration of this research.

- The distribution line resistance is very small compared to the reactive component and is ignored ($x_{ij} >> r_{ij}$). Therefore, for all lines, the impedance components are

$$x_{ij} = 8r_{ij} \quad or \quad r_{ij} \approx 0 \qquad (5-5)$$

- The phase voltage angle difference of the distribution line is very small, i.e.

$$Cos\theta_{ij} \approx 1 \qquad (5-6)$$

$$Sin\theta_{ij} \approx \theta_{ij} \qquad (5-7)$$

- The node voltage is equal to 1.0 pu, i.e.

$$V_i = 1.0, \quad i = 1,2...N \qquad (5-8)$$

- Transformer tapping and the line to earth effect are neglected, which implies that all transformers will have unity ratio, i.e.

$$t_{ij} = 1 \qquad (5-9)$$

Since these assumptions are within the characteristic of the high voltage distribution line, they will not result in large computational errors of the active power flow distribution.

2.4.1.2 Derivation of Equations

Considering the assumptions in equations (5-5) to (5-8) and substituting into the power systems a.c. flow equation (5-1), the result becomes:

$$P_i = \sum_{j \in 1} B_{ij}\theta_{ij} \quad i = 1,2,...N \qquad (5-10)$$

But equation (5-4) shows that

$$B_{ij} = -\frac{1}{x_{ij}} \qquad (5-11)$$

And thus substituting equations (5-11) and (5-3) into equation (5-10), one obtains

$$P_i = -\sum_{j\in 1} \frac{1}{x_{ij}}(\theta_i - \theta_j) \qquad i = 1,2,\ldots,N \qquad (5-12)$$

Considering the assumption that the line to earth branches are neglected, the diagonal elements of the nodal admittance matrix equal to the sum of its off diagonal elements, i.e.

$$B_{ii} = \sum_{j\in i, j\neq i} \frac{1}{x_{ij}} \qquad (5-13)$$

Equation (5-10) when neglecting the effect of line to earth branches may also be written as in a matrix form as:

$$P = B\theta \qquad (5-14)$$

where P is the injection power vector and its i^{th} element is given by

$$P_i = P_{SI} - P_{DI}$$

where P_{SI} and P_{DI} are the source (transmission substation) output and load at node i respectively, θ is phase angle vector and **B** is the matrix whose elements are imaginary parts of the nodal admittance matrix. Equation (5-14) may further be expressed as:

$$\theta = XP \qquad (5-15)$$

where **X** is considered the nodal impedance matrix. Substituting Equation (5-15) into (5-14), one obtains:

$$X = B^{-1} \qquad (5-16)$$

As for the active power flow, substitute the assumption equations (6-5) to (6-9) into equation (6-2) and also assuming that power flows from branch i to j one obtains:

$$P_{ij} = \frac{\theta_i - \theta_j}{x_{ij}} = B_{ij}\theta_{ij} \qquad (5-17)$$

The active power flow equation from one branch to the other as represented in Equation (5-17) may be written in a matrix form, where PL represents active power and the end terminal phase angle difference between vectors is ϕ. Assuming the network incidence matrix to be A, the following relationships are arrived at:

$$P_L = B_L\phi \qquad (5-18)$$

$$\phi = A\theta \qquad (5-19)$$

B_L represents an L x L diagonal matrix whose elements are branch admittances where L denotes the number of branches in the system. The active power, P_L and phase angle difference, ϕ however are L x 1 matrices.

The basic d.c. load flow equations (5-15), (5-18) and (5-19) are all linear equations. The equations simplify the computation of load flows and even on addition or outage of other branches it is easier and faster to compute new network load flows with the defined relationships.

2.4.1.3 Addition of Branches

If the original network with branches i and j has a nodal impedance matrix X, then on addition of branch k between i and j, the new nodal impedance matrix becomes X'. The incident current and nodal voltage vectors are **I** and **V**, respectively, i.e.

$$I = \begin{bmatrix} I_1 \\ I_2 \\ . \\ . \\ . \\ I_N \end{bmatrix} \qquad V = \begin{bmatrix} V_1 \\ V_2 \\ . \\ . \\ . \\ V_N \end{bmatrix}$$

The relationship between current and voltage may be expressed in a vector form as:

$$V = X'I \qquad (5-20)$$

When the new branch k is added to the network, the current injected to the original may be represented by the vector, **I'** as:

$$I' = \begin{bmatrix} I_1 \\ . \\ . \\ I_i - I_{ij} \\ . \\ . \\ I_j + I_{ij} \\ . \\ I_N \end{bmatrix} = I - e_k I_{ij} \qquad (5-21)$$

The vector e_k represents the transpose of the k^{th} row of the incident matrix A, and may be expressed as:

$$e_k = \begin{bmatrix} 0 \\ . \\ . \\ 1 \\ . \\ -1 \\ . \\ . \\ 0 \end{bmatrix} \qquad (5-22)$$

The entries 1 and –1 in Equation (5-22) represent the elements of the i and j nodes, respectively. The nodal voltage equation may therefore be expressed as:

$$V = I^{'}X = XI - Xe_k I_{ij} \qquad (5-23)$$

The terminal voltage difference between node i and j may be given by the relationship:

$$V_i - V_j = x_k I_{ij} = e_k^T V \qquad (5-24)$$

Substituting Equation (5-23) into (5-24) one obtains:

$$x_k I_{ij} = e_k^T XI - e_k^T Xe_k I_{ij} \qquad (5-25)$$

Therefore,

$$I_{ij} = {e_k^T XI}\Big/{(x_k + e_k^T Xe_k)} \qquad (5-26)$$

Again, substituting equation (5-26) into equation (5-23) one obtains the nodal equation as:

$$V = (X - \frac{Xe_k e_k^T X}{x_k + e_k^T Xe_k})I \qquad (5-27)$$

Comparing equation (5-27) with equation (5-20), the new nodal impedance matrix becomes:

$$X^{'} = X - \frac{Xe_k e_k^T X}{x_k + e_k^T Xe_k} \qquad (5-28)$$

Equation (6.2-28) may further be reduced as follows:

$$X' = X + \beta_k Xe_k e_k^T X \qquad (5-29)$$

where

$$\beta_k = -\frac{1}{x_k + \chi_k} \qquad (5-30)$$

$$\therefore \chi_k = e_k^T X e_k \qquad (5-31)$$

e-arranging Equation (5-29) one obtains the incremental change of nodal impedance matrix as follows:

$$\Delta X = X' - X = \beta_k X e_k e_k^T X \qquad (5-32)$$

According to Equation (5-15) and (5-31) the change of the original vector after the addition of line k is :

$$\Delta\theta = \Delta XP$$

$$\Delta\theta = \beta_k X e_k \phi_k \qquad (5-33)$$

where $\phi_k = \theta_l - \theta_j$ is the terminal phase angle difference of branch k before addition. The two network state vectors are then given as:

$$\theta' = \theta + \Delta\theta = \theta + \beta_k X e_k \phi_k \qquad (5-34)$$

Thus, when line k is added, the new network nodal impedance matrix and incremental change in state vector of Equations (5-28) and (5-33) can be obtained from the original network parameters. However, if line k fails, the above equations can still apply but with x_k substituted for by $-x_k$. In practice, the relationship between the state vector and the line admittance can be obtained by using equation (5-14) as **P = Bθ**.

2.4.2 Sensitivity Analysis

According to Wang and McDonald [69], sensitivity analysis is very common in power system planning, decision analysis and control. The aim of sensitivity analyses is to establish the fundamental relationships that exist between specific network variables and network performance. The outcome of sensitivity analyses usually suggests appropriate action to improve network performance. Heuristic planning mainly requires sensitivity analysis to determine the effect of adding a line/ s to alleviate network overloading. The heuristic exchange methods can be applied within the branch and bound approach described in chapter 2. Wang and McDonald highlighted that a number of sensitivity analysis based heuristic planning models were emerging as planning requirements changed. According to them, the two key methods under the heuristic approach are successive expansion and successive backward method. The successive expansion method develops the network step by step by addition of possible effective lines until network overloading is eliminated. Successive backward method on the other hand adds a set of dummy network lines and eliminates the least effective lines on the basis of load capability in the system.

The sensitivity analysis in the **Modified Heuristic Planning Approach** does not only consider overload checks but return on investment, voltage drop constraints and quality limits. The return on investment sensitivity shall be utilised to analyse variations on capital returns with the addition of new lines. According to Stephen et al [62], investment returns below the discount or hurdle rate for any network development indicate that the project is not economically viable. It is proposed that sensitivity analysis should be used to evaluate system voltage behavior against load variations. This is necessary to check for voltage collapse, which according to Willis [71] and Eskom [17] occurs when a +/- 5% change in load results to an equal or greater change in system voltage.

2.4.2.1 Successive Expansion Method

Wang and McDonald [69] proposed the step-by-step development of the network through the use of the so called, 'successive expansion method'. They assumed that the addition of branch k, would result in the same branch being overloaded. Based on the assumption and using the d.c. load flow Equation (5-17), the flow through the line is proportional to the terminal phase angle difference, i.e.

$$P_k = \frac{1}{x_k}\phi_k$$

The overload will be eliminated by a reduction in the terminal phase angle. However, the problem is to find the possible line to be added through sensitivity analysis such that when it adds to the system the terminal phase angle is reduced. According to Equation (5-33), after addition of line, L the incremental change in phase angle is given by:

$$\Delta\theta = (\beta\phi e)_L X$$

The change then in terminal phase angle difference of line k is expressed by

$$\Delta\phi_L = e_k^T \Delta\theta = \beta_L e_k^T X e_L \phi_L \qquad (5-35)$$

Equation (6.2-35) indicates the effect of line L on reducing the terminal phase angle difference of line k. Assuming the investment in the line L is C_L, after the consideration of investment factors, the effectiveness index of a possible line may be defined as follows:

$$E_{kL} = \frac{-\Delta\phi_{kL}}{C_L} = -\frac{\beta_L e_k^T X e_L \phi_L}{C_L} \qquad (5-36)$$

It is proposed that Equation (5-36) be modified to incorporate quality related costs, C_Q, which can represented be as:

$$C_Q = CCQ + CME \qquad (5-37)$$

where: CCQ represent the capital cost of quality (cost of mitigating equipment), and
CME is the cost of network quality condition monitoring equipment

Including the quality related costs proposed in Equation (5-37), the effectiveness index in Equation (5-36), becomes:

$$E_{kL} = -\frac{\beta_L e_k^T X e_L \phi_L}{C_L + C_Q} \qquad (5-38)$$

When no line is added but mitigation is required, the effectives index of a line is calculated for quality related costs only, i.e. $C_L = 0$ in Equation (5-38). The obtained effectiveness index is known as the mitigation effectiveness index. Generally, a number of possible line additions would be made and the one with the largest effectiveness index (E_{kL}) is considered the most effective line provided all other network technical constraints are satisfied. When a number of lines in the system are overloaded, the overall effectiveness of adding a new line on top of an overloaded system may be expressed according to the relationship:

The sets S_c and S_e represent sets of overloaded lines and possible line additions, respectively. The set of distribution system equations derived in this chapter up to the

$$E_L = \sum_{k \in S_c} E_{kL} = -\frac{\beta_L \phi_L}{C_L + C_Q} \sum_{k \in S_c} e_k^T X e_L \qquad L \in S_e \qquad (5-39)$$

effectiveness index in Equation (5-39) results in a successive step by step network expansion flow diagram as shown in Figure 5- 3.

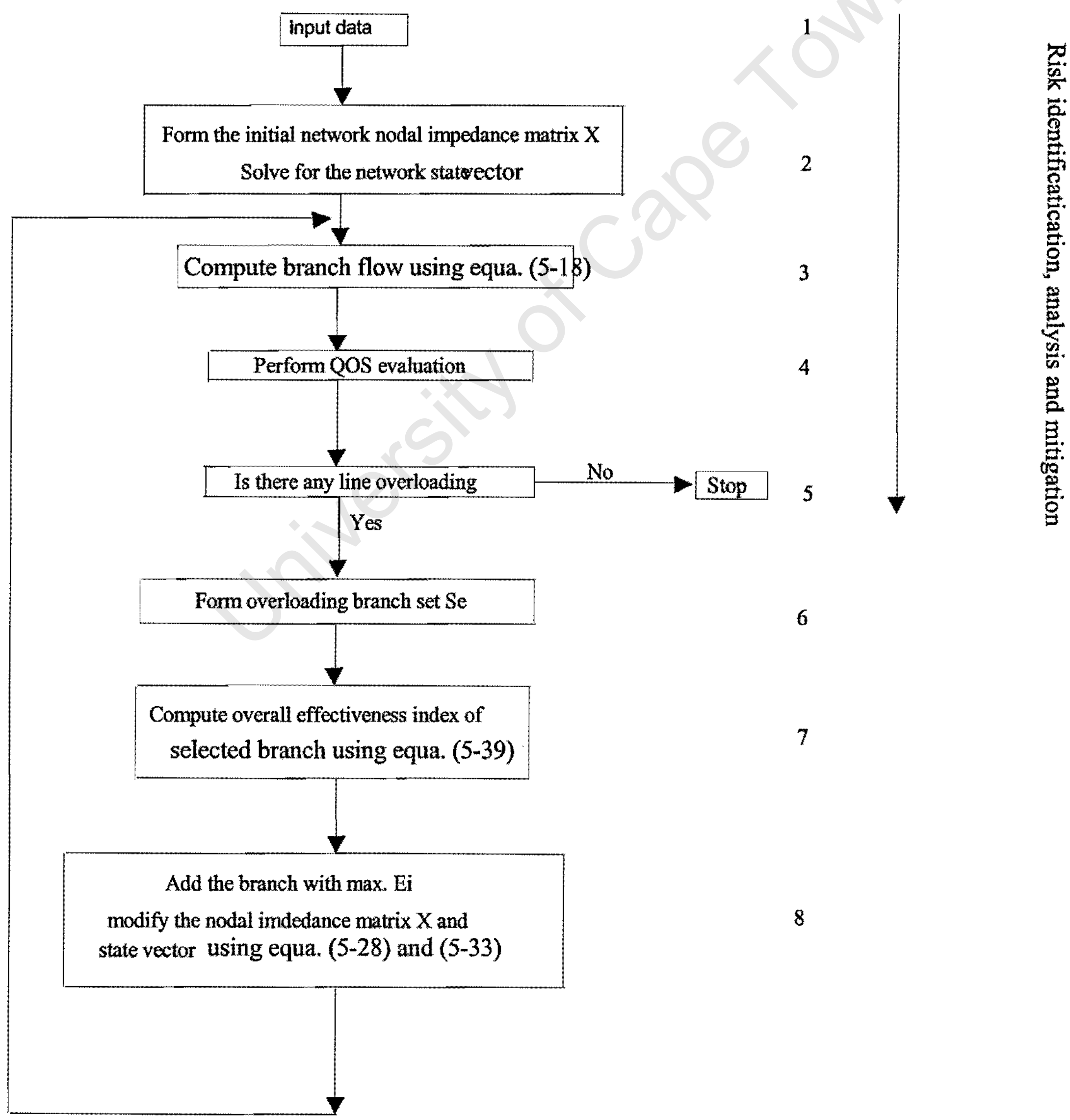

Figure 5- 3: Successive network expansion flow diagram [69]

The successive expansion method may be explained in eight steps as indicated in Figure 5- 3, as follows:

Step 1: The input data in this stage for any horizon year under consideration includes source output data, load forecasts, nodal load profile and/ or distribution parameters of possible lines, existing network configuration and line transmission capacity.

Step 2: The initial network nodal impedance matrix can be obtained through the inversion of the nodal admittance matrix or branch addition methods. The network state vector can then be obtained using Equation (5-15).

Step 3: This step calculates line load flows using Equation (5-18).

Step 4: The step performs cost evaluation of power quality using Figure 4- 8 and Figure 4- 9 for mitigation costs, and test.xls for penalty and revenue loss costs.

Step 5: Line overloads are evaluated in accordance with the relationship:

$$|P_k| \leq \bar{P}_k \qquad (5-40)$$

where: P_k is the calculated flow in line k and $\bar{P}_k$ is the transmission capacity of line k.

Note: Power flow in any feeder, k determines line overheating, stability, QOS and voltage drop requirements. Transmission capacity is determined from the conductor size and maximum permissible phase angle difference on scheme formation.

Step 6: The lines that do not satisfy equation (5-40) are put in the set of overloaded lines S_e.

Step 7: Equation (5-39) is used to compute the overall effectiveness index of each possible line. A new relationship is introduced if the line k is connected to nodes i and j and the line L is connected to m and n, respectively. The relationship is:

$\mathbf{e}^T_k\mathbf{X}\mathbf{e}_L = x_{im} + x_{jn} - x_{jm} - x_{in}$

where: x_{im}, x_{in}, x_{jm}, x_{jm} are elements of the nodal impedance matrix, **X**.

Step 8: The line that is finally chosen as the best alternative is the one with the largest effectiveness index, E_L. The resulting nodal impedance matrix can now be calculated using Equations (5-28) and (5-33) as the state vector.

The shortcoming of this method is due to its limited application in the existence of isolated nodes because the nodal impedance matrix cannot be computed in such cases. The problem of a disconnected node may be resolved by introducing a dummy line of high reactance, which effectively reduces system fault levels.

2.4.2.2 Successive Backward Method

According to Wang and McDonald [69], successive backward heuristic planning is a very popular method because of flexibility of its effectiveness index and scheme formation. The successive expansion method on the other hand requires that the network have strong links (higher fault levels). It is important to note that when the horizon year planning is far in the case of successive planning, the system might be weaker at the time with disconnected nodes or including new load centers and generation stations. Wang and McDonald reported that successive backward planning was more suitable in such circumstances.

Successive backward flow planning unlike successive planning starts with a dummy network, where all nodes including possible lines and isolated nodes constitute the network. The method is applicable to any horizon year planning. The dummy network is usually strongly connected, uneconomic and highly redundant. Power system analysis is performed on the dummy network. Lines with least effectiveness index are compared and eliminated first. The process is iterative until there is no redundancy in the network. Where network redundancy is removed, the elimination of any further lines will result in overloading or system disconnection. The approach assumes that a line with the largest current carrying capacity is the most likely to be an effective line.

It is proposed that the investment costs (C_{LQ}) consist of the sum of line capital costs and quality equipment mitigating costs. According to the proposal, the effectiveness index may be represented as:

$$E_L = \frac{|P_L|}{C_{LQ}^2} \qquad L \in S_e \qquad (5-41)$$

where:

P_L	:	power flow in line L,
C_{LQ}	:	optimised investment cost of line L, and
S_e	:	set of possible lines.

On eliminating lines with the lowest effectiveness, one must keep the lines with relatively low effectiveness but which have great effect on the system or other lines. Such lines may be grouped into:

- lines that cause system disconnection and
- lines that will cause overloading on other lines.

The successive backward method can only be used to eliminate possible line alternatives that do not meet the set criteria but the original network lines, independent of their apparent effectiveness will remain as part of the network. The description of the backward flow chart is similar to that of a successive expansion planning but the following steps.

Step 6: All possible lines are arranged in an ascending order of their effectiveness for analysis and elimination of lines with the least effectiveness.

Step 7: This step eliminates line L and the network state vector, θ is modified but the nodal impedance matrix is not altered. If β_L becomes infinite during the elimination process of line L, the elimination of this line will result in system disconnection otherwise line flows may be calculated using Equation (5-18) and overloads are checked using Equation (5-40).

Step 8: Checking of line overloading takes place in this step. If the decision here is to eliminate the line L, then only the nodal impedance matrix needs modification because the state vector and line flows have been obtained. However, if the decision is to keep line L, the nodal impedance matrix needs not be modified and the state vector should revert to that before elimination of line L. i.e. step 9.

Step 11: Risks identified in the earlier steps are critically analysed and mitigated. The objective for performing this task in this step is to simplify the flow process, unlike in the case of successive expansion technique where one deals with only one line at a time. Planners may decide to evaluate risk and provide solutions at each stage but this approach is recommended because it is possible to address a combination of unrelated risks by one method of mitigation.

The flow diagram in Figure 5- 4 shows the successive backward planning algorithm.

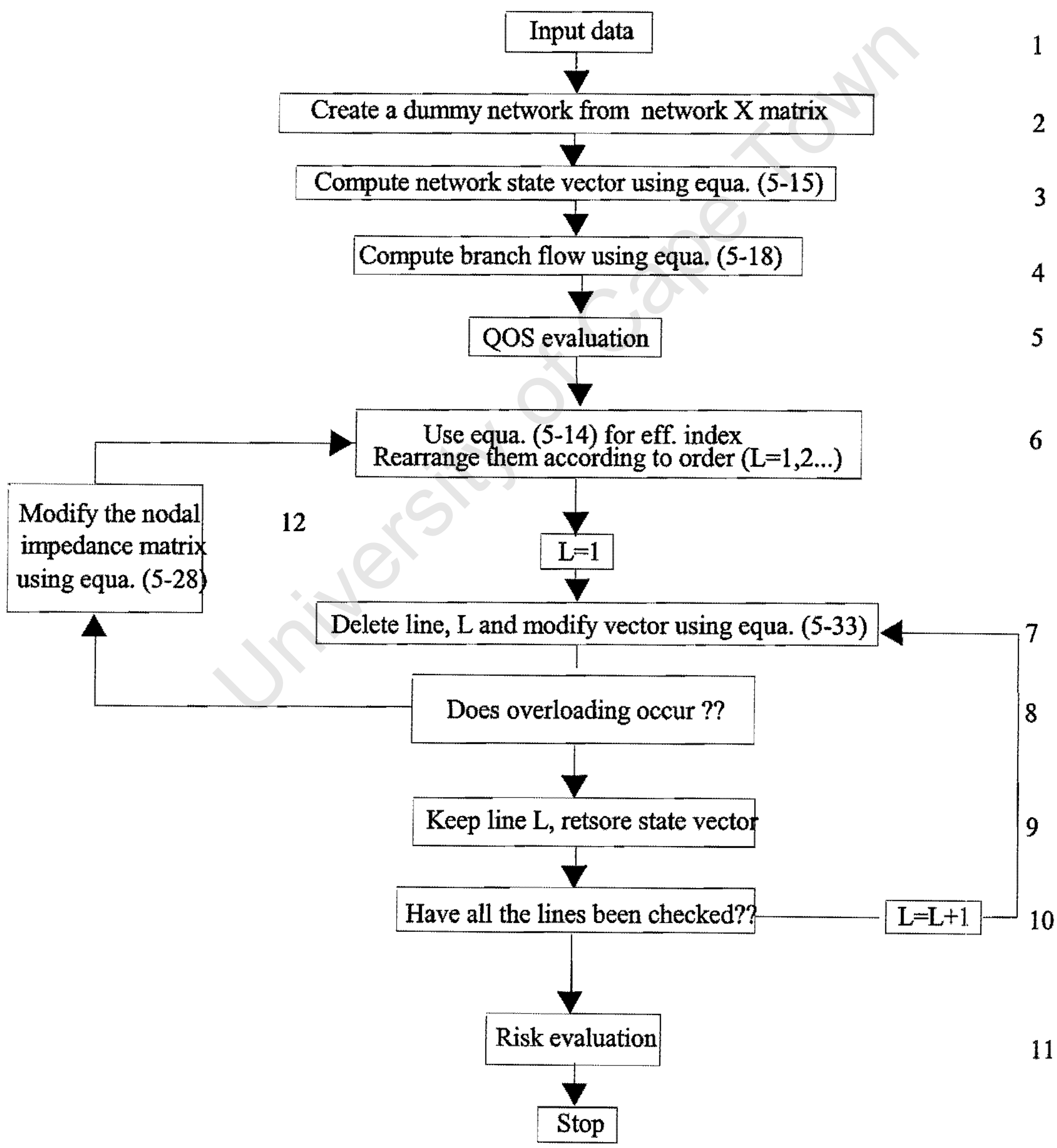

Figure 5- 4: Successive backward planning method [69]

2.4.2.3 Cost of Quality Evaluation Algorithm

The quality costing evaluation algorithm is located in the QOS evaluation stage of the two modified heuristic planning techniques. It is proposed that the mechanism in the flow diagram in Figure 5- 5 be used to evaluate quality related costs.

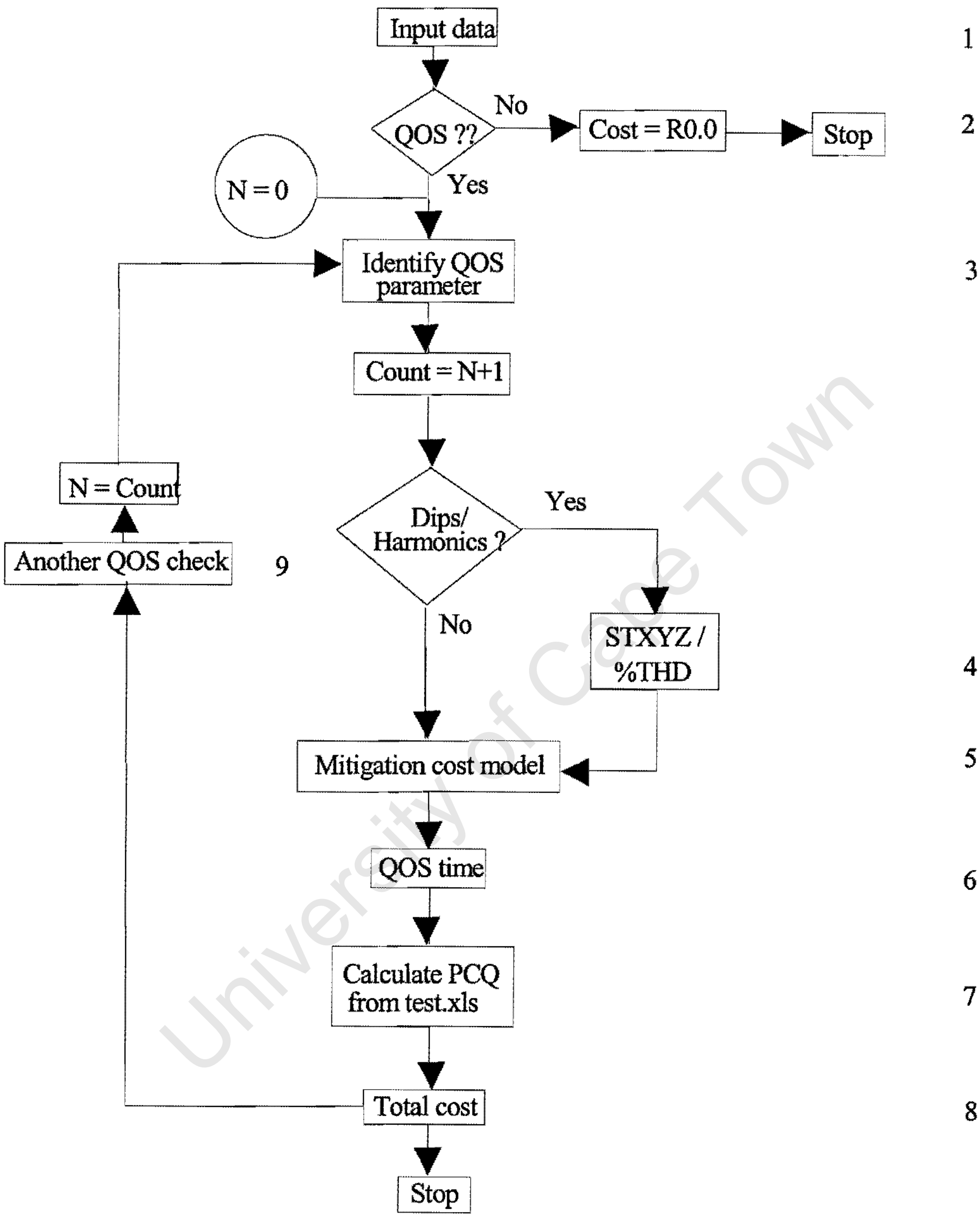

Figure 5- 5: Cost of quality evaluation algorithm

The following steps describe the quality-costing algorithm in Figure 5- 5. The step number in the description corresponds to the state number in the figure.

Step 1: This is the initial step in the QOS costing process which inputs network data such as system voltage (kV), tariff and load type. The input data is used to calculate power delivered by network using $\mathbf{V^2/Z}$ for constant impedance loads and $\mathbf{P = V*I}$ for constant power and current loads. The cost of power quality is initialised to zero.

Step 2: A decision box is used in Step 2 to check for exceeded of quality requirements (QOS incident). The algorithm stops if no exceedance of requirements is detected else it proceeds. The counter which represents the number of quality incidents is initialised to zero i.e. N=0. The shortcoming of this algorithm is that simultaneous consideration of quality incidents is not possible.

Step 3: This phase is concerned with the identification and classification of the quality incidents in terms of its voltage magnitude or frequency and/ or time. The counter for the number of quality incidents is incremented by one.

Step 4: The step checks for voltage dips and harmonics. If found (yes), catergorisation is done according to the STXYZ dip window for voltage dips or harmonic number is allocated for harmonics, else the algorithm proceeds to step 5.

Step 5: Power quality mitigation equipment is selected at this step using the mitigation cost models in Figure 4- 8 and Figure 4- 9. The capacity of selected mitigating equipment depends on the desired overall impact to QOS performance.

Step 6: This stage captures the duration of the quality incident so that the parameters could be compared with the standard.

Step 7: This phase calculates the utility penalty cost of quality for exceeding the standard limits. An Excel spreadsheet, test.xls evaluates this cost once all inputs are entered

Step 8:. This is the final phase of the algorithm that sums up all the quality related costs as:

$$Total\,Cost = \sum_{i=1}^{N} PCQ_i + \sum_{i=1}^{N} CCE_i \quad (5-42)$$

where:

PCQ_i: Penalty cost of quality for exceeding the standard limits

CCE_i: Capital cost of equipment

i: Integer representing the quality incident number

N: Total number of quality incidents for consideration

Step 9: The algorithm performs a loop operation to check for the presence of other quality parameters in the selected network. If more quality incidents are detected, N is incremented by one, else the algorithm stops and total cost becomes the cost of quality.

2.4.3 Contingency Analysis

When the contingency analysis is performed on the selected network, line overloads may occur. The network is then expanded by addition of new lines until the overload is eliminated and the N-1 checking principle is satisfied. The approach hardly ensures that the final scheme is technical and financial optimal. The described network-planning model merely considers the network security constraints as the basic constraints. In this way, a network that satisfies a single line outage is obtained.

The N -1 principle may be defined as the criteria used to ensure supply continuity when one of the lines supplying a certain area fails. The total capacity of all other lines must be greater than or equal to the total load demand in the area, i.e.

$$\sum_{j\in L, j\neq r} \bar{P}_j \geq \sum_{i\in S} P_{Di} - P_{Ti} \qquad (5-43)$$

where: S = set of nodes in an arbitrary area

L = set of lines connecting set S to external bodies

r = line in set L (this line is assumed to be faulted)

When the constraint represented in Equation (5-43) is added to any network with a number of nodes, the system will satisfy the N-1 principle for any single faulted line. However for networks involving nodes in excess of hundred, direct application of Equation (5-43) does not always yield the desired result and as such Ashirifnia and Aashtiani [3] suggested that in such situations, the basic model using Equation (5-43) shall consider only critical areas of the network. Critical areas of the network are those parts of the network for which there are higher penalty costs for supply interruptions and possibly an additional fee for breach of supply contractual agreements.

2.4.4 Optimisation

It is proposed that for multi-stage modified heuristic planning, the objective function be defined as:

$$Min\, Z = \sum_{t=1}^{p} \sum_{i\in N} \beta^t (C_i^t + C_{iQ}^t) \qquad (5-44)$$

where:

t=	planning period
p=	number of planning periods
β^t=	discount factor of node at period t (β=1-0.01X), where X is discount percentage
C_i^t=	capital cost of node i at period t
C_{iQ}^t=	capital cost of quality of node i at period t
Z=	objective function capital cost to be minimised

Applying the same procedure used in the single stage planning case, to each period of the problem separately, can attain minimum cost. Network configuration shall satisfy the following constraints:

a) No exceedance of standard quality limits.

b) No disconnection of any node or overloading when one line is faulted.

c) $V_{drop} \leq 0.1 V_s$.

The network elements of conductor and spans are optimised separately.

2.4.4.1 Spans

The distance between two adjacent structures is usually optimised with consideration to the topography of land and limitations imposed by statutory requirement. For any given conductor, Figure 4- 5 may be used to determine the line cost impact of varying spans. It is important however to note that although wider spans may be minimum cost, they introduce technical difficulties (risks) due to violation of statutory requirements. The difficulties could result in poor performing networks in terms of quality, cost, etc.

2.4.4.2 Conductor Selection

Conductors are usually selected on cost and line capacity basis. Optimisation of conductors on capacity basis is preferred because it provides an indication of the conductor size required to attain a certain line capacity at a cost. The inverse relationship in Figure 4-3 suggests that the cost per capacity for various voltage levels is minimal for conductors with high capacity. Voltage level compatible with the required capacity and cost can be selected. The additional cost of shielding can be analysed and selected for chosen voltage level using the relationship in Figure 4-4. The shielding cost indicates the cost of improved power quality performance.

3. CHAPTER SUMMARY

This chapter discussed power quality recommendations and proposed a new planning approach. The quality recommendations made are established from the concept of value based planning approach, reliability aspects of quality of supply and The Integrated Planning Solution. The basis for value based planning is that electricity creates value for customers and interruptions decrease that value. The real value of electricity to customers is difficult to estimate because value reduction happens for a variety of reasons. The value-based approach suggests that networks could be designed with varying levels of quality. The objective of the approach is to achieve the balance between customer desire for quality and aversion to cost. The chapter stated that radial feeders of varying lengths and equipment would most possibly have different reliabilities. It highlighted that unreliable network components would derail power quality performance and increase costs. The chapter described three TIPS modules as the following:

- planning needs register,
- power system analysis, and
- geobased load forecasting.

According to Eskom [18], TIPS was proposed some years back but to date it has achieved very insignificant success. The chapter proposed that the quality costing module, **test.xls** be incorporated into TIPS as shown in Figure 5- 2.

The chapter proposed **"The Modified Heuristic Planning Approach"** to integrate the elements of planning, risk and quality costing in one planning method. The method is preferred because it allows planner judgement and is straightforward. Planner judgement is important because some unknown risks require judgement based on experience and may never be resolved through scientific analysis alone. Alternative methods discussed in chapter 2 are least preferred because they are problem specific and cannot guarantee optimal solutions because of their rigid nature. Wang and McDonald [69] first reported the heuristic approach and the chapter proposed the following additions:

- redefining initial investment costs and formulae to calculate line effective index,
- introduction of the risk analysis phase in the planning algorithms, and
- the use of the N-1 principle for contingency analysis.

The chapter suggested that elements of spans and conductor selection could be optimised separately. It classified heuristic approaches into the successive expansion and successive backward. It described the successive expansion approach as the least preferred over the successive backward approach. The later approach was chosen because of its capability to handle systems with weaker links (lower fault levels). It was found to be suitable for long term where isolated nodes (isolated generating units or decommissioned substations/ lines) were possible. The chapter developed as set of load flow equations for the modified heuristic planning method on the basis of stated assumptions.

The chapter proposed the cost of quality evaluation algorithm on the basis of quality costing mechanisms developed in Chapter 4.

Chapter 6 presents practical case studies and demonstrates the application of the planning concepts developed in earlier chapters.

CHAPTER 6

6. PLANNING CASE STUDY

1. OVERVIEW

The chapter presents a practical case study to demonstrate the relationship between planning and quality. The study is conducted on a completed network plan of the Peninsula West Coast area. It is first evaluated with a special 6-monthly outage condition and second, the outage condition is removed. The study considers expected load growth at Blouberg, Westwood and Vissershoek areas. The load forecast areas are in the expected line route between Rietvlei and Accacia substations. The contribution of the research to the case study is primarily on quality costing. The Modified Heuristic Planning Approach and planning theory developed in the report are applied in the study.

2. INTRODUCTION

The Cape Metropolitan Spatial Development Plan identified the Peninsula West Coast as one of the potential high growth areas in the Western Cape. The area includes Table View in the south, Melkbosstrand in the north and N7 in the east. Network development had concentrated in the Table View and Melkbosstrand areas with 7 MVA demand being supplied from Rietvlei substation. Rietvlei substation has 2x20 MVA, 132/11 kV transformers and is supplied from Koeberg 132 kV busbar. Other substations connected to Koeberg 132 kV busbar include:

- Duine substation with 2x10 MVA, 132/11 kV transformer,
- Dassenberg substation with 2x10 MVA, 132/11 kV and 2x80 MVA, 132/33 kV transformers, and
- Accacia substation emergency generators with 3x65 MVA transformers.

Figure 6- 1 shows the existing network power line diagram for the West Coast.

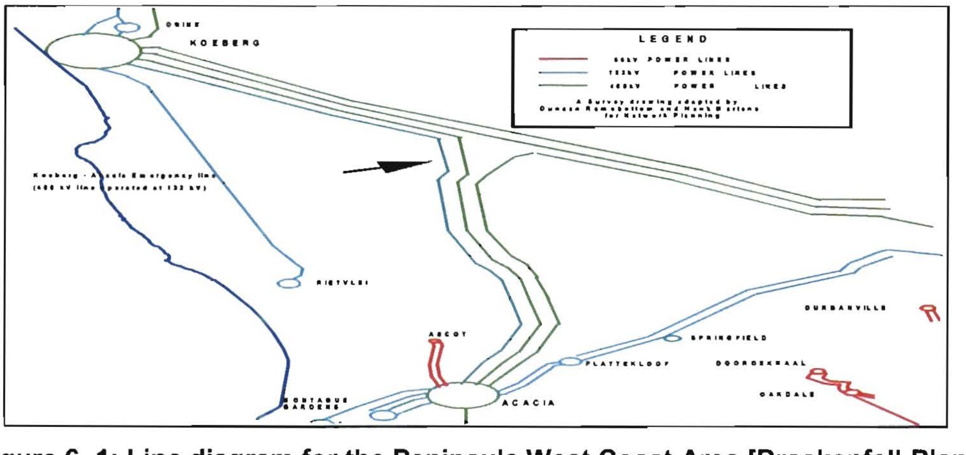

Figure 6- 1: Line diagram for the Peninsula West Coast Area [Brackenfell-Planning]

The geographical map of the Peninsula West Coast area is shown in Figure 6- 2.

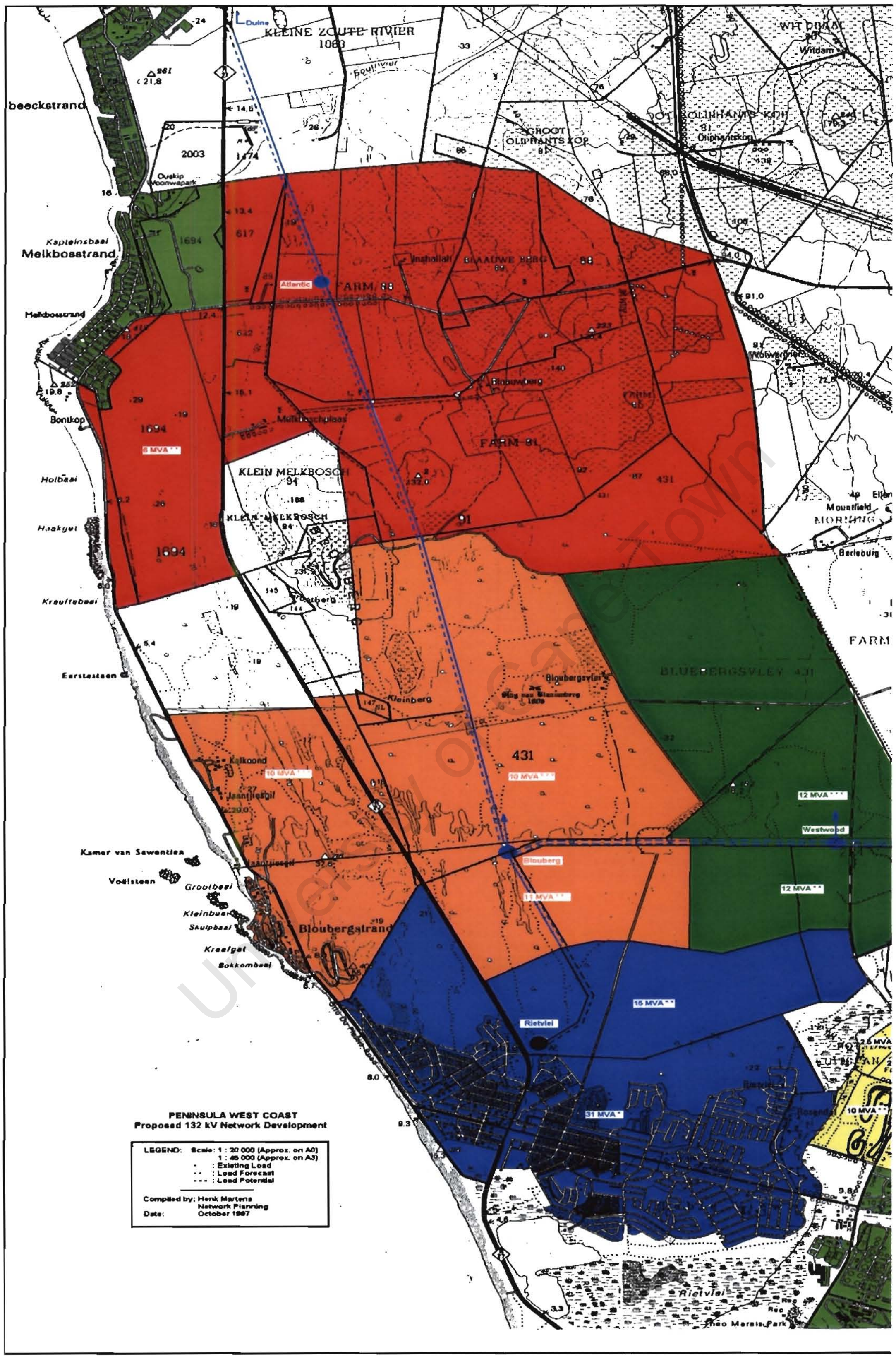

Figure 6- 2:Geographical map showing the proposed line route [Brackenfell-Planning]

3. LOAD GROWTH

Load growth is usually described as the actual load, load forecast and load potential. Credible actual load demand values for any substation or area are obtained from the metering data. It is important to obtain peak demand values of actual loads to ensure appropriate thermal ratings of line equipment. Load forecasts are load growth trends usually established from historical data and/ or use of scientific modeling and analysis methods. Load potential has limited scientific basis and is usually due to expected and possible future developments in an area. Load growth patterns cannot be guaranteed due to the influence of combinations of uncertain parameters such as economic performance, natural disasters and the impact of HIV/AIDS.

The load growth for the West Coast Area is shown in Table 6- 1.

Substation Name	**Actual Load (MVA)**	**Load forecast (MVA)**	**Load Potential (MVA)**
Rietvlei	31	15	XX
▪ **Blouberg**	XX	11	XX
▪ **Westwood**	XX	12	XX
▪ **Vissershoek**			
Killarney Racing	XX	16	XX
Rosendal	XX	10	XX
Factory Area	XX	2.5	XX
Potsdam	XX	15	XX
Amadale	XX	14	XX

Table 6- 1: West Coast Area load forecast [Brackenfell-Planning]

- ▪ : proposed substation, XX: No forecast

4. PROBLEM DESCRIPTION

The load at Reitvlei substation was initially 5 MVA and supplied from Ascott substation via the Killarney feeders. It was possible to connect to the supply at Killarney in cases of a fault either at Koeberg or Rietvlei substation. The load at Rietvlei substation grew in 1997 to a maximum winter peak demand of 35 MVA and the supply through the Killerney substation was no longer possible. The annual average load growth rate at Rietvlei substation between 1990 and 1997 was 10.8% as opposed to the forecast of 4.5%. The problem as a result of this load growth was that the supply to Rietvlei substation could no longer be considered as firm in cases of faults at Koeberg substation. A winter load profile of Rietvlei substation is shown in Figure 6- 3.

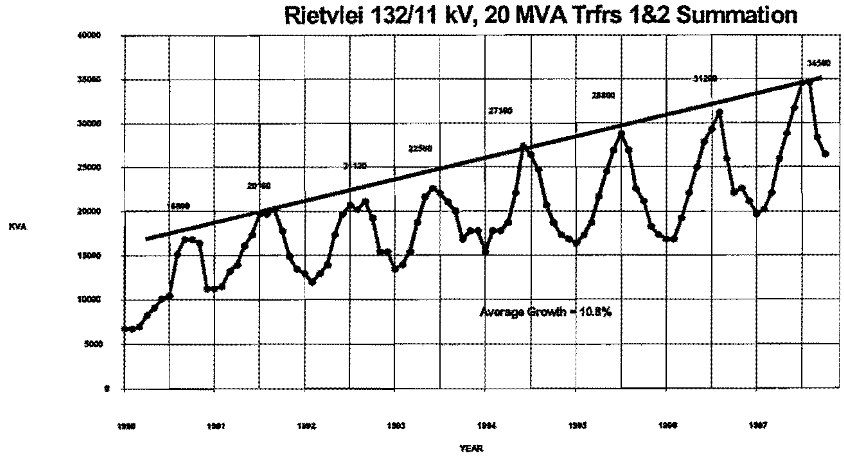

Figure 6- 3: Load profile of Rietvlei 312/ 11 kV feeder

Acacia substation is the transmission substation and provides supply to the bulk of industrial loads to which the Cape Metropolitan Council distributes. The National Nuclear Regulator (NNR) imposed a half yearly, 30 minute black start restriction at Koeberg substation. The black start restriction causes supply interruptions with negatively affect customer and utility productivity in the area. Acacia substation is equipped with 3x57 MW gas turbine engines which supply power to Koeberg Nuclear Power Station via the 400/ 132 kV coupling transformers on emergency operation (30 minute black start). The 400 kV transmission line from Koeberg to Acacia substation is used as an emergency line and is operated at 132 kV. The problem with the down rating operation of the 400 kV line is the under utilisation of its transmission capacity with possible slower returns on investment. The outage restriction could pose power quality related problems due to equipment failures during the stop-start operations. The result would be prolonged outages and significant loss of revenue.

5. ALTERNATIVES CONSIDERED

Eskom considered the following alternatives in resolving the supply problems:

- Adding another 132 kV line from Koeberg to Rietvlei substation.
- Provision of a 66 kV supply from Ascott to Vissershok substation.
- Supply from the 400 kV line that is operated at 132 kV between Koeberg and Acacia.
- Linking Rietvlei and Plattekloof substations through a 132 kV distribution power line.

A combination of the alternatives was however not considered. An additional alternative proposed in the report would be to relieve the 400 kV line currently used for emergency. This could be achieved by establishing a dedicated emergency 132 kV line from Koeberg to Acacia.

The alternatives were directed to resolve supply problems at Rietvlei and provide solutions to emergency supply requirements for the special outage condition at Koeberg.

6. RISK ANALYSIS

6.1 ACACIA FEEDERS

Load at Acacia substation is shared between 400 kV lines one from Koeberg and other from Mouldersvlei. The third 400 kV line from Koeberg substation is unavailable to supply load at Acacia. Each of the 400 kV lines to Acacia has a 50% chance to fail. Table 6- 2 shows the failure risk evaluation results for each of the 400 kV lines to Acacia.

Appendix	Score	Interpretation
A	12	Likely to occur
B	100	Serious
C	1200	Severe
D	+1000	Intolerable, eliminate

Table 6- 2: Summary of failure risk of 400 kV line to Acacia

The evaluation results in the table were obtained on the basis of Appendices A-D. According to the table, loss of a 400 kV line is more than likely to occur. It is serious and has severe consequences. The analysis method used in Table 6- 2 indicates that loss of a 400 kV is intolerable and must be eliminated.

6.2 QUALITY PERFORMANCE RISK

Koeberg quality performance risks discussed in this subsection include risks due to:

- insulator flashovers, and
- quality interruptions recorded at Koeberg 132 kV busbars.

It is heuristically expected that pollution levels are high in the line route between Koeberg and Acacia. The result would be poor quality performance due to insulator flashovers from dirt deposits. According to Table 4- 1, it would be adequate to use insulators with creepage ratings greater or equal to 31 mm/ kV. The research proposes that probability of flashovers due to polluted insulators could be evaluated as:

$$p = [\ \frac{1}{sn} + \frac{1}{s'n}\ ]kx \qquad (6-1)$$

The number of string insulators per phase per structure per kilometer is s', and is equal to 2s. The probability in Equation (6-1) then becomes:

$$p = \frac{1.5kx}{sn} \qquad (6-2)$$

and

$$s = \frac{1}{2} \sup ension \qquad insulator / conductor / phase \qquad (6-3)$$

where:

k : number of distribution phases

n	:	number of structures per kilometer
p	:	probability of flashover due to polluted insulators
s	:	number of suspension insulators per phase per structure
s'	:	number of string insulators per phase per structure
x	:	proportion number (0-1) for type of insulators used in a line

In the study, suspension insulators used per kilometer of a line constitute 90% of total number of insulators and the rest (10%) are string type insulators. Therefore, the insulator proportion numbers are 0.9 for suspension insulators and 0.1 for string insulators. Equation (6-3) suggests that there is one suspension insulator per two conductors in one phase in every structure.

The probability of flashovers in the case study is calculated using Equation (6-3) subject to the following assumptions:

- The spans are 200 m.
- There are two conductors per phase.
- The system has three distribution phases.

Substituting into Equation (6-2), probability of insulator flashovers in the West Coast is:

$$p=1.5*0.9*3/5 = 0.81 \text{ or } 81\% \text{ chance.}$$

Table 6- 3 shows a summary of insulator flashover risk in the West Coast.

Appendix	Score	Interpretation
A	12	Likely to occur
B	20	Reduces profit
C	240	Substantial
D	100-1000	Undesirable

Table 6- 3: Risk of insulator flashovers in the West Coast

The evaluation results in the table were obtained on the basis of Appendices A-D. Table 6- 3 suggests that insulator flashovers in the West Coast are likely to occur. The implications will be substantial reduction in profit due to revenue lost as a result of interruptions. Flashovers are undesirable and shall be avoided. It is proposed that line insulators in the West Coast are cleaned frequently (once in three months).

Power quality incidents were monitored and recorded at Koeberg 400/ 132 kV busbars over a 14-month period (01/00 - 03/01). Quality incidents recorded include:

- voltage unbalance,
- harmonics, and
- voltage dips.

The quality-monitoring device (qualimeter) did not detect incidents of flicker and transients over the sampling period. The Koeberg quality data for the period is in the CDROM Excel spreadsheet (Koeberg132QOS.xls). Incidents of voltage unbalance and harmonics were within standard limits. As a result no detailed analysis was done for the two. Voltage dips exceeded the standard quality limits. According to the recorded data, voltage dips at Koeberg could be attributed to the following causes:

- veld fires that are direct on the transmission lines,
- insulator pollution flashovers,
- birds flying onto power lines,
- transit rail locomotives, and
- equipment failures and/ or protection operation.

Table 6- 4 shows the statistical distribution of dip sources for the recorded data at Koeberg.

Dip Source	Number of incidents	% of total number of incidents
Transmission	62	73.8
Distribution	5	6
Customer	6	7.1
Unknown	11	13.1

Table 6- 4: Distribution of dip sources at Koeberg 132 kV [Koeberg-QOS]

According to the table, the majority of dips at Koeberg are due to problems in the transmission network. Distribution has a fewer number of dip initiating incidents.

The profile of Koeberg voltage dips for recorded data is shown in Figure 6- 4.

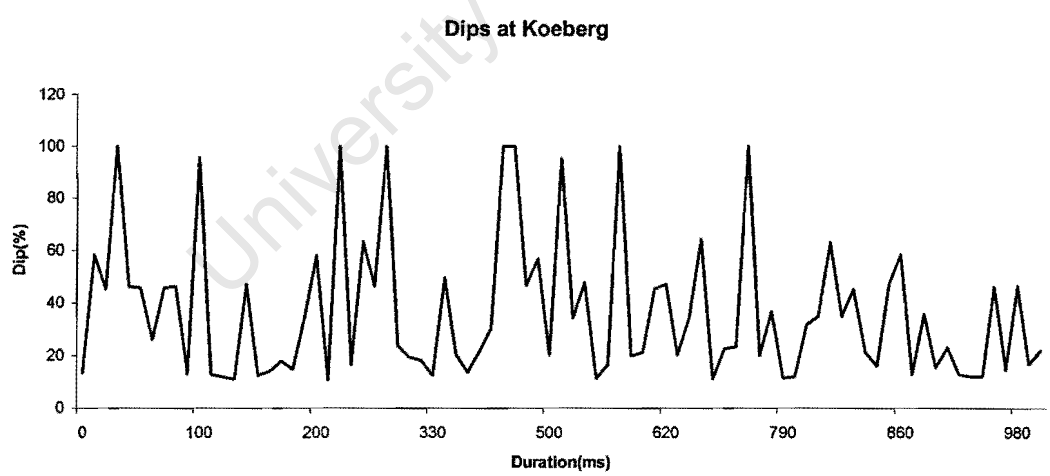

Figure 6- 4: Voltage dips at Koeberg 132 kV busbar

The figure suggests that interruptions of approximate average of 40% voltage depreciation were common at Koeberg over the sampled period. Dips of high magnitude (>60%) seldom occurred and were of short durations. Figure 6- 4 excludes planned outages over the 14-month period. The recorded 100 % depreciation in the duration window of approximately between (415-450 ms) could be protection operation to allow fault clearance, etc.

6.3 COST OF INTERRUPTIONS

Cost of interruptions at Koeberg is limited to voltage dips hence a predominant quality parameter over the sampled period. This is because dips at Koeberg exceeded the standard limits. As a result, cost of penalty and revenue loss would be incurred as shown in Figure 6-5.

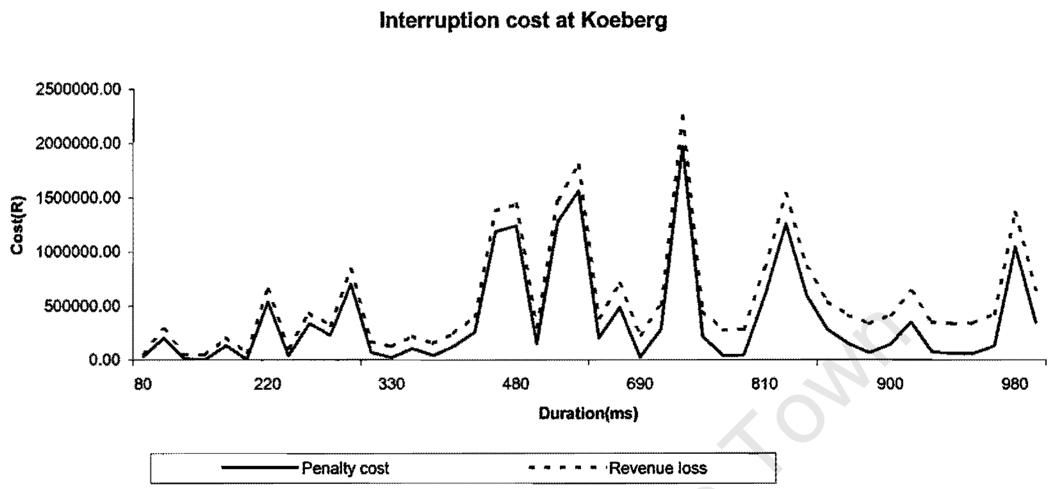

Figure 6- 5: Interruption costs at Koeberg substation

The costs in Figure 6- 5 correspond to the dips in Figure 6- 4. The figure suggests that most dips at Koeberg would cost amounts in excess of R500, 000 in penalties over the 14-month period. A relatively equal amount of money would be incurred in lost revenues. According to Figure 6- 4, dips of 40% average magnitude would cost R500, 000 over the period. The costing model in Figure 4- 9 suggests that it would cost MR3.0 to provide higher voltage at busbars to mitigate voltage dips and obtain a percentage voltage improvement. As a result, where mitigation expected value cannot be estimated or evaluated, it would be acceptable to absorb dips with revenue loses or penalty cost of approximately R500, 000.

7. PLANNING SELECTION

7.1 EVALUATION AND SELECTION OF NETWORK ALTERNATIVES

Addition of second 132 kV line (option 1) from Koeberg to Rietvlei would most likely resolve supply problems at Rietvlei. The shortcoming of this option is that the supply would still be interrupted by the half yearly, 30-minute outage at Koeberg. The option does not address the emergency line problem i.e. relieving the 400 kV line. It would require construction of 15.1 km of new single circuit line to Blouberg substation and another 13.5 km second single circuit line for the double circuit line to Plattekloof substation. Both constructions would use a kingbird conductor. Eskom loadflow studies suggested that the option would not provide firm supply for load potential in the area between Blouberg and Koeberg. Costing showed that the option was expensive.

The option to supply via a 66 kV from Ascott to the proposed Vissershok is not ideal because servitude guarantees for the double circuit line could not be secured. The load at Rietvlei could be transferred to Vissershok during the emergency condition. However, the option does not provide firm supply for Rietvlei. It does not release the current 400 kV emergency line for transmission operation. The option is therefore not recommended.

Eskom considered the third option to supply Vissershok from the 400 kV emergency line. The option does not return the 400 kV line to the transmission operation. Moreover, the option does not address supply problems at Reitvlei. The proposal contradicts the NNR requirement that there should be a dedicated emergency supply to nuclear power plants. The option is not recommended.

The last alternative, which is to link up Rietvlei to Plattenkloof via a 132 kV line through the proposed Vissershok, is the most preferred in terms of costs. This would provide firm supply to Rietvlei, Westwood and Vissershok. The proposed substations at Westwood and Vissershoek could be supplied from both Plattenkloof and Koeberg. The research supports the proposal to link Koeberg to Acacia via a 132 kV line. The proposal would relieve the 400 kV transmission line. It would be used as an emergency line for the special outage condition. The emergency supply would be obtained from Acacia gas turbine engines. The fault level due to parallel lines would increase. Due to increased fault level, the system would inhibit harmonics. The probability of failure of any 400 kV line would be reduced to 33.33%. The reduced chance of failure of any of the 400 kV lines would significantly decrease the risk of additional costs through lost revenues and penalty fees. This is because three 400 kV lines would now be available, two adjoining Koeberg and Acacia, and the third one from Muldersvlei.

Diagram 4

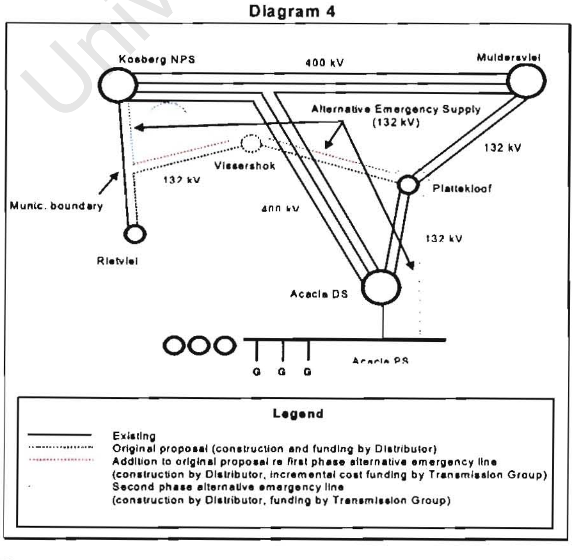

Figure 6- 6: Proposal for the selected alternative [Eskom]

Additional reinforcement proposals to cater for load forecasts in Table 6- 1 include:

- The inclusion of a 132 kV single circuit line between Reitvlei and Plattekloof. The reinforcement would make Rietvlei, Vissershok to Plattenkloof substation links double circuit.
- It is proposed that Westwood is built between Rietvlei and Vissershok.
- Blouberg substation is proposed along the anticipated line route between Koeberg and Reitvlei.

It is proposed that the network development plans shall be reviewed in the medium-term (7-15 years) to account for further load growth in the area. There is however a risk of exposure of the proposed lines to voltage dips in the West Coast. According to the mitigation cost model in Figure 4- 9, the cost of providing HVPCC to mitigate dips is MR3.20 for every percentage voltage (%kV) improvement. This means that to eliminate dips of 40% magnitude, it would cost MR128. However, according to Appendix G7, interruption costs to Eskom would be MR41.6 in lost revenues and penalty fees due to dips over the 14-month period. According to the interruption data (Koeberg132QOS.xls), the likelihood of 40% ± 10 dips over the period is 25.54%. The expected value of 40% dip mitigation over the period would be MR32.69. Therefore, mitigation for 40% dips would provide MR8.91 savings due to utility costs alone. The cost of dips to customers in the Western Cape is not known because of unavailable customer data. However, according to the cost trends defined in Figure 4- 7, it would be reasonable to expect a significant decline in customer interruption costs (due to dips) where mitigation was provided. The overall cost savings due to dip mitigation would be greater than MR8.91 when the customer interruption costs were included.

7.2 COSTING OF PROPOSED ALTERNATIVES

Table 6- 5 shows capital costs for the proposed network development.

Cost Category (R/km)					Unshielded		Shielded	
	Type	cct	Node	km	Emergency	Normal Load	Emergency	Normal Load
Conductor	Chicadee	1	K-B	15.1	35,520			
	Kingbird	1	B-P	13.5	54,810			
	Sycamore	1	P-A	3.6	54,810			
WA Cost			**K-A**	**32.2**	**46,126.30**		**46,126.30**	
E/W		2	K-A	32.2			15,375.48	
Rest					138, 378.90		123,003.47	
Shielding							61,501.92	
Line Cost			**K-A**	**32.2**	**184,505.20**		**246,006.92**	
	Kingbird	1	R-B	14.5		54,810		
	Kingbird	1	B-W	4		54,810		
	Kingbird	1	W-V	5.5		54,810		
	Chicadee	1	V-P	4		35,520		
WA Cost			**R-P**	**28**		**52,054.29**		**52,054.29**
E/W		1	R-P	28				8,675.72
Rest						156,162.87		147,487.15
Shielding								34,702.88
Line Cost			**R-P**	**28**		**208,217.16**		**242,920.02**

Table 6- 5: Costing of the West Coast plan

The costing only includes the construction of line sections in the proposed alternative. It uses the same conductors as the Eskom Network Development Plan (NDP) to demonstrate the cost impact using methods defined in the research (unlike the Eskom costing spreadsheet). Conductor prices are in Appendix F. The costing method is based on the following assumptions:

- The topographic terrain between Koeberg and Acacia is flat.
- Spans are limited to 200 m.
- Total line cost is 4 times the conductor cost.
- Half sized wires are used for line shielding. Shield wires are similar to the power conductors. The number of shield wires required is indicated in Table 6- 5.

The notation in the table to represent nodes or substations and terms is described as follows:

R : Rietvlei substation

B : Blouberg substation (proposed)

V : Vissershok substation (proposed)

W	:	Westwood substation (proposed)
P	:	Plattekloof substation
K	:	Koeberg substation
WA	:	Weighted Average (Cost(R/km))
E/W	:	Earth Wire
cct	:	Circuit (double (2) or single(1))

Shielding costs generally increase the total line costs but effectively reduce the rest of other line costs. This is because spans would be readjusted and additional structure/ s would be introduced to provide the required support to additional mass of shield wire.

7.3 RECOMMENDATION FOR KOEBERG BLACK START

It is important to conform to the nuclear requirements and meet growing load demand in the West Coast. The following is recommended to reduce costs due to Koeberg special outage:

- Perform the black start tests at night or on public holidays to ensure minimum number of customers affected.
- Plan and provide black start information to customers so that they may plan production in accordance with the outage schedules.
- Investigate the viability of providing a bus section at Koeberg 132 kV busbar to allow half station shut down.
- Conduct outage tests outside the period of expected system peak demand.

8. SPECIAL OUTAGE CONDITION REMOVED

8.1 DESCRIPTION

The removal of the special outage condition implies that there would be no dedicated 132 kV line requirement for emergency supply to Koeberg. The primary planning objective would be to supply forecasted load demand in the area. Alternatives considered would be the same as in the first case but a 132 kV system is preferred because:

- There does exist a single circuit on double circuit line configuration between Rietvlei and Plattekloof. It is therefore expected to be less costly to build a second single circuit line on existing structures.
- The system would allow back feeding to Rietvlei or Koeberg 132 without additional voltage transformation requirement.
- It would sustain distribution capacity in the medium-term (7-15 years).

8.2 CONDUCTOR SELECTION

Conductor selection is done with consideration of line cost per km and line MVA capacity on the basis of the following assumptions:

8.2.1 Assumptions

The following are additional assumptions to those applied in the costing of the special outage case.

- Cost of power line is estimated at R140, 000/ km.
- System power factor is 0.9 .
- Line capacity is estimate at 120% of load forecast i.e. 96.6 MVA.
- Discount rate is 25%.

8.2.2 Calculation of required conductor

The required conductor cost may be evaluated from the assumption that conductor cost is 25% of total line cost. The cost of conductor per phase would be R11, 667/ km. The cost per capacity is expressed as:

$$\frac{Cost}{Capacity} = R140{,}000 \Big/ 96.6MVA.km = R1449.27 \Big/ MVA.km \qquad (6-4)$$

According to Appendix F, the cost limitation suggests that conductors that could meet the cost requirement are as shown in Table 6- 6.

Conductor Type	Area (mm^2)	Cost/ km	Line impedance (Ω/ km)
Wolf	156.06	10950	0.2233
Chicaade	212.09	11840	0.417

Table 6- 6: Possible conductors for Rietvlei-Plattekloof plan

However, according to Figure 4- 3, the required conductor size at a cost per capacity of R1449/ MVA.km for 132 kV systems would be 386 mm^2. The required conductor size conforms to the optimum selection criteria of conductor sizes in Table 4- 2. Table 6- 6 suggests that Chicadee is close to the required size and cost compared to Wolf. Chicadee is therefore selected. The conductor selection criteria may have resulted in the conductor, which is outside the proposed optimum due to inaccurate line cost estimate assumption.

8.3 TECHNICAL CONSTRAINTS

8.3.1 Power Transfer Capability

The power transfer capability of the Chicadee conductor at 132 kV is evaluated as:

$$P_L = \frac{(kV)^2 Sin\partial}{X_L} = \frac{132^2}{.3783 * 28} = \frac{17424}{10.59} = 1645.33MW \qquad (6-5)$$

8.3.2 Voltage Drop

The line voltage drop is evaluate according to Gonen and Ramirez-Rosado's [21] that:

$$\%\Delta V = \frac{100 * SL}{V_{nom}^2}[RCos\phi + XSin\phi] \qquad (6-6)$$

Voltage drop in the study is evaluated for the maximum demand condition. The symbols in Equation (6-6) are:

$\%\Delta V$	:	percentage voltage drop
V_{nom}	:	system nominal voltage = 132 kV
S	:	system apparent power = 96.6 MVA
L	:	length of line = 28 km
R	:	line resistance = 0.1755 Ω/ km
X	:	line reactance = 0.3783 Ω/ km
ϕ	:	$phase\,angle\,difference = 86.5^0$
CosΦ	:	0.210
SinΦ	:	0.978

Substituting the values into Equation (6-6), voltage drop is:

$\%\Delta V = 6.3\%$

The voltage drop is within acceptable limits (<%10V_s) of the The Modified Heuristic Planning Approach as described in Chapter 5.

8.3.3 Load Flow

The proposed line is constructed on existing double circuit structures with single circuit. It completes the double circuit line between Rietvlei and Plattenkloof. The load forecast is 80.5 MVA or 72.45 MW. The load in the proposed option is heuristically adjusted to provide for 20% growth in the future. The existing circuit is a Kingbird conductor and Chicadee is used for the proposed line. The line impedances are 10.612 Ωand 11.676 Ω, respectively. Power flows are:

$$P_{chicadee} = \frac{Z_{kingbird}}{Z_{Total}} * Demand \qquad (6-7)$$

$$P_{kingbird} = \frac{Z_{chicadee}}{Z_{Total}} * Demand \qquad (6-8)$$

Substituting into Equations (6-7) and (6-8), power flows in the Chicadee and Kingbird conductors become 34.50 MW and 37.95, respectively. Both lines have the capacity to distribute the adjusted load of 96.6 MVA and failure of one line will not result in disconnection.

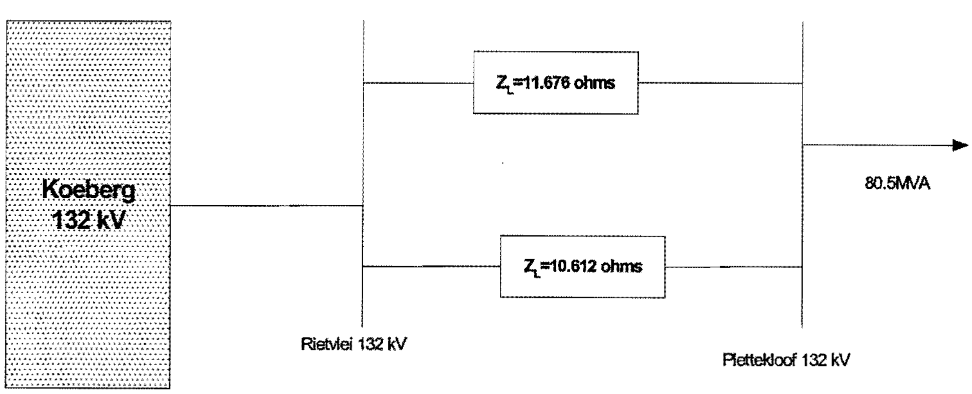

Figure 6- 7: Network model for the proposed 132 kV option

8.4 COSTING

Table 6- 7 shows capital costs for the proposed line to supply demand in the areas between Rietvlei and Plattekloof.

Cost Category (R/km)					Unshielded	Shielded
	Type	cct	Node	km		
Conductor	Chicadee	1	R-P	28	35, 520	35, 520
E/W		1			-	5, 920
Rest		1			104, 480	98, 560
Shielding		1			-	25, 760
Line Cost					**140, 000**	**165, 760**

Table 6- 7: Cost of forecasted demand line in West Coast

Total capital cost for the 28 km distribution line is MR4.64. The average penalty and revenue lost cost over a 12-month period is MR35.66 and cost of mitigating an average dip of 40% would total to MR128. According to Equation (5-42), total quality related costs would amount to MR163.66. The combined quality related and line capital costs, C_{LQ} give combined network cost of MR168.3.

Applying Equation (5-41), the proposed line effectiveness index is 10^{-9}. The index is relatively low but the line is still considered effective because it will not result in network disconnection or over loading when the other lines is fault. Generally, lines with mitigation are costly but effective due to limited penalty fees and revenue loss.

The combined line cost can be minimised using Equation (5-44) by making the following substitutions:

$$\text{Min Cost} = 0.75\sum(\text{MR}168.3) = \text{MR}126.225.$$

9. CHAPTER SUMMARY

The chapter presented a practical case study to demonstrate the relationship between planning and quality. The study consists of the West Coast NDP with a special outage condition twice a year. It was evaluated with the outage first and subsequent the outage condition was removed. The outage requires a dedicated 132 kV line to supply Koeberg auxiliaries during outages. Acacia gas turbines supply Koeberg via the 400 kV line operated at 132 kV. Koeberg has a direct link to Rietvlei, which has difficulties maintaining a firm supply in the region. There are loads forecasted in the anticipated line route from Reitvlei to Acacaia.

The study considered various planning alternatives most of which did not satisfy all the planning requirements. The specific requirement that posed difficulties was the release of the 400 kV line to transmission operation. The alternative to establish a separate 132 kV dedicate emergency line is chosen and another line is proposed to supply loads at Westwood, Blouberg and Vissershok areas. The chosen alternative would relieve the 400 kV line to transmission operation and loads in the forecasted areas would be supplied with the firm supply at Rietvlei. It would make it possible to back feed from Acacia to the proposed substations in the area when the Rietvlei link had a fault, etc.

Quality data at Koeberg 132 kV busbars over the 14-month period indicated the occurrence of harmonics, unbalance and dips. Harmonic and unbalance did not exceed standard limits and as a result not detailed analyses was conducted. Dips on the other hand exceeded standard limits and had a utility cost estimate of MR41.6. The cost estimate excluded customer costs due to unavailable customer data. The expected value of mitigation using the mitigation cost model in Figure 4- 9 indicated that application of HVPCC would result in reduced costs. The study made recommendations to reduce supply inconvenience and costs due to the special outage at Koeberg. The chapter evaluated a case with the outage restriction removed. The study showed that lines with mitigation are generally costly but effective as the chances of penalty fees and lost revenues due to interruptions are significantly reduced.

CHAPTER 7

7. CONCLUSION AND RECOMMENDATIONS

1. RESEARCH ACHIEVEMENTS

The primary objective of the research was to develop a link between risk and quality costing concepts in network planning. The scope of the research was limited to distribution networks of South Africa with voltages ranging from 22 to 132 kV. It defined planning as the application of modeling approaches and scientific analysis to obtain minimum cost solution/ s within statutory and technical constraints. The literature discussed in Chapter 2 revealed that planning techniques could be classified into judgemental and mathematical. Both groups however have no risk and/ or power quality considerations. The risk and quality concepts were defined separately, and costing proposals were developed in an attempt to link the quality risk into network planning. Uncertainty models were proposed as methods that would improve analysis of long-term uncertainties. The research developed quality-costing mechanisms for the utility and customers. It developed and proposed an Excel quality-costing tool **(test.xls)** for consideration to be incorporated into TIPS. The research evaluated component costs of mitigation and developed mitigation cost models in Figure 4- 8 and Figure 4- 9. The models were developed for 22 and 132 kV systems only, and it was assumed that voltages in the range (22-132 kV) would be within the evaluated cost range. It evaluated planning algorithms and proposed additions to Wang and McDonald's [69] traditional heuristic planning approach. An Eskom based case study was undertaken to indicate the validity of the theory developed and obtain practical results. The case study demonstrated costing approaches with consideration of quality and risk evaluation in planning.

2. CONCLUSION

The research studied a variety of planning approaches and related topics to obtain the optimal planning solution/ s. Based on the findings of the research and practical case study, the following conclusions may be drawn:

- Network planning is a very difficulty and complex task. Planning models have evolved from simplistic (linear models) approaches to multiple criteria models. The planning task has challenges but is further complicated by the uncertainty of certain parameters.
- Planning methods include mathematical modeling and judgemental approaches. Mathematical methods use comprehensive mathematical analysis that does not guarantee optimal solutions whereas judgemental approaches are mostly mathematical with an element of planner judgement allowed to reach a planning decision. The shortcoming of the two approaches however is the exclusion of power quality, which often results in inaccurate line costs, or incorrect choice of alternatives. There is however

a specific planning method that is only applicable to reinforcements. This approach has been criticised by modern research efforts as incomplete because it is time based and does not allow for postponement of development plans through feeder sharing strategies.

- Risk in planning is mainly due to uncertainty in the long term and as a result long-term network plans cannot be guaranteed. Uncertainty models based on fuzzy logic can however be used to analyse long-term risks within a degree of accuracy.
- Costs in distribution lines are mainly due to initial capital investment and quality related costs. The key cost components of any distribution line are cost of conductor, structure and insulator. The cost of conductor and structure vary depending on type but the cost of insulator does not vary significantly with variations in insulator type. Utility quality related costs are due to cost of mitigation and supply interruptions (operational). The cost per component of mitigation equipment generally decreases with increasing voltage. Quality impact costs however seem to increase with voltage. The behaviour of impact cost requires further research beyond the scope of this thesis. Customer costs due to interruptions have a linear relationship with interruption duration but the magnitude of costs varies between different industries. It is expected that interruption costs would be less for SWER systems due to higher reliability of these networks (assuming similar line components with multi-phase networks).
- The value based planning approach improves quality performance through better designs at minimum cost. The Modified Heuristic Approach is proposed to integrate risk, planning and quality costing because:
    i. it is simple and straight forward,
    ii. it does not require extra computational space, and
    iii. it is a judgemental approach that allows for integration of other optimisation methods.
- Voltage dips are the most predominant quality parameter at Koeberg. They are mainly due to transmission initiated events. The expected value of mitigating dips at Koeberg over a 1-year period would provide cost benefits. However, the long-term benefits of dip mitigation require further research. The selected alternative for the West Coast plan makes economic sense because the Koeberg-Acacia 400 kV line, which is dedicated for emergency at 132 kV, would be returned to full transmission operation. The forecasted loads in the region would be supplied via the Rietvlei-Plattenkloff link. There would however be a risk of exposure of additional line to voltage dips. The risk could be eliminated or reduced using mitigation listed in the model in Figure 4- 9. Quality mitigation increases line costs but has benefits in the long term. Mitigation significant reduces the risk of quality penalty fees, lost revenues and inconvenience to customers.

The analysis and development of **'The Modified Heuristic Planning Approach'** identified 4 aspects on which further information is required, but need work beyond the scope of this thesis. The issues relate to:

- How to predict the quality costs for risks that are resolvable without mitigation?
- What is the utility cost benefit due to customer standby generation?
- What is the effect of statutory requirements on quality performance?
- Verification of impact cost assumptions to assess mitigation?

3. RECOMMENDATIONS

Based on the findings and conclusion of the research report, it is required that the outstanding research information on The Modified Heuristic Planning Approach is investigated. Despite outstanding information, the proposed approach provides an improvement to a currently used planning method. It is expected that further research will not significantly change the existing information on the proposed approach. As a result, it is recommended that planners use The Modified Heuristic Planning Approach because:

- it is simple, flexible and straightforward than other alternatives,
- it incorporates quality mitigating costs into the distribution line capital cost,
- it first considers reinforcement postponement using Nahman and Strbac's [43] load sharing strategies before applying Partenan's [47] time based reinforcement technique,
- distribution line elements of spans, quality, conductor size, etc may be optimised separately,
- it is a less expensive method not requiring extra computational space since based on the traditional heuristic approach, and
- line overloading on reinforcement could be eliminated in any selected alternative.

Quality recommendations include the following:

- The developed quality-costing tool (test.xls) should be used to evaluate quality related operational costs where quality data is available.
- All network plans should be directed to achieve the objectives of the value based planning approach described in Chapter 5.

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APPENDICES

RISK ASSESSMENT TABLES [31]

This appendix describes a simple technique that is used to prioritise risks for analysis purposes. Each risk is first classified into one of the several likelihood categories, according to it probability of occurrence, and is then classified into several consequences, according to the severity of the consequences if the risk event does occur. Each category table has a score. The product of the scores for likehood and consequence provide a combined score for a particular risk. The higher the score for the particular risk the more unacceptable or intolerable that risk is considered. This approach was used by the institute of Civil Engineers and Actuaries in London and is well suited for risk in power networks although a different environment because it quantifies risk in terms of the financial consequences. Financial consequences are usually the most likely ultimate outcome for every risk.

Description	**Scenario**	**Probability**	**Scale value**
Highly likey	Very frequent occurrence	> 85%	16
Likely	More than even chance	50–85%	12
Fairly likely	Quite often occurs	21–49%	8
Unlike	Small likelihood but could well occur	1–20%	4
Very unlike	Not expected to happen	< 1%	2
Extremely unlikely	Just possible but very surprising	< 0.01 %	1

Appendix A: Probability - risk assessment table [31]

Description	**Scenario**	**Scale value**
Disastrous	Electricity utility investment cannot be sustained (i.e. death, bankruptcy)	1000
Severe	Serious threat to the network investment	100
Substantial	Reduces profit significantly	20
Marginal	Small effect on profit	3
Negligible	No effect	1

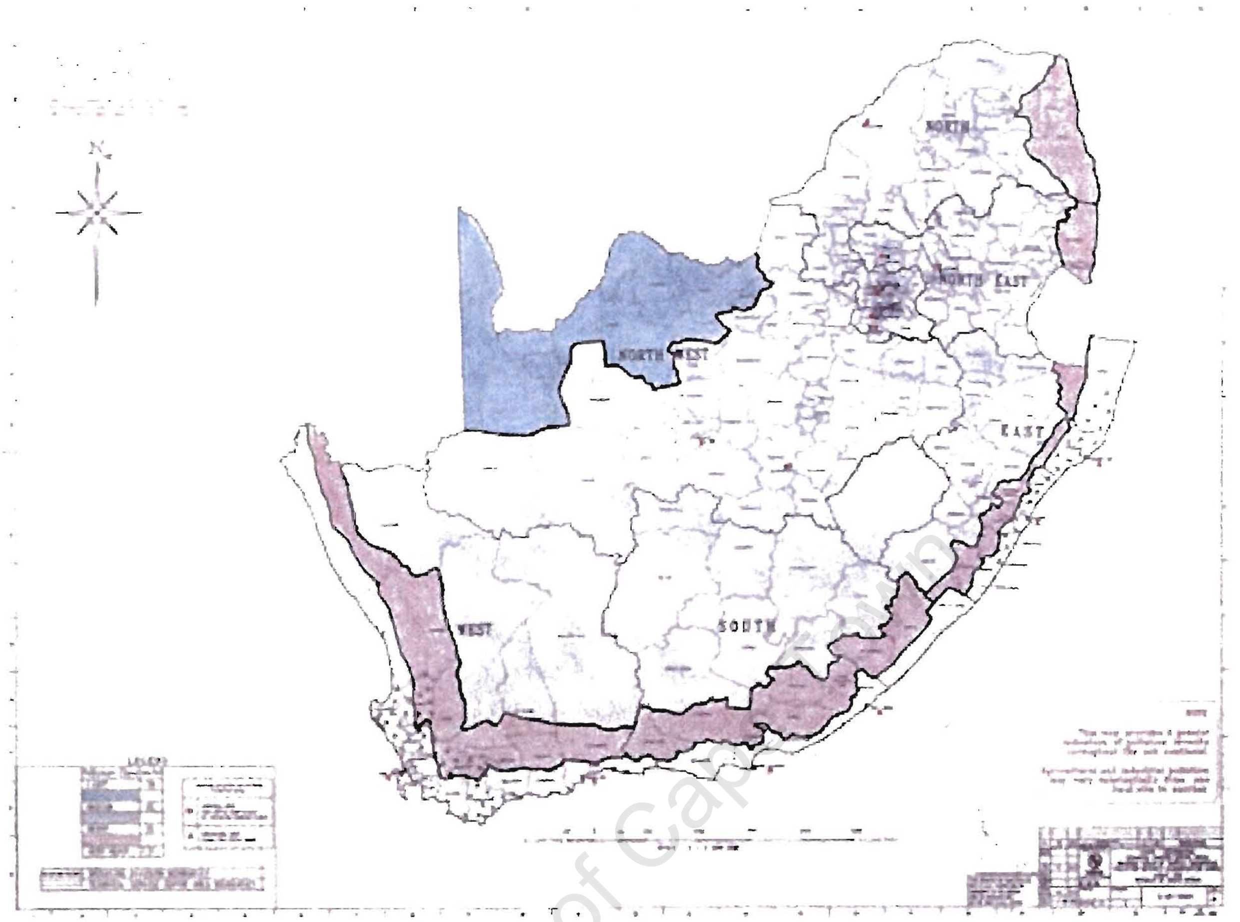
Appendix B: Consequence-risk assessment table

		Consequences				
Likelihood		**Disastrous (1000)**	**Severe (100)**	**Substantial (20)**	**Marginal (3)**	**Negligible (1)**
Highly likely	(16)	16000	1600	320	48	16
Likely	(12)	12000	1200	240	36	12
Fairly likely	(8)	8000	800	160	24	8
Unlikely	(4)	4000	400	80	12	4
Very Unlikely	(2)	2000	200	40	6	2
Extremely unlikely	(1)	1000	100	20	3	1

Appendix C: Risk acceptance assessment table [31

Points	Category	Action required
+1000	Intolerable	Must eliminate or transfer risk
101–1000	Undesirable	Attempt to avoid or transfer risk
21–100	Acceptable	Retain and manage risk
≤ 20	Negligible	Can be ignored

Appendix D: Key to acceptance of risk [31]



Appendix E: Pollution map of Southern Africa [TSI]

Conductor Type	Conducting Area (mm^2)	Conductor Cost (R/m)	Conductor Cost (R/km)	Line Impedance (Ω/km)
Squirell	20.98	1.2	1200	1.6709
Acacia	23.79	1.99	1990	1.6652
Gopher	26.25	1.56	1560	1.3356
Fox	36.68	2.07	2070	0.9556
Rabbit	52.66	2.68	2680	0.6629
Mink	63.13	8.15	8150	0.5554
Pine	71.66	4.73	4730	0.5535
Racoon	78.33	4.01	4010	0.4447
Hare	104.98	4.9	4900	0.3339
Oak	118.9	7.77	7770	0.3342
Mulberry	150.9	9.88	9880	0.2648
Wolf	156.06	10.95	10950	0.2233
Hornet	157.62	8.12	8120	0.223
Ash	180.7	12.18	12180	0.2204
Chicadee	212.09	11.84	11840	0.417
Bear	264.42	16.86	16860	0.1335
Sycamore	303.2	19.35	19350	0.1318
Butterfly	322.66	13.41	13410	0.109
Goat	324.31	17.51	17510	0.1088
Kingbird	340.96	18.27	18270	0.379
Upas	362.1	23.28	23280	0.1103
Centipede	415.22	13.29	13290	0.0848
Zebra	426.62	12.3	12300	0.0823
Yew	479	30.77	30770	0.0834
Dinosaur	662	32.39	32390	0.0544
Bull	665.36	37.21	37210	0.0408

Appendix F: Conductor data [Eskom-Brackenfell]

Appendix G1: 22 kV cost estimate data obtained from Barei's [5] report

Appendix G2: 66 kV cost estimate data obtained from Barei's [5] report

Appendix G3: 88 kV cost estimate data obtained from Barei's [5] report

Appendix G4: 132 kV cost estimate data including shielded (22 & 132 kV) networks

Appendix G5: Revenue Loss due to interruption 132 kV system with 80 MVA load

Appendix G6: Cost of loss of 2x250 MVA load at Koeberg substation

Appendix G7: Voltage dip costs at Koeberg 400/ 132 kV

Appendix G: Data Spreadsheets

Conductor	Conducting Area (mm^2)	MVA.km at o.9 pf	Cond. Cost (R/m)	Cond. Cost (3*R/km)	Line Cost (R/km)	Cost per Capacity (R/MVA.km)	Sending Voltage (kV)	Line Impedance (Ohms/km)	Receiving Voltage (kV)	Current (Amps/km)	Real Power (kW)	Reactive Power (kVArs)	Shielding (R/km)
squirell	20.98	0.03	1.2	3600	53000	1766666.67	23.1	1.6709	21.945	0.691	24.952	4.735	8833.33
acacia	23.79	0.03	1.99	5970	60700	2023333.33	23.1	1.6652	21.945	0.694	25.06	4.756	10116.67
gopher	26.25	0.03	1.56	4680	68400	2280000.00	23.1	1.3356	21.945	0.865	31.235	5.927	11400.00
fox	36.68	0.05	2.07	6210	76100	1522000.00	23.1	0.9556	21.945	1.209	43.656	8.284	12683.33
rabbit	52.66	0.07	2.68	8040	83800	1197142.86	23.1	0.6629	21.945	1.742	62.903	11.937	13966.67
mink	63.13	0.08	8.15	24450	91500	1143750.00	23.1	0.5554	21.945	2.08	75.107	14.253	15250.00
pine	71.66	0.08	4.73	14190	99200	1240000.00	23.1	0.5535	21.945	2.087	75.36	14.301	16533.33
racoon	78.33	0.1	4.01	12030	106900	1069000.00	23.1	0.4447	21.945	2.597	93.776	17.795	17816.67
hare	104.98	0.14	4.9	14700	114600	818571.43	23.1	0.3339	21.945	3.459	124.902	23.702	19100.00
oak	118.9	0.14	7.77	23310	122300	873571.43	23.1	0.3342	21.945	3.456	124.794	23.682	20383.33
mulberry	150.9	0.18	9.88	29640	130000	722222.22	23.1	0.2648	21.945	4.362	157.509	29.89	21666.67
wolf	156.06	0.21	10.95	32850	137700	655714.29	23.1	0.2233	21.945	5.172	186.758	35.44	22950.00
hornet	157.62	0.21	8.12	24360	145400	692380.95	23.1	0.223	21.945	5.179	187.01	35.488	24233.33
ash	180.7	0.21	12.18	36540	153100	729047.62	23.1	0.2204	21.945	5.24	189.213	35.906	25516.67
bear	264.42	0.35	16.86	50580	160800	459428.57	23.1	0.1335	21.945	8.652	312.418	59.286	26800.00
sycamore	303.2	0.35	19.35	58050	168500	481428.57	23.1	0.1318	21.945	8.763	316.426	60.047	28083.33
butterfly	322.66	0.43	13.41	40230	176200	409767.44	23.1	0.109	21.945	10.596	382.615	72.607	29366.67
goat	324.31	0.43	17.51	52530	183900	427674.42	23.1	0.1088	21.945	10.616	383.337	72.744	30650.00
upas	362.1	0.42	23.28	69840	191600	456190.48	23.1	0.1103	21.945	10.471	378.101	71.751	31933.33
centipede	415.22	0.55	13.29	39870	199300	362363.64	23.1	0.0848	21.945	13.62	491.81	93.329	33216.67
zebra	426.62	0.56	12.3	36900	207000	369642.86	23.1	0.0823	21.945	14.034	506.759	96.166	34500.00
yew	479	0.56	30.77	92310	214700	383392.86	23.1	0.0834	21.945	13.849	500.079	94.898	35783.33
dinosaur	662	0.85	32.39	97170	222400	261647.06	23.1	0.0544	21.945	21.232	766.674	145.489	37066.67
bull	665.36	1.14	37.21	111630	230100	201842.11	23.1	0.0408	21.945	28.309	1022.22	193.982	38350.00

Appendix G1

Conductor	Conducting Area (mm^2)	MVA.km at o.9 pf	Cond. Cost (R/m)	Cond. Cost(3*R/km)	Line Cost (R/km)	Cost per Capacity (R/MVA.km)	Sending Voltage (kV)	Line Impedance (Ohm/km)	Receiving Voltage (kV)	Current (Amps/km)	Real power (kW)	Reactive power (kVArs)
squirell	20.98	0.453	1.2	3600	74867.5	165270.42	69.3	1.6709	62.7	3.95	407.52	133.945
acacia	23.79	0.454	1.99	5970	75404.25	166088.66	69.3	1.6652	62.7	3.963	408.861	134.386
gopher	26.25	0.567	1.56	4680	75960.25	133968.69	69.3	1.3356	62.7	4.942	509.864	167.584
fox	36.68	0.792	2.07	6210	76535.5	96635.73	69.3	0.9556	62.7	6.907	712.592	234.218
rabbit	52.66	1.141	2.68	8040	77130	67598.6	69.3	0.6629	62.7	9.956	1027.157	337.61
mink	63.13	1.362	8.15	24450	77743.75	57080.58	69.3	0.5554	62.7	11.883	1225.964	402.955
pine	71.66	1.367	4.73	14190	78376.75	57334.86	69.3	0.5535	62.7	11.924	1230.194	404.345
racoon	78.33	1.701	4.01	12030	79029	46460.32	69.3	0.4447	62.7	14.841	1531.14	503.261
hare	104.98	2.266	4.9	14700	79700.5	35172.33	69.3	0.3339	62.7	19.766	2039.25	670.269
oak	118.9	2.264	7.77	23310	80391.25	35508.5	69.3	0.3342	62.7	19.749	2037.497	669.693
mulberry	150.9	2.857	9.88	29640	81101.25	28386.86	69.3	0.2648	62.7	24.924	2571.399	845.178
wolf	156.06	3.388	10.95	32850	81830.5	24153.04	69.3	0.2233	62.7	29.557	3049.384	1002.284
hornet	157.62	3.393	8.12	24360	82579	24338.05	69.3	0.223	62.7	29.596	3053.408	1003.607
ash	180.7	3.433	12.18	36540	83346.75	24278.11	69.3	0.2204	62.7	29.946	3089.517	1015.475
bear	264.42	5.667	16.86	50580	84133.75	14846.26	69.3	0.1335	62.7	49.438	5100.499	1676.453
sycamore	303.2	5.74	19.35	58050	84940	14797.91	69.3	0.1318	62.7	50.076	5166.321	1698.088
butterfly	322.66	6.941	13.41	40230	85765.5	12356.36	69.3	0.109	62.7	60.55	6246.92	2053.263
goat	324.31	6.954	17.51	52530	86610.25	12454.74	69.3	0.1088	62.7	60.662	6258.475	2057.061
upas	362.1	6.859	23.28	69840	87474.25	12753.21	69.3	0.1103	62.7	59.837	6173.36	2029.085
centipede	415.22	8.922	13.29	39870	88357.5	9903.33	69.3	0.0848	62.7	77.83	8029.69	2639.232
zebra	426.62	9.193	12.3	36900	89260	9709.56	69.3	0.0823	62.7	80.194	8273.583	2719.395
yew	479	9.072	30.77	92310	90181.75	9940.67	69.3	0.0834	62.7	79.137	8164.533	2683.552
dinosaur	662	13.908	32.39	97170	91122.75	6551.82	69.3	0.0544	62.7	121.324	12516.949	4114.122
bull	665.36	18.544	37.21	111630	92083	4965.65	69.3	0.0408	62.7	161.765	16689.231	5485.485

Appendix G2

Conductor	Conducting Area (mm^2)	MVA. km at o.9 pf	Cond. Cost (R/m)	Cond. Cost (3*R/km)	Line Cost (R/km)	Cost per Capacity (R/MVA.km)
squirell	20.98	0.85	1.2	3600	86443.38	101698.09
acacia	23.79	0.85	1.99	5970	86470.21	101729.66
gopher	26.25	1.06	1.56	4680	86498.01	81601.9
fox	36.68	1.48	2.07	6210	86526.78	58464.04
rabbit	52.66	2.14	2.68	8040	86556.5	40446.96
mink	63.13	2.55	8.15	24450	86587.19	33955.76
pine	71.66	2.56	4.73	14190	86618.84	33835.48
racoon	78.33	3.18	4.01	12030	86651.45	27248.88
hare	104.98	4.24	4.9	14700	86685.03	20444.58
oak	118.9	4.24	7.77	23310	86719.56	20452.73
mulberry	150.9	5.35	9.88	29640	86755.06	16215.9
wolf	156.06	6.34	10.95	32850	86791.53	13689.52
hornet	157.62	6.35	8.12	24360	86828.95	13673.85
ash	180.7	6.42	12.18	36540	86867.34	13530.74
bear	264.42	10.61	16.86	50580	86906.69	8191.02
sycamore	303.2	10.74	19.35	58050	86947	8095.62
butterfly	322.66	12.99	13.41	40230	86988.28	6696.56
goat	324.31	13.01	17.51	52530	87030.51	6689.51
upas	362.1	12.84	23.28	69840	87073.71	6781.44
centipede	415.22	16.7	13.29	39870	87117.88	5216.64
zebra	426.62	17.2	12.3	36900	87163	5067.62
yew	479	16.98	30.77	92310	87209.09	5135.99
dinosaur	662	26.03	32.39	97170	87256.14	3352.14
bull	665.36	34.7	37.21	111630	87304.15	2515.97

Sending Voltage (kV)	Line Impedance (Ohms/km)	Receiving Voltage (kV)	Current(Amps/km)	Real Power (kW)	Reactive Power (kVArs)	Capacity (MVA/km)
92.4	1.6709	83.6	5.267	724.53	238.14	762.66
92.4	1.6652	83.6	5.285	727	238.95	765.26
92.4	1.3356	83.6	6.589	906.38	297.91	954.08
92.4	0.9556	83.6	9.209	1266.79	416.37	1333.46
92.4	0.6629	83.6	13.275	1826.1	600.21	1922.21
92.4	0.5554	83.6	15.844	2179.49	716.36	2294.2
92.4	0.5535	83.6	15.899	2187.06	718.85	2302.17
92.4	0.4447	83.6	19.789	2722.16	894.73	2865.43
92.4	0.3339	83.6	26.355	3625.38	1191.6	3816.19
92.4	0.3342	83.6	26.332	3622.22	1190.56	3812.86
92.4	0.2648	83.6	33.233	4571.51	1502.58	4812.12
92.4	0.2233	83.6	39.409	5421.08	1781.82	5706.4
92.4	0.223	83.6	39.462	5428.37	1784.22	5714.07
92.4	0.2204	83.6	39.927	5492.34	1805.24	5781.41
92.4	0.1335	83.6	65.918	9067.65	2980.39	9544.89
92.4	0.1318	83.6	66.768	9184.57	3018.82	9667.97
92.4	0.109	83.6	80.734	11105.73	3650.28	11690.24
92.4	0.1088	83.6	80.882	11126.09	3656.97	11711.67
92.4	0.1103	83.6	79.782	10974.77	3607.23	11552.39
92.4	0.0848	83.6	103.774	14275.1	4692	15026.42
92.4	0.0823	83.6	106.926	14708.68	4834.51	15482.82
92.4	0.0834	83.6	105.516	14514.73	4770.76	15278.66
92.4	0.0544	83.6	161.765	22252.31	7313.98	23423.48
92.4	0.0408	83.6	215.686	29669.65	9751.94	31231.21

Appendix G3

Conductor	Conducting Area (mm^2)	MVA. km at o.9 pf	Cond. Cost (R/m)	Cond. Cost (3*R/km)	Line Cost (R/km)	Cost per Capacity (R/MVA.km)	Shielded 132 kV	22kV Cost (R/MVA.km)	Shielded 22 kV	Sending Voltage (kV)	Line Impedance (Ohm/km)	Receiving Voltage (kV)
squirell	20.98	1.05	1.2	3600	180143.43	171565.17	228753.56	1766666.67	2061111.11	138.6	1.6709	125.4
acacia	23.79	1.05	1.99	5970	192166.9405	183016.13	244021.51	2023333.33	2360555.56	138.6	1.6652	125.4
gopher	26.25	1.31	1.56	4680	204191.841	155871.63	207828.85	2280000	2660000.00	138.6	1.3356	125.4
fox	36.68	1.83	2.07	6210	216218.18	118152.01	157536.01	1522000	1775666.67	138.6	0.9556	125.4
rabbit	52.66	2.64	2.68	8040	228246.005	86456.82	115275.76	1197142.86	1396666.67	138.6	0.6629	125.4
mink	63.13	3.15	8.15	24450	240275.3645	76277.89	101703.86	1143750	1334375.00	138.6	0.5554	125.4
pine	71.66	3.16	4.73	14190	252306.3065	79843.77	106458.36	1240000	1446666.67	138.6	0.5535	125.4
racoon	78.33	3.93	4.01	12030	264338.879	67261.8	89682.40	1069000	1247166.67	138.6	0.4447	125.4
hare	104.98	5.23	4.9	14700	276373.1305	52843.81	70458.41	818571.43	955000.00	138.6	0.3339	125.4
oak	118.9	5.23	7.77	23310	288409.1085	55145.15	73526.86	873571.43	1019166.67	138.6	0.3342	125.4
mulberry	150.9	6.6	9.88	29640	300446.8615	45522.25	60696.34	722222.22	842592.59	138.6	0.2648	125.4
wolf	156.06	7.82	10.95	32850	312486.438	39959.9	53279.87	655714.29	765000.00	138.6	0.2233	125.4
hornet	157.62	7.84	8.12	24360	324527.8855	41393.86	55191.82	692380.95	807777.78	138.6	0.223	125.4
ash	180.7	7.93	12.18	36540	336571.2525	42442.78	56590.37	729047.62	850555.56	138.6	0.2204	125.4
bear	264.42	13.09	16.86	50580	348616.587	26632.28	35509.71	459428.57	536000.00	138.6	0.1335	125.4
sycamore	303.2	13.26	19.35	58050	360663.937	27199.39	36265.86	481428.57	561666.67	138.6	0.1318	125.4
butterfly	322.66	16.03	13.41	40230	372713.351	23250.99	31001.32	409767.44	478062.02	138.6	0.109	125.4
goat	324.31	16.06	17.51	52530	384764.8765	23957.96	31943.95	427674.42	498953.49	138.6	0.1088	125.4
upas	362.1	15.84	23.28	69840	396818.562	25051.68	33402.24	456190.48	532222.22	138.6	0.1103	125.4
centipede	415.22	20.6	13.29	39870	408874.456	19848.27	26464.37	362363.64	422757.58	138.6	0.0848	125.4
zebra	426.62	21.23	12.3	36900	420932.606	19827.25	26436.34	369642.86	431250.00	138.6	0.0823	125.4
yew	479	20.95	30.77	92310	432993.0605	20667.93	27557.24	383392.86	447291.67	138.6	0.0834	125.4
dinosaur	662	32.12	32.39	97170	445055.8675	13856.04	18474.71	261647.06	305254.90	138.6	0.0544	125.4
bull	665.36	42.82	37.21	111630	457121.075	10675.41	14233.88	201842.11	235482.46	138.6	0.0408	125.4

Appendix G4

Voltage Dips	Constant I(A)	Power Delivered (kW)	Tariff (c/kWh)	Cost (R)	pf
Qn(NRS) = 10 tn(NRS)(ms20	80.00	2895.99	7.49	R 0.000	0.95

NRS Magnitude limits built in the formula but number of inciednts not included (Equa. 4-1 to 4-6)

Parameter	Time (ms	Interrup. dur. (sec.)	Interrupted MWh	Revenue Loss [R]	Revenue Loss [R/MWh]	Penalty Cost (R)
2.78E-07	20.00	0.02	0.00000	0.60	749000	0.000
1.39E-06	290.91	0.29	0.00000	3.02	749000	0.000
1.27E-05	561.82	0.56	0.00004	27.59	749000	0.003
6.91E-06	832.73	0.83	0.00002	14.98	749000	0.001
3.67E-05	1103.64	1.10	0.00011	79.54	749000	0.008
5.41E-05	1374.55	1.37	0.00016	117.25	749000	0.012
1.55E-04	1916.37	1.92	0.00045	336.31	749000	0.034
1.87E-04	2187.28	2.19	0.00054	406.23	749000	0.041
2.26E-04	2458.19	2.46	0.00065	490.01	749000	0.049
2.72E-04	2729.10	2.73	0.00079	589.58	749000	0.059
3.26E-04	3000.01	3.00	0.00094	707.09	749000	0.071

Appendix G5

Equations (4-1) & (4-3)

Voltage Dips	Constant I(A)	Power Delivered (kW)	Tariff (c/kWh)	Cost (R)	pf
Qn(NRS) = 10 **tn(NRS)(ms**20	**2187.00**	**475014.59**	7.49	**R 17,789.277**	0.95

NRS Magnitude limits built in the formula but number of inciednts not included (Equa. 4-1 to 4-6)

Parameter	Time (ms)	Interrup. dur. (sec.)	Interrupted MWh	Revenue Loss [R]	Revenue Loss [R/MWh]	Penalty Cost (R)
5.00E-01	1800000.00	1800.00	237.50703	177,892,765.38	749000	**17,789.277**

Appendix G6

Equations (4-1) & (4-3)

		Voltage Dips		**Constant P (MVA)**	**Power Delivered (kW**	**Par. Calculation**	**Tariff (c/kWh)**	**Cost (R)**	**pf**
		QNRSn =	10	**160.00**	**144000.00**	**1.81E+01**	7.49	**R 195,219.360**	0.9
		tNRSn(ms)=	20						
Dip Date	**MILLISEC**	**MAX_DEPTH**	**Penalty Cost[R]**	**Revenue Loss[R]**	**Dip Date**	**MILLISEC**	**MAX_DEPTH**	**Penalty cost[R]**	**Revenue Loss[R]**
02/05/00	310	18.1	70376.04	168105.56	11/26/00	70	45.7	53478.60	95842.04
02/17/00	80	25.9	28581.84	62077.12	11/26/00	90	46.2	75918.64	124573.68
02/21/00	230	16.4	40266.24	113009.12	11/26/00	80	45.7	64174.32	109533.76
02/27/00	910	23.1	349303.64	629789.16	11/26/00	610	45.3	623976.92	827884.68
02/29/00	520	95.3	1277794.00	1484697.76	11/26/00	480	46.7	505784.72	671583.36
02/29/00	100	95.7	205405.76	286717.20	11/26/00	620	47.2	668707.20	876749.44
03/03/00	820	34.8	594406.40	854938.56	11/26/00	860	46.9	928640.16	1208406.64
03/03/00	810	35	591710.00	849366.00	11/26/00	330	49.5	366860.20	489396.60
03/03/00	200	34.7	133202.16	207922.40	11/26/00	580	47.8	634193.28	830611.04
03/03/00	680	34.5	484453.20	702861.60	11/26/00	140	47.1	133381.92	197556.24
03/14/00	440	30.3	255438.96	399426.72	11/26/00	820	45.2	843673.60	1110437.44
03/14/00	360	20.3	104919.92	218947.68	11/26/00	20	46.2	0.00	27683.04
03/28/00	690	11.2	24087.84	231530.88	11/26/00	940	46.2	997787.84	1301102.88
04/01/00	920	12.2	59320.80	336271.04	01/06/01	130	11.9	6261.64	46348.12
04/03/00	900	15.5	145006.40	417942.00	01/09/01	180	17.9	37869.44	96531.12
04/03/00	860	16	150998.40	412249.60	02/01/01	520	34.1	361018.00	531250.72
04/15/00	880	12.6	66990.56	332196.48	02/04/01	980	16.6	189826.56	487389.28
05/05/00	810	63.1	1256792.04	1531285.56	02/04/01	190	14.8	24447.36	84247.52
06/02/00	140	11	3595.20	46138.40	02/04/01	800	31.6	504766.08	757388.80
06/09/00	790	11.6	36910.72	274553.44	02/08/01	590	11.4	23908.08	201510.96
06/10/00	840	21.4	280066.08	538560.96	02/15/01	620	20.2	183355.20	375219.04
06/19/00	230	63.3	335342.28	436187.64	02/15/01	600	19.8	170292.64	355924.80
07/26/00	330	12.4	22290.24	122596.32	02/15/01	680	64.3	1073706.48	1309971.04
08/11/00	460	100	1186416.00	1378160.00	02/15/01	890	35.9	675088.68	957251.96
08/21/00	360	13.8	38708.32	148841.28	02/15/01	200	57.9	258315.12	346936.80
08/22/00	480	100	1240344.00	1438080.00	02/15/01	860	58.4	1218053.76	1504711.04
08/28/00	800	11.9	44400.72	285219.20	02/15/01	780	36.7	607948.32	857634.96
08/31/00	220	100	539280.00	659120.00	02/15/01	490	56.7	657592.04	832378.68
09/09/00	750	100	1968372.00	2247000.00	02/17/01	90	12.9	6081.88	34783.56
09/26/00	600	100	1563912.00	1797600.00	02/18/01	590	16.6	112709.52	293428.24
09/30/00	980	14.5	129427.20	425731.60	02/18/01	690	22.6	252922.32	467196.24
10/04/00	910	12.8	74660.32	348974.08	02/26/01	170	14	17976.00	71304.80
10/04/00	130	12.8	9227.68	49853.44	02/26/01	290	19.3	75229.56	167686.12
10/04/00	930	12.2	59979.92	339926.16	02/26/01	140	12.4	8628.48	52010.56
10/21/00	730	23.3	282912.28	509589.64	02/26/01	280	23.6	105938.56	197975.68
10/30/00	760	19.8	217269.92	450838.08					
10/31/00	210	10.7	3984.68	67320.12	**Total**	**25140**	**36.91**	**R 16,672,470.36**	**R 24,913,867.16**
11/14/00	990	21.9	345828.28	649562.76					
11/15/00	500	20.3	148122.24	304094.00					
11/15/00	380	21.6	125112.96	245911.68	Total revenue loss at Koeberg for the period considered equal to MR 24-91				
11/15/00	610	21.4	201510.96	391097.84	Total penalty cost equal to MR 16.67				
11/19/00	280	100	701064.00	838880.00	78 Incidents of dips were recorded over fourteen months.				
11/26/00	230	46.2	227755.92	318354.96					MR 41, 6
11/26/00	980	46.4	1046922.24	1362341.12					
Appendix G7									

Industry	1 minute	1 hour	5 hours	10 hours
Domestic	4	8	20	48
Chemical Industry	16	32	80	192
Agricultural	24	48	120	288
Food Industry	32	64	160	384
Textile Industry	40	80	200	480

Appendix H: Estimates of customer interruption costs [R/kW]

Several organisations were contacted in the study period (03/99 - 12/01) and provided industrial contribution in the research. They provided information such as practical data for network performance, references to planning documents, standards and cost estimates for quality mitigation equipment. The research information would be communicated verbally where no documentation was provided. Contact people in the organisations included the following:

Name	Organisation	Contact Number	Subject
Andre Botha	Eskom-Simmerpan	011-8713664	Quality Costing Methods
Antonio Baloka	Eskom-Koeberg	021-9159227	Quality Data (Koeberg S/S)
Brendan Jackson	Eskom-Bellville	021-9152657	Network Performance
Chris de Kok	ABB-Transformers	082-8944779	Tap Changers
Duncan Ramsbottom	Eskom-Brackenfell	021-9803028	Network Planning
Dvevad Muftic	Eskom-MWP	011-8005336	Line Technology
Freddie Julie	Eskom-Colesberg	047-7530741	SWER Networks
Gunther Kruise	Eskom-MWP	011-8003323	Line Transposition
Hennie Mostart	Eskom-Brackenfell	021-9803038	Quality Planning
Johan Henry	Aberdare Cables	021-4473032	Power Cables
Johan Weyers	Eskom-Uitenhuige	041-9948272	SWER vs 3 PHASE
Leon Christiaans	Eskom-Brackenfell	021-980 3210	Insulators
Lynne Scott	Aberdare Cables	021-4473032	Power Cables
Paul de Castro	Tswelopele Engineering	083-2747887	Voltage Regulators
Paul Johnson	Eskom-MWP	011-8003013	NRS 048 1- 5
Riaan Smit	Eskom-Brackenfell	021-9803452	Network Planning
Robben Abrahams	Eskom-TSI	011-6295111	Quality Survey Reports
Robbin Scott	Eskom-Brackenfell	021-9803190	Line Design
Sandile Funeka	Eskom-TSI	082 3213772	Quality Survey Reports
Sylvester Barei	University of Cape Town	021-6502810	Line Parameter Estimates

Appendix I: Research Contacts