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VALUE-BASED PLANNING METHODOLOGY FOR THE RESTRUCTURING AND EXPANSION OF AN ELECTRIC UTILITY SUB-TRANSMISSION NETWORK

by

Deon Johann Vrey

A dissertation submitted in partial fulfilment of the requirements for the degree

Master of Engineering (Electrical Engineering)

in the

Faculty of Engineering

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DISSERTATION SUMMARY

VALUE-BASED PLANNING METHODOLOGY FOR THE RESTRUCTURING AND EXPANSION OF AN ELECTRIC UTILITY SUB-TRANSMISSION NETWORK

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A dissertation submitted in partial fulfilment of the requirements for the degree

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Keywords: Composite system reliability, Sub-transmission network planning, Value-based planning, Reliability worth, Customer damage

The main objective of this study is to develop a methodology to assist in the reconfiguration and expansion of an electrical sub-transmission network within the framework of Value-based planning. This methodology applies to typical municipal networks found in South Africa.

A literature study indicates that most of the fundamental concepts for power system reliability is well established with extensive research done in North America, and other parts of the world. Reliability worth assessment of sub-transmission networks in South Africa, which include composite networks and substation reliability, is however not well developed. From a Value-based point of view the literature further does not provide much linkage to the evaluation of alternative long-term network options. This is especially true in terms of the life cycle cost assessment of network alternatives, which include the prediction of customer damages as a function of network performance.

In this dissertation a methodology is proposed which utilises the basic network reliability concepts to assess the performance of existing and future alternative network options. The load point Expected Unserved Energy is used to quantify network performance and is obtained through a contingency enumeration process. An existing Geographical Load Forecasting technique defines all customers connected to a load point, on a homogeneous level. This information along with Sector Customer Damage Functions is used to predict existing and future Composite Customer Damage Functions at the associated load point in the sub-transmission network. To arrive at the total minimum cost, which is the objective of Value-based planning, the present worth for each alternative is obtained from the annual utility and customer cost over the life cycle of the alternative. The alternative that result in the lowest present worth is identified as the preferred alternative.

A case study is conducted on the sub-transmission network of the Greater Pretoria Metropolitan Council (GPMC) in order to prove the methodology. The entire network is analysed in order to identify the sub-system with the worst performance from a reliability point of view. Alternative network options are identified and the methodology is used for the evaluation of these alternatives.

The application of this methodology provides the network planner with the ability to make better decisions with regard to the allocation of reliability. Through the calculation of reliability indices, tangible guidelines can be provided to quantitatively assess the impact of different network alternatives. These guidelines assess contingency probabilities explicitly and along with reliability worth evaluation provide a fundamental tool to conduct Value-based planning. The application of this methodology can lead to significant savings in capital investment while maintaining an acceptable level of reliability.

Samevatting van Verhandeling

Value-Based Planning Methodology for the Restructuring and Expansion of an Electric Utility Sub-Transmission Network

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'n Verhandeling voorgelê ter vervulling van 'n deel van die vereistes vir die graad Magister in Ingenieurswese (Elektriese Ingenieurswese)

Sleutelwoorde: Saamgestelde stelsel betroubaarhei, Sub-transmissie netwerk beplanning, Waarde gebaseerde beplaning, Betroubaarheid waarde, Verbruiker skade

Die hoof doelstelling van hierdie verhandeling is om 'n metode te ontwikkel waarvolgens die herkonfigurasie en ontwikkellings beplanning van 'n elektriese sub-transmissie netwerk gedoen kan word. Die metode moet binne die raamwerk van waarde gebaseerde beplanning geskied.

'n Literatuur studie toon dat die fundamentele konsepte met betrekking tot kragstelsel betroubaarheid tot 'n groot mate ontwikkel is. Die meerderheid van hierdie ontwikkeling is in Noord Amerika gedoen. Die bepaling van die waarde van betroubaarheid wat betrekking het tot sub-transmissie netwerke in Suid Afrika, wat beide saamgestelde netwerke en substasie betroubaarheid aanspreek, is nog nie formeel ontwikkel nie. Vanuit 'n waarde gebaseerde beplannings oogpunt toon die literatuur verder 'n leemte in die metodes wat gevolg word vir die evaluering van lang-termyn netwerk alternatiewe. Dit geld veral in die geval waar die lewensiklus koste van alternatiewe netwerk opsies bereken word, wat die koste aan verbruikers as 'n funksie van toekomstige netwerk prestasie oor 'n periode van tyd vooruitskat.

Hierdie verhandeling stel 'n metode voor wat die fundamentele kragstelsel betroubaarheid konsepte en tegnieke gebruik om die huidige en toekomstige netwerk prestasie te bepaal. Die Verwagte Laspunt Ongebruikte Energie word vir die huidige netwerk asook die langtermyn alternatiewe bepaal, deur middel van 'n gebeurlikheids analise. 'n Bestaande Geografiese Lasramings Tegniek word gebruik om verbruikers wat aan 'n spesiefieke laspunt gekoppel is te identifiseer. Hierdie inligting, tesame met die Sektor Gebruiker Skade Funksie word gebruik om die Saamgestelde Gebruiker Skade Funksie by die betrokke laspunt vir die toekomstige netwerk te voorspel. Die Verwagte laspunt Ongebruikete Energie en die Saamgestelde Gebruiker Skade Funksie word gebruik om die koste aan gebruikers as 'n funksie van netwerk prestasie te bereken. Beide die kapitale koste om die elektriese infrastruktuur te skep en die daaruitvolgende koste aan die verbruikers word genormaliseer na 'n jaarlikse koste. Die alternatief wat lei tot die laagste huidige waarde voldoen aan die sukses kriteria vir die waarde gebaseerde beplannings model.

Ten einde die metode te bewys is 'n gevalle studie op die sub-transmissie netwerk van die Groter Pretoria Metropolitaanse Raad uitgevoer. Die netwerk is in sy geheel geanaliseer om 'n sub-stelsel te identifiseer wat vanuit 'n betroubaarheids oogpunt die swakste presteer. Alternatiewe netwerk opies is met die metode geanaliseer.

Die metode bied die beplanners van elektriese sub-transmissie netwerke die vermoë om beter besluite te maak met betrekking tot die plasing van betroubaarheid in die netwerk. Deur betroubaarheids indekse vir verskillende netwerk opsies te bepaal, verkry die beplanner 'n tasbare kwantitatiewe weerspieëling van alternatiewe netwerk opsies. Tesame met die waarde bepalIng van hiedie alternatiewe kan die metode aangewend word om 'n noemenswaardige besparing aan lewensiklus koste op elektriese sub-transmissie netwerke te bewerkstellig.

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List Of Abbreviations

ESI	-	Electricity Supply Industry
RED	-	Regional Electricity Distributor
GPMC	-	Greater Pretoria Metropolitan Council
EUE	-	Expected Unserved Energy
FEA	-	Failure Effect Analysis
SCDF	-	Sector Customer Damage Function
CCDF	-	Composite Customer Damage Function
IEAR	-	Interrupted Energy Assessment Rate
GLF	-	Geographical Load Forecast

APPENDIX LIST

CHAPTER 1

1. PROBLEM IDENTIFICATION AND BACKGROUND

1.1 INTRODUCTION

The basic function of an electric power system is to satisfy the system load and energy requirements at the lowest possible cost, while maintaining an adequate degree of continuity and quality. The performance of a power system relating to reliability, efficiency and economy depend mainly on how well its generation stations, substations, transmission lines, and distribution feeders are positioned within the utility service area. Furthermore how adequate their capacities and equipment assessment match power needs in their respective localities and how efficient they are protected, operated and maintained.

The planning process of such a power system can be described as generally involving an energy and demand forecast, yielding an expansion plan with associated financial impact and resulting in a capital program with certain construction plans. One of the difficult problems faced by the planners of such a network is to decide how far they are justified in increasing the network investment to improve service reliability. Power system planners therefore need to determine an adequate balance between cost and reliability to satisfy the predicted load.

The basic concepts and principles of power system reliability evaluation are well established and documented [1 2 3]. Evaluation techniques can be classified either as analytical or as Monte Carlo simulation and have successfully been implemented in all three hierarchical levels of a power system.

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[1] R.N. Allan, R. Billinton, S.M. Shahidehpour, C. Singh, "Bibliography on the Application of Probabilistic Methods in Power System Reliability Evaluation 1982 – 1987", IEEE Transactions on Power Systems, PWRS-3, 1988

[2] M. Th Schilling, R. Billinton, A.M. Leite de Silva, M.A. El-Kady, "Bibliography on Composite System Reliability", IEEE Transactions on Power Systems, 4, No.3, 1989, pp.1122-1132

[3] G. Tollefson, R. Billinton, G. Wacker, "Comprehensive bibliography on reliability worth and electric service consumer interruption cost 1980-1990", IEEE Trans. Power Systems, 6(4) (1991) 1508 –14.

Establishing the worth of a specific level of reliability is a difficult task [4]. From a customer perspective, interruption or outage cost can be broadly classified into direct and indirect costs. Direct costs are those arising directly from the electrical interruption and relate to impacts such as lost industrial production, spoiled food or raw materials, lost personnel time and equipment damage. Indirect cost on the other hand are related to impacts arising from a response to the interruption, such as crime during a blackout (short term) and business relocation (long term) [5].

When dealing with expansion planning of sub-transmission networks, typically 132kV overhead line networks as found within large municipal areas in South Africa, the objective of the planner, from a reliability point of view, is to economically minimise the effect of network disturbances on the customers connected to a specific service area.

Utilising reliability assessment techniques, standard reliability indices, such as frequency, duration and severity of events can be calculated. Using these indices in conjunction with the customer perceived value of reliability, the worth of alternative network options can be evaluated.

The availability of a reliable power supply at reasonable cost is an important issue for economic growth in the development of a country [6]. In South Africa, especially within local municipalities, design, planning and operation criteria have not been developed to resolve the dilemma between the economic and reliability constraints of a power system. Most of the techniques used today are still deterministically based and do not reflect the probabilistic nature of system behaviour of customer demand or of component failures, let alone the evaluation of the worth of a specific level of reliability.

Be this as it may, the South African Electricity Supply Industry is on the verge of restructuring, with the possible amalgamation of local supply authorities and municipalities to form Regional Electricity Distributors (RED's). With the first step of regulation felt by most supply authorities, this restructuring could lead to a better understanding of the networks and its customers through improved methodologies and planning techniques.

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[4] R. Allan, "Basic Concepts in Reliability Evaluation", IEEE Tutorial Course on Power System Reliability Evaluation", Director Publishing Services, IEEE, NY, 10017

[5] R. Billinton, G. Tollefson, G. Wacker, "Assessment of Electric Service Reliability Worth", Probabilistic Methods Applied to Electric Power Systems, Third International Conference, 3 – 5 July 1991, Savoy Place, London, pp. 9-14

[6] R. Billinton, M. Pandey, "Reliability Worth Assessment of Electric Power Systems in Developing Countries", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

1.2 PROBLEM IDENTIFICATION

In order to understand the impact of this challenge one should have some background as to the process required to plan the expansion of a typical Transmission or Sub-Transmission network, as provided in Figure 1.1. The planning process is based on a number of logical steps that are performed to reach an optimal planning result.

With relevant data and strategic inputs available, a geographical or land-use load forecast is performed in order to derive a realistic long-term prediction of the electrical load for the complete supply area [7]. Town and regional planners perform an assessment of the current land-use and then predict future land usage. In addition economists calibrate the predicted land-use growth against envisaged economic growth prospects.

The process is followed by the identification of network refurbishment needs. A data capturing exercise is done to collect information regarding electrical equipment age and condition. A long-term capital program is then derived to replace equipment that has reached a certain age. This ensures that the complete electrical network stays serviceable and maintains a certain standard of safety.

With the long-term load forecast and refurbishment requirements in place the network expansion planning is performed. Various alternative supply options are identified. These alternatives are analysed technically by performing load flow and fault level studies to ensure appropriate thermal loading, voltage tolerance and fault current conditions for each alternative.

The successful technical alternatives are costed according to standard cost tables. The financial analysis uses the combined capital per alternative, the corresponding load growth forecast and a number of financial parameters to calculate the financial viability of the proposed strategic development plan.

In most cases a shortcoming to this process is that no consideration is given to the actual reliability of the alternatives. The stochastic nature of the proposed alternatives is not taken into account. Rather the common method of providing for reliability is the so-called (n-1) criterion. This criterion defines that a system is sufficiently reliable if it is able to operate acceptably under any unplanned outage of equipment due to a single cause. The weakness of this criterion is that it cannot account for the stochastic nature of system behaviour, of customer demand or of component failures. The failure rate of an overhead line for instance, is a function of length, design, location and the environment and therefore constructing minimum number of circuits

[7] H. Lee Willis, Michael V. Engel, "Spatial Load Forecasting", IEEE Computer Applications in Power, April 1995, pp. 40-43

cannot ensure consistent risk. Perhaps more important is the fact that different customers perceive the impact of power interruptions or unreliability differently. It is thus not only important to evaluate the stochastic nature of the proposed alternatives, but also their impact on connected customers.

One particular problem associated with the reliability evaluation of a power system is its complex nature, which means that it is not possible to analyse it as one complete entity. It is for this reason that reliability evaluation is not normally applied directly to an entire power system, but is usually conducted on segments of a system [8]. These segments are generating systems, composite generation/transmission (bulk power) systems, station systems and distribution systems and are known as the hierarchical levels of a power system. The representation of the typical hierarchical levels is provided in Figure 1:1.

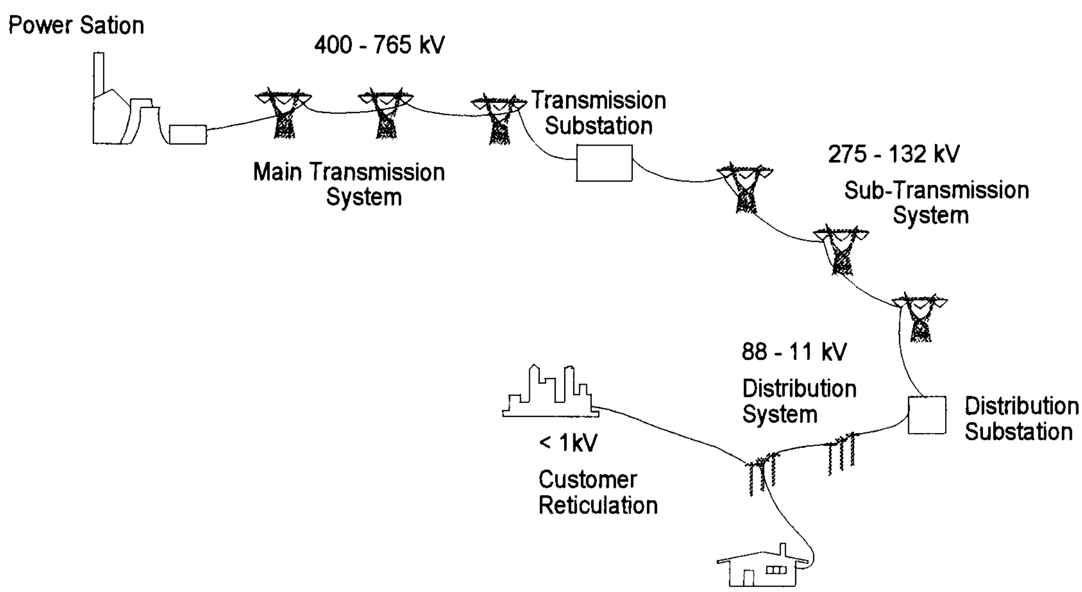

Figure 1:1 Typical Power System Representation

[8] R. Billinton, W. Zhang., "Equivalents in Adequacy Evaluation of Power Systems", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

1.2.1 Fundamentals of Hierarchical Levels

The fundamental reliability requirements of each hierarchical level is as follow:

Generation capacity reliability is defined in terms of the adequacy of the installed generation capacity to meet the system load demand. The basic methodology for evaluating generation system reliability is to develop probability models for capacity during outage and for load. The probability of loss of load is then calculated by a convolution of the two models. A summation of the period indices provide annual indices such as Loss of Load Expectation in days (LOLE) or Hourly Loss of Load Expected (HLOLE) in hours per year [13]. Additional reliability indices which can be computed are Frequency and Duration (F&D) of loss of load, Expected Loss of Load (XLOL) and Expected Energy Not Served (EENS) [14].

The **Bulk Power System** on the other hand encompasses major generation plants and the transmission system which allows transportation of power from these plants to major load supply points. In contrast to generation system reliability, bulk power system reliability focuses on the evaluation of load point indices. In order to compute load point indices it is necessary to recognise the limitations imposed on power transfer from generation to load points. In addition it is necessary to recognise that the very existence of the bulk power transmission system makes it possible for a disturbance in one portion of the system cause a widespread power failure [15].

Transmission station and substation reliability can be measured by the frequency and duration of substation related outage events, particularly the simultaneous outage of two or more circuits (lines, cables or transformers) connected to the substation. Such events may for instance be caused by faults on substation equipment or failure of a breaker to clear a fault.

The reliability assessment of a **Distribution System** is usually concerned with the system performance at the customer end, i.e. at the load points [16]. The basic indices normally used to

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[13] S. Fockens, A. Van Wijk, W. Turkenburg, "Calculating the Expected Unserved Energy in Generating Systems using the Concept of Mean Capacity Outage", Probabilistic Methods Applied to Electric Power Systems, Proceedings of the 3rd International Conference, 3 – 5 July 1991, Savoy Place, London, pp. 9-14

[14] M. P. Bhavaraju, "Generation System Reliability Evaluation", IEEE Tutorial Course, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854

[15] N. D. Reppen, "Bulk Power System Reliability Evaluation", IEEE Tutorial Course, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854

[16] R.N. Allan, R. Billinton, I. Sjarief, L. Goel, K.S. So, "A Reliability Test System for Educational Purposes – Basic Distribution System Data and Results", IEEE Transactions on Power Systems, Vol. 6, No. 2, May 1991, pp. 813 - 820

predict the reliability of a distribution system are load point failure rate, average outage duration and annual unavailability.

The focus of this document with regard to reliability assessment is on the sub-transmission portion of a typical power system. This includes the bulk power system, transmission stations and substations.

1.3 LITERATURE STUDY

Within the introduction the objective has been set for power system planners to economically minimise the effect of network disturbances on customers connected to a specific supply area. With this objective in mind a literature study is conducted, bearing in mind the following questions:

- What techniques exist to evaluate bulk power system reliability?
- How does a specific level of reliability relate to customer perception of power availability?
- What norms exist to evaluate different network alternatives in order to establish "appropriate" network reliability?

The world-wide economic, social and political climate in which the electric power supply industry operates has changed significantly during the last few decades. In the period between 1945 and the end of the 1950's, planning for the construction of generating plant and facilities was basically straightforward. Plant construction was relatively uncomplicated, lead times were relatively small and costs were relatively stable [9]. This situation changed in mid-1970. Inflation and the huge increase in oil prices created a rapid increase in consumer tariffs and fluctuating growth patterns. Their combined effects introduced considerable uncertainty in predicting future demand and the construction of future facilities. One very important outcome of this economic situation was that the electric power supply industry was scrutinised very closely by many different organisations and individuals [10]. The industry is capital intensive and plays a major role in the economic and social well being of a nation. This was the background upon which present

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[9] William M. Smith, "Utility Planning Perspective: A Review", IEEE Transactions on Power Systems, Vol.4, No.2, May 1989, pp 452-456

[10] Enriue O. Crousillat, Péter Dorfner, Pablo Alvarado, Hyde M. Merrill, "Conflicting Objectives and Risk in Power System Planning", IEEE Transactions on Power Systems, Vol.8, No.3, August 1993, pp 887-893

reliability techniques and concepts were developed, utilised and scrutinised especially in North America and Canada [11].

The need for probabilistic evaluation of system behaviour has been recognised since at least the 1930's. It is only in fairly recent times however that quantitative reliability evaluation techniques have become an accepted technique in power system applications. The former Application of Probabilistic Methods (APM) Subcommittee of the IEEE has been active in research and educational aspects of electric power system reliability evaluation and presented its first tutorial on this subject in 1971 [12].

The basic concepts illustrated in the first tutorial are still valid and in use today [2].

1.3.1 Adequacy and Security

Power system reliability is a wide concept and the criteria for the assessment of bulk power system or sub-transmission system reliability can be divided into two classes:

- Adequacy, and
- Security [11 15].

Adequacy comprises of the steady-state or post-outage analysis while security comprises of analysis of critical dynamic conditions. Adequacy assessment may be subdivided into system problems such as overload of components and voltage limit violations. Similarly, security assessment may be divided into instability, overload cascading and voltage collapse. Generally, five system states are defined to describe system operation conditions: normal, alert, emergency, extreme emergency and restorative states. When the bulk power system operating conditions have changed, security calculations capture the system's current state from its original state using

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[11] R. Billinton, R. Allan, "Reliability Assessment of Large Electric Power Systems", Kluwer Academic Publishers, Boston/Dordrecht/Lancaster, 1988, ISBN 0-89838-266-1

[12] R.N. Allan, " Basic Concepts in Reliability Evaluation", IEEE Tutorial Course, Power System Reliability Evaluation, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854, 1982, pp. 5-13

[2] M. Th Schilling, R. Billinton, A.M. Leite de Silva, M.A. El-Kady, "Bibliography on Composite System Reliability", IEEE Transactions on Power Systems, 4, No.3, 1989, pp.1122-1132

[11] R. Billinton, R. Allan, "Reliability Assessment of Large Electric Power Systems", Kluwer Academic Publishers, Boston/Dordrecht/Lancaster, 1988, ISBN 0-89838-266-1

[15] N. D. Reppen, "Bulk Power System Reliability Evaluation", IEEE Tutorial Course, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854

a probability method. A framework for the evaluation of security constraints was developed by the University of Saskatchewan, Canada, [19] taking into consideration the different network states and providing a security index called the Composite System Operating State Risk (CSOSR). This index however only provides probability values and does not incorporate load information. The University of Chongqing, China, developed an expansion on this model. A method that searches for the min-cuts with maximum flow was used and a set of load loss indices developed [20]. The concept of min-cuts will be dealt with in subsequent paragraphs.

In terms of impact on service reliability, adequacy deficiencies may result in partial load curtailment while security deficiencies may result in wide spread interruptions or total system shutdown – blackout. The more popular criteria used by utilities in the assessment of power system reliability is adequacy [17], although security assessment poses a significant concern with bulk power system planners in North America [31].

Many different programs have been developed for the evaluation of adequacy assessment, of which some are listed below:

- MECORE: comprises a composite system reliability evaluation tool that was developed by B.C. Hydo, Canada [24]. In this reference the application of the program is provided on the metropolitan North Vancouver System in Canada,
- COMREL: another composite system reliability evaluation tool developed by the University of Saskatchewan, Canada [25]which is used in the reference to assess the reliability cost/worth, associated with non-utility generation facilities in the IEEE-Reliability Test System,

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[19] R. Billinton, M.E. Khan., "Security Considerations in Composite Power System Reliability Evaluation," PMAPS, 3-5 July 1991, IEE, Savoy Place, London WC2R 0BL, pp 58-63

[20] Sun Xiaohui, Zhou Jiaqi, Sun Hongbo., "Operating Risk Assessment of Composite Systems", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[17] A.M. Leite da Silva, J. Endrenyi, L. Wang, "Integrated Treatment of Adequacy and Security in Bulk Power System Reliability Evaluation", IEEE Transactions on Applied Superconductivity, Vol. 3, No. 1, March 1993, pp. 275-282

[31] M.P. Ehavaraju, R. Billinton, N.D. Reppen, P.F. Albrecht., "Requirements for Composite System Reliability Evaluation Models", IEEE Transactions on Power Systems, Vol. 3, No. 1, February 1988, pp. 149-155

[24] W. Li, F.P.P. Turner., "Development of Probability Transmission Planning Methodology at BC Hydro", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[25] R. Billinton, S. Adzanu., "Reliability Cost/Worth Assessment of Non-Utility Generation in Composite Generation and Transmission Systems", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

- TPLAN: a composite system reliability program developed by Power Technologies, Inc, Schenectady NY [26],
- CARE: developed by the University of Chongqing, China [27], and
- FYPREL: which incorporates weather conditions in the basic system failure mode analysis, developed in Singapore [28].

Most recognised programs use the IEEE test set for benchmarking purposes during the development stages [23].

1.3.2 Indices

Reliability indices are numerical parameters which provide quantitative measures of reliability or upper bounds on unreliability, i.e. annual expected energy not supplied or annual minutes of interruption of system load [30]. The basic adequacy indices [18] for composite systems reliability assessment can be provided through three fundamental attributes:

- Frequency of events, (e.g. the frequency of a circuit overload = 0.5 events / year),
- Duration of events, (e.g. the duration of a circuit overload = 6.5 hours / year), and
- Severity of events (e.g. how does this event impact on load curtailment).

Event probabilities may be derived from the frequency and the average duration of the events.

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[26] X.Y. Chao., "Probabilistic Planning and Applications at the Competitive Age", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[27] Zhou Jiagi, Huang Zhiqiang, Sun Hongbo., "Interactive Graphic User Interface for Reliability Evaluation", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[28] L. Goel, R. Gupta., "User-friendly Software for the Reliability Assessment of Electric Sub-Transmission Systems", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[23] M. Th Schelling, C.R.R. Dornellas, J.C.O. Mello, A.C.G. Mello., "Assessment of the New IEEE Reliability Test System", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[30] R.J Ringlee, P. Albrecht, R.N. Allan, M.P. Bhavaraju, R. Billinton, R. Ludorf, B.K. LeReverend, C. Signh, J.A. Stratton, "Bulk Power System Relaibility Criteria and Indices Trends and Future Needs", IEEE Transactions on Power Systems, Vol. 9, No. 1, February 1994, pp. 181-181

[18] IEEE Working Group Report, "Reliability Indices for use in Bulk Power Supply Adequacy Evaluation," IEEE Transactions on Power Aparatus and Systems, Vol. 97, No. 4, pp. 1097-1103, July/August 1978

The three basic indices may further be differentiated into [21]:

- system problems,
- system state indices, and
- load curtailment indices.

These indices form the basis of the evaluation of different contingency events on a network. The most commonly used load curtailment indices are probabilistic criteria such as LOLE (Loss of Load Expectation) and EUE (Expected Unserved Energy) [33]. Additional load curtailment indices are LOLP (Loss of Load Probability), LOLF (Loss of Load Frequency) and LOLD (Loss of Load Duration), as used in generation and transmission expansion planning in Brazil and Australia [34 38]. These indices are also used as the basis for damage cost calculations in countries such as Thailand and the UK [55 49].

1.3.3 Reliability Assessment Methods

Adequacy evaluation of a composite system can be performed in a variety of ways. The two most concurrent and independent streams of activity with regard to composite system reliability evaluation appears to have been initiated in Europe and North America during the late 1960's. These approaches are fundamentally different and with subsequent development have become

[21] R.N. Allan, "Bulk System Reliability – Predictive Indices," IEEE Transactions on Power Systems, Vol. 5, No. 4, November 1990, pp. 1204-1211

[33] Arun P. Sanghvi, Neal J. Balu, Mark G. Lauby, "Power System Reliability Planning Practice in North America," IEEE Transactions on Power Systems, Vol. 6, No. 4, November 1991, pp. 1485-1492

[34] A.M. Leita da Silva, G. Perez A, J.W. Marangon Lima, J.I. Perez A, J.C.O.Mello, "Expansion Planning of Generation Systems Based on Loss of Load Costs", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[38] A. Cook, I. Rose, "A Monte Carlo Technique for Computing the Benefit Arising from Interconnection of Power Systems", IEEE Transaction on Power Systems, Vol. 8, No. 3, August 1993, pp. 873-878

[55] B. Eua-Arporn, "A Calculation of Interrupted Energy Assessment Rate Using System Performance Data", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[49] R.N. Allan, K.K. Kariuki, "Customer Outage Costs and Their Application to the UK Electricity Supply Industry", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

known as the Monte Carlo and the Contingency Enumeration methods respectively [22]. The *contingency enumeration method* systematically selects and evaluates contingencies that may cause system failure for one or more pre-contingency conditions. The *Monte Carlo simulation method* on the other hand uses random sampling to determine both the pre-contingency conditions and the contingencies to be evaluated.

1.3.3.1 Contingency Enumeration Process

The fundamental procedure for contingency enumeration comprises three basic steps [29]:

1. Systematic selection and evaluation of contingencies,
2. Contingency classification according to predetermined failure criteria, and
3. Compilation of appropriate predetermined adequacy indices.

The relationships of these basic elements are shown in Figure 1.2. [I1]

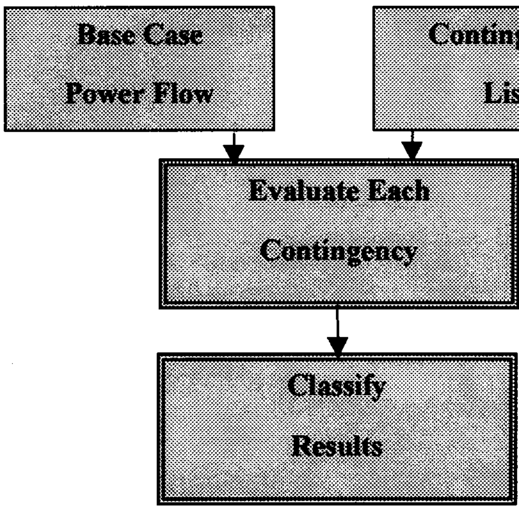

Figure 1:2 Fundamental Contingency Enumeration Process

[22] J.C.O. Mello, A.C.G. Melo, S.P. Rome, G.C. Oliveira, S.H.F. Cunha, M.V.F. Pereira, M. Morozowski, R.N. Fontoura, "Development of a Composite System Reliability Program for Large Hydrothermal Power Systems – Issues and Solutions," PMAPS, 3-5 July 1991, IEE, Savoy Place, London WC2R 0BL, pp. 64-69

[29] R. Billinton, "Composite System Adequacy Assessment – The Contingency Enumeration Approach,"

[I1] R. Austria, Power Technologies, Inc., http://www.pti-us.com/pti/consult/reliab/web2/continge.htm

The contingency enumeration process consists of the systematic selection, evaluation and classification of outage contingencies according to predetermined failure criteria [31]. The outage contingency level is pre-specified in order to minimise the computational requirements. Furthermore, corrective or remedial actions such as generation rescheduling in order to alleviate capacity deficiencies or line overload conditions that may be associated with certain outage contingencies, form part of the evaluation process [22]. The two software programs TPLAN [26] and COMREL [25] mentioned in section 1.3.1. typically follows this process.

Various techniques, depending on the adequacy criteria employed and the intent behind contingency studies, are available for use in the analysis. The three basic analytical techniques are [29]:

1. Network flow methods,
2. DC load flow methods, and
3. AC load flow methods.

1.3.3.2 Monte Carlo Simulation

The difference between the analytical and simulation approach is the way in which the reliability indices are evaluated. Analytical techniques represent the system by means of a mathematical model, which is often simplified and evaluate the reliability indices of this model using direct mathematical solutions.

Simulation techniques, on the other hand, estimate the reliability indices by simulating the actual process and random behaviour of the system. The method therefore treats the problem as a series

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[31] M. P. Ehavaraju, et.al., "Requirements for Composite System Reliability Evaluation Models," IEEE Transactions on Power Systems, Vol. 3, No. 1, February 1988, pp. 149-155

[22] J.C.O. Mello, A.C.G. Melo, S.P. Rome, G.C. Oliveira, S.H.F. Cunha, M.V.F. Pereira, M. Morozowski, R.N. Fontoura, "Development of a Composite System Reliability Program for Large Hydrothermal Power Systems – Issues and Solutions," PMAPS, 3-5 July 1991, IEE, Savoy Place, London WC2R 0BL, pp. 64-69

[26] X.Y. Chao., "Probabilistic Planning and Applications at the Competitive Age", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[25] R. Billinton, S. Adzanu., "Reliability Cost/Worth Assessment of Non-Utility Generation in Composite Generation and Transmission Systems", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[29] R. Billinton, "Composite System Adequacy Assessment – The Contingency Enumeration Approach,"

of real experiments conducted in simulated time. It estimates probability and other indices by counting the number of times an event occurs [32].

The utilisation of Monte Carlo Simulation techniques in reliability evaluation has increased considerably with the advent of high-speed digital computers. When compared to analytical techniques, results obtained from simulation methods give acceptable expected reliability indices which can be used to provide information on the reliability distributions associated with the predicted indices [35]. These simulation techniques are now applicable to a wide range of reliability assessment conditions [36 37 38].

Most of the applied literature encountered, report on the use of a contingency enumeration process for the assessment of adequacy in composite systems. This is due to the computation time required to simulate large networks. From the literature it is however evident that research in the field of Monte Carlo simulation on composite systems is on the increase. If little detail with regard to historic performance of a specific network is available, evaluating future reliability becomes difficult. This problem can partly be overcome if network reliability is assessed through Monte Carlo simulation and one can expect more use of Monte Carlo simulation on composite systems in the future.

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[32] Roy Billinton, Ronald Allan, "Reliability Evaluation of Engineering Systems", Plenum Press, New York and London, 1992

[35] L. Goel, R. Billinton, "Monte Carlo Simulation Applied to Distribution Feeder Reliability Evaluation", ELSEVIER, EPRI, (29 (1994) 193-202

[36] C.C. Mera, C. Sigh, "A sequential Monte Carlo Simulation Model for Composite Power System Reliability Evaluation", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[37] A.A. Chowdhury, P.T. Fung, N.D. Reppen, "System Capacity Reliability Assessment using a Monte Carlo Based Local Area Approach", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[38] A. Cook, I. Rose, "A Monte Carlo technique for computing the benefits arising from the interconnection of power systems", IEEE Transactions on Power Systems, Vol. 8, No. 3, August 1993

1.3.4 Substation Reliability Assessment

Substations and Switching stations are usually modelled as simplified equivalents within the composite system model. Substations consist of a variety of components, such as generators, lines, busses, transformers, circuit breakers, disconnect switches, current and voltage transformers and some auxiliary equipment.

A decoupled approach is followed whereby the probabilistic substation statistics are computed and then used to model the substation equivalent in the composite system. It is the overall reliability that is of concern, as simply maximising station reliability may not be the most cost effective approach in designing a power system. Substation reliability can be measured by the Frequency and Duration of substation related outage events. These events may be caused by failures of the sub-system supplying the station, faults on the substation equipment or failure of a breaker to clear the fault [39].

In contrast to composite system reliability that utilises load flow techniques in the contingency evaluation process, most station reliability methods check for continuity between the load outlet and at least one source outlet. This is done while considering the combinations of possible system states in which the station components could reside [40]. All station components can be in normal, fault, repair, or maintenance states. Additionally the switching components can be in a false trip or stuck states.

1.3.4.1 Reliability Evaluation of Basic Systems

Many systems are either physical networks or can be represented as networks connecting components either in series, parallel or a combination of these [32].

A series systems is defined as a set of components which, from a reliability point of view, must all work for system success or only one needs to fail for system failure.

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[39] J. Endrenyi , "Station System Reliability Evaluation", IEEE Tutorial Course, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854, 1982

[40] T.K.P. Medicherla, M. Chau, R.E. Zigmund, K. Chan, "Transmission Station Reliability Evaluation", IEEE Transactions on Power Systems, Vol. 9, No. 1, February 1994, pp. 295-301

[32] Roy Billinton, Ronald Allan, "Reliability Evaluation of Engineering Systems", Plenum Press, New York and London, 1992

A parallel systems on the other hand is defined as a set of components for which, from a reliability point of view, only one needs to work for system success or all must fail for system failure.

From basic probability laws the probability of system success for a series or parallel system can easily be obtained. Furthermore, the sequential reduction of complicated configurations can be achieved by combining appropriate series and parallel branches of the reliability model until a single equivalent element remains. The same simple reliability laws can then be applied to obtain system success or failure.

1.3.4.2 Reliability Evaluation of Complex Systems

Most other systems, such as substations, are not as simple and there are a number of techniques which can be used to solve these systems. Two of the most prominent methods used to solve this type of network are the conditional probability method and the minimal cut set analysis.

The conditional probability method involves the sequential reduction of the system into subsystem structures that are connected in series/parallel and then to recombine these subsystems using the conditional probability concept. This concept can be illustrated as:

P (system success or failure) =

P(system success or failure given component X is good). P (X is good) +

P (system success or failure given component X is bad).P(X is bad) (1.1)

The minimal cut set method, on the other hand, is a powerful tool for evaluating the reliability of systems and is the basis for most network evaluation methods [13].

A minimal cut set is defined as a set of system components which, when failed, cause failure of the system but when any one component of the set has not failed, does not cause system failure, i.e. all components of a minimal cut set must be in the failure state to cause system failure.

From the definition of minimal cut sets it can be seen that the components of each cut set are effectively connected in parallel and the failure probabilities of the components in the cut set may be combined using the principle of parallel systems.

[13] R.N. Allan, R. Billinton, M.F. Oliveira, "An efficient algorithm for deducing the minimal cut and reliability indices in a general network configuration", IEEE Transactions on Reliability, R-25, 1976, pp. 226-233

1.3.4.3 Frequency and Duration Techniques

Apart from evaluating the system state probability, availability and unavailability, it is essential in substation reliability analysis to evaluate additional reliability indices such as the frequency of encountering a state and the average duration of residing in that state [41]. The basic concept associated with the frequency and duration technique is best described in terms of the single

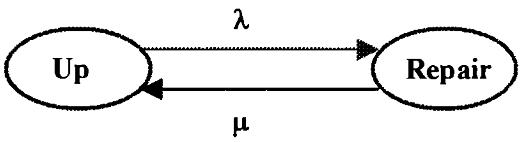

Figure 1:3 Single Component System

repairable system of which the state space diagram is shown in Figure 1:3.

The probability of residing in the operable state (availability) and the probability of residing in the failed state (unavailability) is thus of interest when calculating the overall reliability of the system [42].

1.3.4.4 Modelling Circuit Breakers

In many applications, as with the simple model, a typical component life history is assumed to consist of two alternating states, namely working and failed. Switching devices however provide for an added degree of complexity. The most complex of these switching devices is a circuit breaker. Circuit breakers are unlike most other components in that they can develop several kinds of failures that may need to be considered [39]. Three failure modes that are particularly prominent are: ground faults, failure to operate and false operation. As a further complication, a failure to operate is a hidden type which manifests itself only if the need for operation arises. Since breaker failure to operate is dependent on the failures of components protected by the breaker, a breaker model must include the states of such components. An improved 4-state model to enable the

[41] A.C.G Melo, M.V.F. Pereira, A.M.Leite da Silva, " A Conditional Approach to the Calculation of Frequency and Duration Indices in Composite Reliability Evaluation", IEEE Transactions on Power Systems, Vol. 8, No.3, August 1993, pp.1118-1125

[42] TPLAN User's Guide: Substation Reliability Assessment Add-on Module: Power Tecnologies, Inc, pp.30-49

[39] J. Endrenyi , "Station System Reliability Evaluation", IEEE Tutorial Course, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854, 1982

modelling of circuit breakers was developed by Yongji and Yuhong at the University of China [56]. With this model different pre-fault, fault and post-fault states for scheduled maintenance and fault conditions can be analysed. Software was further developed and conditional probability theory was applied to evaluate the probability of each system state.

1.3.4.5 Failure Effect Analysis

The Failure Effects Analysis (FEA) and the calculation of system reliability indices in station system evaluation can, to a large extent, be computerised. Most of the computer programs that have been written account for the effect of switching after faults, the various breaker failure modes and component maintenance. Most of these algorithms are based on the minimal cut states.

[56] Gou Yongji, Guo Yuhomg, "Station and Substation System Reliability Evaluation Considering Dependant Failures", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

1.3.5 Reliability Cost/Worth

Establishing the reliability of a system only provides part of the solution. In Value-based planning, assessment of the cost of maintaining a certain level of reliability or making incremental reliability improvements include not only the facilities' cost of providing such reliability, but also the customer interruption cost [37]. The Value-based planning approach incorporates reliability in the costing process by comparing overall cost including the societal costs of unreliability [45]. This approach uses subjective and objective measures of customer monetary losses arising from electric energy supply curtailment. The Expected Energy Not Supplied (EENS) is usually used as an index to link system unreliability with reliability worth [46]. The unit cost of losses due to energy not supplied is a composite parameter formed from the various classes of customers affected by a given interruption. Considerable work has been done to develop procedures for assessing customer monetary losses due to electrical supply failures and there is a wide range of available literature [48 3 50].

The Value-based plan is thus the resource plan that minimises the total cost of electric service over the planning horizon. From a social perspective, the total cost of electric service is given by:

$$C_{Total} = C_U + C_C \tag{1.2}$$

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[37] A.A Chowdhury, P. T. Fung, N.D. Reppen, "System Capacity Reliability Assessment using a Monte Carlo Simulation Bases Local Area Approach", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[45] R. Billinton, "Evaluation of Reliability Worth in an Electric Power System", Relaibility Engineering and System Safety 46 (1994) pp. 15-23

[46] Shams N., Martin L. Baughman, "Value-based Transmission Planning and the Effect of Network Models", IEEE Transactions on Power Systems, Vol. 10, No. 4, November 1995, pp. 1835 - 1841

[48] G. Wacker, R. Billinton, "Interruption Cost Methodologies and Results – A Canadian Residential Survey", IEEE Trans. Power Apparatus Systems, Vol. PAS-102, No.10, pp. 3385-3392, October 1983

[3] G. Tollefson, R. Billinton, G. Wacker, "Comprehensive Bibliography on Reliability Worth and Electric Service Consumer Interruption Cost 1980-1990", IEEE Trans. Power Systems, 6(4), 1991, pp. 1508 –14

[50] Karen Guziel, A. Yakushau, "Reliability and Cost Analysis of the Balarus Electricity System Expansion Plan Options", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

Where:

C_U = the cost associated with serving the load, such as capital investment expenditure and production cost to supply energy. This includes the fixed cost and variable cost for both demand-side and supply-side solutions, and

C_C = the cost incurred by customers when the utility is unable to meet their demand. Typical examples include food spillage, loss of leisure activities for residential customers or loss of production for industrial customers [51].

The total cost of supplying electricity is thus the sum of system cost and customer outage cost. The lowest point on the total cost curve defines the optimal balancing of system cost and customer cost and determines the optimal reliability level [52]. The ideal case is shown graphically in Figure 1.4.

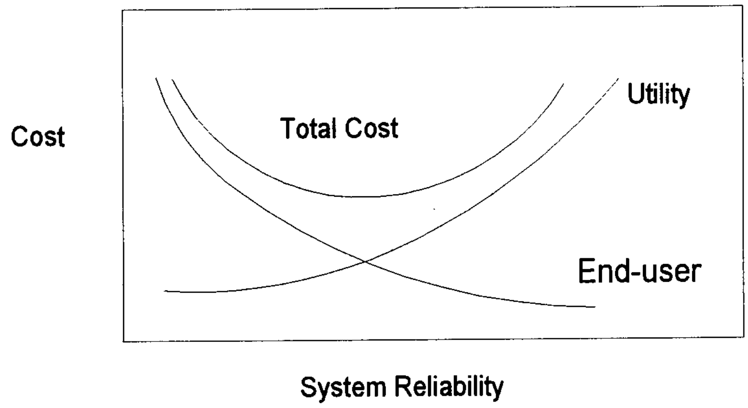

Figure 1:4 The Variation of Cost as a Function of Reliability

1.3.5.1 Customer Damage

To populate the cost curve on the utility side is relatively straightforward. The challenge lies within establishing the customer cost curve. Actual or perceived cost of interruptions can be utilised to determine the benefit or worth of reliability through a variety of approaches. The most

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[51] S. Burns, G. Gross, "Value of Service Reliability", IEEE Trans on Power Systems, Vol. 5, No. 3, August 1990, pp. 825- 830

[52] A. Sanghvi, N. Balu, M. Lauby, " Power System Planning Practises in North America", IEEE Trans on Power Systems, Vol. 6, No.4, November 1991. pp. 1485-1491

excepted approach is through a customer survey whereby the cost of a service interruption is obtained as a function of interruption duration. The interruption cost (R/kW) is a function of the customer categories and varies with the sensitivity of customers to network disturbances and the type of plant or process that it runs. A paper industry will for instance have a greater loss (production, raw material, man-hours and equipment) as a result of a power interruption than would a handyman practising woodcraft.

The data that is obtained through a customer surveys is compiled to formulate a Sector Customer Damage Function (SCDF) which presents the interruption cost of each customer sector as a function of the interruption duration [53]. A hypothetical SCDF is shown in Table 1.1.

Table 1.1: Sector Customer Damage Function (R/kW)

User Class	1 min	20 min	1 hour	4 hours	8 hours
Sector 1	0.005	0.10	0.60	5.20	15.00
Sector 2	0.80	3.40	5.20	20.00	29.50
Sector 3	0.90	5.30	16.50	58.00	150.00

If the intention is to analyse a system supplying a range of different customer sectors, within a supply area, it is necessary to obtain the contribution of each sector to the total Damage Function of that area. To evaluate the damage of an outage occurring at any service area in the system, the Composite Customer Damage Function (CCDF) is calculated. This is done through the weighting of sector interruption costs (shown in Table 1.1) in proportion to their respective demand and energy utilisation (shown in Table 1.2) within the area.

Table 1.2: Distribution of Energy and Peak Demand

User Class	Energy (%)	Peak Demand (%)
Sector 1	31	34
Sector 2	19	14
Sector 3	50	52

[53] Garry Wacker, Roy Billinton, "Customer cost of Electric Service Interruptions", Proceedings of the IEEE, Vol. 77, No. 6, June 1989, PP. 919- 929

Weighting by the annual peak demand is used for short duration interruptions and weighting by the energy consumption is used for interruptions longer than one hour. These weighted costs are then summated to provide the total cost for the area for each specified duration. The variation of this total cost with duration is considered to be the CCDF for the service area. Table 1.3 shows the CCDF calculated from the hypothetical SCDF and the weights in Table 1.2.

Table 1.3: Composite Customer Damage Function

Duration	1 min	20 min	1 hour	4 hours	8 hours
R/Kw	0.60	3.33	9.53	34.73	87.23

The broadest application of a customer damage function is its use to relate the composite customer losses to the socio-economic worth of electric service reliability for an entire utility service area [57]. The cost estimates can be obtained by multiplying the EENS to customers due to interruptions by a suitable factor, designated as the Interrupted Energy Assessment Rate (IEAR) expressed in R/kWh.

Many utilities world wide currently invest resources to obtain utility specific CDF's and associated IEAR's. This is essential if planning proposals needs to be evaluated along Value-based principles. Countries worth mentioning in this regard are Canada [47], the UK [49], Australia [54], Thailand [55] and Utilities in the USA. These utilities or research centres follow similar processes to assess CDF's.

[57] Li Wenyuan, R. Billinton, "A Minimum Cost Assessment Method for Composite Generation and Transmission System Expansion Planning", IEEE Trans. On Power Systems, Vol.8, No.2, May 1993, pp. 628-635

[47] G. Tollefson, R. Billinton, G. Wacker, "A Canadian Customer Survey to Assess Power System Reliability Worth", IEEE Trans. Power Systems, Vol. 9, No. 1, February 1994, pp. 443 - 450

[49] R.N. Allan, K.K. Kariuki, "Customer Outage Cost and their Application to the UK Electricity Supply Industry", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[54] M.E. Khan, M.F. Conlon, W. Mielczarski, M. Zaman., "Electrical Power Interruption Studies in Australia", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[55] B. Eua-Arporn, " A Calculation of Interrupted Energy Assessment Rate using System Performance Data", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

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1.4 MAIN OBJECTIVE

Traditional reliability criteria based on deterministic considerations will become increasingly difficult to apply in developing countries where budget constraints are on the increase [6].

Bulk system performance affects public values in direct, economic and indirect quality ways [51], which lead to the questions:

- What is an appropriate level of bulk system reliability?
- How may societal benefit of improved reliability be compared to the cost of achieving it?

Therefore:

THE MAIN OBJECTIVE OF THIS STUDY IS TO DEVELOP A METHODOLOGY TO ASSIST IN THE RECONFIGURATION AND EXPANSION OF AN ELECTRICAL SUB-TRANSMISSION NETWORK WITHIN THE FRAMEWORK OF VALUE-BASED PLANNING.

The specific objectives derived from the main objective are:

- to develop a Value-based framework for the evaluation of alternative sub-transmission network options,
- to quantitatively assess the reliability of the study network,
- to quantitatively assess the reliability of alternative network proposals,
- to evaluate the impact of existing and future network reliability on connected customers,
- to evaluate the alternative expansion options within the Value-based framework, and
- to make recommendations with regard to the Value-based methodology.

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[6] R. Billinton, M. Pankey, "Reliability Worth Assessment of Electric Power Systems in Developing Countries", Proceedings of the 5th International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, British Columbia, September 21-25 1997

[51] S. Burns, G. Gross, "Value of Service Reliability", IEEE Trans on Power Systems, Vol. 5, No. 3, August 1990, pp. 825- 830

1.5 CONCLUSION

From the literature the following can be concluded:

- The fundamental concepts for power system reliability assessment is well established ,
- Extensive reliability research has been done in North America, Canada and other parts of the world,
- Reliability worth assessment of sub-transmission networks in South Africa , which includes composite systems and substation systems, is non-existent,
- The availability of a reliable power supply at a reasonable cost is essential for the economic growth and development of a country,
- An opportunity exists for the development of a Value-based methodology to form part of standard expansion planning procedures on sub-transmission networks in South Africa.

Chapter 1 of this document dealt with the study problem identification and background with regard to composite system reliability assessment and Value-based evaluation concepts.

The remainder of this document will be divided into six chapters. Namely:

- Chapter 2, ***Background of Study Area***: Which will focus on the overview and technical definition of a real-world sub-transmission network,
- Chapter 3, ***Value-Based Planning Methodology***: This chapter will propose a methodology for the evaluation of alternative network options within value-based principles,
- Chapter 4, ***Base Case Modelling and Analysis***: Will report on the data requirements, modelling and analysis required to assess the reliability of the network provided in Chapter 2,
- Chapter 5, ***Case Study***: Provides the actual evaluation of alternative network options on a portion of the real-world network. This will be used to evaluate the methodology proposed in Chapter 3 and the data requirements and modelling procedures provided in Chapter 4,
- Chapter 6, ***Recommendations***: Will provide recommendations to this study, and
- Chapter 7, ***Conclusions***: Will provide conclusions to this study.

CHAPTER 2

2. BACKGROUND OF STUDY AREA

2.1 INTRODUCTION

The specific objectives identified in Chapter 1 will be applied to a practical sub-transmission network. This practical network will provide for a real world study area. The network chosen for this purpose is the sub-transmission network of the Greater Pretoria Metropolitan Council (GPMC). The annual load growth of this network is in the order of 3% with an expectation of load doubling within the next twenty years. At present deterministic planning criteria is used in the long-term expansion planning of this network, resulting in possible over- capitalisation of the network in certain areas. With the current financial constraints within the GPMC it is vital that a sound Value-based planning approach, which incorporate reliability worth concepts, be used in the medium to long-term network expansion planning.

2.2 OVERVIEW OF STUDY AREA

The GPMC supply area is served by three metropolitan substructures; Centurion to the South, Pretoria which forms the centre and Akasia to the North. The area covers approximately 1 276 km^2 and has in the order of 300 000 customers in total. This makes the GPMC, Eskom's fourth largest consumer with regard to energy consumption, with approximately 5 000 000 MWh consumed during 1998. The sub-transmission network, supplying the bulk energy to the metro consists of roughly 300 km, 132 kV overhead lines with 55 km, 132 kV underground cable. This network in turn, supplies 46, 132/11 kV distribution substations. Supply is imported via two 275 kV, two 132 kV and one 88 kV supply points. The 88 kV supply point feeds a relatively small 33 kV distribution area. These five supply stations, Kwagga, Njala, Rietvlei, Buffel and Mabopane, have firm installed capacities of 900 MVA, 500 MVA, 125 MVA , 60 MVA and 40 MVA respectively. The Metro further operates two coal-fired power stations, Rooiwal and Pretoria West, with full-load capacities of 300 MW and 120 MW respectively. The peak demand for this network during the winter of 1998 was 1 740 MVA.

2.3 TECHNICAL DEFINITION OF STUDY AREA

Over a period of approximately forty years the GPMC sub-transmission network has gradually developed from a small three-distribution station network to what it is today. Each substructure was historically responsible for its own network developments, which unavoidably led to subsequent network differences. The most prominent of these differences can be seen in the sub-system configurations with regard to feeder and substation configurations and their associated protection philosophies.

2.3.1 General Network Definitions

A simplified schematic diagram showing the electrical configuration of the GPMC sub-transmission network is provided in Appendix A.

2.3.1.1 General Configuration of Sub-systems

As can be seen from the schematic, the bulk of the network consists of redundant 132 kV transmission line feeders with 132/11 kV substation T-off's. Usually these substations do not have formal 132 kV busbars and consequently very few 132 kV feeder and transformer circuit breakers are present. Although possible, the network is not operated as a connected grid, but rather as radial feeders supplying these distribution substations from each Eskom supply station. Most of the traditional Pretoria sub-systems are configured in this manner. A portion of such a network is provided in Figure 2:1.

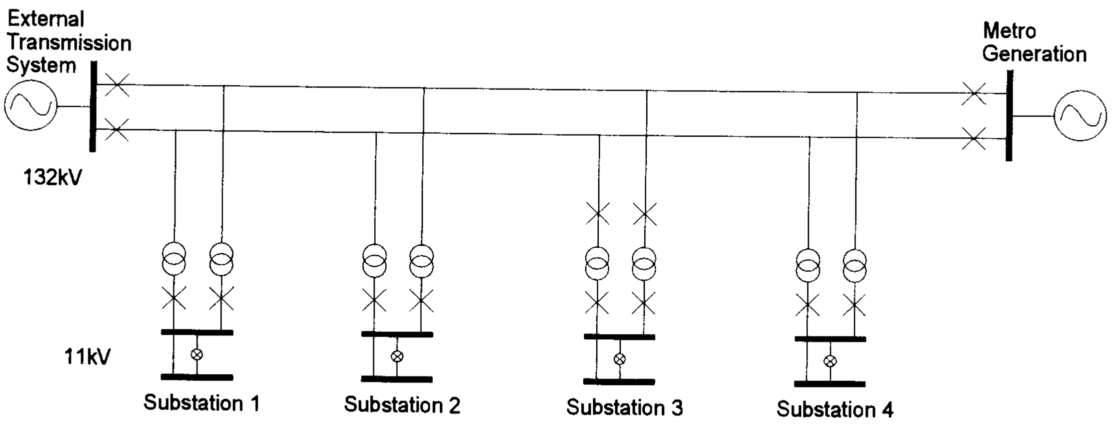

Figure 2:1 Simplified Portion of GPMC Sub-transmission Network (T-Off's)

The Centurion sub-system forms a moderate part of the GPMC network and is similar to the network provided in Figure 2:1. The difference however is that both 132 kV feeder and transformer circuit breakers are present.

The most prominent variation of the traditional network was the introduction of sub-systems commissioned after 1995. These networks are based on a full turn-in scheme, providing differential protection for each major element in the sub-system. A simplified single line diagram for a full turn-in scheme is shown in Figure 2:2.

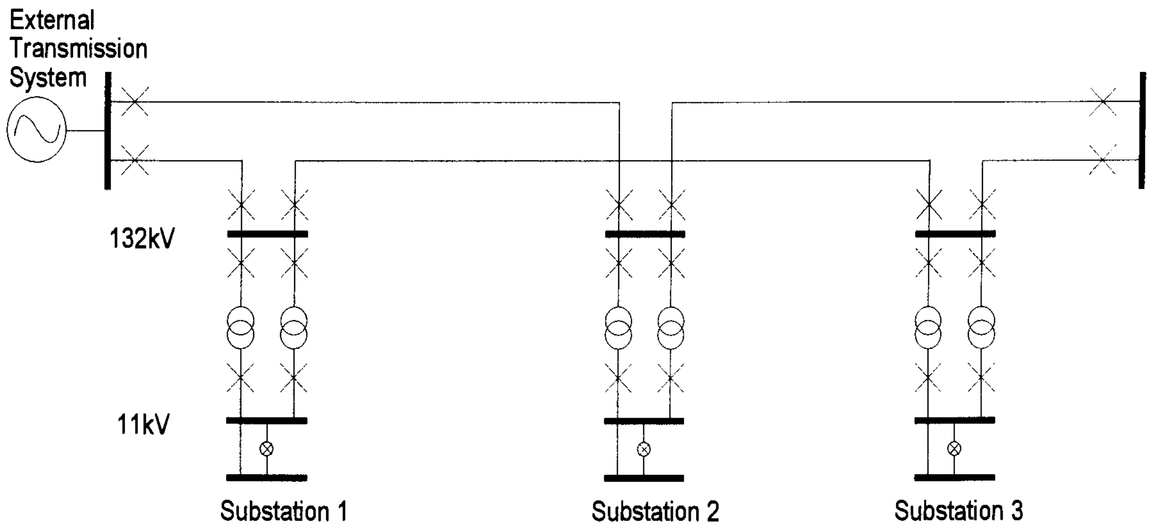

Figure 2:2 Simplified Portion of GPMC Network (Full Turn-in)

The full turn-in feeder configuration implies that the substation is supplied via alternative routes and that such a network should provide superior performance with regard to common-mode feeder failures (e.g. a lighting strike to transmission tower resulting in flashover of both lines).

2.3.1.2 Generation Scheduling

As mentioned earlier, the Metro has two coal fired generation stations which produces roughly 30% of the annual energy consumption. Due to the age of these stations, the cost and output price is increased at the rate of inflation each year. This is high compared to the increase in the electricity-purchasing price from Eskom, which is between 3-5% per annum. As a result of this relative margin, the Metro generation stations are mainly used as peaking plants and are scheduled accordingly. Pretoria West has 6x30 MW and Rooiwal 5x60 MW units. Due to these relative small unit capacities, the loss of a single unit at either one of these stations poses little risk from an adequacy point of view.

2.3.2 Substation Configurations

Apart from the different sub-system configurations, the GPMC network also consists of a number of different substation configurations. In total there are four different topological substation configurations, resulting in seven different substation configuration types. In turn the substation technology applied to these substations can be either indoor (i.e. outdoor equipment utilised indoors), outdoor or GIS (Gas Insulated Switchgear). Both the substation configuration and technology impacts on the substation maintenance, operation philosophy and reliability.

The most prominent substation configuration found on the GPMC network is shown in Figure 2:3: This substation is known as the redundant transformer configuration and is recognised for its redundant line feeders and transformers. This substation is normally found within the T-Off's sub-system as provided in Figure 2.1.

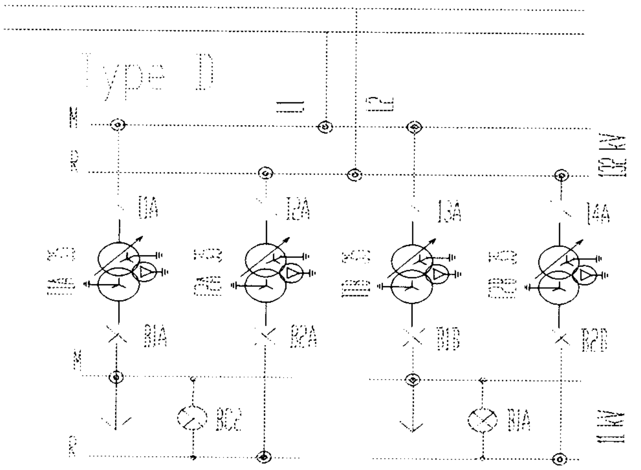

Figure 2:3 Redundant Transformer Substation Configuration

The load distribution on these substations are as shown, with the entire load supplied by transformers T1A and T1B via feeder L1, with T2A, T2B, and feeder L2 providing backup. Although shown in Figure 2.3 for modelling purposes, the substation has no formal HV busbar and the transformers are effectively connected to the HV supply feeder. There is in other words no HV separation point, such as automatic switchgear to isolate the substation in case of a feeder or transformer fault. This substation, if connected as the only station in the sub-system, provides in theory for a highly reliable supply at a relatively high capital cost. This is emphasised when considering a fully developed substation of this type which consist of three load transformers and three reserve or backup transformers. If however the substation is connected to a sub-system with adjacent stations of the same type, the overall reliability is decreased due to the lack of automatic separation point in the sub-system. It is evident from this configuration that the deterministic (n-1) criteria was strictly applied to the substation design.

An improvement on this configuration in terms of capital cost is the scheme known as the ARBC substation configuration. Substations of this configuration have mostly been constructed after 1995 and are found within the full turn-in sub-systems as shown in Figure 2:2. This configuration is shown in Figure 2:4.

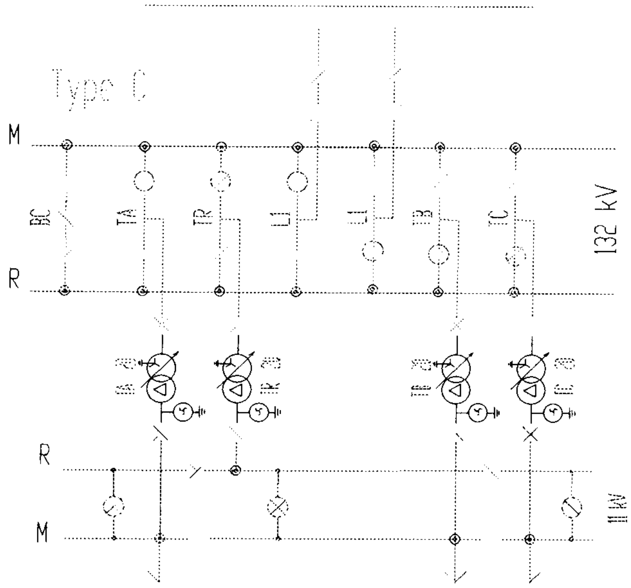

Figure 2:4 ARBC Substation Configuration

The load is supplied via transformers TA, TB and TC with transformer TR providing backup in the case of any transformer failure. This configuration provides for a multiple of automatic separation points that will result in the isolation of portions of the network during fault conditions. A direct spin-off of this scheme is that most failures resulting from one substation connected to a sub-system will be isolated from the remaining substations in the same sub-system. This will theoretically improve the reliability of the sub-system when compared to the configuration discussed in the previous example.

2.3.3 Normal Operation Aspects

The GPMC sub-transmission network is, under normal conditions, configured in such a manner that each supply station forms an island supplying energy to a number of distribution stations. Apart from the sub-systems with a full turn-in scheme, most distribution stations are thus supplied via radial feeders. In order to remain synchronised with the grid, Pretoria West generation station is connected to the Kwagga supply station, with Rooiwal being connected to either Kwagga or Njala. Normal network open points are as indicated on the simplified schematic diagram provided in Appendix A.

Some automatic corrective actions, involving network switching and load transfer actions exist on portions of the network and shall be addressed in the following paragraph. These actions are applied to specific sub-systems and no formal policy with regard to automatic reconfiguration of the grid is utilised. In the case of a widespread interruption within a specific island, network switching to restore power to the effected area is done via SCADA (Supervisory Control and Data Acquisition). This can result in tedious operations due to unreliable pilot wire communications from the control centre to some of the remote terminal units in the substations.

No formal load-shedding policy is followed and in the case of a contingency resulting in sustained overload conditions on specific circuits, these circuits are tripped without considering the load mix connected. The responsible application of a load-shed policy can lead to a decrease in annual unserved energy and an improvement in overall network performance.

2.3.4 Sub-system Protection Philosophy

The three different sub-system configurations discussed under 3.3.1. each have a unique feeder protection philosophy. The following feeder protection schemes form the basis of each philosophy:

- Impedance or distance protection with an automatic load transfer scheme,
- Feeder differential protection, which incorporates automatic load transfer under single transformer failures, and
- Basic Over-current Earth fault protection with Auto Re-close capability.

Impedance and differential protection are the most prominently used protection philosophies and are discussed in concept below.

2.3.4.1 Impedance Protection with Automatic Load Transfer

Impedance protection schemes are found on the T-Off sub-systems shown in Figure 3:1. The protection relay is basically set-up to detect a change in system impedance within a specific margin. A feeder fault impacts on the steady-state current and voltage of the system and thus on the impedance monitored by the relay. Three protection zones are typically monitored with each zone fault being cleared after a pre-set time lapse. These zones and associated pick-up times are as follow:

I. Zone 1: 80% of line length, trip signal ranging from 20 – 30 ms

II. Zone 2: 120% of line length, trip signal typically 250 ms

III. Zone 3: 200% of line length, trip signal typically 3 s

Impedance protection is usually implemented on long transmission feeders where communications between remote points are difficult. The application of this scheme within the Metro network poses two drawbacks.

- The first being that the Metro network consists of relatively short (average 20km) lines making accurate relay operation difficult.
- Secondly fault conditions between T-Off points cannot be isolated and results in the tripping of the complete feeder, thus loss of supply to all substations connected to the feeder.

After an interruption event the faulty feeder is inspected and re-energised when safe. This action, under certain conditions, may take up to several hours. In order to minimise customer losses an automatic load transfer action is initiated immediately after the supply feeder has tripped. The automatic load transfer is a sequence of events to transfer the load from any load transformer to the stand-by transformer, in the case where supply to the load transformer is lost. This scheme is applied to the redundant transformer substation configuration shown in Figure 2:3.

Figure 2:5 shows the typical protection devices that will operate in the automatic load transfer scheme under a line fault condition.

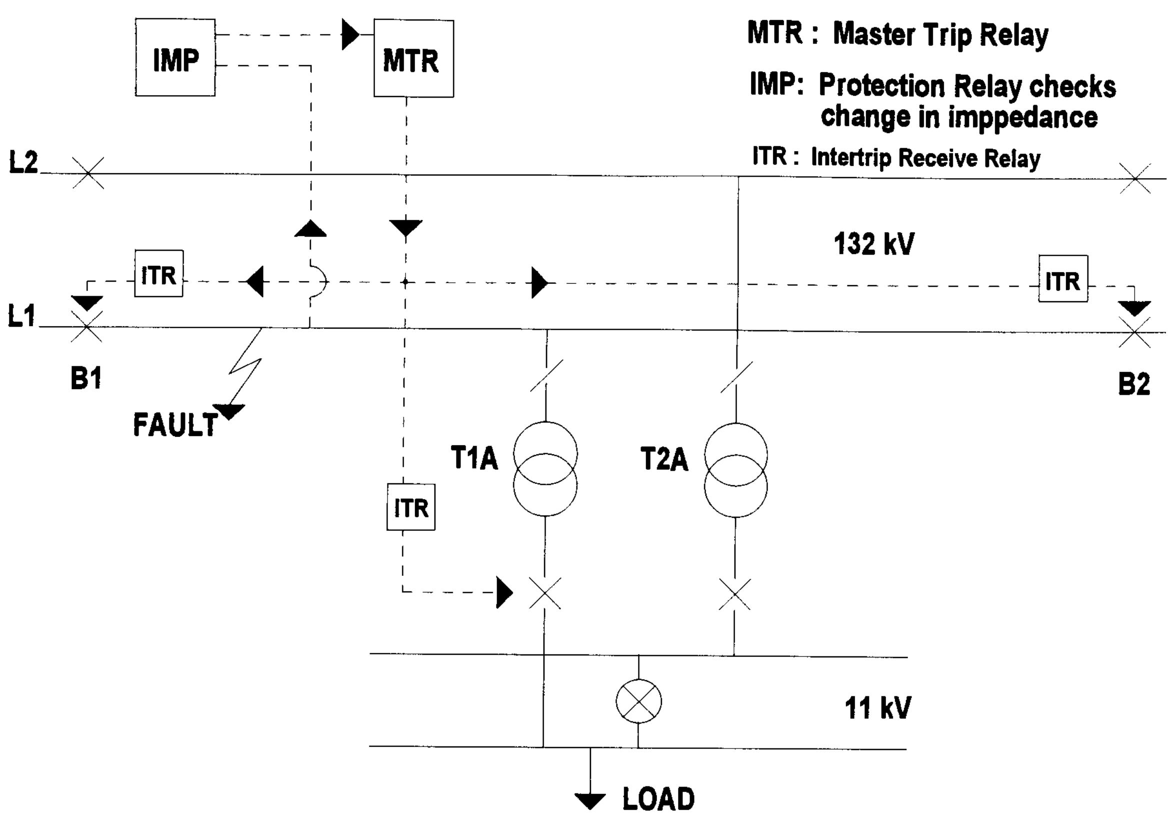

Figure 2:5 Automatic Load Transfer Scheme

The sequence of events is as follow:

I. The protection relay (IMP), in this case the impedance relay, detects the feeder fault and sends a trip signal to the Master Trip Relay (MTR), impedance

II. The MTR sends a trip signal to the 132kV line breaker B1 and the breaker trips,

III. The MTR simultaneously sends an intertrip signal to B2 and the T1A transformer 11kV circuit breaker. (This intertrip is sent to the line breakers at both ends of the line and to all 11kV transformer breakers of transformers connected to the line. This implies that a single line fault will result in the loss of supply to all transformers connected to the line).

IV. The intertrip receive relay (ITR) receives the intertrip signal and sends a trip signal to the relevant 11kV transformer breaker.

V. Five seconds after the 11kV transformer breaker has tripped, the 11kV bus coupler closes, which results in the transfer of load to the stand-by transformer.

2.3.4.2 Differential Protection

Differential protection, as its name implies, compares the currents entering and leaving the protection zone and operates when the difference between these currents exceeds a pre-determined magnitude. The scheme is also referred to as unit protection and is applied on the full turn-in sub-system discussed under 3.3.1. Due to the protection of each individual section of the sub-system, this scheme theoretically provides for a more reliable network than the impedance protection scheme in that smaller portions of the network are impacted upon during fault conditions.

Protection schemes, although secondary to the power system equipment configuration, impacts to a large extent on the overall reliability of a system as well as the capital investment in that system. It is for this reason important when assessing the reliability of a system, that the protection operations are modelled to an adequate degree.

2.3.5 Network Load Forecast

The long-term load forecast of the GPMC supply area forms the foundation on which the long-term network development plan is built. A Geographically based Load Forecasting (GLF) technique is used where land-use forecasts are required to establish the long-term electrical load. For this purpose the complete study area is subdivided into small geographical areas, referred to as load zones. Each load zone is defined in terms of two parameters namely:

- The customer composition, and
- Customer load profile.

Most of the time these load zones are not homogeneous and consists of a combination of land-use categories. The primary land-use categories are provided in Table 2.1. A unique identifier is allocated to the non-homogeneous load zone that defines the percentage allocation for each category as well as the load density per hectare for that particular load zone. As an example the Code 90A10H_72 will indicate that the load zone consist of a 90% Residential sector and 10% Educational sector with a load density of 72 kVA per hectare. In order to construct a yearly load profile for a specific zone, Weekday, Saturday and Sunday profiles for each customer sector is provide. Seasonal changes are catered for through a summer and winter profile.

Table 2.1: Primary Land-use Categories

Category	Code
Residential	A
Low Income Residential	AA
High Rise Residential	B
A.H. &Farming & Open Spaces	C
Business / Commercial	D
Industrial	E
Tertiary Education	G
Other Education	H
Other & Municipal & Government	I

A map presenting these zones for the GPMC is provided in Appendix B. The objective of the GLF is to determine the composition and load for each load zone and to project this load into the future. This provides an indication of growth in the existing customer base as well as system growth due to the addition of new load to the network. The prediction of load growth for a specific load zone is done in conjunction with town and regional planners. In addition to this economists calibrate the predicted land-use growth tempo against envisaged growth prospects.

In order to allocate and aggregate load zones to sub-transmission load points, a bottom up approach is used. This concepts is graphically shown in Figure 4.6:

Three different hierarchical levels are used. These levels are:

- Satellite substations,
- Distribution substations (such as shown in Figures 2.3 and 2.4), and
- Supply substations (sub-transmission load point).

Figure 2:6 provides a typical example of such an aggregation.

Load zones EA1 and EA2 is allocated to satellite Station 1, EA4 and EA7 is allocated to satellite Station 3 and zones EA3, EA5 and EA6 is allocated to satellite Station 2. The three satellite Stations are further allocated to load point Stage A of the distribution substation. Predicting the future growth for each zone thus provides an indication of growth at the sub-transmission load point level.

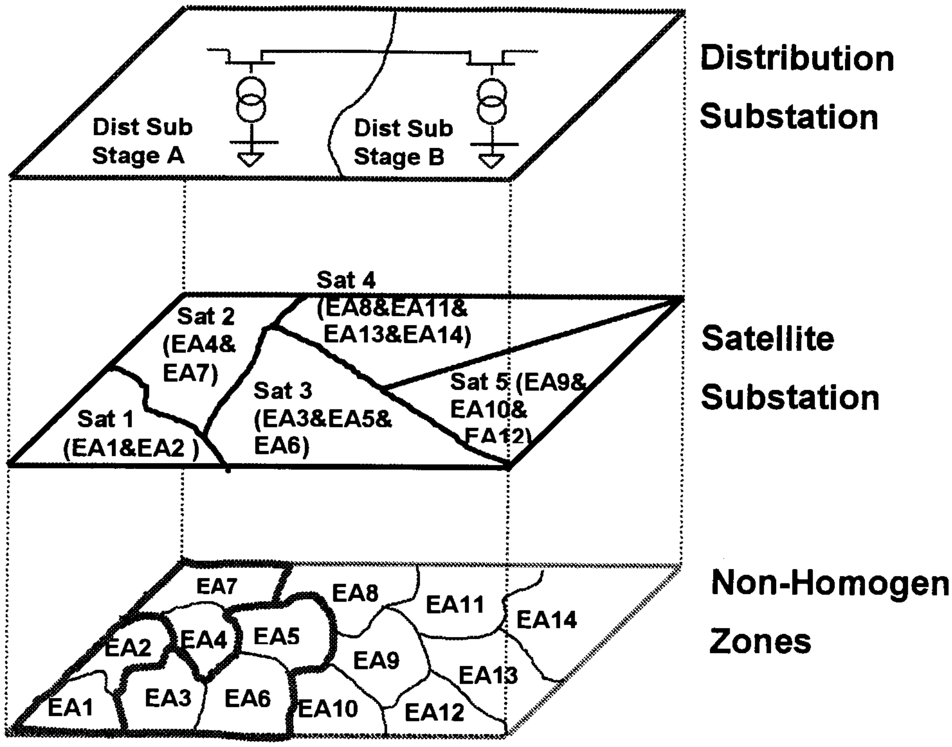

Figure 2:6 Foundation for Geographical Load Forecast

The load composition data for the total supply area becomes vital when the impact of network performance on the load mix at a specific load point are to be quantified (i.e. identifying the customer sectors and compiling a CCDF for a specific load point). In most cases this data is available for the existing network, but is often difficult to predict for the future networks. The GLF model provides a solution to this problem in that it identifies the composition of future load zones or supplies areas, in terms of the different customer sector and their associated load profile. The GLF data is thus not only valuable to plan for network capacity constraints alone but also to predicts customer damage as a function of future network performance. By utilising the data provided in the GLF the expected impact that the performance of future networks will have on future customers can be quantified. This approach can thus provide for a better understanding of future network needs.

2.4 CONCLUSION

This chapter provided a background for most of the fundamental technical issues of the network under study. Aspects which need to be taken into consideration when evaluating the development of this network within a Value-based framework is the following:

- To date, deterministic criteria was used as basis for network development that could result in over capitalisation,
- No clear consideration was given to the actual worth of the network in relation to the connected customers,
- Over a period of time, the influence of different parties in the development of the network lead to distinctive differences in sub-systems, substation configurations and protection philosophies,
- These differences provide some difficulties in the integration of the total system.

The following chapter, ***Value-Based Planning Methodology***, will propose a methodology for the evaluation of alternative network options within Value-based principles. This is done taking into consideration the background of the study area provided in Chapter 2.

CHAPTER 3

3. VALUE-BASED PLANNING METHODOLOGY

3.1 INTRODUCTION

In chapter 1, the main objective of this dissertation was identified as being the development of a methodology to assist in the reconfiguration and expansion of a sub-transmission network within the framework of Value-based planning. The network discussed in the previous chapter provides the bases for the application of such a methodology. The traditional deterministic planning criteria applied to such networks in South Africa have failed to consider, within an integrated framework, the utility's cost of providing a particular level of service reliability on the one side, and customer cost associated with that reliability level on the other side. Within that criteria no economic justification can be provided for changing levels of reliability for the utility and its customers. The methodology provided in this chapter presents an approach to be integrated into the overall planning process, which incorporates customer choices with regard to reliability "worth" and service cost. This methodology will impact on the way network alternatives are currently evaluated and in a practical sense, provide a quantitative measure for the adequacy of supply options.

3.2 BASIC PROCESS

The Value-based plan to achieve the objective, is the resource plan that minimises the total cost of electric service over the planning horizon of the network. The methodology can be presented in three phases. Namely:

- The identification of alternative network options,
  - These options typically emerge as a result of network expansion needs, refurbishment needs or performance deviations in the network.
- The evaluation of these options within a Value-based framework, and
- The proposal of a solution that complies with the Value-based criteria.

The simple block diagram identifying the basic phases is shown in Figure 3:1.

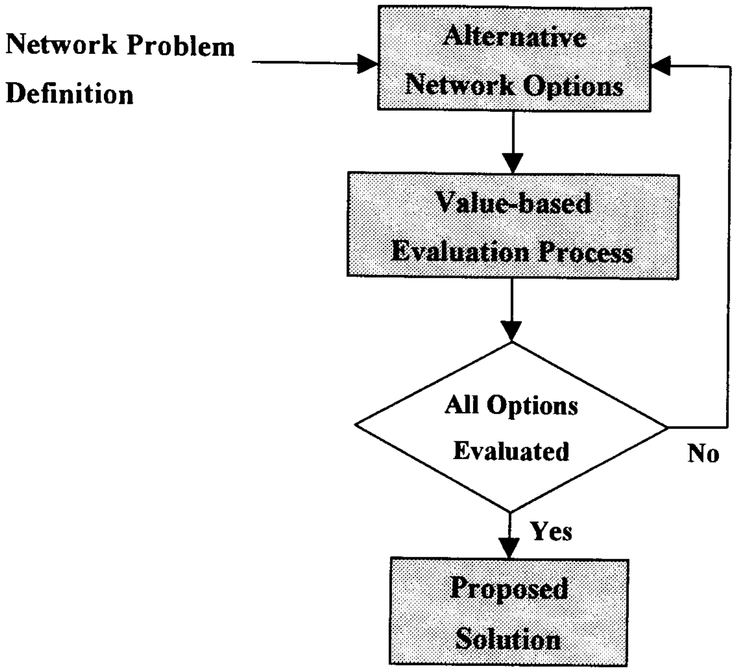

Figure 3:1 Basic Value-based Process

3.3 BASIC VALUE-BASED PROCESS

The objective of the evaluation process shown in Figure 3:1, is to identify the network solution that addresses the network problem, which will result in the total minimum life cycle cost incorporating both the customer and the utility. As discussed in 1.3.5, from a social perspective, the total minimum cost of electric service is given by:

$$C_{Total} = C_U + C_C \quad [R] \qquad (3.1)$$

Where: C_U = Utility cost

C_C = Customer cost

The objective is thus achieved by evaluating each network option with regard to the two cost functions, C_U and C_C.

The utility cost comprises of the following costs over the life cycle of each alternative:

- Capital expenditure,
- Maintenance cost, and
- Operational cost.

These costs are relatively straightforward to calculate. The customer cost however, as discussed in Chapter 1, is a more complex parameter as it is determined by the perception of customer worth with regard to service interruptions. This perception is imbedded in the customer damage function of each customer sector being supplied by the network and is commonly known as the Sector Customer Damage Functions (SCDF).

3.3.1 Conceptual Evaluation Process

The conceptual evaluation process to minimise the total cost is provided in Figure 3:2. The basic inputs to the process is shown to be:

- Alternative supply options to be evaluated,
- The Utility cost to provide and maintain the alternative supply options, and
- The customer cost as a result of network performance for each alternative.

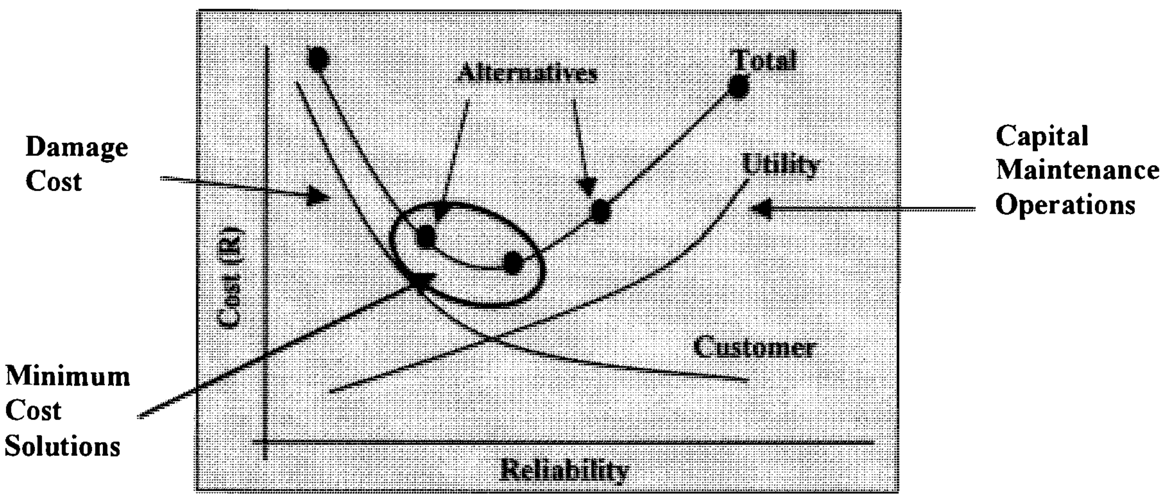

Figure 3:2 Total Cost Minimisation Concept

In a typical utility the network deficiencies are normally identified through structured channels. Typical channels are:

- By comparing the annual system load conditions to the installed capacity. This is done by utilising load flow analysis and identifying component overload conditions for different load conditions at distribution substation supply points. In the case of the GPMC the different load conditions are provided from the GLF for specified study years,

- By identifying refurbishment needs, which makes use of equipment age profiles and condition based monitoring techniques to provide life expectancy figures, and
- Through the identification of deficiencies in network performance. This can be done through the utility SCADA system, Power Quality management system, and Maintenance schedules as well as specific customer complaints.

In order to rectify or improve the deficiencies, workshops are held with relevant stakeholders where the objective is to identify appropriate alternative solutions that can be evaluated.

The calculation of the life cycle cost, from the utility point of view, for these alternatives are discussed under section 3.5 of this chapter.

3.4 CUSTOMER COST

The impact of each alternative supply option needs to be quantified in terms of customer cost in order to calculate the total cost. A wide range of customer sectors can be supplied from a single distribution station. The impact of service interruptions will thus be perceived differently by each sector within a specific supply area. The focus of this dissertation is to provide a methodology to be used in the evaluation of a typical sub-transmission network, which implies that the methodology should not cater for individual customers connected to a distribution station, but rather the composite customer group. As was identified in 1.3.5.1. If the intention is to analyse a network supplying a range of different customers, within a supply area, it is necessary to obtain the contribution of each sector to the total damage of the area. This is done through the weighting of SCDF in proportion to their demand and energy utilisation within the area and is commonly known as the Composite Customer Damage Function (CCDF), for that specific load point.

The cost estimates for a specific customer mix at that load point can be obtained by multiplying the expected energy not supplied to customers due to interruptions by a suitable factor, designated as the Interrupted Energy Assessment Rate (IEAR), expressed in R/kWh.

These factor aggregates the monitory cost incurred by customers for each unit of unsupplied energy due to electric power interruptions. Several approaches have been proposed to evaluate this factor for all hierarchical levels of a power system [58]. All these methods require statistical operations data such as the average duration, average outage time, failure rates and repair rates for

[58] L. Goel, R. Billinton, "A Procedure for Evaluating Interrupted Energy Assessment Rates in an Overall Electric Power System", IEEE Transactions on Power Systems, Vol.6, No.4, November 1991, pp 1396-1403

system components. These parameters are not readily available within the GPMC, which makes the calculation of an accurate load point IEAR virtually impossible. For this reason a practical approach is proposed whereby a modified IEAR is calculated. This is done by using the actual load (Maximum Demand) connected at a specific load point in conjunction with the load point CCDF. The interruption duration for load loss events is assumed to coincide with the duration intervals of the CCDF. The basic calculation for the modified IEAR is shown in eq [3.2] [59]

$$\text{IEAR} = \text{Cost} / \text{EUE} \qquad [\text{R/kWh}] \qquad (3.2)$$

The cost of the expected unserved energy during a load loss event can be obtained from eq [3.3]

$$\text{Cost} = L_i \times \sum C_{LP(i)} \qquad [\text{R}] \qquad (3.3)$$

where:

L_i = Load point load (kW), and

$C_{LP(i)}$ = Load Point Damage Function

The total expected unserved energy for loss of load events can be obtained from eq [3.4]

$$\text{EUE} = L_i \times \sum D_{DF(i)} \qquad [\text{kWh}] \qquad (3.4)$$

where:

$D_{DF(i)}$ = The duration interval form the CCDF

This approach, although being a rough estimate, enables the GPMC to conduct reliability worth calculations that will provide indicative values until such time that the necessary parameters have been accumulated.

The customer damage cost thus consist of the two fundamental parameters shown in Figure 3.3:

- The load point IEAR value (R/kWh), and
- The EUE (MWh) at the load point as a result of network performance or contingencies.

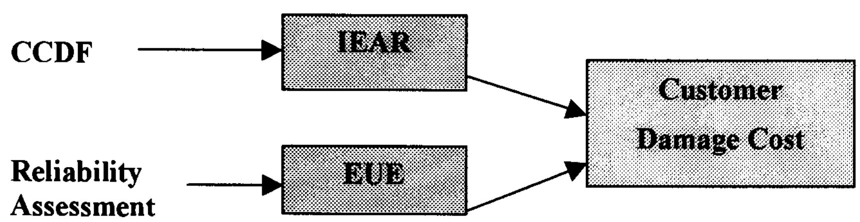

Figure 3:3 Parameters to Calculate Customer Damage Cost

[59] R. Billinton, J. Oteng-Adjei, R. Ghajar, "Comparison of Two Alternate Methods to Establish an Interrupted Energy Assessment Rate", IEEE Transactions on Power Apparatus and Systems, Vol. PWRS-2, August 1987, pp. 751-757

3.4.1 Assessment of Load point EUE

The EUE at a specific load point in a network is a function of the stochastic nature of the network supplying that load point and the actual load connected to that point. The reliability assessment technique for both the sub-transmission system and the substations encountered within that system is thus necessary to quantify load point EUE. The areas of concern are shown schematically in Figure 3:4.

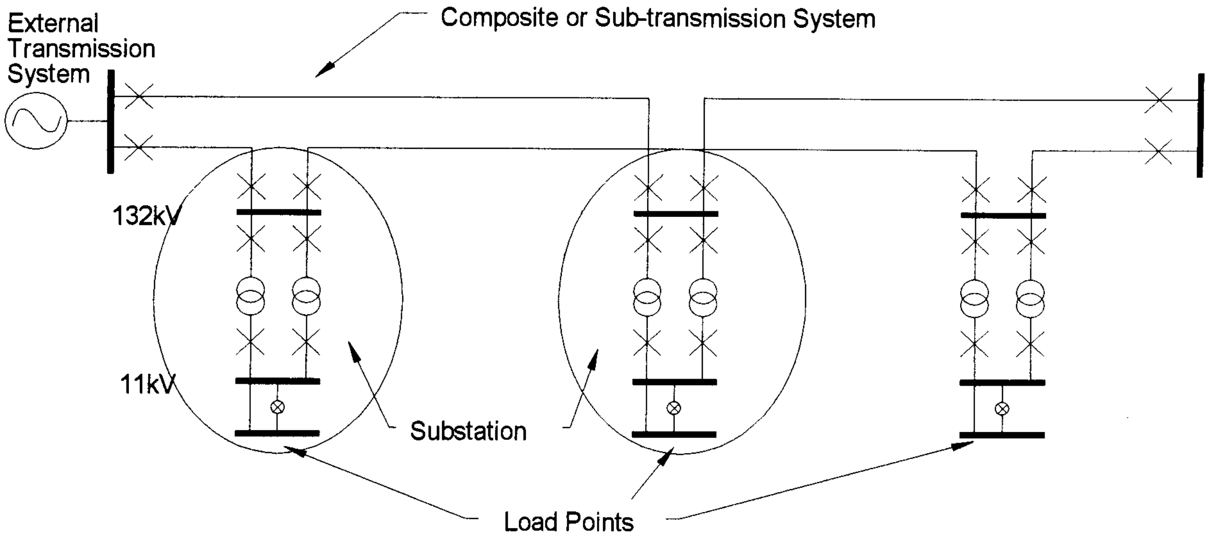

Figure 3:4 Areas of Concern to Evaluate Load Point EUE

The fundamental process followed to assess the reliability indices, which include the EUE index, for the complete network is shown in Figure 3.5. This process consists of two main processes that involve the reliability evaluation of substations and the reliability evaluation of the sub-transmission or composite network from which the substations are supplied. A decoupled approach is followed whereby the probabilistic substation statistics are computed and then used to model the substation equivalent in the composite system. In principle the distribution substations, supply stations and switching stations within the network are modelled to the extent that the impact of interruption events can be quantified on the station load bus. This is done by defining and evaluating the impact of a list of primary contingencies within a specific substation configuration. Frequency and duration indices are typically provided to quantify the post fault and post switching conditions for both maintenance and non-maintenance events. These indices provide an addition to the list of contingencies to be evaluated to quantify the overall composite network reliability.

The sub-transmission network reliability assessment follows a contingency enumeration process and relies on the user knowledge of the most common contingencies that occur on the network. A list of these primary contingencies and combinations thereof are evaluated and composite network reliability indices are provided. These indices include frequency and duration of network deficiencies as well as load point indices such as EUE, the Bulk Power Interruption index (BPI) and Bulk Energy Curtailment (BEC).

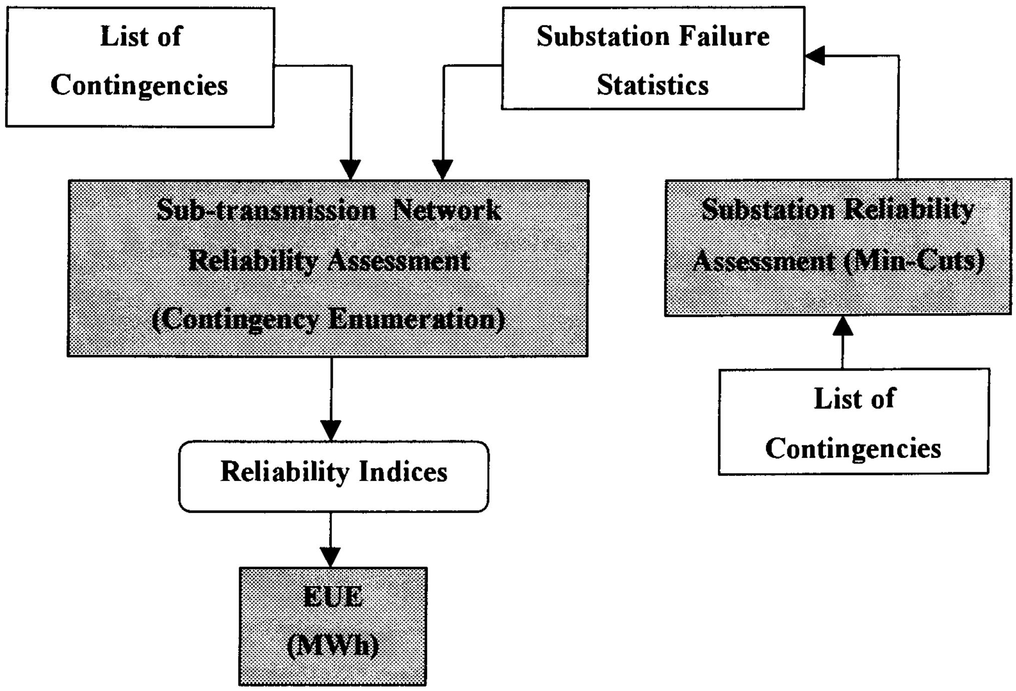

Figure 3:5 Fundamental Reliability Assessment Process

3.4.2 Sub-transmission Reliability Process

The fundamental procedure for contingency enumeration comprises of three basic steps.

- Systematic selection and evaluation of contingencies,
- Contingency classification according to predetermined failure criteria, and
- Compilation of appropriate predetermined adequacy indices.

The contingency enumeration process consists of the systematic selection, evaluation and classification of outage contingencies according to predetermined failure criteria. The contingency level is pre-specified in order to minimise the computational requirements. Furthermore corrective or remedial actions to alleviate network deficiencies form part of the evaluation process.

Various techniques, depending upon the adequacy criteria employed and the intent behind contingency studies, are available for use in the analysis. The three basic analytical techniques are:

- Network flow methods,
- DC load flow methods, and
- AC load flow methods.

The basic structure of the contingency enumeration approach is shown in Figure 3:6 [29].

The process starts with the definition of a base case, which is needed to determine steady state power flow conditions. The selection of contingencies to be analysed is then performed from the pre-defined user list. The particular generation unit or branch or combinations of specified contingencies are taken out of service and is followed by an AC or DC power flow. With modern programming architecture most software can evaluate several thousand specified or automatically selected single or multiple contingencies within one run. On completion of the power flow, system troubles are reported. This is followed by the automatic application of corrective actions to relieve the system problems if possible. General corrective actions include Generation re-dispatch, load shedding and phase-shifter control to eliminate transmission circuit overloads and low voltages. Similarly corrective actions can also be linked to power system trip sequences. These sequences are simulations of events resulting from automatic monitoring equipment such as relays, and automatic circuit breaking and making equipment such as circuit breakers and switchers.

The contingency enumeration process is completed through the calculation of bulk reliability indices such as frequency, duration and severity of events.

[29] R. Billinton, "Composite System Adequacy Assessment – The Contingency Enumeration Approach,"

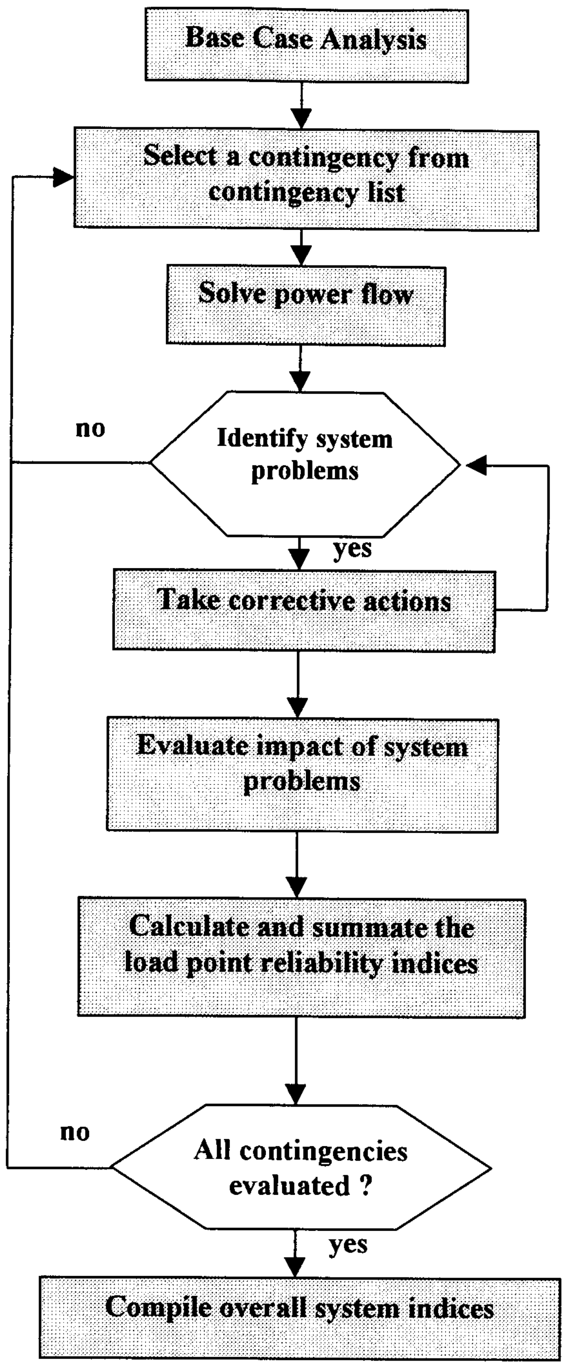

Figure 3:6 Basic Structure for the Contingency Enumeration Approach

3.4.3 Substation Reliability Process

Substations and Switching stations are usually modelled as simplified equivalents within the composite system model. Substations consist of a variety of components, such as generators, lines, busses, transformers, circuit breakers, disconnect switches, current and voltage transformers and some auxiliary equipment.

In contrast to the contingency evaluation process, most station reliability methods check for continuity between the load outlet and at least one source outlet. This is done while considering the combinations of possible system states in which the station components could reside. All station components can be in normal, fault, repair, or maintenance states. Additionally the switching components can be in a false trip or stuck state.

The Failure Effects Analysis (FEA) and the calculation of the system reliability indices in station system evaluation can, to a large extent, be computerised. Most of the computer programs that have been written account for the effect of switching after faults, the various breaker failure modes and component maintenance.

Most of these algorithms are based on the minimal cut states. An outline of a typical process logic for this purpose is provided in Figure 3:7 [39].

Load points are the locations of the outgoing feeders that amount to system failures when undergoing an interruption. The paths between the source and the load points are the continuous paths in the single line diagram of the system through which the load is supplied. They are minimal cuts in the usual sense. All system states are examined in an appropriate sequence in order to identify minimal cut system failure states. Once all the minimal cut states up to the chosen highest contingency level have been determined, the system failure probability, frequency and mean duration are computed. Using the appropriate equations for each state in the system models and cumulating the results performs these computations. These results provide the basic substation reliability statistics that are used to model substation equivalents within the composite network reliability analysis.

[39] J. Endrenyi , "Station System Reliability Evaluation", IEEE Tutorial Course, 82 EHO 195-8-PWR, IEEE Service Centre, Single Publication Sales Dept., 445 Hoes Lane, Piscataway, NJ 08854, 1982

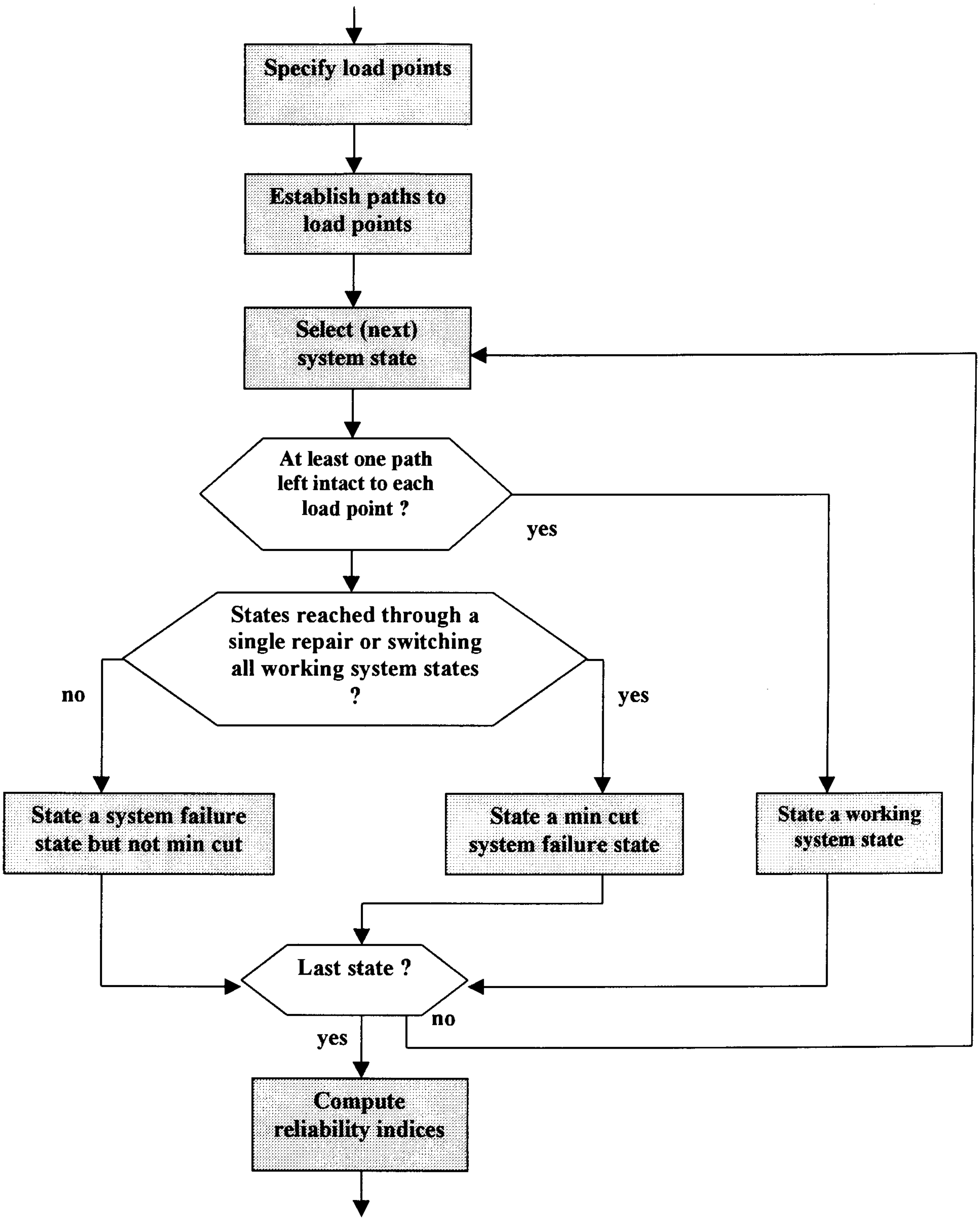

Figure 3:7 Logic for Failure Effect Analysis

3.5 COST EQUATIONS

The Value-based plan to achieve the minimum total cost for electric service over the planning horizon of the network, relies on the evaluation of the two cost equations;

- C_U = Utility cost and
- C_C = Customer cost

Essentially the Utility cost consists of the initial capital investment, the cost to maintain the facilities and the associated operational cost. For the purpose of this dissertation however, only the initial capital investment will be considered. Further work is required to quantify the operational and maintenance cost for each alternative. The technique as proposed hereunder, can then be used to refine the total cost for each alternative.

3.5.1 Cost Evaluation Objective

The objective of the cost evaluation is:

- To quantify the utility and customer cost for each alternative over the life cycle of the project,
- To use these costs to calculate the total cost for each alternative over the project life cycle, and
- To identify the alternative which will result in the total minimum cost solution.

The utility capital investment within this model consists of two components namely:

- The initial investment cost (represented as an annual expenditure), and
- The project salvage cost (a once-off income at the end of the project life cycle).

As an example Table 3.1 provides the investment cost and project scheduling for a hypothetical simplified project life cycle.

Table 3.1: Project Life Cycle Schedule

Construction Scope for Electrical Facilities	Year	Present Cost (R, k)
Provide a 40MVA 132/11kV substation	0	8,700
Provide additional 20MVA 132/11kV Transformer Bay	15	3,000
Provide additional 20MVA 132/11kV Transformer Bay	25	3,000

The customer cost on the other hand is a direct result of the load point reliability delivered by the installed facilities. This relates to a number of factors, which are discussed in more detail in Chapter 4. The bottom line however is that alternative network proposals can result in different load point EUE, which result in alternative specific customer damage. In order to assess the customer cost for evaluation purposes, these cost are calculated for each year of the life cycle of the project and are represented as an annual damage cost.

3.5.2 Cost Calculation

In order to evaluate the different alternatives with regard to their cost, the following assumptions are made:

- The interest rate is assumed at 16% per annum,
- The payback period is 20 years,
- The average life expectancy of all network equipment is 40 years, and
- The capital degradation of equipment follows a decreasing exponential curve as proposed by equation (3.5).

$$C_{salvage} = C_{cap} - e^{n-[40-\ln(C_{cap})]} \qquad [R] \qquad (3.5)$$

Where:

$C_{salvage}$ = salvage cost at the end of the project life cycle,

C_{cap} = the initial capital investment, and

n = years in service.

Furthermore the annual equivalent investment which relates to the initial investment for a specific facility is provided in equation (3.6).

$$C_{annual-equiv} = C_{cap}\frac{i(1+i)^m}{(1+i)^m - 1} \qquad [R] \qquad (3.6)$$

Where:

$C_{annual-equiv}$ = annual equivalent investment,

m = number of annual interest periods, and

i = the annual interest rate.

The total annual cost is thus the summation of the annual investment equivalent, the annual customer damage and the salvage cost. This is provided in equation (3.7).

$$C_{i(annual-total)} = C_{i(annual-equiv)} + C_{i(annual-damage)} + C_{j(salvage)} \quad [R] \qquad (3.7)$$

Where:

$C_{i(annual-total)}$ = annual total cost (including utility cost and customer damage, i.e. cash flow),

$C_{i(annual-damage)}$ = the annual customer damage cost incurred as a result of network performance, and

$C_{j(salvage)}$ = the salvage cost for all equipment at the end of the project life cycle.

Figure 3:8 provides a simplified cash flow diagram with limited investment records shown. The investments relate to the project data provided in Table 3.1.

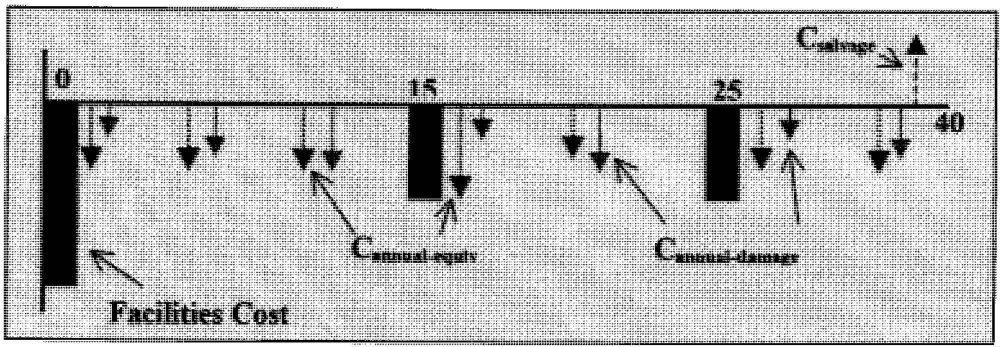

Figure 3:8 Hypothetical Project Cash Flow

The comparison between different alternatives is done by equalising the annual cash flow of each alternative through the calculation of the present worth of each alternative. By definition the present worth is a net equivalent amount at present that represents the difference between the equivalent disbursements and the equivalent receipts of an investment's cash flow for a selected interest rate. The present worth for as specific alternative is provided in equation (3.8).

$$PW(i) = \sum_{0}^{m} C_{i(annual-total)} (1+i)^{-m} \quad [R] \qquad (3.8)$$

Where:

PW(i) = present worth of a specific alternative

The success criterion for the Value-based plan is the resource plan that minimises the total cost of electric service over the planning horizon of the network. Within the cost methodology as proposed above, this implies that the alternative which results in the minimum present worth, presents the resource plan that will provide the solution at the minimum cost.

3.6 CONCLUSION

This chapter provided a methodology for the evaluation of alternative network options within Value-based principles. This methodology provides an approach through which:

- The initial capital cost is used to establish the annual investment equivalent of alternative facilities,
- The degradation of facilities are incorporated in the life cycle cost calculation for a specific alternative,
- The reliability of alternative network options are assessed in order to quantify annual customer losses due to network performance, and
- The total annual investment is used to calculate the present worth of an alternative.

This methodology thus enables the identification of alternative network options which will result in the total minimum cost solution.

The following chapter, **Base Case Modelling and Analysis**, provide data requirements, modelling and analysis requirements to assess the reliability of the network discussed in Chapter 2. This assessment will be regarded as the base case against which alternatives will be identified in order to prove the methodology developed in this Chapter.

CHAPTER 4

4. BASE CASE MODELLING AND ANALYSIS

4.1 INTRODUCTION

One of the key parameters in the Value-based planning methodology that was proposed in Chapter 3 is the assessment of the load point EUE. This index is based on load curtailments due to stochastic events on the supply network and the probabilistic assessment of this index focuses on the impact of unreliability to the customer. The fact that a contingency of a certain probability causes an overload on a transmission element is not of direct interest to the customer of electrical power. If however, this contingency is allowed to proceed unmitigated, it could result in curtailment of some or all of the customer electrical demand.

Hence, the objective of probabilistic load curtailment assessment is not one of finding out the number and severity of system troubles, but rather to determine how customers can be affected by the troubles and what corrective actions can be taken to prevent or minimise the effects. This Chapter provides detail with regard to the data requirements, modelling and analysis of the study area provided in the previous Chapters. This will be used as basis to assess the load point EUE and the associated customer impact for this network. The reliability analysis of the network will provide a global view of customer damage and will be regarded as the base case against which alternative network design options will be evaluated in Chapter 5.

4.2 DATA REQUIREMENTS

The gathering and evaluation of data which is required to sufficiently model a network with regard to reliability and its impact on connected customers is often a difficult task. Data requirements for this purpose can be divided into three basic sections as shown in Figure 4:1.

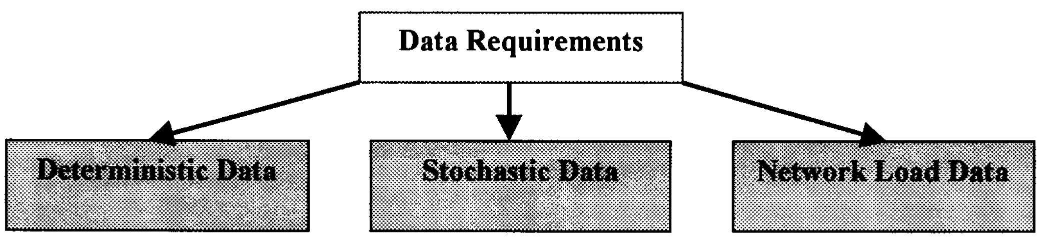

Figure 4:1 Reliability Evaluation Data Requirements

4.2.1 Deterministic Data

Deterministic data is required at both the system and the component level of the network under study. Component data includes known parameters such as line length, impedance and susceptances, transformer impedance, current-carrying capacities, generation unit parameters and other similar factors normally utilised in conventional load flow studies. Furthermore the network operational configuration and generator unit schedule for each load level scenario is required.

The system data, is more difficult to appreciate and should take into account the response of the network under certain outage conditions. The following example illustrates the concept. If one of two parallel line feeders suffered an outage; would the loading on the remaining line be such that it would automatically be removed from service, would it carry the overload for a specific duration, or would some remedial action be taken in the system in order to maintain overall system integrity?

Both the deterministic component and the system data for the GPMC sub-transmission network is contained in the Netbase data-store, which uses a MS-Access database, supported by a geographical CAD interface. This data supports the existing network as well as the future network development plan.

4.2.2 Stochastic Data

The stochastic data requirements can also be divided into component data and system data. The component data requirements are related to the stochastic up states and down states of individual elements within a system. These states can result from component related failure events and maintenance of components (e.g. failure rates and repair rates for failures and maintenance frequency and duration).

The system stochastic data on the other hand is a function of the manner in which the network responds to the stochastic behaviour of elements within the network. This entails the flow of events within a network after the application of a specific contingency up to the steady state post switching state. An example of this is the transfer of load from one load bus to another in the case where one of two parallel lines is overloaded due to the tripping of the other. This data is usually obtained through the evaluation of specified contingencies on the network in an analytical or simulation environment. In the case of this dissertation a contingency enumeration process is followed to quantify the network stochastic behaviour.

Limited stochastic component data for the GPMC sub-transmission network is available and resides in a Power Management database. Some of the difficulties related to this data are the following:

- The data corresponding to failure events is manually updated,
- The actual pre-fault configuration of the network is difficult to obtain, this includes both physical switching statuses and pre-fault load levels at all load busses,
- An integrated knowledge of the network is required to identify the flow of events during a failure,
- The actual cause of system or component failure is often difficult to identify, and
- Data for limited equipment categories are archived.

4.2.2.1 Stochastic Data Assumptions

Bearing in mind the data difficulties, the approach of this dissertation is to utilise existing network specific data where available and to apply generic data to fill the voids. This assumption is regarded as valid when considering the objective of the study.

Due to the relative unavailability of useful data the network specific and generic data is utilised as follows:

- For composite network reliability evaluation purposes, the existing line performance data obtained from the Power Management database is used for both the current and future networks,
- Due to the configuration of the T-Off networks, all failures of equipment above the medium voltage level, but not part of the actual feeder, will result in the feeder line connected to that equipment, to trip. All failure events on these networks are thus filtered in order to identify actual failure of the feeder,
- In the case of substation reliability analysis, generic data is used. This data is related to specific equipment (e.g. Circuit Breakers, Isolators, Transformers and the like).
- In the case of T-Off networks, the substation related failures need to be integrated into the composite system in such a manner that the failure event will result in the failure of the feeder line, resulting in load loss at other stations connected to the same feeder line.

4.2.2.2 Network Specific Data

Network specific stochastic data were obtained from trip reports prepared by Power Management and was used as primary data source to compile outage data records for both single line failures and double line failures caused by common mode events. Common mode failures are of particular importance due to the double line structure used on all feeder lines of the network. Trip reports for three consecutive years were used to compile summary tables consisting of each feeder. The average frequency and duration of line related failures were calculated. In the case where data were not available for a specific line, or where the line has not failed for the period of concern, generic outage data were used.

Tables 4.1 and 4.2 respectively show the single and double line failure statistics for the GPMC network. These frequency and duration data are used to model specified contingencies for individual line failures during a contingency enumeration analysis of the composite network.

Generic equipment failure statistics are provided in Table 4.3. These generic data are used to model the stochastic behaviour of substation related equipment failures. This data correspond to generic data obtained for PTI-PSS/U DRA models [60] while the maintenance data is obtained from PPD Maintenance records.

[60] PSS/U DRA Program Manual: August 1998: Power Tecnologies, Inc

Table 4.1: Single Line Failure Statistical Data

	1996		1997		1998		Average		
Line ID	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Fail/km-yr
KW-DH/NJ 1	3	23.33	4	44.75	1	30.00	2.67	0.54	0.08
KW-DH/NJ 2	2	17.00	3	21.67	3	56.33	2.67	0.53	0.08
KW-PW 1			2	33.50			0.67	0.19	0.13
KW-PW 2					2	30.00	0.67	0.17	0.13
KW-PW 3			1	120.00			0.33	0.67	0.07
KW-PW 4							0.31	0.50	0.06
KW-BL 1					1	32.00	0.33	0.18	0.03
KW-BL 2					1	80.00	0.33	0.44	0.03
KW-BL 3	2	12.50					0.67	0.07	0.06
KW-BL 4							0.68	0.17	0.06
KW-PK/RW 1	1	40.00	6	25.50	3	133.33	3.33	1.10	0.09
KW-PK/RW 2	5	42.40	5	67.00	4	20.00	4.67	0.72	0.12
RW-WA/EL 1	1	15.00	1	33.00	4	71.75	2.00	0.67	0.09
RW-WA/EL 2	3	20.67	2	28.00	2	0.50	2.33	0.27	0.11
WA-MA 1							0.07	2.00	0.06
WA-MA 2			1	360.00			0.33	2.00	0.28
WA-NJ 1					1	100.00	0.33	0.56	0.02
WA-NJ 2					1	90.00	0.33	0.50	0.02
NJ-SC 1			1	50.00			0.33	0.03	0.02
NJ-SC 2					2	45.00	0.67	0.25	0.05
SC-WL 1							0.09	0.17	0.06
SC-WL 2							0.09	0.17	0.06
SC-EL 1					1	15.00	0.33	0.08	0.04
SC-EL 2							0.47	0.10	0.06
SC-CSIR 1							0.09	0.17	0.06
SC-CSIR 2							0.09	0.17	0.06

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Table 4.1: Single Line Failure Statistical Data (continue)

	1996		1997		1998		Average		
Line ID	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Fail/km-yr
EL-VL 1							0.26	0.17	0.06
EL-VL 2							0.26	0.17	0.06
PK-BL 1			4	12.50			1.33	0.07	0.27
PK-BL 2					2	50.00	0.67	0.28	0.14
PP-BL 1							0.01	12.00	0.003
PP-BL 2							0.001	12.00	0.003
BL-BO 1							0.002	12.00	0.003
BL-BO 2							0.002	12.00	0.003
BL-SK 1	1	60.00					0.33	0.33	0.101
BL-SK 2							0.01	12.00	0.003
BL-RV							0.02	12.00	0.003
BL-ED/RV							0.02	12.00	0.003
BL-ED/SK			1	32.00			0.33	0.18	0.074
PK-MV 1							0.004	12.00	0.003
PK-MV 2							0.004	12.00	0.003
BU-K1							0.093	0.17	0.062
BU-K3							0.75	0.17	0.062
K1-K3							0.41	0.17	0.062
ATT-SAU							0.25	0.17	0.062
KW-SAU							0.47	0.17	0.062
KW-ATT							0.22	0.17	0.062
RIE-WAT 1							0.36	0.17	0.062
RIE-WAT 2							0.36	0.17	0.062
RIE-DH 1							2.31	0.17	0.062
RIE-DH 2							2.31	0.17	0.062

Table 4.2: Double Line Failure Statistical Data

	1996		1997		1998		Average		
Line ID	**Frequency**	**Duration**	**Frequency**	**Duration**	**Frequency**	**Duration**	**Frequency**	**Duration**	**Fail/km-yr**
KW-DH/NJ 1 & 2	4	26.75			2	85	2.00	0.62	0.058
KW-PW 1 & 2							0.01	4.00	0.001
KW-PW 3 & 4							0.01	4.00	0.001
KW-BL 1 & 2	1	185.00					0.33	1.03	0.067
KW-BL 3 & 4	1	52.00					0.33	0.29	0.067
KW-PK/RW 1 & 2	1	27.00	1	25.00			0.67	0.29	0.018
RW-WA/EL 1 & 2	3	21.67					1.00	0.12	0.047
WA-MA 1 & 2	1	30.00			1	100	0.67	0.72	0.56
WA-NJ 1 & 2	1	29.00	1	44	1	32	1.00	0.58	0.051
NJ-SC 1 & 2					2	25	0.67	0.14	0.049
SC-WL 1 & 2							0.002	4.00	0.001
SC-EL 1 & 2							0.01	4.00	0.001
SC-CSIR 1 & 2							0.002	4.00	0.001
EL-VL 1 & 2							0.01	4.00	0.001
PK-BL 1 & 2							0.01	4.00	0.001
RIE-WAT 1 & 2							0.01	4.00	0.0012
RIE-DH 1 & 2							0.05	4.00	0.0012

Table 4.3: Generic Component Failure Statistics

Faulted Component Failure / Maintenance	Failure - F (event / yr)	Failure - D (hours)	Maint - F (event / yr)	Maint - D (hours)
132kV Cable	0.012	100	0.2	7 day
Common mode line	0.10	5	-	-
132/11kV Transformer	0.12	120	0.2	12 hour
Instrument Transformer	0.0034	272	-	-
132kV Bus-section	0.04	15	0.2	8 hour
132kV Circuit-breaker	0.02	60	0.2	8 hour
Operational Failure	**Probability**			
Stuck Breaker	0.005			
11kV Chop-over	0.005			

4.2.3 Network Load Data

The probabilistic assessment of load point EUE is a function of the deterministic set-up and configuration of the network, the stochastic behaviour of the network and the actual load connected to the individual load points on the network. In the previous sections data requirements to model the deterministic network configuration and stochastic behaviour of the network was discussed. Additional data to enable EUE calculation is:

- The actual load in MW and MVAR,
- The load mix in terms of customer sectors, and
- Sector Customer Damage Functions.

4.2.3.1 Load at Load Point

Load data at each network bus at which load curtailment needs to be monitored must be specified in terms of:

- A real power component of constant MVA Load entered in MW, and
- A reactive power component of constant MVA Load entered in MVAr.

The data at each bus is the actual base load used as input to the load flow during a contingency analysis and is also the load curtailed if a contingency results in load loss. This data for the GPMC network is contained in the Netbase data-store and is supported by the GLF.

4.2.3.2 Load Mix and SCDF

The load mix at each load point in the network is required to calculate the impact of unreliability on the combination of customers connected to that point. The GLF used by GPMC planning lends itself to the identification of the customer load mix for both the existing and future networks. The fundamental concepts of the GLF were discussed in paragraph 2.3.5. The geographical homogeneous zones within the GLF are categorised into nine primary land-use categories provided in the same paragraph. If SCDF's for each category and maximum demand and energy usage for each zone is available, the calculation of the CCDF for a specific load mix supplied by a sub-transmission load point becomes straightforward. This data is however not available for the network under study and the following are assumed:

- Generic SCDF's are used for simplified sector categories, and
- Zone loads in terms of KVA/ha are used for the weighting of each sector towards the CCDF.

Although generic values are used for the development of this methodology, it is of vital importance that the specific data for each sector is used when assessing the reliability worth of a specific network as the use of generic SCDF's can lead to erroneous cost values.

The nine categories provided in the GLF are simplified to six categories with the Residential sector comprising of Residential, Low Income Residential and High Rise Residential and the Educational sector comprising of Tertiary and Other Education. The six sectors with their associated generic SCDF's are provided in Table 4.4.

Table 4.4: Generic Sector Customer Damage Function (R/kW)

Sector	1 min	20 min	1 hour	4 hours	8 hours
Residential	0.002	0.164	0.850	8.661	27.655
Farming & Open spaces	0.106	0.605	1.144	3.638	7.262
Business / Commercial	0.672	5.233	15.074	55.198	146.308
Industrial	2.864	6.818	16.013	44.352	98.366
Education	0.050	0.470	1.400	10.023	20.145
Other & Municipal & Government	0.078	0.650	2.630	11.559	45.897

The generic SCDF's for each sector are obtained from weighting Sector Customer Damage Functions obtained from various Canadian studies with the per capita GNP ratio between South Africa and Canada.

These GNP values are assumed as: (World Bank @ http://www.worldbank.org/)

Canada:	GNP per capita (US$)	= $ 19 290, and
South Africa:	GNP per capita (US$)	= $ 3 400

4.3 BASE CASE CONFIGURATION

The previous sections of this chapter provide the basic data requirements to assess the reliability of the network under study. The objective of this section is to:

- Define the modelling approach to assess the reliability of stations within the network,
- Incorporate station failure statistics into the composite network model,
- Model aspects of the composite network,
- Model corrective actions during contingency analysis that are unique to the network under study,
- Assess the reliability of the GPMC network base case, and
- Calculate load point damage cost utilising the generic Customer Damage Functions and the load point customer mix provided in the GLF.

4.3.1 Substation Reliability Assessment

The reliability of a substation can be measured by the frequency and duration of substation related outage events. These events may be caused by a number of conditions. The most prominent are failures of the sub-system supplying the station, faults on the substation equipment, failure of a breaker to clear a fault or the false tripping of a breaker, operational failures as well as scheduled and unscheduled maintenance. The frequency and duration at which these events cause substation load curtailment is primarily a function of the substation configuration and flexibility and to a lesser extent a function of the stochastic equipment data.

4.3.1.1 Substation Model

When modelling a particular station in terms of reliability, aspects that should be taken into consideration, which are additional to the basic equipment statistics, are:

- The substation configuration and connectivity,
- Protection of major equipment and possible switching actions to restore load,

- Branch transfer capability, and
- Substation bays or equipment groups affected by common failures.

The station should further be modelled in such a way that a simplified equivalent can easily be derived in order to represent the station model within the composite network model.

These aspects can best be shown through the example provided in Figure 4:2.

The detail single line diagram shows a double bus-bar 132/11 kV distribution substation similar to the ARBC configuration discussed in Chapter 2. The primary equipment groups and thus the primary contingencies to be evaluated during the failure effect analysis are:

- The transformers,
- Individual circuit breakers (CB), and
- The bus-bars.

a) The transformer group consists of the transformer as well as the terminal equipment connected to the transformer. The terminal equipment includes current and voltage transformers, surge arrestors and NECRT's.

b) The bus-bar group consists of the bus-bar, all the isolators connected to the bus-bar as well as any other terminal equipment that could be present (e.g. Current and voltage transformers)

c) The circuit breaker group is modelled as a stand-alone entity with regard to outage statistics, with no terminal equipment forming part of this group. Apart from the normal failure and maintenance statistics represented in the component reliability model, the operational failure rate for circuit breakers is also incorporated. This figure represents the probability of stuck breaker conditions where a localised bay fault can spread to other parts of the system due to the failure of a breaker to clear the fault.

The operational switching flexibility of the substation is primarily a function of bus configuration and isolator and breaker placement. This flexibility within the model is catered for in two ways. The first is being to model the configuration in terms of the actual connectivity and normal operational statuses of the isolators and circuit breakers. The second aspect is to incorporate the actual isolator switching time required to restore load after a fault has occurred (i.e. post-switching conditions).

In order to model a simplified equivalent within the composite network it is important that the main bus-bars within the substation model be represented in the composite network model. Furthermore, that the branches connecting these bus-bars should correspond to those within the composite model.

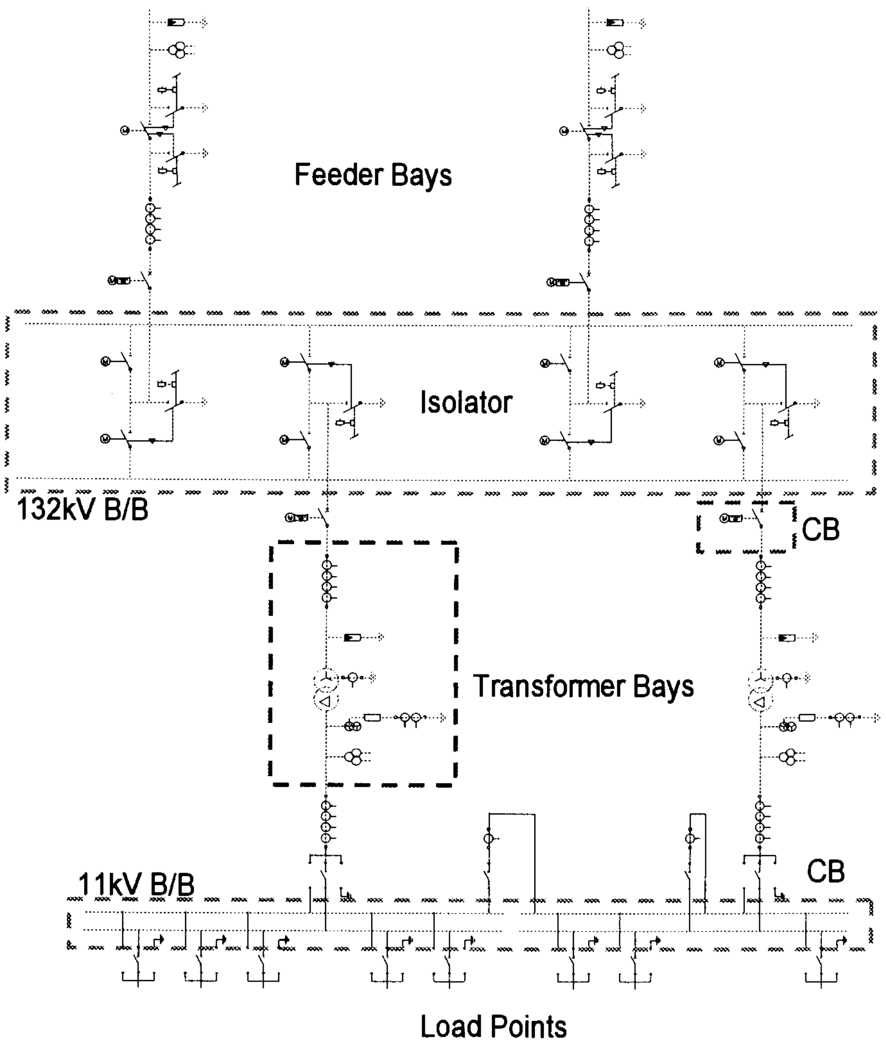

Figure 4:2 Detail Substation Configuration

4.3.1.2 Substation Reliability Indices

The Failure Effects Analysis (FEA) discussed in paragraph 3.4.3., supported by a min-cut max flow algorithm is used to calculate substation outage frequency and probability. Each primary contingency group in the substation is represented within the model by a composite failure frequency and duration. This frequency and duration consists of the combination of the failure frequency and duration of individual components connected to the group.

The calculation of the composite figures can be shown through the following example [42]:

[42] TPLAN User's Guide: Substation Reliability Assessment Add-on Module: Power Tecnologies, Inc, pp.39-41

Consider the transformer group shown in Figure 4.2. For simplicity it is assumed that the group consists of the power transformer as well as a current and voltage transformer. The failure statistics for the components are as provided in Table 4.3 (Generic Component failure statistics).

To form the composite frequency, f_c, and duration, r_c, for the contingency group, the following two equations are applied:

$$f_c = \Sigma (n_i * \lambda_i) \quad \text{events/year} \tag{4.1}$$

and

$$r_c = \Sigma (n_i * \lambda_i * r_i) / \lambda_c \quad \text{hours} \tag{4.2}$$

Where i is the different components connected to the contingency group and n_i is the exposure or quantity of each component type involved. Equation (4.1) and (4.2), if applied to the transformer group provides composite values of:

$$f_c = 1 * 0.12 + 2*0.0034 = 0.1268 \text{ events/year}$$

and

$$r_c = (1*0.12*120 + 2*0.0034*272) / 0.1268 = 128 \text{ hours}$$

A similar approach is used to provide the composite values for scheduled and unscheduled maintenance events. For secondary contingency cases with stuck breaker conditions, the frequencies and probabilities are multiplied by the operational failure rate of the stuck component.

A summary of reliability indices for the substation configuration provided in Figure 4:2 and the statistical data in Table 4.3 is provided in Table 4.4.

Table 4.5: Reliability Indices

Non-Maintenance Events			
	Frequency	**Probability**	**Duration**
Post Fault Conditions	0.5509	0.8741E-7	0 hours
Post Switching Conditions	0.4173E-1	0.7444E-4	15.63 hour
Maintenance Events			
	Frequency	**Probability**	**Duration**
Post Fault Conditions	0.53921E-1	0.8556E-8	0 hours
Post Switching Conditions	0.1196E+1	0.1200E-2	0 hours

The significant results that come from the non-maintenance post-switching conditions which represent the indices for load curtailment after automatic switching has taken place. The switching involves connecting the backup transformer to an active line, or transferring to the alternative line. For this substation configuration, the average frequency of load curtailment is

0.0417 events per year with an average duration of 15.6 hours. The primary causes of these load curtailments are double contingencies and/or breaker failure.

4.3.1.3 Substation Modelling within the Composite Network

The assessment of load point reliability indices is not complete once the substation reliability analysis has been conducted. It is the overall reliability that is of concern, as simply maximising station reliability may not be the most cost effective approach in designing a power system. The approach that is followed involves the modelling of a simplified equivalent substation within the composite network model. The list of contingencies that needs to be evaluated within the composite network typically incorporate the failure statistics for the transformers modelled in the simplified substation equivalent. These statistics needs to be evaluated for each station configuration type encountered in the composite network. The incorporation of station statistics into the composite network can graphically be shown in Figure 4:3.

In the case of T-Off networks, the substation related failures needs to be integrated into the composite system in such a manner that a transformer failure event will result in the failure of the feeder line, resulting in loss of load at other stations connected to the same feeder line. This aspect will be discussed under corrective actions in the remainder of this Chapter.

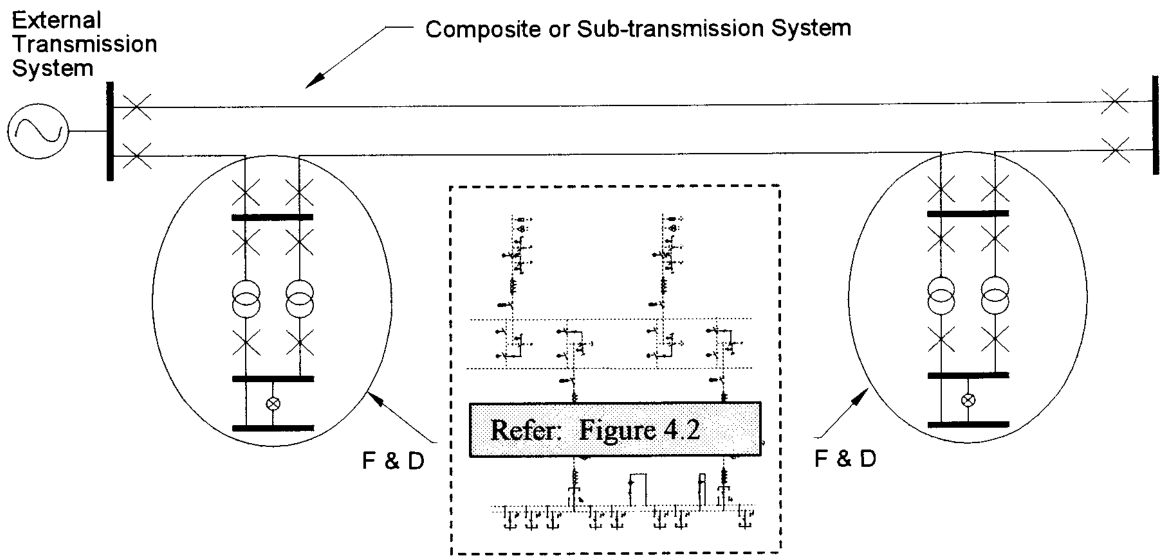

Figure 4:3 Substation Equivalent within Composite Network

4.3.2 Composite Network Reliability Assessment

The objective of assessing the reliability of the GPMC network, as identified in Figure 3:5, Chapter 3, is distinctly to quantitatively predict future performance. This prediction provides valuable information to network planners in terms of [21]:

- How the network is expected to behave in future,
- Benefits of alternative network designs, reinforcements and expansion plans,
- Effects of alternative operational and maintenance policies, and
- Related reliability cost/benefit/worth of the alternatives associated with the above.

Prediction of future network performance is achieved by transforming past experience into information required for future prediction. Past performance is however associated with the operational phase of the network whereas future performance focuses on the design phase. The factors included in these two phases can be different. As an example, predicted measures generally include only adequacy effects and ignore security effects, whereas past performance measures include both. Another difference is that past performance measures only include events that actually happened whereas future predictions must include the likelihood of all possible events. These differences can cause difficulties in the validation of predictive indices and comparison should be done with caution. The approach taken in this dissertation is pessimistic of nature and judgement will be made on every case individually.

A contingency enumeration procedure is followed to assess the reliability of the network. The following sections discuss the fundamental requirements to enable this analysis.

4.3.2.1 Automatic Contingency Analysis

As previously noted, the fundamental procedure for contingency enumeration comprises of three basic steps:

- Systematic selection and evaluation of contingencies,
- Contingency classification according to predetermined failure criteria, and
- Compilation of appropriate predetermined adequacy indices.

[21] R.N. Allan, "Bulk System Reliability - Predictive Indices", IEEE Transactions on Power Systems, Vol. 5, No. 4, November 1990, pp. 1204 - 1211

The number of contingencies that are automatically selected are limited by using fixed probability/frequency values. The analytical solution technique that evaluates the impact of these contingencies on the network, utilises an AC load flow algorithm. This solution technique provides estimates of bus voltages and reactive power requirements of generating units, which are essential when power quality and continuity is of concern.

The failure criteria that is used to identify and evaluate system problems for the GPMC network is the following [22]:

- Thermal overload, for both transmission lines and transformers,
- Voltage violations at monitored busses,
- Load curtailment, due to network capacity deficiencies,
- Voltage collapse, and
- Islanding and separation.

The last two criteria relate to security indices and are used to flag network security constraints. As the focus of this dissertation is to quantify network adequacy, these criteria will be utilised as an indicative index and will not be used to evaluate different network alternatives as such.

4.3.2.2 Specified Contingencies

Contingencies that are evaluated include independent outages such as single transmission lines and units, as well as dependent failures such as transmission lines due to common mode situations and substation originated events. The frequency and duration of single and double transmission line failures are provided in Tables 4.1 and 4.2. In the case of the T-Off sub-systems (Chapter 2, section 2.3.1.1), contingencies which lead to the failure of transmission lines supplying these systems, are modelled as multiple elements consisting of all the individual branches comprising a specific line. The entire sub-system is thus taken out of service during the enumeration process, at the frequency and duration provided in Table 4.1.

The evaluation of failure events originating from substations supplied by the T-Off sub-system is achieved through the following approach:

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[22] J.C.O. Mello, A.C.G. Melo. S.P. Romeo, G.C. Oliveira, S.H.F. Cunha, M.V.F. Pereira, M. Morozowski, R.N. Fontoura, "Development of a Composite System Reliability Program for Large Hydothermal Power Systems – Issues and Solutions", PMAPS, 3-5 July 1991, IEE Savoy Place, London WC2R OBL, pp. 64-69

- The frequency and duration of substation related failures are modelled as equivalent transformer failures within the composite network as discussed in section 4.3.1.3,
- The failure of any transformer within a T-Off sub-system will result in the failure of the transmission line supplying that system, resulting in supply loss to the remaining substations,
- During the contingency enumeration process, all substation transformers are monitored with regard to thermal loading and in the case of transformers supplied by the T-Off system with regard to the transformer being removed from service,
- In the event of a transformer being removed from service due to a substation related failure, a trip sequence is initiated to trip the branches directly connected to the supply points of the specific sub-system,
- This will result in the loss of supply to all substations connected to that particular sub-system, and
- Corrective actions, as discussed in the next section, to restore the load will then be initiated.

The severity associated with an outage event increases as the depth of the contingency increases. It is therefore necessary to probe deeper levels in the search for more severe load curtailment situations. Analysis of the network in this study will be done up-to an N-3 level.

4.3.2.3 Corrective Actions

During the contingency enumeration process, system problems are typically recorded as a failure event. In the reality however, it is in many cases possible to eliminate a network problem by taking appropriate corrective actions. Corrective actions can generally be categorised as [29]:

- Generation rescheduling in the case of capacity deficiencies,
- Correction of generation unit MVAr limit violations,
- Bus isolation and network splitting under transmission line(s) and transformer(s) outages,
- Alleviation of line overloads, and
- Load curtailments in the event of network problems.

The most difficult corrective action to implement during the analysis of the GPMC network is that of controlled load curtailment. This is due to the fact that the GPMC has no formal policy regarding this condition.

[29] R. Billinton, "Composite System Adequacy Assessment – The Contingency Enumeration Approach,"

A common approach is to assume that the load at each bus can be classified into two categories [29]:

- Firm load, and
- Curtailable load.

Based on individual load point requirements, curtailable load may represent some percentage of the total load at the bus. In the case of a deficiency in the network capacity, curtailable load is interrupted first, followed by the curtailment of firm load if necessary. Appropriate management of load curtailment will result in an improvement in network performance. Due to the current GPMC policy, no corrective actions that will result in selective load curtailment will be modelled. Recommendations with regard to this aspect will however be made in Chapter 6.

All the general corrective actions will be applied during the analysis. This provides for a more realistic representation of the actual network and ensures more reliable adequacy indices.

4.3.2.4 Composite Network Reliability Indices

Based on the past network performance and the modelling of dependent and independent contingencies, load point reliability indices are calculated for the 1999 GPMC base case. Table 4.6 provides the overall system indices for the base case study. Table 4.7 show the average frequency and duration as well as expected load curtailment of substations connected to each sub-system or line feeder.

Table 4.6: Overall System Reliability Indices

Solution Converged	Frequency (occ/yr)	Duration (hr/yr)
Load Loss	27.51	0.5
Overload	3.3	0.3
High Voltage	0	0
Low Voltage	0	0
Voltage Collapse	0	0
Not Converged	0	0

29 R. Billinton, "Composite System Adequacy Assessment – The Contingency Enumeration Approach,"

Table 4.7: Sub-system Load Point Reliability Indices

Sub-System	Load Point	Total Load (MW)	Frequency (occ/yr)	Duration (hr/yr)	Curtailment (MWh/yr)
BL-BO	Boomstreet	75.8	0.002	11.5	1.88
BL-ED	Edmond	28.2	0.331	0.2	1.71
BL-RV	River	60.1	0.476	4.167	20.36
EL-VL	Villieria	21.4	2.269	0.6	20.36
KW-DH/NJ	Wingate	49.6	2.269	0.5	73.25
	Kloofsig	5.1	2.269	0.5	7.94
	Zwartkops	27.9	2.269	0.5	40.87
	Claudius	17.3	2.269	0.5	25.09
	Zebra	43	2.269	0.5	63.52
KW-SAU	Saulsville	4.1	< 0.001	-	-
KW-ATT	Atteridgeville	50.1	< 0.001	-	-
KW-BL	Tunnel	17.8	0.682	0.2	2.12
KW-PK/RW	Gomsand	20	3.347	1.1	75.20
	Orchards	22	4.687	0.7	75.76
	Rosslyn	55.1	3.347	0.97	203.13
	Wolmer	25.8	3.347	1.1	96.47
	Wonderboom	39.6	4.017	0.9	143.69
	Pta-North	26.6	4.687	0.7	90.92
NJ-SC	Highlands	39.9			
RW-WA/EL	Koedoespoort	77.8	2.209	0.5	78.57
	Pumulani	19.9			
	Pyramid	19.1	2.008	0.7	26.18
	Waltloo	46.7			
WA-NJ	Mooikloof	12.6	0.331	0.6	2.41
	Wapadrand	27.8	0.331	0.6	5.24
PK-BL	Capital Park	34.5	0.672	0.3	6.67
PP-BL	Princes Park	57.4	0.347	5.9	8.32
PK-MV	Mayville	26	< 0.001	-	-
SC-EL	Lynnwood	76.6			
SC-WL	Willows	58.6	0.9	0.2	0.92
WA-MA	Mamelodi I	49	2.02	2.0	17.79
	Mamelodi II	29.8	2.02	2.0	15.05
	Mamelodi III	4.6	0.71	2.0	0.72
RIET-WAT	Waterkloof	34.1	0.361	0.2	2.15
BL-SK	Skinner	103.5			

Table 4.7: Sub-system Load Point Reliability Indices (continue)

Sub-System	Load Point	Total Load (MW)	Frequency (occ/yr)	Duration (hr/yr)	Curtailment (MWh/yr)
BU-K1	K1	5.5	< 0.001	-	-
BU-K3	K3	0.4	< 0.001	-	-
RIET-DH	De Hoewe	27.7	2.316	0.2	11.10
	Eldoraigne	41.9	2.316	0.2	16.84
	Raslouw	8.5	2.316	0.2	3.54
	Brakfontein	23	2.316	0.2	9.37
	Olievenhoud	0	-	-	-
	Kosmosdal	2.4	2.316	0.2	1.14
	NIVS	10.3	2.316	0.2	4.21
	Kentron	16.2	2.316	0.2	6.73
	Piet Geers	0	-	-	-

The objective of the results shown in Table 4.7 is to identify sub-systems within the network which perform poorly in terms of frequency and duration of load curtailment events as well as identifying the substations where the highest load curtailment is monitored.

The worst load loss condition for the base case occurs when the KW-PK/RW No.1 line and the NJ-SC N0.1 line fail simultaneously. This contingency results in a total load loss of 220 MW. The average frequency of this event occurring is equal to 0.142E-3 events per year.

From the results shown in Table 4.7 it can further be seen that the worst performing sub-systems are the KW-PK/RW, RIET-DH and the KW-DH/HJ sub-systems respectively. This is expected due to the fact that these systems are supplied via the longest transmission line portions of the network and that most of the substations connected to these systems are Tee-offs. The substation most affected in terms of energy curtailment is Rosslyn.

The objective of the following section is to refine the analysis with regard to load curtailment in order to calculate the damage cost incurred by customers as a result of network performance.

4.4 MULTIPLE BASE CASE ANALYSIS

By evaluating load curtailments over a series of load levels rather than the single scenario represented by the base case, it is possible to obtain more accurate energy indices for load curtailment. The approach involves representing the network load duration curve over a period and representing the load through a staircase approximation. Each step thus represents a load level, which in turn is represented by a base case that can be configured in a specific manner. This is important since network switching and generator dispatch can vary significantly as a function of load level and season. Multiple base cases may thus be applied to each load level representing this variation. Furthermore, each base case is characterised by an exposure probability between 0 and 1.0. This represents the exposure to the conditions in the base case over the study period. By summating the EUE for each load period and multiplying each by the probability of being in the specific load state, a more accurate index for energy curtailments is obtained.

4.4.1 Load Duration Curve Approximation

Load profiles obtained for the supply points of the network are used to compile area load duration curves. These load profiles consists of half-hourly demand measurements used for billing purposes at each supply point. Each area load duration curve is represented through a four level staircase approximation. More levels provide for a more accurate approximation which will lead to more accurate reliability indices. This however becomes a tedious process and can be achieved through an automation process. The approximation process followed for the combinations of the Kwagga and Njala supply areas is shown in Figure 4:4.

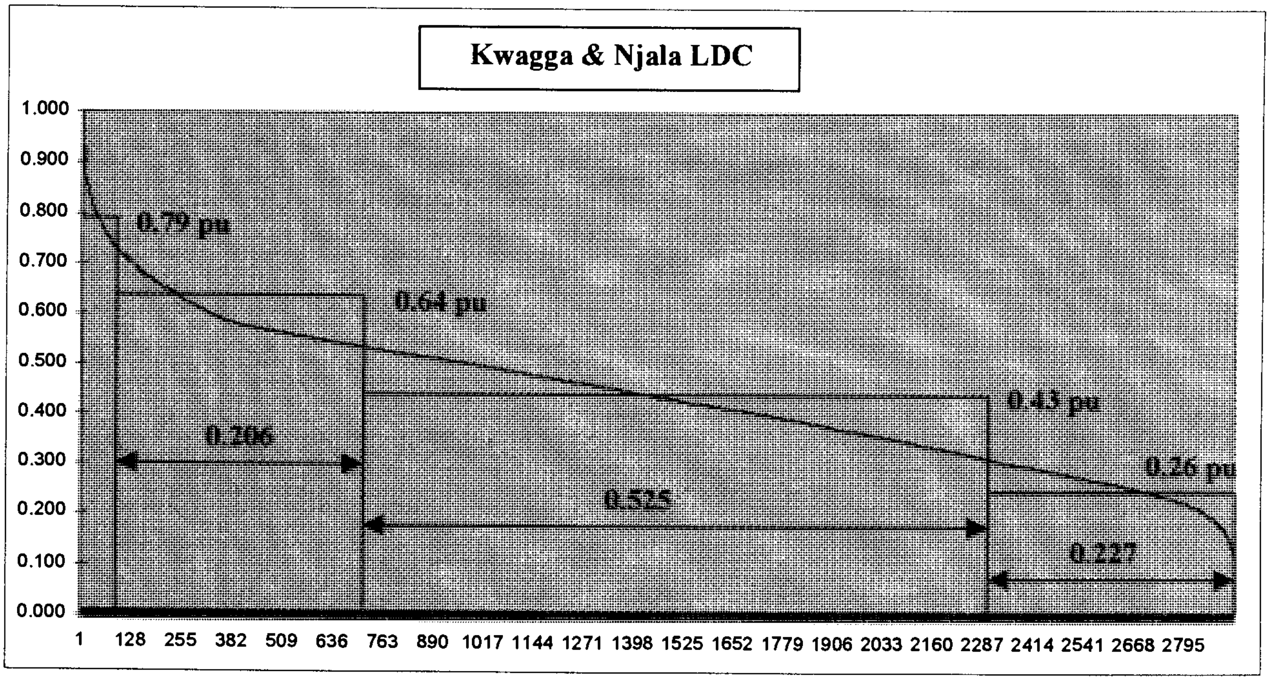

Figure 4:4 Load Duration Curve Approximation

The total system load for these supply areas is approximated through four load levels each having a magnitude and probability of occurrence as shown.

These load levels are in turn represented by four base cases, each having the individual bus loads scaled to the corresponding load level approximation. During the analysis process, the specific case is evaluated against the contingencies provided for the single base case analysis as discussed in the previous sections . Indices are calculated, taking into consideration the probability of the network being in the specific load condition as approximated above. Although possible, no alternative network switching arrangements is modelled. The reason being that the GPMC network operational switching does not normally change due to daily or seasonal load variations.

4.5 CUSTOMER DAMAGE ASSESSMENT

The objective of the multiple load level contingency analysis is to quantitatively assess the Expected Unserved Energy at each load point in the network due to specific network failures. This approximation provides a relatively accurate figure that can be used to calculate the expected damage cost incurred by the group of customers connected at that specific load point. These damage figures are then used to identify load points or sub-systems in the network where the network performance results in high customer damage.

4.5.1 Customer Damage Functions within the GLF

As discussed in paragraph 4.2.3.2 of this Chapter, the GLF used by GPMC planning lends itself to the identification of the customer load mix for both the existing and future networks. Data with regard to customer land-use and load densities are contained in the GLF model in such a manner that the manipulation of the data in order to obtain load point CCDF's becomes relatively straightforward. Once the CCDF for a specific load point is available, the IEAR for that load point can be obtained in order to calculate the customer damage as a result of network performance. As an example the customer data for the individual load zones connected to a specific load point on the sub-transmission network is provided in Table 4.8.

Table 4.8: Load Zone Composition

Zone ID	Area (ha)	Land-use Type
ATT 1	45.50	A_72
ATT 1.1	52.90	A_72
ATT 1.2	171.50	90A10H_72
ATT 1.3	80.90	A_72
ATT 2	134.30	80A10C10H_ATT2
ATT2.1	44.50	A_72
ATT 2A	105.92	C_4

The total supply area for these zones is in the order of 635 ha with a diversified maximum demand of approximately 34 MW. A land-use type represents the land-use for each load zone within the network. For instance, the land-use type for Zone ATT 1.2 consists of a 90% Residential sector load and a 10% Educational sector load. The load density of this zone is 72 KVA/ha. In the current database there are approximately 200 different land-use types representing each non-homogeneous load zones on the GPMC network.

This knowledge, along with the generic SCDF's provided in Table 4.4 are used to calculate the CCDF for the specific load zone. Utilising equation (3.3) in Chapter 3, the IEAR for the load zone is calculated. This process is followed for each load point on the network in order to calculate CCDF"s and the corresponding load point IEAR.

4.5.2 Load Point Customer Damage Calculations

The expected load point customer damage is obtained by multiplying the EUE indices obtained from the multiple load level contingency analysis with the IEAR of each load point obtained from the GLF model. This is shown for a specific load point in equation (4.1).

$$\text{EUE (MWh) x IEAR (R/kWh) = Customer Damage} \quad [\text{R}] \qquad (4.1)$$

The expected customer damage cost with the associated IEAR calculated from the GLF and the EUE obtained from the Multiple base case contingency analysis for each load point within the GPMC base case is provided in Table 4.9.

Table 4.9: Sub-system Load Point Damage Cost (R)

Sub-System	Load Point	EUE (MWh/yr)	IEAR (R/kWh)	Damage Cost (R)
BL-BO	Boomstreet	0.9	12.94	R 11 646
BL-ED	Edmond	0.8	9.72	R 7 776
BL-RV	River	9.3	15.61	R 145 173
EL-VL	Villieria	13.8	2.89	R 39 882
KW-DH/NJ	Wingate	33.7	3.12	R 105 144
	Kloofsig	3.9	6.38	R 24 882
	Zwartkops	18.6	2.79	R 51 894
	Claudius	11.6	2.32	R 26 912
	Zebra	29.4	6.58	R 193 452
KW-SAU	Saulsville	0.0	0.96	-
KW-ATT	Atteridgeville	0.0	2.71	-
KW-PK/RW	Gomsand	34.6	3.08	R 106 260
	Orchards	34.6	2.52	R 87 192
	Rosslyn	93.2	11.69	R 1 089 508
	Wolmer	44.0	2.71	R 119 240
	Wonderboom	65.8	2.24	R 147 392
	Pta-North	41.1	3.53	R 146 142
NJ-SC	Highlands	3.1	4.13	R 12 803
RW-WA/EL	Koedoespoort	35.9	8.06	R 289 354
	Pumulani	12.5	5.23	R 65 375
	Pyramid	12.0	0.96	R 11 520
	Waltloo	-	7.9	-
WA-NJ	Mooikloof	1.1	10.31	R 11 431
	Wapadrand	2.4	2.23	R 5 352
PK-BL	Capital Park	3.1	6.26	R 19 406
PP-BL	Princes Park	3.9	13.85	R 54 015
PK-MV	Mayville	0.0	7.13	-
SC-EL	Lynnwood	2.6	3.40	R 8 840
SC-WL	Willows	2.7	3.26	R 8 802
WA-MA	Mamelodi I	8.1	3.25	R 26 325
	Mamelodi II	6.9	2.69	R 18 561
	Mamelodi III	0.4	1.76	R 704
RIET-WAT	Waterkloof	1.0	2.53	R 2 530
BL-SK	Skinner	0.0	10.13	-

Table 4.9: Sub-system Load Point Damage Cost (continue)

Sub-System	Load Point	EUE (MWh/yr)	IEAR (R/kWh)	Damage Cost (R)
BU-K1	K1	0.0	2.00	-
BU-K3	K3	0.0	0.96	-
RIET-DH	De Hoewe	5.0	3.95	R 19 750
	Eldoraigne	7.7	2.76	R 21 252
	Raslouw	1.7	3.92	R 6 664
	Brakfontein	4.4	2.64	R 11 616
	Olievenhoud	-	-	-
	Kosmosdal	0.6	2.08	R 1 248
	NIVS	2.0	1.26	R 2 520
	Kentron	3.2	4.57	R 14 624
	Piet Geers	-	-	-

The results in Table 4.8 provide a more realistic load point EUE value than those values obtained for the single base case analysis. This is due to the variation of the loads for each case as a function of the system load duration curve shown in Figure 4:4. The objective of the indices and cost provided in Table 4.9 is to identify the sub-systems and associated substations which incur the highest costs as a result of network performance. This information is thus used to compliment the results obtained from the single case analysis of Table 4.7. Together this information is used to flag the areas in the network which, with regard to network reliability improvements, should be addressed first. This implies that network planners can use this information to prioritise network requirements in line with depleting funds.

The above information completes the portion of the methodology to identify possible problem areas (i.e. sub-systems and substations). The next step involves the identification of possible solutions to improve network performance in these areas and involves the evaluation of alternative network options within the Value-based planning framework.

In terms of incurred customer damage cost, the KW-PK/RW sub-system is again identified as being the system with the poorest performance. Customer losses amount to more than R 1,5 million per annum, with Rosslyn substation contributing more than 60% to this figure. This sub-system will be used in Chapter 5 as a case study environment to evaluate the Value-based methodology provided in Chapter 3.

4.6 CONCLUSION

This Chapter provided:

- The basic data requirements and modelling approach to perform a contingency enumeration process for the composite network. This approach includes substation reliability assessment, and
- Reliability indices for both a single and multiple base case contingency analysis.

The Chapter further utilised this data and modelling approach within standard substation and composite network reliability software in order to assess the reliability and associated load point damage cost for the study area. This Chapter concludes with the identification of the KW-PK/RW sub-system as being the worst performing portion of the network in terms of frequency and duration of load curtailment events as well as customer damage.

Chapter 5 will use this information to:

- Identify alternative network options to improve the network performance for this sub-system, and
- Evaluate each alternative within the proposed Value-based methodology of Chapter 3.

CHAPTER 5

5. CASE STUDY

5.1 INTRODUCTION

The previous Chapters provided the background required to evaluate different network alternatives within Value-based principles in order to quantify the reliability of a specific alternative and weigh that measure against the resulting worth of the alternative. Chapter 3 further proposed a methodology through which a specific network can be evaluated in order to identify possible network deficiencies with regard to reliability. The same methodology provides a framework through which network alternatives to improve these deficiencies can be evaluated. The reliability of the GPMC sub-transmission network was assessed in Chapter 4 and damage costs were calculated at each load point of the network. This was done in order to identify the poorest performing sub-system within this network and to use this sub-system as a case study to illustrate the methodology.

The objective of this Chapter is to use the methodology proposed in Chapter 3 to:

- Identify network alternatives to improve the performance for the sub-system identified in Chapter 4,
- To evaluate these alternatives within the proposed Value-based methodology, and to
- Propose the solution that results in the total minimum life cycle cost.

This methodology considers both the utility cost for providing network infrastructure as well as the resulting cost to customers due to the poor reliability of the network alternative.

5.2 CASE STUDY

The case study focuses on the KW-PK/RW sub-system as identified in Chapter 4. Network alternatives to improve the reliability performance of this system are identified. The necessary assumptions to simplify the analysis of these alternatives are made in order to keep to the objective of the dissertation, which is to prove the Value-based evaluation methodology. The case study will provide the environment through which the reliability performance improvements for the total GPMC and similar networks can be conducted.

5.2.1 Case Definition

The KW-PK/RW sub-system has three source nodes from which supply can be taken. These nodes are the Kwagga supply station, Rooiwal generation station and Park Town switching station.

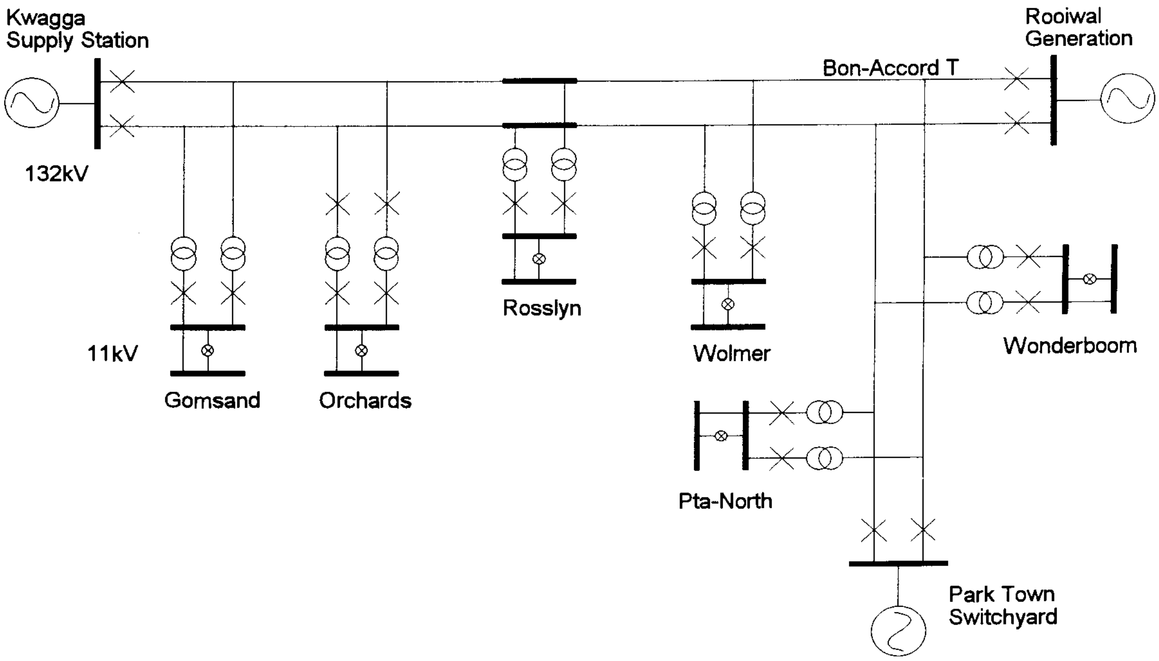

Figure 5:1 KW-PK/RW Sub-system

Six distribution substations are connected to this sub-system. All these substations are of the redundant transformer type as discussed in Chapter 2 and are Teed-off from the 132kV overhead line. A simplified schematic diagram for the system is shown in Figure 5:1.

The reliability indices that are calculated for this system in Chapter 4 are repeated for convenience in Table 5.1 and Table 5.2.

Table 5.1: Sub-system Load Point Reliability Indices

Sub-System	Load Point	Total Load (MW)	Frequency (occ/yr)	Duration (hr/yr)	Curtailment (MWh/yr)
KW-PK/RW	Gomsand	20	3.347	1.1	75.20
	Orchards	22	4.687	0.7	75.76
	Rosslyn	55.1	3.347	0.97	203.13
	Wolmer	25.8	3.347	1.1	96.47
	Wonderboom	39.6	4.017	0.9	143.69
	Pta-North	26.6	4.687	0.7	90.92

Table 5.2: Sub-system Load Point Damage Cost (R)

Sub-System	Load Point	EUE (MWh/yr)	IEAR (R/kWh)	Damage Cost (R)
KW-PK/RW	Gomsand	34.6	3.08	R 106 260
	Orchards	34.6	2.52	R 87 192
	Rosslyn	93.2	11.69	R 1 089 508
	Wolmer	44.0	2.71	R 119 240
	Wonderboom	65.8	2.24	R 147 392
	Pta-North	41.1	3.53	R 146 142

5.2.2 Case Assumptions

The case assumptions are primarily made to simplify the analysis and evaluation of network alternatives. The emphasis of the case study is not to provide an exact real life solution to the specific sub-system, but rather to provide the methodology through which the real life alternatives should be analysed. It is thus critical to realise that not all the practical long-term network alternatives will be catered for in this study. An example of this is the connection of the sub-system to a possible new supply point. The incorporation of this type of alternative will lead to time consuming modelling and analysis and will defeat the objective of this dissertation.

The following assumptions will apply to the evaluation of all network alternatives:

- The study period is 30 years, and will be analysed in discrete steps (i.e. Base year and each year where network changes due to capacity deficiencies are required),
- Linear interpolation will be used to quantify parameters between these intervals,
- The average age of all existing equipment is assumed to be 10 years, this assumption is made to simplify the cost calculations (i.e. no refurbishment costs are incorporated),
- The expansion of the sub-system will be a function of load growth in the supply area and will not take into consideration network reinforcement alternatives to connect the system to other sub-systems (once again this is done to simplify the evaluation method),
- Land-use changes will be taken into consideration, this will be catered for by the Geographical Load Forecast,
- Only alternatives on the sub-transmission network will be considered (in a more detailed environment distribution system alternatives could provide for a more feasible solution),
- The impact of the total GPMC network performance on the sub-system will be evaluated,

- Generic stochastic data will be utilised where existing data is not available, and
- Although not shown in this case study, all network alternatives will be evaluated with regard to load flow, fault level and voltage violations to ensure credible solutions.

5.3 NETWORK ALTERNATIVES

Four network alternatives will be analysed in this case study.

These alternatives are:

- The reconfiguration of the existing T-off system to a full Turn-in system as discussed in , paragraph 2.3.1.1,
- The provision of an interconnected switching station at Bon-Accord T,
- The splitting of the network at Rosslyn substation by means of remotely operated circuit breakers, and
- The incorporation of high voltage (HV) line feeder circuit breakers at each substation.

These alternatives are briefly discussed in the sections that follow.

5.3.1 Alternative 1: Reconfiguration to Full Turn-in Scheme

The first alternative involves the reconfiguration of the existing T-off system to a full Turn-in system. At present the substations transformers within this system are directly connected to the individual feeder lines and no formal HV busbar exist at these stations. For simplicity it is proposed that each station is equipped with a single HV bus. This will simplify the modelling and analysis and should not influence the overall case solution. Furthermore each substation will be equipped with the necessary line feeder bays and the main protection scheme will be changed from the line impedance scheme to a unit protection scheme as discussed in paragraph 2.3.4. The substations are all of the redundant transformer type and will remain like this for the base year of analysis. These stations will however be reconfigured to a modified ARBC (paragraph 2.3.2) configuration, as expansion due to load growth is required. This will apply to all alternatives.

The simplified schematic diagram for this alternative is shown in Figure 5:2.

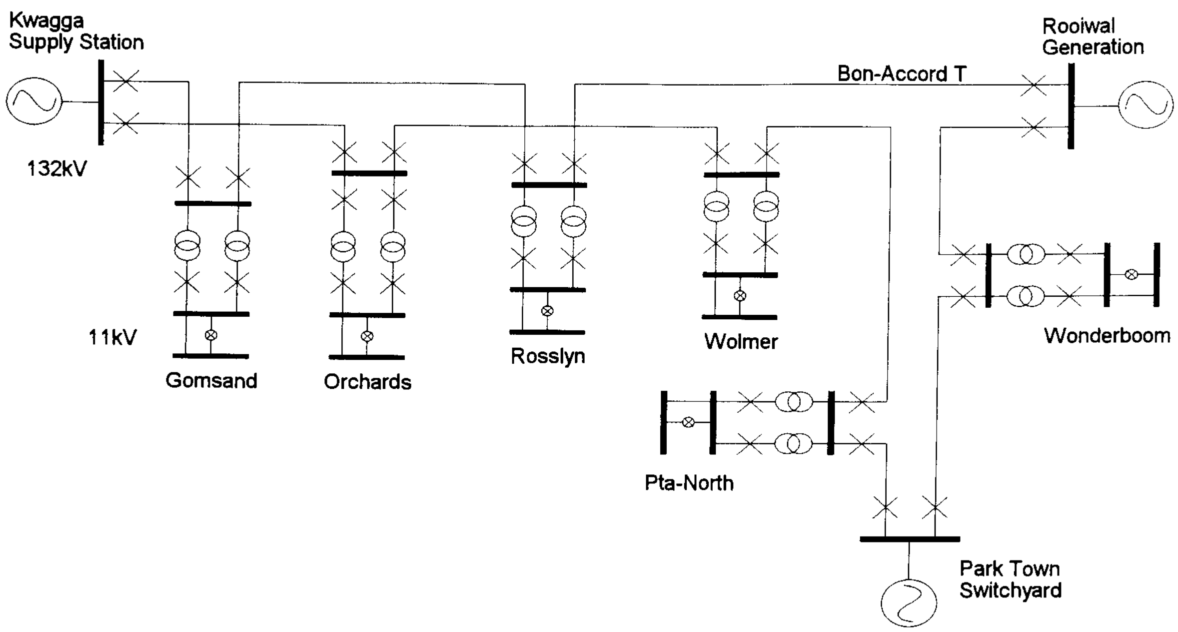

Figure 5:2 Alternative 1; Full Turn-in

5.3.2 Alternative 2: Provide Switching Station at Bon-Accord T

The objective of the second alternative is to divide the sub-system into three sections, forming three new sub-systems in order to isolate the associated system failure events. The simplified schematic is shown in Figure 5:3.

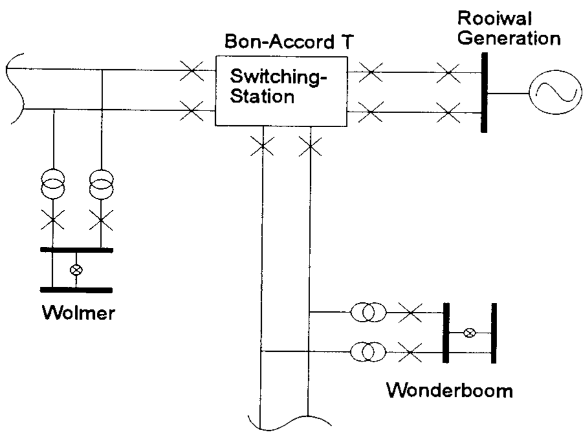

Figure 5:3 Alternative 2; Bon-Accord Switching Station

The main protection scheme for the sub-system will remain. This implies that new protection zones will be defined to cater for the new sub-systems. The switching station will be a double busbar station with the possibility of selecting the incoming feeders to any one of the busbars.

5.3.3 *Alternative 3: Split Network at Rosslyn Substation*

The third alternative is similar to the previous alternative, with the difference being that the sub-system split is provided at Rosslyn substation. The simplified schematic is shown in Figure 5:4.

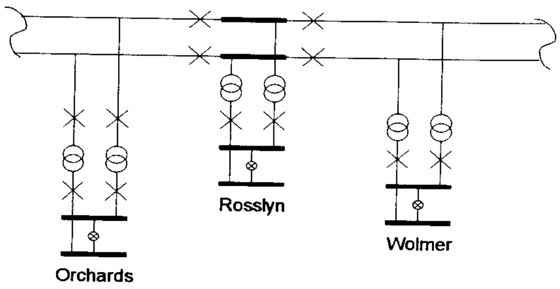

Figure 5:4 Alternative 3; Network Split at Rosslyn

5.3.4 *Alternative 4: Incorporate Line Feeder Circuit Breakers at all Stations*

The final alternative proposes the placement of HV circuit breakers at all the substation line feeder bays. The objective of this alternative is to prevent transformer or substation related failures to spread to the feeder line resulting in the loss of that specific line as well as all substations connected to that line.

5.4 Reliability Analysis and Results

This section provides the results obtained from the evaluation of each alternative. Each alternative is analysed and evaluated for five distinctive years. These years correspond to the investment years at each substation when capacity upgrades are required. The results obtained from the analysis is then used along with the cost methodology provided in Chapter 3 to identify the alternative which will result in the total minimum cost.

For this case study the incremental investment cost to install infrastructure is evaluated against the incremental network improvement or decrease in customer damage cost.

5.4.1 *Alternative 1: Reconfiguration to Full Turn-in Scheme*

Note that the full Turn-in reconfiguration is done during the base year and that all substations in this alternative will be reconfigured to the ARBC configuration once capacity upgrade is required. Evaluation results are provided in Table 5.3.

Table 5.3: Sub-system Evaluation Results: Alternative 1

Alternative Base Year	Load (MW)	Capital (Rm)	EUE (MWh/yr)	Damage Cost (R/yr)
Gomsand	20	R 3 290	0.80	R 2 464
Orchards	22	R 3 290	0.88	R 2 218
Rosslyn	55.1	R 4 835	4.41	R 51 530
Wolmer	25.8	R 3 290	1.55	R 4 195
Wonderboom	39.6	R 4 835	5.54	R 12 419
Pta-North	26.6	R 3 290	2.13	R 7 512
Kwagga/Rooi		R 3 290		
Total		**R 26 120**		**R 80 338**
Year 2001	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	40	R 2 217	1.60	R 4 928
Orchards	25	-	1.00	R 2 520
Rosslyn	68	-	5.44	R 63 594
Wolmer	35	R 2 217	2.10	R 5 691
Wonderboom	46	-	6.44	R 14 426
Pta-North	27	-	2.16	R 7 625
Total		**R 4 434**		**R 98 784**
Year 2007	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	67	R 2 217	2.68	R 8 254
Orchards	38	R 2 217	1.52	R 3 830
Rosslyn	105	-	8.40	R 98 196
Wolmer	76	R 2 217	4.56	R 12 358
Wonderboom	78	-	10.92	R 24 461
Pta-North	32	-	2.56	R 9 037
Total		**R 6 651**		**R 156 136**
Year 2011	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	86	-	3.44	R 10 595
Orchards	45	-	1.80	R 4 536
Rosslyn	107	-	8.56	R 100 066
Wolmer	103	-	6.18	R 16 748
Wonderboom	100	-	14.00	R 31 360
Pta-North	35	R 2 217	2.80	R 9 884
Total		**R 2 217**		**R 173 189**

Table 5.3 : Sub-system Evaluation Results: Alternative 1 (Continue)

Year 2029	Load (MW)	Capital (Rm)	EUE (MWh/yr)	Damage Cost (R/yr)
Gomsand	120	-	4.80	R 14 784
Orchards	80	-	3.20	R 8 064
Rosslyn	110	-	8.80	R 102 872
Wolmer	100	-	6.00	R 16 260
Wonderboom	107	-	14.98	R 33 555
Pta-North	60	-	4.80	R 16 944
Total		**R 0.0**		**R 192 479**

The average annual investment over the life cycle of Alternative 1, amounts to R 3 918 637, to the utility. This investment has an extremely positive result on the connected customers, decreasing the average annual damage cost from R 1 576 494 to R 163 281. The total present worth of the alternative is however high at R 32 473 134. The annual cash flow for this alternative is shown graphically in Figure 5:5.

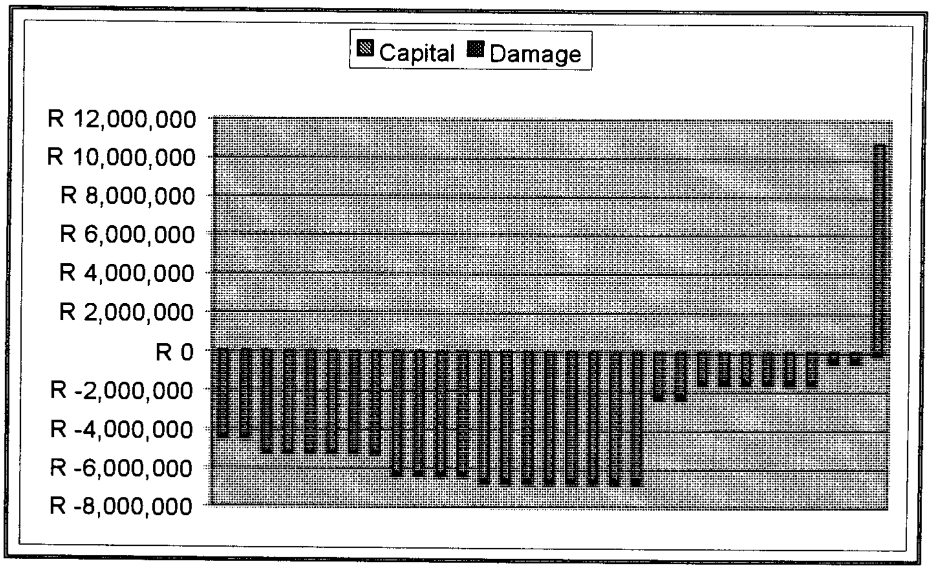

Figure 5:5 Annual Cash Flow for Alternative 1

5.4.2 Alternative 2: Bon-Accord Switching Station

The Bon-Accord switching station consists of a double busbar scheme with six line feeder bays, each having the ability to be selected to either one of the busbars. All feeder circuits are operated normally closed. This configuration will enable the effective isolation of failures in one portion of the sub-system and prevents the spread of the disturbance to the remainder of the system. The switching station is fully modelled during the base year and all substations in this alternative are reconfigured to the ARBC configuration once capacity upgrade is required. Results obtained from the reliability and cost evaluation is provided in Table 5.4.

Table 5.4: Sub-system Evaluation Results: Alternative 2

Alternative Base Year	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	20	-	14.5	R 44 660
Orchards	22	-	15.8	R 39 816
Rosslyn	55.1	-	39.9	R 466 431
Wolmer	25.8	-	18.5	R 50 135
Wonderboom	39.6	-	10.5	R 23 520
Pta-North	26.6	-	7.0	R 24 710
Bon-Accord		R 10 380	-	
Total		**R 10 380**		**R 649 272**
Year 2001	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	40	R 2 217	29.0	R 89 320
Orchards	25	-	18.0	R 45 245
Rosslyn	68	-	49.2	R 575 632
Wolmer	35	R 2 217	25.1	R 68 013
Wonderboom	46	-	12.2	R 27 321
Pta-North	27	-	7.1	R 25 082
Total		**R 4 434**		**R 830 613**
Year 2007	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	67	R 2 217	48.6	R 149 611
Orchards	38	R 2 217	27.3	R 68 773
Rosslyn	105	-	76.0	R 888 843
Wolmer	76	R 2 217	54.5	R 147 684
Wonderboom	78	-	20.7	R 46 327
Pta-North	32	-	8.4	R 29 726
Total		**R 6 651**		**R 1 330 964**

Table 5.4 : Sub-system Evaluation Results: Alternative 2 (Continue)

Year 2011	Load (MW)	Capital (Rm)	EUE (MWh/yr)	Damage Cost (R/yr)
Gomsand	86	-	62.4	R 192 038
Orchards	45	-	32.3	R 81 442
Rosslyn	107	-	77.5	R 905 773
Wolmer	103	-	73.9	R 200 151
Wonderboom	100	-	26.5	59 394
Pta-North	35	R 2 217	9.2	32 513
Total		**R 2 217**		**R 1 471 311**
Year 2029	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	120	-	87.0	R 267 960
Orchards	80	-	57.5	R 144 785
Rosslyn	110	-	79.7	R 931 169
Wolmer	100	-	71.7	R 194 322
Wonderboom	107	-	28.4	R 63 552
Pta-North	60	-	15.8	R 55 737
Total		**R 0.0**		**R 1 657 525**

The average annual investment over the life cycle of Alternative 2, amounts to R 2 380 046, to the utility. This is 40% less than Alternative 1. The average annual damage cost to connected customers decrease from R 1 576 494 in Alternative 1, to R 1 373 099 in this Alternative.

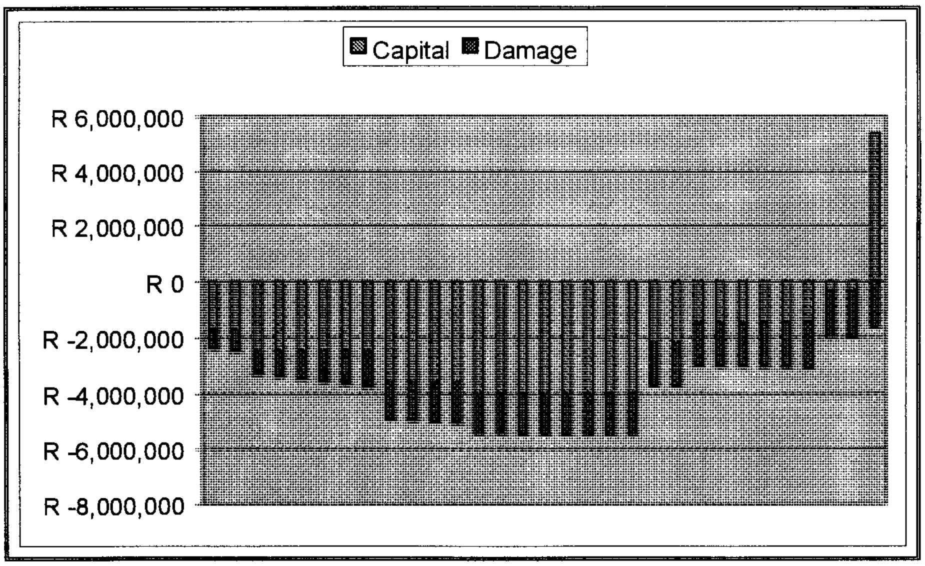

Figure 5:6 Annual Cash Flow for Alternative 2

The total present worth of the alternative is R 22 563 316, which is 30% less than that of Alternative 1. The annual cash flow for this alternative is shown graphically in Figure 5:6.

5.4.3 Alternative 3: Network Split at Rosslyn

Similar to the previous alternative, the objective of this alternative is to provide an electrical split in the sub-system to isolate system failures within the sub-system. The feeder circuit breakers at Rosslyn substation will enable the isolation of failures in one portion of the sub-system and will prevent the spread to the remainder of the system. The reconfiguration of Rosslyn substation is modelled during the base year and all substations in this alternative are reconfigured to the ARBC configuration once capacity upgrade is required. Results obtained from the reliability and cost evaluation is provided in Table 5.5.

Table 5.5: Sub-system Evaluation Results: Alternative 3

Alternative Base Year	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	20	-	8.8	R 27 104
Orchards	22	-	9.6	R 24 192
Rosslyn	55.1	R 3 985 500	29.9	R 349 531
Wolmer	25.8	-	20.3	R 55 013
Wonderboom	39.6	-	31.3	R 70 112
Pta-North	26.6	-	20.8	R 73 424
Total		**R 3 985 500**		**R 599 376**
Year 2001	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	40	R 2 217	17.6	R 54 208
Orchards	25	-	10.9	R 27 491
Rosslyn	68	-	36.9	R 431 363
Wolmer	35	R 2 217	27.5	R 74 630
Wonderboom	46	-	14.6	R 32 785
Pta-North	27	-	21.1	R 74 528
Total		**R 4 434**		**R 695 005**

Table 5.5 : Sub-system Evaluation Results: Alternative 3 (Continue)

Year 2007	Load (MW)	Capital (Rm)	EUE (MWh/yr)	Damage Cost (R/yr)
Gomsand	67	R 2 217	29.5	R 90 798
Orchards	38	R 2 217	16.6	R 41 786
Rosslyn	105	-	57.0	R 666 075
Wolmer	76	R 2 217	59.8	R 162 054
Wonderboom	78	-	24.8	R 55 593
Pta-North	32	-	25.0	R 88 330
Total		**R 6 651**		**R 1 104 636**
Year 2011	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	86	-	37.8	R 116 547
Orchards	45	-	19.6	R 49 484
Rosslyn	107	-	58.1	R 678 763
Wolmer	103	-	81.0	R 219 626
Wonderboom	100	-	31.8	R 71 273
Pta-North	35	R 2 217	27.4	R 96 611
Total		**R 2 217**		**R 1 232 304**
Year 2029	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	120	-	52.8	R 162 624
Orchards	80	-	34.9	R 87 971
Rosslyn	110	-	59.7	R 697 793
Wolmer	100	-	78.7	R 213 229
Wonderboom	107	-	34.0	R 76 262
Pta-North	60	-	46.9	R 165 618
Total		**R 0.0**		**R 1 403 497**

The average annual investment over the life cycle of Alternative 3, amounts to R 1 727 587, to the utility. This investment has a less favoured result on the customer with an average annual damage of R 1 162 393. The total present worth of the alternative is R 15 106 504, which is less than 50% of Alternative 1. The annual cash flow for this alternative is shown graphically in Figure 5:7.

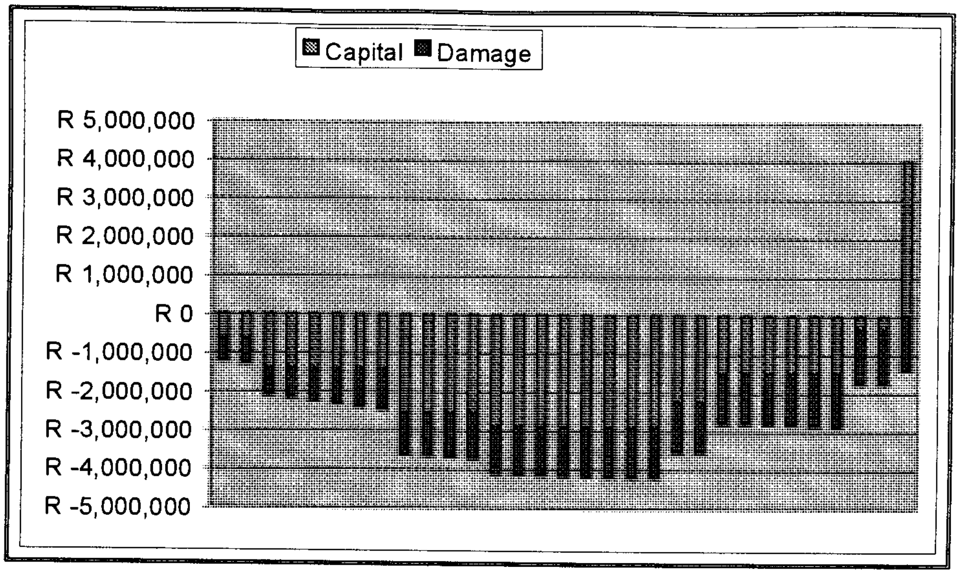

Figure 5:7 Annual Cash Flow for Alternative 3

5.4.4 Alternative 4: Line Feeder Circuit Breakers

Results obtained from the reliability and cost evaluation is provided in Table 5.6.

Table 5.6: Sub-system Evaluation Results: Alternative 4

Alternative Base Year	Load (MW)	Capital (Rm)	EUE (MWh/yr)	Damage Cost (R/yr)
Gomsand	20	R 1 607 750	3.96	R 12 197
Orchards	22	R 1 607 750	4.32	R 10 886
Rosslyn	55.1	R 2 650 000	13.5	R 157 289
Wolmer	25.8	R 1 607 750	9.1	R 24 756
Wonderboom	39.6	R 1 607 750	5.67	R 12 701
Pta-North	26.6	R 1 607 750	9.4	R 33 041
Other	-	R 848 250	-	-
Total		**R 11 537 000**		**R 250 870**
Year 2001	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	40	R 2 217	7.9	R 24 394
Orchards	25	-	4.9	R 12 371
Rosslyn	68	-	16.6	R 194 113
Wolmer	35	R 2 217	12.4	R 33 584
Wonderboom	46	-	6.6	R 14 753
Pta-North	27	-	9.5	R 33 538
Total		**R 4 434**		**R 312 753**

Table 5.6 : Sub-system Evaluation Results: Alternative 4 (Continue)

Year 2007	Load (MW)	Capital (Rm)	EUE (MWh/yr)	Damage Cost (R/yr)
Gomsand	67	R 2 217	13.3	R 40 859
Orchards	38	R 2 217	7.5	R 18 804
Rosslyn	105	-	25.6	R 299 734
Wolmer	76	R 2 217	26.9	R 72 924
Wonderboom	78	-	11.2	R 25 017
Pta-North	32	-	11.3	R 39 748
Total		**R 6 651**		**R 497 086**
Year 2011	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	86	-	17.0	R 52 446
Orchards	45	-	8.8	R 22 268
Rosslyn	107	-	26.1	R 305 443
Wolmer	103	-	36.5	R 98 831
Wonderboom	100	-	14.3	R 32 073
Pta-North	35	R 2 217	12.3	R 43 475
Total		**R 2 217**		**R 554 536**
Year 2029	**Load (MW)**	**Capital (Rm)**	**EUE (MWh/yr)**	**Damage Cost (R/yr)**
Gomsand	120	-	23.8	R 73 181
Orchards	80	-	15.7	R 39 587
Rosslyn	110	-	26.9	R 314 007
Wolmer	100	-	35.4	R 95 953
Wonderboom	107	-	15.3	R 34 318
Pta-North	60	-	21.1	R 74 528
Total		**R 0.0**		**R 631 574**

The average annual investment over the life cycle of Alternative 4, amounts to R 2 463 522, to the utility. This figure is more than R 700 000 per annum higher than that of Alternative 3. The average annual customer damage cost is on the other hand far less with a resulting R 522 395 per annum. The total present worth of the alternative is R 19 617 814, which makes this Alternative competitive with Alternative 3. The annual cash flow for this alternative is shown graphically in Figure 5:8.

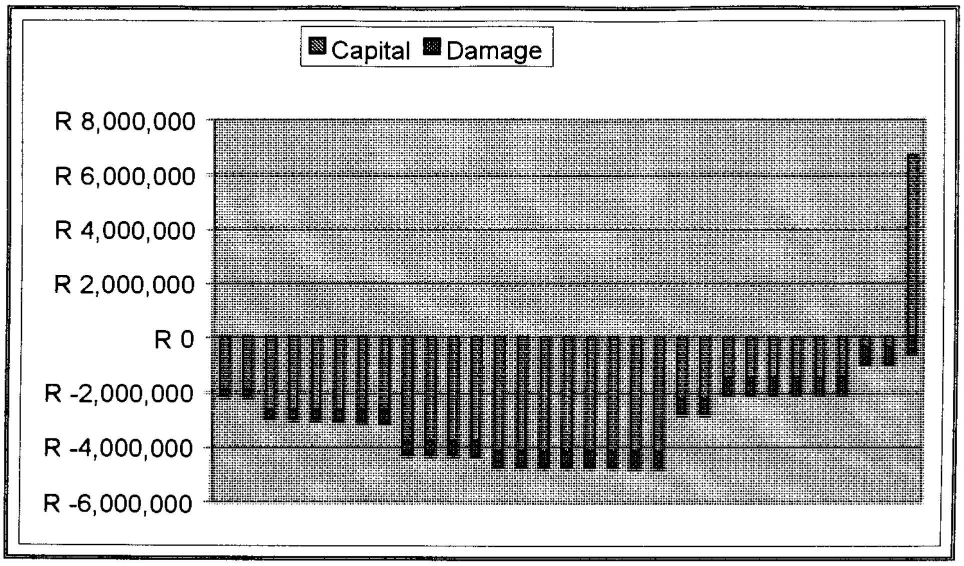

Figure 5:8 Annual Cash Flow for Alternative 4

5.4.5 Summary of Results

Table 5.7 shows a summary of the average annual investment and customer damage cost, as well as the total present worth for each alternative. From this table Alternative 3 can be identified as being the alternative which results in the minimum total present worth. This corresponds to the objective of the Value-based methodology and is the preferred alternative.

Table 5.7 : Summary of Results

Alternatives	Average Annual Investment (R)	Average Annual Customer Damage (R)	Total Present Worth (R)
Alternative 1	R 3 918 637	R 163 281	R 32 473 134
Alternative 2	R 2 380 046	R 1 373 099	R 22 563 316
Alternative 3	**R 1 727 587**	**R 1 162 393**	**R 15 106 503**
Alternative 4	R 2 463 522	R 522 395	R 19 617 814

5.5 SENSITIVITY ANALYSIS

One of the key factors during the assessment of network reliability and its worth is the accuracy of data. The previous analysis has relied heavily on generic data especially in the case of SCDF's and to a lesser extent on stochastic equipment data. In order to test the validity of the answers obtained from the analysis, this section will evaluate the sensitivity of the model to the variation of both the stochastic equipment data and the SCDF's.

5.5.1 Variation of Stochastic Data

In this section the stochastic data utilised for the analysis of Alternative 3 is varied for the base case and the effect is monitored on the load point EUE at each substation in the sub-system. This is done for four distinct steps. The percentage change in EUE as a result of this variation are shown in Table 5.8

Table 5.8 : Variation of Stochastic Data vs. EUE

% Change in Expected Unserved Energy (MWh/yr)				
Load Point	**- 10 %**	**- 5 %**	**+ 5 %**	**+ 10 %**
Gomsand	-19.32	-10.23	10.23	20.45
Orchards	-18.75	-10.42	10.42	**20.85**
Rosslyn	-8.70	-5.69	4.01	12.37
Wolmer	-19.21	-9.85	9.85	20.67
Wonderboom	-18.85	-9.58	10.22	20.77
Pta-North	**-19.23**	-10.10	10.10	20.67
Total	-16.49	-8.86	8.62	18.64

Although the range of variation is limited, it can be seen from Table 5.8 that the model is very sensitive towards the variation of stochastic network data (i.e. Failure and Repair rates of equipment). The worst percentage change is monitored at Orchards substation where a 10% change in the stochastic data results in a 20.85% change in EUE. This analysis can further be expanded to include a wider range of variations. From this basic analysis however it can be seen that it is vital to obtain accurate network specific information if it is required to quantify the reliability indices for a specific network alternative.

5.5.2 Variation of Sector Customer Damage Functions

The same Alternative is used to monitor the sensitivity of the model towards the change in the three major Sector Customer Damage Functions namely, Residential, Business/Commercial and Industrial Sectors. Each SCDF is varied individually for four discrete steps while the remaining sectors are kept constant. This is done to assess the sensitivity of each load point as well as the sub-system towards the individual SCDF's. This information can then be used to identify the

SCDF with the largest influence on the accuracy of the Damage Cost Assessment of each alternative.

Tables 5.9 through to Table 5.11 provide the results obtained from the analysis.

Table 5.9 : Variation of Residential SCDF vs. Customer Damage Cost

% Change in Damage Cost from the Base				
Load Point	**10 %**	**20 %**	**30 %**	**40 %**
Gomsand	4.58	9.16	13.74	18.32
Orchards	4.42	8.84	13.26	17.69
Rosslyn	0.00	0.00	0.00	0.00
Wolmer	4.80	9.60	14.41	19.21
Wonderboom	7.53	15.07	22.60	**30.14**
Pta-North	5.27	10.54	15.81	21.08
Total	2.36	4.72	7.08	9.44

The variation of the Residential SCDF results in a moderate change in overall sub-system Damage Cost with the highest change monitored at Wonderboom substation. At this load point a 40% change in the Residential SCDF result in a 30.14% change in annual Damage Cost.

Table 5.10 : Variation of Business/Commercial SCDF vs. Customer Damage Cost

% Change in Damage Cost from the Base				
Load Point	**10 %**	**20 %**	**30 %**	**40 %**
Gomsand	0.08	0.16	0.25	0.33
Orchards	3.50	7.0	10.50	**14.00**
Rosslyn	1.18	2.37	3.55	4.74
Wolmer	0.55	1.09	1.64	2.19
Wonderboom	0.57	1.14	1.71	2.29
Pta-North	2.15	4.29	6.44	8.59
Total	1.21	2.43	3.64	4.86

Table 5.10 shows that the network model is less sensitive towards the variation of the Business/Commercial SCDF with the highest sub-system change being 4.86% and the worst load point change being 14%.

The SCDF resulting in the largest percentage change for both the sub-system and the load point is the Industrial Sector. At Rosslyn substation the percentage change in Damage Cost is almost linear with the change in the Industrial SCDF. A 40% change in the SCDF results in a 34.91% change in Damage Cost. This is expected due to the fact that the Rosslyn supply area is mainly industrial. The sub-system is further sensitive to the change in the Industrial SCDF with the largest percentage change being 22.93%.

Table 5.11 : Variation of Industrial SCDF vs. Customer Damage Cost

% Change in Damage Cost from the Base				
Load Point	**10 %**	**20 %**	**30 %**	**40 %**
Gomsand	3.32	6.64	9.97	13.29
Orchards	0.00	0.00	0.00	0.00
Rosslyn	8.73	17.45	26.18	**34.91**
Wolmer	2.92	5.85	8.77	11.69
Wonderboom	0.00	0.00	0.00	0.00
Pta-North	1.90	3.80	5.69	7.59
Total	5.73	11.47	17.20	**22.93**

From the above tables it can be concluded that the sub-system is relatively unaffected by the change in the Business/Commercial SCDF and most sensitive towards the change in the Industrial SCDF. This can be ascribed to the following:

- 36% of the sub-system load mix is industrial,
- Very little Business/Commercial load is supplied by the network, and
- The Residential SCDF is in magnitude, on average 20% of the Industrial SCDF.

In order to quantify the impact of network unreliability on the connected customers it will thus be necessary to assess the actual SCDF for this specific supply area. The largest benefit will be gained by assessing the Industrial SCDF.

5.6 CONCLUSION

This Chapter applied the Value-based methodology proposed in Chapter 3, in a case study environment. Four network alternatives were identified and evaluated to improve the KW-PK/RW sub-system identified in Chapter 4.

Each alternative was analysed with regard to its:

- Life cycle cost to the utility in terms of annual capital investment,
- Network reliability indices, specifically load point EUE,
- The resulting annual life cycle Customer Damage Cost, and
- The present worth of each alternative, which is a function of the above.

A sensitivity analysis was conducted on the base year of Alternative 3 to assess the sensitivity of the model towards changes in stochastic equipment data as well as SCDF's. The conclusion on this aspect is that the model is highly sensitive to any change in stochastic equipment data, which emphasise the importance of having utility specific data for the evaluation of network alternatives. The analysis further concludes that the case study is sensitive towards the change of the Industrial SCDF and that generic data for this purpose could result in inaccurate solution proposals.

This Chapter concludes:

- That the application of the basic methodology as proposed in Chapter 3, can assist network planners in the evaluation of long-term network alternatives, and
- That the utilisation of this methodology will lead to the identification of network alternatives, which result in the total minimum life cycle cost, and in the effective application of funding on a national basis.

The basic methodology proposed in Chapter 3 can be improved in a number of aspects and the following Chapter will make recommendations, which address some of these aspects.

CHAPTER 6

6. RECOMMENDATIONS

6.1 INTRODUCTION

Although the basic process to plan an electrical infrastructure is relatively straightforward, planning an electrical network that will address all the requirements for the future will remain a challenge. As knowledge of a network and the technology to model the different aspects and behaviour thereof improves, so will the accuracy of future predictions.

The methodology developed in this dissertation focused on bridging the long-standing gap between deterministic techniques such as N-1 and probability techniques to assist network planners in the analysis and design of future networks. The methodology provides a broad approach, touching on a wide range of aspects that need to be considered during the application. The reason being that reliability assessment of bulk power systems, especially with regard to the planning of future networks, does not form part of an integrated planning environment in South Africa. The objective of this Chapter is thus to make recommendations which will support the methodology in order to guide future developments. These recommendations take into consideration the specific needs of the GPMC, but are not limited to the GPMC network.

6.2 RECOMMENDATIONS WITH REGARD TO DATA REQUIREMENTS

Gathering sufficient data to effectively model a network with regard to its configuration, behaviour and impact on connected customers will remain a difficult task. As shown in the previous Chapter, this data is vital if the methodology developed in this dissertation is to be used to quantify long-term network expansion options. In the case of the GPMC the deterministic data required to model the exact configuration of the network is in place. The data required to model the stochastic behaviour of the network is however not sufficient.

6.2.1 Stochastic Data for Major Sub-transmission Equipment

In the case study presented in Chapter 5, the sensitivity of the sub-system towards the variation of stochastic data was demonstrated in paragraph 5.5.1. Table 5.8 showed, as an example that the largest change in energy curtailment as a function of the variation of stochastic data occurred at Orchards substation. A 10% change in stochastic data resulted in more than a 20% change in energy curtailment. It was concluded that in order to quantify the reliability indices for a specific network alternative, it is vital to obtain accurate network specific information.

Stochastic data for a utility network should typically be maintained for a minimum period of five years. After this period a first in – first out data recording approach is recommended where the first year's data will be dropped and replaced by the next year's data.

As a minimum the following data should be maintained:

- An inventory for all transmission equipment,
- Forced outage statistics, and
- Planned and unplanned maintenance statistics for the equipment.

Forced outage statistics is divided into two categories namely failures involving equipment internal sub-components and secondly failures involving terminal equipment associated with the main component.

As an example Table 6.1 and Table 6.2 provides a typical spreadsheet for statistical data related to power transformers and their associated terminal equipment. The data attributed for the example is similar to that used by the Canadian Electricity Association and should be specific for each utility's use.

Table 6.1 : Transformer Bank Forced Outage Statistics (Internal Sub-Components)

Internal Sub-Components				
Sub-Component	**Number of Outages**	**Frequency (per year)**	**Total Time (h)**	**Mean Duration (h)**
Bushing (Inc. CT's)	-	-	-	-
Windings	-	-	-	-
On-Load Tap Changer	-	-	-	-
Core	-	-	-	-
Leads	-	-	-	-
Auxiliary Equipment	-	-	-	-
Cooling Equipment	-	-	-	-
Other	-	-	-	-

Table 6.2 : Transformer Bank Forced Outage Statistics (Terminal Equipment)

Terminal Equipment				
Sub-Component	**Number of Outages**	**Frequency (per year)**	**Total Time (h)**	**Mean Duration (h)**
Control and Protection	-	-	-	-
Surge Arrester	-	-	-	-
Disconnect	-	-	-	-
Current Transformer	-	-	-	-
Voltage Transformer	-	-	-	-
Other	-	-	-	-
Unknown	-	-	-	-

Further information required is the primary cause that can be attributed to the outage or malfunction of major equipment. Causes that may apply, are defective equipment, adverse weather conditions, system conditions, human elements and foreign interference. These attributes should be maintained with each event.

6.2.2 Auxiliary Equipment Failure and Repair Statistics

Network auxiliary equipment statistics is of specific concern to the GPMC network due to the fact that a major portion of the network relies on the correct functioning during load transfer operations. Auxiliary equipment will for the purpose of this discussion be divided into two categories namely:

- Auxiliary equipment related to the automatic load transfer scheme, and
- All other auxiliary equipment that forms part of primary plant protection.

The reliability of the automatic load transfer scheme used on the T-off sub-systems of the GPMC, could have a vital impact on the overall reliability of the sub-system. This scheme was discussed under paragraph 2.3.4.1. The scheme relies on the operation of auxiliary equipment such as electo-mechanical relays, pilot cables used for communication between relays at remote substations and the battery banks that supply these relays.

Under normal operating conditions load transfer from the main transformer to the back-up transformer will involve the automatic opening and closing of the relevant 11kV circuit breakers. This will cause a momentary interruption to connected customers with a duration of five seconds. If however the auxiliary equipment fails to operate, the interruption becomes a sustained interruption with varying duration. Two distinct time frames apply. The first ranging from five to ten minutes involving an operator remotely opening and closing the appropriate circuit breakers from the SCADA system. The second ranging from thirty minutes to an hour that involve a crew being dispatched to the faulty substation and manually transferring load from the main to the back-up transformer.

In order to quantify the impact of the above conditions on the overall system and the connected customers, the following data are required:

- The failure probability for auxiliary equipment which has a direct impact on the load transfer scheme,
- The probability and average duration of successful remote operations required to achieve load transfer if automatic operations have failed, and
- The average duration for manual operations in the case where remote operation has failed.

Furthermore a model needs to be devised which will effectively represent these conditions during the assessment of substation reliability. Within this dissertation a simplified model was used in which the load transfer scheme was assumed to be fully reliable. This results in optimistic reliability indices.

The second category of auxiliary equipment failures relates to the behaviour of the network under contingency conditions. The stochastic behaviour of equipment within a network only provides part of the requirements to model that network for reliability assessment purposes. Another major requirement is knowing how the network will respond during the occurrence of a network failure. An environment needs to be developed, typically forming part of the SCADA system, through which the network response to disturbances can be monitored and maintained.

6.2.3 Assessment of Customer Damage Functions

The sensitivity of the sub-system studied in Chapter 5, towards Sector Customer Damage Functions, was demonstrated in paragraph 5.5.2.

From the results obtained the conclusion was made that the sub-system is relatively unaffected to the change in the Business/Commercial SCDF's and is most sensitive towards the change in the Industrial SCDF. Table 5.11 has shown that a 40% change in the Industrial SCDF resulted in a 34.91% change in Customer Damage Cost. This corresponds to an R 120 000 increase in annual Damage Cost at Rosslyn substation, for Alternative 3.

This variation can be ascribed to the fact that:

- 36% of the sub-system load mix is industrial,
- Very little Business/Commercial load is supplied by the network, and
- The Residential SCDF is in magnitude, on average 20% of the Industrial SCDF.

Utilising generic SCDF's can thus lead to erroneous values and can impact on the validity of a chosen alternative. In order to quantify the impact of network unreliability on the connected customers it is necessary to assess the actual SCDF's for a specific supply area.

Several diverse categories of end-users can be connected to an electric network. The cost of an interruption from the customer's perspective is related to the nature of and degree to which the activities interrupted or affected are dependent on electrical supply. In turn, this dependency is a function of both customer and interruption characteristics. Customer characteristics include type of customer, nature of the customer's activities, size of operation, demographic data, demand and energy requirements and energy dependency as a function of time of day.

Typical residential loads perform functions such as refrigeration, space heating and cooling, water heating, lighting, entertainment and tasks alike. These loads are normally not sensitive to momentary voltage fluctuations or disturbances and it is difficult to quantify the cost associated with voltage interruptions for residential type activities. These losses are usually regarded as being lower than that experienced by commercial and industrial customers [48].

In the case of industrial customers, direct cost as a result of an interruption can be ascribed to factors such as:

- Plant or equipment damage,
- Raw material or finished product damage,
- Start-up costs (extra cleanup or maintenance),
- Production loss (during failure and restart time), and
- Overtime to make up lost production (e.g. operating standby equipment)

[48] G. Wacker, R. Billinton, "Interruption Cost Methodologies and Results – A Canadian Residential Survey", IEEE Trans. Power Apparatus Systems, Vol. PAS-102, No.10, pp. 3385-3392, October 1983

Indirect effects and social consequences are often quite difficult to assess in monetary terms and depending on the approach adopted, they are often only partially included in cost estimations or neglected altogether.

The cost of interruption data is of critical importance in the evaluation of reliability worth. Many different approaches in various countries have been employed to investigate the impacts and costs of interruptions to different customers [3 50]. The studies show that the interruption cost varies over a wide range and depends on the country and type of customers [53]. Approaches that have been used to assess the cost of interruptions vary between analytical methods, case studies and customer surveys.

The customer survey approach is widely accepted as the most favourable and a commonly used set of queries to obtain information regarding cost of interruptions include the following [54]:

- Direct estimation of losses resulting from a given interruption scenario, and
- Questions based on the Willingness to Pay (WTP) and Willingness to Accept (WTA).

For the GPMC supply area, it is thus recommended that a comprehensive study be done that will define the customer categories for which interruption costs are required. Furthermore the approach should be defined, followed by the assessment of SCDF's for the proposed categories.

6.2.4 Load Duration Curve Approximation

In the analysis of the alternative network options provided in Chapter 5, the contingency enumeration was done over a series of load levels rather than the single load level scenario. The approach involved representing the network load duration curve over a period and modelling the load through a staircase approximation. Multiple base cases were applied to each load level

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[3] G. Tollefson, R. Billinton, G. Wacker, "Comprehensive Bibliography on Reliability Worth and Electric Service Consumer Interruption Cost 1980-1990", IEEE Trans. Power Systems, 6(4), 1991, pp. 1508 –14

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[53] Garry Wacker, Roy Billinton, "Customer cost of Electric Service Interruptions", Proceedings of the IEEE, Vol. 77, No. 6, June 1989, PP. 919- 929

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representing this variation. The system load duration curve was obtained through actual load measurements at the infeed points. At substation level however, yearly measurements were not available. The methodology used to compile the staircase approximation was thus a simplified one that does not take into consideration the variation of load profiles at each substation due to the different customer mixes. In order to refine the multiple load level analysis, two aspects need to be addressed. The first is the capturing and maintenance of load profiles for the different customer categories. Typically those categories currently used in the Geographical Load Forecast (GLF) Technique. Secondly a methodology needs to be developed that will enable the automatic generation of load levels that will represent the individual load profiles for each customer category. These load levels should correspond to the system load duration curve. With some degree of user intervention it should be possible to compile the different load levels at each load point in the network for the different years of study, utilising the GLF as basis.

6.3 Recommendations With Regard to Corrective Actions

The contingency enumeration process that is followed to evaluate the reliability of a network was discussed in paragraph 3.4.2. During the application of the power flow, any number of operating limit violations such as high and low voltage conditions or circuit overloads may occur. When such condition occurs, it may be necessary to interactively determine if the problems can be alleviated by corrective actions. Within typical composite network reliability software this is done by initiating trip commands, which simulate the actual real life network response.

A conservative approach with regard to corrective actions was followed during the analysis of the base case in both Chapters 4 and 5 and improvements can be recommended. Two aspects that needs to be taken into consideration for future development is:

- The ability to operate transmission lines and power transformers at above normal operating conditions, and
- The controlled curtailment of load to prevent voltage and overload violations.

6.3.1 Transmission Line Loading

The thermal rating of a transmission line is not always limited by the effect of temperature on the conductor. Although the conductor will anneal and a degree of strength lost if operated above 100 °C the effect will not be catastrophic. Transmission lines are normally designed in such a way that the thermal rating of the line is generally defined as the current that will result in the templating temperature to be reached. This is defined as the temperature at which the clearance of the conductor above the ground is in accordance with legal requirements. This condition is however dependant on a number of factors such as:

- The position of the conductor above ground,
- The likelihood of an object being present under the conductor,
- The size of the object under the conductor,
- The likelihood of a surge and the magnitude thereof on the line, and
- The likelihood of flashover to the object.

By taking these considerations into account the power transfer capability of a transmission line can be increased substantially. It is thus recommended that a method be devised by which probabilistic load transfer capability is integrated into the conventional contingency enumeration process. This implies that the corrective action to trip a transmission line under overload conditions will not be deterministic of nature but probabilistic.

6.3.2 Load Shedding Policy

An accepted technique to alleviate circuit overloads is to apply controlled curtailment of load. Within the GPMC network however, no formal load-shedding policy is followed and in the case of a contingency resulting in sustained voltage and overload violations on specific circuits, these circuits are taken out of service without considering the load mix connected. This policy assumes that all customers perceive supply interruptions equally. We have learned from previous sections in this dissertation that this is not the case. From an economic point of view it will, for instance be more feasible to curtail customers by category or mix in the case of network violations than the complete circuit. It is thus strongly recommended that a load-shed policy be initiated. The responsible application thereof can lead to a decrease in annual unserved energy and an improvement in overall network performance.

6.4 RECOMMENDATIONS WITH REGARD TO DIP COMPATIBILITY ANALYSIS

Voltage dip performance can be as important as interruption performance in the planning criteria of an electrical transmission or sub-transmission network, especially where industrial customers are concerned. As an example, some industrial plants are sensitive to voltage fluctuations, especially voltage dips, to the degree that these fluctuations could result in a total plant shutdown. These shutdowns can have a costly impact on an industrial plant resulting in similar damages as sustained interruptions.

The number and depth of voltage dips at a specific point in the network is mainly a function of the network configuration and fault level at that point. Furthermore the duration of a voltage dip is a function of the protection scheme and relay settings. The focus of this dissertation was to quantify the interruption performance of a specific network without quantifying the variation in voltage dip events and magnitude as a function of network configuration. In theory a tightly interconnected network will result in less interruption events, but as a result of this grid will have a negative effect on voltage dip events. To illustrate the problem, consider a hypothetical network supplying a voltage sensitive industrial plant. The plant receives five sustained interruptions per annum with an average duration of forty minutes. Disturbances on adjacent networks further account for five voltage dip events that result in the plant to shut down for an average duration of forty minutes. A scenario is proposed whereby the supply network is interconnected with a firmer network which result in a decrease in interruption events from five events to a single event per annum. From a reliability point of view the plant performance has increased. What should however also be taken into consideration is that this scenario exposes the sensitive plant to additional network disturbances. These disturbances increases the number of voltage dips perceived by the plant from five to twenty. The number of events resulting in the plant to shut down has thus increased from ten to twenty-one.

It is thus recommended that the reliability assessment of alternative network options, where industrial plants form part of the customer mix, should not be done in isolation. In these cases the impact of voltage dips should also be quantified.

6.5 Recommendations With Regard to Integration With Other Systems

Power System Reliability assessment relies on a number of systems to provide raw data from which the network model, its stochastic behaviour and customer impact can be modelled and analysed. Integration of these systems will result in the ability to analyse more alternative network options in less time and will increase the efficiency of the analysis. This is especially the case where long-term future development options are evaluated.

6.5.1 Composite Network Reliability Assessment and the Development Plan

The reliability assessment of a network cannot be seen as a stand-alone entity and should be integrated into the planning process. The following are some of the conclusions made in Chapter 1:

- Reliability worth assessment of sub-transmission networks in South Africa , which includes composite systems and substation systems, is non-existent,
- The availability of a reliable power supply at a reasonable cost is essential for the economic growth and development of a country,
- An opportunity exists for the development of a Value-based methodology to form part of standard expansion planning procedures on sub-transmission networks in South Africa.

The basic methodology to assess network reliability within the Value-based framework was defined in Chapter 3 and applied in Chapter 5 within a case study.

It is recommended that this methodology be integrated into the existing GPMC planing environment. This tool bridges the gap between historic deterministic techniques and current probability techniques. The integration thereof has the potential to provide a cost-effective solution to alternative network options in that it quantifies not only the network performance for a specific alternative but also the impact on connected customers.

6.5.2 Integration within an AM/FM Environment

Most of the existing systems utilised in a network planning environment in South Africa are legacy systems. In order to integrate legacy systems and to open access to multiple datasets and complex functionality, most leading utilities throughout the world today implement Automated Mapping and Facilities Management (AM/FM) systems. By providing a realistic model of the "real world objects or facilities", AM/FM systems provides an environment for the efficient support of day to day functions of planning, construction and maintenance of a network. It combines background data such as simple vector or raster maps with structured / topology foreground network elements. The system thus computerises technical information and is designed to take the network through the planning stages up to the as built stage.

The GPMC is currently in the process of developing and implementing an AM/FM system and it is recommended that the methodology developed in this dissertation form part of the implementation.

6.6 CONCLUSION

This Chapter provides the most fundamental recommendations to the Value-based methodology that was developed in Chapter 3. As composite network reliability assessment covers a wide range of activities, the objective of these recommendations is to support the methodology in future developments. These recommendations take into consideration the specific needs of the GPMC, but are not limited to the GPMC network.

Recommendations were made with regard to:

- Data requirements, where the efficient capturing and maintenance of stochastic equipment data is regarded as the most important of all recommendations made. This data represents the true behaviour of a network and is thus essential for the reliability assessment of the network.
- Corrective actions, were discussed with the focus being on the development of a methodology that will enable the use of a probabilistic overload limit that can be used to initiate trip actions during the contingency enumeration process.
- The importance of dip compatibility analysis was emphasised and a simple example was provided to illustrate the effect of network strengthening on dip performance. It was further concluded that a dip analysis is vital during the evaluation of alternative networks supplying sensitive industrial plants.
- The Chapter concluded with the importance of integrating the Value-base methodology with traditional network planning techniques and utilising Automated Mapping and Facilities technology for this purpose.

The following Chapter will conclude on the initial Main Objective and associated Specific Objectives achieved in Chapter 1 of this dissertation.

CHAPTER 7

7. CONCLUSION

7.1 CONCLUSIONS TO THE MAIN OBJECTIVE

The main objective of this study was to develop a methodology to assist in the reconfiguration and expansion of a sub-transmission network within the framework of Value-based planing.

The probable role of a Value-based planning methodology within a sub-transmission network has been described and the existing challenges facing the planners of such networks have been identified. The Value-based methodology to address these challenges was developed in Chapter 3.

Evaluation of this methodology was performed on the sub-transmission network of the Greater Pretoria Metropolitan Council (GPMC). This network is regarded as a sizeable sub-transmission network in terms of South African standards. The entire network was modelled and analysed in Chapter 4 and the worst performing sub-system was identified for which alternative improvement options were identified. These alternative network options were modelled and analysed in Chapter 5. Although the availability of network specific data hampered the accuracy of the analysis, the methodology lends itself to supporting existing expansion planning methodologies in South Africa. Recommendations were provided with regard to data requirements and future development of the methodology.

7.2 CONCLUSIONS TO THE SPECIFIC OBJECTIVES

The specific objectives of the study have been achieved to a large degree. Conclusions on the specific objectives are as follow:

- The development of a Value-based framework for the evaluation of alternative sub-transmission network options has been achieved. The methodology provides an approach through which the reliability of existing and future networks can be assessed. The Expected Unserved Energy at each load point in the network resulting from the network performance is quantified. This index is used with the associated load point Composite Customer Damage

Function in order to quantify annual customer losses due to network performance. The initial capital investment for each alternative is used to calculate the annual equivalent investment over the life cycle of the alternative. The total annual expenditure, which is a function of customer damage cost, investment costs and salvage cost is used to calculate present worth for each alternative over the life cycle of the alternative.

- The evaluation of the methodology was done on an existing network with the first step requiring the reliability assessment of the entire study area. The sub-transmission network of the GPMC was used for this purpose. This involved the capturing and evaluation of mainly network stochastic data, the modelling of the network in a software environment and the assessment of the network reliability through a contingency enumeration process.

- Four network alternatives were identified to improve the performance of the sub-system identified in Chapter 4. These alternatives were evaluated utilising the Value-based methodology and the alternative resulting in the total minimum cost was identified as the proposed solution. A sensitivity analysis was conducted on the base year of Alternative 3 to assess the sensitivity of the model towards changes in stochastic equipment data as well as SCDF's. The conclusion on this aspect is that the model is highly sensitive to any change in stochastic equipment data, which emphasise the importance of having utility specific data for the evaluation of network alternatives. The analysis further concludes that the case study is sensitive towards the change of Industrial SCDF and that generic data for this purpose could result in inaccurate solution proposals. This case study showed that the methodology could assist network planners in the evaluation of long-term network alternatives. It further concluded that the utilisation of this methodology lends itself to the minimisation of the life cycle cost of network alternatives.

- Recommendations to the methodology were made that will result in a more credible representation of the real world. The most important being the establishment of an environment where stochastic equipment data can be captured and maintained. Chapter 5 identified this data along with Sector Customer Damage Functions as being vital to the accuracy of the analysis. Recommendations were further made that identifies the importance of modelling the effect of probabilistic overload violations during the application of corrective actions. The importance of a dip compatibility design was emphasised with the conclusion that a dip analysis is vital during the evaluation of network alternatives supplying sensitive industrial plants.

- Finally, it can be concluded that the methodology is relatively uncomplicated and should help to promote the utilisation of probabilistic technology within the planning environment. The application of this methodology provides the network planner with the ability to make better decisions with regard to the allocation of reliability. Through the calculation of reliability indices, tangible guidelines can be provided to quantitatively assess the impact of different network alternatives. These guidelines assess contingency probabilities explicitly and along with reliability worth evaluation provide a fundamental tool to conduct Value-based planning. This can lead to significant savings in capital investment while maintaining an acceptable level of reliability. The approach bridges the long-standing concept of the more conservative planning criteria with quantitative, probability concepts. It should however be emphasised that the probabilistic planning criterion does not eliminate the critical role of experience and judgement, but enhance the quality of decision making.

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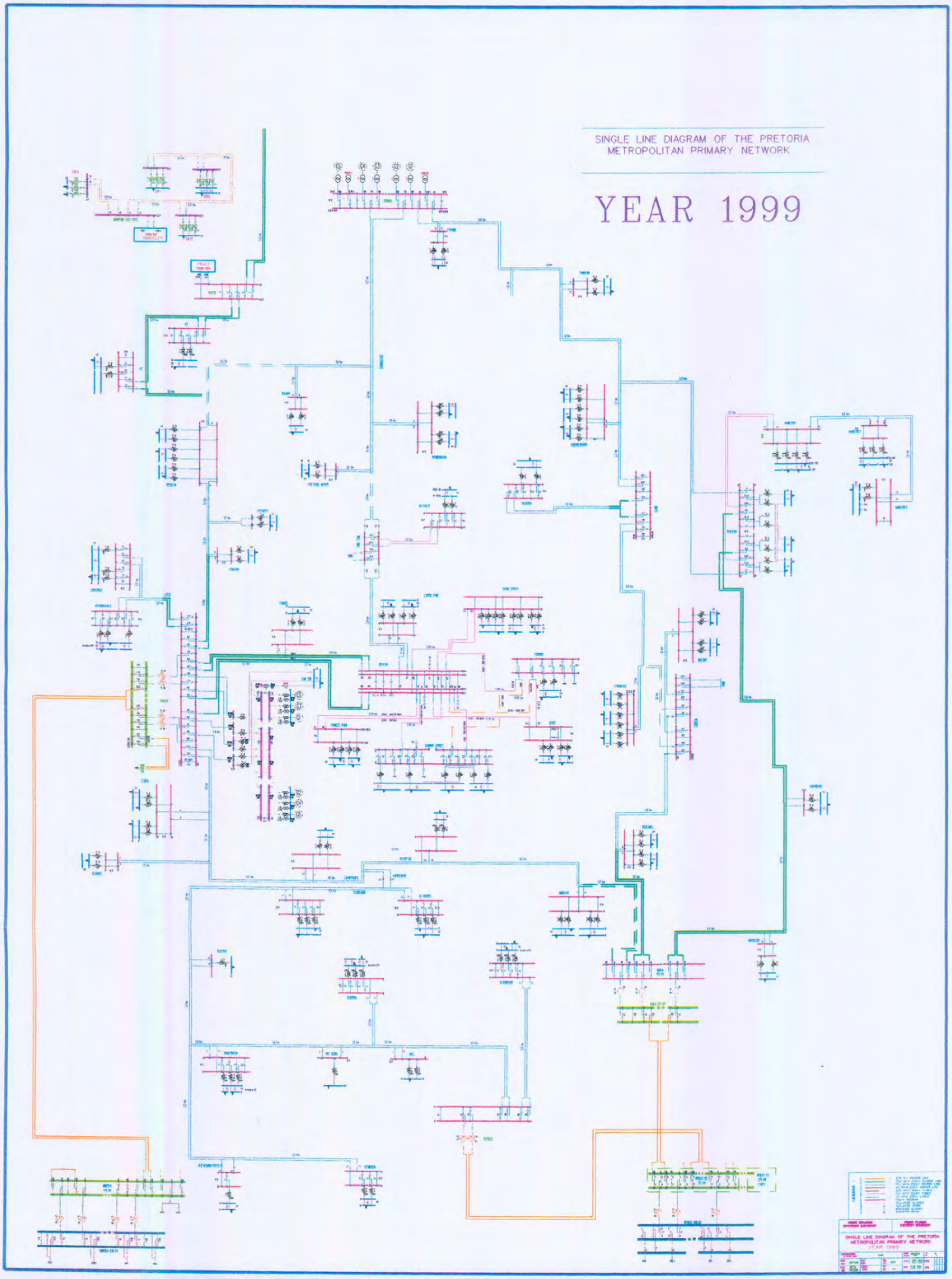
APPENDIX A

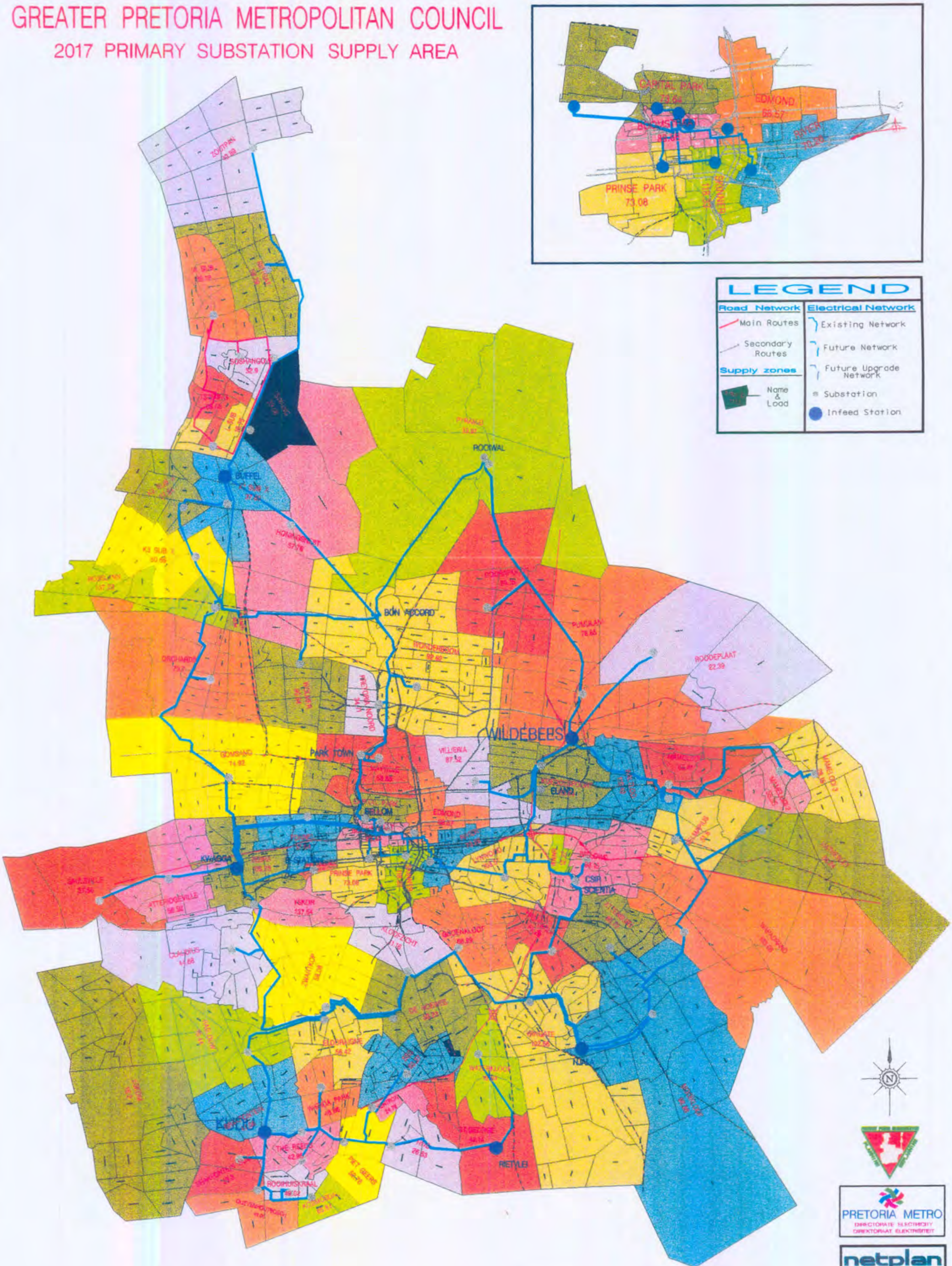


SINGLE LINE DIAGRAM OF THE PRETORIA
METROPOLITAN PRIMARY NETWORK
YEAR 1999
LEGEND :
SINGLE LINE DIAGRAM OF THE PRETORIA
METROPOLITAN PRIMARY NETWORK
YEAR 1999

APPENDIX B

GREATER PRETORIA METROPOLITAN COUNCIL

2017 PRIMARY SUBSTATION SUPPLY AREA



LEGEND	
Road Network	**Electrical Network**
Main Routes	Existing Network
Secondary Routes	Future Network
Supply zones	Future Upgrade Network
Name & Load	Substation
	Infeed Station

PRETORIA METRO
DIREKTORATE ELECTRICITY
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netplan
POWER SYSTEM HOUSE
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