

**AN ANALYSIS OF THE RELIABILITY OF THE 22kV
DISTRIBUTION NETWORK OF THE NELSON MANDELA BAY
MUNICIPALITY**

BY

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DECLARATION

I declare that the work in this dissertation was carried out in accordance with the requirements of the NMMU, Port Elizabeth. The work is original except where indicated by special reference in the text.

Rev. B G LAMOUR

DATE

DEDICATION

I would like to dedicate this dissertation to:

- My loving wife Gail Belinda Lamour for being so understanding and patient with me.
- My children Renetia, Giano and Roget and son-in-law, Wesley for support and understanding throughout my studies.
- My grand-children Makesha, Zacharee and Zarian.
- My father Gustave Harold Lamour for his teachings, upbringing and example he set for me.
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- My Almighty Lord and Father, Jesus Christ who gave me the ability to complete this project.

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ABSTRACT

This dissertation is a systematic study of the 22kV Nelson Mandela Bay Municipality (NMBM) electricity power distribution network reliability evaluation and improvements to be applied. Reliability evaluation of electric power systems has traditionally been an integral part of planning and operation. Changes in the electricity utility, coupled with aging electrical apparatus, create a need for more realistic techniques for power system reliability modelling.

This work presents a reliability evaluation technique that combines set literature and evaluation criteria. In analysing system reliability, this research takes into account the reasons for many outages and voltage dips and seeks to find mitigating approaches that are financially justified.

The study analyses the power system in terms of the methodology developed, using power system reliability techniques, power quality evaluation, protection analyses and evaluating the network against maintenance interventions and programs, manpower availability and weather conditions contributing to the outages.

In evaluating the power system various techniques are used to determine if the power network operates within the NRS standards, namely, reliability calculations, testing of protection equipment, interrogation of power quality instruments and modeling the network on Digsilent.

This study will look at all the important factors influencing power system reliability, analysing the network in terms of the methodology and recommend improvements.

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LIST OF SYMBOLS AND ABBREVIATIONS

AC	Alternating Current
ABC	Arial Bundle Conductor
ALC	Accuracy Limit Current
ALF	Accuracy Limit Factor
ARC	Auto-Recloser
ASAI	Average Service Availability Index
ATPII	Average Time Until Power Restored
BIL	Basic Impulse Level
CAIDI	Customer Average Interruption Duration Index
CEA	Canadian Electric Association
CT	Current Transformer
DC	Direct Current
EEI	Edison Electric Institute
EF	Earth Fault
EPRI	Electric Power Research Institute
<i>F</i>	Frequency
FBH	Fitches Corner, Blue Horizon Bay
FCR	Fitches Corner, Rocklands
HV	High Voltage
I	Current
IEEE	Institute of Electrical and Electronic Engineers
KKG	Kragga Kamma Greenbushes
LV	Low Voltage
MV	Medium Voltage
N/O	Normally Open Point
NER	National Electricity Regulator
NERSA	National Energy Regulator of South Africa
NMBM	Nelson Mandela Bay Municipality
NMMU	Nelson Mandela Metropolitan University
MWN	Motherwell North
NRS	National Regulatory Service

OC	Overcurrent
OMS	Outage Management System
OSI	Open System Interconnection
P	Active Power
PSM	Plug Setting Multiplier
Q	Reactive Power
QOS	Quality of Supply
REF	Restricted Earth Fault
RMS	Root Mean Square
RTU	Remote Terminal Unit
S	Apparent Power
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEF	Sensitive Earth Fault
SGP	Summit Gamtoos Pumps
SVC	Static Var Compensator
TC	Time-Current
THD	Total Harmonic Distortion
TM	Time Multiplier
TMS	Time Multiplier Setting
V	Voltage
Z	Impedance

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LIST OF EQUATIONS

$$Us = \lambda s rs \quad (2.1)$$

$$SAIDI = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total No. Customers}} \quad (2.2)$$

$$SAIFI = \frac{\text{Total Number of Customers Interrupted}}{\text{Total No. Customers}} \quad (2.3)$$

$$CAIDI = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total No. Customer Interruptions}} \quad (2.4)$$

$$\text{Cost per interrupted kW} = \frac{Ci(d)}{Li} \quad (2.5)$$

$$S = \sqrt{3} VI_{FL} \quad (4.1)$$

$$I_F = \frac{I_{FL}}{Z_{nf}} \quad (4.2)$$

$$ALF = \frac{I_F}{I_p} \quad (4.3)$$

$$S = I^2 Z \quad (4.4)$$

$$Z_{\text{source}} = \frac{MVA_b}{MVA_{\text{trf}}} \quad (4.5)$$

$$Z_{\text{trf}} = \frac{MVA_b}{MVA_{\text{trf}}} \times \frac{Z\%}{100} \quad (4.6)$$

$$Z_{\text{line}} = \frac{Z_{\text{act}}}{Z_{\text{base}}} \quad (4.7)$$

$$Z_{\text{base}} = \frac{(kV_b)^2}{MVA_b} \quad (4.8)$$

$$I_b = \frac{MVA_b \times 1000}{\sqrt{3} \times kV_b} \quad (4.9)$$

$$V_b = \frac{V_{\text{ph}}}{\sqrt{3}} \quad (4.10)$$

$$\text{Plug setting (PS)} = \frac{I_{\text{FL}}}{I_{\text{PCT}}} \times 100\% \quad (4.11)$$

$$\text{PSM (M)} = \frac{I_{\text{fault}}}{k t_{\text{ps}}} \quad (4.12)$$

$$t = \frac{0.14}{I^{0.02 - 1}} \quad (4.13)$$

$$\text{TMS} = \frac{t_a}{t_c} \quad (4.14)$$

$$P = \sqrt{3} V I \cos \theta \quad (4.15)$$

$$\text{Impedance of B} = \frac{VA}{I_{\text{ctsec}}^2} \quad (4.16)$$

$$\text{Total sec Impedance} = \text{Imp of B} + \text{CT Sec Resistance} \quad (4.17)$$

$$\text{Emf at sec at ALF} = Z_t \cdot I_{\text{ctsec}} \cdot \text{ALF} \quad (4.18)$$

$$\text{Max allowable primary current} = \text{ALF} \cdot I_{\text{ctprim}} \quad (4.19)$$

CHAPTER 1

THE PROBLEM AND ITS SETTING

1.1 INTRODUCTION

The Nelson Mandela Metropolitan Bay Municipality comprises Port Elizabeth, Uitenhage and Despatch. It covers a geographical area of 3200 square kilometres between the Gamtoos River, Sundays River and Winterhoek Mountains. The Metropole supplies electricity to 250 000 domestic, 9500 commercial and 2100 industrial customers, with an annual sales value of R1,2 billion for 3700 GWH. The metropole electricity power network encompasses 70 HV (22kV to 132kV) substations, 2410 MV (6.6kV to 11kV) substations, 5406 km of HV and MV overhead lines and 1552 km of HV and MV underground cables.

Economic growth is directly proportional to the availability of electricity and quality of supply. The economic, social and political climate in which the electricity power supply industry operates in SA has changed considerably over the last few decades, especially during the last ten years. More investment and increased development requires more capacity. The industry is not in a position to produce the quality of electricity now demanded by its customers. The power networks are overloaded, infrastructure is old and little or no maintenance has been done on the equipment.

Power system reliability has been extensively developed using various indices, but no single all-purpose formula exists. The approach and the formula used depends always on the problem presented and the assumptions made (Billinton and Wenyuan, 1994).

1.2 PROBLEM STATEMENT

Power distribution network systems are important elements for economic growth, emergency services, household use, farming *et cetera*. Everybody is

dependant on power and it is in everybody's interest that the quality of power provided by the utility fulfils the needs of its customers.

Major failures of electric power systems, leaving customers without power, have become common in recent years. The effects of these power failures are catastrophic, causing major users of electricity in heavy industrial areas to write off millions of rands annually.

Over the last five years approximately 6000 MV and HV outages were recorded, giving us an average of 1200 outages per annum. 83% were MV and 17% were HV outages. The rate at which the outages occurred is not acceptable and has a negative impact on the NMBM and the customers. During the 2006/2007 financial year, the average outage time was 1.9 hours per customer per day. The direct consequences of these outages are related to the interconnections between different elements and technical aspects of the power system (NMBM Monthly Reports, 2006/2007).

The reality is that power outages have major direct and indirect consequences on economic growth and security of supply. The rate at which power outages occur, the number of outages recorded and generally, the performance of the power system is beyond the NRS limits.

1.3 SUB-PROBLEM STATEMENT

Serious network problems occurred over the last five-year period. The causes of many of the persisting outages are often directly related to power quality problems. The following contributory factors to the power supply problems in the NMBM are:

- Aging of equipment and poor infrastructure
- Lack of maintenance of existing equipment and infrastructure
- Inability to upgrade and reinforce existing networks
- Protection system failures

- Grading of protection relays
- Failure of communication equipment
- Voltage imbalances
- Voltage fluctuation and flickering
- System harmonics
- Voltage sag/dip
- Automation of operations
- Acute shortage of funds
- Vandalism and theft of infrastructure
- Procurement of inferior quality equipment at low cost
- Manpower shortages
- Inability to secure skilled workers
- Inclement weather conditions

1.4 HYPOTHESIS

Power system reliability is an essential factor in the quality of supply. In the NMBM, power system reliability is directly related to the number of outages.

By analysing the power system properly using available methodology, the weaknesses will then be identified and improvements can be introduced to prevent possible future outages. A decrease in the outage rate will result in an improvement in reliability and quality of supply. This will improve the reliability of the power network, and hence the quality of supply will be positively affected.

1.5 DELIMITATION OF THE RESEARCH

In this project, all the interruptions recorded on the feeders supplying the distribution network will be researched. This includes all feeders and substations operating at 22kV. The interruption data will be recorded, analysed and presented using spreadsheets and graphs. Weaknesses in the power network will be identified. Five case studies will be used to investigate

technical aspects and weak components, while various engineering tests and investigations will be conducted. The results will be analysed and recommendations will be made to effect improvement on the quality and reliability of the power distribution network.

1.6 AIM OF THE RESEARCH

The research project seeks to achieve a more thorough understanding of the factors that affect power system reliability, to analyse the power system and recommend strategies for improvements. The power network will be systematically studied and analysed in terms of the causes of interruptions. The analysis would be conducted using engineering interventions, namely, reliability calculations, protection fault analysis, evaluation of power quality results against the NRS standards, load flows on Digsilent *et cetera*.

1.7 METHODOLOGY

Research for this project was carried out as described below.

An extensive literature review based on the criteria below was consulted to guide the investigation:

- Power System Reliability (Chapter 2);
- Power Quality (Chapter 3);
- Power System Protection (Chapter 4);
- Maintenance and Manpower (Chapter 5), and
- Weather Conditions (Chapter 6).

Analysis was carried out using text books, published journals, the internet, magazines and policy documents.

The impact of the interruptions on the NMBM supply network was assessed and evaluated. Power system reliability was the point of focus. Power outage

data was collected over a period of 5 financial years (2002/2003 to 2006/2007). The data was refined and presented on spreadsheets. Graphs were drawn, investigations were conducted and tests done in order to identify the weaknesses of the power systems. From the NMBM power network, 5 case studies were identified to be examined as case studies, namely:

- Fitches Corner, Blue Horizon Bay (FBH);
- Summit, Gamtoos Pumps (SGP);
- Motherwell North (MWN);
- Kragga Kamma, Greenbushes, and
- Fitches Corner, Rocklands (FCR).

Causes of outages were identified, durations of outages were quantified and equipment testing schedules and preventative maintenance records were examined. Assessing this data provided valuable information on how to reduce outage durations.

The following interventions were effected in analysing the case studies:

- Power quality meters were installed at these sites to monitor the quality of supply.
- Reliability calculations based on Reliability Indices were completed to determine the failure rate.
- Protection equipment was tested to ascertain if it was functional. Re-calculation of fault levels and protection settings was done.
- Investigations were conducted to clarify why SCADA was never installed in some of the case studies.
- Power networks were modelled in Digsilent and load flows were performed.
- The maintenance records of power system equipment were investigated.
- Outage information was captured on the NRS Interruption data analysis program to evaluate the power system against the NRS standards.

- The impact of weather conditions contributing to power outages was linked to these outages.
- Findings were made after the analysis.
- Conclusions and recommendations were made to improve power system reliability.

1.8 REVIEW OF CHAPTERS

Literature pertaining to the reliability of power systems was studied. The focus was on the factors contributing to the increased outages, how they impacted on the industry and what the major financial implications were. The literature also investigated possible solutions to the power outage problem and new methods of dealing with it.

Chapter 1: Problem and its Setting, covers the problem, aim, setting, methodology to be used and the outline of the dissertation and the literature survey.

Chapter 2: Power System Reliability covers reliability calculations used throughout the dissertation to evaluate the overall performance of the case studies. The reliability calculation results will be compared with the reliability indices used internationally to evaluate power systems. Cost of outages and the factors contributing to and influencing power system reliability are examined.

Chapter 3: Power Quality investigates problems in the NMBM power network. This includes research on voltage dips, considered the main cause of power quality problems in NMBM. An overview of the instruments used to record the events is discussed. Estimation and calculation of voltage dips, and methods to reduce them are researched. Other power quality problems included are harmonics, flickering, voltage swells and regulation.

Chapter 4: Power System Protection covers the systems utilized in the case studies researched. Types of protection relays, the function of protection, factors affecting the severity of a fault and the type of faults causing outages are examined. Protection devices are included: fuses, sectionalizers, auto-reclosers and how they integrate with each other. A section on protection for transformers from 1 MVA and smaller is also included since it was found that many of the rural power lines have distribution transformers installed without correct protection measures. Overcurrent, earth fault, sensitive earth fault, current transformers, fault level calculations, fault calculations, discrimination, and surge arrestors are reviewed. A section on the NMBM protection policy is also added.

Chapter 5: Maintenance and Manpower highlights maintenance and manpower factors in the electrical distribution and transmission industry. Maintenance cannot be performed with insufficient and unskilled manpower. The little maintenance done cannot keep up with the pace at which the equipment deteriorates. The current practices, their impact on the industry and the effect of preventive maintenance are discussed.

Chapter 6: Weather Conditions emphasises the impact of adverse weather conditions on the power system. Overhead lines are significantly affected and have countless consequences for the end users, particularly the industry. Adverse weather conditions are unavoidable, but mitigation factors need to be highlighted as well.

Chapter 7: The summary highlights all the important and pertinent aspects in the literature review.

Chapter 8: After the identification of the weak power systems, each was analysed to determine why it had underperformed. The use of graphs, spreadsheets and outage data assisted in performing this exercise. Common trends in terms of the factors affecting the under-performance of the power system were identified.

Chapter 9 – 13: In the case studies, the power systems were analysed and evaluated in terms of the following criteria described in the literature review:

- Power System Reliability
- Power Quality
- Power System Protection
- Digsilent Power Factory
- SCADA
- Maintenance and Manpower
- Weather Conditions
- NRS Data Analysis

The literature review guided the analysis of the case studies. Test, site inspections, interviews with field staff, contractors and customers indicated the impact of the outages.

After the analysis and evaluation of the case studies the findings were recorded and recommendations introduced.

Chapter 14: The Conclusions are outlined to improve the performance of power systems, and hence improve power system reliability.

1.9 SUMMARY

Electricity networks must supply electricity at the lowest cost per unit with an acceptable degree of reliability. To achieve this, the utility must remain within electricity supply quality regulations.

Reliability is an essential factor in quality of supply. The main factors used to evaluate the reliability of electricity supply to customers are the:

- Frequency and magnitude of the interruptions;
- Cost to repair or replace the faulted network or equipment;

- Duration of the interruption, and
- Cost to the customer for the time the supply of electricity was not available.

Constraints relating directly to the reliability of electricity supply are the frequency variations, equipment ratings and fault levels. Reliability analysis of an electricity power network is an integral part of planning and operation, and with the shortfall of engineering staff, utilities are not in a position to perform this important function.

In this dissertation the impact of the interruptions on the NMBM supply network are assessed and evaluated over a period of 5 years. Causes of outages were identified; the duration of outages was quantified, and equipment testing schedules and preventive maintenance records were examined. Assessing the data provided valuable information on how to minimise the duration of power outages.

CHAPTER 2

LITERATURE REVIEW: POWER SYSTEM RELIABILITY

2.1 INTRODUCTION

The function of an electricity power system is to provide electricity energy to all its customers as economically as possible. This supply of electricity must be of an acceptable quality and degree of reliability. Contemporary users of electricity expect that the supply of electricity is available continuously. This is sometimes impossible because of the malfunctioning of power system equipment and other factors outside the control of power system controllers.

Power system reliability refers to the performance of the power system measured by the frequency, duration and magnitude of the interruption (Kueck, Kirby, Overholt, Markel, 2004). The reliability of a power system is evaluated against the total loss of electricity and the complete loss of voltage; it is not just a distortion of the sine wave. However, it does not include sags, swells or harmonics.

Power system outages can cause major inconvenience to users of electricity. The financial losses and economic impact are not confined to the utility or the major industrial user, but impacts indirectly on the entire community and the environment. Power system outages impact more on businesses than any other user of electricity (Short, 2006).

The probability of customers being interrupted by power outages can be reduced by increased investment during the planning phase. It is evident that when a power system is designed, the planner designs it at the lowest cost. This is done because the customers have to pay for the infrastructure. Major refurbishments and reinforcements are planned on the same principle, as the capital investment remains the responsibility of the local authority, hence the customers are indirectly paying. It is therefore obvious that economics and

reliability can conflict, leading to difficult decisions. The capital investment also impacts on the operational constraints.

According to Billinton and Wenyaun (1994) the term “reliability” has a wide range of meanings, not just a specific meaning. It is safe to use the term in a general rather than specific sense. Power system reliability can be divided into system adequacy and system security as illustrated in Figure 2.1 (Billinton and Allan, 1994).

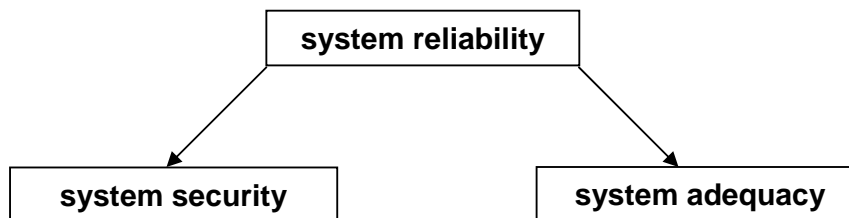


Figure 2.1 – Subdivision of System Reliability (Adapted from Billington and Allan, 1994)

2.2 SYSTEM ADEQUACY AND SECURITY

Adequacy is the availability of adequate facilities in terms of equipment and infrastructure to supply electricity to the consumer. The magnitude of the power supply is determined by the customer load demand and/or the system operational constraints. The facilities required to ensure system adequacy include power stations to generate electricity, transmission lines, transformers and downstream substations, all necessary to transport electricity to the customer load point (Billinton and Allan, 1994).

Security is the capability of the power system to react to dynamic and static disturbances which arise within the power system. Security relates to the manner in which the power system responds to disturbances. It is difficult to access security, hence most probabilistic techniques available are based on adequacy assessment. Consequently, most of the indices available are adequacy indices (Billinton and Allan, 1994).

2.3 RELIABILITY EVALUATION

Power system reliability was developed and researched based on whether the number of interruptions and the duration of the interruption could be statistically analysed, but not predicted precisely (Bollen, 2000). Power system reliability evaluation, evaluation techniques and methods have been further developed over the last few years. Through these interventions, a broad range of appropriate indices were developed, therefore a single technique or method does not exist. The approach and the formulae that a utility will be using depends on the problem and the assumptions. It is therefore clear that power system reliability techniques, methods and formulae are hugely dependent on probability. The basic steps to apply this technique are:

- Clarifying how the system and its components operate;
- Identifying possible causes of failure;
- Deducing the results of the failures;
- Deriving one's own models, and
- Selecting the evaluation technique or method (Billington and Wenyaun, 1994).

2.4 REASONS FOR RELIABILITY EVALUATION

Due to the changing political, economic and social conditions of the world, the electricity supply industry has been forced to change. Inflation, the increase in the oil price and growth in terms of the economy resulted in an increase in domestic, commercial and industrial customers. This increase creates uncertainties in predicting future demand for energy. Reliability evaluation techniques form one method used to keep up with changing political, economic and social conditions. The reliability evaluation techniques can be related to these economic aspects and the planners and designers of power systems can find this useful for future power system development and reinforcements (Billinton and Allan, 1994).

2.5 FACTORS INFLUENCING POWER SYSTEM RELIABILITY

There are many factors affecting and influencing the smooth operation of a power system, hence also affecting power system reliability. However, certain factors are more prevalent in transmission power systems, and others are more prevalent in distribution power systems.

2.5.1 Radial Systems

Most of the case studies in this dissertation are based on radial topology. In radial systems, each equipment or infrastructure failure will result in an outage. Where parallel or meshed systems are utilised, the power system would operate normally with an open point elsewhere in the circuit (Bollen, 2000).

2.5.2 Failure of Protection Equipment

Power system protection equipment is primarily installed to remove the faulty part of the power system in minimum time and to limit the risk of damage to the equipment and infrastructure.

Failure of any power system protection equipment can lead to major damage and financial losses to the utility. This will also lead to extended power outages for customers (Hewitson, Brown, Balakrishnan, 2007).

2.5.3 Weather Conditions

Adverse weather conditions namely, strong winds, lightning, rain and storms are the most frequent causes of power interruptions. During normal weather, failure of equipment is regarded as an independent event. During adverse weather equipment failures resulting in extended outages can occur at the same time (Brown, 2002).

Overhead power lines are more likely to be affected by adverse weather conditions. Approximately 70% of all faults on overhead lines are transient faults (Burke, 1994).

2.5.4 Duration of Interruption

The duration of an outage is a major concern in power system reliability studies. The cost of an interruption is also directly linked to the outage duration. According to Bollen (2000) the average outage duration and hence the outage cost may vary significantly throughout the power network. Bollen (2000) states that the following contributory factors impact on the outage duration:

- Travelling to the affected equipment;
- Finding the fault,
- Switching of equipment, and
- Restoring of power supply.

The obvious approach would be to reduce the number of faults which form the source of the interruption. Due to the duration of interruptions, damaged equipment, overtime payments, loss of sales and claims from customers cost utilities more (Short, 2006).

2.5.5 Failure Rate

The failure rate of equipment increases significantly with time, if not maintained according to a planned maintenance program in conjunction with the supplier's manuals.

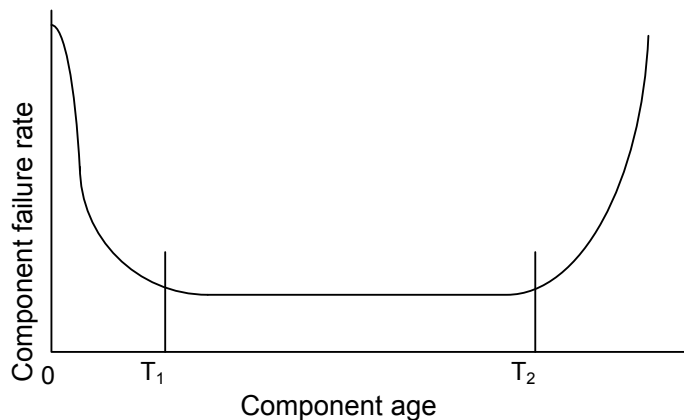


Figure 2.2 – Bathtub curve: component failure rate vs age (Adapted from Bollen, 2000)

The Bathtub curve, Figure 2.2 (Bollen, 2000) quantifies the occurrence of equipment failure rate through the aging of equipment. The period 0 to T1 is known as the wear-in-period, period T1 to T2 is the useful life of the equipment and the time when it is more valuable to the user, and T2 is the wear-out period.

In Figure 2.3 (Bollen, 2000) the failure rate increases with time until the equipment is maintained. After maintenance, the failure rate drops to the original value. The dotted line represents the average failure rate.

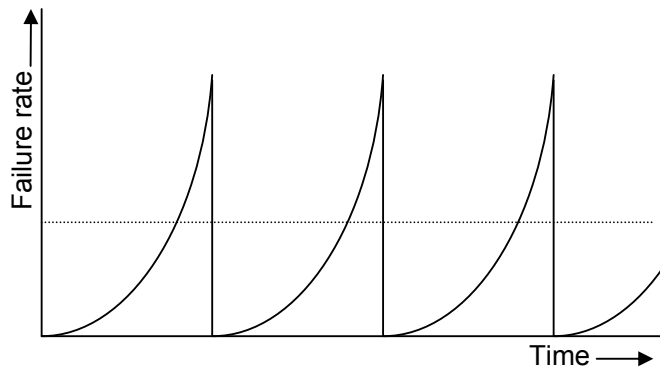


Figure 2.3 – Failure rate vs time for regular maintenance intervals (Adapted from Bollen, 2000)

2.6 RELIABILITY INDICES

Reliability indices typically consider such aspects as the number of customers, the connected load; the duration of the outage measured in seconds, minutes, hours, days; the amount of power (kVA) interrupted and the frequency of interruptions.

There are many indices for measuring reliability. The three most commonly used indices according to Burke (1994) are SAIDI (82%), SAIFI (76%) and ASAI (64%). He adds that reliability of a power system is really evaluated in terms of the outage rate and outage duration. Thus, the basic formula for evaluating radial power systems is as follows:

Series Components

$$\lambda_s = \lambda_1 + \lambda_2$$

λ_s = System Outage Rate

λ_1 = System Outage Rate for component 1

λ_2 = System Outage Rate for component 2

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_1 + \lambda_2}$$

r_s = System Average Outage duration

r_1 = System Outage Duration for Component 1

r_2 = System Outage Duration for Component 2

$$U_s = \lambda_s r_s$$

U_s = System Average Total Outage Time (2.1)

Reliability Indices are also used to evaluate overall power system performance. Useful Reliability Indices, according to Burke (1994), are as follows:

SAIDI- System Average Interruption Duration Index

$$SAIDI = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total No. Customers}} \quad (2.2)$$

SAIFI- System Average Interruption Frequency Index

$$SAIFI = \frac{\text{Total Number of Customer Interruptions}}{\text{Total No Customers}} \quad (2.3)$$

CAIDI- Customer Average Interruption Duration Index

$$CAIDI = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total No. Customer Interruptions}} \quad (2.4)$$

SAIDI, or System Average Interruption Duration Index, is commonly referred to as customer minutes or customer hours of interruption, and is designed to provide information on the average time that customers are interrupted. SAIDI calculates the average total duration of interruptions. It quantifies how many interruption hours an average customer will experience in one year (Brown, 2002; Burke, 1994; Short, 2006).

SAIFI, or System Average Interruption Frequency Index, is the average frequency of sustained interruptions per customer over a predefined area. SAIFI is the average failure rate. It quantifies how many sustained interruptions an average customer experience in one year (Brown, 2002; Burke, 1994; Short, 2006).

CAIDI, or Customer Average Interruption Duration Index, is the average time needed to restore services to the average customer per sustained interruption. CAIDI is a measure of how long an average interruption lasts. It is used to measure the utility response time to interruptions (Brown, 2002; Burke, 1994; Short, 2006).

2.7 COST OF POWER OUTAGES

The inability of a utility to provide electricity to its customers due to a planned or an unplanned outage needs to be quantified in the design and planning phases of power systems. Not much in terms of research has been completed on this and the likelihood of designers and planners of power systems incorporating the cost of interruption into the study is almost zero. Bollen (2000), Figure 2.4 uses the graph to compare cost against reliability.

It is apparent from Figure 2.4 that designs incorporating more reliable power systems will increase the cost of the power systems. Therefore, reliable power systems are more expensive than less reliable power systems. The total cost curve is a resultant of the two curves and will show a minimum, which is an indication of the optimal reliability (Bollen, 2000).

Different methods are used to determine outage costs. The method employed also depends on the type of customer. An industrial customer would use a different method from a domestic customer. The only accepted method according to Bollen (2000) is to conduct a survey among customers. The answers given by the customers can be used to determine the average cost of an outage.

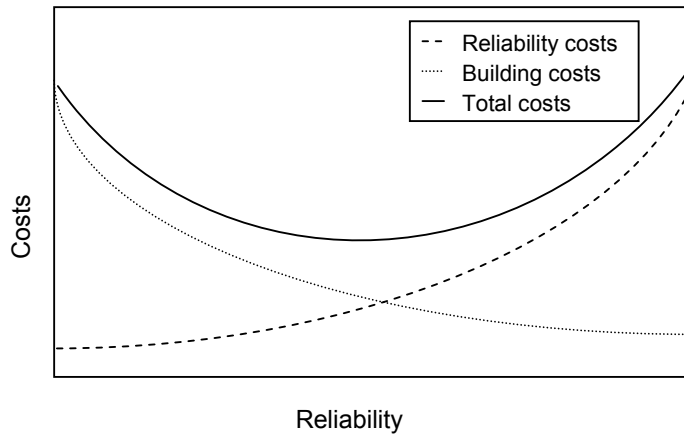


Figure 2.4 - Cost vs Reliability (Adapted from Bollen, 2000)

The cost per interrupted kW can be defined as:

$$\frac{C_i(d)}{L_i} \quad (2.5)$$

d = duration
 Li = load of customer
 Ci = cost per kW

Cost can be expressed in Dollar/kW, or in any other currency, for example Rand/kW.

Cost per kWh not delivered, is expressed in Rand/kWh.

Some utilities use an average cost per kWh for power not delivered for all customers (Bollen, 2000).

CHAPTER 3

LITERATURE REVIEW: POWER QUALITY

3.1 INTRODUCTION

The quality of electricity supply affects every consumer, from the homeowner to large industry, mining and commercial. Customer awareness of poor quality of electricity supply is increasing due to the more “sensitive” nature of modern equipment and to the increasing deployment of non-linear loads (Dugan, McGranaghan, Santoso, Beaty, 2003). Added to this, the harsh South African environment, long transmission and distribution lines, high lightning occurrence, utility switching, vegetation, animals, birds, insulator pollution from coastal and industrial sources all contribute to making quality of electricity supply a topical issue.

Good power quality is complicated, because it is measured in terms of the equipment or the customer that it supplies. What is good power quality for a motor might not be good for a computer (Burke, 1994).

The electricity supply industry is interested in power quality for economic reasons. There are major financial implications for the utilities and the customers, especially the major industrial users of power. The modernization of industrial machinery means more electronic and energy efficient equipment. These are more sensitive to supply voltage variations (Bollen, 2000).

Power quality problems, particular voltage dips and the factors affecting them need analytical research.

3.2 VOLTAGE DIPS

3.2.1 Introduction

Suppliers of electricity over the years have had to deal with an increasing number of complaints relating to poor power quality due to voltage dips and interruptions. The crucial issue is that voltage dips affect sensitive loads. The influx of digital computers and electronic controls and equipment is at the heart of the problem.

Voltage dips are the most general power quality abnormality, accounting for almost 80% of such problems. Dips are a common cause of power related computer system failures, stalling of motors, reduced motor life and flickering of lights (CT Lab Power Quality Recorder Manager User Guide, 2005).

The terminology used to describe the magnitude of voltage dips or sags is often confusing. The recommended international usage is “a sag to 20%,” which means that the line voltage is reduced down to 20% of the normal value, not reduced by 20%. This is consistent with other practices and with most analysers who report on voltage quality (IEEE Std 1159 - 1995). In SA use of “dip” is more acceptable.

A voltage dip is described as a sudden reduction measured in root mean square (RMS) voltage between 20 ms and 3 s of one or all the phase voltages. The duration of the voltage dip is measured from the moment the voltage decreases below 0.9 pu up to when the voltage rises above 0.9 pu of declared voltage (NRS 048-2:2007). Figure 3.1 depicts the voltage dip parameters.

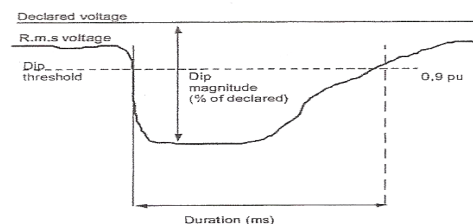


Figure 3.1 – Measured voltage dip parameters (Adapted from NRS 048-2:2001)

Voltage dips are the most common cause of customer complaints on poor power quality. The NRS 048 specifications provide targets for each dip category, namely, Y, X, S, T and Z and the utilities are assessed in terms of this. In Table 3.1 the compatibility levels for voltage dips are given in the form of the maximum number of voltage dips per annum within defined ranges of voltages. Voltage dips are dependent on different environmental conditions which have an effect on power quality. In the case studies, many of the voltage dips were caused by lightning, storms, wind, birds, animals, vegetation, ground resistivity and protection malfunctioning.

Table 3.1 – Characteristic values for the number of voltage dips per year for each category of dip window (adapted from NRS 048-2:2007).

1	2	3	4	5	6	7
Network voltage range (nominal voltages)	Number of voltage dips per year					
	Dip window category					
	X1	X2	T	S	Z1	Z2
6,6kV to 44kV extended overhead	13	12	10	13	11	10
6,6kV to 44kV	7	7	7	6	3	4
44kV to 220kV	13	10	5	7	4	2
220kV to 765kV	8	9	3	2	1	1

3.2.2 Causes of Voltage Dips

When heavy loads are started, such as large drives, the starting current can be many times the normal running current. Since the supply and the cabling of the installation are designed for normal running current, the high initial current causes a voltage drop in both the supply network and the installation. The initial starting current flowing through the system impedance, causing a voltage dip, which causes contactors to drop, dims lights and disrupts sensitive electronic equipment. Figure 3.2 depicts a typical motor-starting voltage dip (Dugan et al, 2003).

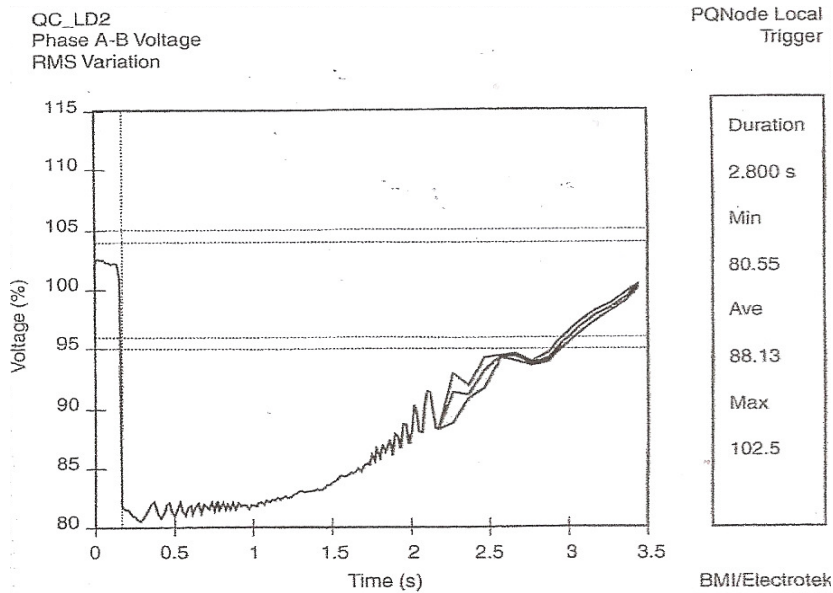


Figure 3.2 – Typical Motor-starting voltage dip (adapted from Dugan et al, 2003)

Arc furnaces generate large voltage dips in power systems. Arc furnaces produce high temperatures and use inductors to regulate the current caused by the arc. A large current is drawn during the initial process for a few seconds. After the arc becomes stable, the current also stabilises. During the starting process, the arc furnace produces voltage dips. Figure 3.3 depicts the current drawn by an arc furnace (Sankaran, 2002).

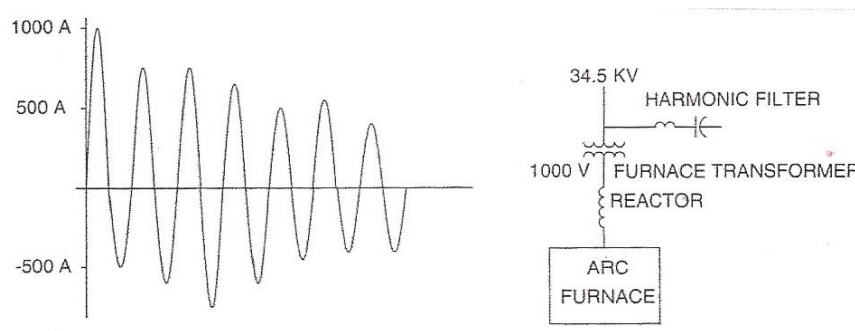


Figure 3.3 – Typical current drawn by arc furnace at primary transformer (adapted from Sankaran, 2002)

According to Sankaran (2002), approximately 70% of all power system outages occur on overhead lines. Lightning, vegetation, birds, animals and

failure of equipment cause these faults. The reclosing and sectionalising devices used to clear such faults cause voltage dips on the power system.

Both Sankaran (2002) and Dugan et al (2003) confirm that the worse feeders in terms of power system reliability indices, voltage dips and interruptions were recorded on overhead lines.

El-Arina, Yousseff, Hendawy (2006) states that abnormal operating conditions, namely, heavy loads, frequent starting, large induction motors and transmission faults are the main reasons for voltage dips. To mitigate the impact of voltage dips, over saturated transformers and uninterruptible power supplies should be installed.

3.2.3 Instruments Used to Measure Voltage Dips

Four types of power quality instruments are used by the NMBM, namely, Impedograph, Vectograph and Provograph.

CT Lab, an electronics company located in SA, currently supplies most of the utility's power quality measuring equipment as per NRS 048:2 requirements. These instruments are three-phase voltage quality measurement tools. They quantify quality of supply anomalies over short and long periods. The instruments are capable of measuring all of the quality of supply anomalies as prescribed by the NER in the NRS 048:2.

In this study, unreliable sections of the network are identified as per their performance, outage data and available statistics and the relevant instruments were installed to measure the power quality. The data retrieved from these recorders was analysed and recommendations made to improve power system reliability.

Table 3.2 – Dip Categories (Adapted from NRS 048-2:2004)

Dip Category	Values of duration and depth
Y	Duration: >20 ms to 3 sec; Depth: 30%, 20%, 15%
X1	Duration: >20 ms to 150 ms; Depth: 30% to 40%
X2	Duration: >20 ms to 150 ms; Depth: 40% to 60%
S	Duration: >150 ms to 600 ms; Depth: 20% to 60%
T	Duration: >20 ms to 600 ms Depth: 60% to 100%
Z1	Duration: >600 ms to 3 sec; Depth: 15% to 30%
Z2	Duration: >600 ms to 3 sec; Depth: 30% to 100%

3.2.4 Importance of Voltage Dips

Prior to the introduction of the NRS 048 in 1996, there was no approved measuring yardstick for poor power quality in SA. Customers install specialised equipment without being aware of the high number of voltage dips measured on the distribution networks. So the question arises, are the number of voltage dips a real problem in SA?

During fault conditions, high current is drawn from the supply and because current (I) is proportional to voltage (V) ($V = IZ$ – Ohm's law) this causes a minor drop in the voltage for the duration of high current being drawn as impedance (Z) stays constant. If the fault is not cleared within a short time, as determined by protection settings, either a voltage dip or an interruption will result.

3.2.5 Factors Influencing Voltage Dips

The severity of a voltage dip will be determined by the location of the fault in the power system in relation to the customer equipment and its sensitivity. The frequency of the faults on a utility's power system depends on the weather, maintenance and the age of the equipment. Further, the protection equipment is a critical factor in the determination of voltage dips. This implies that the speed of operation of the protection system will determine if the power quality event is a voltage dip or an interruption (Short, 2006).

The location of the fault is one factor which will affect voltage dips. Urban substations have many shorter feeders connected to the busbars. Urban power system equipment is mostly enclosed and not exposed to the weather. Rural power lines provide power in low-density. This is done by transporting power over extra long overhead lines. Therefore, many of the faults on the rural lines are too far away from the sub to pull down the voltage, while almost every fault in an urban substation will result in a voltage dip on the power system. On lower voltage levels, fewer voltage dips occur compared to higher voltage levels (Short, 2006).

3.2.6 Reducing Voltage Dips

According to Short (2006), there are limited options to reducing voltage dips. From the utility's point of view, if these options are available these are hardly ever done for the sole purpose of reducing voltage dips.

According to Dugan et al (2003), design and fault clearing practice have a tremendous impact on voltage dips and outage frequency within a power system. There are two basic options to reduce the impact of faults, that is, prevention of faults and modification of fault-clearing practices. There are benefits to both the utility and the customer in terms of prevention of faults. The customer will be more satisfied and the utility will observe a reduction in the cost to repair damaged equipment caused by faults.

A voltage dip compensator is amongst the most cost effective methods to solve voltage dip problems on sensitive loads. One important issue to deal with is the inrush current which could trigger the overcurrent protection or expulsion fuse. One way to overcome this is to use oversize transformers. Obviously this will have a cost implication, but the cost of the voltage dips must be compared to the capital investment in order to make an informed decision (Cheng et al, 2005).

3.2.6.1 Maintenance

Ensuring that the trees along an overhead line are regularly trimmed is one of the most successful techniques. Insulator washing is critical on the coast and in dusty regions. Routine pole, line and insulator inspections will identify possible faulty equipment. Overhead lines tensions should be inspected and re-tensioned to reduce clashing of conductors (Dugan et al, 2003).

3.2.6.2 Birds and Animals

In SA a minimum of 10 700 animal-related outages, lasting a total duration of 25 630 hours, were reported on the national power system, affecting approximately 136 533 customers over a 16 year period (www.eskom.co.za). Birds caused approximately two thirds of these outages.

Birds, especially raptors, are vulnerable to electrocution on certain types of structures. The cause of these electrocutions have been studied in depth by several researchers and the broad consensus is that death is a result of the physical dimensions of the bird, coupled with the design of the particular electricity structure (R. Kruger, "Electrocution of Wildlife", Eskom report, 2000).

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The design of certain electricity utility structures can result in bird electrocutions. To understand the electrocution problem, the relationship between the body size of birds and the design of structures must be considered. Electrocution of birds is directly related to power line design, and more specifically, to the spacing between elements that can result in phase-to-phase or phase-to-ground contact. The following are indications that bird electrocutions are a problem (Dugan et al, 2003):

- Unexplained auto-reclosing occurring in clear weather conditions and no vegetation problem.
- The presence of large birds in the area where the faults occur.
- Absence or scarcity of alternative roosting and perching substrate like cliffs, trees and buildings.

- Agricultural activity, especially irrigation and fallow land.
- Arid habitat with water reservoirs, coupled with pole transformers in close proximity.
- The presence of bird carcasses lying directly under the pole.

Squirrels, monkeys and baboons are the cause of many outages in SA. These outages usually occur in fair weather conditions. Mo and Taylor (as cited in Short, 2006) say that many of these faults caused by animals are classified as “unknown.” According to Short (2006), the following problem conditions can lead to animals causing outages:

- Transformer bushings – faults across bushings cause outages and voltage dips. Bushing guard protectors and insulated lead wires provide protection.
- Arrestors – animal guards could protect faults across arrestors mounted on tanks.
- Cutouts – sometimes installed where there is low clearance between phase conductor and grounded object.

3.2.6.3 Fuses, Reclosing and Sectionalising

If more fuses were installed to smaller sections of networks, fewer customers would be interrupted. To reduce outages, it is important that utilities increase the number of fuses. According to Dugan et al (2003) one way of dealing with momentary interruption (voltage dips) is to disable fast-tripping or fuse-saving features. Fuse-blowing has the advantage of reduced customer complaints about poor power quality, but it also has the disadvantage in that affected customers will have to wait until the fuse is replaced. This will increase the reliability indices.

There are many schools of thought regarding fuse-saving and fuse-blowing techniques. According to Dugan et al (2003) customers are more sensitive to voltage dips in urban areas than in the rural areas. They argue that the

solution to power quality problems is to eliminate fuse-saving techniques to save operating costs and improve the reliability indices.

Fuse-blowing techniques will probably not eliminate all the power quality problems faced by industrial customers. They will reduce the momentary voltage dips, but faults on other sections of nearby power system will still have an effect on the industrial customer. Dugan et al (2003) say that as a rule of thumb, fuse-blowing will eliminate one-third of the power quality problems of industrial customers.

According to Short (2006), one reason for not using the fuse-saving technique is the difficulty in making it work. Fuses generally blow before circuit breakers trip. When the fault current is high and the fuse is installed near a substation, then the fuse will blow before the breaker trips.

Fuse-blowing has the disadvantage of taking longer to clear the fault, which could result in damage to equipment (Short, 2006).

The best choice in terms of fuse-saving or fuse-blowing depends on the application and the type of customers connected to the power network and the utility's philosophy.

Auto-reclosers are used in conjunction with sectionalisers and fuses. Normally, sectionalisers would be installed at major lateral lines with many customers. Fuses would be used in minor lateral lines and transformers.

3.2.6.4 Surge Arrestors

Surge arrestors are usually used to protect power system equipment, but utilities are also using them to protect lines against faults, outages and voltage dips. For these purposes, arrestors must be basically installed on each pole and on each phase, which could be a costly exercise (Short, 2006).

3.2.6.5 Co-ordination of Protection Equipment

Improving co-ordination of protection equipment is critical for power system reliability and the reduction of voltage dips. More protective devices that can assist with sectionalising, automating of operation, faster fault clearing time and reduction of outage time should be installed (Dugan et al, 2003).

Some protection devices have been difficult to co-ordinate. Misco-ordination of reclosers, sectionalisers and fuses cause longer outage time and more power quality problems for customers. Electronic reclosers and digital relays should be used for easier co-ordination (Short, 2006).

3.3 HARMONICS

3.3.1 Introduction

Harmonics are not a new phenomenon on power systems. Between the 1930's and 1940's there were concerns about harmonics. The primary sources of harmonic problems then were transformers and the interference of telecommunication wiring. If a power system is capable of handling the load demand, the possibility of harmonic problems will be negligible but could cause telecommunication problems. The increase in the use of electrical equipment that produces harmonics has posed significant problems for electrical networks and in power quality. The problems arise only when the capacitance of the system results in resonance at a critical frequency that causes abnormal distortion. This is more likely to happen in industrial power systems (Dugan et al, 2003).

Deviations from a perfect sinusoidal waveform are termed a harmonic distortion (Burke, 1994). Harmonics are sinusoidal voltages or currents, the frequency of which are a multiple of the fundamental frequency (50 Hz) of the power system. Because electrical devices that act as non-linear loads draw current in a non-linear way, they are responsible for injecting harmonic currents into the electricity network. Some problems caused by harmonics include cable/conductor failure and the overheating of transformer windings.

The impact of harmonics on electrical equipment, especially on sensitive electronic equipment, has only become apparent recently. Interference in telecommunication is only one of the undesirable side effects that harmonics cause when present in an electricity network. There is clearly a need to investigate the effect of harmonics on electrical power systems.

3.3.2 Cause of Harmonics

Harmonics are not usually generated by the utility's power system, but rather by loads connected to the power system. Burke (1994) states that the following loads are common sources of harmonics:

- Static power converters;
- Overexcited transformers;
- Fluorescent lights, and
- Solid state devices namely, computers, dimmers, variable speed drives

Harmonics can also arise in the generation of electricity, and in the transmission and distribution power systems. If a generator produces a non-ideal sinusoidal waveform, the voltage waveform will contain a certain amount of harmonics. In the distribution system, transformers are capable of producing harmonics due to magnetic core saturation. This is more prevalent when transformers are lightly loaded. The greatest production of harmonics is via harmonic current generation from non-linear loads. Non-linear loads are those in which the load does not draw a sinusoidal current. With the introduction of power electronic devices, there are now many devices that act in this manner. With the introduction of power electronic devices in rectifiers, motor drives and power supplies, the increasing level of harmonics has become quite a concern (Arrilaga, Bradley and Bodger, 1985).

Research has shown that non-linear loads inject harmonic currents into the power system. These harmonic-producing loads can be treated as current sources. However, the harmonic currents that pass through the power

system cause a voltage drop for each harmonic. This results in voltage distortion at the load bus as well as current distortion (Alexander and Thompson, 2007). The power quality instruments are capable of producing harmonic data and waveforms. This research study used power quality instruments to retrieve harmonic data. This will be analyzed and compared to the benchmark. If it is found that the harmonics pose a problem to the power network, further investigations will be done in terms of identifying the possible causes.

3.3.3 Location of Harmonics

The common route for harmonic currents to flow is from the harmonic producing load into the power system as illustrated in Figure 3.4. Generally, the impedance of the power system is lower than that of the load, thus the bulk of the current will flow into the power system.

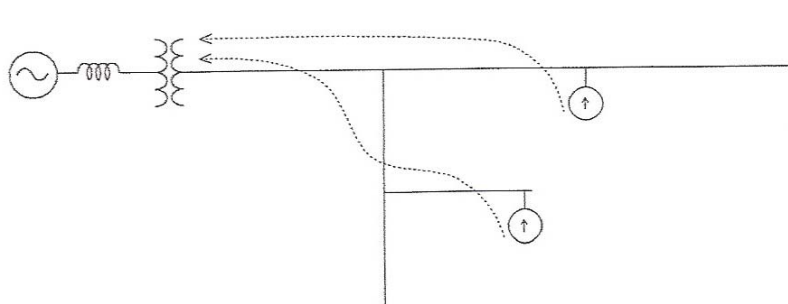


Figure 3.4 – General flow of harmonic currents in a radial power system (Adapted from Dugan et al, 2003)

Where evidence of harmonics are detected, suitable power quality monitoring equipment could be fitted to measure the harmonics to the source (Dugan et al, 2003).

3.3.4 Effects of Harmonics

The most notable effect that harmonics have on a power system is on their impact on the quality of the AC voltage waveform as it will become distorted. This causes problems with other sensitive loads connected to the same supply (Mohan, Undeland and Robbins, 1986).

Generally, harmonic problems surface at capacitor banks. The capacitor bank will experience excessively high distortions during resonance, which will result in a high flow of current into the capacitor. Figure 3.5 depicts the current waveform of a capacitor bank in resonance (Dugan et al, 2003).

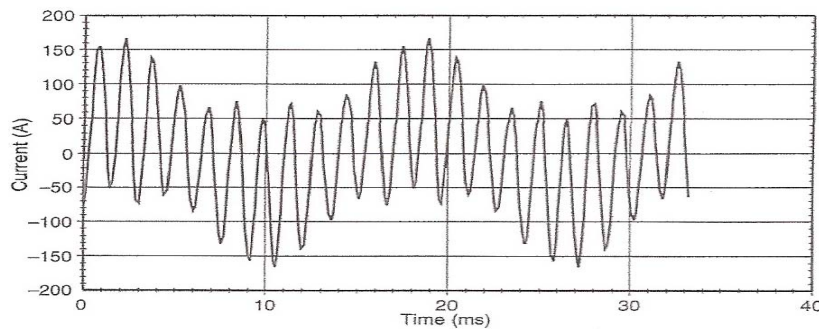


Figure 3.5 – Typical capacitor current from a system in 11th harmonic resonance (Adapted from Dugan et al, 2003)

In transformers, harmonic currents cause the RMS current to be greater than their capacity, leading to increased conductor power loss and heating. In motors, decreased efficiency, excessive heating and vibration are symptoms of harmonic voltage distortion. The tripping of protective relays, telephone interference and false meter readings are other consequences of harmonics in power systems (Dugan et al, 2003)

3.3.5 Reduction of Harmonics

According to Lakervi and Holmes, (2003), harmonics can be reduced by installing harmonic filters into the MV or LV circuits. It is more economical to install these filters on the MV bars, but since harmonics are generally produced from the LV loads, it is probably the best solution to install filter onto the LV bars.

Power factor correction capacitors can alter the flow of harmonic currents. By installing a capacitor as per Figure 3.6, a large amount of current would be diverted to the capacitor circuit (Dugan et al, 2003).

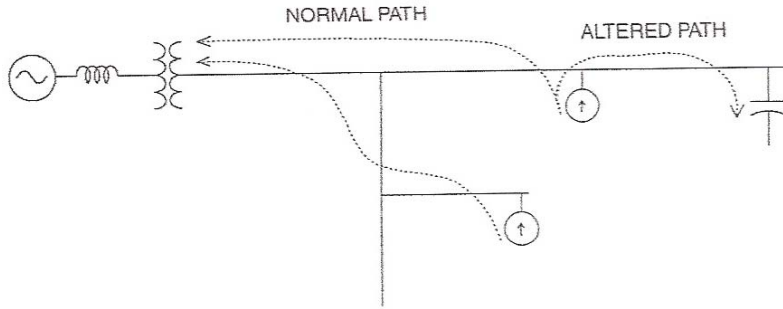


Figure 3.6 – Capacitor can alter the direction of flow (Adapted from Dugan et al, 2003)

Harmonics are not a major power quality concern in the NMBM, but they contribute to the power quality problems of the NMBM.

3.4 FLICKERING

3.4.1 Introduction

Flickering is not a new phenomenon. It has gained more attention as power users became more aware of power quality. Power Engineers dealt with flickering in 1880 when AC was considered above DC. The low frequency AC voltage caused flickering. To overcome this problem a higher frequency of 60 Hz was introduced. Other synonyms for flickering are voltage fluctuations, voltage flickering, light flickering and lamp flickering *et cetera* (Dugan et al, 2003).

Dugan et al (2003) state that flickering can be divided into two types, namely, cyclic and non-cyclic. Cyclic is the result of periodic fluctuations and non-cyclic is the result of occasional fluctuations. An example of cyclic flicker is shown in Figure 3.7. Flicker is generally identified as a percentage of the normal operating voltage. Percentage voltage modulation is expressed as follows:

$$\text{Percentage voltage modulation} = \frac{V_{max} - V_{min}}{V_o} \times 100\% \quad (3.10)$$

where,

$$V_{max} = \text{Maximum value of modulated signal}$$

V_{min} = Minimum value of modulated signal
 V_o = Average value of normal operating voltage

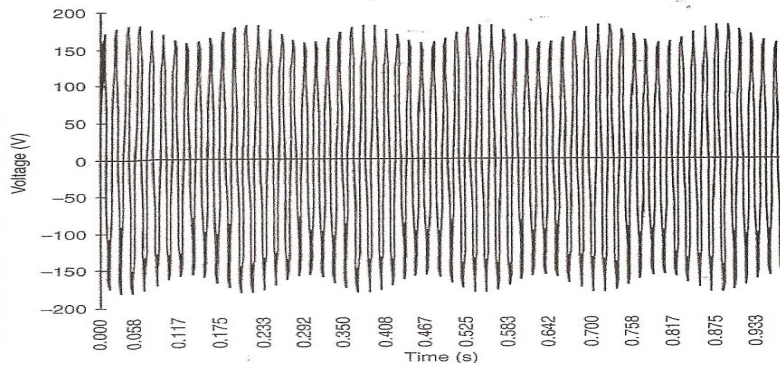


Figure 3.7 – Flicker waveform (Adapted from Dugan et al, 2003)

3.4.2 Causes of Flickering

Flickering is caused by fast changing loads which impact on the customer's voltage. Although flickering does not cause any harm to or disruption equipment, it irritates users. Sawmills, irrigation pumps, arc welders, spot welders, elevators, laser printer *et cetera* are all mechanisms in which current can change rapidly (Short, 2006).

According to Short (2006), the flicker tendency of different lights differ extensively:

- Small incandescent lamps – lamps with small filaments cool fast, therefore the light output changes more for a given fluctuation.
- Dimmers – electronic dimmers significantly increase voltage flicker.
- Fluorescent lamps – electronic and magnetic ballasted fluorescent lamps normally flicker.

Flickering affects mostly lighting, but can also cause television and computer monitors to waiver. Flickering is a human perception and some people are more sensitive to it than others. Flickering is also more visible in low-light settings.

3.4.3 Eliminating Flickering

Varying load conditions are responsible for flickering. One method of overcoming flickering is to increase the capacity of the power system. This means a major financial injection, which is not always viable. Upgrading could include reconductoring, replacing of transformers with higher kVA ratings and increase the operating voltage (Dugan et al, 2003).

Generally, capacitors are installed in series with the power lines supplying the load. The capacitor in series with an inductor cancels the inductance represented in Figure 3.8, resulting in less inductance, therefore less volt drops and fewer fluctuations (Short, 2006).

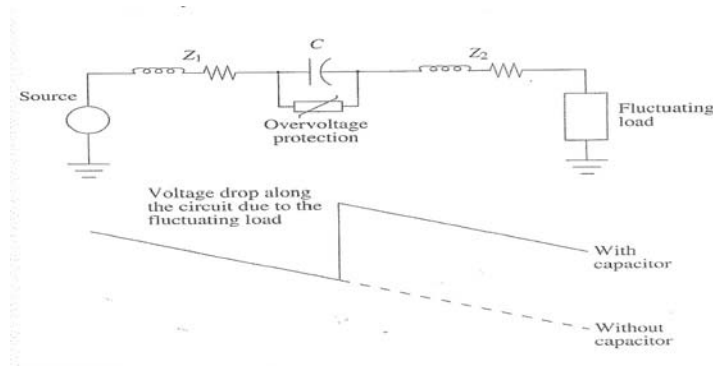


Figure 3.8 – Series capacitor (Adapted from Short, 2006)

The advantage of capacitors is that the reaction time for correction to load fluctuations is instant. The disadvantage is that those customers upstream from the capacitor do not benefit from the elimination of flickering (Dugan et al, 2003).

SVC's have many roles to play in power systems. One role is to reduce flickering. The SVC changes its reactance by injecting or absorbing reactive power. This equipment is used in arc furnaces on distribution lines. The cost of SVC's is high, but sometimes it is the only cost-effective solution for the flickering problem (Dugan et al, 2003; Short 2006).

Dedicated circuits running to customers affected by flickering could be a solution, depending on the cost and the viability. This will isolate the affected customer from the flicker producing load.

Series reactors could be installed to reduce flickering. This assists in stabilising the arc, thus reducing the current during the beginning of the melting process. By using series reactors, the additional reactance reduces the current fluctuations.

Step starting of motors is another method of reducing flickering. This will significantly reduce the starting current during start-up.

3.5 VOLTAGE SWELLS

Swells are linked to power system faults, but they are not as common as dips. A swell is identified by the RMS voltage magnitude and duration of the power quality event. The impedance, earthing and the magnitude of the fault defines the severity of a swell.

On un-earthed power systems with zero-sequence impedance, the phase to earth voltage will be 1,73 pu during fault conditions. Closer to the substation on un-earthed power systems, there will be no voltage rise on the unfaulted phases. The reason for this is that a transformer is normally connected in delta-wye, thus providing a low-impedance zero-sequence path for the fault current. Faults at different locations on a multi-earthed four-wired power system will react differently to voltage swells. This all depends on the distance of the fault. A 15% swell as per Figure 3.9 is typical (Dugan et al, 2003).

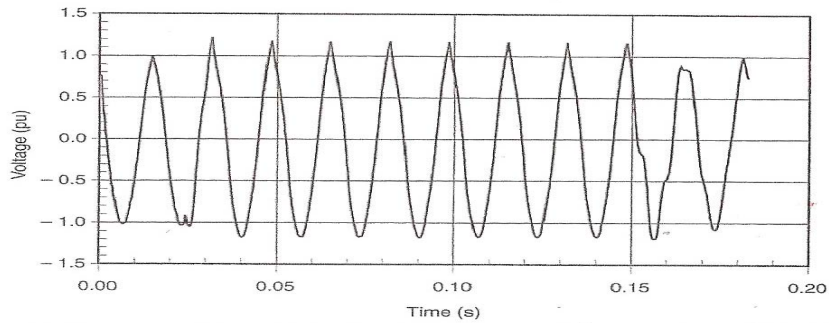


Figure 3.9 – Instantaneous voltage swell caused by fault (Adapted from Dugan et al, 2003)

Voltage increase on the unfaulted phases in a 4-wire multi-earthed power system can rise by approximately 30%, and on a 3-wire system by approximately 70%. The duration depends on the protection equipment responsible for clearing the fault (Dugan et al, 2003).

3.6 REGULATION

The cause of voltage regulation is that the impedance is too high to properly supply the load. This means that the power system is too weak for the load and the voltage drops too low under such load conditions (Dugan et al (2003).

3.6.1 Eliminating Voltage Regulation

Dugan et al (2003), list options to reduce voltage regulation:

- The addition of shunt capacitors to reduce the current and shift it to become more in phase with the voltage.
- The addition of voltage regulators to boost the voltage.
- The reconductoring to larger size overhead lines to reduce the impedance.
- The changing of transformers to larger sizes to reduce the impedance.
- The addition of reactive var compensators.
- The addition of series capacitors to cancel inductive impedance.

The NMBM power network will be analyzed in term of the NRS 048 standards. If it is found that voltage regulation poses a problem for the power network and the customer, power quality instruments should be installed. The data will be analysed and compared to the benchmark and standards based. Once the problem is established, recommendations will be made based on the principles described above.

CHAPTER 4

LITERATURE REVIEW: POWER SYSTEM PROTECTION

4.1 INTRODUCTION

Protection and reliability improvement are significant problems in power systems. Protective devices are used to deal with fuse, recloser, circuit breaker, relay and lightning protection device faults.

The operation settings of protective devices require accurate parameters appropriate to the characteristic and configuration of power networks. An essential part of the design of a power network is calculation of the currents when faults of various types occur. The magnitude of the fault current gives the engineer the current settings for the protection to be used and the ratings of the fuses, reclosers, and circuit breakers (Anderson, 1999).

According to Power System Protection: Volume 1 (1990), the purpose of protection is not as its name describes: that it prevents something from happening. Protection only takes action after a fault has occurred. It is the ambulance at the foot of the cliff, rather than the fence at the top. Exceptions are Buchholtz relay gas operated devices and surge arresters.

The basic purpose of power system protection is to detect abnormal operating or system fault conditions and to prevent any damage to the plant connected to a power system. The basic function of a power system is to ensure that sufficient electrical energy is available to all its customers without interruption. To safeguard this continuity of supply, the protection system must initiate the isolation of faulted sections of the power system as fast and selectively as possible (Hewitson et al, 2007; Bollen, 2000).

The demand for power capacity requirements to accommodate industrial and domestic growth has resulted in the increase of possible interruptions. Interruptions could cause voltage surges and increase the magnitude of the

current flowing from the healthy to the faulty components or between any faulty equipment and earth. Most faults on power systems could be controlled to limit damage to equipment and improve reliability (Anderson, 1999).

The protection equipment used for protecting 22kV power networks in NMBM within this study are differential, over current, earth fault on cable and overhead lines, sensitive earth fault, type K fuses, auto-reclosers and sectionalisers on overhead lines. Power system protection equipment could increase the reliability of power systems.

4.2 FACTORS AFFECTING THE SEVERITY OF A FAULT

According to Power System Protection: Volume 1 (1990), the factors affecting the severity of a fault on a power system can be assessed in terms of the damage the fault could cause, the magnitude of the fault current and the duration of the fault. The factors responsible for the severity of faults are as follows:

4.2.1 Source Conditions

These relate to the amount of all connected generation including all other power sources such as interconnections with other systems (Power System Protection: Volume 1, 1990).

4.2.2 Power System Configuration

This is determined by the plant, namely, generators, transformers, overhead lines, cables and normally open points et cetera. System configurations might change during the fault, resulting in changes in the magnitude and distribution of the fault current. This could result in typical sequential tripping of the circuit breakers at the two ends of the faulted transmission line and the clearance of multiple fault conditions (Power System Protection: Volume 1, 1990).

4.2.3 Nature and Type of fault

The type of fault and its location within a power system may have a considerable effect on the magnitude and distribution of the system fault current. The effects of a fault may be significantly altered by the simultaneous presence of other fault conditions. Another factor to take into consideration is the fault impedance. Three-phase short-circuits are regarded as the most severe fault conditions in terms of fault severity, and it is thus the maximum possible fault level value which could be used to determine the short-circuit current rating of the power system switchgear. An important factor is the maximum value of the single-phase to earth fault current, which, in a solidly earthed system, may exceed the maximum three-phase fault current (Power System Protection: Volume 1, 1990).

The factors affecting the severity of power system faults cannot be ignored. These factors and the understanding of the types of power system faults can assist utilities in their attempt to identify power system faults, apply corrective measures and hence increase power system reliability.

4.3 CURRENT TRANSFORMERS

Current transformers (CT) are regarded as the most important components of a protection system. The current transformer is responsible for stepping down the primary current and isolating the main system from the auxiliary system. Current transformers for protection purposes may have small errors or operational problems during fault conditions. During normal conditions, when the relay is not required to operate, the accuracy is insignificant (Howritz, Phadke, 2008).

Two types of current transformers are available, namely, protective current transformers for the use of overcurrent protection and class X transformers for the use of differential protection. Both these current transformers must sustain high fault currents. It is therefore imperative that these transformers stay accurate during fault conditions. The accuracy classes of current

transformers are 5P and 10P and the standard secondary current ratings are 1A and 5A (Walker, 2007). Table 4.1 depicts the maximum error for the different classes.

Table 4.1 – Maximum errors for different classes of current transformers (adapted from Walker, 2007)

Class	% current error at rated primary current	Phase error at rated current in minutes	% composite error at rated primary ALC
5P	± 1	± 60	5
10P	± 3		10

Another important specification of a current transformer is the accuracy limit factor (ALF), which denotes the maximum current a transformer is to withstand to remain accurate (Walker, 2007). The larger the ALF, the less likely the CT is to become saturated. IEC typical ALF values are 5, 10, 15, 20 and 30. Two requirements for a protective CT are that it must have an ALF and accuracy class suitable for the application (Prév  , 2006). Pr  v   (2006) adds that for overcurrent applications a class 10P CT is suitable and for differential protection a class 5P is suitable. Differential protection is fast and it requires a CT with a lesser margin of inaccuracy.

The magnetisation curve is a method of determining the accuracy and performance of a current transformer. The method of performing this test is to apply an input voltage on the secondary of the current transformer, leaving the primary winding open-circuit and increase the voltage on intervals, starting from zero. The resultant current is plotted on a curve against the voltage. From the magnetisation curve in Figure 4.1, the saturation region of the current transformer can be determined. This is termed the knee point voltage at which a 10% increase in voltage at the secondary will result in a 50% increase in excitation current (Hewitson et al, 2007).

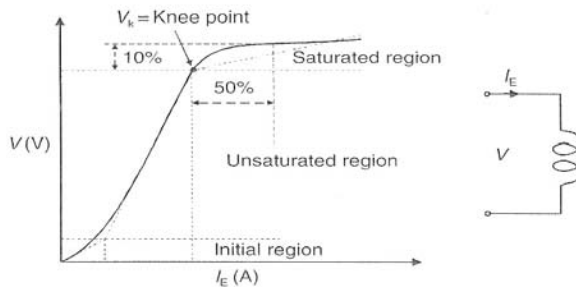


Figure 4.1 – Typical CT Magnetisation Curve (adapted from Hewitson et al, 2007)

Preventative routine maintenance is very important to ensure that the CT is still in a condition that ensures reliability of the power system. Very often the protection system is blamed for outages of unknown cause. The magnetization curve, insulation resistance, saturation and primary injection tests are performed to ensure that the CT is in a good condition. This will be applied in the case studies to ensure proper performance of the CT and decrease the possibility of unnecessary power outages.

According to Walker (2007), certain factors have to be considered when selecting the primary current of a CT. One method is to determine if the CT is still suitable for the application. The following should be considered:

- The full-load current of the load;
- The full-load current of the transformer if the power system is supplied by a transformer;
- The maximum fault current calculated;
- The application of the CT;
- The primary current should be twice the load current, and
- The CT must not overload under full-load current conditions.

4.4 FUSES

4.4.1 Introduction

Fuses are the oldest and simplest protection methods acting as both protective and disconnecting devices. Fuses are installed in series with the

apparatus they protect. Fuses function through the melting of a fusible element fitted in response to the current flowing through it. A fuse is strictly a one-shot protective device, as the fusible element disintegrates on operation. The melting time of a fuse is inversely proportional to the current flowing through it (Horowitz, Phadke, 2008).

Fuses must allow maximum load current without operating. Fault current through a fuse is limited before the current reaches its maximum value. In selecting a fuse, it is important to provide protection against faults rather than to protect the equipment against overload. Using different time/current characteristics, discrimination with other fuses and protective devices can be achieved. The characteristics of a fuse would vary from manufacturer to manufacturer (Lakervi, Holmes, 2003).

4.4.2 Application

According to Hewitson et al (2007), fuses can be used for overload and short-circuit protection. In short-circuit protection fuses can be used where:

- The load does not fluctuate much during switching and operating conditions. Resistive loads would demonstrate such characteristics, hence fuses for overload and short-circuit protection could be used;
- The load fluctuates to a great extent compared to the normal rating, for example, direct-on-line starters, cranes, rolling mills, welders et cetera. In these instances, fuses could be utilised to provide short-circuit protection as it would be impossible to determine a fuse for both overload and inrush conditions.

Power fuses are more economical, thus these are used instead of oil circuit breakers. Many factors influence the use of fuses, namely, the frequency of operation, the speed at which the supply must be restored and the return on the investment. Fuse links are manufactured in two types, namely K and T. The difference between the two is the melting time which is measured in terms of the speed ratio, which is equal to the melting current at 0.1 s divided

by the melting current at 300 or 600 s (Anderson, 1999). In the case of the NMBM, type K drop-out fuse links are normally used. The type K drop-out fuse links are installed at the beginning of lateral lines and sometimes between bundle conductors and bare conductors.

4.4.2.1 Protection of Transformers

Transformers with a capacity rating less than 2500 kVA are normally protected by means of fuses (Horowitz, Phadke, 2008). Step down transformers in distribution and industrial sites use fuses to protect both the primary and secondary sides of the transformer. High voltage fuses are installed on both the primary and secondary side of 33/11kV transformers rated up to 5 MVA (Wright, Christopoulos, 1993). The standard purpose of a fuse on the low voltage side of a transformer is to protect the load connected to the secondary windings. The fuse to be selected in this case must match the load and the cabling. Fuses on the primary side must protect the transformer against faults and must be done without causing loss of supply to the healthy parts of the network.

According to Wright and Newbery (2004), the following factors are to be considered when selecting fuses:

- It is common practice that transformers are deliberately operated above their ratings for predetermined periods, often for several hours. This is done due to their relatively long thermal time constant. To allow for this practice, fuses capable of carrying maximum currents must be selected.
- Transformers draw high transient currents when they are energised. The magnetic core of the transformer may go into saturation over time. This is accompanied by the magnetising inrush current, which forms a wave shape as in Figure 4.2. These surge currents may reach values many times the rated current of the transformer even though the normal exciting current may only be 2-3% of the rated current. The actual value is determined by the transformer design, maximum system voltage and the fault current available. In practice, the inrush current tends to

decrease as the kVA rating increases. On the other hand, the time duration of the inrush current increases as the kVA rating increases. It can therefore be safely assumed that the inrush current of a transformer is 10 to 12 times the rated full-load current for a duration of 100 ms.

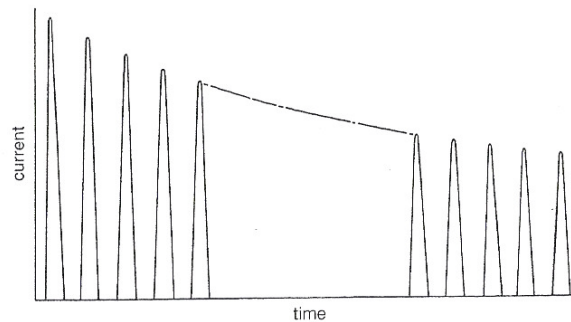


Figure 4.2 – Magnetising current of transformer (Adapted from Wright and Newbery, 2004)

- To ensure that faults in a transformer are cleared fast, the current needed in the 10 s region should be as low as possible.
- The minimum fusing current of the primary circuit should be as low as possible to ensure that many internal faults are cleared. It must be accepted that in some instances interturn faults may cause primary currents less than full-load value to flow and will not cause the fuse to operate.
- Correct discrimination between the fuse and other protective devices on the network, including the fuse on the secondary windings, should be achieved under all conditions.
- In instances where transformers are supplied by overhead lines it is likely that they will be exposed to lightning, resulting in high overvoltages. The fuse on the primary side should ideally withstand the high currents, but this normally requires highly rated fuses which cannot provide adequate protection for other conditions. A compromise must be reached and some degree of risk must be accepted in these cases.

It is critical that care must be exercised when selecting fuses associated with transformers. The characteristics of a high voltage fuse will differ from a low voltage fuse. Generally, the high voltage fuse will operate at higher current levels than that of a low voltage fuse with similar time changes. Figure 4.3

below show the different time/current characteristics to be observed when selecting and grading fuses (Wright and Newbery, 2004).

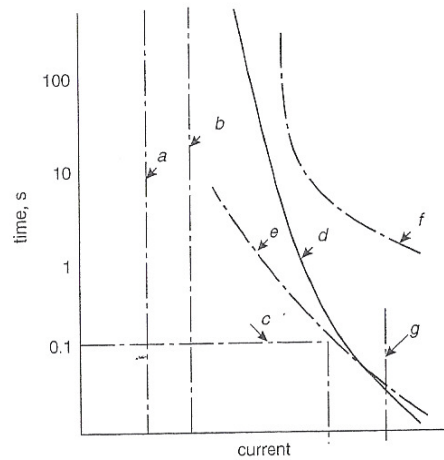


Figure 4.3 – Time-Current (TC) Characteristics of transformer (Adapted from Wright and Newbery, 2004)

Where:	a	-	Full-load current of transformer
	b	-	Permissible overload current of transformer
	c	-	Magnetising inrush equivalent current
	d	-	HV fuse characteristic
	e	-	LV fuse characteristic (referred to HV side)
	f	-	Characteristic of source circuit breaker relay
	g	-	maximum current on HV side with fault on LV side

According to Brown (2002), power transformers with an MVA rating less than 100 MVA should never exceed 200% of their nameplate rating. Transformer temperatures do not increase instantaneously when subjected to overloads. This allows transformers to be overloaded for short durations, provided that the temperature remains below the normal rating.

4.5 AUTO-RECLOSERS

Eighty percent of faults in rural power systems are transient and would cause no permanent harm to a plant. Normally, fuses would be used to clear these faults, but an interruption of the supply could be long and would inconvenience customers. One method to reduce the outage time and the operational cost is to have the supply restored automatically. Auto-reclosers

are the answer to these problems and consequently this equipment is being installed more extensively (Dugan et al, 2003).

For successful operation of the device, the speed of operation of the circuit breaker is critical. If the opening of the circuit breaker is delayed for more than a few cycles, the heat generated by the fault current may cause more serious damage to the equipment and could create a persistent fault (Short, 2006).

The time interval between tripping and reclosing is called “dead time”. It may vary depending on the characteristics of the circuit breaker, the nature of the fault and the load it is supplying. “Dead time” must always be sufficient to de-ionise the fault path and to stabilise the circuit breaker. In certain practices, times between 0.4 and 120 s are used, but comments from field staff suggest times between 10 and 15 s (Brown, 2002).

Another important characteristic of a recloser is the resetting or reclaim time. The resetting times become significant when repetitive faults occur, namely, lightning and conductors clashing. If the resetting time is in excess of the intervals between the incidences of successive faults, it may cause unnecessary lockouts and outage time. In practice, a good reset time is approximately 5 s (Power System Protection: Volume 3, 1995).

Auto-reclosers are very popular on overhead line transmission and distribution power systems. The devices have time-current characteristics that simplify the co-ordination with other equipment, namely, fuses, relays, sectionalisers et cetera. This could be further simplified if all the equipment which has to be co-ordinated is from the same manufacturer. However, this is not always the case in practice, thus making co-ordination more difficult. Co-ordination of reclosers is a constructive feature as it allows for flexibility in selection of time-current characteristic curves from memory. This includes instantaneous tripping and fast tripping. There are many TC characteristics that are used in the field, but Figure 4.4 depicts a typical TC characteristic employed in the NMBM power system. These reclosers are programmed for one

instantaneous trip (Curve A) and two delayed operations (Curves B and C) (Anderson, 1999).

In some instances, reclosers are designed and developed by arranging the source circuit breaker to carry out various tripping and closing by employing appropriate relaying. Sometimes it is not possible to install reclosers at the source because the initial section of the circuit is cable. In these instances, the recloser should be installed at the first pole supplying the overhead line (Lakervi, Holmes, 2003).

Reclosers are normally designed for fuse-saving technology, therefore a fast tripping TC characteristic must be used. Reclosers are the fastest fault interrupters on power systems. They are valuable in limiting dip durations. If fast tripping is deactivated, the downstream fuse will clear the fault. In instances where lightning is prevalent, four shot reclosers could be utilised (Dugan et al, 2003).

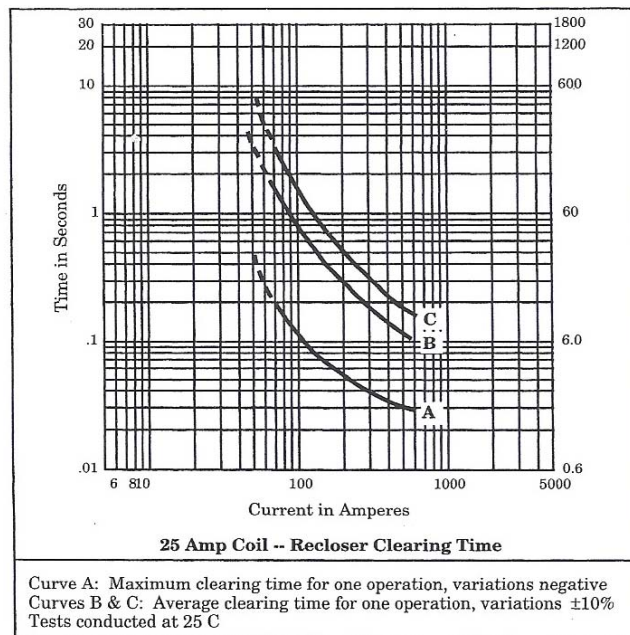


Figure 4.4 – TC Characteristics of a Recloser

Policy in terms of the operation of reclosers is not clear. This creates tremendous problems. From a control and fault analysis point of view, policy

is critically needed with respect to operation of reclosers, TC characteristics, number of shots and discrimination of other protection equipment. Co-ordination of reclosers with other power system protection equipment is necessary.

4.6 SECTIONALISERS

Sectionalising is one method of isolating faulty sections on overhead power lines. It could be used instead of fuses or in conjunction with fuses and reclosers. These devices are pole-mounted, but not limited to oil immersed disconnecting devices. A sectionaliser is not capable of breaking fault current, but it may be closed onto a fault and used to provide suitable protection for lateral lines. Normally, the lateral lines are not automatically monitored through SCADA in the control centre, which may have the consequence of extended outage time. But, if the recloser is monitored through SCADA in the control centre, it will be easier to identify the operation of the sectionaliser as the number of openings of the reclosers will be displayed on the event list (Lakervi and Holmes, 2003).

For power system reliability, outage time and operation of protection equipment is a priority, thus the operation of sectionalisers in conjunction with reclosers needs to be investigated. Sectionalisers in the NMBM power system are normally installed on lateral lines with reclosers upstream. The possibility of sectionalisers on lateral lines with downstream fuses and upstream reclosers thus also needs investigation.

4.7 OVERCURRENT PROTECTION (OC)

Overhead lines are protected by overcurrent, distance or pilot wire protection, depending on each individual application or the profile of the overhead line. Overcurrent protection is probably the simplest and cheapest, but it is the most complicated to apply and requires more setting and replacement as a power system change. It is used for phase and earth fault protection, and for

back-up protection on most transmission lines where pilot wire protection is used as main protection. Overcurrent protection should not be confused with overload protection. In practice a compromise is made to cover both objectives. Overcurrent protection is related to the correct and fast clearance of faults, while overload protection is related to the thermal capabilities of the plant or circuit it is protecting (Anderson, 1999).

Many industries moved to the rural areas which are mainly supplied by overhead lines. The overhead lines are protected with overcurrent and earth fault protection. According to Apostolov (2005) many power quality problems can be solved by using advanced protection schemes, particular when a utility supply electricity to a manufacturing plant, namely, selective back-up tripping and fuse-saving technology. This means that the infrastructure investment will be increased.

Overcurrent protection is well suited for transmission and distribution power systems. Often it is not a requirement that the relays need to be directional, so no AC voltage source is required. Also, two phase relays and one earth fault relay as one unit are permissible. The greatest advantage of overcurrent protection is the inverse-time characteristic because the fault current magnitude depends mostly on the fault's location. Overcurrent relays with extremely inverse curves provide the best selectivity with fuses and reclosers. However, if earth fault current magnitude is severely limited by neutral earth impedance, there is little or no advantage to be gained from the inverse characteristic of an earth fault relay (Mason, n.d). The NMBM use mainly inverse-time characteristic curves. The difficulties to achieve best co-ordination with fuses form a very important aspect of power system reliability.

Overhead lines are exposed to phase-to-phase and phase-to-earth faults. These faults form the basis of damage to other equipment connected to the overhead line. In considering overhead line protection it is imperative to take cognisance of the fault current likely to be generated, the impact of the connected load, the system configurations and directionality. The overcurrent protection must also be compatible with the protection of the adjacent and

other connected elements of the power system. In order to apply this properly one has carefully apply the settings, operating times and characteristics. It is also important to note that in a radial system the fault current is flowing in one direction, but in a parallel and an interconnected system the fault current can flow from any direction. It is therefore important that the relay must be able to distinguish between the directions (Howoritz, Phadke, 2008).

In terms of TC settings, the general practice is a 0.4 to 0.5 s tolerance between relays. For electronic relays the tolerance is reduced to 0.3 s. By adjusting the current sensitivity of the relay, it can operate at the same time on a reduced current (from 100% to 50%). By adjusting the time setting, the operating time of the relay can be varied. The option of the relay to vary the TC settings makes it suitable to co-ordinate with other protection equipment (Lakervi, Holmes, 2003).

4.8 EARTH FAULT PROTECTION (EF)

Protection schemes ensure that no fault remains uncleared. Back-up earth fault protection is provided by an IDMT relay, which is set at a longer operating time in order to achieve proper co-ordination. It is also common practice to provide HV and LV earth fault protection on transformers (Power System Protection: Volume 2, 1995).

Earth fault protection is normally used on the NMBM power network, combined with overcurrent protection in an IDMT relay. Most of the HV transmission lines are earthed systems, either solidly or through a resistor or a reactor. According to Anderson (1999), 90% of all transmission faults are earth faults and in practice earth faults dominate trips on overhead line power systems. It is also evident that phase-to-phase faults occur, but the earth fault relay detects the fault before the phase-to-phase relay.

In multiple earth power systems, any fault between a phase and earth will be supplied by a zero-sequence current originating in the earthed neutral of the

transformer. Current flowing to earth has a zero-sequence component and a zero-sequence voltage will be measured. Earth fault relays will detect zero-sequence currents and voltages as abnormal conditions and will be triggered to operate. Under normal operating conditions, no zero-sequence currents should flow apart from those flowing due to imbalances. It can be safely assumed that under normal conditions no zero-sequence currents are present. Polarisation is achieved in the same way as in overcurrent protection (Anderson, 1999).

The standard in the NMBM power system in terms of earth fault plug setting is 20% and the TMS at 0.1 (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

4.9 SENSITIVE EARTH FAULT PROTECTION (SEF)

In instances where the ground is of such a nature that it is difficult to make an effective earth connection, it sometimes happens that the fault to earth may result in a current which is too small to operate the earth fault relay. This is aggravated when continuous earth conductors are not used or cut away. It also happens that phase conductors may fall on trees, hedges, dry ground or on road surfaces, so the fault current might be too low to trigger the earth fault protection. This poses a serious danger if the supply is not isolated. It is not possible to lower the settings of a normal earth fault relay to cater for this danger as the setting has to be reduced by a factor of 10 or more. It is also difficult to use a current transformer to provide effective settings for this purpose. For this reason a special sensitive earth fault relay is used, based on the very sensitive elements of the power network. This relay is based on a definite-time principle and, although it is suitable to grade with other protection devices, it is usually graded as an independent system (Power System Protection: Volume 2, 1995).

The SEF must detect low-level earth faults. The SEF setting will therefore be the greater of 5 amps or 3% of the CT primary rating and the $T_M = 10$ s (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

4.10 FAULT LEVEL

Fault level is an important parameter of any power system. Protective devices for power systems such as circuit breakers, protective relays and fuses provide adequate protection and isolate faulty equipment only if they operate within their design short-circuit current values. It is therefore important to recognise the maximum fault current in determining the interrupting rating of the devices (Anderson, 1999).

In power networks the maximum fault level occurs at the busbars of the source substation. The fault level is defined as the product of the magnitude of the pre-fault voltage at a busbar and the post-fault current, which would flow if that busbar is short-circuited. The fault level or short-circuit capacity is a measure of interconnections at any point in the power system. In the event of a short-circuit occurring at a busbar in an interconnected system, the pre-fault voltage of the busbar is near to the nominal value 1 p.u. and as soon as the fault takes place, the voltage of the busbar reduces to almost zero. The voltage of the other busbars will dip during the fault. The reduction in voltage of the various busbars depends on the strength of the network. The strength of a busbar is directly related to the short-circuit level, thus the higher the short-circuit level of the busbar, the more it is able to maintain its voltage in case of a fault on any other busbar (Prévé, 2006).

The strength of a system indicates the severity of short-circuit stresses. Strength is revealed by a quantity known as short-circuit capacity or fault level of the busbar in question. The strength of a busbar refers to the ability of the busbar to maintain its voltage when a fault occurs at another busbar. Also revealed is that the higher the short-circuit capacity, the lower the equivalent

impedance between the faulted busbar and the zero potential busbar of the system (Hewitson et al, 2007).

The fault level is actually the short-circuit MVA that will flow into a fault. It is important to know how to calculate the fault level or short-circuit MVA so that equipment can be chosen to withstand and isolate these faults without causing major damage. According to Hewitson et al (2007) the fault level of a power system can be calculated by using the following formula:

$$\frac{\text{Short - circuit MVA}}{\text{Rated MVA (P)}} = \frac{I_s}{I} = \frac{100}{X\%}$$

Hence,

$$\text{Short-circuit MVA} = \frac{100P}{X\%}$$

- I_s = r.m.s. short-circuit current
- I = Normal full load current
- P = Transformer rated power (rated MVA)
- X_p = Reactance per phase
- E_p = System voltage per phase

And,

$$S = \sqrt{3} VI_{FL} \quad (4.1)$$

Hewitson et al (2007) state that this formula is based on a few assumptions:

- That the fault occurs very close to the busbar, source or circuit breaker;
- Arc resistance is ignored;
- Cable impedance between the transformer secondary and switchgear is ignored, and
- The impact of source impedance is ignored.

Hewitson et al (2007) conclude by stating that if this method is employed, the results would be correct within 5%.

4.11 FAULT CALCULATIONS

A power system is usually regarded as a balanced symmetrical three-phase network. During fault conditions, the symmetry is disturbed. The result is unbalanced currents and voltages. The only exception is the three-phase fault, which includes all three phases and is described as a symmetrical fault. By using symmetrical component analysis and replacing the normal system sources with a source at the fault location, it is possible to analyse fault conditions. It is therefore important to know the fault current distribution throughout the system and the voltages in different parts of the system. According to Lakervi and Holmes, (2003), the information generally required for a fault is the following:

- Maximum fault current
- Minimum fault current
- Maximum through fault current

The general procedure to analyse three-phase balanced faults is as follows:

- Convert all impedances to common base values;
- Represent the power system by an equivalent single-phase diagram;
- Reduce the equivalent single-phase diagram to the equivalent Thevenin diagram, and
- Convert common base per unit values to actual values, (Walker, 2007).

These are useful methods to calculate the fault currents in a power system.

4.12 EARTHING

Power system earthing is very important as the majority of faults involve earthing. Although the primary reason for earthing is the safety of humans, it also has a significant effect on the protection of equipment. For this reason, the principle purpose of earthing is to minimise transient overvoltages.

4.12.1 Overhead line earthing

The construction of overhead lines in terms of earthing in the NMBM has to comply with the PEE Code of Practice – Overhead Line Earthing. The overhead line earth conductors must be connected to the substation earth mat. A soil resistivity test should be conducted to determine the type of earth electrode to use. All metal part on the overhead lines should be bonded and every eighth pole, as well every pole with special equipment, should be bonded to an earth electrode in the ground.

According to Dugan et al (2003) 80% of power quality problems relate to earthing on the equipment of either the customer or the utility. Proper earthing practice in terms of the operation of protection equipment is critical. It is clearly important that required earthing practice is applied and checked constantly to ensure proper operation of protection equipment and improvement in power quality. This will maintain the reliability of the power system.

4.13 SURGE ARRESTORS

Lightning is one of the main causes of power outages on overhead lines (Dugan et al, 2003). Many times the causes of these outages are recorded as “not established”, because the utility has no method to prove that lightning is the cause of the outages. One method of reducing outages on overhead lines is the installation of surge arrestors. Surge arrestors are also called lightning arrestors.

Overhead lines with no or a minimum number of surge arrestors could cause many flash overs, which could lead to insulation breakdown, and the consequence would be an outage. Installation of surge arrestors will also decrease the impact of voltage dips and voltage swells (Dugan et al, 2003).

According to Lakervi and Holmes (2003) the closer a surge arrestor is located to the equipment it is protecting, the more effective this protection will be. Lakervi and Holmes state further that it should not be more than 10 m away from the equipment. If the equipment is far away from the surge arrestor, the voltage that would be imposed on the equipment would be much higher.

Dugan et al (2003) are very clear on the installation of surge arrestors. They argue that a surge arrestor should be installed at every second or third pole, and in cases where critical loads are supplied, then surge arrestors should be installed at every pole.

In Figure 4.5 it is evident that the surge arrestor bleeds off some of the stroke current as the current passes along the line. The earth resistance plays an important role in the amount of current the surge arrestors will bleed off. Ideally, the surge arrestors must be placed in such a position that the BIL of the insulators is not exceeded (Dugan et al, 2003).

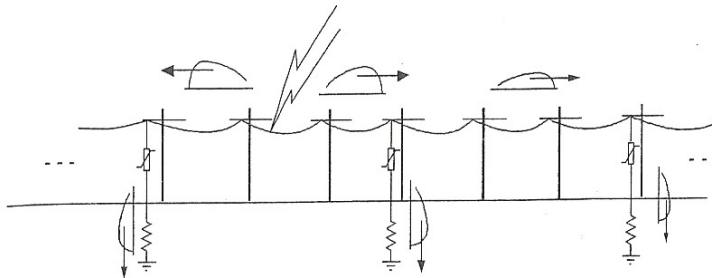


Figure 4.5 – Arrestors spaced to prevent flashover (Adapted from Dugan et al, 2003)

Lightning has a major impact on the reliability of power systems. The approaches of Lakervi and Holmes and that of Dugan could be applied to reduce outages and increase power system reliability.

4.14 DISCRIMINATION

Discrimination is also called grading or co-ordination. Time and current grading is most easily applied to radial power systems and consist of two types, namely, definite time/current and IDMT or Inverse Definite Minimum

Time. IDMT also serves also as backup protection for unit protection (Blackburn and Lewis, 1998).

4.14.1 Grading Margin

In a radial feeder the time that is allowed to pass between the successful tripping time on a downstream circuit breaker and its associate upstream circuit breaker, is the grading margin between the two sets of protection devices. The grading margin is normally set between 400 and 500 ms for oil circuit breakers. For vacuum and SF6 circuit breakers, it is normally between 200 and 300 ms (Christopoulos and Wright, 1999).

4.14.2 Time Grading

Time grading is generally used in calculating earth fault relay settings on a power system that is not effectively earthed through a neutral compensator or neutral earthing resistor. All the relays in series will have the same current setting and will thus operate simultaneously. Grading in terms of time is based on the selection of progressively lower time settings for each successive relay. The relay upstream from the fault will operate first (Christopoulos and Wright, 1999).

4.14.3 Current Grading

Current grading is based on the diversity of the fault current between the successive relaying points, and on the fact that the fault current is inversely proportional to the impedance of the system between the point of the fault and the source.

Current grading settings are not intended to protect the power system against current overload, but to protect the power system only against fault currents. The minimum setting used in practice is usually twice the full load current to stop operation during overloads (Christopoulos and Wright, 1999).

4.14.4 Grading of other equipment

In a typical recloser protected circuit with downstream fuses, the fuse must blow before the recloser operates. This is also dependant on what technology is used, namely, fuse saving or fuse blowing technology. The fuse blowing technology will assist in improving power system reliability, while fuse saving technology will clear transient faults. It is important when selecting the fuse size that the fuse permits a range that is adequate to cover the fault current co-ordination (Dugan et al, 2003).

Lack of grading is responsible for many outages and power quality problems. The NMBM power system also suffers under these conditions.

CHAPTER 5

LITERATURE REVIEW: MAINTENANCE AND MANPOWER

5.1 INTRODUCTION

Deterioration of electrical equipment is normal and this process begins the moment the equipment is installed. If deterioration is not checked and monitored it will lead to malfunctions and electrical failures, which account for many of the outages causing inconvenience to customers and financial loss. The purpose of preventative maintenance and testing is to identify the factors responsible for the deterioration of equipment and provide corrective measures. With an electrical preventative, maintenance and testing program, potential hazards which could cause failure of equipment or interruption of supply can be discovered and repaired or replaced. The program can also extend the life of the equipment if properly maintained. The program should consist of routine inspections, testing, repair and service of electrical equipment (Brown, 2002).

According to Gill (1997) a structured preventative maintenance program should at all times be performed as follows:

- Under the control of management;
- In accordance with the practice and schedule, and
- By a designated team.

According to Lohmann (n.d), the new approach is to shift from the traditional time-based maintenance policy to a condition-based reliability centred maintenance policy. This calls for differentiation among the following four types of maintenance policies:

- Predictive or condition based maintenance, namely to monitor if something is going to fail.

- Preventative maintenance, namely, overhauling items or replacing components at fixed intervals.
- Corrective maintenance, namely, fixing things either when they are found to be failing or when they have failed.
- Detective maintenance, namely to detect hidden failures by means of special functional checks and diagnostics.

The type of maintenance policy to select for specific equipment for transmission and distribution power networks depends on the reliability of the power system, financial implications and the availability of supply to the customers (Lohmann, n.d).

With respect to labour, it is a known fact that the engineering industry endures tremendous pressure due to the skills shortage in the country. This has a direct impact on service delivery and the supply of electricity.

5.2 CURRENT PRACTICES AND PROBLEMS

The different sections of the NMBM have personnel dedicated to perform maintenance on protection equipment, switchgear, transformers and overhead lines. Although many of these staff members were initially employed to perform these dedicated functions, commissioning of new plant, fault investigation and isolation of supplies receives preference. Maintenance is not regarded as a priority. This is probably because the measurable difference in cost is not evident when equipment is over or under maintained.

The NMBM maintenance initiative is based on Gill's (1997) guideline. However, the maintenance plans cannot function without the management component and designated teams. The NMBM suffers from an acute shortage of staff. Maintenance plans are in place, but the execution of these plans remains a quandary. The impact of budgetary constraints also limits the maintenance programs. The most important factor that drives maintenance plans is skilled workers. NMBM do not have the staff complement to maintain

equipment in accordance with the maintenance plans and schedules and guidelines from the suppliers. The staff complement in the substation section was reduced from 18 to 5. High voltage cable and overhead lines sections have only one artisan appointed to maintain them. The alternative is to procure the services of skilled contractors. Only a few contractors are skilled and trained to perform high voltage electrical work and even with their help, the maintenance work is still not sufficient.

5.3 THE EFFECT OF PREVENTATIVE MAINTENANCE

Preventative maintenance is the pre-planned task of inspection and servicing to retain the full operational function of electrical equipment. Many types of distribution and transmission equipment require routine inspection and testing, namely, protection relays, current transformers, poles, circuit breakers, transformers et cetera, to make sure that they function properly and minimise the probability of failures, which will result in power outages (SeEVERS, 1991).

The NMBM predominantly practises the run-to-failure philosophy. This simply means that after the equipment has been installed, it is not inspected or maintained until a failure occurs. This is initially cost effective, but in the long term, it will cost the utility more. The customers suffer the consequences.

The new approach to maintenance is what Gill (1997) and even Brown (2002) call reliability centred maintenance. The maintenance schedules to be implemented are decided based on the condition of the equipment and the cost to repair or replace it. The best results are obtained by implementing schedules that maximise power system reliability. This can be achieved by replacing or repairing equipment which is likely to fail. Equipment which supplies power to important customers is prioritised. However, this approach is difficult to implement and inspections have to be done more often.

The bathtub curve in Chapter 2 (Figure 2.2) gives us an indication as to when maintenance is required. Initially, the equipment is highly likely to fail just

after the commissioning phase. Once this phase has been overcome, the equipment can function for a long period, depending on the conditions. After the equipment has been maintained, the failure rate will decrease to its original value (Bollen, 2000).

Maintenance cannot be separated from the availability of skilled labour. All the maintenance plans and initiatives can be in place, but without the labour to drive it and perform the physical work, all these plans will be futile.

CHAPTER 6

LITERATURE REVIEW: WEATHER CONDITIONS

6.1 INTRODUCTION

Extreme weather conditions can have a dramatic impact on an electric power system. Overhead power lines are devised to withstand the vast range of the weather conditions possible. In case of extreme and infrequent weather conditions, outages are unfortunately inevitable. For economical reasons, power systems cannot be designed to withstand all the weather conditions. Other factors can contribute to the failure of power systems in adverse weather conditions, namely, standard of construction, lack of correct maintenance, type of power system selected et cetera. Power system failures are unavoidable, but their frequency and their consequences on the power supply can be reduced. All the factors contributing to the stability of a power system must be recognised and, depending on the budget, these factors must be included in the design (Bollen, 2000).

Power outages and power quality are major concerns in a power transmission and distribution system. Unacceptable quality leads to customer dissatisfaction. The causes of power outages and voltage dips are sometimes weather related. Hence, it is important to gain an understanding of the effects of adverse weather conditions on power interruptions (Brown, 2002).

6.2 THE IMPACT OF WEATHER ON POWER SYSTEMS

According to Dugan et al (2003) the majority of power outages and voltage dips are weather related. Lightning caused 45% of all the outages recorded. Direct lightning strikes generally cause flashovers generating impulsive transients and voltage dips. Lightning also raises the potential of the local ground above other nearby grounds. This causes surges, voltage dips and swells which result in the failure of sensitive equipment.

According to Bollen (2000), the IEEE standards differentiate among three levels of outages:

- Normal weather;
- Adverse weather, and
- Major storm disaster.

In the NMBM adverse weather conditions occur frequently, while major storm disasters occur rarely. Table 8.1 depicts the adverse weather condition for a typical utility.

Table 6.1 – Contributions of the Outage Rate of Transmission and Distribution Components (Adapted from Bollen, 2000)

Cause of Outage	Transmission System	Distribution System
Lightning strikes	9%	12%
Snow/ice on lines	52%	11%
High winds	32%	7%
Plant failures	5%	39%
Line interference	2%	21%
Animal/bird strikes	-	8%
Adjacent loads	-	2%

Obviously different utilities will have different tables. This table allows us the opportunity to understand the impact of adverse weather conditions on power systems. Wind can cause overhead line conductors to clash, resulting in a phase-to-phase or phase-to-earth fault. It is also evident that strong winds could cause overhead line poles to fall over, causing more damage and increasing the outage period. Branches could be blown onto the overhead lines, causing transient and permanent faults and triggering the operation of auto-reclosers and other power system protection devices. This is often the cause of unknown voltage dips (Bollen, 2000).

Rain impacts on power outages and reliability of supply. Rain is the cause of the malfunction of many cable faults, resulting in extended power outages. It also causes flashovers on overhead lines, causing voltage dips. Rain not only increases the outage time, but it also makes it difficult to repair the faulty equipment (Bollen, 2000).

Overhead lines are more vulnerable to adverse weather conditions, thus during the design phase of the project the weather conditions must be taken into account. Surge arrestors can improve the reliability and quality of power delivered to customers while at the same time lowering maintenance costs by reducing the need to replace and repair lightning damaged power system equipment (Bollen, 2000).

Wind and rain are the cause of many outages, particularly overhead lines. The causes of many of the power outages in the NMBM cannot be determined, but most of them are associated with adverse weather conditions. Planners need to design specific power networks for areas that are badly affected by adverse weather conditions.

CHAPTER 7

SUMMARY

7.1 POWER SYSTEM RELIABILITY

Power system reliability is important as it relates to the performance of the power system. Our industries rely on power for their business, thus it becomes more critical to secure reliable power systems. Power outages impacts on the users of electricity and for that reason our power systems must be designed to reduce power outages. The design of power systems depends on the budget available and often the budgetary constraints hamper the design of power systems resulting in cost effective designs which is not always good for reliability.

Power system reliability is dependent on system adequacy which involves the facilities available to supply electricity to customers, and system security which relates to the behaviour of the system during fault conditions.

Factors impacting on power system reliability include the following:

- Radial topology;
- Failure of protection equipment;
- Weather conditions, and
- Duration of interruption.

The failure rate of equipment increased with time if it is not maintained regularly in accordance with planned maintenance intervals. After maintenance the failure rate of equipment will decrease.

Many reliability indices are available, but the most commonly one's used in South Africa is SAIDI, SAIFI and ASAI. The most basic formula to use for evaluating power systems is:

$$U_s = \lambda_s r_s .$$

Not much in terms of research has been done to incorporate the cost of power outages (planned and unplanned outages) into the design of power network. This opens the door for further research possibilities. It is however important to be able to quantify the cost of an outage.

7.2 POWER QUALITY

Power quality becomes more and more critical because of the increase in sensitive electronic equipment and deployment of non-linear loads. The long transmission lines, lightning, vegetation, switching, animal, birds, pollution and lack of maintenance all contribute to power quality problems.

Voltage dips are the most common cause of power quality abnormality and accounts for approximately 80% of all such problems. In South Africa the NRS standards provide dip categories, namely, Y, X, S, T and Z and the suppliers of electricity are assessed in terms of these categories.

Many factors contribute to voltage dip, namely,

- Large drives with high initial starting currents;
- Arc furnaces;
- Faults on overhead lines caused by lightning, vegetation, birds and animals, and
- Reclosing and sectionalising equipment.

The NMBM used Impedograph, Vectograph and Provograph power quality instruments to measure voltage dips in NMBM. Y-dips in terms of the NRS 048 are regarded as insignificant and users of power should install dip-proving equipment to reduce the dip magnitude on their plant. The severity of a voltage dip depends on the distance of the fault from the customer's plant. The frequency of voltage dips depends on the weather conditions, maintenance and the age of the equipment. The speed of the operation of the protection equipment will determine if the power quality event is a voltage dip or an interruption.

There are many ways to reduce voltage dips, which includes the following:

- The design and fault clearing practices;
- Maintenance of equipment;
- Installation of bird and animal protection;
- The use of more fuses, reclosers and sectionalisers;
- The Installation of more surge arrestors, and
- Co-ordination of protection devices.

There are research opportunities in terms of fuses, sectionaliser, reclosers and particular surge arrestors combined with co-ordination of protection equipment. Research in this field will contribute towards the improvement of power quality problems associated with voltage dips.

7.3 POWER SYSTEM PROTECTION

This chapter concentrates on power system protection, particular how it can increase the reliability of power systems. The basic function of protection equipment is to detect system faults and to prevent damage to the plant, power system equipment and to safeguard human life's.

The severity of faults can be ascribed to the source conditions, the configuration of the power system, the type and the location of the fault. The function of a CT is to step down the current and to isolate the main system from the auxiliary system. Generally two types of CT's are available, namely, protective CT's for differential protection and class-X CT's for overcurrent protection. During fault condition these CT's must sustain high fault currents, thus it is imperative that they remain accurate during fault conditions. Magnetisation curves are used to determine the accuracy of CT's. It is therefore important that routine maintenance is performed to reduce the risk of inoperative and faulty CT's. Magnetisation curve, insulation resistance, saturation and primary injection tests are performed to ensure that the CT is in a good working condition. In order to select a CT the following should be considered:

- Full-load current of the load;
- Full-load current of the power transformer;
- CT not to be overloaded;
- The application of the CT;
- Primary current to be twice the load current, and
- The maximum fault current.

Fuses are the most simple and the oldest protection method. It is a one-shot protection device and the melting time is inverse proportional to the current. In selecting fuses it is important to provide protection against faults rather than to protect the equipment.

Transformers with a capacity rating of less than 2500 kVA are normally protected by fuses. This is not always the practice in the NMBM, but the dissertation covers the installation and analysis of the fuses for transformers rated below 2500 kVA. The following factors are to be noted when selecting fuses:

- Transformers are deliberately operated above their ratings for a short period to several hours;
- Inrush current of a transformer is 10-12 times the rated full-load current. In this dissertation 10 times is applicable;
- The current in the 10 s region should be as low as possible;
- The minimum fusing current to be as low as possible to ensure that internal faults are cleared;
- Correct co-ordination should at all times be achieved, although it is not always possible, and
- Fuses on overhead lines exposed to high lightning activity should withstand high currents, but this normally requires highly rated fuses which cannot normally provide protection to other equipment.

Auto-reclosers can be used in conjunction with sectionalisers and fuses and it is important that co-ordination between this equipment is achieved. This dissertation does not cover an in-depth study of this, thus it allows for an opportunity for further research.

Overcurrent protection is mainly used as back-up protection on transmission power systems. In distribution power systems as these case studies, overcurrent and earth fault protection are used in one unit. The IDMT relay provides back-up earth fault protection. As depicted by Anderson (1999) 90% of all overhead line faults are earth faults and the earth faults dominate the trip. The earth fault element will detect the fault first no matter if it is a phase-to-phase fault. Sensitive earth fault relays are used to detect small earth faults which are too small to operate the earth fault relay.

Earthing is very important as the majority of faults involve earthing. It provides safety to humans but is also provides a return path to the source. All metal parts of a power system should be bonded and connected to the substation earth mat. As depicted by Dugan et al (2003) 80% of all power quality problems relates to

earthing of equipment. Thus, proper earthing practices are very important in the correct operation of protection equipment. It is a shortcoming of this dissertation and it creates an opportunity for further research, investigate and analyse earthing as a critical component of power system operation, power quality and protections.

7.4 MAINTENANCE AND MANPOWER

Maintenance of power system equipment is very important for the operation of power systems. During preventative maintenance programs defective equipment can be identified and replaced. Maintenance extends the life of equipment. Gill (1997) depicts that maintenance programs should always be performed under the control of management, in accordance with the schedules and by a dedicated team. Finances drives maintenance programs and labour must be available to perform the maintenance tasks. Maintenance programs cannot be executed because the NMBM do not have the skilled staff. Budgetary reductions and shortfalls also hamper maintenance programs.

Maintenance must be pre-planned and it starts with inspection, then servicing in order to retain the full operation of the equipment. The NMBM practice the run-to-fail philosophy. The equipment is installed and by not inspecting and maintaining it after a certain period, the equipment will fail resulting in power outages.

7.5 WEATHER CONDITIONS

Adverse weather conditions impacts severely on power systems. Due to budgetary shortfalls power systems cannot be designed to withstand all the weather conditions. Lack of maintenance is another factor contributing to failure of power system equipment and during adverse weather the likelihood of failure is greater. The majority of power outages and voltage dips are weather related.

CHAPTER 8

AN OVERVIEW OF CASE STUDIES

8.1 INTRODUCTION

Five case studies have been identified using Annexure A. They are:

- Fitches Corner Blue Horizon Bay feeder;
- Summit Gamtoos Pumps feeder;
- Kragga Kamma Greenbushes feeder;
- Motherwell North feeder, and
- Fitches Corner Rocklands feeder.

Historical data was refined and grouped together to determine the weak links in the power system. The Fitches Corner substation has two 22kV feeders, which were individually analysed as two case studies. Recent planning developments on the Swartkops feeder resulted in a new line being built from the Ditchling substation. The Swartkops line thus does not exist any longer and will not form part of the analysis.

The graphical presentation in Annexure A represents all the outages recorded over five financial years from July 2002 to June 2007. Annexure A represents the power outages per financial year and a summary of all the faults. The case studies will be evaluated in terms of the following criteria:

- Power System Reliability
- Power Quality
- Power System Protection
- Digsilent Power Factory
- SCADA
- Maintenance and Manpower
- Weather Conditions
- NRS Data Analysis

In certain case studies, it was not possible to access the network in terms of all the criteria above due to their design and deficiency at the time of evaluation and analysing. The assessment and evaluation was done in conjunction with available staff and resources. In certain cases all or some of the important information relating to the likely results are omitted because they were not available at the time of the investigation. It became apparent that the power system problems and faults in the case studies are more or less the same, depending on the construction of the power system. There was a common trend in certain case studies, for example, Fitches Corner Blue Horizon Bay (FBH), Summit Gamtoos Pumps (SGP) and Fitches Corner Rocklands (FCR). In these case studies the investigations, tests and results will be summarised and not presented separately.

At the end of the assessment and evaluation process, the results will be formulated and presented in the form of conclusions and recommendations, which will be forwarded to the NMBM. The results will also be available for other utilities to implement in order to improve the reliability of their power networks.

8.2 INTRODUCTION TO CASE STUDY 1- FITCHES CORNER BLUE HORIZON BAY

The Fitches Corner Blue Horizon Bay 22kV feeder is predominantly an overhead line network. At the end of the overhead line is a 1 MVA 22/6.6kV transformer. The LV windings are connected to a ring main unit with two isolators supplying the 6.6kV cable distribution network. The 6.6kV network supplies five distribution substations with 500kVA transformers. Annexure 1A represents a line diagram of the overhead power network and from this line diagram it is evident that many lateral lines with transformers at the end are connected to the main line.

The overhead line is approximately 20km long on H-pole structures constructed with Alliance conductor rated at 365 A. Only the sections from FBH 77 downwards are constructed in the delta formation. A 95 mm² 3-core 11kV copper cable network approximately 3.7 km long supplies 1800 customers. A large section of this network runs along the coast and is therefore exposed to extreme weather conditions, namely, mist, rain, strong wind and lightning.

Annexure 1B indicates the number of interruptions recorded at the Fitches Corner substation over a period of 5 years. 87 interruptions were recorded on the Blue Horizon Bay network. This was much more than the other networks. The details of the interruptions will be analysed and discussed in the sections below.

At the source substation, Fitches Corner, the Blue Horizon Bay feeder is protected by an OCB which is very old (manufactured in 1952), and a Micom Alstom relay.

The protection relay provides auto-reclosing functions, overcurrent, earth fault and sensitive earth protection. From the site investigations it is revealed that the auto-reclose function of the ARC is not operative.

The 1 MVA transformer and the 6.6kV cable network is not protected. The lateral lines are protected by means of expulsion fuses (drop-out fuses). In the middle of the overhead line, an airbrake switch has been installed to isolate the top section from the bottom.

8.3 INTRODUCTION TO CASE STUDY 2- SUMMIT GAMTOOS PUMPS

The Summit–Gamtoos Pumps overhead line is a 22 kV line supplying electricity to milk and chicken farmers, a critical water pump station and a holiday resort at the mouth of the Gamtoos river.

The overhead line is approximately 13 kilometres long, constructed with 70mm² copper conductor and wooden H-pole structures. The copper conductor makes the line vulnerable to theft and vandalism, resulting in many extended outages.

At Summit, the source substation, two 10 MVA 66/22 kV transformers are installed. The feeder supplies 14 pole mounted distribution transformers, some with protection at the beginning of the lateral lines. Most of the lateral lines supply single phase distribution transformers. There are two lateral lines, namely, SGP 14 and 30 supplying various distribution transformers. SGP 30 supplies one relatively large customer, Gamtoos Mouth. The feeder also supplies an important water pump station with two 750 kVA transformers at the end of the line.

The major concern in terms of the power supply is that no adequate system protection is provided to clear faults effectively. Also, the reliability of this feeder is questionable as it under-performed in terms of the research criteria outlined in this investigation.

A Reyrolle oil circuit breaker is installed at the beginning of the line. The TJV protection relay provides overcurrent and earth fault protection. No sensitive earth fault protection is provided. The auto-recloser is set at one trip and lockout. Type K lateral fuses are used to protect some of the lateral lines. At the river mouth, a substation is built with equipment identified in Annexure 2A.

8.4 INTRODUCTION TO CASE STUDY 3- MOTHERWELL NORTH

The Motherwell North 22kV feeder is approximately 17 kilometres long and constructed with 95 mm² arial bundle conductor (ABC) with a current capacity of 265 A on 11m wooden poles. The lateral lines supply 200 kVA distribution transformers, stepping the voltage down to 400 V three phase and 230 V

single phase. On the low voltage side, the transformer provides electricity to mainly low cost houses. The power system is exposed to all weather conditions, namely, mist, rain, strong wind and lightning.

Annexure 3A depicts the MWN single-line diagram and Annexure 3B indicates the number of interruptions recorded at the source substation and the fault types over a period of five years. 85 interruptions were recorded on the Motherwell North network, much more than the other networks in this voltage category. The detail of the interruptions were analysed and reviewed.

At the source substation, Motherwell, a SACE BERGAMO OCB is installed. The SPAJ140C protection relay provides overcurrent and earth fault protection.

The historical fault data recorded in Annexure 3B indicates that many of the faults occurred on the lateral lines, namely, MWN 51 and 80 as well as at the source, MWN 0.

8.5 INTRODUCTION TO CASE STUDY 4- KRAGGA KAMMA GREENBUSHES

The Kragga Kamma Greenbushes (KKG) 22kV power system is approximately 15 kilometres long. The first section of the feeder is approximately 7 kilometres 150 mm² copper cable, which terminates at the first H-pole. The overhead line is approximately 8 kilometres long and constructed on 14 metre H-pole structures. The overhead line is constructed in Pine, which has a current capacity of 262 A. The power system supplies a 22kV substation transforming the voltage down to 6.6kV. The 6.6kV system supplies electricity to smallholdings. Along the 8 kilometre main line, a lateral line supplies smallholdings and a major low cost housing project (KKG 53). KKG 53 is constructed in 185 mm² Aerial bundle conductor with 200 kVA transformers, stepping the voltage down to 400 V three-phase and 230 V single phase. Annexure 4A depicts the single-line diagram of the power

system. This part of the power system is exposed to weather conditions, namely, mist, rain, strong wind and lightning.

Annexure 4B indicates the number of interruptions recorded at the source substation over a period of 5 years. 25 interruptions were recorded on the KKG network.

At the source substation, Kragga Kamma, a Reyrolle A OCB is installed with over current, earth fault and auto-reclose functions. The CDG protection equipment is outdated and the auto-reclose relay was burnt out. It is not normal practice to install an auto-recloser on a cable network.

The historical fault data recorded indicated that many of the faults occurred on the lateral lines. The OCB is used as a means of isolation, but if an in-line ARC is installed, the outage time could be reduced.

8.6 INTRODUCTION TO CASE STUDY 5- FITCHES CORNER ROCKLANDS

The Fitches Corner Rocklands (FCR) 22kV power system is approximately 7 kilometres long on delta pole structures with Pine conductor rated at 262 A. Annexure 5A represents a single-line diagram of the overhead power network. The power system runs inland towards Uitenhage, supplying electricity to farmers, predominantly chicken farmers. This power system is exposed to weather conditions, namely, storms, mist, rain, strong wind and lightning.

Annexure 5B indicates the number of interruptions recorded at the Fitches Corner substation over a period of five years. 28 interruptions were recorded on the FCR network, much more than in the other networks in this voltage category.

At the source substation, Fitches Corner, the FCR network is protected with an ARC with overcurrent, earth fault and sensitive earth fault functions. When

faults occur on the lateral lines, the ARC would operate. This is incorrect, as the fuses should blow before the breaker opens. The auto-reclose function of the ARC also does not operate properly. It was set to 1 shot and lockout.

8.7 COMMON TRENDS IN CASE STUDIES

8.7.1 Power System Reliability

In three of the five case studies (FCR, FBH and SGP), the power systems are constructed with bare overhead conductors, one case study (MWN) is constructed with ABC and the other case study (KKG) is constructed with bare overhead conductors, ABC and underground cables.

The common trends and commonality are as follows:

- Four of these feeders (FBH, SGP, KKG and FCR) are radial having no means of an alternative power supply. The Motherwell North feeder can be alternatively supplied by closing the normally open points. But, an operator must physically close these normally open points, therefore it can be treated as a radial until such time the normally open points have been closed.
- All the power systems analysed are not overloaded yet, but with the development and industrialisation of rural areas they will soon be overloaded in the future. The n-1 principle does not apply and therefore poses a problem in terms of an alternative power supply to cater for overloading and back-up.
- Protection equipment apart from the Motherwell system is very old and some of the relays were replaced during the testing phase of the project.
- Weather conditions pose a problem for any power system, particularly the bare overhead conductors.
- Because the case studies are predominantly rural power systems, the outage time will generally be long and extended due to travelling time, line patrols, faultfinding, no remote switching et cetera.

- Lack of maintenance, coupled with the shortage of skilled workers, increases the failure rate of power systems.

Once the customer feeder Reliability Indices has been calculated, they are compared to the Customer Based Indices in Table 8.1 (Burke, 1994). In comparing Table 8.1 with the case studies, it is evident that in all of them the calculated reliability indices exceed the values represented in Table 8.1. The conclusion that can be drawn from this is that if the duration of the outages decrease, SAIDI will decrease; if the number of outages decrease, SAIFI will decrease; if SAIDI and SAIFI decrease, consequently CAIDI will decrease. This is all linked to the outage cost and average duration, which will eventually impact on the reliability of the power network.

Table 8.1 - Customer Based Indices (Adapted from Burke, 1994)

Customer Based Indices			
SAIDI	SAIFI	CAIDI	ASAI
95.9min/yr	1.18int/yr	76.93min/yr	.999375int/yr

8.7.2 Power Quality

8.7.2.1 Voltage Dips

The factors contributing to voltage dips are the following:

- Birds and animals;
- Faults on the networks as well as neighbouring networks;
- Lack of maintenance;
- Vegetation control;
- Switching operations;
- Operation of protection equipment;
- Adverse weather conditions, and
- Design of the network et cetera.

8.7.2.2 Harmonics

In terms of harmonics, the only commonality is that all the networks analysed comply with the NRS 048-2:2003.

8.7.2.3 Flickering

In terms of flickering, the only commonality is that all the networks analysed comply with the NRS 048-2:2003.

8.7.2.4 Voltage Regulation

The only network that does not comply with the NRS 048-2:2003 is the Motherwell North 22kV feeder.

8.7.3 Power System Protection

In order to comply with the requirements of power system protection in terms of selectivity, stability, sensitivity and speed it is paramount that the entire protection equipment is tested and adjustments affected to improve the system's reliability.

Many of the faults that occur on power systems are incipient faults. This is due to the lack of maintenance, failure to repair faulty parts and failure to effect permanent repairs. Adverse weather conditions increase this. Incipient faults eventually develop into solid faults causing greater damage to power system equipment. The correct operation of power system protection equipment is critical.

Similar protection equipment tests on all the five case studies were performed. Not one of the end results was identical.

Similar methods were used to calculate the CT accurate limit current (ALC), ALF, knee-point voltage, VA rating, fault current magnitudes, relay settings and fuse sizes. In the selection and grading of fuses with other protection equipment, Tables 8.2 to 8.5 were applied to all the case studies. Calculating

the full-load current, inrush current, permissible overloading of the distribution transformers and standard fuse sizes were evaluated. The values in all the case studies were gained from the following methods:

- Determining the MVA/KVA rating of the transformer;
- Calculating the full-load current using formula (12);
- Calculating the inrush current at 10 times the full-load current. The inrush current can be between 10 and 12 times the full-load current (Wright and Newbery, 2004);
- The fuse must be able to carry the inrush current for 0.1 second (Anderson, 1999; Wright and Christopoulos, 1993);
- Allow permissible overload of 20% for this application. It is not clear what percentage to use for overloading of transformers. Wright and Christopoulos (1993) state that suitable fuses must be selected to sustain this overload and Brown (2002) states that the overload should not exceed 200% of the transformer rating. The 20% will be used in all the case studies;
- Type K fuses will be used and the selection will be done using Tables 8.2 and 8.5;
- Co-ordination of fuse will be done as per the description of Anderson (1999), and
- PEE Code of Practice will also be consulted.

Power transformers are deliberately operated above their current rating for several hours. Therefore, the type of fuse selected must withstand these overloads. Fuses must also be able to sustain high overvoltages caused by lightning. Highly rated fuses should be selected. This is not always possible, as highly rated fuses cannot always provide protection to the other equipment connected to the network. A compromise must be reached in terms of the grading philosophy (Wright and Christopoulos, 1993).

According to Anderson (1999) a fuse protecting a power transformer should be able to carry at least 12 times the rated primary current for 0.1 seconds as

depicted in the fuse melting time curve. Fuses that protect distribution transformers are often used, especially for a short line supplying a few customers. Anderson (2009) described two types of fuse links, namely, Type K and Type T. Basically the main difference between the two fuse types is that the Type T takes longer to interrupt the current. In order to verify the ability of a fuse to sustain an inrush current of 0.1 seconds the Type K TC characteristic in Short (2004) will be consulted. Table 8.2 can be consulted to understand the melting currents of Type K fuses. It is to be noted that the minimum melting current of both fuse types is about twice the rated current of the fuse.

For currents above the minimum pickup the Type T fuse link melts slower than the Type K. The speed ratio of a Type K and T range between 6 to 8.1 and 10 to 13 respectively. The speed ratio indicates that any fuse within that range can co-ordinate with each other and protect the next higher rating fuse in that range.

Table 8.2 - Melting Currents for Type K (Fast) Fuse Links (Adapted from Anderson, 1999)

Rated Continuous Current	300 or 600 sec Melting Current*		10 sec Melting Current		.01 sec Melting Current		Speed Ratio
	Min	Max	Min	Max	Min	Max	
Preferred Ratings							
6	12.0	14.4	13.5	20.5	72.0	86.0	6.0
10	19.5	23.4	22.5	34.0	128.0	154.0	6.6
15	31.0	37.2	37.0	55	215.0	258.0	6.9
25	50.0	60.0	60.0	90.0	350.0	420.0	7.0
40	80.0	96.0	98.0	146.0	565.0	680.0	7.1
65	128.0	153.0	159.0	237.0	918.0	1100.0	7.2
100	200.0	240.0	258.0	388.0	1520.0	1820.0	7.6
140	310.0	372.0	430.0	650.0	2470.0	2970.0	8.0
200	480.0	576.0	760.0	1150.0	3880.0	4650.0	8.1
Intermediate Rating							
8	15.0	18.0	18.0	27.0	97.0	116.0	6.5
12	25.0	30.0	29.5	44.0	166.0	199.0	6.6
20	39.0	47.0	48.0	71.0	273.0	328.0	7.0
30	63.0	76.0	77.5	115.0	447.0	546.0	7.1
50	101.0	121.0	126.0	188.0	719.0	862.0	7.1
80	160.0	192.0	205.0	307.0	1180.0	1420.0	7.4
Ratings below 6 Amperes							
1	2.0	2.4	^	10.0	^	58.0	
2	4.0	4.8	^	10.0	^	58.0	
3	6.0	7.2	^	10.0	^	58.0	

Type K and T fuses have similar TC characteristics, therefore they will co-ordinate well together. A mixture of Type K and T will make co-ordination difficult and often impossible. The Tables are provided by McGraw-Edison Power Systems, Cooper Industries. They take care of the arching time, the maximum current for safe co-ordination and the 75% of the minimum melting time curves for protected fuse links. In Table 8.3 the values of the continuous current capacities of the Type K and T fuse are given.

Table 8.3 - Continuous Current-Carrying Capacity of EEI-NEMA Fuse Links (adapted from Anderson, 1999)

EEI-NEMA K or T Rating	Continuous Current (amperes)	EEI-NEMA K or T Rating	Continuous Current (amperes)	EEI-NEMA K or T Rating	Continuous Current (amperes)
6	9	20	30	65	95
8	12	25	38	80	120 [^]
10	15	30	45	100	150 [^]
12	18	40	60*	140	190
15	23	50	70*	200	200

Table 8.4 – Calculated Full-load and Inrush current for transformers

	IFL	Inrush I	Perm O/L (20%)	Comments
16kVA/6,6Kv	1,4A	14A	1,68A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
16KVA/22kV	0,42A	4,2A	0,5A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
25kVA/6,6kV	2,19A	21,9A	2,63A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
25KVA/22kV	0,66A	6,6A	0,79A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
50kVA/6,6kV	10,27A	102,7A	5,24A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
50KVA/22kV	1,31A	13,1A	1,57A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
100kVA/6,6kV	8,75A	87,5A	10,5A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
100KVA/22kV	2,62A	26,2A	3,15A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
150kVA/6,6kV				
150KVA/22kV	3,94A	39,4A	4,72A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
200kVA/6,6kV	17,5A	175A	20,99A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
200KVA/22kV	5,25A	52,5A	6,3A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
300kVA/6,6kV	26,24A	262,4A	31,49A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
300KVA/22kV	7,87A	78,7A	9,45A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
315kVA/6,6kV				
315KVA/22kV	8,27A	82,7A	9,92A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
500kVA/6,6kV				
500KVA/22kV	13,12A	131,2A	15,75A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
750kVA/6,6kV				
750KVA/22kV	19,68A	196,8A	23,62A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
800kVA/6,6kV				
800KVA/22kV	20,99A	209,9A	25,19A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.
1000kVA/6,6kV				
1000KVA/22kV	26,24A	262,4A	31,49A	Use 10K fuse. Consult tables 8.2, 8.3 and PEE CoP.

Note: A 12K fuse link is a non-standard fuse, which is not readily available from a maintenance point of view. Therefore, under fault conditions the possibility to replace the blown 12K fuse with a similar one is possible. A more standard fuse is suggested, namely a 10K. The characteristics of a 10K and 12K fuse are exactly the same. The only major difference is that the 12K can sustain 3 amperes more than the 10K fuse and grade a lesser fault current with other fuses.

8.7.4 Digsilent Power Factory

All the case studies were built on Digsilent 14.0. All the simulations performed were identical, namely, loadflows, protection and co-ordination simulations et cetera. The Digsilent simulation results were compared to the protection calculations. If any differences were evident, both the protection and Digsilent methodologies were revisited. It must be noted that Digsilent computer-based programmes were never initially used in analysing the NMBM power system. Therefore, the results obtained from Digsilent will be recommended for improvement to the betterment of the power system.

Table 8.5 - Co-ordination between EEI-NEMA Type K Fuse Links (Adapted from Anderson,1999)

Protecting	Protected link rating (amperes)													
Fuse Link	8K	10K	12K	15K	20K	25K	30K	40K	50K	65K	80K	100	140	200
Rating A	Maximum fault current at which B will protect A (amperes)													
6K		190	350	510	650	840	1060	1340	1700	2200	2800	3900	5800	9200
<u>8K</u>			210	440	650	840	1060	1340	1700	2200	2800	3900	5800	9200
10K				300	540	840	1060	1340	1700	2200	2800	3900	5800	9200
<u>12K</u>					320	710	1050	1340	1700	2200	2800	3900	5800	9200
15K						430	780	1340	1700	2200	2800	3900	5800	9200
<u>20K</u>							500	1100	1700	2200	2800	3900	5800	9200
25K								660	1350	2200	2800	3900	5800	9200
<u>30K</u>									850	1700	2800	3900	5800	9200
40K										1100	2200	3900	5800	9200
<u>50K</u>											1450	3500	5800	9200
65K												2400	5800	9200
<u>80K</u>													4500	9200
100K													2000	9100
140K														4000

A decision must be made whether to use the Digsilent simulation results or that of the protection tests and calculations and this would become the NMBM philosophy. Whichever one is decided upon will result in some form of compromise in terms of the equipment to be protected.

The co-ordination Table 8.5 shows the maximum values of the fault current at which Type K and T fuse will co-ordinate. The tables are provided by McGraw-Edison Power Systems, Cooper Industries. The tables will be used in the case studies to determine the co-ordination of fuses with each other. Table 8.5 will be used in conjunction with the Digsilent simulations and the protection calculations.

8.7.5 Scada

No common trends are evident. In certain case studies, SCADA is non-existent. Recommendations to install SCADA at Summit and Fitches Corner substations will be forwarded to the NMBM.

8.7.6 Maintenance and Manpower

Routine preventative maintenance is critical for power system reliability and for the continuity of supply. Maintenance is critical and the lack of it will result in disaster. Maintenance tends to be neglected and is the cause of many outages, which can be prevented if maintenance is performed regularly.

Manpower is the driving force behind any maintenance programme. Properly trained and skilled staff is critical in the success of any maintenance programme.

8.7.7 Weather Conditions

The impact of weather conditions on all the case studies is almost identical. All the case studies, apart from the Motherwell North feeder, is bare conductor and the Kragga Kamma Greenbushes feeder is constructed in cable, bare conductor and ABC. The impact of weather conditions, namely, rain, storm, wind is less on arial bundle conductor. Extensive outage time is evident in these case studies. The extensive outages are mainly caused by adverse weather conditions.

8.7.8 NRS Data analysis

It is a necessity that the NMBM power network must fulfil the requirements of the NRS in order to keep its licensee status. No common trends are evident in the case studies.

CHAPTER 9: ANALYSIS OF FITCHES CORNER BLUE HORIZON

BAY FEEDER (FBH)

9.1 POWER SYSTEM RELIABILITY

The Blue Horizon Bay network is not a reliable power system. In terms of system adequacy, the network satisfies certain of the criteria to provide power to its customers. All the equipment necessary to provide power is available, but the question is: How reliable is it; when was it last maintained and when was the equipment repaired or replaced? In terms of system security, the network is not competent to sustain severe disturbances, as the protection equipment does not function properly, preventative maintenance have not been done and automation devices have not been installed.

The factors influencing the reliability of a network are:

- Weather conditions;
- Duration of the interruptions;
- Failure of protection devices;
- Radial topology, and
- Failure rate, (Bollen, 2000).

The researcher concurs with Bollen as the statistics on the interruption data confirmed the above factors, namely, Annexure 1B equations 2.1, 2.2 and 2.3 below. The network is a radial power system and the protection devices are not functioning properly.

In terms of the duration of an interruption, Bollen argues that the location of faults can be assisted by automation of the power system. The use of SCADA will impact on the location of the fault and switching can be done remotely, which will all lead to reduced outage time.

Calculating the power system average outage time

$$\begin{aligned} U_s &= \lambda_s r_s & (2.1) \\ &= 87 \times 352.15 \\ &= 30637.05/5 \text{ yrs} \\ &= 6127.41 \text{ hrs/yr} \end{aligned}$$

Calculating the average outage cost

$$\begin{aligned} P &= 885.9 \text{ kW} & (4.15) \\ \text{Cost per kW} &= 0.363 \text{ (Calculated over 5 years)} \end{aligned}$$

$$\begin{aligned} \text{Outage cost} &= \frac{C_i(d)}{L_i} & (2.5) \\ &= \frac{0.363 \times 352.2}{685.9} \\ &= R 0.186/\text{kW} \\ &= 18.6 \text{ cents/kW} \end{aligned}$$

Calculating Reliability Indices

$$\text{Calculated SAIDI} = 4225.8 \text{ min/yr} \quad (2.2)$$

$$\text{Calculated SAIFI} = 17.4 \text{ int/yr} \quad (2.3)$$

$$\text{Calculated CAIDI} = 242.9 \text{ min/yr} \quad (2.4)$$

It is obvious that the calculated reliability data does not comply with the standard outlined by Burke (1994) in Chapter 8, Table 8.1. It means that this power system under-performed for the 5 year period the data was collected.

9.2 POWER QUALITY

9.2.1 Voltage Dips

The Blue Horizon Bay network is predominantly overhead line, therefore the majority of faults will be transient faults which could be cleared by an auto-

recloser. The expulsion fuses should clear permanent faults on the lateral lines. In rural power systems, it is sometimes very complicated to identify faults. This impacts on the reliability indices and outage times.

The Vectograph voltage dip data recorded over twelve months has been summarised in Table 9.1 below.

Table 9.1 – Voltage Dips – Fitches Corner Substation - Jan 08 to Dec 08

	S	T	X1	X2	Y	Z1	Z2	% Not avail
Jan 08	3	0	3	0	24	1	0	13,3
Feb 08	5	0	19	2	40	2	4	6,6
Mar 08	1	0	2	1	6	2	0	92
Apr 08	1	6	1	2	21	3	1	4
May 08	2	0	2	0	17	3	0	0,4
June 08	0	0	1	0	10	0	0	45,2
July 08	3	1	1	1	18	0	0	0,6
Aug 08	3	1	7	1	14	0	0	66,8
Sep 08	2	5	1	1	22	1	0	0,5
Oct 08	0	0	0	0	3	0	0	68,0
Nov 08	6	0	3	0	37	1	5	0,7
Dec 08	4	2	3	5	29	1	0	80,6
Total	30	15	43	13	241	14	10	

From the Table it can be concluded that Y-dips are the problematic ones. But, according to Table 3.2 the depth of these dips is shallow (15% to 30%) and the duration is normally not longer than approximately 100 ms, and since many of these dips are caused by neighbouring networks they are regarded as insignificant. The customers are responsible for protecting their equipment against Y-dips. If Table 9.1 is compared to Table 3.1, it is obvious that improvement is necessary.

Many factors could influence the voltage dips, namely:

- Maintenance, not being regularly performed;
- Operation of questionable protection devices;

- The age of the equipment which in this case is approximately 40 years;
- Bird and animal protection,
- Bad weather conditions as per Annexure 1B, and
- The omitting of surge arrestors.

9.2.2 Harmonics

The recorded data was retrieved from the power quality instrument and compared to the international benchmark of 5% depicted by Burke (1994) and the NRS 048-2:2003, which allows a total harmonic distortion of not more than 8%. According to the assessment, no sign of harmonics disorder could be determined. Power quality data recorded indicates that the harmonics measured on this power system are within the parameters of the NRS 048-2:2003.

9.2.3 Flickering

The recorded data was retrieved from the power quality instrument and compared to the benchmark of between 0.8% and 1.25% as per NRS 048-2:2001. According to the assessment, no signs of flickering could be determined. Power quality data recorded indicates that the flickering measured on this power system is within the parameters of the NRS 048-2:2001.

9.2.4 Voltage Regulation

The recorded data was retrieved from the power quality instrument and compared to the benchmark of $\pm 5\%$ for power systems above 500 V as per NRS 048-2:2001. According to the assessment, no signs of voltage regulation irregularities could be determined. Power quality data recorded indicates that the voltage regulation measured on this power system is within the parameters of the NRS 048-2:2003.

9.3 POWER SYSTEM PROTECTION

9.3.1 Current Transformers

Since this is an old power system, it would be wise to check the current transformers. It is important for current transformers to stay accurate because they must sustain high fault currents during fault conditions. If the current transformer is inaccurate, the protection equipment will operate incorrectly.

Calculating ALF

Current rating of overhead line	=	365 A; use 400 A	
Load current	=	60 A; use 100A	
I_{FL}	=	262 A; use 300 A	(4.1)
CT Ratio	=	100/1	
CT Class	=	15T10/7.5T10	

Available tapings on CT are 50% to 200%

At 50% plug setting I	=	0.5 x 100	=	50 A
At 100% plug setting I	=	1 x 100	=	100 A
At 125% plug setting I	=	1.25 x 100	=	125 A
At 150% plug setting I	=	1.5 x 100	=	150 A
At 200% plug setting I	=	2 x 100	=	200 A

$$I_{\text{fault}} = 2151 \text{ A} \quad (4.2)$$

(Digsilent simulation confirmed fault level of 2119 A – Annexure 1C)

ALF at 50 A	=	43.02	(4.3)
ALF at 100 A	=	21.51	
ALF at 125 A	=	17.21	
ALF at 150 A	=	14.34	
ALF at 200 A	=	10.76	

Twice the full load current of the system is approximately 120 A (use 150 A). That equates to a plug setting of 150% and an ALF of 14.34 (use ALF of 15) (Prév , 2006). It also allows for load growth and flexibility in terms of grading.

One other important fact is that the overhead line can carry approximately 400 A, but the full load current of the transformer is only 262 A. The transformer not only supplies this feeder, but it also supplies one other 22 kV and a 6.6 kV network. Therefore, it is highly unlikely that this feeder will be loaded to its full capacity.

Determining the knee point voltage

$$\text{Assume VA rating} = 15 \text{ VA}$$

$$\text{Impedance of Burden} = 15 \, \Omega \quad (4.16)$$

$$\text{Assume CT secondary resistance} = 0.1 \, \Omega$$

$$\text{Total secondary impedance} = 15.1 \, \Omega \quad (4.17)$$

ALF (Using maximum most downstream fault - Annexure 1D)

$$= 13.5; \text{ use } 15 \quad (4.3)$$

$$\text{Emf at secondary at ALF (15)} = 226.5 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (20)} = 302 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (30)} = 453 \text{ V} \quad (4.18)$$

Using an ALF of 15 and assuming the VA rating of the CT is 15 VA results in an emf of 226.5 V. The values in Annexure 1J indicate that the knee-point voltage is approximately 250 V. According to Table 4.1 (Chapter 4.3) a 10P CT allows a 10% error. Comparing this against the calculated knee point voltage and that of Annexure 1E, it is within the required parameters.

The class 10P CT is perfect for this application. Pr  v  (2006) states that a 10P CT is suitable for overcurrent protection.

$$S = 15.1 \text{ VA} \quad (4.4)$$

$$\text{Max allowable primary current (ALC)} = 1500 \text{ A} \quad (4.18)$$

The three phase fault current of 2151 A (2119 A Digsilent) is more than the allowable primary current that the CT's will be able to sustain. Therefore, these CT's will not be suitable for this application and CT's with higher ALF should be used.

When selecting an ALF of 20, the ALC increases to 2000 A and when selecting an ALF of 30, the ALC increases to 3000 A. This will impact on the emf at the secondary, which will increase to 302 V and 453 V respectively as calculations show. These CT's are old and the class and VA rating are dubious. It is recommended that the current CT's installed be replaced.

From all of the above, it is evident that the most suitable CT to be used should be an 10P30 15 VA.

An alternative solution is as follows:

Use a 200/1

$$\begin{aligned}
 \text{At 100\% plug setting I} &= 1 \times 200 = 200 \text{ A} \\
 \text{ALF at 200 A} &= 13.5 \text{ (use 15)} \quad (4.3) \\
 \text{Max allowable primary current (ALC)} &= 3000 \text{ A} \quad (4.19)
 \end{aligned}$$

It is evident that the most suitable CT to be used should be a 10P15 15 VA.

A maintenance test was arranged to verify the accuracy of the CT's in terms of primary injection and insulation resistance. The primary injection test results are as follows:

Note: primary injected current is 100A

100/1	Red	White	Blue	Neutral
Phase-Neutral	1005 mA	0 mA	0 mA	1008 mA
Red-White	990 mA	999 mA	0 mA	0 mA
Red-Blue	1004 mA	0 mA	1003 mA	0 mA

Comparing the test results to that of Table 4.1 (Chapter 4.3), it is evident that the CT's pass the test, but the CT's will not be able to withstand the fault current.

The above analysis confirms that the CT's must be replaced with 200/1 CT's.

9.3.2 Fault Calculations

$$Z_{\text{source}} = 1.22 \text{ pu} \quad (4.5)$$

$$Z_{10\text{MVAtrf}} = 0.972 \quad (4.6)$$

$$Z_{\text{base}} = 4.84 \text{ } \Omega \quad (4.8)$$

$$\begin{aligned} Z_{\text{act}} &= R + jX_L \\ &= 0.244 + j0.345 \\ &= 0.224 + j0.345 \\ &= 0.411 \angle 57.08^\circ \Omega \end{aligned}$$

$$Z_{22\text{kVline}} = 0.0859 \text{ pu} \quad (4.7)$$

$$Z_{1\text{MVAtrf}} = 5.09 \text{ pu} \quad (4.6)$$

$$\begin{aligned} Z_{\text{fault}} &= Z_{\text{source}} + Z_{10\text{MVA}} + Z_{22\text{kVline}} + Z_{1\text{MVAtrf}} \\ &= 1.22 + 0.972 + 0.085 + 5.09 \\ &= 7.367 \text{ pu} \end{aligned}$$

$$\begin{aligned} Z_{\text{fault pu}} &= \frac{1}{7.36} \\ &= 0.136 \text{ pu} \end{aligned}$$

$$Z_{b6.6} = 8.747 \text{ kA} \quad (4.9)$$

$$V_{b6.6} = 3.811 \text{ kV} \quad (4.10)$$

$$V_{b22} = 12.702 \text{ kV} \quad (4.10)$$

Fault current at 6.6 kV busbar:

$$\begin{aligned} I_{\text{fault}} &= I_{\text{b6.6}} \times I_{\text{fault pu}} \\ &= 8.746 \times 0.136 \\ &= 1.19 \text{ kA} \end{aligned}$$

(Digsilent simulation confirmed fault level of 1350 A – Annexure 1D)

Fault current at 22 kV transformer:

$$\begin{aligned} Z_{\text{fault}} &= Z_{\text{source}} + Z_{10\text{MVA}} + Z_{22\text{kVline}} \\ &= 1.22 + 0.972 + 0.085 \\ &= 2.277 \text{ pu} \end{aligned}$$

$$\begin{aligned} I_{\text{fault pu}} &= \frac{1}{2.277} \\ &= 0.439 \text{ pu} \end{aligned}$$

$$I_{\text{b22}} = 2.624 \text{ kA} \quad (4.9)$$

$$V_{\text{b22}} = 12.102 \text{ kV} \quad (4.10)$$

$$\begin{aligned} I_{\text{fault}} &= I_{\text{b22}} \times I_{\text{fault pu}} \\ &= 2.624 \times 0.439 \\ &= 1.15 \text{ kA} \end{aligned}$$

(Digsilent simulation confirmed fault level of 1471 A – Annexure 1F)

9.3.3 Relay Settings

$$I_{\text{max}} = 60 \text{ A}$$

$$I_{\text{fault min}} = 1230 \text{ A (minimum most downstream fault current - Annexure 1G)}$$

$$I_{\text{fault max}} = 1350 \text{ A (maximum most downstream fault current- Annexure 1D)}$$

$$\text{CT ratio} = 100:1$$

$$\text{Plug Setting (PS)} = 60\% \quad (4.11)$$

Use a plug setting of 100%

$$\text{PSM (M) at max fault} = 13.5 \quad (4.12)$$

$$t \text{ at TM} = 1 = 2.62 \text{ sec} \quad (4.13)$$

$$\text{Relay operating time} = (2.623 \times 0.01) + 0.4$$

$$= 0.43 \text{ sec}$$

$$\text{TMS} = 0.16 \quad (4.14)$$

Use 0.2

$$\text{PSM (P) at min fault} = 12.3 \quad (4.12)$$

$$t \text{ at TM} = 1 = 2.72 \text{ sec} \quad (4.13)$$

$$\text{Relay operating time} = (2.72 \times 0.01) + 0.4$$

$$= 0.43 \text{ sec}$$

$$\text{TMS} = 0.16 \quad (4.14)$$

Use 0.2

The relay setting for the above should be 100%, TMS = 0.2

The norm in the NMBM power system is to set the earth fault plug setting at 20% and the TMS at 0.1.

The SEF must detect low-level earth faults. The SEF setting will therefore be the greater of 5 amps or 3% of the CT primary rating (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3). Therefore use 5%, TMS at 10s.

9.3.4 Calculating the Size of the Transformer and Lateral Fuses

$I_{fl} 1\text{MVA}$	=	26.24 A	(4.1)
Inrush current	=	262.4 A	
Permissible overload (20%)	=	31.49 A	

From above;

Fault current at 6.6 kV busbar	=	1350 A – Annexure 1D
Fault current at 22 kV busbar	=	1471 A – Annexure 1F

The following fuses should be installed at the beginning of the lateral lines using the information in Chapter 8.2.3, provided it can grade with other equipment. FBH 4, 52, 58, 64 and 69 – Install 10K fuses.

Grading of lateral lines

Refer to FBH 24

Install at beginning of the lateral line supplying transformers A 1636, A1393 and A1399 10K fuses.

Total load at FBH 24	=	13.11 A	(4.1)
Inrush current	=	131.1 A	
Permissible overload (20%)	=	15.73 A	

Use a 20K fuse which is capable of carrying a continuous current of 30 A and the inrush current. Table 8.2, 8.3 and PEE Code of Practice were all consulted. The fuse can sustain an inrush current of approximately 450 A for 0.1 s.

According to Digsilent the fault current is 1595 A if a fault is simulated at the primary side of A1349 (Annexure 1H). According to Digsilent, a 20K fuse cannot grade with a 10K fuse at the fault current of 1595 A. According to Table 8.5 the only other fuse that can grade is a 50K fuse at 1700 A. Therefore, the following fuses should be installed:

- 50K fuse at the line side of A1349

- 10K fuse at the line side of A1635
- 10K fuse at the line side of A1393 and A1399

Refer to FBH 25

Install at beginning of the lateral line supplying transformers A0182 and A0107 install 10K fuses.

Total load at FBH 25	=	2.62 A	(4.1)
Inrush current	=	26.2 A	
Permissible overload (20%)	=	3.15 A	

Use a 10K fuse, which is capable of carrying a continuous current of 15 A and the inrush current. Table 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5 a 10K fuse cannot grade with a 10K fuse. The only fuse that can grade with the downstream 10K fuses at a higher fault current of 1472 A (Annexure 1I) is a 50K fuse. This fuse can sustain the inrush current based on Table 8.2.

Note: A 10K fuse cannot protect the 100 kVA transformer; it can only protect the conductor.

Refer to FBH 24, 25 and 40

Install at the beginning of the lateral line supplying transformers A0309 and A0963 10K fuses.

Install at line side of A0737 using a 10K fuse link

According to Digsilent, the fault current at A0737 is 1425 A (Annexure 1J).

According to Table 8.5, a 10K fuse cannot grade with a 10K fuse. The only fuse that can grade with the downstream 10K fuses at a higher fault current of 1425 A is a 50 K fuse. This fuse can sustain the inrush current based on Table 8.2. Therefore, the following fuses should be installed:

- 50K fuse at the line side of A0737
- 10K fuse at the line side of A0309
- 10K fuse at the line side of A0963

Refer to FBH 77/8

Install at beginning of the lateral line supplying transformers A2168, A2189, A1536 and A0766 10K fuses.

Total load at FBH 77/8	=	2.39 A	(4.1)
Inrush current	=	23.9 A	
Permissible overload (20%)	=	2.87 A	

Use at the beginning of FBH 77/8 a 10K fuse, which is capable of carrying a continuous current of 15 A and the inrush current. Table 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5 a 10K fuse cannot grade with a 10K fuse. According to Digsilent the fault current at A2189 is 1470 A (Annexure 1K). The only fuse that can grade with the downstream 10K fuses at a higher fault current of 1470 A is a 50K fuse. This fuse can sustain the inrush current based on Table 8.2. Therefore, the following fuses should be installed:

- 50K fuse at the start of the spur line
- 10K fuses at the line side of A2168, A2189, A1536 and A0766

Refer to FBH 77/A1

Install at beginning of the lateral line supplying transformer A2170 a 10K fuse.

Total load at FBH 77	=	13.54 A	(4.1)
Inrush current	=	135.4 A	
Permissible overload (20%)	=	16.25 A	

Use at the beginning of FBH 77 a 15K fuse, which is capable of carrying a continuous current of 23 A and the inrush current. Install a 25K fuse protecting C0483 capable of carrying a continuous current of 38 A and the inrush current. Table 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5 a 15K fuse cannot grade with a 15K fuse and 10K fuse because the fault current of 1453 A is higher than the values in Table 8.5 for this particular scenario (Annexure 1L). The only fuse that can grade with the downstream 10K fuse and 15K fuses at a higher fault current is a 50K fuse, which grade at 1700 A. This fuse can sustain the inrush current based on and Table 8.2.

9.3.5 Auto-Recloser

This feeder is predominantly a bare overhead conductor for approximately 20 kilometres, therefore it would make engineering sense to activate the auto-reclosing facility of the relay. The relay is capable of auto-reclosing, but the OCB is not capable. This OCB was installed in 1952 and it cannot auto reclose.

Auto-reclosing is a viable solution because a large portion of the overhead line is constructed along the coastline and lightning is the cause of many outages. Vegetation and animal life along the line also cause problems. A four shot auto-recloser should be considered.

It is critical that the auto-recloser grades with the downstream fuses. A probable solution could be an instantaneous trip to clear transient faults caused by lightning, birds, animals and vegetation. The fuses should clear the permanent faults on the lateral lines and the next shots of the auto-recloser should clear faults on the main line.

According to PEE Code of Practice Number 6.1, circuit breakers which will be used for ARC duties at the beginning of a overhead line should be vacuum or SF 6 type rated for cyclical ARC duties. The circuit breaker panels should be equipped with the following protection systems:

- 2 IDMTL (BS 142 curves) over-current plus high-set elements (OC);
- 1 IDMTL / DTL earth fault element (EF);
- 1 time delayed sensitive earth fault element (SEF), and
- 1 four shot ARC relay.

It is not financially viable to install sectionalisers on this overhead line. Therefore, section 2.9 of PEE Code of Practice Number 6.1 will apply, which states *“ARC’s with only fuses downstream are to be set two fast and two delayed trips, in order to ensure the rupturing of fuses on faulty sections.”*

9.3.6 Sectionalisers

The installation of sectionalisers at the start of the lateral lines (FBH 77/8, FBH 77/A1 and FBH 24) was investigated. This was compared to the installation of fuses. It proved too costly to install sectionalisers for four customers, but the recommendation is to rather install more fuses at each customer transformer to reduce the outage duration per customer.

The cost of a sectionaliser is R 95 000.00 compared to the cost of expulsion fuses at R 15 000.00 each.

9.3.7 Earth Fault Protection

Since 90% of faults on overhead lines are earth faults, it is imperative that earth fault protection is used (Lakervi and Holmes, 2003). The NMBM on 22kV rural lines use earth fault, overcurrent and sensitive earth fault protection as main and back up protection in an IDMT relay (NMBM Protection Guidelines).

On the Blue Horizon Bay 22kV overhead line, the Micom relay earth fault settings are as follows:

Plug setting: 20%

TMS : 0.2

Compare this to the NMBM policy which states the following:

Plug setting: 20%

TMS : 0.1

The difference of 0.1 in the TMS is to grade with the downstream fuses.

9.3.8 Sensitive Earth Fault Protection

The relay has been programmed at a plug setting of 5% and the TMS = 8 s. The SEF must be set to detect low earth faults. The SEF setting must be the greater of 5 A or 3% of the CT primary rating and the TMS = 10 s (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

In many instances, live conductors are found lying on the ground and the earth fault current is too low to be detected by the earth fault relay. The ground is also very dry. This poses a danger to human and animal life.

3% of the CT primary current is 3 A and 5% of the CT primary current is 5 A. Therefore 5% is within the standard. The TMS must change to 10 s, which is within the NMBM policy.

9.3.9 Surge Arrestors

Lightning is one of the main causes of power outages on overhead lines and it is difficult to associate power outages with lightning activity (Dugan et al, 2003). This is true if the power system is situated in the remote rural areas, making it difficult for staff to locate the fault. Many unknown power outages and voltage dips in the NMBM can be attributed to lightning activity along the power lines. Flashovers could be reduced, resulting in fewer power quality problems. From the investigations it is evident that not much has been done to increase the number of surge arrestors. It is suggested that more surge arrestors can be installed. The current policy states that surge arrestors should be installed on the transformer pole or at the beginning of a lateral line. From the investigations, not all of these poles have surge arrestors installed.

Lakervi and Holmes (2003) and Dugan et al (2003) recommend that surge arrestors should be allocated close to the equipment they protect and installed on every second or third pole. This is an expensive method to ensure security of supply, but this will ultimately reduce the power quality problems and unknown power outages.

9.4 DIGSILENT POWER FACTORY

The Fitches Corner – Blue Horizon Bay 22 kV overhead line was modelled on Digsilent. Fault analysis and protection simulation data was compared with the protection fault calculations. The Digsilent and Protection sub-sections should be read together.

According to the information in Chapter 8.7.3 a 25K fuse should be installed. The analysis below will prove why a 25K fuse cannot be used for this application.

Refer to Annexure 1M – determining the fuse to protect the 1MVA transformer

Fuse 1- 20K

- This fuse protects the transformer perfectly;
- It has a reasonable overload duration before damage to the transformer can occur;
- Maintains a reasonable clear margin with the relay at Fitches Corner substation, and
- It grades perfectly with the relay at Fitches Corner.

Fuse 2 – 30K

- This fuse does not protect the transformer;
- It protects the cable, and
- Adjustments to settings at Fitches Corner will increase the delay time.

Fuse 3 – 15K

- This fuse protects the transformer perfectly;

- It has a smaller overload margin than fuse 1, and
- It discriminates perfectly with the relay at Fitches Corner.

It was discovered that 140 A striker pin fuses are installed to protect the 6.6 kV cable network. This fuse will never blow and actually acts as a solid link. This explains why the source breaker at Fitches Corner trips when a cable fault occurs.

As per Annexure 1M, a 15K expulsion fuse will protect both the 1MVA transformer and the 6.6 kV cable network. If a downstream fuse was installed to protect the cable network, the 15K fuse will blow before the downstream fuse in the cable network. If the size of the downstream fuse is reduced to grade with the fuse protecting the transformer, the size of the upstream fuse will increase. This will compromise the protection of the transformer. The disadvantage of the latter method is that more sectionalising is required when a fault occurs in the cable network. The advantage of using a 15K or 20K fuse is that these fuses will certainly blow during fault conditions. This method is supported by the repair and/or replacement cost of a transformer, which is far more expensive. If compared to the outage time, it is obvious that this is the most viable solution. This is also the only 22/6.6 kV transformer in the power network. A transformer is not readily available as a replacement. It is recommended to install a 20K fuse.

Refer to FBH 40

According to Annexure 1N, all the 50K fuses grade perfectly with the 10K fuse, but they cannot grade with the relay. The loadflow was run on a three-phase fault. The next larger fuse to grade with the relay is a 30K fuse, but it cannot maintain a grading margin of 0.4 s (Annexure 1O). By using the 30K fuse, the protection against the fault current is compromised (30K clears at 1060 A).

Refer to FBH 77/A1

According to Annexure 1P, the 50K fuse at the beginning of the lateral line protects the cable, but it cannot protect the transformer and it does not grade

with the relay at a grading margin of 0.4 s. A 40K fuse grades better with the relay, but it still does not maintain a grading margin of 0.4 s (Annexure 1Q), thus a 30K fuse operates better. By using smaller size fuses, the protection against fault current is compromised, but the grading margin has improved.

Refer to FBH 77/8

According to Annexure 1R, the 50K fuse grade well with the 10K, but it does not grade with the relay. Using a 30K (Annexure 1S) as a main fuse improves the grading margin, but it still does not maintain a clear grading margin of 0.4 s. Protection against fault current is compromised when using smaller fuses.

All the other lateral fuses grade perfectly. These fuses cannot protect the transformer. They protect the conductor against fault current. In order to protect the transformer with a fuse, the protection of the conductors must be compromised. The alternative would be to protect the transformer with a relay, but this makes installation too expensive. It is more cost effective to replace or repair the transformer than protect it.

According to Elmore (2004), it is difficult to grade fuses with relays. A fuse has a more inverse curve than a relay. It is critical, when grading fuses with relays, to observe the maximum time the fuse can carry the fault current without any damage to the fuse as well as its melting and clearing time.

9.5 SCADA

The Fitches Corner substation is one of the sites not yet fully commissioned. The RTU has been installed but the OCB and the other power system equipment is not compatible. Radio communication in the rural areas is not efficient. This needs to be investigated and additional antennae and/or repeaters must be installed.

SCADA systems are primarily installed to improve power system reliability (Lakervi, Holmes; 2003). For this reason, it is important to investigate why the

system cannot function properly. The Fitches Corner substation is situated approximately 40 kilometres from Port Elizabeth. This substation supplies an upmarket residential area and many chicken and milk farmers. The industry is extending towards the rural areas probably because it is more cost effective to purchase or hire property here. If the city wants to encourage investment and tourism, it is imperative that power system reliability must be improved.

9.6 MAINTENANCE AND MANPOWER

According to NMBM records, only certain power system equipment has been maintained. The last record was dated November 2006, which was for maintaining the fuse units in the Blue Horizon Bay substation. The transformer at Blue Horizon Bay was last maintained in April 2005, when the silica gel was replaced. At Fitches Corner, the 10 MVA transformer was maintained in November 2003 and no detail of any maintenance could be found for the 22/6.6 kV transformer. From the site visits it is evident that this transformer is in a bad state. The substation has two battery chargers, namely, a 30 volt and 110 volt. The 30 volt battery charger was maintained in September 2005 and the 110 volt battery charger in November 2002. The protection relay does not operate, because the battery charger was faulty.

No overhead line maintenance records are available. Line inspectors would inspect the overhead line and associated equipment 3 to 4 times annually and report faulty equipment to management. A shutdown would then be arranged to repair or replace the faulty equipment. The shortcoming to this approach is that only the equipment on ground level can be inspected. Many times, the equipment on poles fails. This is what Lohmann (n.d) called detective maintenance. In order to perform this type of maintenance properly on high voltage electrical equipment, the plant must be shut down. A follow-up shut down can be arranged for maintenance, repair and replacement of equipment.

The protection maintenance is planned in conjunction with the switchgear maintenance program. If a plant is isolated for maintenance, the protection

team will on the same day perform their maintenance. This is not a good practice, because protection equipment and switchgear do not have the same maintenance intervals.

Maintenance must be controlled by management and performed in accordance with a plan or program by a dedicated team (Gill, 1997). The problem is that the NMBM does not have the necessary manpower to perform preventative maintenance. The plans, programs, schedules and management structure might be in place, but the NMBM does not have staff to implement them. Using contractors requires more supervision and inspection. In the case of high voltage equipment, the plant must be isolated and earthed properly by suitable qualified staff. The skills shortage adds to the barriers discussed.

The run-to-fail practice of the NMBM is costing the customers because extended outages lead to lost of production and impact negatively on industry. This is not only a concern for NMBM, but rather a concern affecting the entire electrical industry.

9.7 WEATHER CONDITIONS

Dugan et al (2003), state that weather conditions cause major power outages, especially lightning. This is confirmed in the case study and Annexure 1B.

From the analysis of the faults, it is apparent that 47% of all the outages in this case study are caused by adverse weather conditions. A large percentage of the not established outages can also be associated with adverse weather conditions. From Table 8.1 it is evident that high winds cause many outages (32% of outage rate). The figure for the NMBM is probably higher than 32%.

Weather impacts on power system reliability and increases outage durations, reliability indices and power quality statistics. Solutions must be built in during the design of power systems. It is not always possible to design power systems which will not be severely affected by weather conditions. Budgetary

constraints prevent this, thus in later years power systems become problematic and under-perform. Routine planned maintenance is critical in rural bare conductor lines, namely, vegetation control, conductor tensioning, routine inspections of the equipment, the installation of more surge arrestors et cetera.

9.8 NRS DATA ANALYSIS

The NRS spreadsheet provides valuable information with respect to outages, equipment failures, planned and unplanned interruptions et cetera. The statistics obtained from the NRS spreadsheet could be used to evaluate the performance of the network.

The historical data available at the time of the investigation was retrieved and captured into the NRS spreadsheet. From this it is evident that the Fitches Corner – Blue Horizon Bay 22kV power network under-performed in terms of restoration times. Refer to Annexure 1T. It is a requirement that 30% of the supply must be restored in 1.5 hours, 60% in 3.5 hours, 90% in 7.5 hours and 100% in 24 hours. The network only complies with the 60% and 100% categories. The major impact on customers is in the first 2 hours without supply.

It is evident that fuses, which are hardware equipment, are the main cause of outages. Reasons for the blowing of fuses are transient faults, lack of grading with upstream protection equipment, lack of power line maintenance, adverse weather conditions, lightning, animals, birds et cetera. Appropriate action must be taken to improve the power system reliability.

9.9 FINDINGS

The findings based on the analysis in terms of the criteria described in the literature review:

- The FBH overhead line is exposed to weather conditions, namely, storm, rain, wind and lightning.
- The ARC does not operate.
- The OCB is very old.
- The calculated reliability data below, does not comply with the standard:
 - SAIDI = 4225.8 min/yr
 - SAIFI = 17.4 int/yr
 - CAIDI = 242.9 min/yr
- The FBH overhead line meets the requirements in term of system adequacy as the conductors can sustain the load requirement.
- The FBH overhead line does not comply in term of system security as the overhead line cannot sustain severe disturbances.
- Only 1 voltage transformer is available at Fitches Corner substation. Therefore the Vectograph dip recording will be the same for both FBH and FCR.
- The FBH overhead line under-performed in terms of voltage dips. The recorded voltage dips exceed the voltage dip category benchmarks.
- The harmonic, flickering and voltage regulation measurements are within the parameters of the standard.
- Relay and fuses does not grade properly.
- The class and VA rating of the CT's are not available.
- The 10 MVA transformer and the overhead line conductor are capable of carrying the load.
- The 1 MVA transformer is not protected.
- The calculated specifications for the CT's are 10P15 15 VA.
- The calculated fault level is 1.2 kA and the Digsilent simulation is 1.5 kA.
- The relay settings are calculated as follows:
 - Plug setting = 100%
 - TMS = 0.2
- The sensitive earth fault settings are:
 - Plug setting = 5%
 - TMS = 8 s
- The earth fault settings are:

- Plug setting = 20%
- TMS = 0.2
- Lateral lines FHB 4, 25, 40, 58 and the 1 MVA transformer at Blue Horizon Bay are not protected with expulsion fuses.
- Many pole mounted transformers are not protected with expulsion fuses.
- SCADA supervisory system is not installed on the FBH overhead line.
- No maintenance records are available for the overhead line.
- Maintenance records are available for the transformers and battery chargers.
- The effect of no maintenance being done increases outage durations.
- The shortage of manpower hampers maintenance programs.
- Adverse weather conditions have a major impact on the FBH overhead line. 47% of all outages are directly linked to adverse weather conditions.
- Installation of a sectionaliser is not financially viable.
- Bird and animal life is prevalent along FBH overhead line.
- Not many surge arrestors were found on the FBH overhead line.
- The FBH overhead line does not comply with the 30% and 90% NRS categories.

9.10 **RECOMMENDATIONS**

To improve power system reliability the following points are recommended:

- The OCB should be replaced as it is very old and the technology is outdated;
- Improve maintenance initiatives, namely, inspection, replacement of equipment, servicing of equipment, tensioning of conductors, doing vegetation control and installing animal and bird guards;
- Install new OCB/ARC and program for 4 shots (1 instantaneous and 3 delayed trips);
- More expulsion fuses should be installed;
- More surge arrestors should be installed on every second or third pole;

- The manpower and skills shortages should be addressed. This can be done by developing the skills of internal staff;
- The SCADA supervisory system should be commissioned at Fitches Corner substation;
- Fuse blowing technology versus fuse saving technology should be investigated. Fuse blowing will reduce the voltage dips and fuse saving reduce the outage time;
- Replace the CT's with 10P15 15VA, ratio 100/1;
- The relay settings should be as follows:
 - Plug setting = 100%
 - TMS = 0.2;
- The sensitive earth fault settings should be as follows:
 - Plug setting = 5%
 - TMS = 10 s;
- The earth fault settings should be as follows:
 - Plug setting = 20%
 - TMS = 0.1;
- Fuses should be installed as per the Protection and Digsilent sub-headings as follows:
 - FBH 4 – Install 10K fuse
 - FBH 24 – Install 30K fuse
 - FBH 24 – Install 30K fuse
 - FBH 25 – Install 30K fuse
 - FBH 40 – Install 30K fuse
 - FBH 52 – Install 10K fuse
 - FBH 58 – Install 10K fuse
 - FBH 64 – Install 10K fuse
 - FBH 69 – Install 10K fuse
 - FBH 77/8 – Install 30K fuse
 - FBH 77/A1 – Install 30K fuse
 - A1836 – Install 10K fuse
 - A1393 – Install 10K fuse

- A0107 – Install 10K fuse
- A0309 – Install 10K fuse
- A0953 – Install 10K fuse
- A2168 – Install 10K fuse
- A2189 – Install 10K fuse
- A1536 – Install 10K fuse
- A0766 – Install 10K fuse
- A2170 – Install 10K fuse
- C0483 – Install 25K fuse
- Blue Horizon Bay transformer – Install 20K fuse;
- Automation devices should be installed at critical points in the power network, and
- In the design and planning phase of a network, the weather conditions should be taken into consideration.

CHAPTER 10: ANALYSIS OF SUMMIT GAMTOOS PUMPS

FEEDER (SGP)

10.1 POWER SYSTEM RELIABILITY

The Summit-Gamtoos Pumps 22kV feeder is not reliable. The line tripped 71 times in 5 years. This is an average of 14 trips per year and approximately 1 to 2 times a month. The average outage duration is calculated at 3576.98 hours per year, which amounts to approximately 298 hours per month. The cost of the outages in terms of power not delivered is calculated at 12.71 cents per kWh.

In terms of system adequacy, the system meets the minimum requirements, namely, the current capacity of conductors can sustain the load requirement and is lightly loaded at 17 A, whereas the conductor can be loaded to 202 A. The structure is in good condition and the equipment is approximately 20 years old. With a little more maintenance, this can improve. In terms of system security, the power system fails. The protection equipment is outdated and there is no alternative power supply to the system.

Factors influencing the power system:

- The power system is a radial system and there is no possibility of an alternative supply when an outage occurs.
- Weather conditions have a major impact on the power system. As per Annexure 2B, 45 trips could be linked to adverse weather conditions.
- The duration of the outages is not acceptable in terms of the calculated average outage time.
- The failure rate will decrease if maintenance programs are implemented.
- The protection relay failed and does not have a SEF facility.

Calculating the power system average outage time

$$\begin{aligned} U_s &= \lambda s r s & (2.1) \\ &= 71 \times 251.9 \\ &= 17884.9/5 \text{ yrs} \\ &= 3576.98 \text{ hrs/yr} \end{aligned}$$

Calculating the average outage cost

$$P = 720.19 \text{ kW} \quad (4.15)$$

$$\begin{aligned} \text{Outage cost} &= \frac{C_i(d)}{L_i} & (2.5) \\ &= \frac{0.363 \times 251.9}{720.19} \\ &= R 0.12714 \text{ per kW} \\ &= 12.7 \text{ cents/kW} \end{aligned}$$

Calculating Reliability Indices

$$\text{Calculated SAIDI} = 3023 \text{ min/yr} \quad (2.2)$$

$$\text{Calculated SAIFI} = 14.2 \text{ int/yr} \quad (2.3)$$

$$\text{Calculated CAIDI} = 212.89 \text{ min/yr} \quad (2.4)$$

It is obvious that the calculated reliability data does not comply with the standard stated by Burke (1994) in Chapter 8, Table 8.1. This means that this power system under-performed for the period when the data was collected.

10.2 POWER QUALITY

10.2.1 Voltage Dips

The Summit-Gamtoos Pumps power system is an overhead line and therefore many of the voltage dips and outages could be ascribed to transient faults.

Many of these faults could be cleared by properly co-ordinated protection devices, namely, auto-recloser and lateral expulsion fuses.

The Vectograph voltage dip data recorded over 12 months have been summarised in Table 10.1 below.

Table 10.1 – Voltage Dips – Summit Substation - Jan 08 to Dec 08

Month	S	T	X1	X2	Y	Z1	Z2	% Not Avail
Jan 08	2	1	3	0	11	0	0	0
Feb 08	4	0	1	1	14	0	0	0
Mar 08	4	3	2	1	44	1	0	0
Apr 08	2	0	9	14	140	4	0	3
May 08	8	0	0	0	38	2	0	0
June 08	2	0	1	0	33	0	0	5
July 08	8	2	0	1	30	0	0	0
Aug 08	7	2	12	2	33	2	2	13
Sep 08	2	1	0	0	17	0	1	0
Oct 08	3	1	2	1	63	2	1	3
Nov 08	1	0	2	0	70	1	0	0
Dec 08	4	1	2	0	37	1	0	0
Total	47	11	34	20	530	13	4	

Many factors could influence the voltage dips, namely:

- Animal and bird life along the overhead line;
- Poor maintenance;
- Poor operation of protection devices;
- The age of the equipment;
- Weather conditions (which is affecting the network severely, as per Annexure 2B), and
- Omitting of surge arrestors.

Comparing the data in Table 8.1 to that of Table 3.1 (Chapter 3.2.1), it is evident that the power system is under-performing. Only the Z2 dips are within

the required limits. Y dips are regarded as insignificant as they are not used to regulate the utility on the basis of the power system performance (NRS 048-2:2001). The S and X1 dips are the problematic ones. By applying the interventions mentioned, the number of dips can be reduced. Improvement is essential for a reliable power system.

From the voltage dip data, a majority of their origins cannot be determined. It can only be assumed that the reporting of incidents is incorrect and/or factors, namely, bird and animal life along the power line, vegetation, human interference and adverse weather conditions are responsible for them. Many of the X, Y and Z dips could also be the result of switching activities, faults and voltage dips on neighbouring and other power networks.

10.2.2 Harmonics

The recorded data was retrieved from the power quality instrument and compared to the international benchmark of 5% stated by Burke (1994) and the NRS 048-2:2003 which allows a total harmonic distortion of not more than 8%. According to the assessment, no signs of harmonics disorders could be identified. Power quality data recorded indicates that the harmonics measured on this power system are within the parameters of the NRS 048-2:2003.

10.2.3 Flickering

The recorded data was retrieved from the power quality instrument and compared to the benchmark of between 0.8% and 1.25% as per NRS 048-2:2001. According to the assessment, no signs of flickering could be identified. Power quality data recorded indicates that the flickering measured on this power system is within the parameters of the NRS 048-2:2001.

10.2.4 Voltage Regulation

The recorded data was retrieved from the power quality instrument and compared to the benchmark of $\pm 5\%$ for power systems above 500 V as per NRS 048-2:2001. According to the assessment, no signs of voltage regulation irregularities could be identified. Power quality data recorded indicates that the

voltage regulation measured on this power system is within the parameters of the NRS 048-2:2003.

10.3 POWER SYSTEM PROTECTION

10.3.1 Current Transformers

Since the SGP power system is a relatively old power system, it would be expected that the current transformers are checked to stay accurate because they must sustain high fault currents during fault conditions. If the current transformer is inaccurate, the protection equipment will operate incorrectly.

Calculating ALF

Current rating of overhead line	=	202 A; use 200 A
Load current	=	17 A; use 100A (from annual load test report)
I_{FL}	=	262 A
CT Ratio	=	400/5
CT Class	=	T10 15 VA

Available tapings on CT are 50% to 200%

At 50% plug setting I	=	0.5×400	=	200 A
At 100% plug setting I	=	1×400	=	400 A
At 125% plug setting I	=	1.25×400	=	500 A
At 150% plug setting I	=	1.5×400	=	600 A
At 200% plug setting I	=	2×400	=	800 A

I_{fault}	=	2670 A	(4.2)
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(Attached see Annexure 2C: fault level = 2665A)

ALF at 200 A	=	13.3	(4.3)
ALF at 400 A	=	6.7	(4.3)
ALF at 500 A	=	5.3	(4.3)
ALF at 600 A	=	4.5	(4.3)

$$\text{ALF at 800 A} = 3.3 \quad (4.3)$$

Twice the full load current of the system is approximately 34 A. The minimum plug setting must be used, which is 50%. The calculated ALF is 13.3 (use ALF of 15). This also allows for load growth and flexibility in terms of grading.

The overhead line can carry approximately 200 A, but the full load current of the transformer is only 262 A. This transformer is not only supplying this feeder. It is highly likely that the load will increase in the near future due to new developments in the area.

Determining the knee point voltage

$$\begin{aligned} \text{VA rating} &= 15 \text{ VA} \\ \text{Impedance of Burden} &= 0.6 \, \Omega \end{aligned} \quad (4.16)$$

$$\begin{aligned} \text{Assume CT secondary resistance} &= 0.1 \, \Omega \\ \text{Total secondary impedance} &= 0.7 \, \Omega \end{aligned} \quad (4.17)$$

$$\begin{aligned} \text{ALF (Annexure 2D: fault level)} &= 1323\text{A} \\ &= 3.3 \text{ use 5} \end{aligned} \quad (4.18)$$

$$\text{Emf at secondary at ALF (5)} = 17.5 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (10)} = 35 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (15)} = 52.5 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (20)} = 70 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (30)} = 105 \text{ V} \quad (4.18)$$

If an ALF of 30 is used, the resultant emf is 105 V. This, in terms of Annexure 2D, is correct. Prév  (2006) states that if the ALF is large, the CT is less likely to become saturated. Therefore, the installed CT should have an ALF of 30, which is within Pr v 's parameters. The graph in Annexure 2E indicates that the knee-point voltage is approximately 105 V.

The class 10P CT is perfect for this application. Pr v  (2006) states that 10P is suitable for overcurrent protection, as in this case.

$$S = 17.5 \text{ VA} \quad (4.4)$$

$$\text{Max allowable primary current (ALC)} = 12000 \text{ A} \quad (4.19)$$

The maximum allowable primary current of 12000 A exceeds the maximum fault current of 2670 A (Digsilent 2665 A – Annexure 2C).

A maintenance test was arranged to verify the accuracy of the CT's in terms of primary injection and insulation resistance. The primary injection test results are as follows:

Note: primary injected current is 100A

Core 1: 400/5	Red	White	Blue	Neutral
Red-Neutral	0 mA	1250 mA	0 mA	1250 mA
Red-White	0 mA	1250 mA	1250 mA	0 mA
Red-Blue	1250 mA	1250 mA	0 mA	0 mA

Core 2: 400/5	Red	White	Blue	Neutral
Phase-Neutral	1250 mA	0 mA	0 mA	1250 mA
Red-White	1250 mA	1250 mA	0 mA	0 mA
Red-Blue	1250 mA	0 mA	1250 mA	0 mA

Comparing the test results to that of Table 4.1 (Chapter 4.3), it is evident that the CT's pass the test. From all of the above, it is evident that the most suitable CT to be used should be a 10P30 15 VA. The tests conducted are proof that the CT is in perfect working order.

10.3.2 Fault Calculations

$$Z_{\text{source}} = 0.99 \text{ pu} \quad (4.5)$$

$$Z_{\text{base}} = 4.84 \text{ } \Omega \quad (4.8)$$

$$\begin{aligned} Z_{\text{ACT}} &= R + jX_L \\ &= 0.356 + j0.3662 \\ &= 0.511 \angle 45.81^\circ \Omega \end{aligned}$$

$$Z_{22kVline} = 1.106 \text{ pu} \quad (4.7)$$

Fault current at 22 kV system:

$$\begin{aligned} Z_{\text{fault}} &= Z_{\text{source}} + Z_{22kVline} \\ &= 0.99 + 0.106 \\ &= 1.096 \text{ pu} \end{aligned}$$

$$\begin{aligned} I_{\text{fault pu}} &= \frac{1}{1.096} \\ &= 0.912 \text{ pu} \end{aligned}$$

$$I_{b22} = 2.624 \text{ kA} \quad (4.9)$$

$$\begin{aligned} I_{\text{fault}} &= I_{b22} + I_{\text{fault pu}} \\ &= 2.624 \times 0.912 \\ &= 2.638 \text{ kA (According to Annexure 2C, Digsilent simulation indicates 2.665 kA).} \end{aligned}$$

10.3.3 Relay Settings

$$I_{\text{fault min}} = 1323 \text{ A (minimum most downstream fault current- Annexure 2D)}$$

$$I_{\text{fault max}} = 1420 \text{ A (maximum most downstream fault current- Annexure 2F)}$$

$$CT \text{ ratio} = 400:5$$

$$I_{\text{max}} = 213 \text{ A} \quad (4.1)$$

$$\text{Plug Setting (PS)} = 65.61\% \quad (4.11)$$

Use a plug setting of 100%

$$\text{PSM (M) at max fault} = 3.55 \quad (4.12)$$

$$t \text{ at TM} = 1 = 5.46 \text{ sec} \quad (4.13)$$

Relay operating time	=	$(5.46 \times 0.01) + 0.4$	
	=	0.45 sec	
TMS	=	0.08	(4.14)
		Use 0.1 minimum	
PSM (P) at min fault	=	3.31	(4.12)
t at TM = 1	=	5.78 sec	(4.13)
Relay operating time	=	$(5.78 \times 0.01) + 0.4$	
	=	0.46 sec	
TMS	=	0.08	(4.14)
		Use 0.1 minimum	

The standard for the NMBM power system is to set the earth fault plug setting at 20% and the TMS at 0.1 (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

The SEF must detect low-level earth faults. The SEF setting will therefore be the greater of 5 amps or 3% of the CT primary rating (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3). It is recommended to use 3% and TMS = 10 sec.

10.3.4 Calculating the Fuse Size of the Transformer

The following fuses should be installed at the beginning of the lateral lines using the information in Chapter 8.2.3, provided it can grade with other equipment. SGP 7, 8, 14A, 17, 38 and 43A – Install 10K fuses.

Grading of lateral lines

Refer to SGP 14

Install at beginning of the lateral line supplying transformers A 3572, A3288, A3287 and A4120 10K fuses.

Total load at SGP 14	=	10.49 A	(4.1)
Inrush current	=	104.9 A	
Permissible overload (20%)	=	12.59 A	

Use a 10K fuse, which is capable of carrying a continuous current of 15 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Annexure 2G the maximum fault current at SGP 14/48 is 2118 A. According to Table 8.5 a 10K fuse cannot grade with a 10K fuse. Only a 65K fuse can grade with a 10K fuse at a fault current of 2200 A. The 65K fuse can sustain the inrush current depicted in Table 8.2 and is capable of sustaining the permissible overload as per Table 8.2.

Refer to SGP 30

Install at beginning of the lateral line supplying transformers A 2169, A1537, A1476, A1506 and A1858 10K fuses. Install a 15K fuse to protect the Gamtoos Mouth feeder.

Total load at SGP 30	=	20.54 A	(4.1)
Inrush current	=	205.4 A	
Permissible overload (20%)	=	24.65 A	

According to Annexure 2I the maximum fault current on the SGP 30 lateral line is 1766 A. According to Table 8.3, install a 20K fuse capable of sustaining a continuous current of 30 A. According to Table 8.5 a 20K fuse cannot grade with a 10K fuse at 1766 A. The only fuse capable of sustaining this fault current is a 65K, fuse which grades perfectly with a 10K and 15K fuse at a

maximum fault current of 2200 A. However, a 65K cannot be used at the beginning of the lateral line as well as a downstream fuse. Therefore, install the next higher size fuse, an 80K which can grade with all the downstream fuses.

Refer to SGP 30/31

Total load at SGP 30/31	=	16.19 A	(4.1)
Inrush current	=	161.9 A	
Permissible overload (20%)	=	19.43 A	

According to Annexure 2H, the maximum fault current on the SGP 30/31 lateral line is 1764 A. According to Table 8.3, install a 15K fuse capable of sustaining a continuous current of 23 A and according to Table 8.5 a 15K fuse cannot grade with a 10K fuse at 1764 A. The only fuse capable of sustaining this fault current is a 65K fuse which grades perfectly with a 10K and 15K fuse at a maximum fault current of 2200 A.

Gamtoos Pump Substation

$I_{fl750kVA}$	=	19.68 A	(4.1)
Inrush current	=	196.8 A	
Permissible overload (20%)	=	23.62 A	

According to Table 8.3, a 20K fuse can be used as it can sustain a continuous current of 30 A. According to Annexure 2F, the maximum fault current simulated at Gamtoos Pump substation is 1420 A. According to Annexure 2J the 20K fuse grades with the relay providing a 0.4 s grading margin, but it compromises the protection of the transformer. However, a 15K fuse at a continuous current of 23 A will be able to grade with the upstream relay at a grading margin of 0.4 s. The fuse is also capable of protecting the transformer. Annexure 2K confirms this.

The permissible overload of the transformer is a fraction more than the continuous current of 23 A of the fuse link. It is suggested that a 15K fuse is used to protect the transformers at Gamtoos Pump station. The 15K fuse, according to Table 8.2, can sustain the inrush current.

10.3.5 Auto-Recloser

The Summit-Gamtoos Pumps 22kV overhead line is constructed with copper conductors on wood H-pole structures. The line is approximately 13 kilometres long. Many traces of dead monkeys were found along the line. Bird life is also prevalent. The vegetation is relatively dense and the line runs towards the coastline. Due to these factors, it would be to the advantage of the customers and the utility in terms of power quality to install an auto-recloser at the beginning of the line. On inspection of the site, it was determined that the TJV relay does not provide auto-reclose facility.

Due to the factors mentioned above, auto-relosing is a good option, as it will eliminate many unnecessary trips and outages and will impact positively on power system reliability. A four shot auto-recloser should be considered (PEE Code of Practice Number 6.1). But, at the end of the power system is an important water pump station supplying water to the city. It would not be good to auto-reclose on these pumps, which will result in stop start. Therefore ARC should be set to one shot and lockout.

10.3.6 Sectionalisers

The cost of a sectionaliser is R 95 000.00. The cost of expulsion fuses is R 15 000.00 each. A sectionaliser could be installed at SGP 30/1. This lateral line supplies 5 customers and the Gamtoos Mouth Holiday Resort. The overcurrent rating of the sectionaliser should be 80% of the rating of the controlling ARC (PEE Code of Practice Number 6.1).

10.3.7 Earth Fault Protection

Since most faults on overhead lines (90%) are earth faults, it is imperative that earth fault protection is used. The NMBM on 22kV rural lines use earth fault, overcurrent and sensitive earth fault protection as main and back up protection in an IDMT relay (NMBM Protection Guidelines).

On the Summit 22kV overhead line, the ABB REF 610 relay earth fault settings are as follows:

Plug setting: 20%

TMS: 0.1

Compare this to the NMBM policy, which states the following:

Plug setting: 20%

TMS: 0.1

The relay settings are within the NMBM policy.

10.3.8 Sensitive Earth Fault Protection

On investigation it was found that the TJV protection relay does not have sensitive earth fault facilities. Live conductors in this area were found lying on the ground and the earth fault current was too low to be detected by the earth fault relay. This line is targeted by thieves because it is constructed with copper conductors. Copper thieves cut the live conductors using insulated tools, or they cut the wooden poles. The ground is also very dry, thus the earth fault does not sense this. Therefore SEF is a very good option for this line. The SEF setting must be the greater of 5 amps or 3% of the CT primary rating and the TMS = 10 s (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

On the Summit 22kV overhead line, the ABB REF 610 relay the SEF settings are as follows:

Plug setting: 5%

TMS : 10 s

3% of the CT primary current equals to 12 A. Therefore 3% is acceptable. Therefore 3% and TMS = 10 s are within the NMBM policy.

10.3.9 Surge Arrestors

According to Dugan et al (2003) lightning is one of the main causes of power outages on overhead lines. Many of the unknown power outages and voltage dips could be attributed to lightning activity. It is evident that not much has been done to use more surge arrestors. The current policy states that surge arrestors should be installed on the transformer pole or at the beginning of a lateral line.

Lakervi and Holmes (2003) and Dugan et al (2003) state that surge arrestors should be allocated close to the equipment they protect and installed on every second or third pole. This will reduce the number of voltage dips and power outages and ultimately, the number of unknown power quality events. This is an expensive method to ensure security of supply, but it ultimately reduces power quality problems and unknown power outages. It is strongly recommended that more surge arrestors be installed as this power system provides power to an important pump station which supplies water to Port Elizabeth.

10.4 DIGSILENT POWER FACTORY

The Summit-Gamtoos Pumps 22 kV overhead line was modelled on Digsilent. Fault analysis grading and protection simulation was done. This was compared to the protection fault calculations. The Digsilent and Protection sub-sections should be read together.

Refer to Annexure 2J and 2K – determining the fuse to protect the two 750 kVA transformers at the Gamtoos Pump Station

Fuse 1- 20K

- This fuse does not protect the transformer well against the maximum fault current of 1420 A and thus the transformer will be damaged before the fuse blows.
- It has a reasonable overload duration
- It is slower than fuse 2.
- It maintains a clear grading margin of 0.4 s with the relay at Summit substation.

Fuse 2 – 15K

- This fuse protects the transformer better against the maximum fault current of 1420 A.
- It has a smaller overload margin than fuse 1.
- It is faster than fuse 1.
- It maintains a clear grading margin of 0.4 s with the relay at Summit substation.

Based on the above, it is evident that the 15K fuse will protect the transformer better than the 20K fuse.

Refer to SGP 7

According to Annexure 2L a three-phase fault was simulated. The fault current produced by this fault is 2535 A. Annexure 2M is a simulation of the grading of the 10K fuse and the relay. It grade reasonably well with the relay at a grading margin of 0.35 s. Annexure 2M reveals that the fuse cannot protect the transformer, but protects the cable well.

Refer to SGP 14

According to Digsilent simulation, Annexure 2N the 10K fuse and 65K fuse grade perfectly with each other. However, the 65K fuse cannot grade with the upstream relay.

The largest fuse that will grade with the relay according to Annexure 2O is a 40K fuse with a 0.35 s grading margin. By changing the fuse size, the fault current and the overload margin are compromised. The 40K fuse will still be able to protect the conductor against overload, but the grading margin on the downstream fuse would have been reduced.

Refer to SGP 30

According to the initial calculation in 12.4.4, a 80K fuse should be installed at the beginning of the lateral line. This proves to be correct in terms of the calculations and the tables mentioned above. In terms of Digsilent, it is evident that the 80K fuse cannot grade with the upstream relay. The next option is to install a 40K fuse (Annexure 2O). By changing the fuse size, the fault current and the overload margin are compromised. The 40K fuse will still be able to protect the conductor against overload, but the grading margin between the downstream fuse would have been reduced.

10.5 SCADA

Summit-Gamtoos Pumps 22kV overhead line is not on the NMBM SCADA network. According to Lakervi and Holmes (2003) it is of utmost importance to have a SCADA system in order to improve the reliability of the power system. This will reduce outage time and cause fewer losses to the farmers connected to this network. It is important to install SCADA equipment at the Summit substation. This substation is situated approximately 70 kilometres from Port Elizabeth. It provides electricity to farmers, an important pump station and a holiday resort. The industry is extending towards the rural areas because it is more cost effective to purchase or hire property in the rural areas. If the city wants to encourage investment and tourism, it is imperative that an improvement in terms of power system reliability must be maintained.

10.6 MAINTENANCE AND MANPOWER

Maintenance must be controlled by management and performed in accordance with a plan or program and by a dedicated team (Gill, 1997). The NMBM is in a crisis in that the maintenance programs cannot be implemented because of the skills shortage and the unproductivity of staff. There are no dedicated teams responsible for maintenance. Most of the maintenance work is contracted out. This in itself poses a problem as Contractors use unqualified staff with limited skills and training. This results in poor workmanship and more supervision is required to check and inspect the work.

According to the maintenance database, the two major 66/22 kV transformers were last serviced in March 1994. Apart from minor oil leaks, these two transformers are still in a good state. The battery charger was maintained in 2005. No records could be found for maintenance done on the switchgear and the protection equipment. The protection relay was tested in 2009 and it failed the test. Subsequently, the relay was replaced with a numerical relay.

No overhead line maintenance records are available. Line inspectors would inspect the overhead line and associate equipment 3 to 4 times yearly and report faulty equipment to management. A shutdown would then be arranged to repair or replace the faulty equipment. The shortfall of this approach is that only the equipment on ground level can be inspected. Many times, the equipment on top of poles fails. This is what Lohmann (n.d) called detective maintenance. In order to perform this type of maintenance properly in terms of high voltage electrical equipment, the plant must be shut down. Unfortunately, the NMBM do not shut down the plant because it will affect continuity of supply to customers. After this inspection, a follow-up shut down should be arranged for maintenance, repair and replacement of equipment.

Many of the outages on this power line are caused by bridges, which are burnt off. On investigation it was determined that the clamps used to join the

conductors fail during high load conditions. Ferrule crimp lugs were introduced and they seem to be the solution to the problem.

According to investigations done and discussions with staff members, animal interference is also a major problem, resulting in many outages and voltage dips. On inspection, traces of skeletons of monkeys were found along the power line. More guards could be used to keep animals away from the equipment.

Protection maintenance is planned in conjunction with the switchgear maintenance program. In other words, if a plant is isolated for maintenance, the protection team will on the same day perform their maintenance. This is not a good practice, because protection equipment and switchgear do not have the same maintenance intervals. Protection equipment maintenance should be planned separately.

The run-to-fail practice of the NMBM is costing the customers because extended outages lead to production down-time and impact negatively on the ordinary person in the street. This is not only a NMBM concern, but rather an electrical industry concern.

10.7 WEATHER CONDITIONS

Dugan et al (2003) found that weather conditions are the cause of major power outages, especially lightning. This is also true in terms of the evidence supported by Annexure 2B.

From the analysis of the faults, it is apparent that 63% of all the outages in this case study are caused by adverse weather conditions. It is also certain that a large percentage of the not established outages can also be attributed to the adverse weather conditions. Table 8.1, shows that high winds are a further cause. From Table 8.1 it is evident that high winds cause many outages (32% of outage rate). The figure for the NMBM could probably higher than 32%.

Weather impacts on power system reliability and affects outage durations, reliability indices and power quality. Care must be taken during the design of power systems. It is not always possible to design power systems which will not be severely affected by weather conditions. Budgetary constraints prevent this. In later years, power systems become problematic and under-perform. Routine planned maintenance is critical on rural bare conductor lines, namely, vegetation control, conductor tensioning, routine inspections of the equipment et cetera.

10.8 NRS DATA ANALYSIS

The NRS spreadsheet was designed to provide statistical data for the utility and produce a report for the NER. This program provides valuable information on outages, equipment failure, causes of outages, restoration time, planned and unplanned interruptions et cetera. The statistics obtained from the spreadsheet can be used to evaluate the performance of the network.

The historical data available at the time of the investigation was retrieved and captured onto the NRS spreadsheet. The Summit-Gamtoos Pumps 22kV overhead line under-performed in terms of restoration times and according to Annexure 2P. It is a requirement that 30% of the supply must be restored in 1.5 hours, 60% in 3.5 hours, 90% in 7.5 hours and 100% in 24 hours. The network complies in the 60%, 90% and 100% categories. It is evident that only 7.1% of all customer supplies are restored within the first 90 minutes. This is the most critical stage of any outage. The major impact on customers is during the first 1 to 2 hours. A survey conducted in Blue Horizon Bay proves that customers feel more inconvenienced during this phase.

It is conclusive that equipment failure is the main cause of outages. The reasons for equipment failures are addressed in the other sub-headings, but many of them can be ascribed to adverse weather conditions as per Annexure 2B. Appropriate action to address these failures has to be taken.

10.9 FINDINGS

The findings based on the evaluation in terms of the criteria described in the literature review:

- The SGP overhead line is exposed to weather conditions, namely, storm, rain, wind and lightning.
- The ARC is set to 1 shot and lockout.
- The TJV protection relay provides overcurrent and earth fault protection and does not have SEF facility.
- The TJV protection relay was tested and failed the tests.
- The calculated reliability data below, does not comply with the standard:
 - SAIDI = 3023 min/yr
 - SAIFI = 14.2 int/yr
 - CAIDI = 212.89 min/yr
- The SGP overhead line meets the requirements in term of system adequacy as the conductors can sustain the load requirement.
- The SGP overhead line does not comply in term of system security as the overhead line cannot sustain severe disturbances.
- The SGP overhead line under-performed in terms of voltage dips. The recorded voltage dips exceed the voltage dip category benchmarks. Only the Z2 dips are within the required limits.
- The S and X1 dips are the problematic ones.
- The harmonic, flickering and voltage regulation measurements are within the parameters of the standard.
- Relay and fuses does not grade properly.
- The 10 MVA transformer and the overhead line conductor are capable of carrying the load.
- The calculated specifications for the CT's are 10P30 15 VA.
- The calculated fault level is 2.6 kA and the Digsilent simulation is 2.7 kA.
- The relay settings are calculated as follows:
 - Plug setting = 100%

- TMS = 0.1
- The sensitive earth fault settings are:
 - Plug setting = 5%
 - TMS = 10 s
- The earth fault settings are:
 - Plug setting = 20%
 - TMS = 0.1
- Lateral lines SGP 7, 14, 14A, 17, 20, 38, 43 and the two 750 kVA transformer at Gamtoos Pump Station are not protected with expulsion fuses.
- Many pole mounted transformers are not protected with expulsion fuses.
- SCADA supervisory system is not installed on the SGP overhead line.
- No maintenance records are available for the overhead line.
- Maintenance records are available for the 2 transformers and battery chargers.
- The effect of no maintenance being done increases outage durations.
- The shortage of manpower hampers maintenance programs.
- Adverse weather conditions have a major impact on the SGP overhead line. 63% of all outages are directly linked to adverse weather conditions.
- SGP overhead line is constructed with copper conductor which makes the line vulnerable to theft and vandalism, resulting in many extended outages.
- Installation of a sectionaliser is not financially viable.
- Bird and animal life is prevalent along SGP overhead line.
- Not many surge arrestors were found on the SGP overhead line.
- The SGP overhead line does not comply with the 60%, 90% and 100% NRS categories.

10.10 RECOMMENDATIONS

In order to improve power system reliability, it is recommended that the points following be considered:

- Improve preventative maintenance initiatives, namely, inspection, replacement of equipment, servicing of equipment, tensioning of conductors, doing vegetation control and installing animal and bird guards;
- Preventative maintenance programs should be initiated under strict control of management;
- Outdated protection equipment should be replaced with new ABB REF 601 relays (some has already been completed);
- More expulsion fuses should be installed. Fuses should be installed as per the Protection and Digsilent sub-headings as follows:
 - SGP 7 – Install 10K fuse
 - SGP 8 - Install 10K fuse
 - SGP 14 - Install 40K fuse
 - SGP 14A - Install 10K fuse
 - SGP 17 - Install 10K fuse
 - SGP 30 - Install 40K fuse
 - SGP 30/31 - Install 30K fuse
 - SGP 38 - Install 10K fuse
 - SGP 43A - Install 10K fuse
 - Transformers A3572, A3288, A3287, A4120, A 2169, A1537, A1476, A1506 and A1858 – Install 10 fuses;
 - The Gamtoos Pumps transformers should be protected with two 15K fuses;
- The auto-reclose facility should be activated to one shot and lock out due to the pump station which is supplied by the SGP overhead line;
- Replace the CT's with 10P30 15VA, ratio 400/5;
- The relay settings should be as follows:
 - Plug setting = 100%
 - TMS = 0.1;

- The sensitive earth fault settings should be as follows:
 - Plug setting = 3%
 - TMS = 10 s;
- The earth fault settings should be as follows:
 - Plug setting = 20%
 - TMS = 0.1;
- The manpower and skills shortages should be addressed. More staff should be trained and employed;
- More surge arrestors should be installed on every second or third pole;
- A SCADA supervisory system should be installed for monitoring and operation;
- Automation devices should be installed at critical points in the power network;
- In the design phase of a network, the weather conditions should be considered;
- More animal protection measures should be installed;
- An alternative power supply (n-1) should be provided;
- Fuse blowing technology versus fuse saving technology should be investigated. Fuse blowing will reduce the voltage dips and fuse saving reduce the outage time, and
- Copper conductors should be replaced with ABC conductors.

CHAPTER 11: ANALYSIS OF MOTHERWELL NORTH FEEDER

(MWN)

11.1 POWER SYSTEM RELIABILITY

The Motherwell North Blue power network is not a reliable power system. In terms of system adequacy, the network satisfies certain of the criteria to provide power to customers. All the equipment necessary to provide power is available, but how reliable is the network? When was it maintained, repaired or equipment replaced? In terms of system security, the network is not competent to sustain severe disturbances. The protection equipment does not function properly and preventative maintenance has not been done regularly.

Bollen (2000) outlines the factors that influence the reliability of a network:

- Weather conditions;
- Duration of the interruptions;
- Failure of protection devices;
- Radial topology, and
- Failure rate.

Bollen's (2000) factors were confirmed by the statistics of the interruption data available. Refer to Annexures 3B, and equations 2.1, 2.2, 2.3 and 2.4 below. The network configuration is in a ring topology and the protection devices do not function properly, in particular the grading between the circuit breaker and the expulsion fuses. The ring has open points, which have to be closed manually; therefore the power system can be regarded as radial.

In terms of the factors influencing the power system, the following is noted:

- The power system can be regarded as a radial system with normally open points for an alternative supply when an outage occurs.

- Weather conditions have a major impact on the power system. Annexure 3B reveals that 52% of the outages can be directly linked to adverse weather conditions.
- The duration of the outages described do not fall within the NRS requirements.
- The failure rate will decrease if maintenance programs are implemented.

Calculating the power system average outage time

$$\begin{aligned}
 U_s &= \lambda s r_s & (2.1) \\
 &= 858 \times 334.1 \\
 &= 28398.5/5 \text{ yrs} \\
 &= 5679.7 \text{ hrs/yr}
 \end{aligned}$$

Calculating the average outage cost

$$\begin{aligned}
 P &= 4108.49 \text{ kW} & (4.15) \\
 \text{Cost per kW} &= 0.363 \text{ (Calculated over 5 years)}
 \end{aligned}$$

$$\begin{aligned}
 \text{Outage cost} &= \frac{C_i(d)}{L_i} & (2.5) \\
 &= \frac{0.363 \times 334.1}{4108.49} \\
 &= R 0.0295 \text{ per kW} \\
 &= 2.95 \text{ cents/kW}
 \end{aligned}$$

Calculating Reliability Indices

$$\text{Calculated SAIDI} = 4009.6 \text{ min/yr} \quad (2.2)$$

$$\text{Calculated SAIFI} = 17 \text{ int/yr} \quad (2.3)$$

$$\text{Calculated CAIDI} = 235.86 \text{ min/yr} \quad (2.4)$$

It is obvious that the calculated reliability data does not comply with the standard described by Burke (1994) in Chapter 8, Table 8.1. This evidently

means that this power system under-performed for the period that the data was being collected.

11.2 POWER QUALITY

11.2.1 Voltage Dips

The voltage dips on this network are fewer than those in the other case studies. This is probably because the network is constructed in ABC. Many factors could influence the voltage dips, namely, maintenance, varying loads, switching, operation of protection devices which are questionable, the age of the equipment, and weather conditions et cetera. These impact on the reliability indices and power quality benchmarks. The Vectograph voltage dip data recorded over twelve months are summarised in Table 11.1 below.

Table 11.1 – Motherwell Voltage Dips – Dec 08 to Nov 09

Month	S	T	X1	X2	Z1	Z2	Swells	% Not Avail
Dec 08	0	1	3	0	0	0	6	83
Jan 09	0	0	0	0	0	0	7	93
Feb 09	1	0	1	0	0	0	619	57
March 09	0	0	0	0	0	0	0	19
April 09	0	0	0	0	0	0	0	20
May 09	1	4	0	0	0	0	235	72
June 09	0	0	0	0	0	0	0	20
July 09	0	0	0	0	0	0	0	19
Aug 09	0	0	0	0	0	0	0	19
Sept 09	0	0	0	0	0	0	0	20
Oct 09	1	1	9	0	1	0	33	88
Nov 09	0	0	1	1	0	0	139	77
Total	3	6	14	1	1	0	1039	49

The Y-dips have been omitted as they are regarded as insignificant and customers have to provide equipment to reduce them. Utilities are not required to report on the number of Y-dips (NRS 048-2:2001).

From Table 11.1, it is evident that the network complies with the requirements of NRS 084-2:2007.

11.2.2 Harmonics

The recorded data was retrieved from the power quality instrument and compared with the international benchmark of 5% identified by Burke (1994) and the NRS 048-2:2003, which allows a total harmonic distortion of not more than 8%. According to the assessment, no sign of harmonics disorders could be found. Power quality data recorded indicates that the harmonics measured on this power system are within the parameters of the NRS 048-2:2003.

11.2.3 Flickering

The recorded data was retrieved from the power quality instrument and compared with the benchmark of between 0.8% and 1.25% as per the NRS 048-2:2001. According to the assessment, no signs of flickering could be found. Power quality data recorded indicated that the flickering measured on this power system was within the parameters of the NRS 048-2:2001.

11.2.4 Voltage Regulation

Voltage swells pose a problem. In terms of the assessment and the parameters described in the NRS 048-2:2003, only voltage swells during February, May and November 2009 were not within the parameters. In February the non-compliance was 84%, May 63%, and November 27%. Voltage swells can be reduced by lowering the tapping on the transformer.

11.3 POWER SYSTEM PROTECTION

11.3.1 Current Transformers

Current transformer and switchgear are approximately 17 years old, so they are relatively new. However, it is important for current transformers to stay accurate because they must sustain high fault currents during fault conditions.

If the current transformer is inaccurate, the protection equipment will operate incorrectly.

Calculating ALF

Current rating of ABC	=	265 A; use 300 A	
Load current	=	73 A; use 100 A	
I_{FL}	=	1050 A; use 1100 A	(4.1)
CT Ratio	=	400/1	
CT Class	=	10P20 15 VA	

Available tapings on CT are 50% to 200%

At 50% plug setting I	=	0.5 x 400	=	200 A
At 75% plug setting I	=	0.75 x 400	=	300 A
At 100% plug setting I	=	1 x 400	=	400 A
At 125% plug setting I	=	1.25 x 400	=	500 A
At 150% plug setting I	=	1.5 x 400	=	600 A
At 200% plug setting I	=	2 x 400	=	800 A

$$I_{\text{fault}} = 8850 \text{ A} \quad (4.2)$$

(Digsilent simulation confirmed fault level of 8848 A – Annexure 3C)

ALF at 200 A	=	44.2	(4.3)
ALF at 300 A	=	29.5	(4.3)
ALF at 400 A	=	22.1	(4.3)
ALF at 500 A	=	17.7	(4.3)
ALF at 600 A	=	14.7	(4.3)
ALF at 800 A	=	11.1	(4.3)

Twice the full load current of the system is approximately 150 A. That equates to a plug setting of 50% and an ALF of 44.2 (use 30 maximum ALF) (Prévé, 2006). This plug setting also allows for load growth and flexibility in terms of grading.

The overhead line can carry approximately 300 A, but the full load current of the transformer is 1050 A. This transformer not only supplies this feeder, but also the other 22 kV feeders in the network. Therefore, it is highly unlikely that this feeder will be loaded to its full capacity.

Determining the knee point voltage

$$\begin{aligned} \text{VA rating} &= 15 \text{ VA} \\ \text{Impedance of Burden} &= 15 \, \Omega \end{aligned} \quad (4.16)$$

$$\begin{aligned} \text{Assume CT secondary resistance} &= 0.1 \, \Omega \\ \text{Total secondary impedance} &= 15.1 \, \Omega \end{aligned} \quad (4.17)$$

$$\begin{aligned} \text{ALF (Using most downstream fault- Annexure 3D)} \\ &= 5.4 \text{ use } 10 \end{aligned} \quad (4.3)$$

$$\text{Emf at secondary at ALF (5)} = 75.5 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (10)} = 151 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (15)} = 227 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (20)} = 302 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (30)} = 453 \text{ V} \quad (4.18)$$

The calculated ALF is 5 and it does not exceed the installed CT parameters. Prév  (2006) states that if the ALF is large, the CT is less likely to become saturated. The installed CT has an ALF of 20, which is within Pr v 's parameters.

The class 10P CT is perfect for this application. Pr v  (2006), states that a 10P CT is suitable for overcurrent protection.

$$S = 15.1 \text{ VA} \quad (4.4)$$

The VA rating is also within the specifications of the nameplate data as a 15 VA CT is used.

According to Table 4.2 (Chapter 4.3) a 10P CT allows a 10% error. When compared with the calculated knee point voltage and that of Annexure 3E, it is within the required parameters.

A maintenance test was completed in order to verify the accuracy of the CT's. The primary injection and insulation resistance tests were conducted. The primary injection test results are as follows:

Note: primary injected current is 100A

Core 2: 400/1	Red	White	Blue	Neutral
Phase-Neutral	250 mA	0 mA	0 mA	250 mA
Red-White	249 mA	250 mA	0 mA	0 mA
Red-Blue	249 mA	0 mA	250 mA	0 mA

Core 3: 400/1	Red	White	Blue	Neutral
Phase-Neutral	250 mA	0 mA	0 mA	250 mA
Red-White	250 mA	251 mA	0 mA	0 mA
Red-Blue	250 mA	0 mA	251 mA	0 mA

Comparing the test results to that of Table 4.1 (Chapter 4.3), it is evident that the CT's pass the test, but the CT's will not be able to withstand the fault current.

The most suitable CT to be used should be a 10P20 15 VA. The tests conducted prove that the CT is in perfect working order.

$$\text{Max allowable primary current (ALC)} = 8000 \text{ A} \quad (4.19)$$

The maximum allowable primary current of 8000 A does not exceed the maximum fault current of 8850 A (Digsilent 8848 A). Using an ALF of 30, the ALC increases to 12000 A. This indicates that the CT will not be able to withstand the maximum allowable fault current in the network. Therefore, this CT is not suitable and should be replaced with a 10P30 15 VA CT.

11.3.2 Fault Calculations

$$Z_{\text{source}} = 0.12 \text{ pu} \quad (4.5)$$

$$Z_{\text{base}} = 4.84 \text{ } \Omega \quad (4.8)$$

$$\begin{aligned}
 Z_{\text{lineact}} &= R + jX_L \\
 &= 3.97 + j0.536 \\
 &= 4 \angle 0.134^\circ \Omega
 \end{aligned}$$

$$Z_{\text{line}} = 0.826 \text{ pu} \quad (4.7)$$

$$\begin{aligned}
 Z_{\text{cableact}} &= R + jX_L \\
 &= 1.26 + j0.388 \\
 &= 1.318 \angle 0.29^\circ \Omega
 \end{aligned}$$

$$Z_{\text{cable}} = 0.272 \text{ pu} \quad (4.7)$$

$$\begin{aligned}
 Z_{\text{fault}} &= Z_{\text{source}} + Z_{\text{cable}} + Z_{\text{line}} \\
 &= 0.12 + 0.272 + 0.826 \\
 &= 1.218 \text{ pu}
 \end{aligned}$$

$$\begin{aligned}
 I_{\text{fault pu}} &= \frac{1}{1.218} \\
 &= 0.821 \text{ pu}
 \end{aligned}$$

$$I_{b22} = 2.624 \text{ kA} \quad (4.9)$$

$$\begin{aligned}
 I_{\text{fault}} &= I_{b22} \times I_{\text{fault pu}} \\
 &= 2.624 \times 0.821 \\
 &= 2151 \text{ A}
 \end{aligned}$$

(Digsilent simulation confirmed fault level of 2172 A – Annexure 3D)

11.3.3 Relay Settings

$$I_{\text{max}} = 265 \text{ A}$$

$$I_{\text{fault min}} = 1659 \text{ A (minimum most downstream fault current - Annexure 3F)}$$

$I_{\text{fault max}}$ = 2172 A (maximum most downstream fault current
Annexure 3D)

CT ratio = 400:1

Plug Setting (PS) = 66.25% (4.11)

Use a plug setting of 100%

PSM (M) at max fault = 5.43 (4.12)

t at TM = 1 = 4.07 sec (4.13)

Relay operating time = $(4.07 \times 0.01) + 0.4$
= 0.441 sec

TMS = 0.08 (4.14)
Use 0.1

PSM (P) at min fault = 4.15 (4.12)

t at TM = 1 = 4.85 sec (4.13)

Relay operating time = $(4.85 \times 0.01) + 0.4$
= 0.448 sec

TMS = 0.09 (4.14)
Use 0.1

The relay setting for the above should be 100%, TMS = 0.1

The norm in the NMBM power system is to set the earth fault plug setting at 20% and the TMS at 0.1.

The SEF must detect low-level earth faults. The SEF setting should therefore be the greater of 5 amps or 3% of the CT primary rating (PEE Code of

Practice Number 6.1 Protection of MV Overhead Lines, 2.3). 5% should be used, with TMS at 10s.

11.3.4 Calculating the Fuse Size of the Transformer

Fuses should be installed at the beginning of the lateral lines, provided they can grade with other equipment. Refer to calculations in Chapter 8.2.3

All the transformers are 200 kVA, except those otherwise indicated on Annexure 3A. Use 10K fuses for these 200 kVA transformers, which are capable of carrying a continuous current of 15 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted. At MWN 26/23/16, 32, 51/38/72 and 51/38/67, 10K fuses can be installed at the beginning of the lateral lines using the information in Chapter 8.2.3, provided it can grade with other equipment.

Refer to MWN 26

The selected fuse must be able to protect the ABC conductor. Connected to the lateral line are six transformers with an apparent power capacity of 200 kVA each. Total capacity at MWN 26/23 is 1200 kVA. The selected fuse must also be able to grade with the 10K fuse at MWN 26/23/16.

$$\begin{aligned} I_{FL} &= 31.49 \text{ A} & (4.1) \\ I_{FL} \text{ at } 120\% &= 37.79 \text{ A} \\ I_{Inrush} &= 10 \times I_{FL} \\ &= 314.9 \text{ A} \end{aligned}$$

Use 25K fuse at MWN 26/23

Total load at MWN 26

$$\begin{aligned} S &= (13 \times 200) + 500 = 3100 \text{ kVA} \\ I_{FL} &= 81.35 \text{ A} & (4.1) \\ I_{FL} \text{ at } 120\% &= 97.62 \text{ A} \end{aligned}$$

$$\begin{aligned}
 I_{\text{Inrush}} &= 10 \times I_{\text{FL}} \\
 &= 813.5 \text{ A}
 \end{aligned}$$

Use a 65K fuse at MWN 26

For transformer 2279 (500 kVA) use 12 or 10 K fuse.

Grading

A 65K fuse grades with a 20K, 15K and 10K fuse. All these fuses can sustain the inrush currents as per the above Tables, Figures and standards.

Refer to MWN 51/38

$$S = (15 \times 200) + (2 \times 500) + 3000 = 4000 \text{ kVA}$$

$$\begin{aligned}
 I_{\text{FL}} &= 104.97 \text{ A} & (4.1) \\
 I_{\text{FL}} \text{ at } 120\% &= 125.97 \text{ A} \\
 I_{\text{Inrush}} &= 10 \times I_{\text{FL}} \\
 &= 1049.7 \text{ A}
 \end{aligned}$$

Use a 80K fuse at MWN 51/38

Refer to MWN 51

$$\begin{aligned}
 S &= 7 \times 200 &= 1400 \text{ kVA} \\
 I_{\text{FL}} &= 36.7 \text{ A} & (4.1) \\
 I_{\text{FL}} \text{ at } 120\% &= 44.09 \text{ A} \\
 I_{\text{Inrush}} &= 10 \times I_{\text{FL}} \\
 &= 367 \text{ A}
 \end{aligned}$$

$$\begin{aligned}
 \text{Total load at MWN 51} &= 1400 + 4000 \\
 &= 5800 \text{ kVA}
 \end{aligned}$$

$$I_{\text{FL}} = 141.71 \text{ A} \quad (4.1)$$

$$\begin{aligned}
 I_{FL} \text{ at } 120\% &= 170.06 \text{ A} \\
 I_{Inrush} &= 10 \times I_{FL} \\
 &= 1417.1 \text{ A}
 \end{aligned}$$

Use a 140K fuse at MWN 51

Grading

A 100K fuse cannot grade with a 80K fuse. A 140K fuse can grade with a 80K fuse at a fault current of 4500 A. This fuse fulfils all the requirements above.

Refer to MWN 66

$$\begin{aligned}
 S &= (11 \times 200) + 500 &= 2700 \text{ kVA} \\
 I_{FL} & &= 70.86 \text{ A} & (4.1) \\
 I_{FL} \text{ at } 120\% & &= 85.03 \text{ A} \\
 I_{Inrush} & &= 10 \times I_{FL} \\
 & &= 708.6 \text{ A}
 \end{aligned}$$

Use a 65K fuse at MWN 66

This fuse fulfils all the requirements above.

Refer to MWN 80/38

$$\begin{aligned}
 S &= 4 \times 200 &= 800 \text{ kVA} \\
 I_{FL} & &= 20.99 \text{ A} & (4.1) \\
 I_{FL} \text{ at } 120\% & &= 25.19 \text{ A} \\
 I_{Inrush} & &= 10 \times I_{FL} \\
 & &= 209.9 \text{ A}
 \end{aligned}$$

Use a 15K fuse at MWN 80/38

This fuse fulfils all the requirements above.

Refer to MWN 80/33

$$\begin{aligned} S &= 500 + 200 &= & 700 \text{ kVA} \\ I_{FL} & &= & 18.37 \text{ A} \\ I_{FL} \text{ at } 120\% & &= & 22.04 \text{ A} \\ I_{Inrush} & &= & 10 \times I_{FL} \\ & &= & 183.7 \text{ A} \end{aligned} \quad (4.1)$$

Use a 15K fuse at MWN 80/33

This fuse fulfils all the requirements above.

Refer to MWN 80

$$\begin{aligned} S &= (13 \times 200) + 500 &= & 3100 \text{ kVA} \\ I_{FL} & &= & 81.35 \text{ A} \\ I_{FL} \text{ at } 120\% & &= & 97.62 \text{ A} \\ I_{Inrush} & &= & 10 \times I_{FL} \\ & &= & 813.5 \text{ A} \end{aligned} \quad (4.1)$$

Use a 65K fuse at MWN 80

This fuse fulfils all the requirements above.

Refer to MWN 89

$$\begin{aligned} S &= 7 \times 200 &= & 1400 \text{ kVA} \\ I_{FL} & &= & 36.74 \text{ A} \\ I_{FL} \text{ at } 120\% & &= & 44.09 \text{ A} \\ I_{Inrush} & &= & 10 \times I_{FL} \\ & &= & 367.4 \text{ A} \end{aligned} \quad (4.1)$$

Use a 30K fuse at MWN 89

This fuse fulfils all the requirements above.

11.3.5 Auto-Recloser

The Motherwell North 22kV overhead line is constructed with ABC conductors on wooden poles. The line is approximately 17 kilometres long, running through a residential area. One factor affecting this line is vandalism.

To benefit the customers and utility in terms of power quality, an auto-recloser should be installed at the beginning of the line. It eliminates many unnecessary trips and outages and will impact positively on power system reliability. But, unfortunately ABC is treated as a cable network on poles. The majority of faults on ABC networks are permanent faults which should be cleared by the relay or the lateral expulsion fuse. Therefore ARC is not an option for this network.

In order to solve the power system reliability problem, more expulsion fuses should be installed. These fuses should grade with the other protection equipment, namely, relays and fuses.

11.3.6 Sectionalisers

The cost of a sectionaliser is R 95 000.00 and the cost of expulsion fuses is R 15 000.00 each. Sectionalisers are not an option as they are normally used with an ARC.

11.3.7 Earth Fault Protection

The NMBM on 22kV rural lines use earth fault, overcurrent and sensitive earth fault protection as main and back up protection in an IDMT relay (NMBM Protection Guidelines). On the Motherwell North 22kV overhead line, the settings in terms of earth fault are as follows:

Plug setting: 20%

TMS: 0.1

Compare this to the NMBM policy which states the following:

Plug setting: 20%

TMS: 0.1

These settings above are correct.

11.3.8 Sensitive Earth Fault Protection

Since this line is constructed in ABC, no SEF is required.

11.3.9 Surge Arrestors

According to Dugan et al (2003), lightning is one of the main causes of power outages on overhead lines. It is evident from the investigations that not much has been done to increase the number of surge arrestors. The current policy states that surge arrestors should be installed on the transformer pole or at the beginning of a lateral line.

Lakervi, Holmes (2003) and Dugan et al (2003) confirm that surge arrestors should be allocated close to the equipment they protect and installed on every second or third pole. This is expensive, but will ensure security of supply. This will ultimately reduce the power quality problems and unknown outages.

11.4 DIGSILENT POWER FACTORY

The Motherwell North 22 kV overhead line was modelled on Digsilent. Fault analysis and protection simulation and co-ordination were performed by the researcher. This was compared with the protection fault calculations. The Digsilent and Protection sub-sections should be read together.

Refer to MWN 26

According to Annexure 3G, grading between the 65K, 25K, 15K and 10K fuses can be achieved. All these fuses can grade with the relay at the source substation. By simulating a fault at MWN 26/23/15, the fuse should clear the fault in 0.01 s allowing a grading margin of 0.229 s. This proves that the selection of the fuses was correct in terms of grading. The fuses can protect

the conductor, but cannot protect the transformer. 65K, 25K, 15K and 10K fuses are recommended for use.

Refer to MWN 51

According to Annexure 3H, the 140K, 80K, 10K fuses grade well with each other, but the 140K fuse cannot grade with the relay. According to Annexure 3I, a 100K fuse grades better. Simulating a fault at MWN 51/38/43, a grading margin of 0.313 s is achieved. By installing a 100K fuse, the maximum loading on the line is compromised and the current capacity is reduced to 150 A. The 100K fuse will still be able to sustain the inrush current in terms of Tables 8.2 and 8.3. 100K, 80K and 10K fuses are recommended.

Refer to MWN 66

According to Annexure 3J, the 65K and the 10K fuses grade well with each other and also with the relay. The fuses cannot protect the transformer, but they protect the conductor well. Under fault conditions the fuse clears the fault in 0.029 s allowing a good grading margin of 0.487 s. The fuses cannot protect the transformer, but does protect the conductor. 65K and 10K fuses are recommended.

Refer to MWN 80

This argument will be the same as MWN 26 as the lateral line has a 65K, 15K and 10K fuses installed. 65K, 25K, 15K and 10K fuses are recommended for use.

Refer to MWN 89

According to Annexure 3K the 30K and 10K fuses grade perfectly with each other and with the relay. Under fault conditions, the fuse clears the fault on 0.01 s, leaving a grading margin of 0.396 s. The fuses cannot protect the

transformer, but do protect the conductor. 30K and 10K fuses are recommended.

11.5 SCADA

The Motherwell North 22kV feeder is part of the broader Motherwell 132/22kV substation and reticulation network. Full SCADA operation is available on this network, so it possible to view the trends, current and voltage analogue readings, receive alarms and the ability to open and close the OCB.

Lakervi and Holmes (2003) state that automation improves power system reliability and secures supply to customers. The outage durations are relatively shorter. This is evident in studying the NRS interruption data and Annexure 3L. Although the number of interruptions over the study period was relatively more than in some of the other case studies, the NRS interruption data improved.

The SCADA information is brought back to the master station via radio communication. During adverse weather conditions and when many events in terms of SCADA operations are performed the data tends to be delayed for a few minutes, sometimes for even up to 30 minutes. The gateway cannot manage the traffic. The radio communication system is also limited as it does not comply with OSI standards. The SCADA master station and the radio network are from different suppliers, hence the difficulties receiving data. Alternative solutions are needed.

11.6 MAINTENANCE AND MANPOWER

Poor maintenance and manpower deficiencies are common causes of outages. From annexure 3B it is evident that lack of maintenance is responsible for many outages. These are failure of conductors, insulator flashovers, broken fuse holders, failure of lightning arrestors, failure of

transformers et cetera. No overhead line maintenance records could be found.

The MWN 0 OCB opened 25 times. Only 9 times the protection operated. The protection did not operate for the remaining 16 operations. Downstream faults are responsible for the 16 operations of the OCB. This is due to the lack of grading between the OCB and the downstream expulsion fuses.

Overhead lines would normally be inspected 3 to 4 times a year. The line inspectors would report faulty equipment and subsequent shutdowns should be arranged to repair or replace the faulty equipment. The shortcoming to this approach is that only the equipment on ground level can be inspected. Many times, the equipment on poles fails. This is what Lohmann (n.d) called detective maintenance. In order to perform maintenance properly on high voltage electrical equipment, the plant must be shut down. A follow-up shut down can be arranged for maintenance, repair and replacement of equipment.

Brown (2002) states that preventative maintenance can extend the life of equipment and Seever (1991) states, that routine maintenance reduces the probability of failures. This will guarantee fewer power outages and will impact positively on power system reliability. But the shortage of manpower hampers routine maintenance programs. According to Lohmann (n.d) maintenance programs should be performed under the close supervision of management. A dedicated team must be responsible for planned maintenance and it must be done in accordance with a schedule. It is impossible for the NMBM to adhere to this requirement as it does not have the skilled labour to perform maintenance.

The run-to-fail practice of the NMBM is costing the customers because extended outages lead to production down-time and impact negatively on the ordinary person in the street. This is not only a NMBM concern, but rather an electrical industry concern.

11.7 WEATHER CONDITIONS

Adverse weather conditions are common in all the case studies. From Annexure 3B it is evident that adverse weather conditions have a major impact on the MWN overhead line. Fifty two percent (52%) of the faults on MWN line were directly related to adverse weather conditions. The end result of this is that power system reliability indices, outage durations and power quality performance suffer.

11.8 NRS DATA ANALYSIS

The NRS spreadsheet provides valuable information on outages, equipment failure, planned and unplanned interruptions et cetera. The statistics obtained from the spreadsheet could be used to evaluate the performance of the network and also to report to the NER.

The historical data available at the time of the investigation was retrieved and captured onto the NRS spreadsheet. The Motherwell North 22kV power network performed well in terms of restoration times (refer to Annexure 3L). It is a requirement that 30% of the supply must be restored in 1.5 hours, 60% in 3.5 hours, 90% in 7.5 hours and 100% in 24 hours. The network complies in all these categories.

The primary cause of outages was equipment failure, namely incorrect operation of fuses. Proper grading and fault clearing should solve this problem.

11.9 FINDINGS

The findings based on the evaluation in terms of the criteria described in the literature review:

- The MWN overhead line is exposed to weather conditions, namely, storm, rain, wind and lightning.
- The SPAJ140C protection relay provides overcurrent and earth fault protection.
- No SEF facility is provided on the protection relay.
- The SPAJ140C protection relay was tested and passed the tests.
- The protection relay and fuses does not grade properly.
- The relay settings are calculated as follows:
 - Plug setting = 100%
 - TMS = 0.1
- The earth fault settings are:
 - Plug setting = 20%
 - TMS = 0.1
- No SEF is required as the MWN overhead line is constructed in ABC.
- The calculated specifications for the CT's are 10P30 15 VA.
- The calculated fault level is 2.2 kA and the Digsilent simulation is 2.2 kA.
- MWN is a radial overhead line.
- The calculated reliability data below, does not comply with the standard:
 - SAIDI = 4009.6 min/yr
 - SAIFI = 17 int/yr
 - CAIDI = 235.86 min/yr
- The MWN overhead line meets the requirements in term of system adequacy as the conductors can sustain the load requirement.
- The MWN overhead line does not comply in term of system security as the overhead line cannot sustain severe disturbances.
- The MWN overhead line complies in terms of voltage dips. The recorded voltage dips does not exceed the voltage dip category benchmarks.
- The harmonic and flickering measurements are within the parameters of the standard.
- The MWN overhead line does not comply in terms of voltage regulation.
- Many of the lateral lines and pole mounted transformers are not protected with expulsion fuses.

- SCADA supervisory system is fully commissioned on the MWN overhead line.
- No maintenance records are available.
- The effect of no maintenance being done increases outage durations.
- The shortage of manpower hampers maintenance programs.
- Adverse weather conditions have a major impact on the MWN overhead line. 52% of all outages are directly linked to adverse weather conditions.
- Installation of a sectionaliser is not financially viable.
- Not many surge arrestors were found on the MWN overhead line.
- The MWN overhead line complies with all the NRS categories.

11.10 RECOMMENDATIONS

To improve power system reliability the following points are recommended:

- Lowering the tapings on the HV transformer can reduce the voltage to comply with NRS 048-2:2003;
- Replace CT with 10P30 15VA, ratio 400/1;
- The relay settings should be as follows:
 - Plug setting = 100%
 - TMS = 0.2;
- The earth fault settings should be as follows:
 - Plug setting = 20%
 - TMS = 0.1;
- Fuses should be installed as per the Protection and Digsilent sub-headings as follows:
 - All 200 kVA transformer - Install 10K fuses
 - MWN 26 – Install 65K fuse
 - MWN 26/23 - Install 20K fuse
 - MWN 26/23/16 - Install 10K fuse
 - MWN 32 - Install 10K fuse

- MWN 51 - Install 100K fuse
- MWN 51/38/72 - Install 10K fuse
- MWN 51/38/67 - Install 10K fuse
- MWN 66 - Install 65K fuse
- MWN 80 - Install 65K fuse
- MWN 80/38 - Install 10K fuse
- MWN 80/33 - Install 15K fuse
- MWN 89 - Install 30K fuse;
- More intense and structured maintenance should be done, namely, vegetation control, routine inspections, et cetera;
- More surge arrestors should be installed on every second or third pole;
- Preventative maintenance should be performed regularly under the control of management to reduce the failure of equipment, and
- The manpower and skills shortages should be addressed. This can be done by developing the skills of internal staff.

CHAPTER 12: ANALYSIS OF KRAGGA KAMMA GREENBUSHES FEEDER (KKG)

12.1 POWER SYSTEM RELIABILITY

The KKG power network is not a reliable power system. In terms of system adequacy, it satisfies most of the criteria to provide power to its customers. All the equipment necessary is available, but how reliable is it? When was it maintained, repaired or replaced? In terms of system security, the network is not competent to cope with severe disturbances as the protection equipment does not function properly. The technology is outdated, preventative maintenance has not been done and automation devices have not been installed to optimise the power system.

Bollen (2000) lists the factors influencing the reliability of a power network as:

- Weather conditions;
- Duration of the interruptions;
- Failure of protection devices;
- Radial topology, and
- Failure rate.

The statistics of the interruption data available confirmed the validity of the above factors, namely, Annexure 4B equations 2.1, 2.2, 2.3 and 2.4 below. The KKG network is a radial power system to Greenbushes substation. Greenbushes substation is supplied with two other 22kV feeders from Rowallan Park and Fitches Corner substations. This can be regarded as a ring network with open points at Greenbushes.

Bollen (2000) argues that the location of faults can be assisted by automation of the power system. The use of SCADA will identify the location of a fault, and switching can be done remotely. This will lead to reduced outage time.

Calculating the power system average outage time

$$\begin{aligned} U_s &= \lambda s r s & (2.1) \\ &= 25 \times 81.6 \\ &= 2040/5 \text{ yrs} \\ &= 408 \text{ hrs/yr} \end{aligned}$$

Calculating the average outage cost

$$\begin{aligned} P &= 6491.97 \text{ kW} & (4.15) \\ \text{Cost per kW} &= 0.363 \text{ (Calculated over 5 years)} \end{aligned}$$

$$\begin{aligned} \text{Outage cost} &= \frac{C_i(d)}{L_i} & (2.5) \\ &= \frac{0.363 \times 81.6}{6491.97} \\ &= R 004563/\text{kW} \\ &= 0.456 \text{ cents/kW} \end{aligned}$$

Calculating Reliability Indices

$$\text{Calculated SAIDI} = 979 \text{ min/yr} \quad (2.2)$$

$$\text{Calculated SAIFI} = 5 \text{ int/yr} \quad (2.3)$$

$$\text{Calculated CAIDI} = 195.8 \text{ min/yr} \quad (2.4)$$

It is obvious that the calculated reliability data does not comply with the standard depicted by Burke (1994) in Chapter 8, Table 8.1. This evidently means that this power system under-performed for the period during which the data was collected.

12.2 POWER QUALITY

12.2.1 Voltage Dips

The KKG feeder is a combination of bare overhead conductor, ABC and underground cable. A power quality recorder has been installed at Greenbushes

substation. Its reads the power quality events on this feeder and on all the other outgoing feeders. Many factors could influence the voltage dips, namely, maintenance, varying loads, switching, operation of protection devices, age of equipment, weather conditions, and the presence of bird and animal life. These factors affect reliability indices and power quality benchmarks. The Vectograph voltage dip data recorded over twelve months has been summarised in Table 12.1 below.

Table 12.1 – Voltage Dips – Greenbushes Substation – Sept 08 to Aug 09

Month	S	T	X1	X2	Z1	Z2	Swells	% Avail
Sept 08	3	0	1	0	3	0	0	62
Oct 08	23	0	0	2	2	3	0	98
Nov 08	13	0	2	1	2	0	0	99
Dec 08	6	3	2	0	1	0	0	87
Jan 09	0	0	0	0	0	0	0	59
Feb 09	0	0	0	0	0	0	0	21
March 09	0	0	0	0	0	0	0	19
April 09	0	0	0	0	0	0	0	20
May 09	12	8	4	0	0	0	0	35
June 09	6	0	2	1	0	0	0	41
July 09	0	0	0	0	0	0	0	19
Aug 09	0	0	0	0	0	0	0	19
Total	63	11	11	4	8	3	0	48

The Y-dips have been omitted because they are regarded as insignificant and customers have to provide equipment to reduce them. Utilities are not regulated on the basis of the number of Y-dips (NRS 084-2:2001).

From Table 12.1, it is evident that the S and T dips are the problematic ones. Both these dips are relatively long. The S-dip is not too deep, but the T-dip is very deep, up to 100%. These dips cause major disturbances to power electronic equipment utilised by the manufacturing industry. KKG also supplies a newly developed industrial area, so good power quality is critical for efficient production. The performance in terms of voltage dips can be improved by

installing dip improving equipment, protection equipment that grade properly, maintaining this equipment and using animal and bird guards.

12.2.2 Harmonics

The recorded data was retrieved from the power quality instrument and compared to the international benchmark of 5% described by Burke (1994) and the NRS 048-2:2003, which allows a total harmonic distortion of not more than 8%. According to the assessment, no signs of harmonics disorder could be identified. Power quality data recorded indicates that the harmonics measured on the KKG power system are within the parameters of the NRS 048-2:2003.

12.2.3 Flickering

The recorded data was retrieved from the power quality instrument and compared to the benchmark of between 0.8% and 1.25% as per NRS 048-2:2001. According to the assessment, no signs of flickering could be identified. Power quality data recorded indicates that the flickering measured on this power system is within the parameters of the NRS 048-2:2001.

12.2.4 Voltage Regulation

The recorded data was retrieved from the power quality instrument and compared to the benchmark of $\pm 5\%$ for power systems above 500 V as per NRS 048-2:2001. According to the assessment, no signs of voltage regulation irregularities could be identified. Power quality data recorded indicates that the voltage regulation measured on the KKG power system is within the parameters of the NRS 048-2:2003.

12.3 POWER SYSTEM PROTECTION

12.3.1 Current Transformers

The protection equipment and switchgear of the KKG power system are very old and the technology is outdated. Current transformers should always be checked for accuracy because they have to sustain high fault currents during fault

conditions. If the current transformer is inaccurate, the protection equipment will operate incorrectly.

Calculating ALF

Current rating of overhead line (PINE) = 262 A

Current rating of underground cable = 298 A

Current rating of ABC = 265 A

Load current = 213 A

Make minimum primary current 300 A

CT Ratio = 300/5

CT Class = 15D

Available tapings on CT are 50% to 200%

At 50% plug setting I = 0.5×300 = 150 A

At 75% plug setting I = 0.75×300 = 225 A

At 100% plug setting I = 1×300 = 300 A

At 125% plug setting I = 1.25×300 = 375 A

At 150% plug setting I = 1.5×300 = 450 A

At 200% plug setting I = 2×300 = 600 A

I_{fault} = 11850 A (4.2)

(Digsilent simulation confirmed fault level of 11854 A – Annexure 4C)

ALF at 150 A = 79 (4.3)

ALF at 225 A = 52.7 (4.3)

ALF at 300 A = 39.5 (4.3)

ALF at 375 A = 31.6 (4.3)

ALF at 450 A = 26.3 (4.3)

ALF at 600 A = 19.8 (4.3)

The maximum current loading on the KKG power line is 189.3 A (from 2005 annual load test report). At a load growth of 3% per year, the loading is 213.1 A. At twice the load current, a plug setting of 150% equates to an ALF of 26.3, therefore use 30.

Determining the knee point voltage

$$\text{Assume VA rating} = 15 \text{ VA}$$

$$\text{Impedance of Burden} = 0.6 \, \Omega \quad (4.16)$$

$$\text{Assume CT secondary resistance} = 0.1 \, \Omega$$

$$\text{Total secondary impedance} = 0.7 \, \Omega \quad (4.17)$$

ALF (Using most maximum downstream fault- Annexure 4D)

$$= 9.2 \text{ use } 10 \quad (4.3)$$

$$\text{Emf at secondary at ALF (10)} = 35 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (20)} = 70 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (30)} = 105 \text{ V} \quad (4.18)$$

The calculated ALF is 10 assuming the VA rating of the CT is 15 VA. This results in an emf of 35 V, which is below the values in the graph in Annexure 4E. If an ALF of 30 is used, the emf increases to 105 V. If an ALF of 20 is used, the results are better and the emf increases to 70 V. Prév   (2006) states that if the ALF is large the CT is less likely to become saturated. The installed CT should have an ALF of 20, which is within Pr  v  's parameters. According to Table 4.2 (Chapter 4.3) a 10P CT allows a 10% error. This falls within the parameters of the calculated knee point voltage and that of Annexure 4E. The class 10P CT is perfect for this application. Pr  v   (2006) states that a 10P CT is suitable for overcurrent protection.

A maintenance test was arranged to verify the accuracy of the CT's in terms of primary injection and insulation resistance. The primary injection test results are as follows:

Note: primary injected current is 100A

Core 1: 300/5	Red	White	Blue	Neutral
Phase-Neutral	1710 mA	0 mA	0 mA	1710 mA
Red-White	1680 mA	1680 mA	0 mA	0 mA
Red-Blue	1690 mA	0 mA	1740 mA	0 mA

Core 2: 300/5	Red	White	Blue	Neutral
Phase-Neutral	1700 mA	0 mA	0 mA	1711 mA
Red-White	1725 mA	1722 mA	0 mA	0 mA
Red-Blue	1680 mA	0 mA	1680 mA	0 mA

Comparing the test results to that of Table 4.1 (Chapter 4.3), it is evident that the CT's failed the test. It is evident that the most suitable CT's to be used should be a 10P20 15 VA. The tests conducted are proof that the CT's should be replaced. These CT's are old and not all the data is available.

$$S = 17.5 \text{ VA} \quad (4.4)$$

$$\text{Max allowable primary current (ALC)} = 6000 \text{ A} \quad (4.19)$$

The maximum allowable primary current of 6000 A does not exceed the maximum fault current of 11850 A (Digsilent 11854 A Annexure 4C). Using an ALF of 30, the ALC increases to 8000 A, which is still below the ALC. In this case, the CT should be changed to a 400/5 CT with an ALF of 30. The resultant ALC of 12000 A is more than the fault level. Therefore, this CT is not suitable and should be replaced with a 10P30 15 VA CT.

An alternative solution is as follows:

Use a 400/5

$$\text{At 125\% plug setting I} = 1.25 \times 400 = 500 \text{ A}$$

$$\text{ALF at 500 A} = 23.7 \text{ (use 30)} \quad (4.3)$$

$$\text{Max allowable primary current (ALC)} = 12000 \text{ A} \quad (4.19)$$

The most suitable CT to be used should be a 10P30 15 VA 400/5 CT.

12.3.2 Fault Calculations

$$Z_{\text{source}} = 0.221 \text{ pu} \quad (4.5)$$

$$Z_{\text{base}} = 4.84 \text{ } \Omega \quad (4.8)$$

$$Z_{\text{act line}} = R + jX_L$$

$$0.462 + j0.7558$$

$$0.885 \angle 58.65^\circ \Omega$$

$$Z_{22kVline} = 0.183 \text{ pu} \quad (4.7)$$

$$Z_{act \text{ cable}} = R + jX_L$$

$$1.38 + j0.372$$

$$1.429 \angle 0.26^\circ \Omega$$

$$Z_{22kVline} = 0.295 \text{ pu} \quad (4.7)$$

$$Z_{fault} = Z_{source} + Z_{22kVcable} + Z_{22kVline}$$

$$= 0.221 + (0.295 \times 2)972 + 0.183$$

$$= 0.994 \text{ pu}$$

$$I_{fault \text{ pu}} = \frac{1}{0.994}$$

$$= 1.006 \text{ pu}$$

$$I_{b22} = 2.624 \text{ kA} \quad (4.9)$$

$$I_{fault} = I_{b22} \times I_{fault \text{ pu}}$$

$$= 2.624 \times 1.006$$

$$= 2638 \text{ A}$$

(Digsilent simulation confirmed fault level of 2749 A – Annexure 4D)

12.3.3 Relay Settings

$$I_{fault \text{ max}} = 2749 \text{ A (maximum most downstream fault Current- Annexure 4D)}$$

$$I_{fault \text{ min}} = 2290 \text{ A (minimum most downstream fault current- Annexure 4F)}$$

$$CT \text{ ratio} = 300:1$$

$$I_{\max} = 262.43 \text{ A} \quad (4.1)$$

$$\text{Plug Setting (PS)} = 87.48\% \quad (4.11)$$

Use a plug setting of 100%

$$\text{PSM (M) at max fault} = 9.16 \quad (4.12)$$

$$t \text{ at TM} = 1 = 3.09 \text{ sec} \quad (4.13)$$

$$\begin{aligned} \text{Relay operating time} &= (3.09 \times 0.01) + 0.4 \\ &= 0.43 \text{ sec} \end{aligned}$$

$$\text{TMS} = 0.14 \quad (4.14)$$

Use 0.1 minimum

$$\text{PSM (P) at min fault} = 7.63 \quad (4.12)$$

$$t \text{ at TM} = 1 = 3.38 \text{ sec} \quad (4.13)$$

$$\begin{aligned} \text{Relay operating time} &= (3.38 \times 0.01) + 0.4 \\ &= 0.43 \text{ sec} \end{aligned}$$

$$\text{TMS} = 0.13 \quad (4.14)$$

Use 0.1 minimum

The standard in the NMBM power system is to set the earth fault plug setting at 20% and the TMS at 0.1 (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

The SEF must detect low-level earth faults. The SEF setting will therefore be the greater of 5 amps or 3% of the CT primary rating (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3), therefore use 3% TMS = 10 sec.

12.3.4 Calculating the Fuse Size of the Transformer

The following fuses should be installed at the beginning of the lateral lines using Case studies general information, provided they can grade with other equipment. This was calculated in Chapter 8.2.3. Install 10K fuses at KKG 35, 49, 49A, 50, 51, 52, 53A, 53/8, 53/12, 53/21, 53/32/7, 53/42, 53/46, 53/46/16, 53/46/22, 53/46/24, 53/46/33, 53/46/42/7, 54, 55, 56, 57, 61, 63 and 65

Refer to KKG 53/2

Total load at KKG 53/2 = 76.11 A (4.1)

Inrush current = 760.1 A

Permissible overload (20%) = 91.33 A

Use a 65K fuse, which is capable of carrying a continuous current of 95 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5 a 65K can grade with a 10K, 15K, 25K and a 40K fuse at a fault current of 2200 A. This fuse can sustain the inrush current based on Table 8.2.

Refer to KKG 53/32

Total load at KKG 53/32 = 49.86 A (4.1)

Inrush current = 498.6 A

Permissible overload (20%) = 59.83 A

Use a 40K fuse, which is capable of carrying a continuous current of 60 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5 a 40K fuse can grade with a 10K and 15K fuses at a fault current of 1340 A and with a 25K at 660 A. This fuse can sustain the inrush current based on Table 8.2.

Refer to KKG 53/32 towards left

Total load at KKG 53/32 = 10.5 A (4.1)

Inrush current = 105 A

Permissible overload (20%) = 12.6 A

Use a 10K fuse, which is capable of carrying a continuous current of 15 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.2 a 10K fuse cannot grade with a 10K fuse. This fuse can sustain the inrush current based on Table 8.2.

Refer to KKG 53/46/13 towards left

Total load at KKG 53/46/13 = 26.24 A (4.1)

Inrush current = 262.4 A

Permissible overload (20%) = 31.49 A

Use a 25K fuse, which is capable of carrying a continuous current of 38 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5, a 25K can grade with a 10K fuse at a fault current of 840 A. This fuse can sustain the inrush current based on Table 8.2.

Refer to KKG 60

Install at beginning of the lateral line supplying transformers A0078 and A1316 install 10K fuses.

Total load at KKG 60 = 0.66 A (4.1)

Inrush current = 6.6 A

Permissible overload (20%) = 0.79 A

Use a 10K fuse, which is capable of carrying a continuous current of 15 A and the inrush current. Tables 8.2, 8.3 and PEE Code of Practice were all consulted.

According to Table 8.5, a 10K cannot grade with a 10K fuse. The next fuse that can grade with a 10K fuse is a 15K at a fault current of 300 A. This fuse can sustain the inrush current based on Table 8.2.

12.3.5 Auto-Recloser

The KKG 22kV feeder is approximately 15 km long. The first section of the feeder is 7 kilometres of 150 mm² copper cable which terminates on the first H-pole. A lateral ABC line is connected to the main line, which supplies smallholdings and low-cost houses.

At the main substation, a Reyrolle A OCB is installed with over current, earth fault and auto-reclose functions. The CDG protection equipment is very old and the auto-reclose relay was not functioning. It is also not normal practice to install an ARC on a cable network. In this case study, the network consists of bare conductors, underground cable and ABC. An ARC should be installed at the first pole (KKG 1) supplying the overhead line. This ARC must grade with the upstream OCB and the downstream fuses. The Reyrolle A OCB is very old and cannot perform auto-reclose operations; therefore auto-reclose operations were disabled on the new ABB REF 610. If this is accepted, then section 2.9 of PEE Code of Practice Number 6.1 will apply, which states *“ARC’s with only fuses downstream are to be set two fast and two delayed trips, in order to ensure the rupturing of fuses on faulty section.”*

12.3.6 Sectionalisers

The only place to install a sectionaliser on this power system is at KKG 53, but the KKG 53 lateral line is constructed in ABC, which is treated as cable, so a sectionaliser would not be recommended. Also the cost of a sectionaliser is R 95 000.00 and the cost of expulsion fuses is R 15 000.00 each, therefore the sectionaliser is too expensive. Currently an on-load airbrake switch is installed at KKG 53, which assists with sectionalising under fault conditions.

12.3.7 Earth Fault Protection

Since most faults on overhead lines (90%) are earth faults, it is imperative that earth fault protections is used. The NMBM on 22kV rural lines use earth fault, overcurrent and sensitive earth fault protection as main and back up protection in an IDMT relay (NMBM Protection Guidelines).

On the KKG 22kV overhead line the ABB Ref 610 relay earth fault settings follow:

Plug setting: 30%

TMS: 0.3

Compare this to the NMBM policy which states the following:

Plug setting: 20%

TMS: 0.1

This deviation is not critical, but in terms of the construction of the line, the geographical area the line supplies, and the number of faults recorded, a TMS of 0.1 is a better option.

12.3.8 Sensitive Earth Fault Protection

The SEF relay has been programmed at a plug setting of 5% and a TMS of 10 s. The SEF must be set to detect low earth faults. The SEF setting must be the greater of 5 amps or 3% of the CT primary rating and the TMS = 10 s (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

Live conductors were found lying on the ground and the earth fault current was too low to be detected by the earth fault relay. The ground is also very dry and many trees are found in this area, thus it is likely that the earth fault does not sense this. SEF is a good option for the KKG overhead line.

On the KKG 22kV power network the ABB relay the SEF settings follow:

Plug setting: 5%

TMS: 10 s

3% of the CT primary current equals to 3 A. 5% of the CT primary current equals to 5 A. 5% and 10 s are within the NMBM policy.

12.3.9 Surge Arrestors

According to Dugan et al (2003) lightning is one of the main causes of power outages on overhead lines. Many of the unknown power outages and voltage dips could be attributed to lightning activity along the power line. If flashovers can be reduced, fewer power quality problems would arise. In Terms of the investigations not many surge arrestors were installed. The current policy states that surge arrestors should be installed on the transformer pole or at the beginning of the lateral line.

Lakervi and Holmes (2003) and Dugan et al (2003) state that surge arrestors must be allocated closely to the equipment they protect. They should be installed on every second or third pole. This will reduce the number of voltage dips and power outages, and ultimately, the number of unknown power quality events. This is an expensive method to ensure security of supply, but this will ultimately reduce the power quality problems and unknown power outages.

12.4 DIGSILENT POWER FACTORY

Refer to KKG 53/2

According to Annexure 4G, a 65K fuse can grade with 10K, 15K, 25K and a 40K fuse, but the 40K and 65K fuses cannot grade with the relay. These fuses cannot protect the transformer, but they protect the conductor well against fault current. The clearing time between the fuse and the relay is approximately 0.4 s (Annexure 4H). Only 30K fuses and lower can grade with the relay (Annexure 4I). Installing a 30K at the beginning (KKG 53/2) of the lateral line will compromise the maximum current capabilities of the line, reducing it from 95 A to 65 A. Reducing the 65K fuse to 30K will mean that the 40K fuse at KKG 53/32 has to be reduced to 25K and the 25K fuse at 53/46/13 to 20K. This will also allow a grading margin of 0.413 s (Annexure 4I).

KKG 53 Analysis

Refer to Annexure 4J.

The fuses at 53/46/16, 53/46/13, 53/2 and the relay were graded. A fault was created on high voltage winding of the transformer. The fault was cleared by the relay at 0.422 s. This proves that the selection of the fuses was correct in terms

of grading, but in terms of loading the fuse might blow (Refer to the protection calculations above).

KKG 60

Install a 15K fuse at the beginning of the lateral line and a 10K fuse on the high voltage winding of the second transformer as depicted in Annexure 4K. This confirms that the relay can grade with the 15K fuse at a grading margin of 0.394 s and the 15K fuse can grade with the 10K fuse.

12.5 SCADA

According to Lakervi and Holmes (2003) a SCADA system improves the reliability of the power system. This will reduce outage time and cut losses to the customers connected to the network.

At Kragga Kamma 22kV substation, full SCADA operation is available through the ABB master station. The communication medium used is pilot wires. The NMBM is in the process of installing a fibre optic network connecting all the major substations.

The SCADA system assists in control, monitoring and viewing, thus reducing outage time, increasing response time and allowing opportunities for improved power system optimisation.

12.6 MAINTENANCE AND MANPOWER

The power system equipment, namely, OCB, protection n relays are old and the technology is outdated. This means that these equipment needs more servicing and calibration. No maintenance records could be found. According to Gill (1997), maintenance must be controlled by management and performed in accordance with a plan or program by a dedicated team. The NMBM does not have the necessary manpower to perform preventative maintenance. This is the cause of many outages that could have been avoided if proper planned

maintenance was done. The run-to-fail practice of the NMBM is costing the customers because extended outages lead to lost of production and impact negatively on industry.

12.7 WEATHER CONDITIONS

Dugan et al (2003), comment that weather conditions are the causes of major power outages, with lightning being very common. This is supported by data in Annexure 4B.

From the analysis of the faults it is apparent that 93% of all the outages in KKG are caused by adverse weather conditions. Table 8.1 reveals that high winds cause many outages. Bollen (2002) confirmed a figure of 32%. Weather impacts on power system reliability affecting outages, outage durations, reliability indices and power quality. Power system reliability measures should be integrated in the design of power systems. Routine planned maintenance is critical on rural bare conductor lines, namely, vegetation control, conductor tensioning, routine inspections of the equipment et cetera. This will reduce outages drastically.

12.8 NRS DATA ANALYSIS

The NRS spreadsheet was designed to provide statistical data for the utility and at the same time produce a report for the NER. It provides valuable information on outages, equipment failures, causes of outages, restoration time, planned and unplanned interruptions et cetera. The statistics could be used to evaluate the performance of the network.

The historical data available at the time of the investigation was captured onto the NRS spreadsheet. It revealed that the KKG 22kV overhead line slightly under-performed in terms of restoration times (Refer to Annexure 4L). It is a requirement that 30% of the supply must be restored in 1.5 hours, 60% in 3.5 hours, 90% in 7.5 hours and 100% in 24 hours. The network complies in the

30% and 60% categories, but in the 90% category it is slightly below the NER standard. The most critical stage of any outage is the first two hours. Restoration of supply usually takes more than 2 hours.

12.9 FINDINGS

The findings based on the evaluation in terms of the criteria described in the literature review:

- The Reyrolle A OCB is old and outdated.
- The KKG overhead line is exposed to weather conditions, namely, storm, rain, strong wind and lightning.
- The ARC is not operational and the relay has been burnt out.
- The CDG protection relay provides overcurrent and earth fault protection and does not have SEF facility.
- The protection relay and fuses does not grade properly.
- The calculated reliability data below, does not comply with the standard:
 - SAIDI = 979 min/yr
 - SAIFI = 5 int/yr
 - CAIDI = 195.8 min/yr
- The KKG overhead line meets the requirements in term of system adequacy as the conductors can sustain the load requirement.
- The KKG overhead line does not comply in term of system security as the overhead line cannot sustain severe disturbances.
- The KKG overhead line does not comply in terms of S and T voltage dips categories.
- The harmonic, flickering and voltage regulation measurements are within the parameters of the standard.
- The calculated specifications for the CT's are 10P30 15 VA, 400/5.
- The calculated fault level is 2.6 kA and the Digsilent simulation is 2.7 kA.
- The relay settings are calculated as follows:
 - Plug setting = 100%
 - TMS = 0.1

- The sensitive earth fault settings are:
 - Plug setting = 5%
 - TMS = 10 s
- The earth fault settings are:
 - Plug setting = 30%
 - TMS = 0.3
- Lateral lines KKG 13, 40, 50, 51, 53, 53A, 55, 56, 57, 60, 60A, 61, 63 and 65 are not protected with expulsion fuses.
- Many pole mounted transformers are not protected with expulsion fuses.
- SCADA supervisory system is installed at the Kragga Kamma and Greenbushes substations.
- The Reyrolle A OCB is not compatible for SCADA.
- No maintenance records are available for the overhead line.
- The effect of no maintenance being done increases outage durations.
- The shortage of manpower hampers maintenance programs.
- Adverse weather conditions have a major impact on the KKG overhead line. 48% of all outages are directly linked to adverse weather conditions.
- Installation of a sectionaliser is not financially viable.
- Bird and animal life is prevalent along KKG overhead line.
- Not many surge arrestors were found on the KKG overhead line.
- The KKG overhead line does not comply with the 90% NRS categories.

12.10 RECOMMENDATIONS

To improve power system reliability the following points are recommended:

- Replace old/outdated relays with ABB Ref 610 relays (some have already been implemented);
- Program ABB Ref 610 for overcurrent and earth fault only. SEF and ARC facilities not to be used as the first section of KKG power network is underground cable;
- Install ARC on KKG 1 and grade with OCB and downstream fuses;
- Replace outdated OCB's to be compatible for SCADA supervisory system;

- Design power networks to withstand adverse weather conditions;
- Reduce faults and voltage dips by providing dip-proofing equipment on the customer-side and installing animal and bird protection devices;
- Maintain power system equipment as per maintenance schedules, namely, do vegetation control, routine inspections and tensioning of conductors;
- Replace CT with 10P30 15V A; CT Ratio = 400/5;
- Fuses should be installed as per the Protection and Digsilent sub-headings as follows:
 - KKG 13 – Install 10K fuse
 - KKG 35 – Install 10K fuse
 - KKG 40 – Install 10K fuse
 - KKG 45 – Install 10K fuse
 - KKG 49 - Install 10K fuse
 - KKG 49A - Install 10K fuse
 - KKG 50 - Install 10K fuse
 - KKG 51 - Install 10K fuse
 - KKG 52 - Install 10K fuse
 - KKG 53A - Install 10K fuse
 - KKG 53/2 - Install 30K fuse
 - KKG 53/32 - Install 25K fuse
 - KKG 53/46/13 - Install 20K fuse
 - KKG 53/8 - Install 10K fuse
 - KKG 53/12 - Install 10K fuse
 - KKG 53/21 - Install 10K fuse
 - KKG 53/32/7 - Install 10K fuse
 - KKG 53/42 - Install 10K fuse
 - KKG 53/46 - Install 15K fuse
 - KKG 53/46/16 - Install 10K fuse
 - KKG 53/46/22 - Install 10K fuse
 - KKG 53/46/24 - Install 10K fuse
 - KKG 53/46/33 - Install 10K fuse
 - KKG 53/46/42/7 - Install 10K fuse

- KKG 54 - Install 10K fuse
- KKG 55 - Install 10K fuse
- KKG 56 - Install 10K fuse
- KKG 57 - Install 10K fuse
- KKG 60 - Install 15K fuse
- KKG 61 - Install 10K fuse
- KKG 62 – Install 10K fuse
- KKG 63 - Install 10K fuse
- KKG 65 - Install 10K fuse;
- The manpower and skills shortages should be addressed. More staff should be trained and employed;
- More surge arrestors should be installed on every second or third pole, and
- The relay settings are calculated as follows:
 - Plug setting = 100%
 - TMS = 0.1
- The earth fault settings are:
 - Plug setting = 20%
 - TMS = 0.1

CHAPTER 13: ANALYSIS OF FITCHES CORNER ROCKLAND FEEDER (FCR)

13.1 POWER SYSTEM RELIABILITY

The Rockland 22kV feeder is not reliable, in terms of the outage duration and the number of power quality events. 28 outages were recorded over 5 years. This equates to an average of 5,6 outages per year. The average outage duration is calculated at 510.16 hours per year, which adds to approximately 42.5 hours per month. That is approximately 1.4 hours per day. The cost of the outages in terms of power not delivered is calculated at 3.84 cents per kW.

In terms of system adequacy, the system meets the minimum requirements, namely, the current capacity of conductors can sustain the load requirement. The 2005 load test report indicates that the maximum loading recorded was 25 A. If a load growth of 20% is allowed, this equates to 30 A, whereas the conductor can be loaded to 262 A. The structures are in good condition and the equipment is reasonably new. If preventative maintenance is done, the power system reliability can improve. In terms of system security, the power system fails. The protection equipment is not reliable as the ARC on investigation was switched off and there is no alternative power supply to the system.

Factors influencing the power system, are:

- The power system is a radial system and there is no possibility of an alternative supply when an outage occurs.
- Annexure 5B reveals that at least ten of the twenty-eight outages can be directly linked to adverse weather conditions.
- The duration of the outages are not acceptable in terms of the calculated average outage time.
- The failure rate will decrease if maintenance programs are implemented.

Calculating the power system average outage time

$$\begin{aligned} U_s &= \lambda s r s & (2.1) \\ &= 28 \times 94.5 \\ &= 2646/5 \text{ yrs} \\ &= 529.2 \text{ hrs/yr} \end{aligned}$$

Calculating the average outage cost

$$\begin{aligned} P &= 860.8 \text{ kW} & (4.15) \\ \text{Cost per kW} &= 0.363 \text{ (Calculated over 5 years)} \end{aligned}$$

$$\begin{aligned} \text{Outage cost} &= \frac{C_i(d)}{L_i} & (2.5) \\ &= \frac{0.363 \times 94.5}{860.8} \\ &= R 0.0399 \text{ per kW} \\ &= 3.99 \text{ cents/kW} \end{aligned}$$

Calculating Reliability Indices

$$\text{Calculated SAIDI} = 1133.4 \text{ min/yr} \quad (2.2)$$

$$\text{Calculated SAIFI} = 5.6 \text{ int/yr} \quad (2.3)$$

$$\text{Calculated CAIDI} = 202.4 \text{ min/yr} \quad (2.4)$$

The calculated reliability data does not comply with the standard identified by Burke (1994) in Chapter 8, Table 8.1. This means that FCR power system under-performed for the period the data was collected.

13.2 POWER QUALITY

13.2.1 Voltage Dips

The same power quality instrument used to measure power quality events for the FBH network is used to measure the power quality events on the FCR

network. There is only one voltage transformer at the source substation, therefore the voltage dips will be exactly the same. Only two of the recorded voltage dips are directly linked to the FCR feeder.

The FCR power network is predominantly overhead line; the majority of faults thus are transient faults, which could be cleared by auto-reclosers. The expulsion fuses should clear permanent faults on the lateral lines. However, because the ARC setting was set to one instantaneous operation and lockout, the expulsion fuses could not clear permanent faults on the lateral lines. In rural power systems, it is sometimes very complicated to identify faults. This impacts on the reliability indices and outage times.

The Vectograph voltage dip data recorded over twelve months are summarised in Table 13.1 below.

Table 13.1 – Voltage Dips – Fitches Corner Substation - Jan 08 to Dec 08

	S	T	X1	X2	Y	Z1	Z2	% Not avail
Jan 08	3	0	3	0	24	1	0	13,3
Feb 08	5	0	19	2	40	2	4	6,6
Mar 08	1	0	2	1	6	2	0	92
Apr 08	1	6	1	2	21	3	1	4
May 08	2	0	2	0	17	3	0	0,4
June 08	0	0	1	0	10	0	0	45,2
July 08	3	1	1	1	18	0	0	0,6
Aug 08	3	1	7	1	14	0	0	66,8
Sep 08	2	5	1	1	22	1	0	0,5
OCT 08	0	0	0	0	3	0	0	68,0
Nov 08	6	0	3	0	37	1	5	0,7
Dec 08	4	2	3	5	29	1	0	80,6
Total	30	15	43	13	241	14	10	

From the Table, it can be concluded that Y-dips are the problematic ones. The magnitude of these dips is shallow and the duration is normally no longer than approximately 100 ms. Many of these dips are caused by neighbouring networks, therefore they are regarded as insignificant. The customers are responsible for protecting their equipment against Y-dips. No dip improvement

equipment has been installed on the customer equipment. If Table 13.1 is compared to Table 3.1 (Chapter 3.2.1), it is obvious that improvement is desired.

Many factors could influence the voltage dips, namely, irregular maintenance, operation of protection devices, protection against bird and animal life, adverse weather conditions and the absence of surge arrestors.

13.2.2 Harmonics

The recorded data was retrieved from the power quality instrument and compared to the international benchmark of 5% identified by Burke (1994) and the NRS 048-2:2003, which allows a total harmonic distortion of not more than 8%. According to the assessment no signs of harmonics disorders could be identified. Power quality data recorded indicated that the harmonics measured on this power system are within the parameters of the NRS 048-2:2003.

13.2.3 Flickering

The recorded data was retrieved from the power quality instrument and compared to the benchmark between 0.8% and 1.25% as per NRS 048-2:2001. According to the assessment no signs of flickering could be identified. Power quality data recorded indicated that the flickering measured on this power system is within the parameters of the NRS 048-2:2001.

13.2.4 Voltage Regulation

The recorded data was retrieved from the power quality instrument and compared to the benchmark of $\pm 5\%$ for power systems above 500 V as per NRS 048-2:2001. According to the assessment no signs of voltage regulation irregularities could be determined. Power quality data recorded indicates that the voltage regulation measured on FCR power system is within the parameters of the NRS 048-2:2003.

13.3 POWER SYSTEM PROTECTION

13.3.1 Current Transformers

Although this is a relatively new power system, it is essential to check the current transformers. Current transformers need to stay accurate because they sustain high fault currents during fault conditions. If the current transformer is inaccurate, the protection equipment will operate incorrectly.

Calculating ALF

Current rating of overhead line	=	262 A; use 300 A	
Load current	=	30 A; use 100A	
I_{FL}	=	262 A; use 300 A	(4.1)
CT Ratio	=	300/1	

Available tapings on CT are 50% to 200%

At 50% plug setting I	=	0.5×300	=	150 A	
At 100% plug setting I	=	1×300	=	300 A	
At 125% plug setting I	=	1.25×300	=	375 A	
At 150% plug setting I	=	1.5×300	=	450 A	
At 200% plug setting I	=	2×300	=	600 A	
I_{fault}	=	2151 A			(4.2)

(Digsilent simulation confirmed fault level of 2167 – Annexure 5C)

ALF at 150 A	=	14.3	(4.3)
ALF at 300 A	=	7.2	(4.3)
ALF at 375 A	=	5.7	(4.3)
ALF at 450 A	=	4.8	(4.3)
ALF at 600 A	=	3.6	(4.3)

Twice the full load current of the system is approximately 60 A. The minimum plug setting must be used, which is 50%. The ALF to be used is 14.3 (use 15). This allows for load growth. Proper grading can still be achieved as the

maximum primary current of the CT's is 300 A and 50% is 150 A. The class and VA rating of the CT's installed are not available.

The overhead line can carry approximately 262 A, and the full load current of the transformer is 262 A. This transformer not only supplies this feeder but also another 22 kV feeder and the 6.6 kV network. It is highly unlikely this feeder will be loaded to its full capacity.

Determining the knee point voltage

$$\begin{aligned} \text{VA rating} &= 10 \text{ VA} \\ \text{Impedance of Burden} &= 10 \, \Omega \end{aligned} \quad (33)$$

$$\begin{aligned} \text{Assume CT secondary resistance} &= 0.1 \, \Omega \\ \text{Total secondary impedance} &= 10.1 \, \Omega \end{aligned} \quad (34)$$

$$\begin{aligned} \text{ALF (Using most downstream fault of 1417 A - Annexure 5D)} \\ &= 4.7 \text{ use } 5 \end{aligned} \quad (4.3)$$

$$\text{Emf at secondary at ALF (5)} = 50.5 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (10)} = 101 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (15)} = 151.5 \text{ V} \quad (4.18)$$

$$\text{Emf at secondary at ALF (20)} = 202 \text{ V} \quad (4.18)$$

According to Annexure 5E an ALF of 15 is approximately correct.

Assuming the ALF is 10 and the VA rating of the CT is 10 VA. This results in an emf of 101 V, which is below the values of Annexure 5E. If however an ALF of 15 is used, the emf increases to 151.5 V. This is within the values of Annexure 5E. Prév  (2006) states that if the ALF is large, the CT is less likely to become saturated. Assuming the ALF is 15 than the is within Pr v 's parameters.

The class 10P CT is perfect for this application. Pr v  (2006) states that 10P is suitable for overcurrent protection, which is the case in this instance.

$$S = 10.1 \text{ VA} \quad (4.4)$$

$$\text{Max allowable primary current (ALC)} = 4500 \text{ A} \quad (4.19)$$

The maximum allowable primary current of 4500 A exceeds the maximum fault current of 1407 A as simulated on Digsilent without the transformer.

Table 4.2 (Chapter 4.3) a 10P CT allows a 10% error. When compared with the calculated knee point voltage, the test is within the parameters.

A maintenance test was arranged to verify the accuracy of the CT's in terms of primary injection and insulation resistance. The primary injection test results are as follows:

Note: primary injected current is 100A

Core 1: 300/1	Red	White	Blue	Neutral
Phase-Neutral	331 mA	0 mA	0 Ma	329 mA
Red-White	328 mA	328 mA	0 mA	0 mA
Red-Blue	327 mA	0 mA	327 mA	0 mA

Core 2: 300/1	Red	White	Blue	Neutral
Phase-Neutral	330 mA	0 mA	0 mA	330 mA
Red-White	330 mA	330 mA	0 mA	0 mA
Red-Blue	329 mA	0 mA	328 mA	0 mA

The results compared to that of Table 4.2 (Chapter 4.3), indicate that the CT passed the test. From all the above it is evident that the most suitable CT to be used should be a 10P15 10 VA.

13.3.2 Fault Calculations

$$Z_{\text{source}} = 1.22 \text{ pu} \quad (4.5)$$

$$Z_{10\text{MVAtrf}} = 0.972 \quad (4.6)$$

$$Z_{\text{base}} = 4.84 \, \Omega \quad (4.8)$$

$$Z_{\text{act}} = R + jxL$$

$$0.462 + j0.7558$$

$$0.885 \angle 58.65^\circ \Omega$$

$$Z_{22kVline} = 0.183 \text{ pu} \quad (4.7)$$

Fault current at 22 kV system:

$$\begin{aligned} Z_{\text{fault}} &= Z_{\text{source}} + Z_{10MVA} + Z_{22kVline} \\ &= 1.22 + 0.972 + 0.183 \\ &= 2.375 \text{ pu} \end{aligned}$$

$$\begin{aligned} I_{\text{fault pu}} &= \frac{1}{2.375} \\ &= 0.421 \text{ pu} \end{aligned}$$

$$I_{b22} = 2.624 \text{ kA} \quad (4.9)$$

$$\begin{aligned} I_{\text{fault}} &= I_{b22} \times I_{\text{fault pu}} \\ &= 2.624 \times 0.421 \\ &= 1105 \text{ A} \end{aligned}$$

(Digsilent simulation confirmed fault level of 1305 A – Annexure 5F)

13.3.3 Relay Settings

$$I_{\text{fault max}} = 1407 \text{ A (maximum most downstream fault current- Annexure 5G)}$$

$$I_{\text{fault min}} = 1305 \text{ A (minimum most downstream fault current- Annexure 5F)}$$

$$CT \text{ ratio} = 300:1$$

$$I_{\text{max}} = 262.43 \text{ A} \quad (4.1)$$

$$\text{Plug Setting (PS)} = 87.48\% \quad (4.11)$$

Use a plug setting of 100%

$$\text{PSM (M) at max fault} = 4.69 \quad (4.12)$$

$$t \text{ at TM} = 1 = 4.46 \text{ sec} \quad (4.13)$$

Relay operating time	=	$(4.46 \times 0.01) + 0.4$	
	=	0.44 sec	
 TMS	=	0.099	(4.14)
		Use 0.1	
 PSM (P) at min fault	=	4.35	(4.12)
t at TM = 1	=	4.69 sec	(4.13)
 Relay operating time	=	$(4.69 \times 0.01) + 0.4$	
	=	0.45 sec	
 TMS	=	0.095	(4.14)
		Use 0.1	

The standard in the NMBM power system is to set the earth fault plug setting at 20% and the TMS at 0.1 (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

The SEF must detect low-level earth faults. The SEF setting should therefore be the greater of 5 amps or 3% of the CT primary rating (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3), therefore 3% and 10 sec TMS is recommended.

13.3.4 Calculating the Size of the Transformer and Lateral Fuses

The following fuses should be installed at the beginning of the lateral lines provided they can grade with other equipment. The fuse sizes were calculated in Chapter 8.2.3.

FCR 45 – Install 15K fuse
 FCR 58 - Install 10K fuse

FCR 70 - Install 10K fuse

FCR 72/4 - Install 20K fuse

FCR 74 - Install 25K fuse

FCR 75 - Install 10K fuse

13.3.5 Auto-Recloser

The FCR 22kV overhead line is constructed with copper conductors on wooden H-pole structures. The line is approximately 7 kilometres long. Many traces of animals, namely, monkeys and bird life were found along the line. The vegetation is relatively dense. Due to these factors, it would be advantageous to install an auto-recloser at the beginning of the line. On inspection of the site, it was found that the TJV relay does not provide auto-reclose facility. Auto-reclosing will eliminate many unnecessary trips and outages and will impact positively on power system reliability. A four shot auto-recloser should be considered (PEE Code of Practice Number 6.1). The PEE Code of Practice Number 6.1 policy should be used.

13.3.6 Sectionalisers

The cost of a sectionaliser is R 95 000.00 and the cost of expulsion fuses is R 15 000.00 each. All the lateral lines supply only one customer each, so it would not be financially viable to install sectionalisers on the FCR power system.

13.3.7 Earth Fault Protection

Since 90% of faults on overhead lines are earth faults, it is imperative that earth fault protection is used (Lakervi and Holmes, 2003). On 22kV rural lines the NMBM use earth fault, overcurrent and sensitive earth fault protection as main and back up protection in an IDMT relay (NMBM Protection Guidelines).

On the Rockland 22kV overhead line, an ARC has been installed and the settings in terms of earth fault are as follows:

Plug setting: 10%

TMS: 0.1

Compare this to the NMBM policy, which states the following:

Plug setting: 20%

TMS: 0.1

This deviation is not critical, in fact it is a better setting. Considering the construction of the line and the geographical area the line supplies, 10% would be better.

13.3.8 Sensitive Earth Fault Protection

The ARC has SEF and during the testing exercise it was found that the plug setting is 3% and the TMS is 5 s. The SEF must be set to detect low earth faults. The SEF setting must be greater than 5 A or 3% of the CT primary rating and the TMS = 10 s (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

Live conductors were found on the ground, posing danger to humans and animals. The ground is also very dry and many trees are found here. It is likely that the earth fault current is too low to be detected by the earth fault relay. SEF is therefore a good option for this line.

On the FCR 22kV overhead line, the ARC SEF settings are as follows:

Plug setting: 3%

TMS: 5 s

3% of the CT primary current equals 9 A. Therefore 3% is acceptable. 5 s is faster than 10 s. Changing the TMS to 10 s should be considered in terms of the standard.

13.3.9 Surge Arrestors

Lightning is one of the main causes of power outages on overhead lines. It is difficult to associate power outages with lightning activity (Dugan et al, 2003). This is true if the power system is situated in remote rural areas, making it

difficult for staff to locate the faults. Many unknown power outages and voltage dips in the NMBM are attributed to lightning activity along the overhead lines.

Not many surge arrestors were found on the FCR overhead line. The current policy states that surge arrestors should be installed on the transformer pole or at the beginning of the lateral line.

Lakervi and Holmes (2003) and Dugan et al (2003) suggest that surge arrestors shall be allocated closely to the equipment they protect and installed on every second or third pole. This is probably an expensive method to ensure security of supply, but it will reduce the power quality problems and unknown outages.

13.4 DIGSILENT POWER FACTORY

The FCR 22 kV overhead line was modelled on Digsilent. Fault analysis, grading and protection simulation were conducted. This was compared to the protection fault calculations. The Digsilent and Protection sub-sections should be read together.

Grading of lateral lines

FCR 45

Refer to Annexure 5H and Annexure 5I

Although a 12K fuse maintains a grading margin of 0.4 s with the relay, it does not protect the transformer. According to Annexure 5I, a 10K fuse is a better solution in terms of protecting the transformer. The grading margin is the same. A 10K fuse, according to Table 8.3, can carry a continuous current of 15 A. This is slightly less than the permissible overload of the transformer.

FCR58

Refer to Annexure 5J

The 10K fuse protects the transformer and the conductor well and maintains a grading margin of 0.4 s between the fuse and the relay.

FCR70

Refer to Annexure 5K

A 10K fuse cannot protect the transformer. The fuse will blow at a fault current of 20 A in 20 s. By then the transformer would be already damaged. The fuse protects the conductor and the system against overloads, leaving a grading margin of 0.4 s between the fuse and the relay. By reducing the size of the fuse, the protection of the transformer improves but the fault current effects and loading are compromised.

FCR72/4

Refer to Annexure 5L and Annexure 5M

A 20K fuse does not protect the transformer as recorded in Annexure 5L. When the fuse blows the transformer is already damaged. According to Annexure 5M, the 15K fuse protects the transformer and allows a grading margin between the fuse and the relay of 0.4 s. If the fuse fails to clear the fault, the transformer will be damaged before the relay operates.

FCR74

Refer to Annexure 5N and Annexure 5O

A 25K fuse does not protect the transformer as recorded in Annexure 5N. When the fuse blows the transformer is already damaged. According to Annexure 5O, the 20K fuse protects the transformer and allows a grading margin between the fuse and the relay of 0.398 s. If the fuse fails to clear the fault, the transformer will be damaged before the relay operates. The 20K fuse will be a better fuse to protect the transformer Annexure 5O.

FCR75

Refer to Annexure 5P

Although the 10K fuse grades reasonably well with the relay, it does not protect the transformer. By decreasing the fuse size, the overload margin and the grading margin will decrease marginally and the transformer could be protected depending on the size of the fuse. A possible solution to protect the transformer is to reduce the size of the fuse. The problem is that the NMBM policy states that the minimum fuse size to be used on 22kV overhead power

networks should not be lower than 10K (PEE Code of Practice Number 6.1 Protection of MV Overhead Lines, 2.3).

13.5 SCADA

The Rockland 22kV feeder, which is part of the Fitches Corner network, is one of the feeders which has SCADA facilities. This substation is situated in the remote rural areas of the NMBM. SCADA makes it possible to view the trends, current and voltage analogue readings, receive alarms and to open and close the OCB. The ARC can also be switched off or on remotely.

SCADA information is brought back to the master station via radio communication. During adverse weather conditions, and when many operations in SCADA are performed, the data tends to be delayed for a few minutes, sometimes even up to 30 minutes. This is due to the traffic that the gateway can manage. The radio communication system is also limited, as it does not comply with the OSI standards. The SCADA master station and the radio network are from different suppliers, hence the difficulties with receiving the data. SCADA staff is investigating an alternative to this problem. A solution would be to use only equipment which complies with OSI, but this will have financial implications for NMBM.

Lakervi and Holmes (2003) recommend automation to improve power system reliability and to secure constant supply. Key customers, namely, chicken farmers, and factories are supplied by the FCR overhead line. SCADA ensures identification of faults and restoration of supply to customers. This is faster and better than other customers in the rural areas. The outage durations are shorter. With more improvement in alternative communication systems, the service can improve. This can be done by installing more RTU's for rural networks.

13.6 MAINTENANCE AND MANPOWER

Maintenance and manpower are trends for the FCR line is almost the same as the FBH line. No more maintenance records could be traced other than those valid for FBH. The 10 MVA transformer was maintained in November 2003 and from the site visit it is evident that this transformer is in a bad state. The substation has two battery chargers, namely, a 30 volt and 110 volt. The 30 volt battery charger was maintained in September 2005 and the 110 volt battery charger in November 2002.

Protection maintenance should be planned in conjunction with the switchgear maintenance program. If a plant is isolated for maintenance, the protection team will on the same day perform their maintenance. This is not a good practice, because protection equipment and switchgear do not have the same maintenance intervals.

No overhead line maintenance records are available. Line inspectors would inspect the overhead line and associated equipment 3 to 4 times annually and report faulty equipment to management. A shutdown would then be arranged to repair or replace the faulty equipment. The shortcoming to this approach is that only the equipment on ground level can be inspected. Many times, the equipment on poles fails. This is what Lohmann (n.d) called detective maintenance. In order to perform this type of maintenance properly on high voltage electrical equipment, the plant must be shut down. A follow-up shut down can be arranged for maintenance, repair and replacement of equipment.

The shortage of manpower hampers maintenance programs. Maintenance programs should be performed under the supervision of management by a dedicated team in accordance with a schedule (Lohmann, n.d). This is not possible for the NMBM as it does not have the skilled labour to perform maintenance. All equipment deteriorates over time and needs to be repaired or replaced in order to provide good quality power to customers. Brown (2002) states that preventative maintenance can extend the life of equipment and

Seever (1991) states, that routine maintenance reduces the probability of failures. This will guarantee fewer power outages and will impact positively on power system reliability.

The run-to-fail practice of the NMBM is costing the customers because extended outages lead to lost of production and impact negatively on industry. This is not only a concern for NMBM, but rather a concern affecting the entire electrical industry. Annexures 5B display the lack of maintenance. By performing maintenance the outages on FCR could be reduced by 33%.

13.7 WEATHER CONDITIONS

Adverse weather conditions have a major impact on the FCR overhead line. 75% of faults were directly caused by adverse weather conditions. Power system reliability indices, outage durations and power quality performance thus suffer. Routine planned maintenance is critical in rural bare conductor lines, namely, vegetation control, conductor tensioning, routine inspections of the equipment et cetera.

13.8 NRS DATA ANALYSIS

The NRS spreadsheet provides valuable information with respect to outages, equipment failures, planned and unplanned interruptions et cetera. The statistics obtained from the spreadsheet could be used to evaluate the performance of the network and also to report to the NER.

The historical data available at the time of the investigation was captured onto the NRS spreadsheet. The FCR 22kV power network under-performed in terms of restoration times (Refer to Annexure 5Q). It is a requirement that 30% of the supply must be restored in 1.5 hours, 60% in 3.5 hours, 90% in 7.5 hours and 100% in 24 hours. The network only complies in the 90 and 100% categories. The major impact on customers is during the first two hours without

supply, therefore the 21% and 57% in the 30% and 60% categories respectively should improve.

13.9 FINDINGS

The findings based on the evaluation in terms of the criteria described in the literature review:

- The FCR overhead line is exposed to weather conditions, namely, storm, rain, wind and lightning.
- The ARC does not operate properly as it is set to 1 shot and lockout.
- The calculated reliability data below, does not comply with the standard:
 - SAIDI = 1133.4 min/yr
 - SAIFI = 5.6 int/yr
 - CAIDI = 202.4 min/yr
- The FCR overhead line meets the requirements in term of system adequacy as the conductors can sustain the load requirement.
- Only 1 voltage transformer is available at Fitches Corner substation. Therefore the Vectograph dip recording will be the same for both FCR and FBH.
- The FCR overhead line under-performed in terms of voltage dips. The recorded voltage dips exceed the voltage dip category benchmarks.
- The harmonic, flickering and voltage regulation measurements are within the parameters of the standard.
- The class and VA rating of the CT's are not available.
- The 10 MVA transformer and the overhead line conductor are capable of carrying the load.
- The calculated specifications for the CT's are 10P15 10 VA.
- The calculated fault level is 1.1 kA and the Digsilent simulation is 1.3 kA.
- The relay settings are calculated as follows:
 - Plug setting = 100%
 - TMS = 0.1
- The sensitive earth fault settings are:

- Plug setting = 3%
- TMS = 5 s
- The earth fault settings are:
 - Plug setting = 10%
 - TMS = 0.1
- All the lateral lines are protected with expulsion fuses, but the sizes are incorrect.
- Installation of a sectionaliser is not financially viable.
- Bird and animal life is prevalent along FCR overhead line.
- Not many surge arrestors were found on the FCR overhead line.
- Relay and fuses does not grade properly.
- SCADA supervisory system is functional on the FCR overhead line, but during adverse weather conditions the data is delayed.
- No maintenance records are available.
- The effect of no maintenance being done increases outage durations.
- The shortage of manpower hampers maintenance programs.
- Adverse weather conditions have a major impact on the FCR overhead line.
- The FCR overhead line does not comply with the 30% and 60% NRS categories.

13.10 RECOMMENDATIONS

To improve power system reliability the following points are recommended:

- Improve maintenance initiatives, namely, inspection, replacement of equipment, servicing of equipment, tensioning of conductors, doing vegetation control and installing animal and bird guards;
- Reprogram ARC to 4 shots (1 instantaneous and 3 delayed trips);
- More surge arrestors should be installed on every second or third pole.
- The manpower and skills shortages should be addressed. This can be done by developing the skills of internal staff;
- Investigate alternative communication options;

- Fuse blowing technology versus fuse saving technology should be investigated. Fuse blowing will reduce the voltage dips and fuse saving reduce the outage time;
- Replace the CT's with 10P15 10VA, ratio 300/1;
- The relay settings should be as follows:
 - Plug setting = 100%
 - TMS = 0.1;
- The sensitive earth fault settings should be as follows:
 - Plug setting = 3%
 - TMS = 10 s;
- The earth fault settings should be as follows:
 - Plug setting = 20%
 - TMS = 0.1;
- Fuses should be installed as per the Protection and Digsilent sub-headings as follows:
 - FCR 45 – Install 10K fuse
 - FCR 58 - Install 10K fuse
 - FCR 70 - Install 10K fuse
 - FCR 72/4 - Install 20K fuse
 - FCR 74 - Install 25K fuse
 - FCR 75 - Install 10K fuse, and
- In the design and planning phase of a network, the weather conditions should be taken into consideration.

CHAPTER 14

CONCLUSION

14.1 INTRODUCTION

The primary object of this dissertation was to analyse the NMBM 22kV distribution power system using the criteria below. Literature in terms of the criteria was consulted, namely:

- Power System Reliability
- Power Quality
- Power System Protection
- Digsilent Power Factory
- SCADA
- Maintenance and Manpower
- Weather Conditions
- NRS Data Analysis

Case studies were identified by determining the weak networks using the available fault data. The fault data was captured onto spreadsheets and graphs were drawn from it. 5 case studies were identified, namely, FBH, SGP, KKG, MWN and FCR. The case studies were analysed in terms of the literature review. From the results of the analysis findings, recommendations and conclusions were formulated

14.2 POWER SYSTEM RELIABILITY

The electricity industry is capital driven. As more electricity is required to maintain the growing demand and more emphasis is placed on reliability evaluation. The electricity industry is a major contributor in the economy and hence the social interest of the world. Government organisations and political

structures are becoming involved. It is due to these conditions that the need for reliability techniques, methods and concepts are being developed.

Power system reliability in this dissertation evaluates the power network in terms of system adequacy, system security, reliability calculations and reliability indices. There are many factors which affect the smooth operation of power systems, namely, overloading of cables, radial networks, weather conditions, failure of equipment, et cetera. These factors increase the duration of the outages, which impacts on the cost of power outages.

14.3 POWER QUALITY

Utilities have to deal with numerous complaints of poor power quality. Voltage dips and interruptions are the most common complaints of poor power quality. This dissertation concentrates more on voltage dips, as it is causing more problems for the industry. Harmonics, flickering, voltage swells and regulation, although covered in the dissertation does not pose a power quality problem for the NMBM power system.

The causes of voltage dips include the following:

- Faults;
- Lightning;
- Vegetation;
- Bird and animals;
- Failure of equipment;
- Reclosing and sectionalising during fault conditions;
- Motor starting, and
- Arc furnaces.

The weak networks were identified and power quality instruments installed to measure the voltage dips. The results were compared to the dip categories in the NRS documents. It is evident from the literature review and the analysis

conducted that voltage dips can be reduced if maintenance is performed regularly, bird and animal protection guards are fitted to equipment, co-ordination of protection equipment is reviewed, reclosing and sectionalizing practices are revised and more surge arrestors and fuses installed,

14.4 POWER SYSTEM PROTECTION

Power system protection covers a major section of this dissertation. If the protection equipment does not function optimally, the power system will fail in terms of power system reliability. The purpose of protection equipment is to detect the fault and to reduce the risk of damage to plant connected to the power system. It must also ensure continuity of supply to all the customers connected to the power system. Therefore it is imperative that protection equipment function properly. Many factors affect the severity of faults, namely, power system configuration, type of faults, source conditions, earthing, et cetera.

Current transformers are the most important component of a protection system. Faulty current transformers are many times the causes of power outages. It is important that current transformers remain accurate, therefore maintenance must be done regularly.

Fuses cover a major section of this dissertation because the analysis of the case studies focus primarily on overhead lines. Co-ordination of fuse with each other and relays were found incorrect. The sizes of the fuses were also incorrect and more fuses were recommended to be installed.

Fault levels must re-calculated to determine the correct setting of relays and the co-ordination of protection equipment.

It is evident from the research that protection equipment and philosophies are outdated. The incorrect fuse sizes were installed and many of the lateral lines

were not protected. Maintenance is not done regularly, thus the calibration and setting of relays were not revised.

It is important to regularly calculate the ALF of a current transformer as it will determine the maximum current the current transformer can withstand. To calculate the ALF, the ALC and fault current must be known. Therefore, these calculations must be done regularly when maintenance is performed.

14.5 DIGSILENT POWER FACTORY

Digsilent in this dissertation form part of the analysis in the case studies. The Digsilent circuits were built and the different functionalities applied, thereafter engineering decisions and recommendations were made to improve the reliability of the power network.

In studying the reliability of the power network it would be advantageous to use Digsilent to perform loadflows studies, re-calculate short-circuit calculations, connecting subsystems, open point simulations, setting up simulations, protection co-ordination calculations, reliability analysis et cetera.

Digsilent is a practical tool currently under-utilised in the NMBM. The system is only available to certain sections, therefore not all the functions of this system are utilised effectively. The use of Digsilent must be expanded to improve power system reliability in the NMBM.

14.6 SCADA

Control and monitoring of power networks become more and more important in the distribution of electricity. A MicroSCADA system was installed at the NMBM to monitor and control the transmission and certain sections of the distribution network.

The current SCADA system has limitations in terms of the ability to monitor and control only the feeder substations. The communication network also does not assist the supervisory system as it is limited in the transport data events.

SCADA is an important part of power system control and in order to provide good service to the customers our SCADA system must function well, maintained and expanded to other power networks. In the FBH and SGP case studies the networks cannot be monitored and controlled via SCADA. It is utmost important to install SCADA at these two substations.

14.7 MAINTENANCE AND MANPOWER

The purpose of preventative maintenance and testing is to identify faulty equipment and provide corrective measures. In a preventive maintenance program, potential hazards can be discovered and repaired or replaced. This will extend the life of the equipment. A well structured maintenance program should consist of routine inspection, testing, repair and service of electrical equipment under the supervision of management.

The impact of maintenance and manpower requirements were analysed and found that it impacts severely on power system reliability. Many of the maintenance plans and programs discontinued due to shortage of skills. This is a corporate issue, which needs to be addressed. Unless maintenance and shortage of skills are addressed, the power system will fail to operate within the NRS requirements, resulting in poor power system reliability.

14.8 WEATHER CONDITIONS

The impact of adverse weather conditions on power systems was investigated in this dissertation. Weather conditions impact on power and service delivery and it is the duty of the utility to increase the reliability of power systems.

Radial topology are mostly affected, therefore the design of parallel systems for highly populated and industrial areas must be encouraged.

The conductors used in all the case studies are predominantly bare overhead lines. These conductors are more vulnerable to adverse weather conditions. In designing power networks, particularly overhead lines, the impact of the weather must be taken into account.

14.9 NRS INTERRUPTION DATA ANALYSIS

The NRS Data Interruption Analysis spreadsheet can provide constructive information that could be utilized to improve power system reliability and customer services. The data captured onto the spreadsheet was used to evaluate the case studies. Combined with the other engineering techniques the spreadsheet was used as a tool to identify weak systems which reduced the many unwanted and unnecessary power interruptions.

14.10 SUMMARY

It is evident from the research that outdated equipment and technologies should be replaced with more contemporary equipment and technology. Protection equipment and philosophies are outdated. Power quality was extensively covered, because power system reliability is directly linked to power quality. Most of the power quality events were the direct result of adverse weather conditions in the NMBM. Maintenance and manpower remains a challenge for the electricity supply industry. Change in terms of maintenance and manpower is needed.

The NRS documents provide valuable benchmarks based on international standards. Although some of the equipment has been replaced during the investigation and testing phase of this project, more work will be done as the

budget is available. The SCADA supervisory system is a valuable tool to be extended to incorporate the rural lines. Digsilent is a powerful engineering tool to assist power system operators, technicians and engineers in optimising power systems. Planning plays a critical role in increasing power system reliability.

14.11 FURTHER RESEARCH

The further research possibilities are:

- The study and the effective use of surge arrestors, and
- The earthing of power system infrastructure, namely, overhead lines, sub-station earth mats etc.

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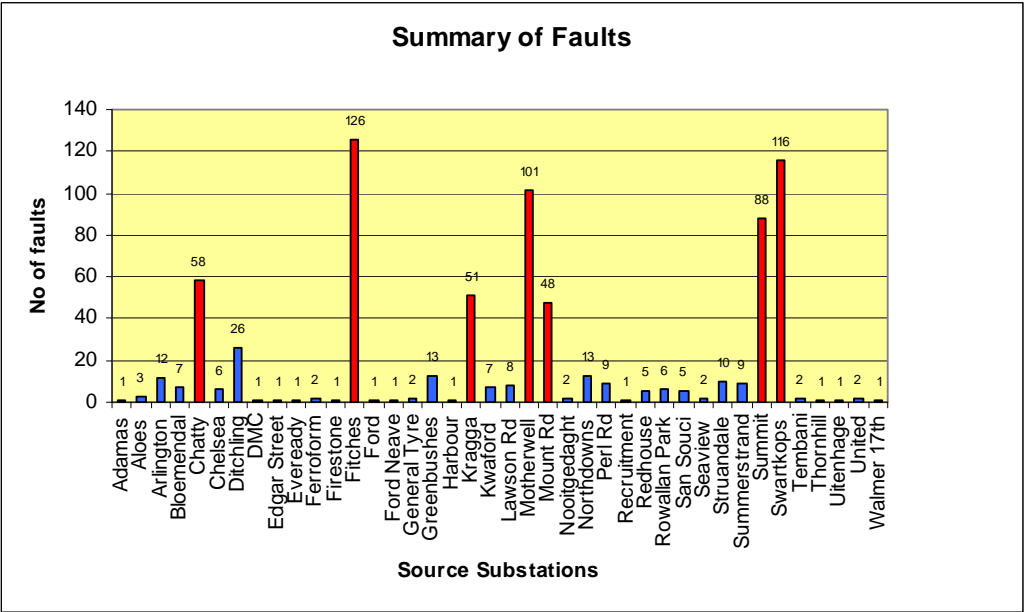
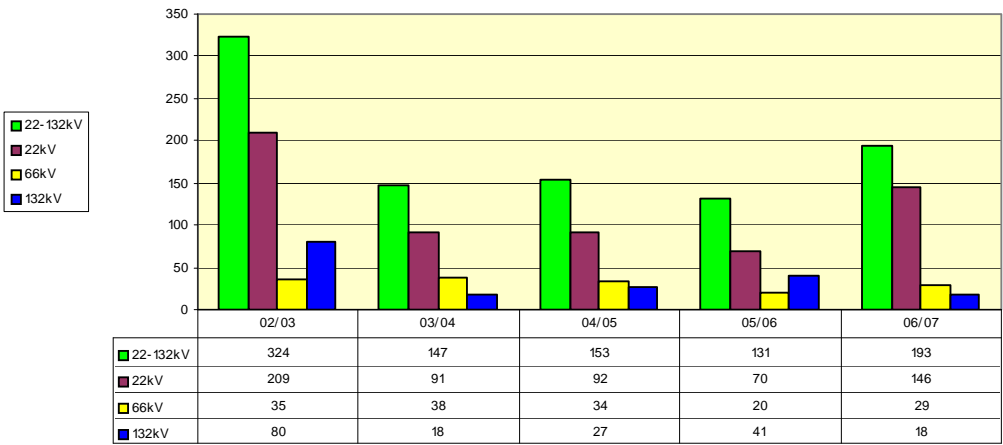
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SUMMARY 22-132KV FAULTS (02-07)



POWER SYSTEM RELIABILITY ASSESSMENT BY ANALYSING VOLTAGE DIPS ON THE BLUE HORIZON BAY 22KV OVERHEAD LINE IN THE NELSON MANDELA BAY MUNICIPALITY

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Abstract

Power system reliability problems are very difficult to solve because the power systems are complex and geographically widely distributed and influenced by numerous unexpected events. It is therefore imperative to employ the most efficient optimization methods in solving the problems relating to reliability of the power system. This paper presents a reliability analysis and study of the power interruptions resulting from severe power outages in the Nelson Mandela Bay Municipality (NMBM), South Africa and includes an overview of the important factors influencing reliability, and methods to improve the reliability. The Blue Horizon Bay 22kV overhead line, supplying a 6.6kV residential sector has been selected. It has been established that 70% of the outages, recorded at the source, originate on this feeder.

Keywords: Power System, Reliability, Security, Power Quality, Voltage Sag/Dip, Outage, Interruption

1. Introduction

Interruptions to the electrical supply network are one of the oldest and most severe power quality concerns. The demand for power has increased tremendously over the last decade as a result of increased investments in infrastructure due to industrialization trends, fast urban growth, changing lifestyles and advancements in technology. The ability to provide electricity to satisfy these factors above is influenced by the power quality the utility provides. In particular, voltage dips are the major contributor, which aggravate the provision of reliable electricity supply. Following the pace of the increasing demand, power systems have grown to immense sizes and complexities in terms of design and operating practices. The question is; how reliable is the power system to resilient unexpected outages. For this reason system security and reliability levels have become of utmost importance, especially in the present situation that calls for

efficient utilization of electricity and encourages energy conservation.

It can be safely assumed that reliability is one of the most important factors to be considered when planning and designing power systems. In order to design and plan power systems correctly, appropriate reliability information must be available to firstly, evaluate and secondly, to apply the improvements to the design based on the result of the evaluation. Over the years, power system reliability evaluation has been significantly developed using probabilistic methods. From these methods appropriate indices were determined [1].

The reliability of power systems is dependent on the reliability of the components, the configurations of the network and the capability of the network to provide an alternative power supply to the customer. In reality power networks funding is influenced not only by reliability, but the cost to fund the building of the network, losses of energy sales and maintenance. All these factors must be considered. To achieve this, adequate outage data must be available to make informed decisions. To calculate the total cost to build a reliable power network, the formulae below can be applied. The non-distributed power is directly related to the reinforcement cost as shown in (1) [5]:

$$C = \Sigma(C_i + C_l + C_m - C_o) \quad (1)$$

C_i	=	Cost of Investment
C_l	=	Cost of Losses
C_m	=	Cost of Operation and Maintenance
C_o	=	Cost of Outages
C	=	Total Cost

If the non-distributed power is reduced by W , the cost/benefit ratio can be defined as:

$$(C_i + C_l + C_m - C_o)/W \quad (2)$$

The cost/benefit saving could take into consideration the saving P (in kW) not supplied. The equation will be as follows:

$$(C_i + C_l + C_m - C_o)/(aW + bP) \quad (3)$$

a and b are coefficients dependant on the importance to customers, the load loss and time of outage.

This paper presents practical methods to increase power system reliability by optimization of the power network components. Various methods will be applied using the case study. The proposed methods are based on a combined contingency analysis and reliability evaluation scheme.

2. Reliability analysis

In principle, the reliability analysis for distribution networks is quite simple because networks are usually radially operated. Basic input data for the analysis is the failure rate of each component and the network topology. However, other information is also needed from the equipment which affects the results of the analysis e.g. interruption times and automation devices installed, which makes analysis more difficult to model.

In the radial reliability analysis, as in this case study, networks are analyzed feeder-by-feeder, zone-by-zone. A zone refers to a part of the feeder, which can be isolated by one or more switches from the rest of the network. The expected number of failures in a zone is calculated as a sum of the individual network component failures in the zone. The basic formulae to calculate or to evaluate power system reliability is as follows [2]:

Series Components

$$\lambda_s = \lambda_1 + \lambda_2 \quad (4)$$

$$\lambda_s = \text{System Outage Rate}$$

$$\lambda_1 = \text{System Outage Rate for component 1}$$

$$\lambda_2 = \text{System Outage Rate for component 2}$$

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_1 + \lambda_2} \quad (5)$$

$$r_s = \text{System Average Outage}$$

$$r_1 = \text{System Outage duration for component 1}$$

$$r_2 = \text{System Outage duration for component 2}$$

$$U_s = \lambda_s r_s \quad (6)$$

$$U_s = \text{System Average total outage time}$$

Parallel Components

$$\lambda_p = \lambda_1 \lambda_2 (r_1 + r_2) \quad (7)$$

$$\lambda_p = \text{System Outage Rate}$$

$$r_p = \frac{r_1 r_2}{r_1 + r_2} \quad (8)$$

$$r_p = \text{System Average Outage duration}$$

$$U_p = \lambda_p r_p \quad (9)$$

$$U_p = \text{System Average total outage time}$$

Reliability indices are used in terms of the NRS (National Regulatory Service) [4] to measure reliability and availability of electricity supply. The reliability indices applied in this paper are based on the following:

$$\text{SAIDI} = \text{System Average Interruption Duration Index}$$

$$\text{SAIDI} = \frac{\text{SCID}}{\text{TNC}} \quad (10)$$

$$\text{SCID} = \text{Sum of Customer Interruption Durations}$$

$$\text{TNC} = \text{Total Number of Customers}$$

$$\text{SAIFI} = \text{System Average Interruption Frequency Index}$$

$$\text{SAIFI} = \frac{\text{TNCI}}{\text{TNC}} \quad (11)$$

$$\text{TNCI} = \text{Total Number of Customer}$$

$$\begin{aligned}
& \text{Interruptions} \\
\text{TNC} &= \text{Total Number of Customers} \\
\text{CAIDI} &= \text{Customer Average Interruption} \\
& \quad \text{Duration Index} \\
\text{CAIDI} &= \frac{\text{SCID}}{\text{TNCI}} \quad (12) \\
\text{SCID} &= \text{Sum of Customer Interruption} \\
& \quad \text{Durations} \\
\text{TNCI} &= \text{Total Number of Customer} \\
& \quad \text{Interruptions} \\
\text{ASAI} &= \text{Average Service Availability Index} \\
\text{MAIFI} &= \text{Momentary Average Interruption} \\
& \quad \text{Frequency Index}
\end{aligned}$$

Reliability of a power system can be evaluated against Table 1 [2], which is used as the bases of reliability analysis evaluation in this case study.

Table 1. Customer Based Indices

SAIDI	SAIFI	CAIDI	ASAI
95.9 min/yr	1.18 int/yr	76.93 min/yr	.999375 int/yr

87 interruptions were recorded on this feeder over a five-year period. 55 of these interruptions recorded were trips at the source substation, 27 were fuse openings in conjunction with the breaker switch at the source substation and 32 were fuse openings at the lateral lines. The outage data was analyzed, reliability calculations were applied and improvements were introduced to reduce the outages in terms of duration and numbers. This information is summarized in Table 2. In comparing the information of Table 2 “Before” column with that of Table 1, it is evident that the calculated reliability results of all the indices exceed the customer based indices in Table 1. However, if the disconnecting devices operated correctly, i.e. the 27 fuse openings, without tripping the source breaker, the indices would have been improved. The technology to be utilized is the fuse blowing technology. This means that when a permanent fault occurs, the expulsion fuse will blow before the source breaker trips. Only the SAIFI result is still below the benchmark, but it reflects a 51% improvement.

Table 2. Results of Reliability Calculations

	SAIDI	SAIFI	CAIDI
Before	2773.4	11	252.13
After	20.68	5.4	3.43
T-Off	13.1	0.073	354.05

Table 3 [7] is a comparison of the reliability of different distribution configurations developed by the New York City’s Consolidated Edison. The case study is in the simple radial category. It is again evident that the results exceed the indices. However, after interventions were affected, the results improved except for the SAIFI. SAIFI will increase moderately if storm data is included and long circuits lead to more interruptions [7]. It is difficult to avoid interruptions on long radial overhead lines. By designing overhead lines, which are able to withstand adverse weather conditions with more reclosers, fuses and automated switching equipment, SAIFI will decrease [7].

It was determined that reducing the number of trips at the source by 10, the SAIFI indices improved by 20%. It is evident that network improvements and optimization are required to improve the quality of supply and the interruption index of this specific power system.

Table 3. Comparison of Different Distribution Configurations

	SAIFI Int/Yr	CAIDI Min/Int	MAIFI Mom Int/Yr
Simple Radial	0.3 to 1.3	90	5 to 10
Primary Auto-loop	0.4 to 0.7	65	10 to 15
Under-ground Residential	0.4 to 0.7	60	4 to 8
Primary Selective	0.1 to 0.5	180	4 to 8
Secondary Selective	0.1 to 0.5	180	2 to 4
Spot network	0.02 to 0.1	180	0 to 1
Grid network	0.005 to 0.02	135	0

3. Power Quality

Power is the rate of energy that is delivered and is proportional to the product of the current and the voltage. Standards are developed to control the voltage within certain limits. Any deviation in the

50Hz sinusoidal voltage waveform could cause potential power quality problems. A close relationship between the current and the voltage is evident as the current resulting from a short circuit causes the voltage to dip/sag. Current from lightning strikes cause high-impulse voltages. These high-impulse voltages lead to flashovers, and breakdown of insulation. The current generated from harmonic-producing equipment causes the voltage waveform to be distorted.

Transmission line faults and the subsequent opening of the protective devices rarely cause an interruption for any customer because of the interconnected nature of most modern-day transmission networks. These faults do however cause voltage dips. Depending on the equipment sensitivity, the device may trip, resulting in substantial monetary losses to the customer.

3.1 Voltage Dips

Over the last decade utilities had to deal with increasing numbers of complaints relating to power quality due to voltage dips and interruptions. The crucial issue is that voltage dips affect sensitive loads and the influx of digital computers and electronic control systems is at the heart of the problem. Due to these problems the NRS 048 specifications provide targets for each dip category i.e. Y, X, S, T and Z and the utility is assessed in terms of this. In table 7 [9] the compatibility levels for voltage dips are given in the form of the maximum number of voltage dips per annum for defined ranges of voltages. The NRS 048-2:2007 introduced a revised table (table 5) to categorize voltage dips according to duration and depth. Table 4 explains the dip category in terms of its duration and depth. Table 4 and table 5 must be read in conjunction to understand the dip categories. For instance according to table 4 the duration of a S-dip is between 150ms and 600ms and the depth of the dip is between 20% and 60%. Reading this in conjunction with table 5 it is apparent where it fits into the dip categorization chart and the impact it will have on the power system.

Voltage dips are geographically dependent on the different environmental conditions, which have an effect on power quality [8]. In the case study many of the voltage dips were caused by lightning, storms, wind, birds, animals, vegetation, lack of maintenance, old equipment, protection malfunctioning and outdated philosophies. etc.

Table 4. Dip Categories

Dip Category	Values of duration and depth
Y	Duration: >20ms to 3sec Depth: 30%, 20%, 15%
X1	Duration: >20ms to 150ms Depth: 30% to 40%
X2	Duration: >20ms to 150ms Depth: 40% to 60%
S	Duration: >150 ms to 600 ms Depth: 20% to 60%
T	Duration: >20ms to 600ms Depth: 60% to 100%
Z1	Duration: >600ms to 3sec Depth: 15% to 30%
Z2	Duration: >600ms to 3sec Depth: 30% to 100%

3.2 Calculating Voltage Dips

It is however important for utilities and even customers, especially industrial customers to understand the impact of voltage dips. Voltage dips can completely shut down a large industrial manufacturing plant, having tremendous financial implications to the company. Utilities on the other hand want to provide a good service and therefore it is important to both parties to understand and know the impact of voltage dips. A voltage divider model for radial power systems can be used to calculate voltage dip magnitudes [3]. The model is simplified but useful to forecast voltage dips (figure 1).

$$V_{sag} = \frac{Z_f}{Z_s + Z_f} E \quad (13)$$

Z_s	-	Source Impedance at point of coupling
Z_f	-	Impedance between pcc and fault
E	-	Voltage at source
pcc	-	point of common coupling

It is assumed that the pre-event voltage is 1 pu, thus $E = 1$. Therefore,

$$V_{sag} = \frac{Z_f}{Z_s + Z_f} \quad (14)$$

It can be deduced that V_{sag} becomes deeper for faults closer to the customer (Z_f becomes smaller) and for smaller fault levels (Z_s becomes larger).

Equation 14 can therefore be used to calculate voltage magnitudes as a function of the distance of the fault.

$$V_{sag} = \frac{zL}{Z_s + zL} \quad (15)$$

z - Impedance of feeder per unit length in km

L - Distance between fault and pcc per km

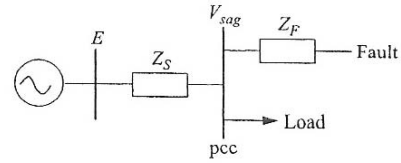


Figure 1: Voltage Divider Model

Table 5. Characterization of voltage dips according to depth and duration

1	2	3	4	5	
Range of dip depth ΔU (expressed as a percentage of declared voltage U_d)	Range of residual voltage U_r (expressed as a percentage of declared voltage U_d)	Duration T			
		$20 < t \leq 150\text{ms}$	$150 < t \leq 600\text{ms}$	$0,6 < t \leq 3\text{s}$	
$10 < \Delta U \leq 15$	$90 > U_r \geq 85$	Y			
$15 < \Delta U \leq 20$	$85 > U_r \geq 80$				
$20 < \Delta U \leq 30$	$80 > U_r \geq 70$	S		Z1	
$30 < \Delta U \leq 40$	$70 > U_r \geq 60$			X1 ^a	Z2
$40 < \Delta U \leq 60$	$60 > U_r \geq 40$			X2	
$60 < \Delta U \leq 100$	$40 > U_r \geq 0$	T			
NOTE: In the case of measurements on LV systems, it is acceptable to set the dip threshold at 0.85 pu.					
^a A relatively large number of events fall into the X1 category. However, it is recognized that dips with complex characteristics (such as phase jump, UB, and multiple phases) might have a significant effect on customers' plant, even though these might be small in magnitude. Customer might not have the means to mitigate the effects of such dips on their plant.					

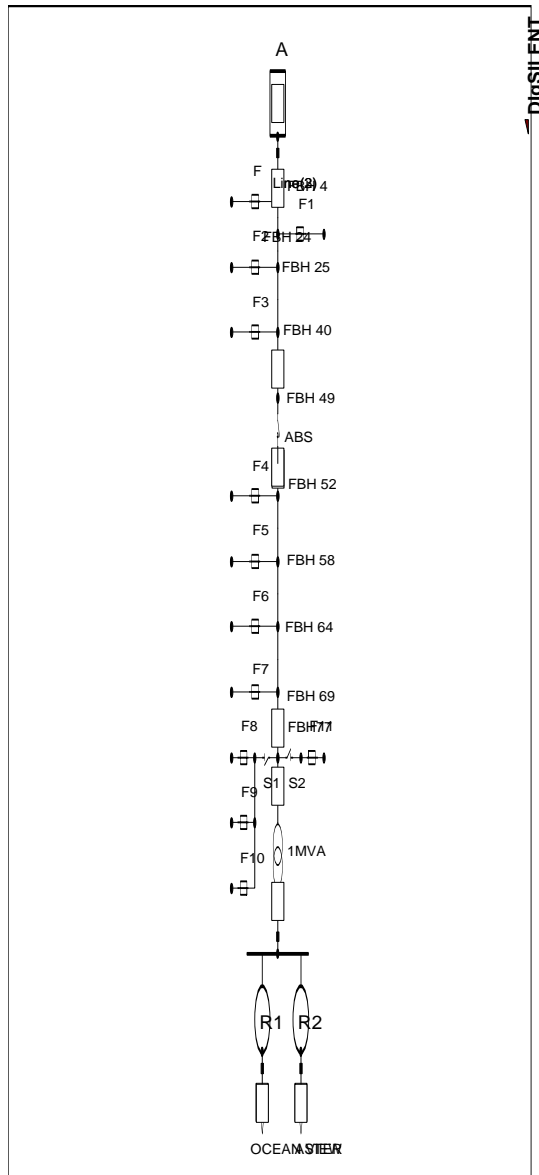
4. Analysis of case study

The case study is a combination of 22kV radial overhead line, approximately 20km supplying a 22/6.6kV, 1 MVA transformer as depicted in figure 2. 18 22kV customers, mainly farming activities are supplied from the 22kV overhead line, while the 6.6kV cable network supplies five distribution substations. The oil circuit breaker installed at the source substation was manufactured in 1952. The Micom relay provides overcurrent and earth fault protection and auto-reclosing. The transformer and the 6.6kV cable network is not protected, therefore a transformer or cable fault will cause the source

breaker 20km away to trip. The fuse technology used is the fuse saving technology, therefore the source breaker will trip before the fuse blows. Because the auto-reclose function of the source breaker is inoperative this will result in extended outage time, poor power system reliability and power quality and a negative impact on the reliability indices.

It is evident from the Vector-Graph recorder information presented in table 6 that voltage dips are a major concern. Comparing table 6 to table 7 it is obvious that the number of voltage dips in table 6 exceeds the values in table 7.

Figure 2: Line Diagram of Network



Symbol relating to figure 2

A	-	Auto-recloser at source substation
FBH	-	Fitches Corner Blue Horizon Bay
F1–F11	-	Expulsion fuse 1 to 11
R1	-	Relay in distribution sub 1
R2	-	Relay in distribution sub 2
S1	-	Sectionalizer 1
S2	-	Sectionalizer 2

Figure 3 represents an actual voltage dip recorded on 11 November 2008 on the Blue Horizon Bay feeder. From figure 3 it can be deduced that the depth of the voltage dip is 50%. In other words it is 50% below the threshold of 90%. According to the

NRS 048 the duration of a voltage dip is measured from the moment voltage decreases below 90% up to when the voltage rises above 90% of declared voltage [9]. The duration of the dip is 0.93s. The duration is measured from the time the voltage reduced below 90% to the time the voltage rises above 90%.

This voltage dip is recorded on all three phases, but the blue phase is regarded as the most severe because of the depth. The most severe dip is used to determine the category in which the dip will be classed. Using both tables 4 and 5 it is obvious that this is a Z2 voltage dip. On 11 November 2008 the weather conditions were fine, but the wind was reasonably strong. No faults were recorded on neighbouring networks. It can be safely assumed that the strong wind or faults on the customer farming activities could be the cause of this voltage dip.

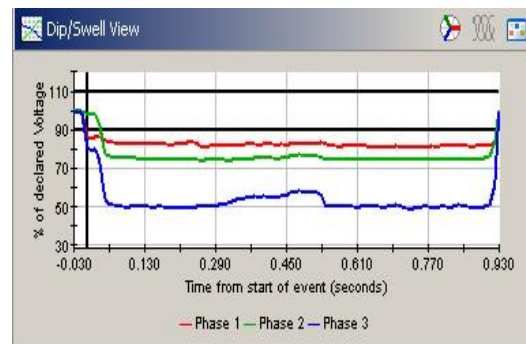


Figure 3: Actual Voltage Dip

Table 6 depicts the voltage dips over a period of twelve months. It must be noted that the last column indicates the percentage time the Vecto Graph recorder was inactive. The data was compared with the outage information for the case study area.

Table 6. Voltage Dips – Jan 08 to Dec 08

	S	T	X1	X2	Y	Z1	Z2	% Not avail
Jan	3	0	3	0	24	1	0	13.3
Feb	5	0	19	2	40	2	4	6.6
Mar	1	0	2	1	6	2	0	92
Apr	1	6	1	2	21	3	1	4
May	2	0	2	0	17	3	0	0.4
June	0	0	1	0	10	0	0	45.2
July	3	1	1	1	18	0	0	0.6
Aug	3	1	7	1	14	0	0	66.8
Sep	2	5	1	1	22	1	0	0.5
Oct	0	0	0	0	3	0	0	68.0
Nov	6	0	3	0	37	1	5	0.7
Dec	4	2	3	5	29	1	0	80.6
Tot	30	15	43	13	241	14	10	

In table 7 [9] the compatibility levels for voltage dips are given in the form of maximum number of voltage dips per annum for defined ranges of voltages.

Table 7. Characteristic values for the number of voltage dips/year

1	2	3	4	5	6	7
Network voltage range (nominal voltages)	Number of voltage dips per year					
	Dip window category					
	X1	X2	T	S	Z1	Z2
6.6kV to 44kV ext oh	13	12	10	13	11	10
6.6kV to 44kV	7	7	7	6	3	4
44kV to 220kV	13	10	5	7	4	2
220kV to 765kV	8	9	3	2	1	1

Faults on municipal equipment are also responsible for voltage dips. Approximately 70% of faults on the municipal networks occur on overhead power lines. The common causes of the faults are birds, animals, lightning and insulator failures. Voltage dips could be generated when load is transferred e.g. from the municipal grid to a standby generator to secure power to critical essential equipment (used by the farmers). Figure 4 represents the starting and shutting down of loads to generators, which could cause significant voltage dips or swells [6].

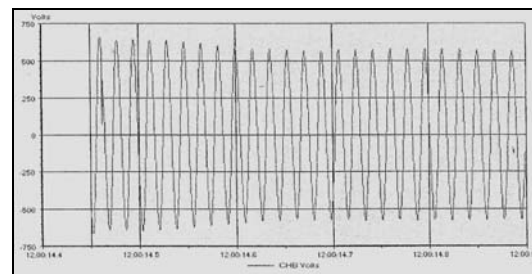


Figure 4: Voltage Dips due to generator application

In comparing the data in table 6 to that of table 7 it is clearly evident that the Blue Horizon Bay 22kV feeder line is under-performing in terms of the number of voltage dips.

As stated before birds, animal life, vegetation, wind, rain, lightning and insulator failures could cause many of these voltage dips. Evidence of these factors was discovered when inspecting the overhead line and many of the unknown voltage dips could be ascribed to these factors.

Table 8. Summary of Voltage Dips

	No of Dips	Perc
Unknown	201	55%
External Source	119	32.5%
Fitches Corner Feeder	46	12.5%
Total	366	100%

It is not always straightforward to determine if lightning was the cause of an outage or voltage dip as lightning can affect power systems through direct or indirect strikes. These strikes cause flashovers that cause short circuits.

Many of the transformer structures are fitted with surge arrestors, which will reduce the effect of voltage dips on equipment. Surge arrestors should be fitted to every second or third pole [4]. The surge arrestor would absorb the lightning strike current, which will flow along the overhead line. The amount of current the surge arrestor would absorb depends on the earth resistivity. The higher the earth resistivity, more surge arrestors are required. The magnitude of the lightning strike current determines the magnitude of the voltage dip. Ultimately if surge arrestors were fitted to every pole, the voltage dips would be significantly reduced and the reliability would increase. It is not always financially viable to install surge arrestors on all the poles. Where it had been determined that the load was highly critical, more surge arrestors should be installed.

Many of the unknown voltage dips are Y-dips. The duration of Y-dips is between 20 ms and 3 seconds and the depth is between 15% and 30%. Hence, the Y-dips are what we would term in the industry as “insignificant” and according to the NRS 048-2:2007 customers are mainly responsible for protecting their equipment against the effects of the Y-dips. Many of the Y-dips and also a significant number of X-dips might be caused by faults on neighbouring remote power networks. Only 12.5% of the voltage dips recorded on this feeder have been caused by faults on this network. The cause of the voltage dips range from adverse weather conditions due to lightning, storms and strong winds, lack of vegetation control, animal and bird life along the overhead line, protection malfunctioning and lack of maintenance. The cable network supplying approximately 1800 customers, predominantly holiday homes and retired citizens is approximately twenty years old. The number of faults recorded on the cable network is insignificant. Therefore, it is evident that the majority of the faults, which were recorded, occurred on the overhead line.

5. Conclusion and Recommendations

Faults are the main reason for voltage dips on the overhead power lines. A voltage dip may cause tripping of sensitive loads if its magnitude is below the critical voltage that equipment can sustain. It is therefore imperative to improve the power system reliability on the Blue Horizon Bay feeder by applying corrective measures as listed below. The lessons learnt from this case study could be used to reduce the impact of voltage dips on other power systems. These lessons include the following:

- Radial topology increase the outage time which impacts on reliability indices.
- Cost effective power networks are more unreliable. The use of more disconnecting devices will improve the reliability.
- Overhead power lines are more unreliable than cable network because adverse weather conditions, vegetation and animal life is one of the major causes of voltage dips.
- Improved maintenance planning and the network configuration of the power system can reduce voltage dips.
- Old outdated equipment cannot be used with contemporary technology.
- Fuse saving technology cause many voltage dips and extended outage time.

The two main strategies to improve power quality is [7]:

1. Reduce the effects of faults
2. Eliminate faults

The above can be achieved by applying the following:

- Fit animal guards where animal life is prevalent along the overhead line.
- Study the bird life along the overhead line. Determine the wingspan of the birds. Compare this with the distance between phase conductors and phase and earth conductors. If the wingspan is longer than the distance between the conductors, the spacing should be revised.
- Improve preventative maintenance initiatives, i.e. pole top, cross-arm, insulator, surge arrestor inspections, tensioning of conductors, vegetation control, switchgear and protection maintenance etc.
- Install more surge arrestors.
- Revise protection philosophies, etc.

It is therefore recommended:

- To replace the auto-recloser (A) in figure 2 at the source substation as it is faulty and very old.
- Introduce sectionalizers (S1 and S2), fuse-blowing technology (F - F11) and revise the discrimination of the protection equipment in figure 2.
- Downstream at the 6.6kV network install OCB's with relays (R1 and R2) as the primary protection for the 6.6kV distribution power system in figure 2.

- Install more surge arrestors.
- Maintenance programs should be reviewed. From the site inspections it is evident that more drastic tree maintenance and animal protection replacement programs are needed. Preventative maintenance programs works well if it is structured and well managed. This would include checking jumper clearances, replacement of old fuses and expulsion surge arrestors and damaged insulators. Cutting away and trimming of trees, and the fitting of animal guards would certainly reduce the effects of voltage dips on any power system.

Finally, voltage dips will never be completely eliminated, but it can be significantly reduced if both the customer and the supplier invest in better practices and equipment. Dip proofing equipment is available on the market. This equipment is expensive. The decision to purchase this equipment depends on how severely the customer's operations are affected and how important the supplier perceive voltage dips as a phenomenon which impacts on its power quality indices and customer service.

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APPLICATION OF EXPULSION FUSES IN POWER SYSTEMS FOR IMPROVED POWER SYSTEM RELIABILITY

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Abstract. This paper presents a comparative analysis of the effects of expulsion fuse operations in distribution systems on power quality and power system protection. This analysis includes the two widely used technologies namely, fuse-saving and fuse-blowing. The most effective and efficient method to improve power quality should be applied. The application of fuse technologies should be carefully selected to provide an optimum solution.

Key words. Power System Reliability, Power Quality, Protection, Fuse-Saving, Fuse-Blowing, Recloser, Power Quality, Voltage Dips.

1. INTRODUCTION

The basic function of a power system is to continuously maintain an adequate and reliable power supply to customers within the limits of the standards and regulations. However, performing these functions is not always possible because various types of failures occur randomly beyond the control of power system operators. Power system operators are generally concerned with the reliability of their systems and the determination of realistic availability targets for their systems.

Residential customers and industries are increasingly dependant on power; therefore power utilities are expected to provide reliable, dependable, and more affordable power. Utilities recognised the consequences of long-term unavailability and persistent interruption of power that could directly translate into a loss of power to customers. Utilities over the years have had to deal with the increasing number of complaints relating to power quality due to voltage dips and interruptions. The crucial issue is that voltage dips affect sensitive loads and the influx of digital computers, electronic controls and equipment, are at the heart of the problem. Voltage dips are the most general power quality abnormality, accounting for almost 80% of power quality problems. Voltage dips are a common cause of power related computer systems failures, stalling of motors, reduced motor life and flickering of lights [1].

As a result, utilities and researchers are constantly developing improved methods and technologies for power distribution systems that will enhance the system's reliability. Many power utilities around the world use expulsion fuses on their lateral lines. In addition to fuses, utilities may employ auto-reclosers for restoration of

supply. Generally, when auto-reclosers are used in conjunction with expulsion fuses, they are configured in a variety of philosophies. For example, the auto-recloser may be configured for fuse-saving mode or fuse-blowing mode.

It would thus be to the advantage of the utility to develop apparatus, philosophies and methods for providing automated restoration of power distribution systems that do not place the power restoration time and components at risk during a fault. These apparatus, methods and philosophies developed must reduce the negative effect on power quality, power system reliability and the operation of protection equipment.

2. DISTRIBUTION RELIABILITY

Reliability is the ability of the power system to supply energy within accepted standards and in the quantity desired. Reliability is measured using various indices characterising frequency, duration, and magnitude of adverse effects on the power supply [2].

The primary causes of faults on a distribution circuit are lightning, tree contact, animals and equipment failure. A survey from thirteen utilities over a two-year period indicates that 79% of the faults are phase to earth, 85% of the recorded faults are temporary and the outage rates on laterals are greater than the main feeder [3]. Approximately 70% of all power system outages occur on overhead lines. Lightning, vegetations, birds, animals and failure of equipment etc cause these faults. In attempting to clear the faults by reclosing and

sectionalising devices cause voltage dips on the power system [4].

Transient faults are temporary faults such as branches on the line and flashovers. Once the fault is cleared the power is restored. Some transient faults are self-clearing; others are cleared by automatic reclosing devices. Permanent faults are faults causing damage to equipment that requires technical staff to repair [5].

Reliability indices are sensitive to the number, type and location of protective devices as well as the restoration practices of the utility. A circuit breaker or auto-recloser will minimise the number of customers affected by a permanent outage and automatically restore power for a temporary outage.

Finally, an expulsion fuse does not have automatic reclosing capabilities and thus, temporary faults are treated the same as permanent faults. The additional time required for replacing a blown fuse must be included in the restoration times. Reliability improvement must focus on reducing the number of faults. This strategy applied to long duration interruptions will reduce the number of voltage dips.

2.1 Reliability Indices

Reliability indices were developed to benchmark utilities. The most commonly used indices to benchmark power system reliability are SAIFI and SAIDI [6]. The basic formula for evaluating radial power systems is as follows:

$$U_s = \lambda_s r_s \quad (1)$$

System average interruption frequency index (SAIFI) is the average frequency of sustained interruptions per customer over a predefined area. SAIFI is the average failure rate. It quantifies how many sustained interruptions an average customer experience in one year.

$$SAIFI = \frac{\text{Total Number of Customers Interruptions}}{\text{Total No Customers}} \quad (2)$$

System average interruption duration index (SAIDI) is commonly referred to as customer minutes or customer hours of interruptions. It is designed to provide information regarding the average time the customers are interrupted. SAIDI calculate the average total duration of interruptions. It quantifies how many interruption hours an average customer will experience in one year.

$$SAIDI = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total No Customers}} \quad (3)$$

Customer average interruption duration index (CAIDI) is the average time needed to restore services to the average

customer per sustained interruption. CAIDI is a measure of how long an average interruption lasts. It is used to measure the utility's response time to interruptions [7].

$$CAIDI = \frac{SAIDI}{SAIFI} \quad (4)$$

In order to design more reliable power systems the cost will increase. It is apparent from figure 1 that designs incorporating more reliable power systems will increase the cost of the power systems. Therefore, reliable power systems are more expensive than less reliable power systems. The total cost curve is a resultant of the two curves and will show a minimum, which is an indication of the optimal reliability [8].

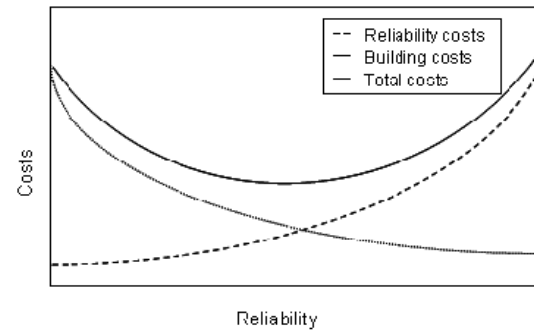


Figure 1: Cost vs Reliability

Interruption costs consist of a number of terms, namely: direct cost, indirect cost and non-material inconvenience. It is almost impossible to quantify non-material inconvenience cost. One way to determine this cost is to calculate the amount of money the customer is prepared to pay to avoid the outage [8].

Different methods are used to determine outage costs. The method employed also depends on the type of customer. An industrial customer would use a different method from a domestic customer. The only accepted method is to conduct a survey among customers [8]. The responses given by the customers will determine the average cost of an outage. The cost per interrupted kW can be defined as:

$$\frac{Ci(d)}{Li} \quad (5)$$

d = duration
 Li = load of customer
 Ci = cost per kW

$$Li(P) = \sqrt{3}VICos\theta \quad (6)$$

3. POWER QUALITY

Power quality is concerned with deviations of the voltage or current from the ideal single frequency sine wave of constant amplitude and frequency. The quality of the

power supply delivered by utilities varies considerably and depends on a number of external factors. Factors such as lightning, industrial premises which switch large loads, non-linear load stresses, inadequate or incorrect wiring and grounding or short circuits caused by animals, branches, vehicle accidents and human accidents involving power systems can create problems to sensitive equipment if it is designed to operate within narrow voltage limits, or it does not have adequate ride-through capabilities to filter out fluctuations in the electrical supply [8].

As stated above voltage dips are the most common power quality phenomenon and account for 80% of power quality problems. Voltage dips are characterised by the measurement of the dip duration below the dip threshold, and by the dip magnitude. The duration of a voltage dip is the time measured from the moment the r.m.s. voltage drops below 0,9 pu of declared voltage to when it rises above 0,9 pu of declared voltage.

For classification purposes, the magnitude of the dip is given by the maximum r.m.s. deviation from declared voltage and the duration of the dip is given by the maximum duration of the worst affected phase in each case [9].

3.1 Causes of voltage dips

A minimum of 10 700 animal-related outages with a total duration of 25 630 hours were reported in SA, affecting approximately 136 533 customers over a 16 year period. Birds caused two thirds of these outages [10].

Birds, especially raptors, are vulnerable to electrocution on certain types of structures. The causes of these electrocutions have been studied and the broad consensus currently is that it is a function of the physical dimensions of the bird coupled with the design of the particular electricity structure. The following are indications that bird electrocutions are a problem [11]:

- Unexplained auto-reclosing occurring in clear weather conditions and no vegetation problem.
- The presence of large birds in the area where the faults occur.
- Absence or scarcity of alternative roosting and perching substrate like cliffs, trees and buildings.
- Agricultural activity, especially irrigation and fallow lands.
- Arid habitat with water reservoirs coupled with pole transformers in close proximity.
- The presence of bird carcasses lying directly under the pole.

Squirrels, monkeys, baboons etc are the cause of many outages in SA. These outages usually occur in fair weather conditions. Many of these faults caused by animals are classified as “unknown.” The following problem areas can lead to animal faults [12]:

- Transformer bushings and arrestors – faults across bushings arrestors cause outages and voltage dips.
- Expulsion fuses sometimes installed where there is low clearance between phase conductor and grounded object.

Ensuring that the trees along an overhead line are regularly trimmed is one of the most successful techniques of reducing the number of faults on an overhead line. Insulator washing is critical at the coast and in dusty regions. Routine pole, line and insulator inspections will identify possible faulty equipment, which could be replaced to reduce outages. The overhead lines tensions should be inspected and re-tensioned to reduce kissing of conductors.

Misco-ordination of reclosers, sectionalisers and expulsion fuses cause longer outage time and more power quality problems for customers [12]. Improving co-ordination of protection equipment is critical for power system reliability and the reduction of voltage dips. More protective devices that can assist with sectionalising, automating of operation, faster fault clearing time and a reduction in outage time is paramount.

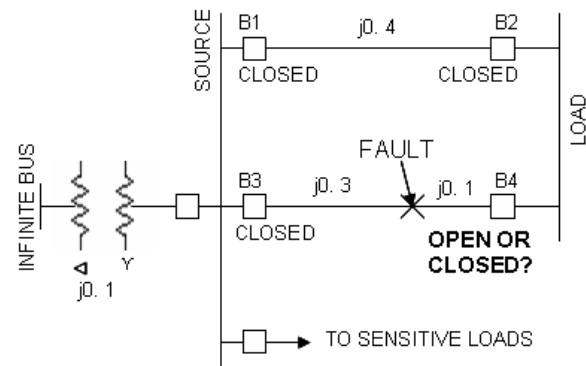


Figure 2: Circuit for impedance increase or decrease

Neighbouring networks with sensitive loads are severely affected by voltage dips. It is sometimes possible to reduce the magnitude of the voltage dip by connecting more impedance between the fault and the sensitive load. In figure 2 the magnitude of the voltage dip depends on the operation of the lines between the source and the load. Closing the open point B4 will have the result that the power supply to the load is not interrupted during fault conditions, but it increase the risk of having voltage dips on the sensitive loads connected to the source.

The frequency voltage dips to the source is the same, but the voltage dip magnitude increase if B4 is closed. A three phase fault with B4 closed will result in voltage dip of 0.65 pu.

$$V_s = 1.0 * \frac{(j0.3) * (j0.4 + j0.1)}{j0.3 + j0.4 + j0.1 + \frac{(j0.3) * (j0.4 + j0.1)}{j0.1 + j0.3 + j0.4 + j0.1}} = 0.65 \text{ pu.} \quad (7)$$

Opening B4 will eliminate the parallel path, but it will increase the impedance and reduce the voltage dip magnitude on the sensitive equipment.

$$V_s = 1.0 * \frac{j0.3}{j0.1 + j0.3} = 0.75 \text{ p.u.} \quad 25\% \text{ dip} \quad (8)$$

The decision to operate the power system with B4 open or close depends on the importance of continuity of supply versus the impact on sensitive loads.

If more fuses are installed to smaller sections of networks, fewer customers will be interrupted. To reduce outages it is important that utilities increase the number of fuses.

4. EXPULSION FUSE PROTECTION

Expulsion fuse are the most commonly cost effective protection device used on distribution power systems. It is easy to change and the interruption is relatively fast and can occur in a half of a cycle for large currents. Two types of expulsion fuses are generally used, i.e. K and T types. The K type is faster than the T type.

Normally reclosers are used in conjunction with expulsion fuses. The size of the expulsion fuse will determine the curve. The trip coil of hydraulic reclosers limits the curve adjustment; therefore it reduces the options in terms of co-ordination with fuses. On the other hand electronic reclosers are more flexible. The recloser can co-ordinate over a wider range currents and the sensitivity can be increased to co-ordinate better with downstream fuses [12].

In terms of co-ordination of expulsion fuses, a few aspects are relevant to power quality [5]:

- Employing fuse-saving technology on transient faults, the recloser must have a time-current characteristic to the left of the minimum melting curve.
- For permanent faults the recloser must have a curve to the right of the maximum clearing time curve.
- Repeated faults, inrush currents and lightning activity particular using fuse-saving technology will shift the time-current characteristic to the left. This is what is called degrading the fuse.

4.1 Selecting fuses

Transformers with a capacity rating less than 2500 kVA are normally protected by means of fuses [13]. High voltage fuses are installed on both the HV and LV sides of 33/11kV transformers rated up to 5 MVA [14].

The following factors are to be considered when selecting fuses [15]:

- The fuse must be capable of carrying maximum currents.
- The inrush current of a transformer is 10 to 12 times the rated full-load current for a duration of 100 ms.

- Faults in a transformer are to be cleared fast and the current needed in the 10 s region should be as low as possible.
- The minimum fusing current of the primary circuit should be as low as possible to ensure that many internal faults are cleared.
- Correct discrimination between the fuse and other protective devices is critical.

The characteristics of a high voltage fuse will differ from a low voltage fuse. Generally, the high voltage fuse will operate at higher current levels than that of a low voltage fuse with similar time changes. Figure 3 below show the different time/current characteristics to be observed when selecting and grading fuses [15].

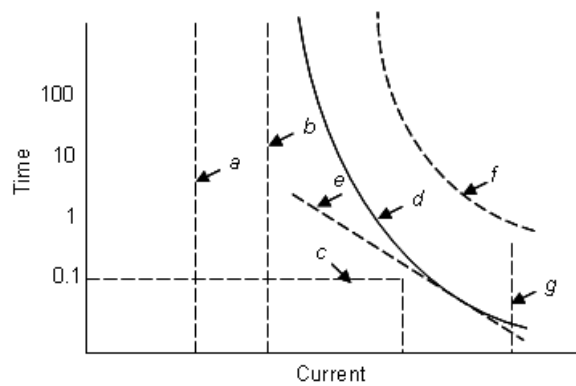


Figure 3: Time-Current (TC) Characteristics

Where:

- a- Full-load current
- b- Permissible overload
- c- Magnetising inrush equivalent current
- d- HV fuse characteristic
- e- LV fuse characteristic (referred to HV side)
- f- Characteristic of source circuit breaker relay
- g- Maximum current on HV side with fault on LV side

4.2 Fuse-saving technology

Fuse-saving technology is used in conjunction with auto-reclosers. At the source substation an auto-recloser is installed and slow expulsion fuses protect the lateral lines. The expulsion fuse must not trigger during transient faults beyond the fuse, which will be cleared by the auto-recloser. For permanent faults the expulsion fuse must clear the fault, resulting in a sustained outage for some customers. Fuse-saving technology is achieved by using the two settings on the auto-recloser, i.e. instantaneous trip and delayed trip. The instantaneous trip must be set to be faster than the expulsion fuse and the delayed trip slower than the recloser [8].

It is difficult to make fuse-saving technology work. It is not always easy to co-ordinate a recloser relay with a fuse, using fuse-saving technology if the fuse is installed near the source substation. The fault current at the start of the feeder is normally very high. Since the auto-recloser is slower than the fuse, the fuse will blow,

leaving customers off for an extended time. One way to overcome this is to either block the instantaneous operation or using fuse-blowing technology. Another method to use is to install automatic sectionaliser, which makes the installation expensive [16].

Figure 4 illustrates that for very high fault currents of short durations the fuse will always operate, which would be a problem for temporary faults. Therefore, as per figure 4, there will be areas when the fuse will always operate, never operate or operate optimally.

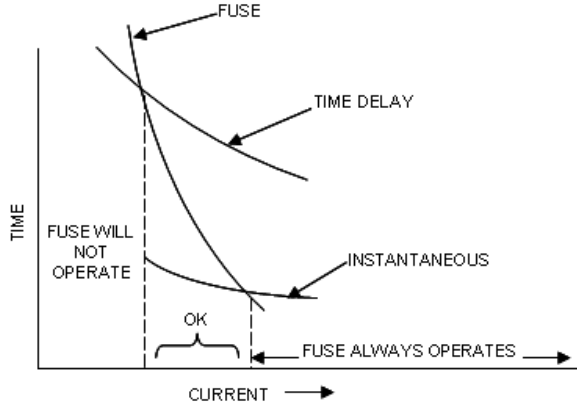


Figure 4: Fuse-saving

It is evident that fault current is a major factor, therefore in order to optimise the power system it is important to know the magnitude of the fault current. The calculating of the fault current can be done by using the following approach:

$$Z_{\text{source}} = \frac{\text{MVA}_b}{\text{MVA}_{\text{trf}}} \quad (9)$$

$$Z_{\text{base}} = \frac{(kV_b)^2}{\text{MVA}_b} \quad (10)$$

$$Z_{\text{trf}} = \frac{\text{MVA}_b}{\text{MVA}_{\text{trf}}} \times \frac{Z\%}{100} \quad (11)$$

$$Z_{\text{act}} = R + jxL \quad (12)$$

$$Z_{\text{line}} = \frac{Z_{\text{act}}}{Z_{\text{base}}} \quad (13)$$

$$Z_{\text{fault}} = Z_{\text{source}} + Z_{\text{trf}} + Z_{22kV\text{line}} \quad (14)$$

$$I_{\text{fault pu}} = \frac{1}{Z_{\text{fault}}} \quad (15)$$

$$I_b = \frac{\text{MVA}_b \times 1000}{\sqrt{3} \times kV_b} \quad (16)$$

$$I_{\text{fault}} = I_b \times I_{\text{fault pu}} \quad (17)$$

For fuse-saving technology to work, the protection devices must function correctly.

- Use bigger and slower operating fuses near substations
- Use faster auto-reclosers and circuit breakers

4.3 Fuse-blowing technology

In using the fuse-blowing technology the instantaneous trip on the auto-recloser is disabled. During transient or permanent faults beyond the expulsion fuse, the fuse will operate before the auto-recloser operate. This minimises the number of instantaneous trips and the number of customers affected, but these customers will suffer sustained interruptions until such time the fuse is replaced. This impact negatively on the reliability indices. 40% of utilities indicated that they solved customer problems by using fuse-blowing technology [5].

Using fuse-blowing technology, the number of momentary interruptions will decrease. One third of the utilities use fuse-blowing and one-third use fuse-saving and the other third use a combination of the two technologies. The number of fuse operations increase from 40 to 500% using this technology, increasing the frequency of sustained interruptions from 10 to 60%. Customers on long lateral lines have more sustained interruptions [12].

Faults can last long for 0.5 to 1 s, resulting in damage to equipment eg.

- Conductor burn downs
- Damage to inline equipment
- Evolving faults
- Damage to transformers

5. MITIGATION TECHNIQUES ON THE POWER SYSTEM

5.1 Power System Reliability

The Rockland 22kV feeder was used to apply the literature. This power system is considered to be reasonably reliable, but in terms of the outage duration and the number of power quality event which will be discussed in the power quality sub-heading, the feeder is not reliable.

Calculating the power system average outage time

$$\begin{aligned} U_s &= \lambda s \text{ rs} & (1) \\ &= 28 \times 94.5 \\ &= 2646/5 \text{ yrs} \\ &= 529.2 \text{ hrs/yr} \end{aligned}$$

Calculating the average outage cost

$$\begin{aligned} P &= 860.8 \text{ kW} & (6) \\ \text{Cost per kW} &= 0.363 \text{ (Calculated over 5 years)} \end{aligned}$$

Outage cost = R 0.0399 per kW (5)
= 3.99 cents/kW

Calculating Reliability Indices

Calculated SAIDI = 1133.4 min/yr (3)

Calculated SAIFI = 5.6 int/yr (2)

Calculated CAIDI = 202.4 min/yr (4)

The power system under-performed in terms of the calculated reliability indices. The current capacity of conductors can sustain the load requirement. The structures and power system equipment are in a reasonable condition. If preventative maintenance is done, the power system reliability can improve. In terms of system security the power system fails. The protection equipment is not reliable as the ARC, on investigation, was switched off and there is no alternative power supply to the system.

In terms of the factors influencing the reliability of the power system, the following is noted:

- The customers connected to this power system are supplied from lateral lines and there is no possibility of an alternative supply when an outage occurs.
- Weather conditions have a major impact on the power system.
- Many of the outages are caused by vegetation, birds and animals.
- The duration of the outages do not comply with the standards in terms of the calculated average outage time.
- Protection equipment mal-operation.
- Lack of maintenance.

5.2 Power Quality

The voltage dips recorded on this power system in all the dip categories, are more than the NRS standards. These dips cause major problems to the industrial processes and electronic equipment. 241 Y-dips were recorded. The magnitude of these dips were shallow and the duration normally not longer than approximately 100 ms. Many of these dips were caused by neighbouring networks. If the principle in figure 2 is applied, the impact of the voltage dips in terms of Y-dips will be reduced. Y-dips are regarded as insignificant in terms of the NRS standards. The customers are responsible to protect their equipment against Y-dips, but no dip improvement equipment has been installed on the customer's equipment.

5.3 Expulsion Fuse Protection

Considering figure 3, curve f depicts the characteristics of a normal inverse curve. This curve does not follow a similar format of the fuse, which makes grading difficult. Figure 3 will be used for fuse-saving technology, which will work, but when used for fuse-blowing, grading becomes more complicated. In figure 5 an extreme

inverse curve is used. It is evident that this curve is similar to that of the fuses. Therefore for improved grading between fuses and circuit breakers, extreme inverse curves should be used.

It is evident from figure 5 that the K-type fuse is faster than the T-type and can sustain higher fault currents for longer periods. The calculated fault current is 1105 A using the equation 9 to 17. From figure 5 the K-type will operate in 0.7 seconds and the T-type fuse in 2 seconds. It would therefore be better to use T-type fuses nearby the source as the fault currents are higher at the source.

It is important to note that the fuses do not protect the transformer and the relay only protects the transformer at fault currents which exceed of 65 A. Hence, fuses although selected using the criteria in 4.1 cannot protect the transformer, but protect the conductor. To protect transformers would require additional relays on every lateral line. This is very expensive and therefore not a viable option. It is cheaper to replace the transformer than procuring protection equipment.

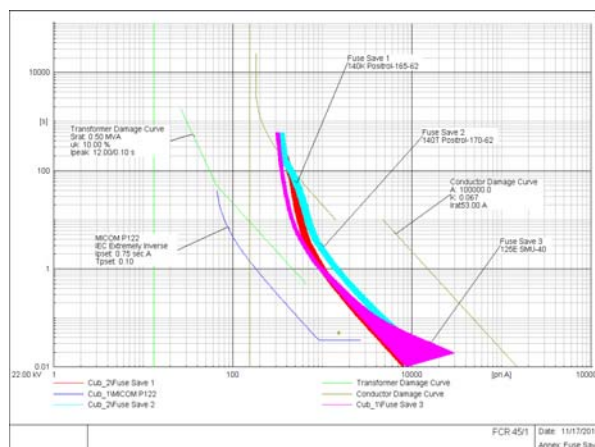


Figure 5: Fuse/Relay Grading

The grading margin between the relay and the fuse depends on the size of the fuse and the relay settings. The grading margin will increase as the fuse size increase. The settings of the auto-recloser are critical in the grading of fuses, i.e. the uses of instantaneous trips or delays trips.

According to the investigation conducted approximately 30% of all sustained interruptions on rural lines are due to incorrect expulsion fuse/auto-recloser operation, selection of fuse size or co-ordination between the fuse and the recloser. By improving this using fuse-saving technology SAIDI and CAIDI improved significantly and SAIFI improved reasonably.

5.3.1 Impact on Reliability

There are many schools of thought regarding fuse-saving and fuse-blowing techniques. Customers are more sensitive to voltage dips in urban areas than in the rural

areas. Domestic customers complain more about sustained outages, but in most cases short momentary voltage dips have negligible effect on them. Fuse-blowing technique will probably not eliminate all the power quality problems industrial customers face. As a rule of thumb, fuse-blowing will eliminate one-third of the power quality problems of industrial customers. The best choice in terms of fuse-saving or fuse-blowing depends on the application and the type of customers connected to the power network and the philosophy of the utility [5].

Auto-reclosers are designed for fuse-saving applications and the most common models are (1) one fast and three delayed operations or (2) two fast and two delayed operations. The auto-recloser at the main substation can clear permanent faults, but it will lead to long outages for all the customers connected to that feeder. Instead expulsion fuses on lateral lines can clear permanent faults. In order to achieve proper auto-reclosing with fuse-saving features, there must be a trade-off, i.e. a short outage for all the customers instead of long outages for some customers. The alternative would be more long outages and not all short outages would become long outages.

5. CONCLUSION

Neither a fuse-saving nor a fuse-blowing protection scheme is the best choice for all applications. One scheme is better in some applications than others. The best choice depends on many factors, including fusing practices, conductor sizes and location of customers on a circuit and the philosophy of the utility. It is helpful to review the choice made (even on a network-by-network basis) because many situations would be better served by a different choice.

Many unexplained operations of the protection equipment were detected. All the causes of voltage dips described in 3.1 were evident on this power system. Hence, maintenance programs must drastically be implemented, animal and bird protection installed, more fuses installed and co-ordination of protection devices revised.

Reviewing current philosophies and practices will only benefit both the customer and the utility in terms of power system reliability. Utilities generally apply one of the two expulsion fuse co-ordination philosophies on a given distribution feeder, fuse-blowing or fuse-saving. When fuse-saving works, it benefits both the utility and its customers. Power is automatically restored to all customers and utility staff does not have to travel to the expulsion fuse location to replace a blown expulsion fuse. However, fuse-saving practices have co-ordination limitations at higher fault currents. This is common for the upstream device to trip and the expulsion fuse to operate at the same time. This results in frequent momentary outages for many customers and blown expulsion fuses, even for temporary faults. These challenges have led some utilities to discard fuse-saving and instead use fuse-blowing technology.

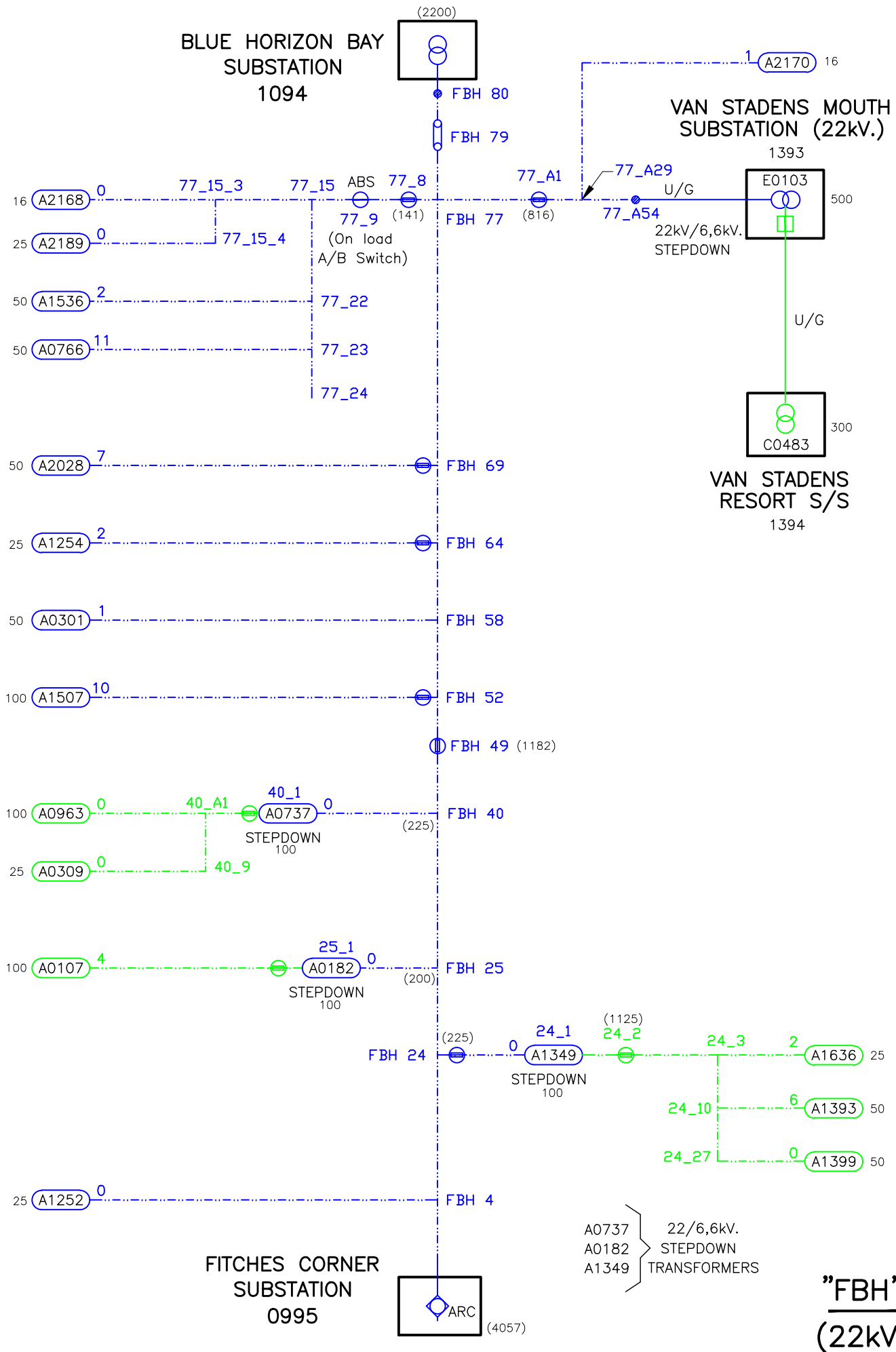
The conventional fuse-saving practice has an inherent tradeoff of sustained interruptions improvement at the expense of increased momentary activity, which causes SAIFI and SAIDI improvements.

Fuse-blowing is obviously less problematic and easier to coordinate. Most utilities use a mix of fuse-blowing and fuse-saving on different feeders depending on the customers and the fault currents.

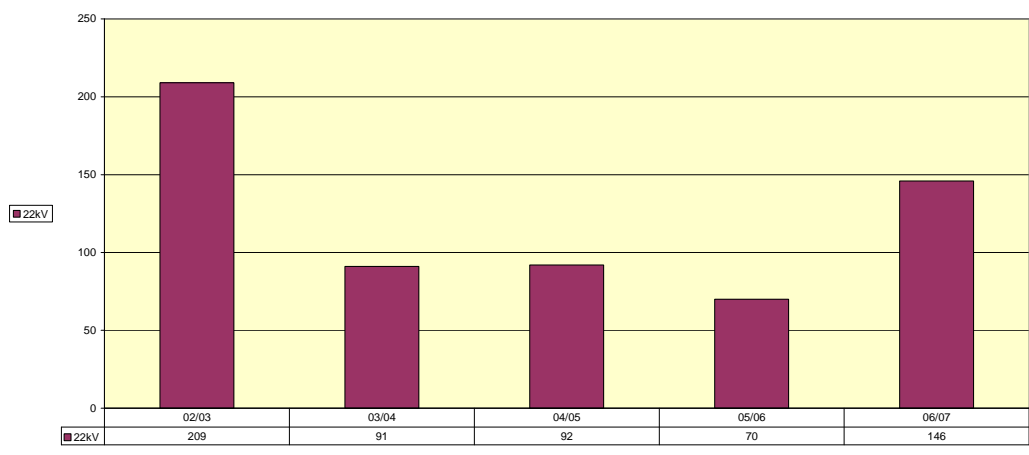
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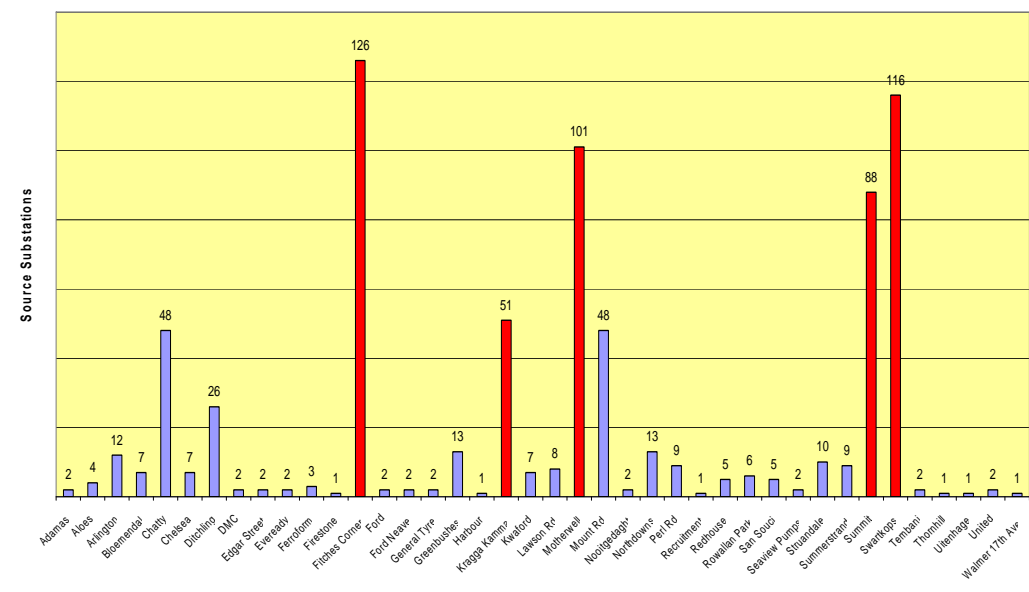
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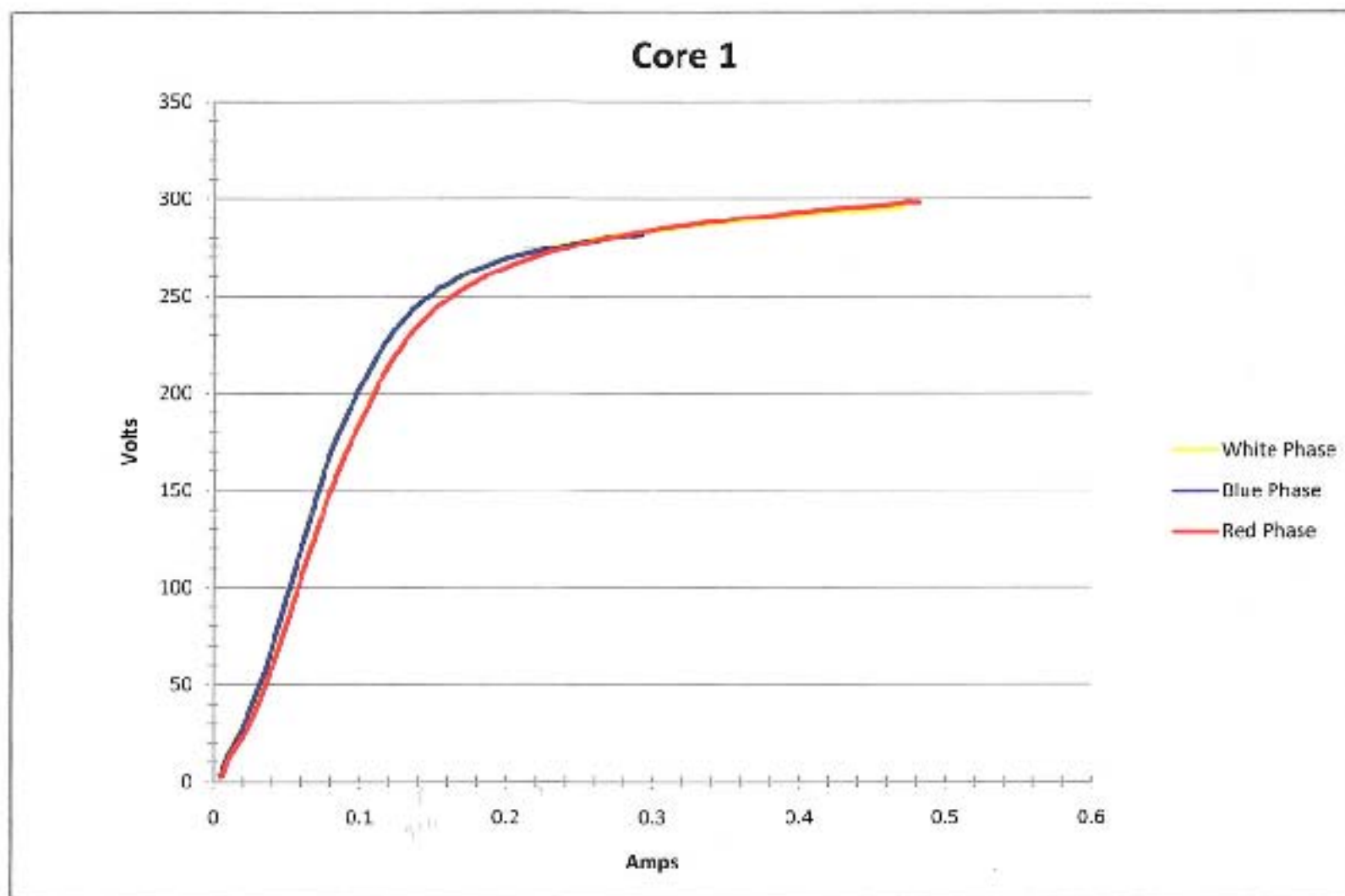


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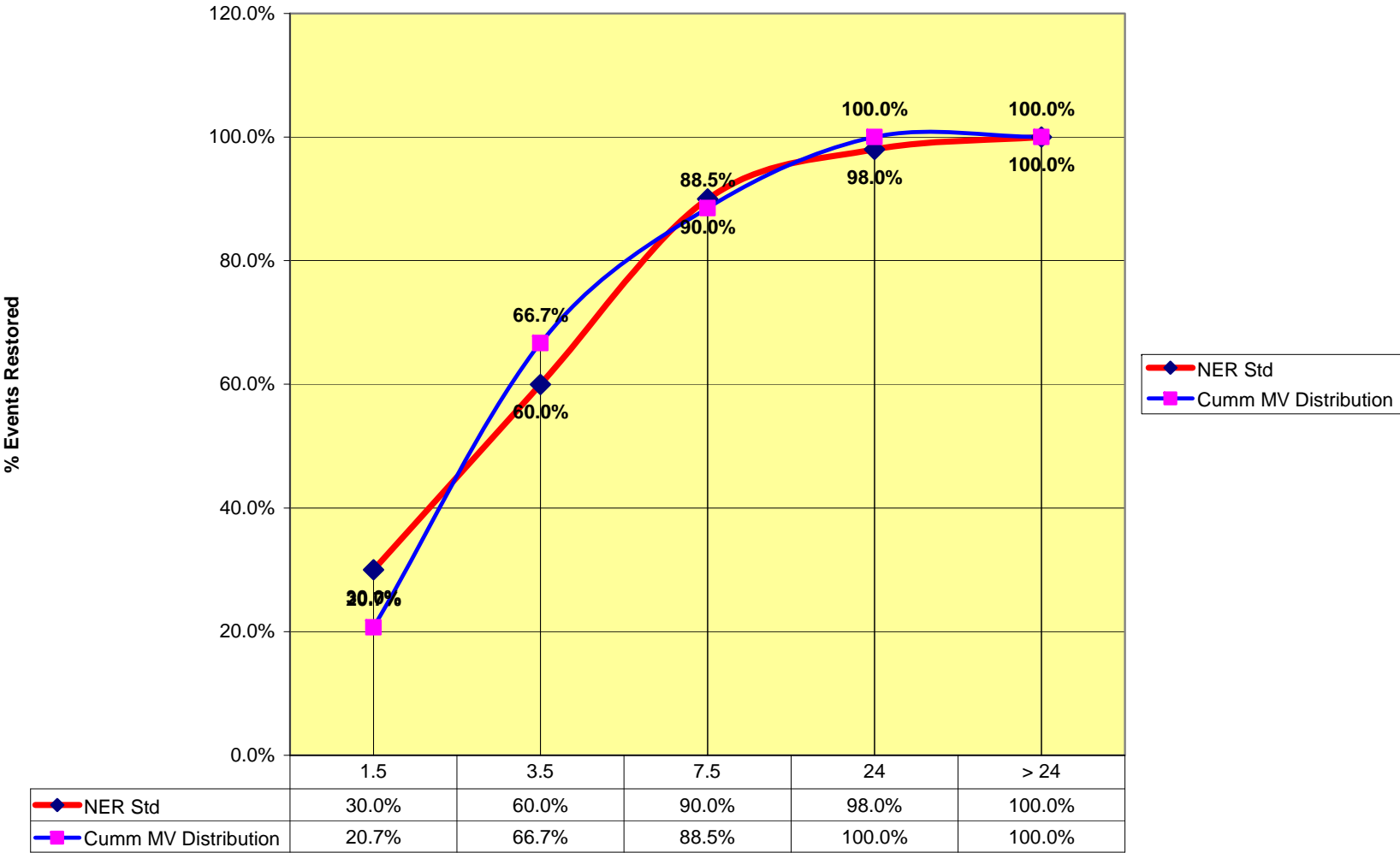


Summary of Faults





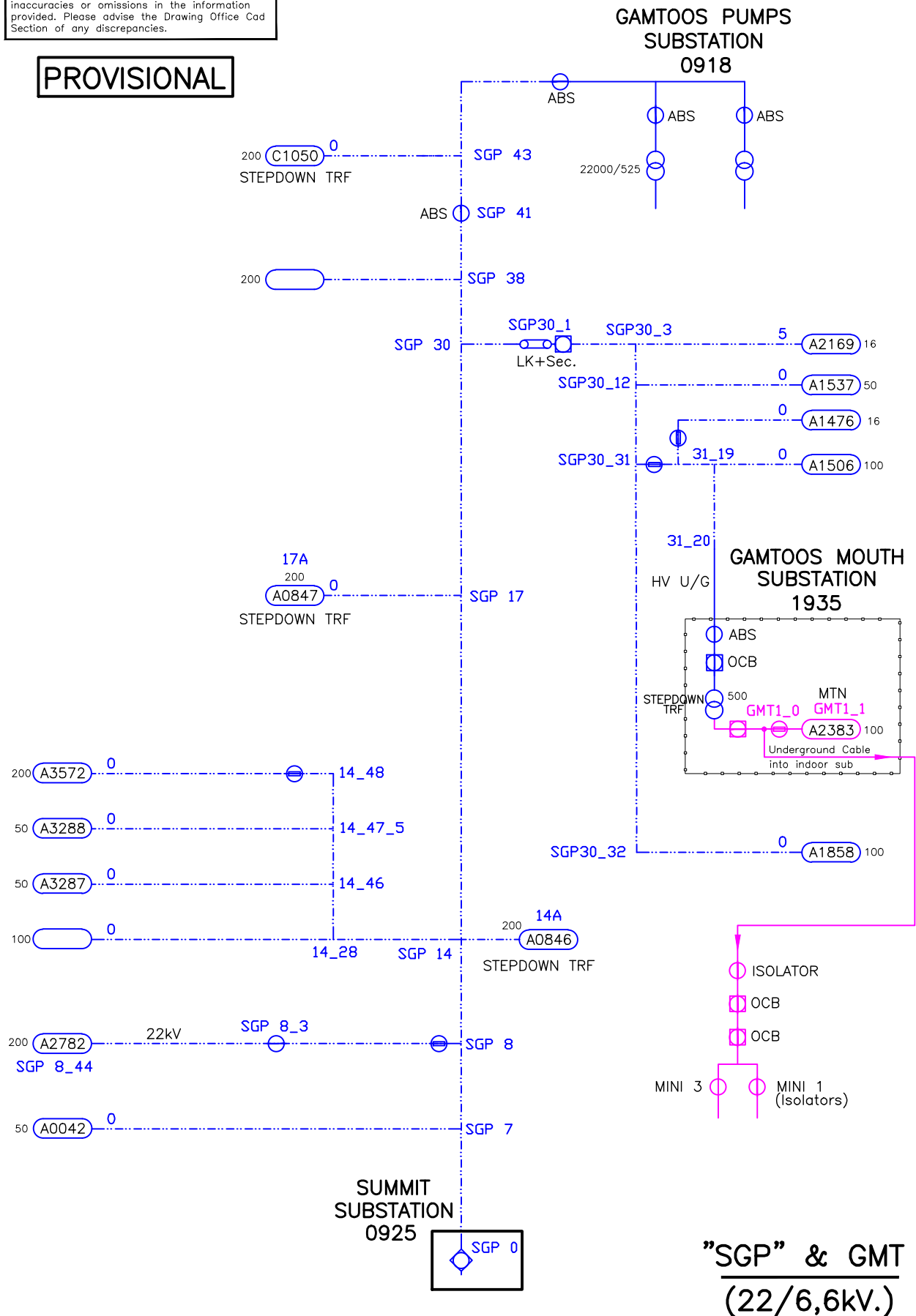
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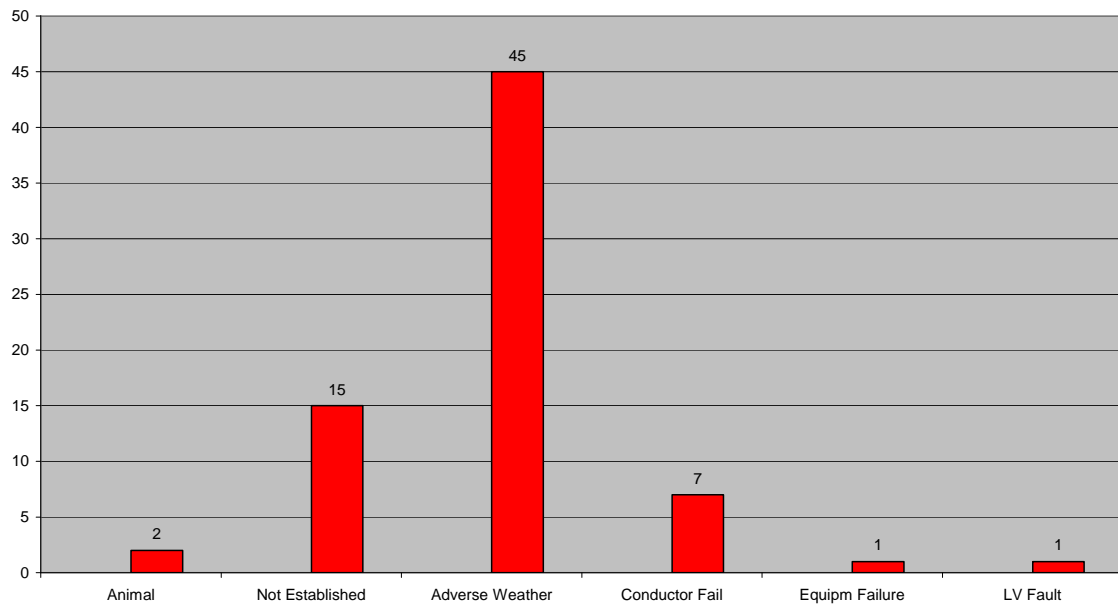
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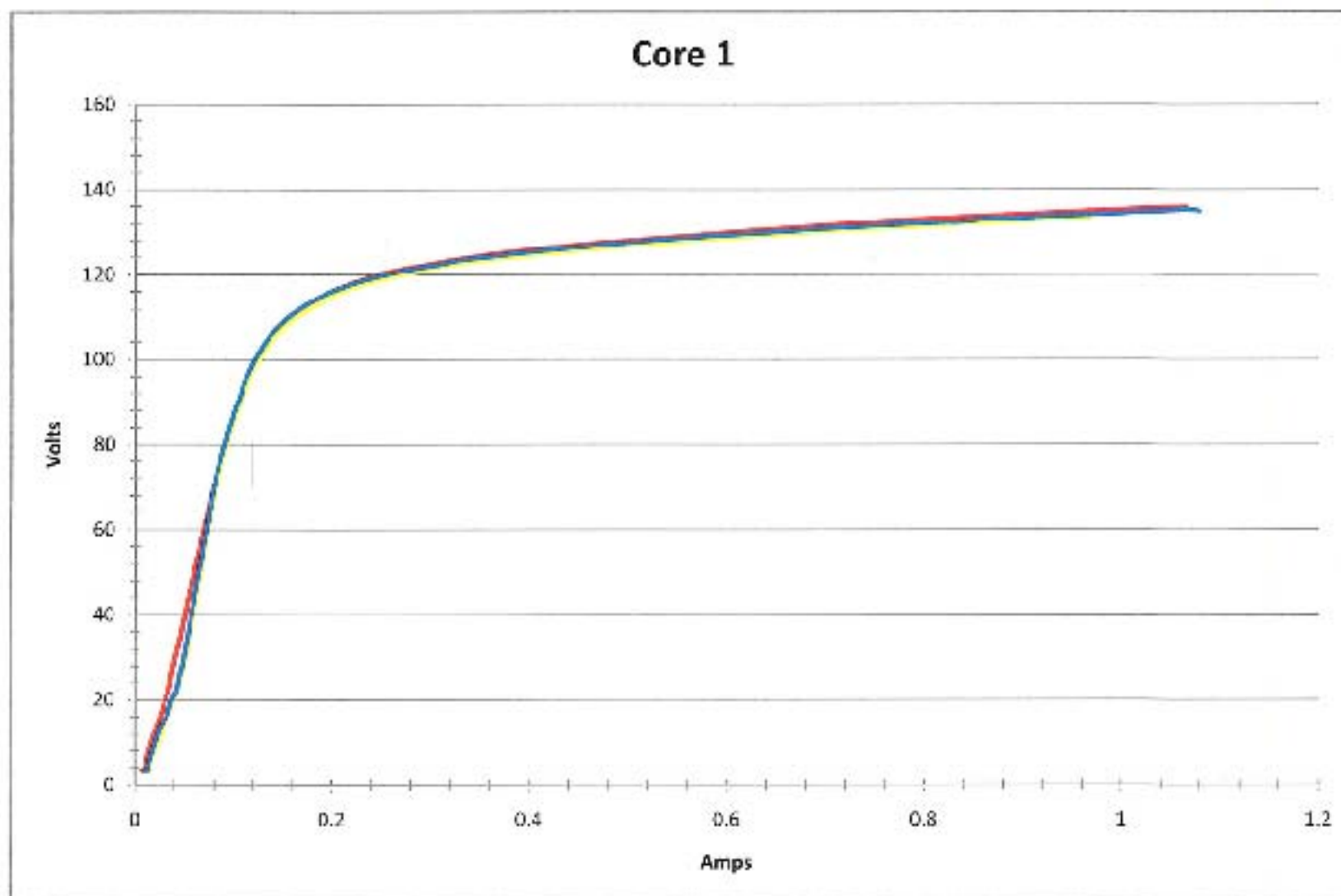
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Fault Types

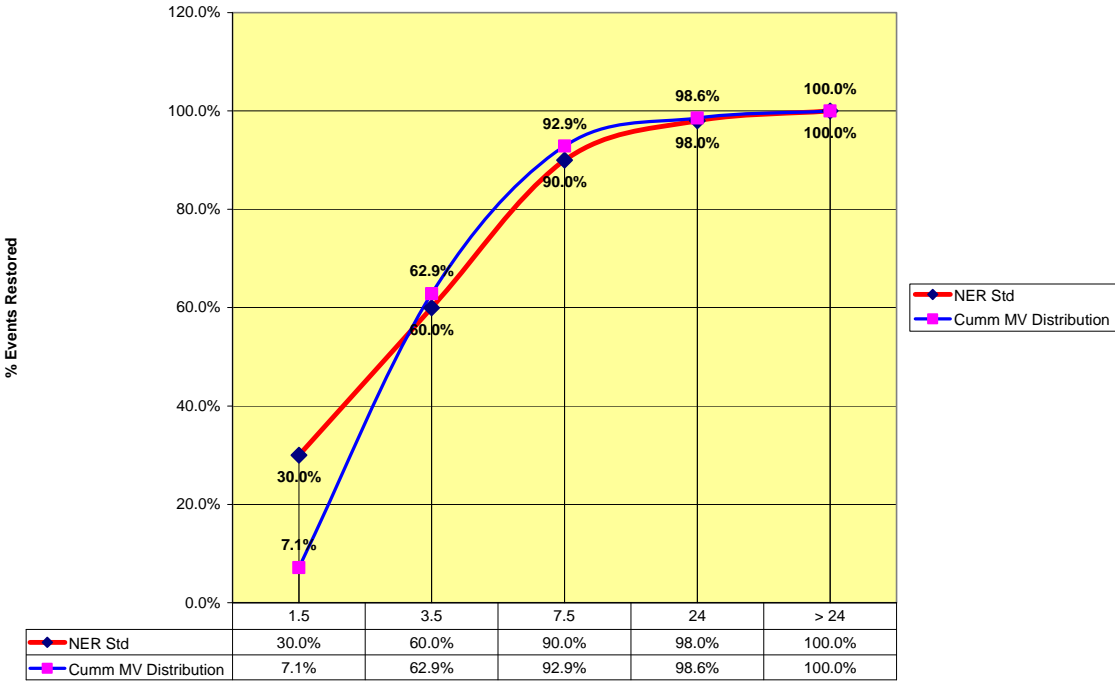




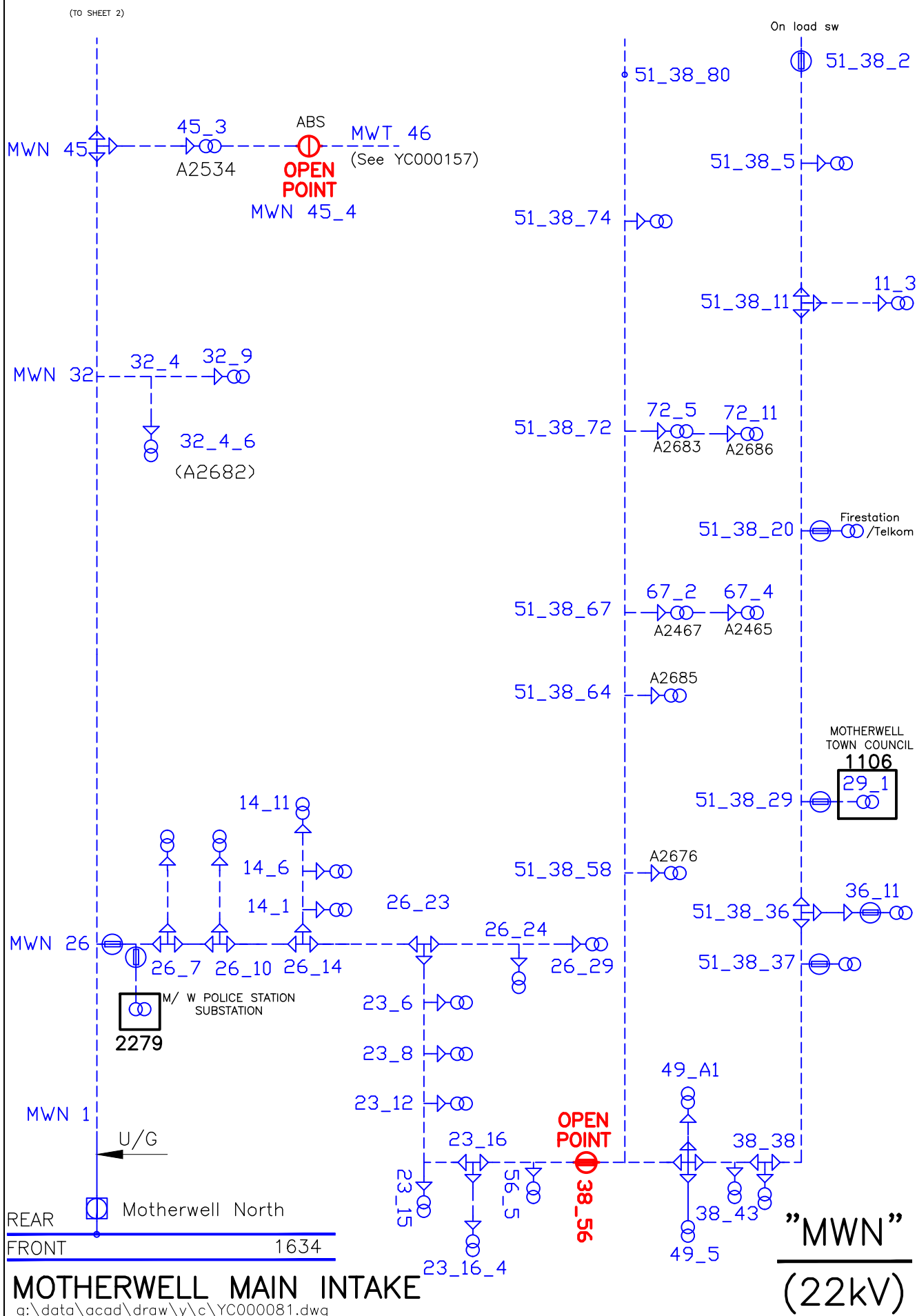
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As Knowledge Increases, Wonder Deepens

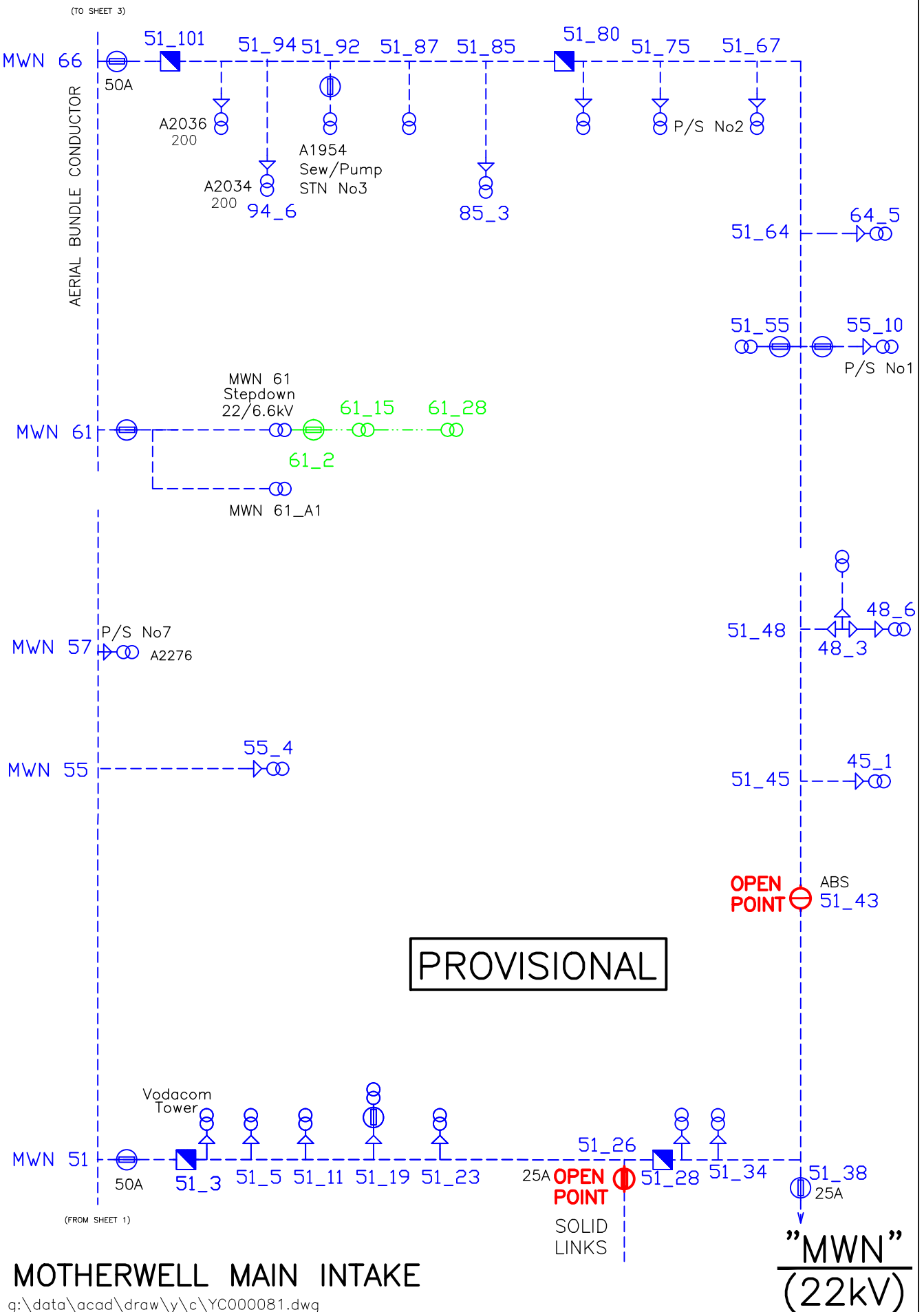
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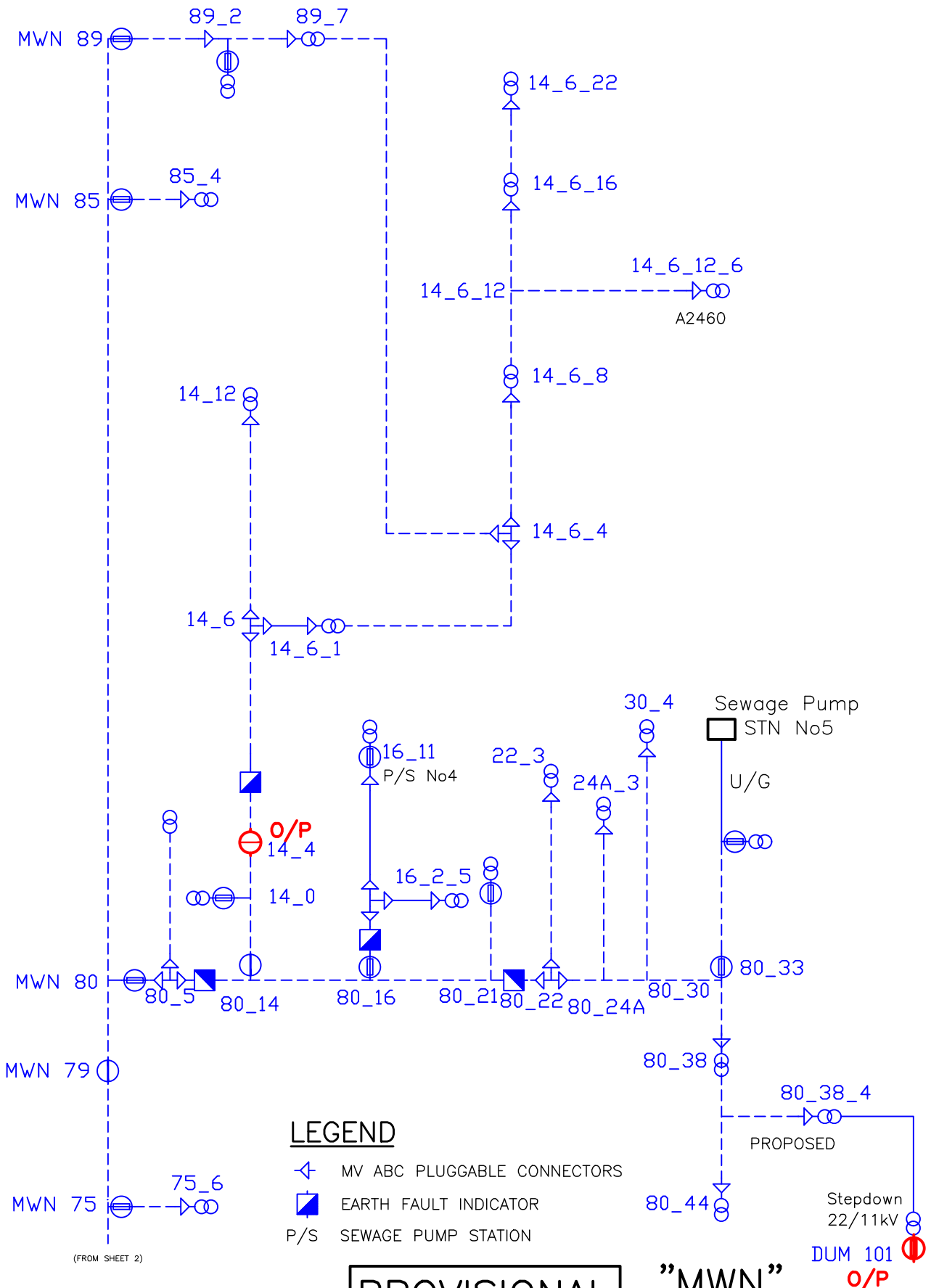
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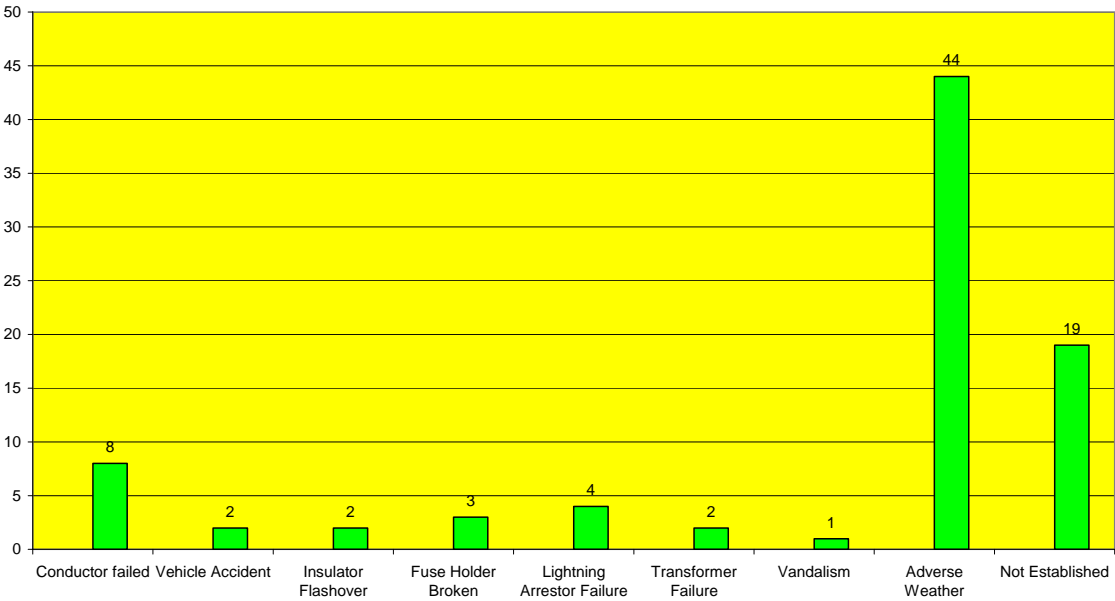
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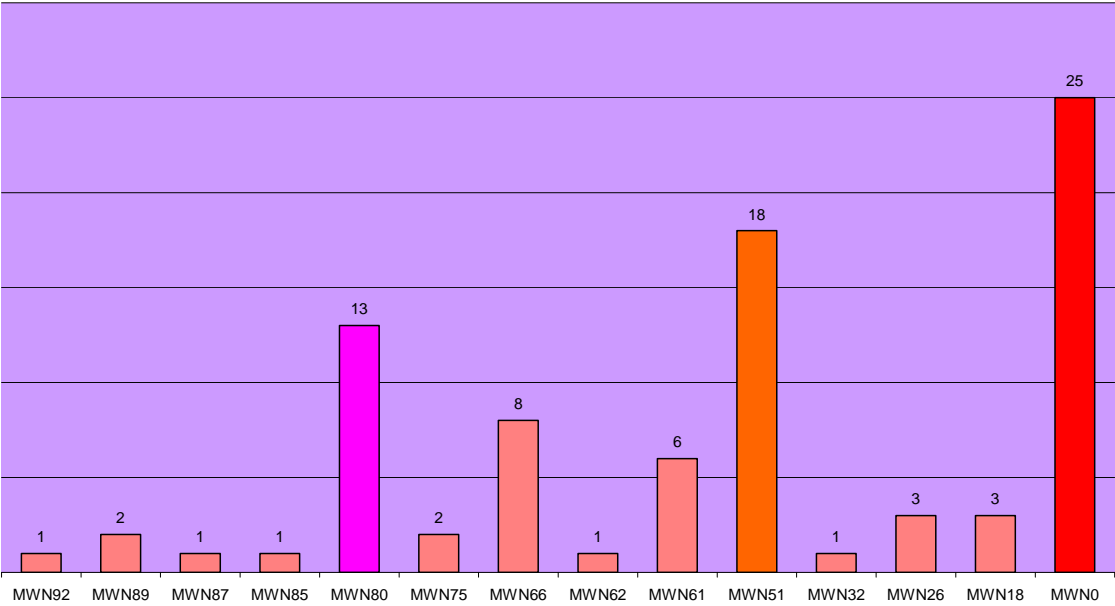
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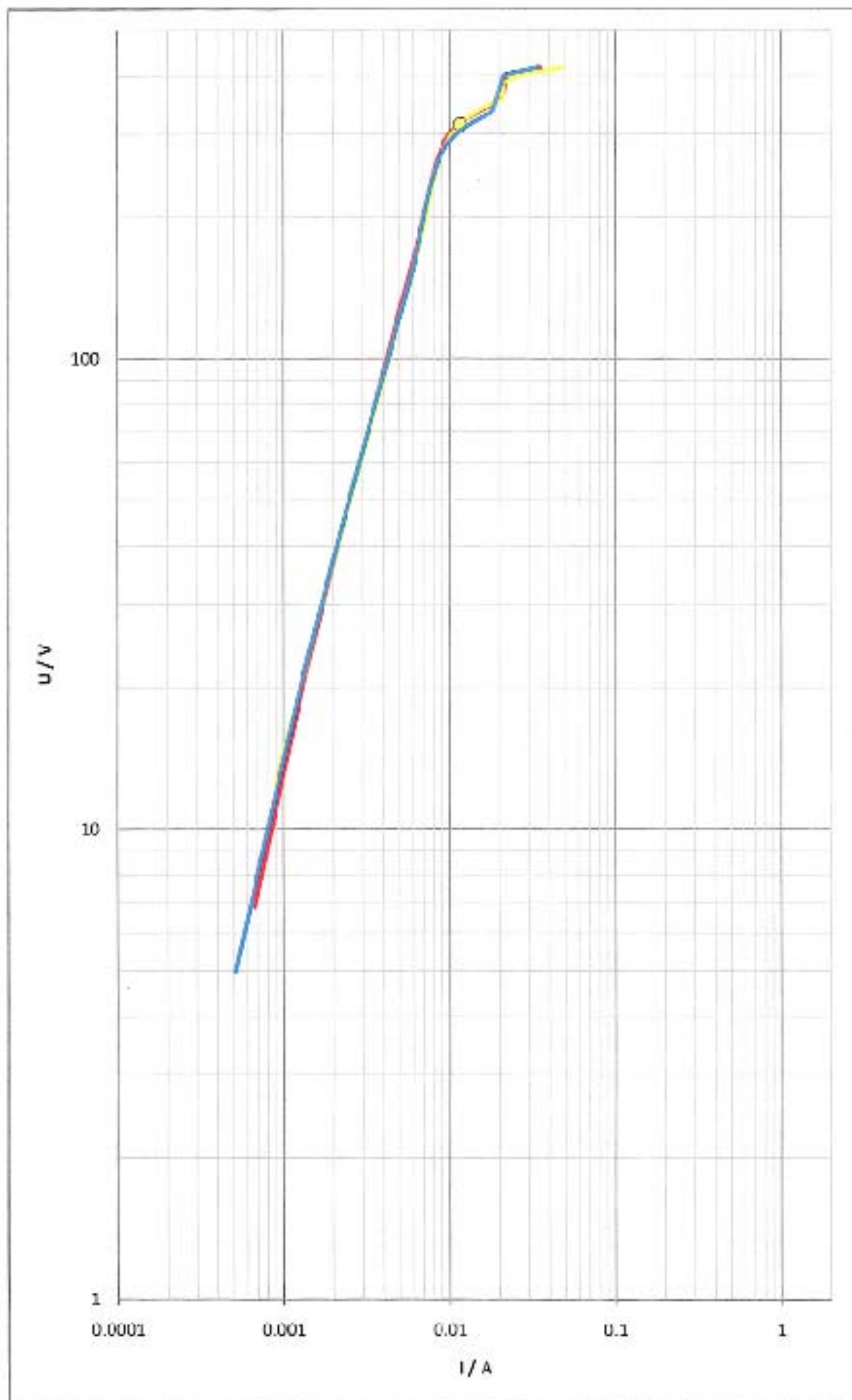
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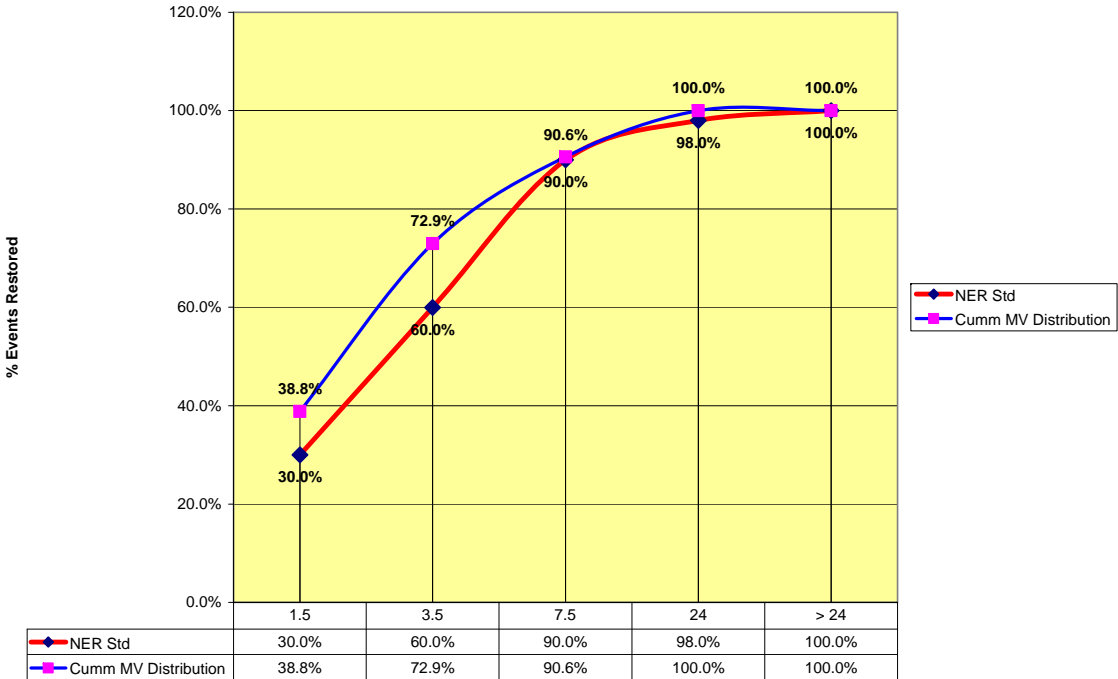
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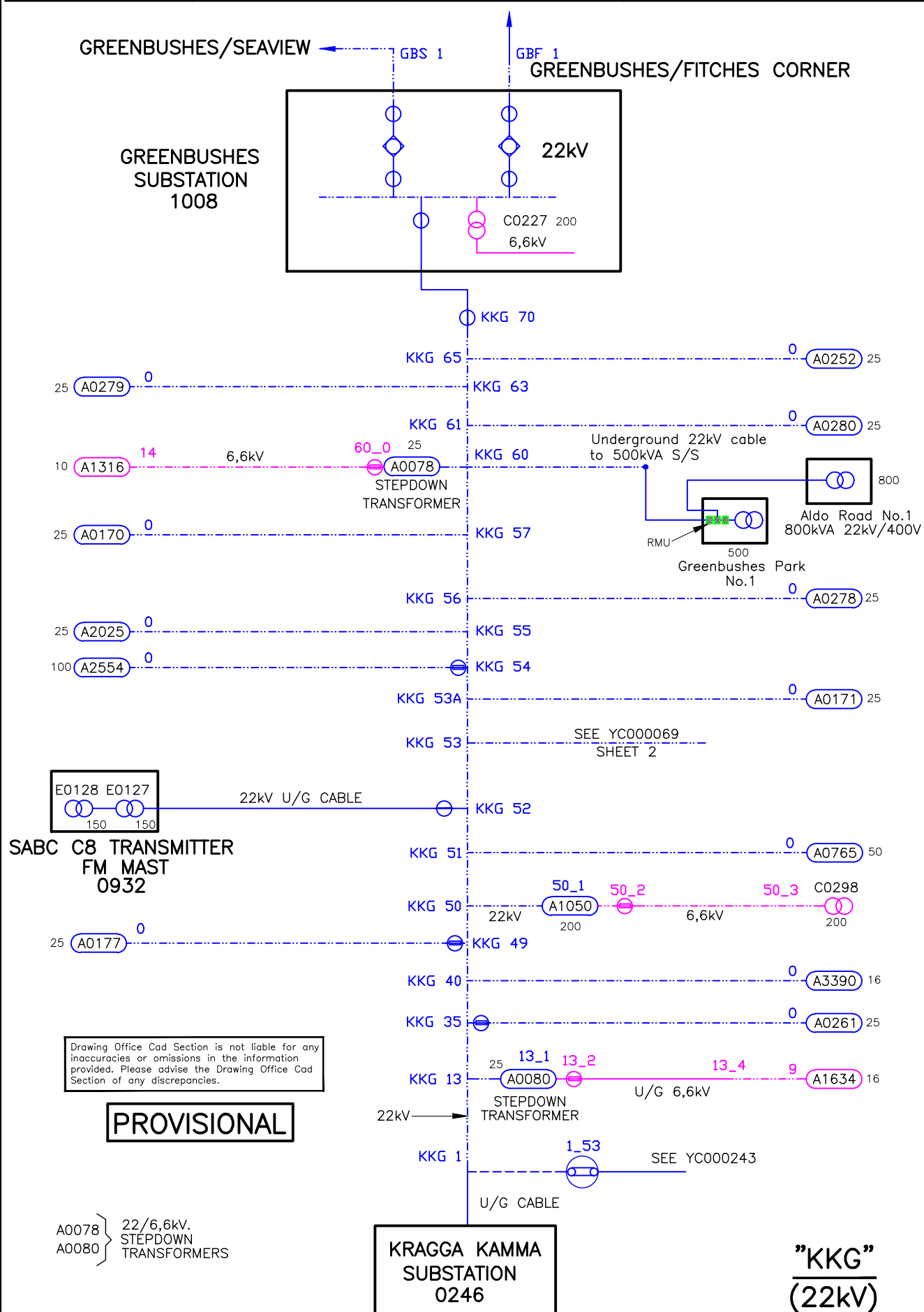
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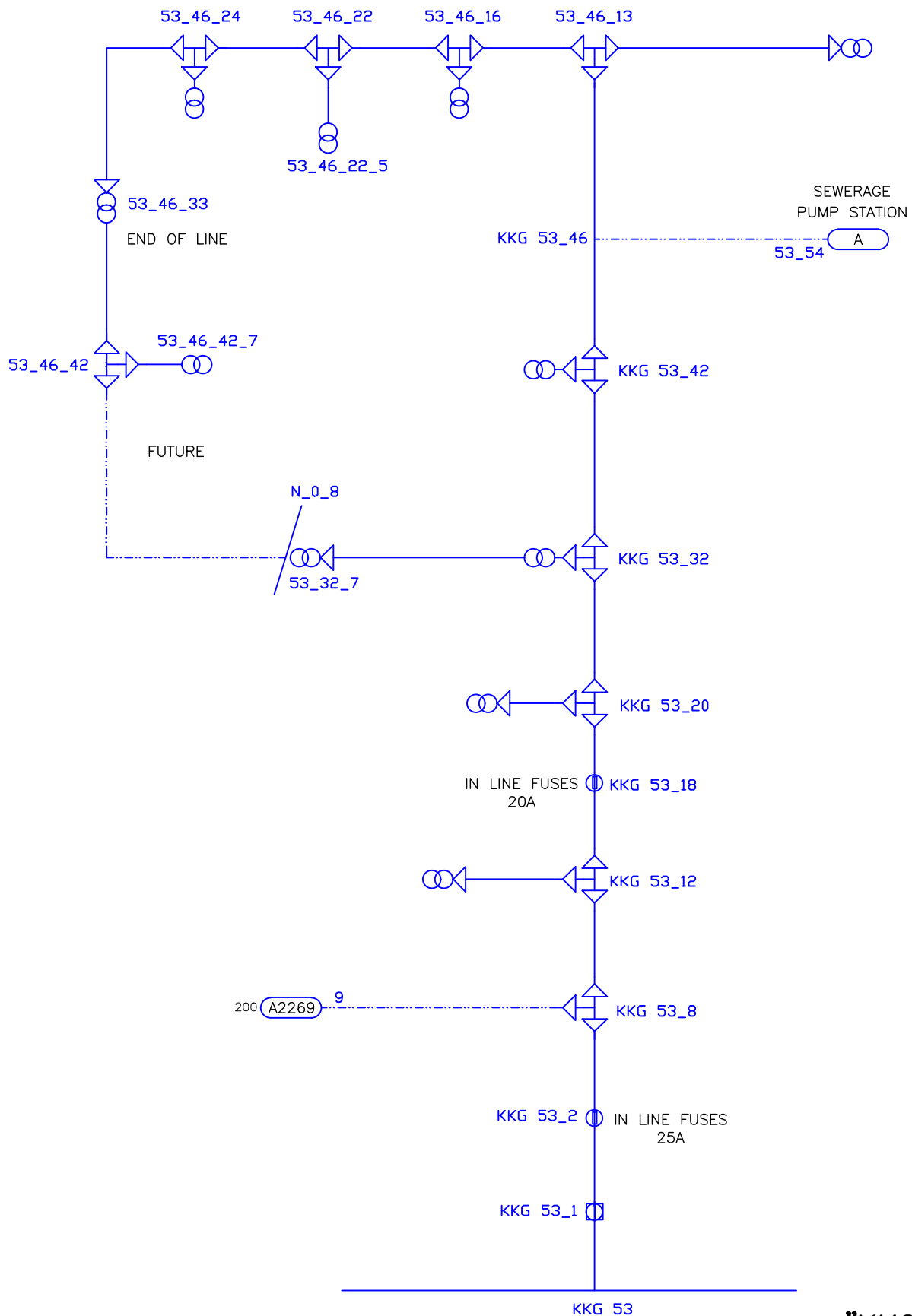
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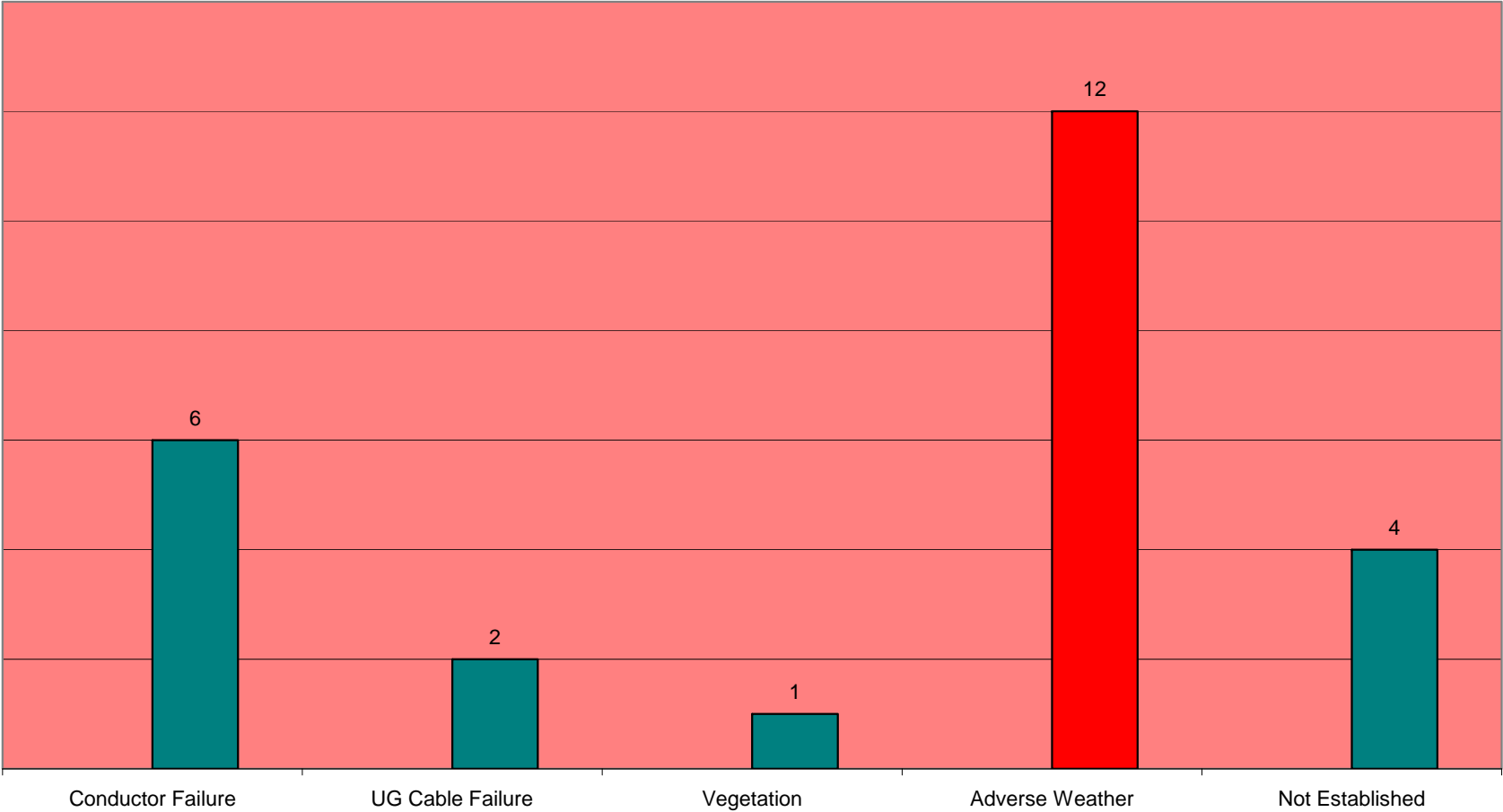


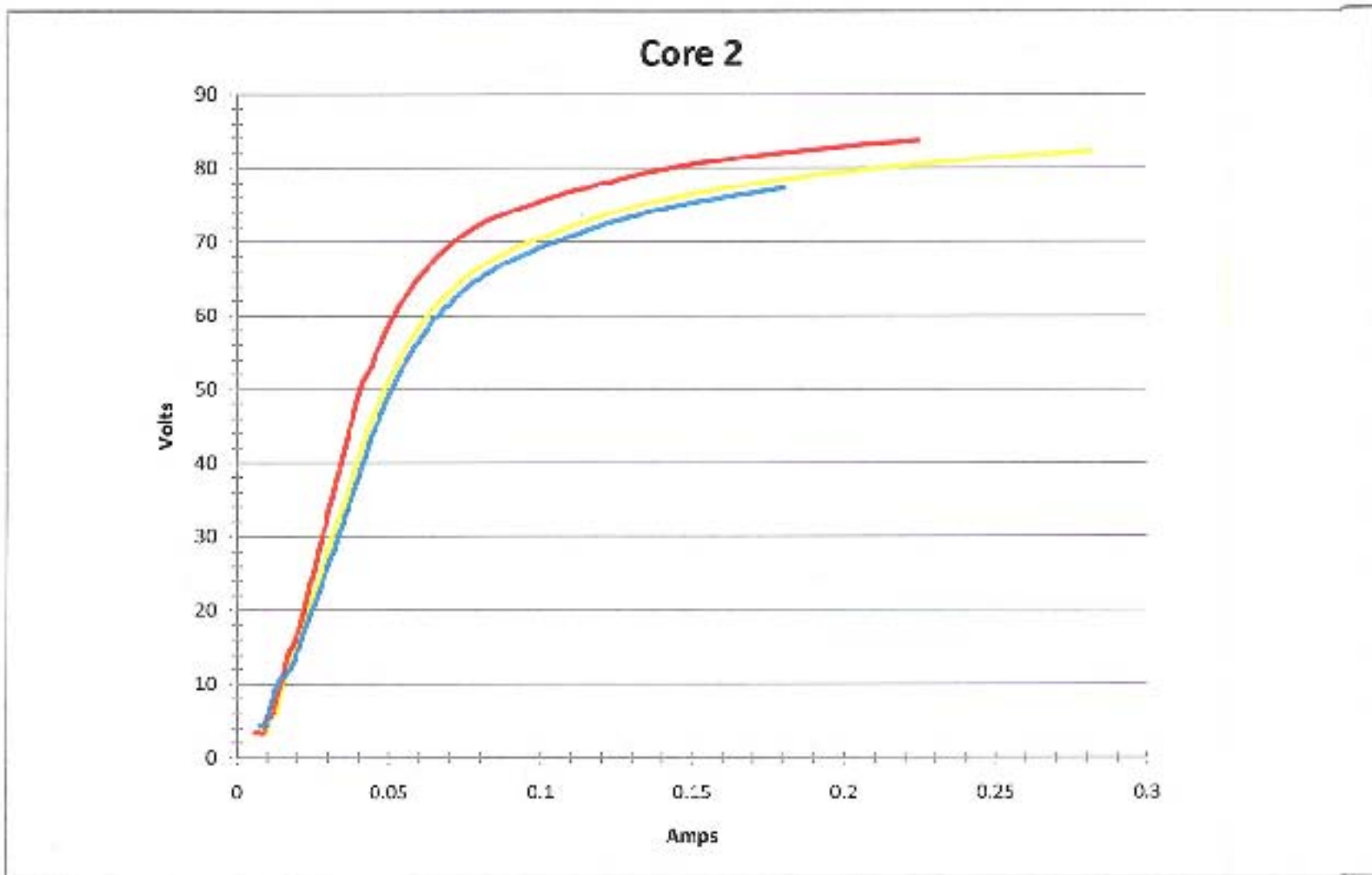
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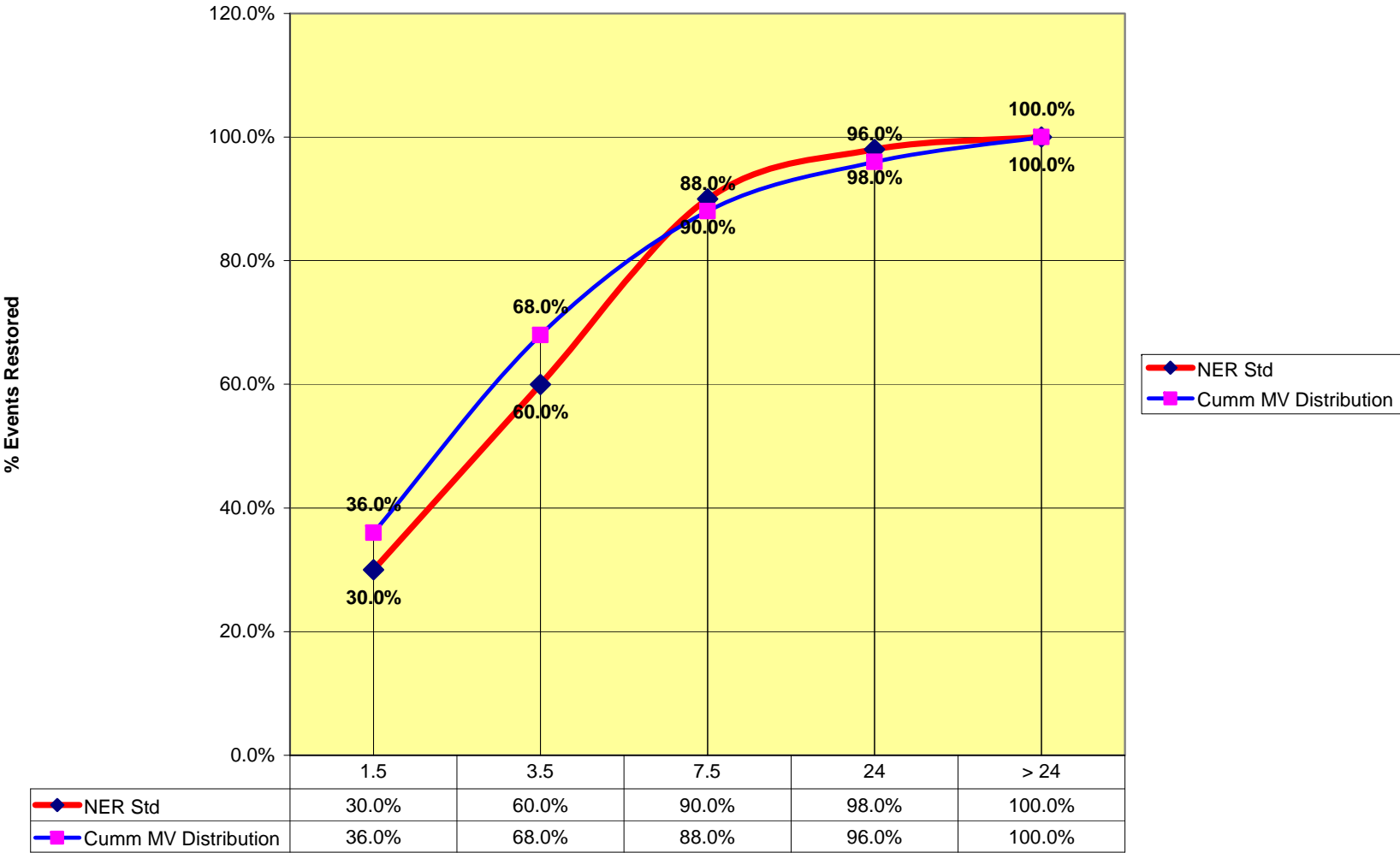
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Fault Types KKG





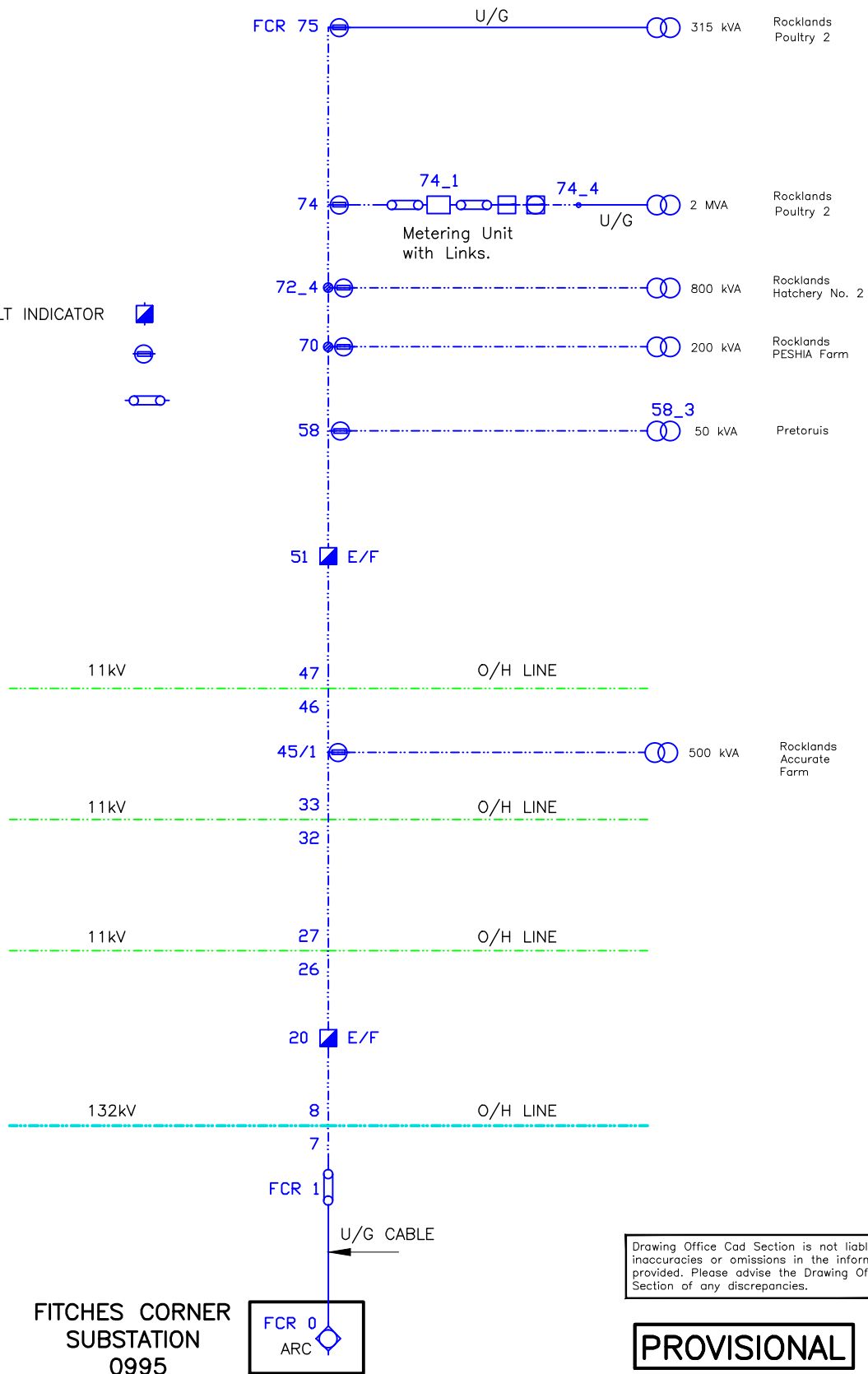
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LEGEND

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FUSE	⊖
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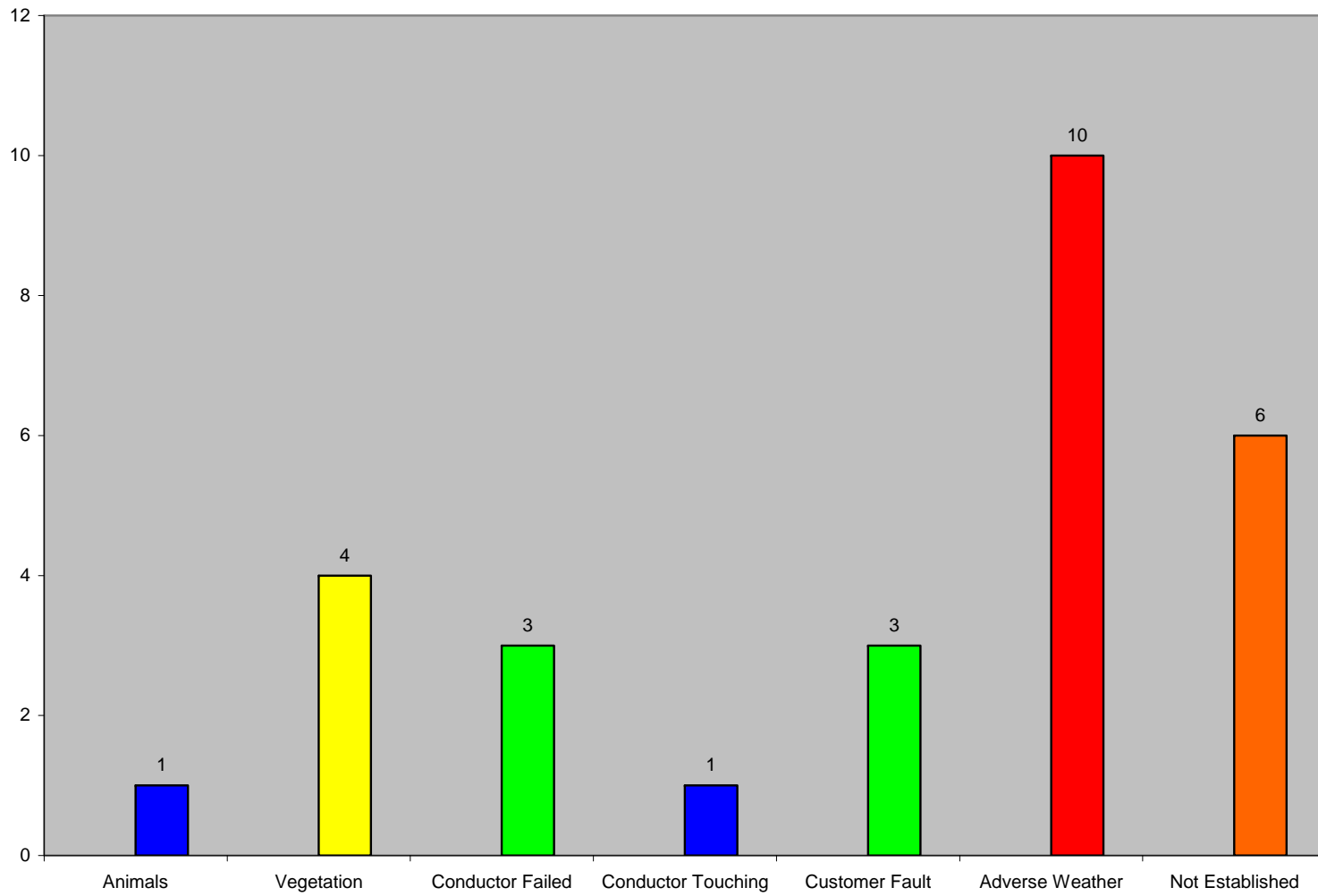


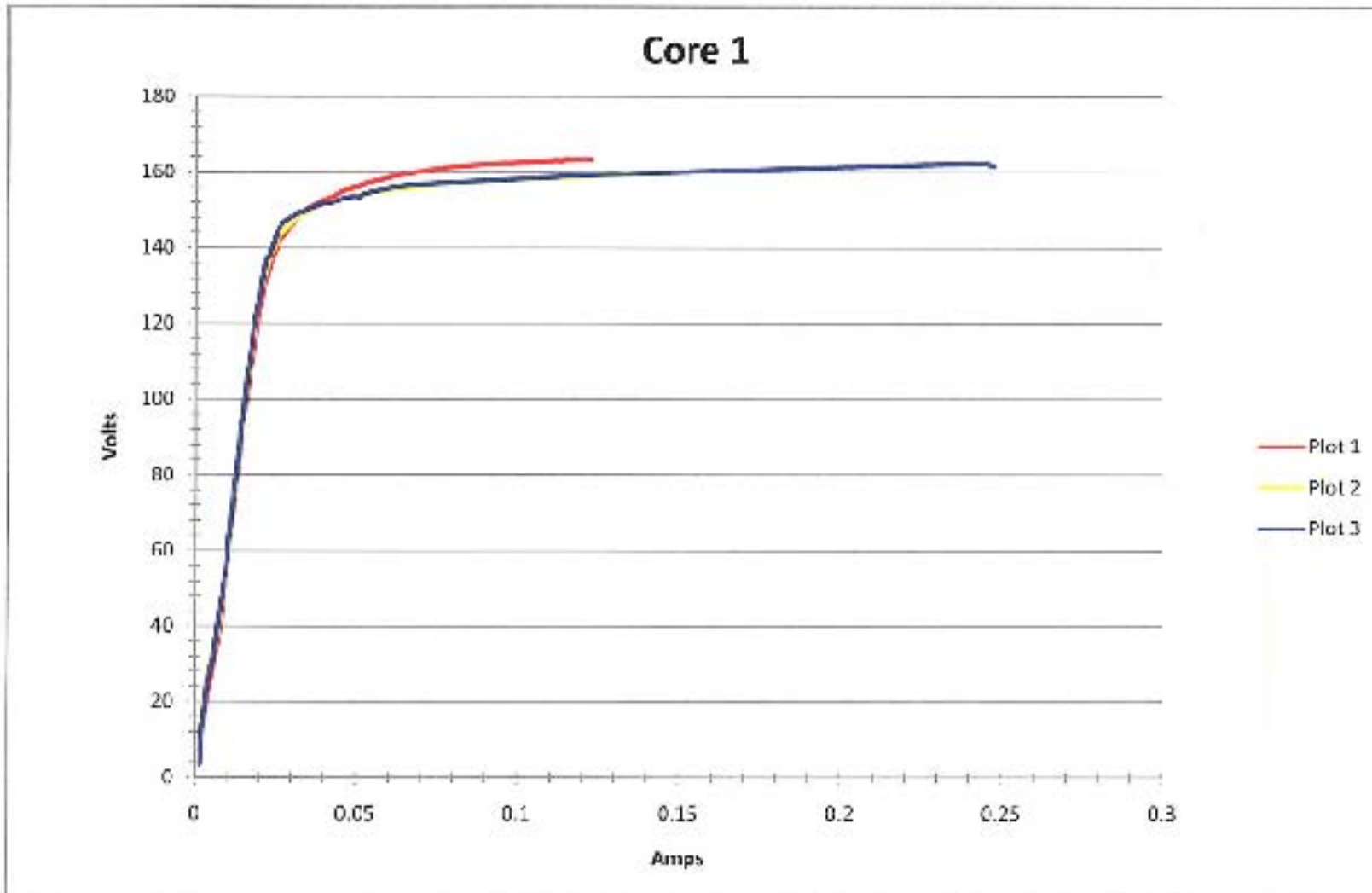
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"FCR"
(22kV)

FCR Summary of Faults





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