BENEFITS OF SMARD GRID TECHNOLOGIES IN SOUTH AFRICA

MSc(Eng) Dissertation Prepared by

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DECLARATION

I declare that this postgraduate dissertation is my own work. All sources that I have used and quoted have been referenced. This work has not been submitted to any other University for any other degree or examination.

Signed by candidate

09/09/2014

Immaculate Angela Masembe

Date

DEDICATION

To my Father, Creator, Lord and God

From whom I draw my strength and who makes all things possible. He never leaves nor forsakes me. This complete dissertation is a clear testimony of how He shows Himself mighty on my behalf.

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First and foremost I would like to thank my Father in Heaven and who always goes before me and makes my crooked paths straight. This dissertation is a dedication to HIM. May Your will always be done. I thank You and I Love You.

'The eyes of the LORD search the whole earth in order to strengthen those whose hearts are fully committed to Him '

II Chronicles 16:9

I would like to thank my supervisor Prof CT Gaunt for his in depth insight, criticism and guidance.

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ABSTRACT

The main purpose of a power system is to deliver the electrical energy requirements of its customer, at the lowest possible cost and at an adequate level of reliability. A power system may be divided into three sub systems: generation, transmission and distribution. Each sub system plays a different role for the entire network.

The distribution sub-system in South Africa, much like many other countries in the world, is still based on 20th century technology. According to some sources, 20th century technology cannot efficiently sustain a 21st century economy, and that power networks need to be 'modernized'. A report released in 2007 by the National Energy Regulator of South Africa (NERSA) on the state of the Electricity Distribution Industry (EDI) infrastructure, indicated that although there were pockets of good performance, assets needed urgent rehabilitation and investment. Further studies have revealed that the distribution grid infrastructure is aging and poorly maintained, and that its state was steadily deteriorating. Ageing infrastructure has been identified as the key challenge for the electricity generation, transmission and distribution sectors. It has also been estimated that between 2012 and 2020, more than 250 billion (2008) ZAR will be needed to maintain and expand the transmission and distribution network infrastructure.

Smart grid technologies have been proposed as one of the possible means of implementing new technologies and techniques into the grids of different countries. The main motive towards smart grid technologies is to improve reliability, flexibility, accessibility and profitability; as well as to support trends towards a more sustainable energy supply.

Besides aging infrastructure, inadequate generation capacity has also been a problem faced by the industry. Since 2007, South Africa has faced electricity supply problems due to inadequate generation capacity, which culminated in rolling black outs and load shedding in 2007 and 2008. The main causes of the blackouts were: insufficient generation capacity to meet growing demand, unreliable transmission and distribution networks, as well as inadequate operation of existing plants. Traditionally, generation capacity has not been present in the distribution zone. However, due to technological developments in distributed generation technology; constraints ont he construction of new transmission lines and grid infrastructure; increased customer demand for highly reliable electricity; and environmental concerns; the presence of generation in the distribution subsystem has increased.

This dissertation, entitled **BENEFITS OF SMART GRID TECHNOLOGIES IN SOUTH AFRICA**, aims to show the potential reliability benefit of smart grid technologies and distributed generation.

There are a variety of smart grid technologies available on the market, each aimed at improving different aspects of power system performance. Smart grid technologies, which are said to improve distribution feeder reliability, were identified and selected in this study. These are fault passage indicators, distance to fault estimators and feeder automation. Distributed generation in the form of solar PV was also introduced into the study.

In order to determine the potential reliability benefit of the identified smart grid and DG technologies, an experiment was designed and setup. A feeder from the Roy Billinton Test System (RBTS)was selected and used for the analysis. The effect of aging infrastructure was modelled into the system, as this is the greatest challenge facing the South African power distribution network. The identified smart grid technologies and distributed generation were then integrated in the system and their impact on reliability was evaluated. The reliability worth of the different technologies was also determined and this was used to conduct a cost/benefit analysis regarding the economic feasibility of the technologies.

From the research findings, a number of key conclusions were drawn. An important conclusion was that the added technologies had no impact on the frequency of interruptions and made no contribution towards decreasing the frequency of interruptions. It was however noted, that implementation of feeder automation saw a decrease in the frequency of sustained interruptions (interruptions longer than 5 minutes) and an increase in the experienced momentary interruptions (interruptions longer than 3 seconds but no longer than 5 minutes). Another key observation was that the frequency of interruptions was directly related to the state of the infrastructure. The presence of aged and worn out transformers on the system increased the average failure rate of the system by about 20%.

The added technologies did contribute towards decreasing the outage duration experienced by customers on the feeder. Despite the addition of the different identified smart grid technologies, the greatest decrease in outage duration was experienced when the system infrastructure is not aged. This points towards the importance of addressing the underlying issues of the system before attempting to implement more advanced technological systems.

The financial feasibility of implementing the identified technologies was also considered. The greatest saving in interruption costs arose when the aged transformers were replaced with new ones. In most cases, the payback periods for the investments were extremely lengthy and would most likely be deemed unfeasible by the investor. The most feasible payback period was experienced when new transformers were installed in the system. An investment which would need to be done nonetheless in the long run as eventually the worn out transformers would get to a point where they fail completely is not replaced. A sensitivity analysis conducted on the payback period of the investments also strongly brought out the fact that the greatest contributor to the interruption costs experienced on the network was as a result of the and not the lack of more modern technologies.

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1 ACRONYMS

ASAI	Average System Availability Index
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CDF	Customer Damage Function
CIC	Customer Interruption Costs
CTAIDI	Customer Total Average Interruption Duration Index
DBSA	Development Bank of South Africa
DG	Distributed Generation
ECOST	Expected Interruption Cost
EDI	Electricity Distribution Industry
EENS	Expected Energy Not Served
ENS	Energy Not Supplied
EUR	Euro
FLISR	Fault Location Isolation and Service Restoration
HL	Hierarchical Level
IEA	International Energy Agency
IEAR	Interrupted Energy Assessment Rate
IEEE	Institute of Electrical and Electronic Engineers
kW	kilo Watt
kWh	kilo Watt hour
LP	Load point
MAIFI	Momentary Interruption Frequency Index
MCS	Monte Carlo Simulations
NELT	National Energy Technology Laboratory
NERSA	National Energy Regulator of South Africa
PV	Photovoltaic
r	average outage duration

RBTS	Roy Billinton Test System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SANEDI	South African National Energy Development Institute
SASGI	South African Smart Grid Initiative
TTF	Time To Failure
TTLF	Time To Locate Fault
TTR	Time To Restoration
U	Annual outage duration
US$/USD$	United States Dollar
ZAR	South African Rand
λ	Failure rate

1 INTRODUCTION

This chapter introduces the state of the current South African power distribution system and outlines the challenges it is currently facing. It introduces smart grid techniques as a potential solution to improve the performance of the network. This chapter also identifies the hypothesis to be tested and describes the approach adopted in conducting the research.

1.1 BACKGROUND

1.1.1 Smart grid technologies, what are they?

The term 'smart grid' refers to a class of technologies that are being developed and used by utilities to deliver electrical systems into the 21st century using computer-based remote control and automation. These technologies are believed to improve the reliability, resilience, flexibility, and efficiency (both economic and energy) of the electric delivery system [NELT, 2007b].

1.1.2 The state of the South African power network

The distribution sub-system in South Africa, much like many other countries in the world, is still based on 20th century technology [DBSA, 2012]. According to some sources, 20th century technology cannot efficiently sustain a 21st century economy, and power networks need to be 'modernized' [NELT, 2007b; SANEDI, 2012a]. A report released in 2007 by the National Energy Regulator of South Africa (NERSA) on the state of the Electricity Distribution Industry (EDI) infrastructure, indicated that although there were pockets of good performance, assets needed urgent rehabilitation and investment [NERSA, 2007].A study conducted in 2008 by the EDI Holdings on the state of the distribution grid of the country, revealed that the distribution grid infrastructure was aging and poorly maintained, and that its state was steadily deteriorating. The study estimated that the maintenance, refurbishment and strengthening backlog in the distribution grid amounted to about 27.4 billion 2008 South African Rand (2008 ZAR). This backlog was growing at an alarming rate of 2.5 billion ZAR per annum [EDI Holdings, 2008]. The same study pointed out that the current practices in the EDI do not promote business sustainability and economic growth. It also highlighted the fact that the increased use of an under-maintained distribution grid could be a potential risk to the industry.

A more recent report released in 2012 by the Development Bank of South Africa (DBSA) on the State of South Africa's Economic Infrastructure, identified ageing infrastructure as the key challenge for the electricity generation, transmission and distribution sectors. The other challenges faced in the South African power industry include: poor performance networks, shortage of generation capacity, significant infrastructure backlog, ageing work force, inability to effectively introduce renewable energy options into the grid, and the inability to effectively introduce demand response strategies [SANEDI, 2012b].

It has been estimated that between 2012 and 2020, more than 250 billion (2008) ZAR will be needed to maintain and expand the transmission and distribution network infrastructure [SANEDI, 2012b; DBSA, 2012].

1.1.3 Smart grid technologies: A potential solution?

Smart grid technologies have been proposed as one of the possible means of implementing new technologies and techniques into the grids of different countries [SANEDI, 2012a]. The main motive towards smart grid technologies is to improve reliability, flexibility, accessibility and profitability; as well as to support trends towards a more sustainable energy supply [Slootweg, 2009].

There have been a number of smart grid demonstration and deployment efforts internationally. Many governments have invested financially into these initiatives and a few examples are provided in Table 1-1 below. The outcome of these initiatives is yet to be published.

Table 1-1 National smart grid demonstration and deployment efforts [IEA, 2011]

Country	National smart grid initiatives
China	The Chinese government has developed a large, long-term stimulus plan to invest substantially in smart grids. Smart grids are seen as a way to reduce energy consumption, increase the efficiency and manage electricity generation from renewable technologies. China's State Grid Corporation outlined plans in 2010 for a pilot smart grid programme that maps out deployment to 2030. Smart grids investments will reach at least 96 billion US Dollars (USD) by 2020.
France	By 2011, the electricity distribution operator of France, ERDF, had already started deploying about 300 000 smart meters in a pilot project based on an advanced communication protocol named Linky. If the pilot is deemed a success, ERDF intendsto replace all of its 35 million meters with Linky smart meters by 2016.
Italy	In 2011 the Italian regulator (Autorità per l'Energia Elettricaedil Gas) awarded eight tariff-based funded projects on active medium voltage distribution systems, to demonstrate at-scale advanced network management and automation solutions necessary to integrate distributed generation. The Ministry of Economic Development also granted over 200 million Euro (EUR) for the demonstration of smart grids features and network modernization in the Southern Italian regions.
Japan	In 2011, the Federation of Electric Power Companies of Japan started developing a smart grid that incorporates solar power generation with a government investment of over USD 100 million. The Japanese government also announced a national smart metering initiative and large utilities have announced smart grid programmes.
South Korea	The South Korean government launched a USD 65 million pilot programme in partnership with their power industry on Jeju Island. The pilot consists of a fully integrated smart grid system for 6 000 households, wind farms and four distribution lines. Korea has announced plans to implement smart grids nationwide by 2030.
United States of America	USD 4.5 billion was allocated to grid modernization under the American Recovery Reinvestment Act of 2009, including: USD 3.48 billion for the quick integration of proven technologies into existing electric grids, USD 435 million for regional smart grid demonstrations, and USD 185 million for energy storage and demonstrations.

Smart grids have many attractive features; among these include [Uluski, 2010; Ton et al., 2011; Huang et al., 2012]:

- Their ability to self-heal, which make them more resilient to disturbances on the network.
- They incorporate two way real time communication between the consumer and the utility
- They allow for the easy integration and management of energy storage schemes, distributed generation and renewable energy sources such as solar and wind (of which a large potential exists in South Africa) [Albert Molderink et al., 2009].

In order to maintain the quality of electricity supply, ensure stability of the electricity network, minimise electricity load shedding and avoid blackouts, the DME published regulation 773 in terms of section 35 of National Electricity Regulation act in 2008. Regulation 773 requires all end users with a monthly electrical energy consumption of 1000kWh and more to install a smart system. A smart system referring to an electricity meter that allows for: the measurement of consumed energy on a time interval basis, two-way communication between the end user and the licensee, storage of interval data and transfer it remotely to the licensee and remote load management. The installation of this smart system was to be completed by 01 January 2012 [DME, 2008]. Though this regulation has been in effect since 2008, the specified timeframe and details regarding smart grid and time of use tariff implementation as allowed for in the regulation was under review in March 2013 [SANEDI, 2013].

Whether or not smart grid technologies are the solution to the major problems the South African power distribution industry faces, is yet to be completely tested. By the end of 2012, apart from Regulation 773 of the National Electricity Regulation Act, there was no other policy advocating for the implementation of smart grid techniques, and therefore a great bulk of the anticipated 250 billion (2008) ZAR financial investment will most likely be spent on 20th century technology [SANEDI, 2012a]. The South African Smart Grid Initiative (SASGI) was established in May 2012 and is an industry forum established under the guidance of SANEDI and chaired by the Department of Energy. The main objectives of SASGI are to facilitate cooperation, to contribute to policy formulation, to provide guidance in the establishment of standards, identify technology functionality and to provide leadership in the deployment of appropriate technology.

This research project will therefore investigate the benefit of smart grid techniques in terms of reliability improvement, and conduct a cost/benefit analysis of whether these techniques could be a potential solution to the major problem(s) within the industry. This will help determine whether the anticipated financial investment between 2012 and 2020 of about 250 million ZAR should potentially be invested in smart grid technologies.

1.2 POWER SYSTEM RELIABILITY

Reliability may be defined as the probability of a system performing its required tasks adequately for a period of time and under set operating conditions [Billinton & Allan, 1992]. This definition in itself highlights the uncertainty surrounding the ability of the power system to perform as desired. Therefore, the purpose of power system reliability evaluation is to try and quantify the reliability of a system for planning and decision making.

The reliability of a power system may be divided into two: system adequacy and system security. System adequacy concerns the existence of sufficient facilities within the power system to meet the demands of the customers. On the other hand system security encompasses the ability of the network to respond to any disturbances.

While it is helpful to know the events which cause the unreliability of a system, the more important issue is to know and understand the impact of these events on the power system. Reliability indices are therefore introduced as a means of quantifying and assessing the reliability of the power system. Reliability indices measure the frequency, duration and severity of disturbances on the network [Fong & Grigg, 1994; Reppen & Feltes, 2001; Edimu, 2009]. Utilities take note of these indices and use them to determine power system reliability for a particular area [Brown, 2006]. These indices shall be discussed in more detail in chapter 2.

Several techniques have been developed and used to evaluate power system reliability and to quantify reliability indices. These are grouped into deterministic and probabilistic approaches. Deterministic approaches simply use past experiences to predict the future operation of the system. They are generally simple to implement and easy to understand but generally result in over-designed and uneconomic solutions [Pereira & Balu, 1992; Reppen & Feltes, 2001].Probabilistic techniques on the other hand, incorporate the stochastic and random nature of the power system and are able to take into account inherent unplanned events [Reppen & Feltes, 2001].

1.3 APPLICATION OF RELIABILITY EVALUATION TECHNIQUES

As already mentioned, a power system may be divided into three: generation, transmission and distribution. Hierarchical levels (HL1 –HL3), shown in Figure 1-1,were identified as functional blocks in order to ensure consistency in the application of power system reliability evaluation [Billinton & Allan, 1992]. Reliability indices may be evaluated in each hierarchical level and used by planners and operators to develop strategies and to make decisions [Kim & Singh, 2009].

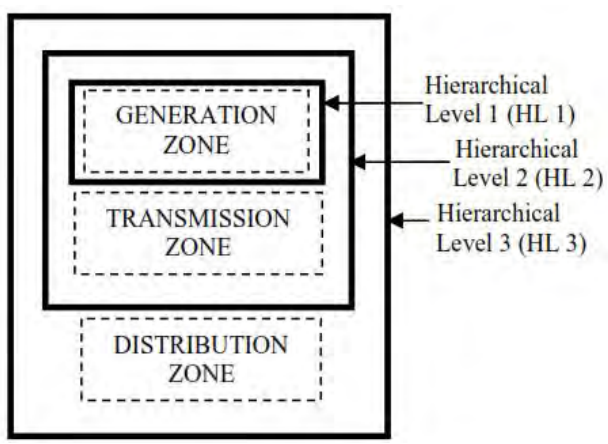

Figure 1-1 Hierarchical levels of power system [Billinton & Allan, 1992]

Hierarchical level 1 (HL1) represents the generation zone where electrical energy is produced from primary energy sources, such as coal, wind, solar and hydro energy. Hierarchical level 2 (HL2), which is commonly referred to as the composite zone or system, consists of the generation and transmission zones combined. Both the transmission and distribution zones are responsible for transporting electrical power, whereby the distribution sub-system transmits to customer points. Hierarchical level 3 (HL3) refers to the entire system or generally for easier analysis, the distribution zone and its facilities [Billinton & Allan, 1988].

An interruption or disturbance in any hierarchical level has an impact on the electricity availability to a number of customers on the network. In most cases the interruptions in the distribution zone are more frequent compared to those of the other zones. However an event causing an interruption in the distribution zone does not affect as many customers as a disturbance in any of the other two zones. In general, an outage in the composite system will last longer and have higher financial costs compared to an outage in the distribution zone [Edimu, 2009].This research project will concentrate on the reliability of the distribution subsystem because the majority of interruptions, about 80% [Billinton & Allan, 1988], occur in this zone. Therefore if the power interruptions in the generation and transmission are included in the analysis, the reliability cost/worth indices will not change considerably [Billinton & Allan, 1988].

1.4 POWER GENERATION INADEQUACIES AND DISTRIBUTED GENERATION

ESKOM, the national power utility in South Africa, dominates the electricity industry, supplying about 95% of the country's electricity demand. The remaining 5% is supplied by municipalities, redistributors and private generators [DBSA, 2012]. A vast majority (more than 80 %)of South African electricity is generated from coal, which is highly emissions intensive and raises environmental concerns [ESKOM, 2011; DBSA, 2012].

ESKOM also owns and operates the transmission grid which consisted of about 300 000 km of power lines and 30 005MVA of installed transformer capacity by 2011. With regard to the distribution sector, ESKOM retails about 60% of its electricity sales to licensed municipalities in the country and 40% to a small number of private distributors. The distribution industry has an asset base of 261 billion ZAR, and as previously mentioned, these assets need urgent financial investment, refurbishment and rehabilitation [EDI Holdings, 2008; DBSA, 2012].

Since 2007, South Africa has faced electricity supply problems due to inadequate generation capacity, which culminated in rolling black outs and load shedding in 2007 and 2008 [Eberhard, 2008]. According to Eberhard [2008], the main causes of the blackouts were: insufficient generation capacity to meet growing demand, unreliable transmission and distribution networks, as well as inadequate operation of existing plants. Between 1994 and 2007 the reserve margin decreased from 31% to 6% [Eberhard, 2008] and currently sits at about 1% [Strydom, 2013].

The network planning and design criteria adopted by distribution utilities in South Africa, were meant to maximize the number of consumers connected with the funds available. Lengthy radial distribution networks were therefore built, supplying numerous consumers (in some cases, more than 10000 consumers on a single-medium voltage feeder) with little or no alternative supply options [Carter-Brown et al., 2008]. Distributed generation offers the opportunity to integrate electricity generated from renewable resources into the system, and offers the chance to increase the reliability of supply.

Traditionally, generation capacity has not been present in the distribution zone, and in fact, the design of power systems did not take into consideration generation facilities at this level. However, this has changed over the last decade, and due to technological developments in distributed generation technology; constraints on the construction of new transmission lines and grid infrastructure; increased customer demand for highly reliable electricity; and environmental concerns; the presence of generation in the third hierarchical level has increased [IEA, 2002].

Based on what has been mentioned above, this research study will also incorporate distributed generation as a means of mitigating power supply problems, and consider its impacts on the distribution system reliability.

1.5 MOTIVATION FOR RESEARCH AND HYPOTHESIS

The South African power industry has been facing many challenges over the past few years. These include meeting the demand for power, as well as attaining great performance with a power grid filled with aged equipment. As mentioned previously, it has been estimated that about 250 million ZAR will be needed to be invested into the power grid for refurbishment [SANEDI, 2012a]. Proponents for smart grid technologies, like the South African National Energy Development Institute (SANEDI), believe that these types of technologies could be the answer to South Africa's power industry problems.

Therefore, whilst taking into consideration the main purpose of a power system, which is to deliver power at the lowest possible cost and at an adequate level of reliability, this research project aims to determine the impact that smart grid techniques could potentially have on distribution reliability, in order to determine whether they could be a potential solution to the industry's key challenges. It also aims to conduct a cost/benefit analysis on this impact by attaching a value to the reliability change.

Based on what has been discussed, this research project tests the following hypothesis:

***Smart grid technologies and distributed generation could beneficially improve the reliability of a distribution feeder in South Africa*.**

1.5.1 Research questions

The questions which will be used to test the validity the hypothesis are:

(a) Which reliability evaluation techniques are available and which is most suitable for the analysis?

(b) How is distribution reliability quantified?

(c) Which factors affect reliability assessment and which are most applicable in the South African context?

(d) Which is the most suitable test system to analyze?

(e) Which smart grid technologies affect distribution reliability at a feeder level?

(f) How do these identified smart grid techniques improve the reliability of a distribution network?

(g) What is the reliability worth of smart grid technologies?

(h) What is the reliability worth of distributed generation?

(i) Is there any difference between the results with smart grid technique and distributed generations or not?

(j) What will be used to determine the benefit of smart grid technologies and distributed generation?

1.6 SCOPE AND LIMITATIONS

This research project will focus on the distribution system reliability analysis. In particular it will focus on power system adequacy, which means power system dynamics, transient disturbances are not considered.

1.7 REPORT FORMAT

This dissertation comprises of seven main chapters:

- Chapter 1 introduces the dissertation and motivates why the study needs to be conducted. The hypothesis to be tested and main research questions to be answered are also given in this chapter.

- Chapter 2 gives details on the different reliability assessment techniques. It describes reliability and reliability worth indices. Details on smart grid techniques and distributed generation and their impact on reliability are also discussed in this chapter.

- Chapter 3 discusses the theory applied in the development of the experiment used to test the hypothesis.

- Chapter 4 describes the experiment design, test system and the assumptions made in the analysis. Details on the simulation technique are also covered.

- Chapter 5 discusses the simulation procedure and the different cases and contingencies implemented on the test system. Details on the evaluation of the financial feasibility of the different cases are given.

- Chapter 6 presents the results of the different cases in the form of beta distributions and average values. These results are then discussed and compared.

- Chapter 7 concludes and summaries the research findings of the dissertation. The validity of the proposed hypothesis is examined.

2 LITERATURE REVIEW

This chapter aims to answer the research questions posed in the previous chapter. It discusses methods for reliability and reliability worth assessment. It also examines the relevant reliability indices, smart grid techniques, distributed generation and how each of them affects distribution system reliability.

2.1 POWER SYSTEM RELIABILITY

Reliability may be defined as the probability of a system performing its required tasks, adequately for a period of time and under set operating conditions [Billinton & Allan, 1992]. This definition in itself highlights the uncertainty surrounding the ability of the power system to perform as desired, and therefore, the purpose of power system reliability evaluation and assessment, is to try and quantify the reliability of a system for planning and decision making. It has been acknowledged since the 1930s [Billinton & Allan, 1994], that the behaviour of a power system is stochastic in nature and therefore it is vital that any reliability evaluation techniques reflect this.

It was mentioned in section 1.2, that reliability evaluation techniques can be categorized into two groups: deterministic and probabilistic. Deterministic approaches simply use past experiences to predict the future operation of the system. They are generally simple to implement and easy to understand but generally result in over-designed and uneconomic solutions [Pereira & Balu, 1992; Reppen & Feltes, 2001]. Probabilistic techniques on the other hand incorporate the stochastic and random nature of the power system and are able to take into account inherent unplanned events [Reppen & Feltes, 2001].

2.1.1 Probabilistic reliability assessment techniques

According to Cross et al. [2006], the study of system reliability is best achieved when using statistics and probability distribution functions (pdfs) to describe both the inputs and outputs of the system, as the uncertainty of these parameters are taken into consideration. Probabilistic assessment methods use probability distribution functions to account for the random behaviour of the power system. These may be further divided into two categories: analytical and simulation methods.

i. Analytical techniques

These techniques are relatively simple and easy to understand and execute. The power system is modelled mathematically and the expected value of the reliability indices is determined using numerical analysis. Many assumptions are made to simplify the modelling of the power system and as a result some significance in the analysis is lost, most especially when the system is large and complex [Billinton & Allan, 1994; Billinton & Wang, 1999a].

ii. Simulation techniques

This group of techniques treats the problem as a series of real experiments. The main simulation method is Monte Carlo Simulations (MCS).

Monte Carlo Simulations solve difficult reliability problems using random variables. They involve repeatedly finding deterministic solutions to a given problem, with each solution corresponding to a set of deterministic values of underlying random variables. Random numbers are generated from probability distribution functions used to describe reliability variables which behave randomly. When executing MCS, the number of simulations is important and in many cases, thousands of simulations need to be repeated in problem solving. Due to the availability of high speed computing facilities in the last decade, MCS techniques have become a more viable method for reliability assessment. MCS are very useful and yield more information on load point reliability indices [Anders, 1990; Alkuhayli et al., 9-11 Sept. 2012; Godha et al., 2012]

There are two types of MCS namely time sequential and non-sequential simulations. Time sequential simulations comprise of the generation of realistic artificial operational histories for the relevant elements of the system in chronological order [Billinton & Wang, 1999b; Godha et al., 2012]. With regard to non sequential methods, the state of each element in the system is obtained by sampling the components states space and ignores the chronological order of events [Véliz et al., 2010].

Time sequential MCS is also very flexible and has high reality potential. However it has extreme computational demands [van Casteren et al., 2000].

2.1.2 Probability distribution functions used in reliability assessment

Probabilistic reliability evaluation techniques mimic the random behaviour of the power system using pdfs. Literature describes the use of many different pdfs in reliability modelling and analysis. These include the Weibull, binomial, gamma, exponential, beta and normal pdfs.

The exponential distribution is probably the most used distribution in reliability assessment [Nadarajah & Kotz, 2006].The negative exponential distribution has been used to represent times to failure (TTF) when the failure rates of these components were assumed to be constant. This is because of its mathematical elegance [van Casteren et al., 2000]. Edimu et al. [2011] dispute this assumption and give examples of scenarios where the failure rate is not constant (e.g. at peak load and during extreme weather conditions).

The Weibull distribution has been used in many work of reliability assessment. Although it has been used to represent the restoration and maintenance durations [van Casteren et al., 2000], one of its limitations is that is has an infinite range [Cross et al., 2006]. Cross et al. [2006] also argue that despite its extensive application reliability assessment works, both the gamma and Weibull distributions are not suitable for reliability assessment modelling as they are only applicable to specific data sets. Cross et al. [2006]proceed to propose the use of the beta pdf to describe reliability system inputs and outputs.

Edimu et al. [2011]also advocate for the use of the beta pdf in the description of reliability input parameters and output indices. These authors deem it superior because unlike the other pdfs, the beta pdf has a finite range, and has the ability to attain a variety of shapes, allowing it to be used to describe a variety of data sets. Many other authors are in support of this argument and have used the beta pdf extensively in their works. It has been used in the determination of reliability worth [Dzobo, 2010], and also in the assessment of composite system reliability indices [Edimu, 2009]. Edimu et al. [2011] use the beta pdf for reliability evaluation and apply it in an investigation to determine the effect of normal, adverse and severe weather on the reliability of a power network. Herman& Gaunt [2008] use this same distribution, to describe customer interruption costs.

2.2 POWER SYSTEM PERFOMANCE INDICES

Reliability indices are used extensively in the power system industry as a means to quantify and assess reliability. Reliability indices measure the frequency, duration and severity of disturbances on the network and give insight into the performance of the system. These indices can be regarded as predictive indices or past performance indices. This depends on whether they are to provide information relating to future system performance or relate to actual system reliability and therefore show the actual performance of the system [Endrenyi, 1978; Fong & Grigg, 1994; Reppen & Feltes, 2001; Edimu, 2009].There are different groups of indices and these provide information about different aspects of the system. The indices which are listed below pertain to the distribution system.

i. **Distribution Reliability Indices of a series system** [Billinton & Allan, 1994]

- Average failure rate of system (λ_s)

$$\lambda_s=\sum_{i=1}^{N} \lambda_i \tag{2.1}$$

where λ_i is the average failure rate of load point i.
N is the number of series components in the system.

- Average annual outage time of system (U_S)

$$U_S=\sum_{i=1}^{N} \lambda_i r_i \tag{2.2}$$

where r_i is the average annual outage duration of load point i.

- Average outage time of system: (r_s)

$$r_s=U_s/ \lambda_s \tag{2.3}$$

These three indices are fundamentally important but do not give a complete picture of the power system's behaviour and response. It is for this reason that additional indices are evaluated. These indices give a good reflection on the severity of system interruptions and outages [Billinton & Allan, 1994] and are used to assess the performance reliability of the distribution system. They can be split into two categories; namely load and energy orientated indices and customer orientated indices. These are further explained below.

ii. **Load and energy orientated point indices** [Billinton & Allan, 1994]

- Energy Not Supplied(ENS) index

$$ENS =\sum L_{a\,(i)}U_i \tag{2.4}$$

where $L_{a(i)}$ is the average load of load point i.
U_i is the total number of customer served in the Load point i.

- Average Energy Not supplied (AENS) index

$$\text{AENS}=\frac{\text{total energy not supplied}}{\text{total number of customers served}}=\frac{\sum \text{La(i)U(i)}}{\sum \text{N(i)}} \tag{2.5}$$

where N(i) is the number of customers of load point i.

- Average customer curtailment index

$$\text{ACCI}=\frac{\text{total energy not supplied}}{\text{total number of customers affected}} \tag{2.6}$$

iii. **Customer orientated indices** [Billinton & Allan, 1994]

- System Average Interruption Frequency Index (SAIFI)

$$\text{SAIFI}=\frac{\text{total number of customer interruptions}}{\text{total number of customers served}}=\frac{\sum \lambda\text{(i)N(i)}}{\text{NT}} \tag{2.7}$$

where N(i) is the number of customers of load point i.

NT is the total number of customer served in the system

- Customer Average Interruption Frequency Index(CAIFI)

$$\text{CAIFI}=\frac{\text{total number of customer interruptions}}{\text{total number of customers affected}} \tag{2.8}$$

- System Average Interruption Duration Index(SAIDI)

$$\text{SAIDI}=\frac{\text{sum of customer interruption durations}}{\text{total number of customers}}=\frac{\sum \text{U(i)N(i)}}{\text{NT}} \tag{2.9}$$

where U(i) is the average annual outage time.

- Customer Average Interruption Duration Index(CAIDI)

$$\text{CAIDI}=\frac{\text{sum of customer interruption durations}}{\text{total number of customers interruptions}}=\frac{\sum \text{U(i)N(i)}}{\text{NT}} \tag{2.10}$$

- Average Service Availability Index(ASAI)

$$\text{ASAI}=\frac{\text{customer hours of available service}}{\text{customer hours demanded}}=\frac{\sum N(i)\ x\ 8760-\sum U(i)N(i)}{\sum N(i)\ x\ 8760} \quad (2.11)$$

where 8760 is the number of hours in year.

- Average Service Unavailability Index(ASUI)

$$\text{ASUI}=\frac{\text{customer hours of unavailable service}}{\text{customer hours demanded}} \quad (2.12)$$

$$=1-\text{ASAI}$$

The indices mentioned above are the expected values of underlying probability distribution functions. According to Billinton & Kumar [1990], it is difficult and misleading to draw conclusions using overall system and bus average indices. It is therefore recommended to not only use the expected value of the index, but also the underlying probability distribution in order to get a better understanding [Billinton et al., 1991]. Edimu [2009] is in agreement with this statement and discusses the usefulness of probability distributions to describe the inputs and outputs of reliability analysis.

The most commonly used indices are the SAIFI, CAIDI, SAIDI and ASAI indices. Other indices which are not very popular but are still used, can be found in Table 2-1.These indices are the Customer Total Average Interruption Duration Index (CTAIDI), the Average System Interruption Frequency Index (ASIFI) and the Average System interruption Duration Index (ASIDI). A more recent index, also included in Table 2-1, called the Momentary Average Interruption Frequency Index (MAIFI) was proposed by Brown [2006]. The purpose of this index was to give an indication on the costs involved due to momentary interruptions, when the duration of the interruption is very short.

Table 2-1 Uncommon reliability indices [Brown, 2006]

Index	Formula	Unit
CTAIDI	$\frac{\sum \text{customer interruption duration}}{\text{customers experiencing one or more interruption}}$	hours per year
ASIFI	$\frac{\text{connected kVA interrupted}}{\text{total connected kVA served}}$	per year
ASIDI	$\frac{\text{connected kVA hours interupted}}{\text{total connected kVA served}}$	hours per year
MAIFI	$\frac{\text{total number of customer momentary interuptions}}{\text{total number of customers served}}$	per year

2.3 FACTORS AFFECTING RELIABILITY

Power reliability indices are used widely by utilities for decision making and planning. These indices are random and are affected by different factors such as weather conditions, power system component failure due to wear and tear et cetera. The impact of these factors or events could lead to various ramifications whose severity ranges from mere inconvenience to drastic loss of property, equipment and even human life. Therefore, in order to get a more realistic indication of reliability indices, it is important to identify major factors affecting power system reliability specific to a place or area, and integrating the impact of these factors into the reliability evaluation [Edimu, 2009]. The main factors which have been recognized for having the most impact on the reliability indices are [Short, 2004]:

i. Weather

Severe weather greatly affects the failure and restoration duration of the components in the distribution network and contributes to the variance of distribution indices [Alvehag & Söder, 2011]. For example, heavy ice deposits on overhead lines during the cold season could result in faults [Rabinowitz, 2000]. A study conducted by Edimu et al. [2011], reports that even with the different seasons, certain severe weather elements are likely to occur at certain times of the day. For example, lightning is more prominent in summer afternoons in South Africa [Edimu et al., 2011].

ii. Age

The age of components in a power system has a great impact on its reliability. An aging component of the power system is defined as a component with an average service age greater than its design lifetime [Willis et al., 2001]. When a number of key components of the power system are aged, aging failures become a prevailing factor of system unreliability [Li, 2002]. Willis et al. [2001] and Bollen [2001] argue that a component in the power system is more likely to fail due to aging and that the failure rate of a component increases as it continues to age. Li et al. [2007] emphasises the importance of age in power system reliability and stresses that aging failures cannot be excluded in reliability evaluation.
According to the a report released by the Development Bank of South Africa (DBSA) in 2012, ageing infrastructure is the key challenge facing the electricity generation, transmission and distribution sectors of the country [DBSA, 2012].

iii. Physical environment

The physical environment and in particular, the tree coverage and vegetation surrounding the distribution grid have an impact on the system reliability [Short, 2004]. Vegetation maintenance involves the removal of trees and vegetation which could potentially cause faults and interruption if they were to come in contact with overhead lines.

iv. Percent underground

There are two ways of delivering power: through overhead lines and underground cables. The overhead lines cost less to install and maintain and as a result have been the dominant means of power delivery. But the use of underground cables has been increasing because they are more reliable than overhead lines. Underground cables are less likely to fail and are more reliable than overhead lines [Short, 2004]. They are less susceptible to disturbances from weather elements and the physical environment, but on the otherhand, they are more complex to install and maintain [Rabinowitz, 2000; Sahin & Aras, 2007; Hall, 2009].

v. Distribution Voltage

The reliability of a power system decreases as the voltage level increases. The greatest advantage associated with higher disitribution voltages is that more power can be delivered for a given current.This means less line losses. Higher voltage systems also require fewer capacitors and regulators. Utilities can also decrease the size of the conductor or distribute more power for the same conductor size. A higher distribution voltage also allows utilities to run much longer distribution circuits with few distrbution substations. But as already mentioned a higher disitribution voltage results in reduced distribution reliability due to longer circuits and more exposure to lightning and wind. Higher distribution lines have more voltage sags and interruptions. There is also an increased safety risk for maintenance personel and the cost of equipment (transformers, cable insulators,etc) is higher [Burke, 2001; Short, 2004].

vi. Load density

The load on the power system is never constant and is continuously varying. The load directly impacts the reliability of the system because if the system is overloaded and the components stressed, the chances of an interruption increase [Burke, 2001].

Although all the six factors listed above are important and have been highlighted in literature as having a great impact on power system reliability, this research project will concentrate on the impact of aged equipment reliability. There are three main reasons for this: the first is that this research project focuses on the potential benefits smart grid techniques could offer the country in terms of reliability improvement. Secondly, aged and under maintained equipment components have been identified as the key and main challenge facing the power industry in South Africa [NERSA, 2007; EDI Holdings, 2008; DBSA, 2012]. It is therefore imperative to include the impact of aging in the analysis. Lastly, literature has indicated that in a system where aged equipment is prevalent, the effect of aging must be incorporated in the reliability evaluation [Willis et al., 2001; Bollen, 2001; Li et al., 2007]. The next sub section will highlight the impact that aged equipment has in power system reliability analysis.

2.3.1 Aged equipment

It has been well documented in literature that the relationship between failure rate or failure probability and age, can be represented using the basin or bath tub curve as illustrated in Figure 2-1 [Wang et al., 2002; Li et al., 2006].

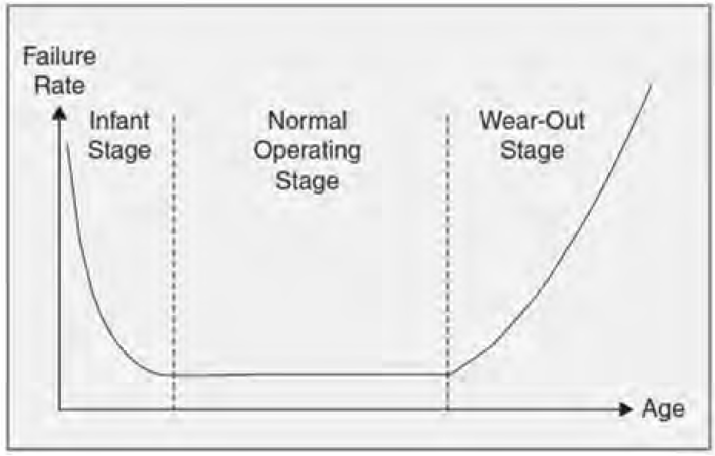

Figure 2-1 Bath tub curve for failure rate of equipment [Li et al., 2006]

During the infant stage, the failure rate decreases and eventually stabilizes. Most of the failures during this stage are due to manufacturing, design, misuse, packaging, transportation, storage, and installation faults. It reflects the failure rate due to weak parts that escape final testing and screening [Oroge, 1991]. Rigorous testing, environmental stress screening and high quality control can be used to minimize the number of weak components leaving factories [Cheng, 2006]. During the normal operating stage, the failure rate of equipment is generally constant and most failures are random [Oroge, 1991]. Most reliability assessments assume that equipment is operating in this stage. During the wear-out stage, the equipment has reached or is approaching end of life and the failure rate increases dramatically with age. Although the useful period of a power system component may be extended through regular maintenance, in practice the component will fail as a result of wear out and aging [Billinton & Allan, 1992; Li et al., 2006].

2.4 BENCH MARK TEST SYSTEMS

Two published bench mark test systems have been identified for reliability assessment namely, the IEEE Reliability Test System (RTS) and the Roy Billiton Test System (RBTS). The IEEE RTS is a 24 bus system, with 10 generator buses, 17 load buses, 33 transmission lines, 5 transformers and 32 generating units. This test system is applicable for bulk power and composite system reliability evaluation methods [Reliability Test System Task Force, 1999]. Billinton et al. [1989] describes the IEEE RTS as a large power network which can be difficult to use for initial studies in an educational environment. It requires the use of computer programs to perform the vast majority of reliability analyses. According to Billinton et al. [1989], "*a technique, however elegant it may be, should first be applied to a small system which can be easily solved and appreciated by the student using hand calculations before being extended to computer development.*"It is for these reasons that Billinton et al. [1989] developed the RBTS, which is simple enough to allow reasonable evaluation times but could still ensure that the studies have enough detail to reflect the actual complexities involved in practical reliability analysis. At first publication, the RBTS did not include the description of necessary distribution and sub transmission networks, but this was later changed in 1991 [Allan et al., 1991] and these networks were further developed in 1996 [Billinton & Jonnavithula, 1996].

The next section will discuss smart grid techniques and will particularly emphasis those which impact distribution reliability.

2.5 SMART GRID TECHNOLOGIES

Smart grid technologies refer to a group of improved technologies and concepts, that use digital and other advanced technologies, to monitor and manage the transmission of electricity from all generation sources, to meet the varying electricity demands of end users [IEA, 2011].In a broad sense, a "smart grid" refers to a conventional electric power system equipped with these technologies for the purpose of reliability improvement, ease of control and management, integrating of distributed energy resources and electricity market operations. Figure 2-2depicts the concept of what a completely smart power grid envisioned in the future entails.

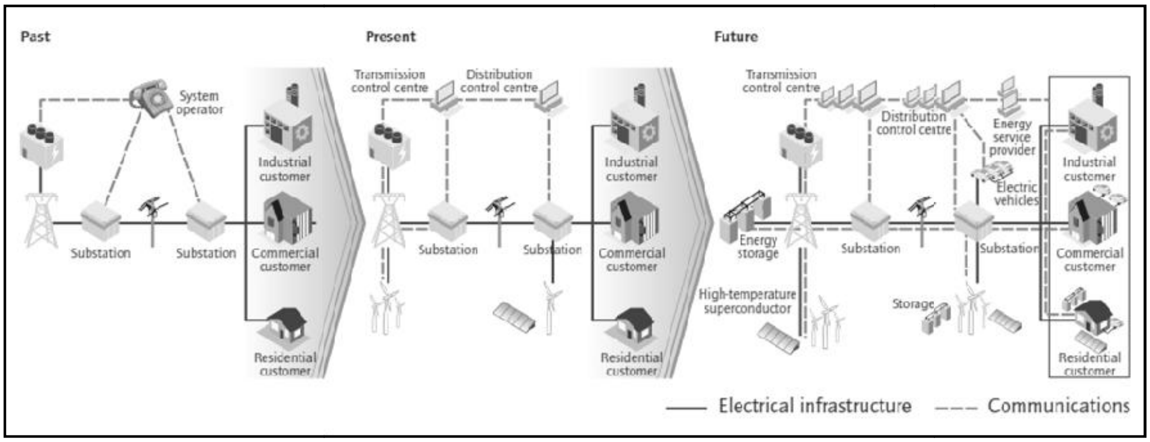

Figure 2-2 Smarter Electricity Systems [IEA, 2011]

Some the characteristics of a smart grid are as follows. A smart grid [Uluski, 2010; IEA, 2011]:

- Enables informed participation by customers
- Accommodates all generation (including renewable energy supply) and storage options
- Provides power quality for the range of needs
- Optimizes asset and utilization and operation efficiency
- Provides resilience against disturbances, attacks and natural disasters. It can detect and isolate disturbances and minimizes its impact i.e.it is self healing.

According to Uluski [2010], the two main objectives of smart grid technologies are to:

i. Provide information that will enable the customer to make informed decisions
ii. Enable the electric utility to make decisions, to operate the power system more effectively and efficiently in order to achieve higher reliability.

In order to fulfil the two main objectives of the power system, different types of technologies and techniques have been developed. These may be grouped together into five key areas [NELT, 2007a]:

i. **Integrated Communications**

These are high speed, fully integrated, two-way communication technologies which make the smart grid a dynamic and interactive infrastructure for real-time information exchange. This group of technologies allow network grid components to 'talk', 'listen' and 'interact'.

ii. **Sensing and Measurement**

These technologies improve power system measurements and enable the transformation of data into information. They assess the condition of grid equipment and evaluate the integrity of the grid. They also support advanced protective relaying.

iii. **Advanced components**

Advanced components are the latest research in materials, superconductivity, energy storage, power electronics and microelectronics. Together, these components will lead to higher power densities, greater reliability and improved energy efficiency.

iv. **Improved Interfaces and Decision Support**

The time available for operators to make decisions in many instances is very short. Decision support with improved interfaces will amplify human decision making at all levels of the grid.

v. **Advanced Control Methods**

These are devices and algorithms that will analyse, diagnose and predict conditions in the smart grid. They determine and take appropriate corrective actions to eliminate, mitigate and prevent outages and power quality disturbances. To a large extent, these technologies are dependent on the other four key technology areas. For example, these technologies will monitor essential components (sensing and measurement), provide timely and appropriate response (integrated communications) and enable rapid diagnosis(improved interfaces and decision support) of any event [Kazemi, 2011].

Smart grid technologies are used to fulfil a specific set of applications or functions in the electric power system. There are a number of smart grid technologies available which can be classified in the above mentioned areas. The scope of this study will only include smart grid technologies which can be used to improve the reliability of a distribution feeder. These technologies have been identified and will be discussed next.

2.5.1 Smart grid technologies for distribution feeder reliability enhancement

One of the most appealing advantages of smart grid technologies is the reduced reaction and restoration time. This is most apparent when a fault has occurred. Ordinarily when a disturbance causes a fault on the network, grid operators are unable to identify the exact location of the faulted section of the feeder. The repair crew are dispatched, and have to perform trial and error switching actions on circuit breakers and isolators, in an effort to find the exact location of the fault. This can take a considerable amount of time during the day and more especially at night or during unfavourable weather conditions, resulting in increased outage duration.

There are a number of smart grid technologies which have been developed in order to reduce the fault location time. These are discussed below:

i. Distance to fault estimator

Fault locators reduce the impact of faults as they speed up the restoration process, by allowing isolating and switching operations to be performed much faster [Morales-España et al., 2009].

Distance to fault estimators, are an optional module of modern distribution protection equipment which can be used for estimating the fault location. When a fault occurs, this module calculates the fault location as a distance from the substation to the fault. It can also notify this information to the control centre or the utility repairs crew using a suitable communication medium. By using distance to fault estimators, a much smaller zone of the distribution network is inspected for faults. However, when a feeder has multiple taps, there might be several probable fault locations for the fault distance indicated by this module. In order to overcome this problem, fault passage indicators should be used in conjunction with distance to fault estimators [Kazemi, 2011].

ii. Fault passage indicators

Fault passage indictors are devices which are located at strategic points along the feeder, and are designed to indicate whether fault current has passed that particular point. They are usually installed at points where switching decision can be made. Fault passage indicators are able to distinguish between fault current and load current. Several fault passage indicators installed along a feeder will enable quick identification of the passage of fault current. The status of these devices can be recognized remotely or by visiting its physical location. In the past, fault passage indicators could only be used in radial distribution networks, but there are new generation fault passage indicators which can be used in other electricity distribution networks [Newman, 1990; Kazemi, 2011; Nortech, 2013]. Figure 2-3 depicts the configuration of an automatic fault location system using a fault passage indicator. Further details on this type of technology are provided in Appendix A.

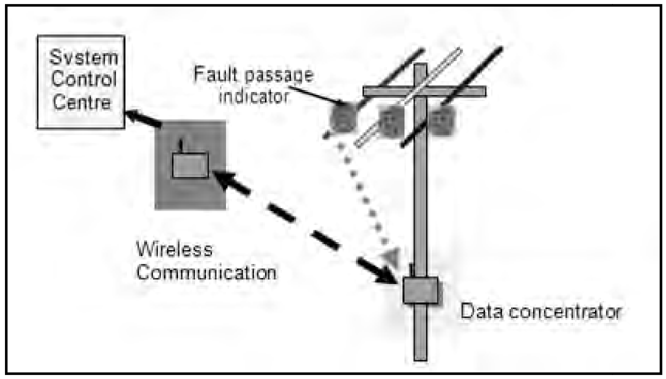

Figure 2-3Configuration of self-developed automatic fault location system[Cheng et al., 2009]

One of the primary features of the smart grid is its ability to automate a number of feeder functions such that the grid becomes more efficient and robust.

iii. Feeder Automation

Feeder automation is an automatic control scheme that is used for automatic fault detection and isolation, and service in an electricity distribution network. Utilizing modern computer technology, micro-electronics and communication technology, modern feeder automation technologies conduct operations and risk assessments, in order to make decisions regarding the operation of the distribution feeders and the distribution grid as a whole [Huang et al., 2012].

An automated grid is self-healing and recovers quickly from faults. When a permanent fault occurs, the customers affected by the fault may be categorised into two groups. The first group of customers are those who will have to wait until the faulted feeder section has been repaired. The second group includes those customers whose power supply has been interrupted, but can be restored through the main or alternate supplies by means of switching and isolating healthy and faulted feeder sections. In most cases the second group is larger than the first group [Uluski, 2010; Kazemi, 2011].

In the case of manually operated distribution systems and feeders, the fault isolation and service restoration activities can only be done after the fault has been located. However, feeder automation can reduce outage duration and restore supply to as many customers as possible by performing fault location, isolation and service restoration (FLISR) automatically. FLISR is able to restore service to customers in one minute or less, resulting in significant reliability improvement compared to traditional manual switching [Uluski, 2010; Kazemi, 2011].

Uluski [2010] illustrates the FLISR procedure and this is shown in Figure 2-4 to Figure 2-7.

a. Fault detection:- the system detects that a feeder fault has occurred.

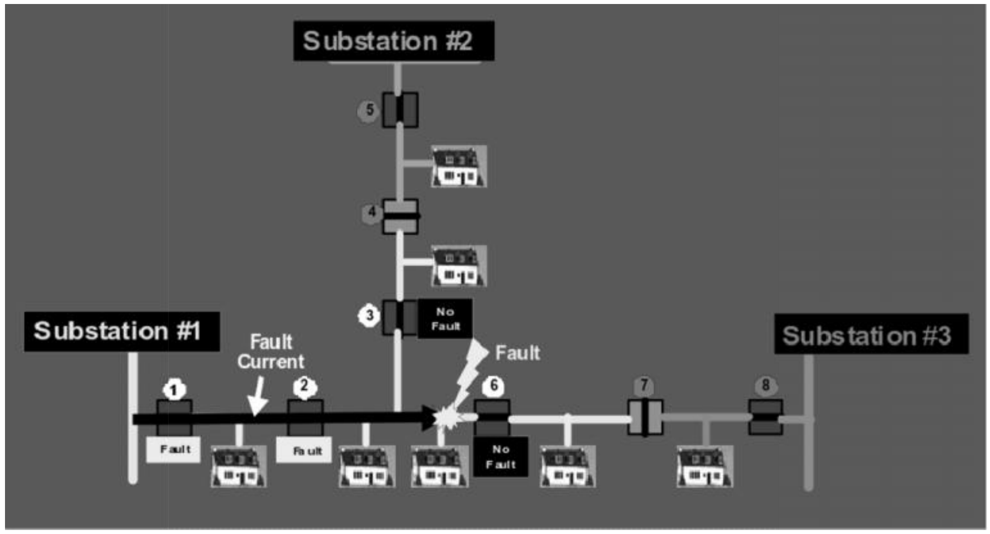

Figure 2-4 Fault detection [Uluski, 2010]

b. Fault location:-the faulted feeder section is identified and located between two remote controlled line switches.

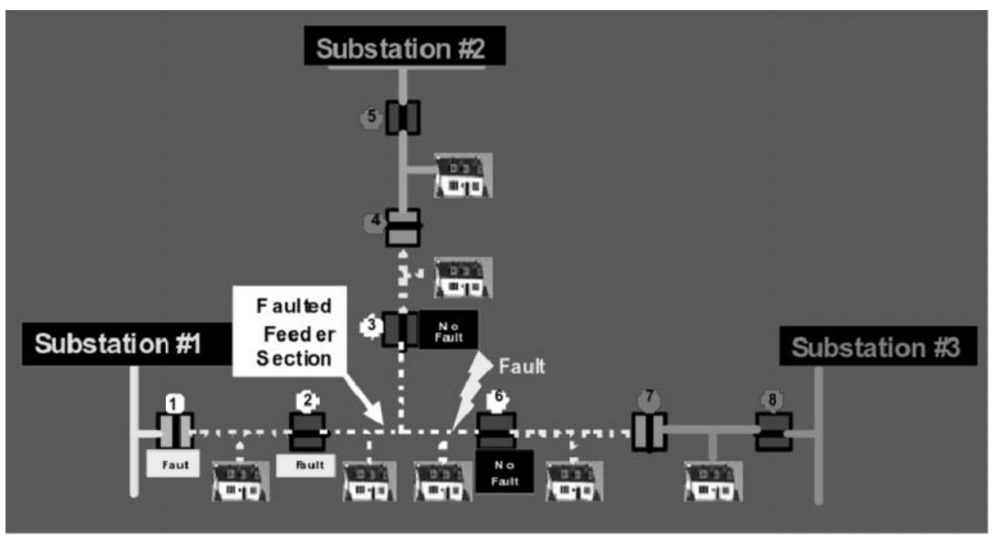

Figure 2-5 Fault located [Uluski, 2010]

c. Fault isolation:-the faulted feeder section is isolated using the appropriate line switches.

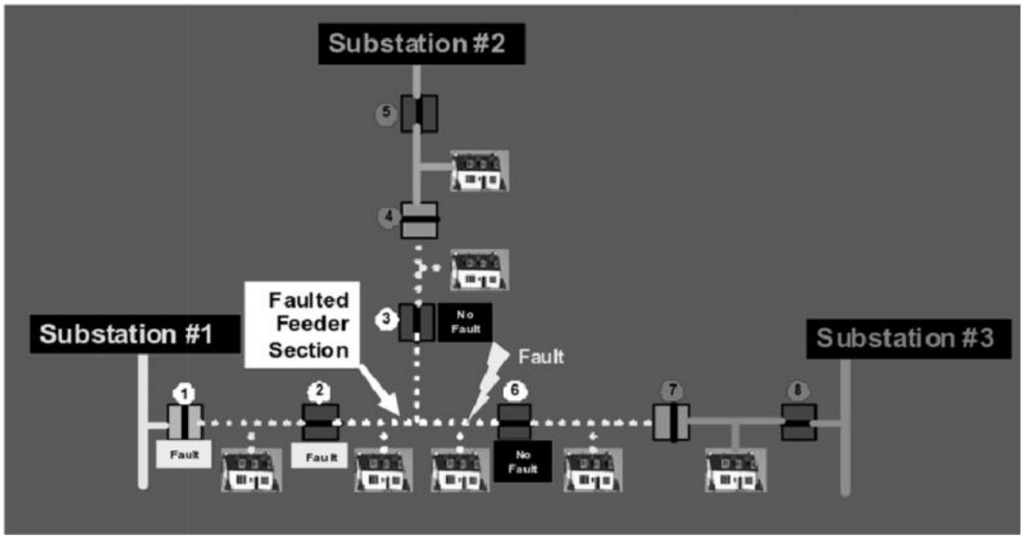

Figure 2-6 Fault isolated [Uluski, 2010]

d. Service restoration:-the undamaged sections of the feeder are re-energized via the primary feeder source or back up sources using remote controlled tie switches.

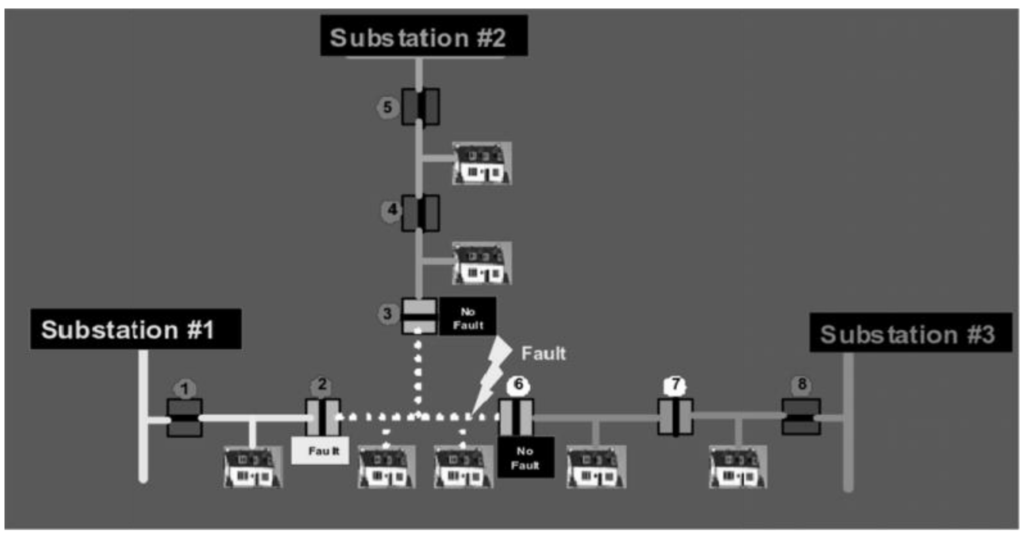

Figure 2-7 Service restoration [Uluski, 2010]

There are many advocates for smart grid techniques in literature [NELT, 2007a; Uluski, 2010; Enerweb, 2011; Kazemi, 2011; Hidalgo et al., 2011; Huang et al., 2012]. Kazemi [2011] evaluates the reliability benefit of a number of smart grid technologies under the assumption that all system components are operating in the normal stage, where the failure rate is at its lowest and is for the most part constant. Hidalgo et al. [2011] evaluates system performance with smart grid technologies and distributed generation integrated into the system. Despite these advocates, none have evaluated and quantified the benefit of smart grid within a grid with aging infrastructure, which is a prevalent challenge in many countries like South Africa. However, IEA [2011] mentions that smart grid technologies provide an opportunity to maximise the use of existing infrastructure through better monitoring and management whilst new infrastructure is strategically deployed.

2.6 DISTRIBUTED GENERATION

Many different definitions have been put forward for distributed generation, which is also commonly known as embedded generation or dispersed generation [Pepermans et al., 2005; Keane, 2007]. Distributed generation (DG) may be defined as power generation or production units located on-site serving a customer, or providing support to a distribution network connected to the grid at distribution voltage levels [IEA, 2002; Zhang et al., 2011]. Others have defined DG as only small-scale, environmentally friendly technologies such as photovoltaic (PV) and small wind turbines, that are installed on and designed primarily to serve a single end user's site. It could include all generation installed near a customer's load, regardless of size and energy source. Other definitions limit the size of DG between 10kW to 50MW of capacity [Daly & Morrison, 2001]. This research project will adopt a definition by Barker & de Mello [2000], who define DG as power generation which is about 10MW or less and is interconnected at the substation, distribution feeder or customer load levels.

DG can take the form of renewable generation, fuel cells or small and micro sized turbines packages, stirling-engine based generators, and internal combustion engine generators [Barker & de Mello, 2000]. The main drivers for distributed generation globally include: electricity market liberalisation, developments in DG technology, constraints on the construction of new transmission lines and grid infrastructure, increased customer demand for highly reliable electricity, and environmental concerns [IEA, 2002].

2.6.1 Benefits of Distributed Generation (DG)

Many benefits of DG have been listed in literature. These benefits include economic savings, reduced transmission and distribution costs (T&D) of about 30 % [IEA, 2002], voltage support, improved power quality, energy loss reduction, improved environmental performance and improved system reliability. Proponents of DG say that these economic savings from T&D costs are large, but many utilities have disputed this and stated that these savings are negligible [Daly & Morrison, 2001].

The arguments presented by advocates for DG may be used to identify the potential benefits of DG on a global level, but achieving these benefits is much more difficult than is often realized. According to Barker & de Mello [2000] and Daly & Morrison [2001],decision makers and system planners must address local conditions on a case by case basis in order to determine whether DG can in fact improve reliability and provide all the other above mentioned benefits in that specific instance. This requires a detailed analysis.

2.6.2 Problems associated with the integration of DG

The design of distribution networks does not usually consider the presence of distribution generation units and as a result, a number of uncertainties may be introduced into the system. Despite the previously mentioned potential benefits, DG may bring about many problems when it is added to an already existing network and could even worsen the performance of the network [Khan, 2008; Zhang et al., 2011]. For example, the reliability of the power system may be degraded if the distributed resource is not properly co-ordinated with the electric power system protection [Khan, 2008]. On the other hand, a well designed and implemented system could handle the addition of generation if there is proper grounding, transformers, and protection provided [Barker & de Mello, 2000; Khan, 2008]. There are also limits to the amount of additional generation that can be added to a particular system. Beyond this point, it would be necessary to modify and change the existing distribution system and to add more equipment in the form of protection relays, switch gears, change the voltage regulation system and revised grounding [Khan, 2008]. Other problems associated with DG include: increased harmonics, voltage flicker and power flow reversal.

This study will focus on analysing the impact distributed generation could have on distribution reliability.

2.6.3 Distributed generation in the context of reliability

If DG units are well co-ordinated, they may have a positive impact on distribution reliability. Implementation of distributed generation can increase reliability if DG units are configured to provide backup-islands during upstream utility source outages. Islanding occurs when a DG unit or units, continue to energize a portion of the utility system that has been separated from the main utility system [Barker & de Mello, 2000; Brown & Freeman, 2001].

Islanding is an important operation mode. Coupled with reliable DG units and careful co-ordination of utility sectionalising and protection equipment, islanding can result in improved reliability [Barker & de Mello, 2000; Atwa & El-Saadany, 2009]. This mode of operation needs to be well planned in order to prevent the occurrence of other problems within the system. Figure 2-8 illustrates intentional islanding. In this diagram, a fault is depicted to have occurred along the distribution feeder. In order to re-energise the customers downstream of the fault, the DG unit(s) should be able to supply the load in the islanded section whilst maintaining suitable voltage and frequency levels. An isolating device is necessary in order to separate the different sections of the feeder. In this setup, the distributed generation could result in a momentary interruption for the customers in the area supported by the generator, depending on the duration it takes to detect, locate and isolate the fault as well as the DG unit's start up duration. Power flow analysis of island scenarios is necessary to ensure that proper voltage regulation is established and maintained within the island. When the faulted section has been repaired, the isolating switch should not be closed unless the utility and 'island' are in tight synchronisation [Barker & de Mello, 2000; Wang et al., 2008].

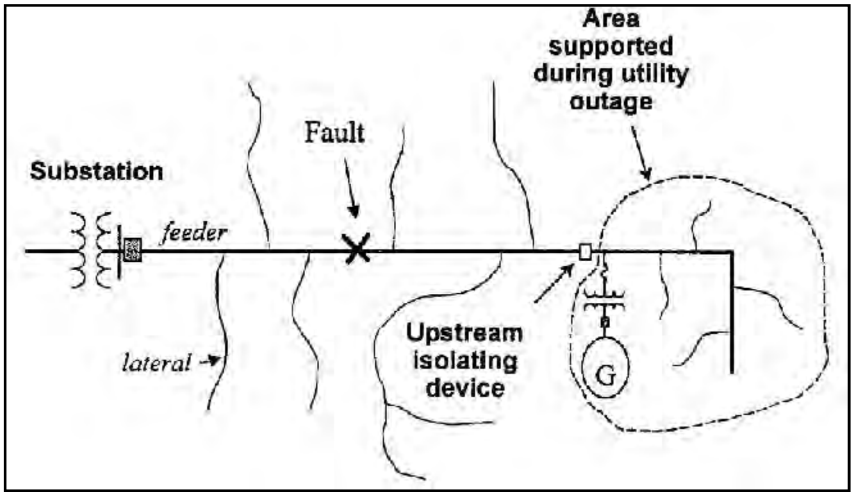

Figure 2-8 Intentional Islanding of distribution feeder [Barker & de Mello, 2000]

2.6.4 Distributed generation, enabling smart grid technologies

Overall, using islanding to improve power system reliability is a complicated task, but new automated switch technologies and communication approaches make this scheme more practical [Barker & de Mello, 2000]. According to Hidalgo et al. [2011], smart grid technologies and distributed generation mutually enable one another; and they technically and economically support each other. There are a number of smart grid technologies on the market, which, unlike the traditional grid, enable the easy integration of DG into the existing power system, to achieve flexible and efficient application of DG technology [Huang et al., 2012; Barker & de Mello, 2000].

Using advanced sensing technology like fault detectors, communication technology, advanced distribution automation, feeder automation and control technology like FLISR, smart grid technologies effectively take advantage of DG technology in order to achieve flexible DG integration, maintaining and even improving system reliability [Huang et al., 2012].

Advanced sensors and metering, monitor the operation of feeder equipment and DG technology on the distribution grid. This information is then transmitted using communications technology [Huang et al., 2012].

Utilizing modern computing technology, micro- electronics and communication technology, advanced distribution and feeder automation technology use this information to make decisions regarding the dispatching of DG. For example, by implementing FLISR, DG can also be dispatched in order to restore power supply to customers who do not have to wait for the faulted feeder section to be repaired [Uluski, 2010; Huang et al., 2012].

2.7 POWER SYSTEM RELIABILITY WORTH

It was previously mentioned in section 1.2, that the fundamental purpose of a power system is to deliver the electrical energy requirements of consumers at the lowest possible cost and at an adequate level of reliability. The expectations of customers regarding quality of service are continuously increasing as the dependence on electricity increases. In addition to this, customers also expect to receive electricity at the lowest possible cost [Ghajar et al., 1996].

These two factors, reliability and cost as depicted in Figure 2-9 are in constant conflict, and in order to balance the economic and cost considerations, utilities incorporate both reliability and cost considerations in decision making processes [Ghajar et al., 1996; Billinton & Zhang, 2001].

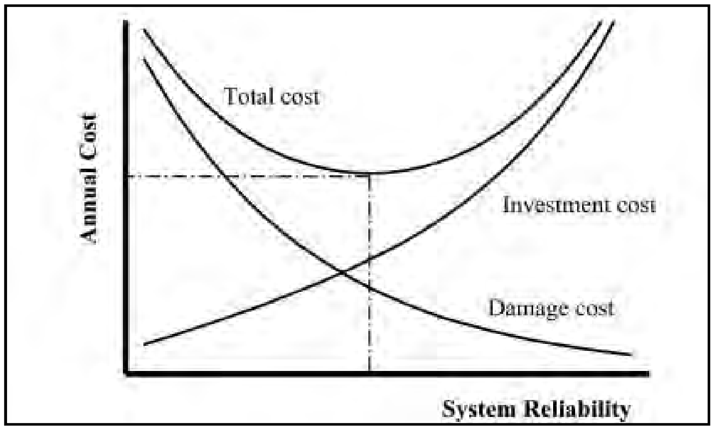

Figure 2-9Investment, damage and total cost as a function of system reliability [Billinton & Zhang, 2001]

Figure 2-9 illustrates the concept of reliability cost/benefit analysis. The investment cost represents the costs incurred by the utility which consists of capital, maintenance and operation costs. In general, as the investment cost increases the system reliability also increases. The damage cost represents the customer interruption costs, which are the economic losses of the customer due to the absence of electricity. Reliability worth refers to the value or benefit of power supply reliability. The damage cost acts as a surrogate for the worth of reliability and is not equal to it. They are instead the costs incurred by customers or the utility due to unreliability. The total cost curve is a sum of both the investment cost and the damage cost. Optimum reliability is achieved when the total cost curve attains a minimum [Ghajar et al., 1996; Billinton & Zhang, 2001].

2.7.1 Reliability worth assessment

Cost/benefit analyses of power systems have become very important in the determination of system reinforcement and expansion [Billinton & Zhang, 2001]. Assessing the worth of reliability is a difficult and subjective task and has even been deemed impossible by some authors [Tollefson et al., 1994; Billinton & Wang, 1999a].

Nonetheless, the evaluation of customer interruption costs is considered an adequate surrogate for reliability worth [Ghajar et al., 1996; Vásquez & Vaca, 2012]. Evaluating the damage cost and reliability worth indices requires three distinct models: a reliability model, cost model and load model [Alvehag, 2008].

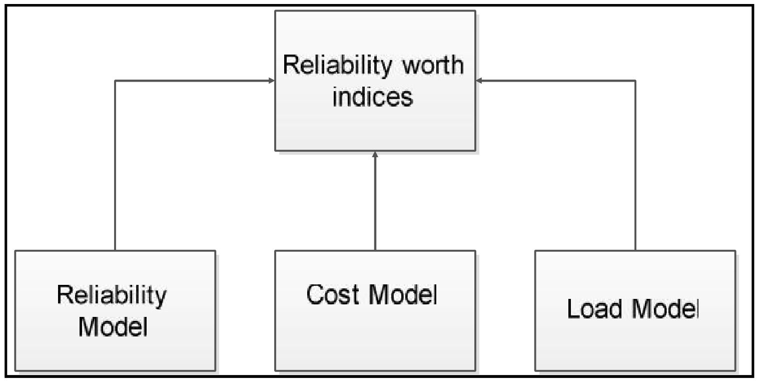

Figure 2-10 Reliability Worth Assessment components

The following indices are usually used to evaluate the reliability cost/worth of a system [Billinton & Wang, 1998]:

- Expected Energy Not Supplied (EENS)index

$EENS = \Sigma L_i r_{i,j} \lambda_{i,j}$ (2.13)

where L_i is the average load at load point i

$r_{i,j}$ is the outage duration of load point i due to the failure of load point j

$\lambda_{i,j}$ is the failure rate of load point i due to the failure of load point j

- Expected Customer Interruption Cost (ECOST) index

ECOST at a load point, which is equivalent to the Customer Interruption Cost (CIC) is given below.

$ECOST = c_{ij} L_i \lambda_{ij}$ (2.14)

where c_{ij} is the per unit interruption cost of load point i due to the failure of load point j

- Interrupted Energy Assessment Rate (IEAR)

$IEAR = \frac{\mathbf{ECOST}}{\mathbf{EENS}}$ (unit/kWh) (2.15)

2.8 SUMMARY

This chapter has answered some of the research questions posed in chapter 1. These are as follows:

(a) Which reliability evaluation techniques are available and which is most suitable for the analysis?

Deterministic and probabilistic approaches were identified as the two main approaches used to evaluate distribution reliability. Deterministic approaches simply use past experiences to predict the future operation of the system. They are generally simple to implement and easy to understand but generally result in over-designed and uneconomic solutions [Pereira & Balu, 1992; Reppen & Feltes, 2001]. Probabilistic techniques on the other hand, incorporate the stochastic and random nature of the power system and are able to take into account inherent unplanned events [Reppen & Feltes, 2001]. The most appropriate approach and techniques is selected in the next chapter.

(b) How is distribution reliability quantified?
Reliability indices are used to quantify distribution reliability. The most appropriate reliability indices to be quantified have not been selected as yet.

(c) Which factors affect reliability assessment and which are most applicable in the South African context?
The main factors which have been recognized for having the most impact on reliability indices are weather, age, physical environment, percent underground, distribution voltage and load density. Ageing infrastructure has been identified as the key challenge facing the distribution industry.

(d) Which is the most suitable test system to analyze?
This has not been completely answered, but the IEEE RTS and RBTS have been identified as bench mark test systems.

(e) Which smart grid technologies affect distribution reliability at a feeder level?
The identified smart grid technologies include: fault passage indicator, distance to fault estimators and feeder automation.

(f) How do these indentified smart grid techniques improve the reliability of a distribution network?
Not yet answered.

(g) What is the reliability worth benefit of smart grid technologies?
Not yet answered.

(h) What is the reliability worth benefit of distributed generation?
Not yet answered.

(i) Is there any difference between the results with smart grid technique and distributed generations and not?
Not yet answered.

(j) What will be used to determine the benefit of smart grid technologies and distributed generation?
Not yet answered.

Research questions (f) to (j) were not completely answered in literature. The next chapter discusses the development of the theory used in order to find answers to these research questions.

3 THEORY DEVELOPMENT

This chapter discusses the development of the theory used in the designing of the experiment used to test the hypothesis. The key reasons behind the selection of the applied assessment technique and models are presented.

3.1 RELIABILITY EVALUATION

In order to evaluate the reliability benefit of the selected smart grid techniques and distributed generation; a test system, reliability assessment technique, and modelling approaches needed to be selected. These attributes were discussed in detail in chapter 2, and where necessary, the advantages and disadvantages were highlighted. This subsection will discuss the reasons behind the selection of the different modules needed to develop a power system reliability evaluation model.

3.1.1 Reliability evaluation approach and technique

There are two main approaches which can be used to evaluate system reliability: deterministic and probabilistic. For the purposes of this study, the probabilistic approach was selected, because unlike the deterministic approach, the probabilistic approach incorporates the stochastic behaviour of a power system [Pereira & Balu, 1992].

As discussed in chapter two, there are also two main techniques which have been implemented in reliability evaluation: analytical techniques and simulation techniques. The time sequential Monte Carlo Simulation (MCS) technique was selected for a number of reasons, namely [Anders, 1990; Billinton & Allan, 1994; Billinton & Wang, 1999a; van Casteren et al., 2000]:

i. Analytical techniques require many assumptions to be made, resulting in the loss of the significance in the analysis
ii. It is well established and used extensively in literature
iii. It allows for the random nature of the power system to be modelled by using random reliability variables, and random numbers generated from probability distribution functions.
iv. The availability of high speed computing facilities make it a more viable option
v. MCS yields more information on load point and system indices.
vi. Time sequential MCS is flexible and has a high reality potential.

3.1.2 Probabilistic Reliability assessment

The study of system reliability is best achieved when statistics and probability distribution functions are used to describe both inputs and outputs of the system [Cross et al., 2006]. Billinton & Kumar [1990] emphasise that it is difficult and misleading to draw conclusions on system performance using the average value of system indices. This is in agreement with Cross et al. [2006], who recommend that output reliability indices be represented by probability distribution functions. Edimu [2009] also supports this view and illustrates the usefulness of probability distributions to describe input and output parameters. It is in the light of this argument, that the input parameters and output reliability indices in this study, will be described using a probability distribution functions.

3.1.3 Need for the Beta Distribution

Many different probability distribution functions have been used in reliability modelling and these are discussed in section 2.1.2. However, a strong case has been made in literature for the use of the beta distribution to describe system inputs and outputs [Cross et al., 2006; Edimu et al., 2011]. The main advantages associated with this distribution are its flexible shape and finite range. As a result, the beta distribution can be used to describe a variety of data sets. Therefore, the beta distribution will be used extensively in this study to model reliability input parameters and output reliability indices. The beta distribution is described below.

The Beta distribution

The beta distribution is defined as follows:

$$f(x, \alpha, \beta) = \frac{x^{\alpha-1}(1-x)^{\beta-1}}{\int_0^1 u^{\alpha-1}(1-u)^{\beta-1}du} \qquad (3.1)$$

where alpha (α) and beta (β) are the parameters of the function.

The beta distribution is very versatile in the shapes it exhibits. A given shape is derived by assigning the necessary values to its parameters. Figure 3-1shows some of the shapes the beta distribution can exhibit, given the values of its shape parameters. It also has a finite range (0 to 1), but this range increased or decreased by a scaling factor equal to the maximum value (c) in the data set [Herman, 1993; Cross et al., 2006].

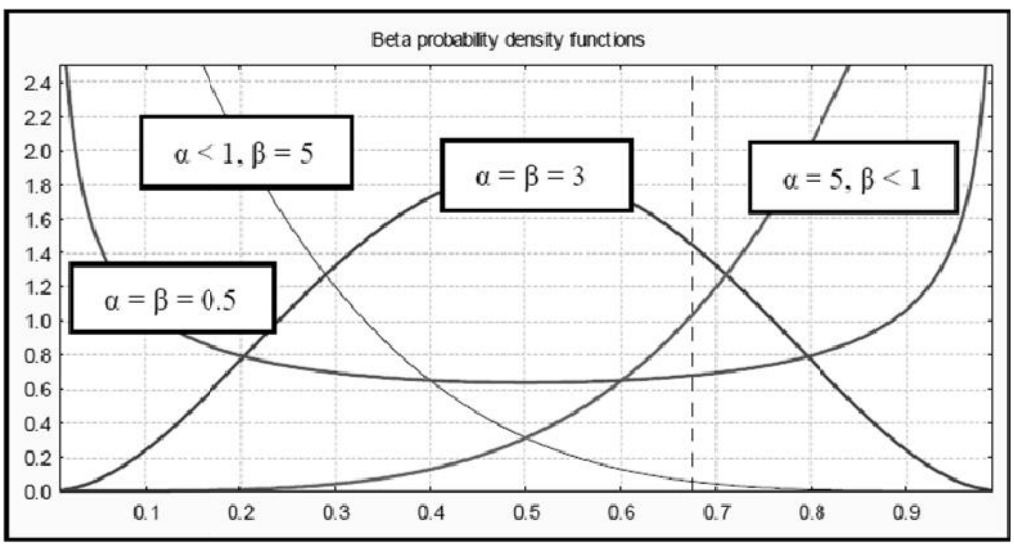

Figure 3-1 Examples of the beta probability density functions [Cross et al., 2006]

The parameters of the beta distribution may also be defined in terms of the mean (μ), the standard deviation (σ) and c (the scaling factor) as described by equations 3.2 and 3.3. The inverse is also applicable i.e. the mean, standard deviation may also be determined from alpha, beta and c [Herman, 1993; Cross et al., 2006].

$$\alpha = \frac{\mu(c\mu-\mu^2-\sigma^2)}{c\sigma^2} \quad (3.2)$$

$$\beta = \frac{(c-\mu)(c\mu-\mu^2-\sigma^2)}{c\sigma^2} = (c-\mu)\alpha \quad (3.3)$$

Percentage risk and Confidence levels

Since the output reliability indices of the MCS will be described using a probability distribution, there is a variety of different single indicative values which can be sampled from the distribution for each index. A risk value is associated with each single indicative value. The risk is defined as the probability of exceeding the percentile value. The risk level translates into the uncertainly associated with the specific value. For example, a risk level of 10 % (or conversely 90 % confidence level), resulting in a certain calculated output value, means that there is 90 % confidence the output value will not be surpassed. A value corresponding to a specific confidence level can be calculated using the alpha and beta parameters of that specific distribution [Kendall & Stuart, 1973].

In order to get an indication of the variation and spread of each distribution, the 10^{th}, 50^{th} and 90^{th} percentile values of each distribution describing the output reliability indices will be given. This also allows for the comparison of different distributions at different confidence intervals.

3.1.4 Reliability indices selection

A wide variety of indices have been used extensively in literature and by utilities to determine customer and system reliability.

Research conducted by the South African electricity regulator, National Energy Regulator of South Africa (NERSA), found SAIDI to be the best index for it to use in its distribution incentive scheme, which regulates the revenue of the distribution [NERSA, 2011].Therefore, the distribution system operators (DSOs) in South Africa have great incentive to reduce SAIDI. Since this research project is considering a South African context, the impact of smart grid techniques and distribution generation on SAIDI will be included.

Although SAIDI has been deemed the best index for regulatory purposes by NERSA, the frequency of interruptions is also important. In emerging economies small to medium sized enterprises are vulnerable to chronic interruptions. High SAIFI figures can threaten the viability of a business by eroding commercial confidence [Herman & Gaunt, 2008].Therefore SAIFI and MAIFI will also be included in the results section.

In this study, a momentary interruption is defined as an interruption with duration greater than 3 seconds but no longer than 5 minutes, as defined by the NRS 048-6:2006 specification for the Electricity Supply Industry for medium voltage (MV) and low voltage (LV) systems [Chatterton et al., 2006]. SAIDI, SAIFI and MAIFI are customer orientated indices. In order get an indication of the overall feeder performance, the feeder failure rate (λ_{feeder}) and unavailability (U_{feeder})will also be given.

3.1.5 Modelling of aged transformer behaviour

System components tend to fail as they wear out with age. This results in an increased failure rate. The reliability modelling and evaluation in this research project, will concentrate on distribution transformers operating in the wear-out stage, as this is the current state of most transformers in the South African distribution grid. Distribution transformers are a key component of distribution grids and their reliable operation directly impacts that of the entire network [Jagers & Tenbohlen, 2009]. Transformers also represent a significant cost to the electric utilities, both as a capital investment and as an ongoing operating expense. They can account for up to 20 % of the total distribution capital spending per annum [Van Zandt & Walling, 2004]. As transformers age, their internal condition deteriorates, increasing the risk of failure. Both their mechanical and dielectric strength degrade to a point where they cannot effectively withstand system events such as short circuit faults or transient over-voltages [Wang et al., 2002; Bartley, 2011]. According to Bartley [2011], ageing transformers are a huge risk to the electric power supply and could cause major losses.

Failure rate data of distribution transformers operating in their end life was used to model the effect of aging on transformers. From Figure 2-1, it is evident that the failure rate of components operating in the worn out region varies considerably. The uncertainty in transformer failure rate can be accounted for using the beta distribution.

3.1.6 Distributed generation

The effect of distributed generation on reliability was also investigated in this study. The technology selected in this study was solar PV. It was chosen for the following reasons:

- The solar resource available for the selected area (Johannesburg, South Africa) is favourable for solar PV.
- Electricity generation from solar PV is environmentally friendly.
- It is a renewable source of energy.
- The cost of solar PV systems has declined tremendously over the past few years and this is expected to continue into the next decade [IRENA, 2012].
- The installation of solar PV into the South African grid has been promoted through the Renewable Energy Independent Power Procurement Programme (REIPPP) in broad accordance with the Integrated Resource Plan (IRP) for Electricity [2010]. About 1450MW has been allocated for solar PV through this programme [Department of Energy, 2013]

Solar PV Model

The solar PV model selected for the analysis is dependent on the time of day and season of the year. The output of a solar PV system is highly reliant on the available direct solar insolation available in a specific area. The direct solar insolation is dependent on the time of day and on the season of the year as shown in Figure 3-2. The available direct solar insolation in the afternoon differs from that available in the late evening. The available direct solar insolation in the summer is generally much greater than that available in the winter. Therefore a time of day and time of year dependent model will yield a more realistic estimate of the output power of a solar PV system.

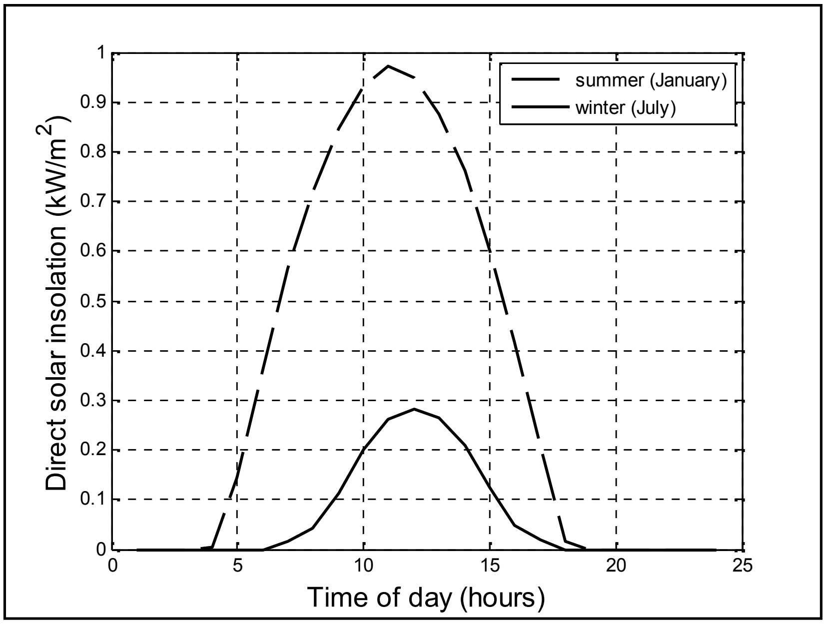

Figure 3-2 Direct solar insolation for different months [SoDa, 2005]

3.1.7 Test system selection

As mentioned in chapter 2 above, there are two benchmark test systems that have been published in literature .i.e. the IEEE RTS and the RBTS. But for distribution system reliability analysis, the RBTS is the only published bench mark test system. For the purposes of this study the RBTS was selected. Although it is not a South African test system, its system components are similar to those of the South African power system. The advantages regarding the RBTS include the fact that is best suited for educational purposes; it is used extensively in research and it is well defined. Although it is a simple system, it allows for reasonable reliability evaluation and ensures that the studies reflect, with enough detail, the actual complexities involved in the practical reliability analysis [Billinton et al., 1989].

The RBTS, shown in Figure 3-3, is a 6 bus system containing 5 load buses, 2 generator buses and 9 transmission lines. Bus1 and bus2 each have 4 and 7 generating units respectively, with a

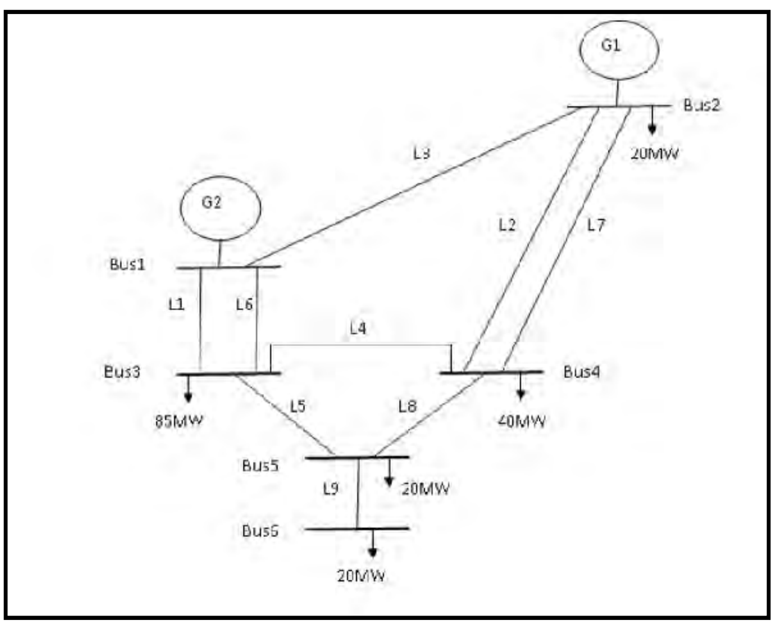

Figure 3-3 Single line diagram of RBTS [Billinton et al., 1989]

combined total of 11 generating units.

The hypothesis of this study aims to test the reliability improvement of the selected smart grid techniques and distributed generation on a feeder. Feeder 1 of bus 6 of the RBTS was selected for the analysis. This feeder contains a good mix of all possible system components and a sufficient number of load points. Due to the limited South African load and cost data available, the customer type composition of the feeder was slightly altered to suite the available data resources.

Similar to the RBTS data assumptions, the bulk of the customers on the feeder are still assumed to be residential, but in this case, the residential customers belong to the medium to high income group. In order to create a more realistic setting, a few commercial retail customers were added to the feeder. These changes had no impact on the components and structure of the test system.

Further details of the test system and customer type categories will be presented in chapter 4.

3.2 RELIABILITY WORTH EVALUATION

The evaluation of the reliability worth indices requires a load and cost model to be integrated in to the model used to evaluate system reliability. This subsection will discuss the selection of the load and cost models, and will also briefly discuss the method selected for the economic feasibility assessment.

3.2.1 Reliability worth indices

The EENS and customer interruption costs are the reliability worth indices to be explored in this analysis. The EENS gives an indication of the energy requirements of the customer that were not met. The EENS can also be used by utilities to determine the loss of revenue as a result of an interruption. The customer interruption costs give an indication of the monetary loses of customers.

3.2.2 Load model

The evaluation of the reliability worth index, EENS requires the development of a load model. Accurately modelling the load of a power system continues to be difficult. A few of the key reasons for this are [IEEE Task Force, 1993; Chan, 2003]:

i. Variation in load composition depending on the time of day and day of week, season, weather etc.
ii. Lack of precise information on the composition of the load.
iii. Large number of diverse load components.
iv. Ownership and location of load devices in customer facilities not directly accessible to the electric utility.

According to Coutto Filho et al. [2002], using probabilistic methods in load modelling, results in a more consistent analysis of power system performance. Leite da Silva et al. [2002] support this position, and explain that deterministic methods represent past experience and future expectation by numbers, without assigning any degree of likelihood to these numbers. A more realistic way of incorporating past experience, is to identify factors which contribute to a particular load, and associating factors with a probability [Do Coutto Filho et al., 3-5 Jul 1991 ; Leite da Silva et al., 2002]. Based on this argument, a probabilistic approach will also be adopted in modelling the system load.

Probabilistic load modelling

There is a large variety of distributions which have been used in literature to model load, the most common is the Gaussian pdf. The use of this distribution to model load has been discouraged by a number of authors [Seppala, 1995; Singh et al., 2010]. Seppala [1995] argues that the power system load distribution is generally skewed. This is contrary to the Gaussian model which is symmetrical. Seppala [1995] goes on to recommend the use of the lognormal distribution.

Herman & Kritzinger [1993] fitted the Weibull, normal, Erlang and beta distributions to grouped domestic loads and found the beta distribution to be most suitable. Heius & Herman [2002] also use the beta distribution to describe load uncertainty for a South African residential load model and deem the model appropriate. This view supports the finding of an extensive load monitor program conducted in South Africa. The program found that for residential consumers in South Africa, a typical distribution of the load current of one consumer measured over a period of time, may be approximated using the beta probability distribution [Heunis & Herman, 2002].

The arguments given above indicate that beta distribution has been found to be suitable for modelling load and more importantly, that this distribution is suitable in the South African context. Therefore the beta distribution will be adopted for load modelling purposes.

The load of the power system varies with the time of the day and season of the year, and the careful incorporation of these factors, improves the accuracy of the load model. The unavailability of South African commercial load data, resulted in the use of a deterministic time varying load model, which was developed based on the RBTS data sheet assumptions. The focus of this study was not on load modelling, and therefore this had no significant impact on the analysis. On the other hand, the availability of sufficient residential load data allowed for the development of a probabilistic load model for residential customers, who constitute more than 90 %of the customers on the test system feeder. The data was used to model the load at different times of day and during different seasons of the year. This is described in more detail in chapter 4.

3.2.3 Cost Model

The purpose of the cost model is to quantify the monetary value of losses incurred by the customer due to an interruption. The most commonly used cost model is in the form of a customer damage function (CDF) [Alvehag, 2008]. The CDF models the interruption costs as a function of outage duration. The particular CDF used in this analysis was independent of the load of the customer. This is because studies have found that the value of an end product may not be directly related to the amount of electrical energy used for all sectors (e.g. a commercial enterprise may require the use of intelligent appliances such tills, computers. These devices use relatively small quantities of energy, but their availability is important.) Therefore in many cases, continuity of supply rather than capacity is the most important factor [Herman & Gaunt, 2008].

A CDF based on South African customer interruption cost data published by Herman & Gaunt [2008] was used. In their publication, the customer interruption cost data for both residential and commercial retail customers is given.

3.2.4 Economic Feasibility

This section of the study aims to determine the economic feasibility of the different smart grid technologies and distributed generation, by calculating the discounted payback period for the investment required to implement these techniques. The payback period refers to the amount of time it takes to recover the initial investment of an opportunity. A commonly used method to evaluate the economic feasibility of investments is the Net Present Value (NPV) method. The advantage of this method is that it takes into consideration the time value of money [Department of Ecology, 2005]. This method is used to determine the discounted payback period.

4 EXPERIMENT DESIGN

This chapter presents the experimental procedure used in investigating the reliability benefit of smart grid technologies and distributed generation. The aim of this investigation is to determine the impact of the smart grid techniques and distributed generation on reliability, as well as to conduct a cost/benefit analysis of implementing these technologies into the system. The approach used in evaluating distribution reliability, with and without smart grid techniques/distributed generation of an identified test system, is described. It also outlines the procedure followed in assessing reliability worth and economic feasibility.

4.1 COMPUTATIONAL TOOLS

The main computational software package used in this research project is MATLAB 2009b. It was used to develop and execute the time sequential Monte Carlo Simulations. Microsoft Office Excel 2007 was also used, particularly for curve fitting and regression analysis.

4.2 TEST SYSTEM

The test system used was feeder 1 (F1) of bus 6 of the RBTS system(More details of this bus and the RBTS are given in Appendix B). This is illustrated in Figure 4-1. It consists of nineteen failure components, a combination of 1 circuit breaker, 6 transformers(T1-T6) and 12 overhead lines (O1-O12). There are 6 load points (LP1-LP6) present on this feeder. The feeder and overhead line lengths are provided in Appendix B.

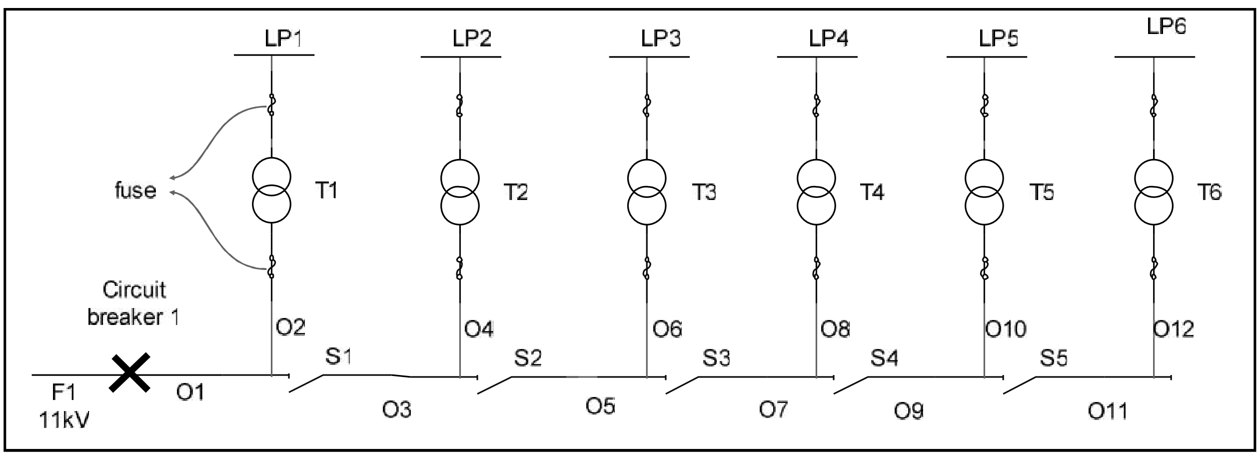

Figure 4-1 Test System [Billinton & Jonnavithula, 1996]

The protection devices within the test system are as follows:

- Circuit breaker- used to break short circuit current and operating currents. Breakers can be operated remotely and can generally be operated multiple times.
- Fuses- fitted on both sides of each transformer. These are used to protect the rest of the system in case of a transformer fault. The presence of fuses means that any transformer failure affects only the load point, associated with that specific transformer. For example, the failure of T1, results in the discontinued supply of electricity to LP1 but no effect on the supply to LP2-LP6. Fuses have to be replaced after they have been triggered.

- Isolators (S1-S5)- used to isolate different sections of the feeder, particularly when a fault has occurred.

4.3 RELIABILITY EVALUATION PROCEDURE

As mentioned in chapter 3, a time sequential Monte Carlo Simulation (MCS) was the selected method used to evaluate the reliability of the selected test system. The basis of MCS is to determine reliability indices based on repeated sampling of the state of the system. This sub-section discusses the method used to model components, the assumptions made and the simulation procedure followed.

4.3.1 Component Models and Parameters

Distribution system components (transmissions lines, transformers, breakers etc) can have one of two states: an up state or a down state. The up state is when the component is working as expected and the down state is when the component has failed [Billinton & Wang, 1999b]. These states are shown in Figure 4-2.

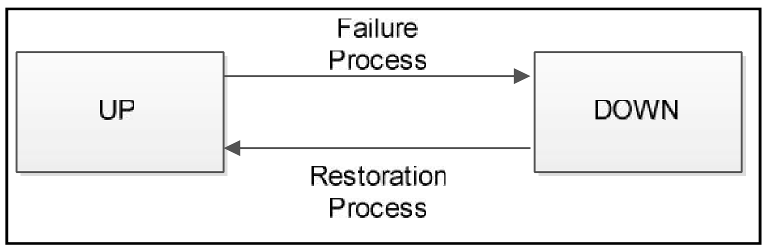

Figure 4-2 State Space diagram of electrical components[Billinton & Wang, 1999b]

The process of transiting from up state to down state is called the failure process whereas the transition from down state to up sate is called the restoration process. The time during which the element remains in the up state is called the time to failure (TTF). The time during which the element is in the down state is called the restoration time, and can either be the time to replace or time to repair (TTR) [Billinton & Wang, 1999b]. These times can be seen in Figure 4-3 below.

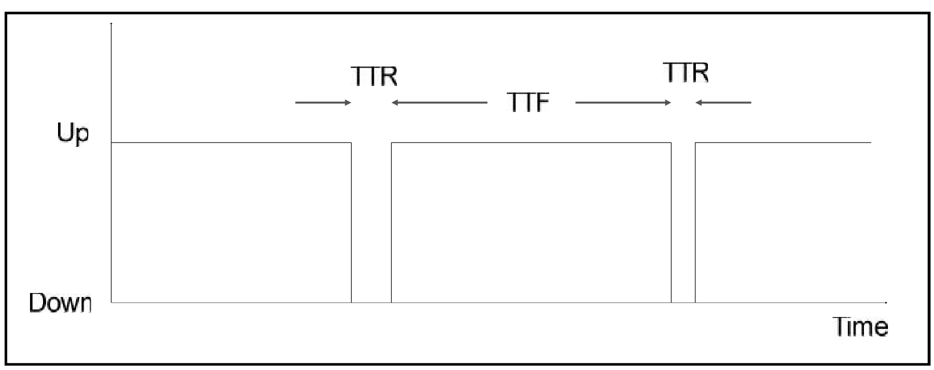

Figure 4-3 Typical operating history of component [Billinton & Wang, 1999b]

The failure and restoration processes may be modelled using probability distribution functions.

Another important component of the simulation process is the inclusion of fault management activities. Fault location time was included in the simulation procedure and is described as time to locate fault (TTLF). Therefore the Figure 4-3 may be modified as shown in Figure 4-4.

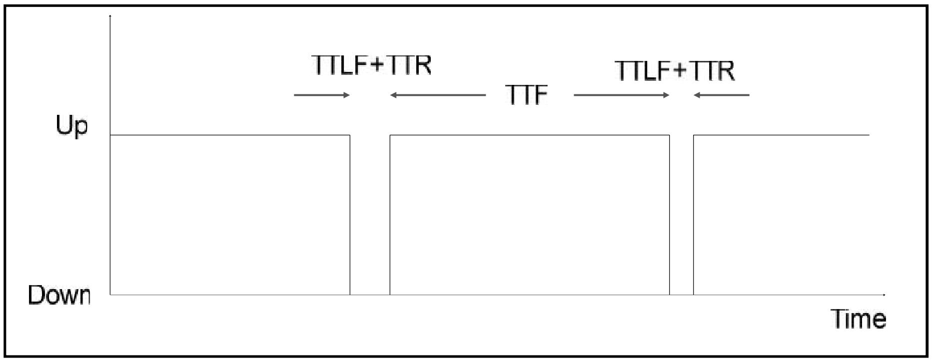

Figure 4-4 Operating histories including time to locate fault

TTLF comprises of the duration it takes to conduct all fault management activities before the actual faulted feeder section is repaired. These activities include fault notification, dispatching of repair crew, travelling time, trial and error switching for manual fault location and any decision making.

4.3.2 Assumptions

The following assumptions were made in the development of the MCS:

- The mission time was set to 1 year and the simulation period was 1000 years unless otherwise stated.

- Smart grid techniques and fuses were assumed to operate without failure.

- The failure of a transformer only affects the load point connected to that specific transformer. The fuses protect the rest of the system.

- Transformers may only be repaired and not replaced, unless otherwise stated.

- A failure of the circuit breaker affects all the load points, resulting in an outage duration equal to the reclosing time of the breaker.

- A failure in the main feeder section results in an interruption of service to all load points. Load points upstream have an outage duration equivalent to the time it takes to locate the fault and conduct manual switching. Load points downstream have to wait for the fault to located and for the faulted component to be repaired.

- Assuming constant failure rate, the Time To Failure (TTF) for all nineteen components in the system was modelled using a negative exponential function given in equation4.1.

$$\mathbf{f(t) = e^{-\lambda t}} \qquad (\mathbf{4.1})$$

where λ is the failure rate of a component and t is the TTF.

therefore if equation 4.1 is rearranged:

$$TTF = \frac{-\ln(f(t))}{\lambda} \qquad (4.2)$$

- The failure rates of the transformers were randomly sampled from a beta distribution for the simulation period.
  Note: The failure rate for the transformers is constant during the mission time (1 year) and each simulation period, allowing for the use of the negative exponential, which assumes a constant failure rate in the specific year. But the failure rate of the transformer changes randomly from one simulation period to the next.

- The failure rates of all components except the transformers were assumed to be constant throughout the entire MCS.

4.3.3 Monte Carlo Simulation Algorithm

The simulation procedure executed was based on the algorithm developed by Billinton et al.[1999] with a few modifications. A number of different cases were executed but the general algorithm in each case followed the steps listed below:

Step 1: Randomly sample the failure rate for each transformer from a beta distribution.

Step 2: A uniformly distributed number was generated to represent f(t)for all failure components.

Step 3: For each failure component the TTF is calculated using equation 4.2.

Step 4: The TTF for each component was compared to the mission time.

Step 5: If a failure occurred, (i.e. TTF is less than mission time) the load points affected by the failure of the specific component were determined.

Step 6: The number of outages for each load point was noted.

Step 7: The outage duration for the affected load points was recorded and added to the total outage time for each load point.

Step 8: The failure rate, repair rate and unavailability of the load point were then obtained.

Step 9: If the simulation period had not elapsed then steps 1-8 were repeated.

Step 10: Calculate the number and duration of failure for each load point.

Step 11: Calculate the system indices and customer orientated indices.

Steps 1-11 were repeated 1000 times and at the end, 1000 values for the load point, system and customer orientated distribution reliability indices were obtained. Each index was represented using the beta pdf. The outcome was a pdf representation of each index. The algorithm followed is shown in the flow chart in Figure 4-5.

A number of cases were investigated each with different values for inputs, namely switching time, repair duration, et cetera. The input criteria for each case used during the execution of the MCS will be described in the chapter 5.

Table 4-1 outlines the reliability data concerning the components of the test system. These values were adopted from Billinton & Jonnavithula [1996]. The different input parameters, their details and distributions are shown below in Table 4-2. The input data was adopted from Billinton & Jonnavithula [1996] and Alvehag [2008]. The maximum values of the input parameters as indicated in Table 4-2 were estimated using the standard deviation of the average, which gives a measure of the dispersion from the average.

Table 4-1 Test system network components' failure rates

System Component	Failure rate (failures/year)	System Component	Failure rate (failures/year)
Circuit breaker 1	0.006	O7	0.04875
O1	0.04875	O8	0.039
O2	0.039	O9	0.039
O3	0.039	O10	0.04875
O4	0.052	O11	0.052
O5	0.04875	O12	0.039
O6	0.04875		

Table 4-2 Input parameters for MCS

Input parameter	Distribution	Average	Standard deviation of mean	Maximum
Time To Failure (TTF)	exponential	-	-	-
Time To Locate Fault (TTLF)	beta	1.5 hours	0.4 hours	2 hours
Repair time (RT/TTR) overhead lines breaker transformer	beta	 5hours 4hours 200 hours	 1 hour 0.4 hours 10 hours	 6 hours 5 hours 220 hours
Switching time(SwT)	beta	1 hour	0.4 hour	1.5 hours
Reclosing time (RcT)	beta	1 minute	1 minute	2minutes

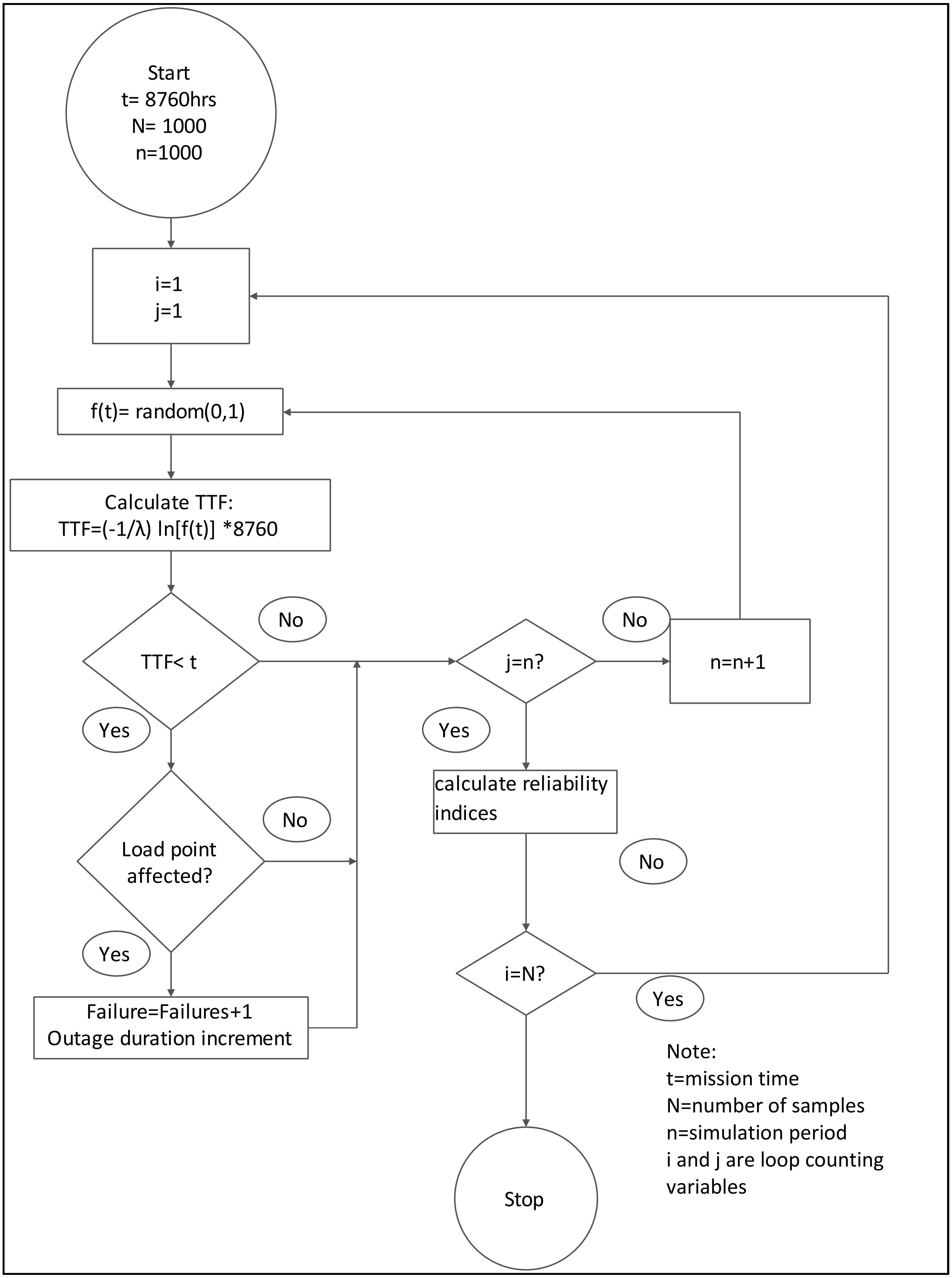

Figure 4-5Skeleton Algorithm of MCS

4.4 RELIABILITY WORTH EVALUATION PROCEDURE

This sub-section describes the procedure followed to estimate the distribution reliability worth of smart grid technologies and distributed generation. As mentioned in section 2.7 three distinct models are required: reliability model, load model and cost model.

4.4.1 Reliability model

The reliability model implemented is the model described in section 4.3 above.

4.4.2 Load model

The customer model was developed using data from the RBTS data sheet and NRS data. This study only considered residential and commercial customers. The customers at each load point were defined as shown in Table 4-3below.

Table 4-3 Customers on the test system

Load point	Number of Customers	Type of Customers
1	138	138 Residential
2	126	126 Residential
3	138	138 Residential
4	126	126 Residential
5	120	118 Residential + 2Commercial
6	121	118 Residential + 3 Commercial
Total	769	764 Residential + 5 Commercial

- Residential Load model

  NRS Load Research data was used in the development of the residential load model. NRS Load Research data comprises of the load consumption data collected in 5 minute intervals for different residential households in different locations in South Africa. This data was collected between 1994 and 2003.Thedata was used to develop a profile of the load consumption in amperes (A) of a residential customer residing in Claremont, Johannesburg, South Africa. Four seasons of the year and different times of the day were identified. The load profile is given in Figure 4-6.

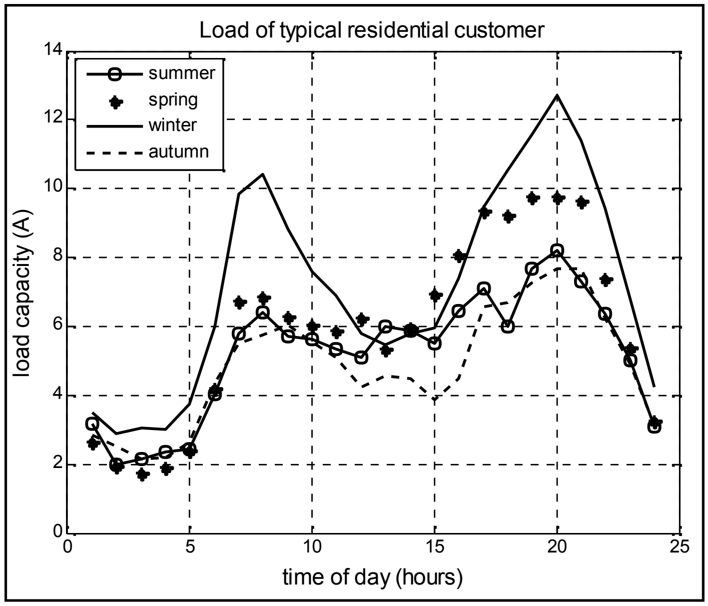

Figure 4-6 Load profile for a typical residential customer [NRS Load Research Group, 1994-2003]

The beta distribution was used to describe the load of each residential customer during different seasons of the year and for every hour of the day. The resultant was a 24x4 matrix, each block containing a unique alpha and beta parameter for a specific beta distribution describing the load of a residential household. This matrix is best described in Table 4-4.

Table 4-4 Residential load model

Season (months of year) / Time of day	Summer (Mid October-Mid February)	Autumn (Mid February -April)	Winter (May to July)	Spring (July to mid October)
00:00 - 00:59	$\alpha_1\beta_1c_1$	$\alpha_{25}\beta_{25}c_{25}$	$\alpha_{49}\beta_{49}c_{49}$	$\alpha_{73}\beta_{73}c_{73}$
01:00 - 01:59	$\alpha_2\beta_2c_2$	$\alpha_{26}\beta_{26}c_{26}$	$\alpha_{50}\beta_{50}c_{50}$	$\alpha_{74}\beta_{74}c_{74}$
02:00 - 02:59	$\alpha_3\beta_3c_3$	$\alpha_{27}\beta_{27}c_{27}$	$\alpha_{51}\beta_{51}c_{51}$	$\alpha_{75}\beta_{75}c_{75}$
. . .	. . .	. . .	. . .	. . .
23:00-23:59	$\alpha_{24}\beta_{24}c_{24}$	$\alpha_{48}\beta_{48}c_{48}$	$\alpha_{72}\beta_{72}c_{72}$	$\alpha_{94}\beta_{96}c_{96}$

- Commercial load model

  There are a total of 5 identical commercial customers on the feeder. There are 3 commercial customers on LP5 and the remaining 2 on LP6. All 5 were assumed to be in the retail business. The loads of the commercial customers were time dependent and remained the same regardless of the season of year. The load of these customers was based on data given with the RBTS and this is indicated in Table 4-5.

Table 4-5 Commercial customer Load data

Time of day	Load per commercial customer (MW)
00:00 -07:59	0.0497
08:00-17:00	0.085
17:00-23:59	0.0497

4.4.3 Cost model

As mentioned in chapter 3, customer damage functions (CDFs) based on customer interruption cost data published by Herman & Gaunt [2008]were used. Two separate CDFs were developed for each customer type. Figure 4-7 and Figure 4-8 depict the CDFs for a typical residential and commercial customer respectively.

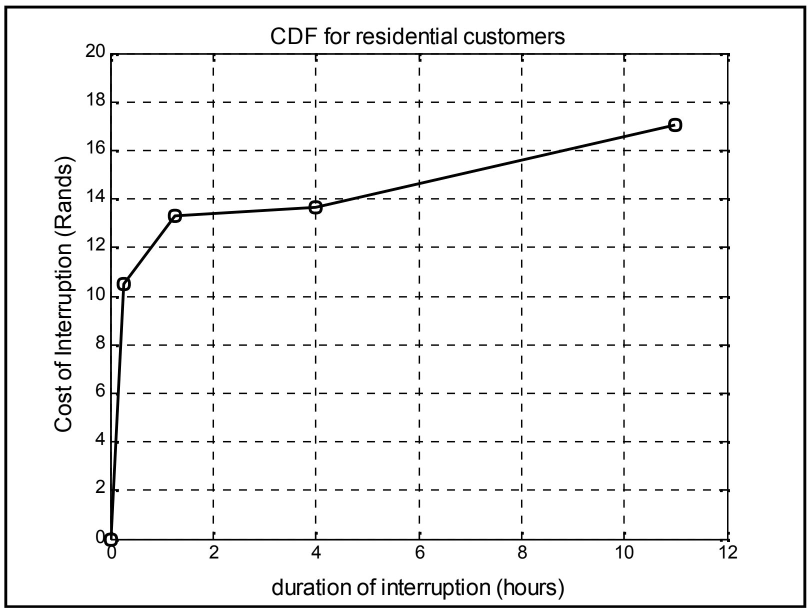

Figure 4-7 CDF for residential customers[Herman & Gaunt, 2008]

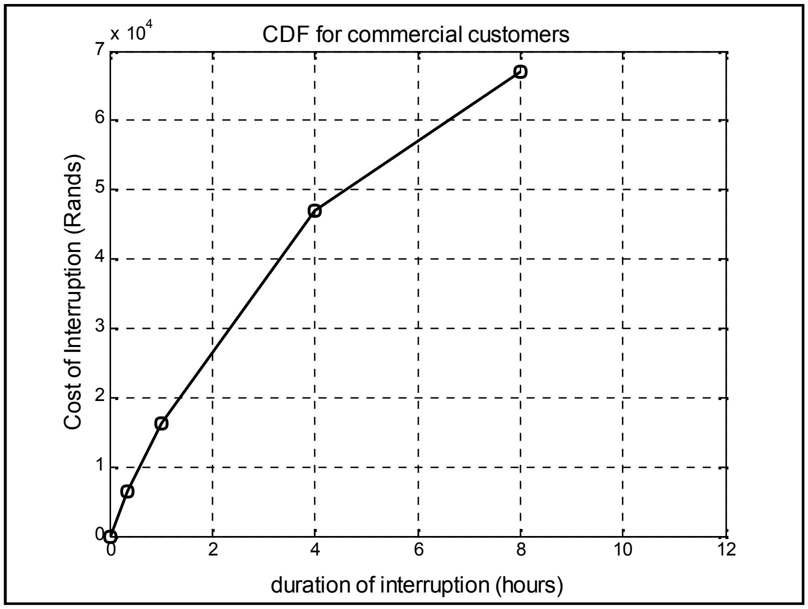

Figure 4-8 CDF for commercial customers[Herman & Gaunt, 2008]

4.4.4 Reliability worth algorithm

The algorithm developed is similar to the algorithm used to evaluate reliability. The major difference is that each time an interruption occurs; the faulted feeder component is identified. For each load point affected by this faulted feeder section, the outage duration is determined. Using this outage duration, the EENS of each load point is identified and incremented. From there, the damage cost to the customer as a result of the interruption is determined and incremented. This algorithm is illustrated in Figure 4-9.

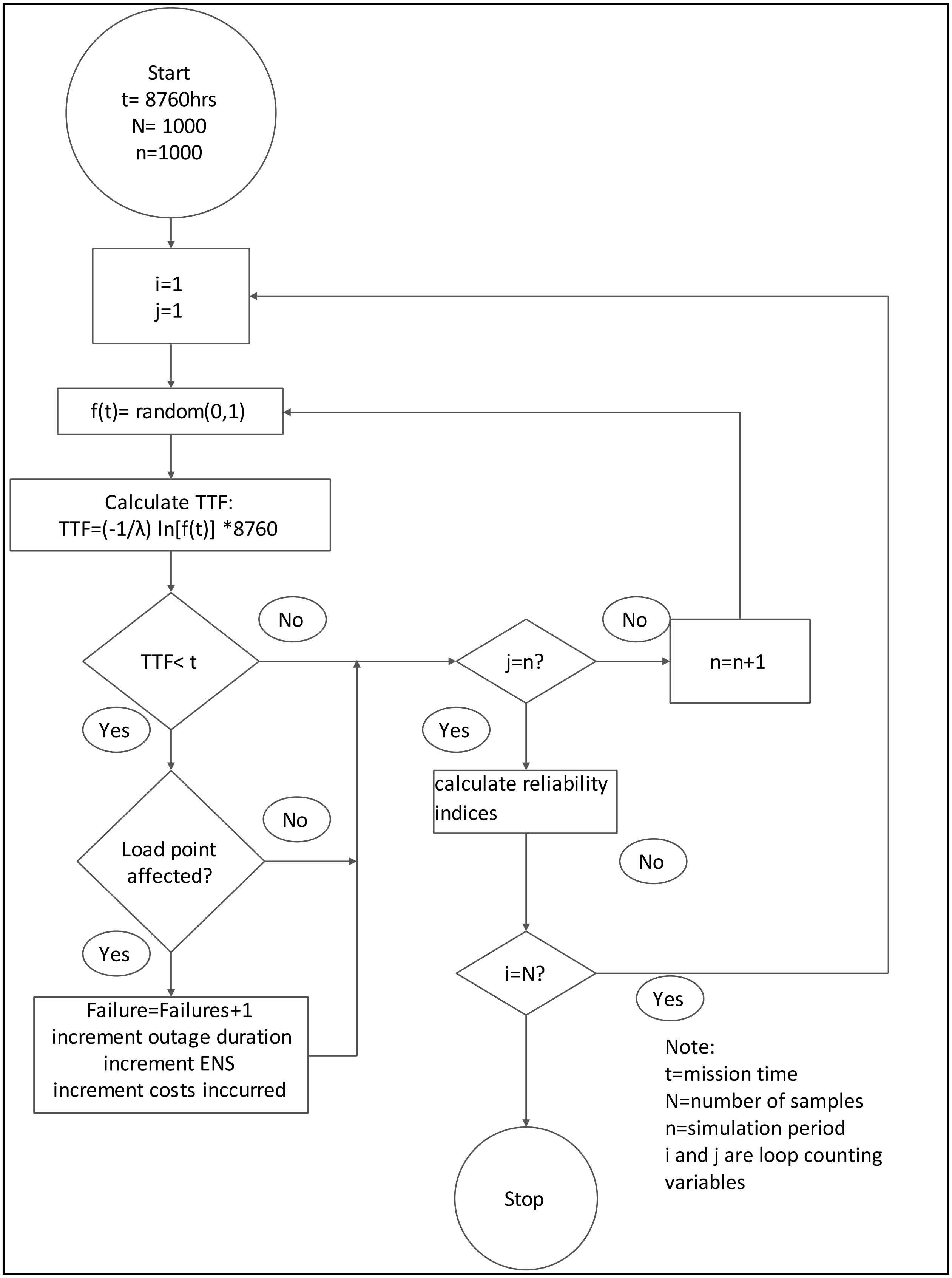

Figure 4-9 Algorithm used to determine reliability worth

5 SIMULATION PROCEDURE

This chapter describes the different scenarios and cases simulated, as well as the input parameters pertaining to each specific case.

5.1 RELIABILITY EVALUATION CASES

5.1.1 Aged transformers (Base case)

In this case, all failure components, including the transformers, in the tests system were assumed to be operating during the worn out stage. Data for failure rates of distribution transformers operating in the system with age was collected and plotted by Jagers & Tenbohlen [2009]. This is shown in Figure 5-1. The graph plotted by Jagers & Tenbohlen [2009] does not correspond to the bath tub curve (Figure 2-1), as the failure rate does not decrease in the infancy stage, but instead from the first year of operation the failure rate is fairly constant. This could be because the transformers were rigorously tested for manufacturing faults before their installation.

In this case, the failure rates of transformers during the worn out stage were fitted to a beta distribution. During the MCS, the failure rate of each transformer (T1-T6 in Figure 4-1) was sampled from this distribution. It was assumed that the normal operating stage was from 1 to 33 years of age and that the wear out stage was from 33 to 40 years of age. All other input parameters are the same as those given in Table 4-2.

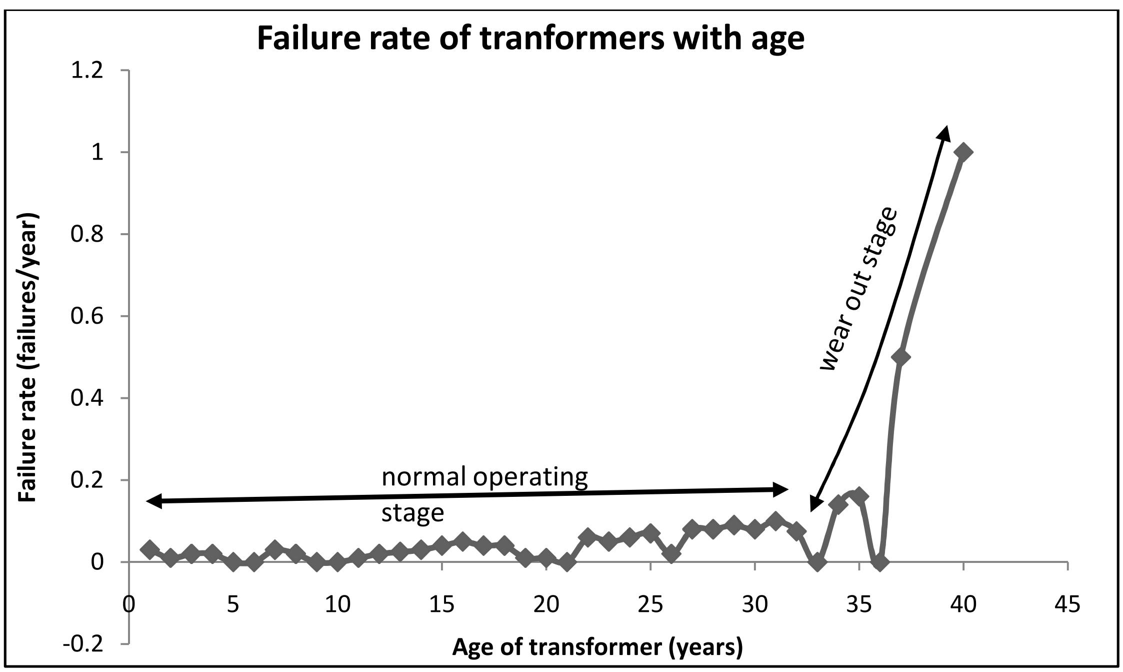

Figure 5-1 Failure rate of transformers with age [Jagers & Tenbohlen, 2009]

5.1.2 Case 1: New transformers

The procedure executed in case 1 was exactly the same as that of the base case, with one exception. The failure rate of each transformer (T1-T6 in Figure 4-1) was sampled from a beta distribution fitted to the failure rate data corresponding to the normal operating stage in Figure 5-1. All other input parameters are the same as those given in Table 4-2.

5.1.3 Case 2: Fault Passage Indicators and Distance to Fault Estimators (FPI and DFE)

In case 2, the impact of two smart grid technologies: distance to fault estimators and passage fault locators working in collaboration was investigated. The fault passage indicators were installed at each switching point (S1 to S6).It is assumed that these devices operate without fault and that they communicate wirelessly with the substation operators. This results in less time spent locating the fault. The exact same procedure described under 4.3.3 was followed. The only difference was the reduction in time to locate faults (TTLF). Switching and isolating faults was conducted manually. The only change to the input parameters given in Table 4-2, is shown in Table 5-1.

Table 5-1 Input parameter change for case 2

Input parameter	Distribution	Average	Standard deviation	Maximum
Time To Locate Fault (TTLF)	beta	0.5 hours	0.4 hours	2 hours

5.1.4 Case 3:Feeder Automation

This case investigated the effect of feeder automation on the feeder's reliability. FDLISR is performed each time a fault is detected. The changes to the input parameters are as follows:

Table 5-2Input parameter change for case 3

Input parameter	Average
Time To Locate Fault (TTLF)	30 seconds
Switching time(SwT)	30 seconds

5.1.5 Case 4: Distributed Generation-Solar PV

In this case, DG was added to the system. The DG technology integrated into the system was solar PV (Photovoltaic)and was connected to the end of the feeder as shown in Figure 5-2. The main purpose of this plant is to act as a backup source of power for LP5 and LP6 in case of an interruption. For example, if a permanent fault were to occur on O5, LP1 and LP2 would be restored to the main source of supply by opening S2. Ordinarily without the presence of DG on the feeder, LP3 to LP6 would have to wait for the faulted feeder section to be repaired. But due to the solar PV plant, LP5 and LP6 can be supplied by opening S4 and closing S5 and S6. In the event that the power output of the DG is not sufficient to supply both LP5 and LP6, S5 will be opened and the DG will supply LP6 only. If the power output of the DG cannot supply LP6, then both LP5 and LP6 will have to wait for the fault to be repaired.

The solar PV plant has been sized to 3MW, enabling it to supply both LP5 and LP6 independently at peak load. LP5 and LP6 have a combined peak load of about 2.70MW. It should be noted that the solar PV plant is continuously feeding into the system i.e. S6 is a normally open switch. If the power output from the solar PV plant cannot meet the demand of LP5 and LP6 at any point, the remaining energy requirements are supplied by the utility. The implication of this is that in case of an interruption, the solar PV plant can be used immediately, avoiding the start up delay associated with starting up a PV plant.

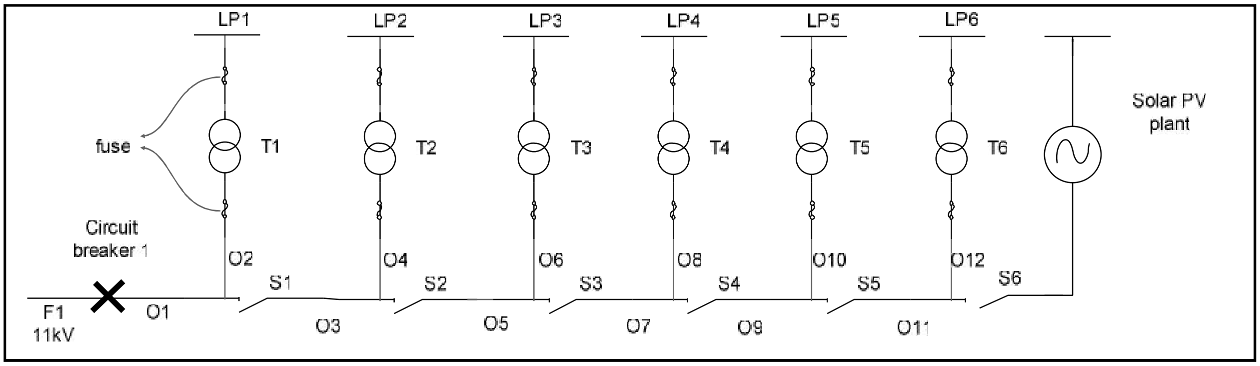

Figure 5-2Test system including distributed generation

Solar PV model

It was mentioned in chapter 3, that a solar PV model dependent on time of day and season of year was selected. Hourly solar insolation data for Johannesburg, South Africa, over a period of one year, was used for in the development of the solar PV model. This data was retrieved online from the Soda Service website [SoDa, 2005].

Equation 5.1 [Alkuhayli et al., 9-11 Sept. 2012] outlines the relationship between the power output of the photovoltaic system, with surface area (S) and direct solari nsolation (I(t)). The efficiency of the system is dependent on the amount of direct solar insolation available. When the available direct solar insolation is below a certain threshold (called K), the relationship between efficiency and solar insolation is linear. Above this threshold, the efficiency is generally constant.

$$\mathrm{Pout(t)} = \begin{cases} \frac{\mathrm{nc}}{\mathrm{K}} * \mathrm{S} * \mathrm{I(t)}^2 & 0 < I(t) \leq \mathrm{K} \\ \mathrm{nc} * \mathrm{S} * \mathrm{I(t)} & \mathrm{I(t)} > K \end{cases} \quad (5.1)$$

where nc is the efficiency of the PV system including the inverter

K is the threshold. According to Cha et al. [2004], K is about 200 W/m^2.

The general algorithm described in Figure 4-5is still applicable to load points 1 to 4. The algorithm applied to load point 5 and 6 changed slightly. This change is described in Figure 5-3.

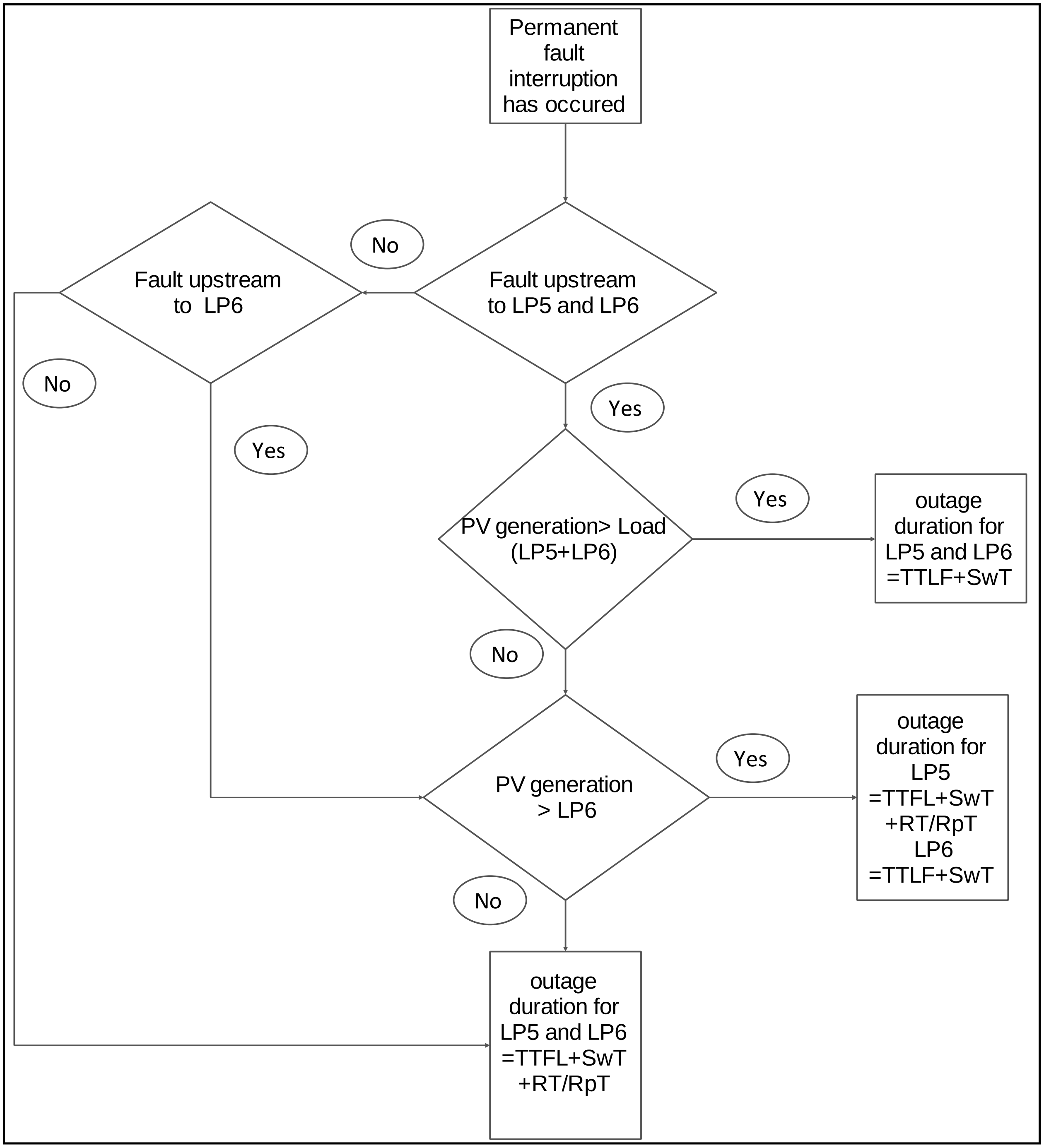

Figure 5-3 Algorithm followed for case 4

5.1.6 Case 5:Feeder Automation and Distributed Generation

In this case, the combination of feeder automation and distributed generation was explored. The input parameters of this case are the same as case 3 and the algorithm executed is that of case 4.

5.2 RELIABILITY WORTH

The reliability worth of each of the above mentioned cases was determined using the algorithm described in 4.4.4.

5.3 RELIABILITY COST/BENEFIT ANALYSIS

The previous two sub sections of this chapter, discussed the simulation procedures carried out in order to quantify the reliability and the reliability worth for the different identified smart grid technologies, and the distributed generation. This section discusses the inputs, assumptions made, and the steps followed in order to conduct a cost/benefit analysis of the different cases compared to the base case. It should be noted that all monetary figures are 2013 values unless indicated otherwise.

5.3.1 Case 1 :New transformers

This case investigated the impact of transformers working in the normal stage of operation on the reliability of the feeder. In this stage the failure rate is relatively low and the failure rate is more or less constant. In order to implement this case, six new transformers, to replace aged distribution transformers T1 to T6, were required.

Table 5-3 Input investment costs for case 1

	Cost per device	**Cost in US$**	**Cost in ZAR**
11 kV/0.4 kV 5MVA transformers	US$ 82 781.00 [MidWest Switchgear Group, 2014]	US$ 82 781.00 X6	ZAR 82 7810.00 X6
Total cost		US$ 496 686.00	ZAR 4 966 860.00

The conversion from US$ to ZAR assumed a ratio of 1US$=ZAR 10 [Standard Bank, 2013].

5.3.2 Case 2: Fault Passage Indicators and Distance to Fault Estimators

This case investigated the implementation of distance to fault estimators and fault current passage indicators which could communicate remotely with a control centre. A distance to fault estimator was installed at the substation. A fault passage indicator was installed along the feeder at each switching point (S1-S5) of the test system shown in Figure 4-1. The cost of the an upgraded communication system with enhance functions cable of supporting the distance to fault estimator and fault passage indicator technologies is also included. The entire costs involved in this case are shown in Table 5-4.

Table 5-4 Input investment costs for case 2

	Cost per device	Cost in US$	Cost in ZAR
Distance to fault estimator	US$ 2550.00 [Schweitzer Engineering Laboratories, 2013]	US$ 2550 X 1 = US$ 2550	ZAR 25 000
Fault passage indicator	US$ 15-50 for a set of 3 (Minimum order of 50 sets) [Alibaba, 2013]	U$15 X 50 to US$50 X 50 = US$ 750 to US$ 2500	ZAR 7500 to ZAR 25 000
Communication system	US$ (2011) 20 000 per feeder [EPRI, 2011] This is equivalent to US$ (2013) 21 150 [Officer & Williamson, 2014]	US$ 21 150	ZAR 211 500
Total cost			**ZAR 244 000 to ZAR 261 500**

5.3.3 Case 3: Feeder Automation

This case investigated the implementation of feeder automation. The cost of implementing distribution feeder automation ranges from US $200 000 to US $300 000 per feeder [Uluski, 2013]. Therefore, the cost of implementing feeder automation in this case ranges from ZAR2 000 000.00 to ZAR3 000 000.00 (2 million to 3 million ZAR).

5.3.4 Case 4:Distributed Generation-Solar PV

This case investigated the impact of solar PV plant operating with intentional islanding, on the reliability of the feeder. Table 5-5 shows the input data used to determine the cost of upgrading an existing solar PV plant, with the necessary communication systems to include intentional islanding.

Table 5-5 Input investment costs parameters for case 4

Input parameter	Value
Cost per Watt Peak for solar PV	US$ 0.9/Wp [IRENA, 2012]
Estimated additional cost per Watt Peak to upgrade solar PV plant communication system to include intentional islanding	US$ 0.2/Wp

Using the above mentioned data, the cost of upgrading solar PV plant to include intentional islanding is as follows:

=(0.2US$/Wp) x (10 ZAR/US$) X (3MW)

=ZAR 6 000 000 (6 million ZAR)

5.3.5 Case 5: Feeder Automation and Distributed Generation

In this case, feeder automation and distributed generation were both implemented. The amounts used in cases3 and 4 above were used. The total investment cost required in this case amounted to ZAR 8 000 000 to ZAR 9 000 000 (Approximately 8 million to 9 million ZAR).

5.3.6 Economic Feasibility of cases

The average savings customer interruption costs were determined for each case. The present value (PV) of these savings was determined using equation 5.2 [de Blas, 2006]. The discount rate, mentioned in equation 5.2,is used to equate future values to current values. It was assumed that the discount rate was equal to 10% [Khatib, 2010].

$$\mathrm{PV} = \frac{\text{amount received in future}}{(1+\text{disount rate})^{\text{number of years}}} \quad (5.2)$$

In order to determine the discounted payback period, the present value of annual savings realized was subtracted from the investment cost, until the initial investment cost was completely paid backed. The discounted payback period for each the different cases was then compared.

6 RESULTS AND ANALYSIS

This chapter presents and discusses the results for the different cases and scenarios described in chapter 5 and is based on the assumptions and procedures given in chapter 4.

6.1 RELIABILITY EVALUATION

This sub section presents and discusses the findings of the reliability evaluation. The findings are presented in the form of beta distributions describing the selected reliability indices: SAIFI, feeder failure rate, SAIDI and feeder unavailability and MAIFI where applicable. The 10^{th}, 50^{th} and 90^{th} percentile values of each distribution are also given for comparison purposes. The selected reliability indices were discussed in chapters 2 and 3, but are briefly described again below:

i. SAIFI gives an indication of the average number of sustained interruptions that a typical customer on the feeder would experience in one calendar year (NRS 048-6:20060).
ii. MAIFI is the average number of momentary interruptions that a typical customer on the feeder would experience in one calendar year (NRS 048-6:2006).
iii. The feeder failure rate is the frequency with which a fault occurs on the feeder.
iv. SAIDI gives an indication of the average number of interruptions that a customer on the feeder would experience in one calendar year.
v. The feeder unavailability is the total outage duration of the feeder

For simplicity the case names were abbreviated as follows:

Table 6-1 Case definitions and abbreviations

Case	Abbreviated name	Explores
Base case	aged_tr	Effect of transformers operating in worn out stage on feeder reliability
1	new_tr	Effect of transformers operating in normal stage on feeder reliability
2	FPI_DFE	Effect of fault passage indicators and distance to fault estimators on feeder reliability
3	Feeder_auto	Effect of feeder automation feeder reliability on feeder reliability
4	DG	Effect of distributed generation feeder reliability on feeder reliability
5	Feeder_auto_DG	Effect of feeder automation and distributed generation feeder reliability on feeder reliability

6.1.1 Case aged_tr (Base case)and Case new_tr

i. SAIFI

The beta distributions of SAIFI for both case new_tr and case aged_tr are compared in Figure 6-1. The bell shape of these distributions indicates that the possible magnitudes of SAIFI are evenly distributed on either side of the mean value in each case. The beta distribution for case new_tr is much sharper and narrower than that of case aged_tr, because the failure rate of transformers and all other system components in case new_tr is generally constant. This is different from case aged_tr, where the possible transformer failure rates are more dispersed and higher in magnitude. Another important observation is that the possible values for SAIFI in case aged_tr are for the most part higher than those of case new_tr, and this is expressed in the different percentile values of SAIFI for each case shown in Table 6-2. Once again, this is attributed to the increased transformer failure rate experienced when transformers operate in the wear out region.

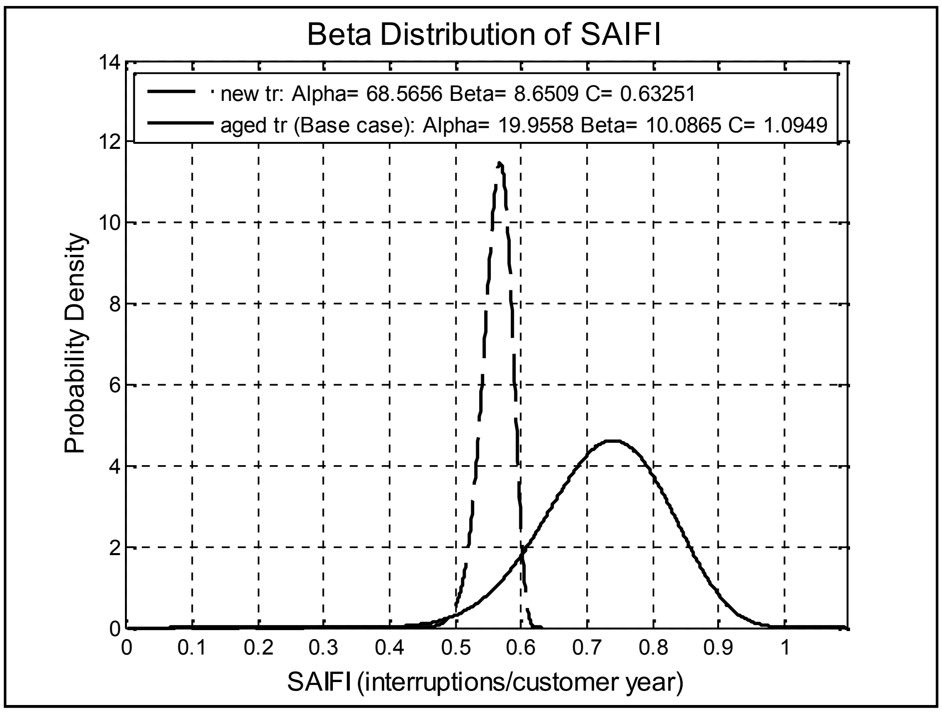

Figure 6-1 SAIFI comparison of case aged_tr and case new_tr

Table 6-2 SAIFI for case aged_tr and case new_tr

SAIFI (interruptions/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case new_tr**	**Percentage difference**
10^{th}	0.60	0.53	-11.6%
50^{th}	0.73	0.56	-23.3 %
90^{th}	0.84	0.59	-29.8%

ii. Feeder failure rate

A comparison of the feeder failure rate for both cases new_tr and aged_tr is given in Figure 6-2. The observations made regarding SAIFI are also applicable to the feeder failure rate. The possible range of feeder failure rate magnitudes in case aged_tr are higher than those of case new_tr due to the higher transformer failure rate as a result of the worn-out, aged transformers.

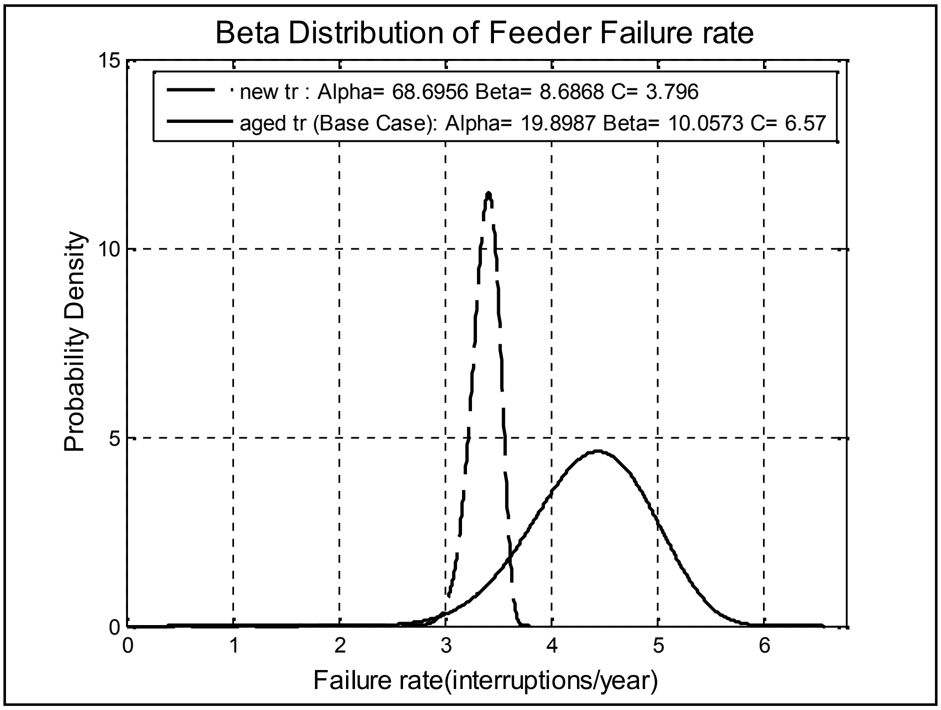

Figure 6-2 Feeder failure rate comparison of case aged_tr and case new_tr

Table 6-3 Feeder failure rate for case aged_tr and new_tr

Feeder failure rate (λ_{feeder}) (interruptions/year)			
Percentile	**Case aged_tr (Base case)**	**Case new_tr**	**Percentage difference**
10^{th}	3.61	3.19	-11.6%
50^{th}	4.39	3.38	-23.0%
90^{th}	5.05	3.53	-30.0%

iii. SAIDI

In Figure 6-3 the beta distributions describing SAIDI for both case new_tr and case aged_tr are compared. The distribution of SAIDI for case aged_tr incorporates a wider range of values than that of case new_tr, and as a result, the distribution for case new_tr is not clearly visible. Therefore Figure 6-4 was included and depicts a close up representation of this distribution.

From these two figures, it is observable that the shape of the two beta distributions is different. The exponential shape of the beta distribution in case aged_tr indicates that most possible values of SAIDI in that case are less than its mean. The difference in the percentile values in case new_tr and case aged_tr are for the most part much larger. The main reason behind this is the failure rate of the transformers. The transformers in case aged_tr are assumed to be worn out and aged, and therefore are more prone to failing. The transformers also have a much longer repair time, of about 200hours, followed by overhead lines, with a repair time of about 5 hours. Therefore an increased transformer failure rate, as experienced in case aged_tr, results in a tremendous increase in the outage duration experienced by customers. This drastic increase in outage duration is reflected in SAIDI.

From Table 6-4, the 10^{th} percentile of SAIDI in case new_tr is higher than that of case aged_tr because of the much narrower range of values.

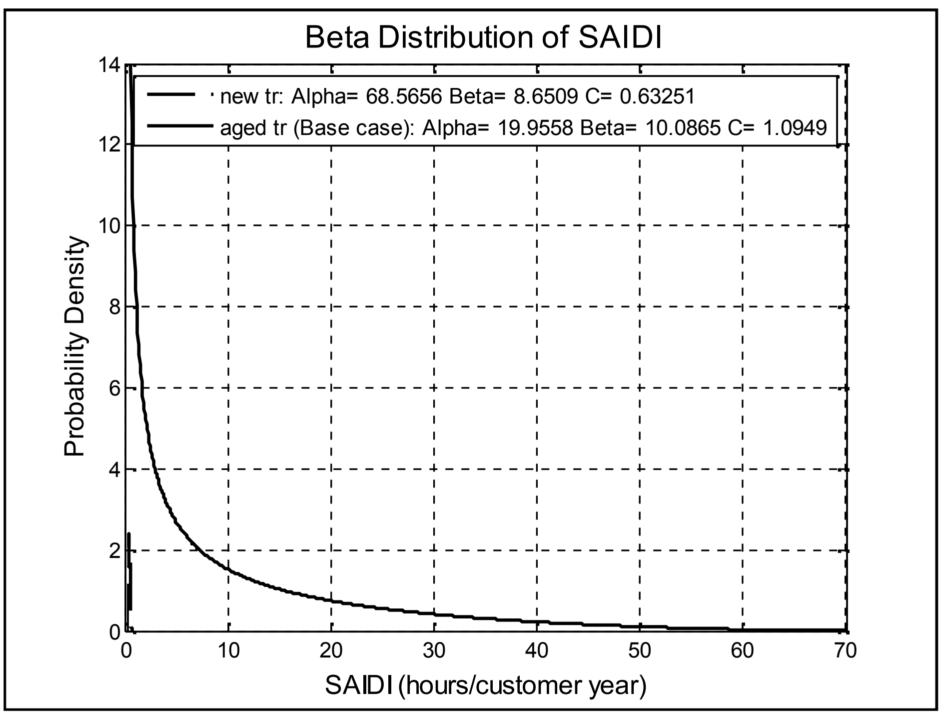

Figure 6-3 SAIDI comparison of case aged_tr and case new_tr

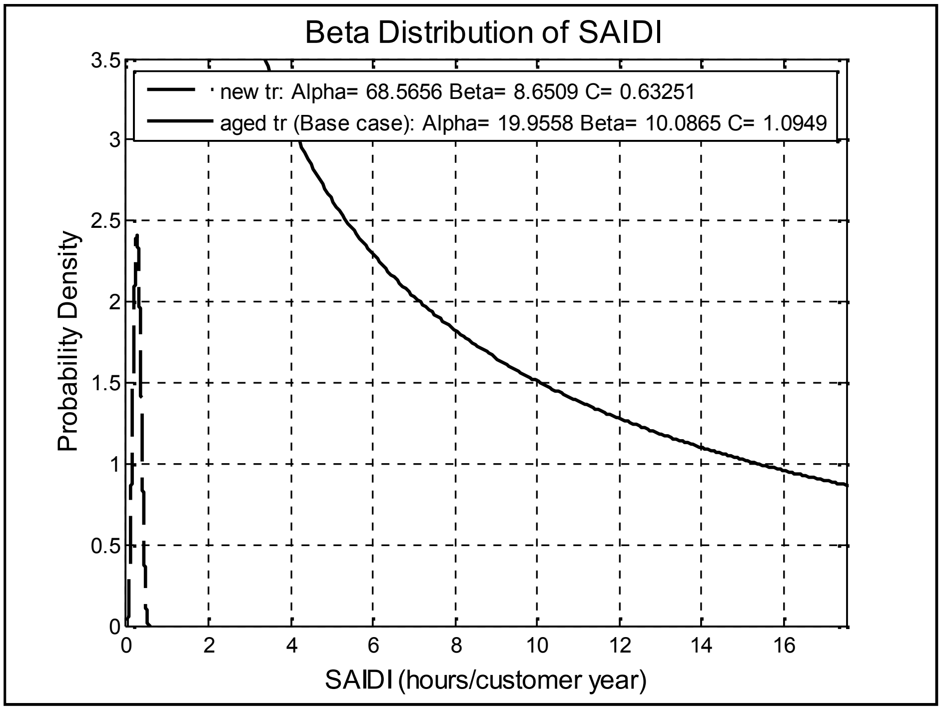

Figure 6-4 SAIDI comparison of case aged_tr and case new_tr(close up)

Table 6-4 SAIDI for case aged_tr and new_tr

SAIDI (hours/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case new_tr**	**Percentage difference**
10th	0.04	0.15	+275%
50th	3.58	0.26	-92.7 %
90th	26.62	0.38	-98.6 %

iv. Unavailability

The feeder unavailability for the two different cases is compared in Figure 6-5 and a close up is shown in Figure 6-6. Similar observations made regarding SAIDI above may be made for the feeder unavailability. The unavailability hours for the feeder system with worn out transformers (case aged_tr),are much longer than that of the system with transformers operating in their normal life period (case new_tr).The worn out transformers result in a higher feeder failure rate and hence an increased outage duration. As observed with SAIDI above, the 10th percentile of the feeder unavailability (shown in Table 6-5) in case new_tr is higher than that of case aged_tr because of the much narrower range of possible values.

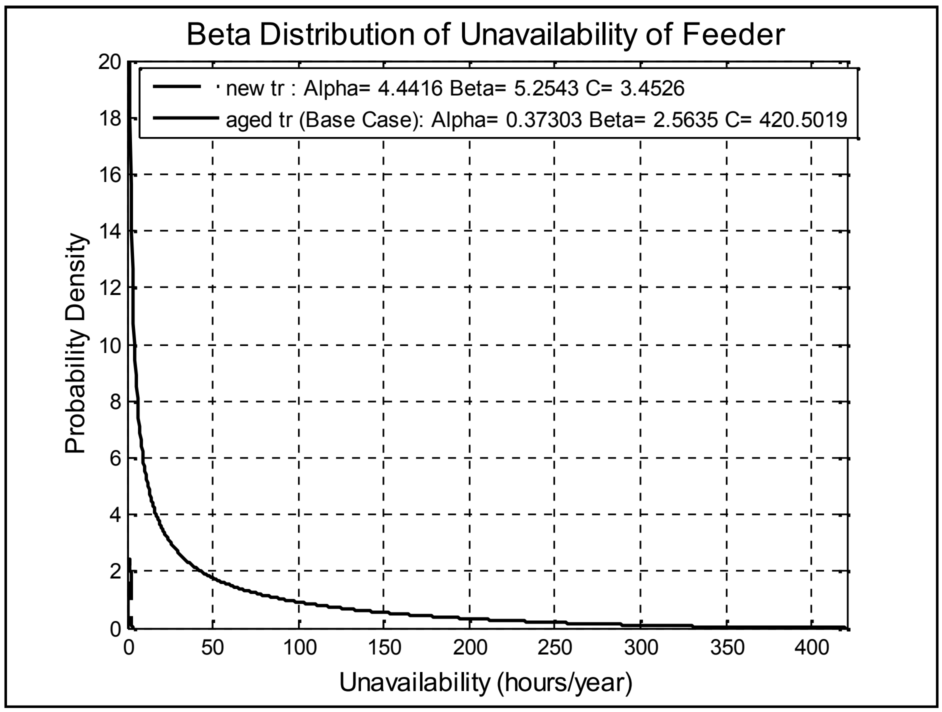

Figure 6-5 Feeder unavailability comparison of case aged_tr and case new_tr

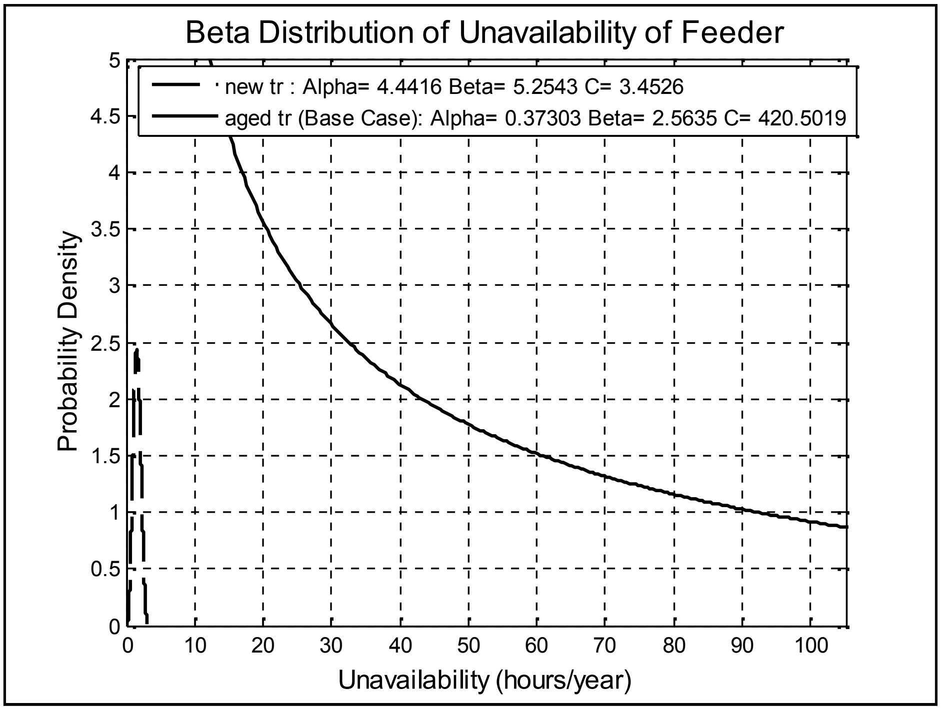

Figure 6-6 Feeder unavailability comparison of case aged_tr and case new_tr

Table 6-5 Feeder unavailability for case aged_tr and case new_tr

Feeder Unavailability (U_s) (hours/year)			
Percentile	**Case aged_tr (Base case)**	**Case new_tr**	**Percentage difference**
10^{th}	0.28	0.89	+217.8%
50^{th}	22.48	1.58	-92.9 %
90^{th}	157.40	2.29	-98.5 %

A crucial observation seen in the comparison of case new_tr and case aged_tr is that, the observations noted for SAIFI were also applicable to feeder failure rate and vice versa. The same applies to SAIDI and the feeder unavailability. This carried through to the remaining cases, indicating that SAIFI gives a good reflection of the feeder failure rate and SAIDI, the feeder unavailability. This is expected, as SAIFI and SAIDI are the respective scaled down values of the feeder failure rate and feeder unavailability respectively. Therefore the remaining distributions of feeder failure rate and unavailability for the remaining cases will be presented in Appendix C.

6.1.2 Case aged_tr and case FPI_DFE

i. SAIFI

The beta distributions describing the magnitudes of SAIFI for the case aged_tr and case FPI_DFE are shown in Figure 6-7. It is apparent from this figure that there is no significant change in this reliability index. The spread and shape of the two distributions is similar and the change in value of SAIFI at the different percentiles as shown in Table 6-6 is negligible. It can be seen that the incorporation of distance to fault estimators and fault current passage indicators has no impact on the systems average failure frequency. This is expected because these two devices do not affect the state or condition of the main system components, but instead assist in the location of faults, after an interruption has occurred. They do not help prevent or decrease the occurrence of faults.

The slight difference in the two distributions and their percentile values is insignificant and could be attributed to slight statistical differences during the execution of the MCS.

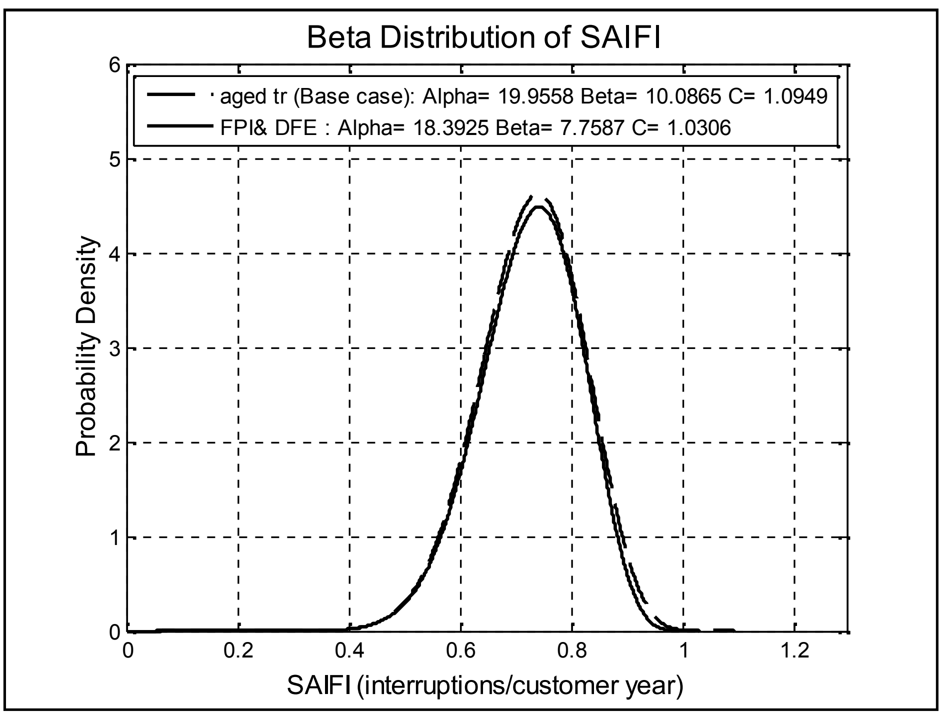

Figure 6-7 SAIFI comparison of case aged_tr and case FPI_DFE

Table 6-6 SAIFI for case aged_tr and case FPI_DFE

SAIFI (interruptions/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case FPI_DFE**	**Percentage difference**
10^{th}	0.60	0.60	0%
50^{th}	0.73	0.72	+1.3 %
90^{th}	0.84	0.82	2.4 %

ii. SAIDI

Unlike the failure rate of the feeder and SAIFI, the SAIDI in case FPI_DFE does differ from the SAIDI of the case aged_tr. This change is not very evident in Figure 6-8, but it can be seen in Table 6-7 in the 10^{th} and 50^{th} percentile values. This decrease in SAIDI from case aged_tr to case FPI_DFE is as a result of the installation of the distance to fault estimators and fault current passage indicators, which contribute towards decreasing the interruption duration, by assisting in the fault finding process. The 90^{th} percentile value in both cases is very similar, indicating that the overall change in SAIDI is very modest.

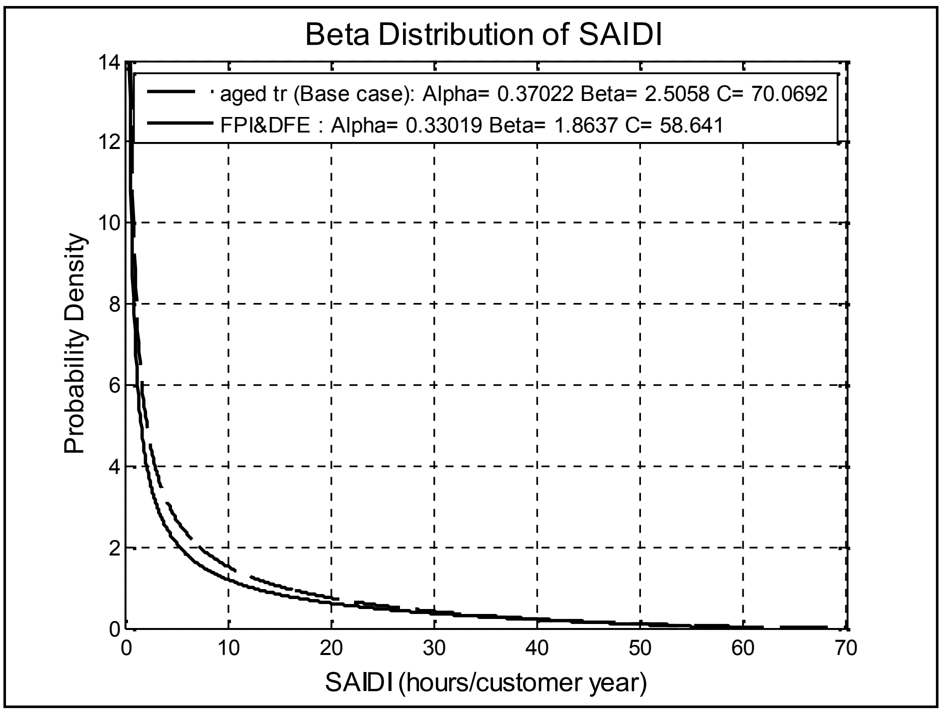

Figure 6-8 SAIDI comparison of case aged_tr and case FPI_DFE

Table 6-7 SAIDI for case aged_tr and case FPI_DFE

SAIDI (hours/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case FPI_DFE**	**Percentage difference**
10^{th}	0.05	0.02	-60 %
50^{th}	3.79	3.33	-12.1 %
90^{th}	26.64	26.5	0.52 %

6.1.3 Case aged_tr and case feeder_auto

i. SAIFI

Unlike in case FPI_DFE, the implementation of feeder automation does result in a decrease the frequency of failures on the system. The comparison of the SAIFI beta distributions for case aged_tr and feeder_auto is shown in Figure 6-9. The difference in the SAIFI at the different percentiles is significant, as depicted in Table 6-9. Feeder automation implements fault location and isolation. It then restores electrical energy supply to customers who need not be disconnected from the main supply. This group of customers instead experience a momentary interruption, where they previously would have experienced a sustained interruption. Therefore the implementation of feeder automation sees a decrease in SAIFI which is a measure of the frequency of sustained interruptions experience by each customer in the system in one calendar and an increase in MAIFI, the measure of the frequency of momentary interruptions per customer in one calendar year.

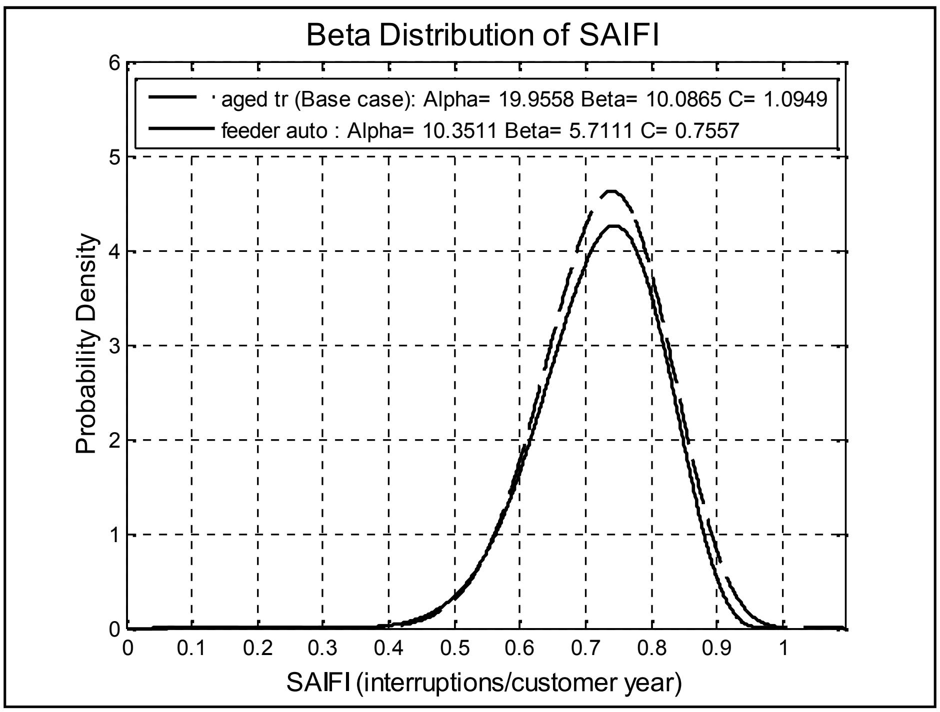

Figure 6-9 SAIFI comparison of case aged_tr and case feeder_auto

Table 6-8 SAIFI for case aged_tr and case feeder_auto

SAIFI (interruptions/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case feeder_auto**	**Percentage difference**
10th	0.60	0.37	-38.3 %
50th	0.73	0.49	-32.9 %
90th	0.84	0.60	-28.6 %

ii. SAIDI

The distributions describing SAIDI for the case aged_tr and case feeder_auto are shown below in Figure 6-10. The decrease in SAIDI illustrated by the percentage difference in the 10th and 50th percentile, show that feeder automation has a positive impact on the overall interruption duration experience by customers. Feeder automation detects and isolates faults within 1 minute, allowing customers whose energy supply can be immediately restored via switching, to be reconnected in a shorter period of time. It also facilitates in the quick identification of faults to be attended to by the repair crew. These operations are responsible for the decrease in SAIDI.

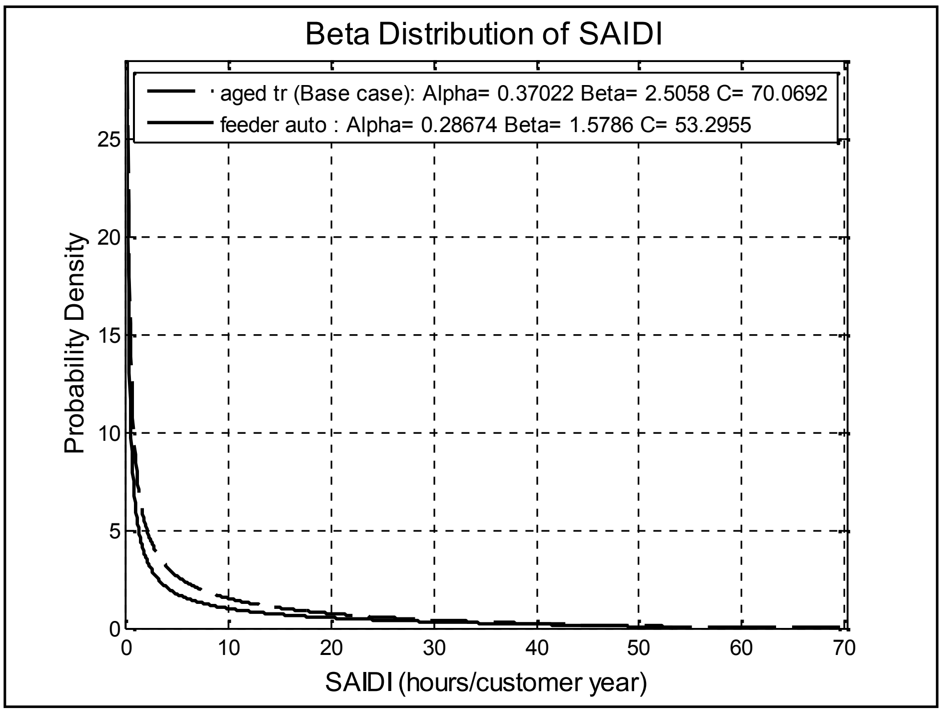

Figure 6-10 SAIDI comparison of case aged_tr and case feeder_auto

Table 6-9 SAIDI for case aged_tr and case feeder_auto

SAIDI (hours/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case feeder_auto**	**Percentage difference**
10^{th}	0.05	0.01	-80 %
50^{th}	3.79	2.70	-28.8 %
90^{th}	26.64	26.02	2.3 %

The implementation of feeder automation only affects the fault location and switching time. In case aged_tr, the average switching time and fault location time is about 2.5 hours and this is reduced to about 1 minute in case feeder_auto. This is highly beneficial for load points upstream to a fault, as they can be restored to the main power supply within a minute. On the other hand, load points downstream to a fault, still have to wait a substantial amount on time for the faulted feeder component to be repaired. Feeder automation has no impact on the repair time of the components, which ranges from 4 hours for circuit breakers, to 200 hours for transformers. Therefore the decrease in SAIDI in this case, is a reflection of the decrease in fault location time, which is only a fraction of the total outage time per interruption. In order to realize a much greater decrease in SAIDI, the repair time of the different components needs to be decreased, or alternative means of energizing the downstream load points affected by the fault needs to be implemented.

iii. MAIFI

With the implementation of feeder automation, the detection and isolation of faults on the feeder may be carried out with 1 minute. This means that customers not directly affected by a fault, may now experience a momentary interruption, unlike before, when switching was performed manually. The beta distribution given in Figure 6-11 describes MAIFI. About 31 % of the average number interruptions in this case, which would have been sustained interruptions prior to the implementation of feeder automation, are now momentary. The slight difference in the magnitude of MAIFI varies from the 10^{th} to 90^{th} percentile, indicates that the distribution has a small range and that most values of MAIFI are close to its average value.

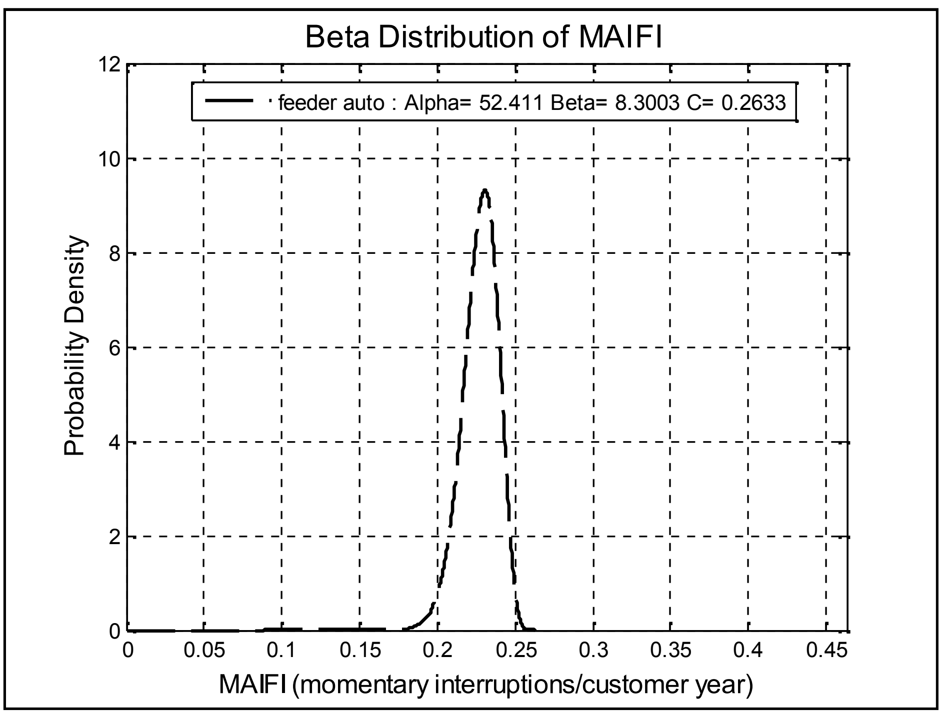

Figure 6-11 MAIFI beta distribution for case feeder_auto

Table 6-10 MAIFI for case feeder_auto

MAIFI (momentary interruptions/year)	
Percentile	Case feeder_auto
10th	0.21
50th	0.22
90th	0.24

6.1.4 Case aged_tr and case DG

i. SAIFI

As with the case FPI_DFE, the reliability index, SAIFI did not differ from the base case. The comparison is depicted in Figure 6-12 and Table 6-11. Distributed generation is implemented to supply energy to LP5 and LP6 in the event of an interruption. It does not assist in preventing the occurrence of faults. Therefore, as experienced with distance to fault estimators, fault passage detectors and feeder automation, distributed generation plays no role in the avoidance of faults.

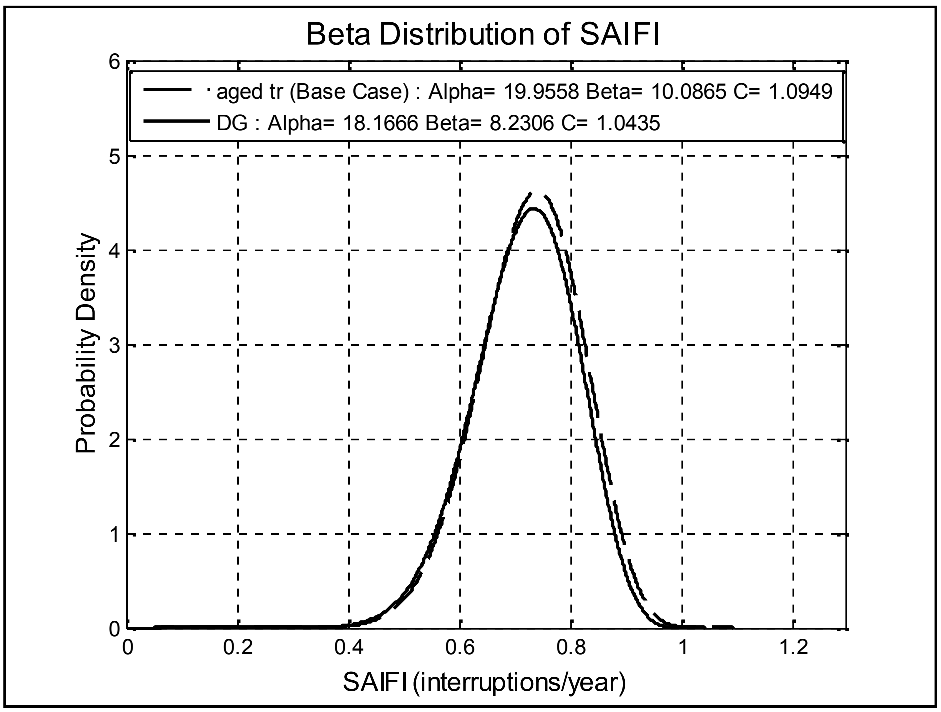

Figure 6-12 SAIFI comparison for case aged_tr and case DG

Table 6-11 SAIFI for case aged_tr and case DG

SAIFI (interruptions/customer year)			
Percentile	Case aged_tr (Base case)	Case DG	Percentage difference
10th	0.60	0.60	0 %
50th	0.73	0.72	1.3 %
90th	0.84	0.83	1.1 %

i. SAIDI

The beta distributions of SAIDI for both case new_tr and case DG are given in Figure 6-13. The solar PV plant was sized to supply and restore LP5 and LP6 in the event that an interruption was to occur upstream to these load points. Fault location and switching times were the same as those in the case aged_tr. In order to further highlight the impact of the DG on LP5 and LP6, the comparison of the average unavailability of LP1,LP5 and LP6 is given in Table 6-13.

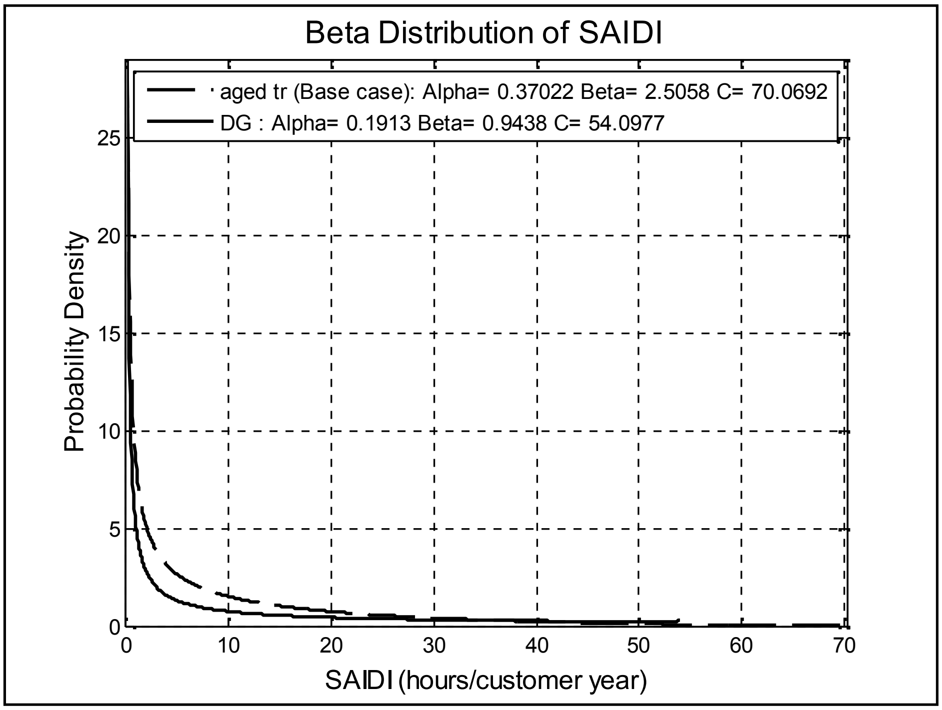

Figure 6-13 SAIDI comparison of case aged_tr and case DG

Table 6-12 SAIDI for case aged_tr and case DG

SAIDI (hours/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case DG**	**Percentage difference**
10th	0.05	0.00	-100 %
50th	3.79	1.57	-58.6 %
90th	26.64	32.75	+22.9 %

As already mentioned, the solar PV plant acts as a backup power source for LP5 and LP6 if an interruption were to occur upstream to either or both of these load points. The impact of the distributed generation on the average unavailability of LP1, LP5 and LP6 is given in Table 6-13. As can be seen, the impact of the distributed generation on LP1 is small and negligible. On the other hand, the impact on LP5 and LP6 is substantial. This shows that locally, distributed generation does contribute towards the decreasing outage duration.

Table 6-13 Average Unavailability of Load points 1,5 and 6

Average value of index	**Base case**	**Case 5**	**Percentage difference**
$U_{Loadpoint1}$	15.8	15.6	-1.2 %
$U_{Loadpoint5}$	10.2	7.8	-23.5 %
$U_{Loadpoint6}$	8.7	7.2	-17.2 %

Another observation from Table 6-13 above, is that distributed generation had more of an impact on the average unavailability of LP6, than on that of LP5. This is because, in the event that an interruption occurs upstream to LP5 and LP6, preference is given to LP6. So if the power output of the solar PV plant at that moment cannot meet the demand of both load points, but can only sufficiently supply one of them, LP6 is given preference.

Currently in South Africa, renewable power plants are prohibited from connecting to the distribution or transmission grid through islanding operation for safety reasons . They are in fact required to shut down immediately upon the detection of an islanded operation [RSA Grid Code Secretariat, 2012]. This regulation therefore limits the implementation of the scenario presented in this case.

6.1.5 Case aged_tr and case feeder_auto_DG

i. SAIFI

The same observation noted in case feeder_auto regarding SAIFI, is also applicable in this case. The application of distributed generation in union with feeder automation does result in a decrease in SAIFI. The observed decrease in SAIFI in similar to that of case feeder_auto, with a slight decrease in SAIFI. This further decrease is brought about by the combination of DG and feeder auto. This decrease SAIFI is brought about by the feeder automation which implements automatic fault location, isolation and service restoration and DG which can now supply LP5 and/or LP6 preventing them from experiencing sustained interruptions in a number of different circumstances. This is further explained under MAIFI for this case.

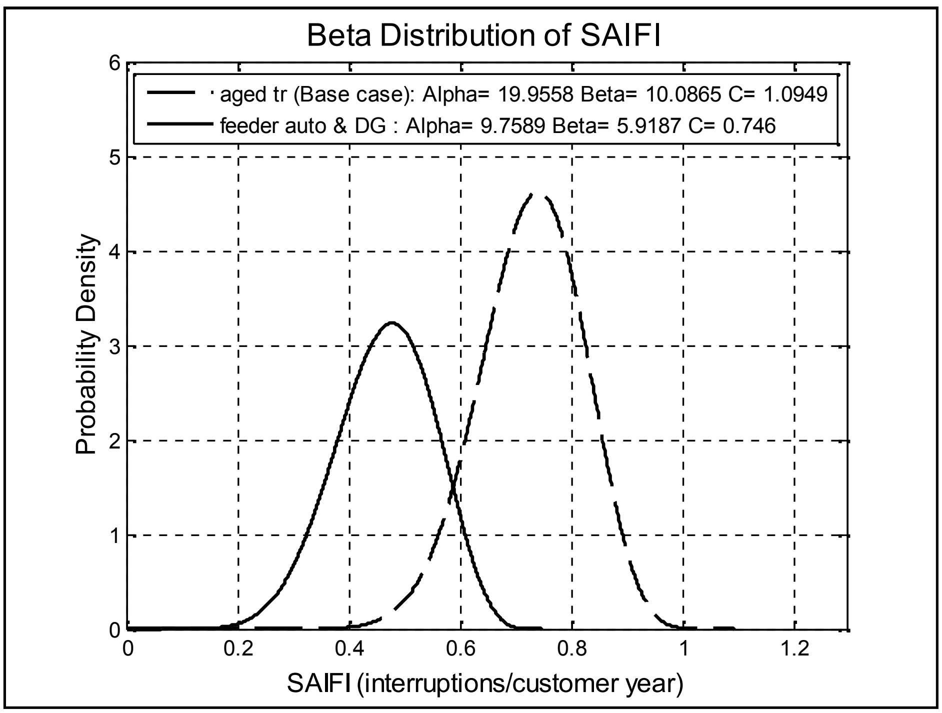

Figure 6-14 SAIFI comparison of case aged_tr and case feeder_auto_DG

Table 6-14 SAIFI for case aged_tr and case feeder_auto_DG

SAIFI (interruptions/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case feeder_auto_DG**	**Percentage difference**
10th	0.60	0.35	-41.6 %
50th	0.73	0.47	-35.6 %
90th	0.84	0.58	-31.0 %

ii. SAIDI

The impact of distributed generation and feeder automation on SAIDI is the most significant of all the cases excluding case new_tr. The combined effect of feeder automation and distribution generation on the system impacts the fault location time and restoration time for LP5 and LP6, as experienced in case feeder_auto and case DG.

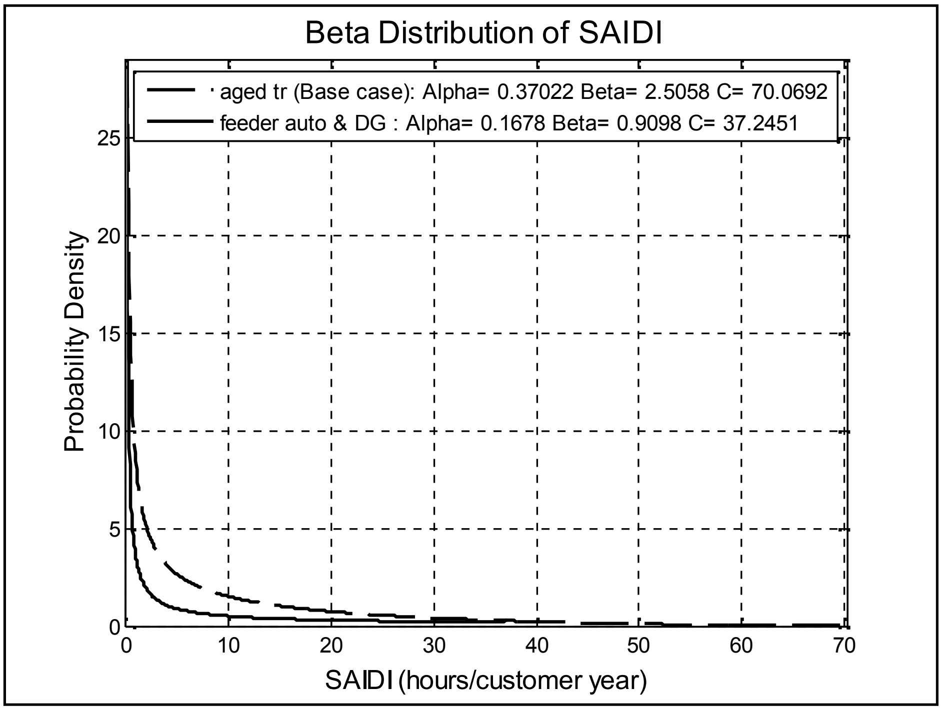

Figure 6-15 SAIDI comparison of case aged_tr and case feeder_auto_DG

Table 6-15 SAIDI for case aged_tr and case feeder_auto_DG

SAIDI (hours/customer year)			
Percentile	**Case aged_tr (Base case)**	**Case feeder_auto_DG**	**Percentage difference**
10^{th}	0.05	0.00	-100 %
50^{th}	3.79	0.69	-81 %
90^{th}	26.64	21.65	-18.7 %

The average unavailability of LP1,LP5 and LP6 is shown in Table 6-16. This combination of feeder automation and distributed generation has a greater impact on the feeder as a whole and on LP5 and LP6. Case feeder_auto illustrated that feeder automation decreases the unavailability of the feeder as whole, because it impacts all the load points, hence the decrease in the average unavailability of load point 1 in this case. Case DG showed that the solar PV plant significantly impacts LP5 and LP6 only. The addition of feeder automation to the distributed generation further improves the feeder unavailability of LP5 and LP6 from case DG to case feeder_auto_DG. This goes to show that feeder automation facilitates the operation and incorporation of distributed generation into the grid, when it is used as a backup source of power.

Table 6-16 Average Unavailability of load points 1, 5 and 6

Average value of index	**Base case**	**Case 5**	**Case6**
$U_{Loadpoint1}$	15.8	15.6	10.5
$U_{Loadpoint5}$	10.2	7.8	6.1
$U_{Loadpoint6}$	8.7	7.2	4.5

iii. MAIFI

The momentary interruptions increased from case feeder_auto to case feeder_auto_DG. This is due to the presence of distributed generation on the feeder, which could potentially supply load point 5 and/or load point6 in the event of an interruption. For example, previously in case feeder_auto, without the inclusion of DG, a permanent fault on O7, would result in a momentary interruption for LP1-LP3 and a sustained interruption for LP4,LP5 and LP6. But due to the presence of DG in case feeder_auto_DG, LP5 and LP6 will only experience a momentary interruption, depending on whether the power generation available from solar PV plant can supply the load on LP5 and LP6.

The average number of sustained interruptions decreased from case feeder_auto to case feeder_auto_DG. Momentary interruptions now account for 36 % of the interruptions in the system, compared to 31 % in case feeder_auto.

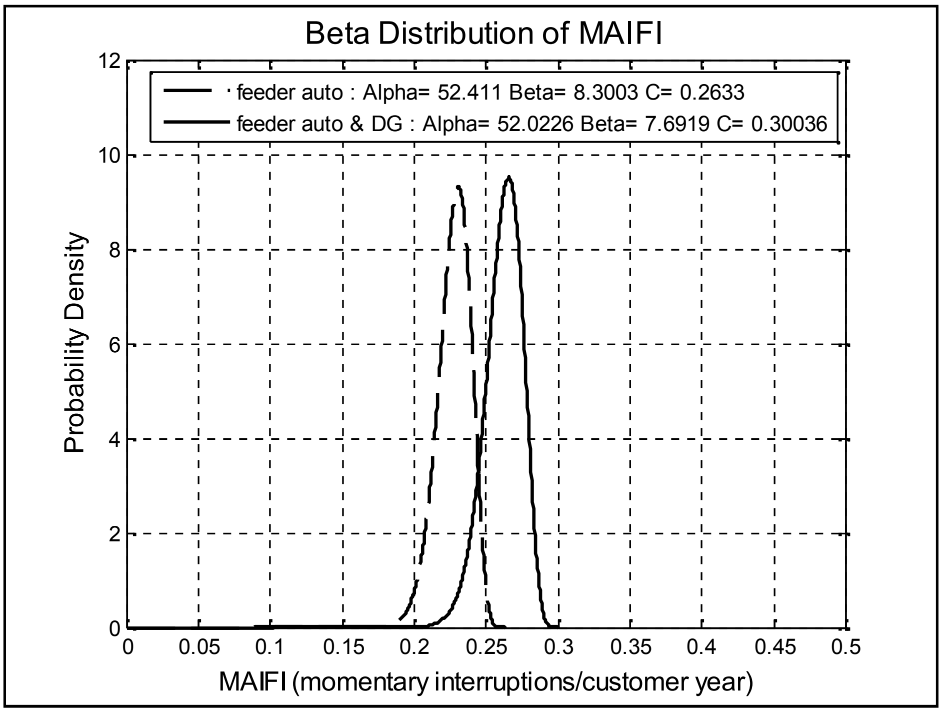

Figure 6-16 MAIFI comparison of case feeder_auto and case feeder_auto_DG

Table 6-17 MAIFI for case feeder_auto and case feeder_auto_DG

MAIFI (momentary interruptions/customer year)			
Percentile	**Case feeder_auto**	**Case feeder_auto_DG**	**Percentage difference**
10^{th}	0.21	0.24	+14.2 %
50^{th}	0.22	0.26	+18.2 %
90^{th}	0.24	0.28	+16.6 %

6.2 RELIABILITY WORTH EVALUATION

This sub section presents and discusses the findings of the reliability worth evaluation. The findings are presented in the form of beta distributions and average values of two reliability indices: EENS and the customer interruption costs. The average values are given in order to get a sense of the expected losses in energy and cost per year. EENS, the Expected Energy Not Served, is the average amount of energy not supplied to the customer as a result of an outage. It is dependent on the load of the customer at the time when an interruption occurred. The customer interruption costs are the monetary losses incurred by the customer due to the unavailability of electricity.

6.2.1 EENS (All cases)

The comparison of the EENS for all six cases is made in the distributions given in Figure 6-17.

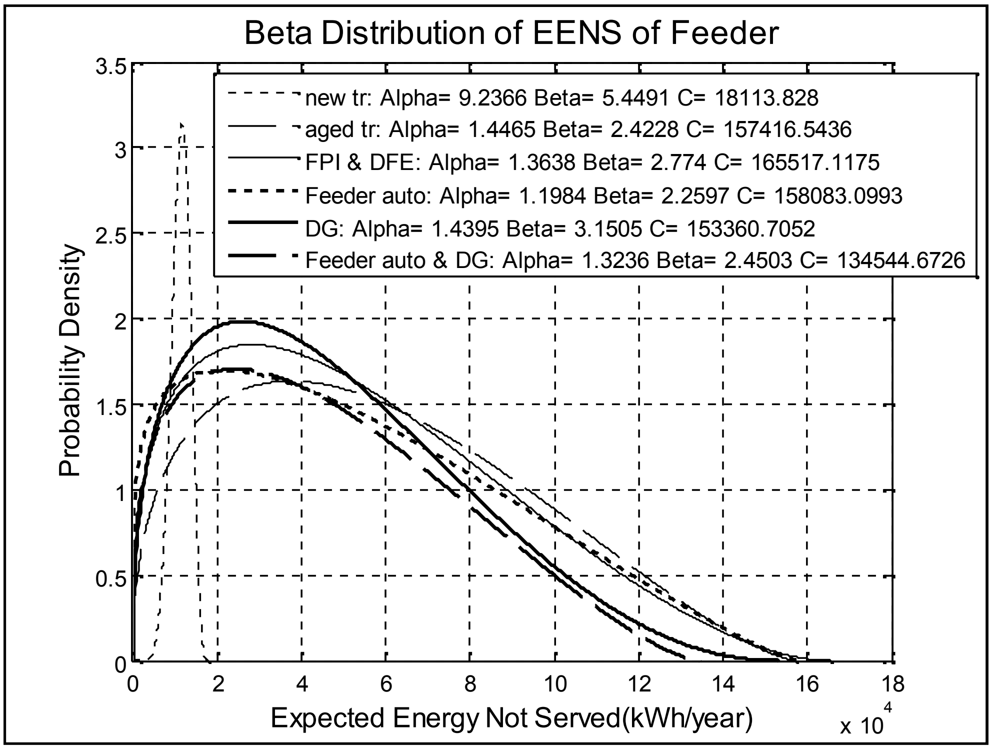

Figure 6-17 EENS comparison of all cases

Table 6-18 Average value of EENS for all cases

Case	Average value of EENS (kWh/year)	Percentage difference from base case
aged_tr (base case)	58 848.92	-
new_tr	11 392.73	-80.6 %
FPI_ FDE	54 553.47	-7.3 %
feeder_auto	53 656.91	-8.8 %
DG	48 096.73	-18.3 %
feeder_auto_DG	47 189.09	- 19.8 %

The narrow range of EENS distribution for case new_tr indicates that the EENS is more or less constant and does not vary significantly. This stems from the failure rate of each

component in this case, which is more or less constant. The other cases have distributions with a wider range because of the large variability of the failure rate of the transformers.
As expected, the base case has the highest average EENS, because in this case no techniques have been put into place to try and improve the system reliability.

The difference in EENS between case new_tr and all other cases is very large because the EENS is directly related to the outage duration. The highest decrease in outage duration is observed in case new_tr and this decrease is therefore carried through to the EENS.

An important observation is the difference in EENS in cases feeder_auto and DG. For all 3 percentile values, the decrease in SAIDI in case feeder_auto was greater than that of case DG, particularly at the 50th percentile. But the decrease in EENS in case DG is significantly greater than that of case feeder_auto. This is related to the loads of LP5 and LP6 which are much larger than that of the other load points. These two load points contain residential and commercial customers, unlike all the other load points which only contain the former. The DG is dedicated towards supplying LP5 and LP6 in the event of an interruption. In case feeder_auto, there was quicker fault detection and switching but the absence of DG still resulted in lengthy interruption durations of load points like LP5 and LP6, which did not have access to alternate sources of electricity, in the event on upstream faults. An alternative option in the form of DG, results in a decrease in the outage duration experienced by these load points (LP5 and LP6) and since they carry the greatest loads on a system, the decrease in EENS in that case will be more substantial.

The next observation entails the difference in EENS between cases feeder_auto and feeder_auto_DG. Both these cases consider the implementation of feeder automation, but case feeder_auto explores the implementation of feeder automation independently. The addition of DG to that system resulted in a modest decrease in SAIDI and but a significant decrease in EENS. The key reason behind this is also the magnitude of the loads of LP5 and LP6, which are greater than all other load points. The DG can now supply LP5 and LP6 in instances (e.g. a fault in O5) where these load points previously had to wait for a faulted feeder section to be repaired. Therefore, a decrease in the unavailability of these two load points will result in a more significant impact on the EENS as observed in Table 6-18.

6.2.2 Expected Customer interruption Cost

The annual customer interruption costs for all the customers on the feeder are described by the beta distributions in Figure 6-18.

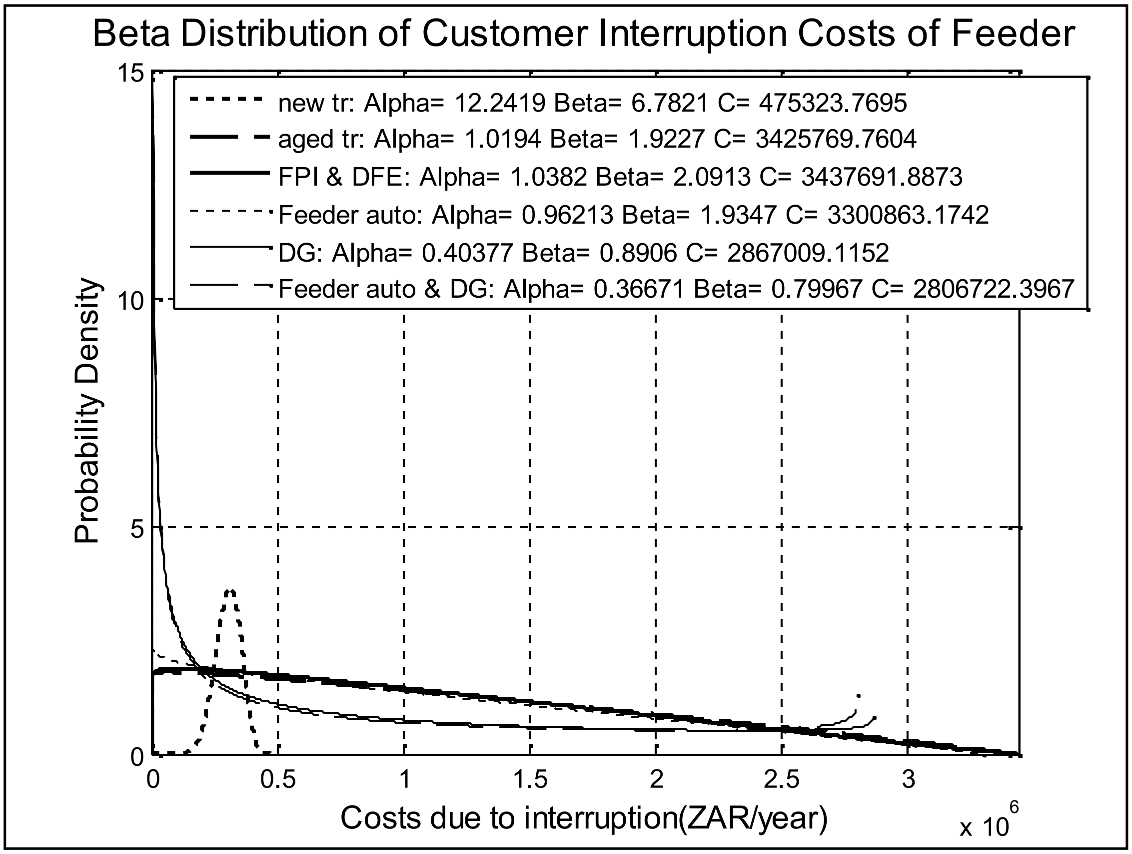

Figure 6-18 Customer interruption costs for feeder for all cases

The narrow range and shape of the beta distribution of the case new_tr once again stems from the fact that the failure rate of all the test system components fairly constant and hence the variability in component failures is low. The range of values for the customer interruption costs experienced in this case is also the smallest, as the number interruptions is low. This is all a result of the low failure rate of the components in the system. A decreased failure rate assists in decreasing the total unavailability and interruption costs of the system.

The highest costs are experienced in case aged_tr and case FPI & FDE because case aged_tr contains no techniques to try and decrease the frequency or duration of interruptions, and the FPI & FDE have a relatively small impact on the duration of interruptions i.e. SAIDI. The large variability in the transformers' failure rate contributes towards the large range of the distribution. The same is applicable to all the other cases except case new_tr.

Table 6-19 Average customer interruption costs for all cases

Case	Average value of ECOST (ZAR/year)	Percentage difference compared to base case
aged_tr (base case)	1 186 994.46	-
new_tr	305 869.50	-74.23%
FPI_FDE	1 159 923.87	-2.28%
feeder_auto	1 096 321.65	-7.64%
DG	1 031 833.97	-13.07%
feeder_auto_DG	906 885.70	23.60%

There are some similarities between the EENS and the customer interruption costs. The greatest decline in interruption costs is observed in case new_tr followed by case feeder_auto_DG and DG. This observation is applicable to the EENS. Same as the EENS, the costs incurred by the customer incurred in the absence of electricity supply, are interruption duration dependent. A decrease in the unavailability of the system carries through to the interruption costs. The largest decrease in unavailability is experienced in case new_tr and the same applies to the interruption costs.

Cases DG and feeder_auto_DG have a greater impact on the customer interruption cost outside of case new_tr. These two cases have a larger impact on the decrease in the unavailability of LP5 and LP6, which contain commercial customers. The costs incurred per hour without electricity supply are much higher for commercial customers than those for residential customers. Therefore the implementation of DG provides an alternate source of energy supply dedicated towards decreasing the outage duration of these load points. This will therefore result in a substantial decrease in the interruption costs of the feeder. This observation also highlights the sensitivity of customer interruption costs to the type of customers on the feeder.

The next sub section analyses of the feasibility of investing in the different technologies listed in the different cases.

6.3 ECONOMIC FEASIBILITY EVALUATION

The average annual savings in customer interruption costs were determined and used to determine the payback period for the different cases and this is given in the table below.

Table 6-20 Discounted payback period

Case	Average annual savings (ZAR/year)	Cost to implement (ZAR)		Discounted Payback Period (years)	
		Minimum	Maximum	Minimum	Maximum
new_tr	881 125.00	4 966 860	-	7	-
FPI _FDE	27 070.59	244 000	261 500	11	12
feeder_auto	90 672.81	2 000 000	3 000 000	29	45
DG	155 160.50	6000000	-	38	-
feeder_auto_DG	280 108.80	8000000	9000000	38	43

From Table 6-20 it is evident that cases new_tr and FPI_DFE have the shorter payback periods. Although case FPI _DFE has one of the shorter discounted payback periods, the distance to fault estimators and fault passage indicators had the smallest effect on the duration of interruptions and no impact on the frequency of interruptions.

Cases feeder_auto, DG and feeder_auto_DG, require much larger investment costs and have longer discounted payback periods. An important point to highlight is that the average life of a small solar PV plant ranges from 25 to 30 years [Alsema et al., 2009; Lin-Lin, 2012]. It would not be feasible to invest in a project to upgrade a solar PV plant to include islanding communication methods, when the payback period of this investment is longer than that of the life of the solar PV plant. Nonetheless this decision remains in the hands of the investor.

Simply looking at the payback periods, the most feasible option would be to implement case new_tr which would require the purchasing and installation of new distribution transformers. This case has a maximum discounted payback period of about 7 years and the greatest annual savings per year. The implementation of new transformers drastically decreases the both the frequency and duration of interruption. The greatest decrease in SAIFI, SAIDI, EENS and customer interruption cost was observed in this case. The shape of the beta distributions describing these indices for case new_tr were bell shaped, with narrow range, indicating small variability. The average design lifetime of a typical distribution transformer, depending on its operating conditions, ranges from 30 to 35 years [Blackburn, 2007; Yazdani-Asrami et al., 2011]making this case the most financially feasible.

Sensitivity analysis

A brief sensitivity analysis considering three different scenarios was conducted in this sub section.

<u>Scenario i</u>

This scenario considers the effect of the TTLF on the interruption costs experienced in the base case.

Table 6-21 Effect of TTLF on average ECOST scenario 1 -sensitivity analysis

Aged_tr (Base case)		
Average TTLF (hours)	**Average value of ECOST (ZAR/year)**	**Percentage difference (%)**
1.5	1 186 994.46	reference value
0.375	1 137 565.04	-4.16
0.75	1 148 112.14	-3.28
3	1 195 769.70	0.74
4.5	1 213 240.91	2.21
6	1 231 682.33	3.76

Table 6-21 gives an indication of how TTLF affects the average customer interruption costs. The TTFL value considered in the base case is reduced to a quarter of its original value i.e. 0.375 hours and increased to up to four times its value, at 6 hours. The results of this table show that a decrease in the TTLF translates to a decrease in the experienced customer interruption costs. The opposite is also applicable. A key observation is that halving the value of the TTLF results in a small decrease in the customer interruption costs and doubling it, results in a small increase. Even when the TTLF is tripled and even quadrupled, the corresponding increase in the average ECOST is still minimal. This indicates that the TTLF parameter has minimal impact on the customer interruptions costs, which are outage duration dependent. When an outage occurs, the time take to repair a components accounts for the more significant portion of the outage time than the time taken to repair a fault. This is translated to the interruptions costs and is confirmed in the sensitivity analysis results given in Table 6-21.

<u>Scenario ii</u>

The customer interruption costs are directly dependent on the outage duration. As mentioned in chapter 4, it was assumed that transformers were repaired and not replaced in the event of a fault. The average repair time was about 200hours, which is equivalent to about 9 days, which is not common in modern day South Africa for a residential area for medium to high income household. In this brief analysis, it was assumed that a faulted aged transformer was instead replaced with another aged transformer. The replacement time was set to about 9 hours. The impact of this change on the payback period is shown in Table 6-22.

Table 6-22 Discounted payback periods for all cases of scenario 2 -sensitivity analysis

Case	Average annual savings (ZAR/year)	Cost to implement (ZAR)		Discounted Payback Period (years)	
		Minimum	Maximum	Minimum	Maximum
new_tr	72 434.11	4 966 860	-	99	-
FPI _DFE	12 182.17	244 000	261 500	26	28
feeder_auto	52 679.18	2 000 000	3 000 000	52	81
DG	54 973.30	6000000	-	165	-
feeder_auto_DG	101 857.00	8000000	9000000	115	131

From Table 6-22, it is evident that the discounted payback period for the investments in all the cases has increased and for case DG and case feeder_auto_DG it has more than tripled. The increase in the discounted payback period stems from the decrease in the outage duration. Substituting 200hours with 9 hours in the analysis resulted in an overall decrease in the outage duration. The costs are dependent on outage duration. Therefore a decrease in outage duration also results in a decrease in the customer interruption costs involved. Nonetheless the extremely lengthy payback periods of the all the cases, would deem them unfeasible.

<u>Scenario iii</u>

This scenario considers a situation whereby the transformers are not aged but are instead operating in the normal stage of operation and are maintained regularly. This is the base case in this scenario. The fault passage indicators, distance to fault estimators and the necessary communication systems were implemented in one case and in the other, feeder automation. These results are shown in Table 6-23 . Compared to the results in Table 6-20, where aged transformers were considered, the discounted payback periods in this scenario are much longer. This is attributed to the avoided interruptions brought about by the presence of non aged transformers and the decrease in the duration of interruptions experienced as a result of distance to fault estimators, fault passage indicator and feeder automation. This result highlights that the bulk of the interruption costs are incurred due to the aging infrastructure and not from the lack of more modern grid techniques. This results also points out that the before mentioned smart grid techniques may not be financially feasible even within a system with non aged transformers.

Table 6-23 Discounted payback periods for cases of scenario 3- sensitivity analysis

Case	ECOST	Average annual savings (ZAR/year)	Cost to implement (ZAR)		Discounted Payback Period (years)	
			Minimum	Maximum	Minimum	Maximum
new_tr (new base case)	305 869.50	-	-	-	-	-
new_tr & FPI_DFE	298 416.72	7 452.78	244 000	261 500	44	48
new_tr & feeder auto	265 721.18	40 148.32	2 000 000	3 000 000	70	109

7 CONCLUSION

This chapter concludes the dissertation and discusses the validity of the hypothesis. It also highlights the limitations of the selected approach.

The primary aim of this dissertation was to determine the potential reliability benefit of smart grid technologies and distributed generation on a South Africa distribution feeder. This required the evaluation of reliability of a test system and the selection of smart grid and distributed generation technologies. The impact of these technologies on reliability worth was also evaluated.

7.1 IMPACT ON RELIABILITY AND RELIABILITY WORTH OF SYSTEM

The reliability evaluation of the selected test system was conducted for different cases. The output of this evaluation was reliability indices, which give an indication of the reliability of the system. Aging infrastructure was identified in literature as the key challenge faced by the South Africa power industry. This led to the incorporation of aged infrastructure in the form of aged transformers in to the system.

A number of smart grid technologies, which affect distribution reliability, were identified and their impact was incorporated into the system. These smart grid technologies were distance to fault estimators, fault passage indicators and feeder automation. The effect of distributed generation in the form of solar PV, with and without feeder automation on the distribution reliability was also explored.

A probabilistic approach was selected for the analysis and a time sequential MCS was developed.

Based on the research findings, the following can be concluded:

i. Aged transformers drastically increase the frequency of interruptions experienced in the system, as they are more prone to failure. This was illustrated by the comparison of SAIFI in case new_tr and case aged _tr. The likelihood of failure in the system with aged transformers was order of magnitudes higher. This is reflected by the difference in SAIFI and the feeder failure rate in these cases.

ii. The aged transformers also significantly increased the unavailability of the feeder because the average repair time of the transformers is very large (about 200hours). This observation was apparent in the comparison of SAIDI for case new_tr and case aged_tr. The transformers in case aged_tr failed much more often than those in case new_tr. Each time there was a transformer failure, an outage duration equivalent to the repair time of 200hours was experienced. This drastically affected SAIDI and the feeder unavailability.

iii. The distance to fault estimators, fault passage indicators and feeder automation smart grid technologies contributed towards decreasing the outage of duration of the test system by assisting in fault management and location activities. This impact, although noticeable, was very modest. During the time taken to restore energy to customers after the occurrence of an interruption, most time is spent repairing the fault. Distance to fault estimators and fault passage indicators reduce fault location time from an average of 1.5 hours to 0.5 hours. Whereas feeder automation reduces fault location time to about 30seconds. In a system with a high transformer failure, this impact is minimal, as the transformer repair time is about 200hours. Even if the TTLF could be reduced to 0 seconds, consumers would still have to wait 5 hours for an overhead line to be repaired or even, 200hours in the event of a transformer failure. A greater impact on the reduction of the outage duration is only realized when faults are avoided and prevented altogether, as observed in case new_tr.

iv. The decrease in feeder outage duration, as a result of the implementation of the identified smart grid technologies and distributed generation, is carried through to the EENS and the customer interruption costs of the feeder.
The cases with the higher outage duration also experienced the higher EENS and interruption costs. This is because these two factors are dependent on outage duration.

v. The implementation of distance to fault estimators, fault passage indicators and distributed generation do not have an impact on SAIFI. This is because in the study, the effect of these technologies would only come into effect after a fault has arisen and an interruption has occurred. These technologies did not in any manner contribute towards the avoiding the occurrence of faults and therefore the effect on SAIFI or feeder failure rate was not observed.
On the other hand feeder automation resulted in a significant decrease in SAIFI and an increase in MAIFI. An even greater impact on these indices was realised when feeder automation was incorporated with distributed generation. The main reason behind this would be the speed at which feeder automation locates and isolates faults and then restores customers not directly impacted by the fault. This meant that the group of customers not directly impacted by a fault, would experience a momentary interruption instead of a sustain interruption, due to the implementation of feeder automation.

7.2 FEASIBILITY OF INVESTMENTS

Investing in the identified smart grid technologies and distributed generation is a highly capital intensive venture. Though the smart grid technologies and distributed generation have a positive impact on some reliability indices, they were found to have relatively long discounted payback periods. The type of customers on the feeder directly affects the customer interruption costs, and therefore also impacts the financial feasibility of investing in the different technologies. In this case the customers were assumed to be residential (medium to high income) and commercial retail customers. A different composition of customers and the inclusion of other customer categories (industrial, agricultural), could well have resulted in a completely different outcome. More especially for industrial customers who generally have much higher customer interruption costs than residential and commercial customers.

Another key factor which affected the discounted payback periods for the different cases, was the value assigned to the net discount rate. A discount rate of 10 % [Khatib, 2010] was assumed in the analysis. A lower net discount rate would have resulted in more favourable payback periods. The opposite would apply to a higher discount rate.

Looking simply at the finances in the analysis only, it would be best to invest in new transformers and replace the aged transformers, which are the cause of the high interruption frequency. New transformers resulted in the highest savings in interruption costs, as well as the shortest payback period. Even if the investor was to implement distributed generation and smart grid technologies into the system, the aged transformers would eventually have to be replaced due to their inability to perform altogether. This stresses the importance of addressing the real issues affecting the system before investing in new and different technologies. Cases 3 and 4 particularly highlighted the impact of reducing the time to locate a fault on the system interruption costs. A decrease of between 2 to 8 % from the base case was realised in these cases respectively, with extensive payback periods ranging from 11 to 45 years.

The scenarios conducted in the sensitivity analysis pointed to a number of important outcomes. In the first scenario the sensitivity of the interruption costs to the TTLF parameter was examined, in order to determine how the TTLF affects the costs. The assumed TTLF value in the base case was reduced to a quarter of its value and increased gradually up to four times it original value. From the results of this sensitivity analysis it could be concluded that the TTLF has a minimal impact of the customer interruption costs. The interruption costs are outage duration dependent, and in the event of an interruption, the repair duration of the failed component is much more significant than that of the TTLF. The second scenario of the sensitivity analysis pointed to the effect repair times had on the interruption costs and hence the payback periods. If the repair times can be kept short, the outage duration can be greatly reduced and this will directly translate positively to the interruption costs. With or without smart grid techniques electrical components on the electrical grid will fail and the ability of the repair crew to quickly solve and repair or replace the faulted component can greatly reduce outage costs. In the third scenario it was assumed that the base case contained non aged transformer operating in their normal stage of operation. The effect of distance to fault estimators, fault passage indicators and feeder automation on this new base case was then investigated. The outcome of this analysis highlighted that the high interruption costs experienced in the previously investigated cases were as a result of the aged transformers and not the lack of modern infrastructure in the form of smart grid technologies.

7.3 VALIDITY OF THE HYPOTHESIS PROPOSED

The analysis of this research study indentified fault passage indicators, distance to fault estimators, feeder automation and distributed generation (solar PV) technologies, and investigated their effect on four reliability indices i.e. SAIFI, SAIDI, feeder failure rate and unavailability.

The research findings indicate that, the indentified smart grid technologies and distributed generation can improve reliability indices dependent on outage duration such as SAIDI, unavailability (U), EENS et cetera, and that they have no impact on the frequency of interruptions. The findings also indicate that the frequency and number of interruptions of the feeder among other things, is dependent on the age and state of the infrastructure and not on the inclusion of fault passage indicators, distance to fault estimators, feeder automation or distributed generation. One of the identified technologies i.e. feeder automation, does however have an impact on SAIFI and MAIFI. Feeder automation contributed towards the reduction of sustained interruptions, and this reduction translated to an increase in momentary interruption. However feeder automation did not contribute towards the avoidance of interruptions or the failure frequency on components on the system.

The hypothesis proposed in 1.4 stated that smart grid technologies and distributed generation could beneficially improve the reliability of a distribution feeder in South Africa. The research findings have indicated the partial validity of the proposed hypothesis, and that the hypothesis would be better stated as follows:

Smart grid technologies used in conjunction with distributed generation could improve the reliability of a distribution feeder, by reducing the outage duration of interruptions.

It is however also important to note that not all smart grid technologies on the market were evaluated in this study and that the partially validity of the hypothesis, is based on the before mentioned identified technologies.

7.4 FINAL REMARKS

The research analysis has found that the identified smart grid technologies, namely fault passage indicators, distance to fault estimators and feeder automation and distributed generation in the form of solar PV, have a positive impact on SAIDI and feeder unavailability and no impact on SAIFI and feeder failure rate. The findings of this research study hold for the assumptions in the design of the experiment. A key assumption which affected the findings is that the identified smart grid technologies and distributed generation are perfectly reliable and operate without fail. In reality, all components in a system are prone to failure, and hence the inclusion of the failure probability of these components and system could yield a completely different set of results.

The findings have highlighted that the identified smart grid technologies and distributed generation have no impact on the frequency and rate of interruptions, but decrease the total outage duration of the feeder. They also pinpointed that a network with aged infrastructure has a much higher failure rate, and that this increase carries through to the increased outage duration of the system. This therefore points to the importance of first addressing the root causes of the problems in the network.

South Africa seeks to invest billions of Rands in the coming decades in order to improve and upgrade its distribution network. In-depth analyses into the exact causes of poor performance need to be addressed. This research work has identified that smart grid technologies may not be the solution to the problem of aged infrastructure faced by the distribution power industry of the country.

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8.1.1 APPENDIX A

Appendix A contains an extract from a brochure released by Nortech [2013], a manufacturer of fault passage indicators (FPI). This extracts gives a detailed description of how their fault passage indicators operate and how they improve system reliability by reducing fault location time.

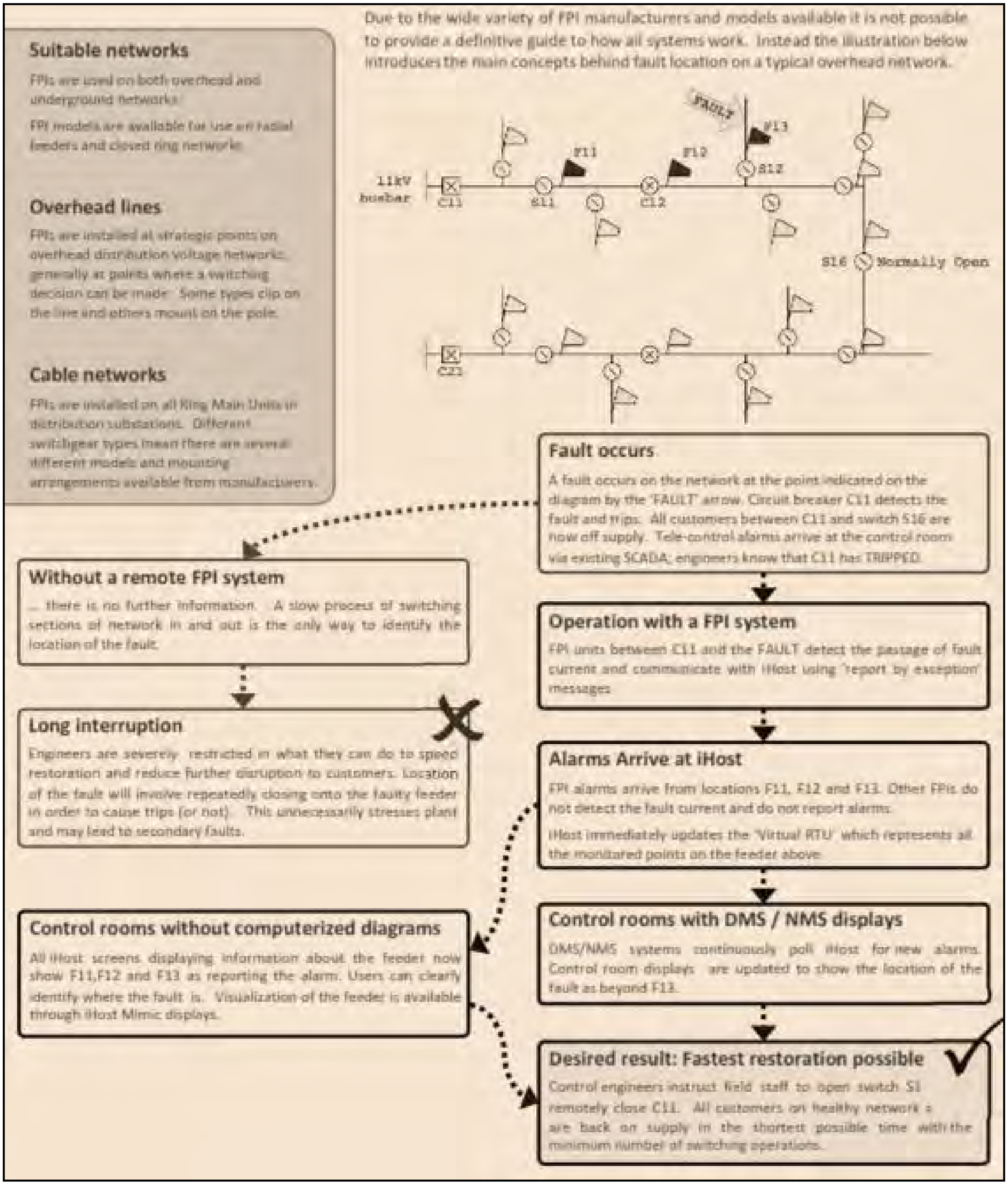

Figure A-8-1 Fault passage indicator operation [Nortech, 2013]

8.1.2 APPENDIX B

Appendix B gives details of the RBTS test system.

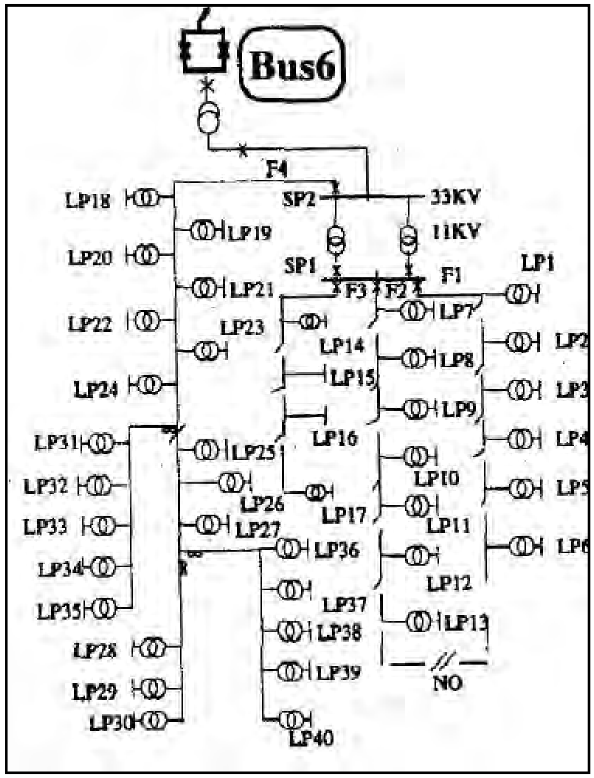

Figure B-8-2 Complete RBTS Bus 6 [Billinton & Jonnavithula, 1996]

Table B-8-1Feeder Type and Lengths [Billinton & Jonnavithula, 1996]

Feeder Type	Length (km)	Feeder Section Numbers
Bus 6		
1	0.6	2 3 8 9 12 13 17 19 20 24 25 28 31 34 41 47
2	0.75	1 5 6 7 10 14 15 22 23 26 27 30 33 43 61
3	0.8	4 11 16 18 21 29 32 35 55
4	0.9	38 44
5	1.6	37 39 42 49 54 62
6	2.5	36 40 52 57 60
7	2.8	35 46 50 56 59 64
8	3.2	45 51 53 58 63
9	3.5	48

Table B-8-2 Reliability and System data[Allan et al., 1991]

component	λ_P	λ_A	λ_T	λ''	r	r_P	r''	r_C	s
transformers									
138/33	0.0100	0.0100	0.050	0.5		15	168	0.083	1.0
33/11	0.0150	0.0150	0.050	1.0		15	120	0.083	1.0
11/0.415	0.0150	0.0150			200	10			1.0 ("line" system) 3.0 ("cable" system)
breakers									
138	0.0058	0.0085	0.050	0.2	8		108	0.083	1.0
33	0.0020	0.0015	0.020	0.5	4		96	0.083	1.0
11	0.0060	0.0040	0.060	1.0	4		72	0.083	1.0
busbars									
33	0.0010	0.0010	0.010	0.5	2		8	0.083	1.0
11	0.0010	0.0010	0.010	1.0	2		8	0.083	1.0
lines (single weather state)									
33	0.0460	0.0460	0.060	0.5	8		8	0.083	2.0
11	0.0650	0.0650			5				1.0
lines (two weather states)									
33 (normal)	0.0139	0.0139	0.016	0.5	8		8	0.083	2.0
(adverse)	5.860	5.860	7.60						
cables									
11	0.0400	0.0400			30				3.0

weather data: average duration of normal weather = 724hr
average duration of adverse weather = 4hr
line failures occurring in adverse weather = 70% of total

33kV line lengths: SP1-SP2 and SP2-SP3 = 10km
SP1-SP3 = 15km

transformer ratings: SP1(Bus4), SP(Bus2) = 16MVA each
SP2 and SP3 (Bus4) = 10MVA each

where: λ_P = permanent (total) failure rate (f/yr) [for lines/cables (f/yr.km)]
λ_A = active failure rate (f/yr) [for lines/cables (f/yr.km)]
λ_T = temporary failure rate (f/yr) [for lines/cables (f/yr.km)]
λ'' = maintenance outage rate (out/yr)
r = repair time (hr)
r_P = replacement time by a spare (hr)
r'' = maintenance outage time (hr)
r_C = reclosure time (hr)
s = switching time (hr)

and: single weather state - rates are annual averages
two weather states - rates are per year of appropriate weather condition

APPENDIX C

Appendix C contains the beta distributions of feeder failure rate and feeder unavailability for case FPI_DFE, case feeder_auto, case DG and case feeder_auto_DG.

C.1 Case aged_tr and case FPI_DFE

i. Feeder failure rate

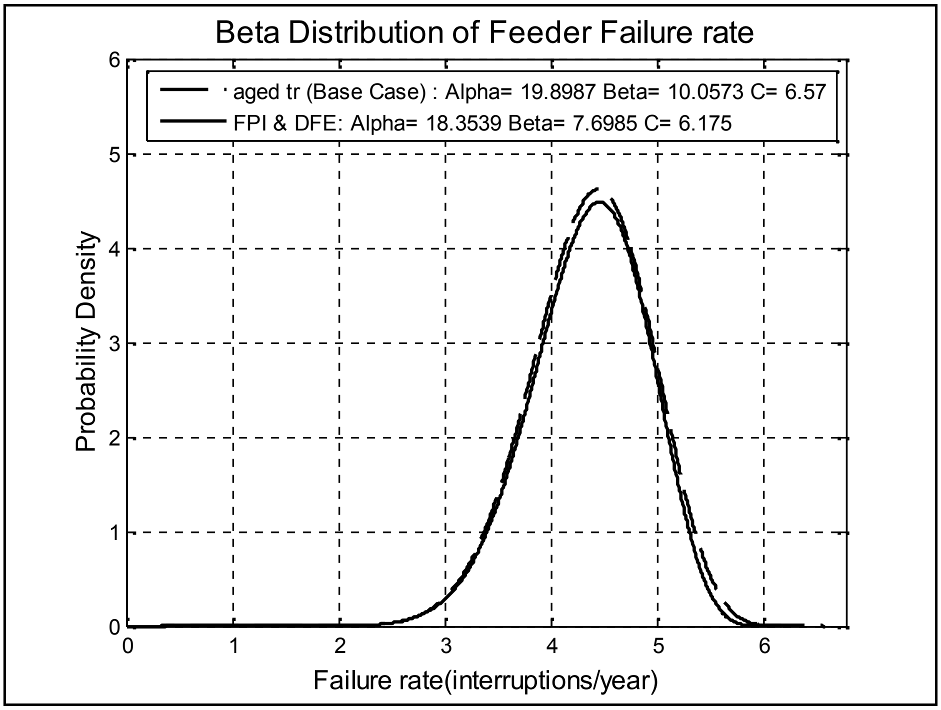

Figure C-8-3 Feeder failure rate comparison of case aged_tr and case FPI_DFE

Table C-8-3 Feeder failure rate of case aged_tr and case FPI_DFE

Feeder failure rate (λ_{feeder})(interruptions/year)			
Percentile	**Case aged_tr (Base case)**	**Case FPI_DFE**	**Percentage difference**
10^{th}	3.61	3.63	+0.5 %
50^{th}	4.39	4.38	-0.2 %
90^{th}	5.05	5.03	-0.4 %

ii. Feeder unavailability

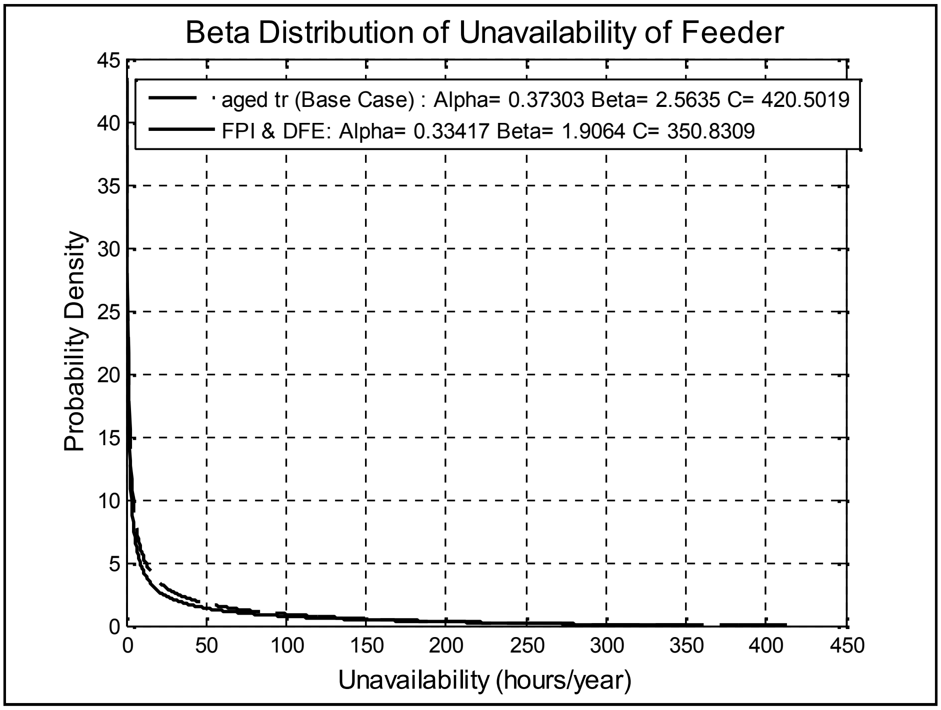

Figure C-8-4Feeder unavailability comparison of case aged_tr and case FPI_DFE

Table C-8-4 Feeder unavailability of case aged_tr and case FPI_DFE

Feeder Unavailability (U_s) (hours/year)			
Percentile	**Case aged_tr (Base case)**	**Case FPI_DFE**	**Percentage difference**
10^{th}	0.28	0.16	-42.9 %
50^{th}	22.48	20.46	-9.0 %
90^{th}	157.40	158.79	+0.9 %

C.2 Case aged_tr and case feeder_auto

i. Feeder failure rate

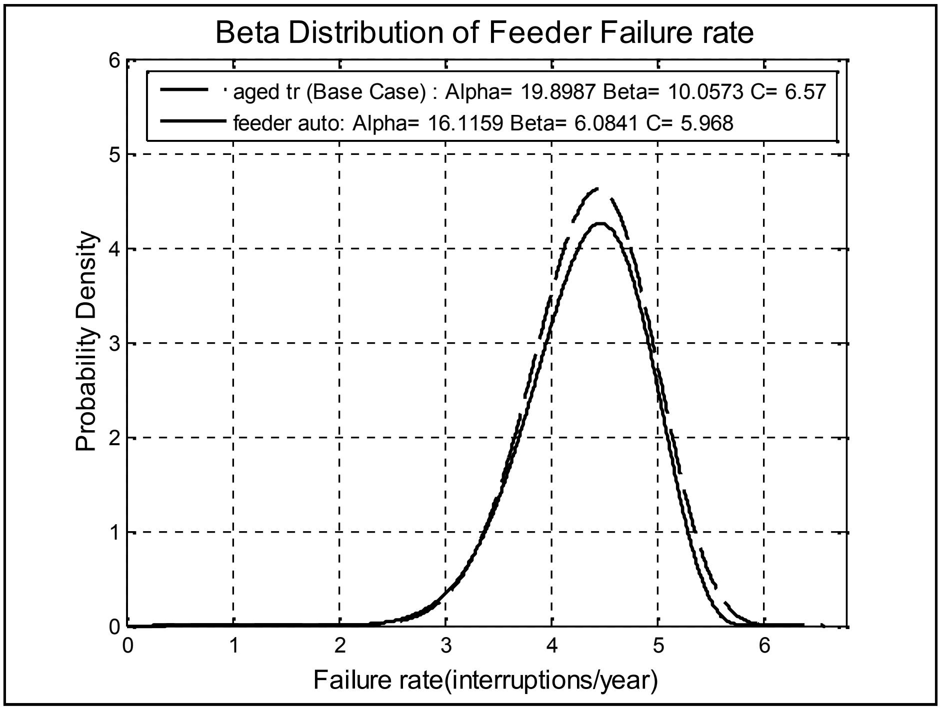

Figure C-8-5 Feeder failure rate comparison of case aged_tr and case feeder_auto

Table C-8-5Feeder failure rate of case aged_tr and case feeder_auto

Feeder failure rate (λ_{feeder})(interruptions/year)			
Percentile	**Case aged_tr (Base case)**	**Case feeder_auto**	**Percentage difference**
10^{th}	3.61	3.60	-0.3 %
50^{th}	4.39	4.37	-0.5 %
90^{th}	5.05	5.02	-0.6 %

ii. Feeder unavailability

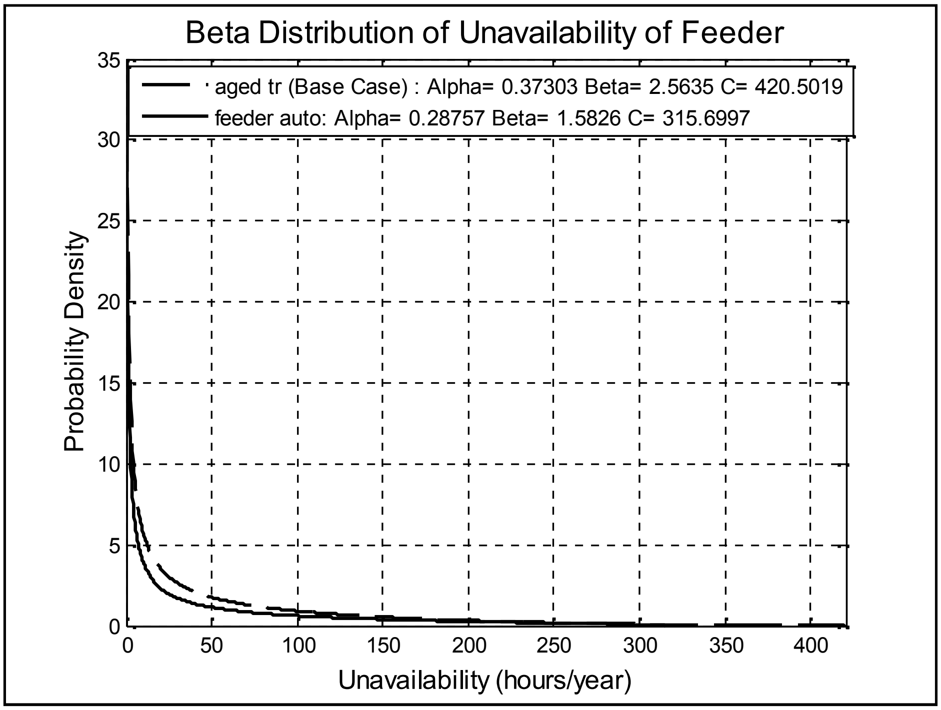

Figure C-8-6 Feederunavailabilitycomparison of case aged_tr and case feeder_auto

Table C-8-6 Feeder unavailabilityrate of case aged_tr and case feeder_auto

Feeder Unavailability (U_s) (hours/year)			
Percentile	**Case aged_tr (Base case)**	**Case feeder_auto**	**Percentage difference**
10^{th}	0.28	0.06	-78.6 %
50^{th}	22.48	15.98	-28.9 %
90^{th}	157.40	154.05	-2.1 %

C.3 Case aged_tr and case DG

i. Feeder failure rate

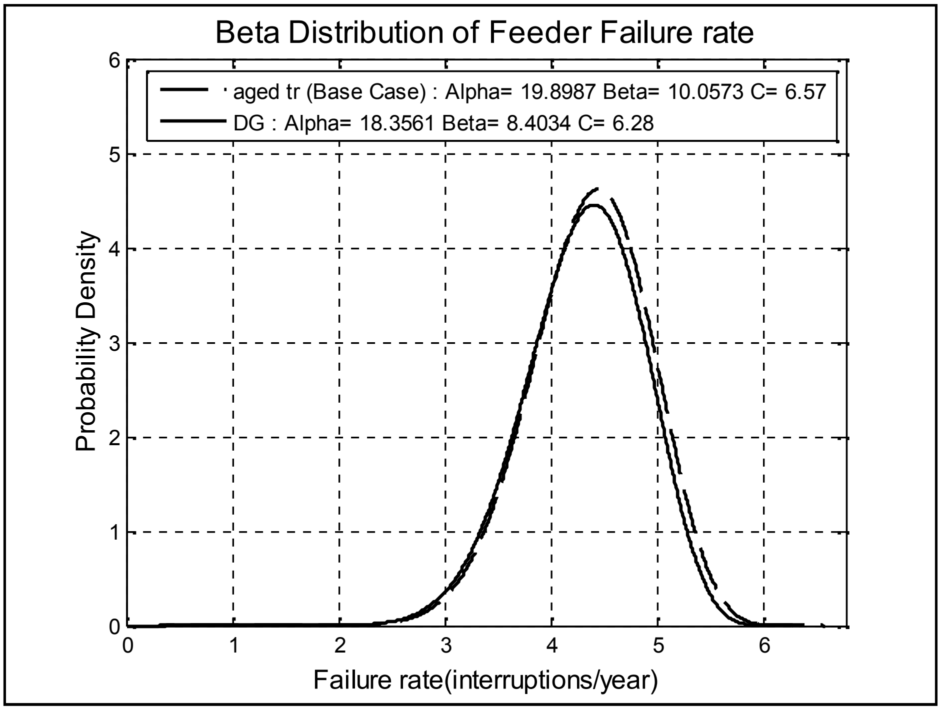

Figure C-8-7Feeder failure ratecomparison of case aged_tr and case DG

Table C-8-7Feeder failure rate of case aged_tr and case DG

Feeder failure rate (λ_{feeder})(interruptions/year)			
Percentile	**Case aged_tr (Base case)**	**Case DG**	**Percentage difference**
10^{th}	3.61	3.57	-1.1 %
50^{th}	4.39	4.33	-1.3 %
90^{th}	5.05	5.00	-0.9 %

ii. Feeder unavailability

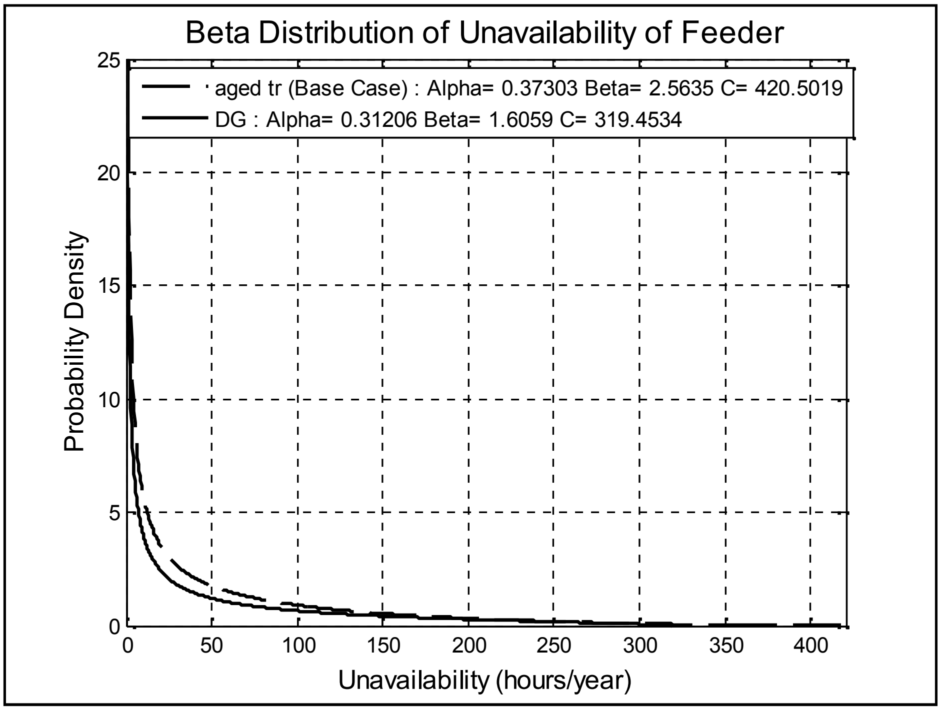

Figure C-8-8 Feederunavailabilitycomparison of case aged_tr and case DG

Table C-8-8 Feederunavailability of case aged_tr and case DG

Feeder Unavailability (U_s)(hours/year)			
Percentile	**Case aged_tr (Base case)**	**Case DG**	**Percentage difference**
10^{th}	0.28	0.11	-60.7 %
50^{th}	22.48	19.43	-13.6 %
90^{th}	157.40	160.83	+2.1 %

C.4 Case aged_tr and case Feeder_auto_DG

i. Feeder failure rate

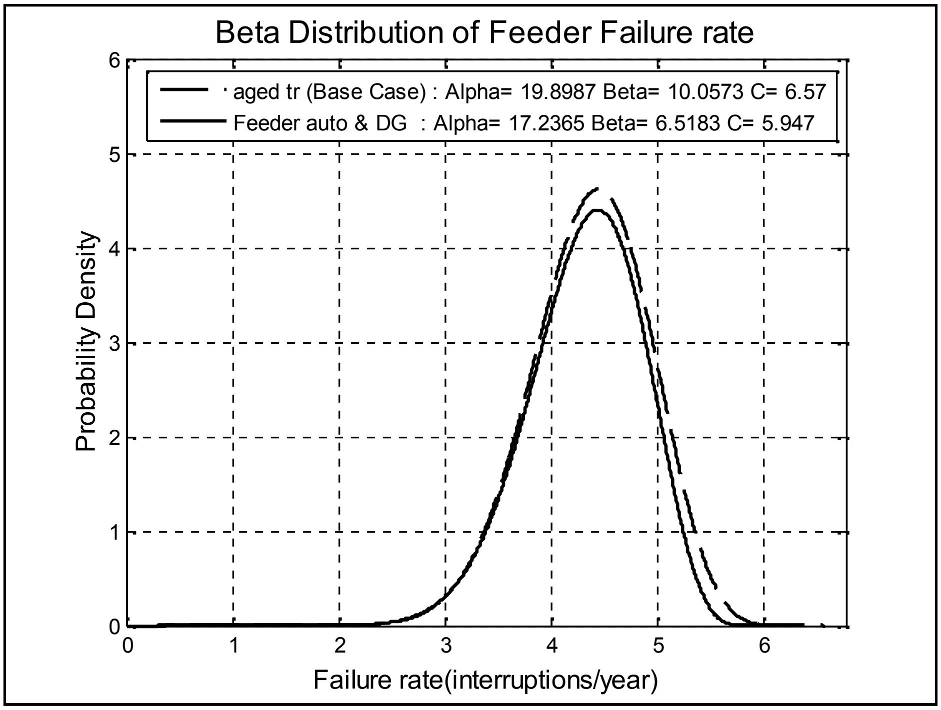

Figure C-8-9 Feeder failure rate comparison of case aged_tr and case Feeder_auto_DG

Table C-8-9 Feeder failure rate of case aged_tr and case Feeder_auto_DG

Feeder failure rate (λ_{feeder})(interruptions/year)			
Percentile	**Case aged_tr (Base case)**	**Case Feeder_auto_DG**	**Percentage difference**
10^{th}	3.61	3.60	-0.3 %
50^{th}	4.39	4.35	-0.9 %
90^{th}	5.05	5.00	-0.9 %

ii. Feeder unavailability

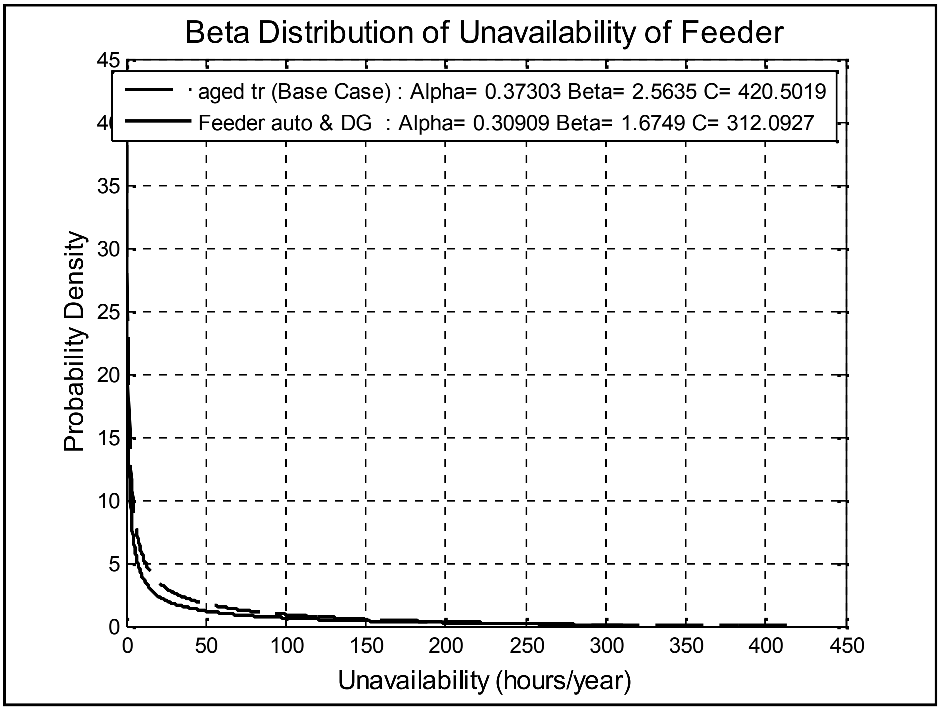

Figure C-8-10Feederunavailability comparison of case aged_tr and case Feeder_auto_DG

TableC-8-10Feederunavailability of case aged_tr and case Feeder_auto_DG

Feeder Unavailability (U_s)(hours/year)			
Percentile	**Case aged_tr (Base case)**	**Case Feeder_auto_DG**	**Percentage difference**
10^{th}	0.28	0.09	-67.3 %
50^{th}	22.48	17.64	-21.5 %
90^{th}	157.40	150.95	-4.1 %