Development of Regional Reliability Hurdle Rate for South Africa

M.A. Van Harte

Thesis Presented for the Degree of

MSc(Eng)

in the Department of Electrical Engineering
Faculty of the Built Environment

UNIVERSITY OF CAPE TOWN

August 2008

ACKNOWLEDGEMENTS:

This thesis “Development of Regional Reliability Hurdle Rate for South Africa” was written for the MSc (Eng) at the Department of Electrical Engineering at the University of Cape Town.

I would like to thank the following persons for their contribution to this work:

- This thesis would have not been possible without the financial support for the research and support for my further studies as part of my personal and career development within Eskom Distribution.

- I express my deep gratitude to Prof Trevor Gaunt and Dr Ron Herman for continuous guidance.

- The national Value Based Reliability Planning working group for their knowledge, ideas and help.

- And not the least, my Network Planning colleagues for many interesting discussions and for their support throughout this project.

- Robert Koch for the many interesting discussions, as well as for providing ideas, questions, support and encouragement. Especially for the invaluable knowledge and guidance, he has provided me within the field of Quality Regulation.

- Special thanks to my wife, Karin and kids Kowen and Meeka.

Abstract:

Thesis Title:	Development of Regional Reliability Hurdle Rate for South Africa
Auhor:	M.A. Van Harte
Date:	Jan 2008
Key Words	Reliability Hurdle Rate, Incentive Based Regulation, Reward / penalty Scheme, Benefit-to-cost Analysis, Quality Regulation, Reliability Decision-making Approach

The reform of the electricity distribution industry has resulted in the national regulator authorities moving from Rate of Return (ROR) to Incentive Based Regulation (IBR) quality regulation mechanism. This has influenced the reporting, planning, design, operating and maintenance (O&M) philosophy surrounding distribution networks and service delivery to the end customer. The introduction of IBR regulation has created a need to understand how the IBR scheme implemented will influence the capital and operating investment decisions. The aim of the work leading up to this thesis has been to develop reliability hurdle rates that include the effect of the IBR scheme implemented by the national regulator authority of South Africa. This will enable the network planner to compare the investment decision with the reward / penalty scheme.

The thesis addresses the challenges facing distribution network planning to achieve the appropriate (optimal) balance of investment cost vs. reliability levels. Value Based Reliability Planning (VBRP) methodology is an approach to evaluate capital investment decisions by quantifying, in economic terms, the benefits of improving reliability (System Average Interruption Duration Index (SAIDI) per capital cost required) by comparing different reliability improvement alternatives. This is achieved by relating the investment decision to the reward / penalty scheme introduced by National Electricity Regulator for South Africa (NERSA). To reach this goal this thesis derived a reliability hurdle rate by utilising benefit-to-cost analysis principles by considering the shape of the reward / penalty scheme. Furthermore, this necessitates the determination of the optimal balance between investment decisions to obtain improvement in the continuity of supply indices. One of the fundamental objectives is therefore to relate the IBR and VBRP in an efficient and effective way, that is the aim of the national regulator authority.

A new method to determine a regional and national reliability hurdle rate is proposed by the thesis. This is a first step in obtaining an optimal expansion alternative and allows the planner to compare the preferred alternative selected against a hurdle rate. Since the method considers the reward / penalty scheme, the thesis first reviews the principles that influence the quality regulation mechanisms and the benefit-to-cost analysis techniques. The second step demonstrates the derivation of the reliability hurdle rate utilising the reward / penalty scheme adopted within South Africa. Parameters considered include the number of customers and the interruption indices in each region. The application studies demonstrate the derivation of the regional reliability hurdle rate from the six regions within South Africa. This allows the derivation of regional reliability hurdle rate from the different regional reward / penalty schemes. Finally, a sensitivity analysis is performed to understand the influence of different parameters, which will influence the regional reliability hurdle rate. The results from the case studies show that, when NERSA creates the reward / penalty scheme, it is crucial that the approved method is applied to determine the shape of the scheme implemented, which will allow the derivation of the reliability hurdle rate.

The new method is suitable for implementation where the IBR quality regulation mechanism has been adopted by the national electricity authorities. Furthermore, the reliability hurdle rate derived can be used to compare the investment decision against the improvement required in the continuity of supply indices. This ensures the trade-off between the expansion investment and improvement in the reliability levels

Blank Page

Table of Contents:

Terms and Abbreviations

Terms:

Benefit-to-cost Analysis	This method involves taking all relevant costs in the life of the project, comparing them with the benefits that will be accrued from the project over the same period.
Incentive Base Regulation	The Incentive Based Regulation methodology was developed in response to problems encountered with the application of the Rate of Return methodology internationally. The IBR methodology puts a cap on the utility's revenue, profits, or price in order to persuade management to produce and supply electricity at the least cost possible. IBR as a form of incentive mechanism is an extent ion to the minimum standard criteria by linking the profit margin with the level of quality.
Life Cycle Costing	Life cycle costing is a process to determine the sum of all expenses associated with a product or project, including acquisition, installation, operation, maintenance, refurbishment, discarding, and disposal costs.
Reliability Hurdle Rate	This is a mechanism derived from the reward / penalty scheme proposed by national regulator authority, based on the benefit to cost analysis principles. It enables the planner to compare reliability investment against the minimum improvement required.
Return of Return	Rate of Return is more predictable and a guarantees returns investment and is a predominant form of cost-based regulation. The objective is to ensure that prices are set at a level that allows ongoing supply of service (including investment) by the utility, but not so high as to allow excess profits.
Value Based Reliability Planning	Value Based Reliability Planning (VBRP) methodology will evaluate investment decisions by quantifying in economic terms the benefits of improving reliability (trade-off) by comparing different strengthening alternatives. This approach is based on the concept that there is a relation between network costs and the level of reliability; this is then again associated with a certain level of customer benefit. The aim is to seek a level of reliability such that the optimal reliability level is reached.

Abbreviations:

AM	Asset Management
BCA	Benefit-to-Cost Analysis
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenses
CML	Customer minutes lost per year (equivalent to SAIDI)
DME	Department of Mineral and Energy
DSLI	Distribution Supply Lost Index
EDI	Electricity Distribution Industry
ENS	Energy Not Supplied
ESI	Electricity Supply Industry
EWP	Energy White Paper
FSA	Field Service Area
HV	Nominal voltage levels that are used in power systems for bulk transmission of electricity in the range 44 kV < Un < 220 kV. [NRS 048-2]
IBR	Incentive Based Regulation
LCC	Life Cycle Cost
LPIF	Load Point Interruption Frequency
LPIT	Load Point Interruption Time
MV	Nominal voltage levels that lie above low voltage and below high voltage in the range 1 kV < Un < 44 kV [NRS 048-2].
NERSA	National Electricity Regulator for South Africa
NPV	Net Present Value
O&M	Operating and Maintenance
OPEX	Operating Expenses
QOS	Quality of Supply
RED	Regional Electricity Distributor
RHR	Reliability Hurdle Rate
ROR	Rate of Return
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TEIPI	hours lost per year, weighted by the installed transformer capacity for MV
VBRP	Value Based Reliability Planning

1. INTRODUCTION:

South Africa faces many challenges in adopting reliability assessment within electricity distribution planning [1], [2] & [3]. The basic reliability assessment principles have been described by others [4], [5] & [6], but certain aspects need to be addressed before implementation of reliability assessment is possible. This chapter provides a general background to the research objective, hypothesis and contribution of this thesis.

1.1. Background:

Historically in South Africa, distribution planners selected the most cost-effective alternatives based on the network and financial analyses. Distribution planners within Eskom Distribution adopted limited reliability assessments or crude rule-of-thumb design criteria when evaluating network constraints [1]. A lack of data on equipment failure, repair rates and customer interruption costs forced planners internationally to adopt deterministic approaches to network planning [7], [8] & [9].

It is imperative to prevent overinvestment, which can lead to excessive capital and operating expenses (CAPEX and OPEX respectively). However, increasing the reliability of the supply usually incurs higher total costs for a utility. Electricity utilities constantly try to balance the costs for higher reliability with the price customers are prepared to pay to ensure that the investment decisions are prudent. This can lead to difficult managerial decisions at both the planning and operating phases for any project required to improve reliability levels [10]. Quantitative reliability analysis is an important input to the decision-making process to enhance the asset management principles.

The Electricity Distribution Industry (EDI) within South Africa is receiving pressure from three stakeholders, viz. customers, the regulatory body and utility management, to develop or review the strategies for providing adequate reliability at suitable cost levels for short, medium and long term [11], [12] & [13]. This requires the EDI to adopt a sound strategy to balance expenditure to ensure the appropriate reliability with the allocation of OPEX and CAPEX funding.

Continuity of supply is one of the major factors that drive the customers' perceptions about the efficiency of the utility [14] & [15]. The restructuring of the EDI worldwide allowed policymakers to prescribe the reliability or quality aspects concerning service delivery to the end user [16]. The need to reduce costs and to satisfy customer needs present an interesting planning challenge. The capital investment, operation and maintenance (O&M) decisions must be supported by explicit analysis of this cost trade-off [17].

The trade-off to evaluate different investment alternatives during the planning of a project requires the inclusion of a mechanism to select the preferred alternative. The utility needs to develop a hurdle rate for the planner to compare the investment decision against a desired reliability improvement required within the region, or nationally. The proposed method is based on principles of benefit-to-cost analysis for selecting preferred alternatives. This method considers the inherent benefit derived by the reliability improvement projects (i.e. benefit = reduction in SAIDI).

This thesis deals with issues relating to the regulation of continuity of supply within South Africa. It forms the basis for the creation of the reliability hurdle rate by utilising the reward and penalty scheme introduced by the National Energy Regulator of South Africa (NERSA) [1]. At this time, expansion decisions are not linked to this scheme. However, NERSA and policy makers generally pursue higher economic efficiency, as well as reliability improvement strategies for formulating investment decisions within a limited budget. The national reward / penalty quality regulation scheme can be translated into a higher regional reward / penalty scheme to improve the decision-making process. The approaches are similar to those that need to be applied by utilities in many countries, so the work should be internationally relevant.

---

[1] NER is the regulatory authority over the ESI in South Africa. It is a statutory body, established in terms of the Electricity Act No. 41 of 1987 and amended 1995. Amongst others, it has the responsibility to determine prices and conditions at which a licensee may supply electricity.

1.1.1. Electricity Distribution Industry Reform:

There is a process of change within the EDI through “deregulation” [11]. The South African government believes that the industry must be restructured to ensure reliable and low-cost electricity for domestic and industrial purposes. The restructuring of the Electricity Distribution Industry has resulted in the NERSA proposal to move from Rate of Return (ROR) to Incentive Based Regulation (IBR) [12]. This will influence the reporting, planning, design and O&M philosophy surrounding distribution networks and service delivery to the end user. IBR was a way to solve some of the challenges introduced by the changes processed by government and regulated by the NERSA.

The absence of a strategic framework to address reliability investment decisions will shape business functions envisaged by government. ~~A~~ lack (e.g. policy, standardise, guidelines, etc) of a strategic framework will be a major obstacle for the implementation of reliability assessment within the planning phase of a project.

NERSA’s policy changes are partly due to a lack of investment in electricity infrastructure and a reduction in maintenance and refurbishment by existing electricity supply authorities (Eskom and municipalities) [13]. At present, NERSA’s requirements prescribe minimum quality of supply standards without any incentives to encourage utilities to improve reliability levels.

In Europe, the availability of electric energy has long been regarded as a basic condition for economic development and prosperity [8]. The regulators within these countries are regarded as pioneers in the implementation of quality regulation schemes, which have been in place since 1998 (Italy), also replacing rate of return, etc [16]. They encourage the utilities to improve performance by means of appropriate rewards / penalties.

> *The introduction of quality mechanism acknowledges the interdependence between the three main stakeholders to serve mutual gains. Closer examination will reveal that distributors and customer’s objectives are not mutually exclusive, and that cooperative strategic plans can be made to ensure value to all parties [8].*

The major concern for regulators worldwide is that utilities can increase profit by reducing costs. This often leads to the reduction of continuity of supply to customers [14]. Incentive-based regulation methods are popular among European regulatory bodies in recent years. The downside of this approach is the reduction of O&M costs to increase profit margins [14] & [16]. This represents a challenge for the regulatory bodies in the sense of finding suitable methods to compensate for the effects of cost reductions, whilst at the same time maintaining quality of electricity supply.

1.1.2. New Network Planning Problem:

Presently in South Africa (and probably most developing countries) distribution planners plan distribution networks to satisfy both the capacity constraints (i.e. voltage and thermal limits), and at the same time ensure the viability of the capital investment projects. The introduction of reliability requirements (ensuring sustainability of supply) for distribution networks ensure that the reliability constraints are addressed during the design and planning phases of projects [1] & [17].

Once the regulatory framework and strategic intent are established (e.g. distribution code, tariff code, change in regulation mechanisms), the application of reliability assessment and improvement from the planning arena will be possible. This will provide a foundation upon which standards, methods and guidelines can be formulated to facilitate the implementation of Value Based Reliability Planning (VBRP) principles. This will enable the EDI to integrate the needs of the customer, the regulator and the management board into the planning process. Currently all expansion projects are evaluated only on network and financial analyses and the tariff structure does not support reliability investment. Billington et al [7] report:

> *Quantifying to what extent we should improve reliability levels is a challenge facing planners: “how much redundancy and at what cost?”*

The major components for the implementation of VBRP principles will rest on four important cornerstones [1]:

(1) Equipment reliability data (i.e. historical data for the probability of failure and duration);
(2) Customer interruption cost data (i.e. influence/value an interruption has on a customer);
(3) Reliability analysis tool (i.e. tool to apply probabilistic techniques to predict the future behaviour) and
(4) Skills development.

The demands from stakeholders force distributors to have a sound strategy for balancing expenditures with the appropriate levels of reliability. This encourages distributors to reduce costs and at the same time provide the reliability required by customers. Changes in government and regulator policies are needed to ensure the appropriate allocation of OPEX and CAPEX to improve reliability of supply to customers. Distribution planners have a major influence on CAPEX. The allocation of capital for networks to accommodate future reliability constraints is important.

1.2. Research Objective:

1.2.1. Scope and Definitions:

The thesis addresses the challenges facing distribution network planning to achieve the appropriate (optimal) balance of investment cost vs. reliability levels. Value Based Reliability Planning methodology is an approach to evaluate EDI investment decisions by quantifying, in economic terms, the benefits of improving reliability (SAIDI per capital cost required) by comparing different reliability improvement alternatives. This is achieved by relating the investment decision to the reward / penalty scheme introduced by NERSA.

The requirement is to develop techniques to determine a regional reliability hurdle rate by considering the reward / penalty scheme imposed by a national electricity regulator within South Africa.

The problem of establishing a reliability hurdle rate is influenced by the input parameters to the reward / penalty scheme adopted by the national regulator authority. The problem is further exacerbated by the fact that many different factors influence the accuracy of the predicted reliability improvement achieved by the investment decision.

Utilising benefit-to-cost analysis techniques will provide the planner with the basis to compare the investment decision against a reliability hurdle rate to ensure the investment is effective. Benefit-to-cost analysis techniques will enable the planner to relate the influence to the reward / penalty scheme.

1.2.2. Research Hypothesis:

Based on the apparent need for a new approach to distribution infrastructure planning, it is hypothesised that:
a regional reliability hurdle rate is related to and can be estimated from the national reward and penalty scheme introduced by the National Electricity Regulator of South Africa, and that the selection of the preferred reliability improvement alternative based on the hurdle rate will result in a change of the decision-making process.

1.2.3. Research Method:

The research will focus on the development of regional reliability hurdle rates to compare investment alternatives for distribution networks. This thesis primarily makes use of three research methods, namely literature reviews, development of reliability decision-making process, and sensitivity analysis to test the influence of the input variables on regional reliability hurdle rates.

The following steps are envisaged to test the hypothesis:

- The literature review (in the next two chapters) assesses both the academic and non-academic literature. The academic literature consists mainly of publications on the quality regulation issues of the regulatory problem. The non-academic publications include regulatory publications such as electricity laws, consultation documents and regulatory decisions.
- A proposed reliability decision-making process is developed to meet planning and design needs for selecting a preferred alternative.
- The accuracy of the method needs to be tested by using sensitivity analysis.
- The method needs to be applied to practical networks to establish suitability and relevance.
- Conclusions need to be drawn regarding the validity of the hypothesis.

1.3. Scientific Contribution:

This thesis will derive a regional reliability hurdle rate from the reward / penalty scheme proposed by the national regional regulator within South Africa.

The main contributions in this thesis are summarised within the text below:

- The equations derived provide three important concepts, namely regional funding allocation, regional reward / penalty scheme and regional hurdle rate. They provide the foundation for the formulation of a regional reliability hurdle rate. This is achieved by creating a connection between the national reward / penalty scheme and regional reward / penalty scheme.
- The new approach attempts to relate the reward / penalty scheme to a Reliability Hurdle Rate (RHR) that defines the benefits to improve the continuity of supply within each region.
- The thesis will also illustrate the influence of the reward / penalty scheme using sensitivity analysis to demonstrate the influence of different input variables.

These methods proposed would be applicable for any national electricity regulator using a reward / penalty scheme.

1.4. Outline of the Thesis:

Apart from the introduction and conclusions, the thesis is divided into two main parts. Chapters two and three provide foundations for the development of the reliability hurdle rate. The main output of this part is an analysis of the complexities involved in reliability economics as applied to the planning decisions. Chapter four proposes a reliability decision-making process to select the preferred alternative. The factors discussed in chapters two and three will form the foundation for the development of a regional reward / penalty scheme. This is further developed in order to estimate the reliability hurdle rate and is analysed to determine the influence of the input parameters to derive the regional reliability hurdle rate for South Africa.

Chapter two: *Quality Regulation* – The strategic intent is defined by the national electricity regulator's decision to monitor the quality mechanism prescribed within the licensee conditions. This chapter discusses the different quality mechanisms proposed by national electricity regulators worldwide and the challenges facing the national electricity regulator of South Africa.

Chapter three: *Project Evaluation* – The evaluation of the different alternatives investigated by a planner is validated by the financial and economic worth of an investment decision. Most of the literature ignores the influence of scheduled and unscheduled maintenance costs. It normally assumes a fixed percentage related to the capital cost. This chapter further explores the application of benefit-to-cost analysis and the main principles for life cycle costing methodology.

Chapter four: *Reliability Decision-Making Process* – This chapter provides an overview of the proposed reliability decision-making process to identify networks that require investment within Southern Africa. The approach identifies which distribution networks require investment to improve reliability in support of national reliability targets and incentives. This will enable the planner to compare the reliability improvements to select the preferred alternative.

Chapter five: *Development of Regional Reliability Hurdle Rate* – This chapter proposes a technique to develop regional reliability hurdle rates based on various factors. It further explores the influence of these factors using sensitivity analysis.

Chapter six: *Assessing the hypothesis* – The chapter provides a brief summary of the findings and assessment of the research hypothesis. It also provides a summary of proposed further research required to remove the uncertainties of certain input variables that influence the reward / penalty scheme.

2. QUALITY REGULATION:

2.1. Introduction:

This chapter aims to provide the foundation for development of reliability hurdle rate based on incentive-based regulation schemes proposed by the national electricity authority within South Africa. However, before doing so, it is useful to study the different quality regulation mechanisms introduced by national electricity regulatory worldwide. Chapters 3 and 4 look more closely at the other aspects to influence the development of the regional reliability hurdle rate. Before doing so, however, this chapter first reviews the theory underlying quality regulation and discusses the characteristics of the reward / penalty scheme. In addition, the last few sections expose the impact of the quality regulation mechanism adopted within South Africa.

2.1.1. Background:

> *The Chairman, Dr Ian C McRae of NERSA stated within the 1996 Annual Report: "The only way of ascertaining whether an ESI is performing well, is by asking the right questions, obtaining accurate relevant data, setting benchmarks/standards and measuring the performance of the respective suppliers against these."*

The purpose of quality regulation is to ensure that the public and private electricity utilities become more efficient [18] & [19]. National regulatory authorities have different regulatory mechanisms to shape the Electricity Supply Industry (ESI). The major concern for national regulators is that utilities can increase profit by reducing operating and capital investment costs, which will contribute to the decline in quality and continuity of supply. The absence of incentive-based regulation may result into sub-optimum quality of supply [18], [19], [20] and [21]. In addition, the national regulator authorities have to provide adequate economic incentives for the maintenance and construction of the necessary network infrastructure [20].

In most European countries, a quality regulation mechanism is in place or is in the process of being established [19], [21] & [22]. There can be severe financial penalties if these standards are not met (e.g. Hungary = 400 000 Euro) or the profits (e.g. typical 2 to 4%) can be at risk based on the quality of supply received by the end customers' [19].

2.1.2. Chapter Outline

Chapter two starts by looking at the definition of quality of electricity as applied by electricity regulators worldwide to monitor and control ESI. It also discusses the method used to control price of electricity through a quality regulation mechanism. It further focuses on the characteristics related to reward / penalty schemes. It also exposes the problems encountered in implementing these quality regulation mechanisms within South Africa and it discusses problems that may be encountered in setting a reward / penalty scheme. Finally, it concludes by identify that will influence the decision-making process for investment decision for planners.

2.2. Regulatory Mechanisms:

The concern with ROR regulation is that it does not encourage utility companies to improve efficiency. Consequently, utilities are monitored to ensure that investment and operating expenses improve the overall continuity of supply to the end customers. ROR does not encourage distribution companies to prevent over-investment that will lead to sub-optimum levels concerning quality and efficiency.

National Regulatory authorities' regimes therefore focus on preventing these types of inefficiencies and avoiding excessive investments [21]. Simple types of cap regulation, on the other hand, may allow a regulated company to reduce its cost by reducing its quality of supply, or by cutting investments, maintenance or personnel with the aim of increasing its profits. Consequently, price regulation may thus also provide incentives for under-investment into infrastructure to ensure sustainability.

The European countries are seen as pioneers within the field of quality regulation [18]. These different quality regulation mechanisms have influenced the philosophies adopted by distribution planners for investment decisions. A number of European utilities have changed their allocation of funding to ensure financial viability and to achieve the improvement in overall reliability level to the end customers. The regulator mechanisms minimise CAPEX and OPEX expenditure by optimising socio-economic trade-off, thereby encouraging reliability improvement initiatives.

2.2.1. Why do we need quality regulation?

The overall challenge for the regulator is to balance the mismatch between expectations and perceived quality of service and to establish a “system” to distinguish between the two [23]. At some point, there will be an optimal trade-off between the costs and benefits. The trade-off investment decision should occur where the marginal benefits of quality are equal to marginal costs of delivery [24], [25] and [26].

Utilities increasing profit by reduce costs, represents an interesting challenge for the national regulatory bodies to find a suitable method to compensate for the effects of cost reductions.

In addition, the regulator has to provide adequate economic incentives for the maintenance and construction of the necessary network infrastructure.

2.2.2. What is quality in electricity networks?

Quality issues within special reference [27] to European regulators indicate that quality of supply regulation should focus on four dimensions of service quality, which are:

a) Power quality

Power quality is related to voltage waveform quality and deals with disturbance experienced within networks. In South Africa, the minimum waveform quality is prescribed by the national standard: NRS 048-2 [28]. The principle adopted in NRS 048 is to set voltage compatibility levels, based on 95 % probability levels for the upper limit of system disturbance levels.

b) Commercial quality

This describes the interaction between customer and utility that may drive the perception of the efficiency of the utility. This involves issues such as the connection of new customers, accuracy of billing information, effectiveness of handling customer complaints, etc.

c) Continuity of supply

A sustained interruption is a planned or unplanned event experienced by the network. It is a measure of the capability of the network to sustain the power flow within the network to meet the demand of the customer. Electric power system reliability can be subdivided into two categories, namely adequacy and security [29]. Adequacy relates to network integrity (e.g. voltage, thermal rating and fault level constraints) under steady-state conditions influenced by the demand requirement of existing and future customers. Security focuses on the influence of disturbances (e.g. fault) or the recovering of the network within dynamic and transient conditions.

d) Price Regulation:

In general, price quality regulation considers the mismatch that occurs between the cost incurred for electricity delivered and the perceived worth of electricity by the customer. This concept is important to ensure that the utility is able to recoup the investment required for future infrastructure and optimal profit margin for investors.

2.3. Method for Price Regulation

Regulatory control has three fundamental aspects, namely cost-based, incentive-based (US call it performance-based) and marketing-based. The characteristics of these price regulation mechanisms are highlighted in Table 1, namely cost-based or rate of return, performance or incentive-based and market-based.

Table 1: Price control mechanism

Type of Regulation	**Cost-based** (e.g. Rate of return)	**Incentive-based** (e.g. Price caps)	**Market based** (e.g. Auctions)
Incentives	Regulation	Mixed	Market Forces
Market	Pure Monopoly	Oligopoly	Pure Competition
Price Elasticity	Inelastic	Unitary	Elastic
Regulatory Role	Fix Revenues & Expenses	Fix Rules & Prices	Monitor & Antitrust

In cost-based ROR, quality is a fixed constraint, a threshold. In incentive based regulation, quality is a variable to which price is linked by a formula. In market based regulation, quality is a variable to which price is sensitive, but quantifying the relationship is not (yet) possible.

2.3.1. Cost-Based:

Rate of return or cost-based regulation is a more predictable (i.e. investor is guarantee returns) regulation mechanism, which provides sustainability of the electricity sector and comfort for investors. This mechanism enables decisions to be made that are aimed at economic profitability. This is achieved by annual price reviews to ensure that the utility recoups funding to sustain the operating and capital expenditure for future investment, as illustrated in Figure 1.

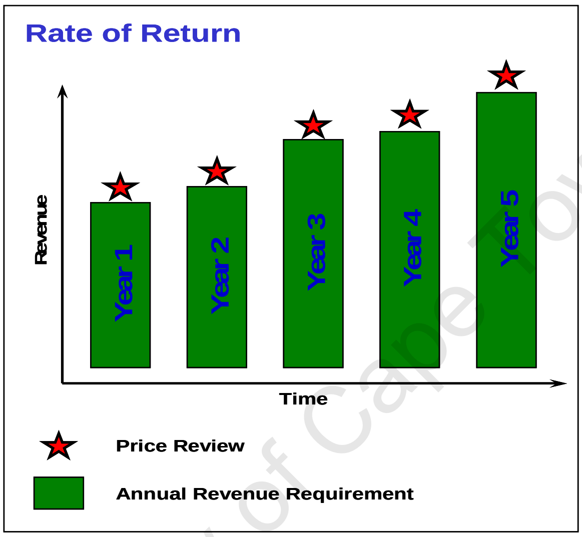


Figure 1: Annual price review

Rate of Return is based on the following principles to allow recovery of capital and operating expenses of the utility via electricity pricing. The electricity price increase should be sufficient to assure confidence in the soundness of the utility. This is sufficient to maintain a credit rating that will allow the utility to raise capital [29].

South Africa utility Eskom provides NERSA with the revenue requirements based on equation (1), which incorporates a rate of return that will enable the recovering of cost to operate the business and earn a reasonable return. The required revenue requirement based on the financial statement is scrutinised by NERSA. The average price increase guarantees a sufficient capital recovery to meet the revenue requirement. The rules applied are set out in [31].

$$R = E + (V - d + w)\, r \qquad (1)$$

Where:

R = the required revenue of the regulated entity

E = the operating expenses

V = the value of the qualifying property, plant and equipment

d = the accumulated depreciation on qualifying property, plant and equipment

w = the allowance for working capital held by the regulated entity

r = the calculated rate of return using the weighted average cost of capital (WACC)

The primary problem with a ROR regulatory system is the lack of incentive to improve efficiency, which may result in a utility increasing its costs and passing them on to consumers without diminishing its profits. A utility can earn even larger returns by simply spending more money.

2.3.2. Incentives-based:

The national regulators worldwide have recognised the problem with rate of return regulation mechanism. The majority of the national electricity regulators within Europe have adopted an alternative mechanism to introduce incentives to increase efficiency. IBR can be grouped into three regulation mechanism categories [32], [33] & [34] , namely

Incentive-based: IBR has a common goal of linking tariff to quality. This form of regulating scheme allows the regulator to establish a reward / penalty scheme to encourage utilities to optimise existing asset and manage risk.

Yardstick: The regulator should have information systems to manage the target-setting process. This enables the regulator to set regional targets and provide price adjustments based on the variation from the target prescribed by the regulator.

Price cap: This regulator mechanism is mainly influenced by the tariff structure, which encourages maximisation of energy utilisation to increase sales.

This thesis discusses estimation of a reliability hurdle rate based on the reward / penalty mechanism proposed by NERSA. IBR is sometimes referred to as performance-based regulation, or CPI-X regulation, within the US. In this process, as illustrated by Figure 2, the tariff increase is not reviewed every year and the next tariff increase is estimated after 5 years. This is based on a productivity or efficiency factor that is derived from the performance of the network. These incentives are likely to influence a utility's behaviour and thereby the potential affected customers. This behaviour consists of an operating and maintenance regime, or capital investment, to improve the existing and future asset base. The principal equation (2) is utilised to derive the next tariff increase.

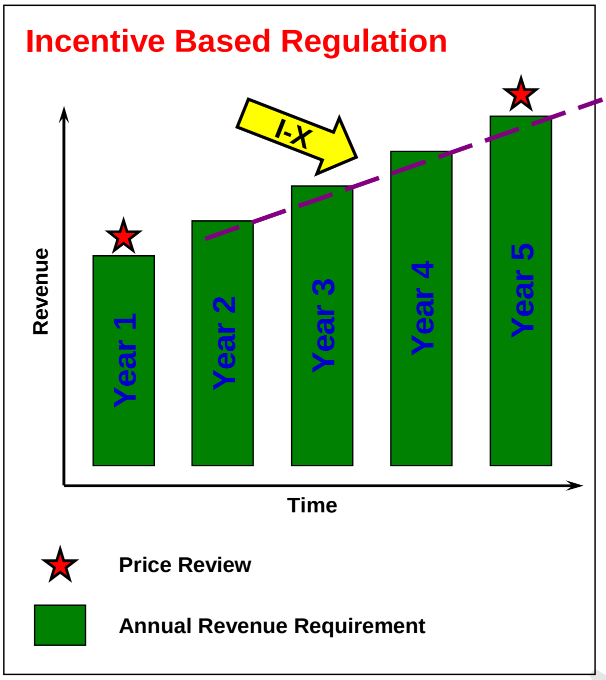


Figure 2: Initial price review for 5-year period

$$R_t = R_{t-1} ([1 + (I - X)] + Z \pm K) \qquad (2)$$

Where:
R_t = the required revenue of the regulated entity in the current year
R_{t-1} = the required revenue of the regulated entity in the previous year
I = an inflation index
X = a productivity or efficiency factor
Z = adjustments for unforeseen events or defined pass-through items; and
K = adjustments for under or over-recovery against the previous year's ceiling

The principle of IBR mechanisms is to mimic competition within the ESI [34][74]. In a competitive environment, utilities are constantly seeking to maximise profits by reducing capital and operating costs. These cost reductions should however, not be incurred at the expense of customer or network performances.

Certain developed countries have a high level of adequacy and will not require major investments to improve continuity of supply. In developing countries, such as South Africa, however, the investment and refurbishment of assets are low (based on age profile vs investment) and greater investment is required to improve adequacy of the networks [1] & [2].

2.3.3. Market-based:

A competitive market uses intelligence, expertise, and enthusiasm of consumers and producers in the marketplace. Price signals generated by market transactions ensure that resources are allocated efficiently and effectively. The results are lower prices, improved quality and an increased rate of innovation.

2.4. Reward / penalty Scheme

2.4.1. Background:

The reward / penalty scheme was implemented in European countries to ensure that the continuity of supply indices improve to an acceptable level as prescribed by the national regulators [18], [19], & [22]. These continuity of supply indices normally address system averages or worst served consumers by the introduction of guaranteed standards on duration and number of long interruptions (i.e. SAIDI or SAIFI). Five out of eight European national regulators require the distribution utilities to improve the continuity of supply indices. As far as the distribution and service is concerned, reward / penalty schemes are in place in eight countries out of 19 surveyed by the Council of European Energy Regulators [19]. In Europe, most of the regulators have implemented an IBR quality regulation mechanism from the year 2000, as illustrated by Table 2.

Table 2: Summary of regulatory mechanism and implementation date [19]

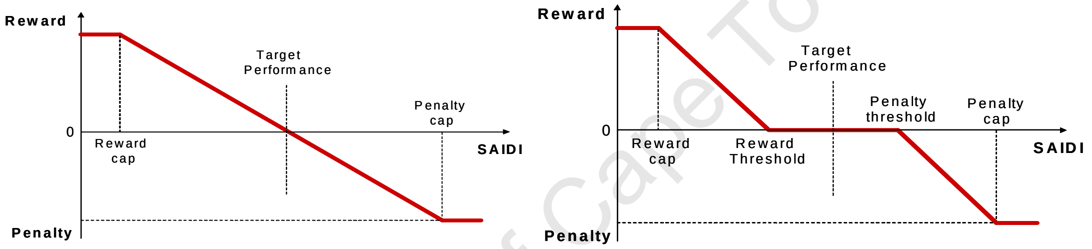
No	Country	Year	Regulator	Mechanism (and period)
1	Italy	2000	AEEG	Quality-dependent price cap (2000 – 2003)
2	Austria	2000	ESC	Quality-dependent price cap (2000 – 2005)
3	Norway	2001	NVE	Quality-dependent revenue cap (2001 – 2006)
4	UK	2002	OFGEM	Quality-dependent revenue cap (2002 – 2005)
5	Hungary	2003	Minister	Quality-dependent price cap (2003 – 2005)
6	Portugal	2003	ERSE	No predetermined duration
7	Sweden	2004	STEM	No predetermined duration

Note: Regulators' names can be obtained from [19]

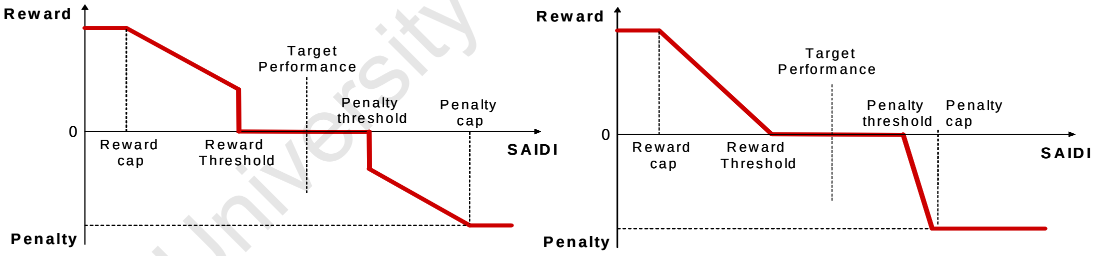
2.4.2. Characteristics of Reward / penalty scheme:

a) Shape :

Graphically, the shape of the reward / penalty scheme links the performance of the network with a financial impact (either a reward or penalty). The x-axis represents the measured continuity of supply index prescribed by the national regulatory body and the y-axis the reward or penalty for not achieving the decided performance. The national regulator can implement a symmetrical or asymmetrical scheme to regulate the utility. As illustrated in Figure 3, the symmetrical scheme can include or exclude a dead band and may have a stepped dead band [35] & [36]. The national regulator can decide to implement a larger gradient for the reward / penalty region of the scheme.



(a) Symmetrical – no dead band (b) Symmetrical with dead band



(c) Symmetrical with stepped dead band (b) Asymmetrical with dead band

Figure 3: Examples of Reward / penalty scheme [35]

Figure 4; illustrates the reward / penalty scheme introduced by the National Electricity Regulator of South Africa for the period of April 2006 to April 2009 [35] & [36]. The determination of the threshold, penalties and ramp slope will be discussed within Chapter 5.

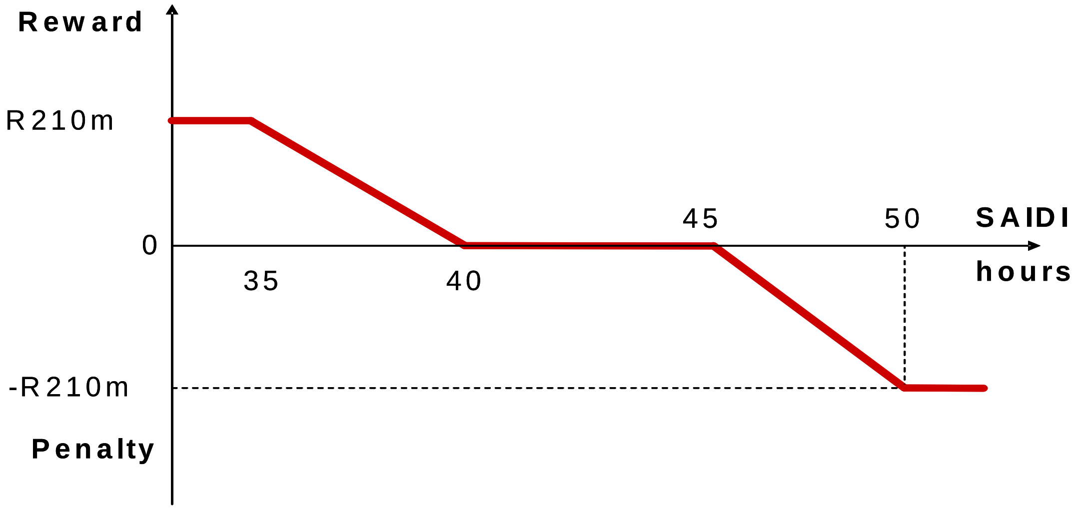


Figure 4: Reward / penalty scheme proposed by NERSA [36]

b) *Target performance:*

The national electricity regulator negotiates a target performance, normally based on the historical performance for the overall network. Countries such as Italy have set regional targets to ensure that the different regions move toward one target nationally [21] and [34]. This is in contradiction to the theory that indicates that the environmental and geographical location of the network have a large influence on the network performance. The shape of the reward / penalty scheme is derived around the target performance.

c) *Performance index:*

The majority of the national regulators worldwide have selected one of the continuity indices such as SAIDI to measure efficiency. Table 3 provides a review of the different continuity of supply indices utilised by the national regulators worldwide [19].

Table 3: Summary of regulatory index

No	Country	Continuity of Supply Indices
1	Italy	SAIDI
2	Spain	TEIPI and NIEPI
3	Norway	ENS
4	UK	SAIDI and SAIFI
5	Hungary	Outage rate, faults/km, avg repair time, avg number of grouped faults (LV), SAIDI and SAIFI
6	Portugal	ENS
7	Sweden	SAIDI and SAIFI
8	Ireland	SAIDI, SAIFI and losses

Note: Energy Not Supplied (ENS), which is determined based on TEIPI (indicator of frequency of interruption weighted with the installed power in MW). CI: Customer interruption per year (equivalent to SAIFI, System Average Interruption Frequency Index). CML: Customer minutes lost per year (equivalent to SAIDI, System Average Interruption Duration Index).

5 out of 8 countries have selected SAIDI as a continuity of supply mechanism to regulate the distribution companies. SAIDI and SAIFI consider each customer equal, regardless of the size of the customer. The Cigré 2002 Paris Session Special Report illustrated that there is a relationship between customer satisfaction and SAIDI, as illustrated in Figure 5. Indices based on sustained (planned or unplanned) interruption are preferred as a guide to regulate supply companies. On the other hand, short-term interruptions (e.g. power quality aspects: dips) are becoming important, because customers are becoming more sensitive to these occurrences [14].

> *SAIDI has been shown to have a strong correlation with customer perceptions in other countries where regulators have initiated interruption performance improvements [15]. It is therefore commonly chosen as the "broad-brush" index to achieve initial improvements and to indirectly quantify customer satisfaction to the interruption performance levels* [35].

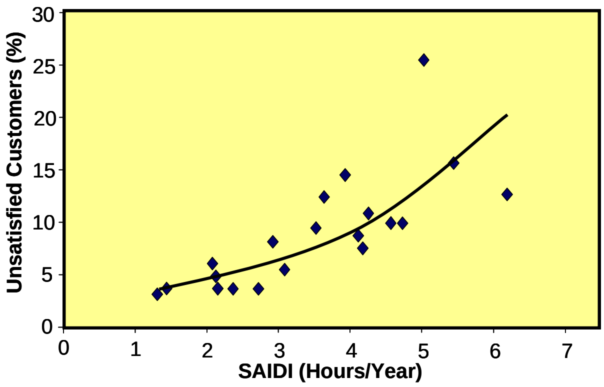


Figure 5: Customer survey and performance (CML) [15]

It is clear if we compare **Figure 4** and **Figure 5** that interruptions in South Africa are longer than those experienced within Europe. This is largely due to a lack of investment and maintenance on MV networks within South Africa [13].

Other national regulators (i.e. Norway and Spain) have chosen energy indices such as expected ENS as measure of the customer interruption cost due to interruption experienced by the customers [19].

d) Dead Band:

The introduction of a dead band reduces the administration burden placed on national regulators with the implementation of the reward / penalty scheme. This is to accommodate the random nature of the continuity of supply indices of networks. Three (Italy, Portugal, and Hungary) out of the seven European countries have selected dead band within the reward / penalty scheme, as indicated by Table 4.

Table 4: Summary of Dead Band [19]

No	Country	Dead Band
1	Italy	Yes: +/- 5 % from target
2	Norway	No
3	UK	No
4	Hungary	Yes: 5% for penalties and 10% for rewards
5	Portugal	Yes: +/- 12% from target
6	Sweden	No: Target varied from year to year
7	Ireland	No: Yearly decreasing of target

In Norway the regulator, whose aim is to achieve a socio-economically acceptable level of continuity and not necessarily to improve it, requires no improvement. However, the regulator does not want to introduce changes in tariff unless long-term changes in continuity of supply indices have not been achieved.

e) Claw back unspent reliability funding:

Reward / penalty schemes, in one form or another, affect revenues earned by supply companies. The reward and penalty achieved is limited to ± 3 % (e.g. UK) of price control revenue exposed to performance of the utility [19]. On the other hand, countries such as Norway have no limit related to reward and penalty achieved. Some regulators would want to avoid any changes in tariff structure due to performance enhancement strategies.

2.4.3. Reward / penalty scheme adopted by Portuguese Regulator:

This section illustrates the regulatory mechanisms adopted within Portugal [16][19]. The national regulator (ERSE) has established a reward / penalty scheme to encourage distribution utilities to improve continuity of supply to the end user. This scheme affects the annual adjustment of the allowed revenue for the activity on MV networks. Portuguese regulators compare the current continuity indicators (Energy Not Supplied (ENS)) with the predefined target. The reward / penalty scheme adopted by the Portuguese regulator is illustrated in **Figure 6**.

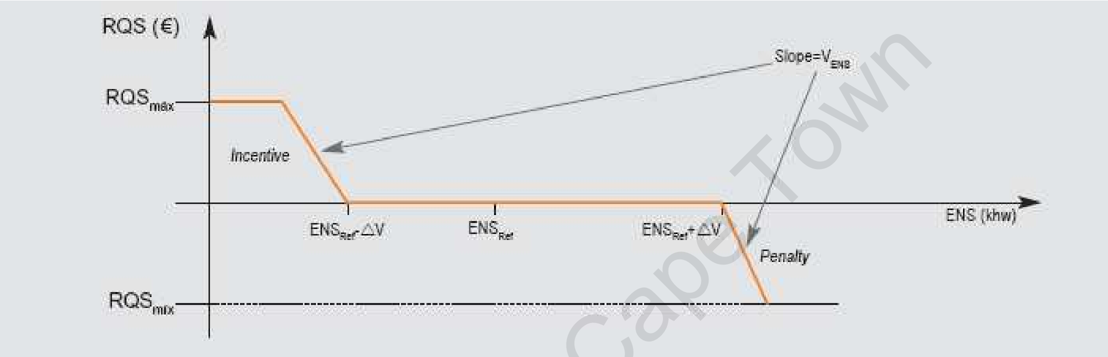


Figure 6: Portuguese Incentive Scheme **[19]**

The reward / penalty scheme adopted is symmetrical and continuity indicator is ENS. In **Figure 6**, the X-axis is related to the current ENS and the Y-axis represents the revenue adjustment required to the next regulator period. The reference continuity indicator (denoted by ENS_{Ref}) is the negotiated target. The dead band adopted allows for the influencing of seasonal changes without influence the revenue.

- If the value of ENS in a given year is less than $ENS_{Ref} - \Delta V$, which means that the network has a good performance, the distributors' revenue are increased by an amount RQS (revenues for quality of supply), expressed in €. RQS is computed using a per-unit-value of the ENS, V_{ENS} and is proportional to the difference between the actual ENS in the year and the target $ENS_{Ref} - \Delta V$:

$$RQS = V_{ENS} \times [(ENS_{Ref} - \Delta V)-ENS] \qquad (3)$$

- If the value of ENS in a given year is near the ENS_{Ref} value, the distributor's revenues are not affected.

If:

$$ENS_{Ref} - \Delta V \leq ENS \geq ENS_{Ref} + \Delta V, \text{ then } RQS = 0$$

2.5. Case Study: South Africa

2.5.1. Background:

Continuity of supply for distribution networks has always been a concern for numerous stakeholders within South Africa [13]. Reliability of supply is one of the major factors that drives the perception and expectation of the customers about the efficiency of the utilities. The restructuring of the EDI within South Africa will influence the reporting, planning and design philosophy of distribution networks [11] & [12]. In addition, the future incentive regulatory mechanisms (introduced April 2006) will influence capital, operating and maintenance expenses after the establishment of the Regional Electricity Distributors (REDs).

2.5.2. Regional Electricity Distributors:

The worldwide restructuring of the Electricity Supply Industry (ESI) started in the early 1990’s. This revolution of the ESI can also be contributed to new pressures from global markets and government opening up the country to foreign investors with the view to the expansion of the infrastructure. Furthermore, the recent issue of the Energy White Paper (EWP) set an important milestone in the direction for the ESI in SA. The restructuring of Eskom will be done in terms of Government Policy or rationalisation of State-owned assets [11].

The traditional vertically integrated Electricity Supply Industry structure consisting of Generation, Transmission and Distribution is operating as three different business entities under Eskom. The municipalities have also restructured by amalgamating different smaller and larger municipalities into larger metropolises. This has assisted a municipality to remain an electricity authority even within the new proposed system of Regional Electricity Distributors. The vision of government is the amalgamating/consolidating Eskom Distribution and the numerous municipalities into six single-service entities.

Objectives of the South African Energy White Paper [11] were to:

- Improve social equity by specifically addressing the energy requirements of the poor;
- Enhance the efficiency and competitiveness of the South African economy by providing low-cost and high quality energy inputs to industrial, mining and other sectors; and
- Achieve environmental sustainability in both the short and long-term usage of our natural resources

2.5.3. Future Regulatory mechanism:

The move from the ROR to IBR mechanism will change the shape of the EDI [12]. In addition, the development of the Distribution Network Code will prescribe the boundaries or rules for distribution utilities. There is a move from a financial to a least cost, socio-economic methodology for investment decisions within the Distribution Network Code.

This will require distribution utilities within South Africa to apply reliability assessment techniques to influence short- to long-term investment decisions. This will also ensure the move from a utility to a customer focus to improve the continuity and quality of service [13].

2.5.4. Regulatory Period:

The reliability improvement initiatives should be driven in a holistic manner to ensure long-term sustainability. Reliability improvement strategies can be applied to short (1 to +/- 2 years), medium (2 to +/- 3 years) and long-term (> 3 years) programmes. These time lines will focus the direction for CAPEX and OPEX reliability decisions [1] and [2]. This is an interesting challenge due to the lack of systems and data to support regulatory decisions. Standardisation on monitoring, reporting and systems is imperative for development within the REDs to ensure effect monitoring.

2.5.5. Distribution Association:

Norwegian and Swedish distribution utilities and regulators have formed an association to discuss the implementation of quality regulatory mechanisms [1]. The association issues information on aspects such as component reliability data, customer interruption cost and reporting parameters. This makes evaluation of the reliability improvement initiatives easier. All electricity distribution utilities make use of these parameters to ensure that all utilities use the same basis for evaluation. It is not the objective of the association to provide 100% correct values, but to validate assumptions that will be used by the whole of the electricity distribution industry. The formation of an industry association for reliability aspects is a reality for South Africa in the future, even under the formation of the REDs'.

2.5.6. Electricity Price:

In certain countries, the regulators should address future network investments in order to avoid quality degradation and ensure financial viability. Electricity prices may increase (even under cap regulation) as a result of a low starting level, as in the South African case. There may be cross subsidies between different customer categories and the customer may not be paying cost-reflective tariffs.

The main difficulties in applying this scheme are that many different factors influence costs and performance. For example, the costs to deliver equal levels of reliability in a rural area may be a multiple of that in a city area [14].

Price and quality of supply is imperative under incentive regulation mechanisms. This incentive regulation, by capping income, will have a profound influence on the utilities or REDs in future. Electricity price control has numerous factors, but the main issues are to set initial price, adjusting price to limit revenue gain and ensure that efficiency is maintained. The electrification cost per connection target will also have to increase because the majority of the outstanding customers are located further away from the existing grid. This will have to be discussed with the Department of Minerals and Energy (DME), who subsidises these projects. The operational cost is also likely to increase due to increasing customer numbers and network size.

The majority of the electrification customers will be connected to poor performing networks, which will deteriorate the presenting performance. Currently planning and design philosophies for Eskom Distribution do not provide any guidance to the limiting of the number of customers to MV feeders or substations. At this stage Eskom Distribution is planning to connect additional customers (mainly electrification customers) to feeders with already a large number of customers (e.g. 17 000). The nominator for SAIDI is the number of affected customer hour impacted by an interruption. The connection of more customers to MV feeder, substation and sub-transmission feeder will result into an increase in the overall SAIDI for the network.

2.5.7. Electrification:

> *President Thabo Mbeki Presidential Address, 2004: "Through our integrated system of government, with a strengthened local government working with our state enterprise, Eskom, we will, within the next eight years, ensure that each household has access to electricity."*

DME estimates that 3,4 million households currently remain to be electrified [37]. DME, municipalities and Eskom are in the process of developing strategies to ensure that SA realises universal access to electrical energy.

South Africa is sparsely populated and electrification of deep rural communities presents an interesting challenge for the EDI. There are various aspects that the new regulatory mechanism needs to ensure that the distribution companies have a customer focus.

- It is very difficult to factor aspects such as political weight associated with the customer damage function (resulting from poor supply quality) for electrification communities.

- Electrification only caters for low-consumption customers, so the design requirement is based on the bare minimum capacity for supplying electricity to these communities.
- The conflict between connecting more customers, reducing cost per connection, and providing a more reliable network solution is a challenge for the regulator.

The direction of the reliability-improvement strategies is only possible by estimating a cost and worth to improve reliability for existing and future distribution networks.

2.6. Conclusion:

Development reliability framework: The NERSA and stakeholders should ensure that the evolution of the ESI would provide a better quality of service to the customer. The need to establish new reliability policy for regulating the unbundled network functions, in the restructured ESI and the dissatisfaction with traditional quality regulation mechanism have led national regulators to adopt schemes such as price or revenue caps. These schemes provide strong incentives for efficiency, thus making inclusion of quality (and particularly reliability) regulation elements imperative.

Tariff needs to align with reliability improvement strategy: The challenge facing the ESI in SA is to quantify investment decision to improve reliability, to ensure network integrity and viability of reliability improvement projects. A conflict exists between providing a low price for electricity and providing cost reflective tariffs. The removal of cross subsidisation will result in an increase in cost-reflective tariffs. It is evident from the CEER regulatory benchmark report 2005 that many of the regulatory bodies do not have the authority to remove the subsidies.

Ensure the balance between OPEX and CAPEX funding: The regulator should provide adequate economic incentives for the maintenance and planning of the existing and future network infrastructure. Incentive-based regulation mimics an environment for competition within the Electricity Distribution Industry. A mismatch is created by the continuous decrease of variable cost (OPEX and CAPEX) to reduce electricity price. This behaviour does not encourage the distributor to invest in maintenance and refurbishment, nor future infrastructure. The experience from utilities worldwide is that minimal optimisation techniques are always used. The quality regulation mechanisms introduced will influence the business principles.

Setting regional reliability hurdle rates: Finally, linking the planner's investment decision to the reward / penalty scheme proposed by the national electricity regulator will assist the decision-making process of the planner. This is achieved by the development of a regional reliability hurdle rate against which a planner is able to compare if the investment decision is prudent.

Value-based reliability planning principles supports IBR: As discussed before, reliability is considered the most important quality aspect of electricity supply.

Theoretically, it is impossible to reach 100 percent reliability, since the electricity network consists of individual components that all exhibit stochastic failure. The capital cost to improve reliability increases, as higher reliability levels are required.

Economic theory implies that the optimal point of reliability is reached when the marginal costs and benefits of reliability are the same [38] and [39]. Figure 7 illustrates the balance between marginal benefit and cost to improve reliability. The selection of the investment alternative attempts to trade-off the customer cost of interruption against the utility cost to provide an improved reliability level.

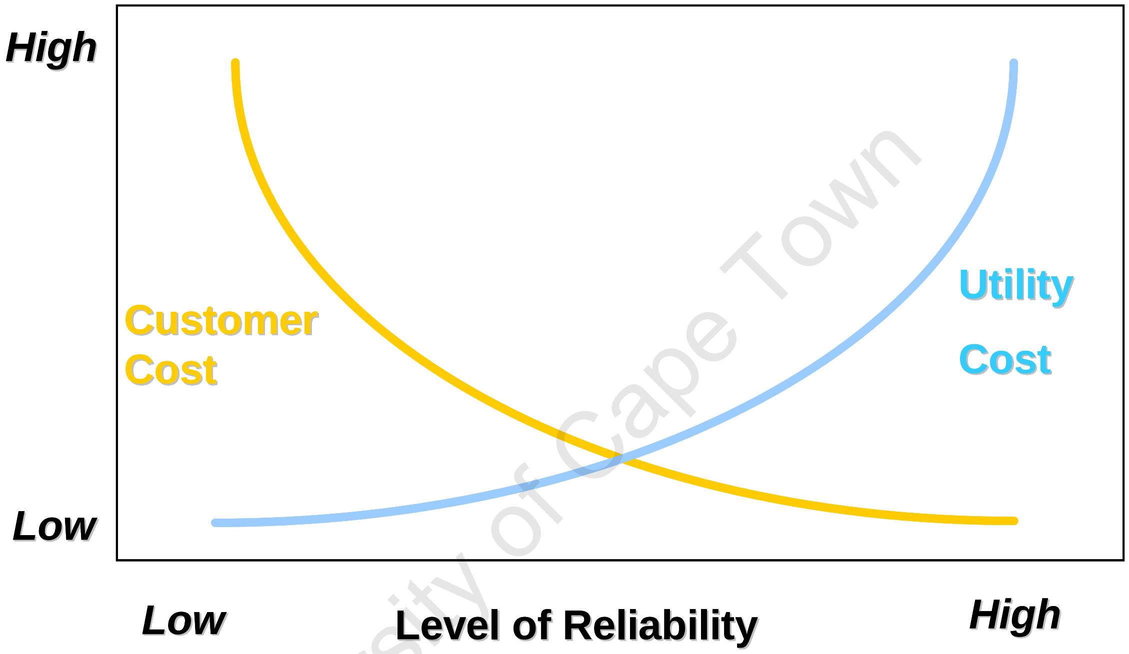


Figure 7 : Balance between marginal benefit and cost to improve reliability

2.7. The Way Forward

This chapter dealt with the quality regulation aspects that shape the investment decision-making process for OPEX and CAPEX. In the next chapter, the investment decision process for CAPEX investment is explored and, more especially, focus is on the application of benefit-to-cost analysis techniques. This methodology serves as a foundation for the development for the reliability hurdle rate.

3. PROJECT EVALUATION:

3.1. Introduction:

The Eskom Distribution Network Planning investment decision was concerned with the optimisation of network configuration to obtain the least-cost solution for existing and future load connected. The change drivers within the EDI (e.g. regulatory mechanism “IBR”, Distribution Code and Tariff Code”) are imposing a change in the evaluation of investment decisions [40] - [42]. This is supported by the Distribution drive to incorporate life cycle cost principles into the investment decisions. The planning decision will have to operate within the following constraints [43]:

- Budgetary
- Technical
- Reliability
- Environmental
- Licensee Requirements
- Safety
- Political influence

This chapter provides an overview of the different project evaluation techniques implemented within the investment decision-making process.

3.1.1. Background:

The current financial model within Eskom Distribution will always theoretically ensure that the investment is financially viable, based on forecasted load and considering the long-run marginal cost of generation [44] - [46]. This may understate the impact of the continuity of supply benefits which is especially true when the initial load connected is small, but the number of customers connected may have a large contribution to the overall continuity of supply. This poses an interesting challenge for the investment in networks that require improvement in reliability.

Every planning scenario has a mixture of these constraints plus some unique constraints related to the geographical influence. The relative importance or area of influence of these constraints will affect the future financial modelling to motivate the CAPEX projects for future and existing networks.

Network Planning mainly strives to answer the following questions [43]:

- When should plant be installed?
- Where should plant be installed?
- What type of plant should be installed?
- What size of plant should be installed?

The total investment cost can be minimised using VBRP principles, where the total cost is the sum of the utility and customer costs are miniminised [47] and [48]. Eskom stakeholders (e.g. NERSA and customers) demand a sound strategy for minimising costs and optimising reliability [40] - [42].

A good rule-of-thumb is that sustaining costs can vary between twice and 20 times the initial costs [49]. Similarly, once a project choice has been made for reliability improvement, up to 65% of the total LCC have been committed, even though only 10% may have been spent [50].

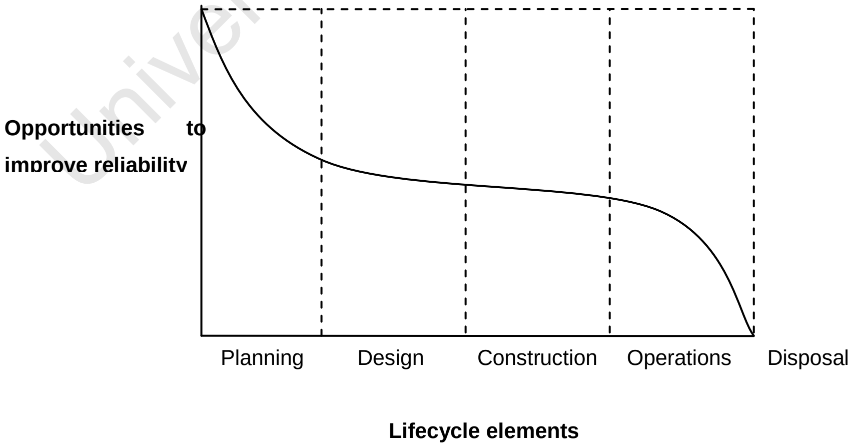


Figure 8: Reliability improvement opportunities [50]

3.1.2. Chapter Outline

Chapter 3 starts by glancing at the main financial and economic techniques utilized by planners to evaluate alternatives for investment decisions. It further discusses two main techniques, namely benefit-to-cost analysis and least life-cycle costing principles. It then considers the modification to the benefit-to-cost principles to incorporate reliability improvement achieved by different investment decisions. Finally, the last section concludes with the different decision criteria utilised to select the preferred alternative.

3.2. Financial and Economic Analysis

The economic analysis assesses an investment project from the national viewpoint, whereas the financial analysis assesses the project from the viewpoint of the utility [51] - [52]. The selection of the most desirable investment alternative is determined by using the financial and economic indicators to evaluate the investment projects [53]. These indicators are only a tool to aid the analysis of investment projects [54] and selection of the preferred project. This is generally required to ensure that prudent investment criteria are adhered to (further discussed in last section 3.5).

The present Financial Evaluation Model (FEM) primarily (broad overview provided in Appendix A) computes the present value for a future net cash flow, minus the initial investment cost [46]. The income is discounted to determine the present value of the cash flow. The present values for each year of the investment project are determined based on the tariff breakdown for the overall connected load. It also roughly estimates the cost of the O&M of the project, which is defined by the R/kVA for the load connected [45]. These costs are derived by considering the total OPEX cost and proportional allocated cost per load size.

3.2.1. Project Evaluation Indicators:

It is important to remember that there is probably more than one correct project evaluation indicator available [53] when evaluating different investment projects. After evaluating the different alternatives, the planner desires to determine the viability of the preferred investment decision. This therefore means that there must be some way of comparing alternatives against one another [53].

The planners can utilise either financial or economical project evaluation indicators, or a combination of both. Some risk analysis can be applied and some decision-making process can be followed to ensure that the risk is minimised, if not eliminated, to ensure that the benefits from the project are maximised.

The preferred project is commissioned long after the capital outlay was made, the time value of money becomes a crucial factor in the consideration. The time value of money principle recognises the fact that money has a value, which is related to time. The existence of interest and inflation reduce the value of money over time [43]. The cost of capital and time value of money concepts therefore become fundamental in the evaluation of projects

Table 5: Time value indicator

Time Value of Money	$\mathrm{FV_n = PV(1+r)^n}$	(4)

There are a number of ways of evaluating whether or not a project is worth undertaking from a financial analysis point of view [43]. The four most commonly - used methods are the least-cost solution, the net present value, the internal rate of return and the discounted payback period.

Table 6: Financial project evaluation indicators:

Net Present Value (NPV)	$NPV = \sum_{t=1}^{n} \left[\frac{C_t}{(1+k)^t} \right] - I$	(5)
Internal Rate Of Returns (IRR)	$\sum_{t=1}^{n} \left[\frac{C_t}{(1+r)^t} \right] - I = 0$	(6)
Discounted Payback Period	$PP = \frac{COF}{CIF}$	(7)

There are a number of ways of evaluating whether or not a project is worth undertaking from an economic analysis point of view [52]. The four most commonly - used methods are the benefit-to-cost analysis, profitability index, return on investment, the return on investment, accounting rate of return and the levelised cost

Table 7: Economic Project Evaluation Indicators:

Benefit-to-cost Analysis	$BCA = \frac{EquivalentBenefits}{Equivalent\cos ts}$	(8)
Profitability Index	$\frac{PV\,benefit}{Cost} = \frac{\sum_{t=1}^{n}\left[\frac{CIF_t}{(1+r)^t}\right]}{\sum_{t=1}^{n}\left[\frac{COF_t}{(1+r)^t}\right]}$	(9)
Return on Investment (ROI)	$ROI = \frac{net\,income\,before\,income\,tax}{previous\ year's\,total\ assets}$	(10)
Accounting Rate Of Return	$ARR = \frac{average\ incremental\ net\ income}{average\ investment}$	(11)
Levelised Cost (LC)	$LC = \frac{present\ value\ of\ \cos ts}{present\ value\ of\ production}$	(12)

Where:
r = Annual interest rate
m = Number of payment periods per year
FV = Amount of money that will have accrued by a certain date emanating from an earlier investment or series of investments.
PV = Original investment (principal sum)
r = Interest rate
Ct = Net cash flow at time t “cash inflow”
I = Cost of the investment “cost outflow”
k = Cost of capital
r = Internal rate of return
CIF = Cost Inflows
COF = Cost Outflows

3.3. Benefit-to-cost Analysis:

The purpose of Benefit-to-cost Analysis (BCA) is precisely to ensure that limited resources (e.g. reliability improvement funding) are used to their best advantage in terms of meeting specific predetermined objectives (e.g. improvement of regional and national continuity of supply indices). This method of comparing the costs against the benefits of a project has led to a relatively well-developed theory for project appraisal known as benefit-to-cost analysis [56] & [57]. A common term also used is "bang-per-buck" factor. It expresses the result of a trade-off analysis, which identifies the most cost-effective solution of those available. Accepting the least LCC alternative without considering the benefit achieved is a major risk when evaluating investment projects.

The BCA principle enables the planner to reject or accept reliability improvement projects. Figure 9 illustrates the principle for selecting the preferred alternative based on the BCA. Project X and Z generated a benefit-to-cost a value of less than 1 and the only prudent project is project Y.

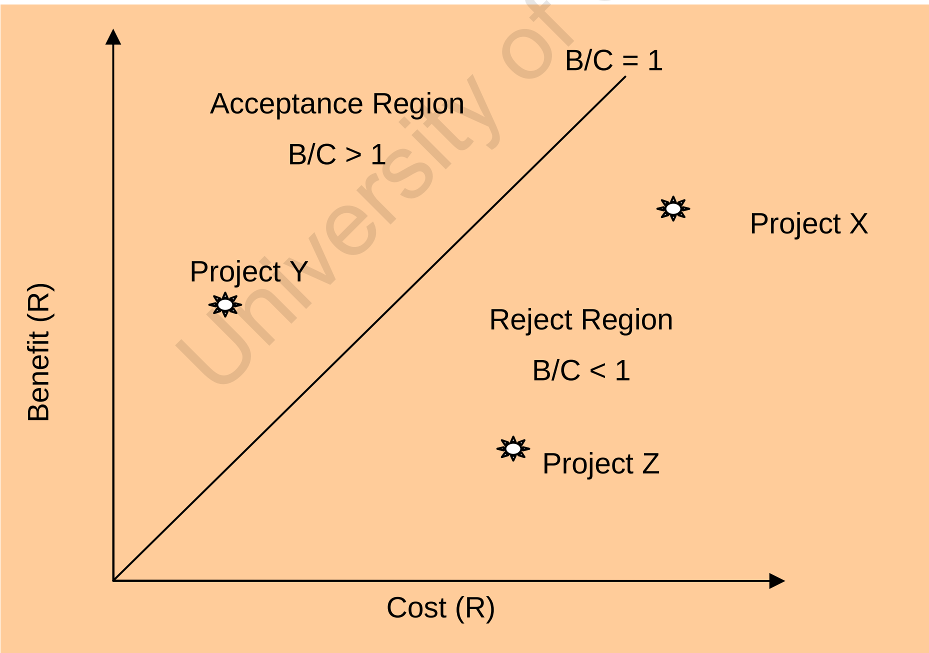


Figure 9: Benefit-to-cost Principle

In principle, BCA can be a unit-less ratio when the nominator and denominator have the same units. The BCA can also produce a useful index to compare the benefit vs energy usage (R/kWh). If we consider the SAIDI improvement/LCC, the incremental capital cost required to achieve the reliability improvement aims to maximise the benefit, which will be further explored in section 3.4. This method involves taking all relevant costs in the life of the project or asset (considering life cycle costing) and comparing them with the benefits (e.g. SAIDI improvement).

In certain applications a ratio is utilised, which defines the ratio of the present value of the benefits to the present value of the costs. In effect, BCA can be expressed as a discounted benefit per rand of the discounted cost. This process involves deflating costs and benefits to the present value, which ignores the income derived from the investment decision.

The final stage of the reliability decision-making process (discussed in chapter 4) is the selection of the preferred alternative and comparing it with the reliability hurdle rate. Chapter 5 will discuss utilising BCA with the objective to improve overall continuity of supply in relation to the IBR scheme.

3.3.1. Type of Benefit-to-cost Analysis:

The two most approaches to compute the benefit-to-cost analysis are known as [76]:

- Conventional BCA
- Modified BCA

1. Conventional BCA:

The net benefit is divided by the net cost for the investment project. This is expressed in equation (13):

$$Conventional\ \ BCA = \frac{(U_p - U_f)}{(C_f - C_p)} \tag{13}$$

A reduction of cost or an improvement can be considered as a benefit. The trade-off is expressed in equation (14):

$$U_n = U_p - U_f \tag{14}$$

Typical investment projects are evaluated to the reduce owner’s costs or improve the current scenario. Cost consists of the annual equivalent costs to the owner, including capital and maintenance costs. Maintenance cost is the function of the scheduled and unscheduled maintenance regime, which is expressed in equation (15).

$$C_n + M_n = C_n + (\mathit{Scheduled\ Maintenance}_n + \mathit{Unscheduled\ Maintenance}_n) \tag{15}$$

Thus, if we include maintenance cost as a cost the BCA equation, it can be expressed in equation (16):

$$\mathit{conventional\ BCA} = \frac{\mathit{Net\ Savings\ to\ owners}}{\mathit{owner's\ (net\ capital\ cost + operating\ and\ maintenance\ costs)}} \tag{16}$$

Income is normally excluded from the BCA equation during the evaluation of projects. Normally income is common to all alternatives considered. Thus, if we include income as a benefit then the BCA equation is expressed as represented in equation (17):

$$\mathit{conventional\ BCA} = \frac{(U_p - U_f) + (I_p - I_f)}{(C_f - C_p) + (M_f - M_P)} \tag{17}$$

Where:

U_p = Present benefit
U_f = Future benefit
I_p = Present Income
I_f = Future Income
M_f = Future O&M
M_P = Present O&M
C_f = Future Capital Cost
C_p = Present Capital Cost

2. Modified BCA:

The net operating and maintenance costs are treated as negative benefits rather than as costs, which is expressed in equation (18):

$$\mathit{modified\ BCA} = \frac{(U_p - U_f) + (I_p - I_f) - (M_f - M_P)}{(C_f - C_p)} \tag{18}$$

BCA studies, by their very nature usually involve a comparison of two or more alternatives against base case “do-nothing”. The principle difference in conventional and modified BCA is that the maintenance and operating cost is in the numerator.

Thus, when the benefit is zero the results are zero, which does not represent the reality. In the numerator, any net increase in benefit (or decrease in cost) is positive, and in the denominator, any net increase in cost is positive. The modified BCA enable the project to be motivated, by a saving achieved in operating and maintenance cost.

3.3.2. BCA Applied within Reliability Evaluation:

3.3.2.1. Implied Cost

An alternative method for evaluating a cost-to-benefit value has received considerable attention in the UK [29]. This is known as "implied cost per kWh saved", which is expressed in equation (19).

$$implied\ cost = \frac{C_a + C_m - C_s}{\Delta E} \tag{19}$$

Where:

C_a = capital cost for reinforcement

C_m = annual costs of operation, maintenance and other services

C_s = annual savings associated with any reduction in electrical system losses or generation costs

ΔE = reduction in 'energy not supplied' in the first year resulting from the investment

3.3.2.2. Adding Wind Turbine Generators (WTG)

The reliability worth of adding WTG as an alternative supply can be represented by an index designed as the wind generation interruption energy benefit (WGIEB) [58]. WGIEB is expressed in equation (20):

$$WGIEB = \frac{EENS_{bw} - EENS_{aw}}{Incremental\ WTG\ capacity} \tag{20}$$

Where:

$EENS_{aw}$ and $EENS_{bw}$ = energy not supplied after and before adding WTG units

The reliability worth to adding WTG can also be represented by an index designated as the wind generation interruption cost benefit (WGICB), which is expressed in equation (21):

$$WGICB = \frac{ECOST_{bw} - ECOST_{aw}}{Incremental\ WTG\ capacity} \tag{21}$$

Where:

$ECOST_{aw}$ and $ECOST_{bw}$ = expected interruption cost after and before adding WTG units

These indices provide direct reliability benefit indicators on the addition of WTG and are important information for planners making decisions such as the size and number of WTG.

3.3.2.3. Project approval process

Deregulation is forcing utilities to optimise budgets and to ensure that reliability improves. It has become necessary to establish accept/reject criteria that best allocate budgets and obtain the highest reliability level of the utility networks. The method formulated a project approval process utilising a cost/benefit principles. The Budget Constrained Planning (BCP) process fixes the budget and projects compete against each other for approval before funding is depleted.

BCP can be formulated as the following optimise budget constraint problem:

Maximize:

Benefit (P) $P = [p_1, p_2, \ldots, p_n]$

Benefit is a function of the project alternatives that require approved.

Subject to:

$\text{Cost}(P) \leq \text{Budget}$

$(B/C)_i \geq (B/C)_{max}$ $i = [1 \ldots n]$

$(\Delta B/\Delta C)_i \geq (\Delta B/\Delta C)_{max}$ $i = [1 \ldots n]$

Where:

n = number of projects considered

C = cost for the project

B = benefit derived with investment project

This project formulation ensures that the utility chooses projects so that it maximises benefit without going over budget. Furthermore, it prevents approving projects that is larger than $(C/B)_{max}$, even if there is budget to do so.

3.3.3. BCA Applied within Reliability Evaluation:

The reliability worth to improve the overall system continuity of supply indices can be represented by an index designated as the SAIDI benefit-to-cost ($SAIDI_{BCA}$).

$$SAIDI_{BCA} = \frac{SAIDI_{base\,case} - SAIDI_{alt}}{IC + [RC + NRC] * \left[\frac{(1+p)^n - 1}{p * (1+p)^n} \right]} \qquad (22)$$

Where:
$SAIDI_{base\,case}$ = System average interruption duration indice for base case
$SAIDI_{alt}$ = System average interruption duration indice alternative considered
IC = Initial investment cost
RC = Recurring cost
NRC = Non-recurring cost
p = Discount rate
n = Equipment lifetime

3.4. Life Cycle Costing:

Life cycle costs (LCC) analysis sums up all cost categories, from installation to decommissioning when evaluating the different investment alternatives [59] - [66]. During the life span of a project, the initial investment cost in certain scenarios can be a fraction of the total cost.

The overall objective of LCC analysis is to determine the long-term costs associated with the investment decision in order to "buy right rather than buy cheaper". **Figure 10** illustrates that the cost over the life span of the project will vary depending on the alternative selected. The capital cost of alternative 2 is more than alternative 1, but the life-cycle cost analysis indicated that alternative 2 is the preferred long-term investment decision. Note that the total project costs should be related to current costs, this is achieved by using Net Present Value (NPV) calculations.

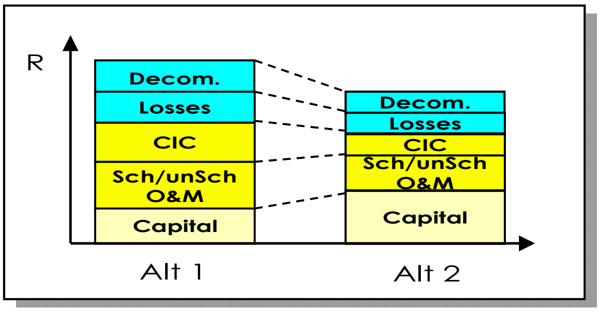


Figure 10: Possible cost element breakdown for two alternative projects.

Life cycle costing adds a long-term financial perspective and provides the means to [59]:

- predict financial performance through life on a quantitative basis;
- assess the financial implications of the contributions made by other functions and
- compare alternative options on a common financial basis.

Some literature [59] - [66] has established a generic LCC model, which is utilised to estimate the total project cost. Applying LCC techniques improves the accuracy of the estimation of the total cost of the alternatives. This improves the estimation of total cost denoted within the denominator of the BCA equation. It is crucial that we understand the availability of the input parameters to these LCC models. The LCC estimation model is the sum of all the cost associated with the equipment or network over its life span. The general LCC estimation models are presented in the equation (23) below.

$$LCC = RC + NRC \tag{23}$$

Where:
RC = recurring cost
NRC = non-recurring cost

In turn, RC (also known as sustaining) has five major components: maintenance cost, operating cost, support cost, labour cost and inventory cost. Similarly, the elements of the NRC (also known as acquisition) are procurement cost, training cost, LCC management cost, support cost, transportation cost, research and development cost, test equipment cost, equipment qualification approval cost, installation cost and reliability and maintainability improvement cost.

If we discount the RC and NRC, we can express the LCC equation as:

$$LCC = IC + \left[RC + NRC\right] * \left[\frac{(1+p)^n - 1}{p * (1+p)^n}\right] \tag{24}$$

Where:
IC = Initial cost
p = Discount rate
n = Equipment lifetime

3.4.1. Cost Categories / Elements

The philosophy behind VBRP is to minimise total cost to society, i.e. not only the utility [47]. The typical cost categories utilised by electricity authorities for project evaluation are:

1. Capital cost for network planning alternatives,
2. Technical and non-technical losses, which include:
    a. Resistive losses in the network (load losses);
    b. Cost of lost load (lost revenue);
    c. Customer Interruption Cost;
    d. Electricity theft;
    e. Aesthetic values (e.g. property values) and
    f. Perceived safety to public and employees.
3. Operation and maintenance costs (O&M).
   Preventative and corrective maintenance costs may include stand-by, call-out and reparation costs.
4. A technical measure of the reliability, i.e. index or indices that accurately reflects reliability of the network.

If at this point only load and energy are considered, then the total annual cost (C_t) is given by [29]:

$$C_t = \Sigma\, c_{li}\, \lambda_i\, L_i + \Sigma\, c_{ci}\, E_i + c_{ri} * \Sigma\, E_i + C_r + C_m + C_s \qquad (25)$$

Where:

i = i^{th} customer or load point
c_{li} = Cost to customer per kW of load discounted
c_{ci} = Cost to customer per kWh not supplied
c_{ri} = Loss of revenue per kWh not supplied
λ_i = Failure rate
L_i = Load disconnected
E_i = Energy not supplied
C_r = Reinforcement annualised investment charges
C_m = Increase in annualised maintenance charges
C_s = Increase in annualised cost of system losses

Two main cost categories for costs incurred over the life span of the assets/project, namely: acquisition and sustaining [49].

1. Acquisition costs:

These costs are associated with the procurement and/or creation of the asset. Acquisition cost is further sub-divided into three cost elements, namely research and development, non-recurring investment costs and recurring investment costs. The main goal of these steps in terms of an electricity utility is to ensure that continuity of supply and integrity of the network is maintained for the future load growth.

2. Sustaining costs:

These costs are associated with the running and/or operation of the asset as well as the decommissioning at the end of its useful life. Operational costs are both scheduled/unscheduled maintenance and other operating costs to ensure the equipment performs its task, as it was intended to perform. Decommissioning costs include expenses for safe disposal of the asset as well as taking into account other legal and economic features.

Figure 11 illustrates generic cost categories and elements [49].

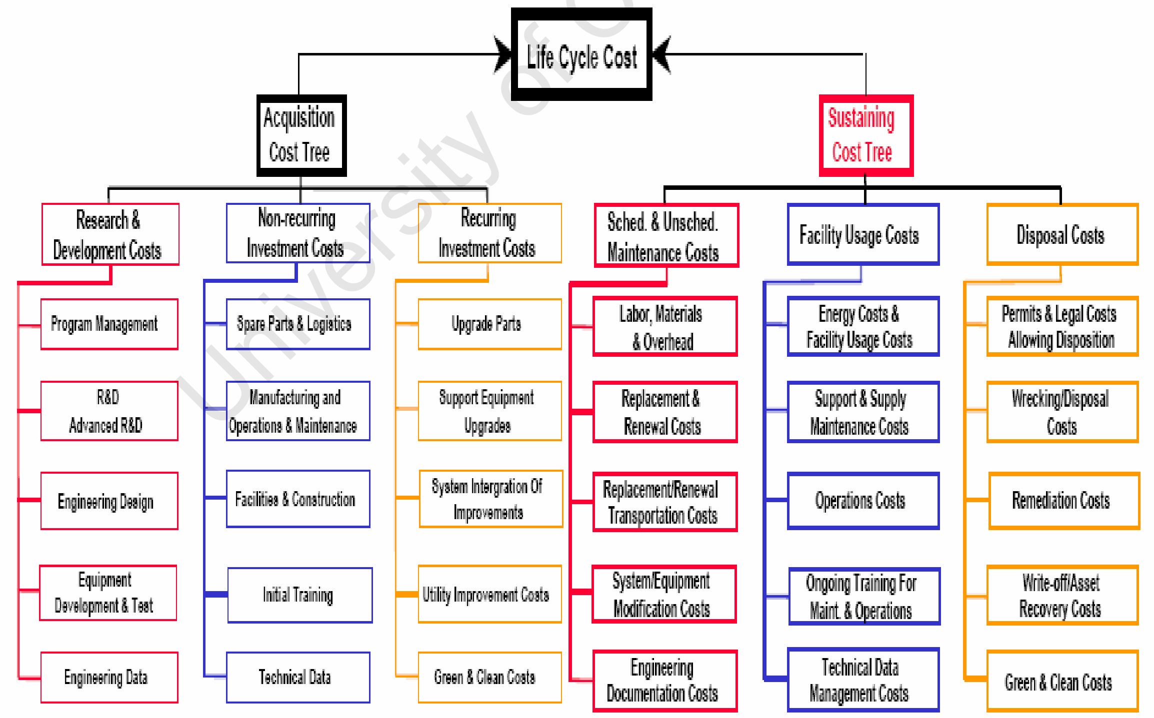


Figure 11: Main cost categories

Some of the cost categories and elements discussed in the previous section may not be available for incorporation into the model, due to a lack of data. The complexity of the evaluation techniques will influence which cost elements need to be included or excluded. Also, note that the same cost categories and elements may be the same, or vastly depending on the alternative evaluated. The cost elements illustrated in the flow diagram in section 3.4.2 are discussed below:

A. Estimated initial and future energy losses:

Technical losses are a function of the type of customers and network characteristics (e.g. voltage, load profile, power factor, etc.). It is directly proportional to the resistance and temperature of the network and is given by I^2R. In transformer no-load losses are not proportional to the load. This results in heat dissipation into the environment.

Costs of losses should be considered as outflows of capital in determining the preferred alternative. The energy (kWh) losses are related to the marginal cost to generate electricity. Secondly, increasing peak loading will result into an increase in demand charge.

B. Estimated customer interruption costs:

Interruptions of electricity supply to the customer inherently results in an economic impact to customers, the severity of which usually depends on the duration of the interruption [38][47]. The customer costs of interruptions can be estimated using equation (26) :

$$ECOST = EENS * CIC \qquad (26)$$

Where:
ECOST = expected cost to customers due to all expected interruptions
EENS = expected energy not served (kW expected to be lost)
CIC = customer interruption costs, usually given in R/kWh

C. Estimated capital cost:

Capital cost generally consists of the procurement cost of the material/equipment, handling, transportation, construction, protection, control plant, commissioning, research and development, overheads and labour.

D. Estimated schedule/preventative maintenance costs for each year:

These are recurring costs and are generally associated with operating and maintenance, labour, inspection etc. Depending on the alternative selected, the maintenance costs will vary due to the maintenance interval or equipment and spares that are required for the maintenance. The alternative options may also include different maintenance philosophies, which may increase (or decrease) the life span of certain components with different cost impacts.

The formula for average annual preventative maintenance man-hours (PMM) is as follows [61]:

$$\text{PMM} = \text{Number of times per year} * \text{Man-hours} * \text{Man-hours rate} \qquad (27)$$

Where:

PMM = is the average annual man-hour cost for preventative maintenance.
Man-hours = number of man-hours required to perform the preventive maintenance routine

E. Estimated unscheduled/corrective maintenance costs for each year:

These recurring costs may vary considerably from year to year, depending on the number and severity of failures at the asset. It includes factors such as labour (normal, overtime and stand-by), materials and travel costs associated with the repair of the asset and restoration of supply.

The formula for average annual corrective maintenance man-hours (CMM) is as follows [61]:

$$\text{CMM} = \lambda * 8760 * \text{MTTR} * A * M \qquad (28)$$

Where:

CMM = The average annual man-hour cost for corrective maintenance.
λ = Total failure rate as number of failures per hour. This includes all failures. (Equals 1/Mean Time between Failures).
8760 = Number of hours in a year.
MTTR = Mean Time To Repair. The time in hours it takes to repair the faulty item back to operating condition.
A = The number of men required to do the work. This also includes the safety aspect.
M = Man-hour rate.

F. Estimated energy delivered to customers for each year:

The additional energy utilisation is computed to determine the future revenue income. If existing energy delivery may be lost if the project is not approved, existing energy utilisation should also be included here. With the capital costs, the expected return on investment can then be calculated.

G. Estimate decommissioning cost:

In most scenarios, this aspect can be ignored due to the following reasons:

1. The expected value for the disposal of the different alternative projects is very similar.
2. The book value of all assets should be zero, due to tax depreciation over the life span of the asset.

3.4.2. Project evaluation process

The Eskom policy [42] states, “The economic evaluation of investments affecting the reliability of supply will take into account the cost to the customer of unsupplied energy, and its probability of occurrence” and applies to Generation, Transmission and Distribution. This policy implies that alternative selection and project evaluation must be performed for the majority of projects using an economic evaluation (since most projects have reliability implications).

The workflow in **Figure 12** illustrates the cost elements, which includes the total costs rather than only the initial capital cost for the investment project. This is evident as the cost of losses, interruptions, scheduled and unscheduled O&M and disposal costs may exceed the initial investment cost. Adopting a LCC approach will enable the planner to perform an economic comparison to select the minimum total cost based on acquisition and sustaining costs.

After the planner has identified the different investment alternatives, the total cost of all alternatives should be calculated based on the life span of the project. This also requires consideration of how and when costs occur during the life cycle of the project.

Two aspects that may be critical in an Eskom Distribution implementation are not included in the process of **Figure 12**, namely:

1. Regulatory aspects such as IBR:

Possible penalties or rewards may be impacted by a specific project or set of projects, depending on the required change in the measured index.

2. The potential change in revenue:

Previous tariff increases were based on a rate-of-return, which were calculated on the value of the approved asset base. However, the IBR scheme adopted by NERSA allows the regulator to influence profit margin.

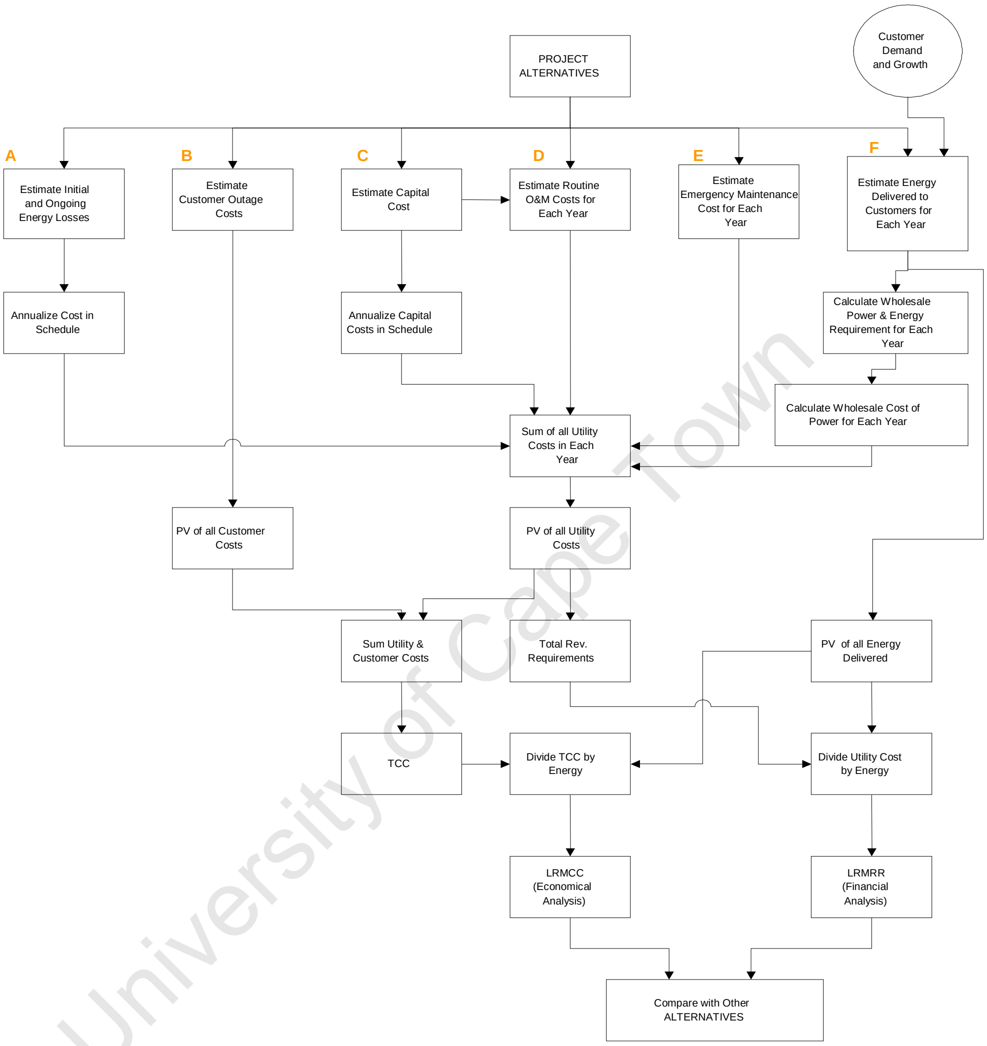


Figure 12: Project Evaluation Process [47].

3.5. Establishment of decision criteria

There are usually more projects than available resources (especially budget, labour, and materials). This competition for resources often means that projects need to be evaluated against each other and they must be prioritised using a certain criteria [53].

Once a preferred investment project has been selected, there is a further complication in that there are usually more ways than one of addressing a particular need. The two main methods of selecting the preferred investment project are by quantitative and qualitative analysis [47]. Financial and economically evaluating the investment alternatives provide some kind of way of comparing alternatives against one another. The project evaluation indicators discussed in section 3.2.1 provide a quantitative manner to evaluate the investment projects.

However, it will never capture all the constraints highlighted and therefore it is imperative that a qualitative analysis is performed. Thus, the decision-making process will overall influence the selection and prioritisation of the investment decision. The challenge is determining which combination of alternatives to select will optimise the investment decision.

The project evaluation model decided by utilities can be categorised into three main evaluation criteria:

- **Business impact**: This estimates the rate of return for the investment in capital.
- **Project evaluation:** This estimates the inherent difference between the alternatives considered.
- **Economic impact:** This estimates the socio-economic benefits derived by the projects considered from a national importance.

These decision-making criteria as illustrated in Table 8, can be further segmented into indices to describe the worth of the projects evaluated.

Table 8: Evaluation indices for different project

Project evaluation indices	**Business impact indices**	**Economic impact indices**
Life-cycle cost	NPV	Benefit-to-cost analysis
Benefit-to-cost analysis	IRR	EIRR
	PI	
	Payback period	
	Break-even	

It can be noted in Table 8, that project evaluation indices ignores the income stream and only considers the benefits derived. The minimum evaluation criteria for each alternative evaluation are described in Table 9. This allows the decision-maker to accept or reject the alternative presented [55].

Table 9: Minimum Evaluation Criteria

Evaluation criteria	**Economic measure**
Payback period	Payback period < Life span of project
Net present value	Net present value > 0
Internal rate of return	IRR > Discount rate
Life-cycle cost	Lowest total cost of all alternatives
Benefit-to-cost	Highest benefit-to-cost of all alternatives

3.6. Conclusion

This section has provided an overview of the different project appraisal techniques available to evaluate or compare the different investment projects against each other. As previously stated, there is probably more than one correct project appraisal technique. The most commonly used techniques have been presented in this chapter. It was also highlighted that these project-evaluation indicators are utilised to select the preferred alternative.

A move from ROR to IBR within the EDI would require the evaluation of project be justified only if the overall benefits to the customers are higher than the costs. Under the current project evaluation techniques utilised by Eskom Distribution, the selection of a preferred alternative is problematic. This is due to the investment project considered is not adding any additional capacity. Indeed, as section 3.3.2 has shown, the application of BCA to evaluate the projects may result in an overall improvement in reliability.

Special attention has been given to the different BCA evaluation techniques and was extended to focus on LCC principles. These techniques will be utilized to evaluate reliability improvement projects. Due to the fact that the budget will always be limited, projects compete for the resources (e.g. money, labour, material, etc). In this chapter certain project decision-making criteria have been documented to accept or reject projects. At the same time it provides a quantifiable measure for making long-term, cost-effective decisions, but it will not replace good engineering judgement. We can then conclude in proposing a modified indicator ($SAIDI_{BCA}$) we are able to evaluate reliability improvement projects.

3.7. The Way Forward

This chapter dealt with the project evaluation techniques, which assist the planner to select the preferred investment alternative. In the next chapter, the reliability decision-making process will ensure that the investment decision is prudent.

4. RELIABILITY DECISION-MAKING PROCESS:

4.1. Introduction:

This chapter describes a proposed reliability decision-making process to identify networks that require investment within Eskom Distribution. The approach identifies which distribution networks require investment to improve reliability in support of national reliability targets. This will enable the planner to compare the reliability improvements to select the preferred alternative with a hurdle rate proposed by this thesis.

4.1.1. Background:

A number of publications consider customer interruption costs as a selection criterion [67] - [71]. This thesis focuses on the application of Benefit-to-cost analysis (BCA) for distribution networks when performing comparative analysis on the different network reliability improvement alternatives evaluated by the network planner [56] [58]. The lack of credible data concerning loading, load forecasting, equipment failure rate, repair rate and customer interruption cost has hindered engineers in making decisions based on the EENS index for Eskom Distribution [73].

This section will further highlight the steps required to make a decision concerning which is the preferred alternative. The steps to evaluate reliability improvement alternatives are as follows:

1. Identify networks for reliability improvement
2. Ranking networks
3. Reliability assessment
4. Perform Benefit-to-cost analysis
5. Compare with network performance target
6. Compare selected alternatives with the hurdle rates

7. Initiate investment projects

This method enhances the comparison of the selected alternatives, which enables the prioritisation of alternatives with use of the hurdle rate derived by this thesis. This method considers the inherent benefit derived by the reliability improvement alternatives using performance indices (i.e. SAIDI).

4.1.2. Chapter Outline

Chapter four starts by looking at the methodology for the selection of the preferred alternative. It also discusses the method to classify and rank networks to ensure that the distribution planner focuses on the correct networks. It further focuses on performing benefit-to-cost analysis to evaluate the benefit (SAIDI) against capital cost required. It also discusses problems encountered utilising customers of interruption cost to estimation of the reliability worth. Finally, it concludes by using the benefit-to-cost with the regional reliability hurdle rate to accept or reject the project evaluated to improve the overall reliability of the network.

4.2. Methodology :

The method is to select networks a planner is able to focus his efforts on, based on the historical performance of the network due to the limitation of funding, where the investment would provide best benefit for those funds. Hence ranking alternatives on BCA is appropriate with the limitation of budget. There are other factors, such as environmental impact, technical losses, project lead-time, etc.

The relative results of the alternatives are compared with minimum reliability criteria prescribed by this Network Planning Reliability Guideline. This minimum reliability criterion serves as a trigger for further investigation of the existing performance and network configuration to improve overall reliability. Figure 14 illustrates the process and the main features of this method: identification of networks, reliability assessment and the comparative analysis to select the investment alternative to improve the existing continuity of supply.

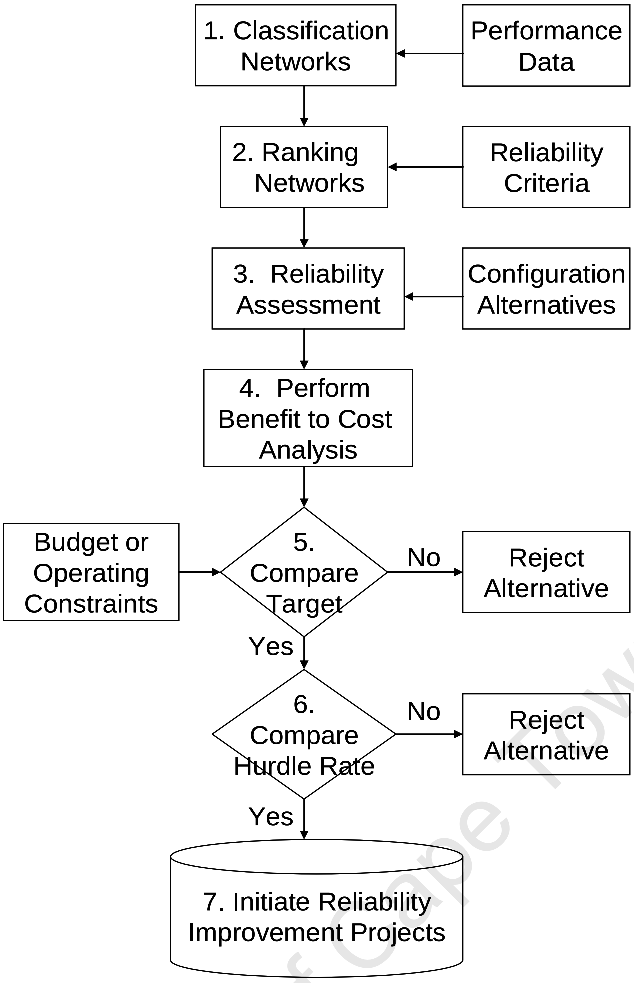


Figure 14: Reliability decision-making process

4.3. Classification of Networks

The critical part of the process is the identification of networks to improve continuity of supply. In stage 2, these networks are analysed in detail, with the purpose of ranking the networks based on the reliability criteria

The classification of MV networks is dependent on the existing performance of these networks, as illustrated in Figure 15. NERSA has decided to introduce SAIDI as a quality regulation mechanism for South African utilities [12]. The simplification of SAIDI is the multiplication of CAIDI and SAIFI [74]. A scatter plot of these performance indices is a representation of SAIDI as illustrated in Figure 15. CAIDI is representative of networks that will require investigation by the planner, because one of the major factors that influence the duration of restoration is the configuration of networks The classification of networks is categorised into three groups of networks:

1. Green networks: These networks do not require any investment. Boundaries are defined by regional gatekeepers of 2.5 and 20 for CAIDI and SAIFI respectively, as illustrated in Figure 15.

2. Red networks: These networks require immediate investigation to improve the continuity of supply. The networks are compared to the overall regional target defined by a SAIDI of 50 hours.

3. Orange networks: The area between the green and red boundaries will define orange networks on the CAIDI (y-axis) and SAIFI (x-axis).

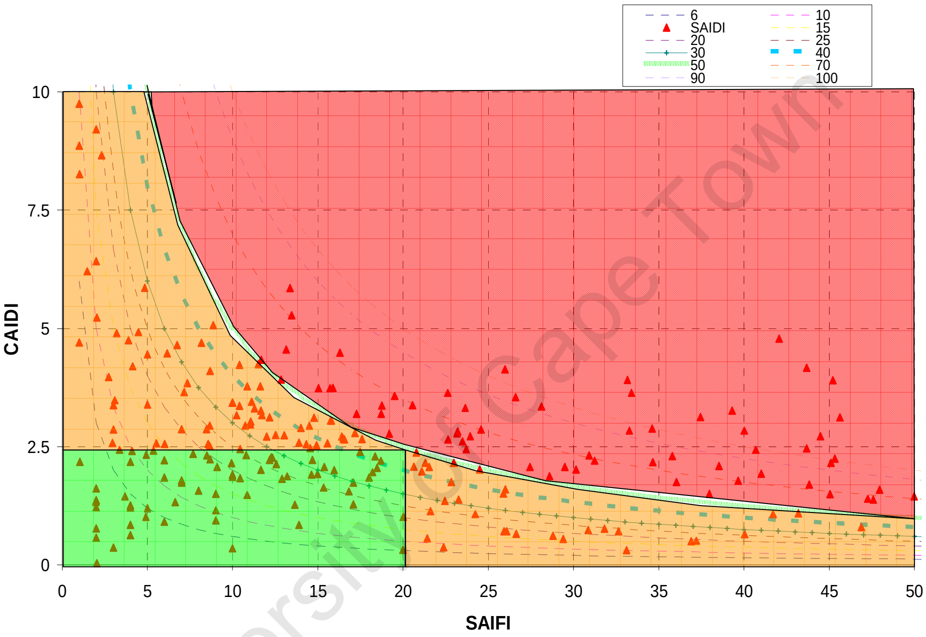


Figure 15: Classification of networks

HV networks should be classified on the top 40 principle, i.e. the 40 HV networks in a Region that have the biggest impact (historical and potential future) on regional SAIDI and DSLI (current criteria: substation supplying a customer base greater than 10 000).

4.4. Ranking Networks

The networks that have been classified are further sorted to rank the importance in relationship to their inherent network characteristics (e.g. number of customers per network). The criterion to sort these networks is determined by the planning reliability criteria as denoted below:

1. Classification of networks;
2. Number of customers connected to the feeder or customer contribution to overall region;
3. If network exceeds the regional performance target;
4. Total line length of the network.

4.5. Reliability Assessment

The third stage is the evaluation of different network alternatives by performing reliability assessment. Reliability assessment enables an engineer to transform knowledge of network (λ - failures/yr and r – hrs/failure) into a “prediction” of its likely future behaviour, based on different network configuration alternatives evaluated by the planner [9]. A quantitative reliability analysis is an important input parameter to improve the reliability decision-making process for the management of the reliability constraints of existing and future networks. Typical equipment reliability data (obtained from published literature) can be used to facilitate the comparative analyses between different expansion or design alternatives within the planning phase of a project [9], [75]. Figure 16 illustrates steps required to perform a reliability assessment on the case study below.

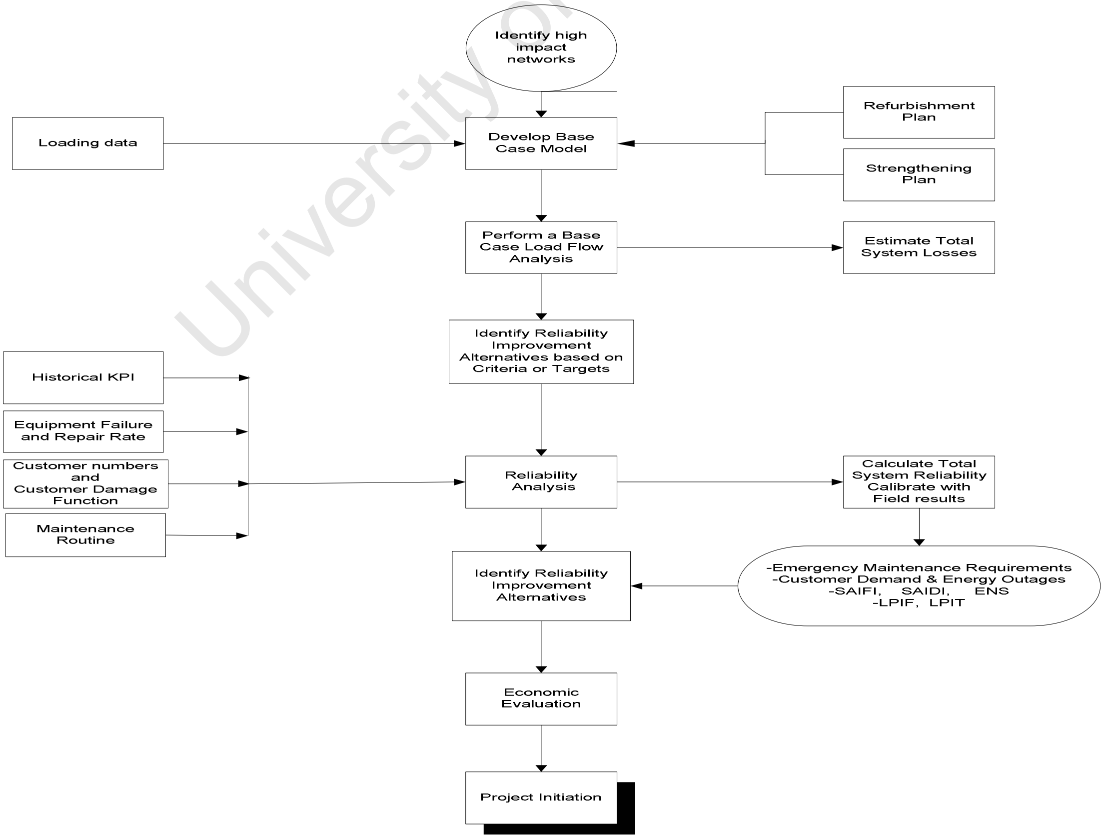


Figure 16: Reliability assessment process (adopted from [9])

Figure 17 illustrates case study results where the relative percentage improvement in SAIDI (y-axis on right in relative %) and capital cost (y-axis on left in R millions) required to achieve this improvement are represented for different alternatives. Alternative 6 is initially the preferred alternative, because it achieves the largest improvement of almost 19% from base case. The selection of the preferred alternative is not obvious, as other considerations such as capital cost have not yet been included. The technique to select the preferred alternative is based on benefit-to-cost analysis and will be discussed further in the next stage of the reliability decision-making process.

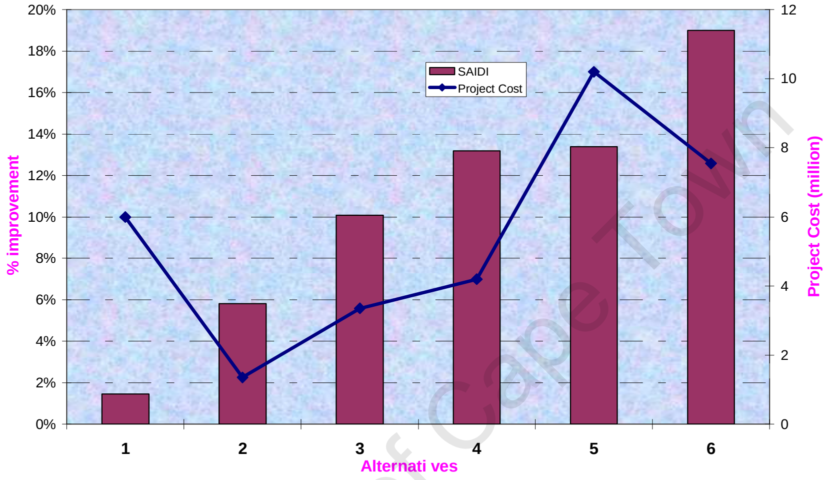


Figure 17: Reliability assessment of alternatives

4.6. Perform Benefit-to-cost Analysis

Finally, in the last stage of the reliability decision-making process, is the selection of the preferred alternative based on the BCA and comparative analysis. This is a commonly - used method of estimating the relative benefit based on the incremental capital cost required to improve the continuity of supply. Unlike Expected Cost (ECOST) estimation of reliability worth, BCA is concerned with the relative improvement in SAIDI of the different expansion alternatives, and not the customer interruption costs. The BCA is denoted by the expression below [56] & [71].

$$BCA = \frac{Benefit}{Cost} \tag{29}$$

The BCA principle enables the planner to reject or accept reliability improvement projects. It is, however, very useful together with NPV in the prioritisation of capital budgets due to budget constraints [69] & [71]. It is clear from Figure 18 that, when considering the benefits and capital cost required, alternative 6 is not the preferred alternative, but rather alternative 2 is preferred.

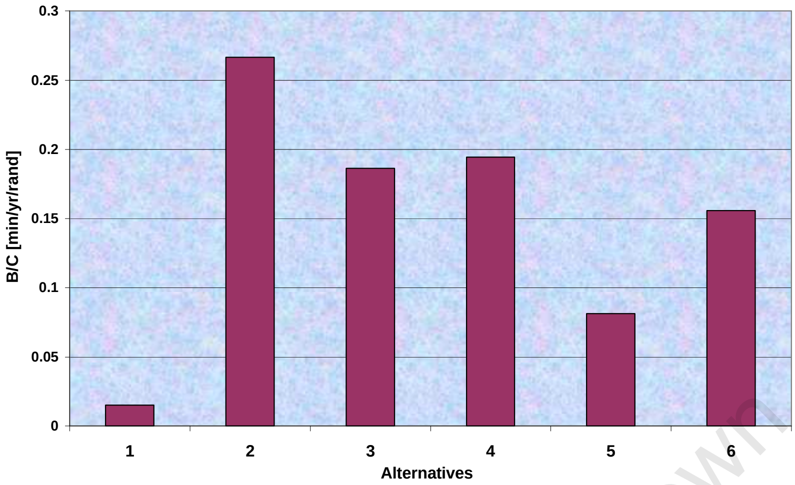


Figure 18: Benefit-to-cost Analysis

4.7. Compare results with target:

Figure 19 represents a bar chart with the improvement achieved by the configuration alternatives and the line chart represents the benefit-to-cost analysis results. Comparing the improvement with the desired improvement required for the network is important in order to align with national targets. Thus, a qualitative analysis of the pros and cons may result in the selection of alternatives, which do not have a high BCA, but have a higher SAIDI improvement. Figure 19 illustrates that alternative 3, 4 and 6 are desirable when considering the reliability improvement target and benefit-to-cost analysis. The selection technique finally indicates that alternative 4 is rather the preferred alternative and not 6 or 2.

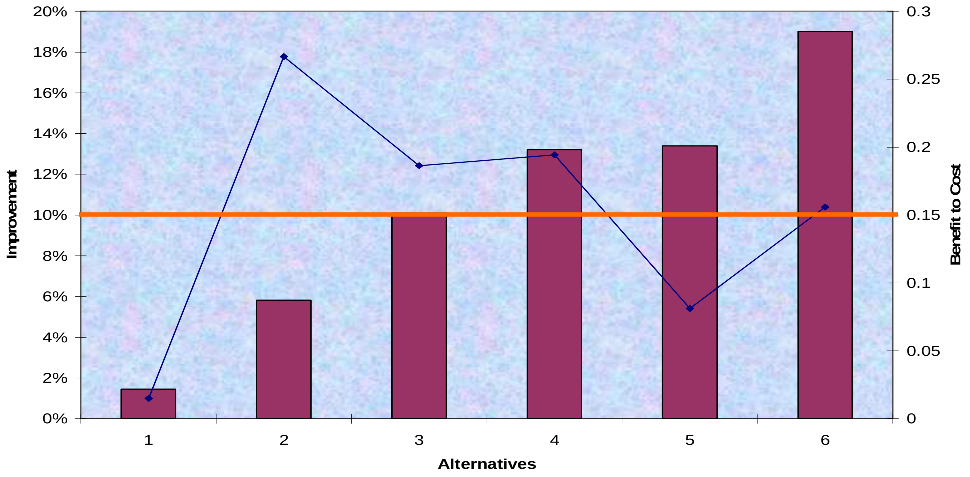


Figure 19: Improvement vs BCA against target improvement

4.8. Compare results with hurdle rate

As the accuracy of the failure rate and customer interruption cost improve, the introduction a FSA, regional and national hurdle rate is possible. This final step is to compare the selected alternatives against the single or reward and penalty reliability hurdle rate. The estimation of the hurdle rate is based on the BCA principle. This provides the planner with a single SAIDI/Rand hurdle rate against which to evaluate alternatives. If consider Table 14 the single or reward and penalty reliability hurdle rate for Region 1, 2.44 and 1.63 min/R/a respectively. Consider Figure 19, alternative 2, 3, 4 and 6 achieve the decided hurdle, which will exclude alternative 1 and 5.

It is important to translate the reward / penalty scheme introduced by NERSA into a single reliability hurdle rate (m_{RHR}) to which the planner is able to compare the investment. When we consider the symmetrical nature of the scheme, we are able to derive the straight line (y = f(x)) required to reduce the scheme into a single m_{RHR} for an investment decision as illustrated in Figure 20.

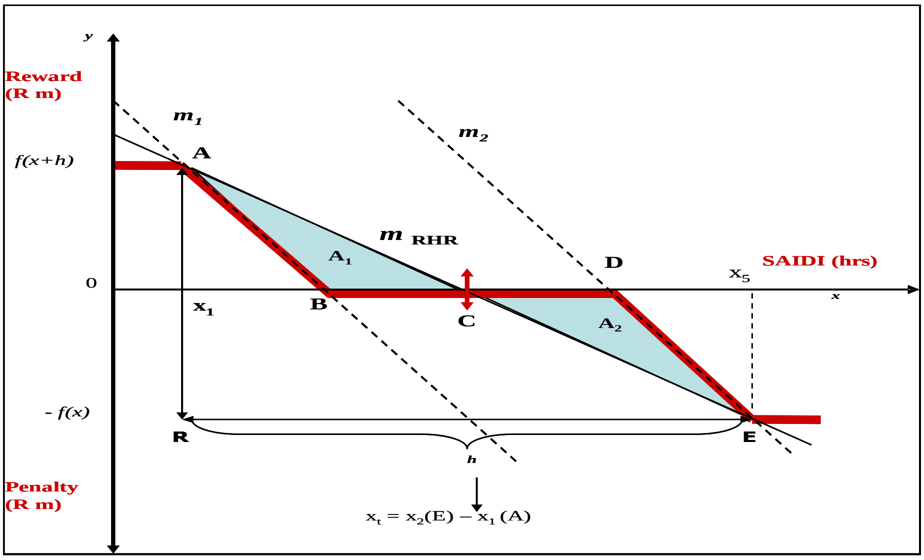


Figure 20: Reliability hurdle rate

This single reliability hurdle rate (m_{RHR}) represents an alternative that results in an improvement in a regional and national SAIDI. However, if the reward / penalty scheme is asymmetrical in shape, more consideration must be given to the derivation of the single reliability hurdle rate. Expressing in symbolic form, we can consider the expression below:

$$\begin{aligned} m_{RHR} &= \frac{f(x+h)-(-f(x))}{h} \\ &Given: \\ &A_1 = A_2 \; and \;\; m_1 = m_2 \end{aligned} \qquad (30)$$

It seems reasonable to suppose that if x_5 (SAIDI) were to be improved to x_1 then expression (30), will achieve a maximum reward for the investment decision.

The distribution planning core objective is to determine the reliability level (based on customer and network types) for which a planner should plan a distribution network to improve reliability on a system level. The application of VBRP principles clarify certain aspects required to make reliability-based decisions during the planning and design phase of strengthening project [9]. This thesis will discuss the derivation of the reliability hurdle rate based on the reward / penalty scheme further in Chapter 5.

4.9. Conclusion

This chapter has presented a method for the prioritisation and selection of the preferred alternative for reliability assessment in support of national reliability targets and reward / penalty schemes. The method has been applied to a case study which demonstrated that, when comparing alternatives against certain criteria, the preferred alternative is not obvious.

The proposed reliability decision-making method assists determining which distribution networks require investment. If a planner is not able to quantify the reliability improvement associated with network alternatives, then the selection of the preferred alternative can only be based on compliance with the criteria described in the guideline.

4.10. The Way Forward

This chapter dealt with the reliability decision-making process, which provides the understanding where the reliability hurdle rate is applied within the planner evaluation. In the next chapter, the thesis discusses the derivation of the reliability hurdle rate, utilising benefit-to-cost analysis principles. This reliability hurdle rate is derived from the reward / penalty scheme proposed by NERSA and special focus is given to the sensitivity of the shape of the scheme.

5. REGIONAL RELIABILITY HURDLE RATE:

5.1. Introduction

The derivation of the Reliability Hurdle Rate (RHR) is based on the IBR which has been discussed in chapter 2. The international trend is that the shape of the reward / penalty scheme can be symmetrical or asymmetrical. A symmetrical scheme allows the determination of a measure, which can be utilised to compare the investment decision. This chapter will discuss the derivation of a reliability hurdle rate.

5.1.1. Background

NERSA has decided to introduce a symmetrical reward / penalty scheme with a dead band for South African distributors [12]. The thesis will discuss utilising a symmetrical reward / penalty scheme to estimate a regional reliability hurdle rate, which allows the planner to compare the reliability improvement projects against the hurdle rate. **Figure 21** below is an example of a symmetrical reward / penalty scheme, which includes a dead band (B-C and C-D).

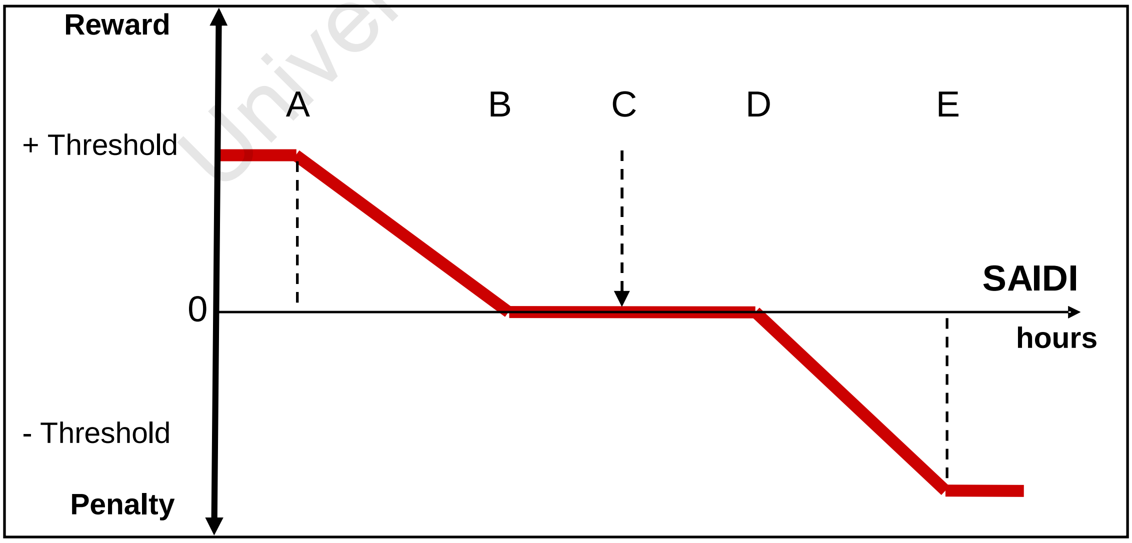


Figure 21: Reward / penalty scheme (adopted from NERSA: Design of distribution reward / penalty scheme for Eskom) [12]

The funding allocation thresholds in **Figure 21** define the amount of revenue exposed to the reward / penalty scheme introduced by the national regulator. The thresholds have been capped at A and E.

In the case of countries such as Great Britain and Ireland, the funding risk is limited to +/-2 to +/-3% of the revenue. The thresholds for reward (A) and penalty (E) are set around the target performance the national regulator would like to achieve nationally. Italy, Hungary and Portugal have defined different dead band values, which vary from ±5% to ±12%. Other countries such as Norway, Sweden, Ireland and Great Britain, do not have a dead band [16].

A reward / penalty scheme within South Africa should be based on the fixed funding allocation for all reliability improvement initiatives related to:

(a) Worst performing networks and
(b) Continuous improvement for the overall continuity of supply for distribution networks.

Funding to improve distribution networks should be different for initiatives (a) and (b). The key differences are highlighted in **Table 10** below.

Table 10: Differences between reliability improvement initiatives

Worst performing networks (a)	**Continuous improvement (b)**
Short-term initiatives	Long sustainable initiatives
Majority of funding allocated to OPEX	Majority of funding allocated to CAPEX
Fixed duration to achieve objective (typical 2 years)	Continuous efforts to incorporate reliability decision-making within planning and design phase of projects
Utility normally defines a few reliability improvement drives	Selection of projects to improve continuity of supply with numerous alternatives which will be based on BCA

Continuous reliability improvement funding should be allocated separately from normal CAPEX funding to ensure sustainability of the utility network for the existing and future load.

5.1.2. Chapter Outline

Chapter five starts by looking at the techniques used for allocating funding per region, based on national importance. It then considers a South African scenario and derives formulae to determine the shape of the regional reward / penalty scheme and allocation of funding. Section 5.2 discusses the method to derive the regional reliability hurdle rate (RHR). Finally a sensitivity analysis is performed to explore the influence of the input variables on the reliability hurdle rate.

5.2. Method

A method to determine a regional and national reliability hurdle rate is proposed by this thesis. This reliability hurdle rate utilizes the reward / penalty scheme adopted by NERSA and is based on benefit to cost principles to determine the reliability hurdle rate.

Figure 22, presents the different steps followed to determine the reliability hurdle rate. As a first step, it is necessary to obtain the reward / penalty scheme adopted the national electricity regulator. The second step is to estimate the regional reward / penalty target for each region. To derive the regional scheme we require regional continuity of supply targets and shape parameters derived from the national reward / penalty scheme. The next stage is to derive the allocation for the regional reliability funding by considering the contribution each region has to the overall national continuity of supply indices and the national reliability funding. This provides the shape of the regional reward / penalty scheme for each region. Finally, it would be possible to derive the reliability hurdle rate for each region.

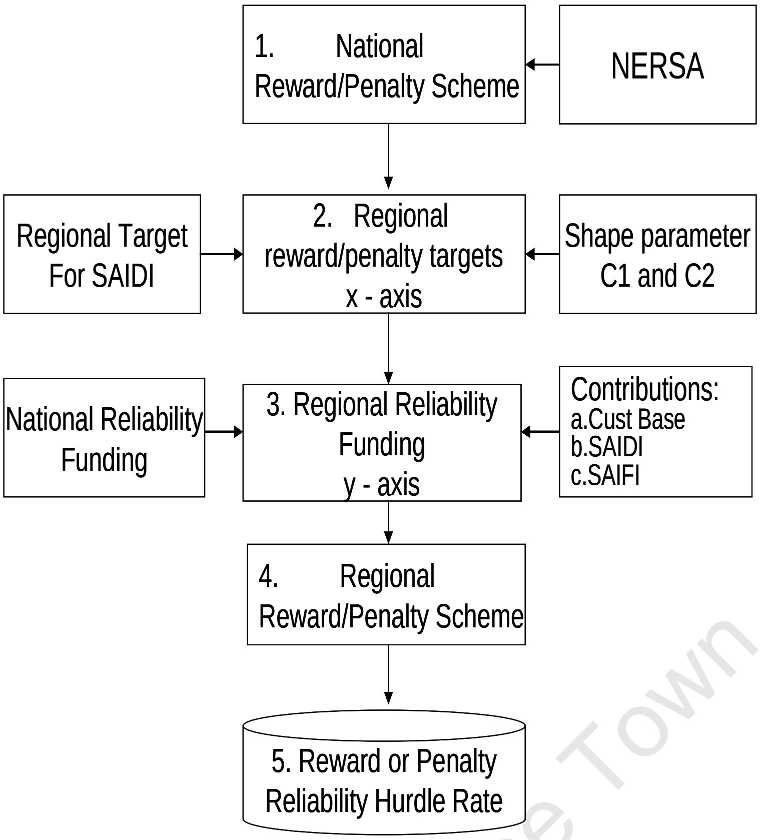


Figure 22: Process to estimation reliability hurdle rate

5.2.1. National Reward / Penalty Scheme:

The first step in deriving the reliability hurdle rate is to obtain the approved reward / penalty scheme adopted by the NERSA as illustrated by Figure 23. The reward / penalty scheme is a quality regulation mechanism utilized within IBR scheme. This mechanism is adopted is to ensure that the public and private electricity utilities become more efficient.

National electricity regulator has different regulatory mechanisms to shape the Electricity Distribution Industry (EDI). The majority of the national electricity regulators worldwide have selected one of the continuity indices such as SAIDI to measure efficiency[16]. **Table 3** as illustrated in Chapter 2, provides a review of the different continuity of supply indices utilised by the national regulators worldwide.

Graphically, in Figure 23 the shape of the reward / penalty scheme is linked to the performance of the network with a financial impact (either a reward or penalty). The x-axis represents the measured continuity of supply index prescribed by the national electricity regulator body and the y-axis the reward or penalty for not achieving the decided performance.

Figure 23; illustrates the reward / penalty scheme introduced by the NERSA for the period of April 2006 to April 2009 [35] & [36].

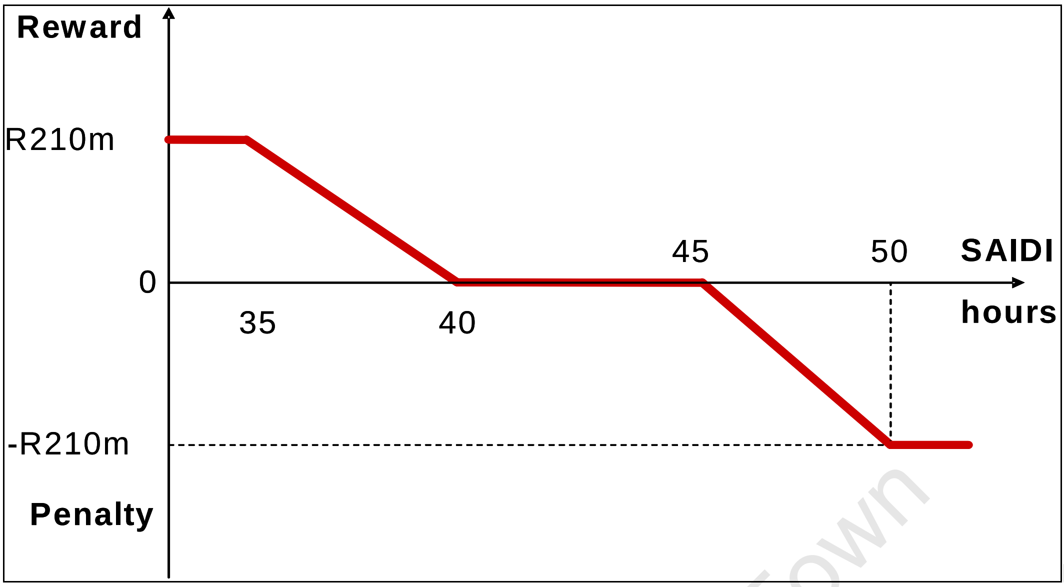
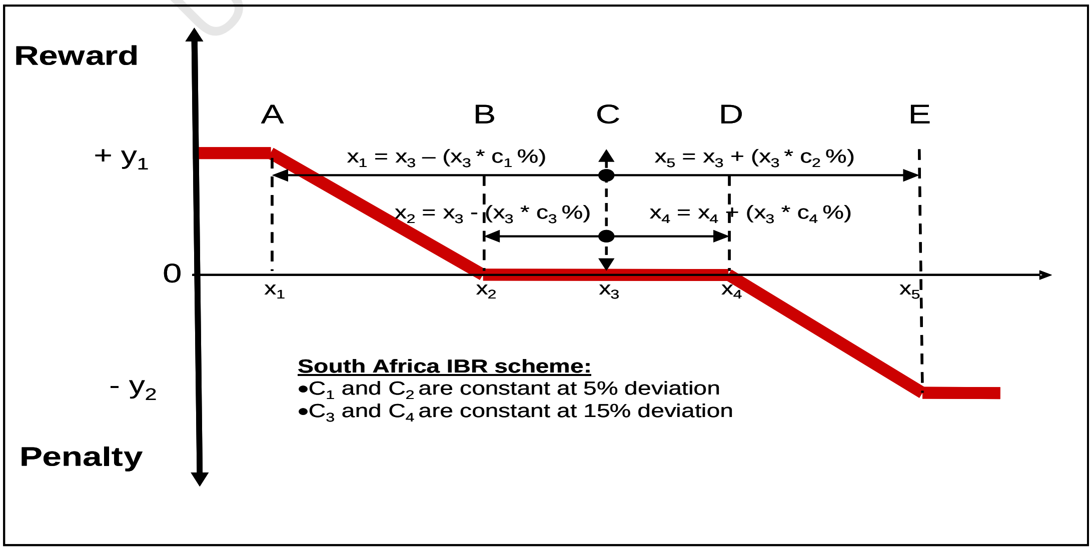


Figure 23: Reward / penalty scheme proposed by NERSA

5.2.2. Shape of Regional Reward / Penalty Scheme:

The next step is to determine the shape (A, B, C, D and E) of the regional reward / penalty scheme adopted within each region, as illustrated in Figure 24. The y-axis defines the penalty or reward achieved after the regulatory period. The x-axis is the continuity of supply prescribed by the national electricity regulator. The symmetrical nature of the reward / penalty scheme is defined by the threshold limits (y_1 and y_2), dead band limits (x_2 and x_4), target performance value (x_3), and threshold clamping limits (x_1 and x_5), as illustrated in Figure 24.



South Africa IBR scheme:
- C_1 and C_2 are constant at 5% deviation
- C_3 and C_4 are constant at 15% deviation

Figure 24: Illustration of a symmetrical reward / penalty scheme

In Figure 24, the following points are indicated:

Clamping reliability funding for a reward and penalty	(A and E)
End of dead band for a reward and penalty	(B and D)
Mean value of the SAIDI target per region	(C)

In the case of South Africa, the threshold for the dead band is set around the desired national performance and is rolled down to the regional level to achieve the overall national target. The estimation of the regional targets is based on the desired national performance target and the contribution (actual and potential) each region has on the national target.

A fixed deviation from the required target is negotiated with NERSA before the implementation of the reward / penalty scheme. In the South African scenario, a fixed percentage of ± 5% were selected for c_3 and c_4. The constant deviations depicted by c_1 and c_2 are set at ± 15% from the national target.

The national and regional targets, depicted by x_3, are based on a 12-month moving average value for SAIDI. The thresholds for the dead band are depicted by

B $$x_2 = x_3 - (x_3 * c_3) \tag{31}$$

D $$x_4 = x_4 + (x_3 * c_4) \tag{32}$$

The clamping limit for the reward / penalty scheme is depicted by:

A $x_1 = x_3 - (x_3 * c_1)$ (33)

E $x_5 = x_3 + (x_3 * c_2)$ (34)

The resultant shape of the regional reward / penalty scheme is based on the symmetrical nature of the national reward / penalty scheme. As a result, it is possible to create a regional reward / penalty scheme after the Performance Department derive the regional targets, denoted by C in Table 11.

Table 11 : Regional targets defining the x-axis per region

	A	B	C	D	E
	15%	5.0%	0%	5.0%	15.0%
Region 1	48.20	53.87	**56.7**	59.54	65.21
Region 2	22.44	25.08	**26.4**	27.72	30.36
Region 3	27.54	30.78	**32.4**	34.02	37.26
Region 4	35.19	39.33	**41.4**	43.47	47.61
Region 5	67.49	75.43	**79.4**	83.37	91.31
Region 6	16.41	18.34	**19.3**	20.27	22.20

5.2.3. Regional Reliability Funding Allocated:

Regional reliability funding is a function of the impact each region has on the overall national continuity of supply indices. The previous step derived the x-axis of the regional reward / penalty scheme. To complete the scheme we need to derive the y-axis next. This provides the clamping reliability funding for the reward and penalty for achieving improvement or not.

The regional funding allocation (RFA) is based a function of variables which will influence the continuity of supply indices for each region, i.e.

RFA is a function of (RCB,%CD,%CI, NFA) (35)

Where: RCB is regional customers base and contribution of each region in relation to national SAIDI (%CD), SAIFI (%CI) and national funding allocated (NFA). If we consider the funding in relation to the regional and national customer base, the regional funding allocated is derived by expression (36):

$$\mathrm{RFAC_i} = \left(\frac{\mathrm{RCB}}{\mathrm{NCB}}\right) * \mathrm{NFA} \tag{36}$$

Then consider the contribution of each region has in relation to the national impact to SAIDI and SAIFI, the regional funding allocated is derived by expression (37) & (38):

$$\mathrm{RFAD_i} = \%\mathrm{CD} * \mathrm{NFA} \tag{37}$$

$$\mathrm{RFAI_i} = \%\mathrm{CI} * \mathrm{NFA} \tag{38}$$

Finally, we have derived the regional allocation of reliability improvement funding by considering the impact the three variables namely, customer base and the contribution to the continuity of supply indices (SAIDI & SAIFI). We can introduce a weight factor to consider focus area for each region. The overall regional allocation is derived with the following expression (39):

$$\mathrm{RFA} = \left(\frac{\mathrm{w} * \mathrm{RFACi} + \mathrm{w} * \mathrm{RFADi} + \mathrm{w} * \mathrm{RFAIi}}{3}\right) \tag{39}$$

Where:

RFA = regional funding allocation
$\mathrm{RFAC_i}$ = regional funding allocation based on customer numbers
$\mathrm{RFAD_i}$ = regional funding allocation based on the regional influence on national SAIDI
$\mathrm{RFAI_i}$ = regional funding allocation based on regional influence on national SAIFI
RCB = regional customer base
NCB = national customer base
NFA = national funding allocation
%CD = % of the regional total number of customer interruption durations
%CI = % of the regional total customer interruption
w = weight

If we apply the derived formulae to the six regions within South Africa for a national funding allocation of R 500 million, we can observe that each region is allocated different funding to improve overall reliability of their networks, in proportion to the customer numbers and interruption indices. The regional funding allocated (RFA) derived is denoted in Table 12 below.

Table 12 : Reliability Funding Allocation per region

	RFAC		RFAD		RFAI		RFA
	Customer Base	R million	% CD	R million	% CI	R million	
Region 1	1040451	R 176	43%	R 215	50%	R 250	R 213
Region 2	450338	R 76	9%	R 46	12%	R 59	R 60
Region 3	341713	R 58	10%	R 48	8%	R 41	R 49
Region 4	459001	R 77	12%	R 62	12%	R 62	R 67
Region 5	444140	R 75	24%	R 118	16%	R 79	R 91
Region 6	228073	R 38	2%	R 11	2%	R 10	R 20

5.2.4. Reliability Hurdle Rate:

This proposed method attempts to translate the reward / penalty scheme adopted by NERSA into a reliability hurdle rate (m_{RHR}) by which the planner is able to compare the investment with the benefits achieved. For the symmetrical scheme, a straight line ($y = m_1x + c$) can be derived, which reduces the scheme to a single reliability hurdle rate (m_{RHR}), as illustrated in Figure 25.

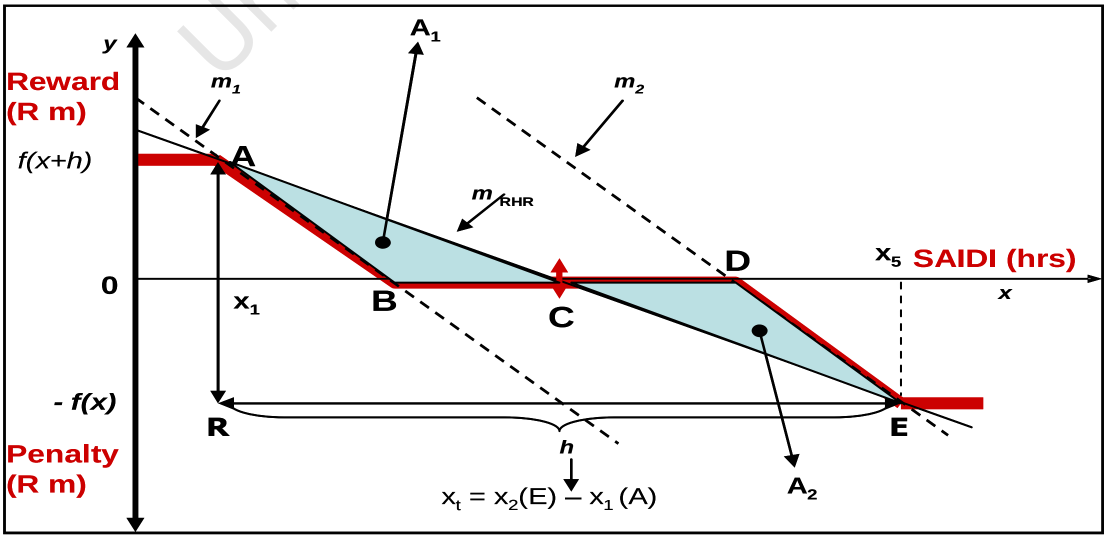


Figure 25: Illustrates the Reliability Hurdle Rate based on tangential line

In Figure 25, it can be seen that with the symmetrical nature of the reward / penalty scheme ensure that m_1 and m_2 are parallel with each other. The gradient (m_1 and m_2) for the reward $A\hat{X}_1B$ and penalty $E\hat{X}_5D$ region is equal; the error margin illustrated by A_1 and A_2 therefore cancel each other out. Expression (40) is the slope of the angle $A\hat{R}E$ and is equal to the gradient or slope of the curve y = *f(x).* This single reliability hurdle rate (m_{RHR}) will define the viability of the investment project that represents a target improvement in SAIDI from x_5 towards x_1.

The reliability hurdle rate can be expressed as follows:

$$m_{RHR} = \frac{f(x+h)-(-f(x))}{h} \tag{40}$$

It seems reasonable to suppose that if x_5 (SAIDI) were to be improved to x_1 then expression (40) will achieve a maximum reward for the investment decision.

Application of the equation:

The following procedure can be used to determine the reward / penalty and single hurdle rate for each region based on national importance.

Determine the denominator of expression (41) for the reward ($x_{m1} = x_2 - x_1$) and penalty ($x_{m2} = x_5 - x_4$) region as illustrated in Figure 25.

$$\tan\theta = m_1 = m_2 = \frac{y_t}{x_t} = \frac{(\mathrm{x}_2 - \mathrm{x}_1)}{\mathrm{AO}} = \frac{(\mathrm{x}_5 - \mathrm{x}_4)}{\mathrm{EO}} \tag{41}$$

Determine the denominator of expression (41) for the reward (y_{m1} = AO) and penalty (y_{m2} = RO) region as illustrated in Figure 25.

The single hurdle rate can also be derived using expression (42) by determining the denominator (y_{RHR} = AR) and numerator ($x_{RHR} = x_5 - x_1$) values as illustrated in Figure 25.

$$\tan\theta = m_{RHR} = \frac{(\mathrm{x}_5 - \mathrm{x}_1)}{\mathrm{AR}} \tag{42}$$

The procedure above was applied to an allocation of R500 million across six regions in order to derive the reliability hurdle rate, results are displayed in Table 13 below.

Table 13: Regional reward / penalty scheme to derive reliability hurdle rate

		F	G	H	I	J	K	L	M
	Reward Penalty (R million)	Δ (E-A)	Δ (C-A)	Reward Δ (B-A)	Penalty Δ (E-D)	Δ (Penalty + Reward)	Reward Δ (G/J)*	Penalty Δ (H/J)*	Hurdle Rate (F/J)*
Region 1	176	17.01	8.51	5.67	5.67	R 351	1.94	1.94	2.91
Region 2	76	7.92	3.96	2.64	2.64	R 152	2.08	2.08	3.13
Region 3	58	9.72	4.86	3.24	3.24	R 115	3.37	3.37	5.06
Region 4	77	12.42	6.21	4.14	4.14	R 155	3.21	3.21	4.81
Region 5	75	23.82	11.91	7.94	7.94	R 150	6.36	6.36	9.54
Region 6	38	5.79	2.90	1.93	1.93	R 77	3.01	3.01	4.51

	Reward Penalty (R million)	Δ (E-A)	Δ (C-A)	Reward Δ (B-A)	Penalty Δ (E-D)	Δ (Penalty + Reward)	Reward Δ (G/J)*	Penalty Δ (H/J)*	Hurdle Rate (F/J)*
Region 1	215	17.01	8.51	5.67	5.67	R 430	1.58	1.58	2.37
Region 2	46	7.92	3.96	2.64	2.64	R 92	3.44	3.44	5.17
Region 3	48	9.72	4.86	3.24	3.24	R 96	4.05	4.05	6.08
Region 4	62	12.42	6.21	4.14	4.14	R 124	4.01	4.01	6.01
Region 5	118	23.82	11.91	7.94	7.94	R 236	4.04	4.04	6.06
Region 6	11	5.79	2.90	1.93	1.93	R 22	10.53	10.53	15.79

	Reward Penalty (R million)	Δ (E-A)	Δ (C-A)	Reward Δ (B-A)	Penalty Δ (E-D)	Δ (Penalty + Reward)	Reward Δ (G/J)*	Penalty Δ (H/J)*	Hurdle Rate (F/J)*
Region 1	250	17.01	8.51	5.67	5.67	R 499	1.36	1.36	2.05
Region 2	59	7.92	3.96	2.64	2.64	R 118	2.68	2.68	4.03
Region 3	41	9.72	4.86	3.24	3.24	R 82	4.74	4.74	7.11
Region 4	62	12.42	6.21	4.14	4.14	R 124	4.01	4.01	6.01
Region 5	79	23.82	11.91	7.94	7.94	R 158	6.03	6.03	9.05
Region 6	10	5.79	2.90	1.93	1.93	R 19	12.19	12.19	18.28

It can be observed in Table 13, that the reward and penalty reliability hurdle rate (m_1 and m_2) is equal, represented by column K and L. The single hurdle rate is higher than the reward and penalty hurdle rate and is represented by column M. To derive the overall regional reliability hurdles rate and funding allocation, we considered the three variables and applied expression (43) & (44):

5.2.5. Regional Reliability Hurdle Rate:

Finally, it would be possible to derive the regional reliability hurdle rate for each region. This is derived from the shape of the regional reward / penalty scheme and hurdle rate for each region.

The regional reliability hurdle rate is derived with the following expression (43):

$$m_{RRHR} = \left(\frac{m_{CB} + m_{CD} + m_{CI}}{3} \right) \qquad (43)$$

Where: m_{RRHR} is regional reliability hurdle rate derived by the reliability hurdle rate impact based on the customer based (m_{CB}) and contribution each region has in relation to national SAIDI (m_{CD}) and SAIFI (m_{CI}).

To derive the overall regional reliability funding allocated (RRFA) for each region derived with the following expression (44):

$$R_{RRFA} = \left(\frac{R_{CB} + R_{CD} + R_{CI}}{3} \right) \qquad (44)$$

Where: R_{RRFA} is regional reliability funding allocated derived by the funding allocation based on the customer based (R_{CB}) and contribution each region has in relation to national SAIDI (R_{CD}) and SAIFI (R_{CI}).

If we apply expression (43) & (44) to the results obtained from Table 13, the overall funding allocation and reliability hurdle rates is represented by Table 14.

Table 14: Overall regional reliability hurdle and funding allocation

	Hurdle Rate (SAIDI (min) per R (m))			
	Funding (R million)	Single RRHR	Reward RRHR	Penalty RRHR
Region 1	213.34	2.44	1.63	1.63
Region 2	60.33	4.11	2.74	2.74
Region 3	48.88	6.08	4.05	4.05
Region 4	67.15	5.61	3.74	3.74
Region 5	90.64	8.21	5.48	5.48
Region 6	19.66	12.86	8.58	8.58
National Avg		6.55	4.37	4.37

5.3. Sensitivity Analysis

Sensitivity analyses were carried out in Excel in order to assess the influence of various factors, such as dead-band width, clamping limits and funding allocation on the reliability hurdle rate. Variations of the reliability hurdle rate were studied for the six regions within Eskom Distribution South Africa. Three scenarios are presented when considering the influence of the characteristic parameters of the reward / penalty scheme on the single and reward / penalty hurdle rate. The following characteristics were varied within this section:

1. Dead band;
2. Clamping limits;
3. Allocation of funding.

5.3.1. Scenario 1- Varying the dead band width

Figure 26 below illustrates the sensitivity of the regional reliability hurdle rate when varying the dead band for all six regions within South Africa. The graph on the left-hand side illustrates a minimum dead band with a minimum slope where $m_{RHR,}$ m_2 and m_1 are equal. The area indicated by $A\hat{X}_1C$ and $E\hat{X}_5C$ for the reward and penalty areas are equal because the scheme is symmetrical.

The graph on the right illustrates a maximum dead band width with a maximum slope where A_3 and A_4 are zero. The dead band has no influence on the single reliability hurdle rate, but the reward and penalty hurdle rate reaches a maximum when the dead band reaches the clamping limits prescribed by A and E, as illustrated in Figure 26. If A3 and A4 are supposed to compare to A1 and A2 in Figure 26, then no dead band results in zero A1 and A2, while for maximum dead band, A3 and A4 results in zero.

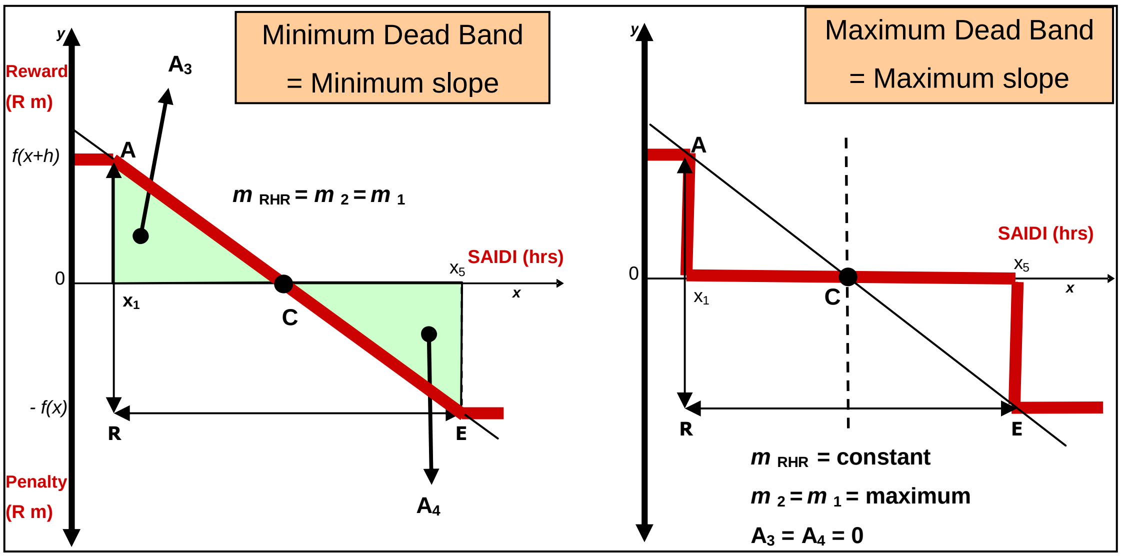


Figure 26: Sensitivity of the dead band on the hurdle rates

In Figure 26 the clamping limits (A and E) are fixed with a 15% variation from the target performance prescribed by C. A decline in the reward / penalty hurdle rate ($m_2 = m_1$) can be seen as the variation moves towards the clamping limits (A and E).

Region 6 has the largest hurdle (i.e. 12) for a fixed dead band of 1% and Region 1 has the smallest hurdle (i.e. 2) for the same variation, as illustrated by the result in Figure 27.

Since the dead band does not influence the single reliability hurdle rate (m_{RHR}), the effect of the hurdle rate is a function of the variables, such as clamping limits and funding allocation. The influence on hurdle rate will be demonstrated with the next scenarios.

Implementing a single hurdle rate for all regions will therefore result in an error with a large variation. The line graph Delta R6 – R1 in Figure 27 illustrates the difference between the outlying Region 1 and Region 6.

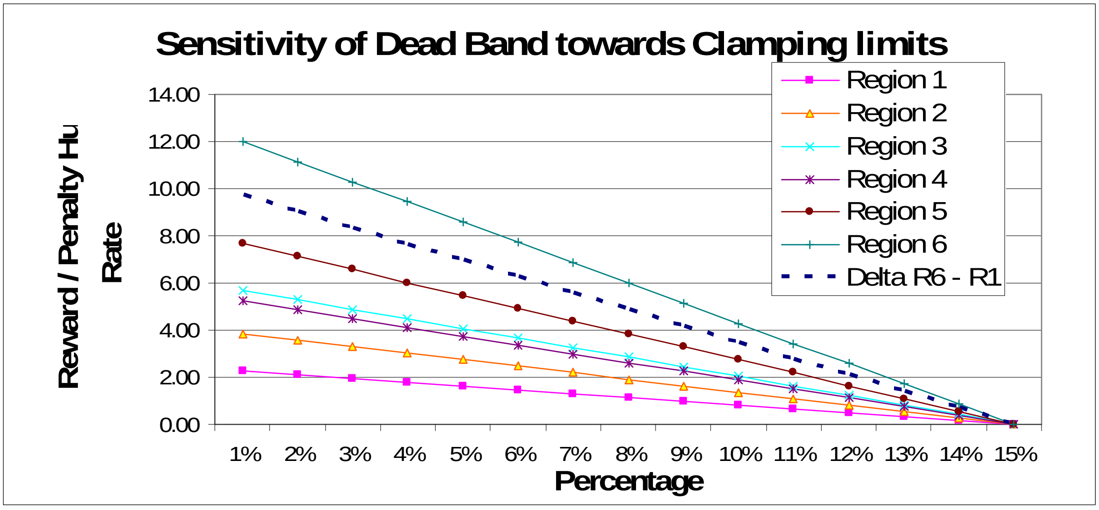


Figure 27: Results for the variation of the dead band

5.3.2. Scenario 2 - Varying the clamping limit

Figure 28 illustrates the sensitivity of the regional reliability hurdle rate when varying the clamping limit for all six regions within South Africa. A fixed dead band of 5% (A''') is applied from the mean performance prescribed by C.

Figure 28 shows how the single reliability hurdle rate increases as the clamping limit is varied from A''' to A and E''' to E.

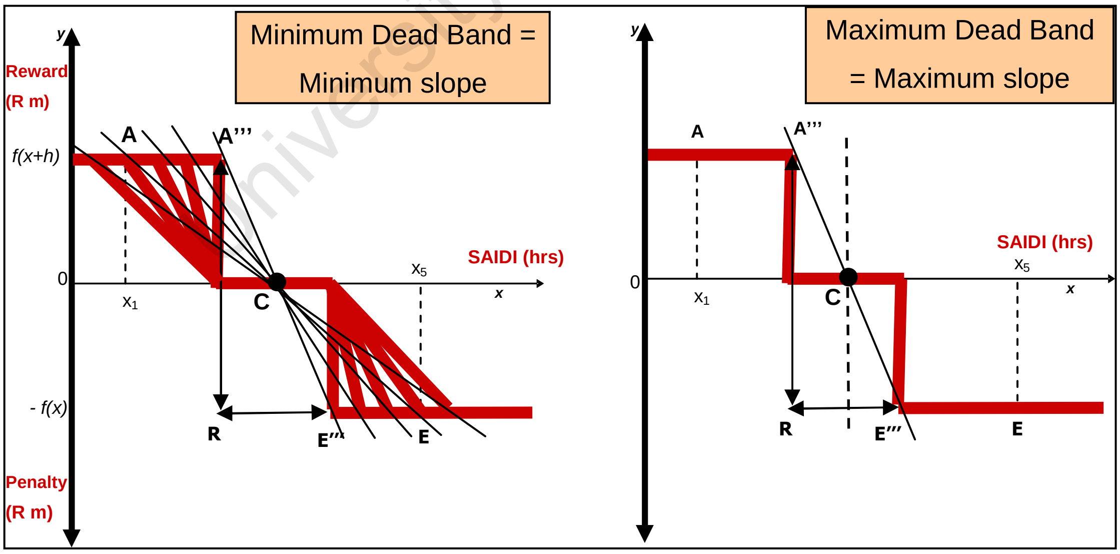


Figure 28: Varying the clamping limits

The results illustrated in Figure 29 show that Region 6 is very sensitive to variation of the clamping limits. The single hurdle rate in Region 6 varies from less than 5 to greater than 15 for a variation of 5% to 20% of the clamping limits from the target performance. On the other hand, Region 1 varies from 0.81 to 3.26 for the same variation of the clamping limits.

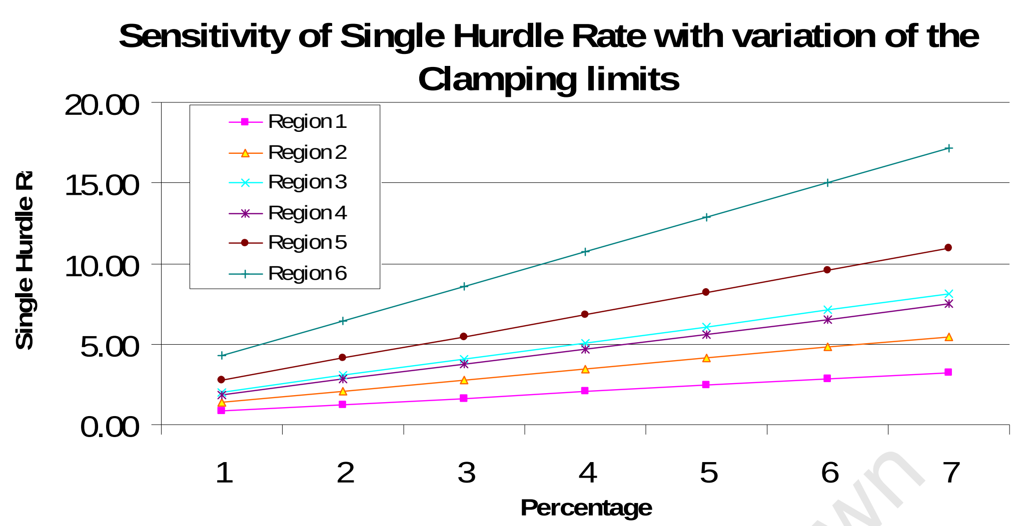


Figure 29: Results for varying the clamping limit on the single hurdle rate

The results illustrated in Figure 30 show the variation of the reward and penalty hurdle rate, with variation of the clamping limits. From Figure 30 it is apparent that the reward / penalty hurdle rate vary from 0 to 12.86 for Region 6 and Region 1 varies from 0 to 2.44 for the same variation of the clamping limits (i.e. from 5% to 20% from the mean performance target).

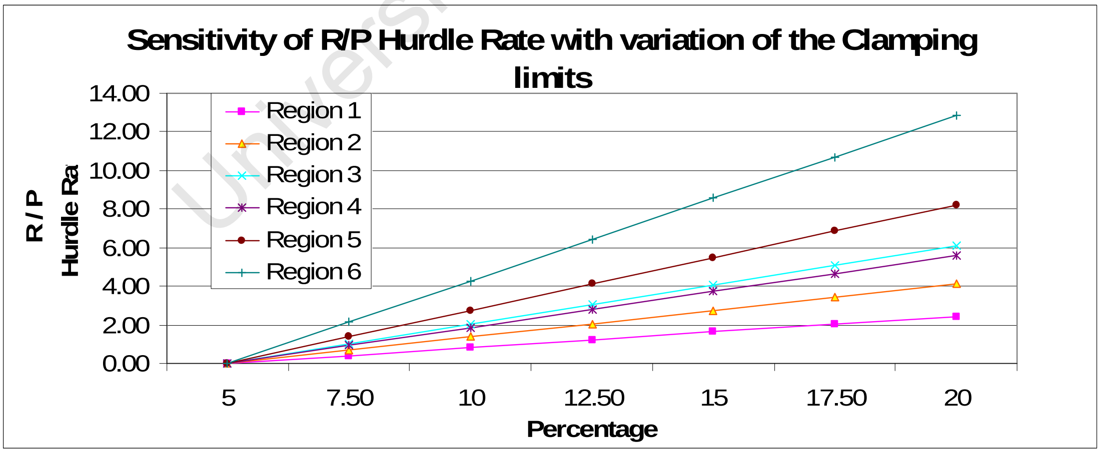


Figure 30: Results for varying the clamping limit on the reward / penalty hurdle rate

Figure 31 shows the incremental difference between the outliers (Region 1 and Region 6) when the clamping limits are varied for the single hurdle rate. The difference ranges from 4 to 14 as the clamping limit varies in relationship to the target performance prescribed by C. The average of all the regions has a smaller difference when changing the clamping limits from 5% to 20% of the mean performance.

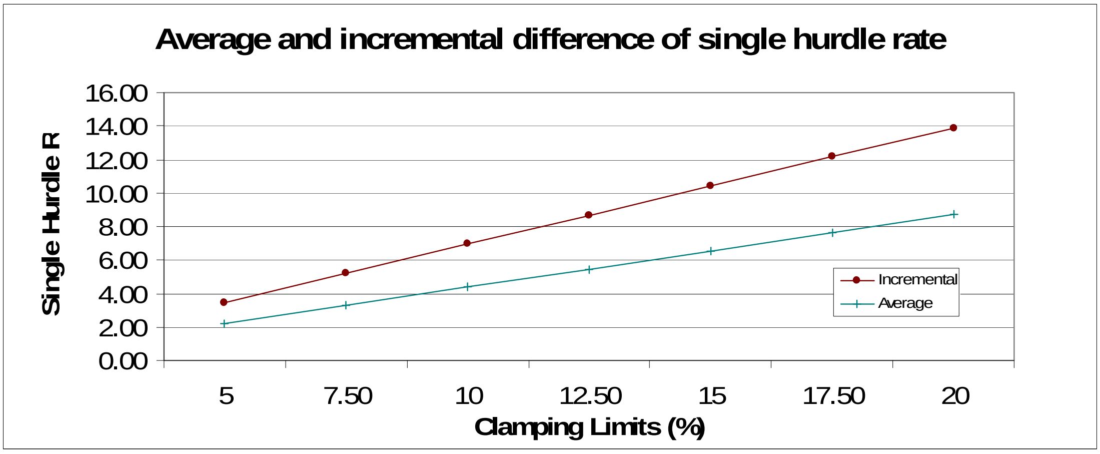


Figure 31 : Results to incremental difference between Region 1 and Region 6

5.3.3. Scenario 3 - Varying the allocation of funding

If we consider the reward / penalty scheme illustrated in Figure 32, varying allocation of funding ($y_1 = y_2 = \Delta y_t$) will influence the clamping limits and slope between A and E.

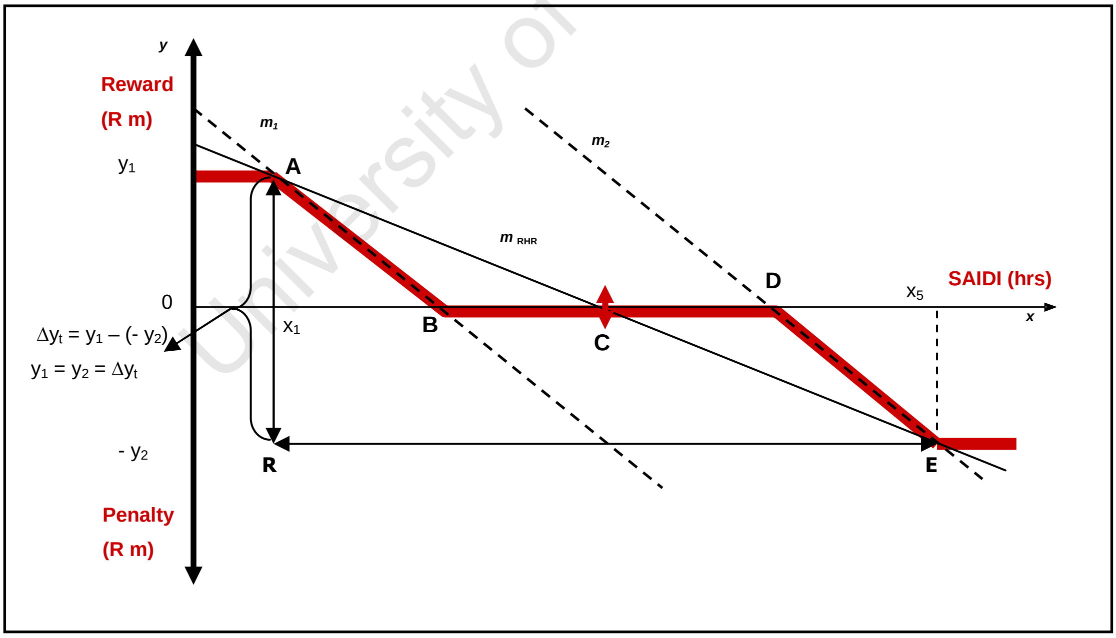


Figure 32: Incremental change in hurdle rate with budget increase

Figure 33 illustrates the sensitivity of the regional reliability hurdle rate when varying the allocation of funding towards reliability expenditure for all six regions within South Africa. From Figure 33 it is clear that the Region 1 is strongly influenced by the variation in the allocation of the funding, where the variance is smaller for the other regions.

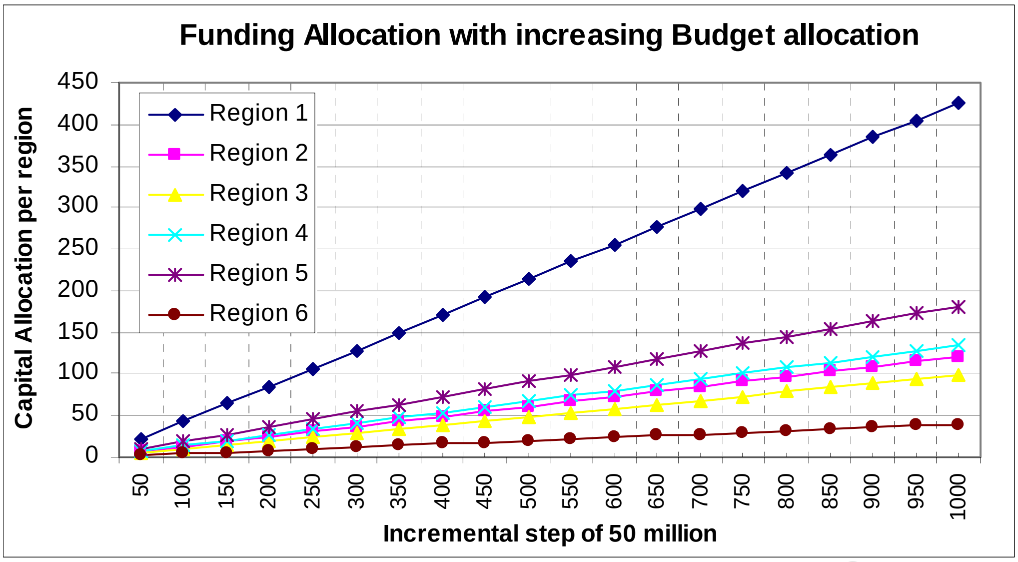


Figure 33: Funding allocation with increasing budget allocation

In Figure 34 a plot of the sensitivity for all six regions shows the influence of the variance of the budget allocation on the single reliability hurdle rate.

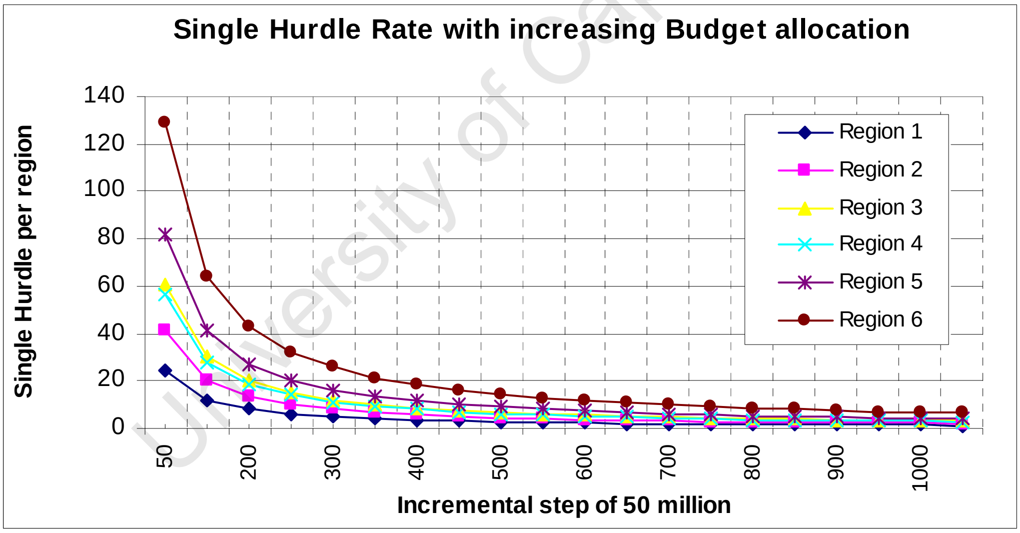


Figure 34: Single reliability hurdle rate with increasing budget allocation

In **Figure 35** it can be seen that, when considering the outliers (namely Region 6 and Region 1), the incremental change reaches a saturation point at a funding allocation of approximately R550 million and R600 million for a single change and reward / penalty reliability hurdle rate respectively. A variation of less than 1 is defined as the saturation point where the incremental difference between the outliers is less than 1.

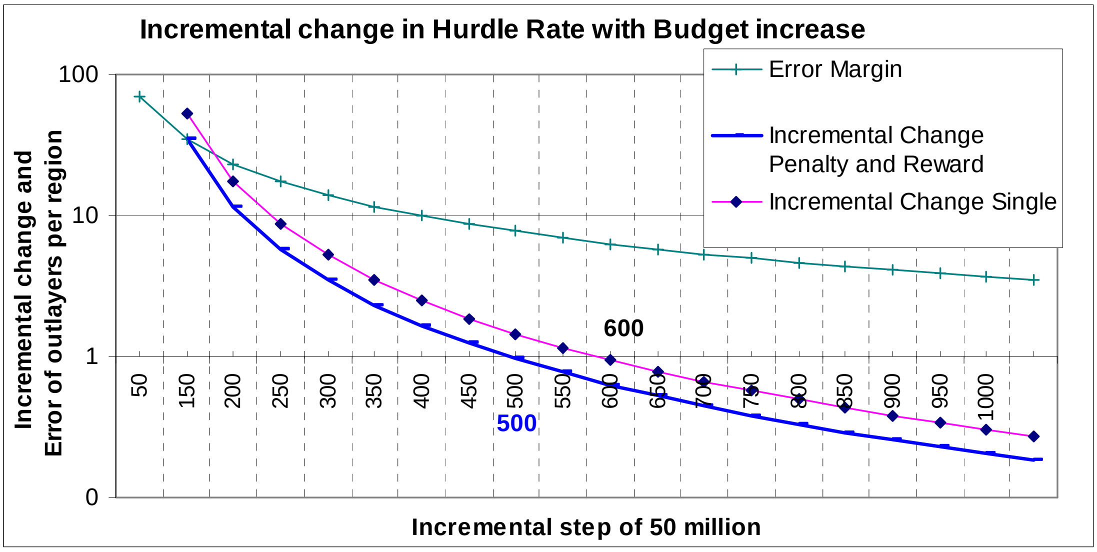


Figure 35: Incremental change in reliability hurdle rate with budget increase

5.4. Conclusion:

This chapter has outlined the theoretical basis for the estimation of the regional single and reward / penalty reliability hurdle rate derived from the national reward / penalty scheme introduced by NERSA. It proved the basis for the comparison of the hurdle against the benefit derived by the alternatives evaluated to improve the overall reliability of the network identified. The expression derived was applied to the six regions within the Eskom Distribution supply area. The chapter has discussed the related difference between the estimation of reliability worth against benefit-to-cost analysis for the evaluation of investment projects. It is the latter concept that is more relevant in the evaluation of reliability improvement projects if we consider the reward / penalty scheme. Application of the equations proposed in this chapter was utilised to derive the reward / penalty scheme for each region. It further derived the single and reward / penalty reliability hurdle rate per region.

The next step is to carry out sensitivity analysis on the shape of the reward / penalty scheme to observe the influence on reliability hurdle rate for each region. The variation of the characteristics clearly illustrate that the selection of the parameters has a large influence on the reliability hurdle rate per region. It is observed that the variation dead band does not influence the single reliability hurdle rate. This is not observed when the clamping limit was varied, which illustrated the single and reward / penalty reliability hurdle rate.

6. Assessing the hypothesis:

This thesis focused on the development of a regional reliability hurdle rate to provide decision criteria to accept or reject a proposed investment project to improve overall continuity of supply to the end customer. An important feature of this thesis is that it considered the reward and penalty scheme adopted by NERSA to develop a reliability hurdle rate. Traditionally, regulators have provided the electricity utility with funding to improve overall continuity of supply but ignored the influence of the funding and target required from the investment decision made. In contrast, this thesis focuses on the issues of how to determine the preferred alternative. It has demonstrated by comparing the investment decision against the reliability hurdle rate will improve the decision-making process for reliability improvement projects.

The thesis explored the different aspects that will influence the development of the reliability hurdle rate. Chapter two and three provide the foundation of the development reliability hurdle rate and serve as the literature chapters. Chapter two centred around the quality regulation techniques adopted by different national regulators world wide. Special attention was given to reward and penalty schemes adopted within South Africa. Chapter three then continued with the project evaluation techniques utilised to select the preferred alternatives. It further investigated the use of benefit-to-cost analysis and life cycle costing principles. This is used as basis for the development of $SAIDI_{BCA,}$ which is extended to the reward and penalty scheme. Chapter four proposes a decision-making process to address the challenge around selecting the preferred alternative to improve the overall continuity of supply indices. Chapter five develops the reliability hurdle rate and demonstrates the calculation based on the six regions within South Africa.

The hypothesis for this thesis was that:

"A regional reliability hurdle rate is related to and can be estimated from the national reward and penalty scheme introduced by the National Electricity Regulator of South Africa, and that the selection of the preferred reliability improvement alternative based on the hurdle rate, will result in a change of the decision-making process."

The hypothesis had two main parts namely:

a) *A regional reliability hurdle rate is related to and can be estimated from the national reward and penalty scheme introduced by the National Electricity Regulator of South Africa,*

Chapter five, clearly demonstrated that it would be possible to derive the regional reliability hurdle rate from the national reward / penalty scheme proposed by the national electricity authority of South Africa. The proposed method derived the shape of the regional reward / penalty scheme from the contribution of the regional performance to the national continuity of supply indices (especially: SAIFI and SAIDI). Added to this is the customer base served by each region, which is used as another variable. These variables are utilised to allocate the funding for each region from a fixed national reliability funding. After the reward / penalty scheme is derived for each region the single reliability hurdle rate (m_{RHR}) is estimated from the gradient. The regional reliability hurdle rate represents the minimum benefit for the investment decision to improve the reliability within each region.

b) *that the selection of the preferred reliability improvement alternative based on the hurdle rate, will result in a change of the decision-making process*

Clearly a key part of the process of investment decision is to consider the proposed method to develop a reliability hurdle rate. It can be concluded that it is possible to incorporate the reward / penalty scheme into the reliability decision-making process discussed in Chapter 4. This assists with the selection of the preferred alternative to improve overall continuity of supply of the network investigated.

Therefore, the hypothesis is valid and flowing from the validity of the hypothesis is a method that is appropriate where national electricity regulators have adopted a reward and penalty scheme. The application of this method within South Africa will prevent the overinvestment in networks, which does not improve the overall continuity of supply of the regional or national indices. This is achieved by estimating the reliability hurdle rate which provide an accept and reject criteria for investment decisions.

Finally, even though the proposed method determines the regional reliability hurdle rate, the lack of detailed analysis in the determination of the reward and penalty scheme remains a challenge when certain decisions by the national regulator are not supported by any scientific methods. It is imperative that national regulators ensure that the provision of funding and targets are assessed carefully.

The thesis is still valid in context of loadshedding within South Africa because any major events and loadshedding is not included in the continuity of supply indices for regulating purpose. Reliability improvement projects on distribution level will not assist in the generation shortage experience currently within South Africa.

The validity of the hypothesis indicates that further development of concepts and rules is needed for the electricity distribution industry and national regulators.

The work carried out in this thesis serves as a basis for subsequent research within the field of the project evaluation process and the reliability decision-making process. It is clear that further research is required to remove the uncertainties of certain input variables.

Future work includes the following:

- The real cost of interruption is only imperfectly known and the method cannot be accurately represent the social and economic impact of interruption. Better customer interruption cost data can be built into model and will affect the allocation of funding, presently allocated in proportion to the customer numbers and the interruption indices.

- A further study might be required on the development of a method of determining the target continuity of supply indices and the shape of the reward and penalty scheme adopted by the national regulator authorities, since these do not yet appear to be derived rigorously.

- Although the results of the development of the regional reliability hurdle rate so far are encouraging, there is still scope for further improvement to investigate the development of a reliability hurdle rate for asymmetrical reward and penalty schemes, in case the Regulator changes the specification.

7. REFERENCES:

[1] M.A. Van Harte, C.T. Gaunt, C. Carter-Brown, “Introducing Reliability Based Distribution Network Planning In South Africa”, 18th International Conference on Electricity Distribution, Turin, 6-9 June 2005

[2] M.A. Van Harte, C.T. Gaunt, “Challenges for reliability regulation in a Developing country”, CIGRE SC-C6 (COLL 2006), South Africa, 2006

[3] M.A. Van Harte, C. Carter-Brown, “The application of Reliability Methodology to select and prioritise Eskom Distribution Networks”, 19th International Conference on Electricity Distribution, Vienna, 21-24 May June 2007

[4] R.N. Allan, R. Billinton, S.M. Shahidehpour, and C. Singh, “Bibliography on the Application of Probability Methods in Power System Reliability Evaluation 1982-1987”, IEEE Transactions on Power Systems, vol. 3, no. 4, November 1988, pp. 1555-1564

[5] G. Tollefson, R. Billinton and G. Wacker, “Comprehensive Bibliography on Reliability Worth and Electrical Service Consumer Interruption Costs: 1980-1990”, IEEE Transactions on Power Systems, vol. 6, no 4, November 1991, pp. 1508-1514

[6] R. Billinton, G. Wacker, and E. Wojczynski, “Comprehensive bibliography on electrical service interruption costs,” IEEE Trans. Power Apparat, Syst., vol. PAS-102, no. 6, pp. 1831–1837, June 1983.

[7] R. Billinton, R.N. Allan, L. Salvaderi, “Applied Reliability Assessment in Electric Power Systems”, IEEE Press, New York, 1990.

[8] V. Ajodhia, “Cost, Reliability and Regulation in Electricity Networks: Mapping The Issues”, IEE Power System Management and Control, IEE, No.488, 2002,

[9] R.M. Godfrey, R. Billinton, “Guide to Value-Based Distribution Reliability Planning Volume I”, Canadian Electricity Association, 3-46 – 3-51, 1996,

[10] J. Woodhouse, “Asset Management Decision-Making”, The Woodhouse Partnership Ltd, June 2001

[11] Department of Minerals and Energy, “White Paper on the Energy Policy of the Republic of SA”, 1998

[12] National Electricity Regulator of South Africa, “Economic Regulation of Distribution using incentive-based Regulation”, 2003

[13] National Electricity Regulator of South Africa, “National Electricity Distribution Industry Maintenance Summit”, Volkswagen Conference Centre, 18 Nov2003

[14] S. Lindgren and K.B. Mortensen, "Deregulation-Management-Organisation-Skills", Special Report, 18th International Conference on Electricity Distribution, Turin, 6-9 June 2005

[15] Cigré Study Committee SC36, "Special Report", Paris Session, 2002

[16] Council of European Energy Regulators "Third Benchmarking Report on Quality of Electricity Supply 2005", Quality of Supply Task Force, C05-QOS-01-03, 06 December 2005

[17] IEEE Power System Planning and Implementation Committee, "Planning for Effective Distribution" IEEE Power & Energy Magazine, pp. 54–62, Sept/Oct 2003.

[18] V.S. Ajodhia, "Reliability regulation in Europe: compatible with optimal cost/reliability approach?", Distributech Europe 2001, Berlin, 2001

[19] G. Szorenyi, "Third Benchmarking Report on Quality of Electricity Supply 2005" QOS Task Force, Council of European Energy Regulators, 06 December 2005.

[20] J. Bargiel, W.G. Sowa, J. Paska, "Problems of Reliability and Power Quality Assessment in Polish Electric Power System", IEEE, 2000.

[21] S. Lindgren and K.B. Mortensen, "Special Report for Session 6: Deregulation – Management – Organisation - Skills", CIRED Conference, Turin - Italy, 06-09 June 2005.

[22] U. Shortall, "Regulatory Benchmark Report 2005 confirms the shortcomings of effective regulation in member states" QOS Task Force, Council of European Energy Regulators, CEER Press Release, 27 January 2006.

[23] U. Shortall, "European Energy Regulators report fewer electricity supply interruptions and call for better service for customers" QOS Task Force, Council of European Energy Regulators, CEER Press Release, 26 January 2006.

[24] R.E. Brown and M. Marshall (2000), "Budget Constrained Planning to Optimise Power System Reliability", IEEE Trans. on PWRS, Vol. 15, No. 2, May. 2000, pp. 887-892.

[25] R. Billinton and R.N. Allan, "Reliability Issues in Today's Electric Power Utility Environment", IEEE Trans. on PWRS, Vol. 12, No. 4, Nov. 1997, pp. 1708-1714.

[26] A.A. Chowdhury and R. Billinton, "Value-based distribution system reliability planning", IEEE Trans. Industry Applications, vol. 34, no.1, pp. 23-29, Jan. 1998

[27] A. Robert, (2001), "Quality Issues for System Operators with Special Reference to European Regulators", CIRED Conference, Amsterdam, 19-21 June 2001.

[28] National Electricity Regulator, "NRS048-2 Electricity Supply- Quality of Supply Part 2: Voltage Characteristic, compatibility levels, limits and assessment methods", 2003.

[29] R. Billinton, R.N. Allan, "Reliability Evaluation of Power System", Pitman Books, New York and London, 1984

[30] NERSA, "Economic regulation of Distribution using incentive based regulation", December 2003

[31] NERSA, "Regulatory Framework for the Economic Regulation of the Electricity Supply Industry in South Africa", July 2002

[32] V.S. Ajodhia, "Regulating electricity networks: Yardstick Competition and Reliability of Supply", 22nd USAEE/IAEE North American conference, Vancouver, 2002.

[33] V.S. Ajodhia, "Regulating Electricity Distribution Network Quality", Science & Technology Policy Programs Meeting, School of Public Policy, George Mason University, 2003

[34] L Lo Schiavo, R Malaman & F Villa, "Continuity of Electricity Supply Regulation Driven by Economic Incentives: Does it Work? The Italian Experience", paper no 152, 18th International Conference on Electricity Distribution, Turin, 6-9 June 2005

[35] R. Koch, D Conradie, " Executive brief: Proposed NERSA Incentive Framework for Eskom Distribution", Eskom Distribution, 26 April 2005

[36] R. Koch, D Conradie, B Chatterton, "Initial comments on the proposed NERSA incentive framework for Eskom Distribution network interruption performance", Eskom Distribution, 20 November 2005

[37] M.P Masemola, "Universal Access Plan", Energy Summit 2007, Sandton Convention Centre, Johannesburg, South Africa, 26 September 2007

[38] L. Goel, R. Billinton, "Determination of Reliability Worth for Distribution System Planning", IEEE Transactions on Power Delivery, Vol.9, No. 3, 1577-1583, 1994.

[39] R. Billinton and P. Wang, "Distribution system reliability cost/worth analysis using analytical and sequential simulation techniques," IEEE Trans. Power Systems, vol. 13, no. 4, pp. 1245–1250, Nov. 1998.

[40] NERSA, "RSA Distribution Code: Distribution Network Code", 2007

[41] NERSA, "RSA Distribution Code: The Distribution Tariff Code", 2007

[42] ESK ADAAX4, "Reserve, Redundancy and reliability standards, criteria and targets", Eskom Directive, Revision 01, 2005.

[43] T.W. Berrie, "Power System Economics", IEE Power Engineering Series 5, 1st Edition, Peter Peregrinus Ltd, London, 1983

[44] Carter-Brown, C, "The role of financial and economic analysis in Distribution capital project evaluation", Eskom Distribution, 13 March 2005.

[45] Kailasanathan. A, "Financial Evaluation Model – Help", Excel spreadsheet

available from, KailasA@eskom.co.za.

[46] Schoeman, J. J, "Capital Investment in Distribution: What needs to be included in the Investment Proposal of a capital project?", Eskom Distribution, 2005, Financial Planning and Performance Manager – Northern Region.

[47] Godfrey, R.M., Billinton, R., "Guide to Value-Based Distribution Reliability Planning: Volume 1", Canadian Electricity Association Report, CEA 273 D 887, January 1996.

[48] Tsao, T-F., Chang, H-C., "Comparative Case-Studies for Value-Based Distribution System Reliability Planning", Electric Power Systems Research, Vol. 68, 2004, pp. 229-237.

[49] Barringer, H. Paul, "Why You Need Practical Reliability Details To Define Life-cycle Costs For Your Products and Competitors Products!", [Online] www.barringer1.com.

[50] The Institute of Asset Management, "International Infrastructure Management Manual", United Kingdom Edition, November 2002.

[51] E. F. Brigham, "Financial Management: Theory and Practice Third Edition", The Dryden Press, New York, 1982

[52] P. A. Samuelson, "Economic : Ninth Edition", Mc Graw-Hill Kogakusha Ltd, 1973

[53] M. Bala, "Capital Budgeting In Electricity Distribution Industry In Eskom Moving Into Regional Distributors", Degree of Master of Science in Engineering at UCT, 18 March 1999

[54] A Kailasanathan, "Development of an economic evaluation tool for comparing alternative electrification options", Degree of Master of Science in Engineering at UCT, 18 March 1999

[55] P. Eiffert, "Guidelines for the Economic Evaluation of Building-Integrated Photovoltaic Power Systems", Technical Report: NREL, U.S. Department of Energy Laboratory, January 2003

[56] W. J Fabrycky, B.S. Blanchard "Life-Cycle Cost and Economic Analysis", Prentice Hall, 1st Edition, Peter Peregrinus Inc, U.S, 1991

[57] R.E. Brown and M.M. Marshall, "Budget constrained planning to optimize power system reliability", IEEE Trans. Power Systems, vol. 15, no. 2, pp. 887–892, May 2000.

[58] P. Wang and R. Billinton, "Reliability Benefit analysis of adding WTG to a distribution system," IEEE Transactions on Energy Conversion, Vol. 16, No. 2, June 2001

[59] IEC60300-3-3, "Application Guide - Life cycle costing", 2004-07

[60] ISO15663 - 2, "Guidance on application of methodology and calculation methods", 2001

[61] NORSOK O-CR-001, “Life cycle cost for systems and equipment”, April 1996

[62] NORSOK O-CR-002, “Life cycle cost for production facility”, April 1996

[63] IEC60300-3-1, “Analysis tchniques for depndability: Guide on methodology”, 2004-07

[64] IEC60300-3-2, “Collection of depndability data from the field”, 2004-07

[65] IEC60300-3-9, “Risk analyis of technolgical systems”, 2004-07

[66] SAE ARP-4293, “Life cycle cost - Techniques and applications”, 1992

[67] R.M. Godfrey, R. Billinton, “Guide to Value-Based Distribution Reliability Planning Volume I”, Canadian Electricity Association, 1996

[68] R. Billinton, R.N Allan, “Reliability Assessment of Large Electric Power Systems”, Pitman Books, New York and London, 1988

[69] M. Munasinghe, 1979, The Economics of Power System Reliability and Planning. The World Bank, John Hopkins University Press, Baltimore, MD.

[70] K.K Kariuki, R.N Allan, 1996, “Evaluation of Reliability Worth and Value of Lost Load”, IEE Proc-Gener. Transmission and Distribution, Vol.143, No. 2, 171-180.

[71] R. Brown, “Electrical Power Distribution Reliability”, Marcel Dekker Inc, Power Engineering Series, New York 2002, 256-265.

[72] J.G. Lonsdale, G.H. Hitchen, “Reliability Evaluation in the Planning of Distribution Systems”, Third International Conference on Reliability of Power Supply Systems 1983, 1983, September, 77-80, IEE, London.

[73] M.A. Van Harte, 2005, “Introduction Reliability Based Distribution Network Planning in South Africa”, CIRED 2005.

[74] J.A.K. Douglas and F. Castro Sayas (2003), "Setting of Targets for Continuity of Supply through Benchmarking", 17th CIRED Conference, Barcelona – Spain, Session 2, No. 78, 12-15 May 2003.

[75] C. Feinstein, P. Morris, 2001, “A Review of Reliability of Electric Distribution System Components: EPRI White paper”, EPRI-1001873, California.

[76] A.C. Courtland, R.G. Charles, “Enigneering Economic & Cost Analysis”, Prentice Hall, New York, 3rd Edition, 20 Aug 1998

Appendix A: The use of the Financial Evaluation Model (FEM) [46]

The introduction of discount cash flow analysis investment techniques some time ago did a lot to give credibility to the process of investment analysis. Investment evaluations will have value if the various technical alternatives that are considered, are compared to each other over the life-cycle of the project.

The FEM tool is a discounted cash flow application to evaluate investment projects within Eskom Distribution (FEM model – Author: Henk Martens). This is quite a complex model and gives a fair representation of the actual application of the various tariffs and cost of purchases.

In applying the model, it is necessary to note and to apply the following:

- Life-cycle: The model makes provision for the evaluation of projects over different time periods. The typical life-cycle for new work projects such as a supply to a new customer, is 25 years, which more or less reflects the economic lifetime of the investment. This typically represents the time period within which a capital investment will be able to provide a return on the initial investment with normal operating and maintenance expenses as a cash outflow. Electrification projects are assessed over a life-cycle of 15 years. Business improvement projects are assessed over a life-cycle of at most 5 years. The life-cycle of refurbishment projects (Assets older than its economic lifetime – normally 25 years) will depend on the economic lifetime of the operations of the end users. If we have a gold mine as the end user, for example and the shaft taking electricity will be in operation for another 15 years with no prospect of a new shaft that may pick up the load, such refurbishment life cycle of the electricity supply will then be limited to the 15 years only.

- Operating and maintenance costs. As mentioned earlier the operating and maintenance costs are based on an average rate per tariff class. This is included in the model as a Reliability Service Charge (Energy based) and a Distribution

Network Charge (Demand based). Where project alternatives are compared with the same load and energy profiles over the life-cycle, the project presenter need to make a call whether there will be a difference between the operating and maintenance cost profiles of the various alternatives. The FEM model have an option on the summary page to include cash flows other than the standard or fixed cash elements (Capital, revenue, ops/maintenance) Should any of the alternative investment options require either more or less operating and maintenance funding over the project life-cycle, this difference can be included in the calculations by using the "Cost Saving" facility on the Summary Page. (Just enter values with a minus to include it as an expense. For savings enter the values as positive entities)

- When the presenter populates the demand and energy data fields over the project life-cycle, it would be prudent to allow for market cycles where it is possible to determine it with reasonable assurance. Other possible changes in the sales/demand profile during the project's life-cycle can be considered to reflect the customer's own regular planned maintenance programmes.

- It is acceptable to use the current income stream from the existing customer base being fed from a network that's to be refurbished. However, it must be noted that network refurbishment in most instances will not include the refurbishment of all the reticulation lines and transformers to all end users being fed from the network being refurbished. It is therefore recommended to reduce the life-cycle of the refurbishment investment to a reduced maximum time period of 15 years only.

- When strengthening projects are presented as investment proposals, the presenter will make certain assumptions on the category and number of customers that will in future take electricity supply from the network. The extent to which this can be allowed will depend on the capacity limitation that is inherently contained in the network configuration. The following will give some illustration of this. If a substation is extended by the addition of a 20 MVA transformer, but the transfer capacity of the line can only accommodate an extra 15 MVA, then the 'assumed new load' cannot exceed 15 MVA. The proposed new load profile growth over the years must be supported by realistic assumptions or historical evidence of recent growth patterns. The philosophy applied here is that all capital required to be invested to enable the utilisation of the increased capacity from the network strengthening will be recovered from the various individual customers by means of capital charges.

- There are many instances where network refurbishment projects also include a strengthening portion. Our recommendation would be to limit the life-cycle of such projects to a maximum of 15 years and to apply the same philosophy in the assumptions on new loads. (Take inherent limits of the network into account when assuming additional future loads from new customers or growth from existing customers.)