THE ECONOMIC ANALYSIS OF

RELAXING FREQUENCY CONTROL

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Declaration

I declare that this thesis is my own, unaided work. It is being submitted for the Degree of Doctor of Philosophy in the University of the Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination in any other University.

_Eighth__ day of _March____2007___

Abstract

Frequency control of interconnected networks is the constant matching of supply and demand. When supply exceeds demand the frequency increases and *vice versa*.

This thesis proposes that economic benefits can be obtained if the frequency control is relaxed. A generic algorithm is presented with the methodology, modelling and economic calculations required to analyse the economic benefits. The generic economic benefits algorithm has been designed for the initial economic analysis or re-analysis of frequency control in any interconnection and proposes monitoring methods to ensure that the optimal performance is maintained. This is applicable to all generator types or sizes in the network, the state of deregulation of the electricity industry or load types. The methodology for the economic frequency control relaxation analysis was published in the IEEE journal "Transactions on Power Systems" in August 2004.

When this methodology was applied to frequency control of the Southern African interconnection, the frequency control was relaxed from controlling to a standard deviation of 30 mHz to a standard deviation of 75 mHz. This change resulted in an 80% reduction of generator movement in Eskom without affecting the consumer, and related to an estimated saving of R 22m per annum. The methodology also led to an improved real time dispatch, improved performance monitoring and a qualitative assessment of the risks involved with frequency control.

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Definitions and Abbreviations

ACE	Area control error
AGC	Automatic generation control
BPC	Botswana Power Corporation
EDM	Electricidade de Mozambique
EMS	Energy management system
EPP	Eskom Power Pool
ERCOT	Electric Reliability Council of Texas
Eskom	(not an abbreviation - electric utility of South Africa)
HCB	Hydroelectrica de Cahora Bassa
LEC	Lesotho Electricity Corporation
LFC	Load frequency control
MCR	Maximum Continuous Rating
NERSA	National Energy Regulator of South Africa
NERC	North American Energy Reliability Council
PLC	Programmable logic controller
RTU	Remote terminal unit
SAPP	Southern African Power Pool
SCADA	Supervisory control and data acquisition

SMP	System marginal price
TLBC	Tie-line bias control
UCTE	Union for the Co-ordination of Transmission of Electricity
UFLS	Under-frequency Load Shedding
ZESA	Zimbabwe Electricity Supply Authority
ZESCO	Zambia Electricity Supply Corporation

Chapter 1 : Introduction

Basic background and thesis outline

1.1 Introduction

This chapter describes the basics of frequency control, and presents the objectives, contribution and hypothesis of this thesis. The final section of the chapter outlines the structure of this thesis.

The thesis analyses the economic benefits of relaxing frequency control and the practical application of frequency control relaxation to the Southern African interconnection with the resulting economic benefits.

Frequency control for this thesis covers all the control options required to manage frequency, such as primary frequency control, Automatic Generation Control (AGC) and customer automatic under-frequency load shedding. The generic economic benefits algorithm is designed for the initial economic analysis or re-analysis of frequency control in any interconnection. This is applicable to all generator types or sizes in the network, the state of deregulation of the electricity industry or load types. The methodology for the economic frequency control relaxation analysis was published in the IEEE journal “Transactions on Power Systems” in August 2004 (Chown G.A. and Wigdorowitz B., 2004). For this thesis the PSS/e© studies were done by Mike Coker and the PROMOD© studies were done by Dr John Dean.

The findings of applying the generic economic algorithm to the Southern African network resulted in development and implementation of a different, more economical frequency control design. This demonstrated that the generic algorithm provided in this thesis is not only theoretical but is also a practical contribution to engineering.

1.2 Basic description of frequency

Electrical power systems vary in size and structural components. However, they all have the same basic characteristics and are comprised of three phase ac systems essentially at constant voltage (Kundur, 1994).

The function of an electrical power system is to convert energy from one of the naturally available forms to the electrical form and to transport it to the points of consumption. The advantage of electricity is that it is transported and controlled with relative ease and with a high degree of efficiency and reliability. A properly designed and operated power system should at least meet some fundamental requirements. One of these fundamental requirements is that the power supply should meet certain minimum requirements with regard to constancy of frequency (Kundur, 1994).

The variation in frequency indicates the mismatch between supply from the generators (power plants) and the customers' demand. If demand equals supply, then the frequency is constant. If demand begins to exceed supply, the frequency drops. The drop of the frequency results in motors running slower, thus using less power. Consequently, the demand drops to meet supply. There is no storage of electrical power, so every time a customer switches on or off, the frequency will change.

The current frequency on the network is changed by either changing the generators' real MW output or by changing the customers' consumption.

1.3 Objectives of the thesis and the contributions to engineering

The objectives of the thesis are a) to analyse the economic benefits of relaxing frequency control for a network and b) to develop a generic economic algorithm for finding the most economically sound strategy. There are many textbooks (EPRI, 1997; and Kundur, 1994) and articles (Asal *et al.,* 1993; UCTE, 1991; UCTE, 1994; and Nordel, 1995) on the fundamental principles of frequency control and many articles on how frequency control is done for the various interconnections. The limitations of previous work are that a full economic analysis of the complete frequency control problem has not previously been reported. Ilic *et al.* (M. Ilic *et al.*, 2000) in their book on engineering and economics of power system restructuring state *"The bounds to which frequency should be controlled have never been fully justified on either engineering or economic grounds"*. The objectives (a) and (b) of this thesis will address this quote with specific reference to the impact on networks.

There is no subsequent literature to date, apart from papers published by the author [Chown, G.A., 1999; Chown, G.A. and Coker, M.L., 2001; Chown, G.A. and Coker, M.L., 2002; Chown, G.A. and Wigdorowitz, B., 2004), that reports on the economic bounds for frequency control and the economic benefits of relaxing frequency control.

Frequency is common in the interconnection, which means that there are many different parties impacted by frequency changes, from generators, through the network, to the end customer. Each of these parties have their own agenda in terms of how the frequency should be controlled for their own maximum benefit. The problem is to merge these many parties' economic solutions into a common strategy that is transparent and fair to all, giving maximum benefit to all.

The simplest solution from a technical perspective is to control the frequency as tightly as possible and this is often the method adopted. This is not necessarily the best economic solution. When a network is initially set up, traditional control methods are copied from other interconnections. The control of the frequency is difficult when a network is small as there are only a few generators and consumers. This makes frequency control possible only through highly tuned controllers to maintain some reliability in supply. As the size of the network grows, the frequency control strategy remains and a tighter frequency control is achieved. However, the impact of controlling frequency tightly is not reviewed from an economic perspective.

Additionally, the introduction of deregulated electricity industries in Europe, North America and Australia has seen a change in the evaluation of frequency control from a cost to a price perspective. The controllers used for cost perspective have been adapted for the new market format without a complete analysis of the financial impact. To date, no literature has been found reporting calculation of the total cost of frequency control and the economic benefits of relaxing frequency control.

The development of the philosophy on the economic benefits of relaxing frequency control resulted in a different and more relaxed control of the Southern African Power Pool (SAPP) frequency, with reported savings to the Operating Members of SAPP.

Further contributions to engineering in the development of an economic frequency control strategy are:

- *Reducing the interactions between existing controllers, such as Automatic Generation Control and Primary Frequency Control, thereby reducing the control effort.* This implementation in 2002 in the Southern African Power Pool reduced the overall cost of controlling the frequency.

- *Implementing a new real time dispatch for the Eskom Power Pool.* The control strategy reduced the costs of real time dispatch within the internal Eskom Power Pool.

- *Frequency control service providers performance monitoring.* The aim of this was to develop techniques to measure the performance of frequency control service providers.

- *The Southern African interconnection* has not undergone a frequency redesign in its history. The practical implementation of a new, more relaxed frequency control philosophy is also a significant contribution to engineering.

1.4 Hypothesis

Economic benefits, considering the impact of deregulation, for some interconnections can be obtained if the frequency control is relaxed. Further, current control strategies are not optimal as there is a non-economic overlap in the hierarchical structure of the control loops and an overlap between centralised and decentralised control philosophies. With deregulation, the cost of frequency control has changed, thus requiring a re-examination of frequency control targets and objectives. A paper on the methodology to redesign frequency control has already been published in the IEEE (Chown G.A. and Wigdorowitz B. (2004)). This paper mainly focused on the methodology to determine the most economic frequency control strategy and this thesis further builds on the economic benefits of frequency relaxation.

1.5 Contributions to literature

- **Chown, G.A. and Wigdorowitz, B.,** A proposed methodology for the re-design of Frequency Control for AC networks and as applied in Southern Africa, IEEE Transactions on Power Systems, Vol. 19, No. 3, TPWRS.2004.825902, August 2004.

- **Chown, G.A. and Coetzee, M.C.,** Regulation as an Ancillary Service in Eskom, IEEE Transactions on Power Systems, PE-028-PWRS-06-2000, May 1999.

- **Chown, G.A.,** Control of the frequency in South Africa, *Cigre* High and Low Frequency Conference, Midrand, South Africa, September 1999.

- **Chown, G.A. and Coker, M.L.,** Quality of Frequency in Southern Africa and the Impact on Customers, 3rd Southern African Power Quality Conference, Zambia, October 2001.

- **Chown, G.A. and Coker, M.,** Southern African frequency control verification using simulation studies, IEEE Africon 02 Conference, October 2002.

- **Chown, G.A. and Hartman, R.C.,** Design and Experience with a Fuzzy Logic Controller for Automatic Generation Control (AGC), IEEE Transactions on Power Systems, May 1997, PE-143-PWRS-16-09-1997.

- **Chown, G.A.,** Development, Implementation and Optimisation of a Fuzzy Logic Controller for Automatic Generation Control, Master's Dissertation, University of Witwatersrand, December 1997.

1.6 Thesis structure

Chapter 2 is the literature survey of current frequency control methods used by interconnections around the world. The literature survey specifically addresses published material in the area of the research of this thesis. The chapter is concluded by a summary of research that has not been reported on in literature and defines the problem statement for the research.

Chapter 3 presents an overview of the proposed algorithm to determine the economic benefits of relaxing frequency control. This chapter sets out the method proposed to calculate the most relaxed philosophy that gives the best economic solution. Chapters 4, 5 and 6 present the detailed proposed methodology in three stages, applying the methodology to the Southern African interconnection as an example.

Chapter 4 is the first stage in the proposed algorithm, which determines the economic impact and minimum control of large disturbances on the generator, consumer and network. This stage determines the possibility to relax frequency control and sets the boundary conditions for frequency. The output is the minimum control, *i.e.* the boundary for the worst acceptable frequency control; but this may not be the optimal economic solution.

Chapter 5 is the second stage in the proposed algorithm and develops the algorithms for the calculation of cost and benefits of controlling frequency. The calculation of the cost of additional control with the associated cost benefit of tighter frequency control is determined. This phase also looks at cost and benefits of controlling frequency for deregulated environment where the costs and benefits are determined by the market bids and offers. This forms the foundation in determining an optimal economic strategy when relaxing frequency control.

Chapter 6 is the third phase and designs the overall frequency control strategy to determine the most economic relaxed frequency. An equation is developed incorporating all the costs and benefits of frequency control. This phase then explores different frequency control strategies as the frequency is relaxed and thereby determines the optimal economic frequency control strategy. The benefit of additional control on the optimal relaxed solution is studied to determine the savings compared to the additional costs for controlling.

Chapter 7 is the final phase and develops performance-monitoring techniques to ensure optimal control is maintained. Monitoring performance ensures that the frequency control systems are still optimal and suppliers of frequency control services are performing as expected.

Chapter 8 presents a summary of the results and impact on Eskom after relaxing frequency control in SAPP. The frequency control was relaxed in September 2002 and this chapter focuses on the results, which confirmed all the simulation results and validated the proposed methodology.

Chapter 9 is the conclusion of the thesis, and reviews the thesis and results of the research.

Chapter 10 presents the recommendations for further work. The chapter examines improvements that can be made to in the economic algorithm and further work that can be done to determine the benefits of relaxing frequency control.

Appendices discuss the various technical studies, important in the development of an optimal frequency control strategy, that must be considered when evaluating frequency control. These technical studies are steps in the methodology proposed to determine an optimum control strategy (Chown and Wigdorowitz, 2004) and are required to determine the practical possibilities and limitations of control. The appendices also contain the models and simulations used for evaluating frequency control relaxation.

Chapter 2 : Literature Survey

Literature survey on the economic benefits of relaxing frequency control

2.1 Introduction to literature survey

This chapter discusses the literature survey. The first section of the literature survey details the available literature on frequency, frequency control and how various interconnections control their frequency. General information on the interconnection, frequency control techniques and ancillary services relating to frequency control, is discussed. The literature survey indicated that there was no literature that addressed the economic benefits of relaxing frequency control.

The chapter concludes with the problem statement.

2.2 Literature on frequency and frequency control

There are many papers that deal with the different aspects of frequency control. Many textbooks and articles have been written on electrical networks. Each of these has a section on the basics of frequency control. There are national and international standards that define the minimum requirements for the manufacture of generators, motors and electrical equipment, and the quality of frequency of the electrical network. There are also books and papers that cover specific areas of frequency control such as: modelling the network, primary frequency control, Automatic Generation Control, economic dispatch of generators from a cost and market perspective, and frequency control as an ancillary service.

2.2.1 Literature on overall aspects of frequency and frequency control

There are many textbooks (Anderson and Fouad, 1993; EPRI, 1997; Kimbark, 1995; and Kundur, 1994) and articles (Asal *et al.,* 1993; UCTE, 1991; UCTE, 1994 and Nordel, 1995) on the fundamental principles of frequency control. These cover the fundamentals such as how and why the frequency changes, how the traditional frequency control loops such as primary frequency control and AGC operate, and how the frequency control loop is modelled. Some of these textbooks and articles detail the engineering principles for each of these topics (EPRI, 1997 and Kundur, 1994). These principles are important when calculating the economic benefits of relaxing frequency control. None of the literature surveyed presented a generic algorithm that studied the economic benefits of relaxing frequency control.

2.2.2 National and international standards on frequency

There are international and national standards on the manufacturing of generators, motors and other electrical equipment. These govern the minimum specifications and quality requirements of electrical equipment. Standards also address the quality of supply the customer can expect when connected to the electrical network. All these standards are presented in detail in the section on customers requirements in **Chapter 4.**

An internet search with the key words “frequency control standards and electricity”, revealed 960 articles on this topic. The following are a summary of the papers that were of interest to the theme of this thesis.

The North American Energy Reliability Council USA (NERC, 2002; NERC, 2003), has changed its methodology for measuring frequency control performance of a control area within the North American Interconnections. NERC decided to maintain the same quality of frequency for each of the three interconnections in the USA. Changing the performance standard has reaped some economic benefits in reducing AGC control cycling and has certainly improved the optimisation objectives of AGC control loops. No literature quantifying the economic benefits of relaxing frequency control for the interconnection could be found.

South Africa's central region changed the target frequency to 51.2 Hz in the 1920's for the benefits of increasing the pumping capability of the gold mines. The target frequency was changed back to 50 Hz in the 1950's (Vermeulen, 2001) when the central network was interconnected to the Cape network. The economic justification for such a large change in target frequency is not documented in the literature.

2.2.3 Primary frequency control

Primary frequency control is a control loop located at the level of individual generators. This changes the generator power output according to the frequency. Primary frequency control is a proportional controller that is designed to increase the output of the generator by opening the governor valve in response to a drop in frequency, **Figure 2.1** (Chown, 2006). The amount of control is dependent on the droop, R, which represents the change in frequency for a particular change in MW generated. The lower the value of R, the higher the amount of control required from the generator. The original essence of the controller is that all generators assist in controlling the frequency.

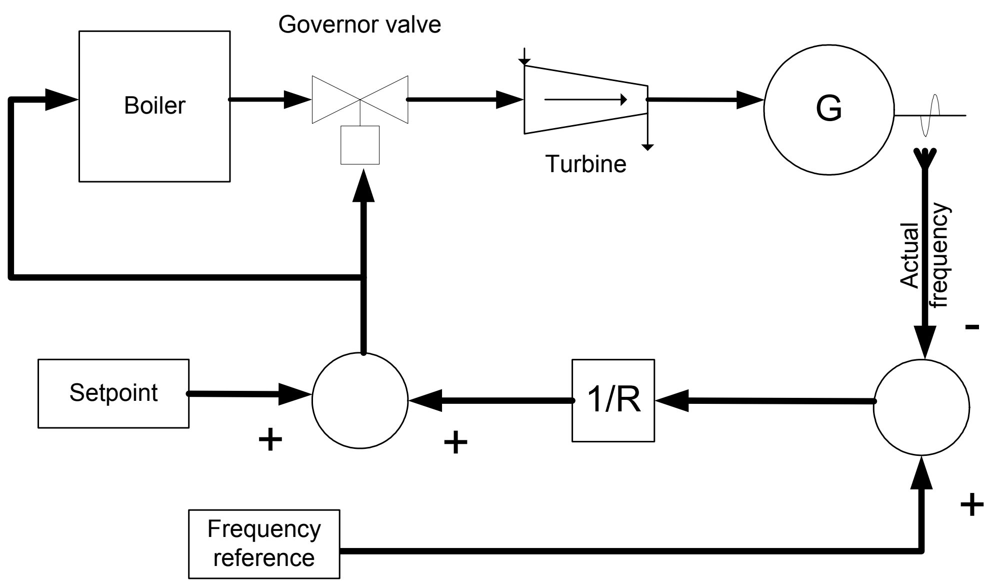

Figure 2.1. Primary frequency control structure.

The droop characteristic is expressed as a percentage, where a 4% droop (R = 1/droop = 25) means that a 4% change in frequency will alter the generator output by 100%. The slope of a 4% droop curve for smaller frequency changes showing percentage change in generator MW output as a percentage of the generator maximum continuous (MW) rating, MCR, is represented in **Figure 2.2.** Practically, for a 4% increase in frequency, generators can go from rated MW output to zero. However, for low frequencies, the design of the plant often means that only a small MW output can be achieved (Chown, 2006).

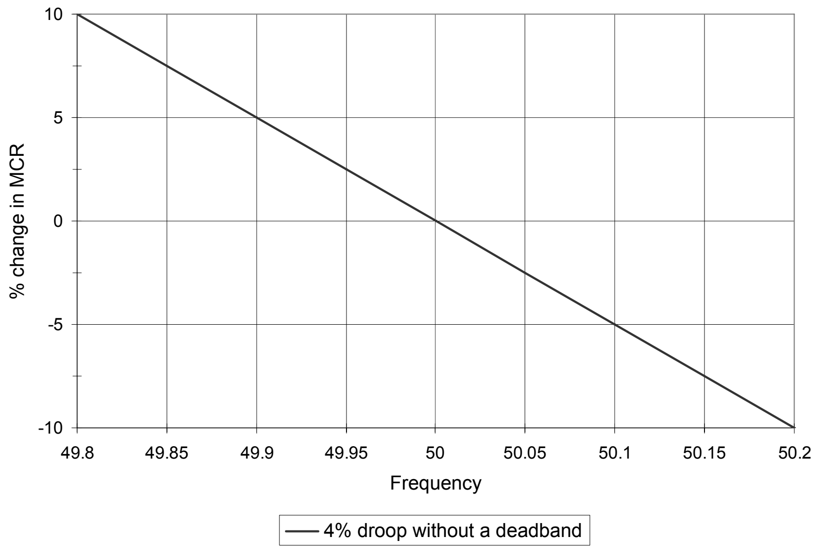

Figure 2.2. Generation-frequency relationship for a 50Hz nominal frequency with 4% droop curve.

Traditional proportional-only control will only arrest the frequency and a typical example of this effect is shown in **Figure 2.3,** where the frequency was arrested at point B.

The tail in the frequency, point C, is due to the response of the generators being slower than the rate of fall of the frequency, which gives a slight over-shoot.

Three methods are used to restore the frequency to nominal:

1. Some generators have their droop set to 0 which maximizes their change in MW generated for small deviations in frequency.

2. Some generators have proportional and integral action set in their control loop. The integrator is to reduce long-term frequency deviations

3. Secondary control of the governor MW setpoint is performed from a central control centre.

As the frequency is restored to nominal, generators that have only proportional control and have had no secondary control applied, will change their output back to where it was before the frequency incident occurred.

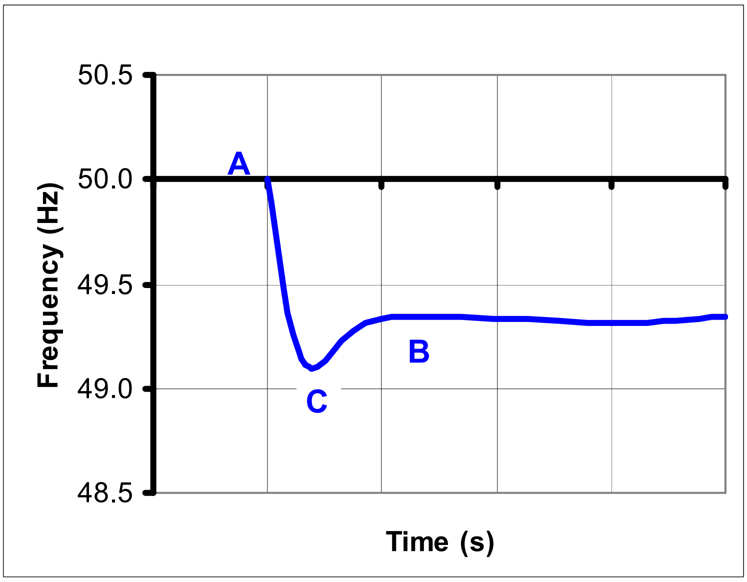

Figure 2.3. Typical frequency with governing only.

The literature researched focuses on three major areas of primary frequency control.

- Textbooks and articles that cover the fundamental operation of the control loop and the main purpose for having generators that respond automatically to frequency deviations (Anderson and Fouad, 1993; EPRI, 1997; Kimbark, 1995; Kundur, 1994; Asal *et al.,* 1993).

- Articles from a system operations perspective that define the minimum system requirements for an interconnection, locational requirements for members of the interconnection and the minimum response requirements of generators. (UCPTE, 1991; National Grid Company, 2002a; Transpower, 2003a; Wood, 1995; and Arnot *et al.,* 2003).

- Articles that deal with the practical problems experienced by generators in providing primary frequency control. The main issue is the inability of generators to respond as the interconnection requires. Subsequently, the frequency service provided does not meet expectations. (EPRI, 1979; Conradie and Paterson, 1979; Chown and Coker, 2002; Pereira *et al.,* 2004; and Kosterev, 2004).

2.2.4 Automatic Generation Control

Secondary frequency control occurs when generators are requested to change their output from a central control centre. This is performed either manually or via Automatic Generation Control (AGC). This balances the minute-by-minute supply and demand. Most large utilities use an energy management system (EMS) to control their main transmission system from a centralised control centre. The main components of the EMS are normally the supervisory control and data acquisition (SCADA) with its state estimator, and automatic generation control (AGC) (Chown, 2006).

Automatic Generation Control (AGC) is a centralised control loop that co-ordinates the generators. It has two main functions:

- To restore the frequency to the nominal value
- To ensure optimal cost operation

Secondary frequency control is traditionally done by AGC, but in some countries, such as Great Britain and Norway, instructions to power stations are issued via electronic or manual commands (Chown, 2006).

A typical AGC control loop is shown in **Figure 2.4** (Eskom,1985). The inputs to the AGC are the frequency and contractual obligations with other Control Areas (an AGC specifically controls the generation within one control area but may communicate with other AGCs in other control areas) and these variables are used to calculate the shortfall or surplus in MW. The required MW control is then allocated to each governor MW setpoint, which will increase or decrease the respective generator MW output (Chown, 2006).

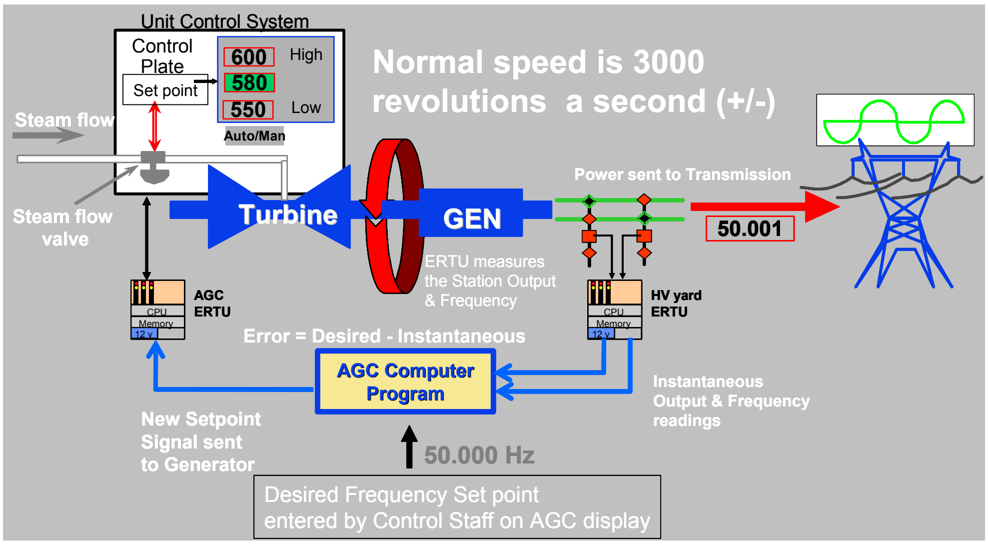

Figure 2.4. Basic AGC system (Eskom, 1985).

The Eskom AGC control system is set up to control the unit target setpoint of the generators (Chown, 1997). This is a closed-loop control system. Here the unit target setpoint is moved up and down with the use of up and down pulses until the unit target setpoint is equal to the desired generation. The unit target setpoint of the power station then controls the actual unit MW output. This control loop is located at the power station. Robert Hartman describes the original Eskom AGC system in his Master's dissertation(Hartman, 1996).

Under disturbance conditions, the governor has the function of arresting the frequency deviation and the function of AGC is to return the frequency to nominal, **Figure 2.5**. Primary and secondary controllers need to be carefully managed to avoid both controllers negatively interacting with one another (Chown, 2006).

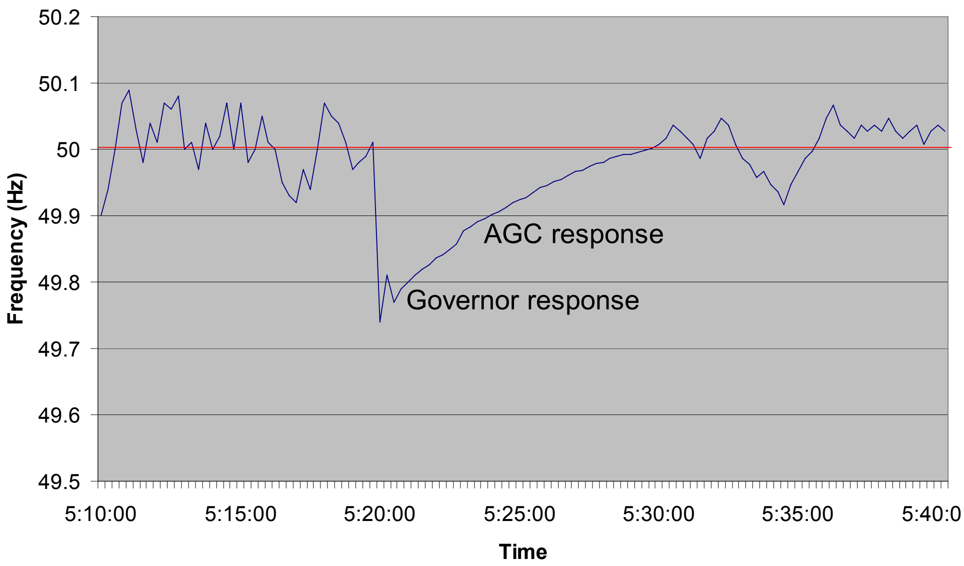

Figure 2.5. Interaction between governing and AGC.

Automatic Generation Control is an area that is often covered in the literature. There are many articles and theses on improving this control loop. Most articles focus on the minimisation of the ACE as the only control objective (Bevrani *et al.*, 2004; Kumar, 1998; and Prowse, 1998). The introduction of the new control performance standards to the USA: NERC CPS1, CPS2 and DCS (NERC, 2002; and NERC, 2006), has led to many articles on how to tune the AGC controller to meet these new performance criteria (Yao *et al.*, 2000; and Lefebvre *et al.*, 2000). When introducing the new performance criteria, NERC decided to maintain the same quality of frequency for each of the three interconnections in the USA. The quality of the frequency and methods for the control of the frequency were not changed.

Whilst many of the articles focus on trying to maintain the tightest control possible, in practice, the manufacturers of AGC systems do not design their control systems to control to such stringent limits. This is impractical and the manufacturers use deadbands and other techniques to prevent controlling in the areas of noise in the frequency measurement (Hartman, 1996).

2.2.5 Economic Dispatch

Economic dispatch of generators using the traditional AGC control loop is a complex problem. Many textbooks and articles deal with the topics of how to solve the economic dispatch of generators in both a cost and market environment (Kundur, 1994 and EPRI, 1997). Technical papers deal with algorithms to solve this problem (Danai *et al.*, 2001). Economic dispatch algorithms are focused on obtaining a generation pattern that is economic from a cost of energy perspective. This means the cost curves or the offer curves of generators are used and the economic algorithm then optimises the level of dispatch for each generator. The more sophisticated algorithms provided by manufacturers also try to maintain certain constraints. Typical constraints are the maintaining of reserves, transmission constraints and managing of energy production for energy-limited generators. With deregulation, the algorithms now also include offers from demand side participants. The more recent dispatch algorithms developed for deregulated interconnections can produce a solution at 5-minute intervals. (Hunt and Shuttleworth, 1996; Shahidehpour *et al.,* 2002; Shelbe, 1999; and Danai *et al.*, 2001).

The economic dispatch for the interconnections is regarded as tertiary control. This can influence the quality of control and will form part of the determination of the economic benefits should frequency control be relaxed.

2.2.6 Frequency Control as Ancillary Services

The introduction of electricity markets and the creation of regulation ancillary services has challenged the role of AGC and created methods to pay generators that are willing to provide AGC services. There have been many textbooks and articles on how to create ancillary service markets and on the inter-relationship with energy markets. (Hunt and Shuttleworth, 1996; Shahidehpour *et al.,* 2002; Shelbe, 1999; and Danai *et al.*, 2001). The survey of countries and interconnections in the sections below shows that very few markets have changed their technical requirements since the introduction of deregulation to the electricity industry.

2.2.7 Summary of frequency targets of interconnections

The detailed literature study of interconnection frequency control standards, the use of AGC and the state of deregulation, as reported in **Appendix A,** is summarised in **Table 2.1.**

Table 2.1 Comparison of Interconnections Frequency and Control.

Interconnection	Peak Demand (MW)	Frequency Std dev (Hz)	AGC	Deregulated
Great Britain (GB)	50 000	0.06	No	Yes
Nordic Power Pool (NPP)	70 000	0.06	No	Yes
UCTE	370 000	0.04	Yes	Yes
Australian Eastern interconnection (AUS)	27 000	0.024	Yes	Yes
New Zealand North Island (NZ(N))	4200	0.06	No	Yes
New Zealand South Island (NZ(S))	2200	0.03	No	Yes
Tasmania (TAS)	1600	0.05	No	Yes
USA Eastern interconnection (USA(E))	588 000	0.018	Yes	Yes
USA Western Interconnection (USA(E))	133 000	0.0228	Yes	Yes
ERCOT	58 000	0.020	Yes	Yes
Hydro Quebec	36 000	0.021	Yes	Yes
Japan 50 & 60 Hz combined (JAP)	184 000	0.03	Yes	No
Southern Africa (SA)	33 000	0.03	Yes	No

Figure 2.6 shows the standard deviation of the control against interconnection peak demand. A trend line of the data shows that the frequency control is generally tighter as the interconnection grows. This is expected, as the relative size of disturbances decrease when the network becomes more interconnected. The graph does show large discrepancies in that the USA controls the frequency twice as tightly as the UCTE. Further, the research showed that the UK and Nordic interconnections, which

do not have AGC, control the frequency in a much more relaxed fashion compared to other utilities of a similar size. There is no correlation between interconnections that have or have not deregulated. Therefore, the state of deregulation has not yet had an influence on frequency control strategy.

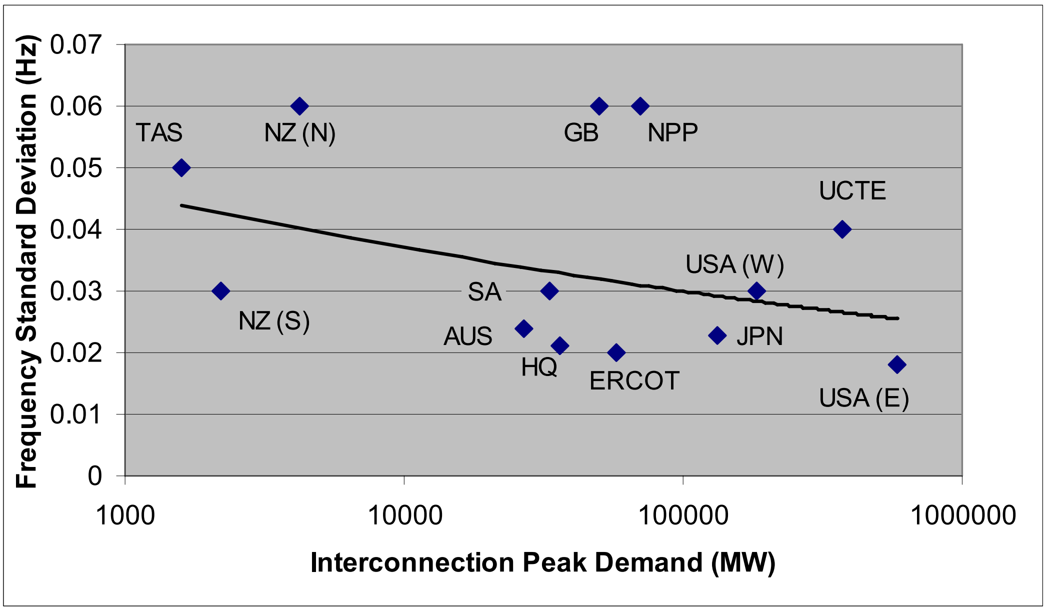

Figure 2.6 Comparison of frequency and interconnection peak demand.

2.3 Summary of literature survey

This chapter presented a literature survey on the general topic of frequency control as well as the frequency control strategies and associated ancillary services for numerous interconnections. From the literature research, it is observed that the standards, objectives for the frequency control loops and markets for frequency control vary dramatically between interconnections. There is no consistency of approach to solving the frequency control problem. The literature research also showed that the economic benefits in relaxing frequency control, considering all the aspects of the control problem, have not been reported.

Chapter 3 : Proposed algorithm

Introduction to the proposed algorithm to determine the economic benefits of relaxing frequency control

3.1 Why relax frequency control?

Governments, system operators, co-ordination centres or regulatory bodies set the targets for frequency control. As frequency is common to the interconnection, the setting of frequency control targets should be done in consultation with major stakeholders, such as generators and consumers. The process of changing frequency control targets is hence logistically complex, simply because of the many interested and affected parties. This thesis does propose that the frequency targets should be reviewed as the interconnection grows in size. The frequency control problem becomes easier to manage as the relative size of disturbances from generators and loads to the total interconnection size decreases. Frequency control for a small interconnection is difficult and requires that all generators, and even some loads, actively participate in controlling the frequency. This is just to prevent unacceptably large frequency deviations with unacceptable levels of customer load shedding or frequent blackouts. As the interconnection grows in size, the control of the frequency becomes easier and the frequency standard deviation naturally improves. If all generators were still participating in frequency control, the frequency control would just become tighter and tighter as shown in **Figure 3.1**. The problem with this development is that this could be economically sub-optimal to control the frequency this tightly.

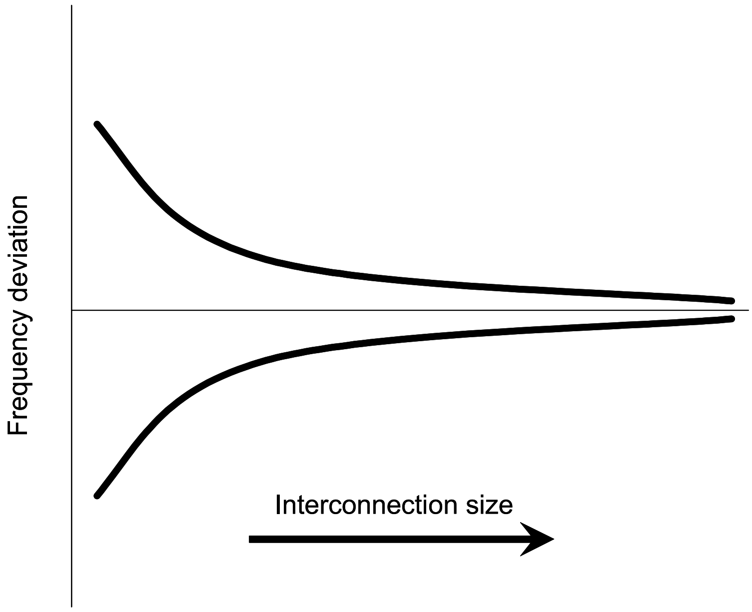

Figure 3.1. Expected frequency deviation if all generators are controlling as the size of the interconnection increases.

Therefore, at some stage the need for all generators to control the frequency becomes unnecessary. At this stage, the frequency should not be controlled any tighter from an economic perspective. This stage can be identified by calculating the potential economic benefits of controlling the frequency less tightly. **Figure 3.2** shows an example of a frequency relaxation step.

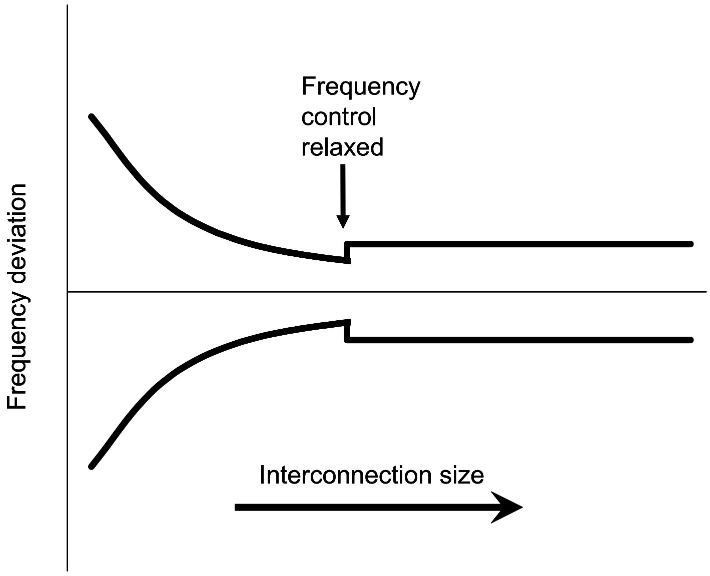

Figure 3.2. Frequency control relaxed once as the interconnection grows.

Potentially it is possible that frequency control can be relaxed more and more as the interconnection grows. Again, this is because single and multiple disturbances become less and less significant. The frequency relaxation should not be seen as a single once-off step but a progression of steps, **Figure 3.3**. The counter to this potential for a more and more relaxed frequency control philosophy as the interconnection grows, is the reality that as the interconnection grows so then transmission lines between areas within the interconnection have to be carefully managed to prevent them being overloaded. Tight control of these intra-interconnection area power flows requires the balancing of demand and supply within these intra-interconnection areas. This tight control naturally leads to a management of frequency of the overall interconnection within tight limits. The frequency control problem now moves from pure frequency control to the management of intra-interconnection flows. In an interconnection as large as Europe or the USA the frequency control is secondary to the management of power flows within and between control areas.

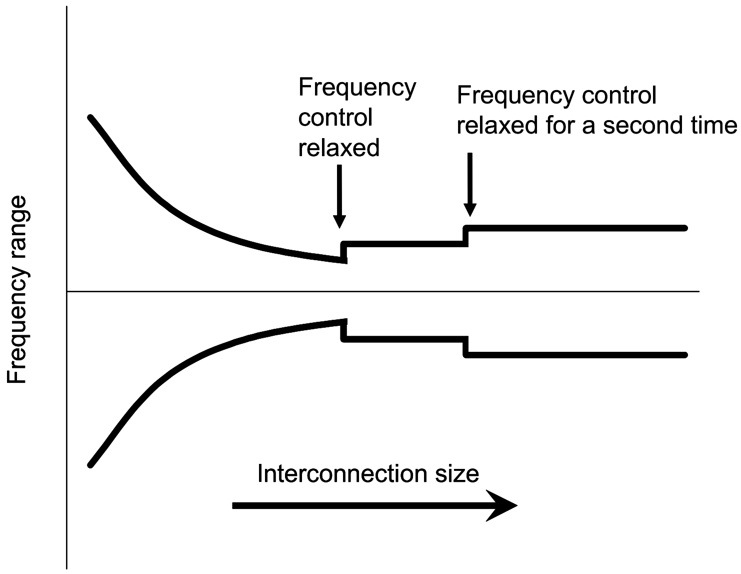

Figure 3.3. Potential to relax frequency more than once as interconnection grows.

From a frequency control perspective, interconnections could be broken down into three size zones, as shown in **Figure 3.4**. Zone 1 is where the network is small and it is necessary to use all generators to control the frequency to prevent frequent blackouts or frequency going outside an acceptable range for the consumer or generator. Zone 2 is where there is an economic benefit not to use all the generators for frequency control and the potential to relax the frequency control exists. Zone 3 is where the interconnection is so large that frequency control is a secondary problem to managing power flows on intra-interconnection areas. The proposed algorithm to calculate the economic benefits is most applicable to Zone 2 and has limited use in Zone 1 and Zone 3.

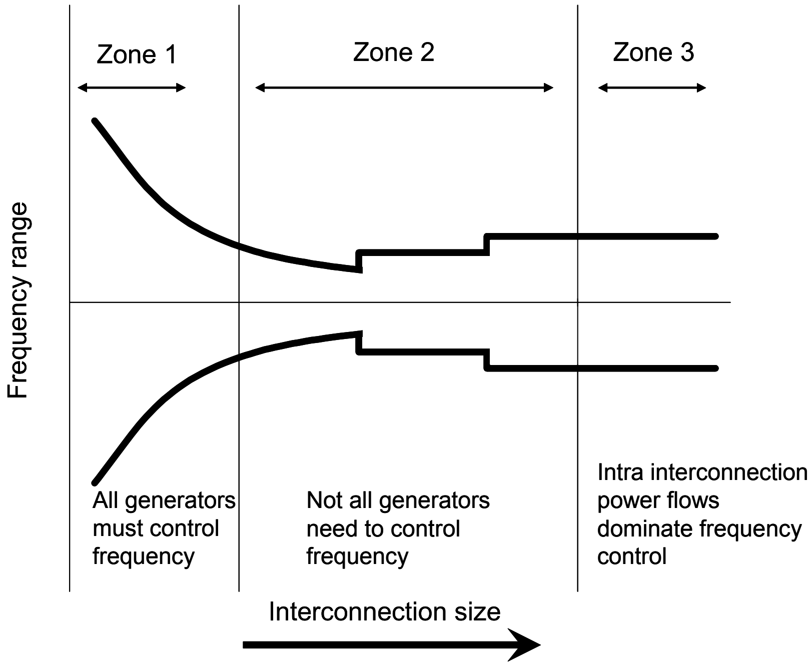

Figure 3.4. Frequency control zones as a function of interconnection size.

3.2 Method for solving controls problems

The process followed in solving a typical control problem is shown in **Figure 3.5**. The control problem can be broken into four sections:

1. Determining the boundary conditions of the process and the minimum control required to meet the boundary conditions.

2. Calculating the cost of and benefits of control.

3. Developing an optimal control strategy.

4. Maintaining the optimal performance of the control loop.

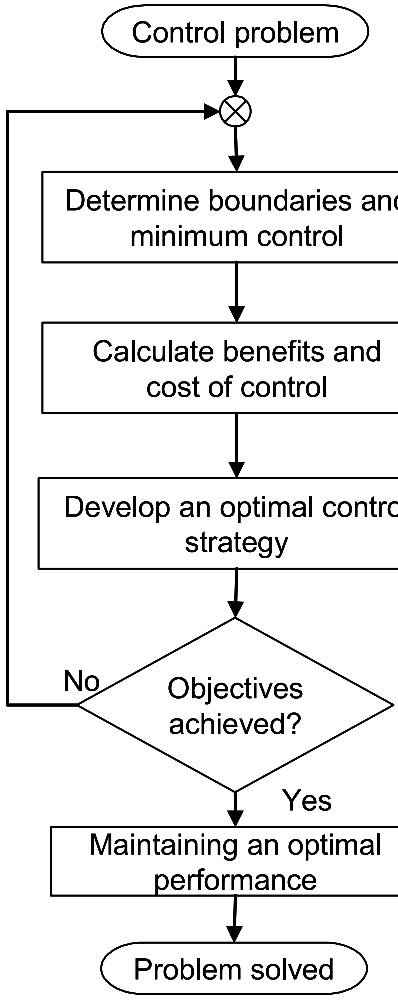

Figure 3.5. Flow chart showing the process followed in the solving of a typical control problem.

3.2.1 Determining the boundary conditions of the process and the minimum control required to meet the boundary conditions

The first step in solving a control problem is to understand the process to be controlled.

The engineer will first have to understand the main objective of the process. What is the desired product? The product could vary in quality such as various grades of steel. The engineer needs to identify the worst quality product that is still acceptable to any customer, which sets the outer limits of the control, from the tightest control possible to the most relaxed control acceptable. A cost benefit analysis is performed and refined as the control strategy is developed.

The absolute limits from the output of the processes and sub-processes are required to determine boundaries for control. Such boundaries are absolute, such as a high level on a tank, others are limited by time such as the temperature of a process could exceed a high limit for only a short time otherwise the plant is damaged.

Following this, the dynamic behaviour of the process needs to be studied. What are the time lags and other non-linearities in the process?

What can go wrong in the process is always an issue. There can be disturbances in the process that are both measurable and un-measurable. The controller design needs to control these in an acceptable fashion.

The engineer would also require some knowledge of what other variables would influence the variable being controlled. Making changes to the one control loop could affect the others.

Finally, the minimum amount of control required is determined to meet the targeted boundary conditions. This can be an iterative process as there might be a limit on one of the sub-processes that can be changed through changing the plant design. It could be cheaper to remove some limitations than to apply a more stringent control strategy.

3.2.2 Calculation of the cost and benefits of control

Identifying the variables that can control the process is required. Often there is more than one method to control the process. Each method has its own level of effectiveness with respect to the other control variables.

The development of an economic strategy requires that the cost of controlling the process must be determined. The cost of control can then be traded off against the increased value of an improved product.

Extra control can have a cost on the efficiency, wear and tear and the long-term life of the plant and equipment used for controlling.

The benefits of controlling the output tighter could result in a product that has a higher market value. In some cases, there is a limit to the quality required by the consumer and extra control makes the product more expensive than a competitor's product.

3.2.3 Developing an optimal control strategy

The first step in developing an optimal control strategy is to measure the error from an ideal product. Understanding the measurement process and potential errors in the process is critical to developing the optimal strategy.

Calculation of the cost of the control is required to determine the optimal control strategy. This is developed into a cost function against which potential control strategies can be tested.

The engineer should study how the control problem has been solved in the past as this can give an easy way to solve it without much further research.

In large manufacturing industries where the control engineering is reliant on many participants to provide the right products at the right time, the engineer needs to understand the market practices and the variable prices for raw materials. The variances in raw material prices and other market influences should be included in the cost function.

The engineer can now design the control philosophy. The cost function is determined from the cost of tighter control of the process versus the profit of a better product. The proposed process is to simulate the process, starting from the tightest control possible and gradually relaxing the control, whilst monitoring the potential savings over each relaxation step. This may require a modelling of the process and the testing of different philosophies to determine the optimal strategy.

Once the optimal strategy has been determined, risk management strategies, such as stock management, can be developed.

It is possible that, even with the best control possible, not all the control objectives and boundary conditions have been met. The design engineer might have to go back to the beginning of the design process to understand what can be challenged in the process to further improve the design. This is an iterative process and when this happens, it will require some lateral thinking and test the creativity of the engineer. Even if the control objectives have been met, an iterative step might be worth doing to confirm that the proposed design cannot be improved upon.

3.2.4 Maintaining an optimal performance

Maintaining the optimal performance of the control is often a process that receives little attention. The control can become sub-optimal as the plant ages. A process with a single control variable is easy to monitor. However, in the frequency control problem with many generators and loads participating in the control process, the monitoring of their performance becomes crucial to maintaining the optimal control.

Monitoring best practices in the industry and external influences that can affect the control, should be done to maintain, or even improve, optimal control.

3.3 Proposed generic algorithm

The proposed generic algorithm is broken down into the four phases as presented in **Section 3.2** and shown in **Figure 3.5**.

3.3.1 Phase 1: Determine the boundary conditions of frequency control and the minimum control required to meet the boundary conditions for frequency control

Phase 1 is firstly the determination of the impact of frequency deviations on generators, consumers and the network. From this a set of boundary conditions is developed. The impact of large frequency variations is determined and the minimum amount of control to remain within acceptable zones is calculated. The determination of what is acceptable has not only technical considerations but also economic considerations. Finally, the minimum control required to meet regional constraints and voltage disturbances is calculated.

The process for Phase 1 is shown in **Figure 3.6.** The algorithm proposes that firstly, the customers' requirements are fully understood. Then from this the boundary conditions are developed. The process of determining the boundary conditions from the customer requirements is proposed to be iterative to analyse the effects of single customer's specific requirements in the broader context of the control problem.

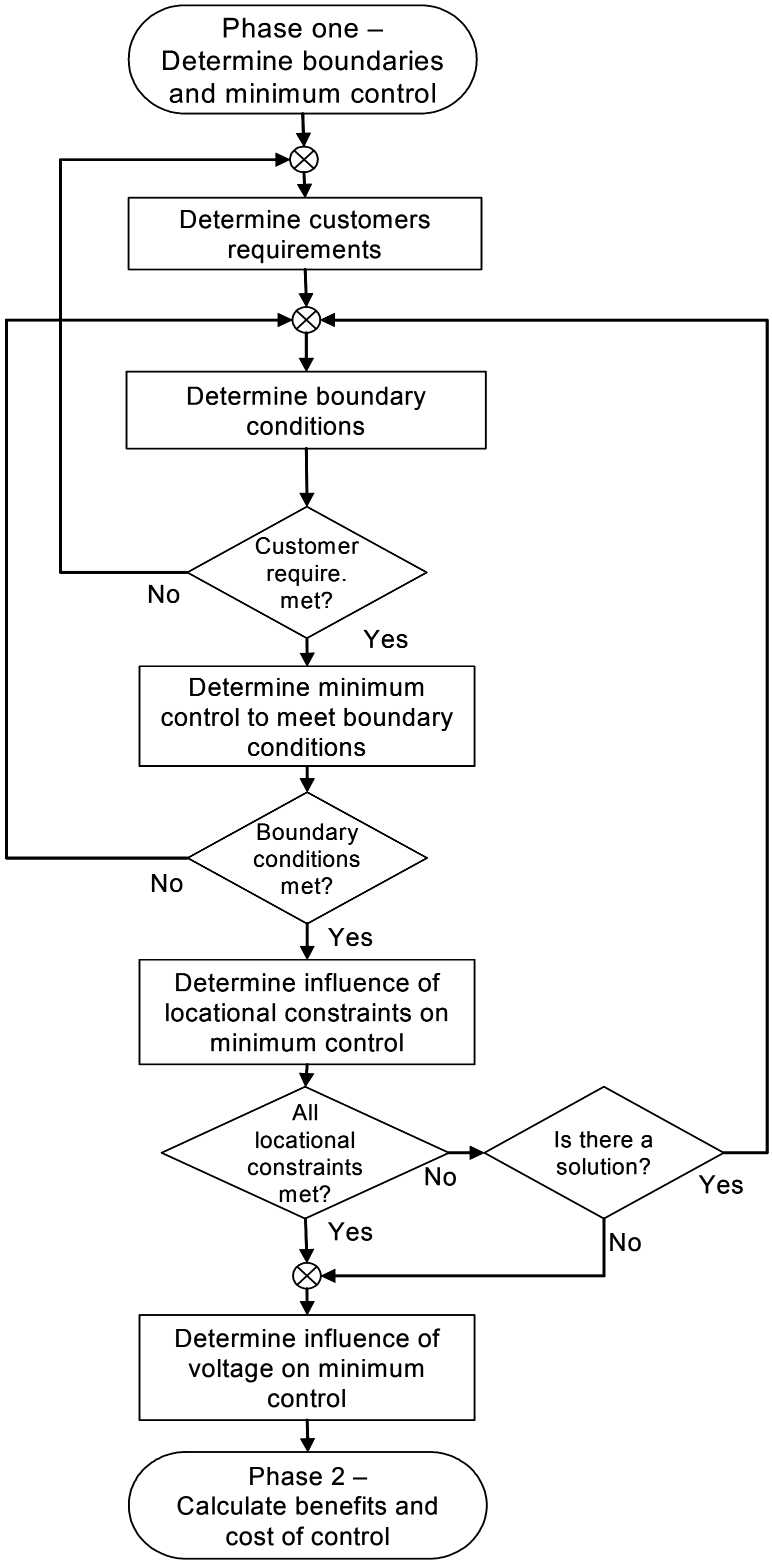

Figure 3.6. Flow chart for understanding the process to be controlled.

The frequency control problem cannot be solved without some understanding of the dynamics of the process. Simplified models to determine the rate of frequency change and a reduced model of the interconnection are proposed to calculate the minimum amount of control. The development of these models for Eskom is shown in **Appendix C**. Possible large disturbances such as single and multiple contingencies are analysed and checked on the simplified model. The minimum control required to meet the boundary conditions is calculated. If the boundary conditions cannot be met, the frequency control problem needs to be started over to see which customer requirements or boundaries can be relaxed.

Analysis of locational constraints and disturbances that can be expected is performed, as further inputs into determining the minimum control required. The specific disturbance investigated for solving the frequency control problem is a voltage change that can occur with a large disturbance. The change of voltage will affect the consumption of loads and hence directly influence frequency control.

If, at the end of Phase 1, it is found that all generators and even some loads are required to control the frequency for single disturbances that frequently occur, the possibility to relax frequency control is minimal. Similarly, if the transmission constraints require a continuous tight management of the balance of supply and demand within most of the subsections of the interconnection, the possibility to relax frequency control is also limited.

Chapter 4 gives a detailed description of Phase 1 showing how the boundary conditions and minimum control was determined for the Eskom frequency control redesign project.

3.3.2 Phase 2: Calculate the cost and benefits of frequency control

The calculation of an economic strategy to control frequency cannot be done if the cost of controlling is not known. Before calculation of the cost of control, the limitations of control need to be understood. Disturbances in the process have already been identified.

Phase 2 is firstly to understand who can control the frequency and the limitations of the plant providing the frequency control service. The key aspects are the time response, the amount of control that is provided, repeatability and sustainability of the control. The investigation of the thermal plant showed that a more detailed model of the boiler and turbine was needed to do the studies required. An example of the tuning of the model for primary (step) response and investigating different control strategies is presented in the technical background in **Appendix H.**

The costs of providing a frequency control service are due to extra equipment, extra manpower, wear and tear, long term life degradation, loss of efficiency, loss of opportunity, and start-up costs. The costs of providing frequency control services is the difference in costs for a generator or consumer when providing the frequency control service and when not providing the frequency control service. The formula is:

$$Cost_{frequencycontrol} = Cost_{withfrequencycontrol} - Cost_{withoutfrequencycontrol} \tag{3.1}$$

If the interconnection is deregulated, a different calculation for cost of control is required. The providers of frequency control services are compensated in the market and this is price based. The market rules and the potential influences of market power, risks and incentives, penalties, and the liability of the new entities will need to be understood.

Finally, Phase 2 calculates the benefits and costs when relaxing frequency control. An additional cost could be introduced when frequency control is relaxed due to increased inadvertent energy. This cost is dependant on the rules in the interconnection. If the interconnection is deregulated, inadvertent energy is often determined by a balancing price which is often higher than the day-ahead price. A further cost when the frequency is relaxed is the potential for generators to operate at sub-economic levels for longer. A relaxed frequency might also require more governing to cater for contingency as the possibility of the frequency being below nominal increases with further relaxation in frequency. A benefit to relaxing frequency control would be to not dispatch an expensive generator to cater for a short peak. This could decrease reserve requirements and the costs thereof.

Chapter 5 gives a detailed description of Phase 2 showing some of the cost calculations done for the Eskom relaxation of frequency control project.

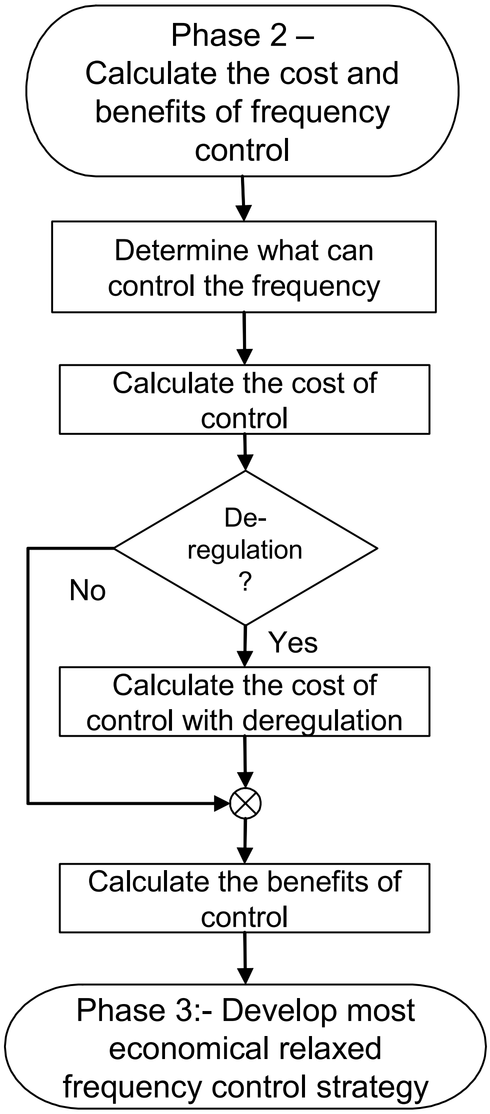

Figure 3.7. Phase 2 flow chart calculating the costs and benefits of control.

3.3.3 Phase 3: Develop the most economic relaxed frequency control strategy

Developing the most economic relaxed frequency control strategy covers the process required to give the best control for the interconnection being studied. The optimal control will vary from interconnection to interconnection depending on the network design, types of generators and customer requirements. The first part of this phase is to understand the errors that are incurred in measuring the frequency and converting this to a calculated supply-demand mismatch. An incorrect calculation of the amount of control can undo all the economic benefits. Known errors in the determination of the mismatch can be compensated for in the control loop. If tight frequency control is not required there might not be any economic benefit in trying to determine the supply demand mismatch accurately.

The next part is to develop a simulation model of the network that can be used to determine the economic benefits. The development of the final formula to determine the economic benefits is next. This is the formula used to evaluate the costs of the various cases that will be developed. This cost function will vary between interconnections and even over time with factors changing such as costs of controlling, state of deregulation, network changes and introduction of different types of generators. The starting point for determining the best economic strategy is the tightest frequency control possible. If, as the control is relaxed, the economic benefits are not realised, the best technical and economic solution is the tightest control. The minimum control has already been determined, so the end-point for assessing any economic benefit is known, and the relaxation study can end when this point is reached.

The proposed process to obtain an optimal solution is to change one variable at a time, calculating the cost savings due to this variable change. This solution is proposed as the problem is too large to solve in a single optimisation and the optimal solution might not be the least cost case.

The initial instinct is to simply minimise the cost function, point A on **Figure 3.8.** In practice, it is prudent to choose some point which gives a slightly higher cost but gains more security, such as point B on **Figure 3.8**. This is a better solution from a risk management and safety perspective. One of the major considerations for erring on the side of safety is the magnitude of the slope of the cost to the customer. The cost curves have been linearised for this example, but in practice, these curves are not linear and there is a set of frequency cost curves for different control strategies. For each case there is a minimum and some prudent level of savings to target.

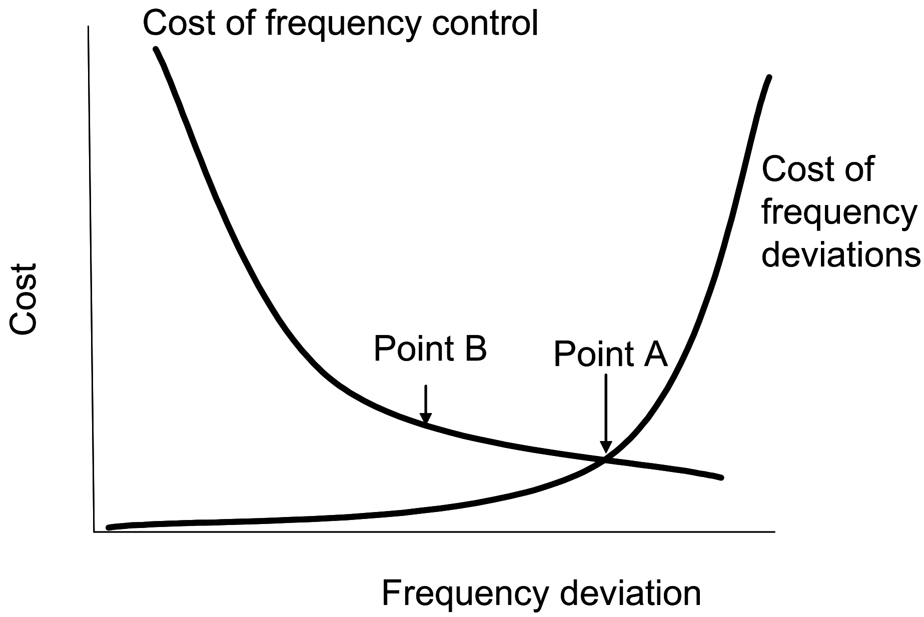

Figure 3.8 Cost of frequency control and cost to the interconnection as the frequency deviation increases.

The proposed solution is to change one variable at a time and observe the influence on the savings.

The proposed steps are:

Step 1: Investigate the possibility of no frequency control with no generator movement and the possibility that generators just follow the day-ahead schedule or a derivative of this.

Step 2: Determine areas of no frequency control such as increasing the AGC deadband and increasing the governor deadband. This step calculates the need for increased Instantaneous Reserve for contingencies due to a potentially lower starting frequency when a contingency occurs.

Step 3: Determine how relaxed the frequency can be controlled under normal conditions. The economic dispatch movement is limited to only when required for frequency control.

Step 4: Determine the additional savings if units are moved for economic dispatch reasons only.

Step 5: Fine-tuning the solution for other variables that could give extra savings. For Eskom, the additional fine-tuning was done by investigating the impact if the delay in the initial response of units on AGC is increased.

Each of these steps is described in more detail in the following sections.

After completion of the above steps, the cost savings for the various relaxed frequency control strategies is known and a final optimal frequency control solution can be determined.

Finally, Phase 3 then develops reserves and markets (if required) for the new optimal frequency relaxed strategy.

A flow chart of how the steps are interrelated and decisions after each step is shown in **Figure 3.9. Chapter 6** shows the detailed calculations done for each step in the Eskom frequency redesign project.

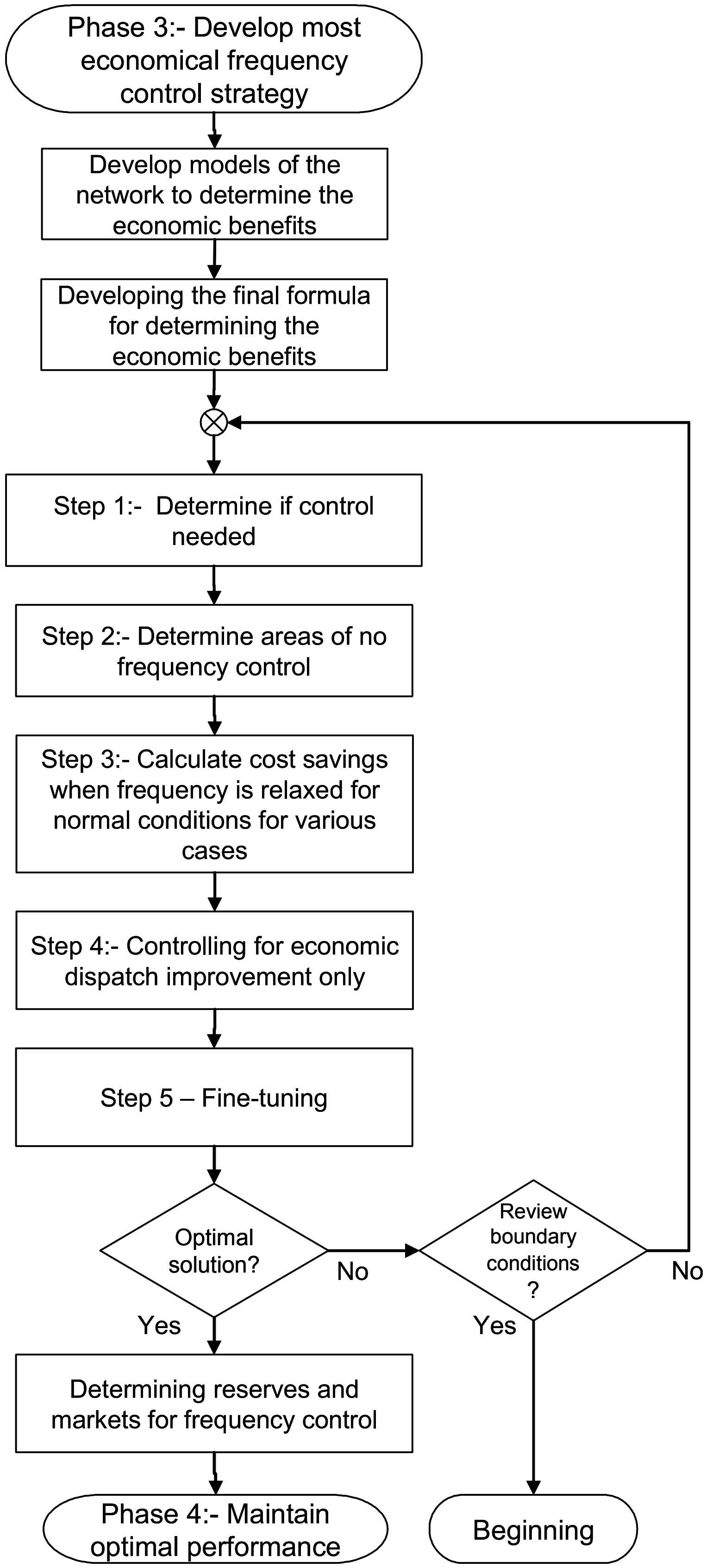

Figure 3.9. Flow chart for developing an optimal frequency control strategy.

3.3.3.1 Step 1*:* Determine if control is needed

The boundary conditions defined in the cost function are required to answer this question. The cost of controlling this way should also be calculated as there are costs that are incurred by the customer as the frequency deviates from nominal. If the frequency is continually within the boundaries required by generators and consumers then, theoretically there is no need to take any control action, **Figure 3.10.** However, this is very hypothetical for most networks due to the size of contingencies and local power flow problems.

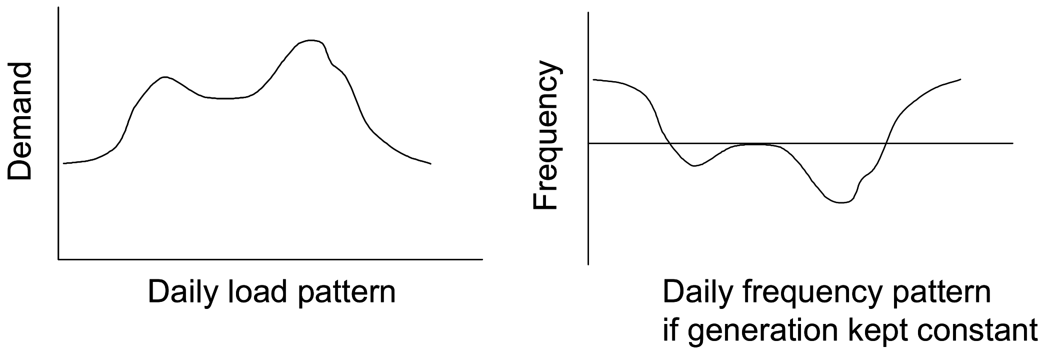

Figure 3.10. Frequency if generation is kept constant over a day.

3.3.3.2 Step 2*:* Determine areas of no frequency control

If possible, there should be no control in the region of measurement uncertainty and general noise of customers continuously switching on and off. Similarly, the primary governors should not be active in the area of mechanical deadband or whiplash. The frequency control is naturally relaxed as the area of no control increases. The savings in control will have to be traded off against the worse quality and the cost implications. Where there is no AGC and the system operator controls the generation manually, the system operator will often let the frequency deviate from nominal frequency and will do no control if they are certain the frequency will return back to nominal in a short time. For example, the frequency drops below nominal but the system operator knows the customer demand also drops at this time of the day, therefore they do no control but just wait for the demand to drop. This is the practice in the UK and Nordic networks where there is no AGC. However, in these networks the primary frequency control is continuously active. The primary frequency control is incurring a cost and this control increases the frequency bias characteristic (MW/Hz) and allows the system operator more time to control the frequency.

The effect of increasing the governor deadband is an area of no control that is studied in this step. The minimum control from primary frequency control has already been calculated for disturbances and possible locational requirements in Phase 1, described as Case A in **Figure 3.11.** However, the optimal control strategy might be different from this minimum control. An area of no control can be introduced and the savings of having no governor movement within the deadband can be calculated as well as the extra costs of governing reserves to meet the same boundary conditions. Case B in **Figure 3.11** assumes the frequency is starting at the boundary of the governor deadband. This is the most expensive solution for governing reserves as there is a reduced load frequency support. The costs for governor reserves also need to be re-calculated for the frequency starting at nominal. The turning frequency is lower than the case without a deadband due to a delay in the governor responding and an increase in governing might be required to meet the boundary conditions.

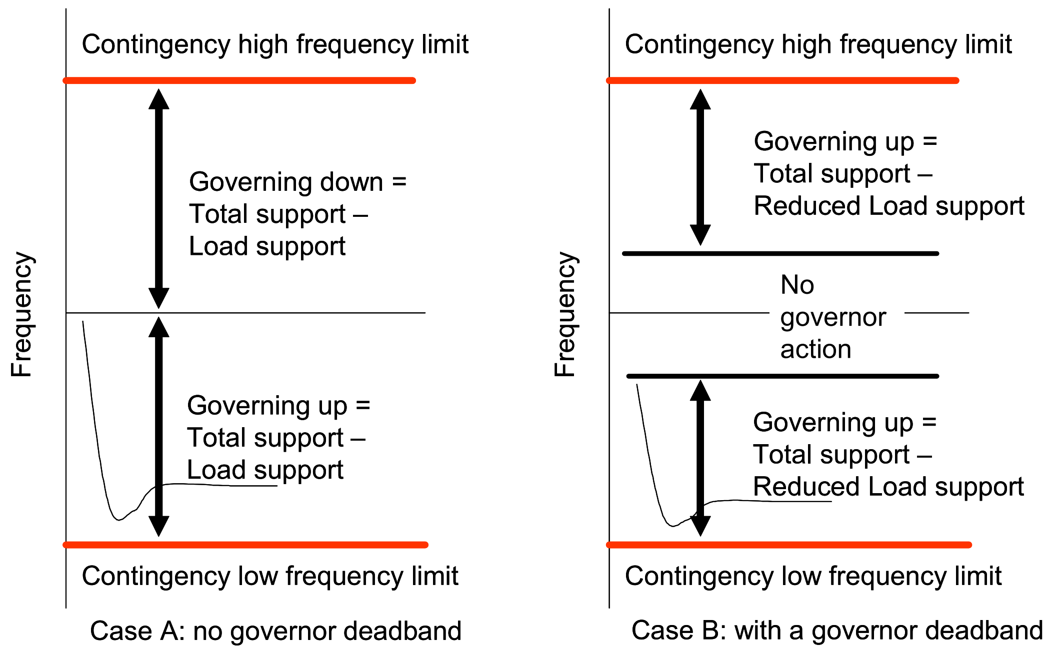

Figure 3.11. Governing requirement with and without a deadband on the governor.

As the deadband increases the cost function changes as shown by the arrows:

Cost function$_{(increasing\ governor\ deadband)}$ = *Cost to generator governing(↓) + cost of governing reserves(↑) + other costs(→)* **(3.2)**

The amount of control and the time response required from generators or customers to arrest the frequency at acceptable levels is also now known. The frequency declines rapidly for most networks so control must be quick and has to be performed automatically at the generator or the customer. Restoring the frequency within acceptable times is determined in terms of MW per min. required from the sum of all participants.

3.3.3.3 Step 3*:* Calculate cost savings when frequency is relaxed for normal conditions for various cases

Various cases can be developed and the savings are calculated for each case. The proposed strategy, as used in Eskom is to*:*

- Firstly, increase the deadband of the governors (primary control).
- Secondly, the AGC controller is tuned to minimise control whilst trying to maintain the frequency deviation less than the deadband for more than the 95% range for control in the normal state.

Given that 95% is equivalent to two standard deviations the new condition for the optimisation can be rewritten as:

Frequency standard deviation < Governor deadband / 2

The solution proposes that the required control is done on those units that will improve the economic dispatch solution. Thus, with one control step economics and frequency control is satisfied. This will be true for a cost-based dispatch and some deregulated market designs.

The cases are now compared and the thesis proposes that these cases form a set of trend curves. From these curves the optimal solution is determined by looking at the cost savings and the slope of the cost savings shown in **Figure 3.8**.

In this step, some fine-tuning of the solution is done. For Eskom this included the modification of the day-ahead bids and offers to a balancing bid and offer that respected the more optimal day-ahead solution. The solution was also fine-tuned by changing the target frequency to prevent the frequency from lagging in high loading and de-loading periods.

3.3.3.4 Step 4*:* Controlling for economic dispatch improvement only

The frequency controllers have been set up to minimise the amount of control. One part of the cost function that has not yet been considered is the cost of generators not being at an optimal economic dispatch level. In a deregulated environment this could include dispatchable loads. All the major energy management system suppliers have methods to determine the optimal economic solution from both a cost perspective and for a de-regulated (market) perspective. Recent market dispatch algorithms contain unit commitment algorithms and network models to ensure that transmission constraints and security are considered by the dispatch algorithm:

$$\begin{aligned} \textit{Cost function}_{(\textit{moving to better economic dispatch})} = {} & \textit{Cost to generator to control } (\uparrow) \\ & + \textit{cost to generator improved economic solution } (\downarrow) \\ & + \textit{other costs } (\rightarrow). \end{aligned} \qquad \textbf{(3.3)}$$

There are three options proposed on how to implement the economic solution provided by these algorithms:

- The first option is to ensure that if any control is required for frequency control, it is performed by the generators that will give the most economic benefit. The result of this option is that the AGC control is still minimised and the control system is also dispatching along economic guidelines. This was the method proposed in Step 3.

- The second option is to investigate whether increasing the amount of control and thereby controlling the frequency tighter will further minimise the total cost function. Increased control can imply a better economic dispatch solution. This was also evaluated in Step 3 where the cost of relaxing frequency includes the cost of uneconomic dispatch.

- The third option is to investigate if, or when, it is cost effective to increase and decrease generators simultaneously or against the frequency control required to get a better cost solution to **Equation 3.3** than provided by option 1 and option 2. Here generators are not being moved to assist in the frequency control problem but only to improve the economic dispatch solution.

The generic algorithm proposes that all three options are considered and the objective is to find the minimum solution to the total cost function. **Chapter 6** describes in detail how the optimal solution for Eskom was achieved.

3.3.3.5 Step 5*:* Fine-tuning the solution for other variables that could give extra savings

The final step is to fine-tune the solution one last time to ensure the most economic solution has been found. In many cases, this step will not be required, but with all the knowledge gained from the simulations and studies it is worth taking a moment to reflect and consider if anything has been omitted.

For Eskom, the impact of delaying the initial response for generators on AGC was investigated. Although this was a good idea, it did not provide any financial savings. The results of the studies are detailed in **Chapter 6**.

3.3.3.6 Defining reserves and markets for frequency control

Defining reserves for frequency control

Whether there is a market or not, the system operator needs to ensure that there is sufficient reserved capacity to maintain continuity of supply and demand, as defined by the boundary conditions. For adequate frequency control, the optimisation has identified at least two types of reserves available for primary and secondary frequency control. As described in the literature survey, these two reserves are often combined into one reserve called Spinning Reserve. If the two reserves are combined it is difficult to determine which reserves are available for direct frequency control.

The time needed to respond to a disturbance and for the restoration time from a disturbance for primary frequency response has already been studied. Defining the duration required for the frequency service is important for frequency control service providers. Defining this time boundary is important in the development of control strategies for generators, and for demand side participants, to realize the impact of the interruption.

The response time for AGC should at least overlap with the minimum sustaining time of primary frequency control. The duration for participants to provide full output whilst on AGC should also be determined, which could be for the rest of the schedule period or at least long enough for an alternative plan to be made.

Additional reserves need to be activated to restore the above reserves in preparation for further incidents. The methods for calculating the other reserve requirements depend upon the period and risk allocations. It may be an acceptable risk for one network to run for periods without reserves, while to another network, that is an unacceptable risk.

In Eskom, the reserve for primary frequency control is called Instantaneous Reserve, for secondary control the reserves are Regulation Reserve for participants on AGC and Ten-minute Reserve for participants not necessarily on AGC or synchronised.

Defining markets for frequency control

In defining a market for each of the frequency control services it is important to ensure there is sufficient bids and offers for the service to avoid market power being exercised. Frequency control services are being implemented in many countries, and most countries have decided to maintain the same level of security and reliability they had before the market. The frequency control services that were compulsory before de-regulation have also remained mandatory, such as primary frequency control. The steps taken thus far in this generic algorithm have given sufficient information to ensure a least cost solution has been sought. However, if the provision of frequency control services in Eskom becomes more market-related there will be a need to check that the least cost solution is still valid. An important issue addressed in most markets surveyed in **Chapter 2** is the potential participation by demand side.

A complication in frequency control services is that they vary between being energy intensive in some frequency control services and virtually no energy usage in other frequency control services. Energy intensive frequency control services should be driven by an energy price both in contracting and dispatching, whereas non-energy intensive services need to driven by capacity payments or some other financial incentive (Singh and Papalexopoulos, 1999). If a market is non-competitive in terms of the number of potential suppliers, the choice is then to enter into long term agreements with these suppliers. If there are only one or two suppliers, then the contracting for the service can be based on cost of provision of the service, as calculated in Phase 2, plus some acceptable profit.

The electricity market design can also influence reserve levels and other frequency services. If too much energy is being traded close to real time then the System Operator must contract more reserves to ensure that the predicted demand can be met. One of the principles recommended in the Federal Energy Regulatory Commission of the USA (FERC) standard market design is that the design should ensure that the participant is encouraged to be in balance prior to real time (FERC, 2002).

In Eskom, Instantaneous and Regulation reserve are regarded as energy intensive reserves and the day-ahead scheduling of the reserve is based on day-ahead energy offers. The highest loss of profit of any participant determines the capacity price that is paid to all scheduled participants. Energy payments for Regulation service are made according to each participant's individual day-ahead offer and actual deviation in metered energy from day-ahead schedule. Regulation service also attracts a usage payment according to the number of MW moved at an annually agreed fixed rate (per MW moved) for all participants. The energy and usage payments are subject to satisfactory performance criteria that are presented later. Other reserve categories are scheduled according to prices offered for capacity. In real time, energy is dispatched according to the next cheapest solution for all units on AGC contracted for regulation reserve. Rescheduling is performed when there is a large change in demand or supply, which restores reserves. Mandatory frequency control services are under-frequency load-shedding for low frequencies and governing for high frequencies.

3.3.4 Phase 4: Maintain optimal performance

Maintaining an optimal performance means the controller design and performance are constantly checked to ensure an optimum is maintained. The process flow chart for this section is shown in **Figure 3.12.** Many things can change in this process, so it is important to monitor that everything is working as designed. This is also a process that monitors changes in supplier and customer performance or needs, which can trigger a complete review of the implemented design.

Chapter 7 shows the detailed calculations done for the Southern African frequency redesign project.

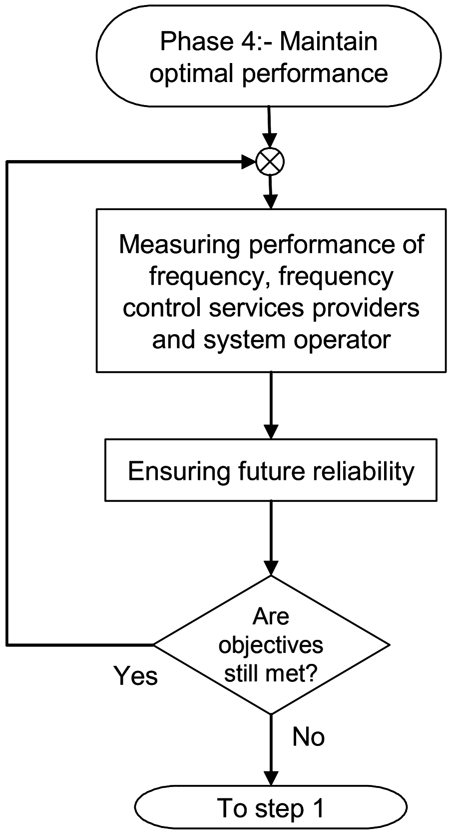

Figure 3.12. Flow chart for maintaining an optimal performance of frequency control.

3.3.4.1 Measuring performance of frequency, frequency control service providers and system operator

The performance of frequency, frequency control service providers and the system operator need to be monitored to ensure that the solution remains optimal.

Measuring the performance of the frequency

Research has shown that the performance monitoring of frequency varies between utilities. IEC 61000-4-30 (IEC, 2003) proposed that frequency measurement for performance monitoring for the customer is calculated as a ten-second average. An average of 10 seconds is too slow for control purposes on most networks - in 10 seconds the frequency could vary by 1 Hz or larger. The measurement of standard deviation will vary depending on the averaging of the raw data. For example, a utility in Japan reports on the standard deviation of frequency based on one-minute average samples. For Eskom, this would reduce the standard deviation from 60.6 to 41.5 mHz (In December 2002, 4 second data was averaged to one-minute samples).

For control areas in a network the measurement of ACE is also important. This indicates how well the supply and demand balance in each control area is being managed. NERC Control Performance Standard 1 (CPS1) combines ACE and frequency to have an overall measure of performance. The Southern African Power Pool has adopted the new NERC standards to measure each control area's performance.

The number of times the frequency exceeds boundary limits is also a key indicator in determining performance of the network. Eskom records the number of incidents below 49.5 Hz, 49.2 Hz and 48.8 Hz. The latter two indicate the number of times load is shed automatically by the customer voluntary and mandatory under-frequency load shedding schemes.

Measuring performance of frequency control service providers

For markets to operate successfully, the suppliers of a service need to prove that they can provide the service. The participants should also be monitored to ensure that the service is being provided. Financial penalties for poor performance could also be implemented.

In Eskom, all the frequency control markets have certification and performance monitoring. Most of the frequency control services have automatic performance monitoring (Chown and Coetzee, 2000).

Measuring the performance of the system operator

The system operator is affected by the introduction of the market, as the traditional way of dispatching generators is no longer valid. This requires new tools, training and, in some cases, more staff. The market is more volatile than traditional dispatch based on marginal costs and the system operator often has to justify actions that are not strictly according to the least cost dispatch. Metering is also an issue as there are discrepancies between instantaneous values received in the Energy Management System (EMS) and the billing meter. The dispatching is not always straightforward due to technical limitations.

In Eskom, there are times in the day when many generators are required to keep up with the increase in demand and the dispatch cannot strictly follow the merit order. Participants who are not dispatched strictly according to the merit order might require justifications. Furthermore, the system operator has some discretionary power to allow the frequency to run low for a short period instead of scheduling an expensive balancing option. Although this is fair to the participant paying for the imbalance, it may not be fair to the generator not dispatched. These issues require careful consideration when deciding on incentives for the system operator, as the least cost dispatch might have a high risk associated. The author has developed a model in Matlab© to re-run the previous day and compare theoretical against actual dispatch. This tool is used to evaluate system operator dispatch performance.

3.3.4.2 Ensuring future reliability

In a non-regulated industry, the system operator should be involved in the specification of new generators, networks and customers to understand the impact on frequency and frequency control.

When the industry is deregulated, it is important to ensure that minimum standards are set for the design of new plants. This can be done through a connection code that specifies the minimum requirements for new participants. This minimum standard can always be changed but at least all participants are aware of connection code changes.

The system operator should be involved in any connection code changes and market rule changes for possible impact on frequency or frequency control strategies. This will determine whether there is a need to redesign the current frequency control strategies.

3.4 Summary of Chapter 3

The proposed generic algorithm to determine the cost savings if frequency control is relaxed is broken into four phases. Phase 1 determines the boundary conditions for frequency and the minimum control required to meet the boundary conditions. Phase 2 calculates the cost and benefits of control of frequency. Phase 3 is the development of an optimal relaxed strategy and Phase 4 is the maintaining of the new optimal strategy. The broad strategy has been proposed in this chapter. **Chapters 4, 5, 6 and 7** give the detailed economic calculations that are proposed, and which were applied in the Southern African frequency control relaxation project.

Chapter 4 : Phase 1 - Determine the boundary conditions and minimum control

Determining the boundary conditions of frequency control and the minimum control required to meet the boundary conditions

4.1 Introduction to Chapter 4

This chapter describes the economic impact of large frequency variations and determines the minimum amount of control required to remain within acceptable zones. This section is the first phase in the method to determine whether it is economically beneficial to relax frequency control. Maintaining the frequency within frequency ranges acceptable to the customer, generators and the transmission network seems obvious. However, this chapter will show that the determination of what is acceptable has not only technical considerations but also economic considerations. In a large interconnection, there are many types of generators, all with different frequency tolerances and cost curves for off-nominal operation. **Appendix B** presents the relevant standards applicable to the various electrical equipment and the economic aspects will build on this information.

Chapter 4 formulates economically acceptable boundaries for the overall interconnection. The amount of control needed to achieve these boundaries is formulated through detailed modelling and analysis of disturbances. The problem is partially linearised with some simple models to make it easier to determine the minimum amount of control required. The chapter analyses the influence of external factors such as voltage and locational constraints on minimum control.

4.2 Understanding and costing frequency deviations on generator, consumer and network

The literature study of networks around the world, presented in **Chapter 2** and **Appendix A**, revealed that the quality of frequency control varies vastly. The Eastern Interconnection of the USA targets a standard deviation of frequency of 0.018 Hz from nominal 60 Hz (NERC, 2006), whereas in India an acceptable frequency deviation is 1 Hz from nominal 50 Hz (Rebati, 2001). **Appendix B** lists the standards that govern the manufacturer of electrical equipment which is important in determining the tolerable frequency range. What can electrical equipment tolerate without damage and what is the largest frequency the consumer can tolerate while still producing a product? If the consumer cannot produce a product because the frequency is out of bounds then the cost to the customer is high. This section will develop the costing of generator, consumer and network.

4.2.1 Sensitivity study of frequency on electrical machines

4.2.1.1 Impact of frequency deviations on steam turbine type synchronous machines

Studies done by IEEE and manufacturers (EPRI, 1979) have shown that frequency deviations can damage turbine-type synchronous machines. Turbine blades are the most affected with the most serious consequences. Turbine blades have a natural frequency of oscillation near to nominal frequency, and the oscillations of the blades are magnified if the turbine is operated at speeds near to these natural frequencies. The increased vibration of the blades can lead to total failure of the blades. The long blades of the low-pressure turbine are the most susceptible to damage from abnormal frequency operation. If a single blade fails, the damage can be catastrophic as nearby blades are also damaged when the faulty blade travels through the turbine. These failures then require a major turbine outage. A suspected blade failure in an Eskom

600 MW generator caused extensive damage to both the turbine and generator and led to a fire that destroyed the entire turbine and generator. The increased blade vibration and subsequent fatigue due to network frequency is shown in **Figure 4.1.** Below stress level A, the vibration stress is low enough to cause no damage to the turbine blade. This design point should correspond to the zone A boundary described in the IEC 60034-1 standard shown in **Figure 4.1.** Operation at stress level B would produce a failure after 10 000 cycles, and produce a failure at 1 000 cycles at stress level C.

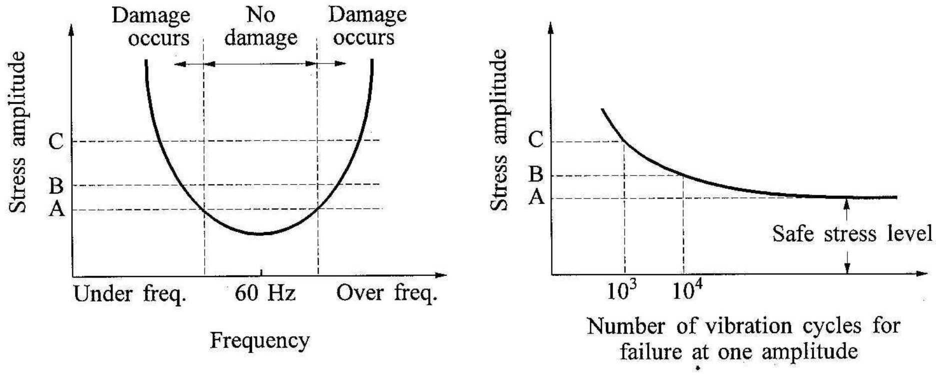

Figure 4.1. Vibration amplitude, stress and failure due to steam turbine off frequency operation (Kundur, 1994).

The effect of off-frequency operation applies to instances when the unit is both synchronised and not synchronised to the network. During the periods when the unit is being run up to nominal speed and when it is being shut down, damage can occur if the turbine operates at the natural blade frequencies. Manufacturers have procedures to prevent damage and most turbines are run up and shut down with the assistance of automatic control systems to prevent damage. Over-speed can occur on the unit when it is suddenly disconnected from the network. Speeds as high as 105% could be experienced. This overshoot has been significantly reduced with modern electro-hydraulic turbine governor valves and automatic control systems.

Each time a turbine blade is exposed to harmful operation a certain amount of turbine life is lost and the destruction is cumulative. Utilities normally track the amount of abnormal frequency operation and can have under-frequency and over-frequency tripping if the turbo generator is operated for too long outside predetermined limits. A composite of the worst-case limitations of five manufacturers in the USA is shown in **Figure 4.2** (IEEE, 1987). If the frequency rises to 61.5 Hz, the operating time limit for the unit is 35 minutes. These operating ranges where damage can occur have to be considered when determining the boundary conditions for frequency control otherwise generators will be damaged which will cause long term reliability problems on the network. An additional problem occurs when the frequency is low and online generators need to trip. If these generators actually trip, this will lower the frequency further and will result in a partial or total blackout of the network. To prevent the frequency remaining low for extended periods, networks employ under-frequency load-shedding schemes where load is automatically shed to restore the frequency.

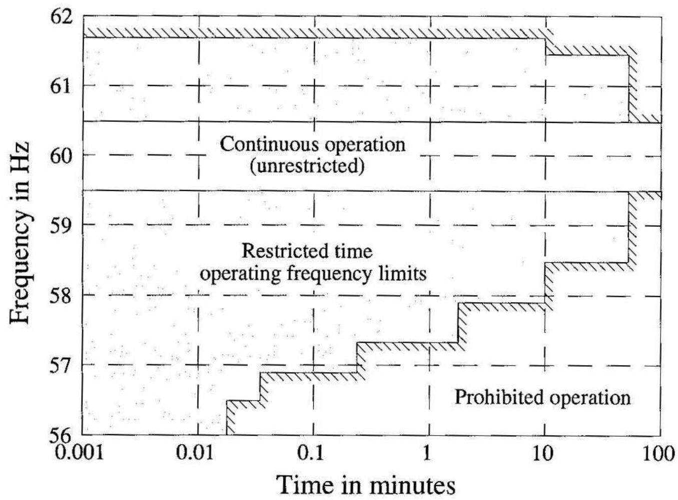

Figure 4.2. Off-frequency worst-case limitations from five turbine manufacturers (Kundur, 1994).

4.2.1.2 Economic analysis of the impact of large frequency deviations on steam turbine type synchronous machines

From **Figure 4.2** a function of frequency deviation *vs.* cost of damage is developed. Most steam turbines are designed to have a life of at least 30 to 50 years and some blade repairs every 5 to 10 years. According to this curve, a catastrophic failure could occur in seconds if exposed to frequency deviations greater than 5% of nominal. The repair time could be as long as a year and hence the cost of repairing all the blades is high.

Equations 4.1 to **4.7** calculate the acceptable time or number of allowable incidents per frequency range.

$$f(incident\_blade\_damage) = \int_0^n e^{-k\Delta ft}\,dt \qquad \textbf{(4.1)}$$

Where:

$f(incident\_blade\_damage)$ is the blade damage that occurs for each incident the frequency is outside the acceptable continuous range

n is the time the frequency has been outside the acceptable continuous range

k is the conversion factor from time to damage

The potential damage is described as follows*:*

$$Potential\_damage = \rho_{failure} * \sum_1^m f(incident\_blade\_damage)_m \qquad \textbf{(4.2)}$$

Where:

$Potential\_damage$ is the potential damage over the life of the plant.

$\rho_{failure}$ is the probability of a blade failure.

$\sum_1^m f(incident\_blade\_damage)_m$ is the sum of the damage for all incidents.

A probability of failure is required as it is not an exact science to determine the time, exact damage on the turbine blades and the cumulative damage. Practically, the capital cost of a coal-fired steam turbine is very high, so these calculations will conclude that it is best to operate the generator predominantly within the continuous band. The cost calculation is the expected number of times and time per incident that the frequency is going to move outside the acceptable continuous operation band.

Therefore, one can calculate for the first band from **Figure 4.2** when:

f < 59.4 Hz (1% of 60 Hz)*:*

Number of times where Δf < 1% = x / year **(4.3)**

If the time frequency is < 1% is y min per incident then the time outside the 1% bound per year is

$T_{outband}$ = *Time outside a band = x * y * life expectancy of plant* **(4.4)**

And the manufacturer requires that

$T_{outband}$ < *Allowable band per year* **(4.5)**

or

*Number of excursions outside band < band time / (life expectancy of plant * time per incident*) **(4.6)**

For the first band from **Figure 4.2,** with a 30 year plant life and an average of 2 minutes per incident, the maximum number of incidents outside the allowable frequency band per year is:

*Number of excursions outside band < 90 / (30*2) = 1.5 incidents per year* **(4.7)**

The target for frequency control is then to limit the number of excursions outside the one percent on nominal frequency. This information is required to set targets for frequency control during contingencies.

4.2.1.3 Impact of frequency deviations on hydroelectric-type synchronous machines

Hydroelectric units are not subjected to the same extremes as steam turbines but still do have some problem zones. Typically, frequency deviations up to 8% from nominal can be tolerated. Some hydroelectric machines have been designed to operate with very high frequencies. In Southern Africa if there is a disturbance on the HVDC line from Cahorra Bassa, the local frequency goes as high as 55 Hz. These hydroelectric machines were designed to tolerate these large frequency variations.

4.2.2 Study of the sensitivity of the customer to frequency deviations

The specified frequency bands for generator operation are known and have been well documented in the standards (EPRI, 1997 and EPRI, 1998). On the contrary, information on the effects of power system frequency variation on customer equipment is limited. This section aims to clarify the frequency sensitivity of common end use devices found on an electrical network (Chown and Coker, 2000).

4.2.2.1 Computer Equipment

EPRI and NECA have researched the effects of frequency variation on computer equipment (EPRI, 1979 and NECA, 1998). A survey of manufacturers' equipment indicated that the frequency range for computer equipment was relatively large (60 ±1 Hz). These studies were done in 1979 and 1998 respectively, and since then there have been advancements in computer supplier technology. Many computer manufacturers supply computer equipment with multi-voltage, multi-frequency switched mode power supplies. These power supplies typically allow for large variations for frequency. A common value of 47 – 63 Hz has been used.

Most of the minicomputer and mainframe parts have their own power supplied and are more sensitive to frequency variation than personal computers. The most sensitive part of these larger computers is the disk drive, yet it will function under a relatively wide range of frequency. HP specifies their range to be 47 – 63 Hz. A more stringent specification comes from Digital Equipment, being 60 ± 1 Hz for all their computer components.

Research done by EPRI (EPRI, 1979) in 1979, revealed that computer monitors typically plug into line AC power at a wall socket or the back of the computer power supply. According to several manufacturers and service companies, most of the monitor parts are DC driven and are not affected by frequency. Other parts, however, such as the filament which some manufacturers use is transformed from mains supply to 6.3 V_{ac} , and are frequency sensitive. These parts are designed to operate without any problem with fluctuations as large as ± 3 Hz in the power line frequency. A 2001 survey of three large computer monitor manufacturers indicated that the current monitors would work correctly for a 45 - 65 Hz frequency input variation

(Chown and Coker, 2001). Other manufacturers specify a 47 – 63 Hz frequency variation for computer monitor equipment.

Hajagos and Danai (1998) detailed the response of common office equipment to variations in frequency (±10%). This equipment included modern air conditioners, discharge lighting, computers, monitors, printers and fax machines. It was found that the active power component of these loads is essentially frequency-independent. This is the only documented testing on devices with frequency excursions in excess of 5%.

4.2.2.2 Consumer Electronics

Most electronic equipment produced today is designed to operate on both 50 Hz and 60 Hz power systems. Tolerance is usually given as ±5% that equates to an operating frequency range of 57 – 63 Hz for 60 Hz systems. As for computer equipment, current consumer electronics should be unaffected by small variations in frequency. This would include TVs, VCRs, photocopiers and communication equipment.

4.2.2.3 Consumer Household Appliances

An EPRI survey (EPRI, 1979) showed that consumer household appliances (such as microwaves, refrigerators, clothes washers, and clothes dryers) are not affected by fluctuating frequency anywhere in the range of 60 ± 1 Hz. Some manufacturers even allow for 60 ± 2 Hz.

4.2.2.4 Motors

Motors rotate at a speed that is dependent on the frequency of the power system. If the frequency is low, the torque developed by the motor is reduced. The magnitude of the motor load varies directly with the frequency. An additional impact on motors involves the natural cooling action of their rotation by a mechanical fan. When the frequency is reduced, this natural cooling action is reduced. A survey of the large motor manufacturers (Alstom, Siemens, ABB) indicate that the motors would still operate correctly within a ±2% variation from 50Hz frequency (Chown and Coker, 2001).

4.2.2.5 Variable Speed Drives

Many electrical motors on power systems today are controlled by variable/adjustable speed drives. DC drives and current source inverter drives, which use phase commutator inverters, may malfunction under varying system frequency. A survey of the following drive manufacturers in South Africa (SAFTRONICS, ABB, Siemens, Telemacanique) indicated an allowable frequency range of 50 Hz $\pm$2% (Chown and Coker, 2001). ABB drives are able to operate normally with a 50 $\pm$5 Hz bandwidth. Alstom LV drives have an allowable frequency deviation of 45 – 65 Hz as these drives are designed for both 50 and 60 Hz systems. Older drive technology may be affected by frequency variation.

4.2.2.6 Timing Systems

Electrical clocks and other equipment that measure, or are based on time derived from the electrical mains system, are affected by the cumulative effect of low or high frequency. However, there has been a move away from calculating time based on power system frequency. Current timing clocks in computer and control systems use DC excited crystals to create a timing reference. As noted above, AC to DC supplies are insensitive to $\pm$1Hz changes in frequency. Information obtained from the SABC (South Africa's public TV and radio broadcaster) and TELKOM (South Africa's telephone company) revealed that equipment that generates the timing/frequency standards is specified to operate correctly within the 25 - 400Hz range. These systems are also connected to UPS for greater reliability.

4.2.2.7 Electricity metering devices

Old electricity metering devices use frequency for determining the metering period, where typical metering periods are hourly or half-hourly. If the frequency is operated below the nominal frequency then the metering period is longer than required. This error will only be cumulative if the frequency is continuously run above or below the nominal frequency. If there is a variable tariff, where the rate charged for electricity varies from one hour to the next, then the meter could be in error for one or more of these periods and incorrect billing is done. Meters surveyed of this era have an accuracy of 0.5% and this error will be increased if the frequency is operated with an average frequency error greater than 0.5% (0.25 Hz for 50 Hz).

4.2.2.8 Economic analysis of large frequency deviations on consumer equipment

The research shows a minimum operating range of 2% from nominal frequency for consumer equipment. Outside this range, some electrical equipment might not be able to operate. In some cases for large electrical equipment, the plant will have under- and over- frequency protection. The cost is the economic impact due to not having any production from this electrical equipment, graphically represented in **Figure 4.3.** The term often used for the cost incurred when the consumer cannot produce because there is no electricity is the cost of unserved energy, commonly priced as at least 10 times the cost of electricity. An Eskom survey of 32 customers found the un-served energy cost in the range of 3 - 15 R/kWh (Pabot, 1998) when the average cost of electricity sold was 0.102 R/kWh (Eskom, 1998).

The conclusion that is drawn from this information is that there is no economic impact to consumer electrical plant life if the frequency is within the 2% of nominal frequency and there might be some cost implication outside this range. Later chapters will discuss the financial impact of small frequency changes on efficiency and electrical production as the frequency control over small ranges is optimised.

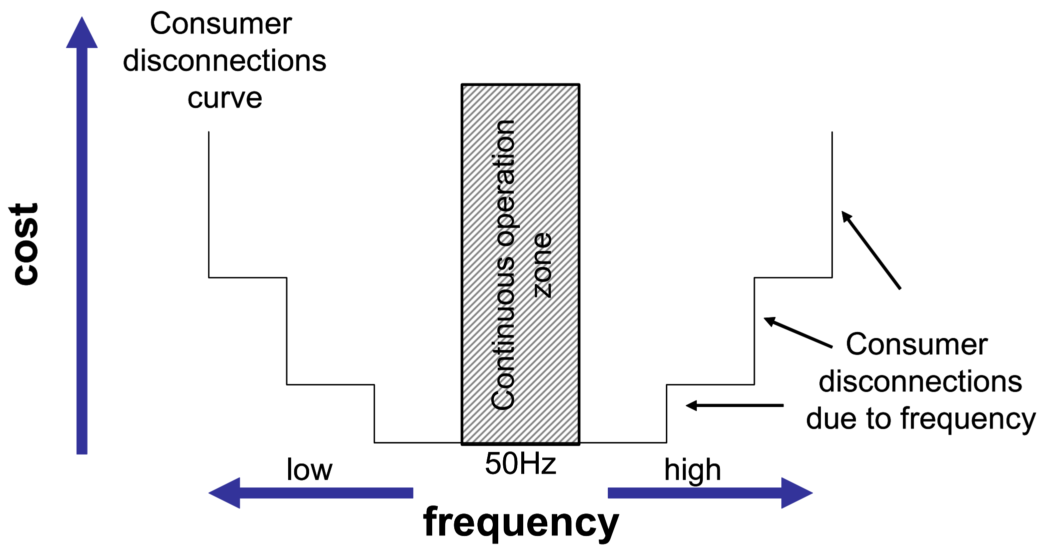

Figure 4.3. Graphical representation of cost against frequency for the consumer.

4.2.3 Study of the sensitivity of the network to frequency deviations

In the transmission and distribution network, there are devices that are frequency sensitive. Metering devices have already been identified as the old electricity meters use the nominal frequency to calculate the integration period. Metering is only applicable between different transmission companies and in interfaces to distribution and generation.

Any equipment in the transmission system that has an inductance with capacitance configuration has been designed for nominal frequency. When the frequency is not at the nominal frequency this type of equipment will not operate optimally. Essentially this equipment should be manufactured to the standards presented previously and hence should be able to tolerate the same frequency deviations.

In Eskom, the filters on the HVDC link to Cahorra Bassa from Apollo are frequency sensitive. The AC filters at Apollo are sharply tuned for the $5^{th,}$ $7^{th,}$ 11^{th} and 13^{th} harmonics of 50 Hz (Goosen, 2001). The High Pass (HP) filter has a broader band due to its damping resistance.

All filters except the HP filter are tunable to neutralize de-tuning by temperature effects and capacitance variations or due to fuse operations. The slow tuning is provided by tap-changers that vary the inductance. This tuning takes place at about 10 seconds per step. The impact of about 0.5% inductance change per step on the respective tuned frequency varies per filter but could be ~0.7% change in tuning frequency. A step could thus neutralize ~350 mHz of grid frequency change.

For protection against possible parallel resonance between the filters and the grid, the filter bank as a whole (only one breaker) is protected against grid frequency deviations away from 50 Hz. This protection has two settings. The first trip setting for ±800 mHz deviation from 50 Hz is time-delayed for 20 seconds, while the second trip setting for ±1 Hz causes instantaneous tripping.

The high level of harmonic currents that are injected into the grid in the absence of the filters makes it prudent to discontinue or reduce HVDC import as soon as practically possible.

Provided the grid conditions created by the injection of the large amount of harmonics are acceptable, and as long as no converter auxiliary system - like transformer or valve cooling - or UPS systems for the valve controls, are affected by the under-frequency and possible concomitant under voltage, HVDC operation can continue indefinitely in the absence of AC filtering (Goosen, 2001).

4.2.3.1 Economic analysis of large frequency deviations on the network

The research shows that whenever the frequency is off nominal, there is an impact and potential damage for transmission devices that have either capacitance or inductance. Most equipment on the transmission network has some protection to prevent damage and hence the impact is the effect on the network when the capacitive and inductive devices trip. This will eventually lead to a voltage collapse and probably cause parts of the network to trip. **Figure 4.4** shows a graphical representation of this behaviour. The particular studies done in Eskom focused around the impact of the loss of the HVDC filters, which trip when the frequency is less than 49.2 for 20 seconds. In this case, harmonics are no longer filtered and are injected into the network. The conclusion of these studies showed no impact to the network as long as the period operated without the filters is short (Goosen, 2001).

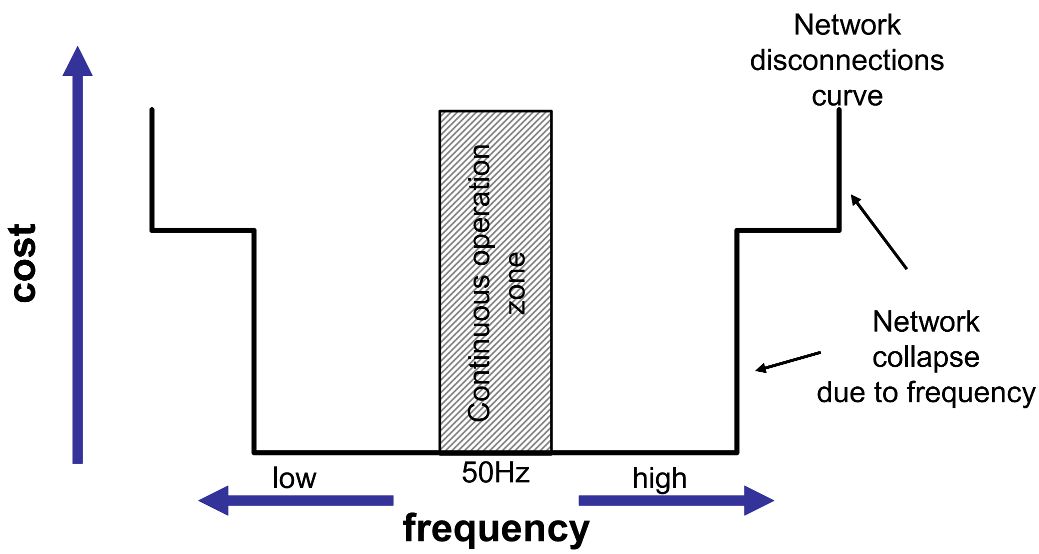

Figure 4.4. Graphical representation of cost against frequency for the network.

4.2.4 Combining generator, consumer and network requirements

It is difficult to combine the various standards for generators for electrical equipment due to the different perspectives put forward by each standard. It is concluded that there is no damage, hence no extremely high costs, to electrical equipment to frequency deviations less than 0.5 Hz. No standard is stricter than this for any generator, network or customer electrical equipment. All standards allow the frequency to vary beyond these limits for short periods. If generation equipment is manufactured strictly according to these standards then it is assumed that there is an economic impact when the frequency goes beyond a frequency deviation of 0.5 Hz. All the customer standards expect the electrical equipment to operate within a frequency deviation of 1 Hz. When the frequency is outside the range of 1 Hz from nominal then it can be assumed that there is a high economic impact, there is potential generator and turbine damage and systems are required to ensure a fast frequency restoration. The damage to generators and turbines due to frequency deviation could come as a great cost to the interconnection and to the consumer. A composite curve of the consumer, generator and network is built up for the interconnection under study. **Figure 4.5** shows the possible relationship between the three components.

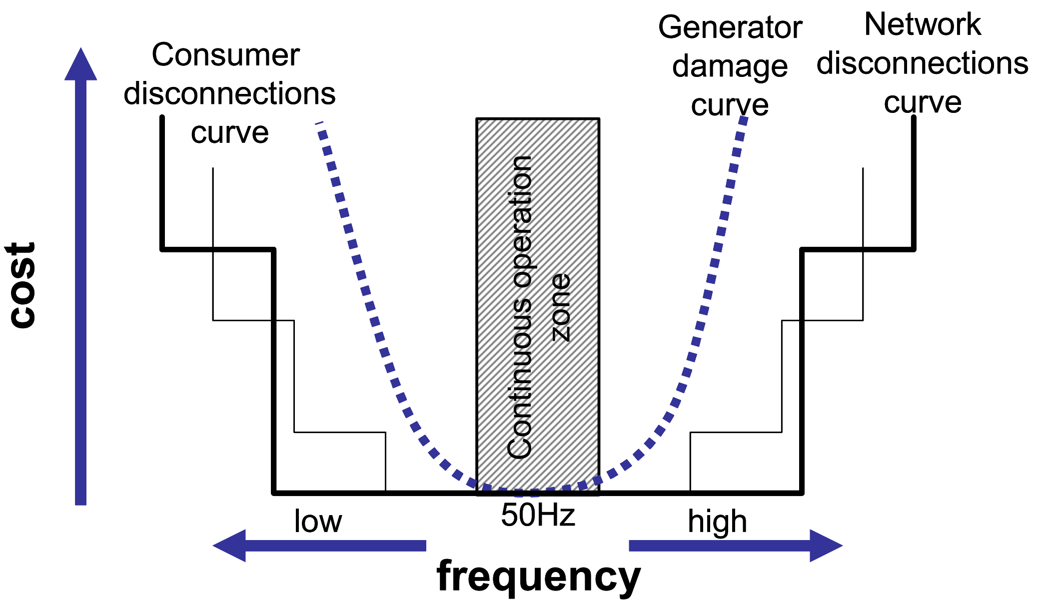

Figure 4.5. Composite cost curve of consumer, generator and network costs due to large frequency deviations.

Appendix B, Section B.2.2.4, discusses the conflict between the existing method for under frequency load shedding in South Africa and the new frequency standards introduced for generators in the South African Grid Code. Such conflicts influence the determination of acceptable boundaries. For this study, the conflicts will not influence the frequency relaxation study as this conflict is in the region outside the acceptable boundary of 1 Hz for multiple contingencies.

4.3 Determining acceptable frequency boundary conditions

From the study of the economic impact of large frequency deviations on electrical equipment, it is possible to determine frequency extremes, or boundary conditions, for various contingencies acceptable for a particular network. This chapter describes the process required to determine acceptable frequency boundary conditions considering the economic impact.

4.3.1 Why are boundary conditions required?

Boundaries determine levels of frequency that are acceptable for a particular network. This is the first phase in determining: whether control is required, when it is required and why it is required. Any control that is required will have an economic impact because the generator or consumer that is changing its output will have a cost associated with the control.

Boundaries that are set too tight will result either in generators being over-controlled, or in customer loads being disconnected too early. The setting of too wide a boundary will lead to inefficient operation or damage to customer equipment and generators. The consequences of a too wide boundary may only be in the long-term health of equipment where, for example, turbine blades are damaged over periods of years. Early replacement of generator and customer equipment could cause a massive expense to the economy of the country, whether this is due to too tight or too slack control of the frequency.

4.3.2 Determining frequency extremes for single and multiple contingencies

The outer boundaries for the various components of the electrical system have now been determined. The highest and lowest frequency that is acceptable to the network, consumer and generator are known. The maximum deviation tolerable is determined by the boundary acceptable to all. The next question is: when single or multiple contingencies occur, what maximum frequency deviation is acceptable for the network being studied? Important information at this point is that the size of the frequency deviation to a contingency is proportional to the size of the contingency if no control is performed. This is explored in further detail later.

4.3.2.1 Acceptable frequency deviation for single contingencies

A single contingency is a single event of the sudden and unplanned disconnection of a generator or consumer. The largest single contingency that will cause a low frequency is the largest generator that can trip or the largest consumer that can switch on. The largest single contingency that can cause a high frequency is the largest disconnection of a consumer. The single tripping of a line in the network connecting consumers or generators is also considered. Historical data is important to determine what single contingency may be disregarded. For example, the largest generator historically might only trip infrequently and in some cases may be disregarded. However, if the largest single contingency occurs often it will be prudent to restrict the frequency deviation to a tighter band due to the risk of another event occurring while the frequency is on the boundary of tolerance.

Small networks with a few large generators or consumers will experience a larger frequency deviation than larger networks. The risk of a second event occurring is smaller due to the fewer generators. For a small network, it could be acceptable for the frequency to remain within the maximum deviation tolerable. This is to say that a single generator trip will not cause the network to black out, or generators to trip, on an over-frequency. The single generator trip will also not cause any damage or loss of production to consumers.

Networks that have a fast restoration time, for example in 10 minutes, could opt to push the boundaries further. Careful consideration needs to be given to this option as essential supplies, such as a hospital where a loss of electricity could be life threatening, would need to have backup generators.

4.3.2.2 Acceptable frequency deviation for credible multiple contingencies

A credible multiple contingency is the event of the sudden and unplanned disconnection of more than one generator or consumer that is likely to occur within a predefined period due to a known weakness in the network. The causes of such events are many and they include a voltage depression at the connection point of more than one generator that will cause all the generators to trip. In some networks, adverse weather can be the major cause of multiple generator trips or multiple consumer disconnections. At a power station with more than one unit, a common fuel supply, control air supply or common auxiliary electrical supply can cause a multiple unit trip.

4.3.3 Southern African Power Pool new frequency boundaries

The determination of boundaries takes the information presented in the previous section into consideration. If the proposed boundaries require a legal or quality-of-supply standards change, this will have to be taken through the legal processes. A process of discussions with customers would also be required. If the proposed boundaries were within these requirements then there is not the need to have major discussions with customers.

4.3.3.1 Largest single contingency in the Southern African interconnection

The largest single event of the sudden and unplanned disconnection of the largest unit in Southern Africa is the loss of a Koeberg unit at full load, i.e. 920 MW (the Cahora Bassa infeed is classified as a multiple incident). This represents a contingency of 2.8% of peak demand (33 000 MW) and about 4.2% of minimum demand (22 000 MW). The next calculation is the probability of a second single contingency before the frequency is significantly restored. Eskom currently records around 100 generator trips during a year. Historically, the frequency from a single contingency is typically restored within 5 minutes.

4.3.3.2 Largest credible multiple contingencies in the Southern African interconnection

The largest credible multiple event is the sudden and unplanned disconnection of more than one unit in Southern Africa or the largest credible other contingency. The time frame for the trips to occur is within 10 minutes. Historically, the number of multiple trips is summarised in **Table 4.1**.

Table 4.1. History of sudden and unplanned disturbances in Eskom.

Date	Number of disturbances 900 – 1800 MW within a ten minute period (per year)	Number of disturbances > 1800 MW within a ten minute period (per year)
1971 to 1980	~ 30 (Levy (1980) and Levy (1978))	~ 5 over ten year period (Conradie and Paterson, 1979)
1981 to 1990	~ 5	2 over ten year period
1991 to 2000	~ 3	3 over ten year period (one loss of generation & 2 loss of load)
2001 to 2002	~ 14	2 over the last 2 years (both loss of load)

The number of disturbances between 900 and 1800 MW is significant per year. The largest credible contingency was defined as the largest credible disturbance that can occur once or more a year. This decision was based on an iterative process of finding an acceptable level of under-frequency load-shedding that should occur per year and on the above historical data of disturbances. The largest credible multiple contingency is hence defined as the loss of 1 800 MW generation (typically three coal-fired units, both Koeberg units, or the loss of the Cahora Bassa infeed).

4.3.3.3 Defining of boundaries for Southern Africa

An initial decision was taken to control the frequency within 1 Hz following the largest multiple credible contingencies as defined above. This was made for two reasons:

a) An 1 Hz deviation is within international guidelines and acceptable deviation to all consumers and the network as discussed previously in this chapter and shown in **Appendix B**.

b) There is a cost to the generators but this is minimal given the cost curve in

Figure 4.2. As long as there are only a few incidents and the frequency is restored quickly to within 0.5 Hz it is not necessary to take drastic measures to restore the frequency rapidly via mandatory and indiscriminate load-shedding.

This boundary is confirmed later, after completion of further detailed studies.

For single contingencies, it was decided to control the frequency within 0.5 Hz, for the following reasons:

a) This is within boundaries of IEEE recommended practice (IEEE, 1995) and IEC quality of supply standards for continuous operation of all electrical equipment (IEC 1988, IEC 1999). There is no economic impact to the generator, consumer and network in terms of damage or inoperability.

b) The probability of a second single contingency occurring before the frequency is restored is relatively high. Historically this occurs more than once a year.

Again, this boundary is confirmed later, after completion of further detailed studies.

The single contingency boundary for Eskom was modified from 0.3 Hz to 0.5 Hz, see **Figure 4.6** and **Figure 4.7**. These boundaries were proposed to the Southern African Power Pool for their consideration and adoption, as there were no specified boundaries for contingencies in SAPP.

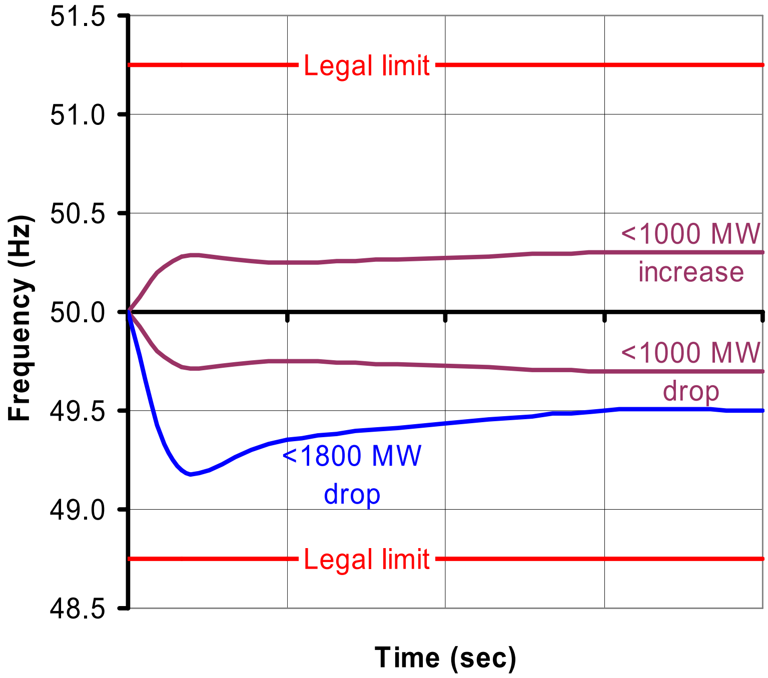

Figure 4.6. Eskom boundaries before the project was initiated.

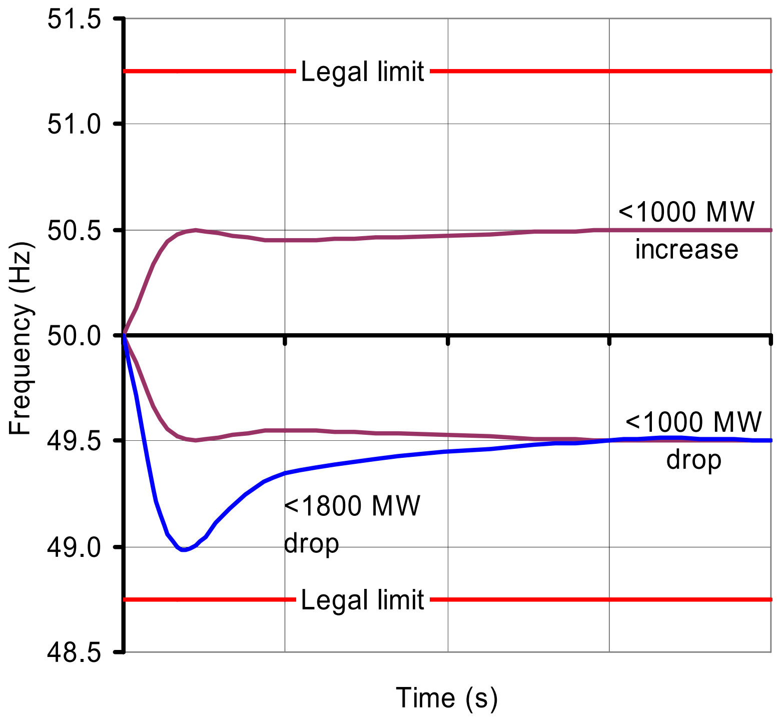

Figure 4.7. Proposed boundaries for single and multiple contingency.

4.3.3.4 Control of frequency with incidents greater than the largest credible multiple contingency

The development of boundaries for single and multiple contingencies is complete. There is a possibility of a larger disturbance on the network. The generator capability curve shown in **Figure 4.2** can be developed into an incident curve. The allowable time per incident has been developed as an example and the allowable time and frequency per incident is redrawn in **Figure 4.8.**

This can be expressed as an equation and for South Africa, the equations from the South African Grid Code for low frequencies are (NERSA, 2003):

- *Frequency not to be < 47.5 Hz for more than 0.1 seconds*
- *Frequency not to be < 48.0 Hz for more than 10 seconds*
- *Frequency not to be < 48.5 Hz for more than 60 seconds*

The under-frequency load shedding scheme then needs to be designed to ensure these conditions are satisfied.

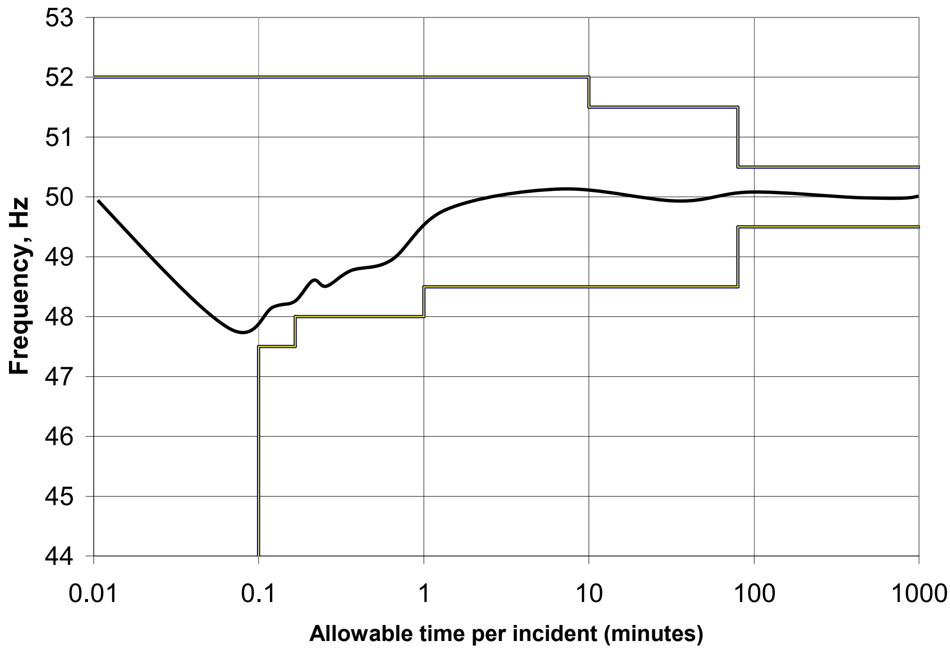

Figure 4.8. Graph showing the allowable time per incident for disturbances greater than the largest multiple contingencies.

4.3.3.5 Average frequency

The average frequency was a concern to members of the Southern African Power Pool. The average frequency is measured by the time difference between real time and time using the network frequency. The original requirements at the formation of the Southern African Power Pool (SAPP, 1996) were that the network time should be within 10 seconds of real time. The new proposed boundary was that the time should be within 30 seconds of real time under normal conditions. The economic impact of this decision is studied later in this thesis.

4.4 Calculating the minimum control required to meet boundary conditions

This section calculates how much control is required to achieve the boundaries targeted in the previous section. The section will determine and cost a suitable control strategy for controlling frequency within the proposed bounds for single and multiple contingencies for Southern Africa.

4.4.1 Calculation of minimum control in Southern Africa

The theory and practical aspects related to the dynamic behaviour of the frequency especially during disturbances is studied in **Appendix C**. The model developed in **Appendix C** has been tuned for the Southern African network and has proved to be accurate for disturbances up to 1800 MW. Beyond the 1800 MW trip it has been decided that automatic under-frequency load-shedding is required. The simplified model is now used to calculate the minimum amount of control for disturbances. A disturbance is simulated and the spinning reserve, customer load shedding and inertia is manipulated until the minimum control is determined.

If the boundary conditions cannot be met, the frequency control study needs to be started over to see what customer requirements and or boundaries can be relaxed.

For Eskom, it was calculated that a minimum of 390 MW on governing or from customer under frequency load shedding is required to meet the multiple contingencies boundary, **Figure 4.9**. With 390 MW, there was sufficient governing to also meet the single boundary condition. No addition of reserve to cater for credible multiple contingencies under low demand times were deemed necessary for two reasons. (1) Reserves at low load are high due to the many plant at low load and able to govern up, and (2) at off peak times only a few base load stations are at full output.

The largest single contingency for a load is 700 MW. In order to keep the frequency within 1% of 50 Hz the requirement is 300 MW. The ancillary services requirement for contingencies causing a low frequency is set to 500 MW. The value for high frequencies is set to be the same as the requirement for low frequencies. This is currently mandatory for generators that are contracted to provide the low frequency service.

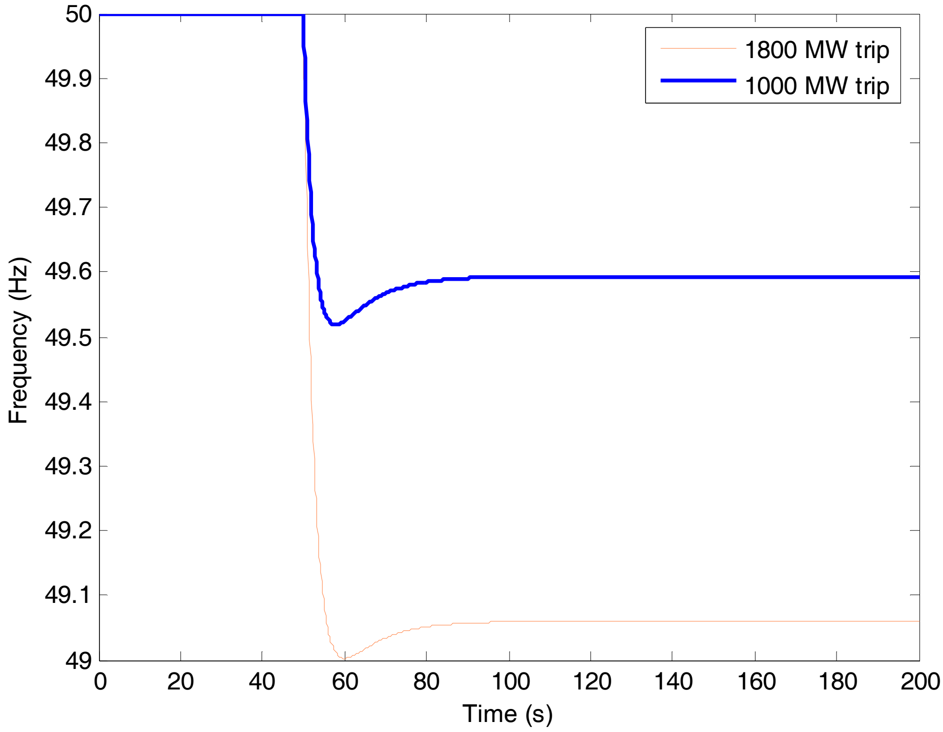

Figure 4.9. Simulation results for the Eskom network with trips of 1000 and 1800 MW and with 390 MW of governing.

4.4.2 Time of response required to arrest frequency for largest credible multiple contingencies in Southern Africa

In Southern Africa, the highest rate of frequency decline for an 1845 MW loss was measured as 0.225 Hz per second, and is shown in **Figure 4.10**. For the largest credible multiple contingencies (1800 MW) the highest frequency is hence calculated as:

0.225*(1800/1845) = 0.22 Hz per second

This calculation assumes the inertia of the network is reasonably constant which is true for the Southern African network, as most of the coal-fired power stations remain online throughout the day and night. The rate of change of the frequency decays exponentially as the difference in supply and demand decreases. In order to ensure that the frequency is arrested within 1 Hz, the response from generators or consumers must be within 10 seconds. A typical Eskom coal-fired generator responds around 3% of rated power (18 MW for a 600 MW generator).

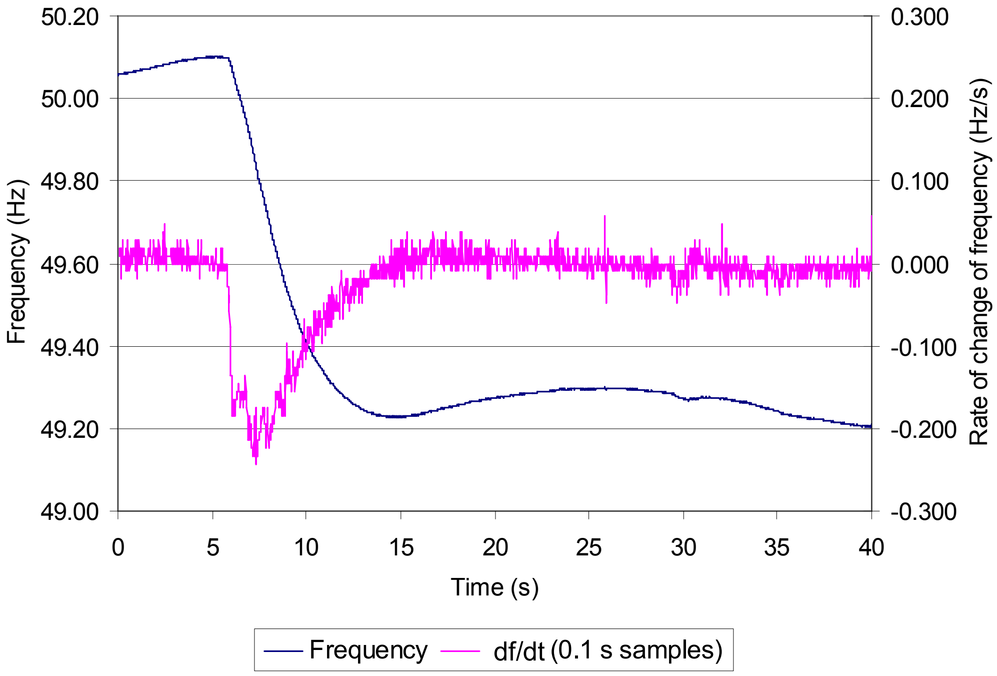

Figure 4.10. Frequency and rate of change of frequency for loss of 2760 MW of generation on 25 June 2003 at 16:30.

4.4.2.1 Co-ordinating generators and consumer response

Generators typically start reacting within 1-2 seconds and the response is proportional to the frequency error up to a limit. Consumers can switch off within 100 milliseconds. These are to be co-ordinated if both are providing the primary frequency control.

In Eskom, generators providing primary frequency control must start their response by 49.85 Hz and be fully responsive by 49.75 Hz. Note that the droop characteristic is not specified, but if a generator is on a 4 % droop, the response is 5 % of MCR. On the demand side, the criterion is that the participant must fully respond within 4 seconds if the frequency drops below 49.75 Hz. Currently, there is only one demand-side customer who has requested to certify as a primary frequency response participant. If there were more demand-side participants, the response would need to be in frequency steps to avoid over-shedding.

4.4.2.2 How long should the response be sustained?

The requirement in Southern Africa is that the frequency should be restored within 10 minutes of the disturbance. Governing and automatic under-frequency load shedding are designed to arrest the frequency and not to restore the frequency. Therefore, other control actions must be taken to restore the frequency to 50 Hz within 10 minutes. The response from power station governing or load being shed must therefore be sustained for at least 10 minutes, or as long as the frequency is below 49.85 Hz, to allow the system operator to call upon other participants to restore the frequency.

4.4.2.3 Restoring the frequency

The loss of any generation will require at least the equal number of MW capacity available to make up for the shortfall. The Southern African Power Pool (SAPP, 1996) requires that at least the capacity for the largest single contingency multiplied by a factor of 1.5 must be available for events. The Southern African Power Pool requires that a control area must be restored within 10 minutes following the largest single contingency (SAPP, 1996). Thus for Eskom, the frequency must be restored within 10 minutes following the loss of 920 MW. This translates to a minimum restoration rate of 92 MW/min. The average rate offered by 600 MW coal-fired generators is 15 MW/min therefore at least seven coal-fired generators are required to assist in the restoration. The ramp rate is not a problem if the hydroelectric units are available to restore the frequency, as all the hydroelectric generators are able to respond well above the required 90 MW/min rate.

4.5 Determine influence of locational constraints on minimum control

System security is primarily determining whether the system can survive a given set of contingencies and, hence, whether the system is reliable (Laughton and Say, 1985). Security determines that the network voltages, stability and constraints for contingencies are acceptably managed. In controlling the frequency, care needs to be taken to ensure that transmission lines are not overloaded and that corrective actions taken do not add constraints, voltage and stability problems. The control action needs to consider network security and this must be part of the final solution. Any additional control action required for locational constraints needs to be added to the minimum control determined in **Section 4.4.**

4.5.1 Security

The determination of the security of the network needs a similar analysis to that used in determining the boundaries for frequency control. The voltage boundaries of the network for normal and disturbance conditions need to be decided. What constitutes a credible disturbance also needs to be determined. Most networks also design for N-1 criteria. N-1 requires that a single contingency should not cause any loss in supply to any customer. The backbone of the transmission network where most supply is transferred is often operated to N-2, allowing for at least two contingencies before any loss of supply to customers. Eskom has a large radial network and small or distant suppliers are fed via single lines, as multiple lines are too expensive. Supply to these customers is hence lost if the supplying line trips.

The Southern African network is limited at the boundaries of the various countries. These become the main bottlenecks for power flow. The generation type is also split across these constraints where in the north the plant is mainly hydroelectric and in the south the plant is mainly coal-fired thermal. When re-designing the frequency control strategies these limitations must be considered. The following sections contain various examples of what need to be considered.

4.5.2 Economic considerations and network security

The understanding of where the constraints in the network are complex as it involves determining the different real and reactive power flow scenarios that can occur on the network. This includes identifying power lines that might be overloaded and determining points of voltage collapse. The introduction of deregulation has made the problem more complex as the determination of generation patterns and flows is unknown until market participants have made offers and consumers have entered their bids for power. In some markets, the bids and offers are only received within 2 hours of real time. The impact of deregulation is discussed in **Section 5.4**.

The cost impact of splitting a network is simple. If the network is split, causing a big mismatch between generation and consumer demand, the only way to restore the balance on the generation deficit area is to shed load. This cost can be calculated using the cost of un-served energy and the time to restore. An additional cost is the cost of generator trips and restarts should generators trip when the network splits. The final cost is that of uneconomic operation whilst the network is split. A voltage collapse would mean that load is shed due to the under voltage and could result in a partial blackout. The costs for a voltage collapse can be calculated using the same formula:

$$Cost_{networksplit} = \rho_{split} * \left(L_{shed} * CUE * t_{restore} + G_{start} + P_{split} * CUO * t_{split}\right) \quad \textbf{(4.8)}$$

Where:

ρ_{split} is the probability the network will split at a given point.

L_{shed} is the estimated load that will be shed (MW)

CUE is the Cost of Un-served Energy (R/MWh)

$t_{restore}$ is the estimated time to restore the load

P_{split} is the estimated power flow across the spilt before the network split (MW)

G_{start} is the estimated start up costs for generators that have tripped

CUO is the estimated Cost of Uneconomic Operation whilst the network is split (R/MWh)

t_{split} is the time that the network is split

The least cost case when the network has split is when no load is shed and no generators trip. The only cost in the calculation is the cost of operating generation at uneconomic levels to maintain the balance on each side of the split.

To overcome network security problems it is common practice to have regional control requirements for governing (spinning reserve in SAPP) and other reserves. The SAPP Operating Guidelines contain the minimum regional reserve requirements for each Operating Member. This will come at some economic cost as generators will have to be backed off to maintain these regional requirements. **Appendix E** describes incidents in the Southern African network, which have, and could have, resulted in a network split and describes some of the causes for this split.

Eskom and Zesa did a study to ensure the proposed frequency control strategy would not cause any load shedding or generator trips for various single contingencies. The results of these studies is presented in **Appendix E, Section E.4**. The existing minimal regional requirements for spinning reserve did not need to be increased. The modelling was done using PTI PSS/e© to ensure adequate capacity was available on these lines during contingency conditions. This work also considered the effects of contingencies on voltage and network stability. The final recommendation was that the locational reserves required in the Southern African Power Pool are sufficient. The total spinning reserve requirement is 690 MW that must be responsive in 10 minutes. There was no need for Eskom to increase its governing reserve.

4.6 Determine possible influence of voltage on minimum control during disturbances

A voltage increase, following the loss of generation, will increase resistive demand and hence further increase the imbalance between supply and demand. From a control perspective, the influence of voltage is seen as an external disturbance as it is not a part of the traditional frequency control loops. Voltage is however measurable and can be considered to be a control variable in the frequency control loop. The determining of minimum control strategy must include voltage disturbances. The voltage profile across the transmission network also determines where the power flows. If the voltage increases during a disturbance, causing an increase in resistive demand, the frequency will fall further than initially predicted. A network that is not adequately damped can experience frequency control problems as a result of the voltage perturbations.

Extra control might be required to counter the effect of high voltages on disturbances. Voltage increases can be caused by the shedding of too many customers or by reactive power swings at the point of the disturbance. Alternatively, there is a possibility to utilise the transmission network for frequency control such as switching out capacitors. The cost and risks of using such methods needs to be determined.

Appendix F studies the phenomena of high voltages during disturbances and the subsequent effect on frequency in Southern Africa. The studies show that Eskom measures a 1% increase in voltage when the HVDC connection to Cahora Bassa is lost. The HVDC substation is near to a major load centre in South Africa and the effect of the voltage increase causes an extra 0.1 Hz frequency drop. To counter the voltage effect it would be necessary to have about another 100 MW under governing for single and credible multiple contingencies. The voltage problem experienced at Apollo is the subject of a research project launched by the author at the time of writing this thesis. Until this phenomenon is corrected, the additional reserve amount is required.

Voltage control and stability of the network is a specialised field. When relaxing the frequency control such expertise is needed to give an understanding of potential voltage problems that could influence the frequency control and the possibilities available for frequency support.

4.7 Summary of Chapter 4

Chapter 4 has described the detail of phase 1 for determining the economic benefits of relaxing frequency. This covers the calculations required to determine acceptable boundary conditions and the minimum control to achieve these boundaries. The outer bounds of the control are now known and this is the most relaxed strategy possible. **Chapter 6** will use these boundaries as the limits for determining the best economic relaxed strategy.

For Eskom a minimum of 390 MW under governing is required to meet the boundary conditions for most single and multiple credible contingencies. This amount of governing is also sufficient for regional constraints within the Southern African Power Pool. However, when catering for the voltage disturbance when the HVDC link from Cahorra Bassa trips, it is necessary to increase the governing by 100 MW. The decision in Eskom was hence to have a minimum of 500 MW on governing. The governing response could also be provided by demand side customers who are willing to trip when the frequency drops below 49.75 Hz.

Chapter 5 : Phase 2 – Calculate the cost and benefits of frequency control

Determining the costs to providers of frequency control services and the economic benefits to consumers of tighter frequency control

5.1 Introduction to Chapter 5

Chapter 5 first investigates the technical abilities of the power plant and consumer to control frequency. The chapter then focuses on the cost of controlling - the cost when the power station or demand side participant changes its output. This chapter develops from the previous chapter where the minimum control is identified. Any further control required to make the frequency control tighter comes at a cost. The cost of controlling is determined by two methods, firstly by calculation of costs to the plant and then by calculating price if the electricity industry is deregulated. There are also benefits to tighter control and this chapter studies these benefits and equates these in financial terms. These cost and benefit items form the formula that is used to determine the potential savings as the frequency control is relaxed.

5.2 Ability of generators and demand side to control frequency

Constantly matching supply and demand is the key to controlling frequency. Generators or loads that are able to change their output can hence control frequency.

Generators have traditionally been designed to move up and down to meet the consumer's demand. The consumer of electricity can control the frequency very quickly by switching off the supply and it is also possible to change the voltage to change the consumption for resistive type load. Traditionally this type of control is limited to operation in emergency conditions and switching off of the plant is done via under-frequency relays.

It has been the tradition in most networks to allow the consumer the right to choose when and how much electricity they consume and then match this by changing the generator's output. The cost of electricity to the consumer is often low compared to the value of the product being produced. Thus a reliable supply of electricity is important to the consumer and being interrupted is costly.

Furthermore each generator and consumer type has its own quirks, some can change output quickly but only for a short period of time and some have long time delays and only move slowly. The response of the generator or the consumer is driven also by economics. The ability to be flexible is more costly than operating at a steady output or letting the output or consumption of electricity drift. An electric arc furnace consumes electricity extremely erratically as the arc is formed and lost. A waste boiler's output also varies erratically as the source fuel varies in calorific value and wind power varies with the wind strength.

Appendix H describes the ability of power stations and demand side participants to change their electrical output and thereby participate in frequency control.

5.3 Calculating the cost of control

The frequency control cost is needed to determine the least cost solution. The costs for a generator are: efficiency loss, the cost of not operating at an economic point and the wear and tear when actually moving up and down. The cost to the consumer of electricity is the reduction in output in induction motors due to lower frequency and the cost of being interrupted or of the load being curtailed. For Eskom, the cost of using thermal generators to control the frequency was determined using methodologies developed by EPRI (1997a and b) and by performing field tests. These calculations are presented in this chapter.

5.3.1 Calculating costs of generators to control frequency

The costs of providing frequency control services are the extra costs to generate to the unit whilst providing the service compared to the costs to generate when not providing the frequency control service.

$$Cost_{frequencycontrol} = Cost_{genwithfrequencycontrol} - Cost_{genwithoutfrequencycontrol} \tag{5.1}$$

The costs can be broken down into the following categories:

Capital costs is the value expected by an investor for investing in the asset, and the cost of debt. The rate of return on asset is often calculated as the Weighted Average Cost of Capital (WACC) which is the weighted average of the investment in equity and the cost of debt. The cost of capital is the actual or replacement cost of the asset when the actual cost is not known. The return on asset per annum is the cost per annum that needs to be recovered to pay off the debt and give the investor his expected returns. The apportioning of the asset used for frequency control to the total asset value is complex. A simplified method is to apportion the asset according to the frequency capability of the unit divided by the MCR of the unit.

Extra equipment and manpower required such as extra hardware to communicate with the System Operator for units that are on AGC and governing. The unit might now need to have manpower available at night. Extra control system hardware and software is required to have a more advanced unit control strategy. The unit might require a quicker and more sophisticated governor valve to perform the governing required.

Wear and tear on the unit could be significantly higher on items such as control valves and dampers. This will require extra maintenance and operating costs. There is also extra wear and tear on the turbine because of temperature variations and increased vibrations.

Appendix H, Figure H.8, showed the movement of the governor valve and the pressure when a coal-fired unit is constantly governing. There are a significant number of controls that are affected by the constant movement of the governor valve.

Long term life could be reduced. The life of a unit is reduced due to higher temperatures in superheaters, increased number of startups and extra thermal stress on the turbine and generator. The long-term health is affected every time the output of the unit is changed due to the lags in the process.

Loss of efficiency is a cost factor as the unit is not operating at the most efficient operating point. For a thermal plant there is also a loss in efficiency in tuning the plant to respond quickly. The major change for a thermal unit is the increase in boiler pressure as the governor valve is partially closed to allow reserve for the governor valve to open and decrease in feed water pump input. This causes an increase in heat rate and the difference between the two heat rates determines the loss in efficiency as shown in **Figure 5.1**.

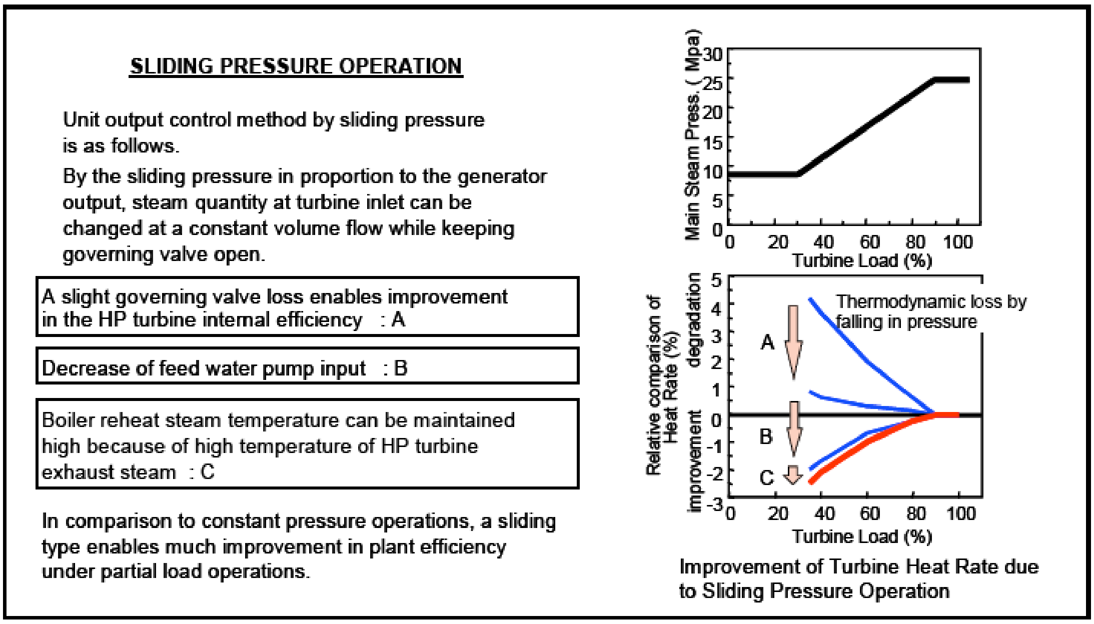

Figure 5.1. Heating rate vs. boiler pressure for a thermal unit (Kimura et al, 2003).

For hydroelectric units, the loss in efficiency is measured as the difference in efficiency at the normal operating point compared to the new operating point. The normal operating point should be where the efficiency is at its peak (Figure 5.2) or at full output, if the unit is not energy limited (Kundur, 1994).

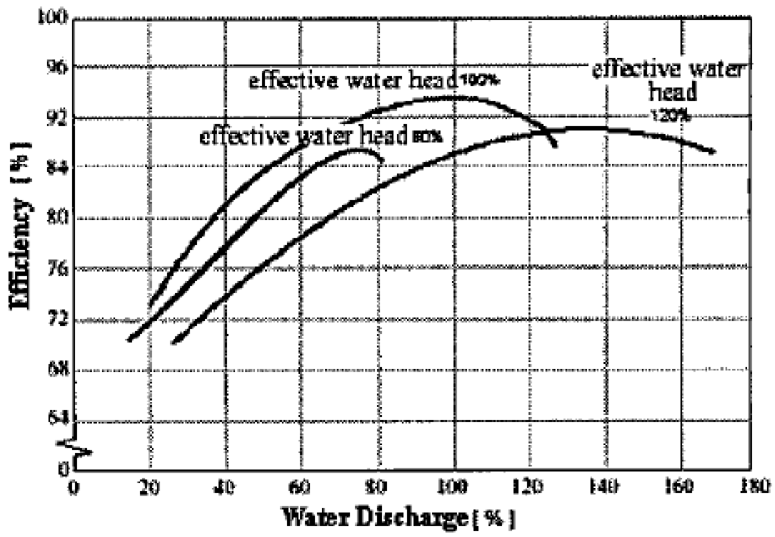

Figure 5.2. Efficiency vs. Water Discharge for a hydroelectric unit (Sousa et al 2004)

Loss of opportunity if the unit is backed off from producing to provide reserves. The loss of profit calculation is the difference between the price energy could have been sold at, and the marginal cost of production, multiplied by the MW's the unit is backed off by. **Figure 5.3** shows the loss of profit in a deregulated environment**.** There is also an extra cost if an expensive unit is dispatched in order to provide frequency control services.

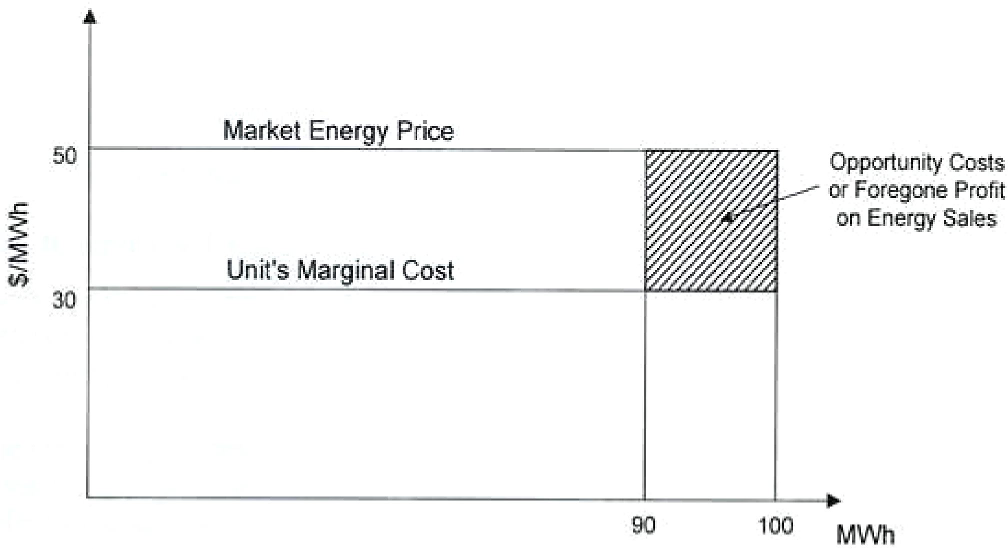

Figure 5.3 Opportunity costs in a deregulated environment (Cigre, 2000)

Start up costs for a unit that is started up to provide reserves for frequency control.

EPRI (EPRI,1997a) identified the key thermal generator costs for regulation and frequency control services as:

- Additional fuel due to increased (poorer) heat cycle rate.
- Additional hardware from more severe duty on turbine.
- Additional fuel due to reduced boiler efficiency caused by frequent control adjustments.

5.3.2 Calculating costs of consumers to control frequency

The costs of providing frequency control services are the extra costs to the consumer whilst providing the service compared to the costs when not providing the frequency control service. There are costs directly related to being switched off, such as loss of raw material, lost production and salary costs. A saving is in the electricity costs. Indirect costs can be the loss of future orders due to late delivery caused by an interruption. Non-material inconvenience could be experienced by staff that need to work longer on a particular day to make up production and even though they are financially compensated, if this happens often the morale could decline.

$$Cost_{frequencycontrol} = Cost_{consumewithfrequencycontrol} - Cost_{consumewithoutfrequencycontrol} \quad \textbf{(5.2)}$$

The costs can be broken down into the following categories:

Extra equipment and manpower required such as extra hardware to communicate with the System Operator for consumers. This could be extra control system hardware and software to have a more advanced control strategy such as under-frequency relays and automatic plant shutdown controls. The consumer may require extra manpower to shut the production down at the instruction from the system operator. The workers might have to work over time to make up for lost production.

Wear and tear on the consumers' plant could increase when assisting in frequency control. This is on items such as control valves and dampers. This will require extra maintenance and an increase in the operating costs.

Long term life could be reduced. The life of the plant could be reduced due to increased number of shutdowns and start-ups, extra mechanical stress and extra thermal stress.

Loss of efficiency could be a cost factor, as the plant is not operating at the most efficient operating point, and with chemical and thermal plants there is a loss in efficiency when the plant is not kept at a steady output.

Loss of opportunity as the plant could be switched off when it is inconvenient for the consumer and cause a loss of production.

Start up and shut down costs for plant that is switched off and restarted to provide frequency control services.

From the above factors, it is observed that the calculation of a single cost to the consumer to provide frequency control services is difficult as each consumer's costs are different, even for two manufacturers that are producing the same product. On a particular day one factory could incur high interruption costs due to a large order whilst the other incurs no costs due to low orders.

5.3.3 Cost Calculations for the Eskom Thermal Units

The method used in this document to calculate the regulation costs to a power station is the one developed by EPRI in document, TR107270, Volume 2: "Cost of Providing Ancillary Services from Power Plants, Regulation and load following" (EPRI, 1997a). Further tests were performed at two Eskom power stations to calculate the cost of providing regulation on their plant and the results of these tests are presented in this section.

5.3.3.1 EPRI cost calculations

The overall cost (for loss of efficiency and additional maintenance only) is estimated to be 1-3% of the kWh cost at the station terminals, according to the EPRI document, TR 107270 V2 page 10-1 (EPRI, 1999a). This roughly translates to a cost to Eskom of R 4m to R 12m per unit per year, assuming a 640 MW unit operating at 90 % availability with a total output cost of R 80/MWh (Chown and Coetzee, 2000).

It is believed that the usage of regulation is high for Eskom units compared to generating units in the USA, and that Eskom's regulation costs are closer to the upper limit of R 12m per unit. Also, the calculation in the EPRI document does not include the effect on the long-term health of the plant (plant life reduction).

In the opinion of the author, the long-term plant health is affected by the provision of regulation, especially as the plant is more susceptible to tripping and steam temperature problems, when units are running with a boiler-follows-turbine control philosophy, which is used by most of Eskom's generators. This philosophy requires the units to run in an inherently unstable mode, as opposed to a unit running with a turbine-follows-boiler control philosophy, which is inherently stable. Every control action with a boiler-follows-turbine control mode requires a degree of over-control which causes a mismatch between fuel and steam flow, leading to temperature control problems, and ultimately affecting the long term plant health of the units.

This long-term plant health effect could dramatically increase the cost of regulation.

5.3.3.2 Matla power station cost calculations

Matla power station ran real time tests to calculate the marginal cost of operating under AGC (Veldman and Botha, 1999). The marginal cost to the power station was calculated to be R 1.2m per year.

5.3.3.3 Lethabo power station cost calculations

Lethabo power station ran further tests to advance the calculations to include wear and tear on valves and actuators in the power plant while operating under AGC (Ledwaba, 2002). The marginal cost to the power station including wear and tear to valves and actuators was calculated to be R 2.0 m per year.

5.3.4 Reduction in spinning reserve

5.3.4.1 Introduction

It is predicted that regulation up reserve can be reduced by 100 MW by letting the frequency drop to 49.9 Hz when the system is at its peak (Chown, 1999). This is as motor load is dependent on the frequency of the power system to which it is attached. If the frequency declines, the connected motor load magnitude will also decline. The measured decline for the whole of Eskom is 100-125 MW / 0.1 Hz depending on the magnitude of the demand. The cost savings can be calculated by using the average cost of Spinning Reserve although this reserve would normally have been taken up at above average cost.

5.3.4.2 Cost Calculations as detailed in EPRI document TR107270, Volume 4 (EPRI, 1997a)

The EPRI approach, based on opportunity cost is given in EPRI document TR107270, Volume 4 “Cost of Providing Ancillary Services from Power Plant: Spinning Reserve” (EPRI, 1997a). The opportunity cost due to holding back units to 95% of Maximum loading over peak was calculated as R145m. This was based on Spinning Reserve of 716 MW. For 100 MW of Spinning Reserve the lost opportunity costs were:

100/716 x 145 = **R20.2 million**

5.3.4.3 Eskom internal cost calculations

PROMOD simulation of Eskom commitment and dispatch, and of the energy usage by plant was performed for several levels of synchronised or “spinning” reserve. (PROMOD refers to the extra capacity committed over peak as spinning reserve). (Dean, 1999)

The operating reserve is set equal to the spinning reserve. The difference in annual total fuel cost is then assumed to be the cost of spinning or synchronised reserve. In the case of spinning reserve, a maximum of 6 % of MCR is allowed for reserve on each on-line unit. For synchronised reserve, no limits are placed on the allocation since a unit can generally ramp up from minimum to maximum in 30 minutes. The report calculated that if Spinning Reserve was dropped from 716 MW to 600 MW the cost of providing Spinning Reserve would drop by R3 million/year.

5.3.5 Summary of cost calculations

The section demonstrates that it is possible to calculate the cost of control to the generator and the customer. The calculations of marginal costs can also be done. The long-term costs are difficult to determine, as these calculations use many assumptions and there is some speculation of the long-term effect of wear and tear and thermal stress on coal-fired generators.

For the Eskom Frequency Control Redesign project, the EPRI cost calculations showed a higher cost for the provision of regulation than that of the Eskom internal calculations. The Eskom internal cost calculations which is the lower of the two cost calculations is used for calculating the economic benefits of relaxing the frequency control. The cost savings due to the reduction in Spinning Reserve of R 3 million per annum per 100 MW of reserve reduced was also used by Eskom for calculating the economic benefits of relaxing the frequency control.

For the Eskom Frequency Redesign project, it was assumed that the costs to the consumer to control frequency were less than or equal to the costs for generators for those consumers who are participating in frequency control (other than for emergencies).

5.4 The calculation of the costs of providing frequency control services in a deregulated environment

The introduction of deregulation has dramatically changed the costing of frequency control services. In some electricity markets, generators and consumers offer a separate price to provide frequency control services *i.e.* the generator or load is paid additional payment from normal energy production. In other electricity markets, providing some frequency control services is mandatory. As the provision of frequency control services is mandatory, services providers recover their costs in the energy market. If the cost of provision is the same for all participants then there is no need to differentiate between suppliers. Most markets are a combination of some mandatory frequency control services and some paid frequency control services. Utilities that have been deregulated have mostly chosen to control the frequency to the same quality as before deregulation. The control strategies have also remained similar to before deregulation, except that services provided by participants are now classified as ancillary services. However, the introduction of electricity markets has added pressure to redefine the way that frequency is controlled. A mandatory service where a participant incurs an expense without remuneration is not well received in markets with the focus on moving towards individual participant profits and losses. Many emerging markets are concerned about a possible decline in the quality of frequency control. This was the focus of discussions of a system operators' working group at the Paris meeting of Cigre in August 2002 (Johnson, 2002).

5.4.1 Payment methods for frequency control service providers

The payment methods for frequency control service providers vary between countries and types of deregulation. Generally, there are four payment possibilities which are (Bhattacharya *et al.*, 2001):

- Availability payment, which is made to frequency control service providers for making the service available. A typical example of an availability payment is the payment for making spinning reserve available.
- Enabling payment, which is made for enabling a frequency control service such as starting costs for a quick start generator.
- Usage payment, which is based on the usage of the service. This covers the variable costs for proving the frequency control service and can cover wear and tear and long-term life costs.
- Compensation payment is based on the provider's loss of opportunity whilst providing a frequency control service. This is related to the constraining down of a generator to provide reserves and hence the provider losing the opportunity to sell energy.

The market structure for the interconnection being studied could also combine the above payments or introduce more payments. All these payments will have to be considered when calculating the cost of providing frequency control services.

5.4.2 Calculating frequency control service provider costs

Two types of markets exist, the Nordic type model where the market price is determined solely by the matching of bids and offers. This market does not consider generation constraints and the bids and offers are aggregated. Therefore, it is up to the participants to ensure their bids are realizable. If this is not possible, the participant will be out of balance and have to purchase energy on the balancing market.

Other markets such as the USA consider all possible constraints from start-up times and rates, reserves, ramping rates and energy limitations.

Frequency control services can be calculated based on day-ahead energy prices. This is how short term reserves are calculated in the Eskom Power Pool.

A typical purchase of day-ahead reserves uses the following formula to ensure sufficient reserves available (Bhattacharya K. et al (2001)):

$$\sum P_{i,k} \cdot W_{i,k} + (I_k - E_k) \geq PD_k + RESV_k \qquad \textbf{(5.3)}$$

Where

k denotes the hour

P_i is the maximum power from unit i

Wi is a binary which is 1 if the unit is on and 0 if the unit is off

I is imports to the area

E is exports from the area

PD is consumer demand, and

RESV is the reserve requirements

The price paid for reserves and frequency control services can be used to determine an optimal economic strategy and whether the frequency control can be relaxed. The prices can be used to determine what the savings would be if less frequency control services are purchased. Historical prices can also be used to determine future prices and whether a strategy will remain economical for a further period. Frequency control should not be relaxed if this is only based on expensive control service prices that are expected to decline.

5.4.3 Determining the impact of the new regime

Deregulation of the electricity market has split vertically integrated utilities into competitive groups on all levels. The generators are now competing with each other and the transmission owner now has a different set of rules and regulation. The system operator is now independent and has to fend for itself. The consumer now has numerous sources from which to purchase electricity. The key question is how will all these new entities behave?

This can be related to driving a car in different countries. In some countries people drive with calmness, respecting the rules of the road and being courteous to other drivers. Drivers stop to let people cross the road even when there is not a pedestrian crossing. In other countries the opposite is true, drivers have a very different attitude. The rules of the road are still obeyed for the most part, but their behaviour when driving is very different. In some electricity markets, the players are very compliant with the rules and are compliant to the system operator instructions etc. Rules are not only obeyed, but the participant is also observant of other issues that face the electrical network such as system security. In other electricity markets the participants have a different attitude. They challenge any decision that does not increase their bottom line and push the market rules to the very limit.

When developing new markets, the potential behaviour of the participant needs to be looked at from all angles to ensure frequency control is maintained to the desired level.

5.4.4 Participants must be aware of what they are paying for

Participants in a market will be billed for the provision of frequency control services. In some market structures, only the consumer is billed and in other market structures both the producer and consumer are billed. It is important that the participants who are paying for frequency control services are aware of what they are paying for. The payment for frequency control services might be low compared to the payments for energy provided. The frequency control might be so good that the frequency is well within the specified boundaries, that the consumer is not even aware what the real impact of frequency could be on his plant if it was not controlled tightly. However, if the electricity does not flow from supplier to consumer then the cost to both parties is very high. The participants paying for frequency control services and the regulator who controls the payments for frequency control services need to be educated, otherwise there could be pressure to pay less for frequency control services without realising the full impact of such a decision.

5.4.5 Manipulation by the market participants

The ability of participants to manipulate the market needs to be considered when designing frequency control services. Suppliers of frequency control services who withdraw their services because they can make more money in another market could compromise the network. The ability and willingness of market participants to push the rules to the maximum compromises the ability of the system operator to control frequency. This was very evident in the California market where participants were declaring an incorrect day-ahead position to force more capacity into real time markets because the prices in real time were high relative to day-ahead prices. It is argued by many that the participants were operating within the rules and in the opinion of others, they were providing false information. The designer of the frequency control services needs to bear these problems in mind otherwise there could be a disaster.

5.4.6 Risks, incentives and penalties

The system operator in some markets has incentives to lower the usage of ancillary services, including frequency control services, and sometimes incentives to dispatch the market economically in real time. If services are provided cheaper than a budget or a predetermined target the system operator receives a profit. Conversely, if the system operator performs worse than budget or target it is penalised. However, in reality the system operator could have very little influence over the prices paid for some frequency control services and any profit or loss could be a gamble. Conversely, the system operator could compromise the security of the network by not dispatching frequency control services or energy. For example, the system operator could operate with the frequency unacceptably low instead of dispatching expensive generation. The system operator should have some targets to ensure the network is not compromised for financial gain. Therefore, there needs to be some caution when designing an incentive scheme for the system operator.

5.4.7 Who cares about security?

Security is the planning and operation of the network to avoid unnecessary interruptions as defined by quality of supply standards. In a vertically integrated utility, the security of the network is everyone's problem. If there is an interruption, the company's name and reputation is at stake. This means that there is co-operation from the whole organisation when things start to go wrong and the system operator's tasks are simplified, as co-operation can be relied upon. The introduction of markets often means that this co-operative arrangement no longer exists. The first problem for the system operator is that the overall picture of the network is not as clear as before. Generators no longer report when the plant is operating with problems and the transmission network owner and system operator could be different companies with complicated communication protocols. Secondly, many networks have not clearly defined who is responsible for this overall network security and reliability. The regulator wants overall control as it protects the industry, the market operator might be doing some of the contracting and the system operator is taking on some of the tasks.

Since deregulation, many interconnections have suffered blackouts and have not supplied the consumer the same reliability they experienced before deregulation. One of the first major events since deregulation was the California crisis in 2000, where rolling blackouts became a regular occurrence. The blackout of New York and parts of Canada in 2003 is also another example. There are many opinions on the causes of these events and some lay the blame squarely on deregulation. FERC in the USA has led the call for security co-ordinators in the USA for each interconnection whose main responsibility will be the monitoring of the network and ensuring there is an acceptable level of security. The security co-ordinators will have access to all the generator and transmission information and will have to do detailed studies such as contingency analysis. The European interconnection has the same with UCTE based in Switzerland. However, the UCTE co-ordination centre was unable to prevent the blackout of the Italian network in 2003. This was partly due to a lack of information. If a security co-ordinator is appointed then it is important that this co-ordinator be given the full authority and the necessary budget to ensure all data and software required is available.

5.4.8 Penalising bad behaviour

Providers of frequency control services need to know that the service being provided is of vital importance to the whole network. In some markets, the participants will behave with this in mind and will obey the system operator instructions. In these markets, it might not be necessary to penalise bad behaviour. In other markets, the participants need to know that bad behaviour will not be tolerated. This can be managed by applying penalties for non-performance. The system operator does not want market participants not to provide a frequency control service by either selling the energy reserved for the service in another market where the price might be slightly higher or by not declaring they have a technical problem. The purpose of penalties should be that they create the right behaviour and prevent participants from even contemplating misbehaving. The participants will also not want to run a high risk of being exposed to high penalties and therefore the market rules must allow the participant to declare that they are unable to provide due to some technical reason without penalty. This is only if the information is in time for the system operator to make some alternative arrangement. If market participants are constantly misbehaving and are not providing the required frequency control services or energy as contracted, the system operator has no choice than to contract more service than is required. The additional costs often will be to all participants, which can be seen as unfair to those who are behaving.

5.4.9 The potential to sue or be sued

The system operator in a market environment is exposed to an additional risk. This is the potential to be sued for making errors leading to the loss of revenue of one of the participants. In a vertically integrated environment, system operator errors in dispatch are often not significant because the variable cost of dispatch is not very different from one generator to another. However, in the market environment, an incorrect dispatch can be very costly to one of the participants and the participant will want to be fairly compensated. There are a few examples where the system operator was sued (NEMCO, 2003). The system operator in these cases was not liable for the consequential costs and only bore the court case costs of the cases it lost. The problem with these events is that there is a high probability that the system operator will now be more cautious when issuing instructions in the future, which is good, but the pressure could be such that they compromise system security at the same time. The market rules must guard against this happening.

5.4.10 Summary of cost in a deregulated environment

The chapter has presented the different considerations required when a market is introduced to an interconnection. The structure of the market and the behaviour of market participants need to be considered when redesigning frequency control services. It is possible that the frequency control redesign could take place at the same time as the introduction of the market or later. The chapter has highlighted some issues that will have to be addressed. The section highlights that there will be a different relationship between generators, consumers and the system operator when a market is introduced and this will present many challenges for frequency control. Markets are also evolving and this will put pressure on the design of frequency control as frequency service providers change their behaviour due to financial considerations.

5.5 Benefits and costs when relaxing frequency control in the normal region

5.5.1 Introduction

The thesis has so far determined the minimum control for single and multiple contingencies. The basic benefits are that the frequency is in an acceptable range and, for Eskom, no damage will occur to all generators, consumers and the transmission network should these contingencies happen. The chapter has focused so far on how much it costs to control the frequency under normal conditions. The more relaxed the frequency is controlled the less the costs to control the frequency, but there are also benefits to tight frequency control and these cannot be ignored.

5.5.2 Benefits of tight frequency control to generators

Section 4.2.1 studied the costs of being off nominal frequency to the generator and this led to the development of the boundary conditions. These conditions mean that the benefits of tighter frequency control are minimal. One exception to this is units that are governing continuously and subjected to the wear and tear costs discussed in **Section 5.3.1**.

5.5.3 Benefits of tight frequency control to consumers

Section 4.2.2 studied the costs of being off nominal frequency to the consumer and this led to the development of the boundary conditions. These conditions mean that the benefits of tighter frequency control are minimal. One of the key considerations raised in the calculation of costs to consumers is the average frequency. For the Eskom design, this was captured in the requirement to keep the system time within 30 seconds of real time.

5.5.4 Effect and cost on interconnection flows when frequency is relaxed

A benefit to controlling the frequency tightly is that interconnection flows are near to contract. If the frequency control is relaxed the power will naturally flow to the deficit control area and if there is no control the power balance on interconnections will be off schedule. If the energy is returned in kind, as is the common arrangement with co-operative pools, then the cost is the difference in generation costs.

$$Cost_{\,interconnection} = Cost_{\,inadvertently\ energy\ provided} - Cost_{\,inadvertent\ energy\ payback} \qquad \textbf{(5.4)}$$

In essence, this formula is designed to be a zero sum exercise, unless one utility is constantly leaning on another utility during an expensive marginal generation period. If one utility is constantly leaning on another utility then tighter frequency control will also not help.

For deregulated interconnections, the inadvertent energy is settled at the balancing price. The balancing price is normally higher than the day-ahead price. The cost as the frequency is relaxed can be described as follows:

$$\begin{aligned} Cost_{\,interconnection} = \; & Energy_{\,inadvertent\ energy\ flow\ due\ to\ relaxed\ frequency} \\ & * (Day\text{-}ahead\ price - Balancing\ price) \end{aligned} \qquad \textbf{(5.5)}$$

5.5.5 Disadvantage of frequency relaxation on the economic dispatch of generators

The less generators are moved the longer it will take to get to a good economic dispatch. One of the purposes to relax frequency is to reduce the costs of controlling and the drawback to this is that generators might be at a sub-economic solution longer. For a non-deregulated interconnection, the cost of not being at an economic best solution is measured as*:*

$$\begin{aligned} Economic\ dispatch\ costs &= \sum (Cost_{\,avoidable\ generator\ dispatch}) \\ &= \sum ((Cost_{\,optimal\ generator\ dispatch/\ MW} - Cost_{\,actual\ generator\ dispatch\ /\ MW}) \\ &\quad * Energy_{\,generator\ sub\text{-}economic\ MW}) \end{aligned} \qquad \textbf{(5.6)}$$

For deregulated markets the same formula applies, except the optimal costs are replaced by the market price and the actual generator marginal cost are replaced by the offer price for the generator.

$$\text{Economic dispatch costs} = \sum \left((\text{market price - offer price}_{\text{generator}}) * \text{Energy}_{\text{generator sub-economic MW}} \right) \quad \textbf{(5.7)}$$

5.5.6 Disadvantage of frequency relaxation for contingencies

A benefit to tight frequency control is that the frequency is near nominal should a contingency occur. The more relaxed the frequency the higher the probability the frequency is low when a generator trips. The probability of a lower frequency will require additional governing from the minimum control calculated in **Chapter 4**. Furthermore, if governor deadband is increased there is a slower and perhaps less response from generators on governing. This might require more governing than the minimal calculated in **Chapter 4**. Translated to a cost:

$$\text{Cost}_{\text{contingencies}} = \text{Cost}_{\text{additional response required from governing}}. \quad \textbf{(5.8)}$$

5.5.7 Benefit of frequency relaxation for reserves

A benefit to relaxing frequency control is that the frequency can be allowed to decline through a peak period. The benefit is that there are fewer reserves required under AGC control and the need to dispatch an expensive generator is avoided. This could save on start-up costs and the wear and tear associated with starting an extra generator. With a largely thermal utility, such as Eskom, there are savings in not committing a thermal unit, which has long start-up, a high minimum generation and long minimum run times. Running an extra thermal unit therefore causes numerous hours of uneconomic dispatch.

5.6 Summary of Chapter 5

The chapter first determined the ability of power stations and consumers to control frequency. The chapter then determined the types of costs that have to be considered for deregulated and non-deregulated markets. The potential benefits of having a tighter frequency control are finally presented.

These costs and benefits of control are detailed and these will form the equation that will determine whether there are overall savings if the frequency control is relaxed.

Chapter 6 : Phase 3 - Develop the most economic relaxed frequency control strategy

To determine if it is economically beneficial to relax frequency control, to what level the frequency control should be relaxed, and the optimal frequency control strategy.

6.1 Introduction to Chapter 6

The previous chapters are a prelude to this chapter. All the necessary data and understanding of the frequency, its effect on the plant and the ability of the plant to control the frequency should now have been obtained. The costs and the target frequency boundaries are used in this chapter to design an optimal control strategy. This chapter requires us to challenge the boundaries of our thinking and commences by asking the fundamental question: "Why, for the network being studied, is it necessary to have control at all?" The chapter then sets up a methodology to discover the most economic relaxed frequency control strategy that will meet the control objectives. The proposed method is to simulate the process starting from the tightest control possible, then gradually relaxing the control and monitoring the potential savings over each relaxation step. The designing of an optimal control strategy is an iterative process, as when one variable in the control equation is altered other situations might need to be re-studied. There might even be a need to re-visit the work done in previous chapters to challenge assumptions and confirm information.

The minimum control for contingencies made the assumption that the frequency is at 50 Hz at the start of the contingency. As the normal frequency control range is relaxed, this assumption will no longer be valid. The minimum control may thus need to be increased. Fine-tuning of the final design is proposed to ensure that, with all the knowledge gained from the simulations and studies, nothing has been left out.

The chapter ends with the determination of reserves and frequency control markets to meet the resulting optimal strategy.

6.2 Determining an accurate control error

The calculation of the control error is important in any control loop. Before any control action is done the amount of control required needs to be calculated. Any errors in the measurement of the control error that are not compensated will result in either over or under control. Inaccurate control will not help in developing the most cost effective strategy. **Appendix G** analyses the errors and possible improvements in the calculation of the area control error (ACE). The appendix details the control error calculated for South Africa and the compensations done to improve the calculation. The control error calculation method decided for South Africa is used in the models to determine the economic benefits described in the next section.

6.3 Develop models of the network to determine the economic benefits

One or more models of the network are required to model all the different dynamics involved in frequency control. The complexity of the models will vary between networks due to the different network structures, generator types and different market structures. The models are used to study all the permutations and to compare the economic benefits of different control strategies. The Southern African network study required the use of two models. The first was a comprehensive model of the network that was used for short time frame contingency analysis. This model is described in **Appendix D**. The model was developed in PTI PSS/e© and was applied to the first 10 seconds. The inaccuracy of the model beyond this period is shown **Section C.3.7**. A second model was developed using Matlab© to study the effect of the control strategy between 10 seconds and a day. The model has detailed generator models and simulates the balancing market according to the Eskom Power Pool rules, but the model uses a simplified network model. The complete Matlab© model is described in **Appendix I**.

6.4 Developing case costs and savings for determining the economic benefits

The proposed formula is to calculate the total cost savings as the various control loops are detuned and the frequency control is relaxed. The cost problem is broken up into the three control loops discussed in **Section 2.2.** Primary frequency control (governing), secondary control (AGC) and tertiary control (economic dispatch). Each of these control loops is measured against a base case. The base case is the tightest (or current) frequency control design. The savings are recorded as the difference between the base case and the new case. Added to these costs are the additional frequency costs or benefits derived in **Section 5.5**. The generic formula for savings for each case is described as follows:

Case 1 savings = (Base case control costs – Case 1 control costs) **(6.1)**

Where*:*

Case control costs = Primary control costs + Secondary control costs + Tertiary control costs – Additional relaxed frequency costs + Additional relaxed frequency benefits. **(6.2)**

For Eskom, the base case was chosen to be that of 28 08 2002. This was a normal weekday with a 600 MW unit trip at 05:43.

The costs for the savings determination were as follows*:*

Primary control costs = Instantaneous reserve capacity cost + Instantaneous wear and tear costs **(6.3)**

Secondary control costs = Regulation reserve capacity cost
+ Regulation utilisation costs **(6.4)**

Tertiary control costs = cost of balancing according to the Eskom Power Pool Rules

Instantaneous Reserve and Regulation reserve has an EPP market value of R 20m to reduce 100 MW (**Section 5.3.4.2),** and a cost based savings of R 3m per annum to reduce 100 MW reserve, as calculated in **Section 5.3.4.3.**

The least cost of R 3m per 100 MW reduction / increase is used for the cost formulation. This is an annual saving R 30 000 per MW reduced in Instantaneous and Regulating Reserve. For the cost savings, the minimum governing is 390 MW (determined as the minimum to meet the boundary conditions from **Chapter 4**). This excludes the voltage problem from the HVDC disturbances calculated in **Section 4.6**.

The Regulation Usage cost was determined as R 4m for a 640 MW generator providing 100 MW of Regulation Reserve, as calculated in **Section 5.3.3.1**. The total regulation reserve up and down is 1000 MW and hence 10 generators are required to make up the control range. The total Regulation usage cost is thus R 40m. The cost is assumed to be proportional to the movement of the generator. For Eskom the base case absolute movement was 37 511 MW moved per day. This is equivalent to 13 353 916 MW moved per year. The cost per MW moved is calculated as*:*

Cost per Regulation MW moved = R 40m/13 353 916 MW moved
= R 2.995 per MW moved. **(6.5)**

(The EPP internal market value at the time was R 17.86 per MW moved.)

Instantaneous wear and tear is not separately determined as an ancillary service but for the frequency relaxation, it was determined to have a value of about 10% of the wear and tear costs for regulation usage. The conservative estimate was based on the fact that many times the frequency excursion outside the deadband is only a few seconds and hence causes very little wear and tear. The number of MW's for Instantaneous reserve in Eskom is currently 500 MW up. The cost savings are benchmarked against this even though the potential minimum control is 390 MW.

A 600 MW generator can typically provide 20 MW up and 20 MW down. The number of generators required for Instantaneous reserve is hence 25 generators. The cost is assumed proportional to the movement of the generator. The total costs for Instantaneous wear and tear is hence*:*

*Instantaneous wear and tear = 25 x R 4m * 10 % = R 10m per year.* **(6.6)**

The base case calculated the absolute movement on governing as 56 234 MW moved per day or 20 525 410 MW moved per year.

Cost per Instantaneous MW moved = R 10m / 20 525 410 MW moved
= R 0.4872 per MW moved. **(6.7)**

In the EPP, there is demand side participation for Instantaneous reserve. This participation is competing with the generators at the same market price. As the costs of the participants are not known, except that the participant is being paid the same price in the EPP, it is assumed that the cost of Instantaneous Reserve provision is similar to that of the generators.

The base case balancing cost for the day (actual balancing cost on 22-08-2002) was R 5 625 285.00.

Inadvertent energy in the Southern African Power Pool is traded "in kind" and hence although this is monitored in the design the net cost calculation is zero.

For Eskom the final equation for determining savings was*:*

Case 1 savings per annum = (390 – Case 1 Instantaneous Reserve) * R 30 000

+ (20 525 410 - Case 1 Instantaneous daily movement*365) * 0.4872 R/MW moved

+ (500 – Case 1 Regulation Reserve) * R 30 000

+ (13 353 916 - Case 1 Regulation daily movement*365) * 2.995 R/MW moved

+ (5 625 285 – Case 1 Balancing payments) * 365 **(6.8)**

This formula is valid under condition the frequency is controlled for contingencies within the boundaries defined in **Chapter 4**. Using this formula, various cases can now be compared.

6.5 Process to determine maximum benefits for relaxation of frequency control

The ideal solution to the optimisation problem would be to throw all the possibilities into a single optimisation algorithm and then get an answer. In reality, the problem is too large and the best solution for an interconnection might be more conservative than the optimal solution, as shown in **Figure 3.8**. The starting point for determining the best economic strategy is the tightest control possible. If the economics benefits are not realised as the control is relaxed, the tightest control is the best technical and economic solution. The minimum control would have already been determined, so the end-point for determining any economic benefit is known and the relaxation study can end at this point The proposed solution is to change one variable at a time and observe the influence on the savings.

The proposed steps are*:*

Step 1: Determine if control is needed.

Step 2: Determine areas of no frequency control.

Step 3: Calculate cost savings when frequency is relaxed for normal conditions for various cases.

Step 4: Controlling for economic dispatch improvement only.

Step 5: Fine-tuning the solution for other variables that could give extra savings.

Step 1 is looking at a philosophy of no specific frequency control. Steps 2 and 3 investigate the savings starting from the base case and relaxing the parameters identified in the step. Step 4 looks at increasing the control to achieve a better economic dispatch and to understand the potential savings in doing this. Step 4 does not necessarily improve the frequency control. Step 5 is fine-tuning the solution after going through all the previous steps there might be something that can be improved on.

6.6 Step 1: Determine if control is needed

The boundary conditions defined in the chapter on control for large frequency excursions are required to answer this question. If the frequency is continually within the boundaries required by generators and consumers then, theoretically, there is no need to take any action. If the frequency is required to be within 2% of nominal as suggested by IEC 61000-2-2 (IEC, 2002), and no generator is controlling, then, theoretically, using a 1% load frequency support there is a shortfall or surplus of supply of 2% and the frequency would still be within the required bounds for a 50 Hz network. This could be achieved even during multiple contingencies for large networks.

However, this is very hypothetical for most networks due to the size of contingencies and local power flow problems. In Eskom the largest credible multiple contingency is 6% (1800 MW) of peak demand, this exceeds the 2% difference for no control and hence control is required. The largest contingency that occurred in the last 20 years was the loss of 35% of demand due to heavy snowfalls in September 2001.

These strategies assume that the generators do not want to alter their output. In places like India, generators produce as much as they can and frequency control is performed by changing the consumer demand. What if studies are easily done as long as the consumer induction consumption is known? **Figure 6.1** shows a typical example of the frequency of the Southern Africa network over a day, if generators were kept at constant output with enough power to meet the peak demand. This simple calculation also assumes that the induction motors that were operating at the high frequencies would continue to do so. In practice the production from these might be too high, so more motors such as pumps, would be switched off and the frequency would increase. The frequency for this case would have peaked at 58.4Hz. The frequency is outside the 0.5 Hz boundary that was decided as an acceptable range for single contingencies in Southern Africa. Therefore, it is not possible to have absolutely no control.

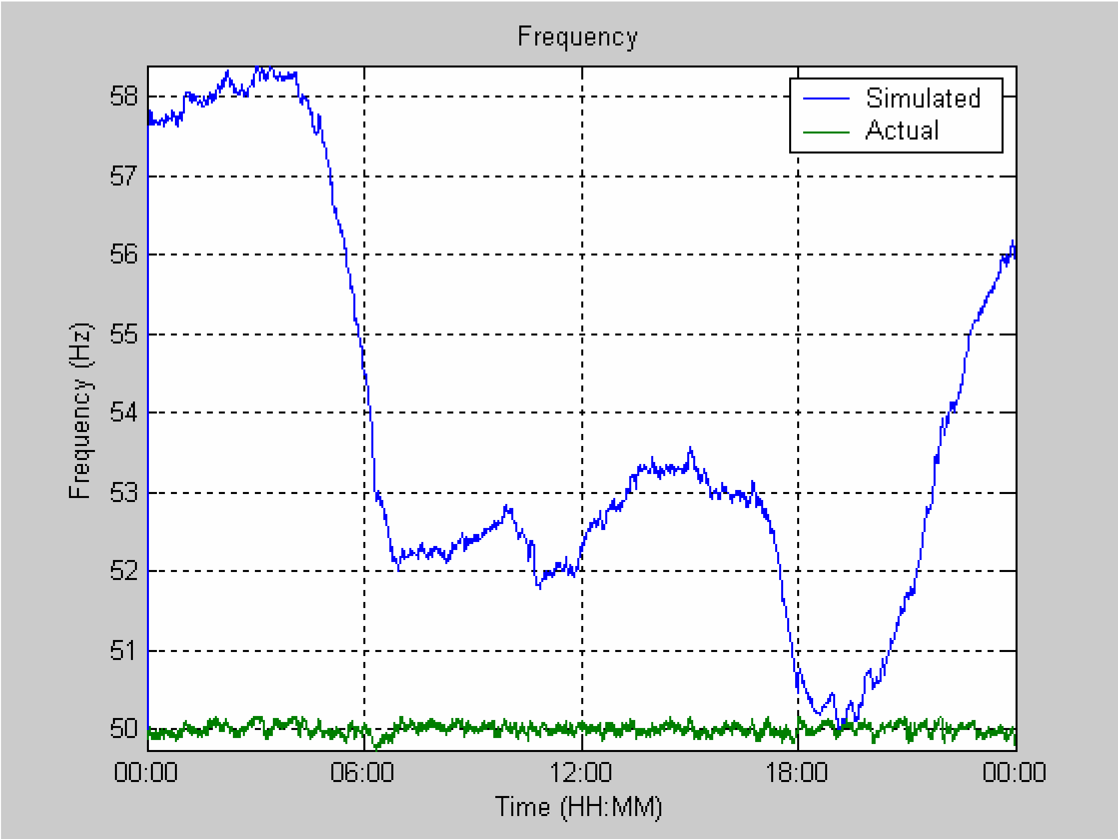

Figure 6.1. Simulated frequency of the network if generators were kept at a constant output over a typical day.

The alternative to absolutely no control is that the generators follow their energy contracts and the frequency then drifts according to the mismatch between generators and consumers. **Figure 6.2** shows the frequency if market participants in the Eskom Power Pool followed their hourly day-ahead energy contracts and performed no frequency regulation. The frequency variations are now smaller but the maximum error is 1.4 Hz. It is also observed that in high loading periods the simulated frequency increases as generators are ahead of the loads and decrease in periods where the demand is falling. Although this is on a dramatic scale, such variations have been observed in New Zealand (Transpower, 2003a) and Norway (Bakken *et al.*, 1999) where the generators were loading to contract at the beginning of the scheduling period to avoid penalties in the energy market. In some periods of the day, there was a steady state error, as shown by the first few hours on **Figure 6.2**. This error is due to a load-forecast error in the day-ahead market. Steady state errors can be corrected by re-scheduling and changing the day-ahead contracts.

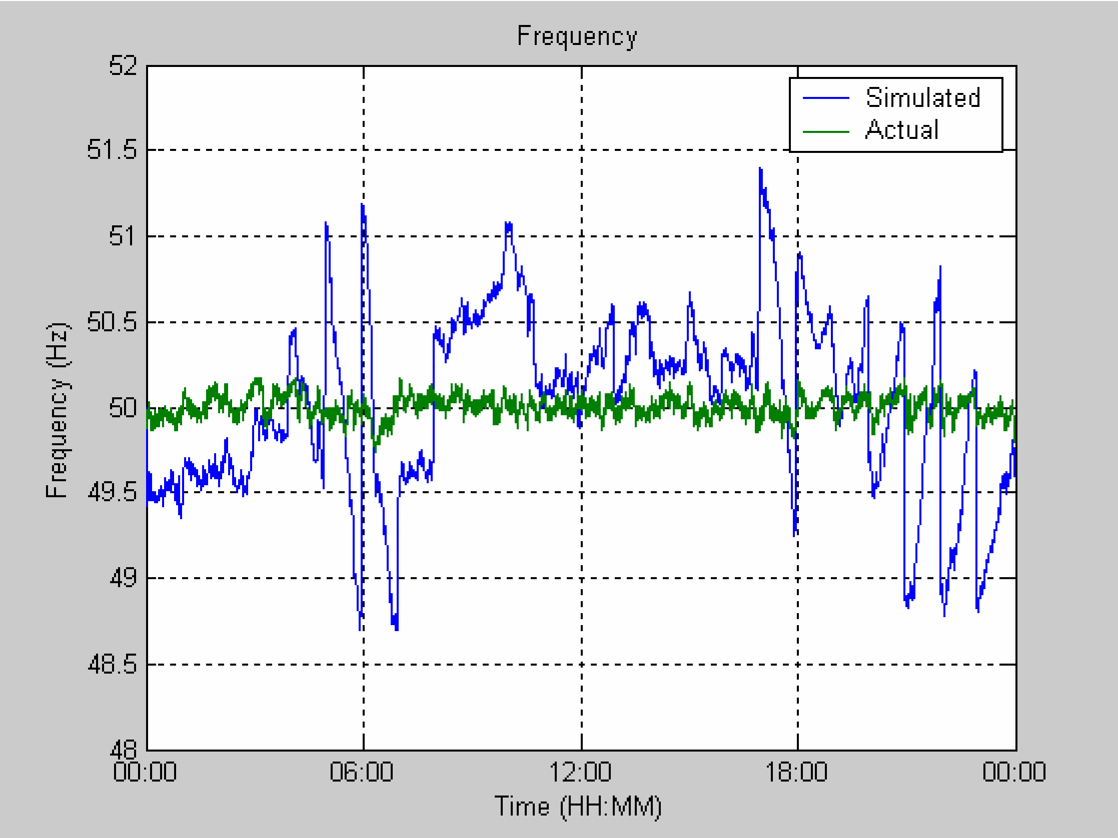

Figure 6.2. Simulated frequency if generators stayed on their day-ahead contracts in the Eskom Power Pool.

If the contractual intervals were smaller than the one-hour period shown above, then the supply and demand mismatch would also be smaller. Thus, the frequency error would also decrease as these intervals are reduced. If a market were running 5-minute intervals, the dispatch would be following consumer demand, or those that are price takers in the market, by 5 minutes. In eastern Australia, which is of similar size to Eskom, the error in the 5-minute market can be as great as 400 MW due to incorrect short-term load forecasting and incorrect state estimator values (Chown and Coetzee, 2001). An error of 400 MW would give a frequency error of 400 MW / 1250 MW/Hz = 0.32 Hz. The target would be within the boundary conditions required of 0.5 Hz and therefore, if there were no other contingencies, dispatching a market every 5 minutes would theoretically not require any further control. These calculations have thus not considered the case that a generator could have tripped when the frequency was low at the time and the frequency could go outside the set boundary conditions. A solution would then be to have a strategy to arrest the frequency before 49.5 Hz for the largest single contingency even if the starting frequency was 49.6 Hz (0.32 Hz below nominal). For Eskom this would require at least 695 MW (920 MW - 125 MW/0.1 Hz * 0.18 Hz) of units on governing that could respond within 1.8 seconds (given a rate of fall of frequency of 0.1 Hz/s). This response is impossible for the current generation in Eskom to achieve so the complete response would have to be supplied by consumers. For Eskom, this option is also impracticable due to not having a 5-minute ahead dispatch tool and enough demand side participation.

6.7 Step 2: Determine areas of no frequency control

If possible, there should be no control in the region of measurement uncertainty and general noise of customers continually switching on and off. The concept of a frequency range where there is no control is initially difficult to contemplate. Controlling in this area leads to continuous up and down movement, which increases wear and tear and gives an uneconomic dispatch. To an extent this is practised where there is no AGC and the system operator only changes the generation when the frequency error reaches predefined targets. This is the practice in the UK (Wood and Hung, 1995) and Nordic (Bakken *et al.*, 1999) networks where there is no AGC. However, in these networks the primary frequency control is continuously active. Therefore, there is still control from generators, which increases the frequency bias characteristic control and gives the system operator more time, also increasing the wear and tear on these plants.

Using a low pass filter can filter the noise but this would introduce a time delay, which could adversely affect the control of the frequency.

In Southern Africa, there is a noise of 0.02 Hz on the frequency, which is equivalent to 25 MW switching on and off. The AGC control is set-up to do no control for a frequency variation of 0.05 Hz for participants that are regulating. Participants that are following the load are loaded if the sign of the ACE is in the right direction. These units are moving towards a predefined target for the schedule period and hence the movement is in one direction only and therefore are not affected by any noise in the ACE.

6.7.1 The effect of increasing the governor deadband on frequency

Another area of no control is to increase the deadband on governing generators. The simplified Matlab© model developed in **Appendix C** is used to determine the influence of the areas of no control.

The deadband of governors was increased and the Spinning Reserve was held constant at 250 MW and a trip size of 400 MW was used. **Figure 6.3** shows the results when the deadband on the model was increased from no deadband to a deadband of 0.05 Hz and then a deadband of 0.15 Hz. Increasing the deadband from 0.05 Hz to 0.15 Hz means that the governor action is delayed by about 80 ms. **Figure 6.4** shows the simulation over the first 0.5 s. The effect of this delay is that the frequency turning point was lower for increasing deadband. The model shows the frequency dropped a further 0.05 Hz for a trip of 400 MW on a system of 3000 MW when the governor deadband was increased from 0.05 to 0.15 Hz. The model assumes there is no delay in the governor valve and any delay would be the same for all three cases and therefore does not impact the turning frequency. The settling frequency was the same and is independent of the frequency deadband.

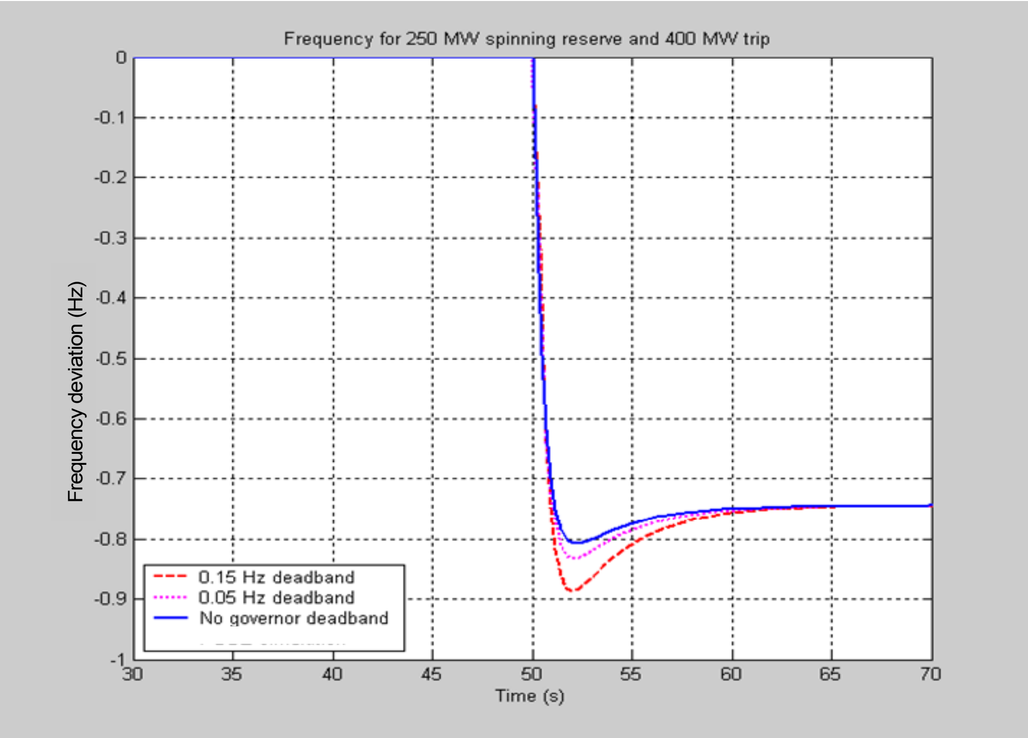

Figure 6.3. Matlab© simulation results for an increase in governor deadband.

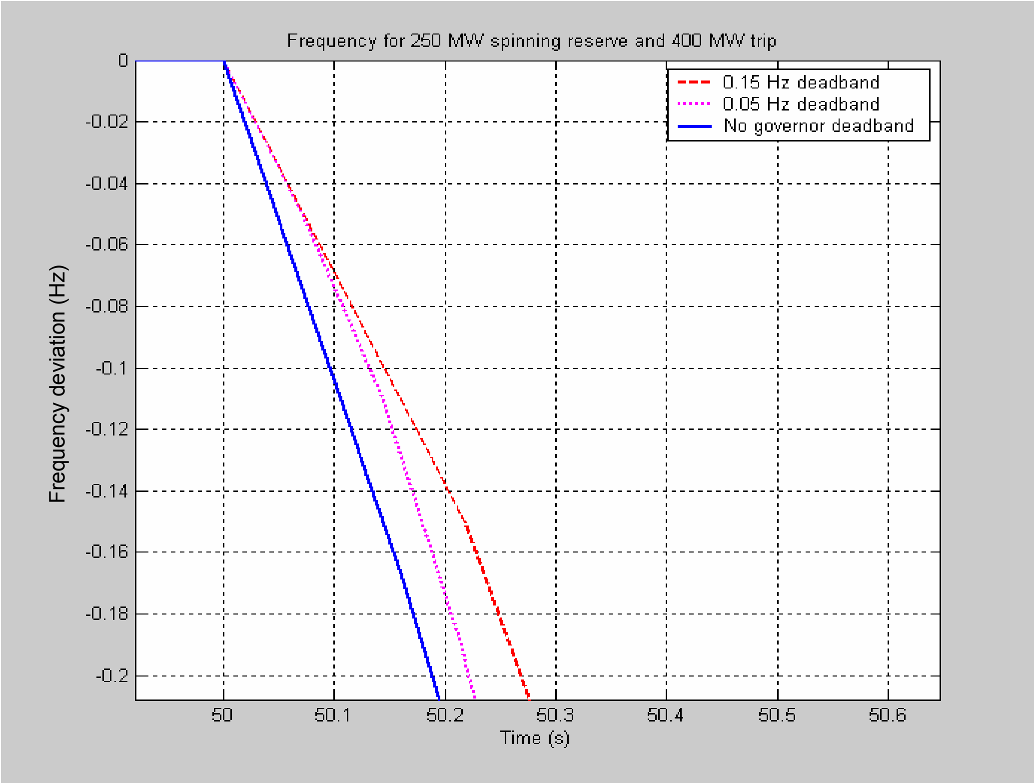

Figure 6.4. Matlab© simulation results for the first 0.5 s for an increase in governor deadband.

6.7.2 Response required for largest single contingency if the deadband is increased to 0.15 Hz in Eskom

The Matlab© model was set up with 500 MW of reserve and with a variable deadband on the governor valve. The introduction of a deadband on governors changes the characteristics of the overall network as generators react slightly slower to frequency incidents. This is due to the frequency not falling instantly, as it is dependant on the inertia of the generators and loads, and the size of the disturbance. **Figure 6.5** shows the difference in frequency with and without a 0.15 Hz deadband on generators for a 1000 MW trip. The delay in the governors means that the frequency will drop an extra 0.05 Hz.

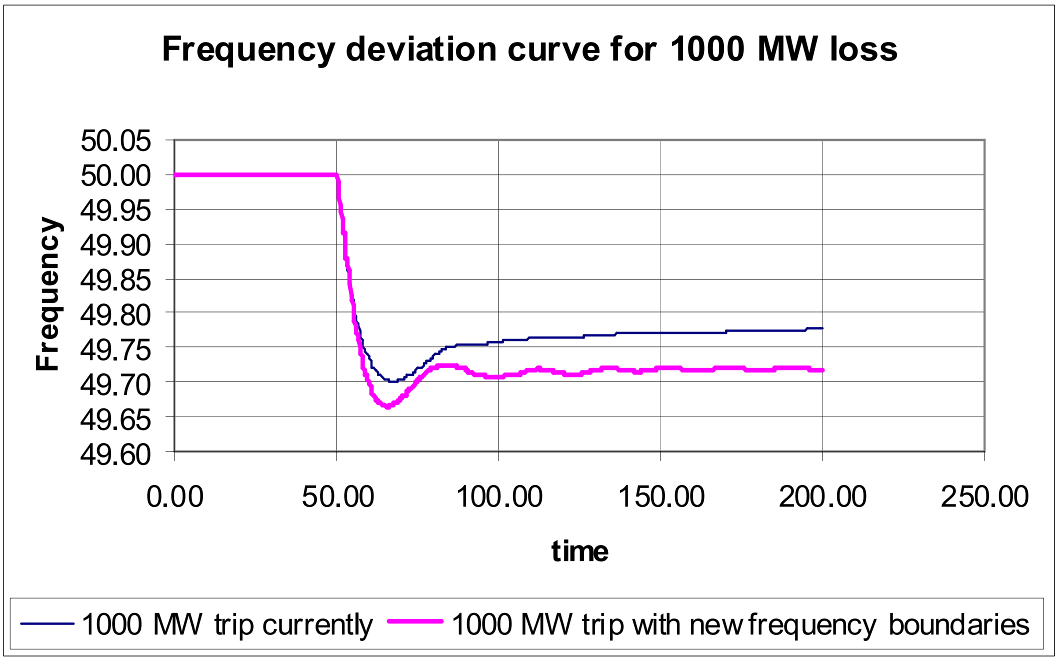

Figure 6.5. Difference in frequency for 1000 MW trip with and without a 0.15 Hz deadband.

The criteria of the new SAPP frequency control boundaries (SAPP, 2002) states: "Keep the frequency between 49.5 and 50.5 Hz for single contingencies, such as the trip of our largest single generating unit (Koeberg, Cape Town), which would result in the loss of 920MW". The Matlab© model indicated that this requirement is met as a 1000MW loss results in a lowest frequency of 49.64Hz. Therefore, even if the starting frequency was 49.85 Hz, the turning frequency is above 49.5 Hz.

6.7.3 Response required for largest credible multiple contingencies if the deadband is increased to 0.15 Hz in Eskom

The requirement for Southern Africa is to keep frequency above 49.0 Hz following all credible multiple contingencies (SAPP, 2002). The largest credible loss is the loss of 3 * 600 MW coal-fired power station units, *i.e.* 1800 MW. With a load frequency characteristic of 125 MW per 0.1 Hz, 550 MW (=1800 – (1.0*125/0.1)) response is required. The 500 MW required for single contingencies was adopted for credible multiple contingencies for two reasons. Firstly, the power station response for such low frequencies is often better than when the frequency only falls 0.5 Hz. Even though there is 500 MW contracted response, more than 550 MW is measured when the frequency drops to 49.2 Hz and below. Secondly, the current setting for under-frequency load-shedding of 49.2 Hz means that 600 MW of load is shed if the frequency fell to 49.2 Hz for longer than 300 ms. These two factors mean that the frequency would not go below 49.0 Hz after the loss of 1,800 MW from Cahora Bassa. These calculations were all confirmed with models developed in Matlab© and PTI PSS/e© (Chown and Coker, 2002). **Figure 6.6** shows the simulated trip in PSS/e© of 1800 MW with a starting frequency of 49.85 Hz and indicates the following:

- At t = 1s, a load increase of 400MW was simulated on the Southern African network.
- At t = 6s (and f = 49.85Hz), a multiple contingency (loss of 1800 MW of generation) was simulated at Hendrina Power Station.
- At t = 12.2s, the lowest frequency of 49.14 Hz was recorded. The multiple contingencies requirement was thus met for the new frequency control boundaries (note that no load-shedding was modelled for this study).

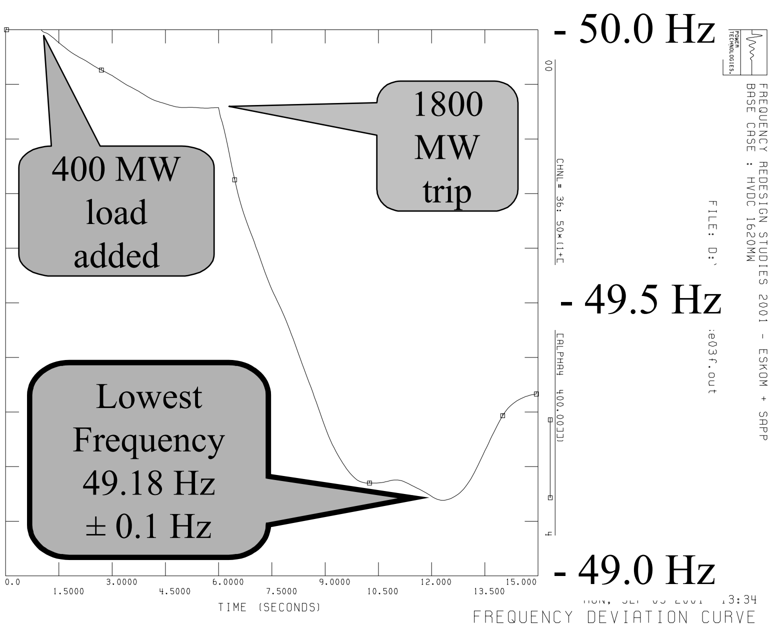

Figure 6.6. 1800 MW trip with a starting frequency of 49.85 Hz.

6.7.4 Effect on high frequency contingencies if the deadband is increased to 0.15 Hz in Eskom

High frequencies occur when there is a sudden loss of a large consumer or consumers, which is probably due to the loss of a part of the network. The losses can be caused by a lack of lines for single contingencies on the network or natural disasters such as fires and storms. The second cause is a sudden injection of a large amount of uncontrollable generation. This could be generation from sources such as wind power or large generators that are increasing to a minimum level after synchronisation for stability. For high frequencies, the largest credible multiple loss of load for Southern Africa is 3000 MW or the loss of supply to the Cape area. To keep the frequency below 51 Hz and with a load frequency characteristic of 125 MW per 0.1 Hz, 1750 MW reduction (= 3000 – (1.0*125 / 0.1)) is required in 10 seconds. As reducing generation is relatively simple, it was decided that a mandatory reduction of 15% of each generator is required for frequencies above 50.5 Hz on a 4% droop curve (NERSA, 2003). The largest single contingency for a load is 700 MW. In order to keep the frequency within 1% of 50 Hz the system requirement was calculated as 300 MW. The system requirement is set to 500 MW to be the same as the requirement for low frequencies. It is currently mandatory for generators contracted to provide the low frequency service to provide at least the same response for high frequencies.

6.7.5 Summary of no control regions and governor deadband increased in Eskom

The studies showed that an area of no control should be at least 0.02 Hz on the frequency, which is equivalent to 25 MW switching on and off. The AGC control is initially going to be set-up to do no control for a frequency variation of 0.05 Hz for participants that are regulating.

If the deadband and normal control region is increased to 0.15 Hz then this would result in an additional amount of governing of 110 MW from the minimum governing of 390 MW required in **Section 4.4.** However, an extra 100 MW is required to counter the voltage disturbance when the HVDC line from Cahora Bassa trips. The probability that the frequency will be 0.1 Hz below nominal at the time of a HVDC line trip is low. For this case, it was accepted that the frequency could go below the credible multiple contingency limit. The loss of one pole also under the same circumstances causes the frequency to go below the single contingency limit and this was also deemed to be acceptable.

The additional cost of Instantaneous Reserve for Eskom to increase the deadband on governing 0.1 Hz, from 0.05 to 0.15 Hz

= 110 MW * R 30 000 per MW

= R 3.3m per year. **(6.9)**

However, it could be argued that this increase of Instantaneous reserve was also required to counter the voltage disturbance when one or both poles are lost on the HVDC link to Cahora Bassa as detailed in **Section 4.6.**

6.8 Step 3: Calculate cost savings when frequency is relaxed for normal conditions for various cases

Normal conditions is when there is no contingency event and the normal region is the region within which the frequency is to be controlled most of the time given a normal consumer demand pattern. In the Southern African Power Pool, the normal frequency region was initially defined as within 50 mHz of 50 Hz at least 90% of the time (equivalent to a standard deviation around 30 mHz). The frequency relaxation project set out to alter this if it proved to be economically beneficial.

The normal frequency control region should consider what would happen if there was a contingency when the frequency is at the bounds of this normal region. This may be an iterative process, as allowing a larger frequency deviation to fall within the normal region reduces the amount of control but increases the risk of not controlling within the contingency boundaries. The proposed strategy is to choose a few cases that will give a profile of the costs options. For each case the AGC controller needs to be tuned to give the minimum amount of control.

The proposed strategy, as used in Eskom, is to:

- Firstly, increase the deadband of the governors (primary control).
- Secondly, the AGC controller is tuned to minimise control whilst trying to maintain the frequency deviation less than the deadband for more than the

95% range for control in the normal state. Given that 95% is equivalent to 2 standard deviations the new condition for the optimisation is rewritten as:

Frequency standard deviation < Governor deadband / 2

Finally, in Step 4, an attempt is made to improve the economic dispatch by doing additional control other than for controlling the frequency.

6.8.1 Eskom governor deadband cases

In Eskom, the case to investigate different deadbands for the governor is shown in **Table 6.1**. Additionally, **Table 6.1** lists the extra Instantaneous Reserve and associated annual costs for this deadband case.

Table 6.1. Governor deadband cases to determine potential frequency relaxation savings for Eskom

Governor deadband Cases	Governor deadband (mHz)	Additional Instantaneous Reserve (MW)	Additional annual Instantaneous Reserve cost (R)
Base (22/08/2002)	50	0	0
1	100	50	1 650 000
2	150	100	3 300 000
3	200	150	4 950 000

6.8.2 Results obtained on 22 August 2002

On the actual day, the governor deadband was already set at 50 mHz and AGC was tuned to control the frequency within 50 mHz for at least 90% of the time. **Figure 6.7** shows the actual frequency as recorded every 4 seconds by the EMS system. The AGC controller was tuned as described in the author's M.Sc. dissertation (Chown, 1997) and this was set up to be the optimal tuning with the tightest control that could be obtained without constant overshoots. The frequency was maintained within a standard deviation of 30 mHz and the AGC movement was 37 511 MW moved for the day or 1 563 MW moved per hour. This movement was slightly less than the average movement for 2002, which was 1 650 MW moved per hour before the relaxation was implemented. The cost of the over- and under- generation for the day was R 4 596 793.

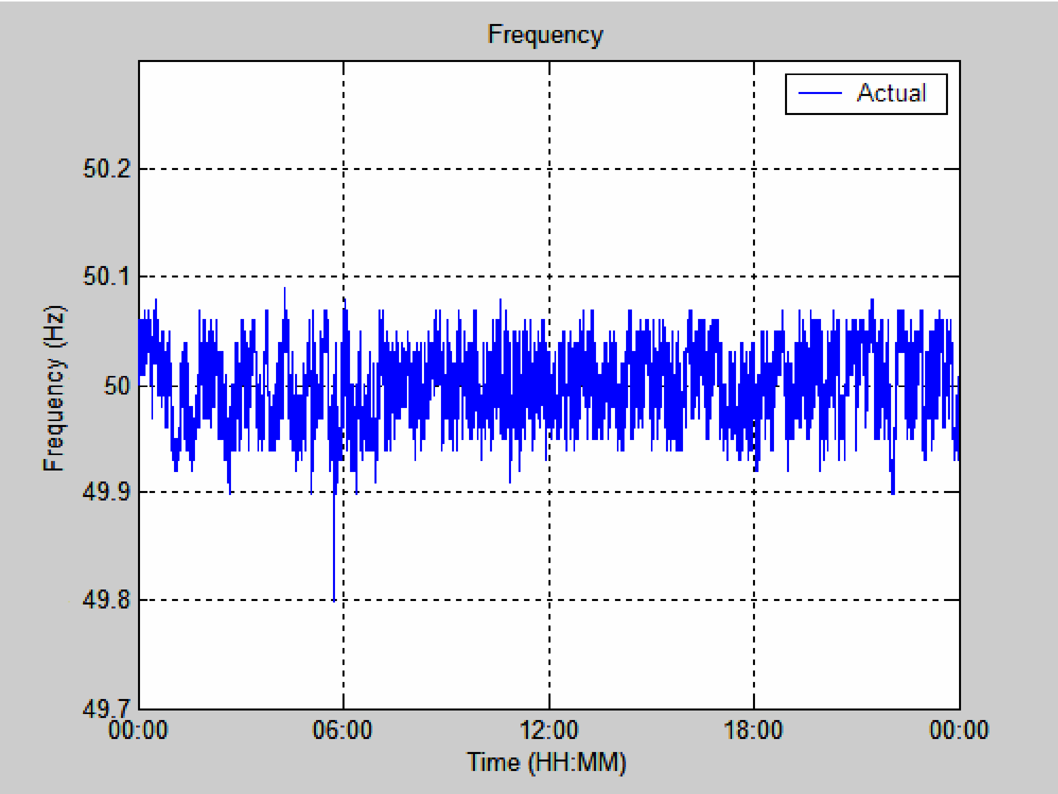

Figure 6.7. Frequency as recorded by the EMS system on 28 August 2002.

6.8.3 Creating balancing offers from Day-ahead contract

The optimal solution for the real time dispatch is for the units to be dispatched at the day-ahead schedule whilst respecting all constraints in the system. The day-ahead schedule considers all constraints to optimize the solution over the day and the day-ahead contract for Eskom is binding on the participants. The bids and offers from day-ahead are used as balancing bids. The real time dispatch tool does not consider constraints such as energy, future ramping and start up and shut down ramping. The solution to obtaining a correct dispatch is complex as there is a trade off between obtaining a quick solution and modelling all the possibilities correctly.

The proposal used in the Eskom AGC dispatch is to modify the daily offer to an hourly offer that respects, as far as possible, the latest intra-day schedule. The intra-day schedule is contractually binding and hence from this schedule an hourly balancing offer can be derived.

In the current settlements in the EPP, a unit generating above day-ahead schedule is paid at the minimum of its offer and system marginal price (SMP). The intra-day actual offer is used to derive the units balancing offer.

A unit generating below intra-day contract is paid a loss of profit, calculated as the difference between offer and SMP. This can be represented in the balancing by calculating the difference between the offer and SMP, making the down prices from intra-day schedule as negative offers.

Figure 6.8 and **Figure 6.9** graphically shows the derivation of the balancing curve from the schedule for a unit that was backed off from its optimal point for the provision of reserves, energy or ramping constraints.

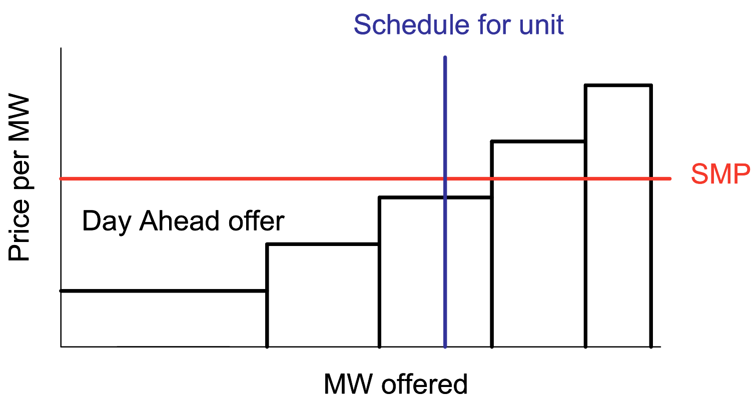

Figure 6.8. Example of a day-ahead offer curve for a unit backed off, the SMP and Schedule for the unit.

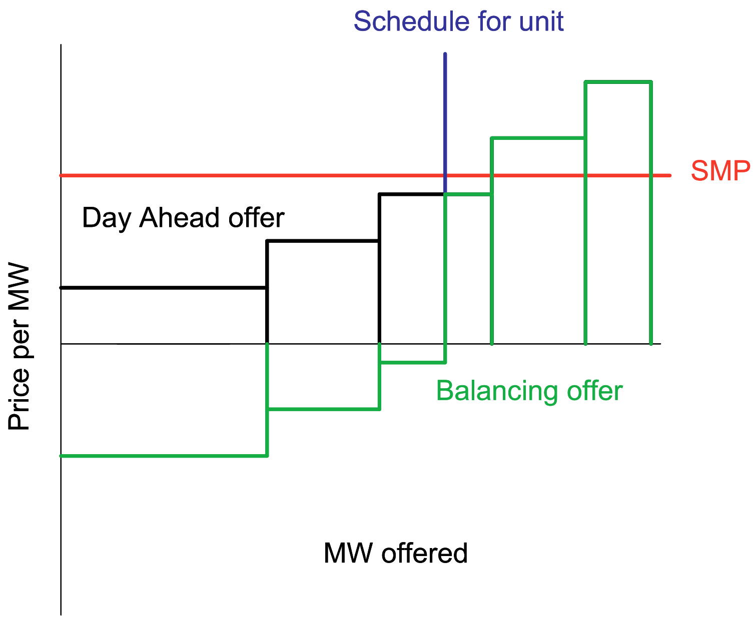

Figure 6.9. Example of a balancing offer curve for a unit backed off, the SMP and Schedule for the unit.

The contract point hence creates a clean break. The process creates another offer if the unit was not contracted at an elbow. The AGC financial model described in **Appendix I** includes this modification.

6.8.4 Combining frequency control and economic control in a single step for normal frequency control for Eskom

To control the frequency within the normal region, the economics of the units should be considered, and the cheapest units should always be moved first. This applies to both a cost and market environment. In essence, this would mean that at any given time the cheapest solution should be in place. However, this is often far from the truth and due to many reasons, the economic solution is not what it should be. Reserve levels also need to be considered, as a cheap generator might have its output reduced to ensure sufficient reserve levels. When the frequency is controlled manually, the system operator makes a value judgement and requests an expensive generator to decrease and a cheap generator to increase its output at the same time. When the control is done primarily by the AGC, the AGC algorithm needs to be set up to do this function.

In Eskom, load-following participants move according to their hourly contract and on the sign of the ACE and hence do the first amount of control. Less control is then required by participants on regulation. In the Eskom Power Pool, units contracted for regulation are selected according to the cheapest offer prices in the energy market. Hence units that are performing load-following are by default a more expensive energy solution (if not generating power according to day-ahead contracts) than units contracted for regulation. Therefore, from these perspectives it makes more sense to move units that are on load following before units that are on regulation.

The regulation units use the derived balancing offers described in **Section 6.8.3** to determine which unit is moved first.

The simulations are performed to determine the optimal economic solution with the least cost in terms of wear and tear, and are presented in the next section.

6.8.5 Simulating the different possibilities or controlling in the normal region combined with economics

The initial frequency redesign proposal was to increase the normal region to 100 mHz for at least 95% of the time. This equates to controlling the frequency to better than a standard deviation of 50 mHz. Many simulation cases were performed with different controller gains and areas of no control. The best results for each level of frequency control are presented in **Table 6.2** for simulations done on the data recorded on 22 August 2002. Studies 1 to 3 in **Table 6.2** relied on AGC to control the frequency within 95% of the governor deadband. This was simulated in the Matlab© model described in **Appendix I**. The results were analysed in terms of estimated generator movement on governing, generator movement on AGC and the simulated balancing market costs for the day. The estimated governor movement assumed that: there were 16 contracted generators to provide the governing as specified in the Eskom Power Pool ancillary service contracts; these generators were on a 4% droop characteristic and each provided a maximum of 5% of continuous rating.

Table 6.2. Results of Matlab© simulations with different deadband cases.

Simulation Case	Governor deadband (mHz)	Frequency Standard deviation (mHz)	Estimated governor movement (MW)	AGC movement (MW)	Total Generator movement (MW)	Daily Market savings (R)
Base Case	50	30.81	56 234	37 511	93 745	0
1	100	54.9	143	27 906	28 049	765 902
2	150	74.6	2 148	22 246	24 394	1 089 227
3	200	90.0	749	17 012	17 761	985 744

The results in **Table 6.2** are then converted to annual savings using **Equation 6.8**, shown in **Table 6.3.**

The Regulation Reserve savings is estimated by reducing the need for peak within peak MW by the frequency difference multiplied by the load frequency characteristic. From studies done, the minimum Regulation Reserve for other hours of the day is around 300 MW, but for the peak hour is 500 MW to cater for the peak within the peak hour.

Table 6.3. Annual savings Results of Matlab© simulations for Cases 1-3.

Simulation Case	Annual Instant. Reserve savings (R)	Annual Instant. usage savings (R)	Annual Regulation Reserve savings (R)	Annual Regulation usage savings (R)	Annual Market savings (R)	Total savings (R)
1	-1 650 000	9 974 571	1 875 000	10 499 946	279 554 230	300 253 746
2	-3 300 000	9 618 025	3 750 000	16 687 316	397 567 855	424 323 196
3	-4 950 000	9 866 807	5 625 000	22 408 994	359 796 560	392 747 361

Figure 6.10 shows the savings for Cases 1-3 against the frequency standard deviation. The trend shows that the optimal savings could be achieved with a frequency standard deviation around 75 - 80 mHz. Four more simulations were done to confirm the results. These are reported as Cases 4 to 7.

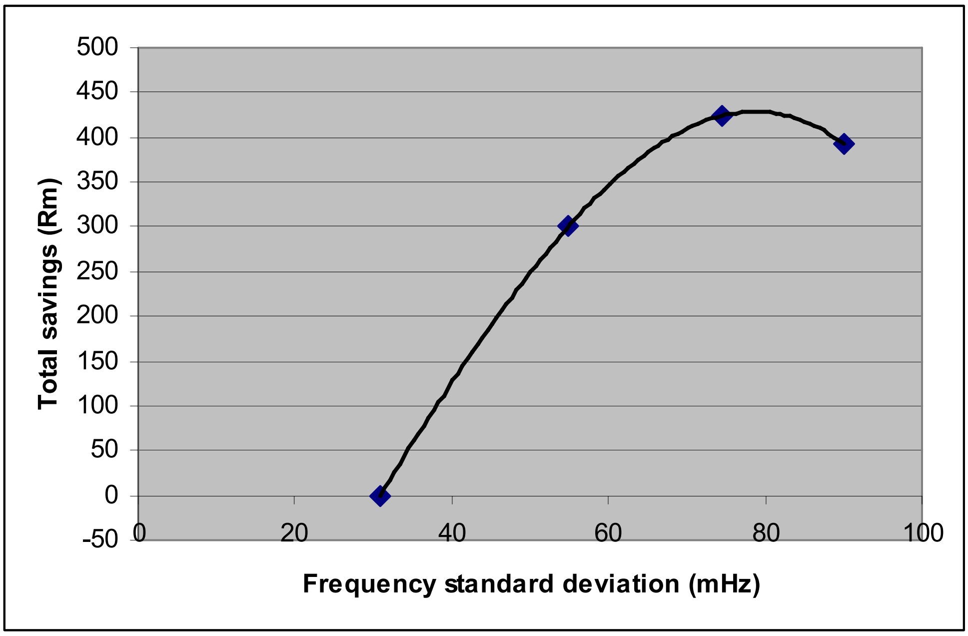

Figure 6.10. Total savings vs. frequency standard deviation for Cases 1 – 3.

For three of these cases the dead bands were left at levels of 150 mHz and 200 mHz as these deadbands will be easy for the generators to implement. Cases 4 and 5 were run with the deadband at 150 mHz with frequency controlled tighter than 75 mHz and Case 6 was run with a deadband of 200 mHz and the frequency controlled at 120 mHz. A final Case 7 was run with the deadband set at 20 mHz, being the mechanical deadband of most generators and the AGC controlling the frequency to a standard deviation around 75mHz. The results of these cases are reported in **Table** 6.4**.**

Table 6.4. Results of Matlab© simulations with different deadband cases.

Simulation Case	Governor deadband (mHz)	Frequency Standard deviation (mHz)	Estimated governor movement (MW)	AGC movement (MW)	Total Generator movement (MW)	Daily Market savings (R)
Base Case	50	30.81	56 234	37 511	93 745	0
4	150	64.6	1 458	24 645	26 103	1 008 631
5	150	68.5	1 788	23 888	25 676	1 109 070
6	200	122.5	1 532	13 866	15 398	602 544
7	20	84.6	208 451	10 781	219 232	-4 619 288

The annual savings in **Table 6.5** show that there are more savings achieved with Cases 4 and 5, where the frequency standard deviation is between 65-75 mHz. The key driver to these savings is the balancing market savings. This is explored in more detail in the next section. Case 7 showed very poor savings overall and this case is discounted as not being a good strategy for Eskom.

Table 6.5. Annual savings results of Matlab© simulations for Cases 4-7.

Simulation Case	Annual Instant. Reserve savings (R)	Annual Instant. usage savings (R)	Annual Regulation Reserve savings (R)	Annual Regulation usage savings (R)	Annual Market savings (R)	Total savings (R)
4	-3 300 000	9 740 726	3 750 000	14 064 790	368 150 315	392 405 831
5	-3 300 000	9 682 043	3 750 000	14 892 323	404 810 550	429 834 916
6	-4 950 000	9 727 567	5 625 000	25 848 123	219 928 560	256 179 250
7	90 000	-27 068 499	-1 125 000	29 220 568	-1686 040 120	-1684 113 052

Figure 6.11 showing the savings for Cases 1 – 6. The trend of savings shows that the optimal savings are achieved if the frequency is relaxed to a standard deviation of 65 mHz and the governor deadband is relaxed to 150 mHz. The following sub-sections show some of trends in the data that are important to analyse and proposes some minor modifications to tune the final design before a final strategy is decided.

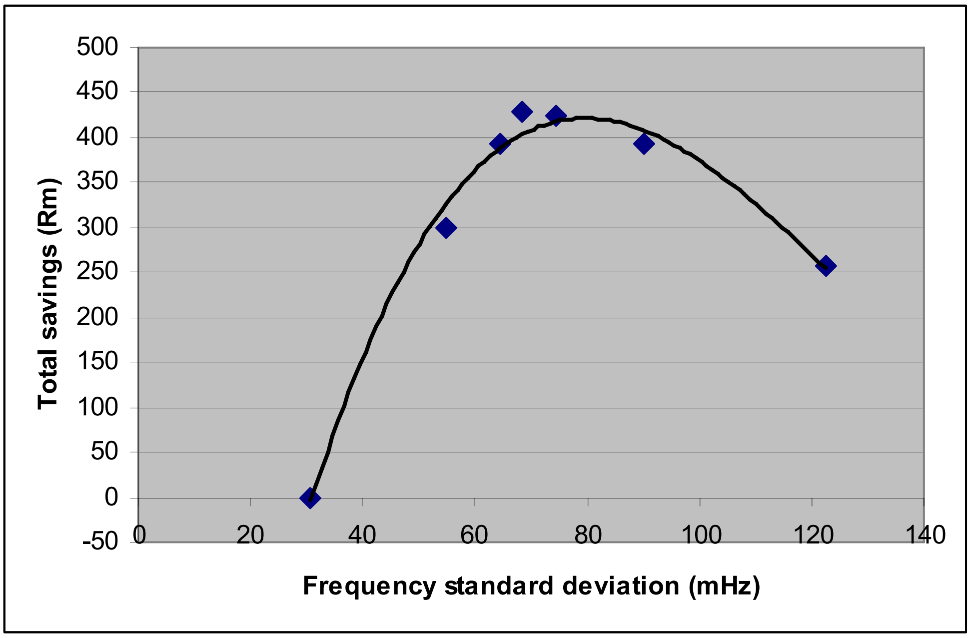

Figure 6.11. Total savings *vs*. frequency standard deviation for Cases 1 – 6.

6.8.5.1 Results of generator movement of Cases 1 to 6

Figure 6.12 below shows the trend in the total generator movement against the standard deviation of the frequency. The results show a dramatic decrease in movement when the frequency was relaxed from a standard deviation of 30 mHz to 54.9 mHz. As the frequency was relaxed from a standard deviation 54.9 mHz to 122 mHz, the generator movement decrease became less pronounced. The absolute minimum movement was calculated as the load-following requirement to get from morning peak, to afternoon trough, to evening peak, to evening trough and back to morning peak. This resulted in a minimum movement of 14 164 MW, as shown in **Figure 6.13**. Case 6 was close to this absolute minimum movement possible. Therefore controlling the frequency with a standard deviation of 120 mHz means that all noise is taken out of the control and generators are simply just following the load.

The generator movement for Case 7, where the generators governing did all the control in the frequency region within 0.15 Hz of 50 Hz, was recorded as being much higher than the case where AGC was controlling the frequency within the 0.15 Hz band. This is due to the governor reacting to any change outside the governor deadband whereas the AGC controller is set up not to control small quick changes.

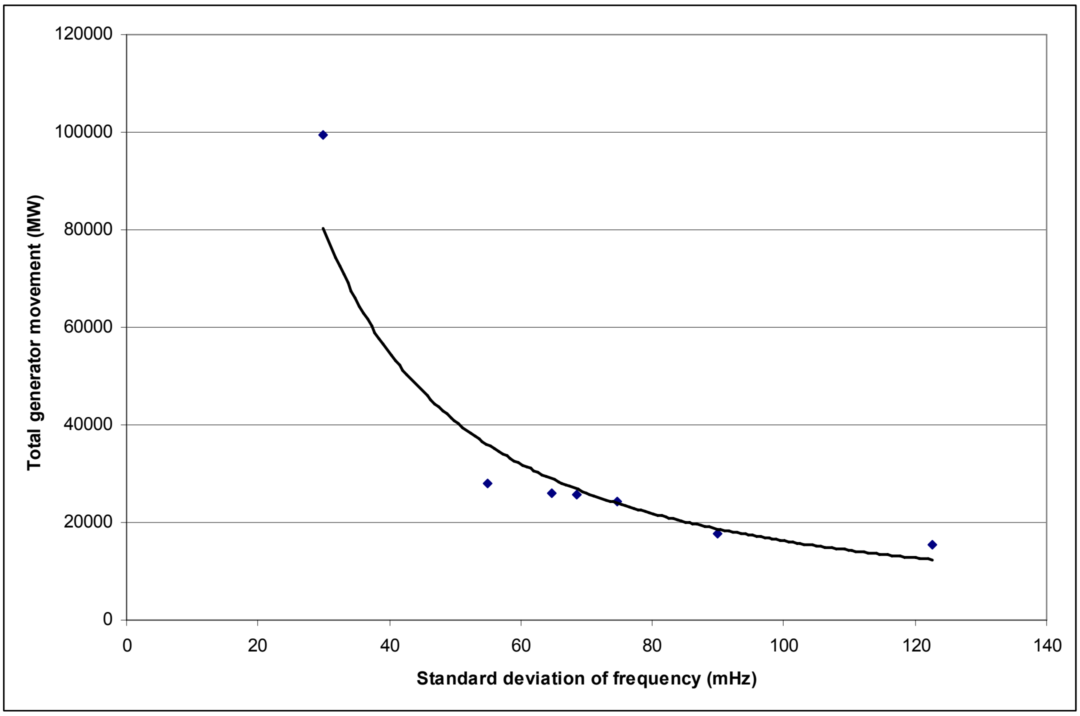

Figure 6.12. Trend of generator movement *vs.* standard of frequency control for Cases 1 to 6.

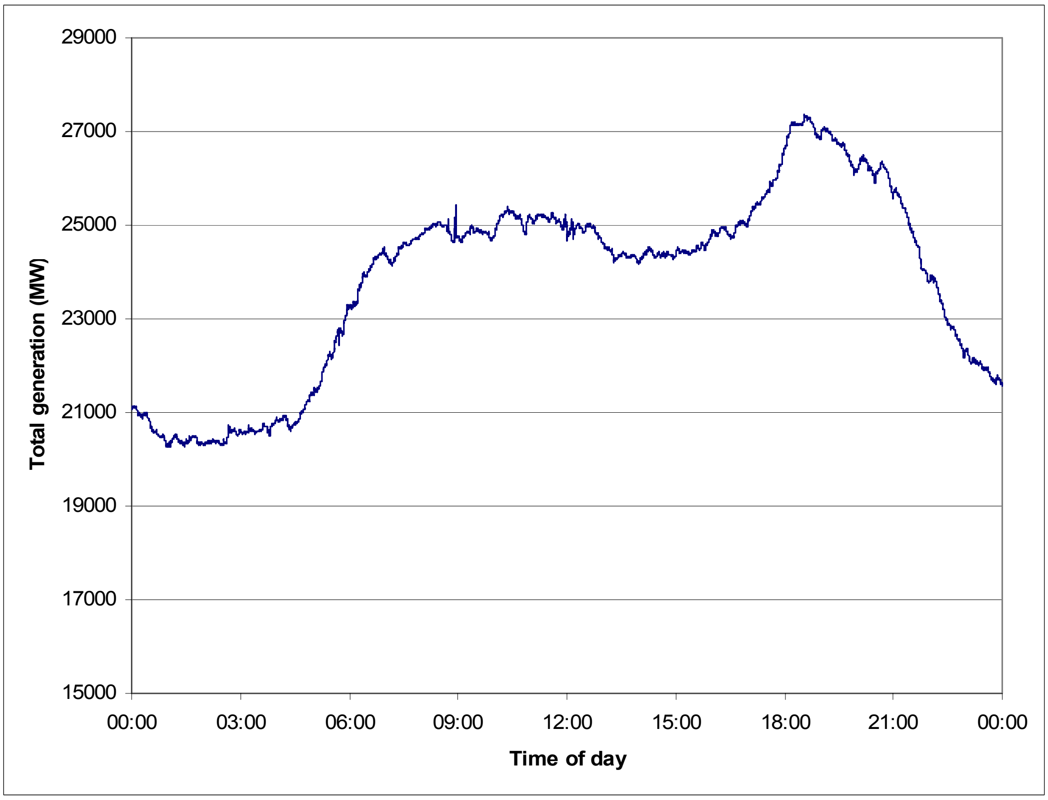

Figure 6.13. Actual generation as recorded on 22 August 2002.

6.8.5.2 Economic results of the Cases

The trend of the economic results for Cases 1 to 6, shown in **Figure 6.14**, shows that the maximum savings in the energy market were achieved with a standard deviation of the frequency between 60 and 80 mHz. The savings at this point were just over 20% when compared to the over- and under- generation costs for the actual day. As the standard deviation was increased from 80 mHz standard deviation in frequency, the savings started to decrease. This is due to the generators not being moved often enough to keep a good economic solution. The strategy adopted for Case 7 gave a very poor economic result for the cost of balancing. This was due to the day-ahead contract in the Eskom Power Pool, which selects the cheapest generators that are available for regulation before selecting generators for governing. This is to give the best economic solution while still using AGC regulation to control the frequency in the normal region. The contracting strategy would need to be altered, to select the cheapest generators available for governing ahead of generators for regulation. It is therefore best to ignore the economic results obtained for Case 7.

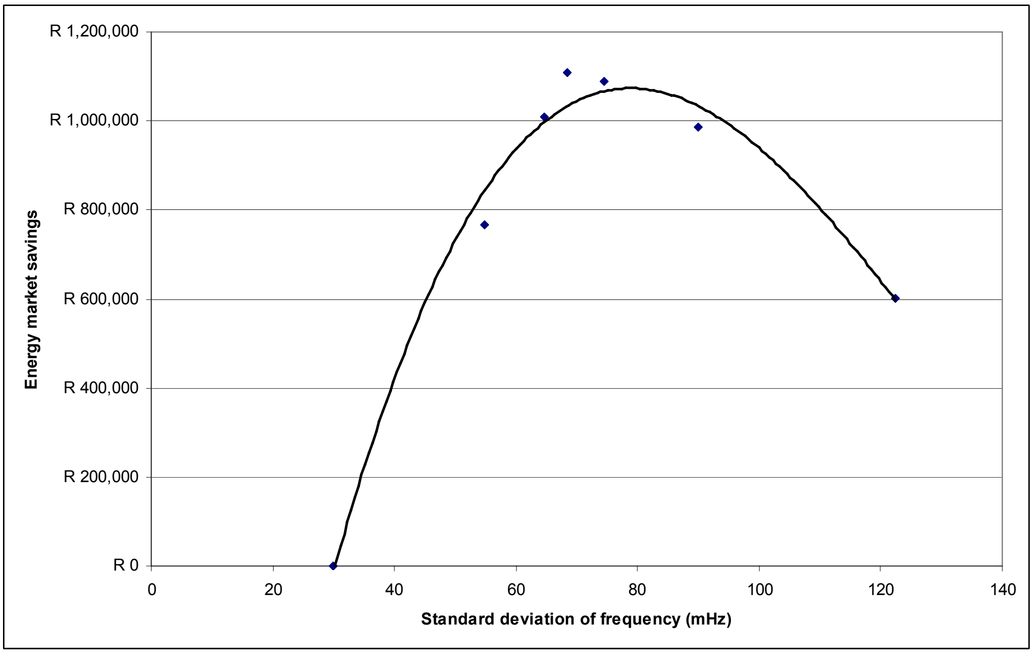

Figure 6.14. Trend of the economic savings against frequency standard deviation for simulations 1 to 6.

6.8.5.3 Time error recorded for Cases

As reported in **Step 2**, a target was set by the Southern African Pool to maintain the system time within 30 seconds of real time (SAPP, 2002). **Table 6.6** shows the maximum absolute time error of system time with respect to real time measured for the various simulations. The table also shows the time error at the end of the simulated day.

For Cases 1, 2, 4 and 5, the time error was maintained well within the required 30 seconds. The time error of the end of the day of less than 2 seconds means that this could be maintained for the future days. For Cases 3 and 6, the time is not maintained within the required boundaries. This could be solved by adding some integral action to the AGC controller which would make the frequency control tighter or else the target of 30 seconds would have to be relaxed. The conclusion is that the time error requirement is met if the frequency is controlled to a standard deviation of frequency of 75 mHz or better. This further confirms that controlling the frequency at 65 mHz standard deviation is the most economic solution that meets all the boundary conditions.

Table 6.6. Time difference between real time and network time for simulations 1 - 6.

Simulation Case	Governor deadband (mHz)	Frequency Standard deviation (mHz)	Maximum absolute time error during day (s)	Time error at the end of the day (s)
1	100	54.9	4.75	-0.57
2	150	74.6	18.09	-1.86
3	200	90.0	36.52	-11.98
4	150	64.6	13.92	-0.15
5	150	68.5	15.87	-1.20
6	200	122.5	55,86	-16.11

6.8.5.4 Impact on inadvertent energy flow between Eskom and Zimbabwe

The inadvertent energy flow between Eskom and Zimbabwe could be impacted by the frequency being controlled less tightly. Table 6.7 below shows the average frequency for each hour of the day for Case 2, where the frequency was controlled to a standard deviation just less than 75 mHz. The worst frequency deviation for an hour was recorded at hour 5 where the average frequency deviation was 0.09 Hz. The load frequency characteristic of SAPP was measured at 125 MW per 0.1 Hz. Hence, the maximum error on the tie line if no generator was performing any primary or secondary control between 49.9 and 50.1 Hz was 125 MW if the error was outside the Eskom control area. If the control error was inside the Eskom control area, the support received from Zimbabwe would be 12.5 MW, assuming the total generation outside Eskom's control area was 3000 MW. The average inadvertent energy for the tie line between Eskom and Zimbabwe from 2000 to October 2002 was 40 MW, shown in **Figure 6.15.** As this is more than the predicted worst case error of 12.5 MW, the inadvertent energy might increase slightly. There is no financial impact of inadvertent energy, as these errors are paid back as energy at similar times during the day when the costs of energy are similar and thus the marginal cost difference is low.

Table 6.7. Average hourly frequency for simulation Case 4.

Hour of day	Average hourly frequency (Hz)
0	50.06
1	49.98
2	50.02
3	49.98
4	49.95
5	49.91
6	49.95
7	49.99
8	49.98
9	50.01
10	49.99
11	50.03
12	50.03
13	50.02
14	50.00
15	49.99
16	49.98
17	49.92
18	50.00
19	50.04
20	50.01
21	50.05
22	50.06
23	50.03

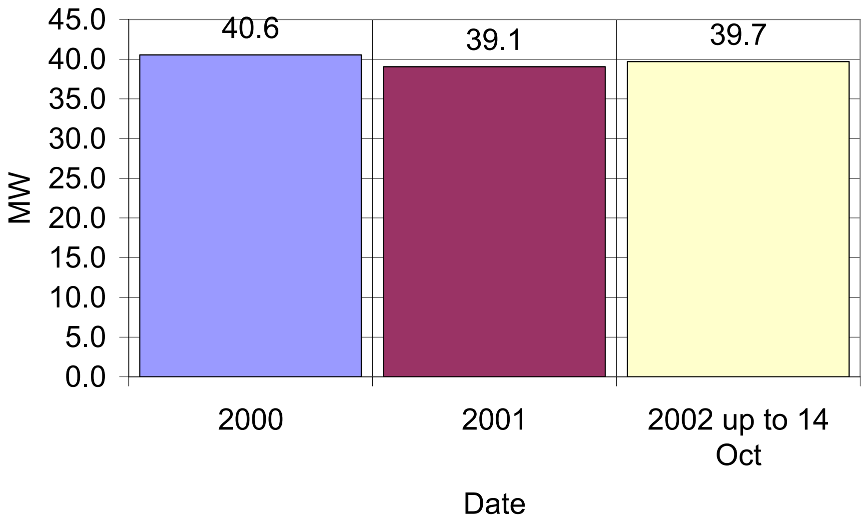

Figure 6.15. Average inadvertent energy for the tie line between Eskom and Zimbabwe from 2000 to Oct 2002.

6.8.5.5 Dynamic frequency during fast loading periods

In manually loaded networks, when the demand is increasing quickly, operators deliberately control the frequency above nominal. This is to be one step ahead of any potential problem such as the demand coming in quicker than they originally estimated or a generator loading that could be delayed for some reason. **Figure 6.16** shows the frequency for Case 5 above. Case 5 is the best economic result and meets the frequency control criteria for the normal region. The frequency drops to around 49.9 Hz during the morning pick-up and evening pick-up and increases to 50.1 Hz when the load drops off quickly in the evenings. A simple method to solve this problem is to set a higher frequency target for control purposes so that the frequency is kept one step ahead of potential problems in the same way as when the network was controlled manually. This philosophy then also allows the frequency to increase when generators are manually loading and not to send any down control, as the deadband around the ACE is set according to the targeted frequency. The strategy developed for the Eskom AGC is described below. The target frequency for control purposes is automatically calculated as follows:

f = 50.03 Hz if $Contract_{(hour+1)} > Contract_{(hour)} + 300$ *MW at 55 minutes past the hour*, *else*

f = 49.98 Hz if $Contract_{(hour+1)} > Contract_{(hour)} - 300$ *MW at 55 minutes past the hour*, *else*

f = 50.00 Hz

Target frequencies, or offset from nominal, and MW settings for the above calculation are parameters that can be adjusted by an engineer. The target frequency is also configurable by the operator.

Figure 6.16 shows that when the demand is increasing, the new higher frequency target during high load periods just keeps the frequency slightly higher and therefore the periods of operating around 49.9 Hz is decreased for about 6 hours of the day.

The results of the simulation, **Table 6.8**, show that the total generator movement increased very slightly from 23 888 to 24 010 MW moved. The balancing market saving dropped slightly from R 1 109 070 to R 1 087 301, which is a slight loss of performance compared to the operating advantages. The result of the lower frequency target does not gain much benefit except to keep the time error within daily target with a maximum time error of 15.2 seconds measured for Case 8 against an error of 15.87 for Case 5. The annual saving for Case 8 are R 421.6m against R 429.8m for Case 5. The overall savings are still amongst the best simulated, confirming that this was a good solution for Eskom.

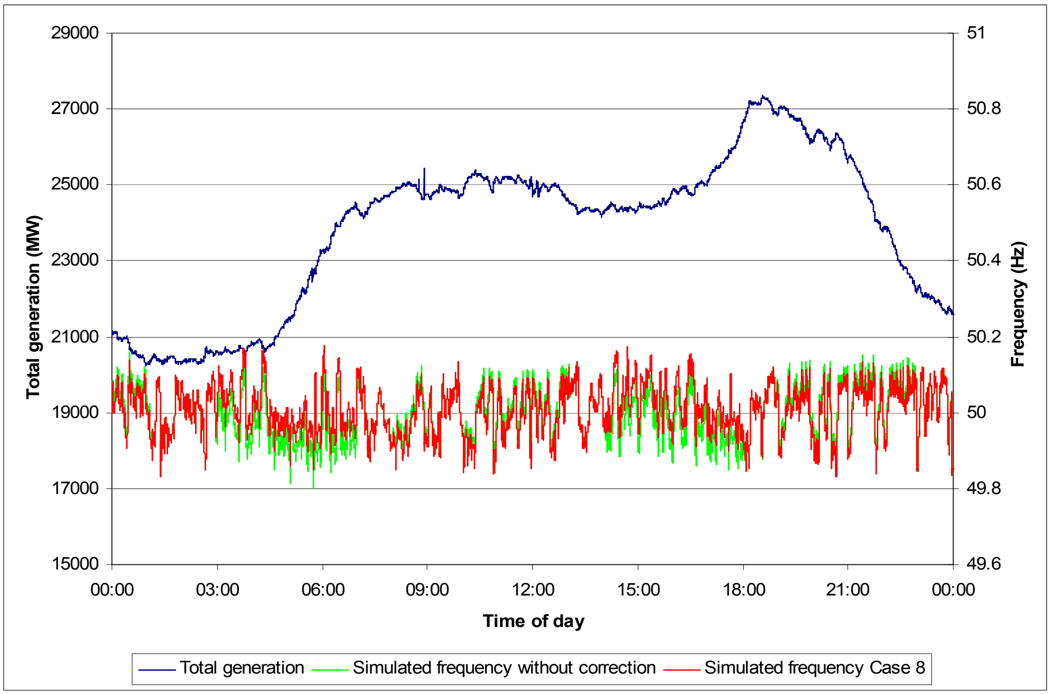

Figure 6.16. Simulation of dynamic frequency.

Table 6.8. Simulation results with frequency set-point offset.

Simulation Case	Governor deadband (mHz)	Frequency Standard deviation (mHz)	Estimated governor movement (MW)	AGC movement (MW)	Total Generator movement (MW)	Daily Market savings (R)
Base Case	50	30.81	56 234	37 511	93 745	0
5	150	68.5	1 788	23 888	25 676	1 109 070
8	150	64.0	2 483	24 010	26 493	1 087 351

6.9 Step 4: Controlling for economic dispatch improvement only

The philosophy adopted in **Section 6.8.3** and **6.8.4** for the economic dispatch can be improved by doing a separate economic control action for economic solution improvement purposes only. The simplest action is to swap the generators by moving the most expensive one down and the cheapest one up. If the economic dispatch algorithm dispatches the same amount of up- and down- control at the same time, then the net effect on frequency is zero, except for timing differences in the response of the generators. Case 9 in **Table 6.9** and **Table 6.10** shows the results when one generator is swapped with another generator, if there is a generator over its day-ahead contract and a generator under its day-ahead contract, represented by the negative offer curve described in **Section 6.8.3**. This is uneconomic, as the one generator is paid to under-generate whist another is paid to over-generate (O/U). The Case is set up to correct this balance whenever there is no other control required. The amount of control has increased by 23% and the economic solution has improved by 36% compared to Case 8.

Case 10 is set up to swap when the price difference between the highest generator to move down and the cheapest generator to move up was R10.00. The results of Case 10 are a doubling in generator movement and a 37% improvement in the economic solution. Case 11 repeats Case 10 but using a price for the swap set at R0.01 instead of R10.00. The result of simulation 11 is that the movement has increased but the financial solution is less than Case 8, as now the generators are moved around the best economic solution. The optimal case for this study was Case 9 where the economic gain with the movement was at an optimal balance. The control strategy used in Case 9 has been implemented in Eskom as a manual action. Eskom is purchasing a 5-minute ahead real time dispatch tool, which will also improve the economic solution.

Table 6.9. Results of Matlab© simulations with economic swapping.

Simulation Case	No. of gens to swap	Price for swap (R)	Frequency Standard deviation (mHz)	Estimated governor move (MW)	AGC move (MW)	Total Generator movement (MW)	Market savings (R)
Base Case	0	N/A	30.81	56 234	37 511	93 745	0
8	0	N/A	64.0	2 483	24 010	26 493	1 087 351
9	1	O/U	64.2	2 347	30 297	32 644	1 520 940
10	1	10	64.7	3 073	53 975	57 048	1 603 942
11	1	0.01	64.4	2 977	61 113	64 090	1 562 192

Table 6.10. Annual savings Results of Matlab© simulations for Cases 8-11.

Simulation Case	Annual Instant. Reserve savings (R)	Annual Instant. usage savings (R)	Annual Regulation Reserve savings (R)	Annual Regulation usage savings (R)	Annual Market savings (R))	Total savings (R)
8	-3 300 000	9 558 452	3 750 000	14 758 956	396 883 115	421 650 523
9	-3 300 000	9 988 583	3 750 000	7 886 164	555 143 100	573 467 848
10	-3 300 000	9 988 495	3 750 000	-17 998 033	585 438 830	577 879 291
11	-3 300 000	9 988 548	3 750 000	-25 801 116	570 200 080	554 837 512

6.10 Step 5: Fine-tuning the solution for other variables that could give extra savings.

Step 5 is the final checking that the solution obtained is optimal. For Eskom a fine tuning step was to investigate the cost savings if the units on AGC are able to delay their response, and thereby putting less stress on the unit. For regulation reserve, the current requirement is that the participants must start responding within 12 seconds of the command to increase or decrease. An increase in delay of the generator response to commands on AGC will cause the frequency deviation to be larger, as the control is slower. The increased delay could lead to over-control if control is sent out but the response is delayed.

Case 8 in **Section 6.8.5** is simulated again, except that this time, delays of 20, 45, 90 and 180 seconds are added to each generator response. The purpose of simulating a 90 second delay is that once-through coal-fired boilers have a delay time in this region and the control philosophy could be changed to give further savings to generators that are contracted for regulation. Similarly, 180 seconds is a typical time constant for drum coal-fired boilers.

The results obtained from the Matlab© model are shown in **Table 6.11**. **Figure 6.17** shows that as the delay in the generator response to AGC commands increases, the frequency control gets worse. Similarly, **Figure 6.18** shows that the total generator movement increases as the delay of the response of generators is increased. Conversely, **Figure 6.19** shows that the market savings improve although the improvement is marginal when compared to the significant increase in generator movement. The results of these simulations are that a delay is acceptable but it must be understood that the total movement of the generator and the frequency is worse.

Table 6.11. Results of simulations with increasing delay on the response of generator to AGC commands.

Simulation Case	Generator delay (s)	Frequency standard deviation (mHz)	Estimated governor movement (MW)	AGC movement (MW)	Total Generator movement (MW)	Market savings (R)
8	4	64.0	2 483	24 010	26 493	1 087 351
12	20	66.4	5 637	26 467	32 104	1 016 003
13	45	69.0	8 286	30 369	38 655	1 052 193
14	90	72.3	12 241	35 995	48 236	1 222 975
15	180	80.3	22 463	47 278	69 741	1 164 608

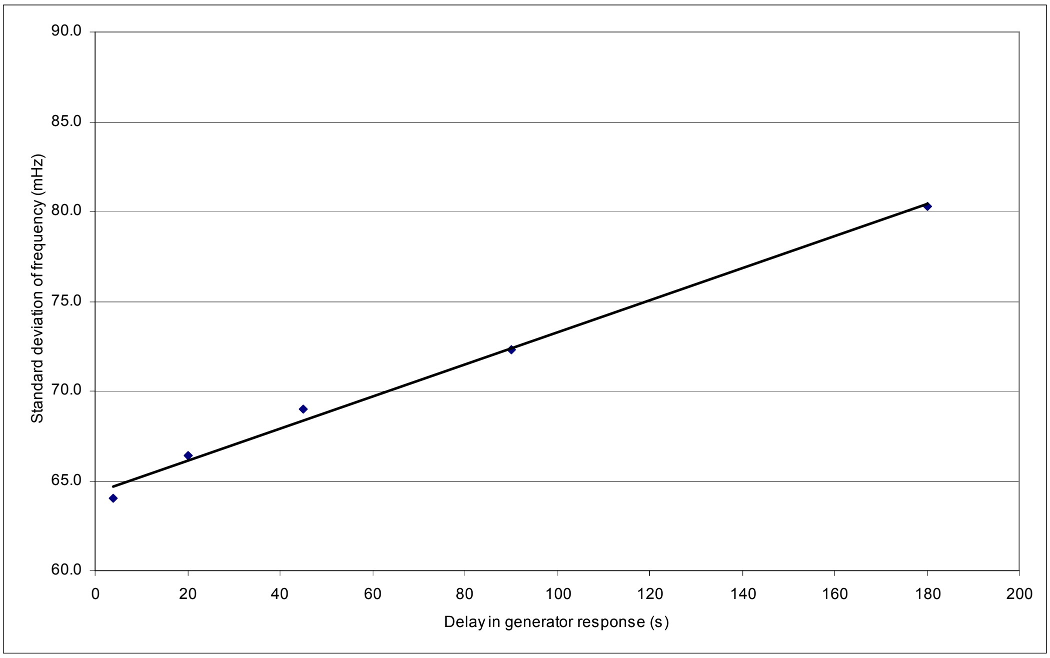

Figure 6.17. Frequency standard deviation *vs*. delay in generator response to AGC commands.

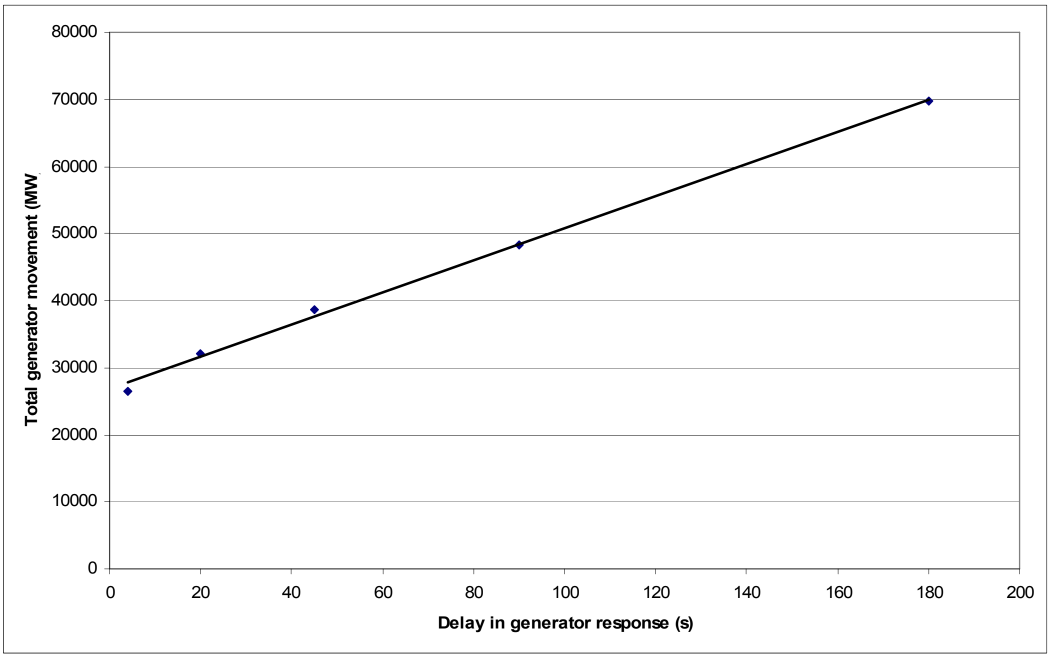

Figure 6.18. Generator movement *vs*. delay in generator response to AGC commands.

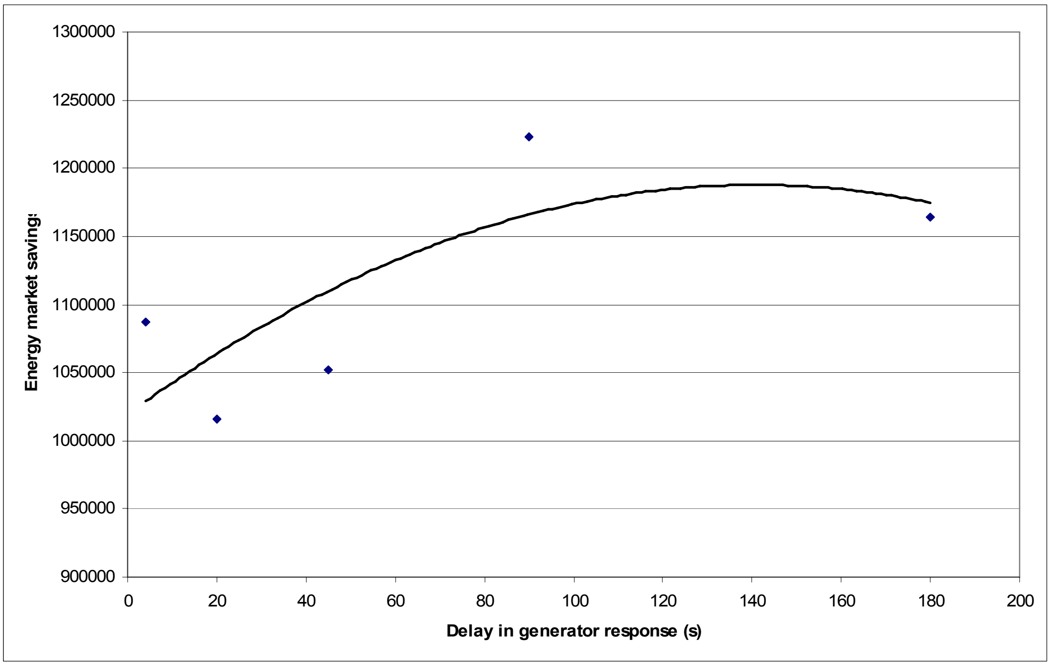

Figure 6.19. Daily energy market savings *vs*. delay in generator response to AGC commands.

6.11 Conclusion of simulations for Eskom

When the frequency is controlled less tightly, the generator movement decreases. However, the economic dispatch solution starts to decline when the standard deviation of the frequency is increased beyond the 80 mHz level. The economic solution can be improved by swapping units over as discussed in **Section 6.9**. Too much swapping increases the generator movement, which then counters the benefits obtained by operating the frequency within these regions. The best solution obtained from the simulations is hence to accept a higher movement with the tighter and more secure control and the best economic solution such as obtained from Case 9. The results confirmed that the frequency should be controlled to a standard deviation of 65 mHz for Southern Africa. As a result, it was not necessary to repeat the contingency studies. If the optimal solution was beyond the defined boundary conditions then there would be a need to revise boundary conditions or the boundary conditions would determine the optimal point for the network being studied.

In Eskom's AGC, the control economics function was redone in terms of the power pool rules. The balancing and settlement is done by using the day-ahead offers, as there is not yet a separate balancing market. These offers, together with the contract, are used to determine the next cheapest generator. All movement on the AGC is done only when required for controlling the frequency in the normal region. Manual control is done to swap units that are both far from their best economic solution. The simulations showed that it is possible to get more economic benefits if this is also done on AGC. The most optimal solution for Eskom is to swap units that are over contract with those under contract, Case 8. This control scheme has not yet been implemented in Eskom.

An alternative is to allow the governing to control the frequency in the normal region *i.e.* a deadband of say 20 mHz, and for AGC to start controlling when the frequency is outside the normal region. This showed a huge increase in generator movement. The cost in the market was also very high due to the wrong market structure and thus cannot be evaluated. This would improve if the market rules were changed to suit this strategy. Based on the results of the generator movement alone, it was decided not to continue with this option.

The time difference between real time and system time is controlled within the boundaries required by the Southern African Power Pool if the frequency is controlled within a deviation of 75 mHz or less. If a larger frequency deviation is optimal, the AGC controller would then require some integration action or the allowable time error could be increased beyond the 30 second target.

The inadvertent energy could increase slightly if the frequency was controlled at 75 mHz but this would have no financial impact on Eskom or Zimbabwe.

The results of the fine-tuning in Step 5 showed that a delay in the generator response can be accepted but the total movement of the generator and frequency control are worse.

6.12 Reserves and markets for frequency control

This section describes the final determination of the reserves required and the setting up of a market for frequency control services in a deregulated environment.

6.12.1 Reserves for frequency control

Reserves are defined as unused generation capacity or consumer capacity that is available for contingencies that occur in the network. Operating reserves is a generic term normally used for reserves that are available for frequency control. The literature survey showed that most networks split the reserves into two distinct categories: spinning and non-spinning reserve. Spinning Reserve is capacity that is available reserve from synchronised generators. Non-Spinning Reserve is capacity available from quick start generators, such as gas turbines and hydroelectric generators, or interruptible capacity available from consumers. This chapter discusses the formation of reserves that will meet the new control regime that was formulated in **Section 6.8**.

6.12.2 Traditional Reserves

Spinning Reserve was traditionally regarded as online capacity that was available from generators within 10 minutes. The purpose of the reserve was to restore the frequency following a contingency. This is assisted by using the Non-Spinning (or Supplemental) Reserve which consisted of offline plant that is available in 10 minutes and consumers who are prepared to be interrupted in 10 minutes. The frequency responsive reserves or governing was mandatory and all generators were required to provide this.

6.12.3 Reserves required to meet the desired frequency control strategy

The minimum reserve level for governing identified in **Chapter 4** was fine-tuned with Regulation reserve in **Section 6.8.**

Defining the duration of the service is important for participants. For SAPP, the control area should restore within 10 minutes after the largest single contingency. Historically, Eskom has restored within 5 minutes. The primary response is hence required for at least 10 minutes. Defining this time boundary is important in the development of control strategies for generators and for demand side participants to realize the impact of the interruption.

For thermal generators, as discussed in **Appendix H**, the sustaining of a response is difficult. On the demand side there are participants who can be switched off for 10 minutes with minimal impact on the cost of production. The typical examples are pumps that pump water into a reservoir, electric water heaters and air conditioning. The response of participants has to be in 10 seconds for it to be useful to arrest the frequency in the Southern African network. This is easily achieved for demand side participants but for thermal generators the limiting factor is the amount of response they can provide. The time factor also requires that the control is automatic.

The response time for participants who restore the frequency must also be within 10 minutes so that the primary response is not required after 10 minutes and the frequency has been restored to the normal range. If this cannot be achieved then the requirements for the primary response would have to be longer. This response should last until other plants can be scheduled or rescheduled to restore the reserves. For Eskom the participant must be available to respond for at least one hour for Regulation Reserve and 2 hours for 10-minute Reserve.

Depending on the final control system design, the needs for various reserves will be different. For Southern Africa, the strategy that was developed was for the AGC to control the frequency within 0.15 Hz for 95 % of the time. For this to be possible, there should be sufficient capacity available. Statistically, actual consumer instantaneous demand does not vary by more than 300 MW from the average hourly demand. In peak loading hours, the difference is larger but this is assisted by many generators who are also loading to meet their contractual requirements. Thus, in the Eskom Power Pool if the load forecast is correct then only 300 MW of regulation reserve is required in every hour. It was decided to increase this to 500 MW in each direction, as there could be a problem such as a contracted supplier of regulation in the day-ahead market who is unavailable on the day or some other minor disturbance that would require more than 300 MW. The additional allowance also gives the operator a load forecast error of 200 MW without having to reschedule the day-ahead contract. The regulation units are chosen according to the cheapest energy offer that is available for regulation.

6.12.4 Markets for frequency control services

In defining markets for frequency control, a key factor is to attract enough suppliers to make the markets competitive, while maintaining an acceptable level of security and reliability. Frequency control services are being implemented in many countries. Most countries have decided to maintain the same level of security and reliability as before the market implementation. The frequency control services that were compulsory before de-regulation have also remained mandatory, such as primary frequency control. As these networks mature, there will be a focus on the cost of reliability and security if the provision of frequency control services becomes expensive. An important issue addressed in markets is the potential inclusion of demand side participants where the service has traditionally been supplied by generators. Demand side participation is crucial to the market being perceived as open and fair to all participants.

A complication in frequency control services is that they vary between being energy intensive for minute-to-minute balancing services; and using virtually no energy in emergency reserves. Energy intensive frequency control services should be driven by an energy price both in contracting and dispatching, whereas non-energy intensive services need to driven by capacity payments or some other financial incentive (Singh and Papalexopoulos, 1999). If a market is non-competitive in terms of the number of potential suppliers, it is then possible to enter into long term agreements via a tendering and negotiation process. If there are only one or two suppliers, then the contracting for the service is based on cost of provision of the service plus some acceptable profit.

The electricity market design can also influence reserve levels and other frequency services. If too much energy is being traded close to real time then the System Operator must contract more reserves to ensure that the predicted demand can be met. One of the principles recommended in the FERC standard market design is that the design should ensure there are few incentives for a participant not to be in balance prior to real time (FERC, 2002).

6.12.5 Determining what payments to make

A central group decides on frequency control services in a vertically integrated utility and the cost of providing the service is included in the price paid for electricity. The expectation is that this will continue is in the mind of some of the market participants, especially when the market is initiated. Some market participants continue to provide a service for free and then find they are penalised for doing this in the energy market. What price should be paid for a service where the value of non-provision is high but the cost of providing is low? Financial principles say that if the market is competitive the price will remain low, however when there are conflicting markets it is an easy decision to pull out of the market that is showing the least profit margin. This type of behaviour happens in business every day as companies sell off less profitable divisions. These conflicts have to be resolved for satisfactory frequency control.

The cost of provision has been discussed in **Section 5.4.** So the cost for providing the various types of necessary control is known. When a service provider is providing a service there are at least 3 categories of costs that need to be recovered: capacity, wear and tear and energy.

6.12.6 Capacity payments

Frequency control services require energy to be available in a short time. This requires capacity to be set aside or reserved. The provider of frequency control services needs to be paid for keeping capacity available. A cost is the loss in efficiency in not operating the plant at an optimal efficiency level. A loss to the frequency control service provider is the potential profit they would have made if they had sold the energy. This is complicated to determine, as the energy that could have been sold would need a willing buyer and the potential supplier would have required the extra fuel or water. The price of the agreement that could have been made is speculative. Nevertheless, it would be necessary to pay the provider some amount for holding capacity.

6.12.7 Wear and tear payments

In providing the frequency control service the provider's plant will undergo some wear and tear for which compensation should be given. The cost for wear and tear can be very low for some plants and significant for others. If the plants in the interconnection are of a similar type then the wear and tear costs will be similar.

6.12.8 Energy payments

The provider of frequency control services supplies energy while balancing supply and demand in real time. The market rules must ensure that the payment for the provision of frequency control services compensates the provider adequately for energy supplied. Some new markets initially did not adequately compensate for the frequency control service provider's energy and have suffered a poorer frequency control as a result (Transpower, 2003a). These markets have had to change their rules.

6.12.9 Possible contractual arrangements

6.12.9.1 Mandatory services

The literature survey revealed that many markets still have mandatory services for frequency control services. This is particularly true for primary frequency control and under-frequency load-shedding schemes. These are mandatory services that are often not compensated for as a separate service. This is not an issue to the service provider if there is not a huge cost differential between market participants. Such mandatory services must be taken into consideration in the energy market, otherwise the service provider could be disadvantaged or penalised in this market, which could make them unwilling to provide the service even if it is mandatory. Payment for the provision of energy whilst providing a frequency control service could lead to the service provider maintaining a good service purely because of this compensation. Another possibility is to make the service mandatory and to compensate for the costs of being able to provide the required service. This can be through a tendering process where each provider submits an offer and is compensated accordingly. The market can also have a fixed price for providing the service. This would be negotiated with all service providers and participants who would want to influence the process. The advantages are that the provider could be compensated according to the amount of service provided and a good level of the service is encouraged.

6.12.9.2 Capacity payments

An energy provider would need to be compensated for the provision of a reserve capability. This can be done in the energy market or as a separate payment. Many suppliers can provide reserves that are not required for local network constraints. Many markets have a separate reserve market to the energy market (Arnot *et al.*, 2003) where separate prices are offered for the provision of a reserve. The contracting of providers for reserves in frequency control services can be done after the energy market has been established. This will operate successfully if there are many participants and the whole reserve provision can be achieved without a need to alter the market solution. The second methodology is to reserve the frequency control service capacity ahead of the market solution. Hence, the responsibility of the provider is to ensure that contracted capacity is not offered into the energy market. The final possibility is to have capacity reservations combined and co-optimised with the energy market. The co-optimisation requires an estimate of the reserve usage probability to estimate the value of the price offered for the energy.

6.12.9.3 Energy market plus

One approach is to pay the energy provider a higher price than the market prices. This can be a fixed percentage or a fixed value added to the energy market price. The disadvantage of this method is that the plant may undergo substantial wear and tear and at the end of the dispatch period may not have provided much energy. This method also disadvantages those where the cost of providing frequency control services is higher than another competitor. A marginal difference could lead to the wrong provider actually providing the service from an over-cost and profit point of view.

6.12.9.4 Annual tendering

Annual tendering is an approach where the provider offers a price for the provision of the service for the whole year. The system operator then keeps these offers and uses the providers when required. The advantage of the yearly option is that the prices offered are fixed for a period, which does take some uncertainty out of the market and simplifies the dispatching of the services for the system operator. This approach is used when there are only one or a few service providers.

6.12.9.5 Bids and offers

The final possibility is a system where bids and offers are given in the short term to balance the network and provide for reserves. A short-term balancing market of, say, 5 minutes apart, can do the major part of the frequency control services especially when the other demand and supply is relatively constant. Bids and offers in this type of market can be fixed for the day, or in other markets, bids and offers can vary between 5 minute periods.

When the network has many transmission constraints, the dispatch can be complicated and will require a constrained dispatch tool to assist the operator. This has become a popular market model used widely in the USA and elsewhere around the world. Major suppliers of control systems for system operators all have dispatch tools that can do a fully constrained schedule every 5 minutes. Operating a 5-minute market with constant price changes is difficult for the system operator to manage and this requires more staff in the 24 hour operations. The ability of providers to change their bids every 5 minutes can be good for them if the plant position changes. There is also the possibility of manipulating the market and so surveillance needs to be tight. This is especially true when there is capacity shortage.

6.12.10 Markets for frequency control services in Eskom

In Eskom, Instantaneous and Regulation reserve are seen to be energy intensive reserves and the day-ahead scheduling of the reserve is based on day-ahead energy offers. The marginal loss of profit determines the capacity price that all scheduled participants will receive. Energy payments for Regulation service are made according to each participant’s individual day-ahead offer and actual deviation in metered energy from the day-ahead schedule. Regulation service also attracts a usage payment at an annually agreed fixed rate per MW moved for all participants. The energy and usage payments are subject to satisfactory performance criteria, which are described in **Chapter 7**. Other reserve categories are scheduled according to prices offered for capacity. In real time, energy is dispatched according to the next cheapest solution for all units on AGC that are contracted for regulation reserve. Rescheduling is performed when there is a large change in demand or supply, which also restores reserves. Mandatory frequency control services are under-frequency load-shedding for low frequencies and governing for high frequencies.

6.12.11 Summary of reserves

Whether there is a market, or not, the system operator needs to ensure that there is enough reserved capacity for potential future occurrences. For adequate frequency control the previous sections have identified two types of reserves: those available for primary frequency control and reserves available for secondary frequency control. In the author's experience, these two reserves are often combined into one reserve called Spinning Reserve. If the two reserves are combined, it is difficult to determine which reserves are available for direct frequency control.

Additional reserves need to be activated to restore the above reserves in preparation for further incidents. The methods for calculating the other reserve requirements depend upon the time frame and risk allocations. It might be an acceptable risk for one network to run for periods without reserves, while for another network, that is an unacceptable risk.

In Eskom, the reserve for primary frequency control is called Instantaneous Reserve, for secondary control the reserves are Regulation Reserve and 10-minute Reserve. The replacement reserve is Supplemental Reserve that must be available within 6 hours. An Emergency Reserve is also defined for reserves that are to be utilized only a few times annually. The reserve category currently consists of reserves that are inexpensive to reserve but expensive to utilize such as interruptible loads and gas turbines.

This section also discusses the possible market solutions that could be applied and some of the advantages and disadvantages of each methodology.

6.13 Summary of Chapter 6

Chapter 6 has developed the final cost equation to determine the potential savings for relaxing frequency control. This equation is used for the various cases developed to determine the optimal solution. Five steps are used to determine the final control strategy. These steps take the process through a sequential development for the optimal solution.

The chapter further described how the steps to determine an optimal strategy were applied to Eskom. Three unique features of the optimal design for Eskom were: the development and implementation of the philosophy of using only the automatic generation control (AGC) to control the frequency within the normal band of operation; the development of a balancing bid to respect day-ahead constraints and the method of including the economic dispatch with normal frequency regulation.

Chapter 6 finishes with a discussion how reserves and frequency control markets can be determined to meet the final designs objectives. **Chapter 7** will describe how the optimal solution can be monitored and maintained and **Chapter 8** shows the results Eskom achieved after the frequency control was relaxed.

Chapter 7 : Phase 4 - Maintain optimal performance

Development of performance monitoring techniques to ensure that optimal control is maintained

7.1 Introduction to Chapter 7

Chapter 7 describes measuring performance of frequency, frequency control service providers and system operator, and ensuring future reliability. This is required to maintain the optimal frequency control strategy.

7.2 Measuring performance of frequency, frequency control service providers and the system operator

Measuring the frequency performance is a step required to maintain the desired reliability of the network. Without measuring the performance of the frequency and key role players, the networks frequency control could be degrading and be under serious risk. Frequency control service providers could be misbehaving or not performing, or the system operator could not be dispatching properly. After designing an optimal strategy for the network, it would be careless not to monitor the performance to ensure that it remains optimal. The performance monitoring is presented in three distinct sections: performance of frequency, performance of participants and performance of the system operator.

7.2.1 Measuring the performance of the frequency

Chapter 2 has shown that the measurement and performance monitoring of frequency varies between utilities. IEC 61000-4-30 (IEC, 2003) proposed that frequency measurement is calculated as the ten-second average of measurements. This performance measurement is designed to ensure a good quality of supply to the consumer. This measurement rate is too slow for controlling purposes on most networks. The measurement of frequency near to the source of a disturbance could be inaccurate due to the changing voltage wave, making it difficult to measure the zero crossings of the frequency.

Figure 7.1 shows a typical example of such an effect where the local frequency is very volatile at the start of the disturbance. The measured frequency could also vary across the network. These factors need to be considered when measuring performance.

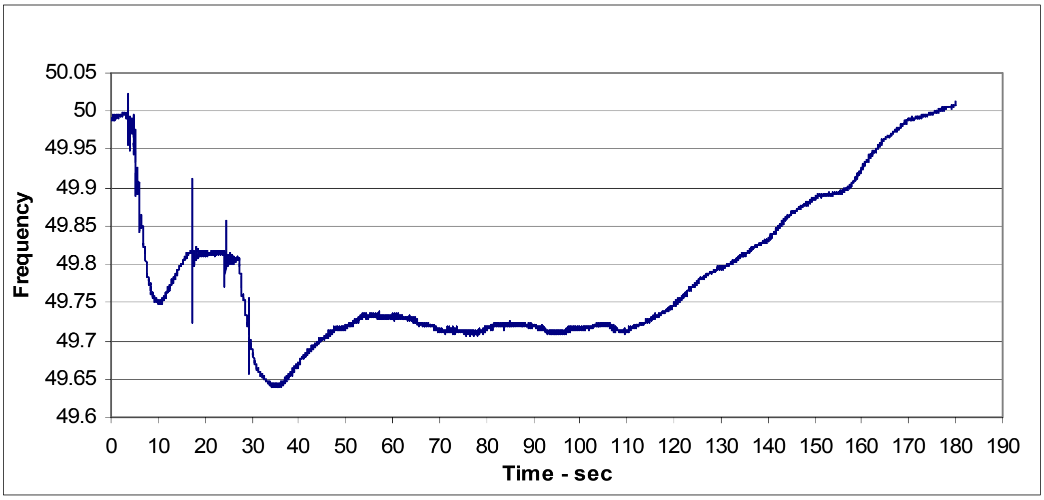

Figure 7.1. Measurement of frequency showing ambiguity at the time of the disturbance.

7.2.1.1 Using Standard Deviation as a measure of frequency performance

Standard deviation is often used for the measurement of frequency performance and is used to benchmark one network against another. However, the standard deviation measurement will vary depending on the time frame used for the raw data. For example, a utility in Japan (Kudo and Mukai, 1994) reports on the standard deviation of frequency based on the one-minute samples. For Eskom this would reduce the standard deviation from 60.6 to 41.5 mHz for December 2002. The reporting of a standard deviation should then state the measurements on which the calculation is based.

7.2.1.2 Combining frequency and ACE as a performance measure.

For control areas in a network the measurement of ACE is also important. This indicates how well the supply and demand balance in each control area is being managed. NERC Control Performance Standard 1 (CPS1), combines ACE and frequency to have an overall measure of performance (NERC, 2002). The essence of this performance is to identify those who are positively contributing to controlling the frequency and those who are not. The Southern African Power Pool has adopted this new standard to measure the performance of each control area. The measurement of ACE over a period also identifies control areas that are leaning on others for support over prolonged periods. NERC uses the CPS2 performance to measure the performance over 10-minute intervals. The average ACE over this period should be less than a predefined target (NERC, 2002).

7.2.1.3 Frequency performance during disturbances.

The number of times the frequency exceeds boundary limits, as defined in **Chapter 4**, is also a key measurement in determining the network performance. This indicates that the boundary conditions for single and multiple credible contingencies have been violated and a possible degradation of the standard of frequency control could occur. The number of times consumers are shed on under frequency is another measure of how well the frequency is managed. Eskom records the number of incidents below 49.5 Hz, 49.2 Hz and 48.8 Hz. The latter two indicate the number of times consumers are shed automatically by the customer voluntary- and mandatory- under-frequency schemes. The recovery time of the frequency is also crucial in preventing prolonged periods where the frequency is outside acceptable limits, leading to an increased risk of a second event happening, hence increasing the risk to the network. NERC DCS1 describes a measurement of the recovery time length (NERC 2006) and has been adopted by the Southern African Power Pool.

7.2.2 Measuring the performance of frequency control service providers

For markets to operate successfully, the suppliers of a service need to prove that they can provide the service. The participants should also be monitored to ensure that the service is being provided. Financial penalties for poor performance should also be considered.

In Eskom, all the frequency control markets have certification and performance monitoring. Most of the services have automatic performance monitoring (Chown and Coetzee, 2000).

7.2.2.1 Measurement of Instantaneous reserve response in Eskom Power Pool

If the participant's data is recorded in the Energy Management System (EMS), the measurement response of participants for Instantaneous reserve uses the 4 second data. Otherwise, the data is sent to the market operator within 24 hours of the incident. There are two parts to the measurement of the response:

- The maximum response from the participant in the first 10 seconds
- The sustained response of the participant from 10 seconds after the incident until the frequency is returned to above 49.75 Hz, **Figure 7.2,** or for a maximum of 10 minutes, **Figure 7.3.**

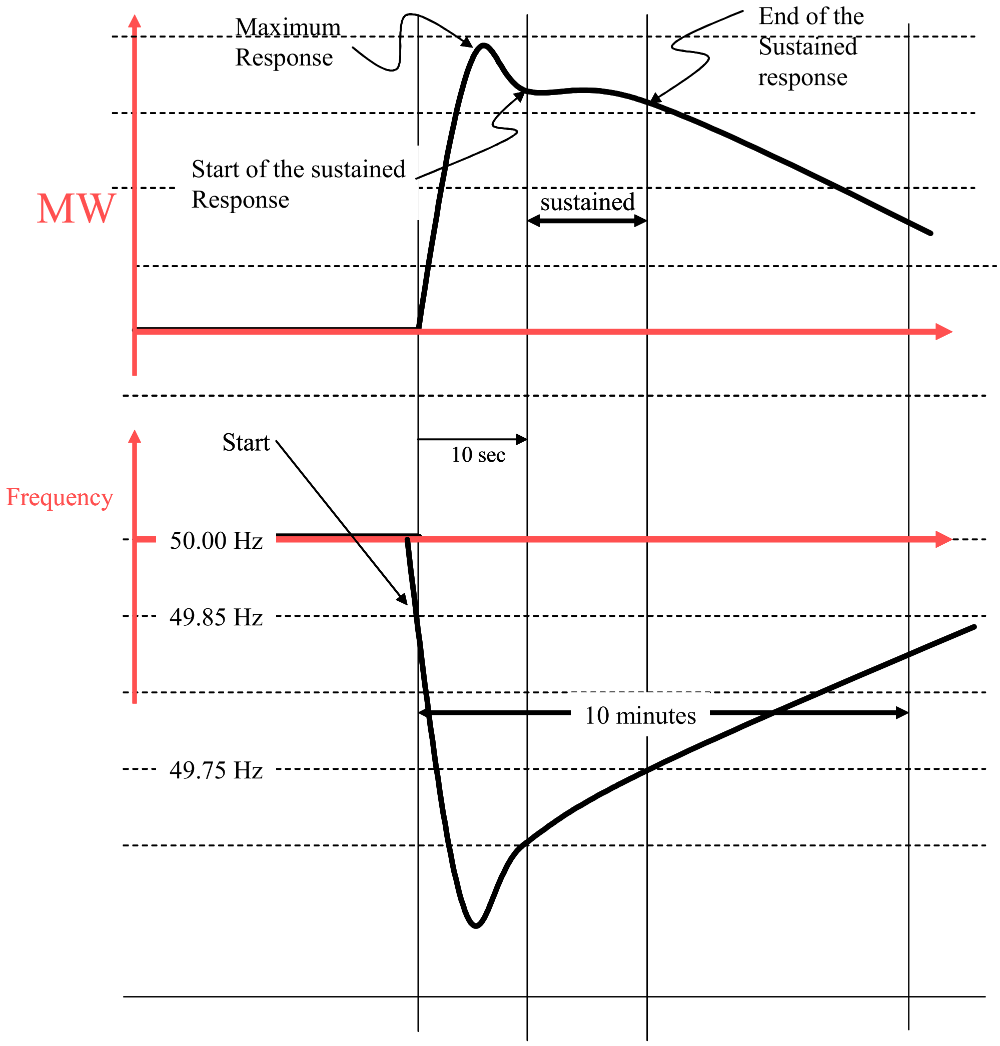

Figure 7.2. Measurement of Instantaneous reserve response when the frequency recovers above 49.75 Hz within 10 minutes.

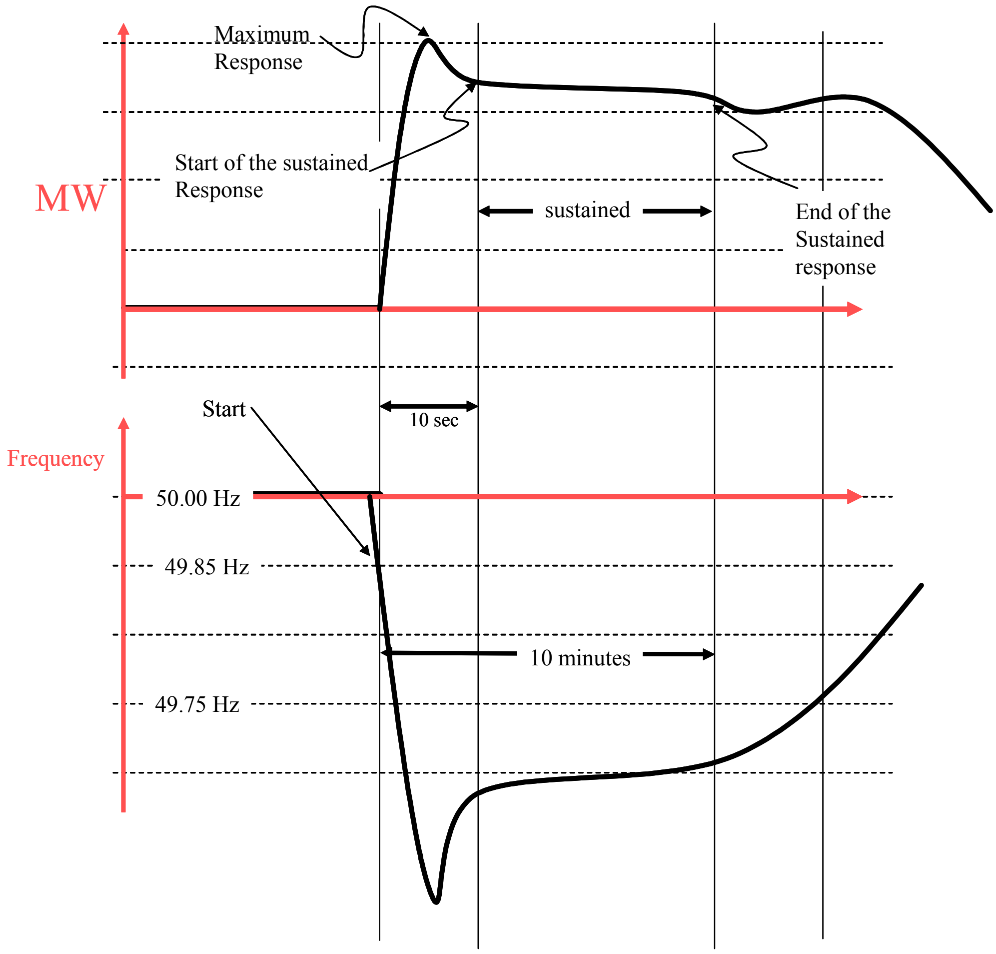

Figure 7.3. Measurement of Instantaneous reserve response when the frequency does not recover above 49.75 Hz within 10 minutes.

7.2.2.2 Measurement of AGC response in Eskom Power Pool

The measurement of performance of a unit is based on the general principles developed in the draft NERC Policy 10 (NERC, 2006). The concept is that a unit providing Regulation must be close to the set point required by the AGC controller, including any Primary Frequency Support requirement.

The set point of the generator can thus be seen as the current contract from the System Operator for units providing Regulation. The performance is measured by the closeness of the actual generation to the new dynamic contracted generation including Primary Frequency Support. It is important to realise that there are calibration errors in the generation output and set point values sent from the power station to the AGC software module. There should be no penalty on the generator due to these errors. A Calibration Error is calculated, which assumes a perfect response from the generator and is the average error between contracted set point plus Primary Frequency Support and actual generation for each hour (**Equation 8.1**):

$$\textit{Calibration Error}_{hour} = \textit{Average Generation}_{hour} - \textit{Average (Contracted Set-point + Primary Frequency Support)}_{hour} \quad \textbf{(8.1)}$$

The contracted set point is then corrected with this Calibration Error for every cycle measured. This, together with the required Primary Frequency Support, gives a final Unit Supply Contract for each cycle (**Equation 8.2**). Actual generation less the Unit Supply Contract will give a Unit Supply Error every AGC cycle (**Equation 8.3**):

$$\textit{Unit Supply Contract}_{cycle} = \textit{Contracted Set-point + Primary Frequency Support + Calibration Error} \quad \textbf{(8.2)}$$

$$\textit{Unit Supply Error}_{cycle} = \textit{Actual Generation - Unit Supply Contract}_{cycle} \quad \textbf{(8.3)}$$

The absolute integral error for the hour is then a measure of the performance of the unit, giving a Unit Contract Error in MWh (**Equation 8.4**).

$$\textit{Unit Contract Error}_{hour} = \textit{Integral (Unit Supply Error}_{cycle}\textit{)} \quad \textbf{(8.4)}$$

If the Unit Control Error is less than 5 MWh then the unit has performed Regulation and will be paid for providing the required service. The value of 5 MWh is based on running the trial performance for 2 months and using an acceptable level of engineering judgement.

7.2.3 Measuring the performance of the system operator

The system operator is affected by the introduction of the market, as the traditional way of dispatching generators is no longer valid. This requires new tools, training and, in some cases, more staff. The market is more volatile than traditional dispatch, which is based on marginal costs, and the system operator also has to justify its actions. Metering is also an issue as there are discrepancies between instantaneous values received in the Energy Management System (EMS) and the billing meter. The dispatching is not always straightforward due to technical limitations.

In Eskom, there are times in the day when many generators are required to keep up with the increase in demand and the dispatch cannot strictly follow the merit order. Participants who are not dispatched strictly according to the merit order require justifications from other market participants. Furthermore, the system operator has some discretionary power to allow the frequency to run low for a short period instead of scheduling an expensive balancing option. Although this is fair to the participant paying for the imbalance, is it fair to the generator who was not dispatched? These issues require careful consideration when deciding on incentives for the system operator as the least-cost dispatch might have an associated high risk.

7.2.3.1 Monitoring AGC movement in Eskom Power Pool

The amount of control issued by AGC is used as a measure of performance of the control system. Every year a target is set based on the amount of control issued over previous years. The System Operator receives a bonus if the amount of control is lower than the target as long as the targeted frequency performance as measured by NERC CPS1 is greater than 130%. Conversely, the System Operator is penalised if the control is worse than budget.

7.2.3.2 Monitoring System Operator dispatch in Eskom Power Pool

Eskom is developing a model in Matlab© which will re-run the previous day and compare theoretical against actual dispatch. This tool will be used to measure the system operator and AGC performance.

7.3 Ensuring future reliability

When a market is established, it is important to ensure that minimum standards are set for the design of new plants. This can be done through a connection code that specifies the minimum requirements for new participants. This minimum standard can always be changed, but at least all participants are aware of connection code changes. The current generators on a network may have a different characteristic to new generators, such as the dramatic increase in the number of gas turbine generators with reduced governing capability in the UK. This can disadvantage other generators, especially for mandatory services. Without a connection code there could be a negative impact on the reliability of the network.

'There are a thousand variations to markets in every country, every situation and every case' (Lee, 2004). The market and rules are constantly changing. Participants are and will be changing their strategy. There are always participants that are testing the rules and regulations. These participants could be compromising the optimal design and the integrity of the network. In the electricity industry one participant can have a huge negative impact whereas in other markets this is rarely possible. 'The process of creating and supervising markets can be managed. Mistakes in evolution, capture by hostile elements or crime, or by simple incompetence occur too frequently for us simply to stand by and watch' (Lee, 2004). Thus, the role of a regulator, market surveillance bodies and a system operator are important in ensuring the market rules are obeyed and market participants' behaviour is appropriate.

The system operator plays an important role in maintaining the optimal design. The system operator has all the information available to determine if things are going wrong or can go wrong. The system operator hence has a role to keep an eye on things. Furthermore, the system operator has to monitor changes that are proposed in market and grid codes. The system operator should have the right to veto any changes if they negatively impact the security of the network. To this extent, the system operator has taken on a new role and will require more technical expertise to monitor participants and all proposed new rules. The system operator could be viewed as conservative but its role should not be underestimated.

In South Africa, the largest single and multiple credible contingencies are defined in the draft connection code. These are the same boundaries as presented in **Chapter 4.** If contingencies greater than this are introduced by a new participant, reserve levels would need to increase at a cost to all participants. The South African Grid Code also sets the minimum performance criteria for issues such as governing, to ensure future reliability of the network. The grid code and market rules allow the system operator to veto rules that negatively impact network reliability. The use of a veto has to have a good technical reason to prove that reliability is impacted by the new proposal.

7.4 Summary of Chapter 7

This chapter has discussed the two steps required to maintain an optimal performance, namely: (1) Monitoring performance of frequency, frequency control service providers and the system operator and (2) Ensuring future reliability. These are required to ensure the optimal frequency control strategy is monitored and sustained.

Chapter 8 : Economic benefits to Eskom after the frequency control was relaxed in SAPP

Results and impact on Eskom after relaxing frequency control in SAPP

8.1 Introduction to Chapter 8

Chapter 8 shows the economic benefits achieved in Eskom after implementing the recommended actions of the author on relaxing the frequency control in the Southern African Power Pool.

8.2 Increase in Instantaneous Reserve deadband

The increase in Instantaneous Reserve deadband means that there is no direct frequency control from generators or loads, except for the change in output of motor loads, as the frequency varies in the range 49.85 to 50.15 Hz. If the frequency is 49.85 Hz, the output of a motor is approximately 0.6 % lower than normal. The increase in deadband also delays governing by 80 ms if the starting frequency is 50.0 Hz for a 600 MW trip. As described in **Section 6.7.1,** this delay results in an additional drop of 0.1 Hz for a trip of 600 MW of generation, 0.05 Hz for a trip of 1000 MW, and is negligible for a trip of 1800 MW.

The new deadband was implemented in September 2002. The implementation of the deadband took most power stations a few hours to do and with relatively small costs.

A few power stations decided not to implement until their governor controls were upgraded.

8.3 Impact of actual incidents on the frequency

From implementation (September 2002) until end January 2003, there have been 10 trips larger than 1000 MW. **Figure 8.1** shows the results of three of these trips with the predicted results from the simulations in Matlab© and PSS/e©. The frequency has been arrested in line with simulated predictions for all but three incidents. These incidents were all caused by the loss of the HVDC (Cahora Bassa) link to Eskom. High voltage alarms were received on the EMS but these levels were too low to trigger incident recorders. To analyze this further, the triggers of the incident recorders were set up to measure voltages on a low frequency. On one occasion, the frequency dropped below 49.5 Hz to 49.4 Hz for a trip of 965 MW. This occurred when there were no reserves on the system and all generators were already at maximum output.

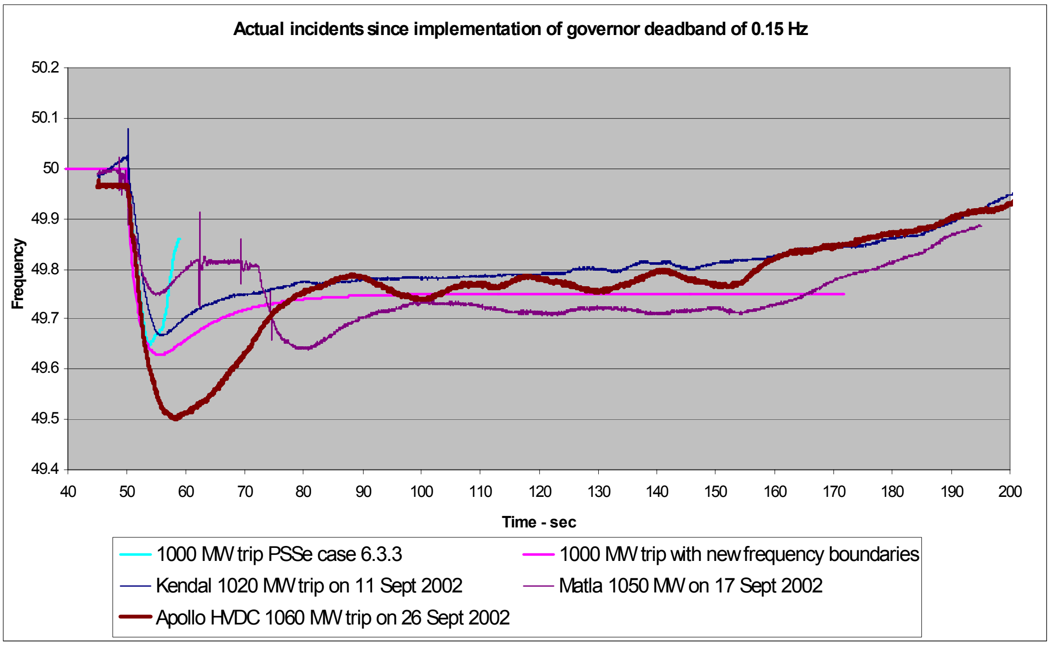

Figure 8.1. Frequency for trips greater than 1000 MW after frequency redesign implementation.

8.4 Reduction in generator movement due to increase in Instantaneous Reserve deadband

The frequency and required governing for a typical day before and after implementation is shown in **Figure 8.2** and **Figure 8.3**. Owing to the increase in the deadband, the generator absolute movement decreased from 750% to 3% of the maximum generator rating per day.

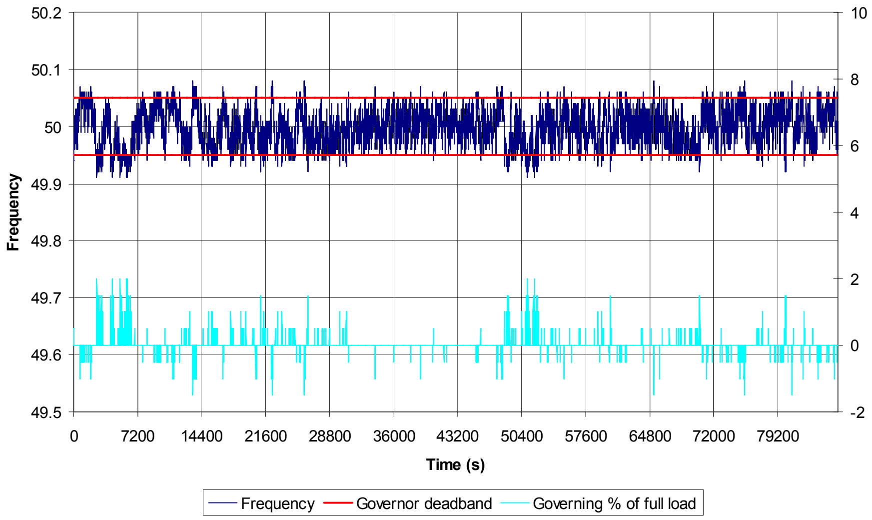

Figure 8.2. Frequency and governing for a typical day before implementation.

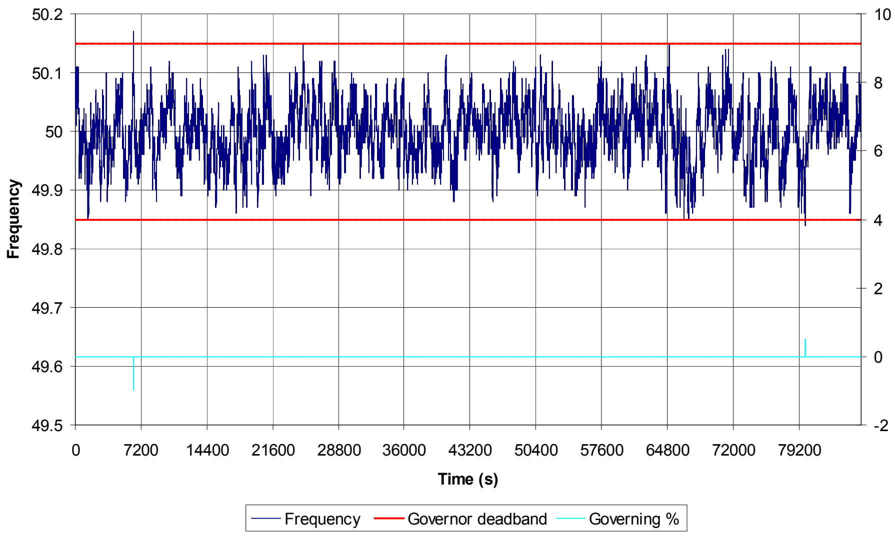

Figure 8.3. Frequency and governing for a typical day after implementation.

8.5 Re-tuning of AGC

Changes in AGC control in 1996 resulted in the reduction of power moved per hour from 4000 to 1800 MW (Chown and Hartman, 1997). In the beginning of 2002, the AGC was re-tuned based on the experience gained through the AGC modelling. This reduced the power moved per hour to 1650 MW without changing the quality of frequency control, as shown in **Figure 8.4**. The AGC was re-tuned to the new boundaries from 14 October 2002. Initial tuning parameters had already been estimated using the models developed in Matlab©. These parameters were altered slightly over the next few days. This re-tuning reduced the power moved per hour to 957 MW. This contributed a further 47% reduction in generator movement on AGC.

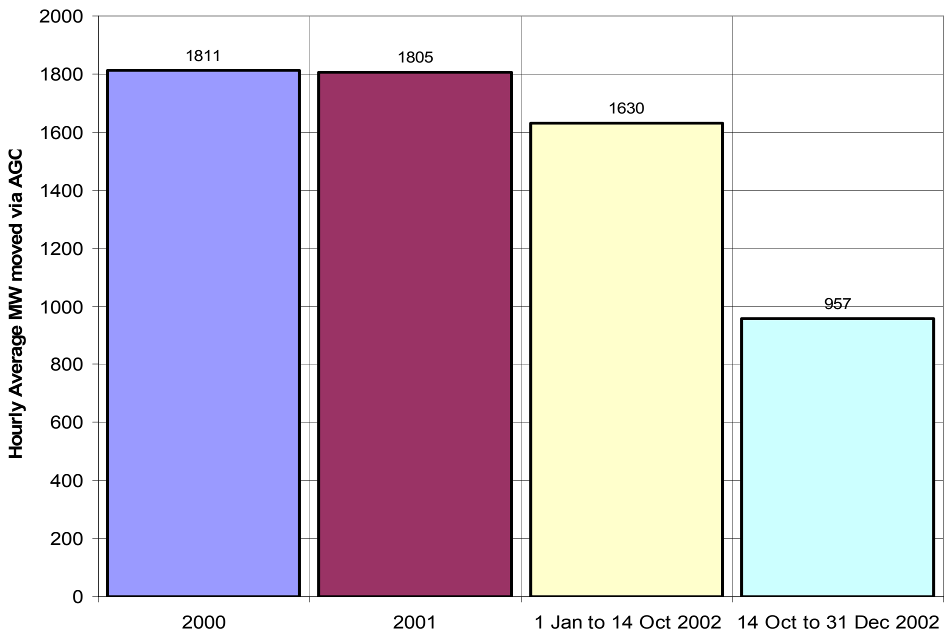

Figure 8.4. AGC MW moved per hour from 2000-2002.

8.6 Reduction in the cost of Regulation energy

Regulation energy costs are those energy costs incurred by AGC in balancing supply and demand in real time. In the Eskom Power Pool, Regulation energy accounts for 4.3% of the total energy costs. Since implementation of the frequency redesign, Regulation energy costs have reduced by 35%. This reduction is in part due to a better dispatch in moving the generators less on AGC. However, it is difficult to analyze Regulation energy costs due to the many variables involved, such as the changes in day-ahead offer strategies. Modelling in Matlab© showed a reduction of 20% in Regulation energy costs when day-ahead offers were held constant.

8.7 Effect on inadvertent energy

Studies done in **Section 5.5.4** showed that the relaxation of the frequency would result in a slight increase in tie-line error. **Figure 8.5** shows an increase in the hourly standard deviation of the hourly tie-line error from 39.7 MW to 42.9 MW.

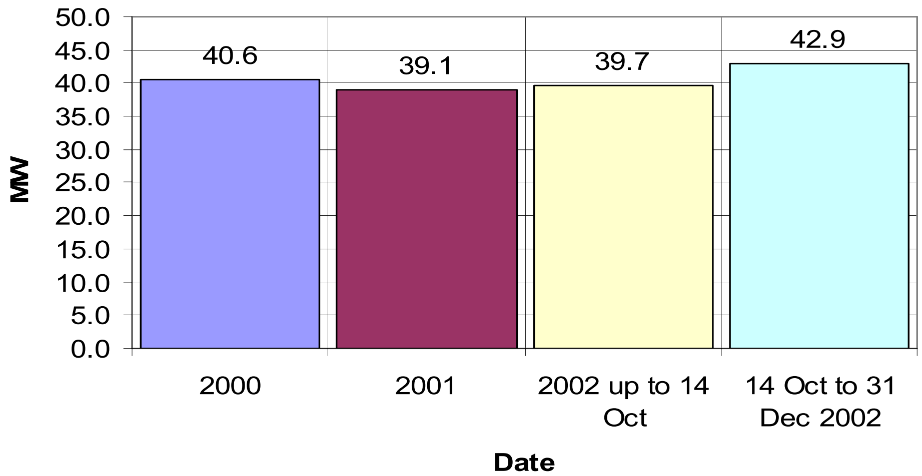

Figure 8.5. Standard deviation of hourly tie-line error from 2000-2002.

8.8 Conclusion of the frequency control redesign results

The new frequency boundaries in Eskom have reduced the generator movement by over 80% without a major impact on the customer or the reliability of the network, as shown in **Figure 8.6.** Regulation energy costs have also reduced as dispatch is done more on merit order. The Inadvertent energy to neighbouring control areas shows a slight negative impact.

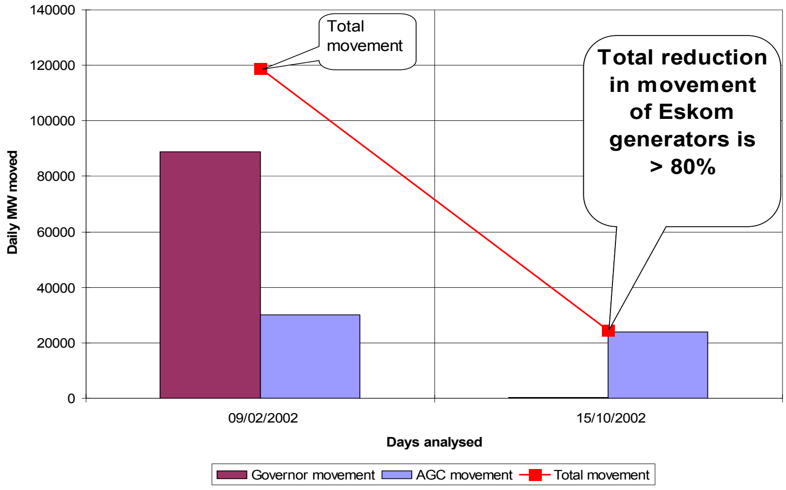

Figure 8.6. Reduction in total generator movement due to the frequency relaxation.

The summary of the reduction in governor and AGC, compared to the base case and Case 8 is shown in **Table 8.1** The balacing market savings are not shown as this is an internal market and for the Eskom frequency relaxation project the justification for implementing was based on costs only.

Table 8.1. Comparison of the base case, Case 8 and Eskom implementation results.

Simulation Case	Governor deadband (mHz)	Frequency Standard deviation (mHz)	Estimated governor movement (MW)	AGC movement (MW)	Total Generator movement (MW)
Base Case	50	30.8	56 234	37 511	93 745
Case 8	150	64.0	2 483	24 010	26 493
Eskom results	150	65.0	224	22 968	23 192

The estimated savings using the calculation developed in **Section 6.4** is shown in **Table 8.2.** Again the market savings are ignored. The Regulation reserve savings are also set to zero due to Eskom deciding not to reduce the amount of Regulation Reserve. The annual total savings are estimated to be R 22m.

Table 8.2. Estimated annual savings of Eskom frequency relaxation project compared to Case 8.

Simulation Case	Annual Instant. Reserve savings (R)	Annual Instant. usage savings (R)	Annual Regulation Reserve savings (R)	Annual Regulation usage savings (R)	Annual Market savings (R))	Total savings (R)
Case 8	-3 300 000	9 558 452	0	14 758 956	0	21 017 408
Eskom results	-3 300 000	9 960 166	0	15 898 044	0	22 558 210

Chapter 9 : Conclusions

Conclusions of the proposed methodology, uniqueness of the methodology and other unique features of implementation

A generic algorithm to determine the economic benefits of relaxing the frequency control has been developed and explained in this thesis. This is unique in that, to date, no other algorithm has been developed for this purpose. The algorithm has successfully been applied to the Southern African network, and in particular, Eskom, as one of the control areas. The algorithm when applied to Eskom resulted in the reduction of generator movement of 80% without affecting the consumer. The estimated savings for the project is R 22m excluding balancing market savings. The algorithm also resulted in improved balancing market dispatch, improved performance monitoring and gave a better understanding of the risk involved with frequency control.

With the development of the algorithm, some unique features and designs were included:

- *The development and implementation of the philosophy of using only the AGC to control the frequency within the normal band of operation*. The governor dead bands are set such that governing only becomes operational when the frequency is outside the normal region.

- *The method of combining the economic dispatch as part of the normal frequency regulation*. This minimises generator movement whilst providing an acceptable balancing market solution.

- *The conversion of day-ahead bids and offers to balancing bids and offers for the EPP*. The conversion reduces the complexity of the balancing calculation whilst respecting the day-ahead solution, which has considered all technical constraints.

- *The author has developed techniques for the performance monitoring of generators, which perform primary frequency control and automatic generation control.* These give a standard methodology against which all generators can be measured and, in future, any demand side participant can also be measured by these standards.

- *The methodology has been successfully implemented in the Southern African network.* This network has a weak AC interconnection of 300 MW in parallel with an 1800 MW HVDC connection between Eskom (with an average peak of 27000 MW) and Northern SAPP Countries (with an average peak of 3000 MW). The Northern Countries in SAPP predominantly use hydroelectric generation and South Africa uses predominantly coal-fired generation. This is an issue as hydroelectric generation and coal-fired generation have different control characteristics.

Chapter 10 : Recommendations

Recommendations and further work

A generic algorithm to determine the economic benefits of relaxing frequency control has been presented and implemented in one network, which can now be applied to other networks. It is recommended that other networks apply a similar methodology to their networks. Alternatively, the algorithm can be used when introducing deregulation to the interconnection. The generic algorithm can be used to periodically to check whether there are possible improvements to the current frequency control design.

The generic algorithm, being a first of its kind can now be further developed. The proposed algorithm can be improved upon and further, more detailed cost calculations added.

For Eskom, the following work still needs to be done:

- The market structure is changing from a mandatory pool to a bilateral, voluntary day-ahead and balancing markets with full demand side participation. These changes might require the frequency control philosophy to be changed.
- The request by generators to reduce tolerances of generators at very low and high frequency, necessitates a redesign of the current under-frequency load-shedding scheme. This study should also aim to align the various philosophies across the various utilities within the Southern African Power Pool.

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Appendix A : Literature study of frequency control in inter-connections

Literature study of frequency control in inter-connections around the world

A.1 Great Britain

A.1.1 General Network information

The Great Britain network has two interconnected sections: a Scotland section that is a vertically integrated utility and an "England and Wales" section that is deregulated. England, Scotland and Wales operate a power-exchange type market called British Electricity Trading and Transmission Arrangements (BETTA) which replaced the New Energy Trading Arrangement (NETA). National Grid Company (NGC) is the system operator for the NETA. The peak for Great Britain is 60 000 MW. NGC is responsible for frequency control for the whole of Great Britain, excluding Ireland (National Grid Company, 2003).

A.1.2 Standards

The Electricity Supply Regulations permit variations in frequency not exceeding 1% above and below 50 Hz. *i.e.* in a range of 49.5 to 50.5Hz. Frequency is allowed outside of these limits under fault conditions or when abnormal operating conditions occur. Losses of generation between 1000 and 1320 MW are possible with the loss of large nuclear generators or the HVDC connection to France. These are considered abnormal and a maximum frequency change of 0.8 Hz may occur and the frequency should return to 49.5 Hz within 60 seconds (National Grid Company, 2002). There is no target for the number of frequency excursions where the frequency is below 49.5 Hz for more than 60 seconds, however, NGC must write a report for each excursion to the Electricity Supply Regulator.

At or below 47 Hz generator automatic under-frequency disconnection is allowed. Generator operators are allowed to manually reduce their generation if the frequency is above 50.4 Hz and can trip their generation if the frequency exceeds 52 Hz.

The frequency is determined to be normal when it is between 49.8 and 50.2 Hz. National Grid targets to maintain the number of events outside these limits to less than 1500 events per year. The current number of events is around 500 per year. National Grid also targets to keep the standard deviation of frequency to be less than 0.07 Hz and the current measured standard deviation is 0.06 Hz.

Figure A.1 and **Figure A.2** summarise the standards.

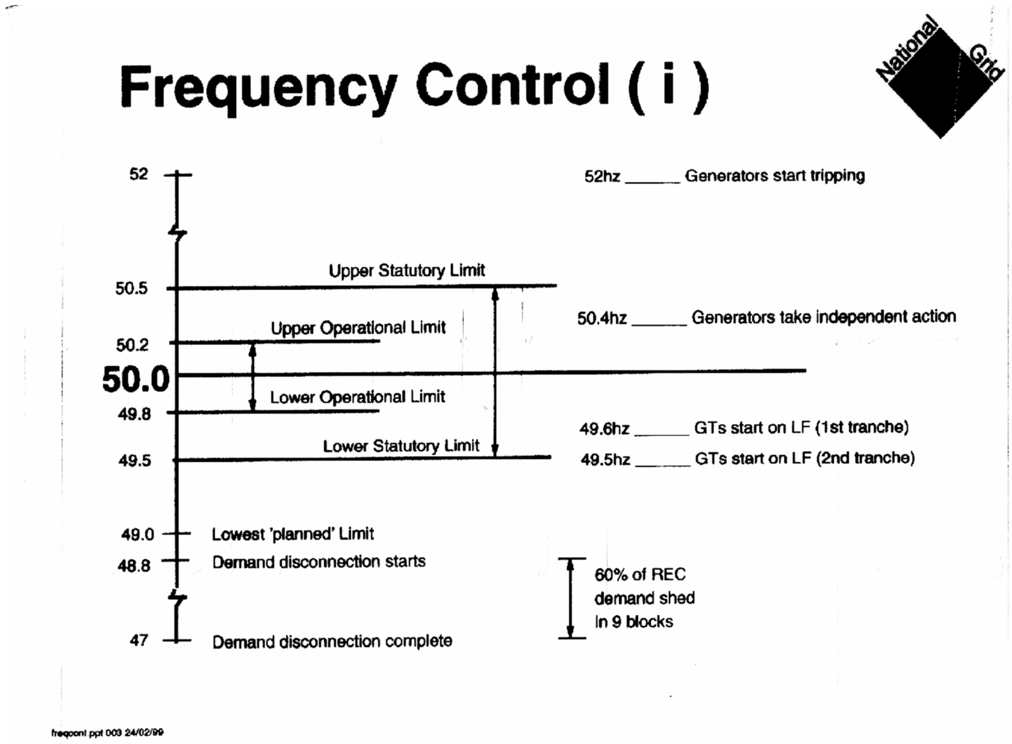

Figure A.1. Statutory limits for the England and Wales network (National Grid Company, 2003).

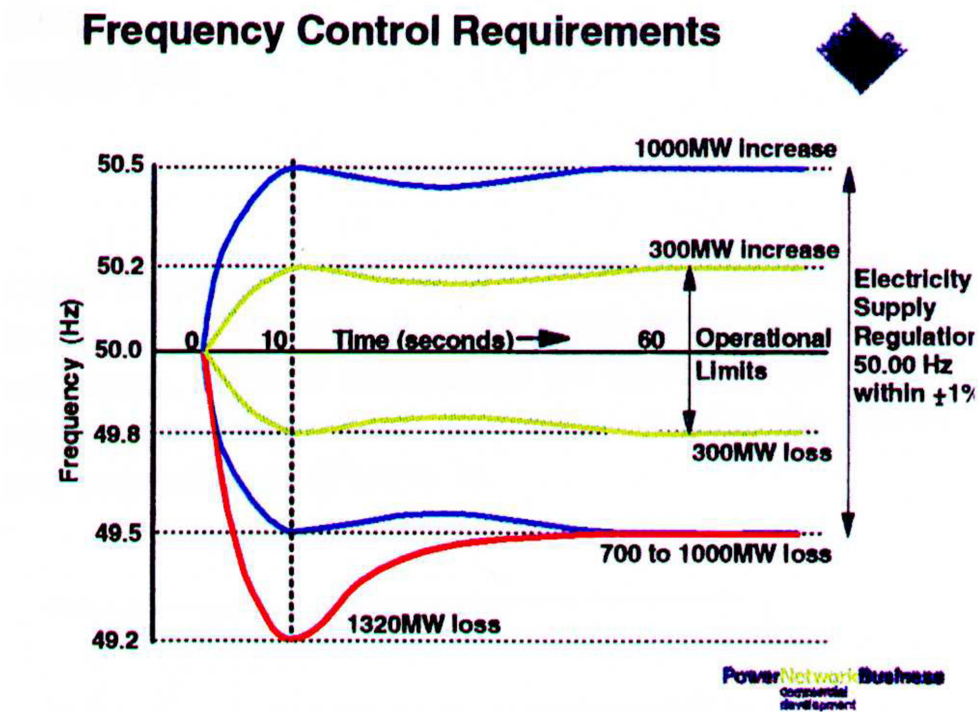

Figure A.2. Frequency control requirements for England and Wales (National Grid Company, 2003).

A.1.3 Methods for controlling frequency

A.1.3.1 Objective of frequency control

The system is usually managed so that the frequency is maintained within normal operational limits of 49.8 to 50.2 Hz by contracting generators to do primary frequency response. Manual intervention by the NGC Operator is required if the frequency varies by more than 0.1 Hz. If the frequency is outside 0.2 Hz for longer than 5 minutes an event is recorded. The target for the operators is to limit the number of frequency events outside 0.2 Hz band for longer than 5 minutes, to less than 14 excursions per month. In 2000, there were an average of 4 such excursions a month. (Arnot *et al.,* 2003).

A.1.3.2 Primary frequency control

The minimum requirements for generators for primary frequency response (governing), when the frequency deviates by 0.5 Hz, are set out in the connection conditions (National Grid Company, 2002a) and are shown graphically in **Figure A.3**. The generators must be on a 3 – 5 % droop characteristic with a maximum deadband of ±0.015 Hz.

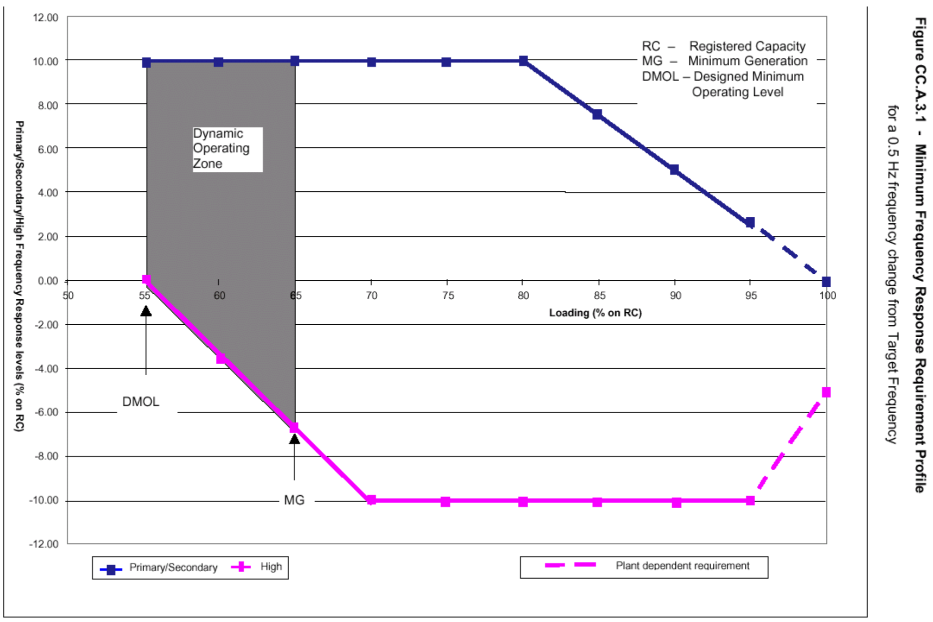

Figure A.3. Minimum primary frequency response requirements in England and Wales (National Grid Company, 2002a).

Each generator's governor is tested for a frequency deviation of 0.5 Hz injected into the generator controls. The real power response of the generator is the response 10 seconds after the 0.5 Hz low frequency deviation injection (parameter P in **Figure A.4**) and the average response of the generator real power from 30 seconds to 30 minutes after the 0.5 Hz frequency deviation injection is parameter S in **Figure A.4.** The real power response of the generator, parameter H in **Figure A.5,** is the 10-second response after the 0.5 Hz high frequency deviation injection.

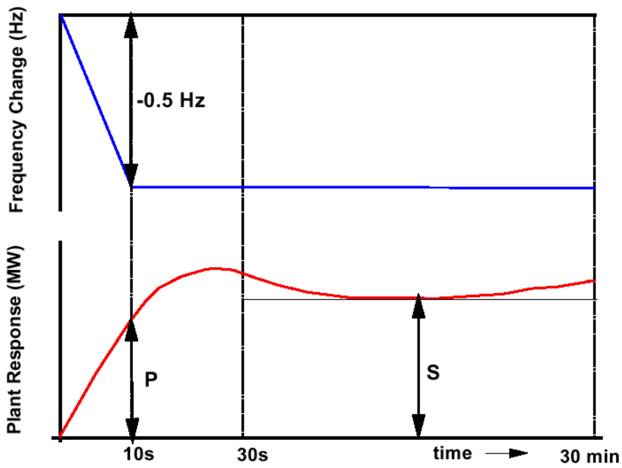

Figure A.4. Low frequency injection parameters (National Grid Company, 2002a).

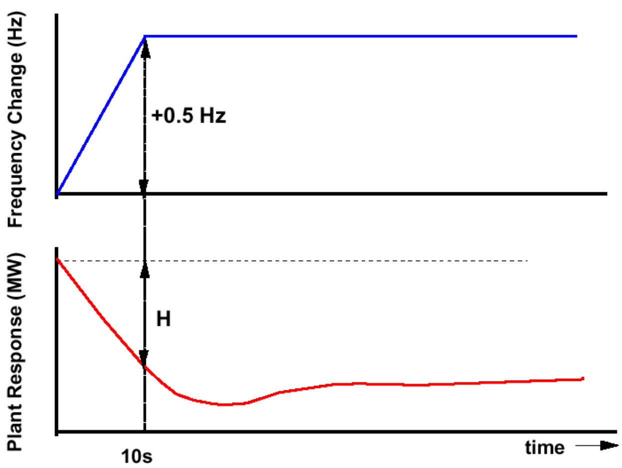

Figure A.5. High frequency injection parameters (National Grid Company, 2002a).

NGC requires that the sufficient primary frequency response from generators is activated such that a 200 MW error in supply and demand will result in a 0.1 Hz frequency deviation. A computer program (dynamic scheduler) constantly calculates the frequency response from the customer motor load based on the actual demand at the time. From this data the number of generators required to be on primary frequency control is derived. The least-cost generators are selected according to ancillary service contracts, in **Section 2.2.4**. These generators are then electronically informed and contracted.

A.1.3.3 Secondary frequency control

Secondary frequency control is done by manual instruction. A program, which considers the load frequency characteristic and expected primary response at each load and frequency level, calculates the number of MW's currently over- or under-generated. The operator has a computer display to show the cheapest option for correcting the over- or under- generation according to market prices for energy offered by the generators in the balancing market. The operator is then required to dispatch generators manually to correct the frequency. The operator is only required to dispatch generators if the frequency goes or is expected to go outside the 49.8 to 50.2 Hz boundary.

A.1.3.4 Under-frequency load-shedding

Paid interruptible load

The first under-frequency load-shedding scheme is a contracted service with large smelters who are paid to have this in place and the purpose is to restore the frequency to 49.5 Hz within the required 60 seconds. The load-shedding has 4 frequency levels, namely 49.5 Hz, 49.4 Hz, 49.3 Hz and 49.2 Hz. The estimated number of times the frequency will go below each frequency level is given to indicate to the contractors the number of times the load could be interrupted. Currently, participants to the scheme are rotated between the four levels on a quarterly basis to ensure an equitable distribution of the number of interruptions.

Mandatory under-frequency load-shedding

Under-frequency load-shedding directly on the Transmission network starts at 48.8 Hz and has 9 levels, as shown in **Table 2.1**. Up to 60% of the demand is shed by this scheme.

National Grid reviewed its under-frequency load-shedding scheme in 2001 (Brozio, C.C. et al, 2001) and proposed to raise the frequency level at which the under-frequency relays should operate, as shown in **Table A.1.** The proposed changes have been implemented.

Table A.1. NGC old and new under-frequency load-shedding (Brozio, C.C. et al, 2001).

Stage	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Demand block size [%]	5	5	10	7.5	7.5	7.5	7.5	5	5
Existing frequency settings [Hz]	48.80	48.75	48.70	48.60	48.40	48.10	47.70	47.30	47.00
Recommended frequency settings [Hz]	48.80	48.75	48.70	48.60	48.50	48.40	48.20	48.00	47.80

A.1.4 Ancillary services for controlling the frequency

A.1.4.1 Primary frequency control as an ancillary service

The amount of MW reserve contracted for primary frequency control is calculated every 15 minutes using an online dynamic scheduling tool. A minimum of 200 MW of primary frequency control reserve must be contracted. The exact response required from each generator is what the unit was capable of under test conditions as described above in the section on primary frequency control. The price is pre-negotiated and this can be changed monthly. The price has to be close to the actual costs otherwise the Regulator is asked to investigate. The online dynamic scheduling tool then calculates the requirements for high and low frequency and advises the operator how much response is required and which units to contract for the least cost solution for each 15-minute period. TV channels are monitored as popular programs and football games *etc.* can mean that the demand will change by 2000 MW during adverts and breaks.

Typical prices for primary frequency is £10-18 per MWh off peak and £20-50 on peak. Because of the high peak price, primary frequency is contracted with a fixed contract in peak times.

Primary response can be obtained from steam generator governing, demand reduction, pump storage reduction, hydroelectric governing and interconnection.

A.1.4.2 Secondary Frequency control as an ancillary service

Secondary frequency control is only used if the frequency is outside, or expected to go outside, the 50.2 – 49.8 Hz band. The operator then decides which generators to raise or lower. The instructions are given electronically and have to be accepted by the generator. The order in which the instructions are given is based on the cheapest energy solution based on the price the unit submitted in the balancing energy market.

The software continuously calculates the least cost solution and the results are displayed on a screen on the control desk.

A.1.4.3 Primary Frequency control co-ordination with Scotland

As part of the interconnection Scotland is expected to provide and minimum response for primary frequency control. The frequency response required is pre-negotiated a year in advance and is based on the relative network size. The frequency response requirement is at least 13% of the total Great Britain frequency response requirement. With the implementation of BETTA Scotland also participates in the market.

A.2 Nordic Power Pool

A.2.1 General Network information

The Nordic Power Pool consists of Norway, Sweden, Finland and Denmark (Nordpool, 2003). The installed capacity is 87 000 MW. The combined peak demand of all the countries was about 70 000 MW in 2002 where 55% of the capacity is hydroelectric (Norway has only hydroelectric capacity), 24% nuclear that is located in

Finland and Sweden and 20% thermal. Norway has had an open electricity market since 1992. Sweden joined the market in 1996, Finland in 1998 and eastern Denmark in 1999. An important part of the development of the common Nordic electricity market is the development of the international power exchange “Nordpool”. A large number of AC and HVDC interconnections link the power systems together.

A.2.2 Standards

Nordel is the organisation for all Nordic system operators (Nordel, 2003). The Nordel Operations Committee and the Nordel Board recommends the standards for frequency, time deviation, regulating power and reserves. These recommendations are included in an agreement between the Nordic system operators. The allowed frequency variation is normally 49.9 to 50.1 Hz. The allowed time deviation is 30 seconds between real time and system time.

A.2.3 Methods for controlling frequency

A.2.3.1 Objective of frequency control

The objective of the frequency control is to not perform any secondary frequency control between 49.9 and 50.1 Hz. If the frequency goes outside these bounds, it must be restored to this level as soon as possible. The network time must also be within 10 seconds of real time.

The Nordel Operations Committee (Nordel, 2003) reports the quality of frequency as the number of minutes during which frequency exceeding the limits of the normal range (high or low). From 1994 until 2002, the number of minutes recorded in a year has increased as follows:

- From 500 minutes in 1994, to 2010 minutes in 2002 for frequency below 49.9Hz.
- From 170 minutes in 1994, to 2400 minutes in 2002 for frequency above 50.1Hz.
- From 670 minutes in 1994, to 4410 minutes in 2002 for all deviations.

In 2002, the frequency was outside the 49.9 to 50.1 Hz band more than 50% of the time. Statistics show that deviations are occurring more in summer time at lower load periods with less generation connected to the power system. Deviations are also occurring near the change of the hour when generators are changing their outputs according to spot market contracts for the next hour, whilst the demand is not doing the same, creating an imbalance between supply and demand.

A.2.3.2 Primary frequency control

All generators must be on primary frequency control and on a 4% droop. No deadband is allowed except for the inherent mechanical deadband of the governor valves. The total primary frequency control from generators is calculated as 6000 MW/Hz.

A.2.3.3 Secondary frequency control

When the frequency approaches the limit of the performance area (49.9 – 50.1 Hz, ±30 sec.), the generation is manually changed by NORDEL until the frequency is re-established at an acceptable level. For secondary frequency control purposes a minimum reserve of 600 MW is required. (Bakken *et al.*, 1997).

The Area Control Error (ACE) is calculated for each control area. Currently each country is a control area on its own in determining where the control is to be performed. The magnitude of the ACE is measured in each control area and not allowed to exceed a predetermined value for each country.

Change in generation shall be performed in the following cases:

- When the instantaneous area control error is about to exceed its limits, and the change simultaneously reduces frequency deviation.
- When the actual value of active power on a tie line is about to exceed its limits.
- When the integrated control error over one hour is about to exceed its limits.
- When the time deviation is about to exceed 30 sec. This is a task for Sweden and Norway.

- When the frequency deviation is about to exceed 0.1 Hz. Sweden and Norway has the main responsibility for keeping the frequency within its limits in these situations.
- When a request comes from a neighbouring country. Economical consequences are settled bilaterally.

A.2.3.4 Under-frequency load-shedding

Automatic start of gas turbines, HVDC-connections and load-shedding are system protection schemes that should prevent the power system from blackouts (Arnot *et al.,* 2003).

The first step of load-shedding is initiated at 49.0 Hz and the last step at 47.0 Hz.

A.2.4 Ancillary services for controlling the frequency

A.2.4.1 Primary Frequency control as an ancillary service

This is not declared as an ancillary service as it is required from all generators. Generators are paid for the fixed costs for the capability to do primary frequency control or for the variable wear and tear costs. In Sweden, a market-based procedure for purchasing primary frequency control is in place. However, this is not operational because of lack of competition. Plans are to widen these arrangements to the whole Nordel area. In the other countries, the services are compensated partly on bilateral agreement basis and partly on mandatory requirements (Arnot *et al.*, 2003)

A.2.4.2 Secondary Frequency control as an ancillary service

Secondary frequency control is done manually and this is done via a balancing market. Generators are raised or lowered according to the cheapest energy price offered in the balancing market. Market bids can be changed up to 2 hours ahead. Generators are paid in the balancing market according to the number of MW dispatched and the price the generator offers. The costs required in keeping the system in balance is calculated as the average price dispatched over a half-hour period. The costs for balancing are then charged to generators or customers that caused the imbalance.

A.3 Union for the Co-ordination of Transmission of Electricity (UCTE)

A.3.1 General Network information

The Union for the Co-ordination of Transmission of Electricity (UCTE, 2003) co-ordinates 35 transmission system operators in 21 European countries. Its objective is to guarantee the security of operation of the interconnected power system.

The UCTE networks have an annual electricity consumption total of ±1750 TWh.

A.3.2 Standards

The discrepancy between synchronous time and universal co-ordinated time must not exceed 20 seconds. The Launfenburg control centre in Switzerland is responsible for the calculation of synchronous time and the organisation of its correction. Correction involves the setting of the set point frequency (*i.e.* 50 Hz) for secondary control in each area at 49.95 Hz or 50.05 Hz, depending upon the direction of correction, for periods of one day.

The quality of frequency will be regarded as satisfactory over a one month period where:

- The standard deviation for 90% and 99% of measurement intervals is less than 40 mHz and 60 mHz respectively for the whole month considered.
- The number of days of operation at a set point frequency of 49.95 or 50.05 Hz does not exceed eight days per month respectively.

A.3.3 Methods for controlling frequency

A.3.3.1 Objective of frequency control

The UCTE main purpose for frequency control is to maintain security of supplies in Europe through the availability of sufficient reserve capacity.

There are three types of operating conditions considered for frequency:

1. *Normal condition:*
   $\Delta f \leq 50mHz$

2. *Impaired condition*:
   $50mHz < \Delta f < 150mHz$

3. *Severely impaired condition:*
   $\Delta f > 150mHz$

In the impaired condition, there are no major risks, provided that control facilities in the affected areas are ready for deployment. During the severely impaired condition, there are significant risks for malfunction of the interconnected network.

A.3.3.2 Primary frequency control

A maximum of 3000 MW primary control is required in the UCTE and this calculation will result in:

- The quasi-steady state frequency deviation not exceeding 180 MHz.
- The instantaneous frequency not falling below 49.2 Hz in response to a shortfall in generation capacity equal to or less than 3 000 MW.

The overall frequency characteristic, which is the sum of the load frequency support and primary frequency control, for the system is set at 18 000 MW/Hz. Primary frequency response of each control area must be at least 1% of peak power. The range of insensitivity of turbine speed governors should be as small as possible, and in any case must be lower than 10 mHz.

The primary control reserves must be maintained, even where the set point frequency differs from 50 Hz. The system operator responsible for each control area should undertake the regular assessment of the performance of primary control.

A.3.3.3 Secondary frequency control

Each control area is responsible for maintaining reserves to restore their control area 15 minutes following the loss of the largest single unit, loss of import and must be at least 5% of the demand. If the loss of the largest generating unit supplying the area concerned is not covered by the secondary reserve of that area, provision must be made for an additional reserve from interconnected areas which will offset the loss of capacity within the requisite time. Most control areas have AGC to perform the required control. The UCTE control area is so large that most control areas are mainly doing tie-line control with each control area having very little influence over the frequency.

A.3.3.4 Under-frequency load-shedding

Frequency thresholds must be defined by each country for load-shedding. It is recommended that members of UCTE should initiate the first stage of automatic load-shedding in response to a frequency threshold no lower than 49 Hz. An accuracy of 50 –100 mHz is acceptable for under-frequency relay trip thresholds.

A.3.4 Ancillary services for controlling the frequency

A.3.4.1 Primary Frequency control as an ancillary service

This service is mandatory for all generators although the minimum requirements per country are small relative to the potential response. Each country is different, in some countries, primary frequency control service is now contracted under ancillary services and in others primary frequency control is mandatory under the grid code (Arnot *et al.*, 2003).

A.3.4.2 Secondary Frequency control as an ancillary service

A balancing market in some countries such as Germany, where the market operates the same as in the Nordic Power Pool, provides the secondary control service. Other countries have not yet developed this into a market and generators are mandated to provide. Most countries contract AGC control with generators as secondary or regulating reserves. The regulating market forms the main part of balancing and energy utilised under AGC is paid as balancing energy. Providers of AGC services have to prove they are capable of providing the service before they can be contracted for reserves. Some countries have a tertiary reserve market. Providers must still meet 15 minute dispatch requirement of secondary reserves but do not have to be on AGC.

A.4 Australian Eastern Interconnection

A.4.1 General Network information

The eastern states of Australia are interconnected and form the National Electricity Market (NEM). The system has a peak demand of about 27 000 MW (Nemmco, 2003). The frequency control standards for NEM are under the National Electricity Code. The Reliability Panel is tasked to set standards for power system frequency, as part of the power system security and reliability standards. The market is a gross pool where the market and system operations are performed by NEMMCO. The pool operates as a single control area and the inter-state ties are not controlled as traditional tie-line control. A 5-minute-ahead-of-real-time constrained dispatch tool ensures none of the inter-state lines are overloaded.

A.4.2 Standards

The Reliability Panel of the National Electricity code (NECA, 2003) is responsible for setting frequency and time standards. The standards are set according to a cost benefit analysis.

The frequency standards are shown in **Table A.2** and applies to any part of the power system other than an island and **Table A.3** applies to an island.

Table A.2. NECA standards for an interconnected system (NECA, 2003).

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds		
No contingency event or load event	49.75-50.25 Hz, 49.85-50.15 Hz 99% of the time	49.85-50.15 Hz within 5 minutes	49.85-50.15 Hz within 5 minutes
Generation event or load event	49.5-50.5 Hz	49.85-50.15 Hz within 5 minutes	49.85-50.15 Hz within 5 minutes
Network event	49-51 Hz	49.5-50.5 Hz within 1 minute	49.85-50.15 Hz within 5 minutes
Separation event	49-51 Hz	49.5-50.5 Hz within 2 minutes	49.85-50.15 Hz within 10 minutes
Multiple contingency event	47-52 Hz	49.5-50.5 Hz within 2 minutes	49.85-50.15 Hz within 10 minutes

Table A.3. NECA standards for an islanded system (NECA, 2003).

Condition	Containment	Stabilisation	Recovery
No contingency event, or load event	49.5-50.5 Hz		
Generation event, load event or network event	49-51 Hz	49.5-50.5 Hz within 5 minutes	49.5-50.5 Hz within 5 minutes
The separation event that formed the island	49-51 Hz or a wider band notified to NEMMCO by a relevant Jurisdictional Coordinator	49.0-51.0 Hz within 2 minutes	49.5-50.5 Hz within 10 minutes
Multiple contingency event including a further separation event	47-52 Hz	49.0-51.0 Hz within 2 minutes	49.5-50.5 Hz within 10 minutes

A.4.3 Methods for controlling frequency

A.4.3.1 Objective of frequency control

NECA determines the legal requirements for frequency. NEMMCO has to control the frequency according to these requirements. NECA has a reliability panel that is currently reviewing frequency as a quality-of-supply issue. As part of its 2000-01 work programme, the Reliability Panel announced a review of the standards for power system frequency in the national electricity market. The review was aimed at incorporating economic criteria and introducing flexibility into the application of those standards. This was intended to help mitigate inappropriately high prices as a result of over-rigid application of the standards without jeopardising the security of the system. The review was completed in September 2001.

A.4.3.2 Primary frequency control

Primary frequency control is an ancillary service and consists mainly of generators under governor control.

A.4.3.3 Secondary frequency control

Secondary frequency control is performed using Automatic Generation Control and the market rules. This further explained in **Section A.4.4.2**: "Secondary control as an ancillary service".

A.4.3.4 Under-frequency load-shedding

A gas turbine in each of the four states is used for emergency reserves. This is fully under the control of the system operator. If the gas turbine is run, it sets the price in the energy market except if it is used for transmission constraints.

A.4.4 Ancillary services for controlling the frequency

A.4.4.1 Primary Frequency control as an ancillary service

Six ancillary services are used for primary frequency control: three for high frequencies and three for low frequencies. These are measured by the response of the generator over 0-6 seconds, 6-60 seconds and 60-300 seconds following a change in the frequency outside the normal band. The amount of service required is determined by a dynamic dispatch algorithm and participants are contracted every 5 minutes. The dynamic dispatch algorithm uses the load frequency support, the size of the largest unit connected and the demand at the time to determine the amount of primary frequency control required.

A.4.4.2 Secondary Frequency control as an ancillary service

This is contracted every 5 minutes and these units are then automatically selected into regulation. The energy management system then uses these units for inter 5 minute variances. NEMMCO currently does not measure the performance of these units but is proposing to do so soon (Arnot *et al.*, 2003). The units are paid at the system marginal price plus an incentive for being on regulation. The amount of service contracted is 300 MW every 5 minutes, which is normally more than adequate. Regulation is used for real time balancing and includes dispatching for load forecast error, inter 5-minute variances or trips.

A.5 New Zealand

A.5.1 General Network information

New Zealand is split into two AC networks: South Island and North Island connected via a HVDC link. The energy transmitted during 2001/02 was 35,697 GWh compared to 36,419 for the previous year. The system peak demand was 6,074 MW, which was recorded at 6pm on 17 June 2002, compared to the peak of 6,054 MW for the previous year (Transpower, 2003). The electricity supply industry in New Zealand has undergone major restructuring in recent years. The functions of generation, transmission, distribution and retailing have been separated. Transpower is the state-owned enterprise that owns and operates the network of transmission lines (which connect power stations to retail power companies and large industrial users of electricity who receive their power directly from the national grid), substations, switchyards and control centres collectively known as the national grid. Currently, grid security and quality levels in New Zealand are administered by Transpower and are defined in its policy document (the *Grid Operating Policy* or "GOSP"). This is an interim standard and is presently the subject of major review.

A.5.2 Standards

Transpower intends to move from a centrally imposed GOSP to an arrangement where industry defines the core requirements. The changes will enable grid users in

New Zealand to determine the standards for real time security and quality of supply from the national grid. They will enable commercial trade-offs intrinsic in common security standards. These common security standards may be minimum levels below which Transpower cannot contract for customer specific variations, or core performance requirements for Transpower.

The GOSP sets out the obligations and requirements of Transpower and all parties connected to and/or using the National Grid for the purposes of achieving grid security. The GOSP includes target conditions for power quality and the variations in power quality that can be expected at points of connection to the grid. The frequency ranges for various system conditions are outlined in **Table A.4**.

Table A.4. New Zealand frequency standards (Transpower, 2003).

System Condition	Frequency Range (Hz)
Normal frequency	49.8 to 50.2
Contingent event*	48.0 to 55.0
Extended contingent event**	45.0 to 55.0

* *Contingent events are those for which, in the reasonable opinion of the grid operator, resources can be economically provided to maintain the security of the grid and power quality without the shedding of demand.*

** *Extended contingent events are those which, in the reasonable opinion of the grid operator, resources can be economically provided to maintain the security of the grid and power quality with the shedding of demand.*

The time standard under the frequency objectives is to maintain synchronous time within 5 seconds of New Zealand Standard Time.

A.5.3 Methods for controlling frequency

A.5.3.1 Objective of frequency control

Under the proposed rules, the System Operator has a Principle Performance Objective (PPO) to maintain frequency within 50 ± 0.2 Hz, except for momentary fluctuations as shown in **Table A.4** above. (Transpower, 2003a).

The number of frequency excursions outside the normal band is shown in **Figure A.6** below and it is observed that the number of incidents for the North Island have increased dramatically which is a concern to the System Operator.

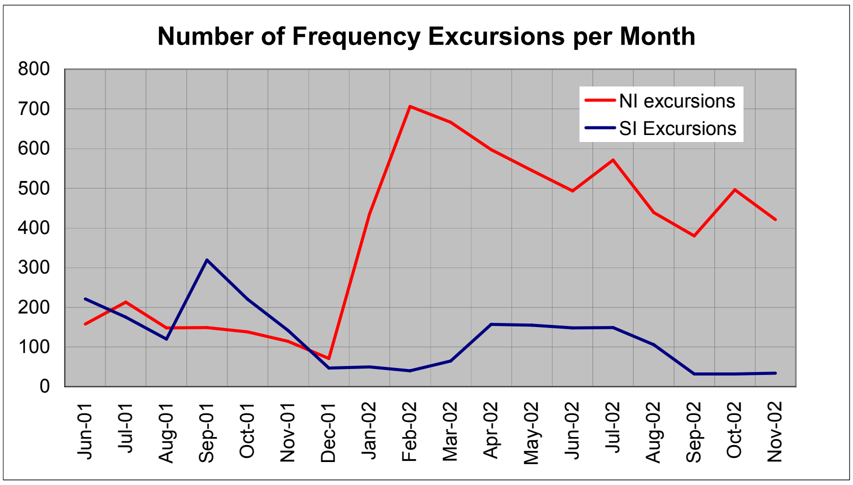

Figure A.6. Number of frequency incidents greater than 0.2 Hz per month for New Zealand (Transpower, 2003a).

The frequency distribution of both networks for frequency data from September to December 2002 is shown in **Figure A.7**. The current average quality is estimated at 50±0.2 Hz for 99% of the time in the North Island and approximately 50±0.1 Hz for 99% in the South Island. The mean absolute error is approximately 0.06 Hz in the North Island and 0.03 Hz in the South Island.

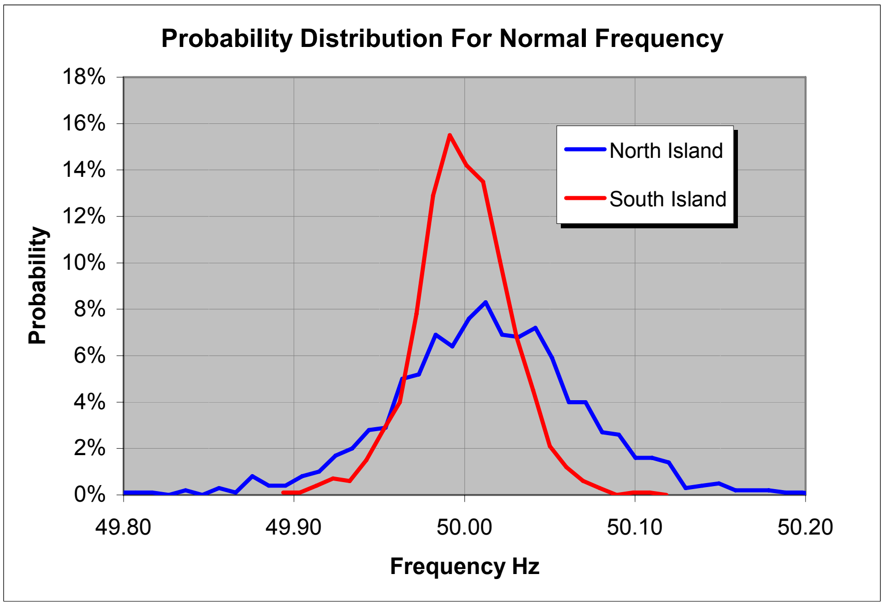

Figure A.7. Frequency distribution graph for New Zealand (Transpower, 2003a).

A.5.3.2 Primary frequency control

Generators have Asset Owner Performance Obligations (AOPOs) requiring them to have governors and to support frequency (*i.e.* enable free governor action).

A.5.3.3 Secondary frequency control

The system operator is responsible to maintain the frequency within limits on each Island. The system operator contracts a single frequency keeper in each island. It is their job to return the frequency to 50 Hz with help from the system operator (who issues new dispatch instructions taking into account forecasts of load changes and generator ramping constraints and unit outages). The HVDC control system also enables frequency stabilisation and reserve sharing between the two islands.

A.5.3.4 Under-frequency load-shedding

It is proposed to install two stages, each of 20% of demand, of under-frequency load-shedding in the South Island. The main purpose of this scheme is to firstly to reduce spinning reserves and secondly to increase import of the HVDC from 500 to 570 MW from the North Island. The under-frequency load-shedding should avoid a blackout of the South Island if the HVDC trips when at 570 MW. The benefit of the scheme is expected to be NZ$ 500 000 per year.

The details of the proposed scheme are as follows:

To enable automatic disconnection of 2 blocks of demand (each block being a minimum of 20% of the total demand at that the transmission grid exit point at any time) with block 1 operating within 0.4 seconds, including circuit breaker time, after the frequency reduces to 47.8 Hz and block 2 operating within:

- 15 seconds, including circuit breaker time, after the frequency reduces to 47.8 Hz, or
- 0.4 seconds, including circuit breaker time, after the frequency reduces to 47.5 Hz.

A.5.4 Ancillary services for controlling the frequency

A.5.4.1 Primary Frequency control as an ancillary service

Generators that have Asset Owner Performance Obligations (AOPOs) requiring them to have governors and to support frequency are paid to provide this as an ancillary service. Energy is paid according to the generators balancing market offers.

A.5.4.2 Secondary Frequency control as an ancillary service

The System Operator issues instructions to generators that are to balance the system according to frequency response offers. The system operator contracts ±50 MW in the NI and ±50 MW in the South Island, this must be provided by a single supplier for each network and at a rate of at least 10 MW/m. These generators are paid according to the generators balancing market offers. Final ex-post prices for each half-hour trading period are calculated based on the actual metered average demand and the final generator offers. During a half-hour trading period, generators are dispatched to meet instantaneous demand and may respond involuntarily under free governor action to frequency variations. The market calculates generator costs by comparing offered generation to dispatch instructions for each trading period, before 2001, the energy was paid without checking dispatch instructions. Generation committed to frequency response service is excluded from these payments and is dealt with through the AOPAs. The current average price of Frequency response service is approximately NZ$ 23/MW/hr or NZ$ 20m per year for 100 MW of service. This means that unless a generator has actually been dispatched to overcome frequency variations, generation shifted away from its dispatch set point due to free governor action is not necessarily included in the balancing market calculations.

A.6 Tasmania

A.6.1 General Network information

The Tasmanian power generation system consisted of 28 power stations with a total installed capacity of 2 502.9 MW. All but Bell Bay Power Station are hydroelectric power stations, grouped into seven separate catchment areas. All the generation facilities are owned and operated by Hydro Tasmania, (formerly HEC). Hydro Tasmania also owns the small diesel power stations on King Island and Flinders Island and a small wind farm on King Island. Tasmania's present average electricity requirement is about 1 010 MW and a typical winter and summer profile is shown in **Figure A.8** below. As the bulk of the capacity is dependent on the quantity and location of rainfall, the Tasmanian system is defined as being energy constrained rather than capacity constrained. System Operations and the transmission owner are an independent company called Transend (Transend, 2003).

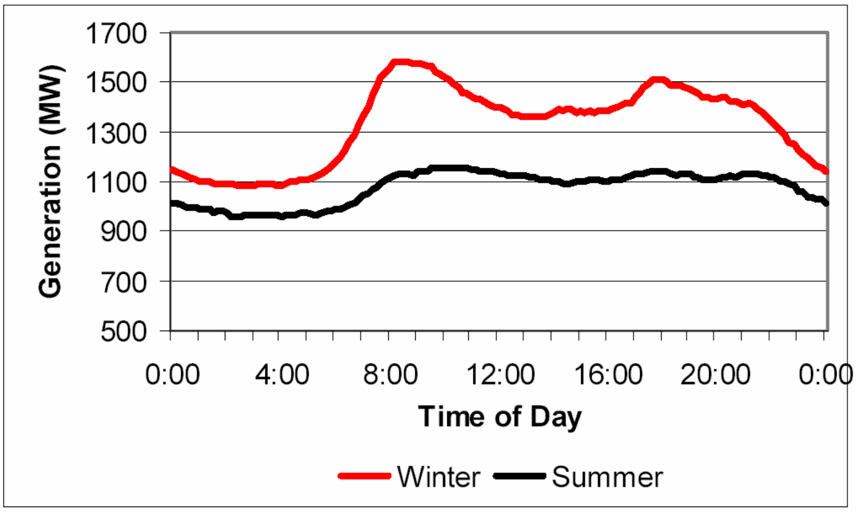

Figure A.8. Typical summer and winter load pattern for Tasmania (Transend, 2003).

A.6.2 Standards

The standards for Tasmania for frequency are shown in

Table A.5 below.

Table A.5. Tasmanian frequency standards (Transend, 2003).

Band	Frequency Operating Standard
Normal	49.85 – 50.15 Hz
Load change contingency band	49.0 – 51.0 Hz
Single generator contingency band	47.0 – 51.0 Hz (prior to gas turbine connection) 47.5 – 51.0 Hz (after gas turbine connection)
(Other) credible contingency band	47.0 – 53.0 Hz (prior to gas turbine connection) 47.5 – 53.0 Hz (after gas turbine connection)
Multiple contingency band	44.8 – 55.0 Hz (prior to gas turbine connection) 46.0 – 55.0 Hz (after gas turbine connection)

Tasmania join the Australian electricity market (NEM) when the HVDC connection, Bass Link, is commissioned between Australia and Tasmania. As such there is a proposal to align the standards of Tasmania with NEM. The issue is that the standards are different for single generator contingencies because of the relative sizes of generators to the total network size. For Tasmania to improve its frequency control for a single generator contingency from the current 47.0 Hz to the NEM standard of 49.0 Hz (NEM standard for an Island network) will be very expensive and nearly impossible.

The following changes however are proposed:

- Alignment of nomenclature used with NEM terminology.
- Increasing the lower limit of the single generator contingency band from 47.0 to 47.5 Hz.
- Increasing the lower limit of the (other) credible contingency event from 47.0 Hz to 47.5 Hz.
- Increasing the lower limit of the multiple contingency band from 44.8 Hz to 46.0 Hz.

The Basslink HVDC link was commissioned in first quarter of 2006.

A.6.3 Methods for controlling frequency

A.6.3.1 Objective of frequency control

The main objective of the frequency control is to keep the frequency within 1 Hz for a load change a 3 Hz for a generator change.

A.6.3.2 Primary frequency control

Primary control is performed by power station governing and power stations must increase output by at least 10% of output and within 6 seconds.

A.6.3.3 Secondary frequency control

Secondary frequency control is the responsibility of the system operator and is performed through manual instruction.

A.6.3.4 Under-frequency load-shedding

Under-frequency load-shedding events are activated when the frequency falls to 47Hz. Retailers must ensure at least 60% of load is shed in up to seven steps if the frequency continues to fall. The last block is shed when the frequency falls to 44.8Hz. The system operator is tasked to keep the network operational for multiple contingencies of up 60% of the demand.

A.6.4 Ancillary services for controlling the frequency

A.6.4.1 Primary Frequency control as an ancillary service

This is contracted as 6 second reserve and is required to arrest a frequency excursion within the single generator or other credible contingency band within six seconds after loss of a single, connected generator unit. This reserve is provided by ensuring a sufficient number of generators are able to increase their output by about 10 % within 6 seconds.

A.6.4.2 Secondary Frequency control as an ancillary service

Sixty-second reserve

The 60-second reserve is required to bring the frequency back into the load change band. Sixty seconds provides sufficient time for any remaining Spinning Reserve to take up load and restore the frequency.

Five-minute reserve

This reserve is needed to re-establish the system frequency back to the normal band. The 5-minute reserve must be of sufficient capacity to cater for the largest load on a single connected generator unit. The maximum requirement is 144 MW for the largest fully loaded generator.

A.7 USA and Canada

A.7.1 General Network information

The Northern American network is made up of four interconnections with a total peak demand of 708 000 MW in the USA and 67 000 MW in Canada recorded in summer of 2002 (NERC 2003). The three interconnections are the Eastern Interconnection of 588 000 MW, the Western Interconnection of 133 000 MW, Hydro Qubec interconnection of 36 000 MW (NERC, 2005) and ERCOT Interconnection of 58 000 MW. The reliability of the network is governed by two bodies: the Federal Energy Reliability Council (FERC) that defines and mandates the electricity industry reliability, and North American Electricity Reliability Council (NERC) that defines regional reliability. NERC currently makes recommendations only and does not yet mandate the utilities, but the intention is to make this a mandatory body.

A.7.2 Standards

NERC has developed standards for the tightness of frequency control (NERC, 2006). The Control Performance Standard (CPS) and Disturbance Control Standard (DCS) define a standard of minimum control area performance. Each control area in the USA is to have the best operation above this minimum.

The NERC standards are defined as follows:

- **Control Performance Standard (CPS1)**. Over a year, the average of the clock-minute averages of a control area's ACE divided by -10β (β is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, Epsilon 1, is a constant derived from a targeted frequency bound set by the NERC Performance Subcommittee. Each control area shall achieve CPS1 compliance of 100%

- **Control Performance Standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. Each control area shall achieve CPS2 compliance of 90%.

- **Disturbance conditions.** In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area or reserve sharing group to monitor control performance during recovery from disturbance conditions

- **Disturbance Control Standard (DCS).** The ACE must return either to zero or to its pre-disturbance level within 15 minutes following the start of the disturbance. Each control area shall meet the disturbance criteria at least 100% of the time for reportable disturbances.

A.7.3 Methods for controlling frequency

A.7.3.1 Objective of frequency control

The objective of the frequency control is defined by the NERC standards. The standards for the various interconnections are defined by Epsilon 1 as the target standard deviation of the frequency in mHz and as shown in **Table A.6** below.

Table A.6. Epsilon 1 for the interconnections in the USA (NERC,2006).

Interconnection	Epsilon 1
Eastern	18.0
Hydro Quebec	21.0
Western	22.8
ERCOT	20.0

Time error must be corrected according to the limits and procedure for the various interconnections, shown in **Table A.7** below.

Table A.7. Time error correction for the interconnections in the USA (NERC, 2006).

Time		***Initiation***			***Termination***		***Scheduled Freq. (Hz)***
	East	**West**	**ERCOT**	**East**	**West**	**ERCOT**	
Slow	–10	–2	–3	–6	±0.5	±0.5	60.02
Fast	+10	+2	+3	+6	±0.5	±0.5	59.98

A.7.3.2 Primary frequency control

All generators greater than 10 MW must be installed with active governors. The droop shall be set to at least 5% and the maximum deadband allowable is 0.036 Hz.

A.7.3.3 Secondary frequency control

Secondary frequency control is done via AGC and must be set up to meet the NERC performance criteria.

A.7.3.4 Under-frequency load-shedding

Under-frequency load-shedding relay settings are co-ordinated and established on a regional basis. It is required that each system and control area must take prompt action to relieve any abnormal conditions, which could jeopardise reliable operation of an Interconnection. **Table A.8** shows the ERCOT requirements for under-frequency load-shedding.

Table A.8. ERCOT requirements for under-frequency load-shedding (NERC,2006).

Frequency Threshold	Load Relief
59.3 Hz	5% of the ERCOT System Load within 0.5 s (Total 5%)
58.9 Hz	An additional 10% of the ERCOT System Load within 0.5 s (Total 15%)
58.5 Hz	An additional 10% of the ERCOT System Load within 0.5 s (Total 25%)

A.7.4 Ancillary services for controlling the frequency

A.7.4.1 Primary Frequency control as an ancillary service

Primary governor control is mandatory and no market has yet been developed (Arnot *et al.*, 2003).

A.7.4.2 Secondary Frequency control as an ancillary service

Only a few regions in North America, such as PJM, New England, New York and California, have developed ancillary service markets for frequency control (Arnot *et al.*, 2003). Almost all regions have developed markets for spinning reserves and other capacity reserves. In some cases, portions of the spinning reserves that are under central control are used for secondary frequency control. For example, in PJM, a secondary frequency control ancillary service market operates for generators under PJM AGC control.

A.8 Japan

A.8.1 General Network information

The peak demand for Japan for 2001 was 184 000 MW (Japan, 2003). The network is split into a 50 Hz and a 60 Hz Network linked by two 300 MW and 600 MW converter stations, see **Figure A.9** below. The network is owned by ten privately-owned electric power companies who are responsible for providing local operations from power generation to distribution and supplying their respective service areas with electricity.

In March 2000, power supply was partially liberalised to allow Power Producer Suppliers to sell to extra high-voltage users (over 2MW). Regional companies were also allowed to begin selling power to users outside their designated area. All other users not targeted under the new liberalisation guidelines will continue to be served by their regional power company.

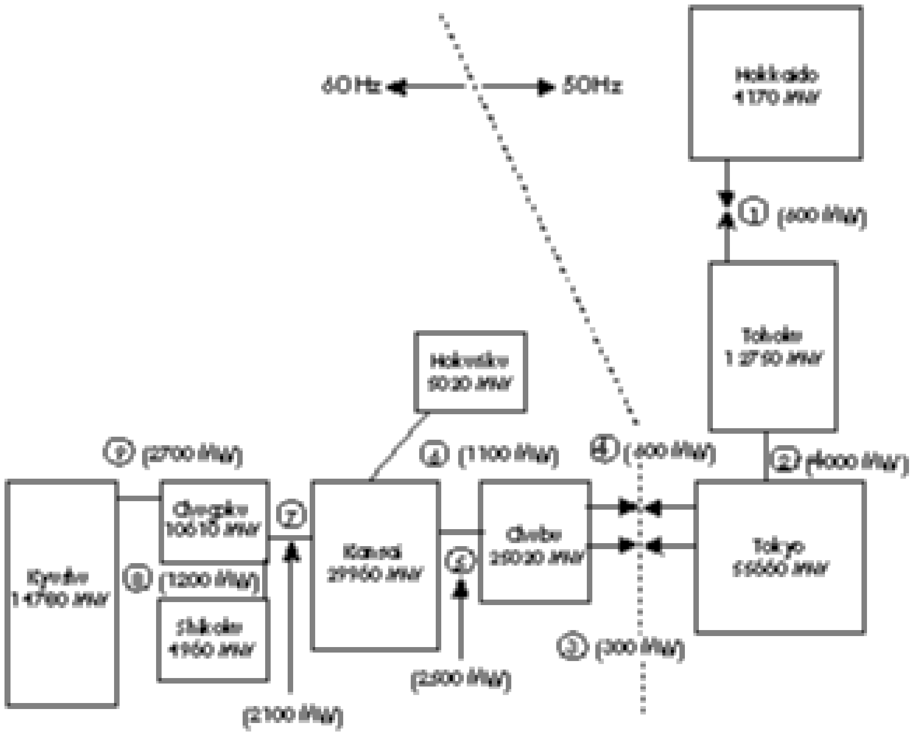

Figure A.9. Schematic diagram of the Japanese network (Japan, 2003).

A.8.2 Standards

Unknown.

A.8.3 Methods for controlling frequency

A.8.3.1 Objective of frequency control

Frequency is controlled to a standard deviation of 30 mHz referenced to the 50 Hz network.

A.8.3.2 Primary frequency control

Primary frequency control is performed by generator governing. The droop of the generators is 4% on the 50 Hz network.

A.8.3.3 Secondary frequency control

Secondary frequency control is done with AGC. Kansai Electric has a large nuclear contingent that cannot change its output easily and so the utility has installed pump storage schemes with variable pumping for the purposes of secondary frequency control not only when the pump storage scheme is generating but also when it is pumping (Kudo and Mukai, 1994).

A.8.3.4 Under-frequency load-shedding

No information available.

A.8.4 Ancillary services for controlling the frequency

A.8.4.1 Primary Frequency control as an ancillary service

No information available, presumably not done yet.

A.8.4.2 Secondary Frequency control as an ancillary service

No information available, presumably not done yet.

A.9 Southern Africa

A.9.1 General Network information

The Southern African network has a peak demand of 33 000 MW. The Southern African Power Pool (SAPP, 2003) was established within the SADC (Southern African Development Community) in 1995. SAPP is a co-operative pool where payment is based on schedules and not on actual energy flow. The inadvertent energy accumulated in a specific period will be paid back in the same period in the form of energy. There are three control areas within SAPP, namely the ZESCO area incorporating Zambia and the Democratic Republic of the Congo; the ZESA area incorporating Zimbabwe and the Eskom area incorporating South Africa, Botswana, Namibia, Swaziland, Lesotho and Mozambique. The connection from South Africa to Zimbabwe is the main constraint on the network.

Eskom, the main supplier of electricity for South Africa with a peak demand of 31 000 MW, has operated an internal competitive power pool (EPP) from 1986 and a competitive ancillary services market from 1999.

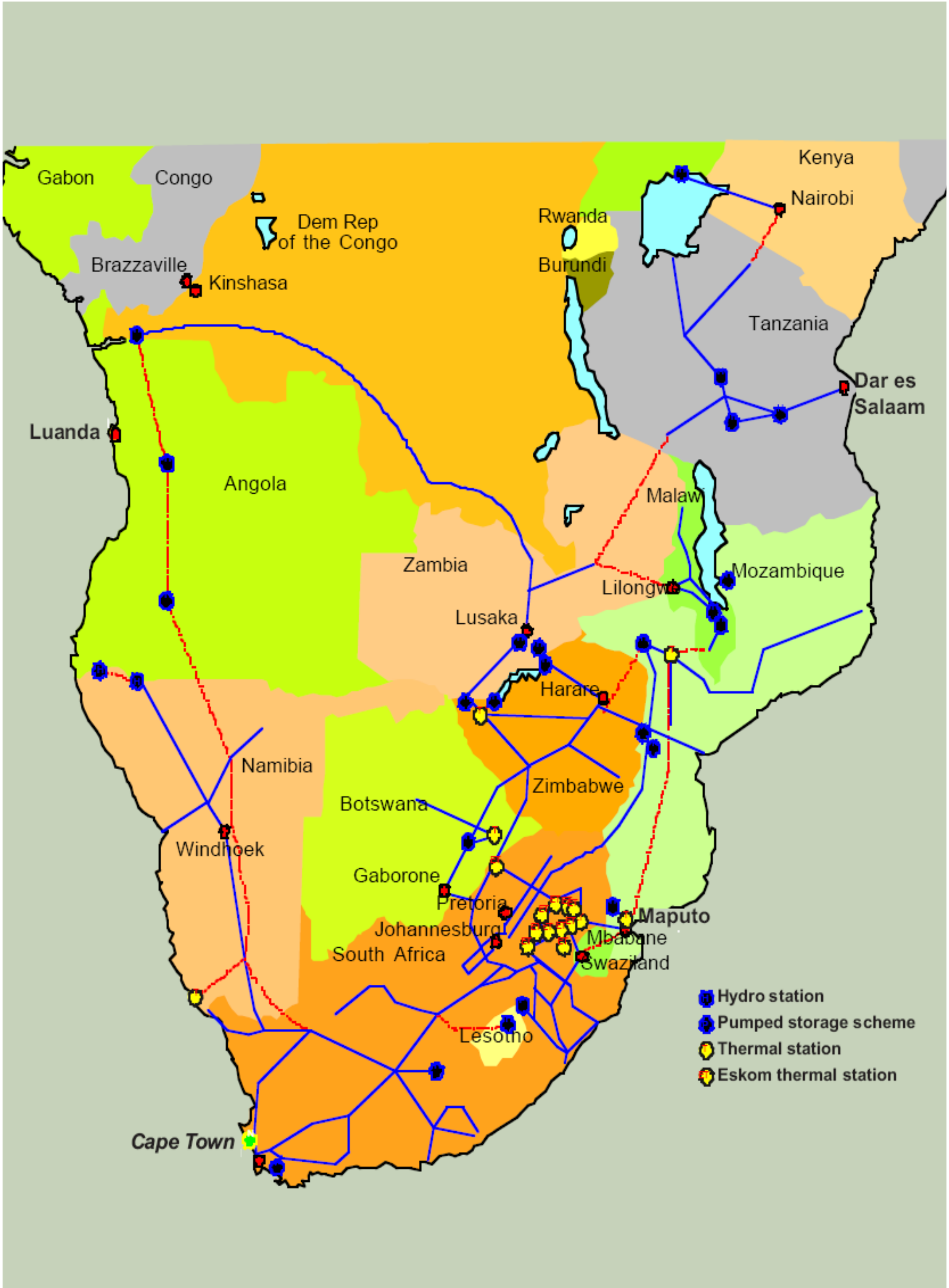

Figure A.10 The Southern African Grid (SAPP, 2002a)

A.9.2 Standards

The South African *Electricity Act, No. 41 of 1987, Regulation 9 (3),* states:
"The frequency of an alternating current supply shall be 50 Hz and the deviation of the frequency shall not exceed plus or minus 2.5 per cent of 50 Hertz." This implies that the frequency must remain between 48.75 and 51.25 Hz at all times.

In South Africa there is an electricity quality of supply standard that is manage by the National Energy Regulator of South Africa. The National Energy Regulator of South Africa (NERSA) standard on Electricity Supply, 1966 – Quality of Supply Standards NRS 048, Part 2, Section 4.7.1, Frequency Compatibility Levels states:
"The standard frequency shall be 50 Hz, and the maximum deviation shall be:

- for grid networks ±2,5% at all times,
- for islanded networks ±5,0% at all times, and ±2,5% for 95% of the period of a week."

The above requirements are the same, except that NRS 048 covers the event of the network being split into separate parts called islands. Since this only occurs in extreme emergencies, the frequency limits are less stringent.

The SAPP target prior to this project was to maintain the frequency between 49.95 and 50.05 Hz for 90% of the time. This was a requirement agreed upon by the member utilities (countries) of the Southern African Power Pool (SAPP) in 1986.

A.9.3 Methods for controlling frequency

A.9.3.1 Objective of frequency control

The objective of frequency control prior to this project was to meet the regulatory and SAPP requirements with a minimum amount of control. The minimum amount of control is determined on an hourly basis and continually monitored. SAPP also used the NERC A1 and A2 criterion. The NERC A1 and A2 criterion state the ACE must cross through zero at least once every ten minutes and the standard deviation of the ACE must not exceed a calculated value, depending on control area size, over six fixed ten minute periods each hour.

A.9.3.2 Primary frequency control

Primary frequency control is defined by the number of MW a generator or load can alter its supply in 10 seconds and according to a change in frequency. This response is only required for 10 minutes. Generators under governing currently do this service. The total number of MW required is fixed according to frequency control requirements where for a single trip of the biggest unit, Koeberg at 920 MW, the frequency is expected to remains above 49.7 Hz. This requirement translates into having at least 420 MW available in Primary Frequency Control under all conditions.

A.9.3.3 Secondary frequency control

Secondary frequency control is performed by Automatic Generation Control. Here generators are raised and lowered according to the ACE calculation. The AGC algorithm has been set-up for the control objectives set out above. The controller determines the ACE with the use of the Fuzzy Logic Controller. Experience gained in trying to optimise the original controller indicated that it has a major shortcoming, as it does not utilise the derivative ACE in its calculations. Even when this component is added, it is still difficult to describe the exact control required in quantitative terms, although it is normally easy for the operator at the National Control Centre to describe the amount of control required.

The fuzzy controller makes it possible to describe the control action in vague terms. A classic example is: if the ACE is positive, but is returning to zero by itself at a slow rate, the controller should do nothing. This is very difficult to implement in a mathematical formula because 'slow' is not an exact number; it is a qualitative expression. To describe the complete system in terms of fuzzy controls would be difficult. The original controller suitably handles the functions performed by the lower-level controllers. Fuzzy logic therefore provided a relatively simple way to implement a derivative controller on the existing control system by replacing only the subroutine that calculated the ACE dead band and gains with the fuzzy logic.

A.9.3.4 Under-frequency load-shedding

Eskom has two types of under-frequency load-shedding schemes, Voluntary and Mandatory.

The first level is a *voluntary* scheme where the load is shed in three levels. At each level, 3 % of the load is shed. This scheme was developed when Eskom was importing 1850 MW on a HVDC line from Mozambique and a demand of 15 000 to 20 000 MW. Whenever this scheme tripped, the frequency fell below 48.8 Hz and the mandatory under-frequency scheme was activated. This is indiscriminate load-shedding. Eskom and major electricity users hence agreed that it would make more sense for customers to choose which part of their load should be switched off and which not. Customers know which part of their load is non–essential and which is not.

Mandatory load-shedding which starts at 48.8 Hz down to 48.5 Hz where 10% of load is shed in 5 steps. These forms part of a scheme to prevent a complete loss of the network. The load is shed in different parts of the network, which is part of a plan to ensure the reduction of one area will cause other areas to be loaded more.

A.9.4 Ancillary services for controlling the frequency

A.9.4.1 Primary Frequency control as an ancillary service

NERC defines frequency response as the provision of capacity from a generator or load that acts automatically to stabilise frequency following a significant frequency deviation on the interconnection. In Eskom, this service is currently provided by generators only and is known as Governing. The current minimum requirement for Governing is that the generator must provide a 4% droop with a maximum dead band of 0.05 Hz. The minimum response requirement is 5% of generator maximum rated sent out in 30 seconds.

This service is also a subset of Spinning Reserve and all generators that wish to provide Spinning Reserve must provide governing. Conversely, generators not contracted to provide Spinning Reserve are not required to provide governing. The ability to provide Governing is also a prerequisite for a generator wishing to provide Regulation.

A.9.4.2 Secondary Frequency control as an ancillary service

Regulation is defined by NERC as the provision of generation and load response capability, including capacity, energy and manoeuvrability, that responds to automatic control signals issued by the Operating Authority (NERC, 2006). The National Control Centre is equipped with a standard Energy Management System. This includes the Automatic Generation Control (AGC) system. AGC is the mechanism that allows generator output to be increased and decreased to match supply to the current demand for electricity.

Eskom consists predominantly of coal-fired plants and which do the Regulation. Constantly altering the generation of a thermal power plant is a factor that reduces the life, reliability, availability and maintainability of the plant. Modern thermal plant control strategies try to improve the above factors but plant wear inevitably occurs. This additional cost to a generator performing Regulation is the main reason that this service should be marketed separately.

The author selected a few power stations to perform the Regulation in the initial set-up of the Eskom Power Pool in 1996. These stations were compensated for providing this service. When Ancillary Services were introduced, the power stations requested that this service should be made competitive. This required a clear definition of the service and for more market principles to be applied.

The capability to provide Regulation requires that the unit's outputs are scheduled with a margin to move both up and down. The required up margin is a subset of Spinning Reserve. Where Spinning Reserve is the provision of capacity from a resources synchronised to the system, that is unloaded, in excess of the quantity required to serve the current anticipated demand, and fully available within 10 minutes.

Appendix B : Standards governing frequency

Standards governing the manufacture of electrical equipment

B.1 Introduction

This appendix describes the international and national standards applicable to frequency. These standards govern the manufacturer of electrical equipment and the information is important in determining the tolerable frequency range. The last section discusses the conflict between the existing method for under frequency load shedding in South Africa and the new frequency standards introduced for generators in the South African Grid Code.

B.2 International standards on frequency tolerance for generators, consumers and networks

This section will study the international standard requirements of electrical equipment manufacturers and customer surveys undertaken by EPRI, consultants to Australia and internal Eskom research.

B.2.1 International standards on network frequency

International standards that apply to electrical equipment are presented in this section.

B.2.1.1 Standards for electrical machines

IEC 60034-1 standard for AC machines

IEC 60034-1 requires AC machines rated for use on a power supply or a fixed frequency supplied from an AC generator, shall be able to tolerate the combination of frequency and voltage variations as shown by zone A and zone B in accordance with Figure B.1 (IEC, 1999). The machine shall be capable of producing its primary function continuously within zone A. The machine shall be capable of producing its primary function in zone B but may exhibit greater deviations from its normal performance such as the operating temperature of the machine.

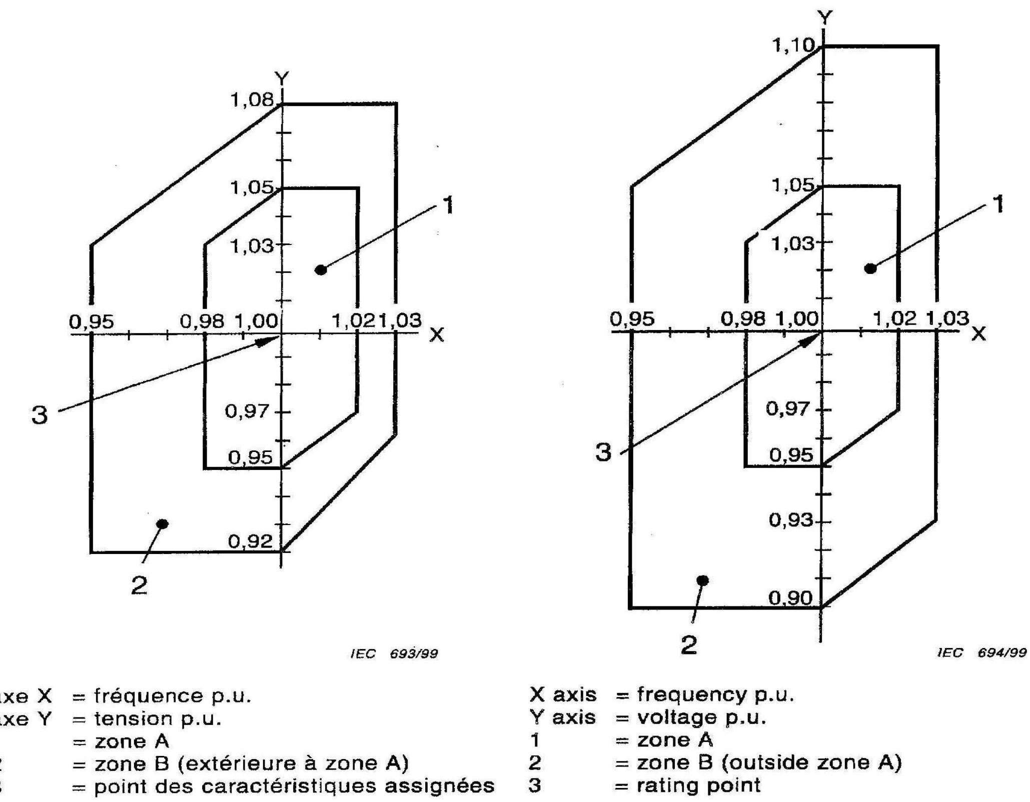

Figure B.1. Frequency range for AC machines defined by IEC 60034-1 (IEC, 1999).

IEC 600034-3 standard for turbine-type synchronous machines

IEC 60034-3 requires machines to be capable of continuous rated output at the rated power factor over the ranges of ±5% in voltage and 2% in frequency, as defined by the shaded area of **Figure B.2** (IEC, 1988). Machines will also carry output at the rated power factor within the ranges of 5% in voltage and +3% to - 5% in frequency, as defined by the outer boundary in **Figure B.2.** If operation over a larger range of voltage or frequency is required, this shall be the subject of an agreement.

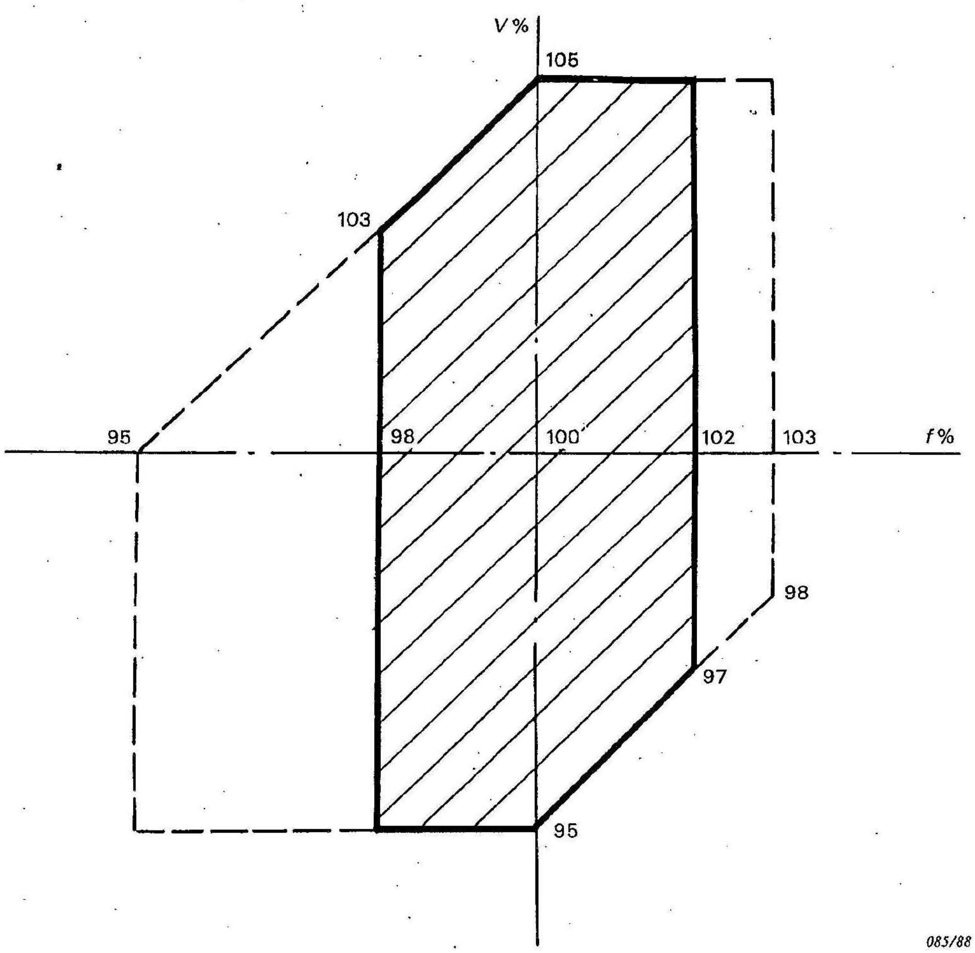

Figure B.2. Frequency range turbine type synchronous machines as defined by IEC 60034-3 (IEC, 1999).

EUROPEAN STANDARD - EN 50160

European standard EN 50160 (EN, 1999) requires the frequency on the distribution network to be in the following range for medium and low voltage networks.

The nominal frequency of the supply voltage shall be 50 Hz. Under normal operating conditions the mean value of the fundamental frequency measured over 10 s shall be within a range of:

- For systems with synchronous connection to an interconnected system:

50 Hz ± 1 %	(*i.e.* 49.5 - 50.5 Hz)	during 99.5 % of a year,
50 Hz + (4 to 6 %)	(*i.e.* 47.0 - 52.0 Hz)	during 100 % of the time.

- For systems with no synchronous connection to an interconnected system (e.g. supply systems on certain islands):

50 Hz ± 2 %	(*i.e.* 49.0 -51.0 Hz)	during 95 % of a week.
50 Hz ± 15 %	(*i.e.* 42.5 -57.5 Hz)	during 100 % of the time.

B.2.1.2 Customer standards

The section covers the standards that are relevant to manufacturers of electrical equipment. Electrical equipment connected to the AC network must be able to tolerate the frequency ranges specified in these standards.

IEEE Recommended Practice 446 : 1995

IEEE Standard 446-1995 (IEEE, 1995) indicates that the frequency deviations on connected loads vary considerably by type of load. A maximum ±0.5 Hz frequency variation is used as a tolerance for the majority of end-use equipment (on a 60Hz system). A value of 1Hz/s for the frequency rate of change is also stated.

BS EN 50160:1995 : Voltage characteristics of electricity supplied by public distribution systems.

BS EN 50160:1995 requires the nominal frequency of the supply voltage shall be 50Hz (BS, 1995). Under normal operating conditions, the main value of the fundamental frequency is measured over 10s.

Systems with synchronous connection to an interconnected system shall be within a range of:

50 Hz $\pm$1 %	(*i.e.* 49.5Hz - 50.5 Hz)	during 95% of a week
50 Hz $\pm$4%	(*i.e.* 48 Hz – 52 Hz)	during 100% of a week

IEC 61000-2-2 standard on quality of supply

IEC 61000-2-2 recommends that frequency be controlled within 1 Hz of 50 Hz (IEC, 2002).

B.2.1.3 Economic analysis of international standards

The standards require a minimum continuous frequency operation range where the electrical equipment is to operate without damage. There are other frequency ranges where the electrical equipment should be designed to operate for a short period of time without damage. The conclusions that can be drawn from this is that there is no cost to electrical plant life if the frequency is within the continuous allowable band and there might be some cost outside this range.

B.2.2 South African standards on electricity

B.2.2.1 South African electricity act

Eskom is legally required to control the frequency within the South African government's requirements as stated in the Electricity Act (RSA, 1987). The *Electricity Act, No. 41 of 1987, Regulation 9 (3),* states: "The frequency of an alternating current supply shall be 50 Hz and the deviation of the frequency shall not exceed plus or minus 2.5 per cent of 50 Hertz." This implies that the frequency must stay between 48.75 and 51.25 Hz at all times.

B.2.2.2 South African electricity quality of supply standard

The electricity industry has standards to ensure quality of supply to the customer. This is further clarified in the Electricity Act.

The National Energy Regulator of South Africa (NERSA, 1996) standard on *Electricity Supply, 1996 – Quality of Supply Standards NRS 048, Part 2, Section 4.7.1, Frequency Compatibility Levels* states:

“The standard frequency shall be 50 Hz, and the maximum deviation shall be:

a) for grid networks ±2,5% at all times,

b) for islanded networks ±5,0% at all times, and ±2,5% for 95% of the period of a week.”

The above requirements are the same, except that NRS 048 covers the event of the network being split up into separate parts called islands. Since this only occurs in extreme emergencies, the frequency limits are less stringent. Customer representatives were involved in the creation and approval of NRS 048. A draft revision of the above standard has revised these requirements and recommended that the frequency should be controlled within 2% of 50 Hz for at least 99.5% of the time for grid networks (NERSA, 2002).

B.2.2.3 South African grid connection code

The draft Southern African grid code (NERSA, 2003) requires that all generators greater than 50 MVA must be capable of continuous normal operation for the minimum operating range indicated in **Figure B.3** and as described in the sections below. Tripping times for units in the range of 47.5Hz to 48.5Hz shall be as agreed with the system operator and the following sections shall be used as guidelines for these tripping times. The design of turbo-alternator units must also enable continuous operation, at up to 100% active power output, within the ranges specified subject to the voltage limitations specified in IEC 60034-3.

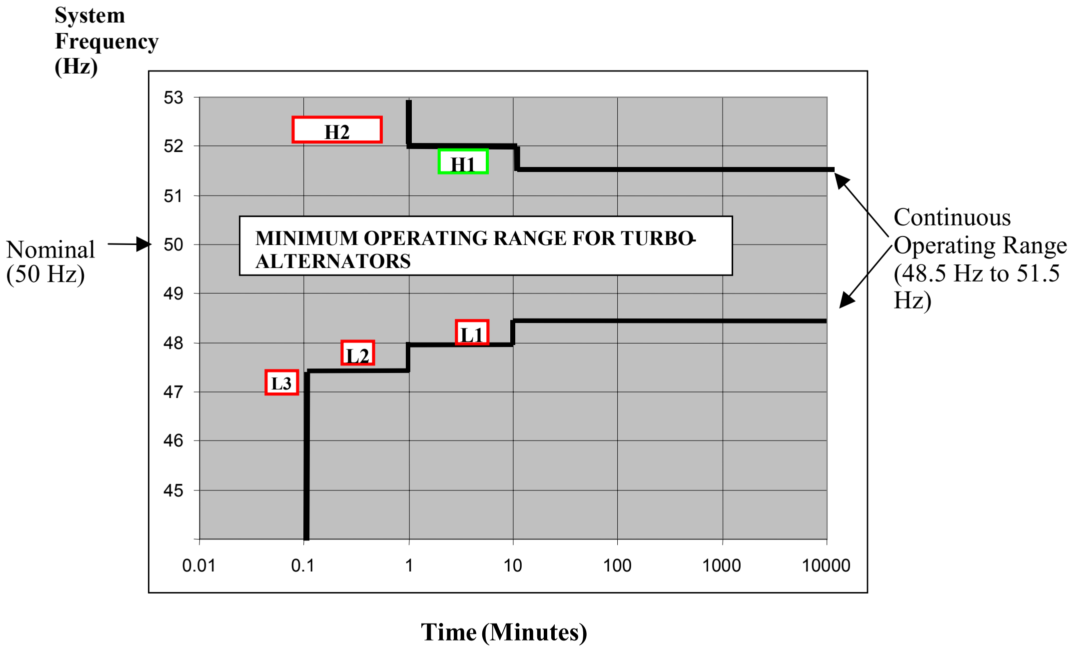

Figure B.3. Time *vs.* system frequency plot, minimum operating range of a unit (NERSA, 2003).

High frequency requirements for turbo-alternators

Over-frequency conditions in the range 51.5 to 52 Hz (Stage H1)

The unit shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes above 51.5 Hz but less than 52 Hz. If the system frequency is greater than 51.5 Hz for 1 minute and the unit is still generating power it can be islanded or tripped to protect the unit. Power stations shall stagger the tripping of the units and the philosophy for tripping shall be approved by the System Operator.

Over-frequency conditions in the range above 52 Hz (Stage H2)

The unit shall be designed to run for at least 1 minute over the life of the plant if the frequency is above 52 Hz. Hence the turbo-alternator units must be able to operate for at least 30 seconds in this range. If the system frequency is greater than 52 Hz for 10 seconds and the unit is still generating power, it can be islanded or tripped to protect the unit. Power stations shall stagger the tripping of the units and the philosophy for tripping shall be approved by the System Operator.

High frequency requirements for hydroelectric alternators

The unit shall be designed to run for at least 5 seconds over the life of the plant if the frequency goes above 54 Hz hence the turbo-alternator units must be able to operate for at least 1 second in this range. If the system frequency increases to 54 Hz for longer than 1 second the unit can be islanded or tripped to protect the unit.

Low frequency requirements for turbo-alternator units

Low frequency in the range 48.5 to 48.0 Hz (Stage L1)

The unit shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes below 48.5 Hz but greater than 48.0 Hz. The unit shall be able to operate for at least 1 minute while the frequency is in this range. If the system frequency is less than 48.5 Hz for 1 minute the unit can be islanded or tripped to protect the unit. Power stations shall stagger the tripping of the units and the philosophy for tripping shall be approved by the System Operator.

Low frequency in the range 48.0 to 47.5 Hz (Stage L2)

The unit shall be designed to run for at least 1 minute over the life of the plant if the frequency goes below 48.0 Hz but greater than 47.5 Hz. If the system frequency is less than 48.0 Hz for 10 seconds the unit can be islanded or tripped to protect the unit. Power stations shall stagger the tripping of the units and the philosophy for tripping shall be approved by the System Operator.

Low frequency below 47.5 Hz (Stage L3)

If the system frequency falls below 47.5 Hz for longer than 6 seconds the unit can be islanded or tripped to protect the unit.

Low frequency requirements for hydroelectric alternator units

All reasonable efforts shall be made by the generator to avoid tripping of the hydroelectric alternator for under-frequency conditions providing that the system frequency is above or equal to 46 Hz. If the system frequency falls below 46 Hz for more than 1 second it can be islanded or tripped to protect the unit.

B.2.2.4 Discussion on the frequency limitations in the South African grid code

Overlaps in the proposed South African grid code with existing under-frequency load-shedding schemes

The existing under-frequency load-shedding scheme was developed with a much wider range of generator operation than is now reflected in the grid code. Generator proposed trips are shown in **Figure B.4.** If the frequency falls below 48.0 Hz the frequency can settle between 48.0 Hz and the next under-frequency load-shedding level of 47.9 Hz for longer than the 10 seconds required to restore the frequency above 48.0 Hz. The result is that generators will start tripping before the full under-frequency load-shedding scheme is activated. The loss of generators whilst the frequency is at this level will cause a partial or full blackout of the network. Eskom Transmission has requested time is given to study this issue before automatic generator tripping is installed. South African generators are largely coal-fired and nuclear units and hence a total or partial blackout will take days to restore at great cost to the consumer. This was the case for the New York blackout in August 2003.

Counter to this a paper by Nelson (2003) argues that over specified grid code requirements lead to the over-design of generators and turbines with an unnecessary cost to the customer.

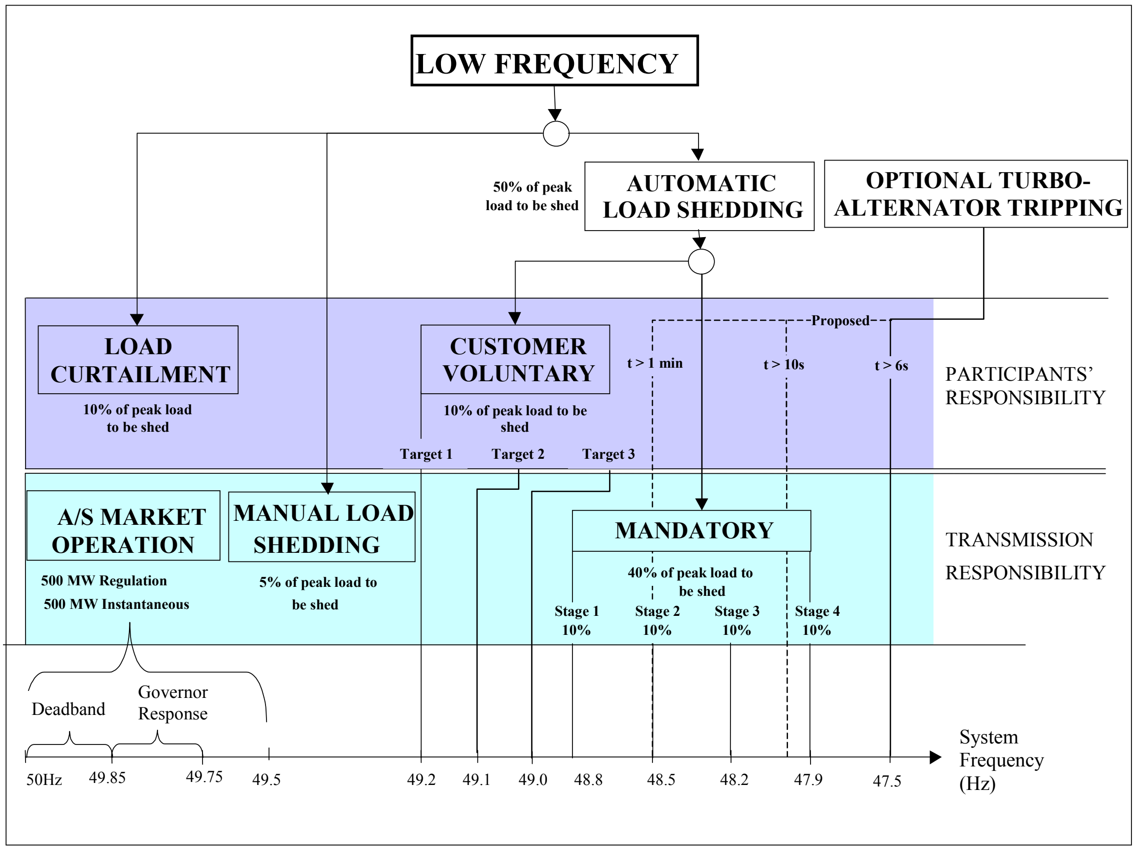

Figure B.4. Low frequency requirements as defined in the South African Grid Code (NERSA, 2003).

Appendix C : Simplified thermal model

Development of the simplified thermal model

C.1 Introduction

This appendix describes the development of a simplified model for a predominantly thermal network.

C.2 Modelling of network dynamic behaviour for a predominantly thermal network

The modelling of the network dynamic behaviour gives a better understanding of frequency changes and the factors that influence this. A simplified model for a predominantly thermal network used for this study was developed by Anderson and Mirheydar (1990) and is shown diagrammatically in **Figure C.1** below.

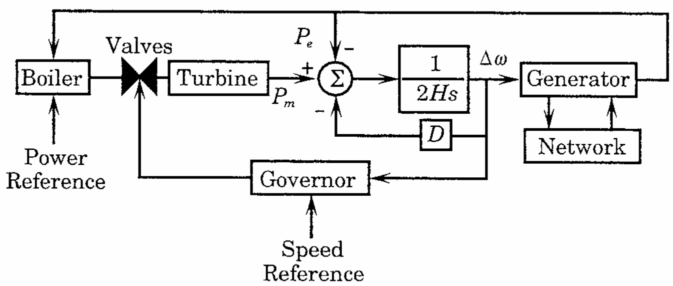

Figure C.1. Simplified model for a predominantly thermal network (Anderson and Mirheydar, 1990).

The model shows that the overall dynamic behaviour is simplified in terms of the inertia constant (H) and the damping factor (D). The output from this model is the change in speed or frequency. The “Generator block” converts the change in speed to the change in generator electrical power output (P_e). One the factors influencing the generator is the status of the network, this could be a change in voltage or angle. The model includes the response from the governor relating to the change in speed and the subsequent change in mechanical power (P_m) from the “Turbine block”. The difference between the electrical power and mechanical power results in the speed change.

Electrical power and a reference power are also fed to the boiler and can correct any imbalance in boiler output. A turbine is assumed to be to a single reheat turbine for a simplified model, this type of turbine is a popular design in many parts of the world, particularly in South Africa. A typical model for a reheat turbine is shown in **Figure C.2** below.

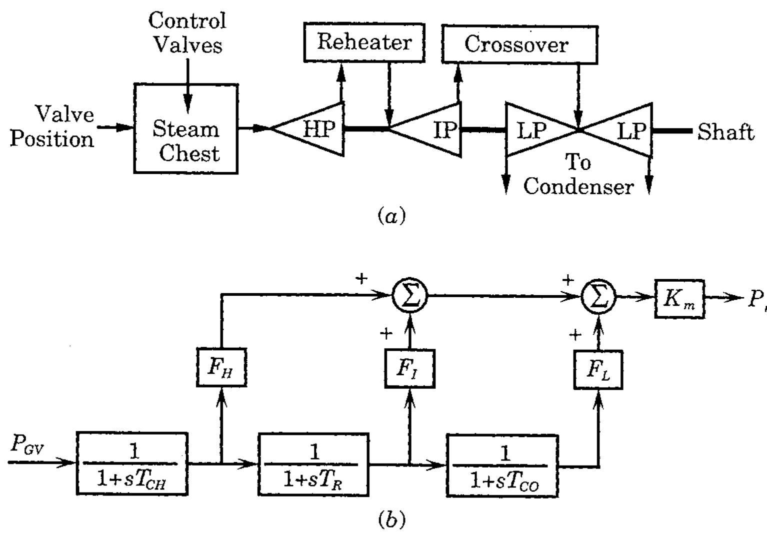

Figure C.2. Typical model for a reheat turbine unit (Anderson and Mirheydar, 1990).

The reheat time constant T_R is the predominant time constant with a typical range of 7-11s. The time constants associated with the steam chest and the crossover are very small and can be neglected for the simplified model. The fractions of total mechanical power produced by the high-pressure turbine are about 0.2 to 0.3 per unit, with the remainder produced by the intermediate and low-pressure turbine. The constant K_m is an overall gain constant and used to fine-tune the turbine model output, which is initially set to unity. The input to the turbine is the speed governor power demand, P_{GV}, which is proportional to the throttle valve area, **Figure C.3**. Speed governors have many different designs, but the model below is shown as a typical example. Again, the time constants are all quite small compared to the reheat time constant and can be neglected for the simplified model, which makes the entire forward loop gain equal to unity. Non-linearities such as mechanical deadbands, whiplash and saturation are also ignored for now.

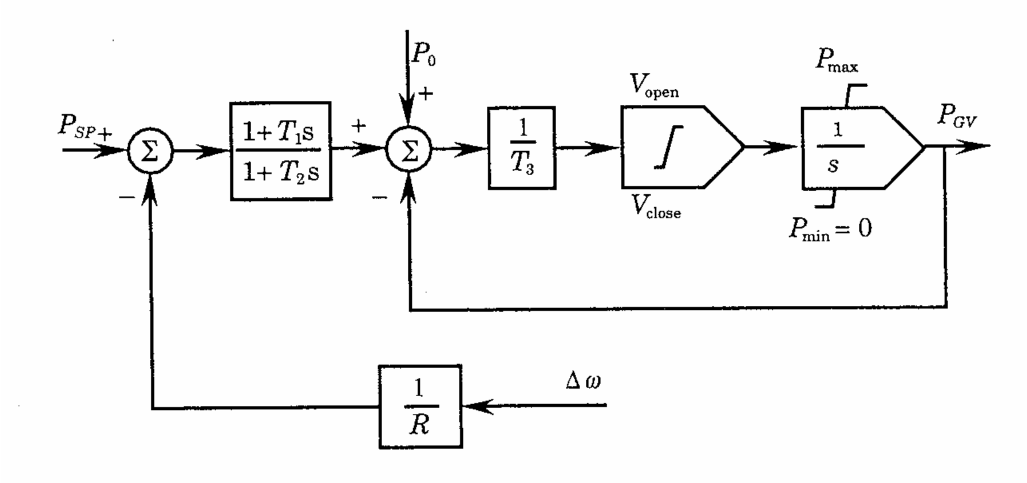

Figure C.3. Simplified model of governor controls (Anderson and Mirheydar, 1990).

The droop constant, R, is the next constant that can influence the dynamics of the model. This is commonly set to 0.05 for generators in the USA and 0.04 for generators in Europe, Australia and South Africa. The droop for the complete system cannot be assumed to be the same as individual generators as often many individual generators are at full load and cannot respond. A typical value is in the range of 0.1 to 0.12 on actual networks.

Using the above assumptions a reduced order model is obtained and shown in **Figure C.4** below, where all the parameters are in per unit on a MVA base equal to the total rating of all generators in the network.

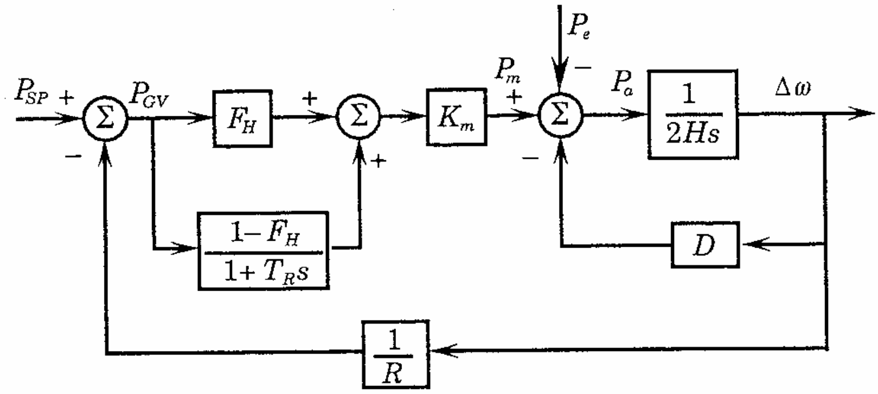

Figure C.4. Reduced model of network for a predominantly thermal system (Anderson and Mirheydar, 1990).

The system block diagram is now reduced to a forward transfer function and a feedback function. The closed loop function of the system frequency is written as follows:

$$\Delta\omega(s) = \left(\frac{R\omega_n^{\ 2}}{DR+K_m}\right)\left(\frac{K_m(1+F_H T_R s)P_{SP}(s)-(1+T_R s)P_e(s)}{s^2+2\varsigma\omega_n s+\omega_n^{\ 2}}\right) \qquad \textbf{(C.1)}$$

where

$$\omega_n^2 = \frac{DR+K_m}{2HRT_R}$$

and

$$\varsigma = \left(\frac{2HR+(DR+K_m F_H)T_R}{2(DR+K_m)}\right)\omega_n$$

ω_n is the undamped natural frequency of the system and ς is the damping factor.

The undamped natural frequency (ω_n) for a network and damping factor (ς) is hence dependent on:

1.) The damping of the network *D*, which is a function of the load that is inductive and sensitive to frequency changes. This results mainly from motor loads that change electrical power demand in response to frequency (i.e. speed) changes.

2.) The inertia of the network *H*, which is influenced by the number of generators synchronised to the network but in general, is considered as fixed for a network. For small networks it is possible to install large rotating masses which will improve the inertia on the network.

3.) The reheat time response T_R is a design of the turbine and cannot be changed.

4.) K_m is a tuning factor for making the network model realistic to the actual situation.

5.) The droop (*R*) of the generators is calculated as the average droop settings on individual generators and can influence the undamped natural frequency of the network. The influence of droop R on the undamped natural frequency and the percentage overshoot which is determined by the damping factor is shown in the graphs below (**Figure C.5, Figure C.6, Figure C.7, and Figure C.8**) for typical values of the other constants.

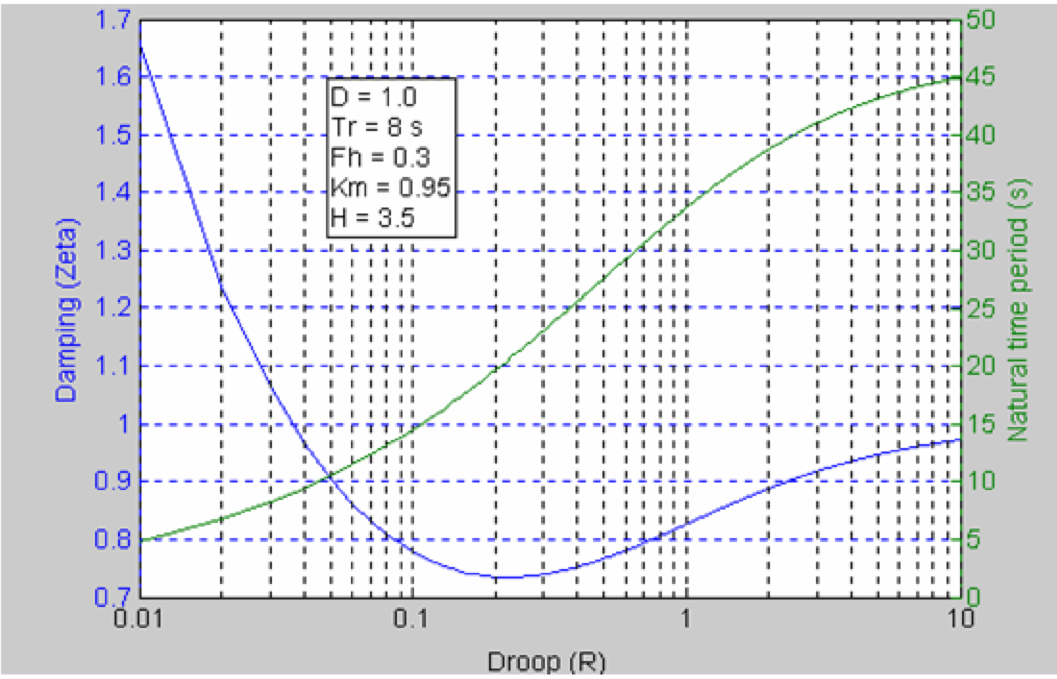

Figure C.5. Damping and natural frequency for reduced thermal model.

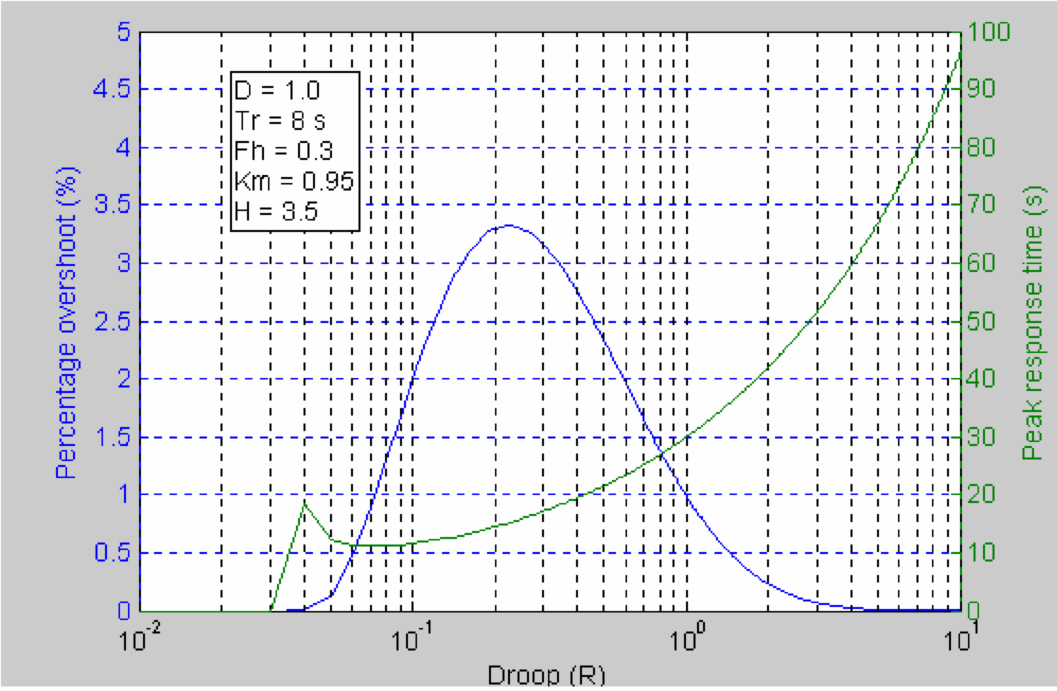

Figure C.6. Percentage overshoot and peak response time for reduced thermal model.

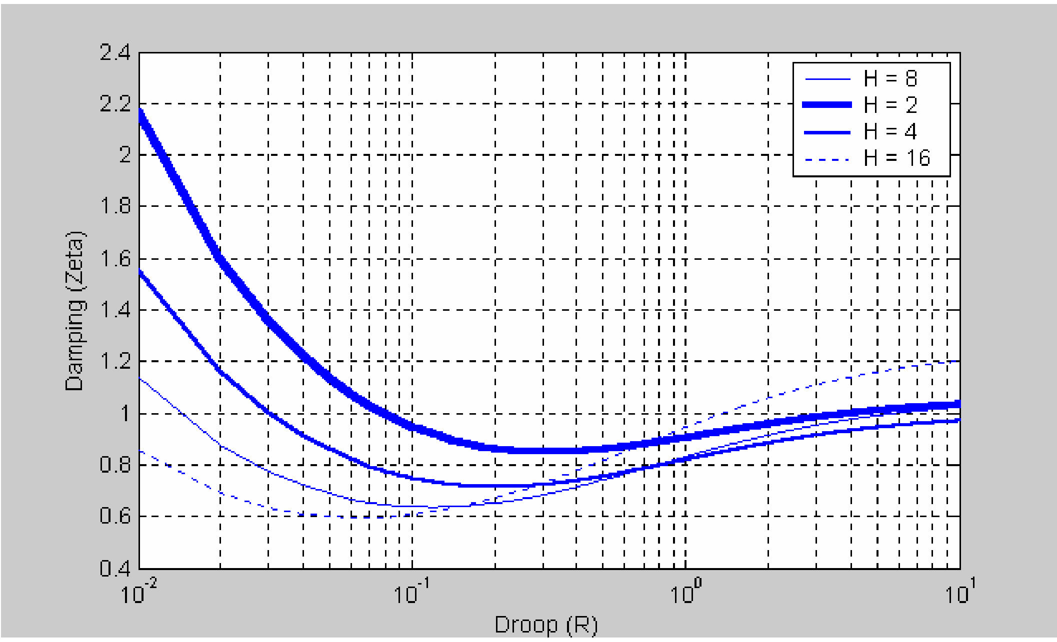

Figure C.7. Damping for different values of droop.

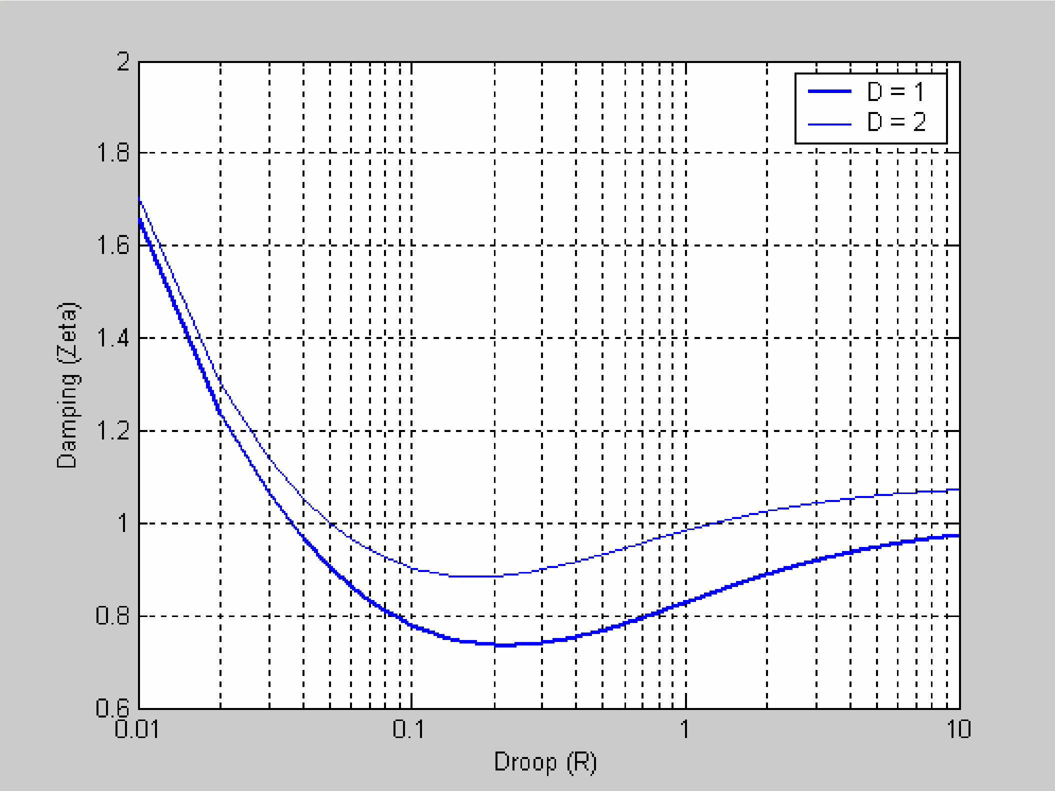

Figure C.8. Damping for different values of induction motor response.

The set point, $P_{SP,}$ is either constant or is changed by a central dispatch for the network. This is typically only updated every 4 seconds or more and for the purpose of the initial analysis, it is assumed to be constant. We can also now define the disturbance, P_d, as:

$$P_d = -P_e$$

where a negative value of P_d corresponds to a load increase. With this change, the model is changed as in **Figure C.9.**

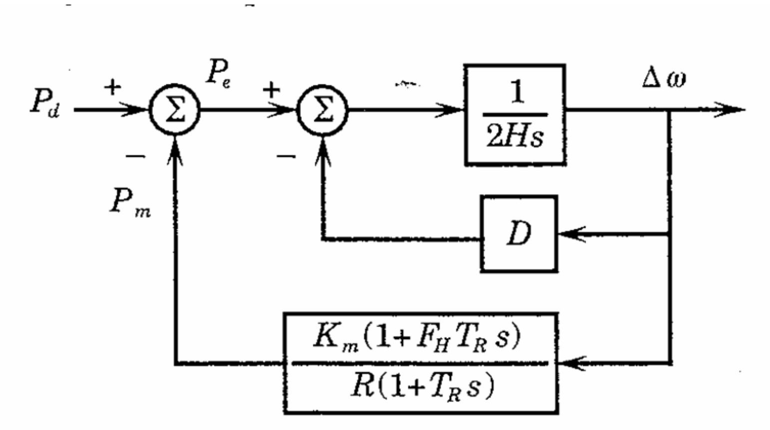

Figure C.9. Simplified model with disturbance *P_d* (Anderson and Mirheydar, 1990).

For this system the model is stated as:

$$\Delta\omega = \left(\frac{R\omega_n^{\,2}}{DR + K_m}\right)\left(\frac{(1+T_R s)P_d(s)}{s^2 + 2\varsigma\omega_n s + \omega_n^{\,2}}\right) \tag{C.2}$$

C.3 Development of simplified model for frequency control analysis

This section develops a simplified model that is used to determine the minimum control for frequency. The model is developed in Matlab© from first principles and then is developed to cater for the Eskom network as an example of the type of modelling required to determine the minimum control. When there is a sudden change in demand or supply introduced to a network the frequency does not change immediately. The effect of a generator tripping is the same as putting the brakes on a moving car. The other generators start to decelerate and the rate of deceleration is determined mainly by the inertia in the network at the time. The rate of the deceleration of the generators results in the frequency dropping at the same rate assuming that the generators remain in synchronization with no pole slipping. This section determines from engineering principles the calculation of the rate of change of frequency in a network, the turning point of the frequency and the settling point of the frequency. This is an important factor when deciding the methods to be used for controlling the frequency as will be seen later. A simplified model is developed from these engineering principles. The simplified model is compared to real data measured in the Southern African network and the model is refined so that it can be used to determine the turning and settling frequency for a predominantly coal-fired network. The refined simplified model is then compared to a full model of the Southern African network developed for dynamic studies.

C.3.1 Stability

Power System stability is defined as the condition in which the various synchronous machines of the system remain in synchronism, or in step with each other. Conversely, instability defines the state in the system involving the loss of synchronisation. In a very simple system with one motor and one generator it can be shown that (Kimbark, 1995):

$$E_G = E_M + jXI \quad \textbf{(C.3)}$$

E_G is the internal voltage of the generator, E_M is the internal voltage of the motor, X is the total reactance of the system = sum of the reactance of the generator, line and motor, and I is the current.

The power out of the generator, also the power input of the motor as the line resistance is very low, is:

$$P = \mathrm{Re}(\overline{E}_G I) \quad \textbf{(C.4)}$$

where Re denotes real and $\overline{E}_G$ means the conjugate of E_G. This is further written as:

$$P = (E_G E_M / X)\sin\delta \quad \textbf{(C.5)}$$

where δ is the displacement angle between generator and motor rotors.

Equation C.5 shows that the power transmitted from the generator to the motor depends on the sine of the displacement angle, δ. The maximum power will flow when the displacement angle δ is 90°. The system is stable when the displacement angle δ rate of change is positive, that is when δ is between –90 and +90°. When the system is operating at steady state the mechanical input of the generator is equal to the mechanical output of the motor (ignoring the losses). If a small increment is added to the mechanical output of the motor shaft then, momentarily, the angular position of the motor with respect to the generator and therefore the power input to the motor is unchanged. But, the motor torque has been increased, therefore the net torque on the motor will tend to slow the motor down. As a result, the angle δ will increase and consequently the power input is increased until equilibrium is reached. This is only true if the speed of the generator is assumed to remain constant. Actually, the generator often has a governor that will increase the power output as the speed of the system decreases and balance the system in this way.

C.3.2 Swing Equation

The swing equation is used to relate the motion of the generator rotor or the turning of the generator relating the inertia in this to electrical and mechanical torque (Anderson and Fouad, 1993):

$$J\ddot{\theta} = T_a \text{ N.m} \quad \textbf{(C.6)}$$

where J is the moment of inertia in kg.m^2 of all rotating masses attached to the shaft, θ is the mechnical angle of the shaft with respect to a fixed reference and T_a is the accelerating torque in N.m acting on the shaft. Since this is a generator, the driving torque T_m is the mechanical torque and the retarding torque or load T_e is electrical, see **Figure C.10**.

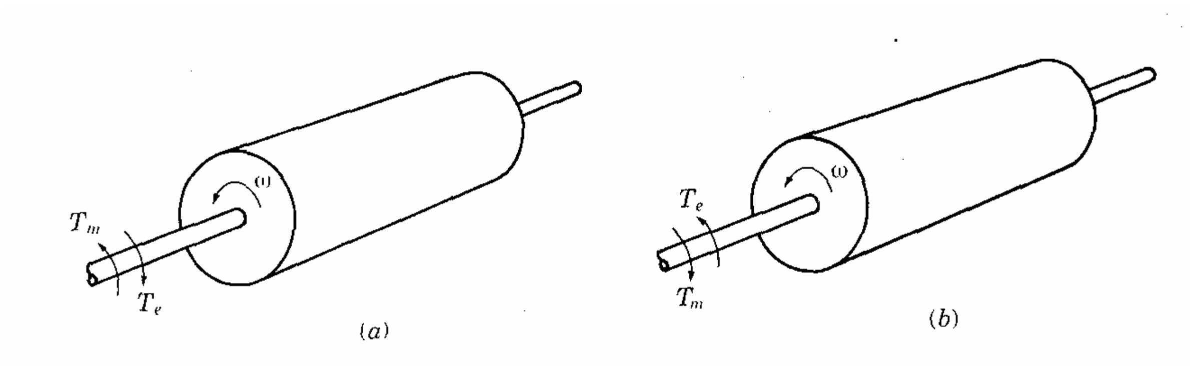

Figure C.10. Mechanical Rotor showing the the driving torque T_m is the mechanical torque and the retarding torque or load T_e for (a) a Generator and (b) a Motor.

Thus we write:

$$T_a = T_m - T_e \text{ N.m} \tag{C.7}$$

The angular reference may be expressed in terms of the machine angular velocity ω_m

$$\mathrm{J}\dot{\omega}_m = T_a \text{ N.m} \tag{C.8}$$

The angular reference may be chosen relative to asynchronously rotating reference frame moving with constant velocity (ω_R):

$$\theta = (\omega_R t + \alpha) + \delta_m \text{ rad} \tag{C.9}$$

Where α is a constant. The angle α is needed if δ_m is measured from an axis different from the angular reference frame.

Converting torque to power by multiplying by the angular velocity ω_m we have

$$\mathrm{J}\dot{\omega}_m \omega_m = P_m - P_e \text{ W} \tag{C.10}$$

$J\omega_m$ is called the inertia constant, M, and is also called the Angular Momentum. It is related to the kinetic energy of the rotating mass W_k, where W_k = (1/2) $J\ \omega_m^2$ joules.

$$M = J\omega_m = 2W_k / \omega_m \text{ J.s} \tag{C.11}$$

M is deemed a constant, as ω_m for most networks does not vary more than 1 – 2 % even under transient conditions.

The inertia (H) is often unitised for simulation studies where

$$H = W_k / S_{B3} \text{ s} \tag{C.12}$$

S_{B3}= rated three phase MVA of the system.

Also

$$H = J\omega_m^{\ 2} / 2\,S_{B3} \text{ s} \tag{C.13}$$

The design of motor or generator will affect the inertia that it provides to the network, as this is directly proportional to the speed and mass of the rotor. Some generators have speeds of 3000 RPM for a 50 Hz network (3600 for a 60 Hz network); some 1500 rpm and hydroelectric generators can be as low as 80 rpm. A slow turning generator of equal mass and radius will have a lower inertia, see **Figure C.11** and **Figure C.12.**

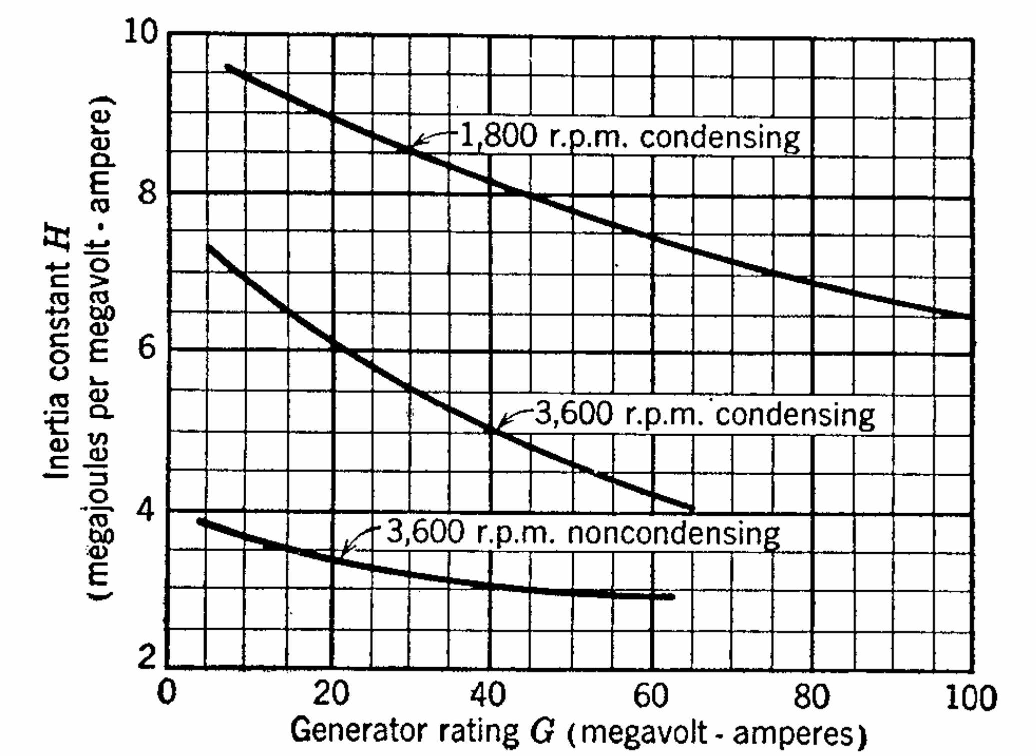

Figure C.11. Typical values of inertia constant for large steam generators including the turbine for a 60 Hz network (Kimbark, 1995).

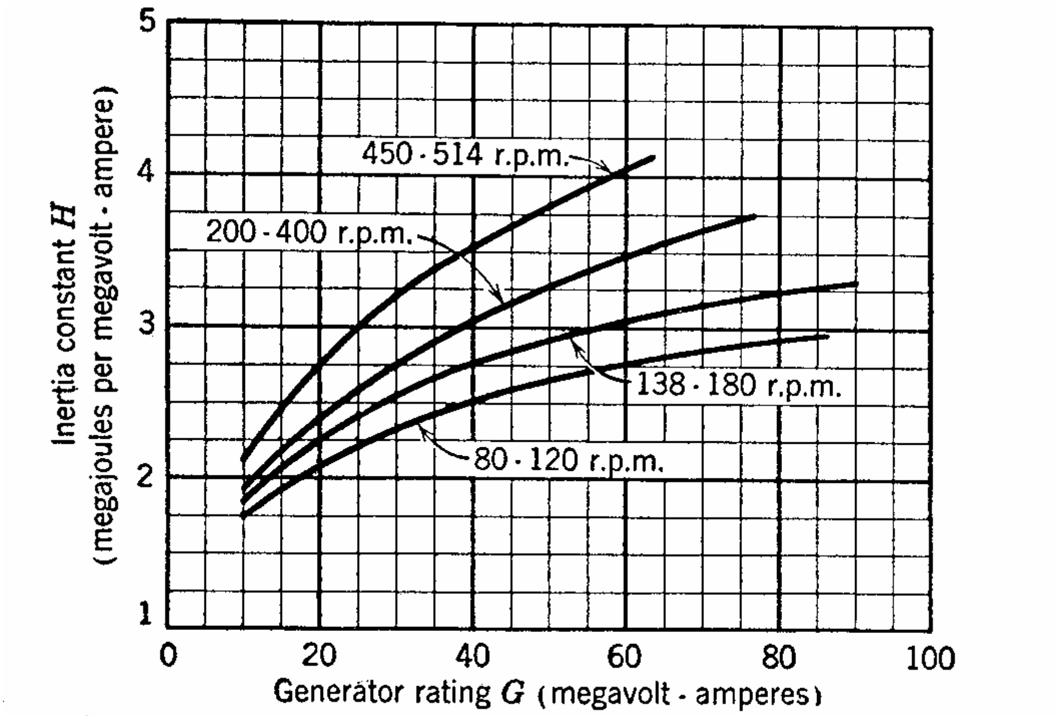

Figure C.12. Typical values of inertia constant for large vertical type hydroelectric generators for a 60 Hz network (Kimbark, 1995).

The rate of change of the frequency is determined by taking the differential of the rate of change of speed (ω) which is identified by the **Equation C.15:**

$$J\dot{\omega}_m = T_a \quad \textbf{(C.14)}$$

$$\dot{\omega}_m = T_a / 2H \quad \textbf{(C.15)}$$

From **Equation C.15** it is determined that the maximum rate of change of speed is when T_a is at the maximum, which is at the time when sudden change is initiated.

The cost of improving the inertia is calculated as the cost running an additional generator or purchasing some specialised devices to allow more time for control:

$$Cost_{inertia} = \cos t_{additional\_generation} + \cos t_{special\_devices}$$

C.3.3 Empirical Methods for calculating network inertia

Network inertia can be calculated from empirical data measured when there is a sudden change to the generation or load using the following equation for a 50 Hz network:

$$\frac{d}{dt}(f_r) = \left(\frac{50}{2H}\right)\Delta P \text{ in } Hz/\sec \qquad \textbf{(C.16)}$$

where ΔP is the per unit change in power.

The calculation from measured data needs to be done at the beginning of the sudden change before any generator action or any under-frequency load-shedding. The time constants of the frequency measurement device can influence the rate of change measurement and the measured data can be averaged by the instrument time constants and give a slower rate of change. A large frequency incident recorded in Eskom is shown in **Figure C.13** and rate of change over 100 ms is shown in **Figure** C.14**.**

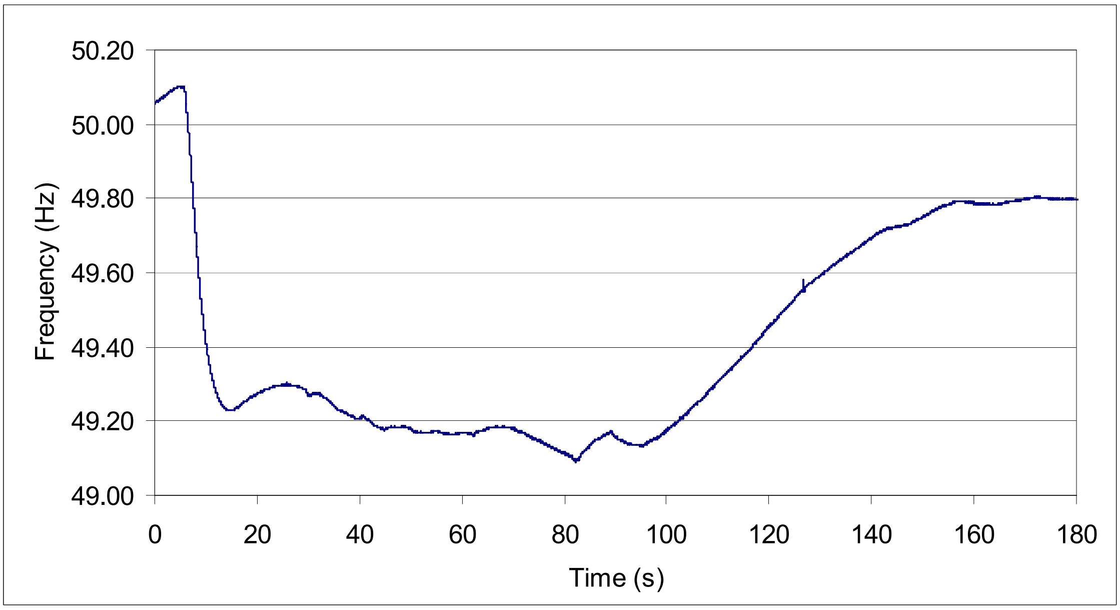

Figure C.13. Loss of 2760 MW from two power stations on 25 June 2003 at 16:30.

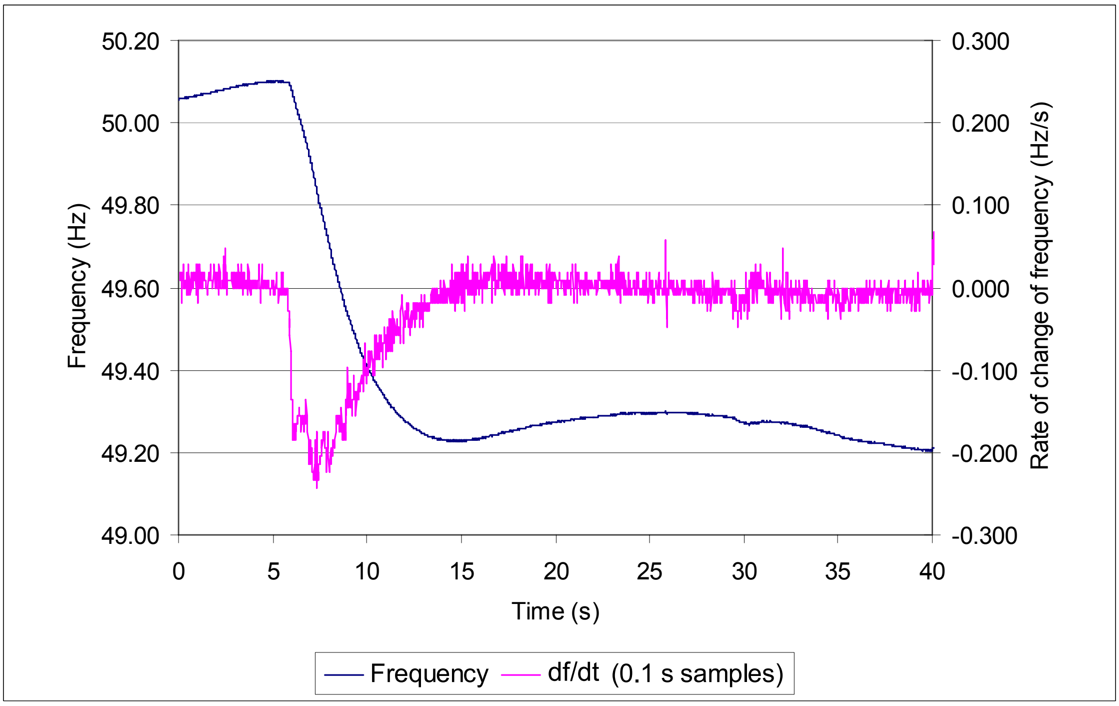

Figure C.14. Frequency and rate of change of frequency for loss of generation on 25 June 2003 at 16:30.

The total demand at the time of the trip was 30 000 MW and the rate of frequency drop at the time was measured as 0.225 Hz per second. The initial loss was an 1845 MW trip followed by the remaining trip of 915 MW ramping down 10 seconds later and finished 60 seconds after the initial trip.

$$H = \left(\frac{50}{2}\right)\Delta P / \frac{d}{dt}(f_r) \qquad \textbf{(C.17)}$$

$$H = \left(\frac{50}{2}\right)(1854/30000)/0.225 = 6.86 \qquad \textbf{(C.18)}$$

for a 40 000 MVA base

$$H = (30000/40000) * 6.86 = 5.15 \qquad \textbf{(C.19)}$$

This value of *H* is higher than the mathematically calculated equivalent *H* for the Eskom system with a 40 000 MVA base of *H* = 3.6 determined by PSS/e. The effect of the error, or change, in *H* on frequency is presented further in the next section of this appendix.

C.3.4 Modelling of network dynamic behaviour for a predominantly thermal network

A simplified model of a predominantly thermal network is developed in **Appendix C1** and shown graphically in **Figure C.9.**

For this system the model is stated as follows (Anderson and Mirheydar, 1990)

$$\Delta\omega = \left(\frac{R\omega_n^{\ 2}}{DR + K_m}\right)\left(\frac{(1 + T_R s)P_d(s)}{s^2 + 2\varsigma\omega_n s + \omega_n^{\ 2}}\right) \qquad \textbf{(C.20)}$$

where

$$\omega_n^2 = \frac{DR + K_m}{2HRT_R}$$

and

$$\varsigma = \left(\frac{2HR + (DR + K_m F_H)T_R}{2(DR + K_m)}\right)\omega_n$$

ω_n is the system undamped natural frequency and ς is the damping factor.

The per unit speed or frequency can be calculated for any P_d.

For sudden disturbances, large or small, we are usually interested in the disturbance power in terms of a step.

$$P_d(t) = P_{step}u(t) \qquad \textbf{(C.21)}$$

where P_{step} is the disturbance magnitude in per unit based on the system base MVA.

In Laplace domain this is written as:

$$P_d(s) = \frac{P_{step}}{s} \qquad \textbf{(C.22)}$$

As a result the change in speed or frequency is written as:

$$\Delta\omega = \left(\frac{R\omega_n^{\ 2}}{DR + K_m}\right)\left(\frac{(1+T_R s)P_{step}(s)}{s(s^2 + 2\varsigma\omega_n s + \omega_n^{\ 2})}\right) \qquad \textbf{(C.23)}$$

This is written in the time domain as:

$$\Delta\omega(t) = \left(\frac{RP_{step}}{DR + K_m}\right)\left(1 + ae^{-\tau\omega_n t}\sin(\omega_r t + \phi)\right) \qquad \textbf{(C.24)}$$

where

$$a = \sqrt{\frac{1 - 2T_R\varsigma\omega_n + T_R^2\omega_n^2}{1-\varsigma^2}}$$

and

$$\omega_r = \omega_n\sqrt{1-\varsigma^2}$$

and

$$\phi = \tan^{-1}\left(\frac{\omega_r T_R}{1-\varsigma\omega_n T_R}\right) - \tan^{-1}\left(\frac{\sqrt{1-\varsigma^2}}{-\varsigma}\right)$$

the slope of the frequency response is written as:

$$\frac{d\Delta\omega(t)}{dt} = \left(\frac{a\omega_n RP_{step}}{DR + K_m}\right)e^{-\varsigma\omega_n t}\left(\sin(\omega_r t + \phi_1)\right) \qquad \textbf{(C.25)}$$

where

$$\phi_1 = \tan^{-1}\left(\frac{\omega_r T_R}{1-\varsigma\omega_n T_R}\right)$$

The two times of interest for this equation are when t=0, this will give us the initial slope or rate of change of the frequency and the time when the slope is zero which will give the maximum deviation of the frequency.

At t=0

$$\left.\frac{d\Delta\omega(t)}{dt}\right|_{t=0} = \left(\frac{a\omega_n RP_{step}}{DR+K_m}\right)(\sin(\phi_1)) = \frac{P_{step}}{2H} \qquad \textbf{(C.26)}$$

for

$$\frac{d\Delta\omega(t)}{dt} = 0$$
$$0 = \left(\frac{a\omega_n RP_{step}}{DR+K_m}\right)e^{-\varsigma\omega_n t}\left(\sin(\omega_r t+\phi_1)\right) \qquad \textbf{(C.27)}$$

this equation is satisfied when

$$\omega_r t + \phi_1 = n\pi$$

n is an integer and can be zero. If the time that this happens is tz then:

$$t_z = \frac{n\pi - \phi_1}{\omega_r} = \frac{1}{\omega_r}\tan^{-1}\left(\frac{\omega_r T_R}{\varsigma\omega_n - 1}\right)$$

It is hence seen that the initial slope of the frequency is dependant on the size of the disturbance. P_{step} and the time of the lowest frequency is not dependant on the size of the disturbance.

The droop *R* is critical to determine the settling point for the classical model and this is calculated as:

$$\Delta\omega_{ss} = \frac{RP_{step}}{DR+K_m} \qquad \textbf{(C.28)}$$

The settling point is also proportional to the size of the disturbance P_{step}.

The effect of each of the parameters is discussed in the next sections.

C.3.5 Developing the simplified model for Eskom network

Using existing data, parameters can be estimated for the inertia constant (H) and effective droop (R) measured on the Eskom network. Matlab© Non-linear Control Design (NCD) toolbox was used to estimate the parameters, **Figure C.15.** The simplified model was tuned for a 1000 MW trip measured on September 2002. The target frequency was set to the bounds of the actual frequency and the tuning parameters were set to H and R, **Figure C.16.**

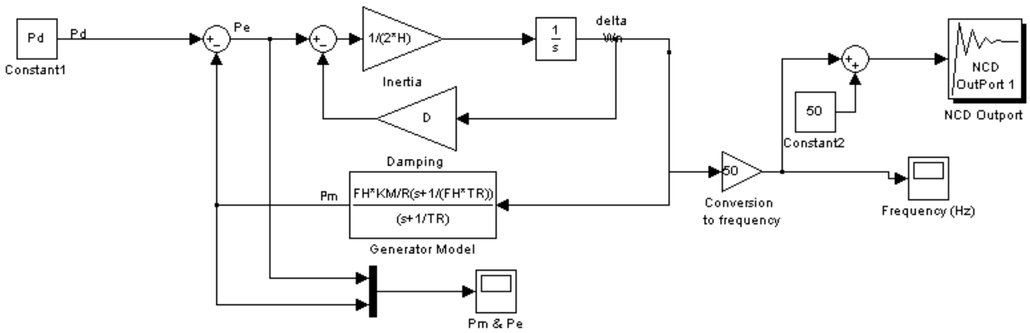

Figure C.15. Simplified model with NCD toolbox set to measure frequency.

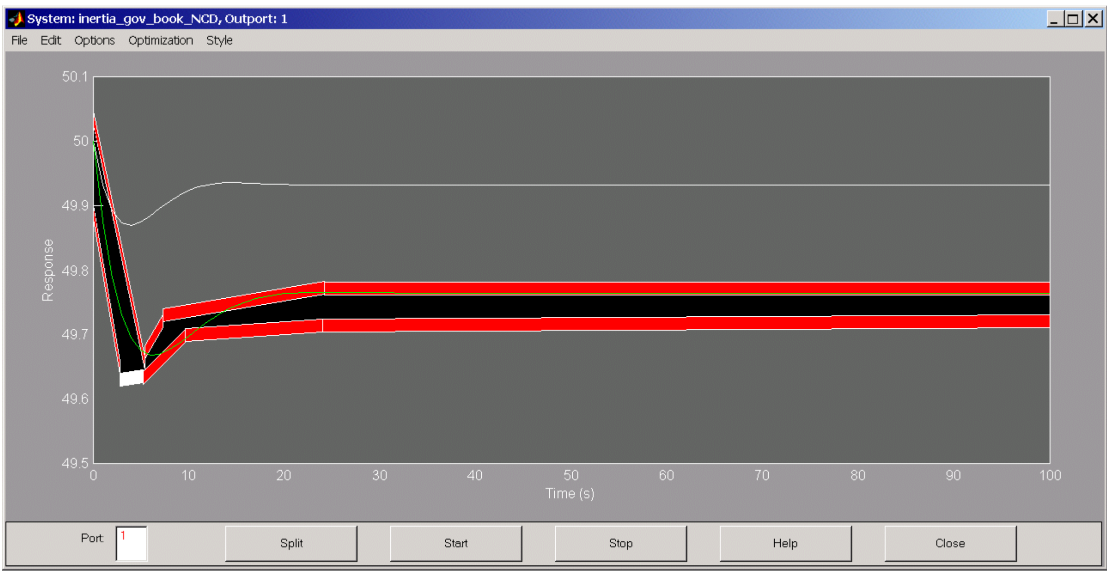

Figure C.16. NCD toolbox boundaries and frequency.

The white line on **Figure C.16.** represents the start of the optimisation with droop R set as 4% and inertia H set to 5.0 s. The green line represents the frequency after NCD toolbox had optimised values of R and H to meet the predefined frequency boundary (shown in red). The estimated value for the droop R was 18.7% and the inertia constant H was 5.7 s for a 30 000 MW base. The measured value of H in **Section C.3.3** was 6.86. If a value of H = 6.86 is used then the error in the frequency is 0.005 Hz, **Figure C.17.** The effect of the error is negligible, as this is less than the accuracy of the measurement of frequency of 0.01 Hz. For the simulation Fh=0.3, Tr=8.0 s, Km=0.95, and D=2.0.

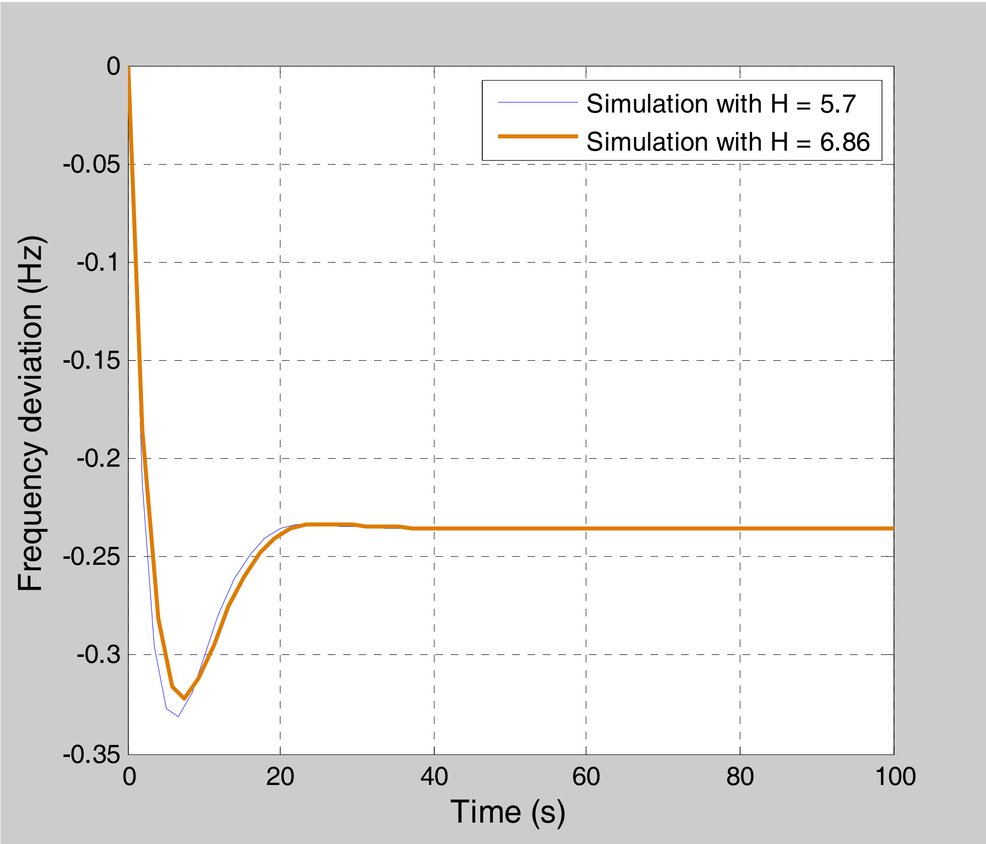

Figure C.17. Effect on the frequency for calculated inertia *vs.* estimated inertia.

The values obtained from the NCD estimation was used to simulate a 600 MW and an 1800 MW trip to check the validity of this simplified model for more cases **Figure C.18.**

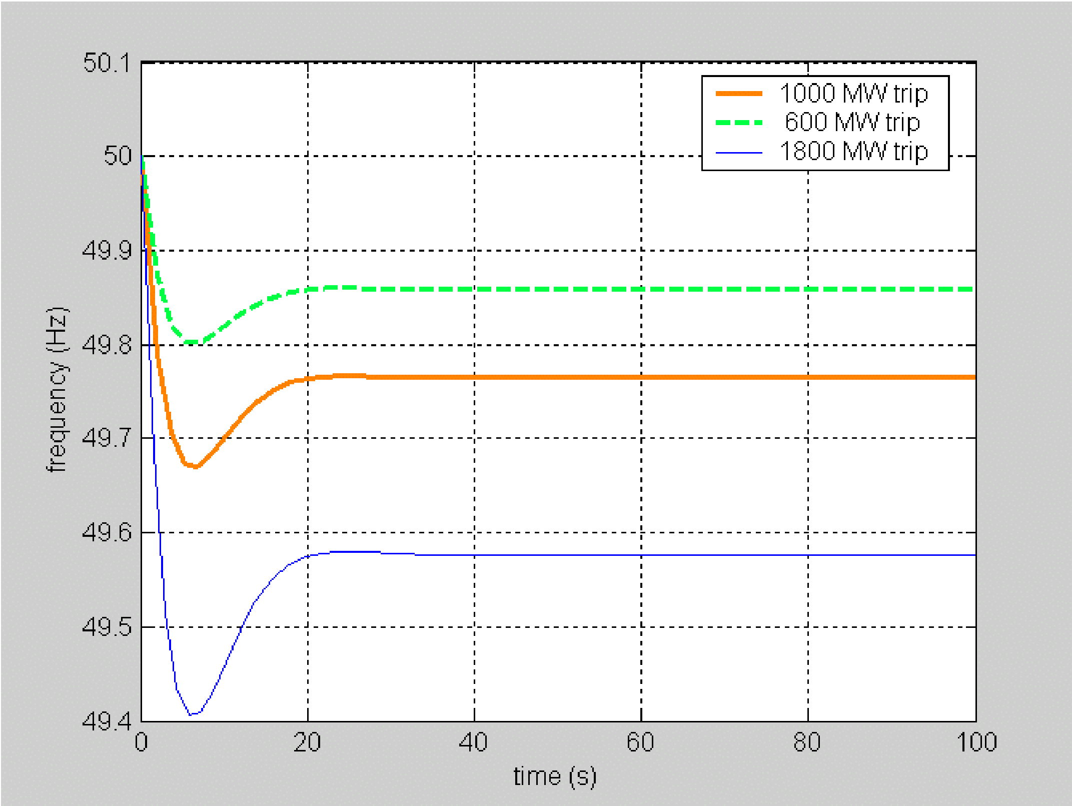

Figure C.18. Simulation of 600, 1000 and 1800 MW trip on the modified model without a limitation of response.

For the 600 MW trip the frequency was predicted to turn at 49.8 Hz and settle at 49.85 Hz. In reality the frequency turned at 49.73 Hz and settled at 49.83 Hz, **Figure** C.21 The model is hence conservative and has an error of 0.07 HZ. There have not been many 1800 trips to validate the model. However, the initial trip in 25 June 2003 was 1800 MW was 49.25 Hz and an initial settling frequency of 49.3 Hz, **Figure C.22.** The simplified model shows a turning frequency of 49.4 Hz and a settling frequency of 49.58 Hz. The simplified model results have an error of between 0.15 to 0.28 Hz than actual depending on the size of the trip. The simplified model is hence only valid around the point of tuning the parameters. One of the reasons for the error is the non-linear response from generators. This is explored in more detail in the next section.

C.3.6 Non-linear governor response

The governor droop response of the network that has been modelled as a constant in the simplified models above is often not true. The previous sections have noted that the overall response of the droop, R, of the network is increased when there are generators that do not respond, to approximate the network. It is known that the response of thermal generation is limited and hence the response of the governing is limited by introducing a saturation limiter as shown in **Figure C.19.** The upper limit can be set to a reserve level which can be adjusted to determine an economic acceptable limit. The higher the reserve the more generators are running at non-optimal points and the higher the costs due to start-up and running of extra generators. Also the response is limited by the stored energy in the boiler and condenser. The conversion from thermal fuel to electrical energy is typically 90 to 300 seconds and is much slower than the 5 – 10 seconds required for direct frequency control. As presented in **Chapter 6** it might be economically advantageous to have an area where there is no response from the generator for governing. A deadband is hence added to the model. **Figure C.19.** below shows the model of the generator with a deadband.

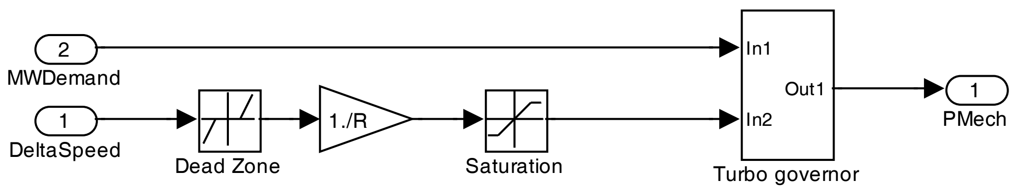

Figure C.19. Model of governor response limitation and a deadband.

The values for the droop R is set to 4% and inertia H is set to 5 s (base of 30 000 MVA). The typical response from generators is 580 MW and the deadband for the case under review is 0.15 Hz. The simulation of 1000 MW trip is close to the base case of the trip 11 September 2002, **Figure C.20.**

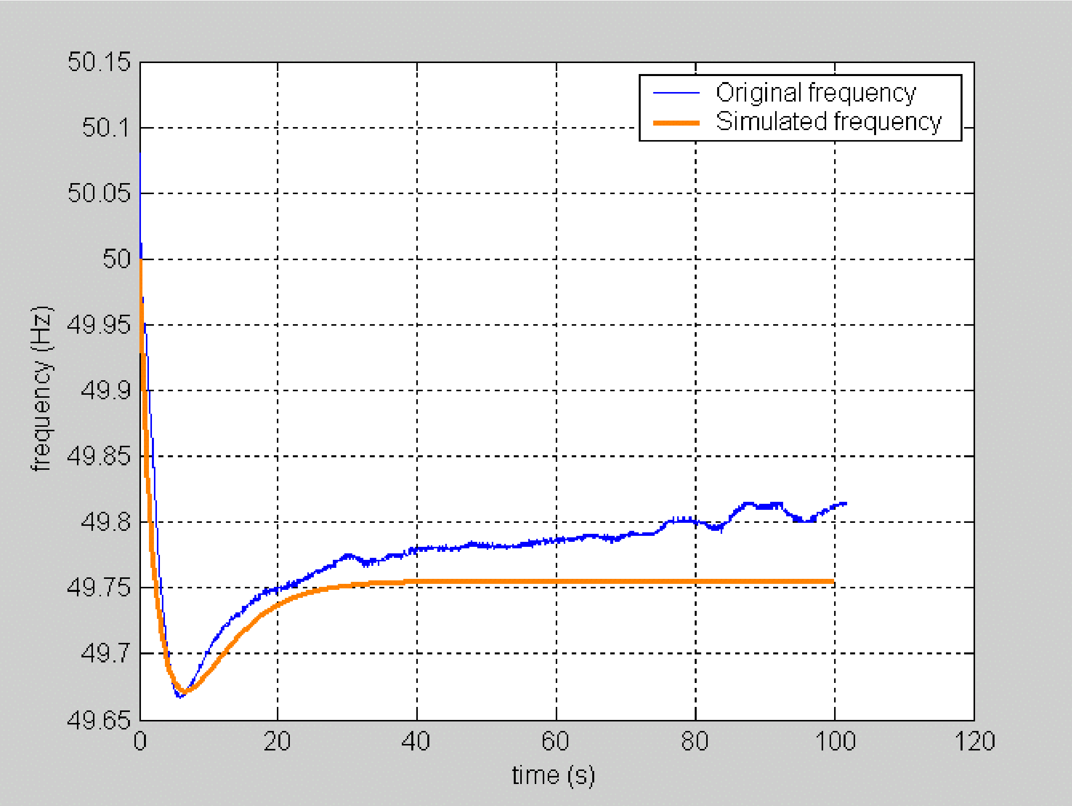

Figure C.20. Simulated 1000 MW trip *vs.* actual trip on 11 Sept 2002.

The simulated values for a 600 MW trip and an 1800 MW trip are shown in **Figure** C.21 and **Figure C.22** for the simplified model with response limitation and a governor deadband. For the 600 MW trip the frequency is predicted to turn at 49.8 Hz and settle at 49.83 Hz. In reality the frequency turns at 49.73 Hz and settles at 49.83 Hz, **Figure C.21**. The model is hence conservative and has an error of 0.07 Hz at the turning frequency. For an 1800 MW trip using the initial trip in June 2003 that was 1800 MW, **Figure C.22**, the turning frequency was 49.25 Hz and the initial settling frequency was 49.3 Hz. The simplified model shows a turning frequency of 49.27 Hz and a settling frequency of 49.32 Hz. The simplified model results have an error of 0.02 Hz compared to actual results. This model is more accurate than the textbook simplified model, Error! Reference source not found., without adding too much complexity for predicting the turning frequency and settling frequency following a disturbance.

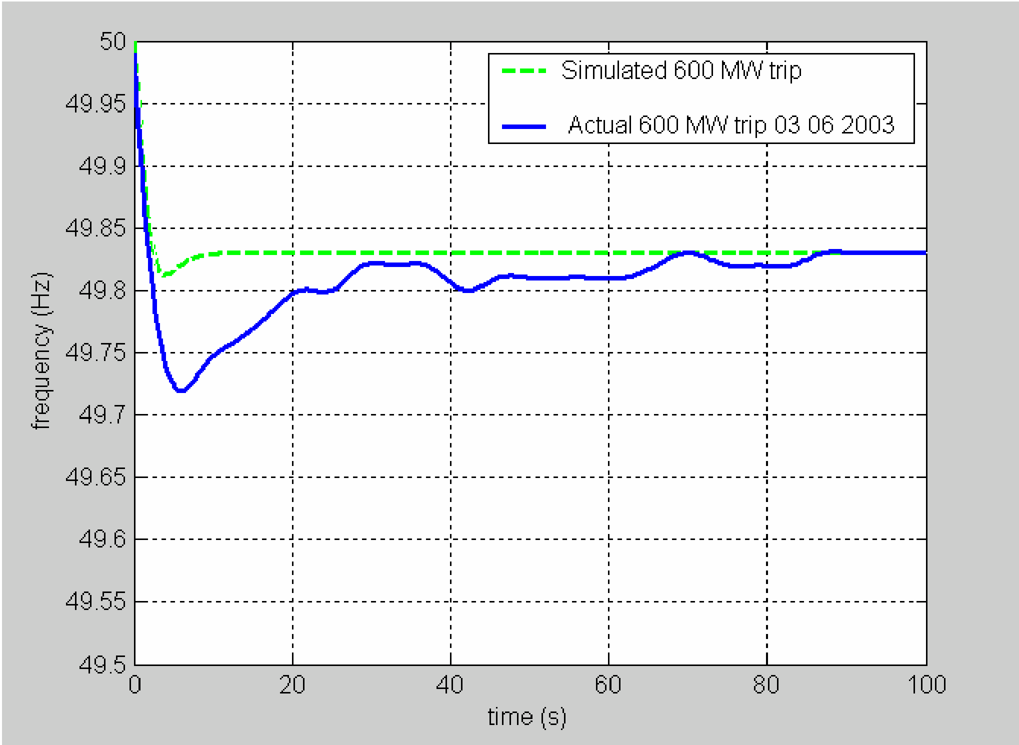

Figure C.21. Simulated 600 MW trip *vs.* actual trip on 3 July 2003.

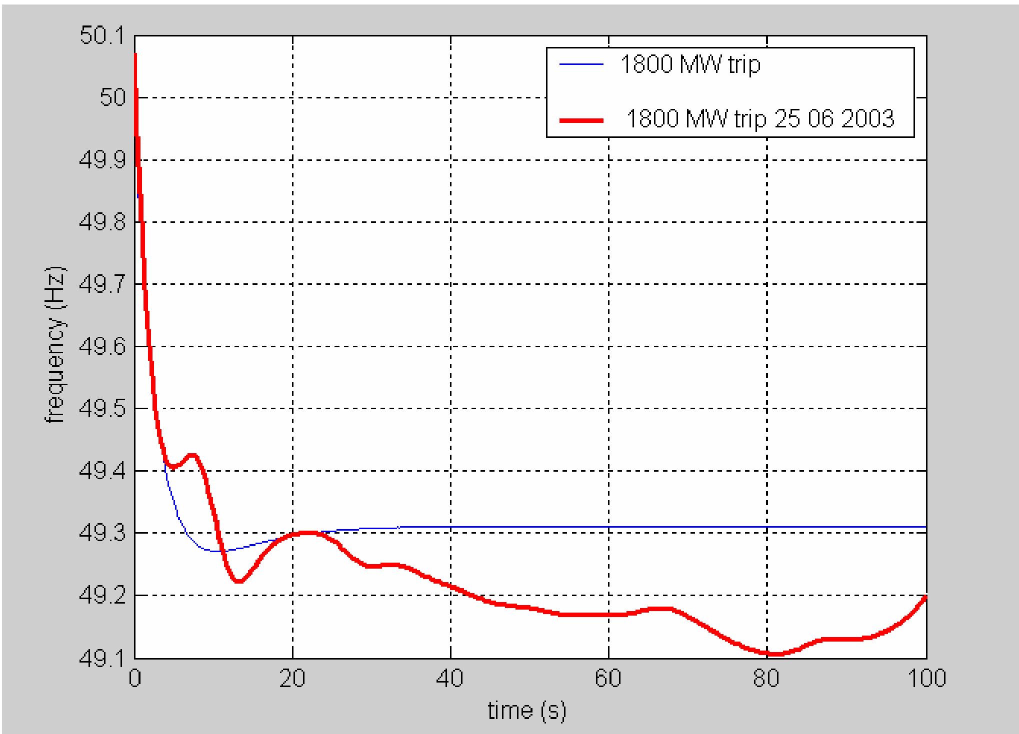

Figure C.22. Simulated 1800 MW trip *vs.* actual trip on 25 June 2003.

C.3.7 Comparison of Matlab© model with limiter with PSS/e© model of SAPP

The purpose for comparing the results to the PSS/e© model, which has the full network model, is PSS/e© can be used to determine voltage collapse, and transmission dynamic and thermal constraints. The next section covers this in more detail. The PSS/e© model is checked for accuracy as it only has predefined models with no governor deadband or governor limiting facility that has now been installed in the Matlab© model. A description of the PSS/e© model developed for SAPP is presented in **Appendix D**.

C.3.7.1 PSS/e© Model Results for a 1000 MW trip

Figure C.23 shows the comparison of the SAPP system frequency for the loss of 1000 MW of generation for the three load models discussed in the sections above.

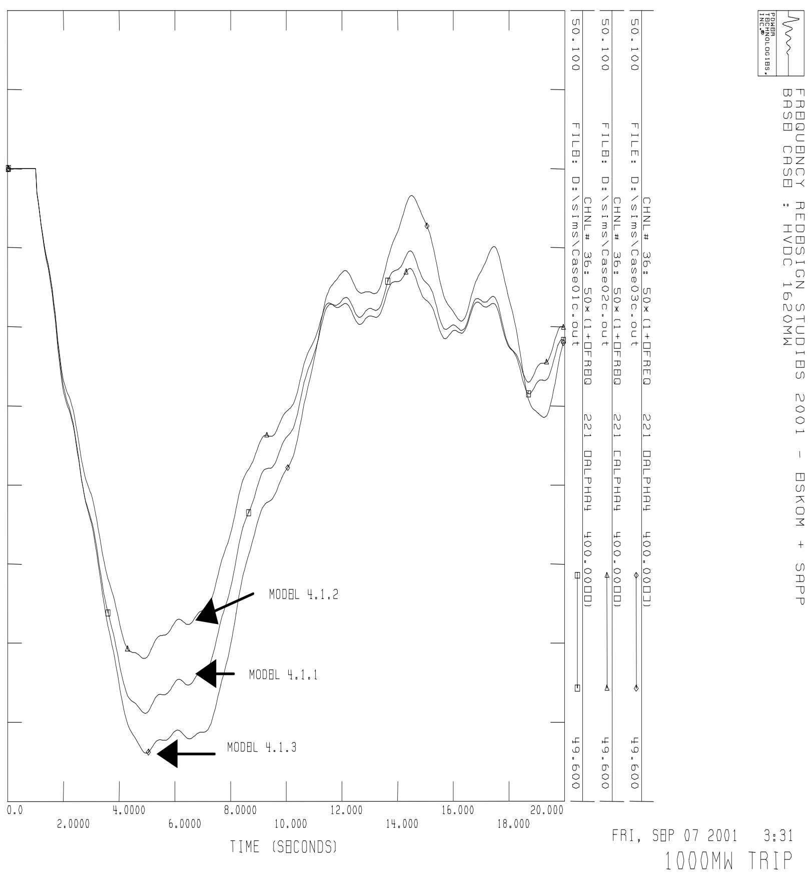

Figure C.23. 1000 MW Loss - Load Model Comparison.

Model 4.1.3 is the most onerous on the system frequency. The simulation in **Figure C.23** was compared to an actual frequency incident on 11/09/2002 when 1047 MW of generation was lost. **Table C.1** shows the results.

Table C.1. Frequency Comparisons for 1000 MW Loss.

Data	Lowest Frequency [Hz]	Frequency Stabilised at [Hz]
Actual Recorded	49.66	49.78
Model 4.1.1	49.67	49.92
Model 4.1.2	49.69	49.92
Model 4.1.3	49.64	49.92

Table C.1 indicates that Model 4.1.3 would suffice for predicting lowest system frequency during large disturbances. The settling frequency in PSS/e© is optimistic due to not limiting the response from the coal-fired power stations. This limiting of response of a coal-fired power station requires the standard models to be altered. PSS/e© is not used in Eskom to do detailed studies beyond 5 seconds and therefore there was no justification to alter the standard model and instead the models developed in Matlab© were used. The detailed PSS/e© model does have a detailed network model and shows the power flow on all transmission lines. This information is required to ensure power lines are not overloaded during disturbances. This issue is addressed in **Section 4.5**.

Appendix D : PSS/e© model

Description of PSS/e© model

D.1 Description of PSS/e© model

The proposed frequency control requirements need detailed modelling of the network to ensure that theoretical calculations are confirmed before implementation. The "Power Technologies Incorporated Power System Simulator for Engineers tool (PSS/e©) is used for short term dynamics studies to confirm the boundary conditions for sudden changes.

D.2 System Model

All simulations were conducted using the PTI Power System Simulator for Engineers (PSS/e© V26.2.1) package. The base case electrical data for ESKOM was derived from the Transmission Operational Planning case file for 2000. Electrical data for SAPP member countries was based on data obtained from the DANIDA study (Chown and Coker (2001)). Dynamic data for ESKOM current generation stations was based on current information supplied by Transmission System Operations (Swart, 1999).

The generation and load values used in the base case electrical network simulation for each SAPP member utility is shown in **Table D.1.** For low load studies the load in each control area is reduced and thereby maintaining the tie-line flows between countries at the desired values. The power transfer on the Cahora Bassa HVDC line was maintained at 1200 MW for all studies.

Table D.1. Base Case Loading & Generation

SAPP Utility	Generation [MW]	Load [MW]
South Africa	27848	27291
Zimbabwe	1320	1894
Namibia	188	289
Mocambique	1550	545
Swaziland	0	32
Zambia	1326	1080
Botswana	133	215
TOTAL	**32365**	**31346**

D.3 Turbine models in PSS/e©

Figure D.1 shows the PSS/e© Tgov5 model that is used to model coal-fired power stations in Eskom. The model is based on IEEE standard models and has a model of the turbine allowing for a three-stage turbine and modelling the delay in the reheater. The model of the control system is detailed enough to allow for the basic functions of a unit co-ordinator and various types of control philosophies. The boiler model contains the basic characteristics of the pressure of the boiler and the time transients of converting coal to steam. The model does not have a facility to model a deadband or a limit on the governors. This is a feature of most modern unit controllers to prevent the unit from becoming unstable.

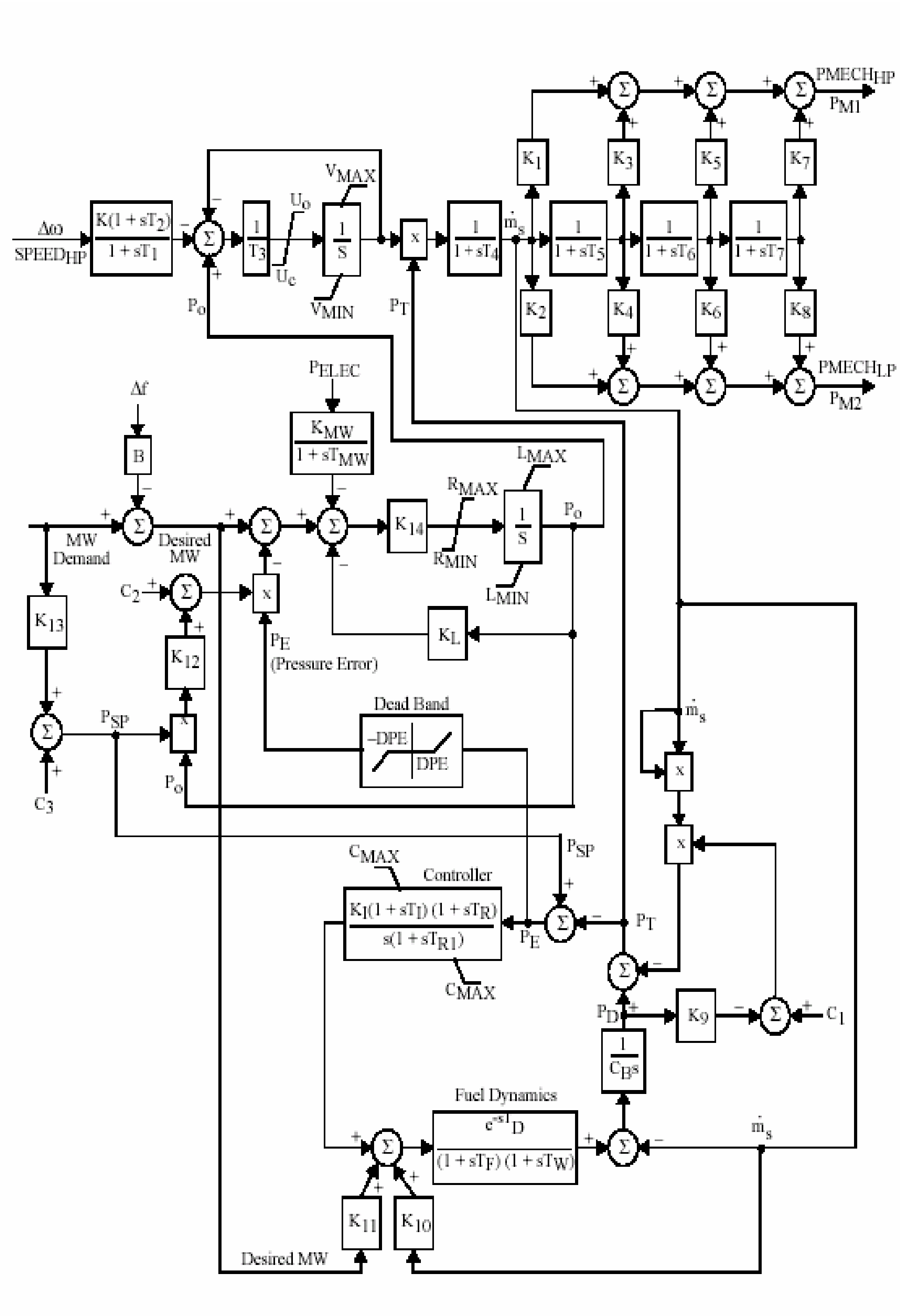

Figure D.1. PSS/e© Tgov5 model.

D.4 Frequency dependant load models in PSS/e©

The methodology contained in Coker and Kgasoane (1998) was used to calculate the load model coefficients for the SAPP system. The model is implemented in PSS/e© using the IEELAR load model (Lafkowski (2000), Lafkowski (2000a), Kundur (1994) and Chown and Coker (2001)) and can be mathematically described as follows:

$$P_{LOAD} = P_{nominal}(A1.V^{n1} + A2.V^{n2})(1 + A7.\Delta f) \tag{D.1}$$

$$Q_{LOAD} = Q_{nominal}(A4.V^{n4} + A5.V^{n5})(1 + A8.\Delta f) \tag{D.2}$$

The three different load models that were implemented for this study are discussed below.

D.4.1 Frequency Independent Load Model

This is the most commonly used model for system studies where the load active and reactive powers are sensitive to changes in voltage only. For this model, coefficients A7 and A8 in **Equations D.1** and **D.2** were set to zero and coefficients A1 to A6 and n1 to n5 were set to the Winter Weekday Peak season (Coker and Kgasoane (1998) and Chown and Coker (2001)). This results in a real power load model comprising of 4% constant power, 75% constant current and 21% constant admittance.

D.4.2 Frequency Dependent Load Model

In this model, coefficients A1 to A8 and n1 to n5 in **Equations D.1** and **D.2** were set to the Winter Weekday Peak season (Coker and Kgasoane, 1998, and Chown and Coker, 2001).

D.4.3 Frequency Dependent Load & Network Model

The 'NETFRQ' system model was added to the IEELAR model used in **Section B.4.2**. This causes the network parameters to become frequency dependent (Lafkowski, 2000a, and Chown and Coker, 2001).

Appendix E : Locational constraints

Generator response across a network constraint and locational constraint analysis

E.1 Introduction

When there is a generator trip or a sudden loss of load then generators that are set to govern automatically respond to the change in frequency and loads can be automatically disconnected via under-frequency load-shedding relays. The generator or load responses can cause a transmission network constraint. Typical issues to be examined for low frequencies and high frequencies are discussed.

E.2 Low frequencies

A generator tripping on one side of the transmission constraint will cause more power to flow towards the side of the generator that tripped, from the governing of generators on the other side of the constraint. This additional power flow can cause the transmission lines to overload and cause the network to go into an emergency condition or worse. This is overcome by reducing the generator governing from the side that will cause a problem, improving the generator response on the side of the constraint where the tripping generator is or by limiting the steady state power flow across the constraint. The reducing of governor performance has a detrimental effect on the network and needs to be examined in detail. The poorer performance could negatively affect frequency deviations and performance of the network should the network split into islands. The following are examples where low frequencies could have caused an overload on the tie line between South Africa and Zimbabwe.

E.2.1 Low frequency incident in Southern Africa on 4 December 2002

On 4 December 2002, a faulty measurement resulted in the loss of all generation from Hydro Cahorra Bassa. The power station was producing 1400 MW at the time: 1000 MW was delivered to Eskom via the HVDC link between Eskom and Hydro Cahorra Bassa, and 400 MW was supplied to Zimbabwe. The power flow between South Africa and Zimbabwe before the incident was zero. The loss of the generators resulted in a shortfall to South Africa of 1000 MW and a shortfall to Zimbabwe of 400 MW. **Figure E.1** shows that the tie line between the two countries went from 50 MW import to 300 MW export to Zimbabwe and increased to 400 MW export even though the frequency had recovered. This indicates that for this incident Zimbabwe had very little reserve capacity on governing and AGC. The power lines between South Africa and Zimbabwe are rated for 600 MW export before being overloaded. However, it could have been possible that South Africa was exporting to Zimbabwe at the time of the incident and this could have caused an overload on this part of the network.

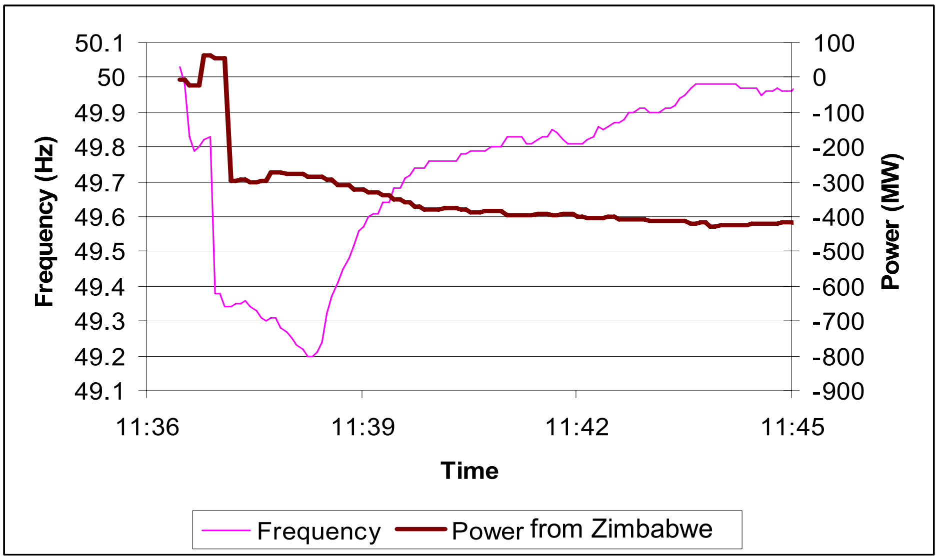

Figure E.1. Trip of Hydro Cahorra Bassa on 4 December 2002.

E.3 High frequencies

A loss of load on one side of a constraint, causing a high frequency, will often put more strain on a network than a low frequency incident. Most generators can govern down very quickly and a response on the wrong side of a constraint can cause the network to go into an emergency condition or worse. Further independent action by generators over their governing requirements can further exasperate the constraint. Generators will trip if the governing causes the unit to go into a negative power flow or if the load change is more than the unit can withstand. This can cause subsequent problems when trying to restore the load for example if a thermal generator trips it can take a few hours before the generator is restored to full load. The following two sections are examples where high frequencies caused an overload on the tie line between South Africa and Zimbabwe.

E.3.1 High frequency incident in Southern Africa on 7 June 1996

At 16h30 on the 7 June 1996 a busbar fault tripped the Alpha-Beta 765kV lines resulting in severe out-of-step conditions with heavy oscillations of voltages and currents on the remaining connections to the Cape region of South Africa. These soon tripped leaving Koeberg power station and part of the Cape islanded from the rest of the "northern system". The Cape separation resulted in a 2400 MW surplus generation in the "northern system". 1200 MW were reduced within the first 12-16 seconds from generators in South Africa, **Figure E.2.** The supply to Zimbabwe increased, in the first 12 seconds, to the north from 350 MW to 530 MW due to governor action of the generators in Zimbabwe and Zambia, point A on **Figure E.3.** The frequency was hence stabilised at an acceptable level of 50.4 Hz.

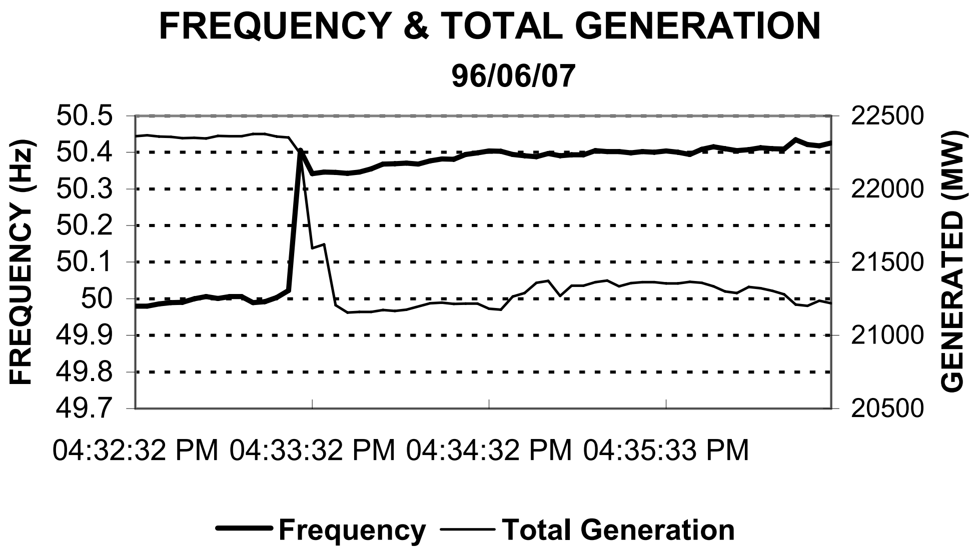

Figure E.2. Response of the Eskom generators to high frequency in the northern system.

Generators in Zimbabwe or Zambia further reduced power, which further increasing the power flow on the tie line to Zimbabwe to 644 MW, point B on **Figure E.3.** The disturbance on the system introduced a power swing through the Zimbabwe system. The power swing blocking and distance protection relays in the southern part of the Zimbabwe system operated. The tie line then tripped because of the high power flow (point C). The system frequency in Eskom increased to 50.6 Hz due to the separation of the South African and Zimbabwean systems. Zimbabwe shed 140 MW and Zambia shed 100MW due to under-frequency load-shedding.

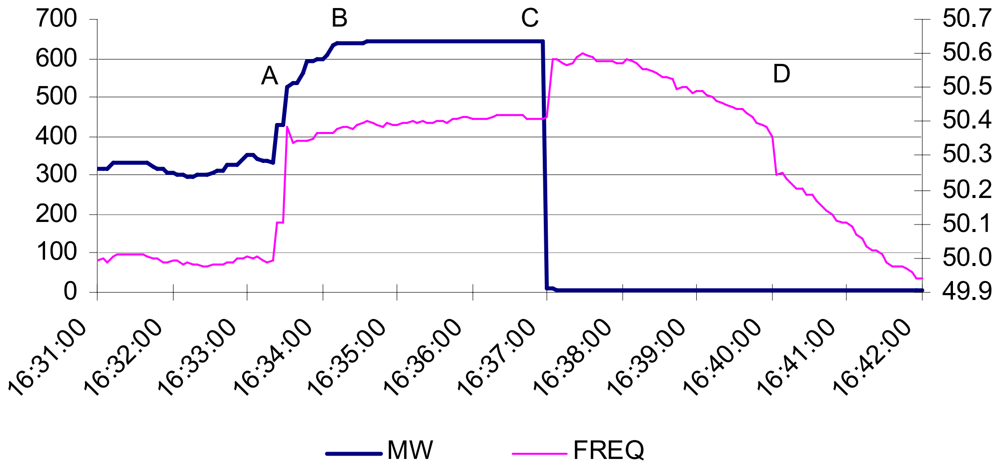

Figure E.3. Power flow to Zimbabwe and the Eskom main network frequency on the 7 June 1996

One of the major advantages of being interconnected is the support received when a disturbance like this occurs. However, the decrease after the first 12 seconds was not correct. This indicates that one of the control areas is only controlling according to the frequency and not according to their control area. The equation for ACE is as follows (**Appendix G** describes derivation of ACE):

$$ACE = (NI_A - NI_S) - 10\beta\,(F_A - F_S) - I_{ME} \qquad \textbf{(E.1)}$$

where *ß* is 30 MW/0.1 Hz representing the combined bias for Zimbabwean and Zambian control areas.

For a frequency error of 0.4 Hz and if the AGC was controlling the ACE to zero, then under these conditions the tie-line error should be 4*30 = 120 MW. At this point, the control areas should have done no control. Instead, the error before the trip of the tie-line was over 300 MW. This additional support that lead to the overloading of the South Africa to Zimbabwe tie line caused the power swing blocking and the tie-line to trip. The systems should not have separated and it is therefore necessary to co-ordinate the governor control and subsequent actions in the interconnection.

E.3.2 High frequency incident in Southern Africa on 14 September 2001

On 14 September 2001 at 03:12, the HV lines to Natal tripped due to heavy snow falls in the Drakensberg Mountains. The estimated loss of load was 4500 MW of the estimated generation of 20200 MW sent out, or 22% of the demand at the time of the incident. **Figure E.4** shows the frequency initially went up to 50.8 Hz, then started to decrease and then a sudden increase occurred when the tie line from South Africa to Zimbabwe tripped. The response from South African generators, **Figure E.5**, was a reduction of 2650 MW within 12 seconds. The response from tie lines to Zimbabwe was a reduction of 250 MW in the first 12 seconds, **Figure E.6.**

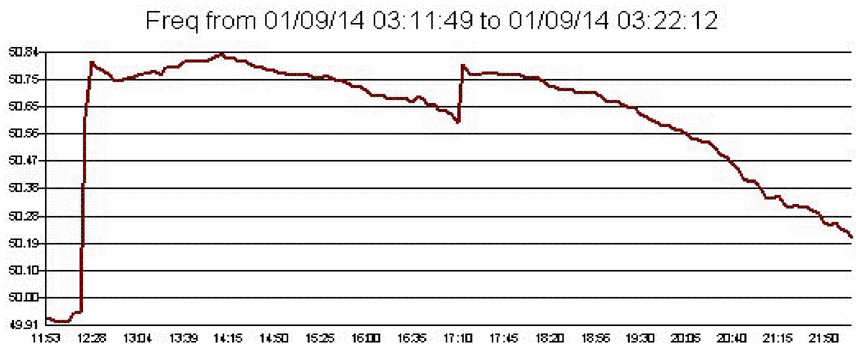

Figure E.4. Frequency for the main island in South Africa on 14 September 2001.

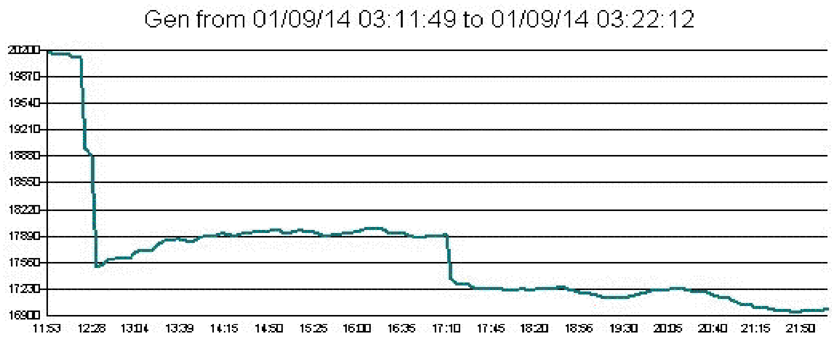

Figure E.5. Generated power for the main island in South Africa on 14 September 2001.

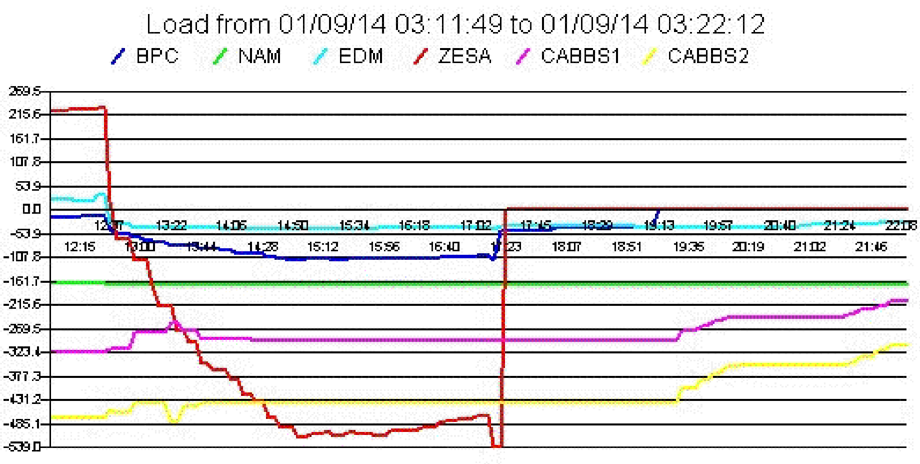

Figure E.6. Power flows on tie line to South Africa on 14 September 2001.

E.4 Investigation done by Eskom and Zesa considering the proposed changes to frequency control boundaries

A working group consisting of Eskom and Zesa engineers investigated the effect on the system frequency following a disturbance due to either: the loss of the interconnection between utilities or that of the largest generator in each control area. The study focused on the potential problems that could arise if the frequency control is relaxed. The studies were done to calculate the impact on miminumum frequency if the starting frequency is at 49.85 Hz at the start of the incident and each utility was carrying spinning reserves as stated in the SAPP Operating Guidelines. The economic target was that no load should be shed or generator trip for the loss of any single contingency, including the loss of interconnections between countries. The cost of control was not considered as long as the existing minimal regional requirements for spinning reserve did not need to be increased. The following scenarios were addressed: peak load condition, light load condition and the selected contingencies.

E.4.1 Peak load conditions

The agreed interchange for peak condition were set as follows:
Songo-Bindura = 400 MW, Matimba-Insukamini = 250 MW and
SNEL-ZESA = 100 MW.

E.4.1.1 Loss of interconnection between utilities

The most severe case was cited as the loss of the Matimba-Insukamini line carrying 250 MW. The loss of this line resulted in frequency increasing from 50 Hz to 50.12 Hz for ESKOM and for ZESA dropping from 50 Hz to 49.3 Hz, which could be set as the arrest point for ZESA.

E.4.1.2 Loss of largest generator in each control area

The loss of the two generators in the ESKOM control area, Koeberg at 920MW and Songo at 400 MW, were simulated. The frequencies in ESKOM were 49.62 Hz for Koeberg and 49.86 Hz for the Songo generator. The corresponding frequencies in ZESA were 49.59 Hz and 49.88 Hz, respectively.

E.4.1.3 Loss of interconnection between utilities when starting frequency is at 49.85 Hz

With base starting frequency of 49.85 Hz, the loss of the Matimba-Insukamini line, the Songo-Bindura feeder and the ZESCO-ZESA line gave the results shown in **Table** E.1**.**

Table E.1. Loss of interconnection between utilities when starting frequency is at 49.85 Hz.

Interconnection Lost	ESKOM frequency (Hz)	Northern network & ZESA frequency (Hz)
Matimba-Insukamini	49.875	49.474
Songo-Bindura	49.8	49.8
ZESCO-ZESA	49.7	49.7

In the case of the loss of the Matimba-Insukamini line, simulations indicated that the ZESA-ZESCO tie has acceptable oscillations when the Matimba-Insukamini line is lost. The same is true for internal lines within the ZESA network such as the line from Insukamini to Bulawayo. The damping was observed to be fine and the angles were well damped.

When Songo-Bindura feeder is lost, both the northern and the southern networks had the same frequency of 49.8 Hz, which is acceptable. For this case, the voltages were not affected.

E.4.1.4 Loss of largest generator in ZESA control area when starting frequency is at 49.85 Hz

When the largest generator at Hwange is lost, the system frequency is the same for both the northern and southern networks at 49.8Hz. The dynamics in the ZESA control area were acceptable.

E.4.2 Light load condition

E.4.2.1 Loss of interconnection between utilities

The most severe case was the loss of Songo-Bindura line. The frequencies in ESKOM and ZESA were 49.98 Hz and 49.92 Hz respectively.

E.4.2.2 Loss of largest generator in each control area

The loss of the largest generators gave the results shown in **Table E.2.**

Table E.2. Loss of the largest generator in each control area

Generator Lost	ESKOM & ZESA frequency (Hz)
Koeberg 920MW	49.62
Hwange 220MW	49.85
Songo 400MW	49.77

E.4.2.3 Wheeling power through ZESA

The interchange considered were: ZESCO-ESKOM=300MW and SNEL-ZESA=100MW. The results are shown in **Table E.3.**

Table E.3. Frequency when interconnection between Eskom and Zesa is lost.

Interconnection Lost	ESKOM frequency (Hz)	ZESA frequency (Hz)
Matimba-Insukamini	49.87	51.31
ZESA-ZESCO	49.85	49.84

E.4.3 Conclusion of studies by Eskom and Zesa

The joint study by Eskom and Zesa has verified that the system response is acceptable under all credible contingencies and has stated that the new and proposed frequency band of 49.85 - 50.15 Hz will be well within tolerance by the SAPP network.

The interconnection from South Africa to Zimbabwe, **Figure E.6**, shows a reduction of 300 MW in the first 12 seconds and further reduction to 450 MW in the next 4 minutes after which the interconnection tripped. However, the decrease after the first 12 seconds was not correct. This indicates that one of the control areas was again only controlling according to the frequency and not according to their control area.

For a frequency error of 0.8 Hz and if the AGC was controlling the ACE to zero then under these conditions the tie-line error should be 8*30 = 240 MW as per the previous section. At this point the control areas should have done no control. Instead, the error before the trip of the tie line was 670 MW. This additional support that led to the overloading of the tie line with Zimbabwe most likely caused the tie-line to trip and caused Zimbabwe and Zambia to be blacked out. This is the same as the incident in June 1996 when the HV lines to the Cape tripped. It has been reported that generators at Hwange and Kariba tripped. This could be the reason for the increase in power on the tie line except that the power flow from the initial governing is linear and more consistent with integral action.

Appendix F : Influence of voltage

Analysis of the influence of voltage control on frequency control

F.1 Introduction

The frequency on the network is the balance between supply and demand. If the voltage on the network is changed, resistive and other loads will change their consumption and the balance between supply and demand is changed.

When there is a step change in voltage the output of the generator is also effected. The voltage is regulated by the Automatic Voltage Regulator (AVR), and is relatively fast in the order of 0.5 seconds (Kundur, 1994). However, if the settings on the AVR are incorrect there will be a voltage swing causing a power swing and subsequent frequency swings.

There are many devices on the transmission network that are designed for voltage control and dynamic stability. These devices can also be set up to control the voltage in order to minimise the effect on frequency. Such a philosophy needs to consider that consumers and generators are more sensitive to voltage than to frequency.

All these devices and their effects on the voltage and subsequent effect on frequency control must be understood. The following section contains the details of actual events in Southern Africa where the voltage control, or lack of it, had an effect on the turning frequency during a disturbance.

Figure F.1 below shows the voltage disturbance, where *Pv* is the extra power due to voltage changes. *Pv* is positive if the voltage goes high during the disturbance. The voltage disturbance *Pv* can be added to the initial disturbance *Pd* and hence for a particular disturbance the result is that it is not only the contingency MW but the secondary effects which determines the total disturbance in MW.

Pdnew = Pd + Pv

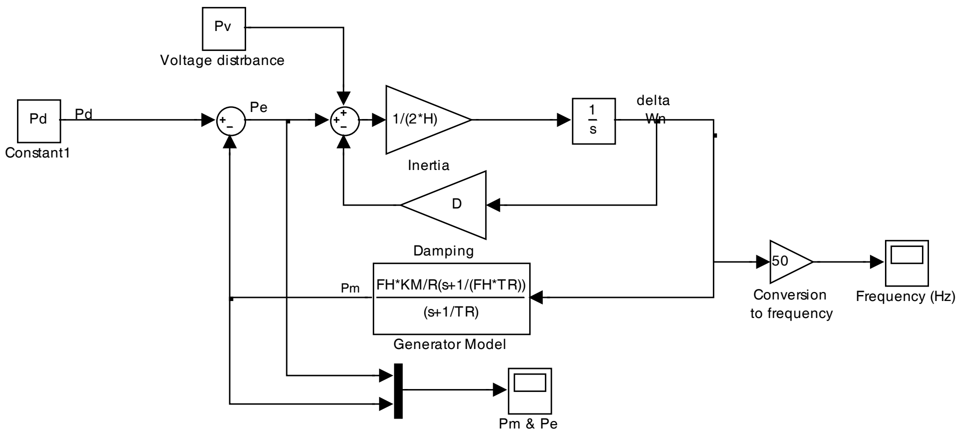

Figure F.1 Simplied model including a voltage disturbance.

F.2 Incidents recorded in Southern Africa on 3 and 4 December 2003

On 4 December 2003, a faulty voltage measurement on the HVDC link between Hydro Cahorra Bassa (HCB) and Eskom caused the loss of both HVDC poles. This disturbance caused the loss of all generators at HCB from a faulty under-frequency relay. The sum of the generation lost on the interconnection was 1386 MW. The fault occurred again the following day. This time a 600 MW generator tripped as well and the total generation shortfall was 1660 MW. The generator tripped from 406 MW while responding to the initial frequency decline due to an incorrect setting in the turbine controls.

For both incidents, the frequency fell further than predicted. The models developed in **Appendix D** showed that the frequency would fall to a lowest frequency 49.08 Hz for an 1800 MW trip with a starting frequency of 49.85 Hz. The trip simulated was the loss of Hendrina Power Station, **Figure 6.6.** If the support from inductive loads on frequency is 125 MW per 0.1 Hz then on a 1386 MW loss of supply the frequency should have fallen to 49.41 Hz and for a 1660 MW loss of supply the frequency should have fallen to 49.19 Hz (without load-shedding).

On the 4 December, the frequency initially fell to 49.34 Hz or 0.05 Hz lower than the predicted worst case, **Figure F.2.** On 5 December, the frequency fell to the level predicted except that 255 MW of load-shedding occurred, without which the frequency would have fallen lower. However, without knowing exactly what frequency and when the under-frequency relays had triggered the lowest frequency without load-shedding could not be determined.

The frequency has fallen lower than predicted in other incidents in Southern Africa. Recent incidents are as follows:

- On 26 September 2002 the frequency dropped to 49.51 Hz for a 1012 MW loss of supply from Cahorra Bassa, which was a drop of 0.14 Hz below similar trips. As a comparison, a station lost 1020 MW on the 13 September 2002 and the frequency only dropped to 49.68 Hz.

- On 10 October 2001, the station blackout of Cahorra Bassa from 1350 MW caused the frequency to fall to 49.34 Hz, which was a frequency decline of 0.1 Hz below expected value.

Both Cahorra Bassa and Koeberg power stations, which caused the unusual incidents, were producing a lot of reactive power, which affected the voltage control during the disturbance.

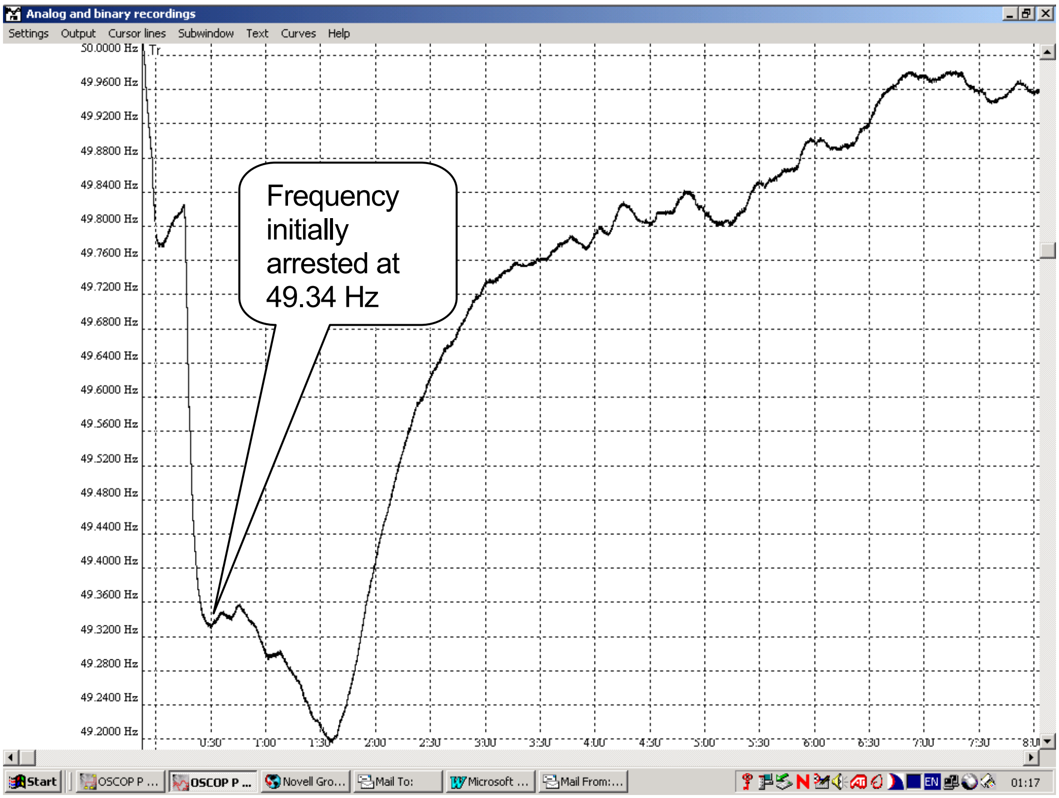

Figure F.2. Frequency on the 4 December as measured by P531 disturbance recorders.

There were power and voltage swings on the HVDC line before it tripped on 4 and 5 December due to the faulty voltage measurement. The main control centre received high voltage alarms at Croydon and Makula substations just prior to the HVDC trip. These caused power and voltage swings on the Transmission network. The voltage changes however, remained within tolerances as no disturbance recorders were triggered due to voltages prior to the incident.

The voltages in the Gauteng, Mpumalanga and Limpopo regions of the network increased by 0.5 to 1 % as measured at Apollo, Arnot and Matimba. **Figure F.3** shows the voltage profiles for 5 December 2003. This increase in voltage was most likely due to the sudden increase in reactive power at Apollo substation where the DC is converted to AC. This would have increased the consumer demand in these regions by 0.5 to 1 %. The Cape and Natal regions voltages remained relatively unchanged. The total demand increase was estimated to be about 120 MW (0.75% of 60% of 27 000 MW). This would have caused the frequency to fall an extra 0.1 Hz. This phenomenon was not prevalent in the Cahorra Bassa station blackout on 17 October, **Figure F.4**. Here the voltage rose 0.5 % at Apollo and Matimba and the voltage fell by 0.5 % in the Cape region. The rest of the voltages were recorded as unchanged at the time of the incident.

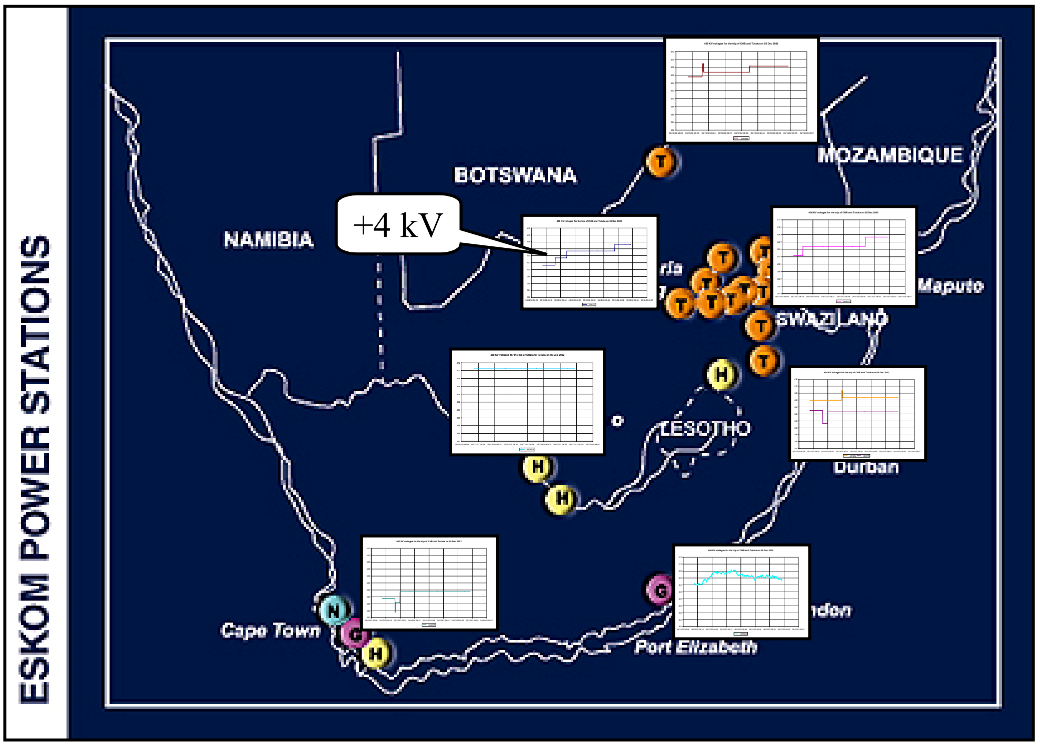

Figure F.3. Voltages on the 400 kV network on 5 December 2002.

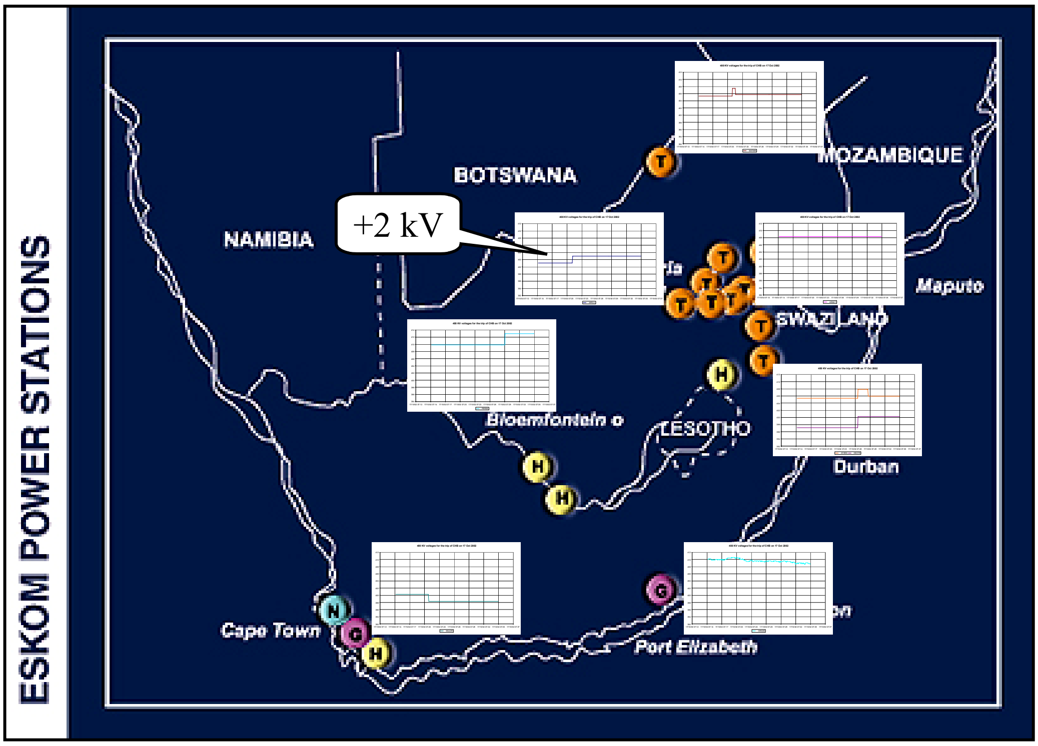

Figure F.4. Voltages on the 400 kV network on 17 October 2002.

F.3 Analysis of the effect of voltage swings measured in South Africa

The high voltages measured on the central network, according to experts in Eskom, could have been avoided if the filters were tripped at Apollo when both poles tripped or if capacitor banks were tripped on high voltage and low frequency. Before any strategy is implemented a study is required to understand the dynamics that are occurring on the network, as tripping the filters or capacitor banks may cause damage to them or result in too low voltages for Transmission customers in the region. The result of implementing a strategy where the impact of the voltage is minimised can result in 100 to 200 MW less consumer load being shed on under-frequency load-shedding.

Appendix G : Calculating control error

Calculation of the control error

G.1 Introduction

This section focuses on the control error. In developing a control loop, it is important to ensure the amount of control required is as calculated accurately as possible and subsequently inaccuracies in the control loop are understood. Frequency control requires the conversion of the frequency error into an equivalent MW error in order to know how much control to perform. A control area is an area within an interconnection that controls its own consumption and production of electricity, including contractual flows to other control areas. It is the obligation of each control area to fulfil its commitment to the Interconnection and not burden the other control areas. Any errors incurred because of generation, load or schedule variations or because of jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept between the involved parties and not passed to the interconnection (NERC, 2006).

The equation for ACE as defined by NERC is:

$$ACE = (NI_A - NI_S) - 10ß\,(F_A - F_S) - I_{ME} \qquad \textbf{(G.1)}$$

In this equation, NI_A accounts for all actual meter points that define the boundary of the control area and is the algebraic sum of flows on all tie lines. Likewise, NI_S accounts for all scheduled tie flows of the control area. The combination of the two $(NI_A - NI_S)$ represents the ACE associated with meeting schedules and if used by itself for control is referred to as flat tie line regulation.

The second part of the equation, $10ß\ (F_A - F_S)$, is a function of frequency. The $10ß$ represents a control areas frequency bias ($ß$'s sign is negative) where $ß$ is the actual frequency bias setting (MW/0.1 Hz) used by the control area and 10 converts the frequency setting to MW/Hz. F_A is the actual frequency and F_S is the scheduled frequency. F_S is normally 50 or 60 Hz but may be offset to effect manual time error corrections.

I_{ME} is the meter error recognised as being the difference between the integrated hourly average of the net tie line instantaneous interchange MW (NI_A) and the hourly net interchange demand measurement (MWh). This term should normally be very small or zero.

The calculation of ACE as defined by NERC (NERC, 2006) is a good indicator for each control area, providing the frequency support from consumer motor loads is constant and the support from generators via governing is linear. However, consumer motor load support is not constant but is more proportional to the actual demand (Kennedy *et al.* (1987)) and neither is generator support. The correct calculation of the ACE is important for optimal performance of the controller. An error in the calculation of the ACE will require some compensation to prevent the frequency from either cycling or unacceptably large errors occurring.

G.2 Calculation of ACE from first principles

ACE can be calculated dynamically from the sum of the responses of the loads and generators to frequency changes and the actual error in the frequency. The response from the loads and the generators is not constant but can be calculated or measured in real time. This is the practice in the UK where by knowing which generators are on governing and by using a curve of the response for each generator the control area error can be calculated (National Grid Company, 2002a).

G.2.1 Load response

Figure G.1 below shows that the load frequency characteristic is assumed to be quadratic for motor loads and no effect for non-motor loads (EPRI, 1997). The overall effect can be linearised and assumed to be proportional to the actual demand at the time. The slope in the example is 1, where a 1% drop in frequency will result in a 1% drop in load. The normal make up of daily load pattern needs to be analysed to determine the slope and the consistency of this. In South Africa the average load is 70% of the peak, which is high for most countries. The base is mainly large industry and mining that operates 24 hours a day. Industry and mining have a large proportion of motor load and hence the total South African load during the entire day is significant. **Figure G.2** shows the demand breakdown in South Africa over the last 10 years.

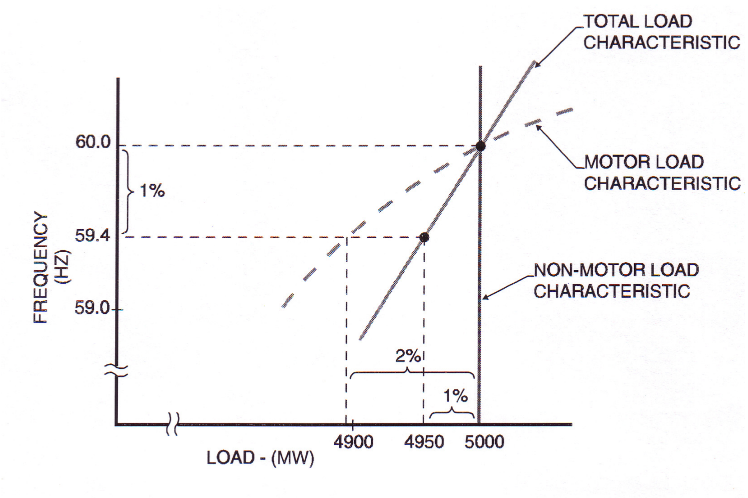

Figure G.1. Load frequency change for motor loads and linear assumption (EPRI, 1997).

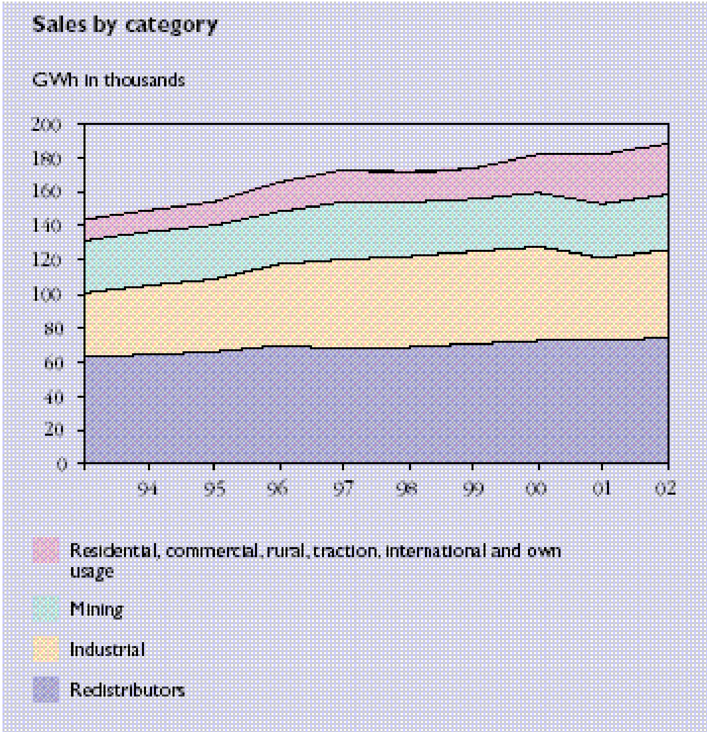

Figure G.2. Breakdown of the demand for South Africa (Eskom, 2003).

Measurements of the load response can be done using data received from the generators and knowing the size of the disturbance. The quality of the data and timing can cause errors in this method. In Eskom, generator output data is received only when the value changes by more than 0.1%. The data is then sent to the central SCADA system via a direct telecommunication system. These values are then updated in the SCADA system every 4 seconds. The time resolution in this process is hence only 4 seconds and up to 12 seconds under disturbance conditions when all analogue values in the entire network could be changing. NERC measures the combined frequency response characteristic of loads and generators after the frequency has settled and is at a steady state, shown as point B in **Figure G.3** below (NERC, 2006), probably due to measurement problems and other dynamics during the disturbance.

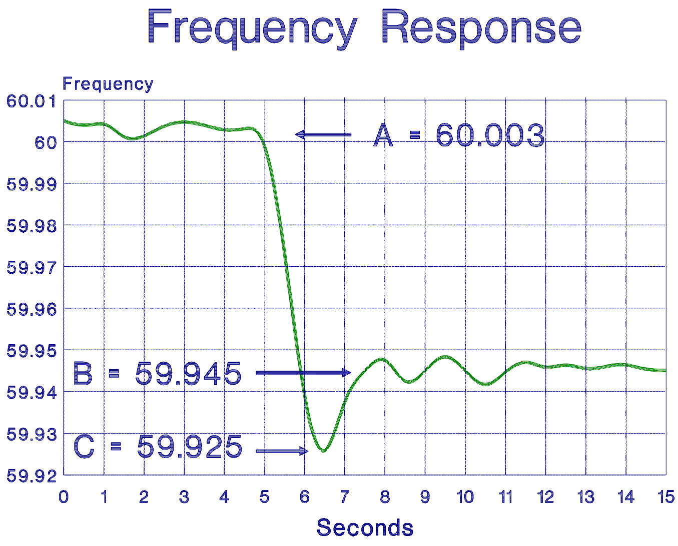

Figure G.3. Calculation of frequency response characteristic for disturbances (NERC, 2006).

Table G.1 shows the load frequency characteristic calculated from trips recorded in Eskom in 2005, (Chown, 2006).

Table G.1: Recorded Load-Frequency Characteristics in Eskom.

Total generation	Total Load Frequency Characteristic [MW/0.1Hz]
24719	109
29186	125
29971	142
29319	147
29113	143
28377	113

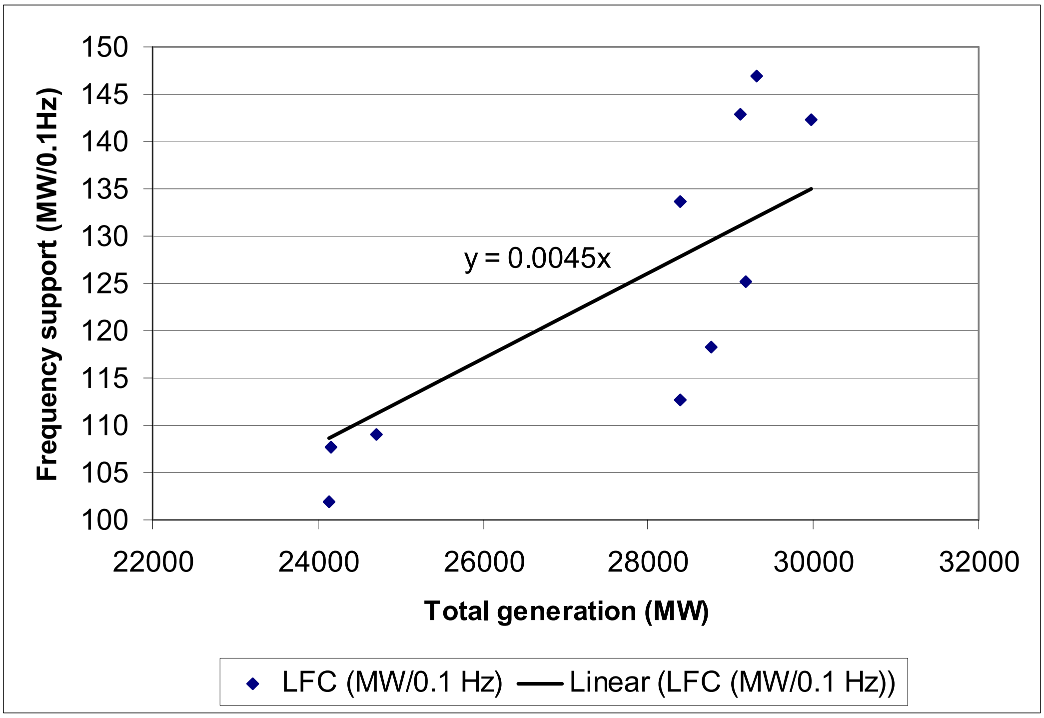

Figure G.4 Load frequency characteristic versus total generation for frequency incidents measured in 2005.

This calculation shows the measured load frequency characteristic to be 0.45 % of the total generation per 0.1 Hz change or 2.25 % change in demand for a 1% (0.5 Hz) change in frequency, **Figure G.4**. The frequency support from loads is higher than the 1% predicted in the theoretical support (Chown, 2006). The percentage change in demand load frequency support is used for the detailed PSS/E studies and an average 125 MW/0.1 Hz is used for simplified Matlab studies.

G.2.2 Governor response

The response from generators is not linear and can vary dramatically depending of the type of plant and sophistication of the control system. The proposed introduction of a relatively large deadband for the governing in Southern Africa also means that in the frequency range inside this deadband there is only the response from motor loads. This strategy was deliberate but needs to be considered when calculating the

ACE. **Figure G.5** shows the varied response to a large frequency deviation in frequency (0.8 Hz) from various coal-fired and thermal power stations in Eskom. **Figure G.6** shows the difference in response to a small deviation and a large frequency deviation for the same thermal unit with an unsophisticated control system (no deadband or limitation on response). If the generators response is repeatable then the response can be modelled. A database of responses can then be used for a dynamic calculation of the total generator response. An example of the modelling of a generator's governing characteristic to various control strategies is presented in **Appendix H.**

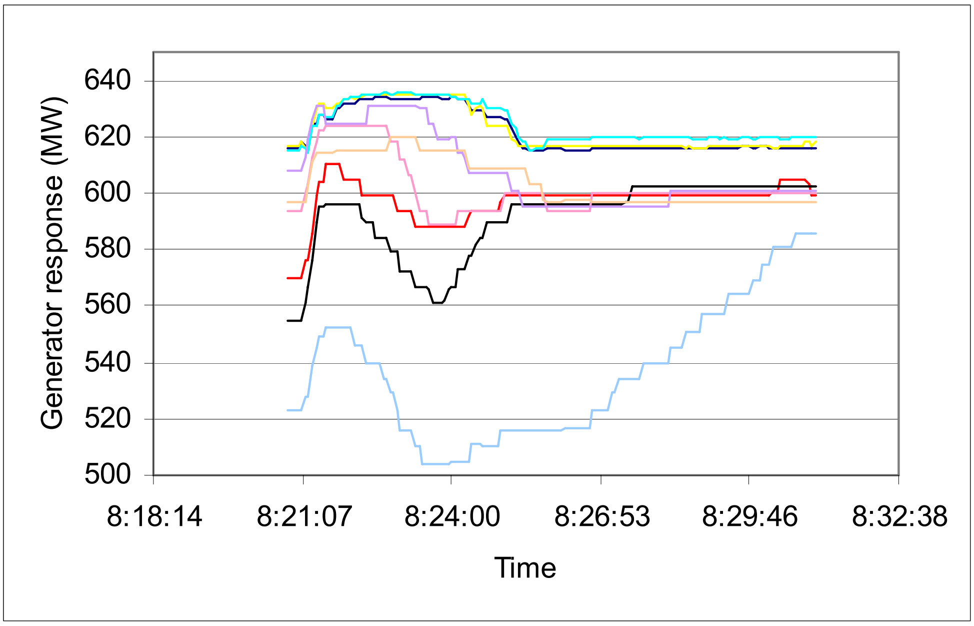

Figure G.5. Generator responses to a 0.8 Hz step change in frequency.

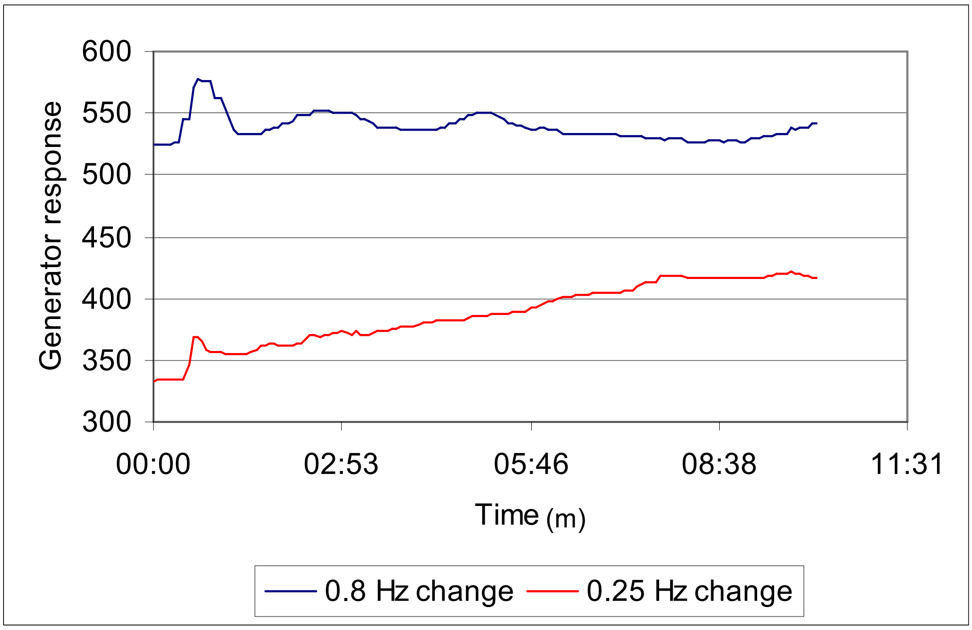

Figure G.6. Difference in response of a generator to a various step changes in frequency.

G.2.2.1 Error in ACE calculation due to non-linear generation response

In order to design a control system the errors in measurements and calculations need to be understood to prevent sub-optimal control. The error for Eskom between a fixed ACE and the actual ACE at a demand of 25 000 MW at steady state is represented by **Figure G.7.** The deadband for Eskom generators for primary frequency response after redesign was 0.15 Hz and the calculated motor load frequency support was 1250 MW/Hz. At a frequency deviation of 0.15 Hz actual ACE was 187 MW for the interconnection whereas the fixed bias ACE was 495 MW. The fixed bias method calculates the ACE 2.6 times higher than the actual ACE.

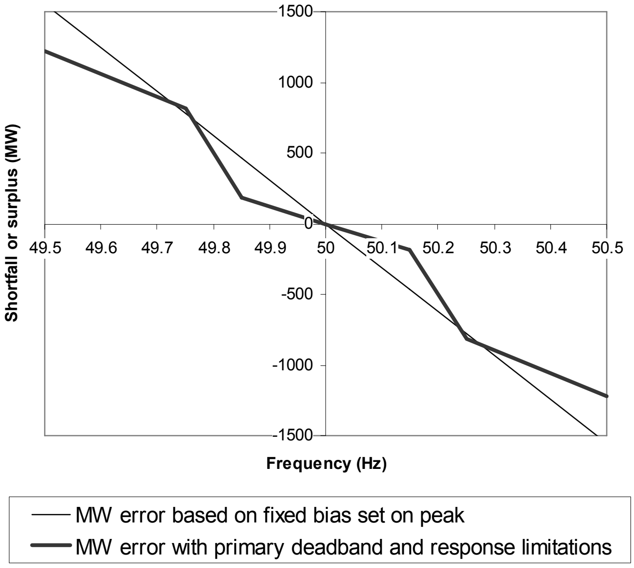

Figure G.7. Estimated and linear MW shortfall or surplus for Eskom.

For Eskom, where the demand varies between 17 000 and 31 000 MW, the calculation error is 28 MW/0.1Hz for load frequency support. Also, generator support is not linear. The introduction of no primary control for a small frequency error in Southern Africa means that the ACE calculation for such frequency changes is incorrect. For example, for a demand of 25 000 MW and a shortfall in the Eskom control area causing a frequency error of 0.1 Hz the ACE was calculated to be 310 MW, whereas the actual shortfall in generation was only 120 MW. **Figure G.7** shows the supply error against frequency curve for Eskom given a deadband of 0.15 Hz for governors and that the response from generators is fully activated by 0.25 Hz frequency error. **Figure G.7** shows that the fixed bias is always over-estimating the error except at 49.75 and 50.25 Hz.

G.2.3 Effect of frequency measurement

The sections above show that adding the generator response and the motor load response are the two major measurements coupled with the actual network frequency that are required to give an accurate calculation of the ACE. The measurement of

ACE at the time of a disturbance is inaccurate unless fast measurements are received from both generators and loads at the time of the disturbance or accurate dynamic models are used to calculate the response. For control purposes the ACE is often filtered to smooth out errors and inaccuracies in the measurement of frequency. The measurement of frequency is calculated by measuring the number of times the voltage or current passes through zero in a given period. Voltage crossings are difficult to measure when the disturbance is caused by a ground fault near the measurement device. Practically, frequency measurement instruments filter out all zero crossings that infer the frequency is outside the normal range of the instrument (3 Hz). SCADA systems to overcome this problem use 3 or 4 frequency measurements from different sources and use a voting system to determine the frequency of the main network. For the purposes of controlling the network the response from generators is slow and an accurate calculation of ACE within a few seconds of a disturbance is not really required as long as the control is in the right direction.

The calculation of ACE can hence be resolved into two parts:

a) Calculating and measuring the motor load response, and
b) Calculating the generator governor response (that will disappear when the frequency returns to zero).

G.3 Calculation of Eskom's ACE using different methodologies

This section shows the various methodologies used to calculate the ACE from a simplified fixed bias to the complex calculation of individual generator and motor load responses. The incidents used for the demonstration are when there was a generator trip. The loss of generation for these cases is known and the accuracy of each method can then be benchmarked against this known value. The assumption is that the consumer demand remains constant for the event.

G.3.1 ACE calculation using fixed bias and variable bias

The fixed bias calculation as defined by NERC (NERC, 2006) requires the value of the bias β to be at least 1% of the previous year's maximum demand. The maximum demand measured for Eskom in 2002 was 32 000 MW and therefore the bias β is calculated as 320 MW per 0.1 Hz change in frequency. A dynamic bias demonstrated here calculates the bias β to be 1% of the current consumer demand. Therefore, if the current consumer demand is 29 800 MW the bias B at the time is 298 MW per 0.1 Hz. This method for calculating the bias has been used by the AGC controller in Eskom for many years to control the generators (Chown, 1997). The fixed bias calculation defined by NERC is still calculated for NERC performance calculations as per the SAPP rules (SAPP, 1996). The first case is the loss of a generator from 604 MW where the total demand at the time was 29 800 MW. The variable bias of 298 MW per 0.1 Hz and a fixed bias of 320 MW per 0.1 Hz both calculate the initial error to 775 MW and 830 MW respectively, **Figure G.8.** This is 1.3 times the actual ACE. The second case is a loss of 585 MW of generation from 585 MW when the then total demand at the time was 21 200 MW. The variable bias calculates the initial change in ACE as 497 MW or 0.85 times the actual error and therefore is under-calculating the error, **Figure G.9.** The fixed bias calculates the initial change in ACE as 730 MW and again over-estimates the error by 1.2 times.

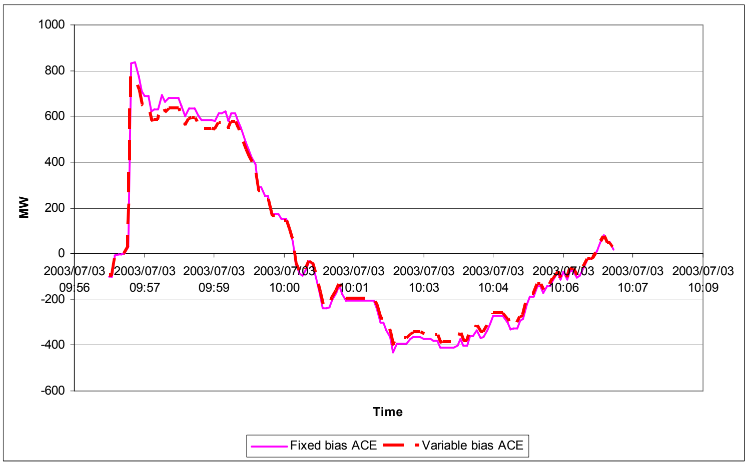

Figure G.8. Fixed and variable ACE calculation for 604 MW generator trip when total demand was 29 800 MW.

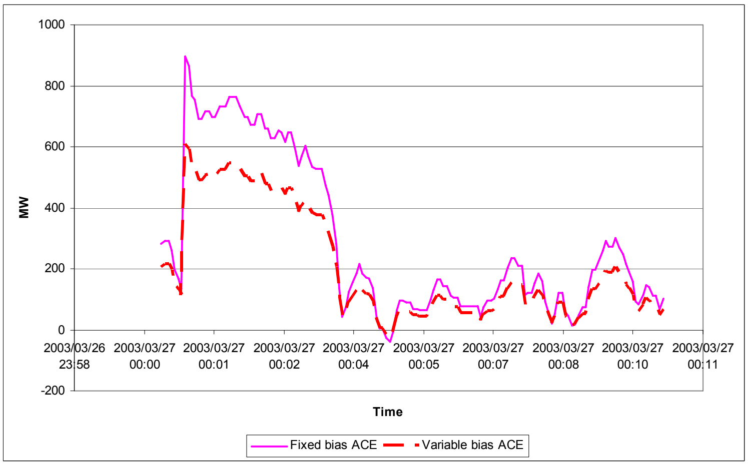

Figure G.9. Fixed and variable ACE calculation for 585 MW generator trip when total demand was 21 300 MW.

G.3.2 ACE calculation using estimated total generation and estimated motor load response

The same two cases as in the previous section are used and the ACE is calculated as the sum of the estimated generation response and the load is estimated for the current frequency error. The estimated load frequency response for this case is assumed to be a constant 1.5 % change in demand per 1 % change in frequency. The total generation response under governing is estimated, as shown in **Figure G.10.** The maximum rate of change is limited to 500 MW in 10 seconds, which is the contracted response in the Eskom Power Pool for generators contracted for governing. **Figure G.11** shows that the calculated ACE peaks at 690 MW where the trip was 604 MW, an over-estimation by a factor of 1.14.

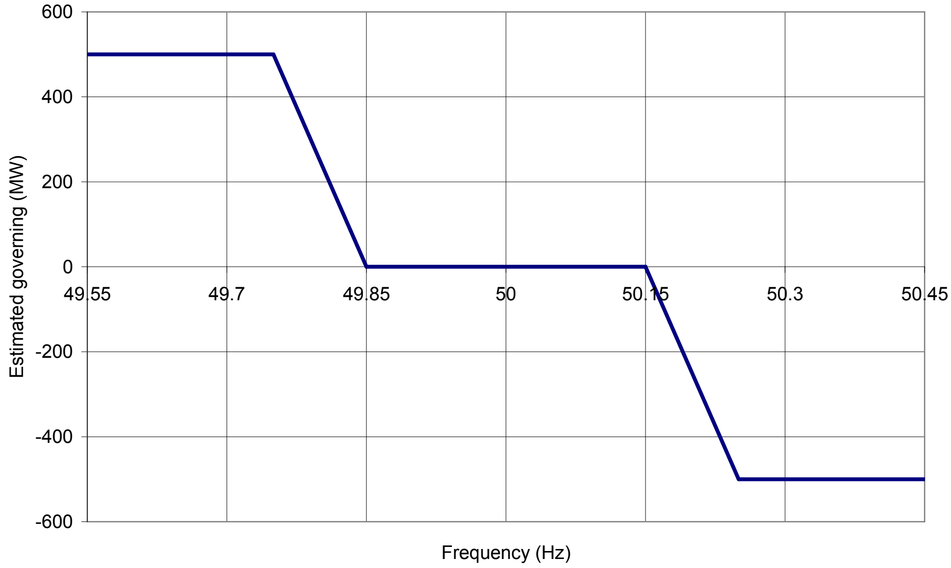

Figure G.10. Estimated generation response against frequency change.

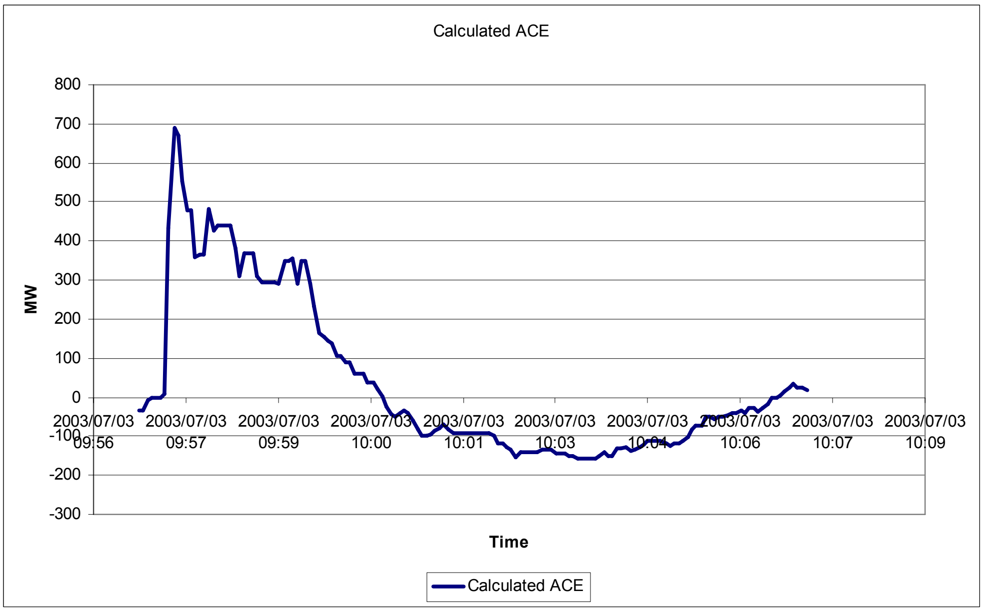

Figure G.11. Calculated ACE using estimated motor load and estimated generation response.

G.3.3 ACE calculation using estimated and measured individual generator responses and estimated motor load response

It is possible to estimate the individual generator response based on its current output and what its contractual requirements were and sum these together to get the overall generator response expected. **Figure G.12** shows the sum of contracted generator response for a 604 MW generator trip. This is the method that is used in the UK. The estimated actual response can be calculated by adding the measured generator output and knowing what the output was before the incident. **Figure G.12** also shows the total for the 604 MW generator trip using the 4 second data recorded on the energy management system in Eskom. For this incident the measured generator response first dropped 100 MW and then the shape was the same as the contracted response. The reason for the drop is the delay in the tripping unit data feedback. The sum of the responses from the individual generators was probably also worse than the contract required for this incident.

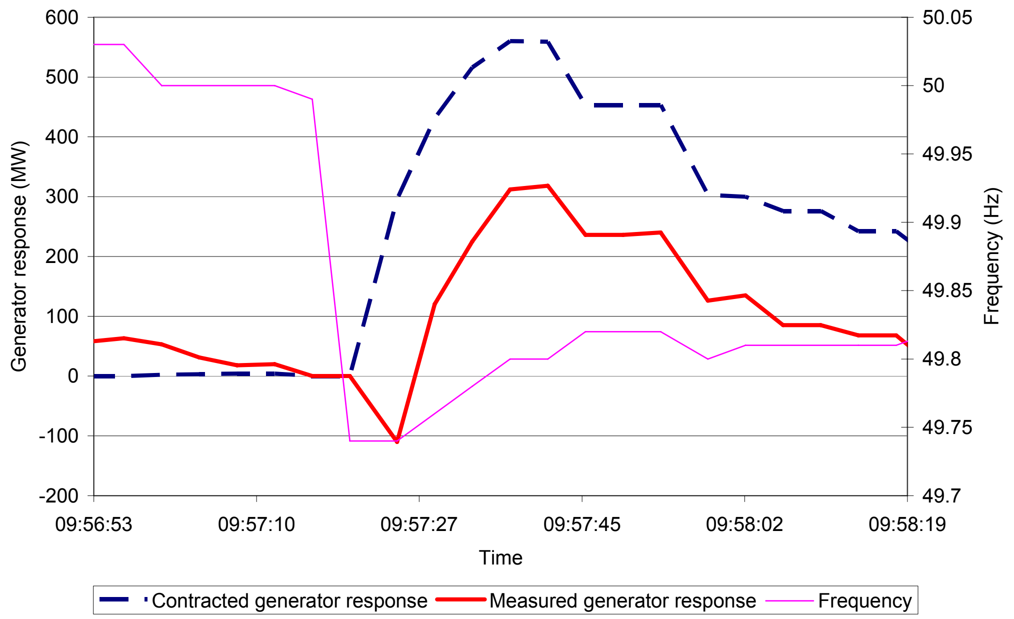

Figure G.12. Expected contractual generator response and measured generator response for a 604 MW generator trip.

The ACE can then be calculated based on both of these methods of measuring generator response and the estimated load frequency characteristic, **Figure G.13.** The ACE using the contractual generator responses over-estimated the control error by 200 MW. This is expected for this case where the response from the generators appears to be less than the contractual requirements. The ACE using the responses from generators as measured by the energy management system slightly under-estimated the error at the turning point of the frequency. However, during the first part of the incident the ACE was inaccurate due to delays in measurements and the ACE for this case was under-reading the actual error.

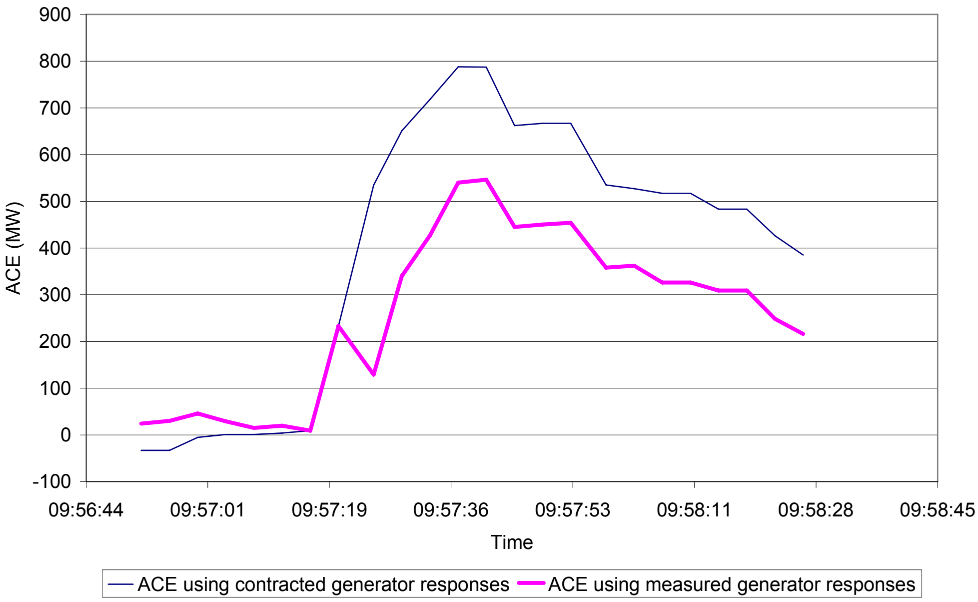

Figure G.13. ACE using contractual generator responses and measured generator response for a 604 MW generator trip.

G.4 Summary of calculation of control error

The traditional calculation of ACE gives errors in determining the control error especially when the response from generators is not linear. The error in ACE will lead to over-control or under-control, which will lead to sub-optimal control unless the error is compensated for. The appendix has shown a few more accurate methodologies for calculating the ACE. A methodology for calculating the ACE needs to be chosen for the network to be controlled. The control strategy can now be developed and will need to cater for errors identified in the methodology to prevent sub-optimal control. In Eskom the ACE for controlling is the variable bias methodology as this was simple to implement and is reasonably accurate.

Appendix H: Who can control frequency

Determining what can be used to control the frequency

H.1 Introduction

This appendix will explore some of the intricacies that need to be understood about a generator or consumer and will also show how the control strategy can be changed to alter the characteristics of the plant. The possible variations in plant design and associated control strategies mean that this appendix is illustrative of the possibilities and not exhaustive.

H.2 Response capabilities of generators

The ability of a generator to change the electrical output varies according to the design and the control strategy. The dynamics of power stations is well documented (Kundur 1994, EPRI 1996) but still each power plant in the system needs to be studied and understood. The purpose of this is that when designing a control strategy the physical limitations of the power plant will hinder the design of an optimum controller. In Eskom, the power stations can only move at a slow rate compared to the reaction speed of the customer. Therefore, it is necessary at times to be moving many power station units at the same time. This is not optimal from a purely economic perspective. Each large coal fired power station can only change its output within a 20 to 25 % range before a coal mill has to be put in service or taken out of service to adjust the boiler output. The process of putting a mill into or out of service can take 5 minutes on one power station and over 30 minutes on another depending on the mill design. The dynamic response of the power station is also a trade off, an example of this is presented in **Section H.7**. Here the choice could be for a large response from the plant in seconds and this response then returning to the original position or lower after about 90 seconds or by limiting the initial response with the possibility of sustaining the response for a long period.

The problem with the power station in question was that the response in the first seconds was so great that the plant had a risk of tripping soon after. Hydroelectric power stations are more flexible than coal-fired stations but even they cannot change their output instantaneously and there are levels at which the plant will prefer not to operate due to cavitations and vibrations. Run-of-river hydroelectric plants in series also need to have their output co-ordinated to avoid wasting water. A gas-fired turbine's electrical output tends to drop as the speed of the turbine decreases. The speed of the turbine is derived from the frequency of the network. Thus, the output of the generator will decrease as the frequency decreases if care is not taken to ensure some over-firing ability of the plant.

H.3 Control strategies

There are many ways to control a power plant. The control strategies are designed to meet the requirements of the network as well as to improve the economics of the operation of the plant. Modern control systems allow for a very flexible control strategy that can be altered to meet different requirements at different times.

H.4 Protection schemes

Most power stations are capital intensive and are designed to operate for at least 30 years. The plant therefore needs to be adequately protected against potential damage, however, the protection of the plant can negatively impact the manoeuvrability of the plant and jeopardise the network. An example of this is a generator that trips due to low frequency. This will cause the frequency to fall even further and could cause a full or partial blackout of the network.

H.5 Response to a step change

The classical analysis of the ability of a generator to respond is to apply a step response to the governor valve. It is important to observe how fast the electrical output can be changed given an instantaneous request and for how long such a response can be sustained. Typically, a unit on governing responding to a large disturbance in the network will have the equivalent of a step applied to the input.

H.6 Ramping up and down capability

The ability of a plant to change over an extended period of time and in a controlled manner needs to be known in order to control general load changes. This will include the ability of the unit to zigzag its output as this might be required if the unit is to be on AGC.

H.7 Modelling, tuning and understanding different control strategies for primary control for a coal fired power station

An Eskom 600 MW once through fixed pressure boiler unit, is modelled and tuned by using the performance measured in real incidents. The model is then used for understanding the response of the unit with different control strategies. This is used to further the understanding of how a unit can be used for frequency control under disturbance conditions and the associated possibilities and complexities.

H.8 Incident performance

The loss of 2600 MW caused the frequency to fall initially to 49.25 Hz, **Figure H.1.** The 6 * 600 MW unit responded to the low frequency by increasing their electrical power output through governing. The initial output from the units was in the region of 100 MW per unit, **Figure H.2.** None of the units could maintain such a high power response and after about 90 seconds the response was between 30 and 60 MW per unit. Unit 1 tripped on a governor fault probably because of this over-response. After 90 seconds the power output of the units was erratic as the boiler turbine sets tried to stabilise.

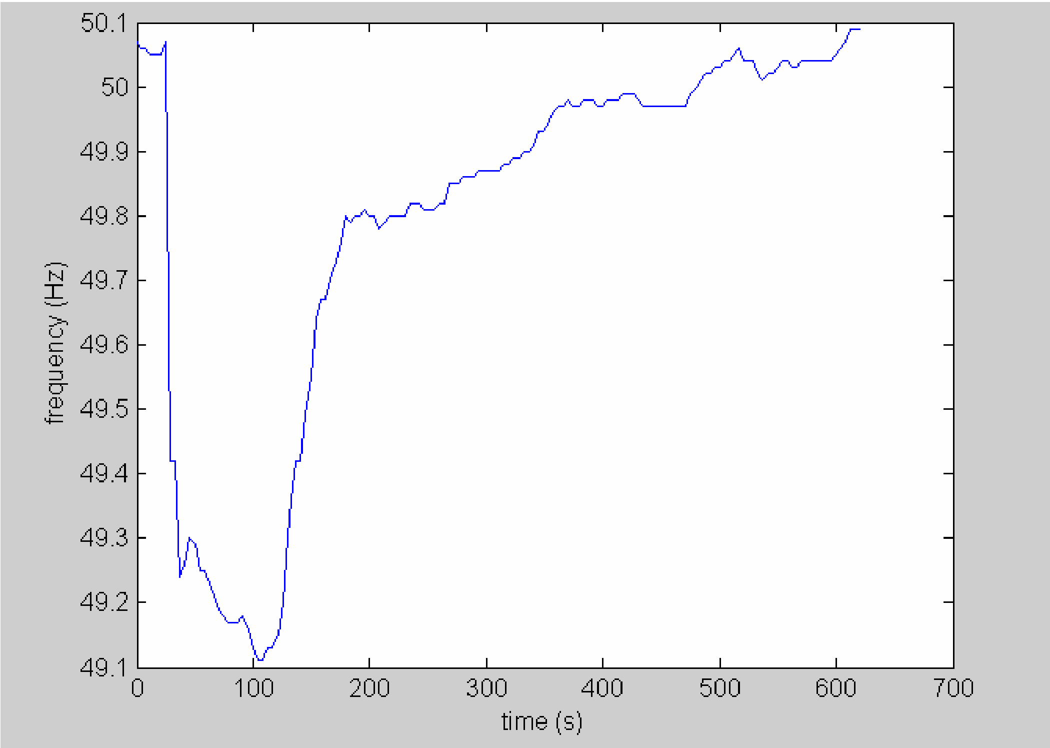

Figure H.1. Frequency recorded on 25 June 2003.

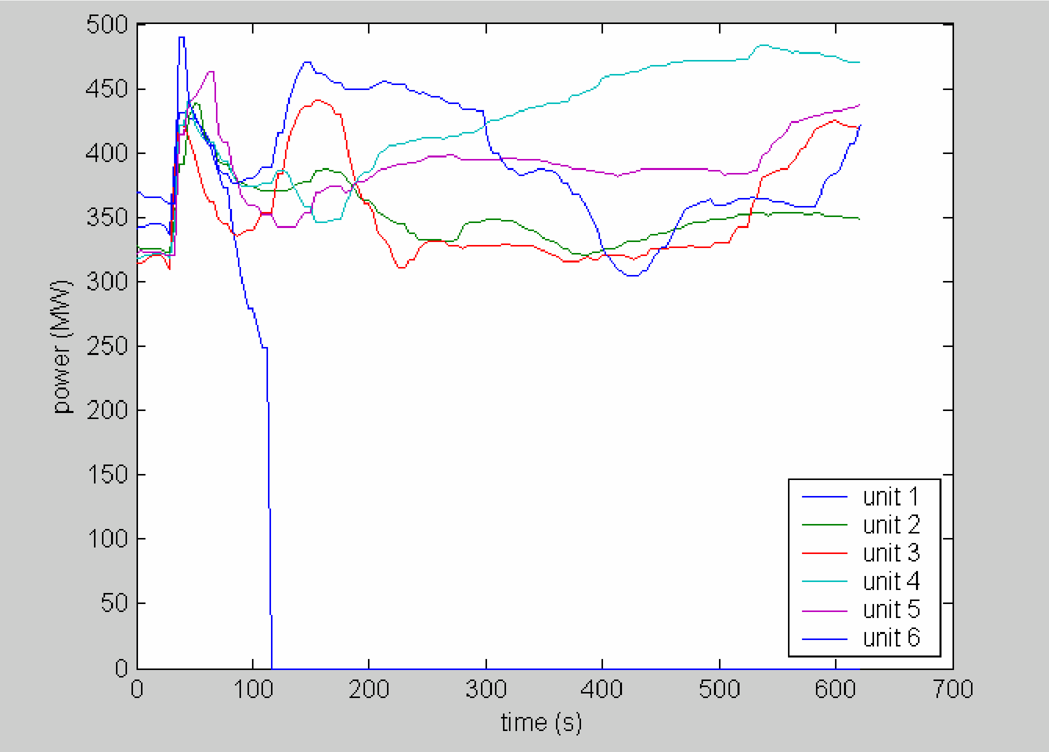

Figure H.2 Unit power output recorded for the incident on 25 June 2003.

H.9 Modelling the event in Matlab©

The event was modelled in a simulation package called Matlab© developed by Mathworks. Matlab© was used to do the extensive studies required for the frequency redesign project. The turbine-boiler model is the TGOV5 model developed for coal-fired boilers with reheat steam turbines (Lafkowski, 2000). The controller parameters were tuned to give a maximum response from the boiler while maintaining enough damping to prevent a cycling of the boiler pressure. The Matlab© tuning tool used was the non-linear design toolbox.

Figure H.3 shows the response from the model compared to the response of units when the same frequency was applied to the model. (Note: the power output is unitised.) The model shows a very good correlation up to 100 seconds, after which it was difficult to correlate due to the different power response from each unit. The model however also had an erratic electrical power.

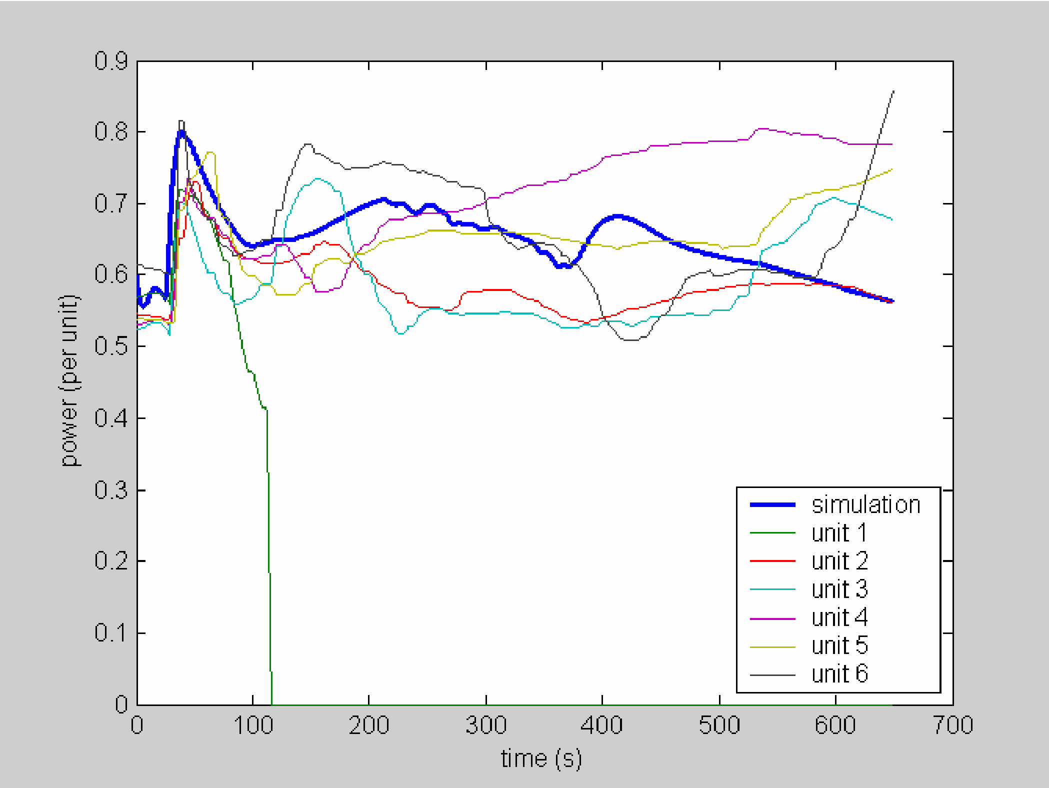

Figure H.3. Response of units compared with the modified IEEEGOV5 model developed in Matlab©.

H.10 Response if a deadband can be applied to the governor controls

Figure H.4 shows the simulated power response from a once through type unit if the maximum deadband of 0.15 Hz is applied to the governor and if the maximum electrical power response is limited to 10 % of MCR. It is noted that the unit's initial electrical response was curtailed but not enough to prevent the unit being unable to sustain the response for the whole frequency incident. **Figure H.5** shows the case where the power output was limited to 5% of MCR. There was enough boiler storage to sustain the response throughout the frequency incident.

After analysing the results from the simulations it is proposed to implement these modifications on the actual unit, except that with the current technology this is impossible to do at the units in question. The main reasons given by engineers for being unable to implement is the age of the equipment and the fundamental design philosophy implemented by the original equipment manufacturer in the control system.

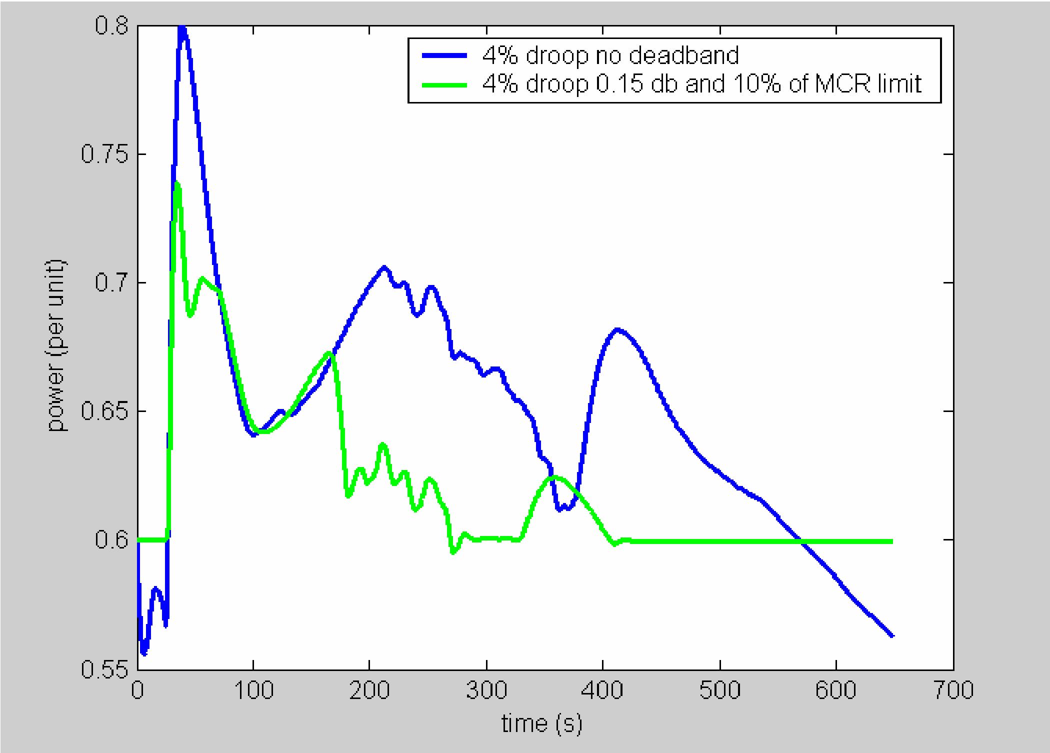

Figure H.4. Difference in power output when a deadband of 0.15 Hz is applied and response is limited to 10 % of MCR.

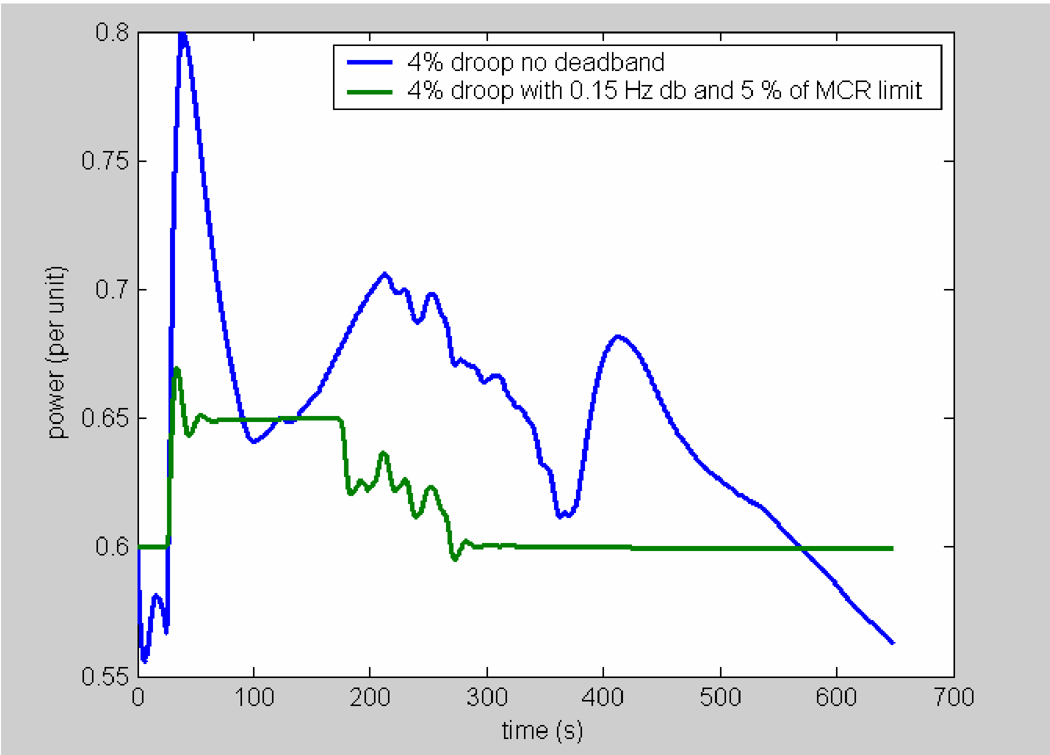

Figure H.5. Difference in power output when a deadband of 0.15 Hz is applied and response is limited to 5 % of MCR.

H.11 Other possible solutions

A possibility to reduce the response of a unit to frequency changes is to increase the droop of the governor valve. The higher the droop the less the response.

If the droop was increased to 10% for the same incident the power response of the unit was simulated as shown in **Figure H.6.** This response is typical to the response of the unit with a 0.15 Hz deadband and a 10 % limit on the maximum power response. The unit would still be unable to maintain the initial power response but the lower initial peak power compared to the 4% droop would assist in a more stable unit after the incident.

Another possible refinement is to reduce the feed forward gain to the boiler. The boiler feed forward gain was reduced by half in the model and the results are shown in **Figure H.7**. The results show that the power response was close to the response obtained from the case where the output was limited to be 5 % of MCR. The power was maintained throughout the frequency incident and the boiler was not over-extended. This should result in a lower trip risk when the unit is subjected to a large drop in frequency.

These two proposals need to be checked. The increase of the droop will influence the behaviour of the speed controller and the modification needs to be checked to ensure the turbine will not go into over-speed condition on a full load rejection and other sudden changes.

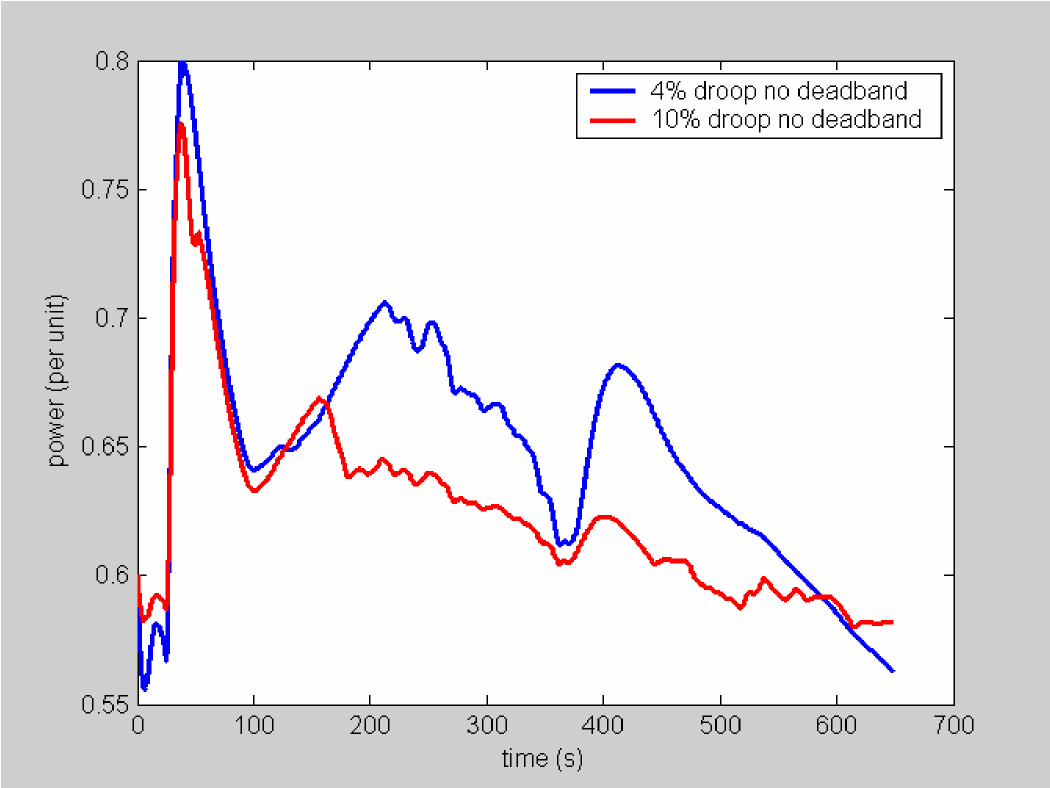

Figure H.6. Simulation of power for a 4% and a 10% droop.

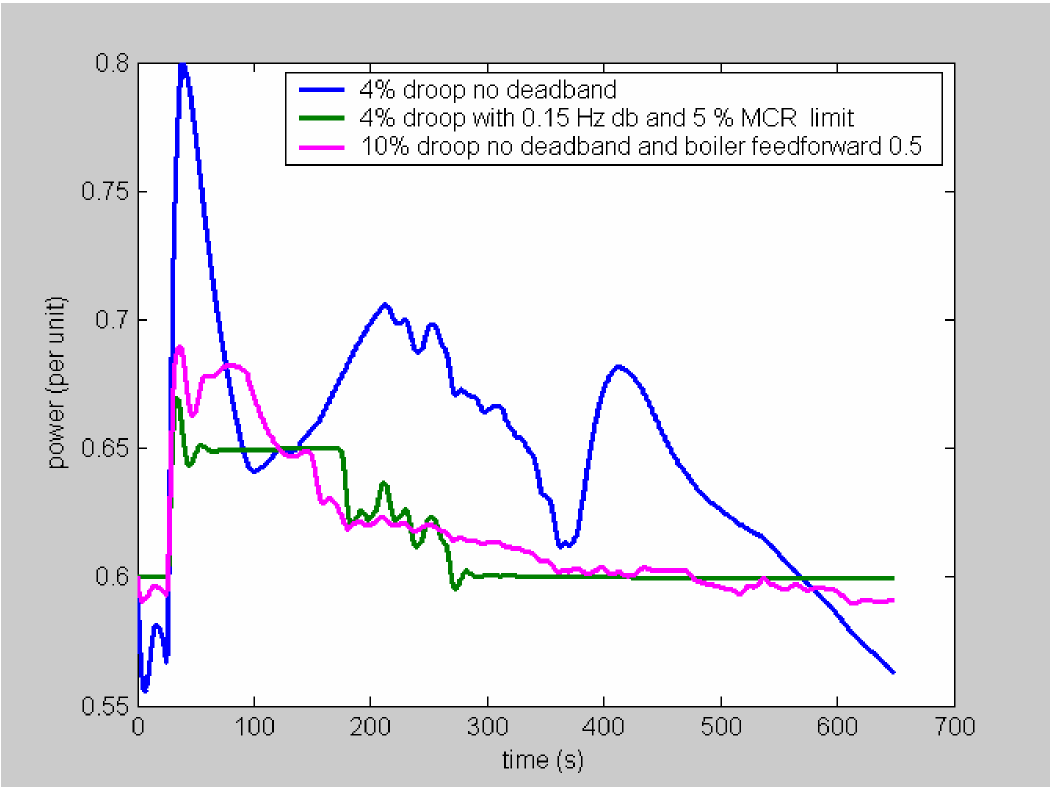

Figure H.7. Simulation with boiler gain reduced.

H.12 Simulation over a typical day

The model was simulated with the frequency as measured on a typical day, 10 June 2003. The setpoint of the unit was held constant so that just the effect of the governing on the electrical power, boiler pressure and governor valve position could be recorded. **Figure H.8** is the case where the droop was 4%, there is no deadband and the feed forward from frequency to the boiler was 0.5. **Figure H.9** shows where the governor droop has been increased to 10% and **Figure H.10** shows when the deadband was implemented. The movement of the governor valve and boiler pressure was reduced when the droop was increased and almost reduced to zero when the dead band was implemented. The temporary solution of increasing the governor droop was definitely not as good as the final solution of implementing a proper deadband.

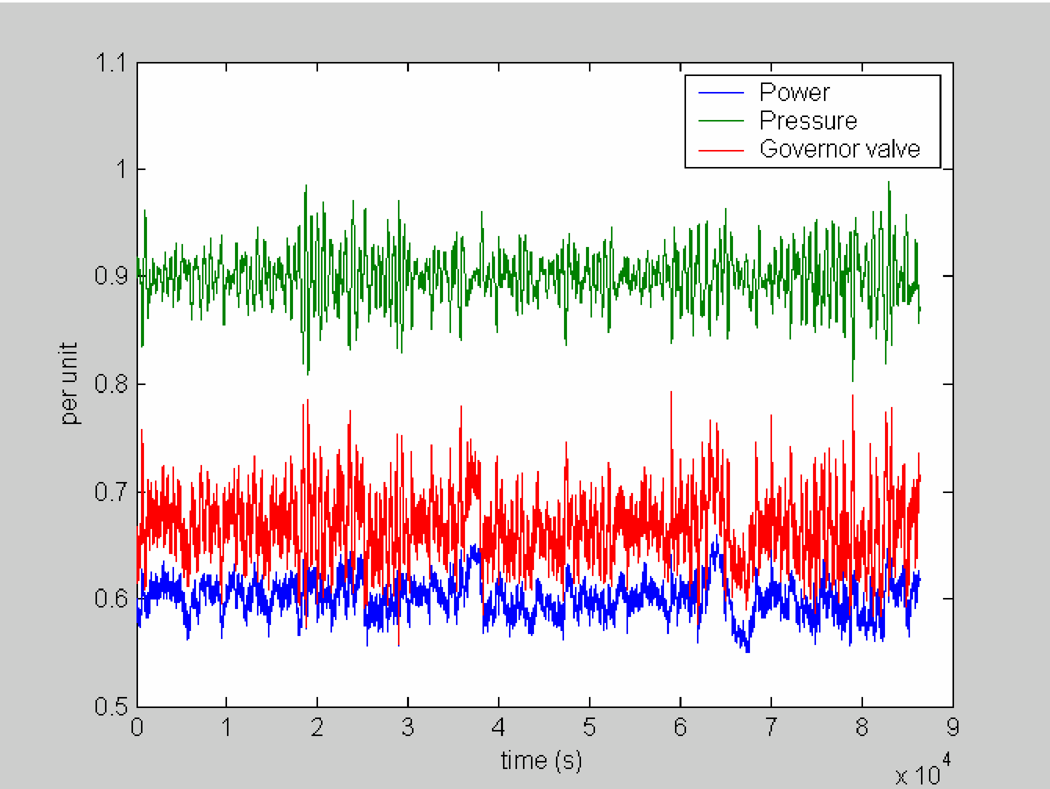

Figure H.8. Day simulation with a 4% droop, no deadband and a boiler feed forward of 0.5.

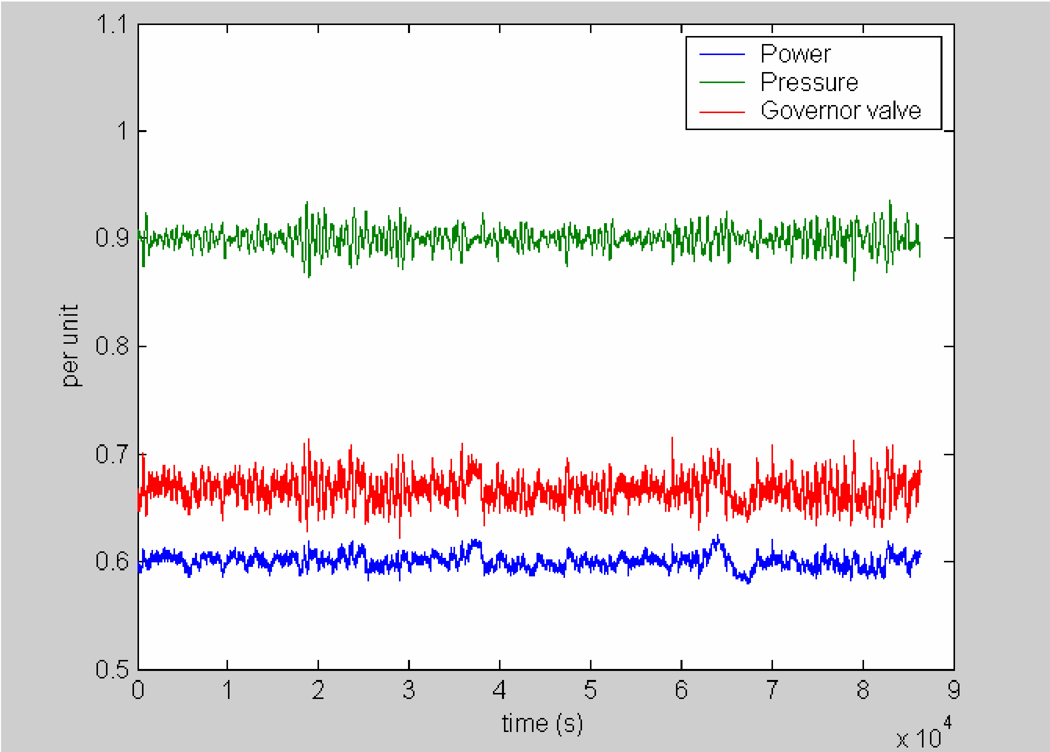

Figure H.9. Day simulation with a 10% droop, no deadband and a boiler feed forward of 0.5.

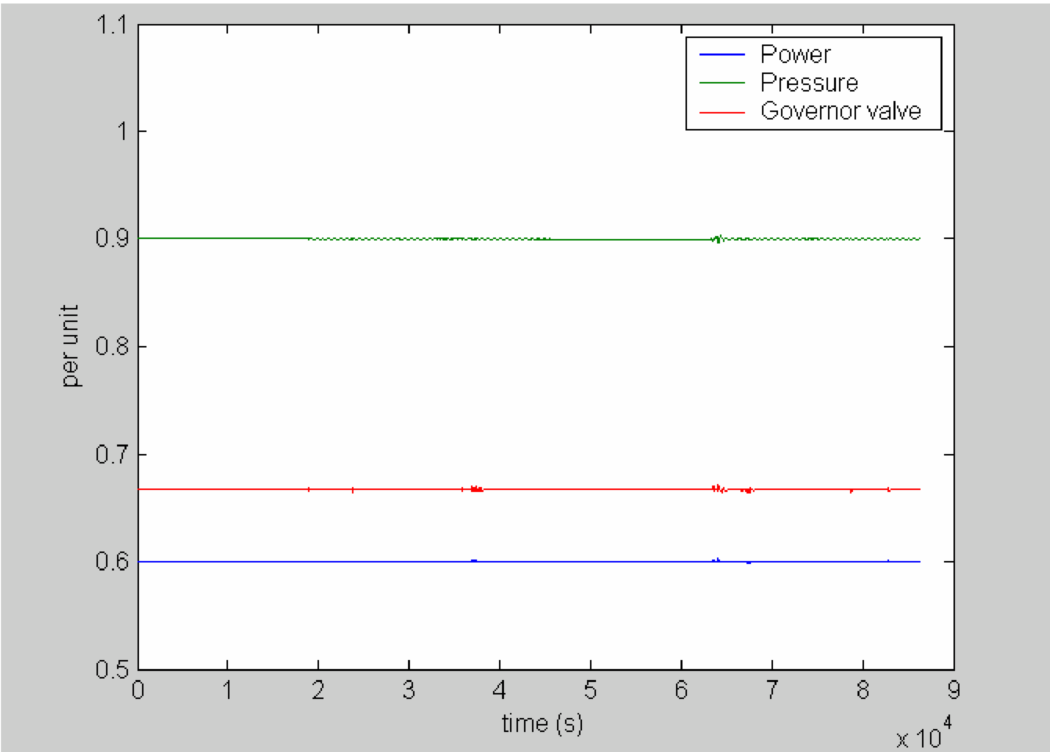

Figure H.10: Day simulation with a 4% droop and a 0.15 Hz deadband on the governor.

H.13 Summary of generation control capabilities

The modelling shows that making a few changes on the control system could drastically alter the response of the unit to frequency changes. The addition of a deadband and a limiter reduced the movement of the unit and made the response more predictable. Without the deadband, the unit's response on a 4% droop was larger in the first few seconds, but this response could not be sustained. When designing the overall strategy for frequency control all these variations and possibilities need to be understood to arrive at an optimal philosophy for the network being studied.

H.14 Special devices for assisting in frequency control

H.14.1 Energy storage

If electricity could be stored for long periods and returned to the network when required, most frequency control issues could be solved and supply and demand would become like the gas industry where surplus is stored in a tank for times of shortage of supply. Consumers currently use un-interruptible power supplies, which have battery back-up and diesel generators for ensuring a high available and reliable power supply. The building of large batteries or similar devices for storage of electricity, apart from hydroelectric pump storage plants, is not yet available. Short-term energy devices such as electro-magnetic flywheels, which can slow the rate of frequency change, are available for installation in small networks. This gives time for governing and other frequency control options to respond. Braking resistors can also be used for times where there is a surplus capacity. This is traditionally used to assist generators that can potentially form a small island where the generation could exceed the demand to such an extent that the frequency would go extremely high. The purpose of the braking resistors is to add additional load to the system for a short period until the frequency is stabilised. The final technique is to reduce the voltage to a portion of the network and thereby reduce the resistive demand. This technique works for a short period of time but many electrical processes might draw more current to keep the plant process at the right output.

H.14.2 Response capabilities of consumers

The tradition is to only use consumers to prevent the network from collapse via under-frequency and under-voltage load-shedding. This tradition is changing as consumers of electricity become more flexible in their electricity usage. A consumer who can vary his production through the day without affecting the cost or volume of the product required is often willing to switch off for a short period. The compensation for the inconvenience in such an event is key to the consumer becoming a willing participant in frequency control. Consumers can cut off their electricity supply by just opening the breaker supplying electricity, the speed of the response in this case is not really an issue. The consumer may want some time to shut down his process in a controlled fashion. This can be done if the time required can be catered for.

H.15 Summary of determining what can be used to control frequency

The key to re-designing the frequency control is to understand the make up of the network being studied in detail. This includes knowledge of all the possibilities available for control, some of which have been presented in this appendix. Without this knowledge an optimal control strategy cannot be developed.

In Eskom, most generators are thermal coal-fired generators from 200 to 650 MW. The boilers consist of both drum and once-through boilers, which have different thermal characteristics. These plants can change their output by 3 – 5% within 5 - 10 seconds. Larger changes cannot be sustained for more than 30 seconds. The generators can also change their output by 20 – 25% of the maximum rating at a rate of 3 – 5% per minute. The hydroelectric pump storage generators of 200 and 250 MW maximum rating in Eskom can ramp from 0 to 100% in 60 seconds. Hydroelectric generators, gas turbines and interruptible loads are available to operate in minutes, but are subject to energy availability, high operating costs, and restrictions such as the number of allowed operations per week. Apart from consumers that have mandatory under-frequency load-shedding, there are consumers who are also willing to participate in frequency control, one such consumer is willing to compete with generator governing in South Africa.

Appendix I : Matlab© model

Description of **Matlab©** model

I.1 Description of Matlab© model

The proposed new frequency control strategy requires detailed modelling of the generators and market rules to ensure that an optimal control strategy can be developed. Mathworks©, Matlab© and Simulink© packages were used for these studies. The appendix details the model structure and development. The model was developed to be able to run studies of frequency control from seconds to a full day study.

I.2 Model of Original AGC controller

The best way of gaining a proper understanding of a control system is by means of a computer simulation. The existing control system was converted from the FORTRAN code using the Matlab© programming code. Once the original control system had been modelled accurately, it was easy to implement and test alterations to this design.

A simplified functional block diagram of the model developed in Simulink© is shown in **Figure I.1.** Each block in the diagram is representative of other smaller block diagrams or subroutines. The regulation component as well as the programmable logic controller (PLC) of each generator type was modelled completely. Only a simplified base-point component model was developed as the specific economic dispatch of generation was not of interest for this purpose. The change in base points required by the simulation was simply distributed among available units to approximate the dispatch done by an economic dispatch (ED) routine.

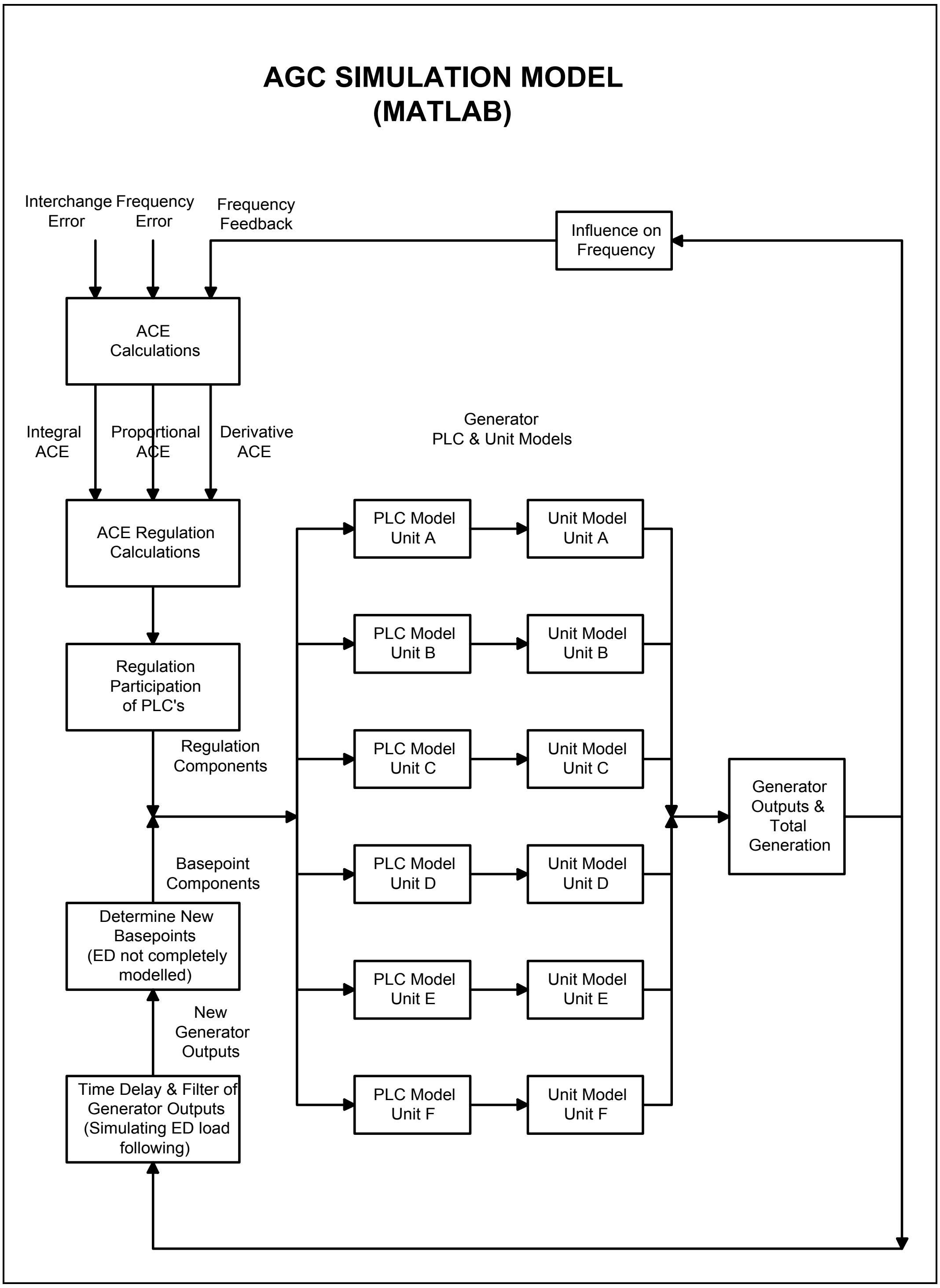

Figure I.1. Original Matlab© model of the AGC controller.

I.2.1 PLC and unit controller models

The programmable logic controllers (PLCs) of all units were modelled in the simulation, **Figure I.2.** The PLC models are very similar to the original AGC controller described in **Appendix D**.

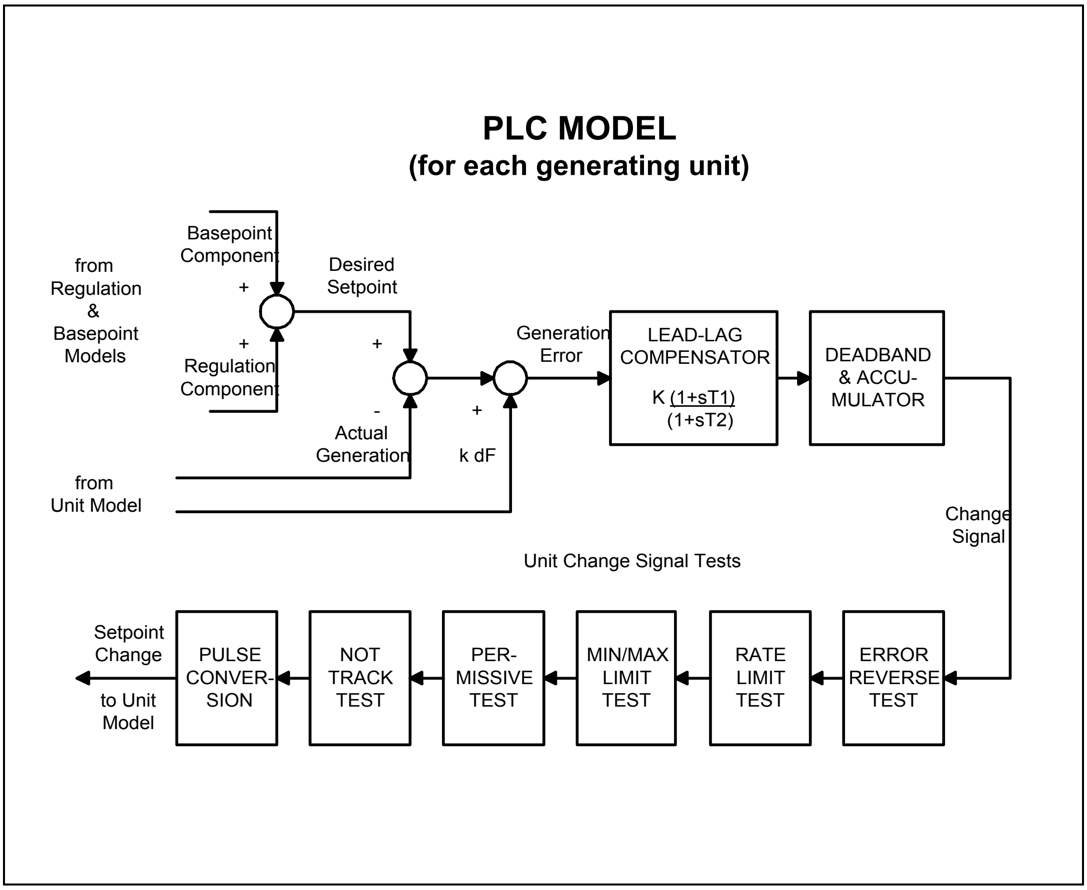

Figure I.2. Model of the PLC controller in Matlab©.

I.3 Fuzzy logic controller for AGC

The AGC controller was updated to be a fuzzy logic controller in 1997. This portion of the control system contains the calculations of the proportional, integral and derivative ACE as well as fuzzy logic routine as shown in **Figure I.3.**

The raw ACE is used in the ACE calculation block to determine all the ACE inputs (integral, proportional and derivative) while fuzzy regions and the associated regulation multipliers are the other main inputs. The fuzzy tables and rules form the main body of the ACE regulation calculation and the advantages of the fuzzy controller are described in the Master's thesis by the author (Chown, 1997) and published in IEEE (Chown and Hartman, 1997). The only two outputs are the total regulation component and the regulation region indicator. The regulation is distributed among the available PLCs by means of the participation function, taking the regulation region indicator into account.

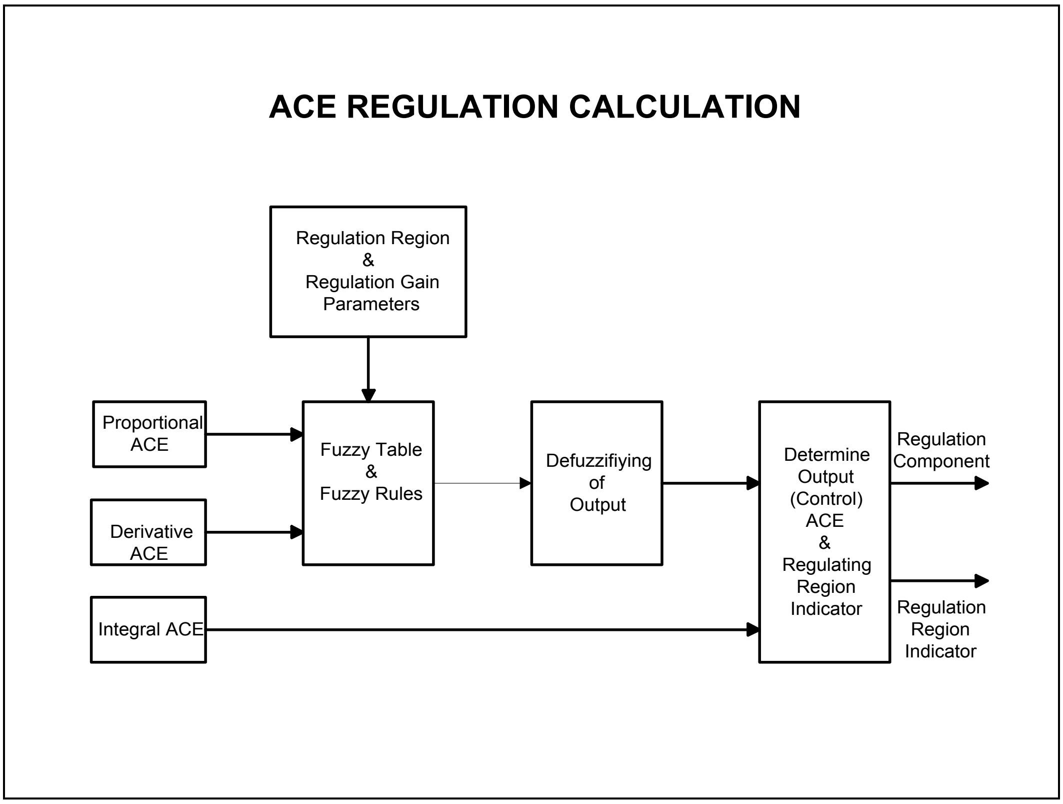

Figure I.3. Simulation of the fuzzy logic controller in Matlab©.

I.4 Financial controller for AGC

With the development of the Eskom Power Pool it was prudent to alter the AGC controller to dispatch the generation units more economically and in-line with market rules, **Figure I.4.** There are many tools available that can do economic dispatch based on market rules but none of these could easily be applied to the current energy management system because of the age of the technology. It was then chosen to develop the market dispatch internally. The market rules were added to the Matlab© model to test different dispatch options available. The basis of the routine is to sort the units on AGC and to choose the cheapest to dispatch. The dispatch error is then converted to which unit to pulse up or down. The permitting tests that exited in the original controller were incorporated in the financial controller when it chose which units are available to move in the given direction. All the participants in the Eskom Power Pool were modelled, see **Figure I.5.** Each participant will then receive pulses according to their offers. The participants that are not being controlled are assumed to have exactly the same output as they did on the actual day the data was recorded. Other values that are sent to each participant are the change in speed or change frequency and the participant's setpoint. Taking the values as they existed at the defined start time initialises the model.

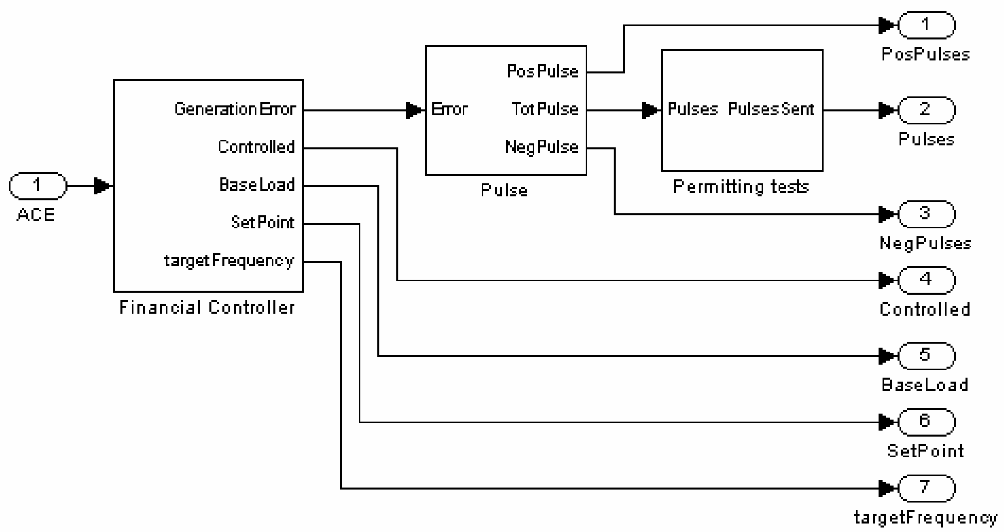

Figure I.4. Financial controller.

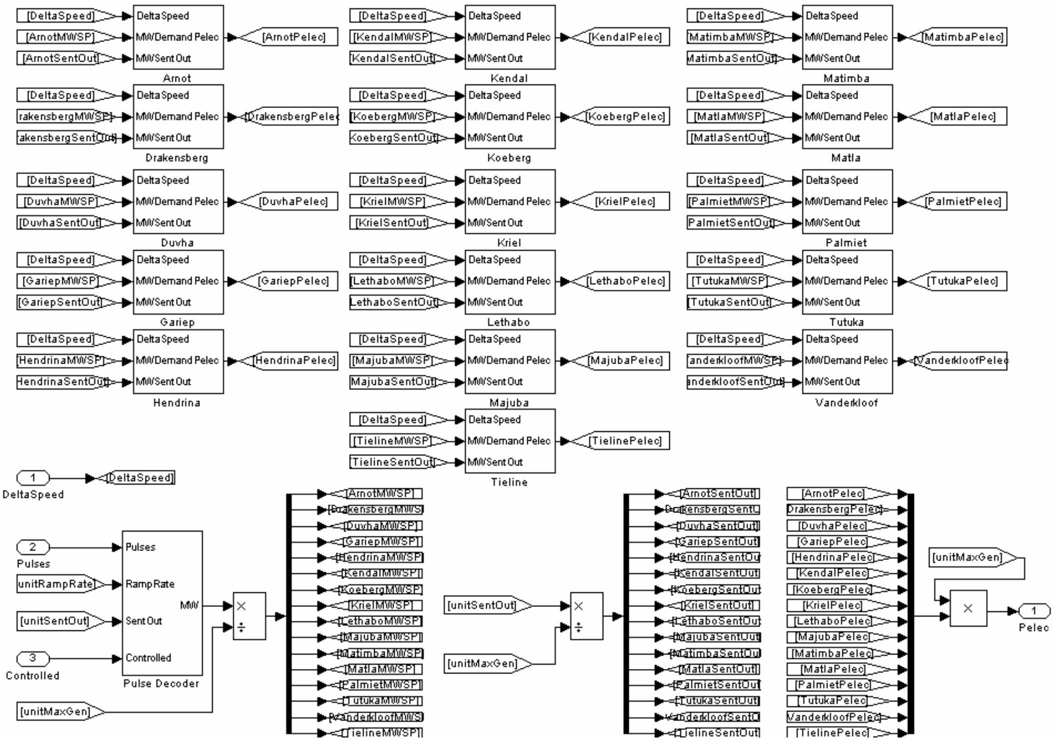

Figure I.5. Interface to all market participants.

The following participant and market data is used in the financial model:

- Participant bid price curves
- Participant flexible or inflexible flags (inflexible means a price taker)
- Regulation reserve up and down contracts
- Instantaneous reserve contracts
- Energy contracts
- Day-ahead market prices
- Participant high and low limits (AGC limits and technical limits)
- Participant ramp rate
- Participant actual demand or supply on the day (4 second data)

I.5 Network Model

The network and consumer model used was developed from the simplified model in **Step 3**. This was represented in **Matlab©** as shown in **Figure I.6.**

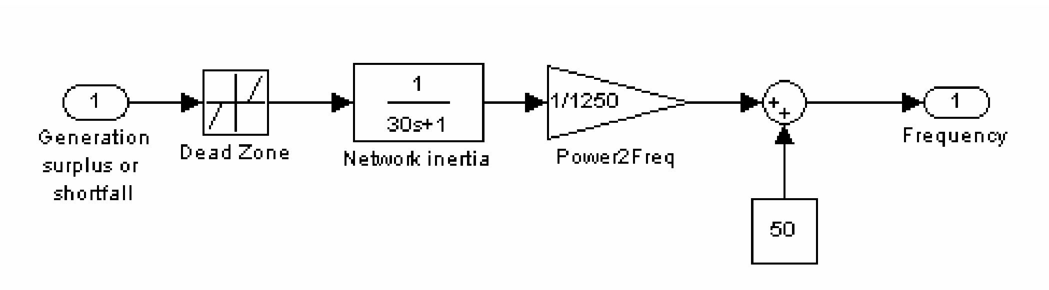

Figure I.6. Simplified model of the network and consumer in Matlab©.

The inertia of the network was modelled as a first order lag and with a load frequency support of 1250 MW per Hz. The dead zone was set at 1 MW to prevent a calculation for a small error in the supply and demand.

I.6 Turbine models in Matlab©

The PSS/e© Tgov1, Tgov5 and Hygov model, which is used to model coal-fired power stations and hydroelectric in PSS/e© were converted to Matlab©. The purpose of this was twofold. Firstly to have some commonality between PSS/e© and Matlab© models and secondly to retune the parameters in the PSS/e© model using the Matlab© System Identification Toolbox. The model of the generator was not included as model was not used for millisecond studies and it was assumed that electrical power equals mechanical power. This was confirmed as a correct assumption using real data and PSS/e© studies.

I.6.1 Tgov5 model

Tgov5 has a model of the turbine allowing for a three-stage turbine and modelling the delay in the re-heater, **Figure I.7.** The model of the control system is detailed enough to allow for the basic functions of a unit co-ordinator and various types of control philosophies. The boiler model contains the basic characteristics of the pressure of the boiler and the time transients of converting coal to steam. The model does not have a facility to model a deadband or a limit on the governors these features were added in Matlab©. This is a feature of most modern unit controllers to prevent the unit from becoming unstable.

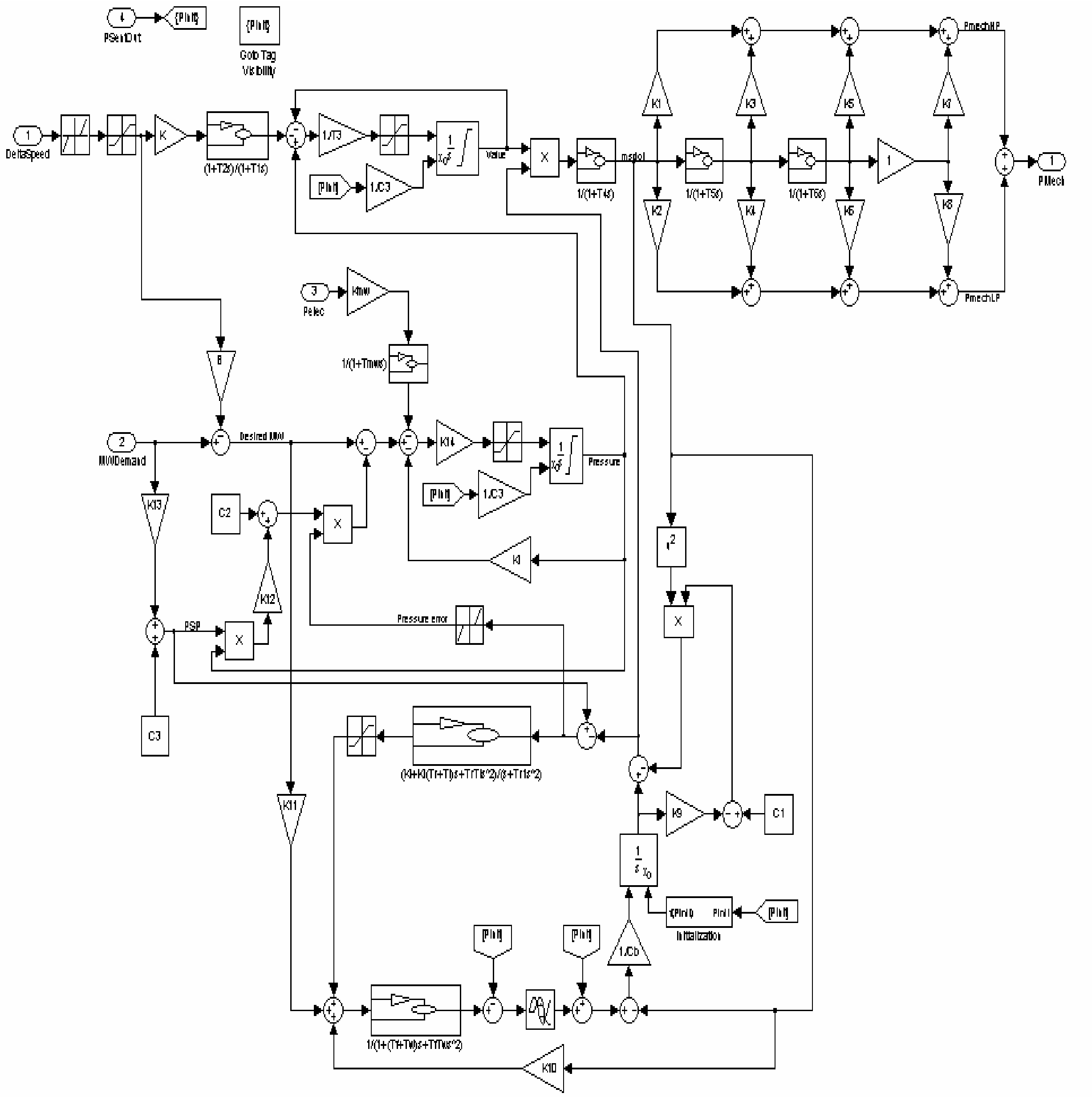

Figure I.7. PSS/e© Tgov5 model as modelled in Matlab©, with governor deadband and saturation.

I.6.2 Tgov1 model

Tgov1 is a simplified model of the turbine and governor, **Figure I.8.** This model does not have any representation of the boiler and assumes the boiler always supplies enough steam and pressure to supply the current demand. This is true if the unit is not ramped at too higher rates and or a too greater step at one time. The governor deadband and saturation were once again added to this model. This limits the amount of unit response to frequency changes. The rate of the unit movement is limited in the AGC controller to prevent the unit being ramped to quickly. This model is useful in that it speeds up the simulation.

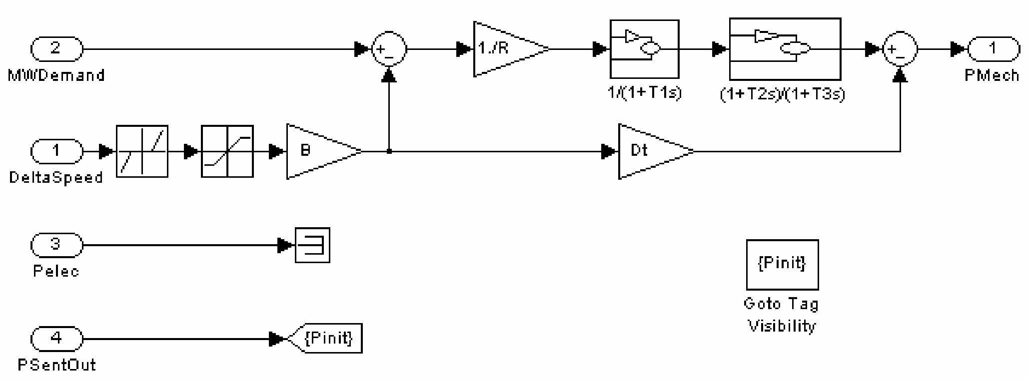

Figure I.8. PSS/e© Tgov1 model as modelled in Matlab© and with governor deadband and saturation.

I.6.3 Hygov model

To complete the suite of units that are in the Southern African network a hydroelectric power station model was used using the PSS/e© Hygov model. This was represented in Matlab© as shown in **Figure I.9.** This model was also enhanced with a governor deadband and saturation. This model did not include an AGC interface and where this was required the Tgov1 model was used instead of the Hygov model.

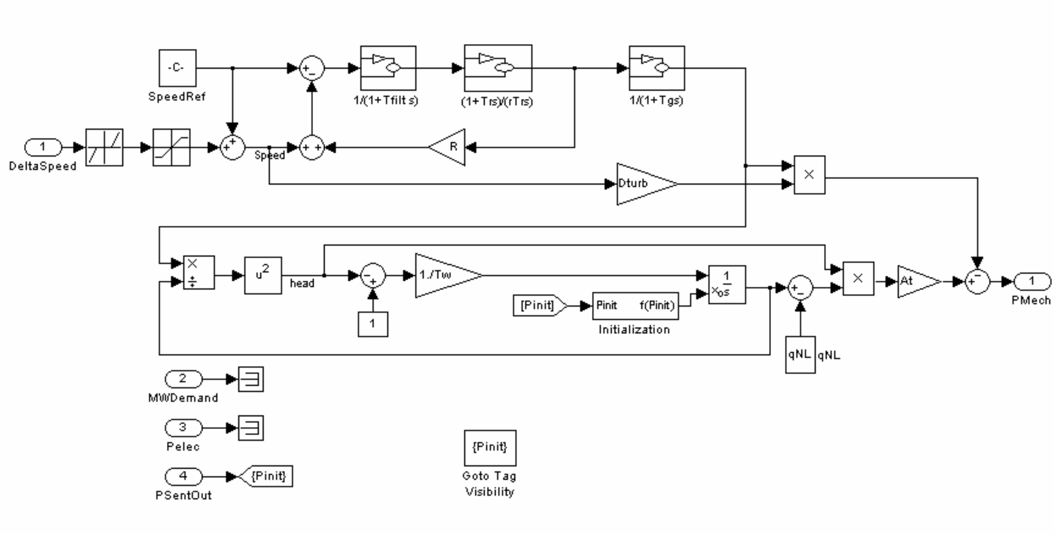

Figure I.9. PSS/e© Hygov model as modelled in Matlab© and with governor deadband and saturation.

I.6.4 User selectable graphical interface

A graphical interface was developed such that the different models could be selected easily and different parameters applied with ease. The purpose of this was to allow the user to model the effect of different control strategies that could be applied on the coal-fired plant with ease. This interface is shown in **Figure I.10.**

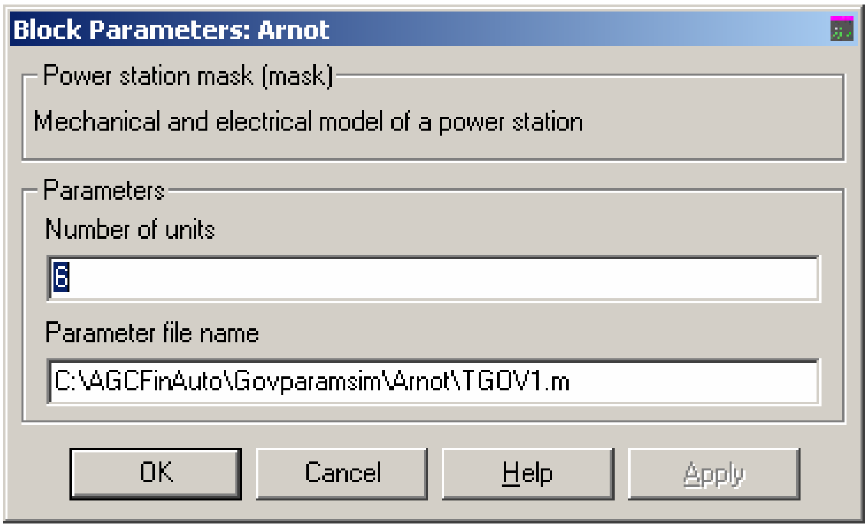

Figure I.10. Graphical interface to select model and parameters.

I.7 Modelling the load in Matlab©

The frequency dependency of the loads was represented by a constant of 1250 MW per Hz. The model is not designed for larger frequency deviations than 1 Hz and always assumes the voltages are stable. This is true if the model is not used for large disturbances where there are large voltage swings. The load is assumed to be the sum of the total power sent out from the power station's units plus any load support as per frequency deviation measured. The power station unit sent out is the generation of the power station unit minus any auxiliary or internal consumption, see **Figure I.11.** All this data is obtained from the energy management system measured every 4 seconds and represents the customer's demand on the network for the time period being studied. The load frequency dependency could have been more accurately represented by a percentage of the current sent out multiplied by the frequency deviation. This was found to have a very little effect on the results and a constant was found to accurate enough. The only problem with the input data used is that the power stations units input could have been faulty this data would then need to be corrected. A typical example is the recorded output of the unit goes to zero and then back to normal without any significant change in the frequency. The data from the state estimator would be more accurate, but the data cannot be obtained quick enough in the Eskom energy management system to correctly model the demand.

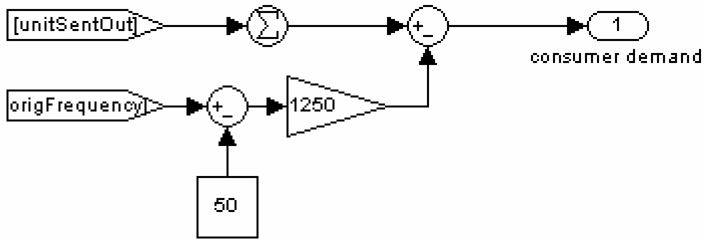

Figure I.11. Model of consumer demand in Matlab©.

I.8 Calculation of ACE

Figure I.12 shows the Matlab© model for the classical calculation of ACE with a fixed bias. In this simulation, the integral ACE is not calculated as it is not used and a derivative ACE is calculated for the fuzzy logic controller. The ACE calculation can easily be changed for different ACE calculations as described in **Step 6**. The frequency error is passed onto the market participants for Instantaneous reserve. The model does not cater for a network that is out of synchronisation or as separate Islands.

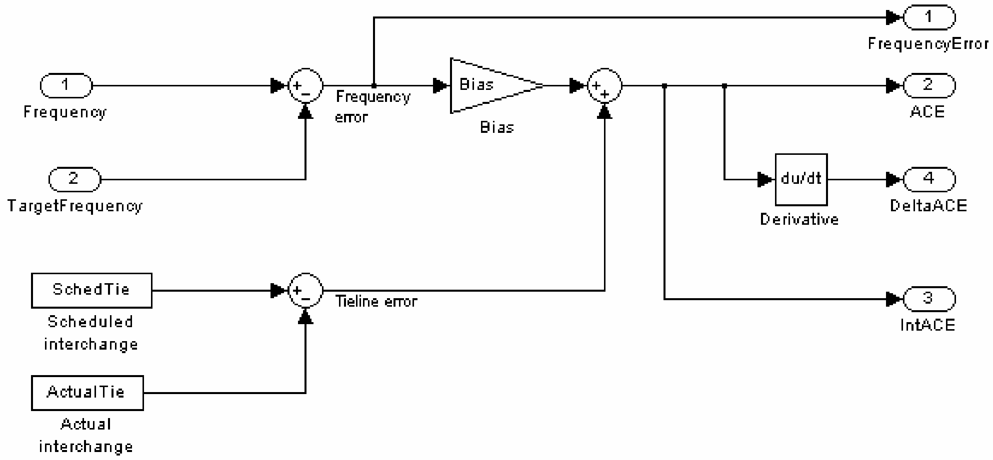

Figure I.12. Calculation of ACE in Matlab©.

I.9 Input data interface

An interface for inputting data and running the Matlab© simulation was developed for ease of use, **Figure I.13.** This was also developed for future operation by personnel that will not have to be familiar with Matlab© code. The interface allows for easily selecting the input data the type of governor model to be used, the input data and the type of financial or other controller. The start and end time and the type of Matlab© solver can also be chosen using this interface. The destination folder for the results can also be selected. The results are saved in a separate subfolder for each simulation run.

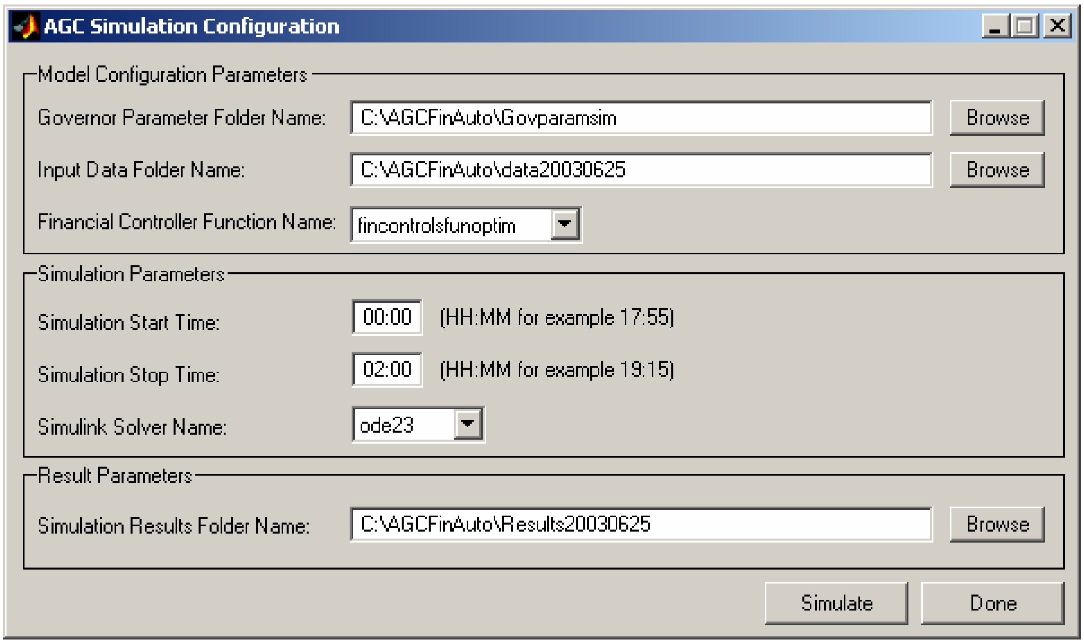

Figure I.13. Input data interface for simulation.

I.10 Publishing simulation results

The results that are stored in the subfolders can be reloaded via another graphical interface, **Figure I.14.** This is designed for easy access to simulated data and exported to Microsoft Excel© via a tabulate button. Data sent to the Microsoft Excel© includes the contracted values the actual hourly average values and market settlement data for actual day and simulated day information for each participant.

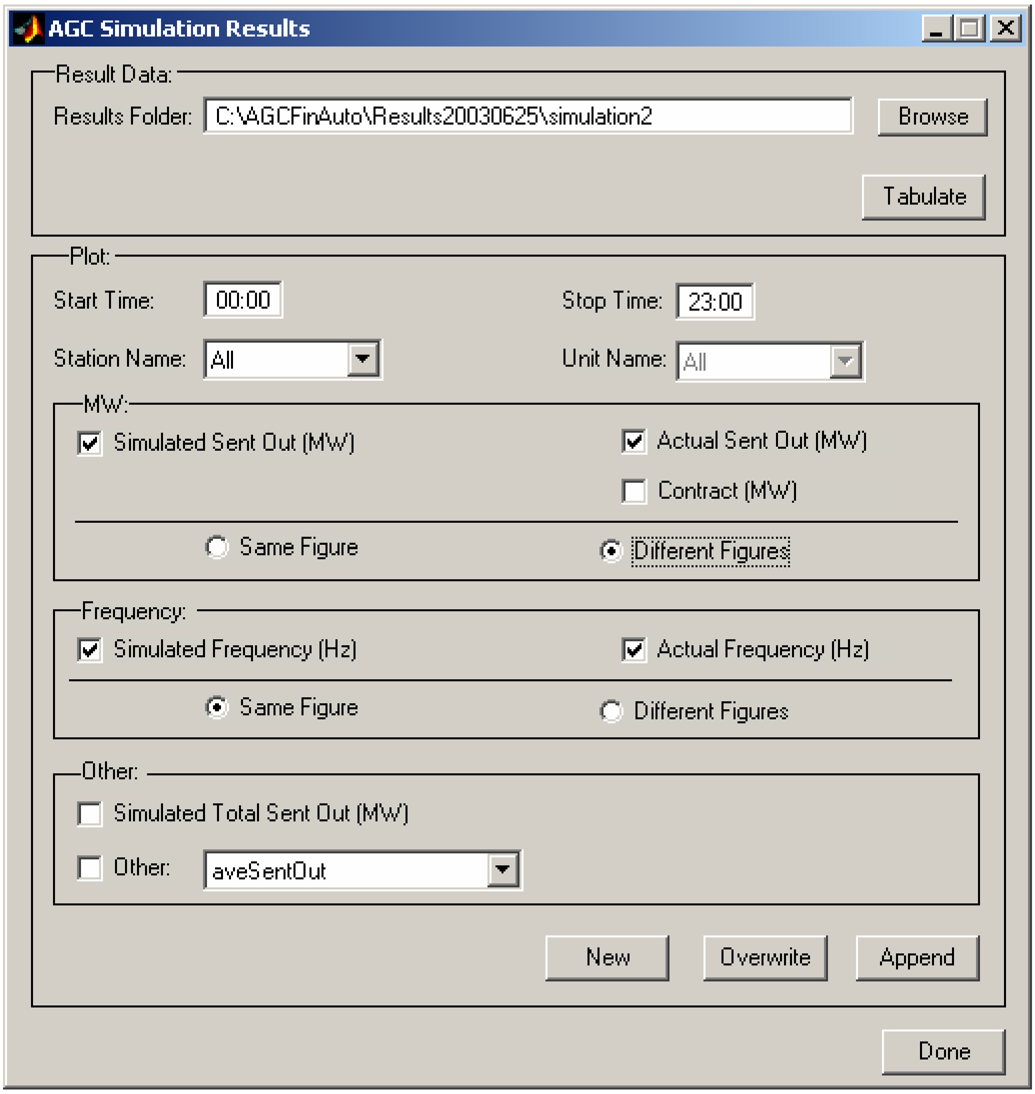

Figure I.14. Graphical interface to easily publish results of a simulation.

Graphs of all power stations or a single power station unit or market participant can be drawn, demonstrated in **Figure I.15** and **Figure I.16.** Each graph can be on separate figure or on a figure by itself. Graphs of the actual frequency and simulated frequency can also be displayed, as shown in **Figure I.17.**

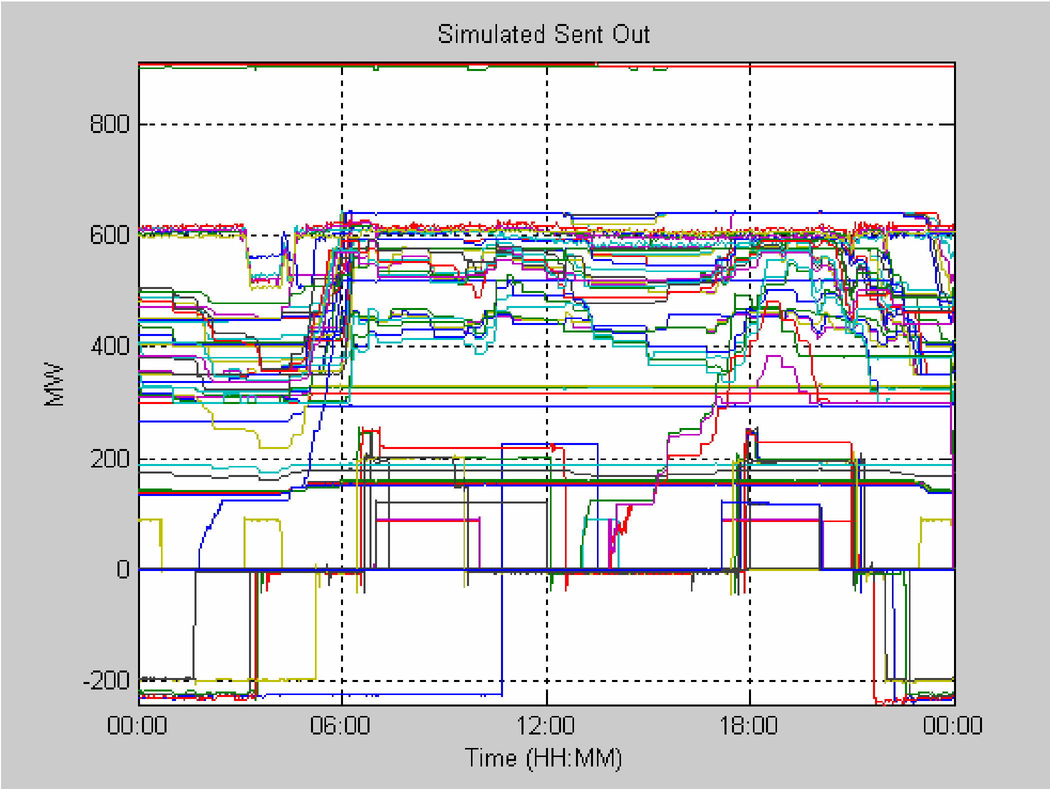

Figure I.15. Typical figure of all participants simulated output.

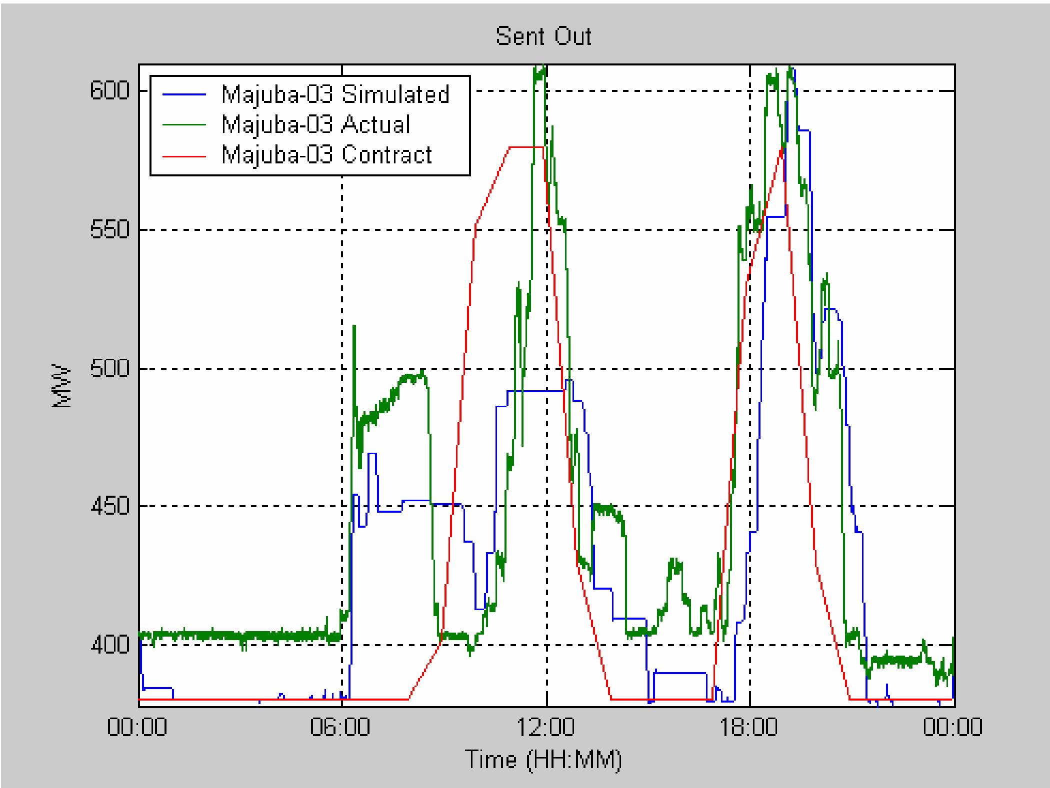

Figure I.16. Participants actual output, simulated output and day-ahead contract.

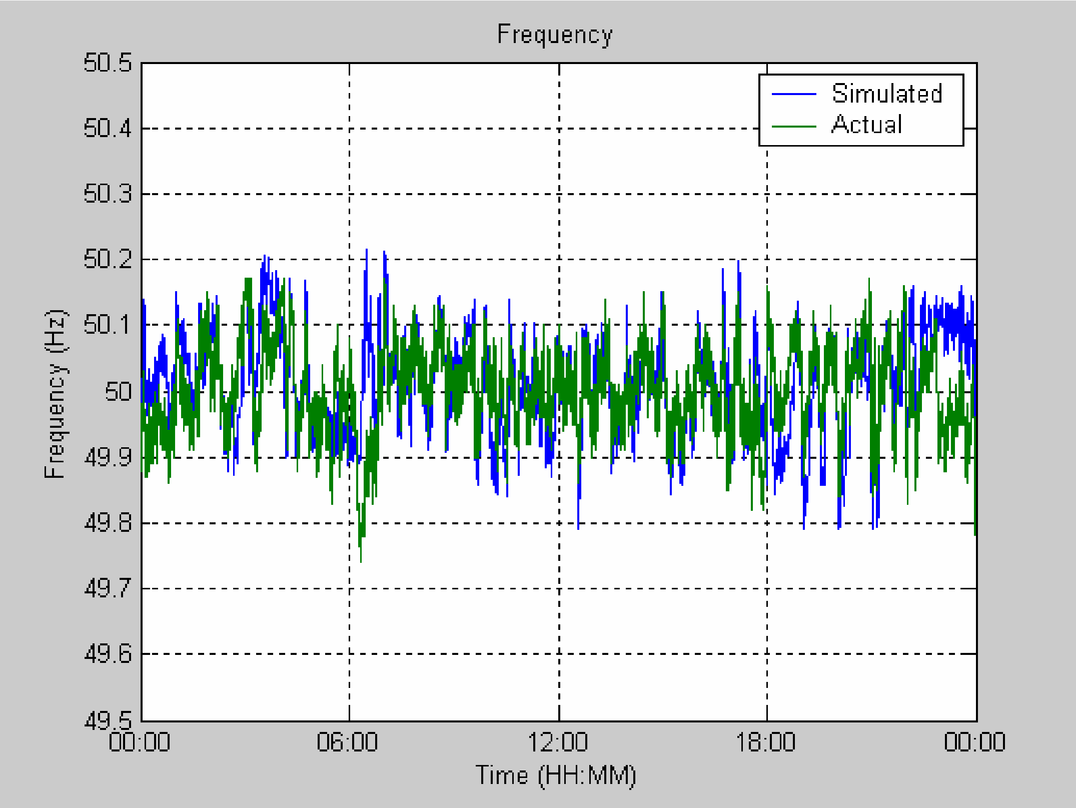

Figure I.17. Actual and simulated frequency for a particular day.