# DEVELOPMENT, IMPLEMENTATION AND OPTIMISATION OF A FUZZY LOGIC CONTROLLER FOR AUTOMATIC GENERATION CONTROL

Graeme A Chown

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# DECLARATION

I declare that this project report is my own, unaided work. It is being submitted for the Degree of Masters of Science in Engineering in the University of the Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination in any other University.

Fifth day of March 1998

# ABSTRACT

This project report describes the design of a fuzzy logic controller for automatic generation control (AGC) in Eskom in 1995 and the process of re-optimisation of the fuzzy logic controller in 1997. The main purpose of the AGC controller is to determine the shortfall or surplus generation of electricity for South Africa. The difficulties associated with optimising the original AGC controller, the design, implementation and optimisation of the fuzzy controller are described in detail.

The criteria for the optimisation of the controller were to minimise the control effort, thereby reducing the cost of operation of generation, without negatively impacting on the customer's quality of supply. The controller was first modelled in MATLAB® to ensure the success of the modification. The result is that the controller showed an improvement of 20% in quality of control and a reduction of control effort of over 55% from the un-tuned, original AGC controller.

The re-optimisation was a result of an additional performance agreement from the Southern African Power Pool for frequency distribution and changes internally in Eskom. The analysis of the performance of the controller is identified with new control performance criterion CPS1, developed by North American Electric Reliability Council to measure the AGC performance of USA utilities. This identified times of poor performance and areas to implement modifications in AGC, based on optimisations done in MATLAB®, to further improve the control performance.

The implementation of the modification to control the individual unit controllers set-point instead of actual MW is described and the process of optimisation using MATLAB® optimisation tools to obtain initial optimised values. The result of the re-optimisation was an improved control performance but the frequency distribution is still not the desired 90% within 50 mHz of 50 Hz. The report recommends the continuation of the process of identification of poor performance areas, using the simulation model to analyse and optimise modifications before implementation in the control system.

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# DEFINITIONS AND ABBREVIATIONS

| | |
|---|---|
| ACE | Area control error |
| AGC | Automatic generation control |
| AUT | Automatic status |
| AV | Average mode |
| BL | Base load mode |
| CE | Control economic mode |
| CFC | Constant frequency control |
| CNIC | Constant net interchange control |
| CV | Calorific value |
| DB | Dead band |
| DT | Decay (discretisation) time |
| ED | Economic dispatch |
| EDR | Economic dispatch routine |
| EMS | Energy management system |
| Eskom | (not an abbreviation - electric utility of South Africa) |
| ESP | Energy scheduling program |
| ICC | Incremental cost curve |
| IHR | Incremental heat rate |
| INT-ACE | Integral of area control error |
| K | Gain |
| Lambda | * *please insert correct wording here* |
| LFC | Load frequency control |

| | |
|---|---|
| MAN | Manual status |
| NERC | North American Electric Reliability Council |
| NTT | Not tracking test |
| PF | Participation factor |
| PL | Partial losses |
| PLC | Programmable logic controller |
| RRI | Regulating region indicator |
| RTU | Remote terminal unit |
| SAPP | Southern African Power Pool |
| SCADA | Supervisory control and data acquisition |
| SUB | Substituted (AGC status) |
| Tausec | Filter time constant |
| TLBC | Tie-line bias control |
| ZESA | Zimbabwe Electricity Supply Authority |
| ZESCO | Zambia Electricity Supply Corporation |

# 1 INTRODUCTION

## 1.1 DESCRIPTION OF AUTOMATIC GENERATION CONTROL

Automatic generation control (AGC) is the short-term closed-loop control of generating units in a control area by means of a centralised Energy Management System (EMS). The main objectives of AGC are:

- to maintain the system frequency at 50 Hz;
- to obtain correct tie-line interchange;
- to operate each generating unit at its most economic value.

## 1.2 BACKGROUND

Most large utilities use an energy management system 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). Eskom's EMS was developed by ESCA of the State of Washington, USA, and installed by the British company Westinghouse Systems Limited. The description of the original set-up of AGC is contained in Appendix A.

The enhancement of AGC was started in 1995 when a joint project was developed between Eskom Transmission and Eskom Generation to see whether AGC control to individual power stations could be reduced. The initial findings were that the AGC had a definite cycle and there was a large amount of unnecessary control. Robert Hartman led the main project and his master's thesis covers the complete project, including all software changes that were made to the original ESCA system to improve performance. This thesis describes the research that led to the selection of a fuzzy logic controller, the design thereof, the original tuning and the re-optimisation based on new performance analysis using MATLAB® tools.

## 1.3 RESEARCH PROBLEM

The cost of operating a regulating (moving) generating unit is higher than that of the same unit used at a fixed output. Primary energy cost as well as longer-term maintenance cost and life expectancy is affected by regulating a unit. In view of the continuous drive to improve frequency control and the efficiency of the system, the question of whether the regulating done by AGC can be justified was raised? The control centre also expressed the concern that AGC might cause the frequency and generator outputs to cycle. These issues could be extended to include the question of whether the total regulation effort, i.e. governing and AGC, is optimal.

The research problem was to reduce the amount of control, thereby reducing costs of the control, without having a negative impact on Eskom's local and international customers.

## 1.4 METHODOLOGY

The latest methods for AGC were researched through literature surveys and visits to Manitoba Hydro in Canada and the original software supplier ESCA.

To gain a precise understanding of Eskom's AGC, a detail analysis of the system developed by ESCA Corporation and installed by Westinghouse had to be done. A block diagram model of the control system was built into a simulation package for analysis and simulation purposes. This model could then be altered easily to test modifications to AGC and to benchmark performance.

Some time had to be spent on improving the existing performance criteria for AGC as these could only be used to evaluate the quality of the outputs and not to evaluate the amount of control required. New performance criteria for the measurement of the control effort were therefore developed before any modifications were made. Robert Hartman reports this in the master's thesis(4)

A control philosophy to obtain the required performance while minimising the control effort was then established. The philosophy was implemented by altering the design and configuration of AGC. The development and implementation of the philosophy can be divided into three main segments:

- Analysis and correction of inaccuracies in the original procedure and general improvement of the control system behaviour. This mainly consisted of eliminating logic that results in high non-linear outputs. During the original development the control system was never simulated, which resulted in a very non-linear design. This is reported in the masters thesis by Robert Hartman[4]

- Implementation of a philosophy of load following (long-term regulation) and ACE (short-term) regulation. According to this philosophy, generator outputs should be moved according to the economic dispatch routine for normal load changes. ACE regulation should only be done when larger short-term deviations in the frequency or tie-lines occur.

- Improvement of the regulating mechanism to allow the implementation of the above. A more proactive response from the control system was obtained by adding a derivative component to the controller. This was achieved by means of artificial intelligence in the form of fuzzy logic.

The performance of the new configuration and design of AGC was first determined by means of the simulation model. The new configuration and design were then installed on the operational system and performance was evaluated against the established criteria before being accepted.

The second phase of the research was to analyse the control system performance using new performance criteria developed by NERC and taking into consideration new requirements in the interconnected power system.

Changes were then modelled using the simulation model to determine whether they would be successful. The models control parameters were then optimised using the optimisation toolbox in MATLAB®.

This information was then used to modify and re-tune the AGC controller on the operational system and the performance was again evaluated against the established criteria before being accepted.

## 1.5 LAYOUT

**Chapter 2** describes the literature survey and overseas visit to the original equipment manufacturer and Manitoba Hydro.

**Chapter 3** presents the criteria for monitoring the performance and optimisation of AGC, including the measuring of control effort and an analysis of disturbances the controller has to cope with.

**Chapter 4** describes the optimisation efforts and problems experienced with the original controller. Describes how the controller would control the grid on manual and includes his expectations of AGC.

**Chapter 5** presents the detailed design of the fuzzy logic controller.

**Chapter 6** presents the AGC system simulation done in MATLAB®® to test and verify the fuzzy logic controller.

**Chapter 7** provides operational results achieved on the actual Eskom grid after implementing the enhanced AGC system.

**Chapter 8** discusses new performance criteria being implemented in the USA and its impact on Eskom and SAPP. This chapter also identifies improvements that can be made to AGC by using this method of analysis.

**Chapter 9** presents the modelling of recommended changes in MATLAB®® and the use of this tool for optimisation and stability analysis to achieve the improvements identified in chapter 8.

**Chapter 10** presents the preliminary results after the implementation of the changes identified in chapter 8 and 9. This is mainly the implementation of set-point control and re-tuning of the controller.

**Chapter 11** provides a conclusion and recommendations based on the research effort.

# 2 LITERATURE SURVEY ON LATEST TECHNICS FOR AGC

## 2.1 BACKGROUND

The literature survey for this project has been and is an ongoing task. The original literature survey suggested that there were great benefits in general optimisation of the AGC algorithm, in terms of better performance, as well as reduced costs by decreasing the movement of the power station units.

Subsequent surveys have been done to keep up to date with world trends and to ensure that the AGC algorithm is at its optimum.

The literature survey also includes the study of fuzzy logic controllers in terms of design, stability and optimisation.

## 2.2 LITERATURE SURVEY PRIOR TO IMPLEMENTATION

### 2.2.1 Enhanced Filtering

Manitoba Hydro(12) designed a filter on the ACE calculation to achieve insensitivity to small load changes and to ensure a prompt response to a power system disturbance. An AGC simulation and non-linear optimisation techniques were used to develop an ACE filter algorithm that reduces the amount of control action and improves control performance.

The implementation resulted in a reduction of 80% in control pulses sent to the power stations.

The implication of this is that there is a real possibility of reducing the amount of control by optimising the AGC algorithm.

### 2.2.2 Non-linear frequency bias

Union Electric Company (14) investigated the linearity of the relationship between frequency and load mismatch. Traditionally this has been accepted as a linear relationship. The findings of this report however prove that the relationship is far from linear. The introduction of a non-linear ACE calculation in the control system of Union Electric Company resulted in reduced generating units regulation.

### 2.2.3 Joint AGC

Minnesota Power and Manitoba Hydro(13) entered into an agreement where Manitoba Hydro agreed to regulate the first 20 MW for Minnesota Power. The reason behind this was to transfer the regulation from Sherbourne County Coal fired plant to the Maintoba hydro plant, which is the cheaper option. Of interest in this paper is the cost saving calculated by Minnesota Power of \$150 000 per year. The potential for Eskom to save money by reducing the amount of control and the number of power stations doing control is hence significant.

### 2.2.4 Self-tuning Algorithms

Lee, K.A. et al. (7) describe a control scheme in which each control area in the interconnection of New South Wales, Australia, was represented by a reduced order stochastic model with parameter estimation using an extended least square technique. The results of the paper showed a simulated performance improvement of 25% over the traditional PI controller. The algorithm also included a simple load disturbance routine.

In a second case study, generation non-linearity was modelled, for an unconstrained model and the improvements were only marginal over the first case.

### 2.2.5 Quality of supply

Frequency control has a potential impact on the end customer as electrical equipment can be adversely affected by frequency variations. Research has been done to determine an acceptable frequency range for the customer. Applications that would use the utility system frequency as timing or synchronisation could be sensitive to system frequency. A survey of various manufacturers by EPRI (20),(21) indicates that the acceptable frequency operating range is relatively large (60± 1 Hz). The EPRI study (20) addressed the range of tolerable frequency deviation for interconnected power systems. This study showed that the interconnected system in the U.S. could operate down to 59.5 Hz for longer than transient intervals without risk of equipment damage. A wider frequency bracket would be appropriate in smaller interconnections. Based on these studies it is acceptable to the customer to maintain the frequency within 0.5 Hz of nominal.

## 2.3 LITERATURE SURVEY AFTER IMPLEMENTATION

### 2.3.1 Application of a Fuzzy Controller to Automatic Generation Control

Indulkar, C.S. et al. (9) describe an application of fuzzy logic to design a controller for the AGC problem for a two area power system. The paper is a theoretical evaluation of the improvement of this controller over the traditional integral controller. The fuzzy logic controller also used the ACE and the rate of change of ACE as inputs into the fuzzy controller. The inputs are broken into 7 regions and the rules table is not presented. The theoretical results showed a response that compared favourably with the responses obtained from the classical controller.

### 2.3.2 EPRI research project RP 3555-04 Enhanced load frequency control

EPRI and Bailey(17) have launched a joint project to address some deficiencies that have been identified in traditional AGC controllers.

The deficiencies are:

- Control actions are based primarily on an estimate of the Instantaneous Area Load
- Frequency Bias Constant is insensitive to System Load and generating unit operating conditions
- Filtering of ACE delays control actions
- Modelling data used for dispatch and control is often static and inaccurate, not reflecting actual operating conditions at the power plants
- Economic and regulation objectives are often in conflict

The objectives of the advanced controller are:

- Match generation trend with the time averaged area demand while recognising operating limit and response rate constraints
- Minimise generating unit fuel costs
- Minimise load-frequency regulation costs
- Improve generation control performance
- Increase communication between load dispatch centre and power plants to allow optimisation of the combustion process and auxiliary equipment, to warn of impending operational problems and recommend possible solutions

The following features are being designed and implemented:

- A short-term load predictor to improve the match of supply to the demand trend
- A dynamic dispatch to co-ordinate economic and regulation objectives which would minimise unit fuel costs
- A fuzzy logic controller to analyse system frequency and net interchange deviation to reduce control requests for load frequency regulation
- A dispatch and control model using dynamic unit performance data to improve control performance
- A control algorithm to produce unit load schedules that allow combustion and auxiliaries

The above work is in progress and it will be seen from this report that many of the problems identified by EPRI in this report are the same as was experienced by Eskom and the solutions are very similar.

## 2.4 STABILITY OF FUZZY LOGIC CONTROLLERS

### 2.4.1 Lyapunov Stability Criteria

Stephen Chui and Sujeet Chand(22) developed a stability technique that defines bounds for each rule block on the table and then does a stability analysis for the closed loop system within the defined bounds using the Lyaponov criteria, ensuring the eigen values are positive. The paper shows that asymptotic stability can be easily demonstrated for regions not to near to the origin. If the fuzzy logic rules behave linear near the origin then stability can also be determined.

Wen-Laing Chen and Ti-Ping Chen(23) introduced an algorithm for the design of a stable fuzzy logic controller for a second-order system. They divided the output of a fuzzy controller into two parts: One to assign poles and the other to guarantee the stability of the whole system. Lyapunov stability criterion was then used to discuss the stability.

## 2.5 OPTIMISATION OF FUZZY LOGIC CONTROLLERS

Pramath Ramaswamy et. al.(24) suggested two approaches to the tuning of fuzzy logic controllers.

- To use a Kalman filter approach which minimises a function of the error and change of error of the output.
- The second approach simplifies on the first using a sub-optimal filter algorithm.

Jinwoo Kim et. al.(25) used a genetic algorithm optimiser for the optimisation of the fuzzy parameters.

# 3 ORIGINAL PERFORMANCE CRITERIA FOR MONITORING AND OPTIMISATION OF AGC PERFORMANCE

## 3.1 BACKGROUND

In large interconnected systems the quality of AGC in individual control centres has to comply with the standards set by the regulatory bodies. The Southern African Power Pool (SAPP) adopted the performance criteria established by the North American Electric Reliability Council (NERC).

There is, however, a further aspect of performance measurement that is often neglected. The amount of control necessary to satisfy the above-mentioned quality criteria has a significant impact on the cost of regulation. As there are no generally accepted indicators available, a measure for the control signals expected from AGC was developed to achieve optimum frequency and tie-line control as well as load following.

To optimise AGC for minimum control, it must adhere to the normal quality performance, as well as to the criteria set by the measurement of the expected control.

## 3.2 NERC PERFORMANCE CRITERIA

The North American Electric Reliability Council, NERC, developed a method to measure the performance of each AGC system in an interconnected system. This system consists of two main performance indicators, namely A1 and A2.

A1 requires the ACE to cross through zero a least once every 10 minutes and A2 requires the mean deviation of the ACE over the ten minute period to be within an acceptable limit according to the grid size. The detailed calculations are described in Appendix B.

Performance is then measured by the number of violations expressed as a percentage of the total number of 10-minute periods. Eskom is committed in terms of the SAPP agreement to a maximum of 20% violations.

This criterion only considers performance from an ACE perspective and does not consider the amount of control that also needs to be minimised. A team was set-up to develop a criterion that would determine the optimal amount of control (section 3.3).

## 3.3 MEASUREMENT FOR EXPECTED AGC

In order to measure the optimal control amount a criterion needed to be defined. The initial solution is to reduce the control until the NERC criteria are just being met, but this may not be optimal. Thus a criterion was developed to obtain an optimal control figure that considering the NERC criteria to determine the control effort dispatched is optimal.

The performance criteria calculation is fully documented in Robert Hartman's masters thesis(4).

## 3.4 DISTURBANCE ANALYSIS

A major part of optimisation is the analysis of disturbances in the control loop. The disturbances in the control loop can be described as measured and unmeasured disturbances. Measured disturbances can be included in the control loop and taken into consideration. The optimisation of the control loop must take such disturbances into consideration and respond to maintain the desired performance.

### 3.4.1 Measured disturbances

The control loop measures the actual Megawatts from each individual power station and tie-line. The power station units can vary their MW outputs due to many reasons. A coal-fired unit can have a disturbance in the fuel supply, or it could have an auxiliary pump trip. Typically in Eskom the common disturbance ranges are 600 MW or less and can be instantaneous in terms of AGC analysis as a breaker can open within 30 ms. This can be measured in the actual load of the unit that is sent to the control system.

The problem with this measurement is the detection of a real disturbance over an unsophisticated communications network. There are cases where the information is not relayed back and in this case the controller would receive a zero value. This is checked in the database and automatically corrected with the previous value. This can cause a delay [illegible] detection of a real disturbance. The accuracy of analogue signals from power stations is poor due to the number of bits sent back. An error on one unit can be tolerated but the errors can become cumulative.

### 3.4.2 Unmeasured disturbances

There are many unmeasured disturbances in a complex system like the AGC system. Unmeasured disturbances lead to a change in the ACE, as the demand will not match the supply. As the individual loads are not measured in the Eskom AGC, any change in load will cause a change in the error (ACE). This then needs to be corrected by changing the supply.

The major problems with this approach is the time taken to correct the mismatch and the possibility that the change was only temporary, thus [illegible] a reversal. The operator is often aware of disturbances in advance. These disturb[illegible] vary from the starting of a pump or the sudden changing in load due to schedul[illegible]tenance, to simple things such as the ending of a major sporting event on televisio

## 3.5 SUMMARY

NERC control performance criteria together with frequency and tie-line statistics are used to measure the quality of AGC. This is measured on an hourly basis and can be summarised monthly. The effectiveness of the control system, i.e. the amount of control needed to obtain the required quality of supply, must also be measured. Optimum control can be described as the minimum control effort required maintaining quality criteria. Minimising the regulation effort results in a reduction of generation cost for the power stations. Like NERC performance criteria, the optimal AGC is a post dispatch analysis that can be calculated on-line but is not used in real-time decision-making. The controller must be set-up to handle measured and unmeasured disturbances.

# 4 OPTIMISATION OF THE ORIGINAL CONTROLLER

## 4.1 BACKGROUND

The optimisation of the original controller was attempted after discussions with the software developer, ESCA. The objective was to obtain the best performance software modifications which would make the software not comply with the manufacturer's standard. The manufacturer's had not installed their software in such a large grid and had little experience in the setting up of AGC for coal-fired power plants. In their experience most utilities used Hydro Power Plants which can be moved quickly and without delay, simplifying the optimisation problem.

Westinghouse, not ESCA had set up the system in Eskom. The system was originally set-up to ensure that no NERC A1 or A2 violations were incurred. In order to achieve this easily the gains on the controller were extremely high. The gains were: 4 in the "normal" region, 16 in "assist" and 20 in "emergency". If one considers that the filtered ACE should represent the error, then a gain of 1 should appear to be accurate. ESCA's typical gains were: 1,2 in the "normal" region , 2 "assist" and 4 in "emergency". The high gains had the effect of constantly pushing the ACE through zero, this led to over-control and cycling.

## 4.2 OPTIMISATION

The optimisation process was to set the gains on the controller to the levels that were acceptable to other AGC systems and observe the effect. From this using intuitive methods to further tune the system to an acceptable level of performance. The optimisation criteria are given in the previous chapter. The setting of the values to the recommended settings reduced the amount of control but the controller was too slow to maintain the NERC performance criteria. This was hence unacceptable. The increase in the proportional gains of the original controller had the effect of pushing the system into a cycle. Reducing the integral time in order to achieve the NERC criteria also had the same effect.

## 4.3 CONCLUSION FROM THIS OPTIMISATION

Due to the delays in the process the controller needed to apply a lot of control when the ACE went away from zero and then send no control while the ACE was returning to zero. The proportional and integral constants are always active while the ACE was outside its dead-band. The AGC algorithm requires derivative action to achieve the above to compensate for the proportional and integral action.

The time spent in the control room was invaluable. The controllers were always challenging by stating that they could outperform any AGC that we installed. This was not surprising, as the control loop was very non-linear with unpredictable delays. The controller however would get a "feel" for the amount of control and when we were optimising the controller we achieved a similar "feel". We could tell by observing the ACE and the amount of control whether the ACE was going to return to zero or under/over shoot. During this time we realised the ease with which a fuzzy logic controller could be installed.

## 4.4 MANUAL OPERATION OF THE GRID IN ESKOM

This section describes how the controller would operate the grid and control the frequency and tie-lines if there was no AGC. This is important to describe, as the fuzzy logic controller would be designed based on these descriptions

The controller looks at the ACE and attempts to control the ACE to achieve the NERC criteria with the minimum amount of control effort.

The controller at all times tries do things intelligently and learns from his mistakes.

Typical actions would be the following:

When the ACE moves from zero slowly the controller first attempts to estimate whether this is a disturbance or random noise. The first action is hence to wait until the error is significant, on the

Eskom grid this would typically be between 50 and 100 MW.

When the ACE error is significant the controller will raise or lower units in the following fashion:

The controller watches the ACE and initiates enough control action until the ACE turns and is no longer increasing. This is then a crucial point to stop and wait. Due to the delays in the whole process there is still more control action to come which will push the ACE further towards zero. The controller will then observe over the next few minutes if the control action he has been waiting for will return the error to zero. If not more control can be issued. The stop and wait is crucial also, as a significant disturbance will often correct itself. When it is certain that the error is returning to zero and if the disturbance disappears then there will not be a major swing in the opposite direction.

The controller only follows the above process for disturbances that are unknown. He will correct for known changes automatically. This type of action happens on a regular basis in the day. There are distinct changes in the demand at specific times of the day of which the controller is aware and corrects accordingly regardless of the control system. The most significant of these is the load pick-up in the morning which can be as much as 3000 MW in an hour. The normal AGC is not able to handle this without the grid incurring time losses due to delays. In these circumstances the controller loads the system with an ACE error on the correct side.

The second typical disturbance occurs when a power station phones as a unit is about to trip from a high load, typically 600 MW. In these circumstances the controller will start to make a contingency plan before the actual event. Typically a hydro or pump-storage power plant will be started.

## 4.5 CONTROLLER EXPECTATIONS OF AGC

The controller expects AGC to take care of normal disturbances that occur over the course of a day that do not compromise the system security. The controller should handle all major disturbances. This control action frees the controller to perform the more important tasks.

An analysis was done to determine the border between normal and major disturbances. An analysis of previous data showed that typical disturbances over a 10 minute integral are up to 300 MW or 150 MW either side of nominal. This can be regarded as the normal load fluctuations in the customer base. AGC should definitely be set-up to control in this region.

Disturbances of 150 - 300 MW from zero also occur reasonably frequently during the day. As disturbances normally cause frequency change up to 0.1 Hz and are not a security risk, AGC should be able to handle them within the defined performance criteria.

Disturbances over 300 MW AGC must react as quickly as possible to return the ACE to zero. Here the controller accepts that these disturbances occur typically 2-3 times a day and controller action might be required to assist AGC.

## 4.6 CONCLUSION OF MANUAL CONTROL

This chapter lists the control actions typically taken by the controller if there was no AGC. This information is essential in building a control system with which the controller feels comfortable. It is important to note that the controller is capable of controlling the grid within the performance criteria set-up above. The AGC algorithm is hence not expected to out-perform the controller.

The criteria that the controller expects from the control system are also described. This will help in setting up the boundary conditions for the optimisation process.

# 5 DESIGNING OF FUZZY LOGIC CONTROLLER

## 5.1 FUZZY LOGIC CONTROLLER DESIGN

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 functions performed by the lower-level controllers are suitably handled by the original controller. 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.

**Calculation of the derivative ACE**

The relative magnitude and direction of movement of the ACE (Δ ACE) is determined by subtracting the filtered ACE from the unfiltered ACE. This is similar to using the standard differential function equation (Eq 9.1 to 9.3).

$$\Delta ACE_{Filtered} = ACE - ACE_{Filtered} \qquad \text{(Eq 9.1)}$$

where:

$$ACE_{Filtered} = \frac{1}{(1 + sT_{leu})} \times ACE \qquad \text{(Eq 9.2)}$$

$T_{tau}$ = Filter time constant

Therefore:

$$\begin{aligned}\Delta ACE &= ACE - \frac{1}{(1+sT_{tau})} \times ACE \\ &= \left(1 - \frac{1}{(1+sT_{tau})}\right) \times ACE \\ &= \frac{sT_{tau}}{(1-sT_{tau})} \times ACE\end{aligned}$$

(Eq 9.3)

The discrete-time equivalent of the differential equation (Eq 9.3) used to determine the direction and rate of movement of the filtered ACE is:

$$\Delta ACE_{Filtered} = (1 - DTF) \times (ACE - ACE_{Filtered}) \qquad \text{(Eq 9.4)}$$

## 5.2 DETAILED FUZZY LOGIC CONTROLLER

Fuzzy logic is used to determine the total regulation component that must be allocated to the generating units. The ACE must be converted into a control ACE that takes the integral, proportional and derivative components into account. The filtered ACE (proportional and integral components) as well as the derivative (Δ) ACE is therefore first determined as described.

The design of the fuzzy logic controller can be divided into three areas, namely: the allocation of the areas of inputs, the determination of the rules associated with the inputs, and the "defuzzifying" of the output into a real value.

### 5.2.1 Allocation of Areas of Inputs

The ACE is the main input into the regulation component of AGC. Therefore the ACE, integral ACE and the derivative ACE (ΔACE) are three factors determining the amount of control required. As the integral ACE is taken care of in the longer-term economic dispatch routine, only the ACE and ΔACE are inputs to the fuzzy controller.

Both the ACE and ΔACE were divided into five control areas based on magnitude and sign. These are negative large (NL), negative small (NS), zero (ZE), positive small (PS) and positive large (PL). The calculation of the gain from input values by means of the control areas is shown graphically in Fig 5.1.

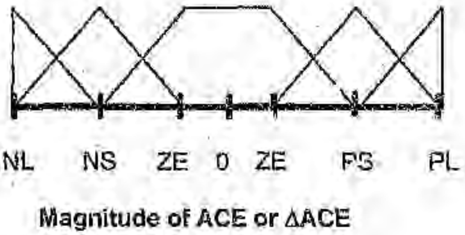

**Fig 5.1**

### 5.2.2 Fuzzy Rules

The rules used for the fuzzy controller are described in the fuzzy rule table shown in Fig 5.2. The rules are interpreted as follows: if ACE is NL and ΔACE is NL then ACE-out is NL, or if ACE is NL and ΔACE is NS then ACE-out is NL, etc.

The mathematical formula applied is the "min/max" rule for "and" and "or" respectively. This was done to reduce the calculation complexity and time.

|  |  |  |  | ACE |  |  |
|---|---|---|---|---|---|---|
|  |  | **NL** | **NS** | **ZE** | **PS** | **PL** |
| ***dACE*** | **NL** | NL | NL | NS | NS | ZE |
|  | **NS** | NL | NL | NS | ZE | ZE |
|  | **ZE** | NS | NS | ZE | PS | PS |
|  | **PS** | ZE | ZE | PS | PL | PL |
|  | **PL** | ZE | PS | PS | PL | PL |

Fig 5.2

As can be observed from the rules, more emphasis is placed on the ΔACE than the ACE. This allows the dead-band for the ACE area to be set high with control in this region only on rate of change.

### 5.2.3 Defuzzifiyng of the Output Value

The simple singleton method proved to be adequate for the output value. A method such as the centroid method was not an option because of its computational intensity.

The output or control ACE (ACE-out) areas were defined as per Fig 5.3.

The control ACE is allocated amongst all the generating units which are controlling the grid. This section was not modified from the original control system.

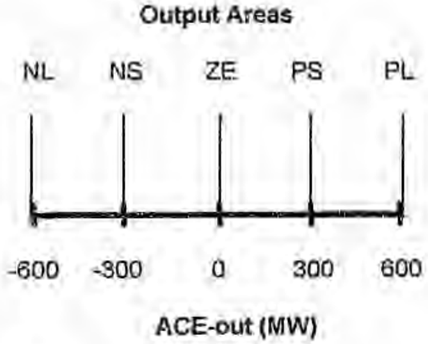

**Fig 5.3**

## 5.3 "ALTERING LOAD ONLY WHEN REQUIRED" PHILOSOPHY

The "altering load only when required" philosophy was implemented to control the grid in the normal operating region, this is an ACE of less than 150 MW for Eskom, making the most of the economic opportunities available and limiting the movement of units.

When more load is required on the grid, only the cheaper units are raised. When a load reduction is required, the more expensive units are dropped, but regulation on small fluctuations in the ACE is minimised. This is very typical of how the grid would be controlled by the operator.

The AGC system already had an economic dispatch routine that calculates economic set-points for the individual units based on the actual generation and incremental cost curves for each unit. The utilisation of this function was enhanced to enable implementation of the new philosophy.

The economic calculator is set to run at short intervals, allocating small generation/demand mismatches economically to generators. This prevents unnecessary control due to ACE regulation and the readjustment of generator outputs due to the economic calculator. This function compliments the fuzzy logic controller. There is a declared region where no pure regulation control action is required as the ACE is within acceptable limits. However, predictive reaction is obtained when the ACE is approaching the boundaries of the acceptable ACE range.

The modified economic controller inherently contains an integration function that removes steady-state errors economically.

## 5.4 SUMMARY

The original AGC system could not be configured to achieve the required quality of supply while using the minimum expected control. The philosophy of distinctive load following and ACE regulation was therefore enhanced and implemented.

The original regulation module, however, could not achieve the control required for the optimisation effort. Major modifications were made, consisting mainly of the application of fuzzy control techniques. The main logic of calculating the control ACE was replaced by a routine using fuzzy logic to incorporate the rate of change of the ACE in the calculation of the control ACE. The two components are combined to determine the desired generation of each generating unit in the PLC components. Th[illegible]ation of the enhanced configuration and design of AGC as well as the operational performance of its implementation on the real system is compared with the original AGC in Chapters 6 and 7, and proves the success of the enhancements.

# 6 SIMULATION OF AGC

## 6.1 BACKGROUND

The best way of gaining a proper understanding of a control system is by means of a computer simulation. It was decided to simulate the AGC system with MATLAB® for Microsoft® Windows by The MathWorks Inc. This is a PC-based version of MATLAB®, therefore a Pentium processor was used to obtain the best performance.

The Simulink® toolbox of MATLAB® was also used as it provides the ability to build the control system in block diagram format. As an existing control system was converted from the FORTRAN code as the direct use of programming code was convenient. Once the original control system had been modelled accurately it was relatively easy to determine, model and test alterations to the design. The detailed MATLAB® model is described in Appendix B.

## 6.2 CONCLUSIONS OBTAINED FROM THE SIMULATION

The first objective of the simulation was to calibrate the existing control system in terms of the quality of the ACE compared with the amount of control issued. Thereafter results from new parameter configurations and code alterations could be compared with the original controller.

Typical frequency charts with step changes were simulated. Emphasis was placed on the ability of the system to maintain the ACE within predetermined limits while minimising the number of control signals issued to the generating units. The model allows outputs to be monitored at any stage of the operation to easily identify occurrences of nonlinearly and ineffectiveness.

The first group of simulations were of different configurations of the original system, with only minor design changes implemented. Then various simulations implementing the enhanced fuzzy logic (PID) design and configuration were performed. Only the initial and final simulation results are discussed in this chapter.

The results of the simulation of the original AGC controller design and configuration compared to the results of the simulation of the final fuzzy AGC controller design and configuration model are shown in Fig 6.1 and 6.2 respectively. The performances of the two controllers were measured against their ability to control the input frequency (ACE) within acceptable bounds while minimising the control issued. The input signal consisted of a typical actual frequency chart of the system taken for one hour without AGC. A step change of -0,20 Hz at 500 s and a ramp change of +0,15 Hz starting at 800 s were added to the signal to simulate a sudden loss in generation and followed by the manual start of pumped storage plant.

From graph (Fig 6.1) of the original system it is evident that the step change of -0,20 Hz was arrested and limited to -0,11 Hz, with a minimum frequency of only 49,89 Hz. The frequency did, however, overshoot significantly to 50,06 Hz thereafter. Note that the amount of control totalled 215 pulses (151 + 64) to the generating units.

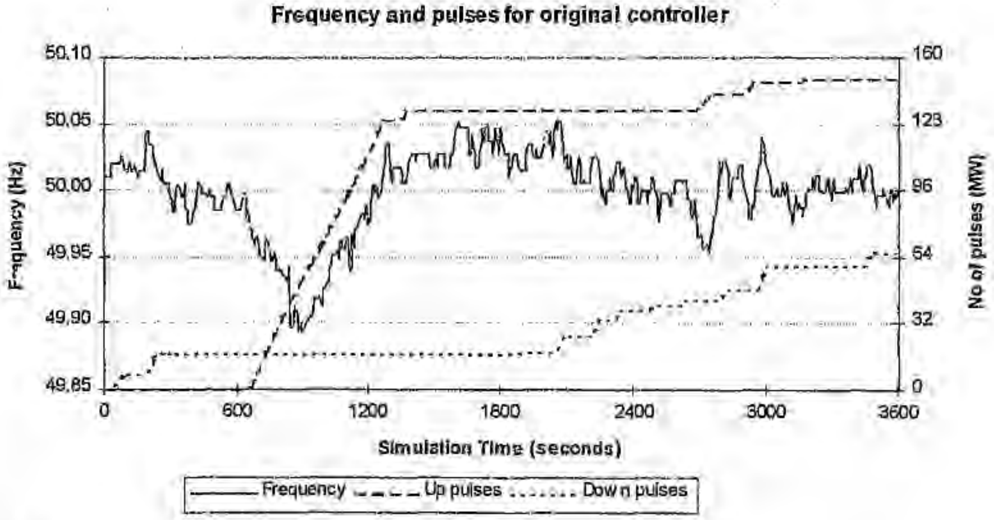

Fig 6.1

The simulation of the enhanced system (fuzzy logic controller with the derivative component) showed that the handling of the step change was very similar to that of the original controller, with the frequency also turning at approximately 49,89 Hz. This time, however, there was virtually no overshoot when the frequency was restored to 50 Hz. Also, note that the number of control pulses issued, totalling 120 (106 + 14), was significantly lower than was the case with the original controller.

Many simulations were done on the original design and configuration, with different input scenarios. The inability of the system to obtain the desired results actually led to the implementation of the enhanced system. The simulations indicate not only that the enhanced design and configurations of AGC result in a better quality of control, but also that the amount of control can be reduced. The alterations could therefore be migrated and applied to the operational AGC system.

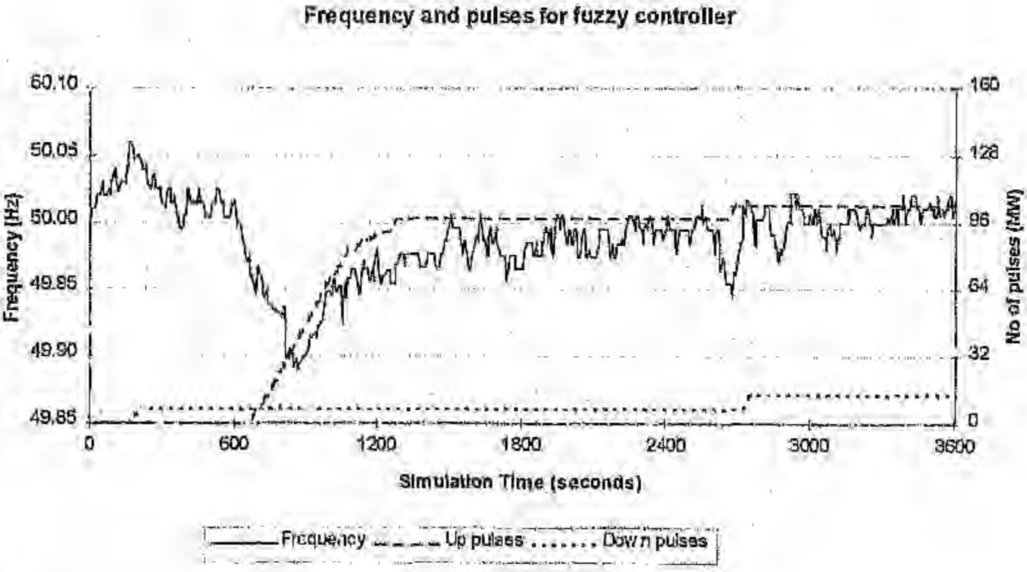

Fig 6.2

## 6.3 SUMMARY

Testing and implementation of philosophy changes on the on-line AGC system are unacceptable. Alterations can be tested and calibrated properly without any adverse effects by means of an accurate simulation of the system in MATLAB®.

Although a great deal of time was spent on the development of an accurate model, the inference drawn from it was indispensable. Although only the results of the original and the final controllers are shown, many simulations had to be done to arrive at the desired end state. The fact that the model has been established also means that future studies can be done with relatively ease.

Many simulations with different inputs and outputs were performed on the different designs and configurations. The simulations indicate that the enhanced design and configuration of AGC outperform the original system both in the quality of control and in the amount of control issued. The results indicate that the design could be implemented on the operational system.

# 7 RESULTS OF THE FUZZY LOGIC CONTROLLER IN THE OPERATIONAL ENVIRONMENT

## 7.1 BACKGROUND

Only the performance of AGC on the live Eskom grid can be used as a true benchmark in determining the extent to which AGC has been optimised. The criteria for control and quality of supply described in Chapter 3 are used to determine the on-line performance, although the perceptions of controllers at the National Control Centre as well as power station staff were also evaluated.

The relative performance of the system after implementation of the modifications is compared with the previous performance in order to evaluate improvements in AGC.

## 7.2 IMPROVEMENTS IN THE AMOUNT OF CONTROL EXECUTED

### 7.2.1 Performance of the on-line Eskom AGC system

The performance of the AGC system in terms of the AGC established control criteria described in Chapter 3 is shown in Fig 7.1.

The original AGC system was in use from the start of the performance measurement in October 1994 until the first alterations were implemented at the end of March 1995. Alterations to the system were implemented during April and May 1994, where after the final modifications were accepted. Some power stations extended their governor dead bands (0,02-0,05 Hz) during December 1994 and January 1995.

From the actual control pulses it is evident that the amount of control issued by AGC decreased significantly, from an initial monthly average of 4 800 MW/hour to an average of 2 000 MW/hour after the modifications had been finalised. The calculated control indicator inherently also reflects the quality of the ACE. As the calculated control increased from an average of 2 100 MW/hour to 2 800 MW/hour, the signal deteriorated slightly. The benefit of reduced control, however, far outweighs the limited adverse consequences.

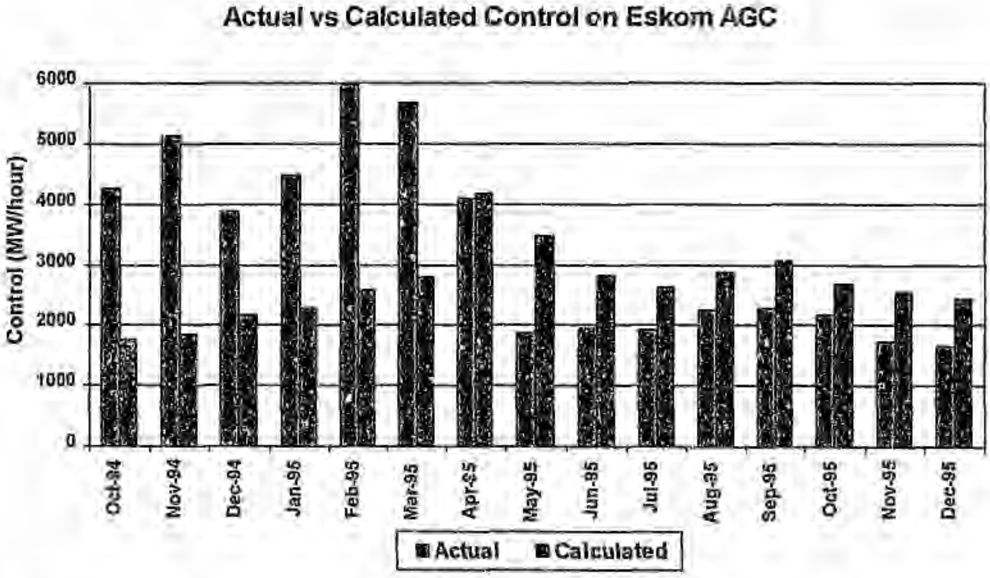

Fig 7.1

### 7.2.2 Effect of modifications on power stations

A reduction in AGC issued to power stations is illustrated clearly in Fig 7.2. The average actual MW/hour control issued for the six-month period from October 1994 to March 1995, before the modifications, is compared with the six-month period from July 1995 to December 1995 following the modifications.

Such a reduction in control results in a significant decrease in the amount of movement of units at a power station. Minimising the movement of a unit results in increased thermal efficiency and should result in long-term savings on maintenance cost at thermal power stations.

The average response of various power stations to control issued for a typical month is illustrated in Fig 7.3. The measurement is done dynamically on the AGC system and the comparison indicates the filtered issued control versus actual movement.

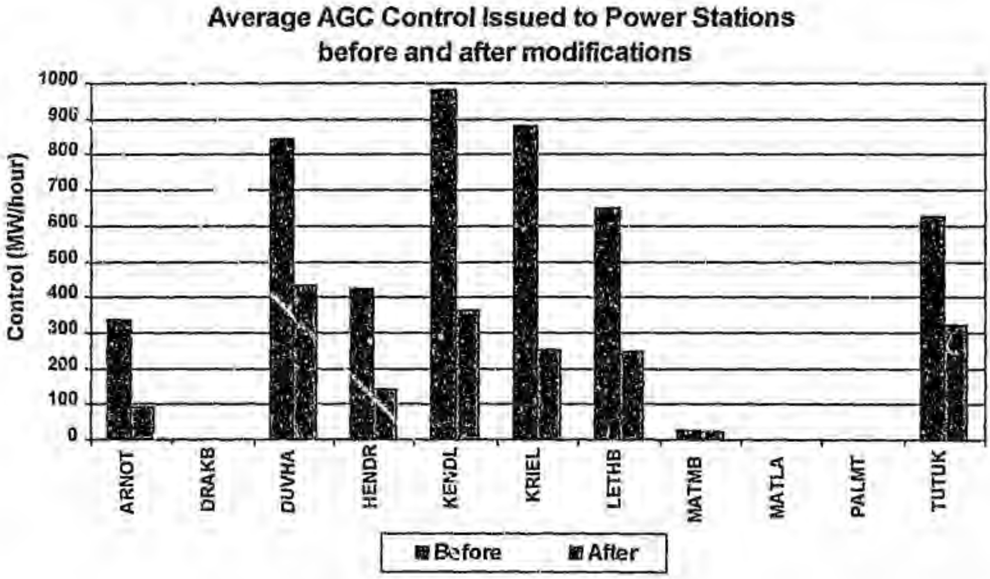

Fig 7.2

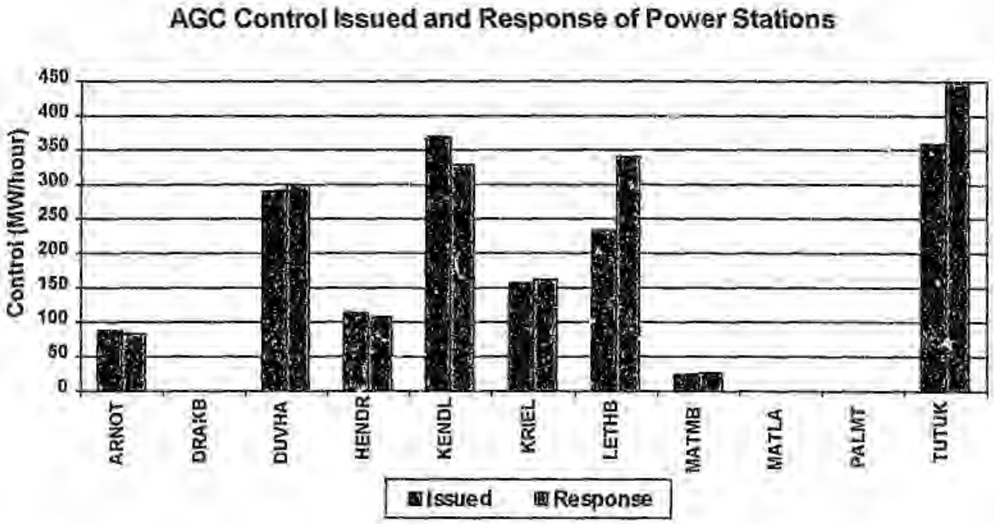

Fig 7.3

## 7.3 EFFECT OF MODIFICATIONS ON THE QUALITY OF SUPPLY

The NERC criteria described in Appendix B are used to determine whether the frequency and tie-line control - (ACE) - meets the requirement of the interconnected power system. Although the Southern African Power Pool only came into operation in October 1995, NERC performance had been measured since March 1995. The rules of SAPP require that members adhere to both the A1 and the A2 criteria 90 % of the time. This is equivalent to not more than 14 violations on average per day.

The calculated control indicator as described in Chapter 3 also shows the quality of supply. Note that the frequency alone cannot be used as a performance indicator of an individual utility in an interconnected system.

On analysing the graph shown in Fig 7.4 it is evident that A2 performance did not meet the standard before the modifications and that the number of A1 violations was unacceptably high during the implementation phase. The NERC performance has, however, been well within the desired area since the final modifications were implemented. Note the slight increase in violations during the initial stages after the interconnected operation started in November 1995.

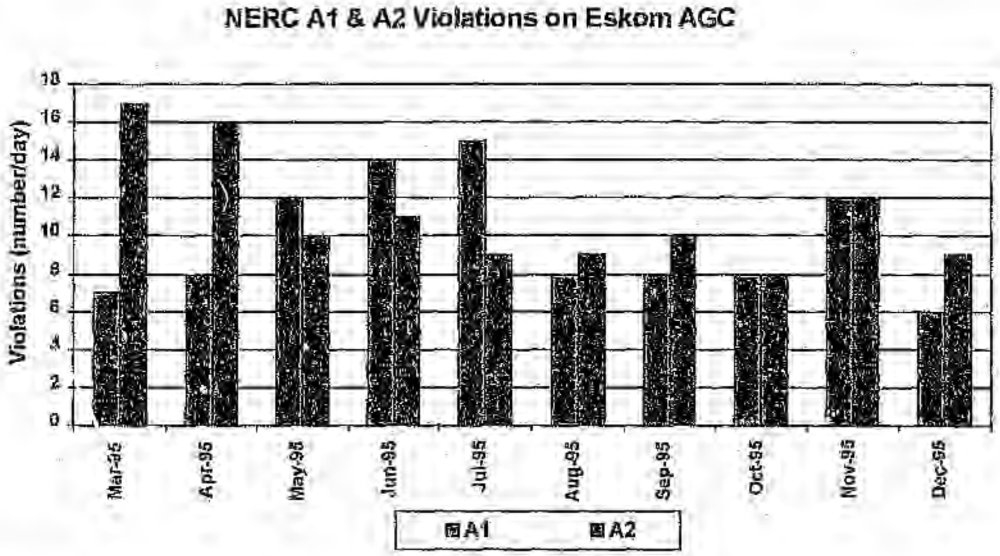

Fig 7.4

## 7.4 SUMMARY

The modifications to the control system have achieved significant improvements in the amount of control issued to power stations by AGC. The actual control issued to power stations has been reduced by approximately 60 % of the original control. This should result in operational cost savings at power stations as well as extended life expectancy.

This was achieved without diminishing the quality of regulation required for membership of the Southern African Power Pool. In fact, the NERC performance improved after the modifications were implemented. The lack of control produced by AGC was visible to control personnel at the National Control Centre and originally created the impression that control was not adequate. The results have, however, proved to both National Control and power station control personnel that performance is excellent.

The continuous drive to lower the cost of electricity production and at the same time improve the quality of supply to customers will, however, result in an ongoing effort to improve performance.

# 8 RE-OPTIMISATION OF AGC

## 8.1 BACKGROUND

Since the original optimisation and tuning of the fuzzy logic controller in 1995, there have been changes in Eskom and in the Southern African Power Pool that require the re-optimisation of the controller. In Eskom an internal power pool has been developed which has impacted the number of units available for AGC and the number of MW available. There has also been a reduction in the number of units performing primary frequency control.

In SAPP there has been the introduction of an additional performance agreement to maintain a frequency distribution of 90% within 50 mHz deviation from 50 Hz.

This chapter describes the changes in detail that have led to the re-optimisation of AGC.

## 8.2 SAPP FREQUENCY DISTRBUTION AGREEMENT

In July 1996 a meeting was held to discuss the impact of frequency and changes in load on the SAPP. This was a result of a disturbance in the Eskom grid that led to the ultimate loss of power in ZESA and Zesco. It was agreed at this meeting that every member of SAPP would positively contribute towards achieving a frequency distribution of 90% within 50 mHz for the interconnection. The impact on Eskom was significant as the SAPP interconnected frequency distribution was only around 85% within the targeted range of 50 mHz, as shown in Fig 8.1.

| Frequency Distribution | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1996 |  | 85.93 | 79.80 | 86.08 | 82.48 | 88.31 | 87.40 | 89.75 | 88.96 | 90.60 | 91.40 | 91.69 |
| 1997 | 89.57 | 85.30 | 86.58 | 87.68 | 86.27 | 83.67 | 84.60 | 84.57 | 84.58 | 85.67 | 82.08 |  |

Fig 8.1

The controllers improved the frequency distribution, which was around the target up until

February 1997. Since then the distribution has been on a steady decline. Eskom was requested by SAPP to look at improving their control, as it is the largest utility in the interconnection and theoretically has the largest influence on the frequency distribution.

## 8.3 ESKOM INTERNAL POWER POOL

In the Eskom Internal Power Pool the power stations bid prices daily for energy for the following day. The power stations are scheduled and contracted to provide energy according to the cheapest solution. This has changed the number of MW available for AGC as this is also contracted on a daily basis. Five power stations have been selected for 1997 to provide AGC regulation and the amount scheduled is based a on the Eskom Short Term Generation Reserve Policy(26).

This means there are fewer units providing regulation with a decrease in total MW. This change also requires that the performance of AGC be analysed with this new requirement.

## 8.4 PRIMARY FREQUENCY CONTROL OPTIMISATION

Primary frequency control is a proportional controller situated on a power station unit that is based only on the frequency. In the linear mode of operation any change in system frequency beyond the governor frequency dead-band will have an immediate governing effect on the turbo-generator. The dead-band was increased from 0.02 Hz to 0.05 Hz during 1995 which was only been implemented at most power stations in late 1996. All units have a 4% governor droop setting when, for a rise in frequency of 4 % above nominal 50 Hz, the machine is de-loaded from full load MW output to zero and visa versa.

Primary frequency controls main function is to arrest the frequency during a large loss of generation or load. This function is hence a complement of AGC but is much faster acting than AGC, after the frequency has been arrested then it is AGC's function to restore the grid back to normal.

In March 1997 the number of power stations providing primary frequency control was reduced to from all to five to save on operation costs[27]. This reduction has not impacted the ability to arrest the frequency satisfactorily in the event of a large loss of generation or load.

The impact of changes in primary frequency control on AGC is that there is now less response in the frequency range from 50.05 to 49.95 by power stations and hence theoretically AGC needs to perform differently in this frequency range. Eskom is the only utility in SAPP at present that has this dead-band in the primary frequency control. The other utilities have stated that they have no dead-band. This theoretically will mean that the tie-lines to Eskom will change as the frequency changes. This is as the primary frequency control is faster than AGC and these utilities correcting their generation faster than Eskom within the frequency range 49.95 to 50.05 Hz.

## 8.5 SUMMARY

The above identified changes in the performance monitoring and evaluation of AGC and the changes in the number of units as well as the reduced primary frequency response required the re-optimisation of AGC. First, an analysis was performed using a new performance criterion developed by NERC to measure AGC performance in the USA.

# 9 ANALYSIS OF AGC PERFORMANCE USING NERC PERFORMANCE CRITERION CPS1

## 9.1 BACKGROUND

The A1 & A2 control performance criteria have measured control performance in the USA in the utility industry. The use of A1 & A2 has resulted in years of reliable operation. However, the heuristic, arbitrary nature of A1 & A2 has prompted the utility industry in the USA to search for technically defensible control performance criteria.

The new performance criteria developed by NERC, CPS1 and CPS2 have been implemented for a trial run during 1997 and will become mandatory from February 1998. The new criteria are subject to penalties for non-compliance whereas the A1 and A2 criteria were not subject to penalties.

The Southern African Power Pool is presently using the NERC A1 and A2 performance criteria to measure the performance of individual utilities. There is a possibility for the SAPP to move to the new criteria, but before this can be done the new criteria must be understood and impact of a penalty system could possibly have on Eskom.

## 9.2 CPS CONTROL OBJECTIVES

A team including Howard Illian and Stephen Hoffman drafted the control objectives for the new NERC criteria. Appendix C contains an article written by the two authors on the new criteria. This section contains excerpts from this article.

Interconnection frequency was selected as the primary control objective. Interconnection frequency can be directly related to reliability in many ways, as described below.

- Generator turbines will encounter vibration problems for frequency variations greater than one or two Hz.
- Interconnection frequency is a direct measure of the net load generation imbalance.
- Inadvertent energy is distributed between control areas by AGC actions and the natural frequency response of control areas. Statistically bounding frequen[illegible]rs will also statistically bound inadvertent energy flows.
- Increased inadvertent flows resulting from larger frequenc[illegible] t potential thermal overload problems for the transmission system. A larger i[illegible] sed to control frequency more tightly than a small interconnection to avoid transi[illegible] esulting from large inadvertent flows.
- Each interconnection tracks and corrects time error because synchronous clock motors, and many digital, clocks will only keep correct time when supplied with 50 Hz power.
- Under-frequency and over-frequency relays are in place on generators and some loads. A unit over-frequency relay trip would act to correct the frequency error, while a unit under-frequency relay trip would protect the generator, but would result in lower frequency. Generating unit and load frequency relay settings provide a hard limit to avoid during abnormal operations.
- Interconnection frequency changes following the loss of load or generation. It takes approximately 5 to 15 minutes for frequency to recover following a disturbance. Frequency margins are maintained so that even if several loads or units tripped off during the recovery period, there is a small probability that additional load or generation would be tripped by frequency relays.

A secondary control objective is to limit inadvertent tie flows. Achieving the desired frequency error profile implies, but does not guarantee, acceptable inadvertent tie line flows. Although inadvertent energy must be returned, no rand value is associated with inadvertent. Since production costs vary over time, it i sible to draw in inadvertent when production costs are high, and pay it back later when production costs are lower.

A control criteria needs enough flexibility to prevent excessive, expensive control action, but must keep inadvertent flows to reasonable levels for transmission overload and economic fairness concerns. This is particularly important with the increased emphasis on competition and wholesale and/or retail wheeling.

$$RMS[\Delta F] \le \varepsilon \qquad 9.1$$

$$ACE = \Delta T - 10 B_i \Delta F - I_{WTC} \pm I_{UIP} - I_{ME} \qquad 9.2$$

ACE is a function of the net tie line error ΔT, the frequency error ΔF, automatic time error control $I_{WTC}$, unilateral inadvertent payback $I_{UIP}$, and the meter error correction term $I_{ME}$, as shown in Eq 9.1 and 9.2.

A2 requires a control area to operate so that the 10 minute average of ACE is between ACE=$L_d$ and ACE=-$L_d$. Thus the region bound by the lines ACE=±$L_d$ illustrates a permissible region of operation under the A2 criterion. If system frequency was low (ΔF<0), a control area operating at ACE=+$L_d$ is doing much more to support system frequency than if the system were to operate at ACE=-$L_d$. However, A2 says that ACE=+Ld and ACE=-Ld are equivalent. A control performance criteria must recognise the obvious; a positive ACE does more to support system frequency than a negative ACE when frequency is low. The implied goal of A1 & A2 is that ACE should be held at, or close to, zero. This has caused control areas to overcontrol in an effort to meet this goal.

AGC is a distributed control problem because frequency, and inadvertent flows, are determined by the control actions of all control areas in an interconnection. Tie-line bias, which introduced the frequency bias component of ACE, has effectively assigned a frequency support obligation to all control areas. As will be shown, the control performance standard requires a control area to provide their frequency support obligation, but allows a control area to provide additional, but limited, frequency support when it will benefit system frequency. In this manner the benefits of tie-line bias control are maintained, but the control performance standard given below may require less generation manoeuvring and control effort. In addition, the arbitrary control performance limits associated with A1 & A2 will be replaced with technically defensible control limits.

## 9.3 STANDARDS

**Continuous Monitoring.** Each control area shall monitor its control performance basis against two standards: CPS1 and CPS2.

### 9.3.1 Control Performance Standard (CPS1)

Over a year, the average of the clock minute averages of a control area's divided by $-10\beta$ ($\beta$ is control area frequency bias) times the corresponding clock minute averages of Interconnections frequency error shall be less than a specific limit. This limit, e, is a constant derived from a target frequency bound reviewed and set as necessary by the NERC performance Subcommittee.

### 9.3.2 Control Performance Standard (CPS2)

The average ACE for each of the six ten minute periods during the hour must be within specific limits, referred to as $L_{10}$.

**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.

### 9.3.3 Disturbance Control Standard

The ACE must return either to zero or to its pre-disturbance level within ten minutes following the start of the disturbance.

## 9.4 REQUIREMENTS

**ACE values.** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to telemetering problems or other influences such as control action.

**Control Performance Standard (CPS) Compliance.** Each control area shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90%.

**Performance Subcommittee Surveys.** All control areas shall respond to control performance surveys that are requested by the Performance Subcommittee.

**Disturbance Control Standard Compliance.** Each control area or reserve sharing group shall meet the disturbance control standard (DCS) 100% of the time for reportable disturbances. A reportable disturbance is defined as an event whose magnitude is less than or equal to the magnitude of an affected control area's most severe contingency, or is greater than or equal to 80% of the magnitude of the control area's most severe single contingency loss.

**Disturbance Control Surveys.** Each control area or reserve sharing group shall submit a quarterly summary report to it regional performance subcommittee representative of the respective control area's compliance to the DCS during the reserve quarter.

## 9.5 DISCUSSION

If a utility is positively contributing to the Interconnection, the control performance standard CPS1 will be low. The inverse of this is also true, for a high CPS1 the control in the control area is poor.

The minute values of CPS1 can be used to determine trends in good and poor performance of the AGC algorithm. This trend could be analysed in terms of times of the day, amount of regulation, actual total load etc. and used to identify when the controller is performing below expectations. CPS1 value is useful to Eskom regardless of whether it is used to measure Eskom's performance in SAPP in the future.

CPS2 and DCS are not new criteria to NERC and are in essence the A2 and A1 criteria respectively. This report does not analyse this in depth except for the defining of new criteria to optimise the AGC algorithm.

## 9.6 ESKOM'S CPS1 PERFORMANCE

Data from the January 1997 to June 1997 has been used to calculate the CPS1 performance. These data were originally 4 second samples that have been averaged to produce one minute averages for both ACE and frequency deviation. The calculation is hence in full alignment with the new requirements.

The calculation gives a value, which represents the square of the frequency and has to be compared to a standard value, $e^2$. The value of this e should represent the quality of frequency required for the total interconnection. The present requirements in SAPP for frequency quality are to maintain the frequency for 90% of the time within a 50 mHz deviation from 50 Hz. The standard deviation for the frequency is hence 30 mHz assuming a normal distribution curve. This study hence evaluates the figure for e=0.03 Hz as a benchmark for Eskom's control.

The trends on the graphs shown below are a sixth order polynomial trend calculated by Microsoft Excel.

### 9.6.1 CPS1 compared to frequency distribution

The relationship between CPS1 and frequency distribution on Fig 9.1 shows that a good control on the Eskom AGC gives a good frequency distribution. This was to be expected as the Eskom grid size is significantly larger than the other utilities in SAPP and hence the other utilities are not able to effect the frequency distribution to the same extent as Eskom.

A frequency distribution of 90% also relates to a CPS1 value of 0.009, as shown in Fig 9.1. Hence if the SAPP has to adopt the new standard a value for e = 30 mHz would be the same as targeting a frequency distribution of 90 % within 50 mHz.

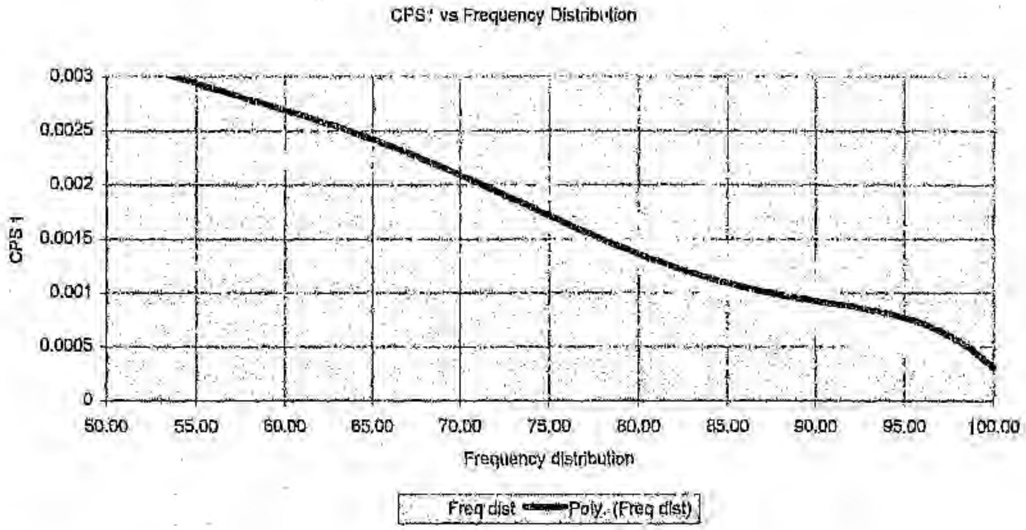

Fig 9.1

### 9.6.2 Daily trends in CPS1

The daily trend in the CPS 1 value, Fig 9.2, shows that the control is better when the demand is steady. However the control performance is worse during morning pick-up from 04h00 to 07h00, evening pickup from 15h00 to 18h30 and evening drop from 20h00 to 24h00. It is to be expected that the control should be worse during these periods due to the requirement to continually ensure there are units are available. The operation of units on manual also affects the control, as the individual units load while ignoring the frequency. The units should look only according to the ACE and not according to the frequency. The AGC controller has the base load facility to perform this task, which is currently not fully utilised. When more units are on AGC in the Base load mode the performance of the control will also improve.

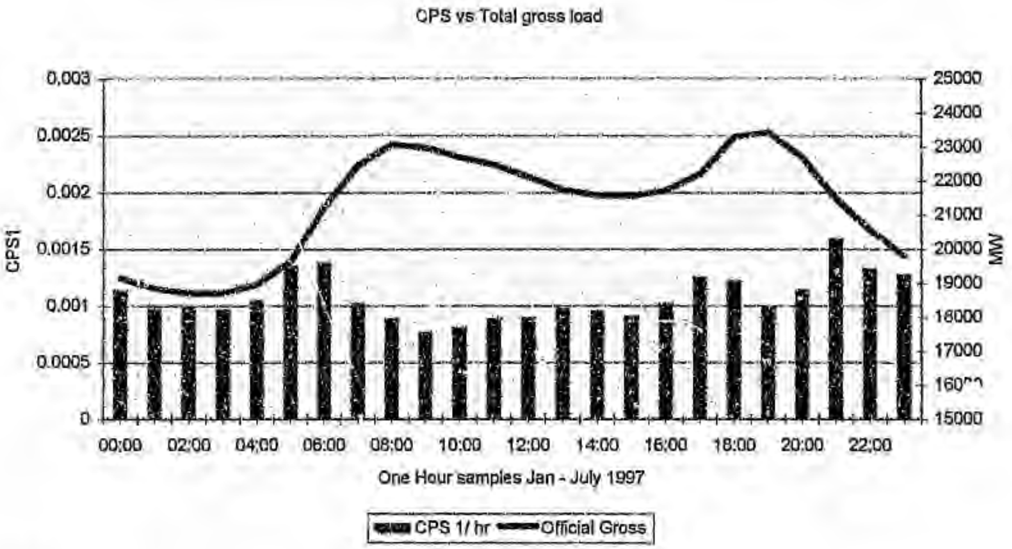

Fig 9.2

### 9.6.3 Weekly trends in CPS1

The weekly trend, Fig 9.3, shows the CPS1 performance does not vary substantially from Tuesday to Friday, perhaps the control is worse on weekends and on Monday. The weekend poor performance could be a result of too few units on AGC or the inability of units to ramp at rates set in AGC when they are at low load. At present the ramp rate of the units is fixed, but the facility is available to receive dynamic ramp rates from the unit controller. This will assist in obtaining accurate information on the actual status of the unit and whether the unit is available for control.

### 9.6.4 CPS1 compared to actual load

The curve in Fig 9.4 shows that the CPS1 performance is steady up to 24 000 MW and improves as the load increases. It is possible that at high loads the controllers are more observant and perform control tighter on the ACE and hence the frequency. The second possibility is that there is less cycling due the lack of units on AGC and primary frequency control throughout the interconnection.

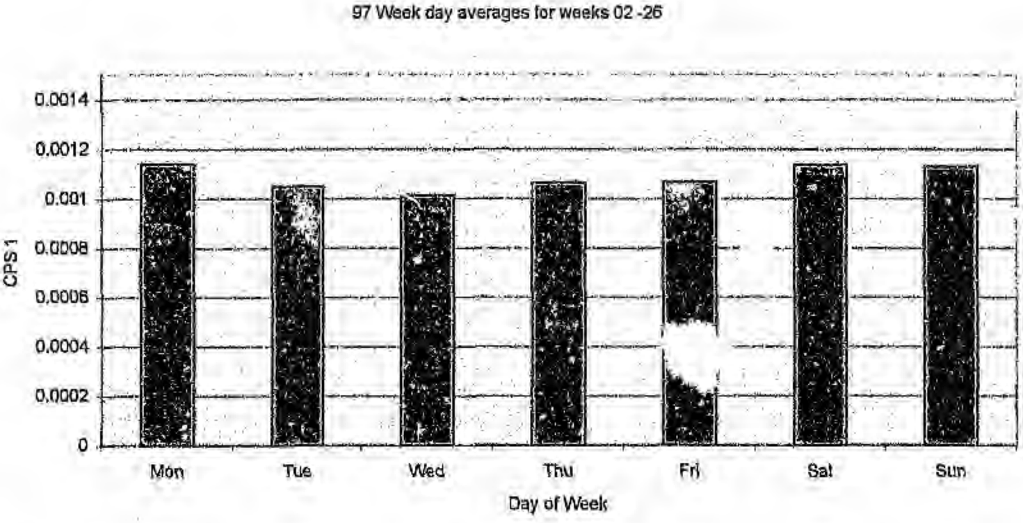

Fig 9.3

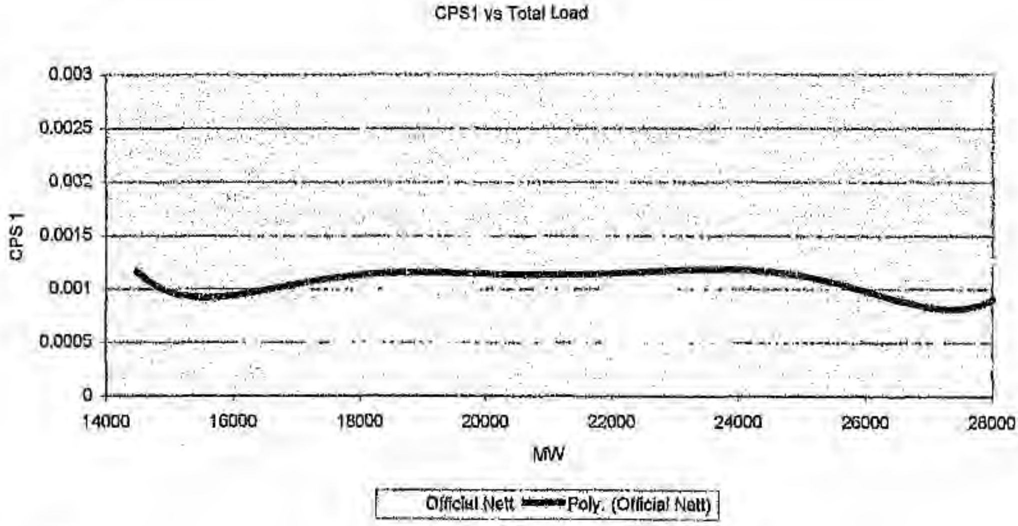

Fig 9.4

### 9.6.5 CPS1 compared to regulating margin

The CPS1 trend, Fig 9.5, shows that a higher regulating margin improves the performance as long as there is more than 400 MW available. Less than 400 MW is to low to effectively control the grid. Fig 9.6 however shows that there is definitely an optimum amount of MW required in the positive and negative direction of 300 to 600 MW. Lower than 300 MW is not enough on regulation to effect good control and higher than 600 MW appears to be too much. This could be due to the high dead-band when too many units are on AGC; this is analysed in Section 9.6.8.

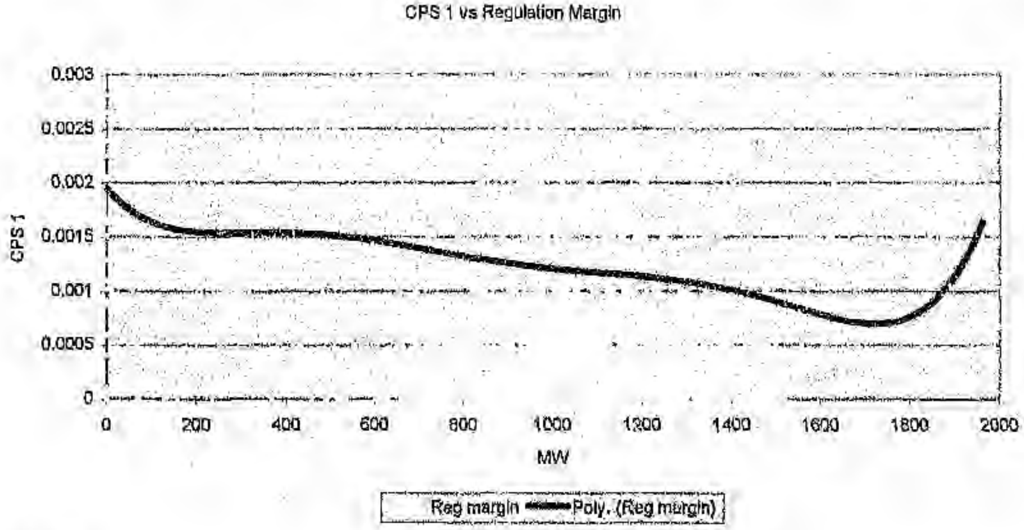

Fig 9.5

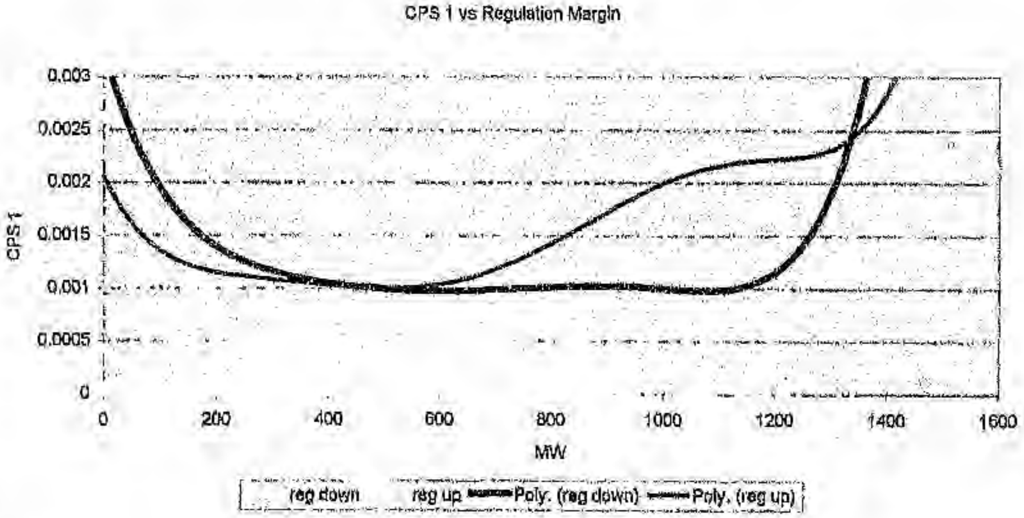

Fig 9.6

### 9.6.6 CPS1 compared to control effort

The trend of number of pulses as a function of CPS1 (Fig 9.7) shows that if few control pulses are sent out, the performance of the control system is poor. An optimum of approximately 2800 pulses per hour is reached and increased control effort does not improve the CPS1 performance. It is probable that a higher number of pulses sent out causes a cycle in the system and hence does not improve performance. A minimum of 2000 pulses per hour is required to maintain CPS1 performance. Hence an average between 2000 and 3000 pulses per hour should be targeted and optimisation should aim for around 2500 average pulses per hour.

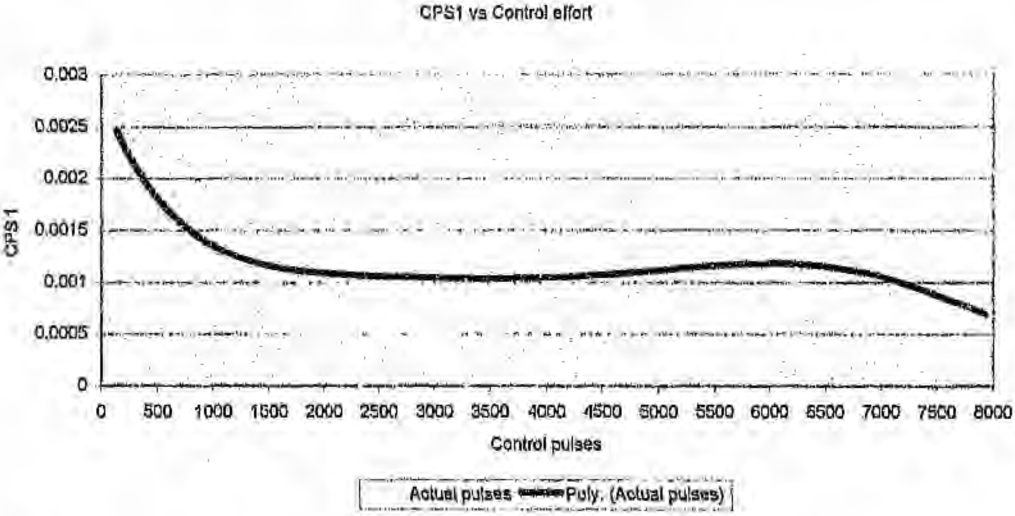

Fig 9.7

### 9.6.7 CPS1 compared to individual station performance

The trend of Palmiet Power Station, Fig 9.8, shows that increased control from the units improves the performance of the grid. This can be expected from the high ramp rate and the speed of these units when on AGC. This tends remove control effort from the other units.

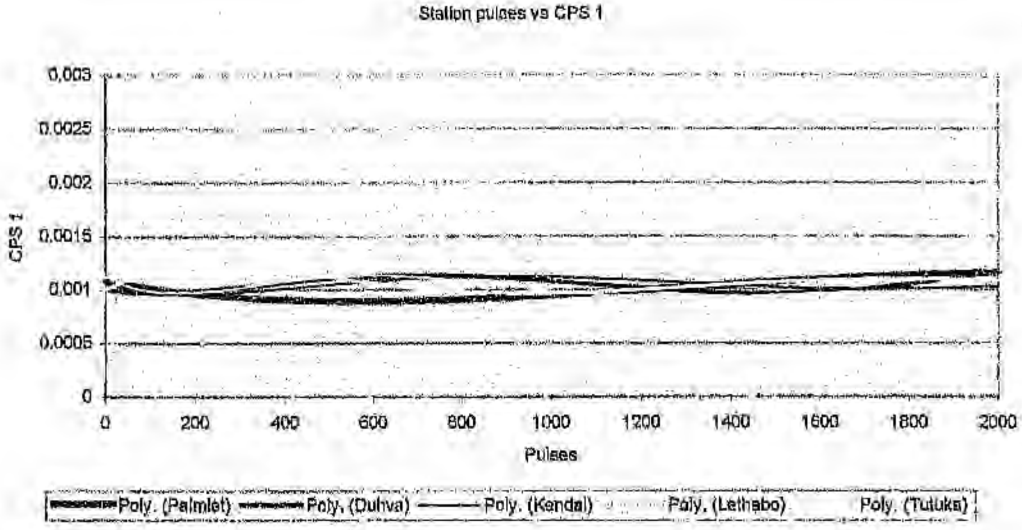

Fig 9.8

### 9.6.8 CPS1 compared to the number of units on AGC

The CPS1 trend, Fig 9.9, shows that the number of units has a large effect on the control performance. This has to do with the effective dead band in each unit controller. This is presently set at 5 - 8 MW depending on the unit and this dead band can be seen as additive. If the dead band of the unit exceeds the dead band of the controller, presently 80 MW. then less control is initially issued causing the control system to under perform. An optimal dead-band, at present, is in the range of 25 – 60 MW, corresponding to 5-12 units on regulation.

Fig 9.10 shows that the optimal rate for units on regulation in AGC is 300 – 375 MW, this requires 20 thermal units, or 2 Palmiet and 8 thermal units, or 1 Palmiet and 13 thermal units.

The solution of 2 Palmiet units and 8 thermal units satisfies both cases. A modification to move the PLC controller to control the set-point control and enable the dead-band to 2 MW, would allow up to 30 units in regulation before the dead-band becomes problematic.

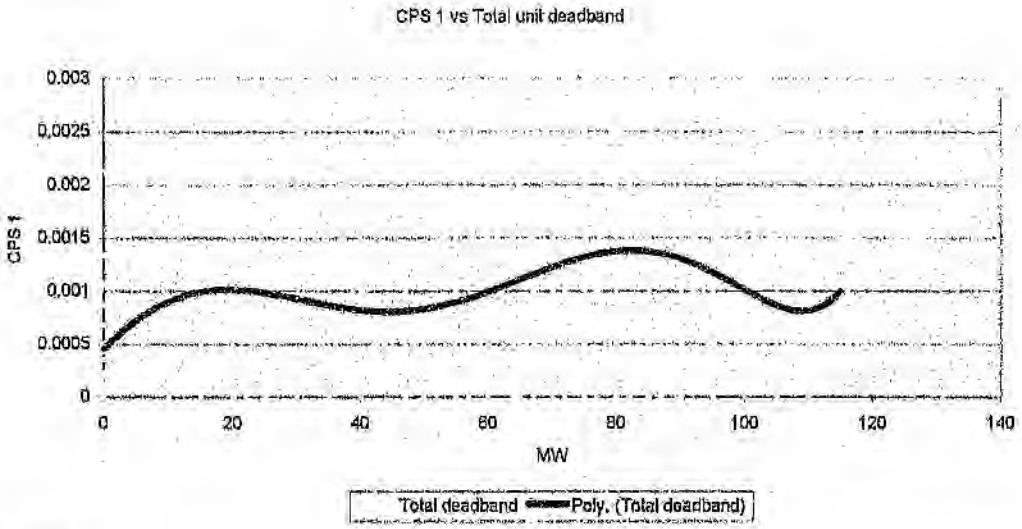

Fig 9.9

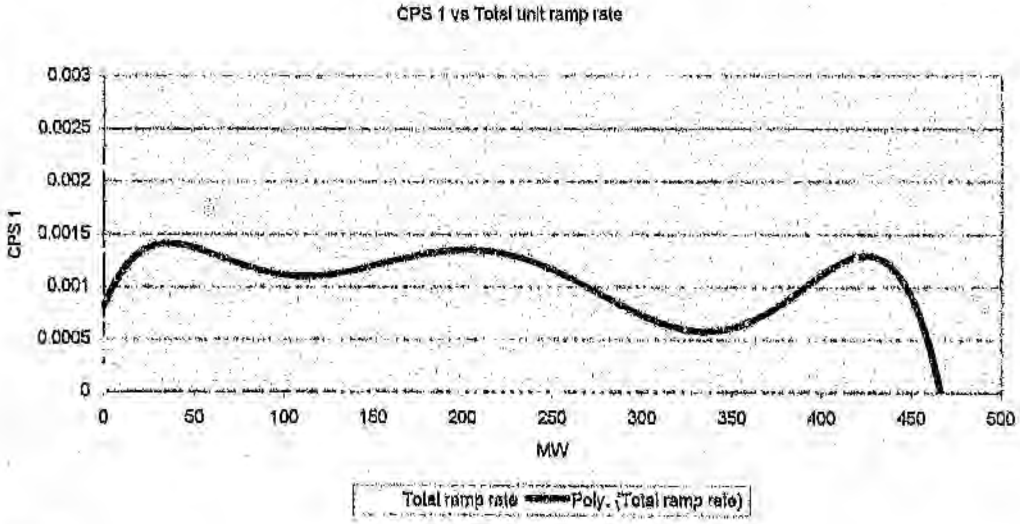

Fig 9.10

### 9.6.9 CPS1 compared to inadvertent energy flow

The trend of inadvertent energy flow against CPS1, Fig 9.11, shows that, for errors greater than 4 %, the Eskom control system performance has little effect on the inadvertent flow. This is due to

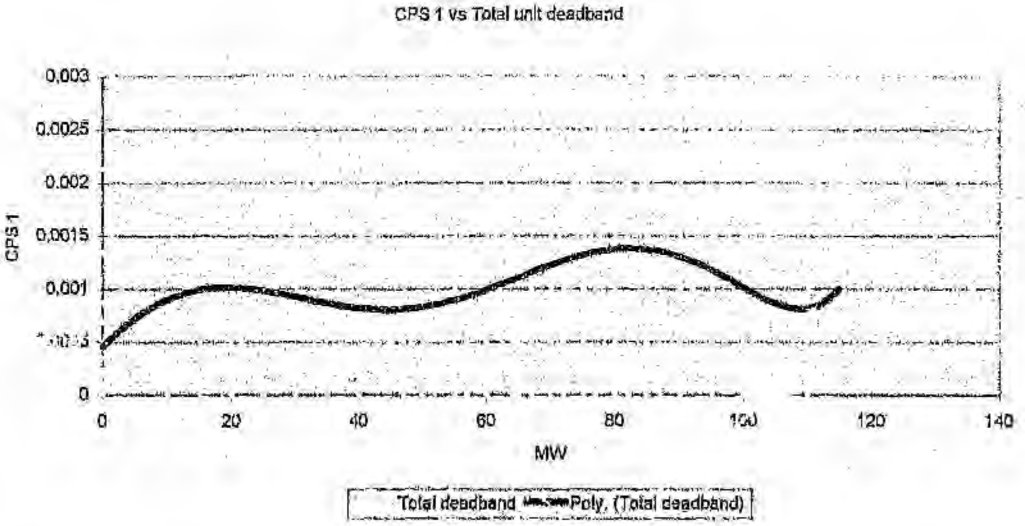

Fig 9.9

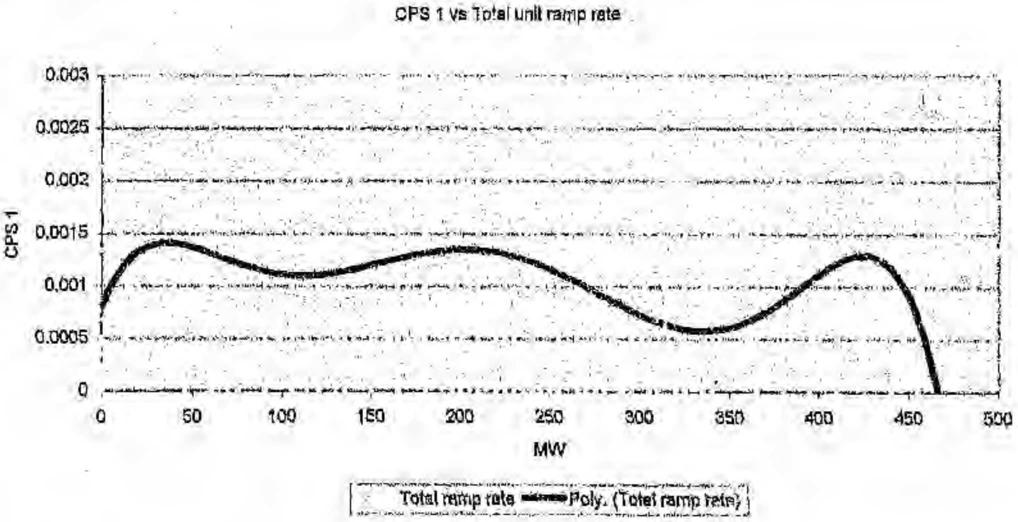

Fig 9.10

### 9.6.9 CPS1 compared to inadvertent energy flow

The trend of inadvertent energy flow against CPS1, Fig 9.11, shows that, for errors greater than 4 %, the Eskom control system performance has little effect on the inadvertent flow. This is due to the larger size of the Eskom grid than the rest of the interconnection. In the smaller utilities over and under generation effect of altering the tie-line flow more. Below errors of 4 % improved Eskom control the improves the tie-line flow. The daily trend, Fig 9.12, shows that the tie-line errors are significantly higher between 00h00 and 06h00 with reasonable Eskom CPS1 values. This indicates poor control from one of the surrounding utilities during these hours.

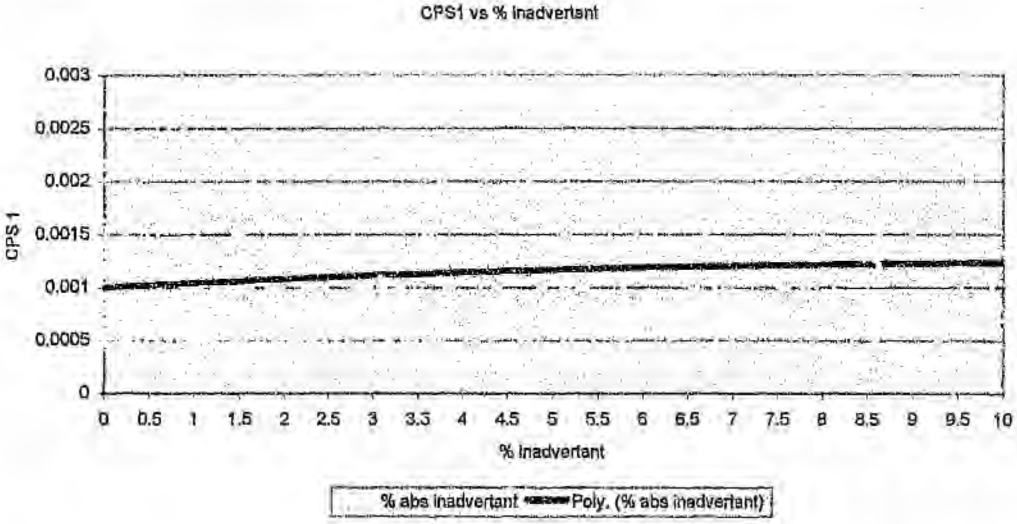

Fig 9.11

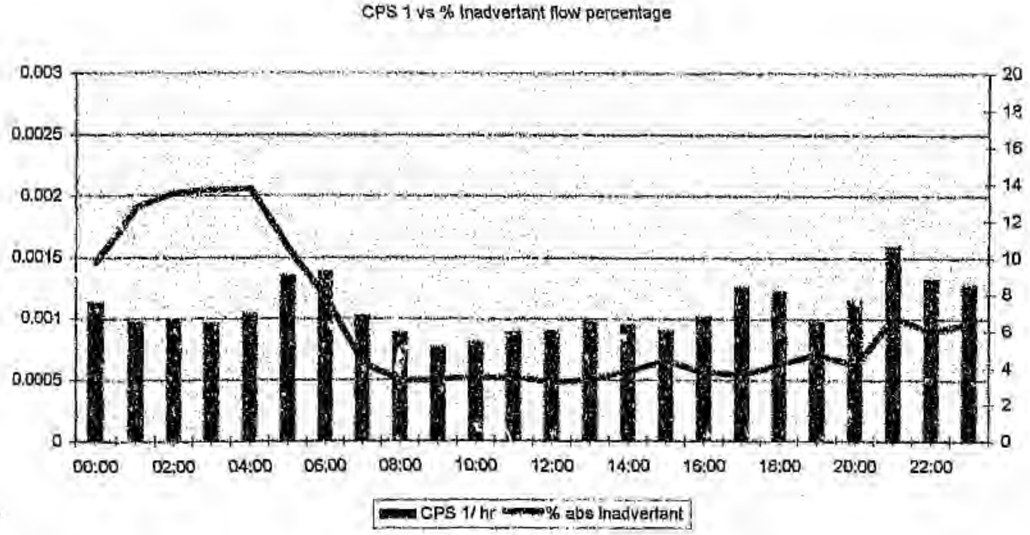

Fig 9.12

### 9.6.10 CPS1 compared to A1 violations

The trend of A1 violations against CPS1, Fig 9.13, shows little correlation between the two calculations except when the A1 violations are high. This indicates that the two calculation methods are completely different thus requiring two optimisation approaches.

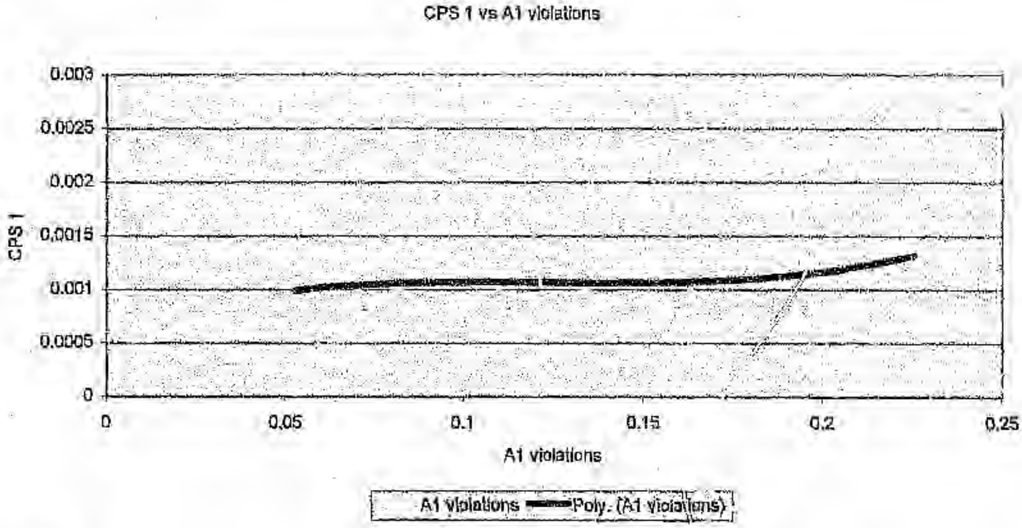

Fig 9.13

## 9.7 SUMMARY

The new criterion if implemented in SAPP, will require the AGC algorithm to be re-optimised to satisfy this. The results show the possibility of potential improvement in AGC even if the new control performance criteria is not adopted by SAPP.

The control performance criterion is equivalent to the maintaining of a frequency distribution in SAPP. The equivalent CPS1 criterion to maintaining the frequency within 50 mHz 90% of the time is maintaining a frequency standard deviation of 30 mHz. This study shows that Eskom does achieve the CPS1 criterion when the frequency distribution is above 90% emphasises that Eskom's AGC control does contribute significantly to the overall SAPP frequency performance.

Analysing the various inputs that can affect AGC performance shows that the number of units on AGC due to the dead-band contribution affects the performance. This is when the cumulative dead-band exceeds the dead-band of the main AGC controller. This can be overcome by modifying the unit control algorithm to unit set-point rather than the actual load control and thereby lowering the dead-band of each unit.

The more units on AGC in the Base load mode will improve the performance, as the AGC system is designed to raise and lower units only when required by the ACE. This is especially true during periods of high load changes in the system. Units on manual cannot do this as they only see the frequency, which is not a good indicator of the ACE in an interconnected system.

In order to check verify the performance improvement, the system changes were modelled using the existing model for AGC in MATLAB® and optimised using the tools provided in the MATLAB® optimisation toolbox. The results of this are covered in chapter 10.

A target of 2500 pulses per hour should achieve the CPS1 criterion and hence also the required SAPP frequency distribution of 90% within 50 mHz of 50Hz.

# 10 RE-OPTIMISATION USING MATLAB® MODEL.

## 10.1 BACKGROUND

Using the analysis of the AGC performance, it was necessary to observe whether there can be a real performance improvement. The enhancements were modelled using the model that was developed to design the fuzzy logic controller in MATLAB®.

The model was simplified to combine the units into a single unit model. A disturbance is added to represent the model equivalent of a start up of pump storage unit at Drakensburg Power Station.

## 10.2 SETPOINT CONTROL MODELING

The initial model simulates AGC system with the dead-band to each unit set at 8 MW, which is the approximate equivalent of the existing AGC system. Fig 10.1 shows that the performance of the controller decreases when the number of units increases above 12. This was observed in the performance of the actual AGC system. Fig 10.2 shows that when the dead-band to each unit is decreased to 2 MW by changing to set-point control, the control is much improved. The AGC system does show an oscillation and hence the gains of the controller need to be re-tuned.

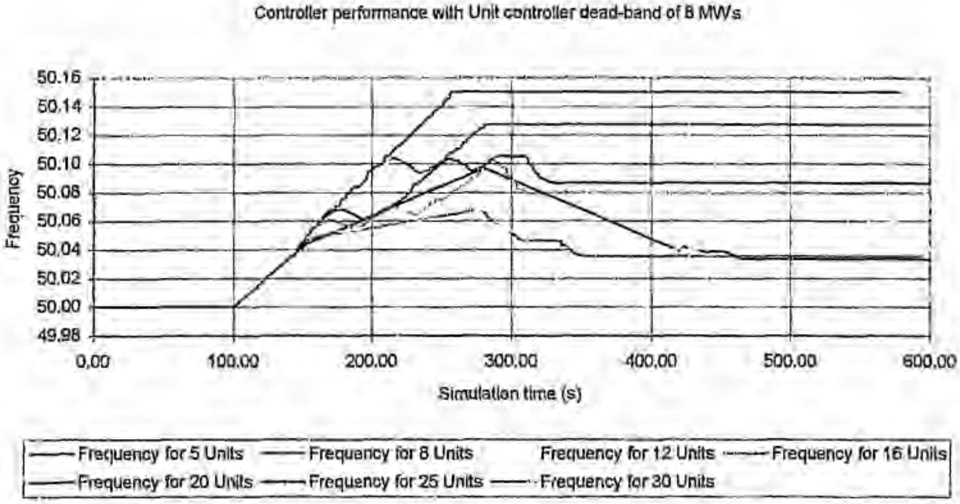
Controller performance with Unit controller dead-band of 8 MWs

**Fig 10.1**

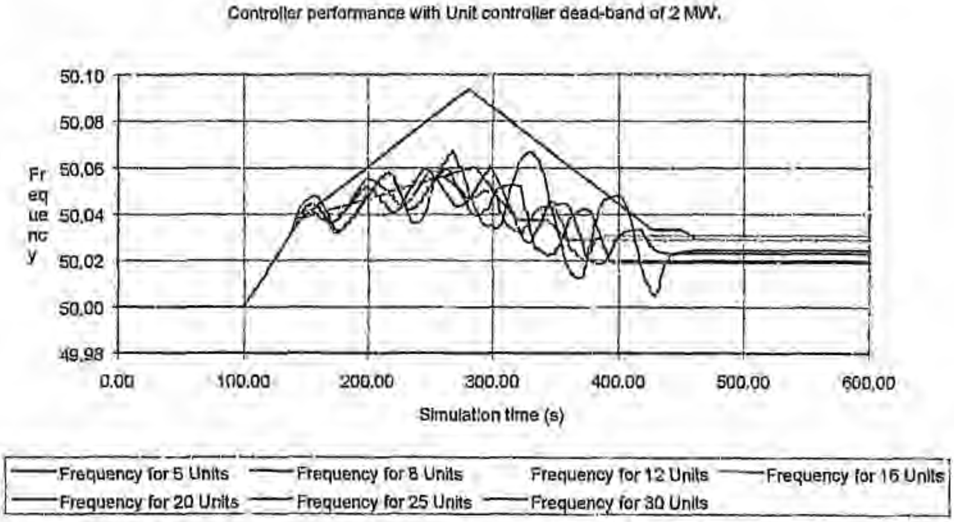
Controller performance with Unit controller dead-band of 2 MW.

**Fig 10.2**

## 10.3 OPTIMISATION USING MATLAB® MODEL

The purpose of the optimisation was to determine the best settings for the controller using set-point control that should give an adequate control while reducing the amount of control. The input regions to the fuzzy logic controller, such as positive small, have not been considered for optimisation as they are well defined areas where the controller should and should not operate. The same applies to the rules of the fuzzy logic controller.

The optimisation parameters were only the positive and negative small outputs of the fuzzy logic controller, these are mirror parameters of each other and so only positive small gain is considered and negative small is given the negative value of this. The fuzzy logic controller for this disturbance does not use the positive and negative large outputs.

The controller was first optimised using the linear constraint optimisation routine provided by the optimisation toolbox in MATLAB®. The optimisation routine was set up to minimise the control effort to the units while constraining the frequency below 50.1 Hz and above 49.95 Hz. These boundary constraints should give the desired frequency control distribution required by SAPP.

The small outputs from the optimised controller small outputs were calculated for both the existing controller i.e. unit controller dead-band of 8 MW, and with set-point control i.e. unit controller dead-band of 2 MW. This was optimised for 5 to 30 coal fired units, 5 being the minimum number required to keep the frequency below 50.1 Hz constraint. The optimised gains, Fig 10.3, show a constant positive small gain is required for the original controller until the number of units increase above 16 where a high gain is required. This is the philosophy adopted by some AGC controllers to increase the controller gain as the number of units increases. The optimised small output for the set-point case is lower than for the original controller and is relatively constant regardless of the number of units. The set-point controller is hence a better option because of the simplicity of a constant small output. The lower small output value also reduces the overall loop gain and hence improves the stability of the control loop.

The performance of the set-point controller is shown for a positive small output of 100 in Fig 10.4, which also shows a good performance for all control except for 30 units. With positive small output of 120, Fig 10.5, the controller's performance was improved slightly. When two Palmiet units were added with positive small output at 120, Fig 10.6, the controller tended to oscillate and the positive small gain had to be reduced to 50 to give an improved control, Fig 10.7. The simplified model of the Palmiet units might not give the true representation and this will have to be tested in the actual system.

The indication of the optimisation is that the set-point controller will give an improved performance but the small output region of the controller will need to be reduced.

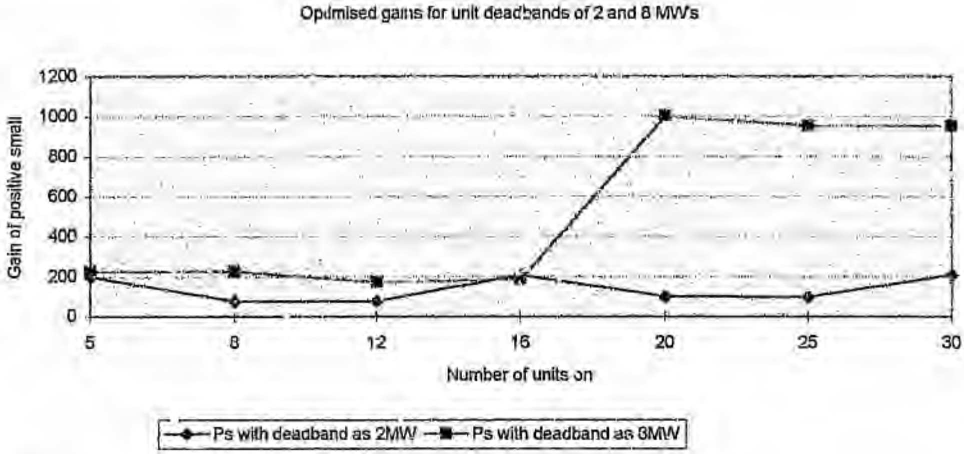

Fig 10.3

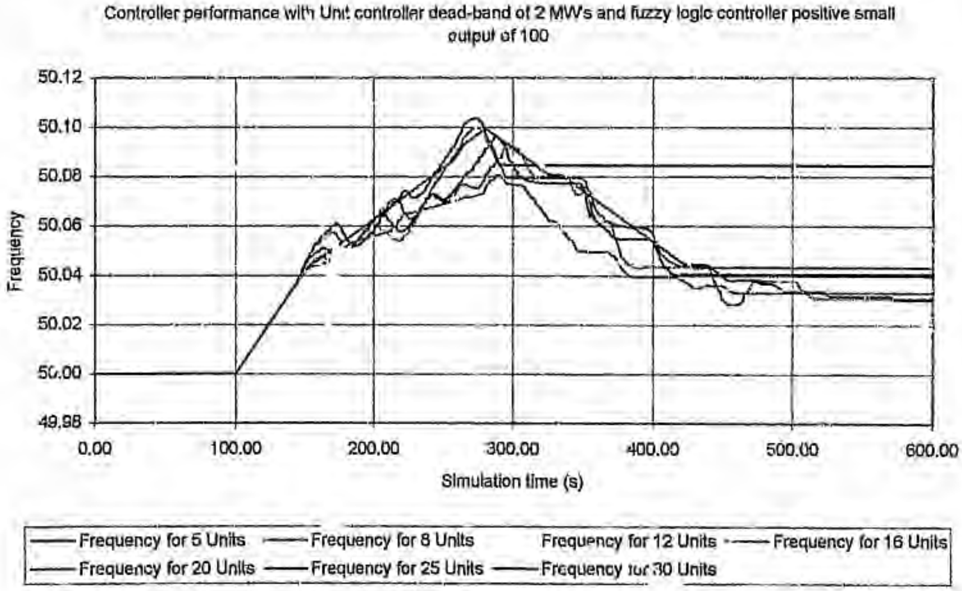

Fig 10.4

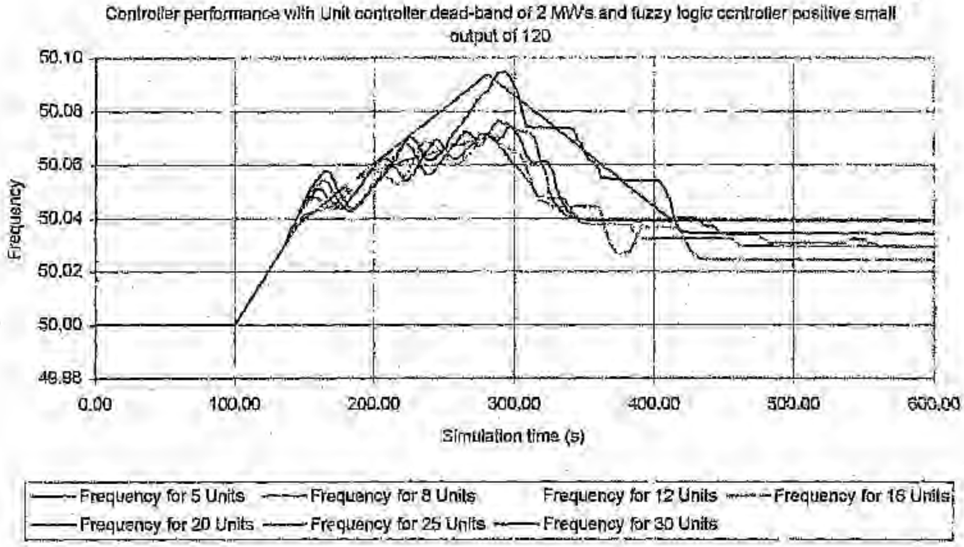

Fig 10.5

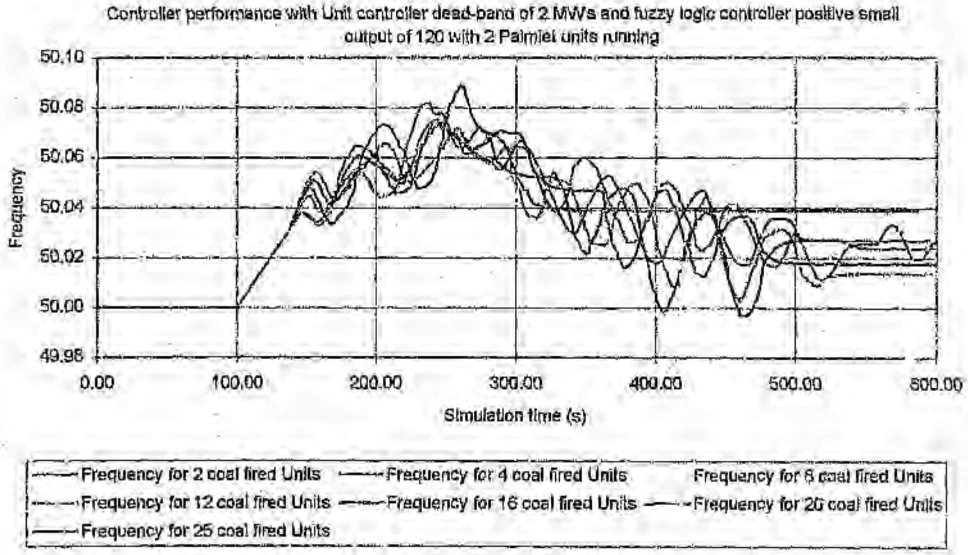

Fig 10.6

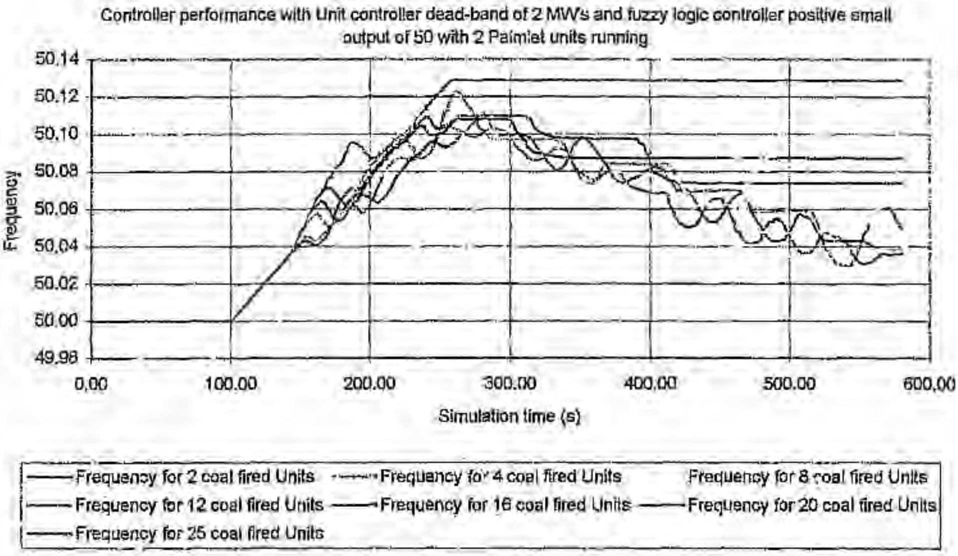

Fig 10.7

## 10.4 SUMMARY

The model of the original controller in MATLAB® showed the same results. The modification to the unit set-point showed an improved performance and also indicated that the AGC controller will require re-optimisation. The optimisation in MATLAB® show that the output regions of the fuzzy logic controller need to be reduced to avoid an oscillation. It is recommended that this modification is implemented with the necessary re-optimisation.

# 11 IMPLEMENTATION OF SET-POINT CONTROL

## 11.1 BACKGROUND

Based on the studies described in Chapters 9 and 10 the implementation of set-point control on the actual AGC controller and the subsequent optimisation of the controller were performed.

The implementation of the new control strategy required a software change as the control system was designed to only have either MW or set-point in the AGC algorithm. Once this was completed and the values were checked and calibrated, the dead band of the individual PLC controllers was reduced to 3 MW from the original values of 8 and 5 MW.

The values from the optimisation process were also entered as starting points for the final tuning of the controller. The preliminary results are presented in this chapter.

## 11.2 IMPLEMENTATION OF SET-POINT IN THE PLC

The ENCOR control system structure made allowances for receiving either the set-point or the actual MW from the unit. The required modification was to use the set-point in the PLC controller, while the actual MW from the unit would still be used for the ACE and economic calculation. This required the updating of the database to include an additional analogue input from each power station unit so that both values would be available as inputs.

The set-point has been available from each station since the implementation of the Phase 2 communication equipment, in 1985, when it was realised that this value could be useful to the controllers at National Control. The values at the power stations were checked for their accuracy and some were re-calibrated.

Once the calibration and database change were completed, the PLC algorithm software was altered to be able to receive either the set-point or actual MW values, as shown in Fig 11.1

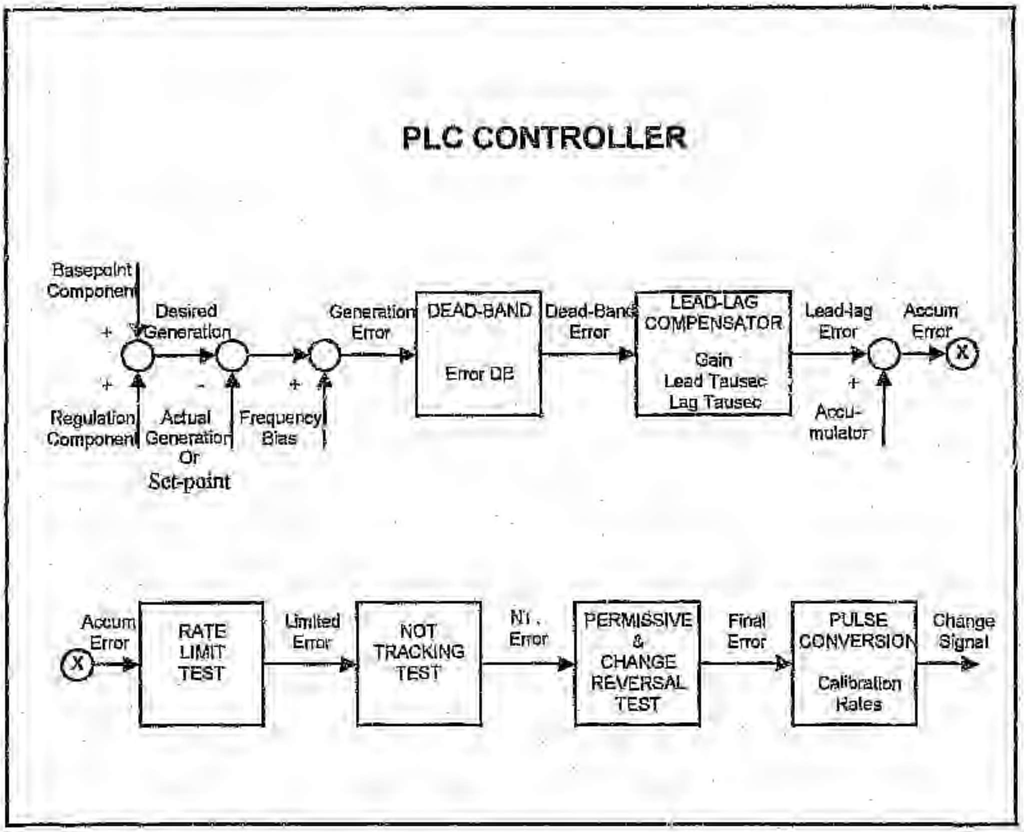

Fig 11.1

The frequency bias shown in Fig 11.1 is set to zero when the PLC is on set-point control. This is done because the set-point is received from the unit controller before any frequency control correction is added in the unit controls on the power station. This reduces the possibilities for errors in this controller, as the response to frequency changes often depends on the dynamic stability of the power station unit at that particular time.

The dead band of the controller is then reduced due to the removal of the frequency bias calculation and as the set-point is altered significantly quicker by the power station unit controller than the MW. There is less noise on this signal compared to the actual MW signal.

The dead bands of these controllers were 5 - 8 MW and this modification allowed them to be reduced to 3 MW.

## 11.3 FINE TUNING OF THE CONTROLLER

The values obtained from the optimisation using MATLAB® as described in Chapter 9 were used as the starting point for the re-optimisation of the AGC controller. As the model is a simplified representation of the real system there were some discrepancies in the final values.

The final negative small and positive small outputs of the fuzzy logic controller were set to -70 and 70 respectively. This was lower than the optimised model negative small and positive small outputs of -100 and 100 respectively.

The negative large and positive large outputs of the fuzzy logic controller were set to 135 and -135 respectively.

The dead band of the main AGC loop was reduced from 80 MW to 70 MW to control the ACE slightly closer to zero.

## 11.4 RESULTS OF THE OPTIMISATION

### 11.4.1 Performance of the on-line Eskom AGC system

The performance of the AGC system in terms of the AGC established control criteria, described in Chapter 3, is shown in Fig 11.4.

The original AGC fuzzy logic controller was in use from the start of the performance measurement in January 1997. Set-point control was implemented in December 1997 and was fine-tuned during the first weeks of December 1997.

From the actual control pulses it is evident that the amount of control issued by AGC decreased from an initial monthly average of 2800 to 2500 MW/hour after the modifications had been finalised. The calculated control indicator inherently reflects the quality of the ACE as well. The calculated control decreased from an average of 2900 to 2550 MW/hour. The control is still higher than it was in 1995 (2000 MW/hour) when the fuzzy logic controller was initially installed and optimised. The CPS1 analysis showed an optimised control to be around 2500 MW/hour

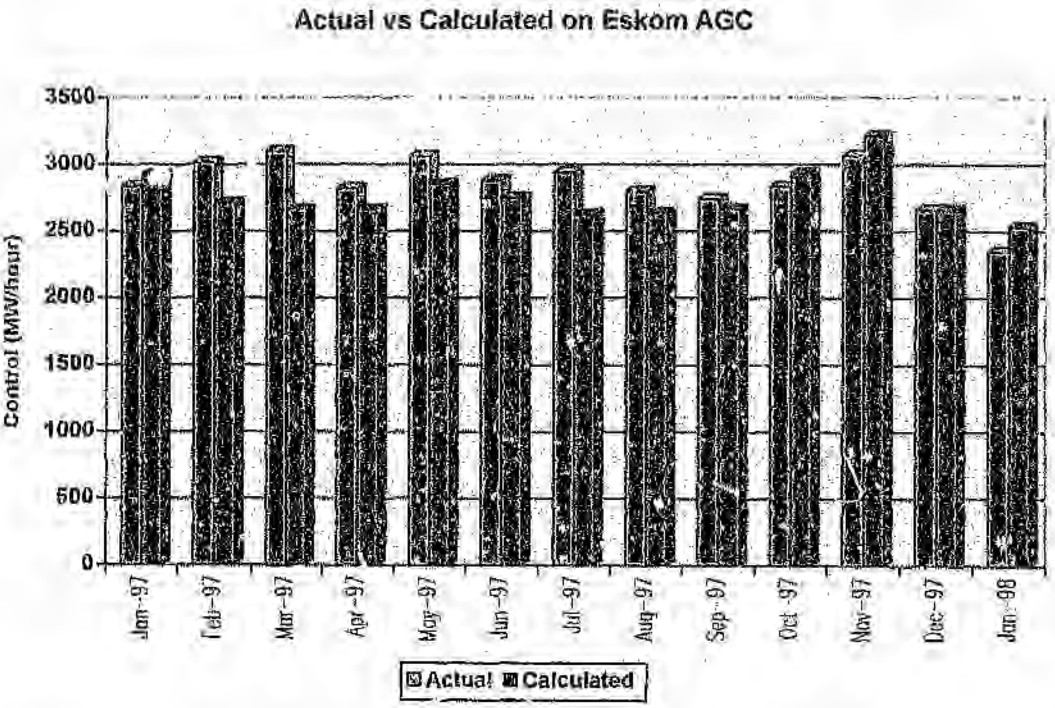

Fig 11.4

### 11.4.2 Frequency distribution

The main purpose of the re-optimisation was to improve the frequency distribution to the required 50% within 50 mHz of 50 Hz. The initial results of December 1997 and January 98 show an improvement from June 1997, Fig 11.5, but not to the distribution levels experienced in the beginning of 1997. The control of the frequency has improved as there is less cycling but there is a relatively high MW swing on the tie-line to Zesa. This indicates some over control outside the Eskom control area.

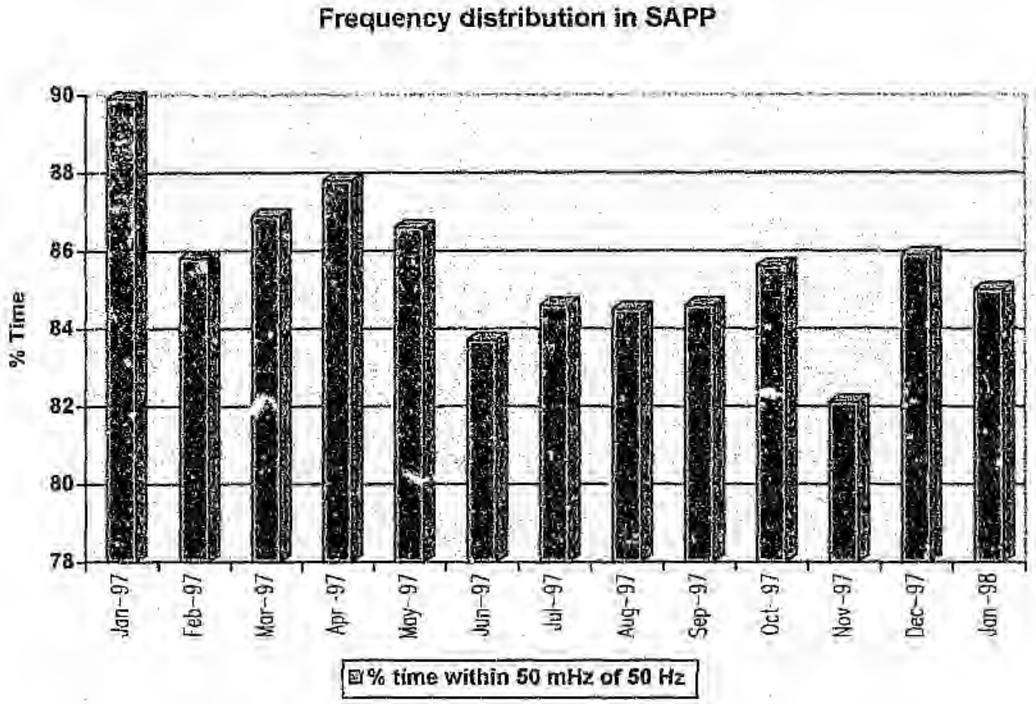

Fig 11.5

### 11.4.3 NERC performance

The NERC performance has improved since the alterations and re-optimisation in December 1997, Fig 11.6. The improvement in the A2 violations indicates that there less cycling as the standard deviation of the ACE is small. Improved control of the ACE is experienced as it is closer to zero.

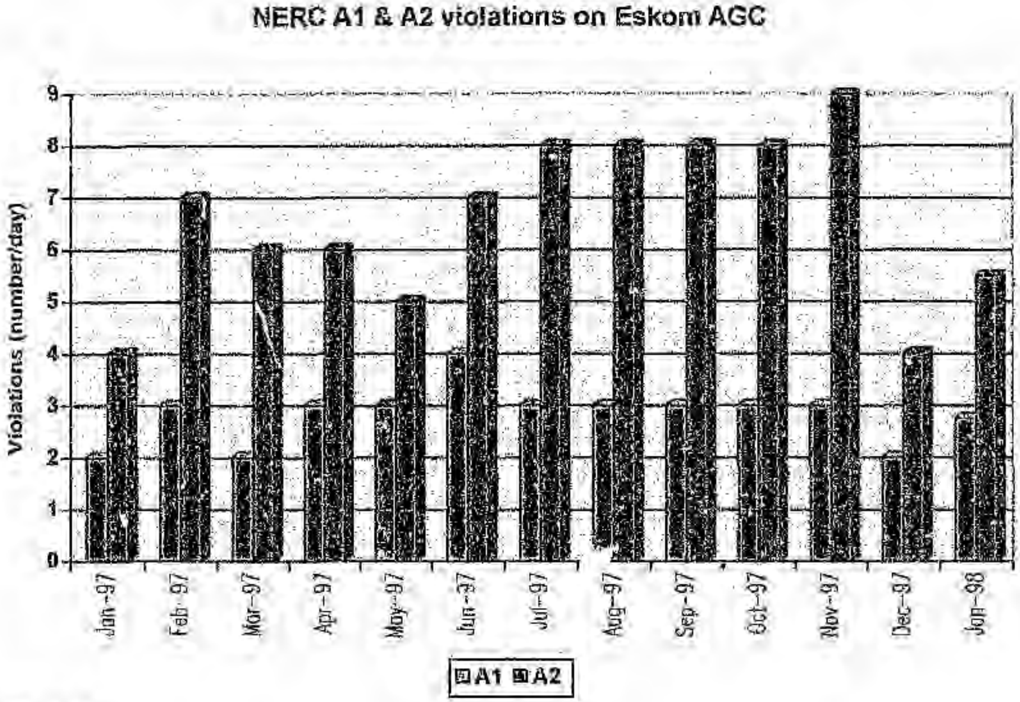
NERC A1 & A2 violations on Eskom AGC

Fig 11.6

## 11.5 SUMMARY

The modifications to the control system and the subsequent re-optimisation has reduced the control, marginally improved the frequency distribution and reduced the NERC violations. This all indicates that the modification is successful but not to the desired extent. The NERC violations indicate that the fuzzy logic controller can be re-tuned to be slower. However the controllers have already indicated that the control system is already much slower than in the past. The evaluation period has been short for such a complex control system and hence it is desirable to keep the settings constant for a few months while continuously monitoring to determine whether further optimisation is required.

For the frequency distribution it is necessary to recalculate the NERC CPS1 performance to establish whether Eskom is satisfying this criterion and hence whether another utility needs to perform a similar exercise. If Eskom is not satisfying the CPS1 criterion then it will be necessary to continue this optimisation phase.

# 12 CONCLUSION AND RECOMMENDATIONS

## 12.1 CONCLUSION

The original AGC system could not be set up to achieve the required quality of supply without using an excessive amount of control. A philosophy of distinctive load following and ACE regulation was therefore implemented. Although the load-following component of the original controller could be applied with minor modifications, the short-term ACE regulation component had to be improved significantly. The main alteration involved the addition of a derivative component by means of fuzzy logic and the elimination of non-linearity.

The results of the simulation indicated that system performance could be improved, while significantly reducing the amount of control issued to generating units. The improvements to the original design and configuration of AGC were therefore implemented on the operational system. The new system achieved slightly improved AGC performance results while reducing the amount of control issued significantly, i.e. by 60 %. The enhanced design and configuration of AGC can therefore be considered as highly successful.

The analysis of the AGC performance using the new control performance criterion CPS1, developed by NERC to measure the AGC performance of USA utilities, was successful in identifying areas of poor control and enhancements in Eskom. The simulation and optimisation of the modifications in MATLAB® proved useful in determining the impact of the modification and initial values for the final fine-tuning.

The implementation of the main modification of set-point control in the individual unit controllers is successful in that it reduced the control sent out and the NERC violations. However, it did not improve the frequency distribution to the required 90% in 50 mHz of 50 Hz.

## 12.2 RECOMMENDATIONS

It is recommended that the philosophy of load following by means of the existing economic dispatch routine and ACE regulation, using a regulation component that includes a derivative component implemented by means of fuzzy logic, is highly successful and should be maintained.

The process to determine AGC performance with the use of the new NERC CPS1 criterion is successful and should be performed on a regular basis, or when changes in performance requirements are required. The modelling of changes using the existing MATLAB® model and the use of MATLAB® tools to optimise the AGC controller before a change is implemented should continue.

The controller with its modifications should be monitored for a period to determine whether the initial results are valid. The analysis should be repeated if the frequency distribution does not improve and if sufficient information is available from the set-point modification to identify reasons for the controller not achieving the desired 90% distribution of frequency within 50 mHz of 50 Hz.

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# APPENDIX A: THE ORIGINAL DESIGN AND CONFIGURATION OF AGC

## A.1 BACKGROUND

Eskom's energy management system, which includes AGC, was developed by ESCA of Washington State, USA, and installed by the British company Westinghouse Systems Limited.

The AGC system consists of three main components, i.e. the base-point module, the regulation module and the programmable logic controller (PLC) of each generating unit controlled by the system (Fig A.6). A short description of each module follows, while details are discussed later on.

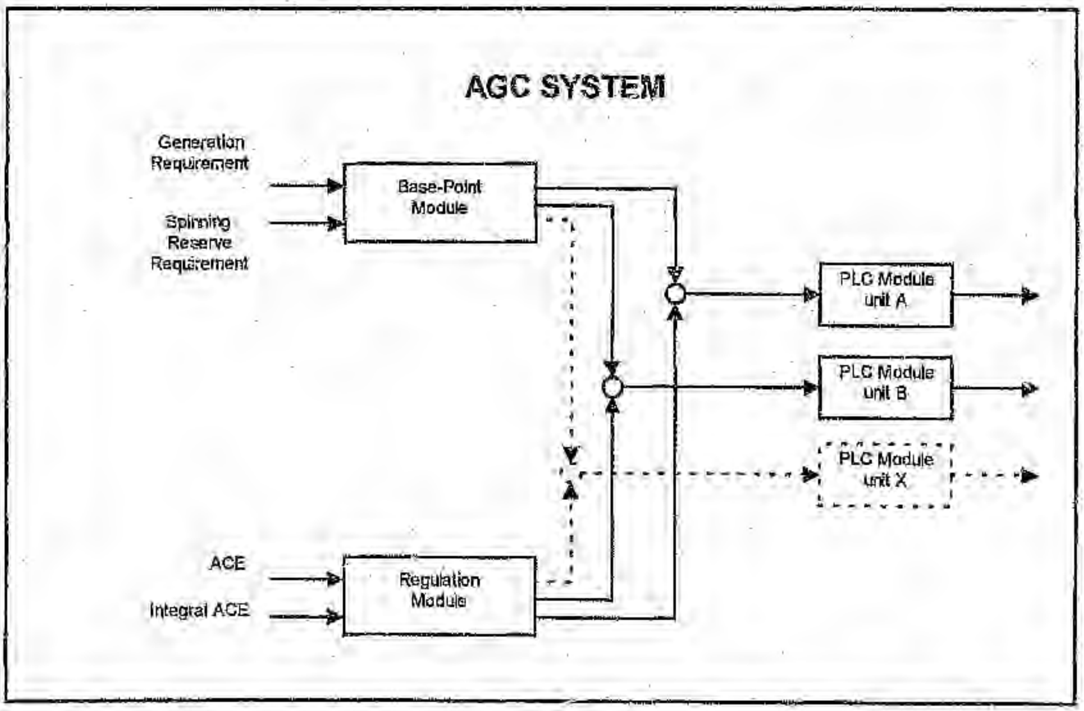


Fig A.1

- The *base-point module* determines the base point or longer-term operating point for each PLC on AGC, based primarily on economics. The generation and spinning reserve requirements of the operating area are real-time inputs.

- The *regulation module* calculates the amount of generation that must be allocated to selected PLCs to maintain the frequency at 50 Hz as well as the correct tie-line interchange. The area control error is the main real-time input.

- The *programmable logic controller modules (PLCs)* model the generating units controlled by AGC. Their main function is to compare the required generation of each unit with its actual generation and determine the control action needed.

AGC has different modes of operation and the PLCs can also be used in different modes. As the description of the control system is based on the modes of operation, a summary of the modes is first provided.

The AGC mode (designation in brackets below) of an operating area (Eskom operates as one operating area) determines whether control is based on the system frequency, tie-line interchange, or both. The AGC mode affects the calculation of the area control error discussed in the regulation module. The AGC modes are:

- *Constant net interchange control (CNIC)* - Only the tie-line interchange values are used in the calculations.

- *Constant frequency control (CFC)* - Only the frequency is used in the calculations.

- *Tie-line bias control (TLBC)* - Both the frequency and the interchange values are used in the computations.

The *PLC status* (designation in brackets) of a generating unit indicates whether the unit is dispatched through AGC or not. PLC statuses are:

- *Off (OFF) status* - The unit is off-line and is not generating any power.
- *Manual (MAN) status* - The unit is on-line but is not dispatched by AGC.
- *Substituted (SUB) status* - The unit is on-line and a dispatch was determined by AGC but was substituted manually by the operator.
- *Automatic (AUT) status* - The unit is on-line and is dispatched by AGC.

The *PLC mode* (also a three-character designation) of a generating unit indicates how the base-point and regulation components of the PLC are determined. The different statuses and modes are discussed in the appropriate modules.

## A.2 BASE-POINT MODULE

The base-point module (Fig A.2) uses three methods to determine the PLC base points. The method used depends on the chosen base-point mode, whose designation (shown below in brackets) also makes up the first two characters of the PLC mode:

- *Control economic dispatch mode (CE)* - AGC uses the results of the control economic dispatch routine to determine the PLC base points.
- *Base-load mode* - *(BL)* AGC retrieves the actual PLC base point from the base-point scheduling function.

- *Average mode (AV)* - If the first two options fail, AGC determines the PLC base point by computing the average of the economic high and low limits.

Outputs are the PLC base points and the system marginal cost. To prevent the effect of a possible step change after an economic dispatch execution, the base points are sent through a typical low-pass filter before being entered into the PLC.

### A.2.1 Control economic dispatch mode (CE)

This is the most desirable mode of operation from an economic as well as a regulation point of view. The PLC base points of units in this mode are calculated by means of the economic dispatch routine.

### A.2.2 Base-load mode (BL)

In this mode AGC retrieves the actual PLC base point from the base-point scheduling function. This function allows the operator to enter a pre-programmed generation schedule for any unit. A unit can be base-loaded at a constant output for the whole period or it can be programmed to follow a specific loading profile, for example to ramp up the unit before peak and deload it gradually thereafter. All units on AGC (AUT) should be loaded by means of a base-load schedule if the operator is unhappy with the automatic loading, as the switching of a PLC between statuses (AUT and MAN) to do loading will cause unnecessary control of units.

### A.2.3 Average mode (AV)

When a PLC has no base load scheduled and cannot be dispatched by the control economic dispatch routine, the average of its economic low and high limits is used as its base point. The limits are normally fixed, but can be adjusted by the operator. This mode is actually only used as a back-up procedure.

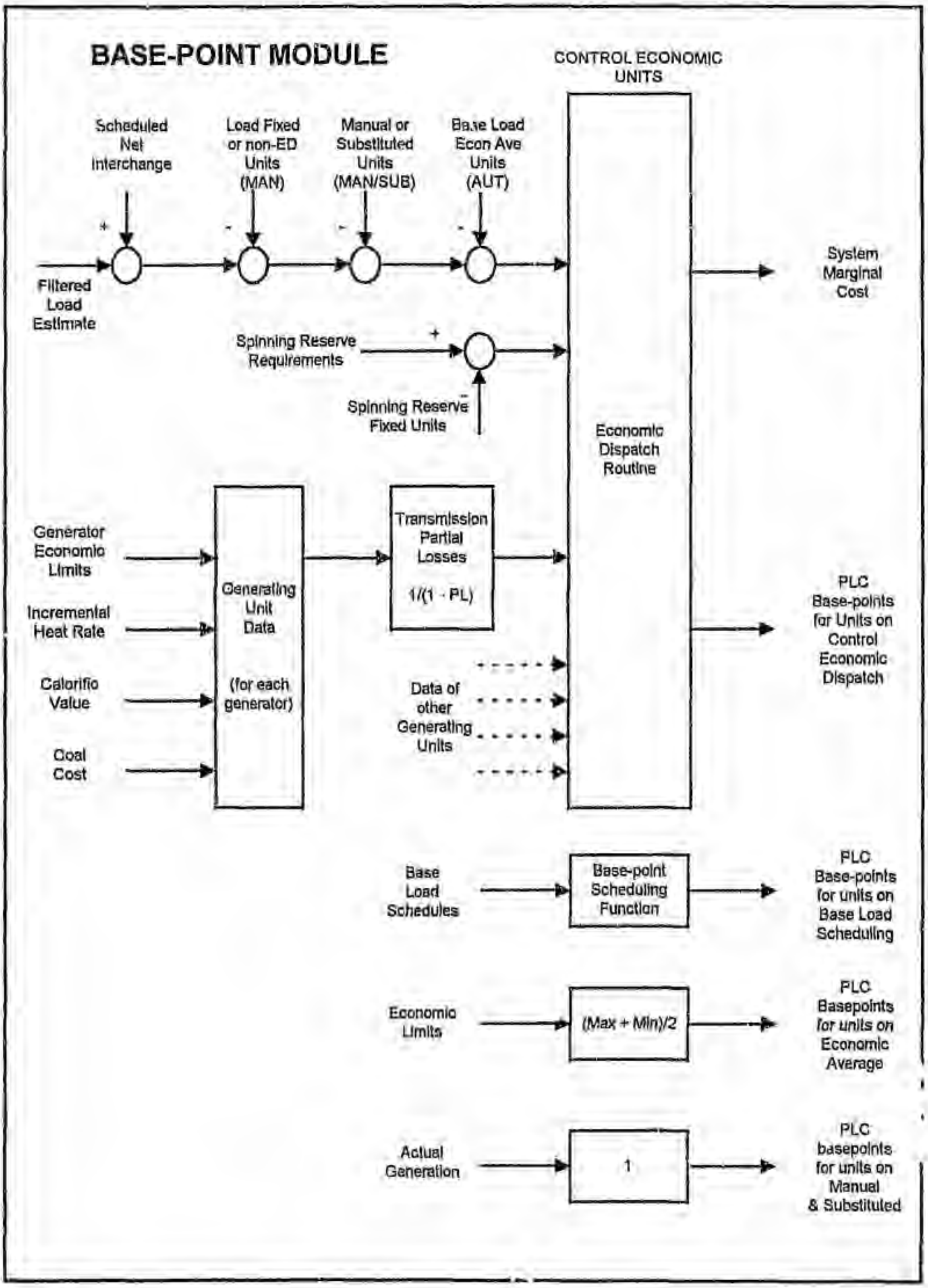

BASE-POINT MODULE
CONTROL ECONOMIC UNITS
Scheduled Net Interchange
Load Fixed or non-ED Units (MAN)
Manual or Substituted Units (MAN/SUB)
Base Load Econ Ave Units (AUT)
+
-
-
-
Filtered Load Estimate
Spinning Reserve Requirements
+
Spinning Reserve Fixed Units
-
Economic Dispatch Routine
System Marginal Cost
Generator Economic Limits
Incremental Heat Rate
Calorific Value
Coal Cost
Generating Unit Data
(for each generator)
Transmission Partial Losses
1/(1 - PL)
Data of other Generating Units
PLC Base-points for Units on Control Economic Dispatch
Base Load Schedules
Base-point Scheduling Function
PLC Base-points for units on Base Load Scheduling
Economic Limits
(Max + Min)/2
PLC Basepoints for units on Economic Average
Actual Generation
1
PLC basepoints for units on Manual & Substituted

**Fig A.2**

### A.2.4 System advisory economic dispatch

This module is only used as an off-line information source for the operator. It does an economic dispatch of all units that are on AGC, i.e. in the AUT status. It gives the operator an indication of how well the units that are not on control economic dispatch are loaded in terms of short-term economics.

## A.3 REGULATION MODULE

The regulation module calculates the amount of generation that must be allocated to selected PLCs to maintain the frequency at 50 Hz as well as to correct tie-line interchanges in the short term.

The regulation module always calculates the total desired regulation according to the same principles but will allocate the regulation component of each PLC on the basis of its regulation mode and participation factors. The regulation mode of a unit is determined in advance by the operator, based on its loading capabilities and short-term frequency response, i.e. the unit's ability to change its output and the rate of change. The choice of regulation mode (designation in brackets below) also makes up the last character of the PLC mode.

- *Off (O) mode* - The PLC will never regulate.
- *Emergency (E) mode* - The PLC will only regulate when the ACE is in the emergency region.
- *Assist (A) mode* - The PLC will regulate when the ACE is in the emergency or assist region.
- *Regulation (R) mode* - The PLC will regulate when the ACE is in the normal, assist or emergency region.

The module consists of two main elements, namely the *raw (proportional) ACE component* and the *integral ACE component*, which are combined to provide the regulation component for those

PLCs which are participating in regulation (Fig A.3). The regulation module can be described as a typical proportional-integral (PI) controller. The main dynamic inputs for both components are the measured frequency and tie-line interchange.

## A.3.1 Raw ACE (proportional) component

The area control error (ACE) represents the mismatch between the power available and the total demand in the operating area. Depending on the AGC operating area mode, as described in (2.1), the *frequency* and/or *tie-line interchange* is used to calculate the ACE. Details of the utilisation of the two inputs in the raw ACE component follow.

### *A.3.1.1 Frequency error*

The system frequency of the power pool is an indicator of the balance between power generated and power required. The difference between the measured frequency and the scheduled frequency constitutes the frequency error. Although a frequency error is universal to all operating areas in a power pool, it is seen as the mismatch between the power generated and the demand in the local operating area. A deviation in frequency as a result of a mismatch in another operating area will be compensated for in the tie-line calculations.

### *A.3.1.2 Frequency filter*

The frequency filter screens out high-frequency noise or locally induced spikes of very short duration from the measured value. Significant frequency deviations, resulting mainly from generator trips, occur within seconds and should not be filtered out. A typical low-pass filter as is used.

### *A.3.1.3 Frequency offset*

A frequency offset is subtracted from the frequency error. It can be an intentional frequency offset entered by the operator, a scheduled frequency setting error or a frequency metering error.

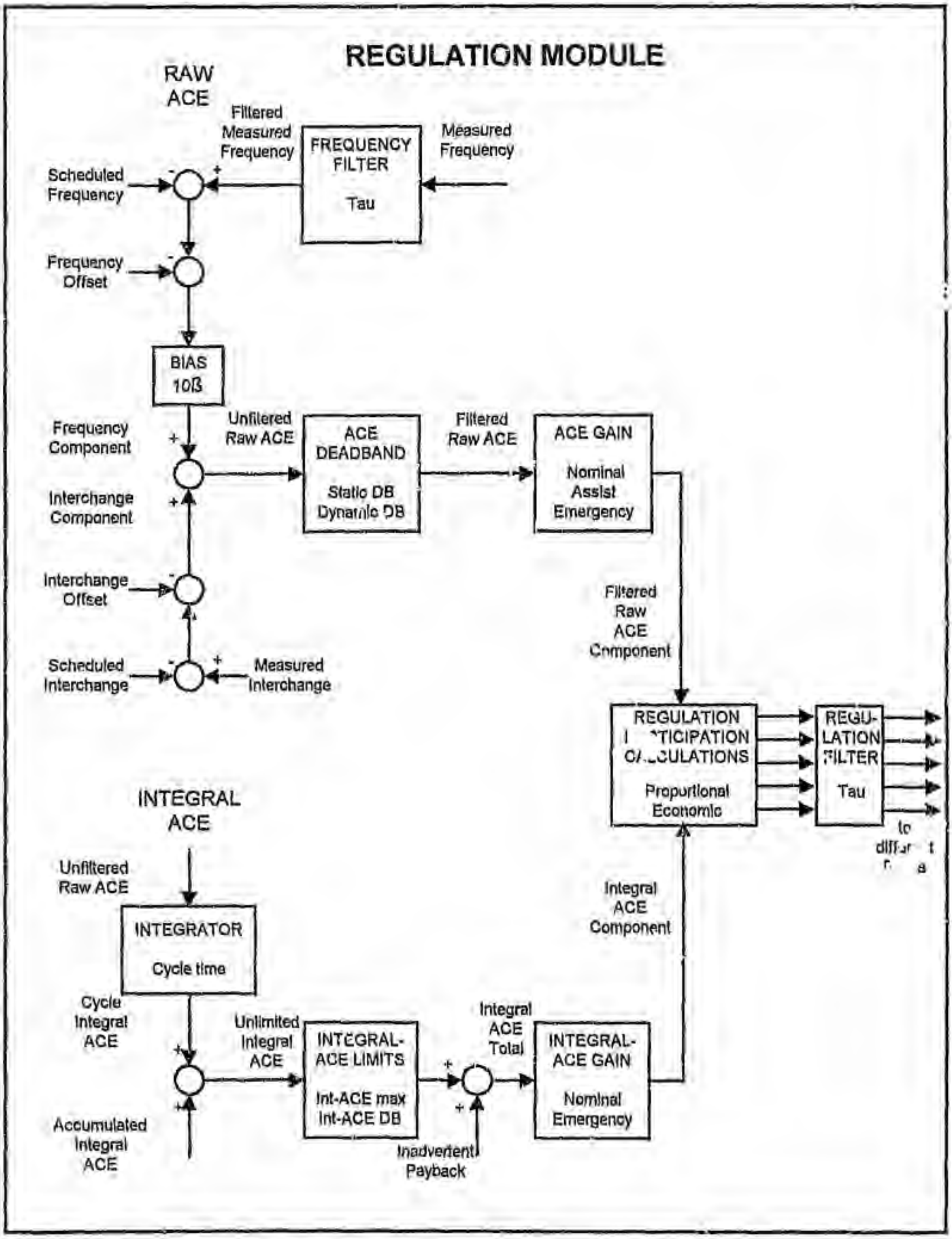

REGULATION MODULE
RAW ACE
Filtered Measured Frequency
FREQUENCY FILTER
Tau
Measured Frequency
Scheduled Frequency
-
+
Frequency Offset
-
BIAS
10ß
Frequency Component
+
Unfiltered Raw ACE
ACE DEADBAND
Static DB
Dynamic DB
Filtered Raw ACE
ACE GAIN
Nominal
Assist
Emergency
Interchange Component
+
Interchange Offset
-
Scheduled Interchange
-
+
Measured Interchange
Filtered Raw ACE Component
REGULATION PARTICIPATION CALCULATIONS
Proportional
Economic
REGULATION FILTER
Tau
to
different
INTEGRAL ACE
Unfiltered Raw ACE
INTEGRATOR
Cycle time
Cycle Integral ACE
+
Unlimited Integral ACE
INTEGRAL-ACE LIMITS
Int-ACE max
Int-ACE DB
+
Integral ACE Total
INTEGRAL-ACE GAIN
Nominal
Emergency
Integral ACE Component
Accumulated Integral ACE
+
+
Inadvertent Payback

Fig A.3

### *A.3.1.4 Frequency bias*

The frequency error with offset is multiplied by the frequency bias of the operating area to convert the expression to power (Hz → MW). The frequency bias is dependent on the size and composition of the load in the operating area. It should be updated on a yearly basis, based on the average bias measured, and is expressed in MW/0,1 Hz.

### *A.3.1.5 Interchange error*

The measured net interchange of an operating area is obtained by the summation (positive-in, negative-out) of all power flowing through the tie-lines connecting the local operating area to other operating areas in the power pool. The combined net interchange of all the operating areas in the pool should accumulate to zero.

Tie-line interchanges are separately negotiated and scheduled by representatives of operating areas. AGC calculates the scheduled net interchange, consisting of all transactions made by the local operating area, and compares it with the measured net interchange to determine the interchange error.

### *A.3.1.6 Interchange offset*

An interchange offset is subtracted from the net interchange error. Like the frequency, it can be an intentional interchange offset entered by the operator, a scheduled interchange setting error or an interchange metering error.

### *A.3.1.7 ACE dead band and ACE gains (control regions)*

After the two raw ACE components have been combined, the result is classified under a control region based on the magnitude of the raw ACE. (Control regions must not be confused with control areas.) A different ACE level and gain is associated with each control region. The control regions and selection of levels and gains are as follows:

- Static dead band - Is chosen in accordance with the governor dead bands of generators controlled by AGC. The gain in the dead-band region is zero.

- Normal region - Caters for deviations in ACE caused by the natural acceptable distribution of frequency and interchange. Gain should be set to achieve unity response.

- Assist region - Is appropriate when ACE is abnormal but does not endanger system stability. The gain can be doubled or trebled.

- Emergency region - Should prevail during serious frequency or interchange mismatches, usually caused by generator or line trips. Gain can be increased dramatically for effective counteraction.

*Filter intelligence is given to the dead-band region by implementing a dynamic dead band.*

## A.3.2 Integral ACE component

The utilisation of the frequency and the tie-line interchange as inputs to the integral ACE component follows.

### *A.3.2.1 Integral frequency and tie-line interchange*

The integral ACE for each new AGC cycle (ACE x cycle time) added to the accumulated integral ACE for a predefined period determines the integral ACE frequency component (MWh). The accumulator resets to zero when the accumulation period has expired. Energy requirements that are not met should be compensated for manually thereafter. The integral ACE frequency component is limited to a certain maximum and will be ignored if it is less than the dead-band value.

### *A.3.2.2 Inadvertent payback*

Transactions scheduled are categorised into peak or off-peak transaction periods, with their distinct tariffs. Inadvertent energy not met in any transaction period must be compensated for in kind in a similar period later on. AGC keeps track of inadvertent energy for each transaction period and adds the appropriate energy to the integral ACE component.

### *A.3.2.3 Integral ACE dead band and gains*

Like the raw ACE, the integral ACE components are combined and classified under a control region based on magnitude. A different integral ACE level and gain is associated with each control region. The integral ACE dead band is, however, a simple region limit (static). The normal and emergency control levels and gains are determined by criteria similar to those for the raw ACE. The control regions are:

- Dead-band region
- Normal region
- Emergency region

The combined ACE and integral ACE will determine the regulation region indicator that tells the operator in what state the system is and what type of control can be expected (Fig A.4).

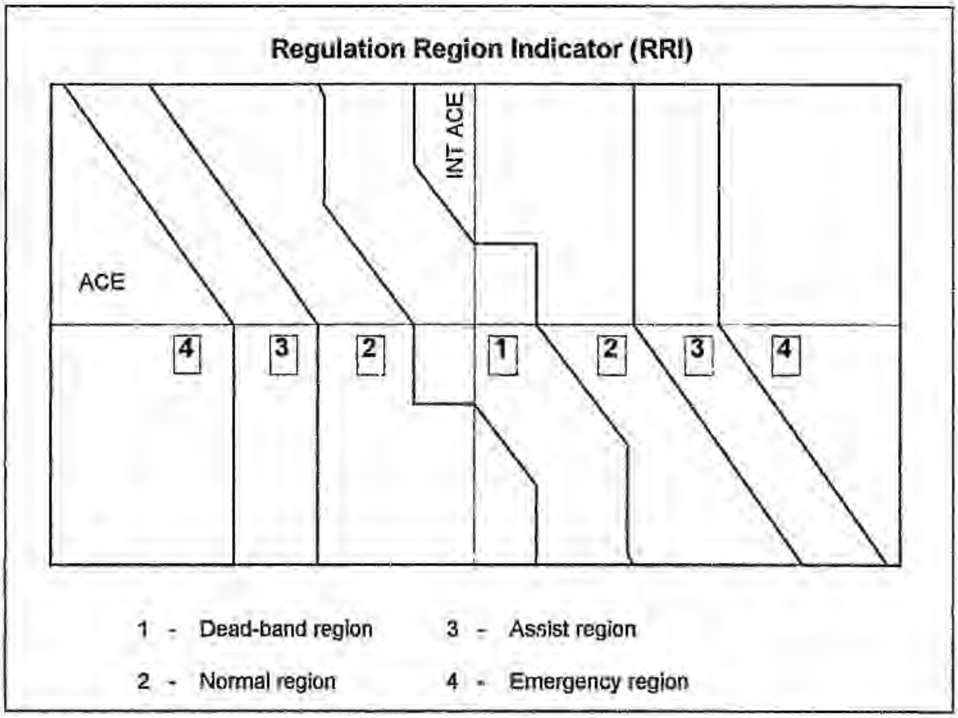


Fig A.4

## A.3.3 Regulation participation calculations

### *A.3.3.1 Proportional participation (raw ACE)*

The relative participation expected from each PLC in its regulation duty must be specified. This is based on the short-term frequency response and loading capabilities of the generator. A proportional participation of between 1 and 100 is allocated.

AGC computes the total proportional participation entered for all units that are regulating. The individual participations are normalised to the total to obtain the relative proportional participation factor of each PLC.

**Example:**

| *Station* | *Prop part allocated* | *Prop part factor* |
|---|---|---|
| Tutuka | 80 | 80/150 = 0,53 |
| Duvha | 50 | 50/150 = 0,33 |
| Kendal | 20 | 20/150 = 0,13 |
| Total | 150 | 1,00 |

### *A.3.3.2 Economic participation (integral ACE)*

As the integral ACE component does not increase rapidly and is also limited, participation is based purely on economics, irrespective of unit capabilities. The inverse of the unit's marginal cost, as calculated by control economic dispatch when the unit is in CE mode or else by advisory economic dispatch, is used for economic participation.

Again AGC computes the total economic participation determined for all units that are regulating and normalises the individual participations to the total to obtain the relative economic participation factor of each PLC.

### *A.3.3.3 Regulation component calculation and filter*

The regulation component of each PLC is determined as follows:

$$\text{Regulation Compnt}_{\text{unit x}} = (\text{PropPF}_{\text{unit x}} \times \text{RawACE}) + (\text{EconPF}_{\text{unit x}} \times \text{IntACE}) \qquad \text{(Eq A.2)}$$

The calculated value of each PLC is filtered through a low pass which has a time constant of ±3 AGC cycles before being passed on to the PLC.

## A.4 PLC MODULES

All generating units recognised by AGC are modelled by means of a programmable logic controller (PLC). It simulates the generator control system and contains information on the capabilities of the generator (minimum and maximum generation limits, ramp rates, and local frequency response) as well as the actual generation of the unit via a remote terminal unit (RTU).

The main function of the PLC is to compare, for each unit, the required generation and the actual generation. The required generation is the summation of the distinct base-point and regulation components. The calculated error is processed and constraints are taken into account to determine the generating unit set-point change signal needed. Fig A.5 represents a simplified block diagram of a PLC. It can be split into the generation error calculation, dead band and filtering, permitting tests and pulse conversion.

Control is enforced on the generator set point, with two options available:

- The change signal is added to a reference set point and an analogue value for a new actual generating unit set point is telemetered to the power station.
- The change signal is converted into pulses, telemetered, decoded at the station, and added to the actual generating unit set point. (This is the option currently used in Eskom.)

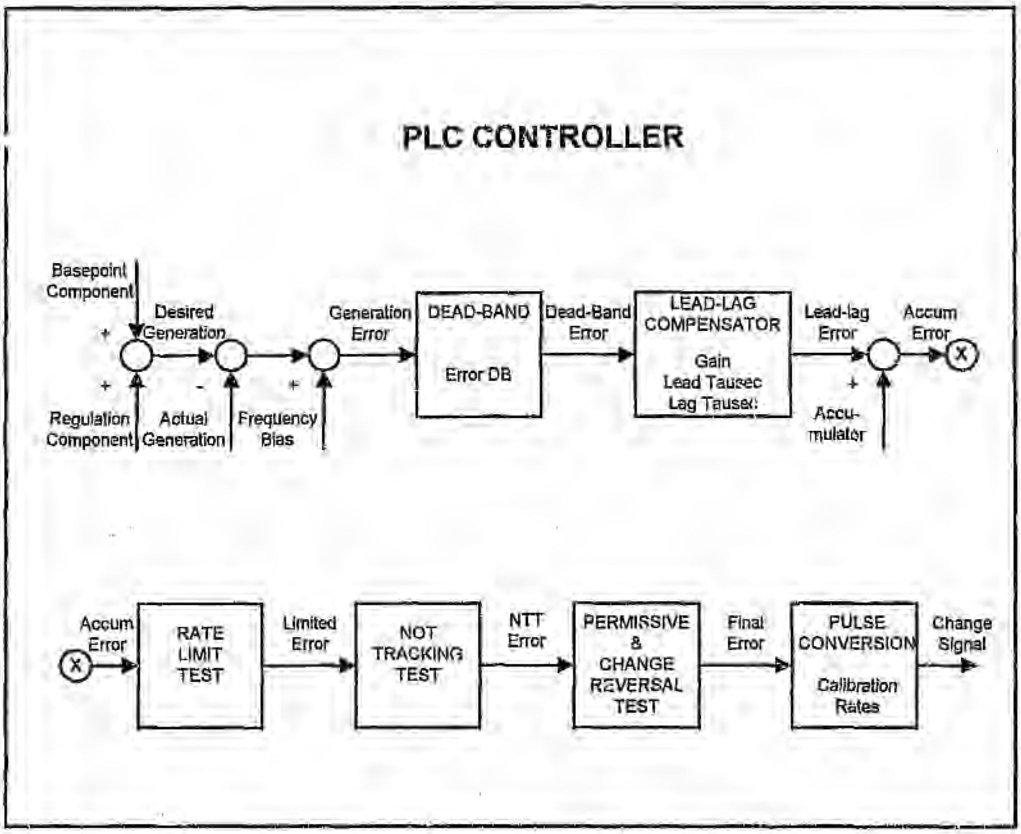


Fig A.5

### A.4.1 Generation error calculation

The calculated generation error (Eq A.3) is the immediate surplus or deficit in capacity generated by a unit.

*Gen Error = (Basepoint + Regulation) - Actual Gen + Freq Response* (Eq A.3)

*Freq Response = Local Freq Bias × Filtered Freq Error* (Eq A.4)

The local frequency response (Eq A.4) caused by the governor valves of all generators affects the actual generation signal. It is considered as noise and is compensated for by adding the noise to the generation error. The local frequency bias of all generating units is determined by evaluating the actual governor response measured during low-frequency incidents. The frequency response used in the equation is therefore actually a prediction of the governor response that can be expected from the unit.

The resultant generation error is filtered by means of a dead band and a lead-lag compensator, and then added to an accumulator.

### A.4.2 Dead band and lead-lag compensator

The dead band is simply specified as a percentage of the maximum generation of the unit and the lead-lag compensator is described as follows:

$$Lead - Lag\ Compensator = K\frac{(1 + sT_1)}{(1 + sT_2)} \qquad \text{(Eq A.5)}$$

where:

$K$ → gain

$T_1$ → lag time constant

$T_2$ → lead time constant

The gain (K), lag time constant ($T_2$) and lead time constant ($T_1$) determine the filtering of the error signal achieved by the lead-lag compensator (Eq A.5). For the purpose of this compensator the low-pass component (lag) should be dominant. An increase in the high-pass (lead) component will result in less damping, its effect mainly being visible at a time close to zero.

### A.4.3 Permitting tests

Permitting tests are used to determine whether AGC should be allowed to send the calculated PLC change signal to the generating unit.

#### *A.4.3.1 Rate limit test*

The PLC change signal in one cycle is limited by the maximum response rate of the generating unit. If the error exceeds the typical response rate of 15 MW/min for a cycle (1 MW/cycle), it will be reduced. This test will also prevent change signals in the *up* direction if the unit is at its AGC maximum limit and change signals in the *down* direction if the unit is at its minimum limit.

#### *A.4.3.2 Not-tracking test*

The not-tracking test compares the AGC change signals sent to the unit with the actual change of the PLC plant. The expected-to-actual ratio is calculated in both the *up* and the *down* directions. To determine the short-term and long-term response ratios in the two distinct directions, the ratios are smoothed with a low-pass filter so that aberrant short-term unit responses are eliminated. The first is used to trigger the not-tracking test alarm and if the suspend option is chosen, the PLC is suspended.

#### *A.4.3.3 Permissive test*

The permissive test compares the direction in which the PLC will be commanded to move with the sign of the ACE. If the command will worsen the ACE, the change signal will be reset to zero. Only if the ACE exceeds a minimum permissive limit will the test be performed. This limit is the only adjustable parameter in the test and should be similar to the ACE static dead band.

#### *A.4.3.4 Change reversal test*

The change reversal test will reset the change signal to zero if the direction of the change signal reverses within a user-defined time. This test can be overruled if the system is in the emergency region.

### A.4.4 Pulse conversion

Pulse conversion is only applicable if the pulse change signal option is used as opposed to the analogue change signal option. The pulses are decoded at the power station by means of the same pulse conversion. It is added to the generator set point after it has been compared with the local generation limits.

## A.5 ECONOMIC DISPATCH ROUTINE

The routine calculates the incremental cost curve (ICC) of each available generating unit by means of their respective incremental heat rate curves, coal costs, calorific values and boiler efficiencies while taking the unit's minimum and maximum limits and ramp rate constraints into account (Eq A.6).

$$\text{Incremental Cost Curve} = \frac{\text{Coal cost} \times \text{IHR Curve}}{\text{Boiler Efficiency} \times \text{Calorific value}} \qquad \text{(Eq A.6)}$$

where:

*Coal cost* → Cost of coal (R/ton)

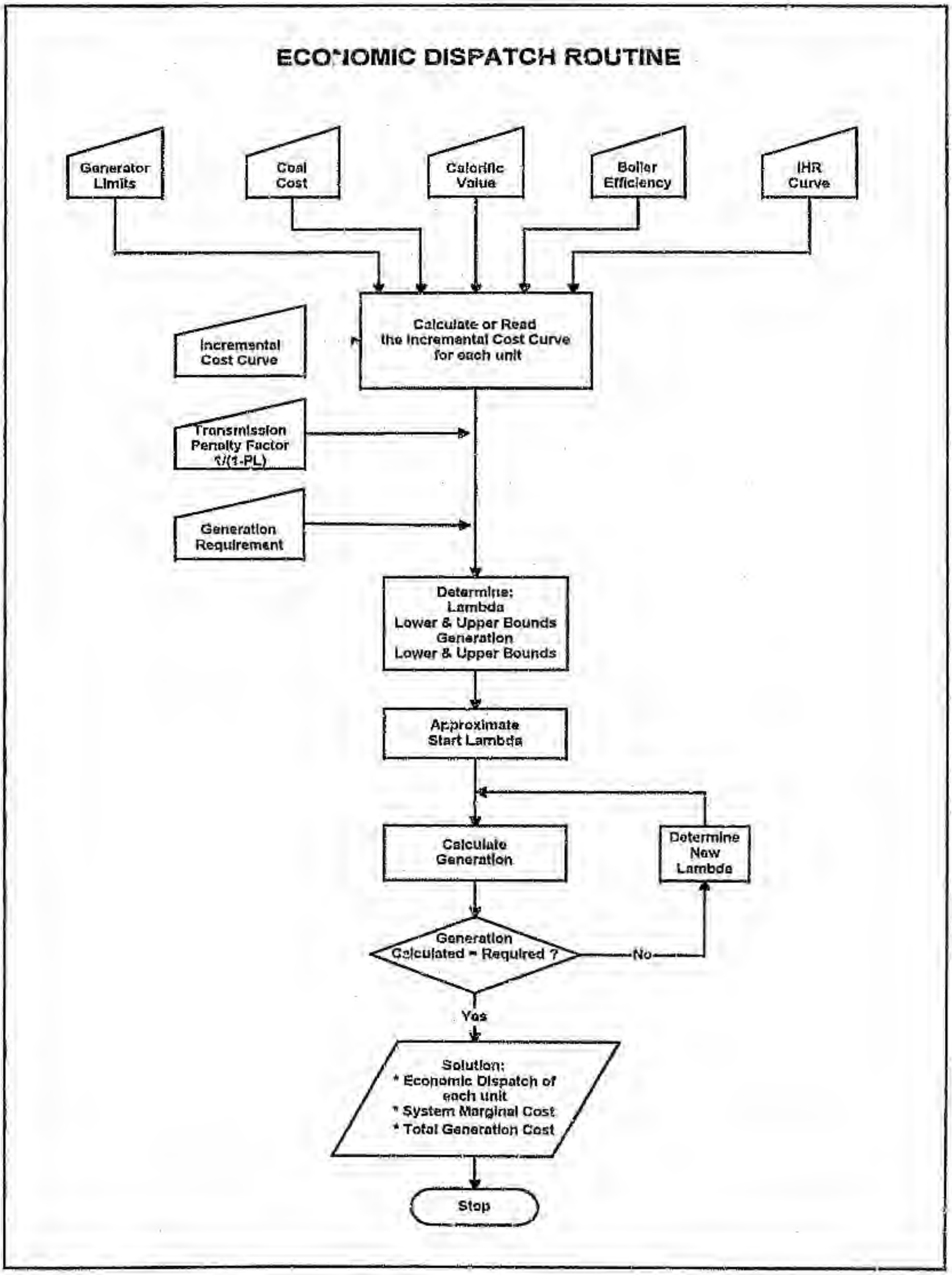
*IHR curve* → Incremental heat rate of the unit on its output range (MJ/MWh)

*boiler efficiency* → Thermal efficiency of the unit's boiler (%)

*Calorific value* → Energy content of the coal (MJ/ton)

When a bidding system is used in the electricity trade environment, the power stations themselves determine the incremental cost curve (ICC) or bidding curve at which they want their generating units to be dispatched. Under such circumstances the IHR curve is replaced by the ICC bid and the other three parameters are altered to unity; in other words, Eq A.6 is not used. Transmission costs are approximated by means of penalty factors.

The generation requirement that must be satisfied by the economic dispatch routine is determined by first calculating the total desired generation (i.e. demand) and then subtracting the actual generation of units not controlled by AGC. The original routine used only the interchange component of the ACE in this calculation, which could be fatal in the Eskom set-up.



ECONOMIC DISPATCH ROUTINE

Fig A.6

$$Total\ Desired\ Generation = \sum Generator\ Outputs_{All\ Units} - ACE \qquad \text{(Eq A.7)}$$

$$Generation\ Requirement = Total\ Desired\ Generation - \sum Generator\ Outputs_{Non\text{-}EDR\ Units} \qquad \text{(Eq A.8)}$$

A distinction between the two components of the regulation effort arises in the filtering of the generation requirement. The filter time constant of the load-following component has to be in the minute horizon to illuminate short-term influences, but smaller than the chosen interval between economic dispatch executions. Therefore the generation requirement is filtered digitally with a time constant of half the economic dispatch routine execution rate of 30 seconds (Eq A.10).

$$GenReq_{Filtered} = GenReq_{New} + \left[ DTF \times \left( GenReq_{New} - GenReq_{Previous} \right) \right] \qquad \text{(Eq A.10)}$$

The routine determines the most economic solution for dispatching units, as shown on the flow diagram. Most importantly, the desired output (base point) of each generating unit is provided, as well as the system marginal cost and total instantaneous generation cost.

Subroutines not indicated in Fig A.6, and which ensure proper allocation of spinning reserve and adherence to ramp rates and limitations of generating units, form part of the main routine. These subroutines will adjust the solution afterwards, resulting in new desired outputs for generating units and costs. The original routine incorrectly allocated the total spinning reserve requirement of the system to the units selected in economic dispatch mode. This resulted in incorrect desired outputs for generating units, especially when only a few units were selected in economic dispatch mode, and was corrected.

## A.6 SUMMARY

The original AGC system as described in this chapter is fairly complete and versatile but has some major deficiencies. The following specific observations can be made about each component by evaluating the model, without doing any simulation.

- The base-point component is well structured, with only minor irregularities.
- The regulation component is unbalanced as the proportional and integral parts are very detailed whereas there is no derivative part. Effort spent on the participation factors would be a duplication of the effort spent on regulating modes of units.
- The PLC component model, especially the lead-lag compensator and accumulator, of generating units is very inaccurate. The permitting tests are adequate.

The simulation in Chapter 6 will prove that the regulation component is also highly non-linear. The shortcomings in the regulation component prevent minimised control by means of simple parameter configuration but the desired quality of regulation is still achieved.

It was found that the only way of enhancing the system to the desired level was by redesigning some of the components, i.e. altering the programming code rather than just changing the code

# APPENDIX B: MATLAB® SIMULATION MODEL

## B.1 COMPLETE AGC SIMULATION MODEL

A simplified functional block diagram of the model developed in MATLAB is shown in Fig B.1. Note that 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 routine. The diagram shows a feedback control loop to demonstrate the effect that the control effort will have on the original input ACE. Some testing was, however, carried out on a system without the feedback loop.

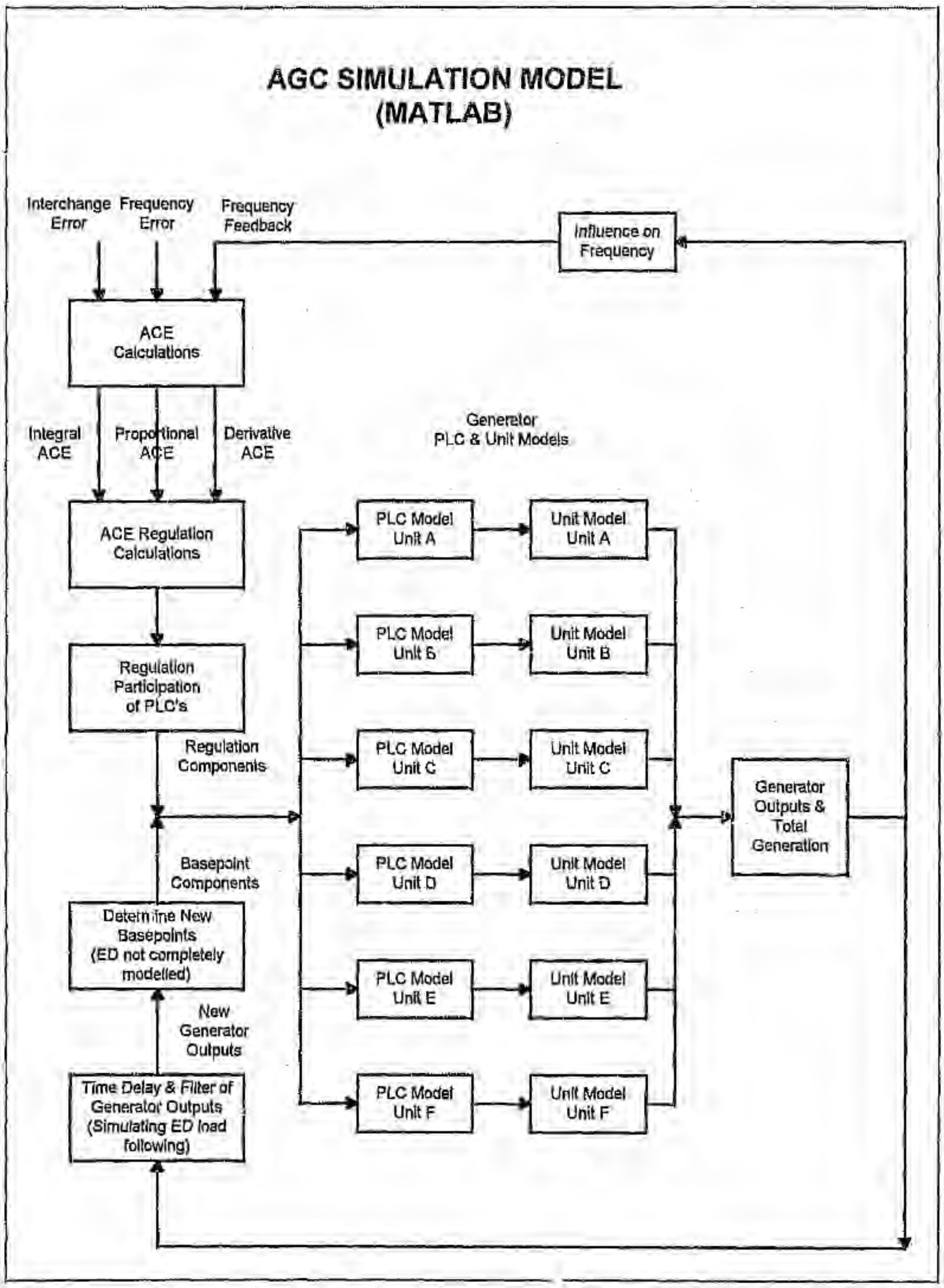

AGC SIMULATION MODEL
(MATLAB)
Interchange Error
Frequency Error
Frequency Feedback
Influence on Frequency
ACE Calculations
Integral ACE
Proportional ACE
Derivative ACE
Generator PLC & Unit Models
ACE Regulation Calculations
PLC Model Unit A
Unit Model Unit A
PLC Model Unit B
Unit Model Unit B
Regulation Participation of PLC's
Regulation Components
PLC Model Unit C
Unit Model Unit C
Generator Outputs & Total Generation
Basepoint Components
PLC Model Unit D
Unit Model Unit D
Determine New Basepoints (ED not completely modelled)
New Generator Outputs
PLC Model Unit E
Unit Model Unit E
Time Delay & Filter of Generator Outputs (Simulating ED load following)
PLC Model Unit F
Unit Model Unit F

Fig B.1

## B.2 ACE CALCULATION AND ACE REGULATION CALCULATION MODEL

This portion of the control system contains the calculations of the proportional, integral and derivative ACE as well as the very important fuzzy logic routine. A more detailed description of the ACE regulation calculation functional block is given in Fig B.2.

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 as described in Chapter 3. 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.

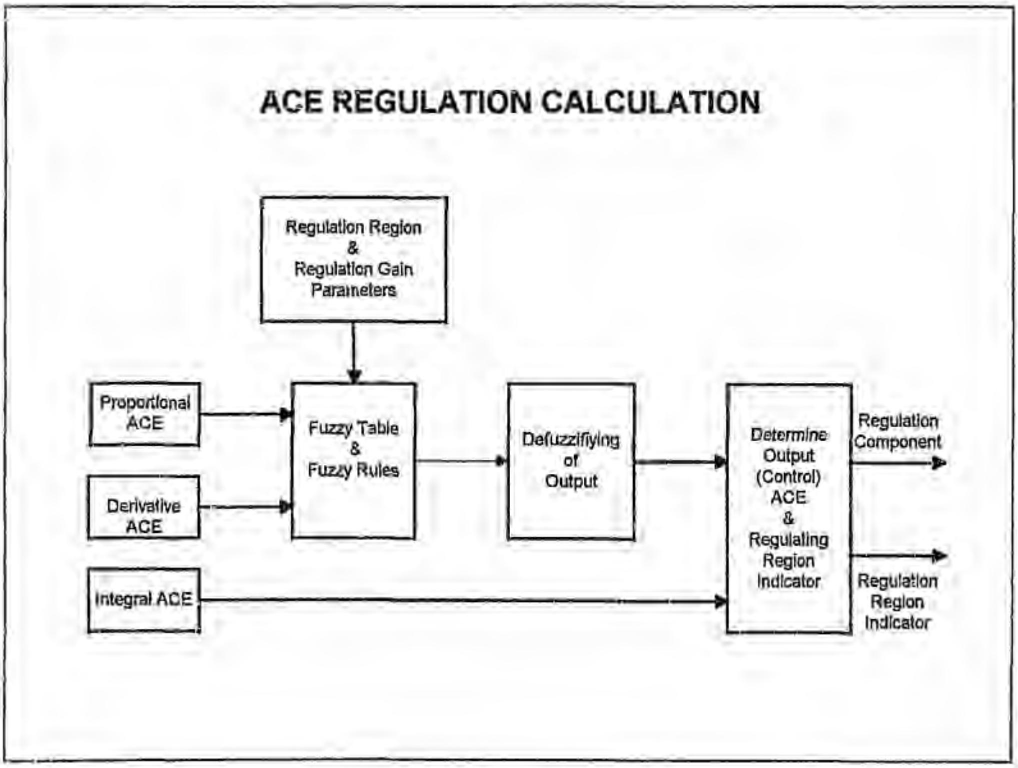


Fig B.2

## B.3 PLC AND UNIT CONTROLLER MODELS

The programmable logic controllers (PLCs) of six units were modelled in the simulation (Fig B.3). In other words, the system was controlled with only six good controllable units. In practice more units will be required as response to control is not always reliable. The PLC models are very similar to the original model described in Appendix A.

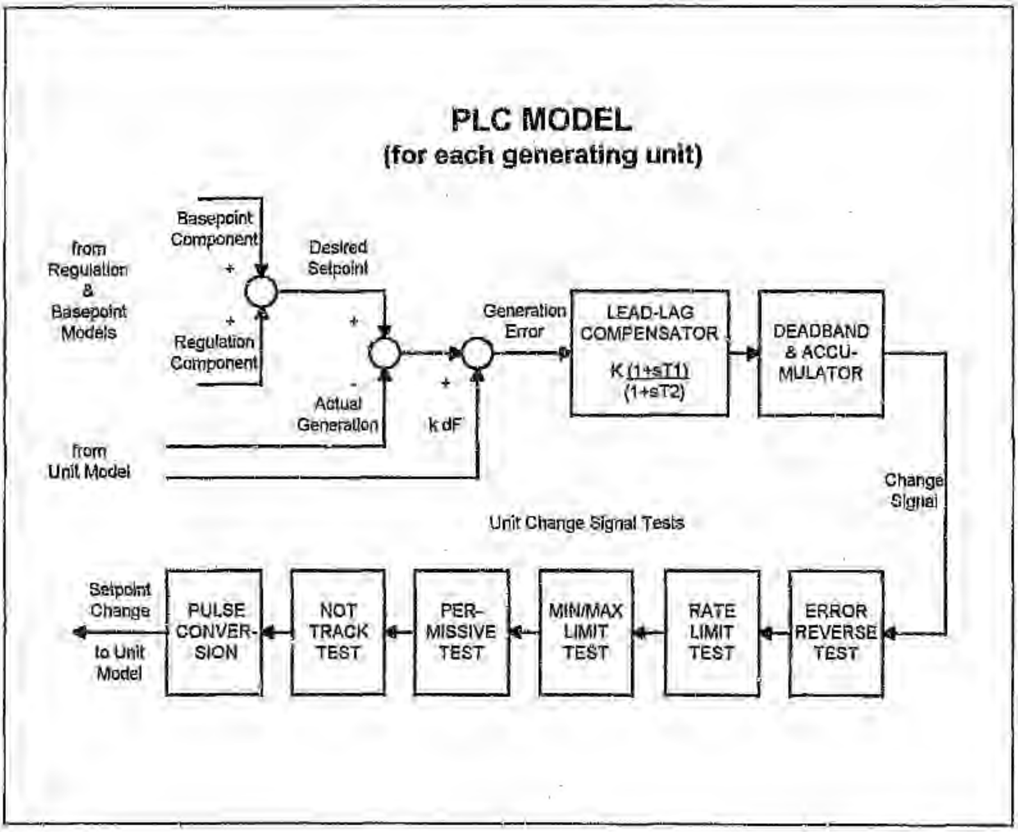


Fig B.3

As the response of the power system (power stations) to AGC was simulated the unit controller models of typical generating units had to be developed as well (Fig B.4). Each PLC model has an associated unit controller model. Both *boiler follow turbine* (constant-pressure) and *turbine follow boiler* (sliding-pressure) units were modelled. The simulated response of the unit controllers was calibrated against the performance of real units on the system.

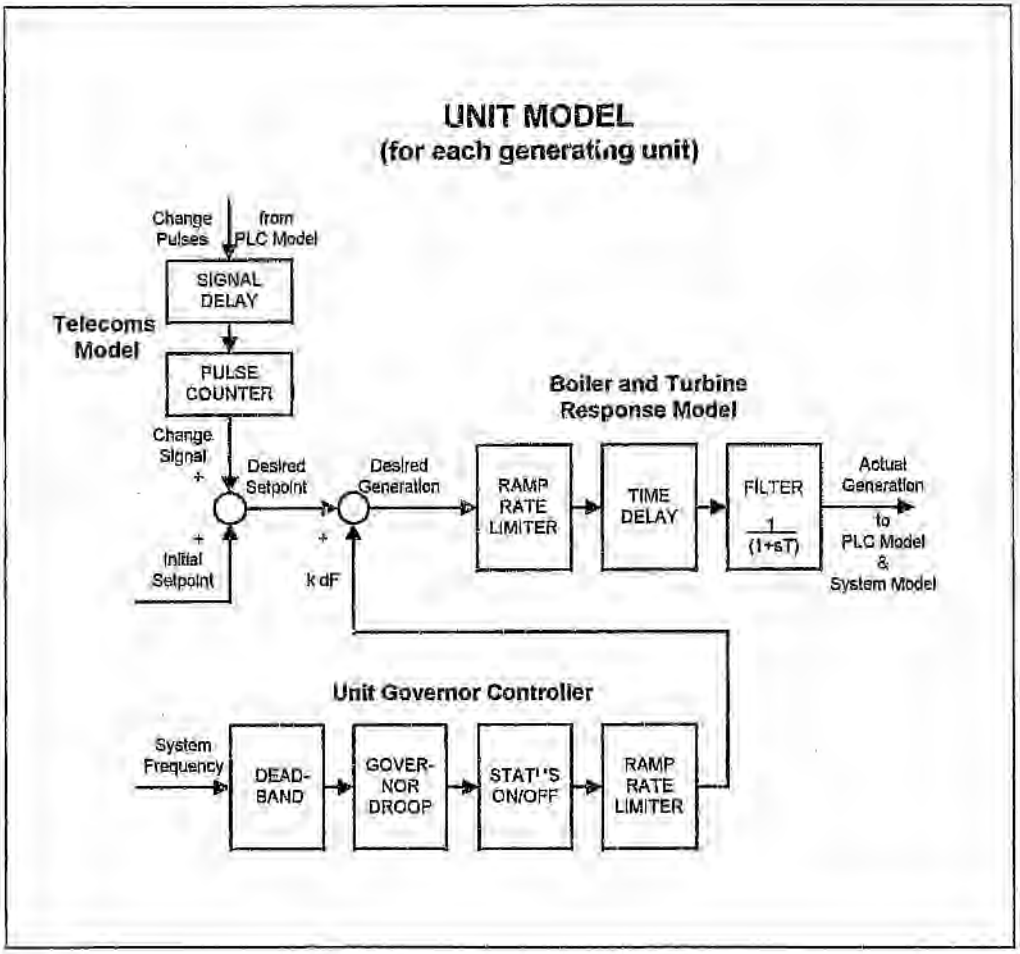


Fig B.4

A unit model comprises telecommunication, governor controller and boiler-turbine response models. The models were configured to emulate the response of different generating units accurately rather than to be an exact representation of the respective generator control systems. As the generating unit in a power station is physically separated from the control centre, the telecommunication between the two systems is also modelled.

Inputs are the initial set point of the generating unit and the system frequency used in the governor controller as well as the change signal received from the PLC model of AGC. The actual generation of the unit is the main output that feeds back to AGC.

# APPENDIX C: NERC PERFORMANCE CRITERIA

## C.1 CRITERIA REFERENCE

The NERC control performance criteria[1] define a standard of minimum control performance for the ACE. Each control area is to have the best operation that can be achieved above this minimum within the bounds of reasonable economic and physical limitations.

Two criteria are used to monitor the operation of the control area under normal conditions. These criteria are supplemented by two additional criteria that apply during disturbance conditions to establish bounds for system recovery.

## C.2 CRITERIA DESCRIPTION

### C.2.1 A1 criterion - zero crossing

The ACE must cross zero within ten minutes of previously reaching zero. Violations of this criterion are counted for each subsequent ten-minute period during which the ACE fails to cross zero.

### C.2.2 A2 criterion - $L^d$ compliance

The average ACE for each of the six ten-minute periods in 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 $L^d$, which are determined from the control area's rate of change of demand characteristics.

---

[1] See Reference 3 on NERC policy for details on the criteria.

### C.2.3 B1 criterion - system recovery

The ACE must return to zero within ten minutes after the start of the disturbance. ACE must begin to trend toward a zero reading and achieve such a reading in a period not exceeding ten minutes. A system should maintain sufficient reserve capability to recover control completely and return to normal operation within ten minutes.

### C.2.4 B2 criterion - recovery in[illegible]

The ACE must start to return to zer[illegible] after the start of the disturbance. ACE is permitted to trend in the same direc[illegible]nge for a period not exceeding one minute. A system should maintain su[illegible]pability, such that after the initial allowance of one minute ACE will begin to trend [illegible]

## C.3 CALCULATION OF CRITERIA

### C.3.1 $L^d$ Calculation

$$L^d = (0.025)\,L + 5\text{ MW} \qquad \text{(Eq C.1)}$$

(The control area must determine its $L^d$ annually.)

where L may be calculated in either of two ways:

(i) The greatest hourly change (either increasing or decreasing) in the control area's net energy for load that occurred on the day of the control area's winter or summer peak demand.

(ii) The average of any ten hourly changes (either increasing or decreasing) in net energy for load that occurred during the year.

### C.3.2 Disturbance conditions

During disturbances, controls can usually not maintain ACE within the criteria for normal load variation. A definition of a disturbance condition is required here. A disturbance is said to have occurred when a sampled value of ACE exceeds the limit called $L^m$ due to a sudden loss of generation or a sudden load increase. The value of $L^m$ has been selected as a function of $L^d$, specifically:

$$L^m = 3L^d \tag{C.2}$$

Normal load and generation excursions (e.g. pumped storage hydro, arc furnace, rolling steel mill, etc) that cause ACE to exceed $L^m$ are not included in the definition of disturbance conditions.

### C.3.3 Performance indicators

Performance indicators are calculated for all NERC criteria for predefined measurement periods (monthly).

The number of ten-minute periods during which the ACE adhered to the A1 and A2 criteria is calculated as a percentage of the total number of ten-minute periods in the measurement period.

The number of disturbances during which the ACE adhered to the B1 and B2 criteria is calculated as a percentage of the total number of disturbances in the measurement period.

# APPENDIX D : NERC CPS1 PERFORMANCE CRITERION

# CONTROL PERFORMANCE CRITERIA

**STEPHEN P. HOFFMAN**
**Security Applications Engineer**

**HOWARD F. ILLIAN**
**Technical Services Director**
**Bulk Power Operations**
**ComEd**
**Lombard, Illinois**

## INTRODUCTION

Control performance has been measured in the utility industry by the A1 & A2 control performance criteria. The use of A1 & A2 has resulted in years of reliable operation. However, the heuristic, arbitrary nature of A1 & A2 has prompted the utility industry to search for a technically defensible control performance criteria. This paper reviews the role of interconnection frequency and inadvertent energy in reliable interconnection operation. The role of control performance criteria and Area Control Error (ACE) is explained. An alternative control performance standard is presented. The differences between A1 & A2 and the new control performance standard are discussed.

## BACKGROUND

Electric utilities receive many benefits by operating with tie lines connecting each other within each interconnection. Tie lines improve reliability and economics because of improved response to contingencies and the ability to exchange economy energy. Frequency changes for a given loss of load or generation are smaller for an interconnected system than the corresponding frequency change for the isolated control area. Interconnected control areas can share generation reserves, and can purchase power if a unit is off for maintenance. Interconnections have allowed a competitive wholesale market for the purchase and sale of energy between electric utilities and wholesale customers.

All load and generation within an interconnection is contained in control areas. Since power will flow from generation to load, despite control area boundaries according to transmission line impedances, control areas must balance their actual interchange to their scheduled interchange, plus some additional power for frequency support. The additional energy for frequency support contributes to intentional inadvertent energy accumulation, and is needed for equitable control performance measurement.

When a control area undergenerates it simply draws power from the rest of the interconnection and lowers system frequency. Each control area uses Automatic Generation Control (AGC) to ramp generation up or down to control ACE close to zero[1]. ACE equals actual net tie flow minus scheduled net tie flow plus a MW amount to support system frequency. This is known as tie line bias control[2]. Control performance criteria are important because they define how tightly and in what manner a control area must meet their control obligation to match generation to load plus frequency support. A control area should provide mutual support to other control areas in times of need while not over burdening other control areas by requiring them to provide more than their equitable share of the mutual support burden.

The North American Electric Reliability Council (NERC) has selected the A1 & A2 criteria for normal operation[3]. The A1 criteria states that ACE must cross zero at least once every ten minutes. The A2 criteria states that each ten-minute average of ACE must be less than a constant value $L_d$. It is recommended, but not required, that a control area meet the A1 and A2 criteria 90% of the time. These criteria have performed well for a number of years. However, these criteria are heuristic in nature and are not technically defensible. The criteria limits are also defined in an arbitrary manner. For example, control areas must choose their frequency bias, B, to be at least as large as 1% of their anticipated peak load, and $L_d$, the 10 minute A2 limit, is based on the hourly changes in control area load.

There is a non-trivial cost associated with AGC and inadvertent energy, and control costs can be transferred between control areas[4]. In a competitive utility market, control services will be needed, but market participants may be unwilling to pay money or expend effort to control to a heuristic control criteria. The industry has recognized the need for a technically defensible control criteria. This paper will report some of the results of the search for a technically defensible control criteria.

## CONTROL OBJECTIVE

Interconnection frequency was selected as the primary control objective. A control criteria that bounds frequency error for the interconnection also bounds the resulting reliability probabilities. Interconnection frequency can be directly related to reliability in many ways, as described below.

- Generator turbines will encounter vibration problems for frequency variations greater than one or two Hz.

- Interconnection frequency is a direct measure of the net load generation imbalance[5].

- Inadvertent energy is distributed between control areas by AGC actions and the natural frequency response of control areas. Statistically bounding frequency errors will also statistically bound inadvertent energy flow.

- Increased inadvertent flows resulting from larger frequency deviations present potential thermal overload problems for the transmission system. A larger interconnection may need to control frequency more tightly than a small interconnection to avoid transmission problems resulting from large inadvertent flows.

- Each interconnection tracks and corrects time error because synchronous clock motors, and many digital, clocks will only keep correct time when supplied with 60 Hz power.

- Under-frequency and over-frequency relays are in place on generators and some loads. A unit over-frequency relay trip would act to correct the frequency error, while a unit under-frequency relay trip would protect the generator, but would result in lower frequency. Generating unit and load frequency relay settings provide a hard limit to avoid during normal operations.

- Interconnection frequency changes following the loss of load or generation. It takes approximately 5 to 15 minutes for frequency to recover following a disturbance. Frequency margins are maintained so that even if several loads or units tripped off during the recovery period, there is a small probability that additional load or generation would be tripped by frequency relays.

A secondary control objective is to limit inadvertent tie flows. Achieving the desired frequency error profile implies, but does not guarantee, acceptable inadvertent tie line flows. Although inadvertent energy must be returned, no dollar value is associated with inadvertent. Since production costs vary over time, it is possible to draw in inadvertent when production costs are high, and pay it back later when production costs are lower.

A control criteria needs enough flexibility to prevent excessive, expensive control action, but must keep inadvertent flows to reasonable levels for transmission overload and economic fairness concerns. This is particularly important with the increased emphasis on competition and wholesale and/or retail wheeling.

## AREA CONTROL ERROR

ACE is a function of the net tie line error $\Delta T$, the frequency error $\Delta F$, automatic time error control $I_{WTC}$, unilateral inadvertent payback $I_{UIP}$, and the meter error correction term $I_{ME}$, as shown in (1)[6].

$$RMS[\Delta F] < \varepsilon \qquad (1)$$

A2 requires a control area to operate so that the 10 minute average of ACE is between $ACE=L_d$ and $ACE=-L_d$. Thus the region bound by the lines $ACE=\pm L_d$ illustrates a permissible region of operation under the A2 criteria. If system frequency was low ($\Delta F<0$), a control area operating at $ACE=+L_d$ is doing much more to support system frequency than if the system were to operate at $ACE=-L_d$. However, A2 says that ACE=+Ld and ACE=-Ld are equivalent. A control performance criteria must recognize the obvious; a positive ACE does more to support system frequency than a negative ACE when frequency is low. The implied goal of A1 & A2 is that ACE should be held at, or close to, zero. This has caused control areas to overcontrol in an effort to meet this goal.

AGC is a distributed control problem because frequency, and inadvertent flows, are determined by the control actions of all control areas in an interconnection. Tie-line bias, which introduced the frequency bias component of ACE, has effectively assigned a frequency support obligation to all control areas. As will be shown, the control performance standard requires a control area to provide their frequency support obligation, but allows a control area to provide additional, but limited, frequency support when it will benefit system frequency. In this manner the benefits of tie-line bias control are maintained, but the control performance standard given below may require less generation maneuvering and control effort. In addition, the arbitrary control performance limits associated with A1 & A2 will be replaced with technically defensible control limits.

## CONTROL PERFORMANCE OBJECTIVE

An AGC system operates with a cycle time of 2 to 4 seconds, yielding numerous ACE values throughout the year. Statistics provides many tools which can extract information from a large number of samples. This feature made statistics a natural choice for the development of a technically defensible control criteria. The Root Mean Square frequency error was selected as the control objective, as shown in (2). Although

$$ACE = \Delta T - 10\,B_i\,\Delta F - I_{WTC} \pm I_{UIP} - I_{ME} \qquad (2)$$

not explicitly stated, there is a sampling rate and a sampling period associated with the frequency error ΔF.

The frequency control objective is defined by the target value ε, which is chosen for each interconnection (2). By selecting a value of ε, the frequency error that the interconnection will experience will be statistically bounded if the frequency distributions do not change significantly and if all of the control areas meet their control obligation. Each year the NERC Performance Subcommittee will evaluate the experienced frequency distribution(s) for the interconnections and recommend ε values to the NERC Operating Committee. These ε values will be used to determine control obligations. This process of setting the value of ε will ensure that the control performance criteria is linked to interconnection reliability. The sampling rate and averaging period for the measurement of ΔF used in selecting the values of ε must be the same sampling rate and averaging period used in the performance criteria for actual measurement.

The frequency bias term, B, in the ACE equation has served a dual function under A1 & A2. It has been used in the *control algorithm* to define the actual frequency response of the control area, and, since the *same* ACE has been used for control performance measurement, it has been used to define the *control obligation*. An example of the special rules required when these dual functions conflict with each other is the requirement that there be a minimum value of 1% of the forecast peak load for the frequency bias for a control area. This rule insures that a control area provide a reasonable share of the *control obligation* regardless of the value of the natural frequency response that the control area would desire to use in the *control algorithm*.

The new criteria only requires the selection of a value for the B defining the control obligation, the B used in the performance measurement equation. It does not require that the same B be used in the control algorithm. In fact, there may be valid reasons for using other values of B for determining the control actions requested. In most cases, the actual frequency response of a control area would not be expected to be equal to the control obligation that the control area should provide to perform their equitable share of interconnection control. The selection of a frequency bias equal to the control area frequency response will minimize AGC control actions. Therefore, if the goal was to minimize the costs associated with AGC control, a control area would set the B in the control algorithm equal to the frequency response of the control area. If this same B is sufficient to meet the control obligation, then it could also be used in the performance measurement equation. On the other hand, if the control area desired to provide a greater control response than the natural frequency response of the control area, it could do so by raising the value of the B in the control algorithm and provide additional frequency control at an additional cost with its AGC system. This supplemental AGC supplied frequency response would affect the control performance as measured by the control criteria. The new rules governing the values of frequency bias used in the performance equation are expected to allow the use of any value that results in the control area meeting its control obligation.

## CONTROL PERFORMANCE STANDARD

The basic description of the control performance standard was first presented by N. Jaleeli and L. VanSlyck in 1992[7]. A simplified form of their derivation is included in Appendix A. Due to a misinterpretation of the result, alternate proposals underwent several years of study and comparison. The authors' contribution was to recommend the reconsideration of the original derivation with a new interpretation. The authors were also the first to recommend that the inclusion of the frequency bias term directly in the performance equation would assure the equitable distribution of the control obligations among control areas. With the inclusion of these changes the control performance standard was selected as the best of the proposals studied.

The control performance standard was chosen because:

- It did not require a Gaussian distribution for ACE or frequency error,
- It did not assume independence between control area ACE's,
- It did not assume independence between ACE and frequency,
- It was the only proposal which recognized that a positive ACE is more beneficial than a negative ACE with low frequency, and that a negative ACE is more beneficial than a positive ACE with high frequency. The control performance standard is equal to ACE times frequency error divided by the frequency bias in MW, as shown in (3). The overline denotes a one-minute average (4).

$$AVG_{12months}\left[\frac{\overline{ACE}\,x\,\overline{\Delta F}}{-10\overline{B_i}}\right] - \varepsilon^2 \qquad (3)$$

$$\overline{X} = AVG_{1minute}(X) \qquad (4)$$

The one-minute average of ACE, ΔF, and BI are used to calculate one control performance standard value each minute. These one-minute control performance standard values are averaged over 12 months to yield the control area's control performance. Instead of allowing the option of only reporting performance for one survey day in a month, the control performance standard will be monitored continuously for all operating conditions. Continuous monitoring is appropriate for a statistically based criteria.

The one minute average was chosen for several reasons. One minute averages of interconnection frequency is the same for all control areas, at least to the accuracy required for control performance reporting. Control areas with non-linear frequency bias can apply this criteria by using the one-minute average frequency bias. The one-minute average will fully capture frequency effects of periods greater than four minutes according to sampling theory. Spectral analysis of the interconnection frequency show a first significant component at 15 minutes[4]. The one-minute samples are more than sufficient to capture these 15 minute characteristics. It is important to be able to measure how well a control area follows the traditional 10 minute ramp used to ramp on to and off of interchange schedules. Also, the one-minute average will also discourage a historical control algorithms. An AGC system should control according to what is happening and what is expected to occur in the future, not what has happened in the past. The ten minute averaging period associated with A2 causes a "rear-view mirror" control strategy, in which AGC actions are based on historic ACE values accumulated within the current ten minute averaging window.

The phase relationship between ACE and ΔF is captured with the ACE × ΔF term. This is significant because a control area's performance will be determined by its ACE value relative to interconnection frequency. The control performance standard replaces the ACE = 0 philosophy associated with A1 & A2, with an effective limit on ACE that varies with the interconnection frequency. The control performance standard maintains the benefits of tie-line bias control, while reducing unnecessary control action.

The control performance standard equation (3) can be expressed as a function of ΔF and ΔT, assuming constant frequency bias. Figure 1 shows the value of the control performance standard as a function of ΔF and ΔT. The control performance standard is non-linear. This surface equals zero at ΔF = 0, and at the ACE = 0 line. Since the control performance standard requires the average value of ACE × ΔF be held less than a small positive limit, $\varepsilon^2$, the quadratic penalty strongly encourages appropriate control action.

## ACE MAGNITUDE LIMIT

The control performance standard will allow large inadvertent flows when they help support interconnection frequency. In order to limit inadvertent tie-line flows, the retention of the A2 criteria has been recommended. The A2 criteria is only retained to prevent large inadvertent flows, and to prevent a control area from adopting flat-frequency control. A new, technically defensible $L_d$ limit is also recommended.

## CONCLUSION

The new control performance standard is technically defensible. It specifically ties control performance to the reliability related frequency profile of the interconnection. It will ensure a desired frequency profile with an expected reduction in control effort. The control performance standard maintains the benefits of tie-line bias control while allowing more control flexibility. This criteria is expected to be recommended to the NERC Operating Committee for adoption as a control performance standard. Frequency control has been identified as an ancillary service. A market could develop in control performance. This would allow control areas to purchase or sell control performance, and may offer some efficiency gains if a control area can buy control at a lower cost than it can provide itself.

The heuristic nature of A1 & A2 has prevented the application of optimal control techniques to AGC. This is because A1 & A2 cannot be represented by a mathematically correct objective function. This criteria should allow the development of improved AGC algorithms.

Control performance criteria are very important to interconnected power system operations. It is critical that the control performance criteria be technically defensible, which will allow for improved, more economical system operations while still maintaining interconnection reliability.

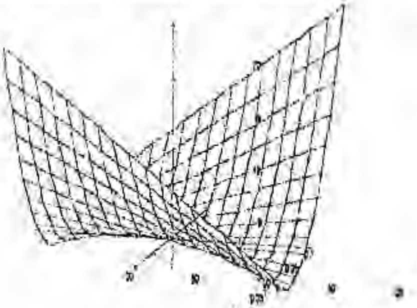


**Figure 1. Plot of ACE × ΔF error surface**

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## APPENDIX A

This appendix contains [illegible] of the control performance standard derivation. This derivation was developed by N. Jaleeli and L. VanSlyck[7], and is included here for thoroughness. There are "N" control areas in an interconnection. The subscript "t" denotes variables that are sampled over a survey period. The area control error for area "i" is (A1).

$$ACE_i = \Delta T_i - 10 B_i \Delta F_i \qquad \text{(A1)}$$

Assume ΔF is the same for all control areas. Sum the ACE values from all control areas in an interconnection (A2). The

$$\sum_{i=1}^{N} ACE_i = \sum_{i=1}^{N} \Delta T_i - \sum_{i=1}^{N} -10 B_i \Delta F \qquad \text{(A2)}$$

$$\sum_{i=1}^{N} ACE_i = -10(B_1 + .. + B_N)\Delta F \qquad \text{(A3)}$$

sum of all tie flows equals zero, giving (A3). This is the load-generation imbalance equation for the interconnection. The frequency control objective is defined as the standard deviation of frequency error over a survey period be held less than a desired value, ε (A4).

$$RMS[\Delta F_t] \le \varepsilon \qquad \text{(A4)}$$

Square (A4) to work with variance (A5) instead of standard deviation.

$$RMS^2(\Delta F_t) = AVG\left[(\Delta F_t)^2\right] \le \varepsilon^2 \qquad \text{(A5)}$$

Rearrange (A3), and substitute for one of the ΔF terms in (A5), yielding (A6). Equation (A6) is rearranged to yield (A7).

$$RMS^2(\Delta F_t) = AVG\left(\Delta F_t x \frac{1}{-10(B_1 + .. + B_N)} \sum_{i=1}^{N} ACE_{i,t}\right) \qquad \text{(A6)}$$

$$\begin{gathered} RMS^2(\Delta F_t)[-10 B_1 + .. + B_N] = \\ \left[AVG(\Delta F_t x ACE_{1,t}) + .. + AVG(\Delta F_t x ACE_{N,t})\right] \end{gathered} \qquad \text{(A7)}$$

Multiply through by the denominator, substitute inequality (A5), yielding (A8).

$$\begin{gathered} -10(B_{1,t} + .. + B_{N,t})\,\varepsilon^2 \ge \\ \left[AVG(\Delta F x ACE_{1,t}) + .. + AVG(\Delta F x ACE_{N,t}\right] \end{gathered} \qquad \text{(A8)}$$

The equation above can be broken down into N equations, one for each control area, yielding the following control performance equation (A9).

$$\frac{AVG(ACE_{i,t} x \Delta F_{i,t})}{-10 B_{i,t}} \le \varepsilon^2 \qquad \text{(A9)}$$

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