DEVELOPMENT AND IMPLEMENTATION OF AN ENHANCED DESIGN FOR AUTOMATIC GENERATION CONTROL

by:

Robert C Hartman

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ABSTRACT

Automatic generation control (AGC) is the centralised short-term closed-loop control (regulation) of generating units in a control area. The main objectives of AGC are to maintain the system frequency at 50 Hz; to obtain correct tie-line interchange; and to operate each generating unit at its most economic value.

The cost of operation of a regulating (moving) generating unit is, however, higher than that of the same unit being used at a fixed output. Primary energy cost as well as longer-term maintenance cost and life expectancy is affected by regulating generating units. With the continuous drive to reduce costs, the question was raised whether the amount of regulation done by AGC is justified.

The original AGC system could not be set up to achieve the required quality of supply while using the minimum control expected. An enhanced design of load following and distinctive ACE regulation was developed and 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 alterations involved the addition of a derivative component by means of fuzzy logic and the elimination of nonlinearities from the control.

This research describes the enhanced design developed to obtain the required performance while minimising the control effort. The design was implemented by altering the code and configuration of AGC. The development and implementation of the design 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 consisted mainly of correcting logic that resulted in high nonlinear outputs. The control system was never simulated by the developer during the original development, and this resulted in a very nonlinear design.

- **Implementation of a design of load following (long-term regulation) and ACE (short-term) regulation.** According to this design generator outputs are adjusted according to the economic

dispatch routine for normal load changes. ACE regulation is only done when larger short-term deviations occur in the frequency or power flow on tie-lines.

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

First the performance of the new configuration and design of AGC was determined by means of the simulation model. The results obtained from the simulation indicated that system performance could be improved while reducing the amount of control issued to generating units significantly. The improvements to the original design and configuration of AGC were therefore implemented on the operational system and performance was evaluated by the established criteria. The new system achieved slightly better AGC performance results while reducing the amount of control effort significantly, namely by 60 %. The enhanced design and configuration of AGC can therefore be considered highly successful.

The implications of the establishment of the Southern African Power Pool are addressed and the possibility of joint AGC regulation is investigated. As AGC was originally designed mainly for tie-line management, it can handle the tie-line bias mode of operation very easily. Joint AGC regulation should be revisited when sufficient low-cost hydroregulation becomes available from other pool members.

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
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

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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 USA, and installed by the British company Westinghouse Systems Limited.

On the whole the original Eskom AGC system can be described as adequate, making use of traditional problem-solving and control methods. As Eskom's was an isolated system until 1995, AGC was used mainly for frequency control and the economic operation of units. The Southern African Power Pool was formed in 1995 and it required interconnected tie-line control from AGC for the first time.

At the beginning of 1996 Eskom's operational generating capacity consisted of 27 850 MW coal-fired, 1 840 MW nuclear, 342 MW gas turbine, 540 MW hydroelectric and 1 400 MW pumped storage capacity. Only the thermal stations were connected to AGC, with about 10 000 MW normally available for control. The average daily peak demand for 1996 is ±21 000 MW, and the yearly peak demand is 27 678 MW.

1.3 PROBLEM STATEMENT

Before 1995 Eskom was interested only in the frequency control achieved by means of AGC and was fairly satisfied with it, apart from the fact that the frequency had a definite cycle. The economic dispatch of generation by AGC was, however, rather suspect, especially if the amount of movement in generator outputs controlled by AGC is taken into account. The availability of plant suited to AGC regulation also started to decrease as more power stations became unable to sustain the burden placed on them by AGC.

It is a fact that the cost of operation of 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 are affected by regulating units. In view of the continuous drive to improve frequency control and the efficiency of the system, the question was raised whether the regulation done by AGC can be justified? The control centre also expressed the concern that AGC might cause the frequency and generator outputs to oscillate. These issues could be extended to include the question of whether the total regulation effort, ie governing and AGC, is optimal.

However, traditional performance criteria for AGC can only be used to evaluate the quality aspects normally required when plant forms part of an interconnected power pool. Such evaluation does not address the impact of excessive control on the primary energy cost, operating and maintenance cost, and life expectancy of plant. Nor has the quality of supply in respect of the system frequency required by end customers and needed for system security been properly investigated.

Manitoba Hydro in Canada experienced similar problems with its system's loading and regulation effort. After a two-year investigation it was able to improve its regulation to the required level while at the same time reducing AGC control effort by 80 %. This was sufficient proof to convince both the author and Eskom that research into this area was needed. The main objective of the research is to optimise AGC for the required quality of supply with the minimum control effort.

1.4. METHODOLOGY

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. Although operator and analyst manuals describe the logic behind the control system, detailed information could only be obtained by examining the FORTRAN code of the related procedures. 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 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.

A control design to obtain the required performance while minimising the control effort was then established. The design was implemented by altering the code and configuration of AGC. The development and implementation of the design 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 consisted mainly of correcting logic that results in high nonlinear outputs. The control system was never simulated by the developer during the original development, and this resulted in a very nonlinear design of the control system.

- **Implementing a design of load following (long-term regulation) and ACE (short-term) regulation.** According to this design generator outputs should be adjusted 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 power flows occur.

- **Improvement of the regulating mechanism to allow for 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 implications of the establishment of the Southern African Power Pool were finally addressed. As AGC was originally designed mainly for tie-line management, it can handle the tie-line bias mode of operation with ease. There are, however, some issues, such as the responsibilities of members and the possibility of joint AGC regulation, that need to be investigated.

1.5. LAYOUT

Chapter 2 describes the original design and configuration of AGC as developed by ESCA Corporation and installed in Eskom by Westinghouse.

Chapter 3 describes the enhanced design and configuration of AGC, incorporating mainly the philosophies for long-term and short-term regulation that were implemented.

Chapter 4 deals with criteria used in monitoring the AGC regulation performance.

Chapter 5 presents the AGC system simulation done in Matlab® to test and verify changes to the original control system.

Chapter 6 provides operational results achieved on the actual Eskom grid after implementing the enhanced AGC system.

Chapter 7 discusses the impact of the establishment of the Southern African Power Pool on AGC.

Chapter 8 provides a conclusion and recommendations based on the research effort.

2. THE ORIGINAL DESIGN AND CONFIGURATION OF AGC

2.1. BACKGROUND

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

The AGC system consists of three main components, ie the base-point module, the regulation module and the programmable logic controller (PLC) of each generating unit controlled by the system (Fig 3.1). A short description of each module follows, while details are discussed later on.

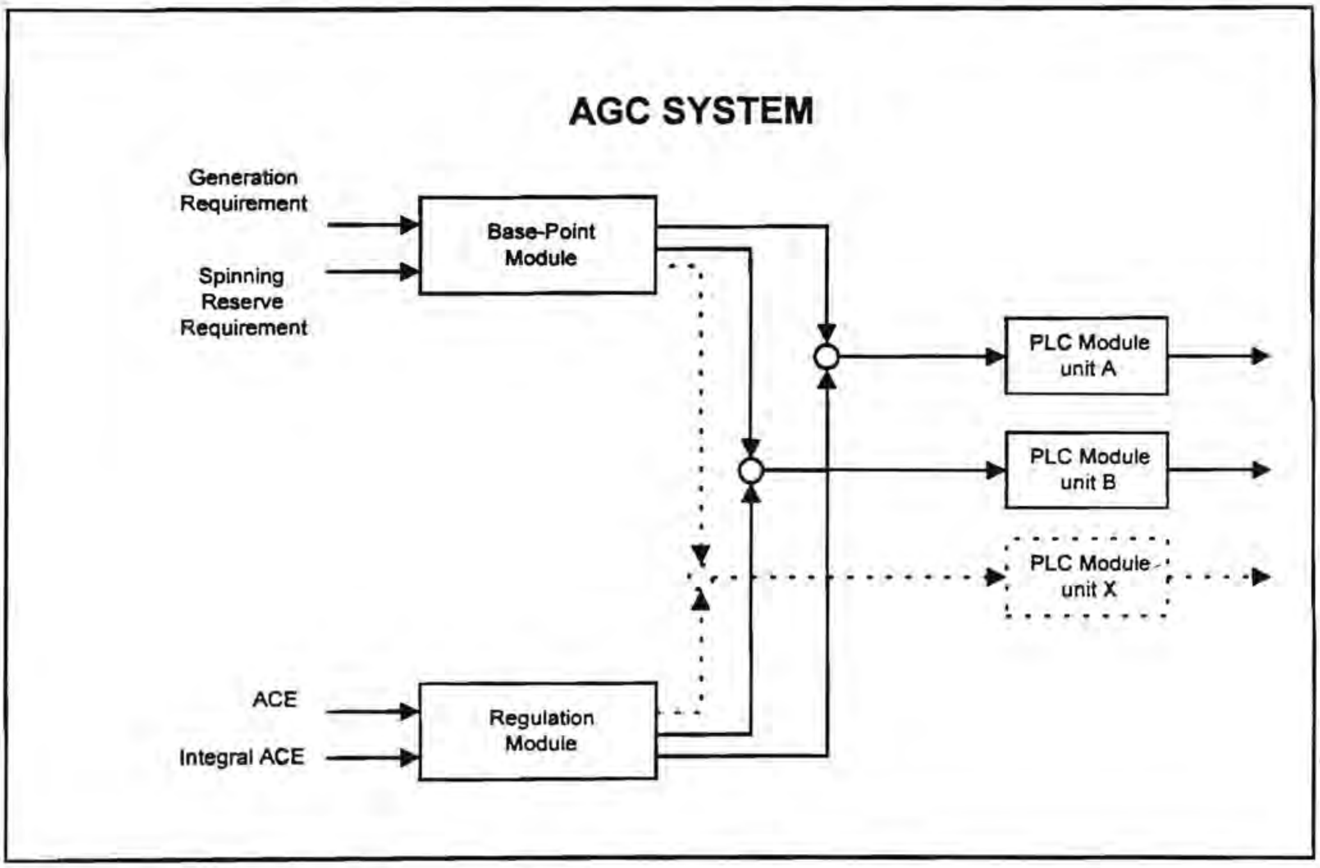


Fig 2.1

- 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.

2.2. BASE-POINT MODULE

The base-point module (Fig 2.2) 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.

2.2.1. 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. As the economic dispatch routine forms an integral part of the enhanced AGC design, it is discussed in Chapter 3.

2.2.2. 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 preprogrammed 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 not satisfied with the automatic loading, as the switching of a PLC between statuses (AUT and MAN) to do loading will cause unnecessary control of units.

2.2.3. 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.

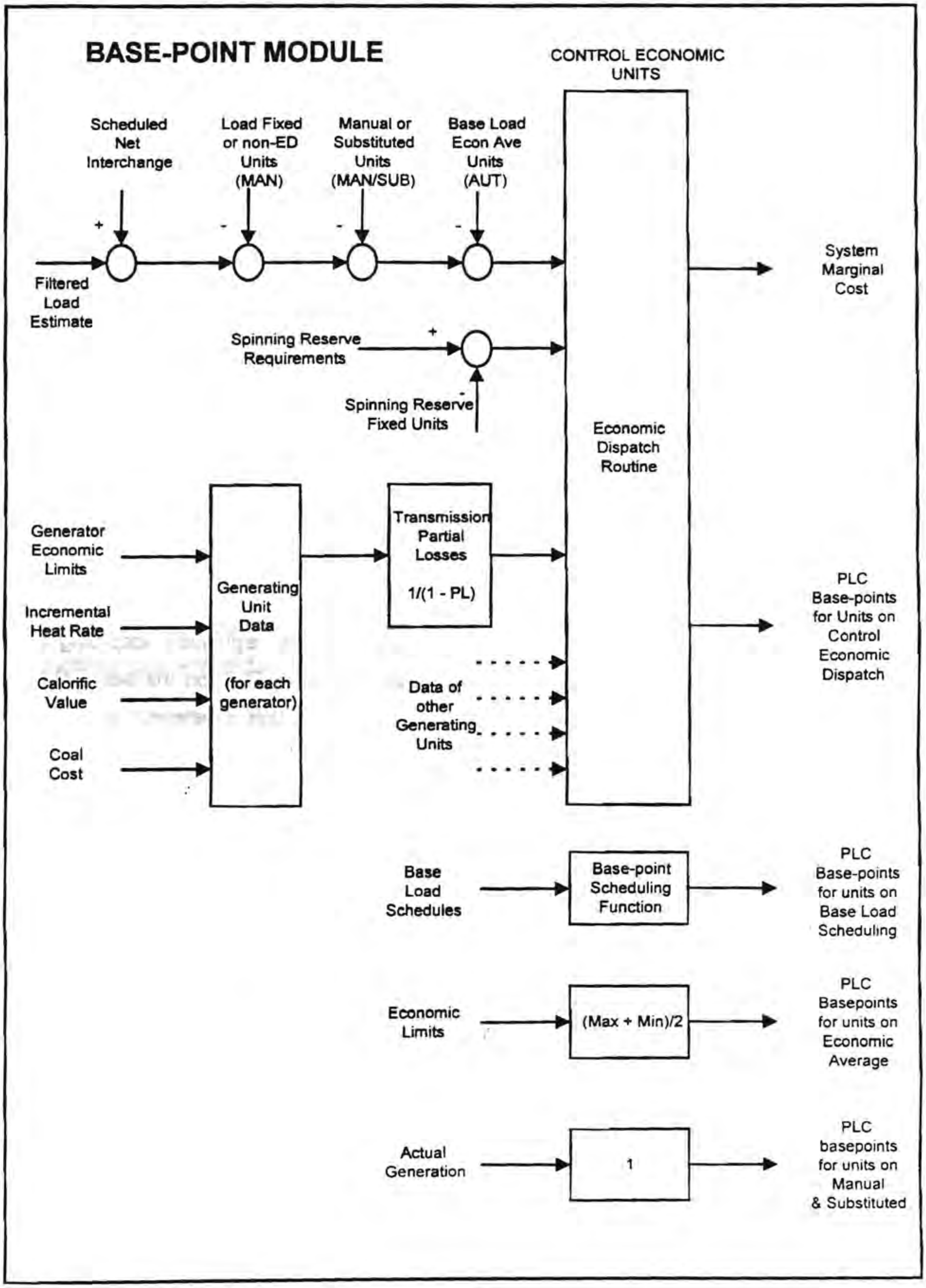

BASE-POINT MODULE
CONTROL ECONOMIC UNITS
Scheduled Net Interchange
Load Fixed or non-ED Units (MAN)
Manual or Substituted Units (MAN/SUB)
Base Load Econ Ave Units (AUT)
+
-
-
-
Filtered Load Estimate
Spinning Reserve Requirements
+
-
Spinning Reserve Fixed Units
Economic Dispatch Routine
System Marginal 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 2.2

2.2.4. System advisory economic dispatch

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

2.3. REGULATION MODULE

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

The regulation module always calculates the total desired regulation according to the sam principles but will allocate the regulation component of each PLC on the basis of its regulatio mode and participation factors. The regulation mode of a unit is determined in advance by th operator, based on its loading capabilities and short-term frequency response, ie the unit's ability t change its output and the rate of change. The choice of regulation mode (designation in bracket 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 t *integral ACE component*, which are combined to provide the regulation component for those PL which are participating in regulation (Fig 2.3). The regulation module can be described as a typic proportional-integral (PI) controller. The main dynamic inputs for both components are the measured frequency and tie-line interchange.

2.3.1. 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.

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.

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 with a time constant (Tau), as described in Appendix A, is used.

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.

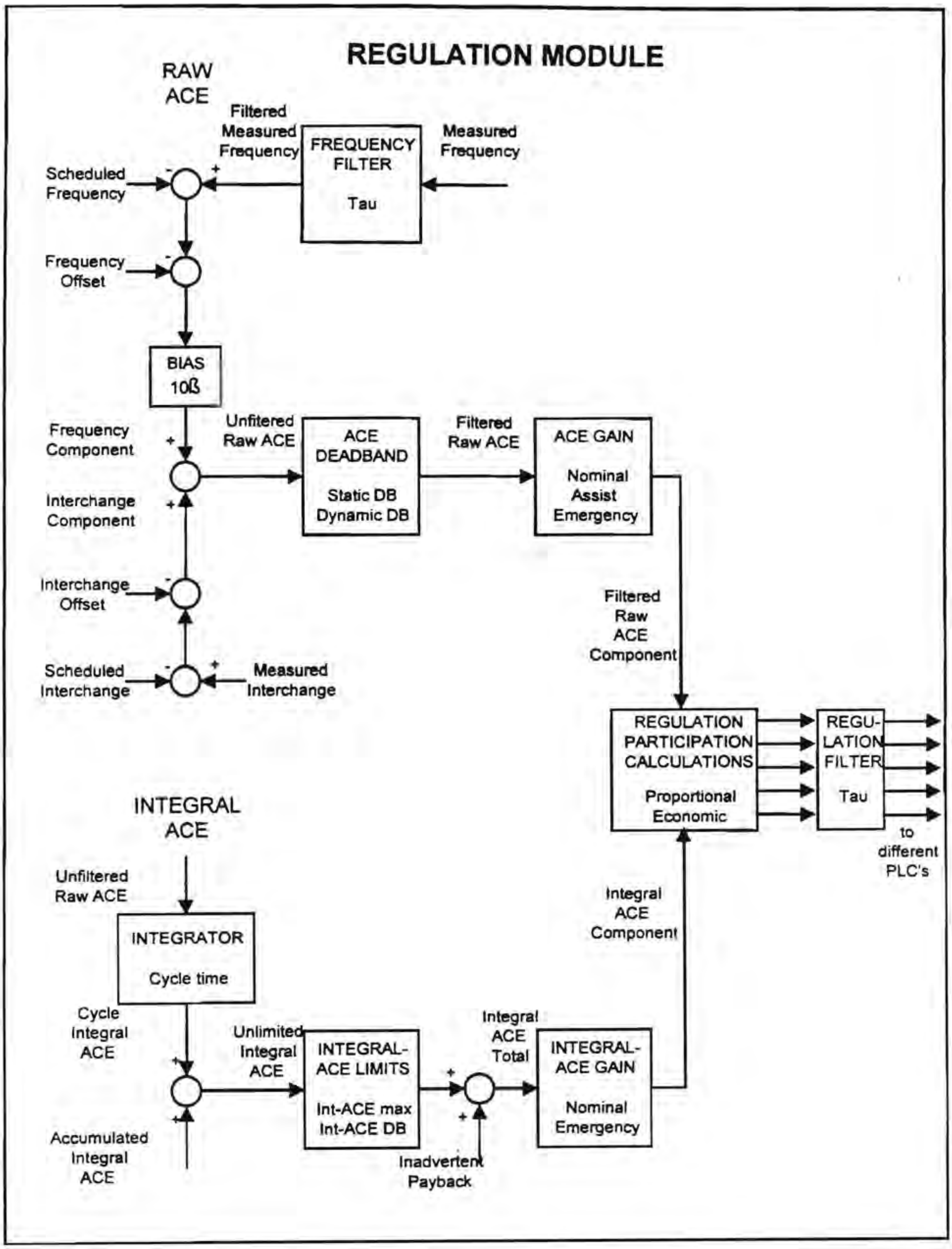

REGULATION MODULE
RAW ACE
Filtered Measured Frequency
FREQUENCY FILTER
Tau
Measured Frequency
Scheduled Frequency
-
+
Frequency Offset
-
BIAS
10β
Frequency Component
+
Unfiltered Raw ACE
ACE DEADBAND
Static DB
Dynamic DB
Filtered Raw ACE
ACE GAIN
Nominal
Assist
Emergency
Interchange Component
+
Interchange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

Fig 2.3

Frequency bias (β)

The frequency error with offset is multiplied by the frequency bias (β) 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.

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.

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.

ACE dead band and ACE gains (control regions)

The sum of the two raw ACE components is then 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. Filter intelligence is given to the dead-band region by implementing a dynamic dead band, described in Appendix B. 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.

2.3.2. Integral ACE component

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

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.

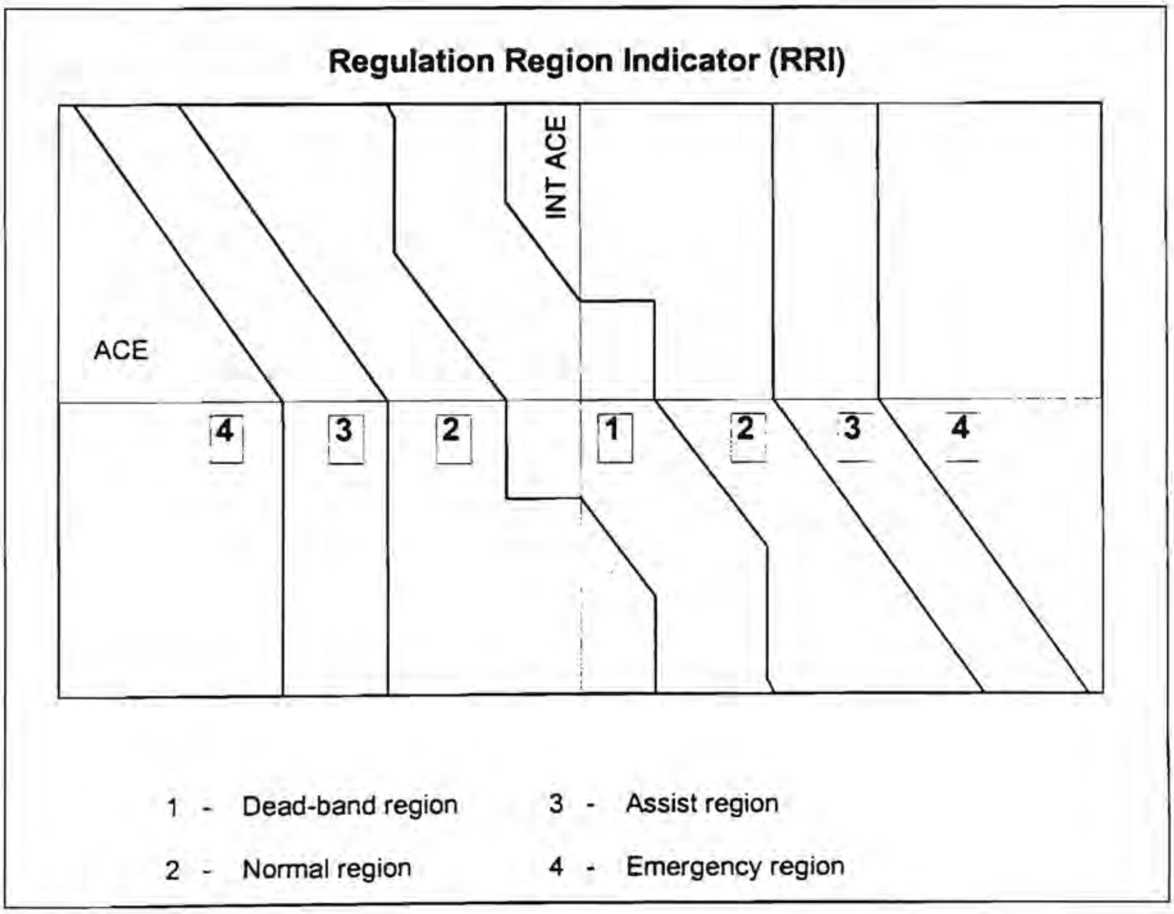
Inadvertent payback

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.

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



Regulation Region Indicator (RRI)

Fig 2.4

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. 2.4).

2.3.3. Regulation participation calculations

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

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.

Regulation component calculation and filter

The regulation component of each PLC is determined as follows:

$$\text{Regulation Compnt}_{\text{unit x}} = (\text{PropPF}_{\text{unit x}} \times \text{RawACE}) + (\text{EconPF}_{\text{unit x}} \times \text{IntACE}) \qquad \text{(Eq 2.2)}$$

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.

2.4. 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, 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 2.5 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.)

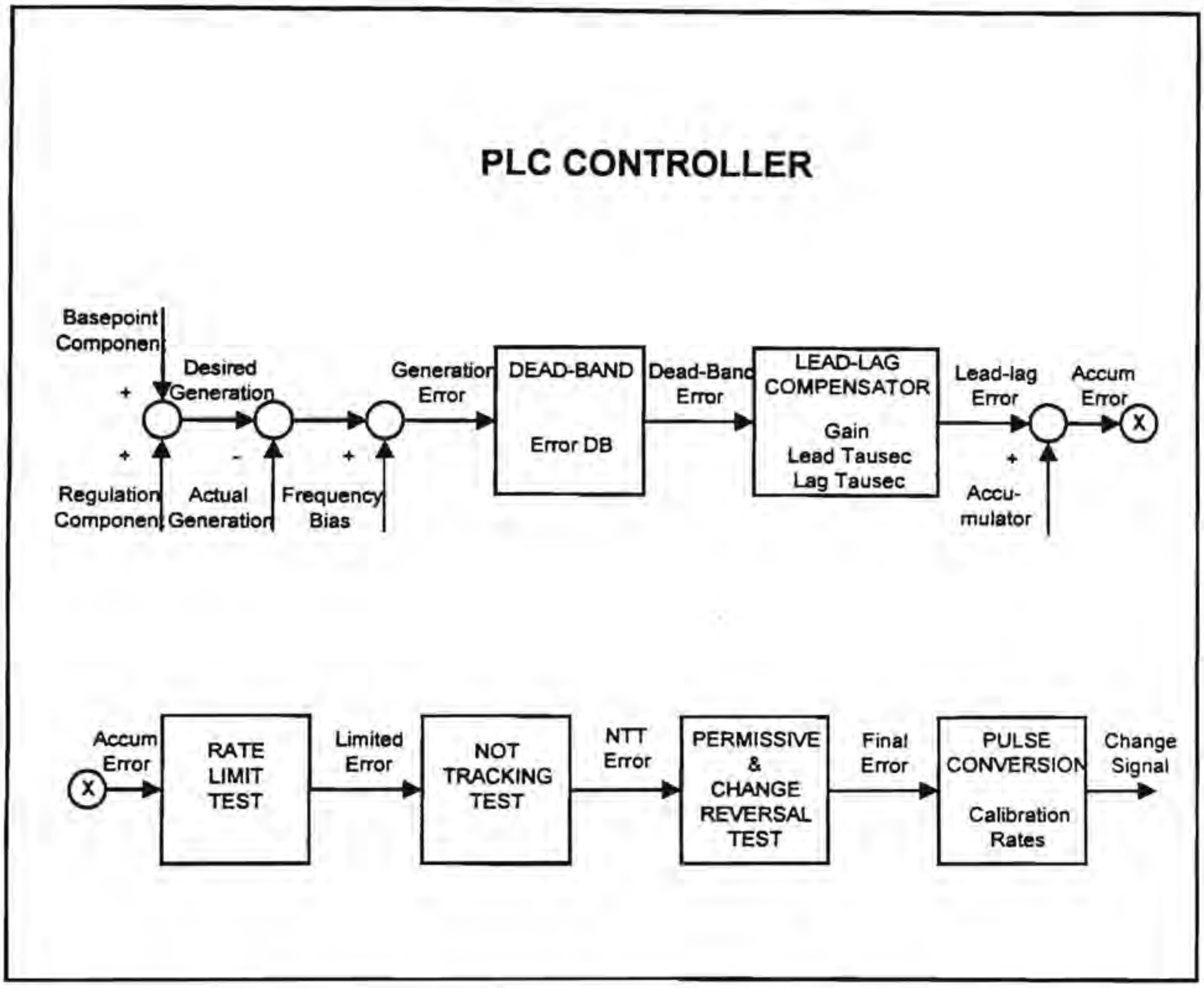


Fig 2.5

2.4.1. Generation error calculation

The calculated generation error (Eq 2.3) is the immediate surplus or deficit in capacity generated by a unit.

$$Gen\ Error = (Basepoint + Regulation) - Actual\ Gen + Freq\ Response \qquad \text{(Eq 2.3)}$$

$$\text{Freq Response} = \text{Local Freq Bias} \times \text{Filtered Freq Error} \qquad \text{(Eq 2.4)}$$

The local frequency response (Eq 2.4) 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.

2.4.2. 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:

$$\text{Lead - Lag Compensator} = K\frac{(1+sT_1)}{(1+sT_2)} \qquad \text{(Eq 2.5)}$$

where:

K → gain

T_1 → lead time constant

T_2 → lag time constant

The gain (K), lead time constant (T_1) and lag time constant (T_2), determine the filtering of the error signal achieved by the lead-lag compensator (Eq 2.5). 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. The time domain response of the lead-lag compensator is shown in Appendix A.

2.4.3. Permitting tests

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

Rate limit test

The PLC change signal in one cycle is limited by the maximum response rate of the generating unit. The error will be reduced if it exceeds the typical response rate of 15 MW/min for a cycle (1 MW/cycle). 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.

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.

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.

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.

2.4.4. 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.

2.5. 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 fairly 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 5 will prove that the regulation component is also highly nonlinear. The shortcomings in the regulation component prevent minimised control by means of simple parameter configuration although 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, ie altering the programming code rather than just changing the configuration.

3. THE ENHANCED DESIGN AND CONFIGURATION OF AGC

3.1. BACKGROUND

This chapter describes the design implemented to optimise AGC for minimum control. It explains the enhancements to the design as well as the configuration developed to overcome the shortcomings of the existing AGC.

The regulation effort on any transmission system can be divided into a long-term *load-following (demand-following)* regulation component that operates in the minutes horizon and a short-term *ACE regulation* component that assures system stability and control performance in the seconds horizon. An optimised AGC system will firstly be able to discriminate between the two regulating components. Secondly, each component must be able to perform its duty successfully. If correctly set up, the load-following component will have the greater economic impact whereas the short-term ACE regulating component is more important for control performance and a stable system. Criteria for monitoring AGC performance are discussed in the next chapter.

The structure of the original AGC system is based on a similar design, but the design and configuration could not support the obligations adequately. The two components, their objectives, and the enhancements to the original control system are discussed.

3.2. LOAD FOLLOWING (LONG-TERM REGULATION)

The load-following component can be described fairly easily and although obtaining the solution is a complex procedure, proven methods are used. Load-following is done by means of the base point module, and more specifically the economic dispatch routine of AGC[1] for units selected in *control economic* mode. Enough generating units have to be selected in *control economic* mode to ensure proper functionality of the load-following regulation effort.

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[1] The positioning of the economic dispatch routine is described in section 3.2.

The main purpose of the load-following component is to determine the ideal output that each selected generating unit on the system should maintain to minimise the cost of generation while meeting the system demand. This component does not have to correct short-term fluctuations in the demand or generation but must be able to correct the integrated effect of such deviations.

3.2.1. Economic dispatch routine

This system makes use of the La Grange[2] theory to obtain its solution and is therefore fairly limited in terms of the characteristics of the incremental cost curves that can be used as inputs. Dynamic programming techniques[3] and artificial intelligence have already been developed to overcome these shortcomings. As the existing routine meets Eskom's current requirements these improvements to the routine had not been addressed.

Minor modifications to the calculation of the generation requirement and the allocation of reserves were, however, made. A simplified version of the algorithm used in the economic dispatch routine is shown in Fig. 3.1.

3.2.2. Inputs and outputs of the 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 3.1).

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[2] Reference 3.

[3] References 4 and 5.

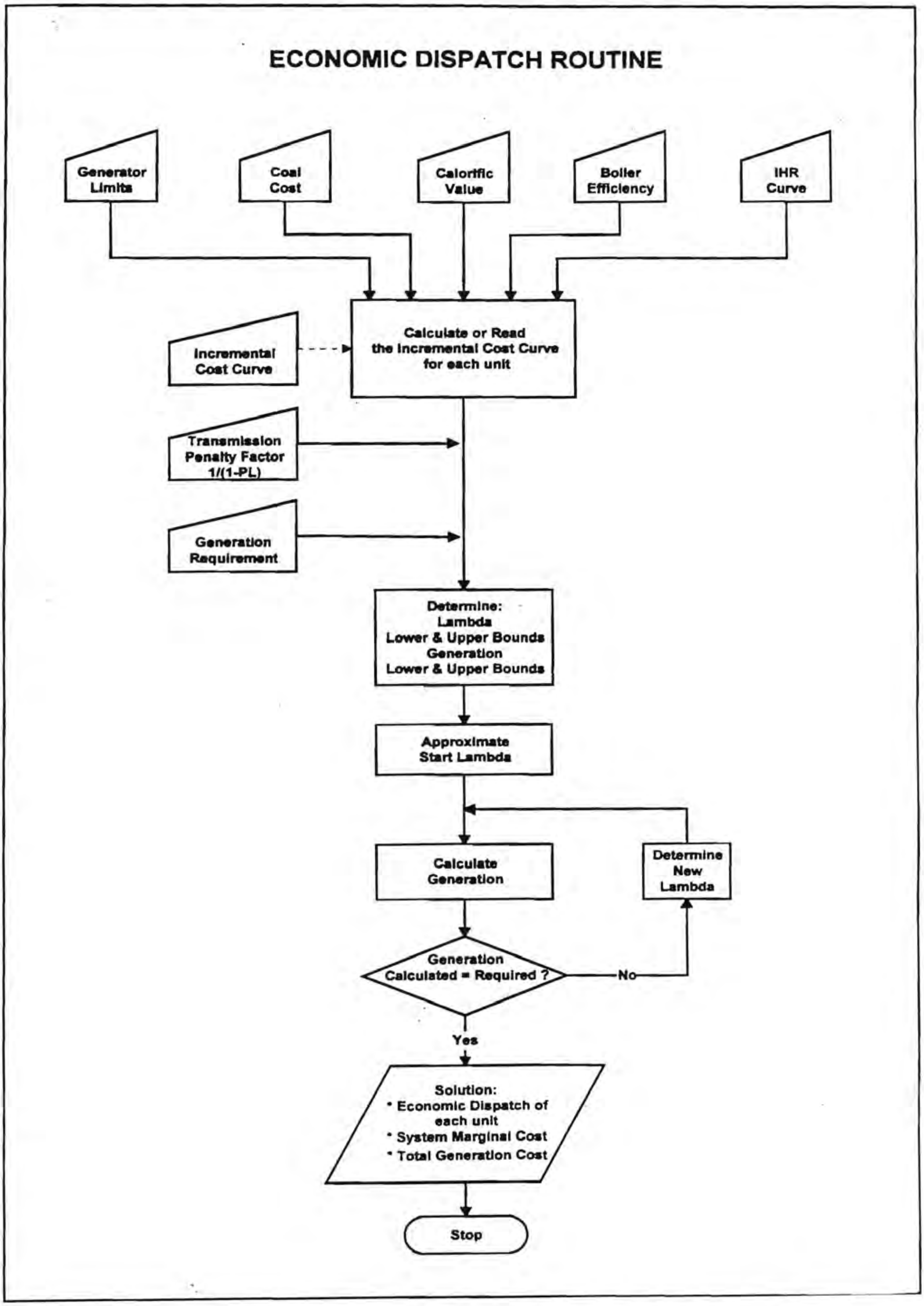
ECONOMIC DISPATCH ROUTINE
Generator Limits
Coal Cost
Calorific Value
Boiler Efficiency
IHR Curve
Incremental Cost Curve
Calculate or Read the Incremental Cost Curve for each unit
Transmission Penalty Factor 1/(1-PL)
Generation Requirement
Determine: Lambda Lower & Upper Bounds Generation Lower & Upper Bounds
Approximate Start Lambda
Calculate Generation
Determine New Lambda
Generation Calculated = Required ?
No
Yes
Solution:
* Economic Dispatch of each unit
* System Marginal Cost
* Total Generation Cost
Stop

Fig 3.1

$$\text{Incremental Cost} = \frac{\text{Coal cost} \times \text{IHR}}{\text{Boiler Efficiency} \times \text{Calorific value}} \qquad \text{(Eq 3.1)}$$

where:

Coal cost → Cost of coal (R/ton)

IHR → 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 3.1 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 (ie 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 setup where the frequency component is dominant.

$$\text{Total Desired Generation} = \sum \text{Generator Outputs}_{\text{All Units}} - \text{ACE} \qquad \text{(Eq 3.2)}$$

$$\text{Generation Requirement} = \text{Total Desired Generation} - \sum \text{Generator Outputs}_{\text{Non-EDR Units}}$$

(Eq 3.3)

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 eliminate short-term influences, but smaller than the chosen interval between economic dispatch executions. Therefore the generation requirement is filtered digitally[4] with a time constant of half the economic dispatch routine execution rate of 30 seconds (Eq 3.4).

$$GenReq_{Filtered} = GenReq_{New} + \left[DTF \times \left(GenReq_{New} - GenReq_{Previous}\right)\right] \qquad \text{(Eq 3.4)}$$

where:

DTF → Discrete Time Filter (Appendix A)

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 3.1, 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. The original routine was therefore changed to allocate spinning reserve to all available units.

3.3. ACE REGULATION (SHORT-TERM REGULATION)

The regulation of the area control error (ACE) within predefined limits is done by the regulatior module of the AGC system. This component calculates the ACE and determines the total reactior required from the system before distributing the calculated requirement among selectec generators. As described previously, the desired output of the generating unit is then determinec by adding its base point (desired output) and regulation component.

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[4] See Appendix A for digital filter description.

Local governor control (frequency bias) to each generating unit assists in maintaining the frequency within acceptable limits. To prevent unnecessary movement in generating units' outputs and interference with AGC action, governor dead bands were extended from -0,02/+0,02 Hz to -0,05/+0,05 Hz. The widening of the governor dead bands did, however, put an extra burden on the regulation of AGC, as control is required beyond -0,02/+0,02 Hz from it.

The calculation of the regulation component is mission-critical in the process of optimising AGC for minimum control. Although some decision-making is also done at PLC control level, the more authoritative calculation is done here.

3.3.1. The original ACE regulation controller

The first strategy of the optimisation process was to achieve the control objectives by means of parameter optimisation (configuration) on the original controller, ie without changing the control system itself. However, results from the simulation[5] as well as the implementation on the real system[6] indicated that the objectives could not be attained, especially with the wider governor dead bands.

It was found that the proportional-integral controller could not be tuned to provide subtle action during stable conditions as well as intense effort during unstable conditions. The controller always resulted in either undercontrol or overcontrol. The design does not include a derivative component that can distinguish the direction in which the ACE is going. Together with a very nonlinear design, which is typical of a system that has not been tested by means of control system simulation, this was the main reason why the system did not perform adequately.

3.3.2. Reason for fuzzy control

Experience gained in trying to optimise the original controller indicated that the original controller has a major shortcoming in that 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

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[5] See Chapter 5.

[6] See Chapter 6.

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. The FORTRAN source codes of the original and new fuzzy logic subroutines as well as other code changes made to subroutines in the regulation component are shown in Appendix C.

3.3.3. Calculation of the derivative ACE

The direction of movement of ACE (Δ ACE) is determined by subtracting the filtered ACE from the unfiltered ACE. The ACE is filtered using a normal lag filter (Appendix A). This is similar to using the standard differential function equation (Eq 3.7).

$$\Delta ACE_{Filtered} = ACE - ACE_{Filtered} \qquad \text{(Eq 3.5)}$$

where:

$$ACE_{Filtered} = \frac{1}{(1 + sT_{tau})} \times ACE \qquad \text{(Eq 3.6)}$$

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 3.7)

The discrete-time equivalent of the differential equation (Eq 3.7) used to determine the direction and rate of movement of the filtered ACE is:

$$\Delta ACE_{Filtered} = \left(1 - DTF\right) \times \left(ACE - ACE_{Filtered}\right) \qquad \text{(Eq 3.8)}$$

where:

DTF → Discrete Time Filter (Appendix A)

3.3.4. Implementation of fuzzy logic

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 (delta) ACE is therefore first determined as described.

This fuzzy logic uses a two-dimensional input, namely ACE and ΔACE. Each of these is categorised into five areas.

NL	Negative large
NS	Negative small
ZE	Zero
PS	Positive small
PL	Positive large

The fuzzy logic calculation is split into three components:

- The magnitude of each category (NL, NS, ZE ,PS ,PL) of the two input values (ACE and ΔACE) is first calculated.

- The inputs are then transformed into five output categories (NL_{Out} , NS_{Out} , ZE_{Out} , PS_{Out} , PL_{Out}) by means of the fuzzy rules table (Fig 3.2). The fuzzy rules selected in this table are the primary decision-making element of the logic.

		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 3.2

- The total regulation component (control ACE) is finally calculated by multiplying each of the five output categories with its appropriate gain (Eq 3.9).

$$Control\,ACE = G_{Large} \times \left(NL_{Out} - PL_{Out}\right) + G_{Small} \times \left(NS_{Out} - PS_{Out}\right) + G_{Zero} \times \left(ZE_{Out}\right) \quad \text{(Eq 3.9)}$$

An additional integral component, which is normally very small, is added to the total regulation component to compensate for any time errors in the frequency and inadvertent payback on the tie-lines. The integral function is primarily performed by the load-following component.

The fuzzy logic therefore replaces the calculation of different control regions and their gains, the dynamic dead band and the integral component as originally designed and described in section

2.3. Units are, however, still selected to do *normal*, *assist* or *emergency* regulation, depending on their capability.

3.4. PUMPED STORAGE ON AGC

Considering the nature of hydroelectric plant, it is normally very suitable for variable output. The short-term as well as the long-term cost of regulation on such a unit is significantly lower than that of a thermal unit. It would therefore make a lot of sense to shift the normal regulating duty of a system to hydroelectric plant.

Eskom however has very limited hydroelectric generation[7] available, such that it cannot be used for regulation. Although pumped storage plant is traditionally not considered for AGC regulation, it was recommended that Eskom's two pumped storage schemes[8] should be made available for control by AGC.

For AGC utilisation the pumped storage units are operated in normal regulation mode around a fixed base point midway in its regulating range. For example, if a 200 MW Palmiet unit can be controlled from 100-200 MW, a base point of 150 MW should be chosen to allow for regulation of 50 MW up and down. If an estimated 200 MW of regulation is available at a ramp rate of approximately 100 MW/min from the pumped storage stations, all the short-term regulation required for the system can be done by them. This will allow the control to minimise the use of thermal stations to the longer-term load following and assisting during emergency conditions.

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[7] Installed hydrocapacity of 600 MW with very low load factor due to shortage of water.

[8] Installed pumped storage capacity of 1 000 MW and 400 MW with sufficient combined pump and generating load factor.

3.5. SUMMARY

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

Although the base-point module has some shortcomings in its economic dispatch routine it ca perform the required load-following function adequately. Minor modifications are necessary whe using incremental cost curves rather than raw inputs when moving into a bidding system.

The original regulation module, however, could not achieve the control required for the optimisatio effort, as is proved (Chapters 5 and 6). Major modifications were made, consisting mainly of th application of fuzzy control techniques. The main logic of calculating the control ACE was replace with a routine making use of fuzzy logic, to incorporate the rate of change of the ACE in th calculation of the control ACE.

As described in Chapter 3, the load following and regulation components are combined t determine the desired generation of each generating unit in the PLC components. The simulatio of the enhanced configuration and design of AGC as well as the operational performance of it implementation on the real system is compared with the original AGC in Chapters 5 and 6, an proves the success of the enhancements.

The use of pumped storage stations for AGC regulation further improves the control performanc as the plant is more suitable for regulation.

4. CRITERIA FOR MONITORING AGC PERFORMANCE

4.1. BACKGROUND

In large interconnected systems the quality of AGC operation 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 no generally accepted indicators available, a measure for the control signals expected from AGC to achieve optimum frequency and tie-line control as well as load following was developed by the author and his colleagues.

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

4.2. NERC CRITERIA

4.2.1. Criteria reference

The NERC control performance criteria[9] 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.

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

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.

4.2.2. Criteria description

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.

A2 criterion - L^d compliance

The average ACE for each of the six ten-minute periods in the hour (ie 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.

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.

B2 criterion - recovery initiation

The ACE must start to return to zero within one minute after the start of the disturbance. ACE is permitted to trend in the same direction as the step change for a period not exceeding one minute

A system should maintain sufficient reserve capability, such that after the initial allowance of one minute ACE will begin to trend toward zero.

4.2.3. Calculation of criteria

L^d Calculation

$$L^d = (0.025)\,L + 5\text{ MW} \qquad \text{(Eq 4.1)}$$

(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.

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:

$$L^m = 3L^d \qquad (13)$$

Normal load and generation excursions (eg 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.

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.

4.3. MEASUREMENT FOR EXPECTED AGC

4.3.1. Background

This paragraph describes the methodology for the calculation of the optimum control expected from AGC. Optimum control can be defined as the minimum control effort required to maintain quality criteria. Minimising the regulation effort results in a reduction of generation cost at power stations. The amount of control needed to satisfy NERC (North American Electric Reliability Council) criteria where real-time values of ACE (area control error) and generation are given, is analysed in this study.

Like NERC performance criteria, expected AGC is a postdispatch analysis that can be calculated on-line but is not used in real-time decision-making. In brief it evaluates the magnitude of changes in demand as well as short-term deviations in the ACE that are unacceptably high.

4.3.2. Objectives

Performance criteria must meet the following requirements:

- Measurement and calculation must be simple and inputs obtainable in the control centre.
- Measurement must be applicable to the total control area and not to individual power stations.
- They must fit in with existing performance criteria and promote the achievement thereof.
- Their main use will be to establish whether generators are not overcontrolled.

4.3.3. Calculations

Like NERC criteria, the indicator for AGC expected control is calculated at hourly intervals, making use of the real-time measurements. The calculations are described in steps, using the ACE and area net generation curves of a typical hour on the Eskom grid as an example. The following characteristics, which were applicable in 1994, are important:

Peak demand:	24 800 MW
Frequency bias:	300 MW / 0,1 Hz
ACE dead band:	-50 to +50 MW

- No tie-line interconnections

Step 1 (Fig 4.1)

The short-term demand (every cycle) of the control area is calculated. Using measurements easily obtainable in the control centre, the area demand is calculated as follows from the measured ACE and area net generation:

Area demand = area net generation - ACE

A moving average of approximately five AGC cycles can be used for the area net generation. The signal is made up of the summation of individual generator outputs and is normally very noisy.

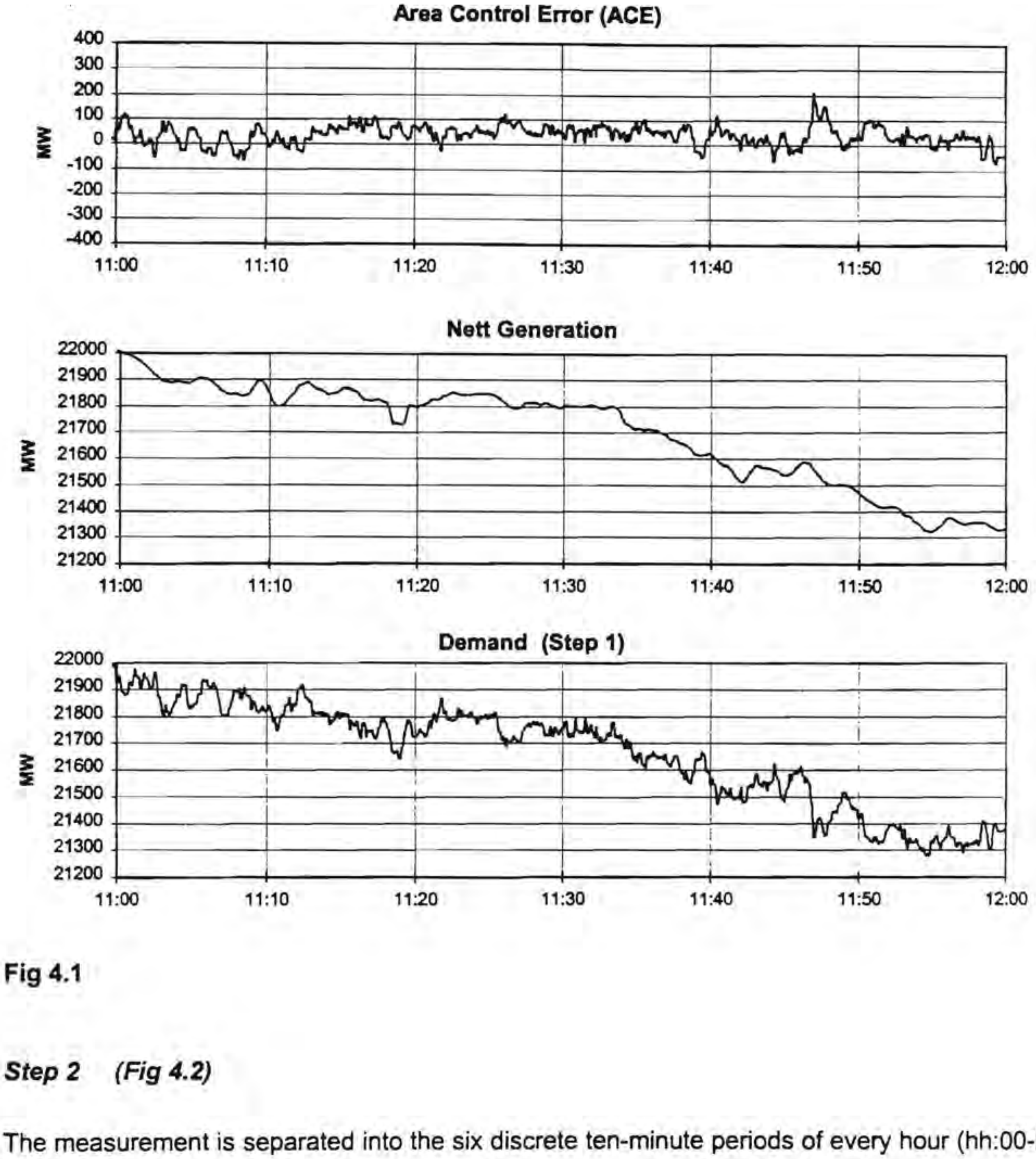

Fig 4.1

Step 2 (Fig 4.2)

The measurement is separated into the six discrete ten-minute periods of every hour (hh:00-hh:1 hh:10-hh:20, etc). This period is similar to that used in some NERC calculations. Control issued t follow the slower demand pattern is hence accounted for at least every 10 minutes.

Normalise the signal for each ten-minute period to the first value of that period. In other words, th deviation of the demand from the starting value at the beginning of the ten-minute period calculated for each value of the signal in that period. The new values can be seen as a deman adjusted ACE.

Fig 4.2

Step 3 (Fig 4.3)

The maximum deviation of the adjusted ACE signal between each zero crossing gives a good measure of the amount of control that should be issued to participating generating units to correct the ACE. The maximum absolute value and its sign between each zero crossing is therefore calculated. An automatic zero crossing will always exist at the end of each ten-minute period.

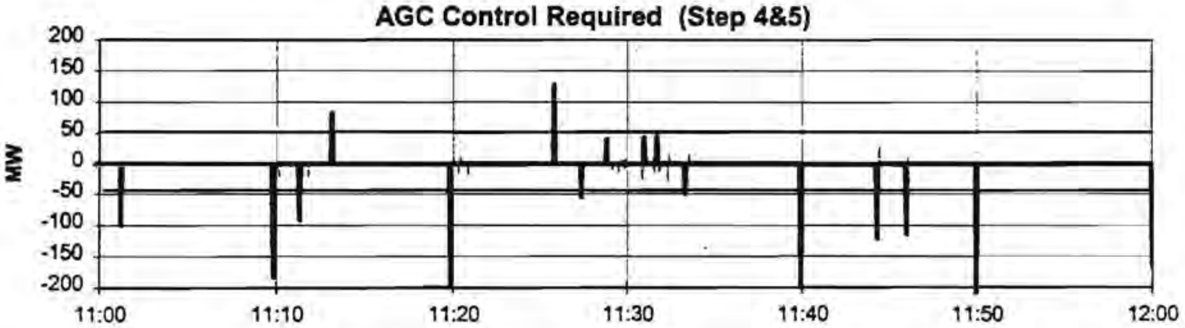

Fig 4.3

Step 5 (Fig 4.3)

Filter out insignificant noise from the signal by implementing a dead band on the calculated deviations. The dead band should be similar to the setting used in the AGC system.

Step 6 (Figs 4.4 and 4.5)

Finally individual deviations in both directions can be summated separately for each hour. The result is the optimum hourly control signals required from AGC to maintain the ACE and meet the demand without unnecessary movement of generators.

At the same time the actual amount of control that has been issued to power stations should be logged. If a pulse system is used the total number of pulses multiplied by their megawatt value is used.

The desired average hourly control in each direction can now be easily compared with the actual hourly control issued to power stations. The number of direction changes required can also be compared with that of individual units.

Required AGC (MW)

Period	Up control	Down control	Total control
00-10	0	284	284
10-20	82	290	372
20-30	169	54	223
30-40	87	248	335
40-50	0	485	485
50-60	0	169	169
Hour total	338	1 530	1 868

Fig 4.4

Actual AGC (MW)

Period	Up control	Down control	Total control
00-10	422	285	707
10-20	428	193	621
20-30	211	73	284
30-40	133	205	338
40-50	360	257	617
50-60	118	202	320
Hour total	1 672	1 215	2 887

Fig 4.5

The following conclusions can be reached for the hour in this example:

- Actual control in the *up* direction was 484 % of what was required.
- Actual control in the *down* direction was 79 % of what was required.
- Actual control in both directions was 150 % of what was required.

4.4. SUMMARY

NERC control performance criteria together with frequency and tie-line statistics are used to measure the quality of AGC. This is measured continuously on an hourly basis and can be summarised monthly.

The effectiveness of the control system, ie the amount of control needed to obtain the required quality of supply, must be measured as well. A methodology for the calculation of the optimum control expected of AGC, developed by the author and his colleagues, is described in this chapter. Optimum control can be defined as the minimum control effort required to maintain quality criteria. Minimising the regulation effort results in a reduction of generation cost at power stations.

Like NERC performance criteria, expected AGC is a postdispatch analysis that can be calculated on-line but is not used in real-time decision-making.

The performance of Eskom's AGC during 1994, 1995 and 1996 against the criteria is discussed in Chapter 6.

5. SIMULATION OF THE ENHANCED DESIGN AND CONFIGURATION OF AGC

5.1. BACKGROUND

The best way of gaining a proper understanding of any control system is by means of a computer simulation. It was decided to simulate the AGC system with MATLAB®. 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 the direct use of programming code was also very convenient. Once the original control system had been modelled accurately it was relatively easy to determine, model and test alterations to the design. All simulation results are shown in Appendix D.

5.2. DESCRIPTION OF SIMULATED MODEL

5.2.1. Complete AGC simulation model

A simplified functional block diagram of the model developed in MATLAB is shown in Fig 5.1. Note that each block in the diagram is representative of other smaller block diagrams or subroutines. The complete simulation model is available from the author. 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.

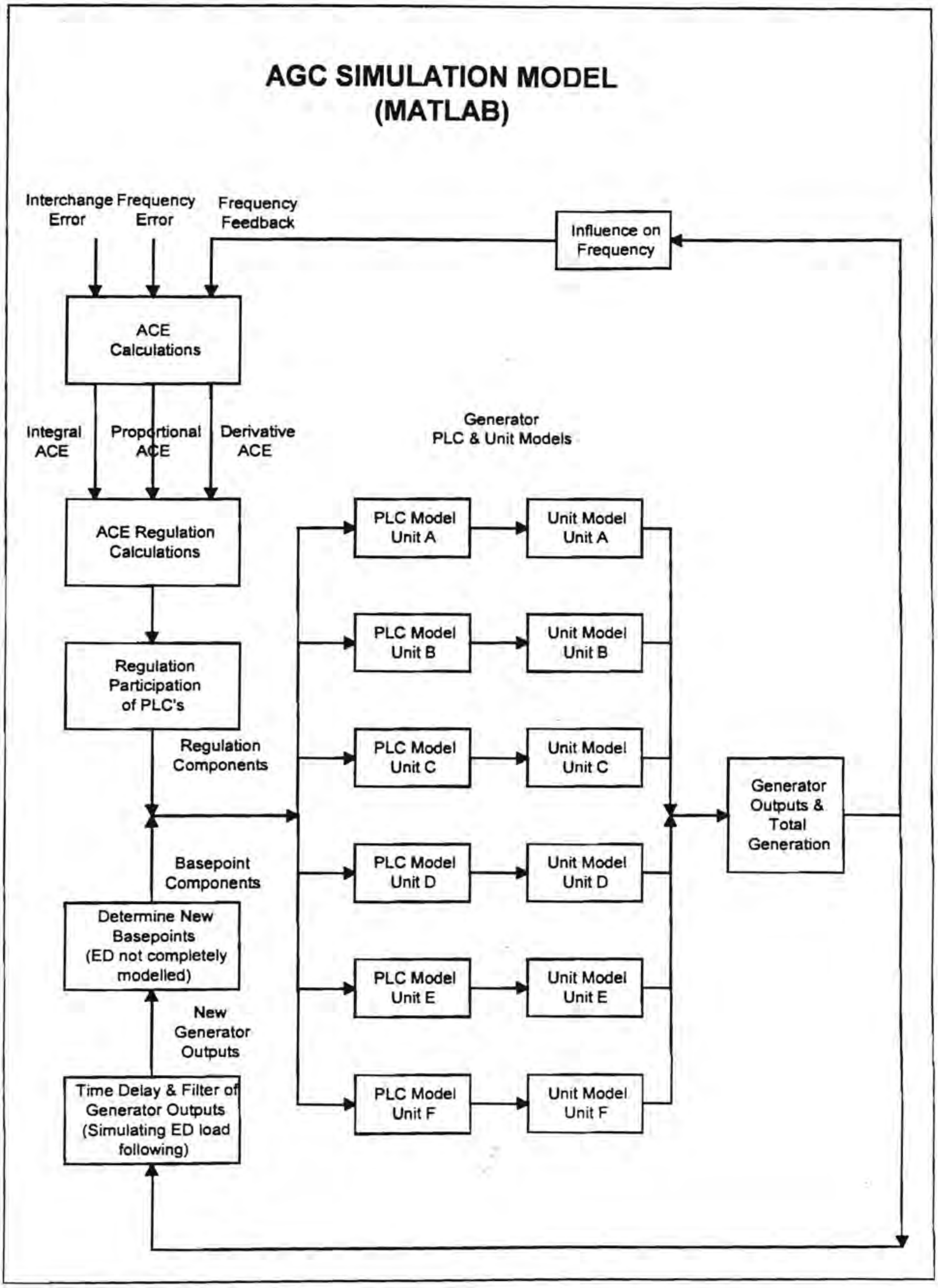
AGC SIMULATION MODEL
(MATLAB)
Interchange Error
Frequency Error
Frequency Feedback
Influence on Frequency
ACE Calculations
Integral ACE
Proportional ACE
Derivative ACE
Generator PLC & Unit Models
ACE Regulation Calculations
Regulation Participation of PLC's
Regulation Components
Basepoint Components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

Fig 5.1

5.2.2. 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 5.2.

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.

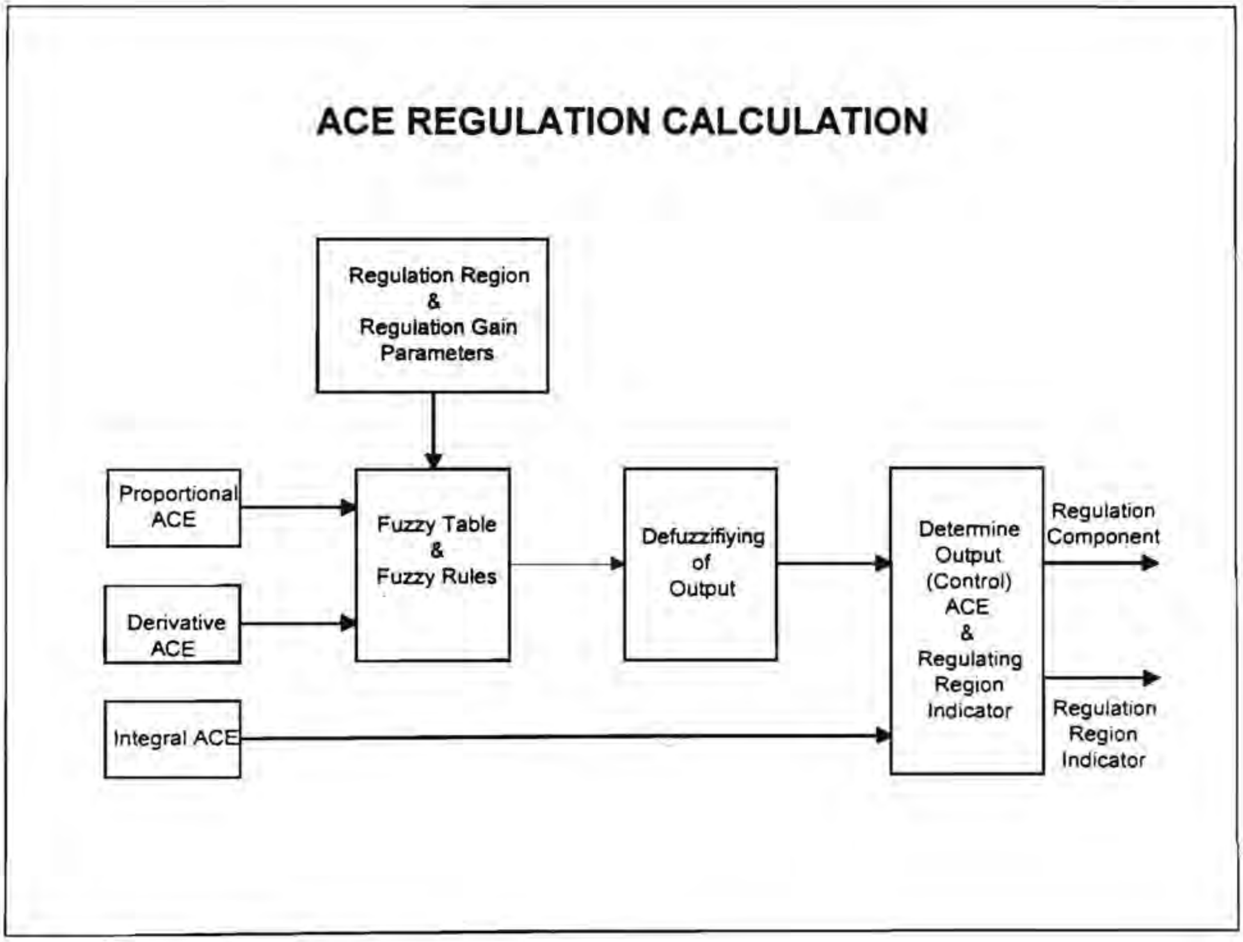

Fig 5.2

5.2.3. PLC and unit controller models

The programmable logic controllers (PLCs) of six units were modelled in the simulation (Fig 5.3). 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 Chapter 2.

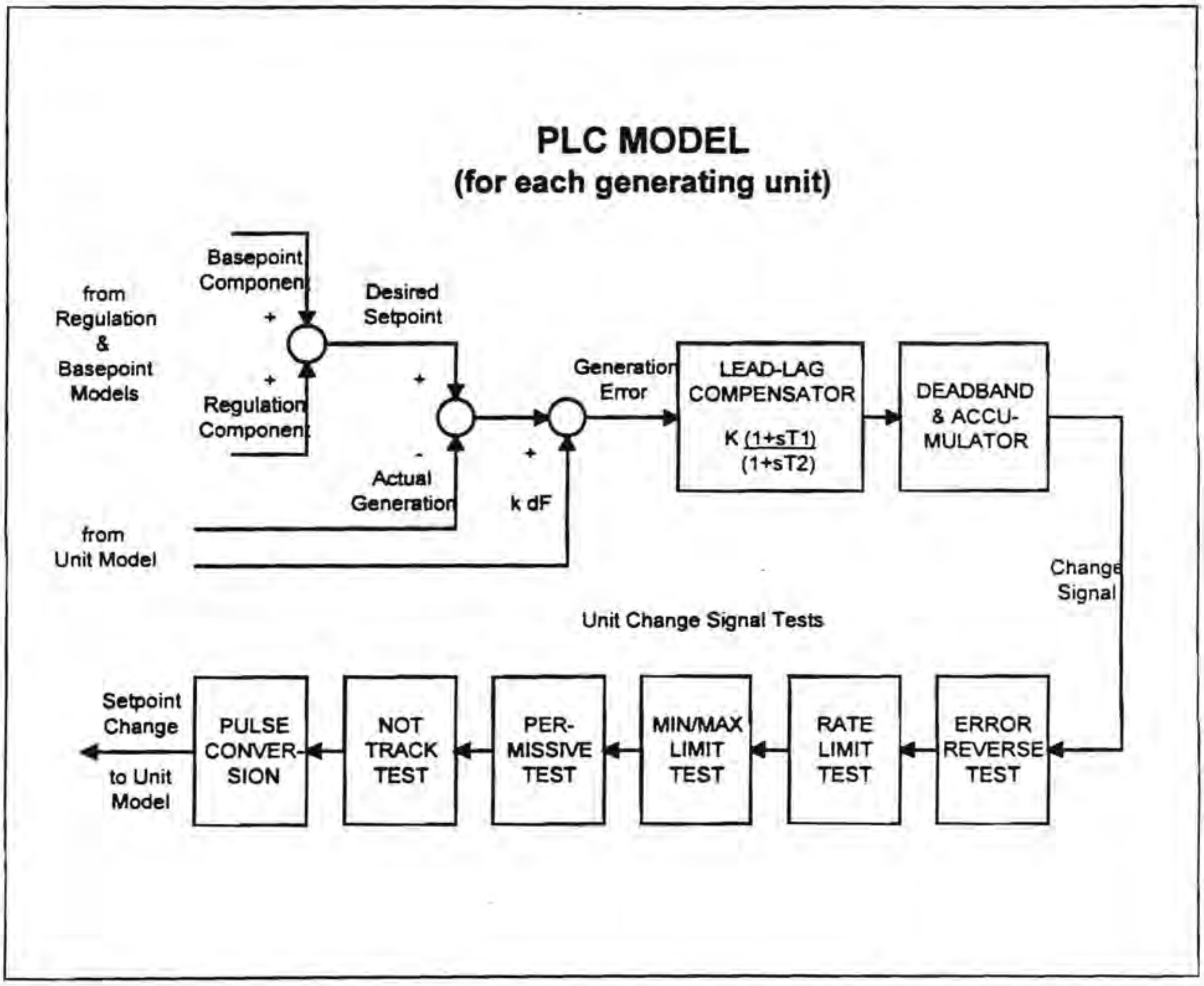

Fig 5.3

As the response of the power system model (power stations) to AGC was simulated the unit controller models of typical generating units had to be developed as well (Fig 5.4). 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.

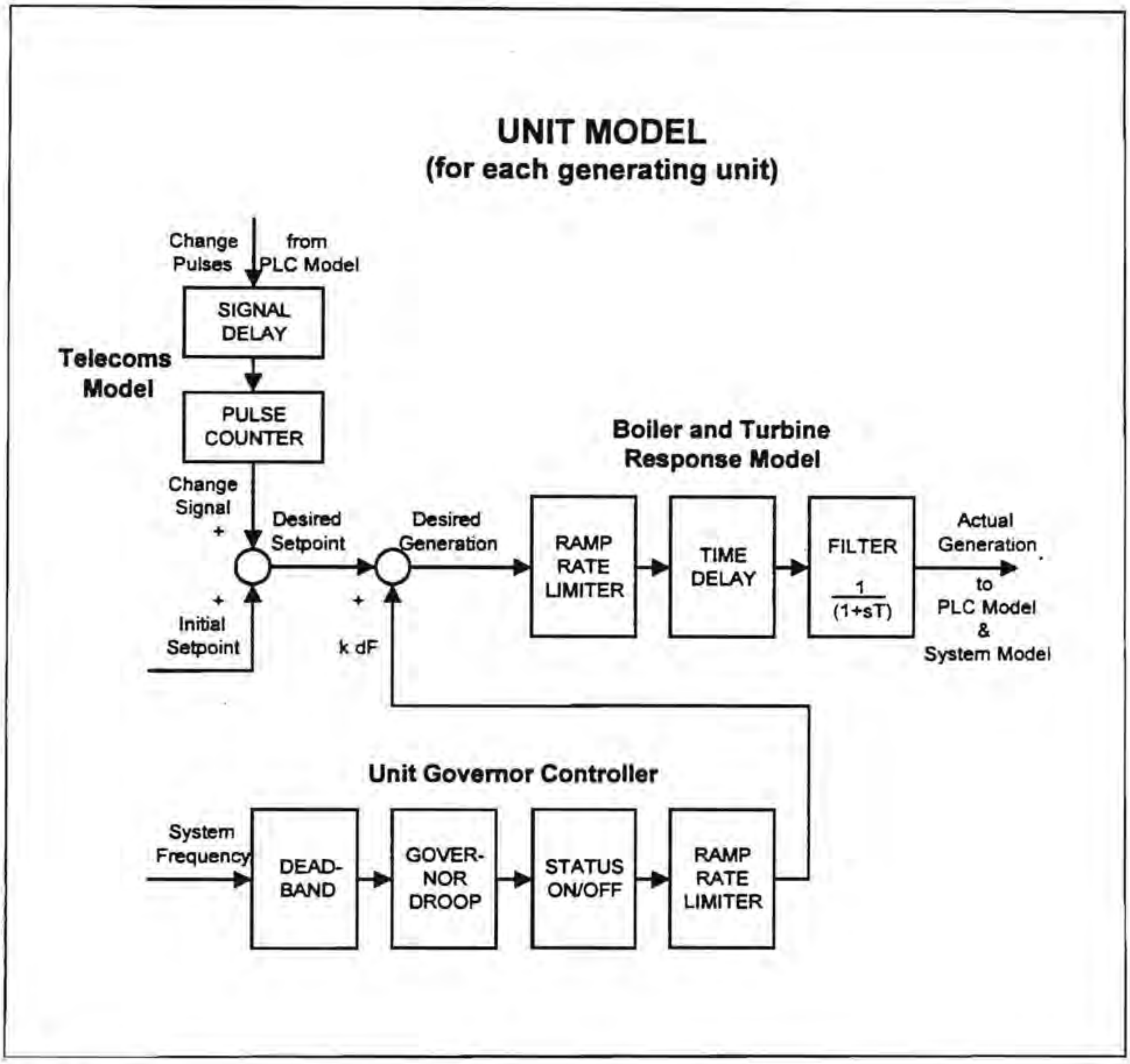

Fig 5.4

A unit model comprises telecommunication, governor controller and boiler-turbine response models. The models were configured to emulate the response of different generating units 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 impact of telecommunication between the two systems was 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.

5.3. 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 design (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 nonlinearity and ineffectiveness.

All significant simulation results are shown in Appendix D and can be categorised as follows:

- The first group of simulations done were with a step input function on different configurations of the original system with and without minor design changes implemented (Appendix D.2, Simulations 2.1 to 2.5).
- The second group of simulations done were with a typical signal input on different configurations of the original system with and without minor design changes implemented (Appendix D.3, Simulations 3.1 to 3.5).
- The last group of simulations done were with a typical signal input on different configurations of the fuzzy logic modified system with all design changes implemented (Appendix D.4, Simulations 4.1 to 4.4).

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 model are shown in Fig 5.5. The results of the simulation of the final fuzzy AGC controller design and configuration model are shown in Fig 5.6. The performance of the two controllers was 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 the manual start of pumped storage thereafter.

From the graph of the original system (Fig 5.5) 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.

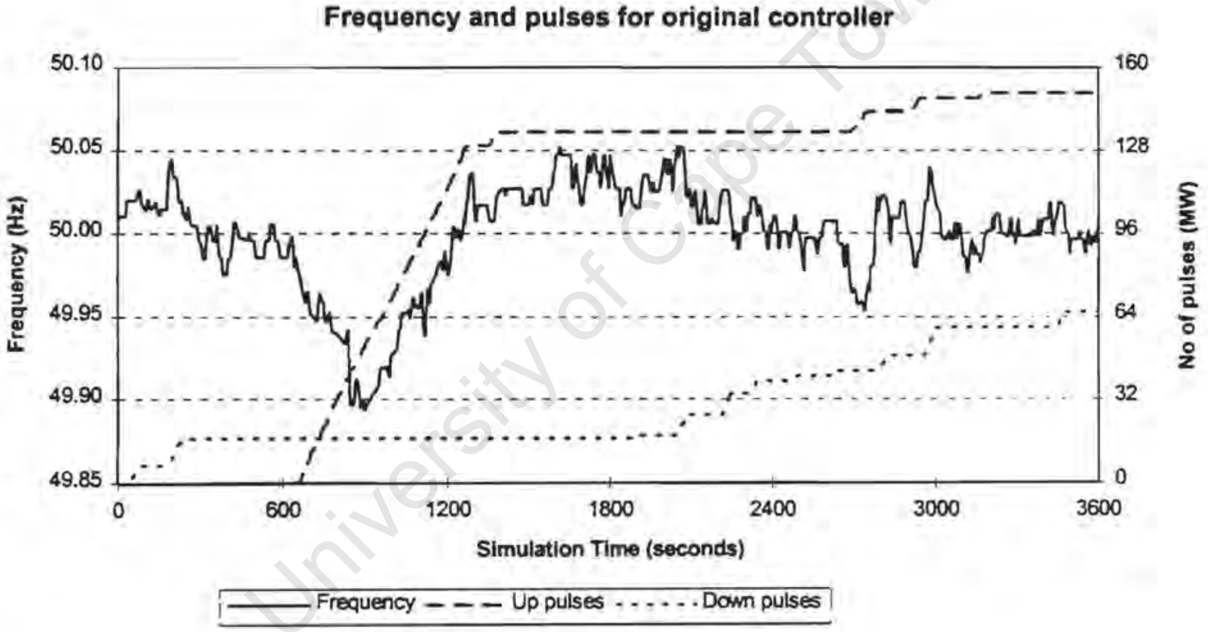

Fig 5.5

The simulation of the enhanced system (fuzzy logic controller with the derivative component) showed that its handling of the step change was very similar to that of the original controller, with the frequency also turning at about 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 configuration 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.

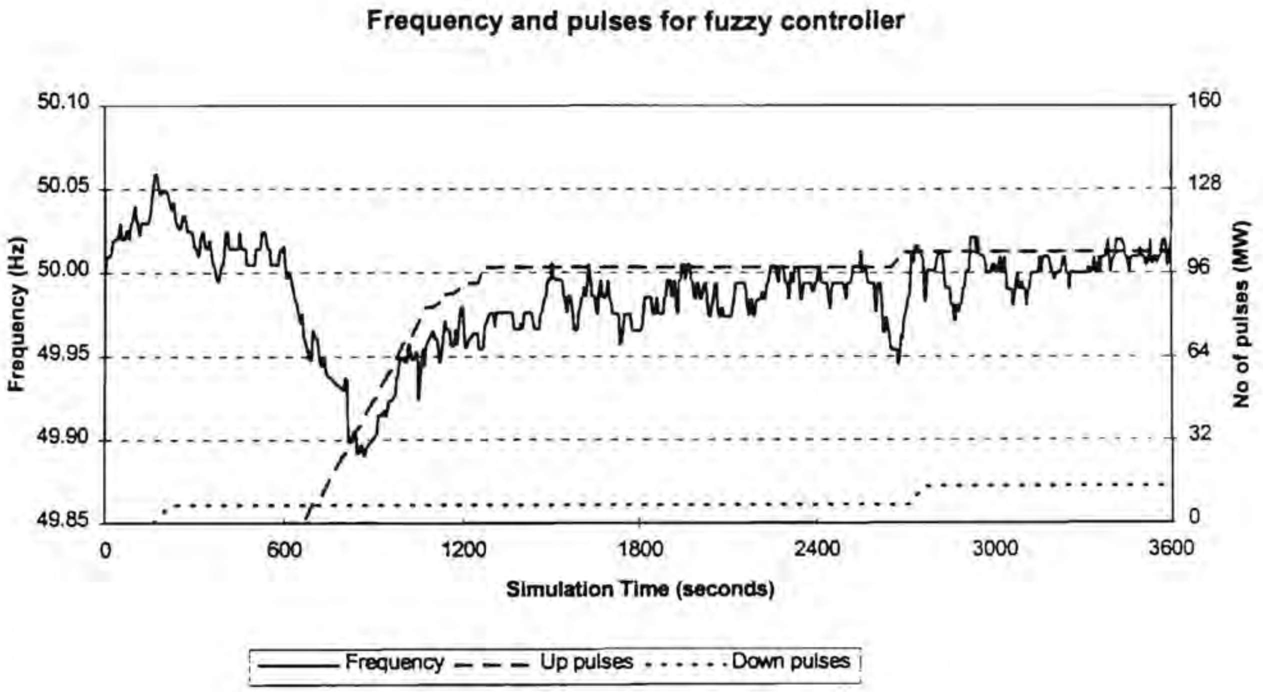
Frequency and pulses for fuzzy controller

Fig 5.6

.4. SUMMARY

Testing and implementation of design 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. Only the results of the original and the final controllers are shown, but 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 relatively easily, without having to go through the same painstaking procedure again.

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

6. RESULTS OF THE ENHANCED DESIGN AND CONFIGURATION OF AGC IN THE OPERATIONAL ENVIRONMENT

6.1. BACKGROUND

Only the performance of AGC on the live Eskom grid can be used as true benchmark in determining the extent to which AGC has been optimised. The criteria for control and quality of supply described in Chapter 4 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 the modifications had been made is compared with its previous performance in order to evaluate improvements in AGC.

6.2. IMPROVEMENTS IN THE AMOUNT OF CONTROL EXECUTED

6.2.1. 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 2 is shown in Fig 6.1.

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, whereafter the final modifications were accepted. Some power stations did extend 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 reflects the quality of the ACE as well. As the calculated control increased from an average of 2 100 MW/hour to 2 800 MW/hour, the signal probably worsened slightly. The benefit of reduced control, however, far outweighs the limited adverse consequences.

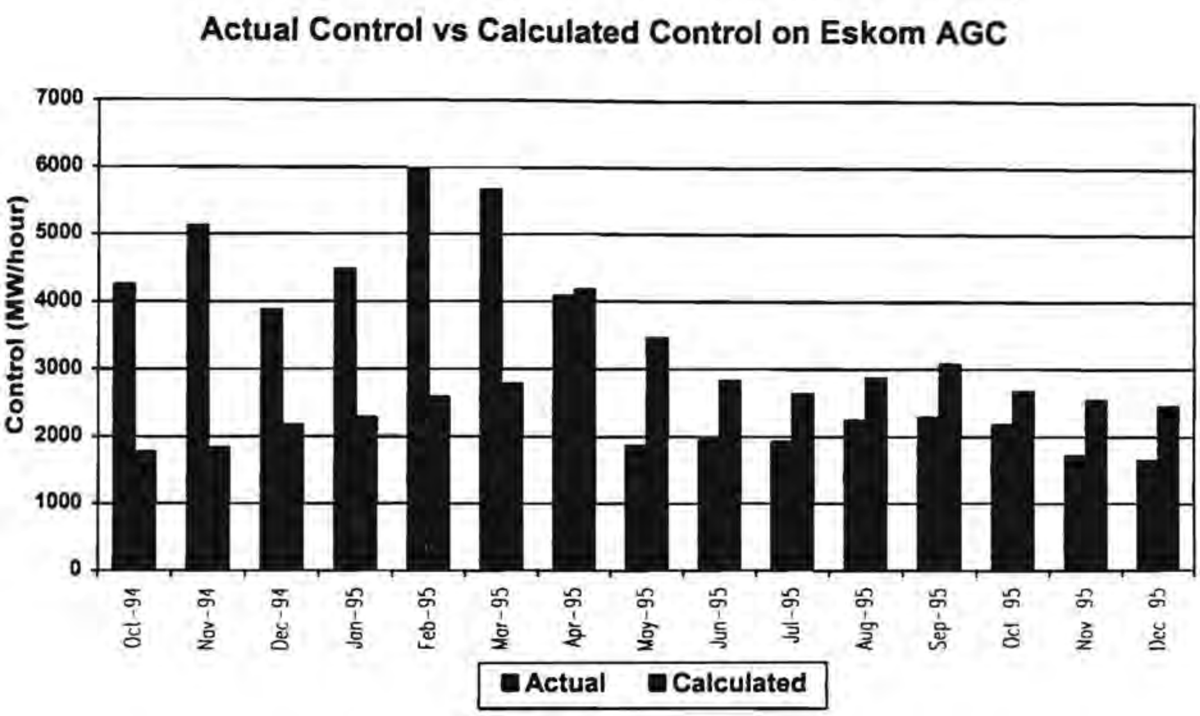

Fig 6.1

6.2.2 Effect of modifications on power stations

The reduction in AGC issued to power stations is illustrated clearly in Fig 6.2. 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 6.3. The measurement is done dynamically on the AGC system and the comparison indicates the filtered issued control versus actual movement.

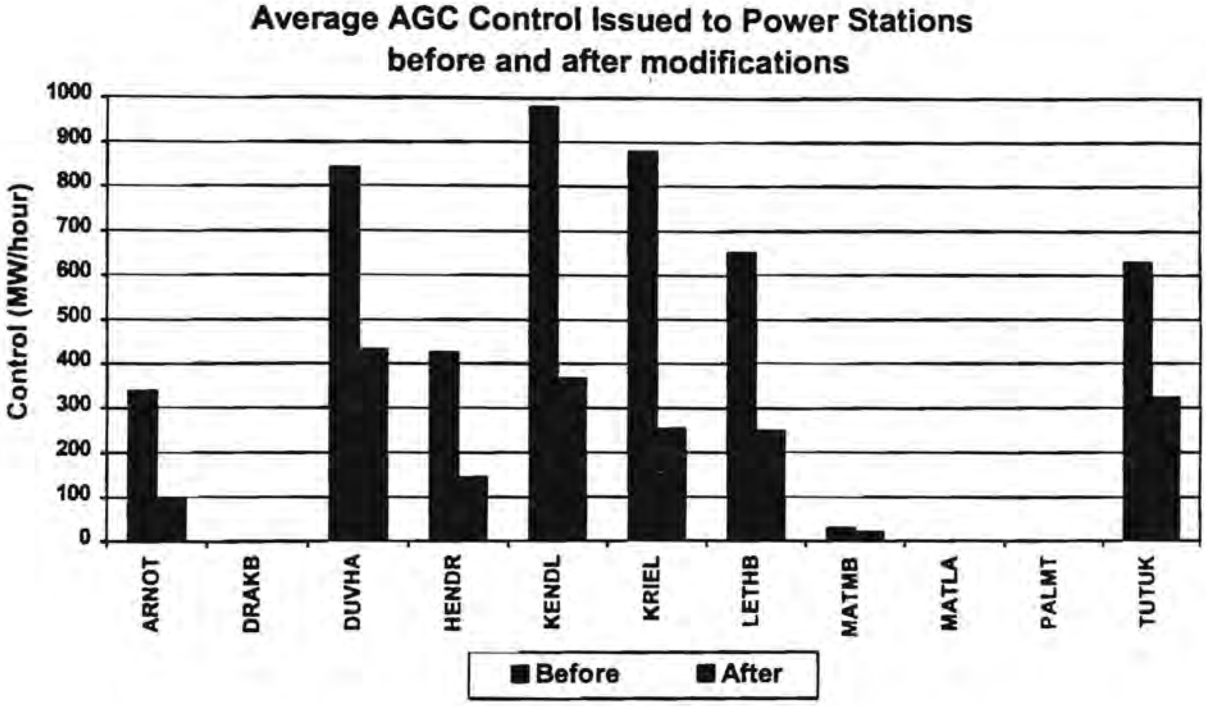

Fig 6.2

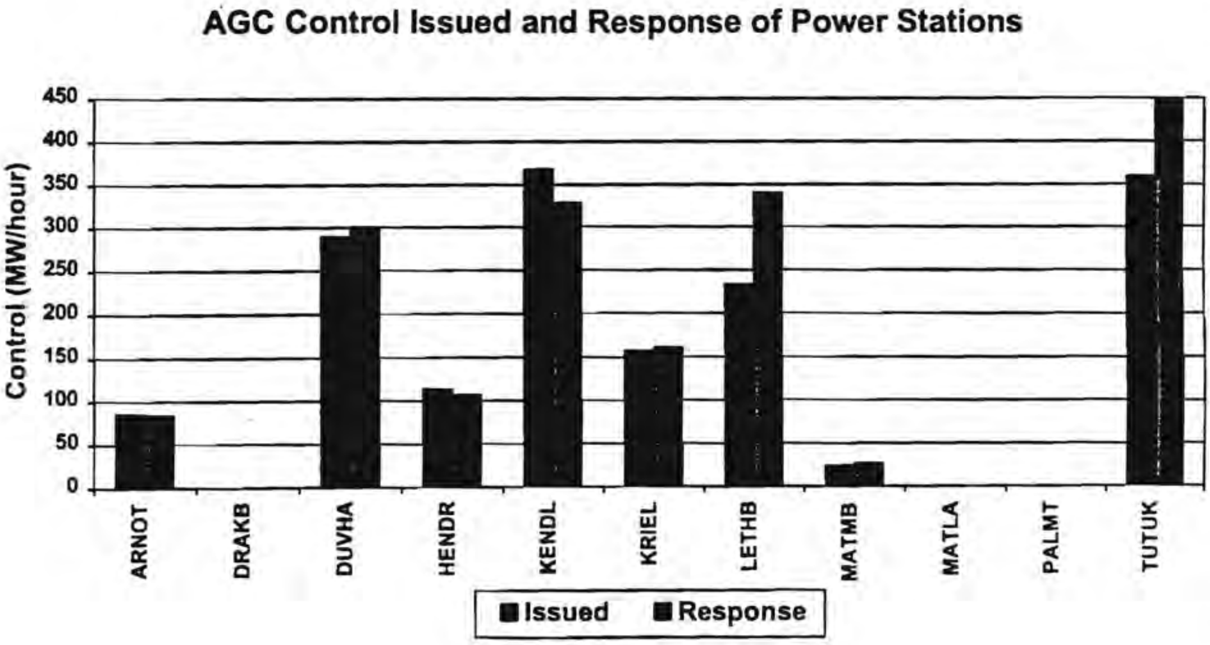

Fig 6.3

6.3. EFFECT OF MODIFICATIONS ON THE QUALITY OF SUPPLY

The NERC criteria described in Chapter 4 are used to determine whether the frequency and tie-line control - area control error - 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 the Pool 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 per day on average.

The quality of supply is also shown by the calculated control indicator, as described in Chapter 5. Note that the frequency cannot be used as an indicator of the performance of an individual utility in an interconnected system.

On analysing the graph shown in Fig 6.4 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.

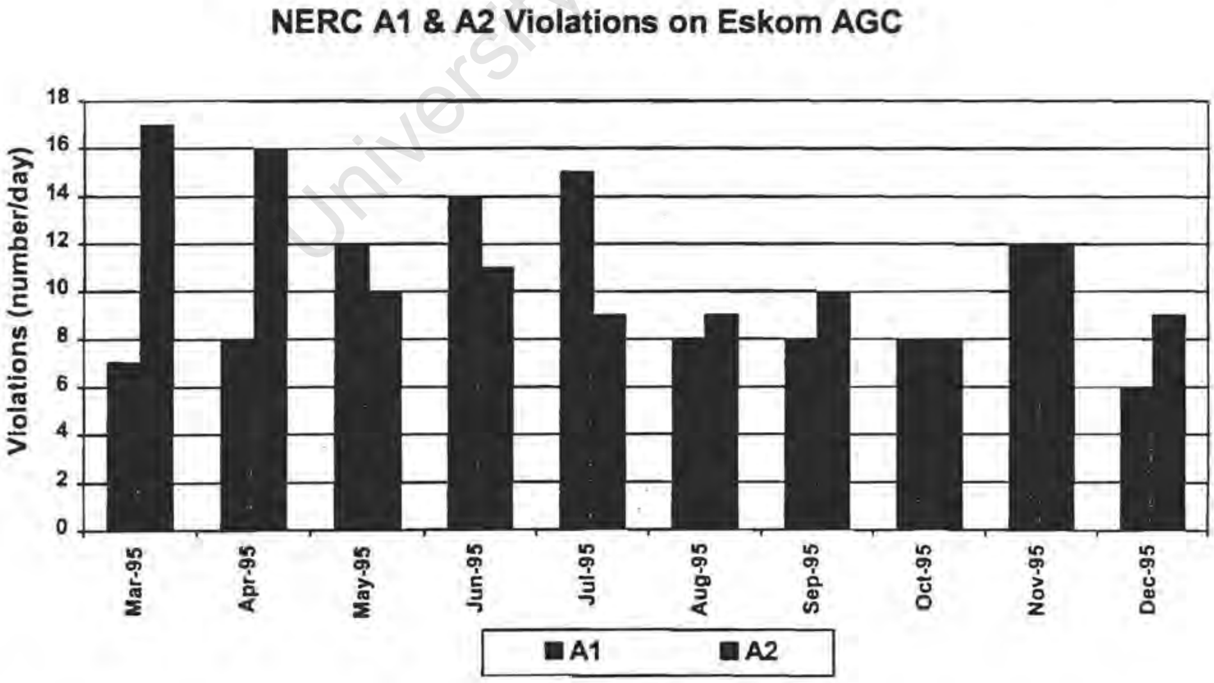

Fig 6.4

6.4. 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 actually improved after the modifications had been implemented. The lack of control signals produced by AGC and visible to control personnel at the National Control Centre 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 even further.

7. IMPACT OF THE SOUTHERN AFRICAN POWER POOL ON AGC

. BACKGROUND

In 1995 electric utilities of Southern African countries agreed, for the first time in history, to establish an interconnected power pool - the Southern African Power Pool (SAPP)-. This was done mainly for economic reasons, but also to improve the quality and continuity of supply in the smaller systems.

Although most utilities in the Southern African region are involved in the establishment of the power pool, only Eskom (South Africa), ZESA (Zimbabwe) and ZESCO (Zambia) will originally trade in the pool environment. Since ZESA and ZESCO upgraded their control centres all three utilities have AGC in their control centres.

2. ALTERATIONS TO AGC DUE TO SAPP

As AGC was originally designed to do tie-line control in large interconnected systems, very little needed to be done to convert Eskom's AGC from constant frequency control (CFC)[10] to tie-line bias control (TLBC). The once-off modifications to the AGC system and the additional responsibilities of the controller at the loading desk that were nevertheless necessary are discussed separately.

7.2.1. Main alterations and additions to the AGC software

- Network modelling of additional components.
- Identification of all tie-line connections.
- AGC mode change from CFC to TLBC.
- Use of tie-line schedules and inadvertent payback.

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[10] See Chapter 3 for the modes of operation of AGC.

- Calibration of the sensitivity on which ACE is controlled between the different AGC systems.

7.2.2. Main alterations to the operation of AGC by the controller

- Although the tie-line error is automatically incorporated in the ACE, the controller has to monitor the tie-line for line limitations.
- The controller must be able to create interchange schedules.
- The controller must schedule inadvertent payback and time error corrections.
- The controller has to do additional information logging and administration .

7.3. RESPONSIBILITIES OF POOL MEMBERS

It is important to bear in mind that AGC only controls the generation of a control area; in other words, no automatic control of power flows or voltages is done. In a classic large interconnected system no individual control area will affect the system frequency significantly under normal conditions. In other words, each individual utility is small compared with the size of the combined system. Under these conditions changes in the generation different from the exact demand in the control area will be reflected in the net energy flow of their tie-lines.

This is unfortunately not the situation in the Southern African Power Pool, where Eskom is responsible for ±90 % of the combined load[11] of the power pool.

Control area	Peak demand	Frequency bias
Eskom	27 000 MW	300 MW/0,1 Hz
ZESA	2 800 MW	30 MW/0,1 Hz
ZESCO	1 000 MW	20 MW/0,1 Hz

Fig 7.1

---

[11] Combined peak demand: ±28 000 MW Combined frequency bias: ±350 MW/0,1 Hz

The effect of AGC executed in the different control areas is illustrated by means of an example in Appendix E. The example discussed in Appendix E indicates that the power flow on the tie-line between Eskom and ZESA is always very sensitive to changes in generation in the small areas, ie ZESA and ZESCO. Conversely it is very insensitive to changes in generation made by Eskom. This is different from the classic interconnected scenario, where errors introduced on a specific tie-line can normally be transferred to another tie-line.

ZESA and ZESCO therefore have a specific responsibility to ensure that tie-line errors are limited while Eskom AGC will affect mainly the system frequency and time error.

7.4. JOINT AGC REGULATION

Joint AGC regulation was first done by utilities in North America, as described in Reference 3. The main objective of joint AGC regulation is to exploit systems with high regulating capabilities to the full. Reference 3 describes the case of Manitoba Hydro, which is a predominantly hydro-based utility contracted to do ACE regulation for Northern States Power, Minnesota Power and the Otter Tail Power Company, which are predominantly thermal-based. This arrangement, called joint ACE regulation, successfully transfers high-frequency regulation components in order to reduce fuel and maintenance costs and allows dynamic interchange scheduling to achieve flexible generation scheduling and improved economic dispatch.

In brief, this means that a portion of one utility's ACE is transferred to another utility which can control it at a lower cost. Joint ACE regulation is illustrated in the following calculations on the ACE of two control areas (Utilities 1 and 2).

$$ACE_{total} = ACE_1 + ACE_2$$

where

$$ACE_i = \sum_{tielines} P_{actual} - \sum_{tielines} P_{sceduled} - 10 \times \beta \times \delta frequency$$

If Utility 1 provides a portion of Utility 2's ACE, the equations can be rewritten as follows:

$$ACE_{total} = \alpha_1 ACE_1 + \alpha_2 ACE_2 + (1 - \alpha_1) ACE_1 + (1 - \alpha_2) ACE_2$$

where α_i is the portion of ACE_i for which Utility 1 will take responsibility.

New ACE values are therefore:

$$ACE_1' = ACE_1 + \alpha_2 ACE_2$$

$$ACE_2' = (1 - \alpha_2) ACE_2$$

Note that the total ACE remains the same; it is just distributed differently.

In the case of the Southern African Power Pool, Eskom comprises mainly thermal generation while ZESA and ZESCO are hydro-based. This would naturally create an opportunity for the latter utilities to provide ACE regulation to Eskom. There are, however, a few consequences that must be mentioned.

- As the ACEs of the utilities are often opposite in sign, the new ACE of the regulating area will not necessarily be greater than the previous one. In other words, doing regulation for another utility does not necessarily mean that the ACE in your own area will be worse than it was before.
- Power flow limitations of the tie-line must be able to handle the scheduled tie-line flow plus the maximum ACE transfer, ie on an existing tie-line the maximum schedule will have to be reduced.
- The regulating utility has the opportunity to obtain a more favourable generation level within the joint AGC regulation limit, thereby increasing its revenue.

7.5. RECOMMENDATIONS

The establishment of the Southern African Power Pool is a great strategic and technical step forward in the trading of electricity in sub-Saharan Africa. The modifications to the control systems in Eskom have been made successfully, together with alterations in the operating environment.

The electrical configuration of the interconnection, in which Eskom accounts for 90 % of the total load, does not create ideal circumstances for interconnected trading. The generation control of the two small utilities, namely ZESA and ZESCO, will mainly determine the error on the tie-lines, while Eskom will have to ensure proper frequency control. Only the expansion of the interconnected system, with more utilities joining and more tie-lines becoming available, will improve this condition.

The possibility of joint ACE regulation has to be investigated properly as ZESA and ZESCO comprise mainly good regulating hydroplant and Eskom comprises mainly thermal plant. The effect of one area doing most of the regulation is almost like relaxing the load-frequency control pool rules in such a small power pool and will result in lower scheduled transfer limits on the tie-lines.

8. CONCLUSION AND RECOMMENDATIONS

8.1. CONCLUSION

The original AGC system could not be set up to achieve the required quality of supply without imposing excessive control effort. A design 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 modified significantly. The main modifications involved the addition of a derivative component by means of fuzzy logic and the elimination of nonlinearities.

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

The control system was originally designed to perform tie-line control and therefore did not require major modifications for operation in the Southern African Power Pool. Joint AGC regulation should be revisited when sufficient low-cost hydroregulation becomes available from other pool members.

8.2. RECOMMENDATIONS

The original AGC design cannot be configured to obtain the quality of supply required while minimising the control effort.

It is recommended that the design of load following by means of the existing economic dispatch routine and ACE regulation, using a regulation component which includes a derivative component implemented by means of fuzzy logic, be adopted. The enhanced design and configuration of the AGC system are highly successful and should be maintained.

The modifications must be submitted to the original designers, ESCA Corporation, for introduction in future releases of the product.

The performance indicators that stipulates that the amount of control required to meet the quality performance criteria, as well as the normal quality criteria for interconnected operation, must be adhered to.

Pumped storage plant should be utilised where possible to replace fossil plant for short term regulation.

Joint AGC regulation should be revisited when sufficient low-cost hydroelectric regulation becomes available in the power pool.

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APPENDIX A: LOW PASS FILTER AND LEAD-LAG FILTER DESCRIPTIONS

A.1. Description of low-pass filter

This appendix describes the modelling of lag and lead-lag filters including discrete time approximations as used and referred to in the main document.

Data signals are often filtered to remove unwanted high-frequency components caused by noise or step changes. Filtering is achieved by means of a first-order low-pass (lag) compensator with a Laplace transform of the form:

$$\mathit{Output\ (filtered)} = K\frac{1}{(1 + s\mathit{Tau})} \times \mathit{Input\ (raw)} \qquad \text{(Eq A.1)}$$

The time domain response of such a filter is shown in fig A.1. The filter with a time constant of Tau can be approximated by a first-order discrete-time filter with a discretisation of DT seconds. Filtering calculations are now done numerically as follows, with the output plotted (where Tau = 4 s). Note the accuracy at the discrete times.

$$\mathit{Output}_t = \mathit{Output}_{t-1} + (\mathit{Input}_t - \mathit{Output}_{t-1}) \times \mathit{DTF} \qquad \text{(Eq A.2)}$$

where:

$$\mathit{DTF} = \mathit{TF} \times (1 - 0.25 \times \mathit{TF})$$

and:

$$\mathit{TF} = \frac{\mathit{CycleTime}}{\mathit{Tau}}$$

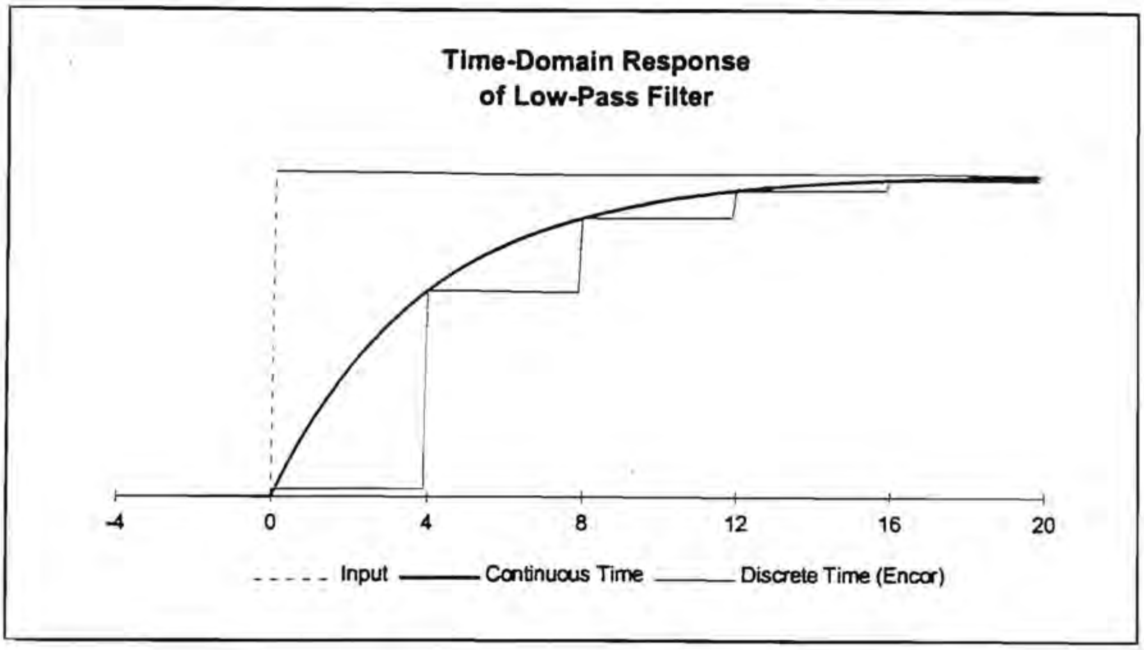


Fig A.1

A.2. Description of lead-lag compensator

$$\text{Lead - Lag Compensator} = K\frac{(1+sT_1)}{(1+sT_2)} \quad \text{... (Eq A.3)}$$

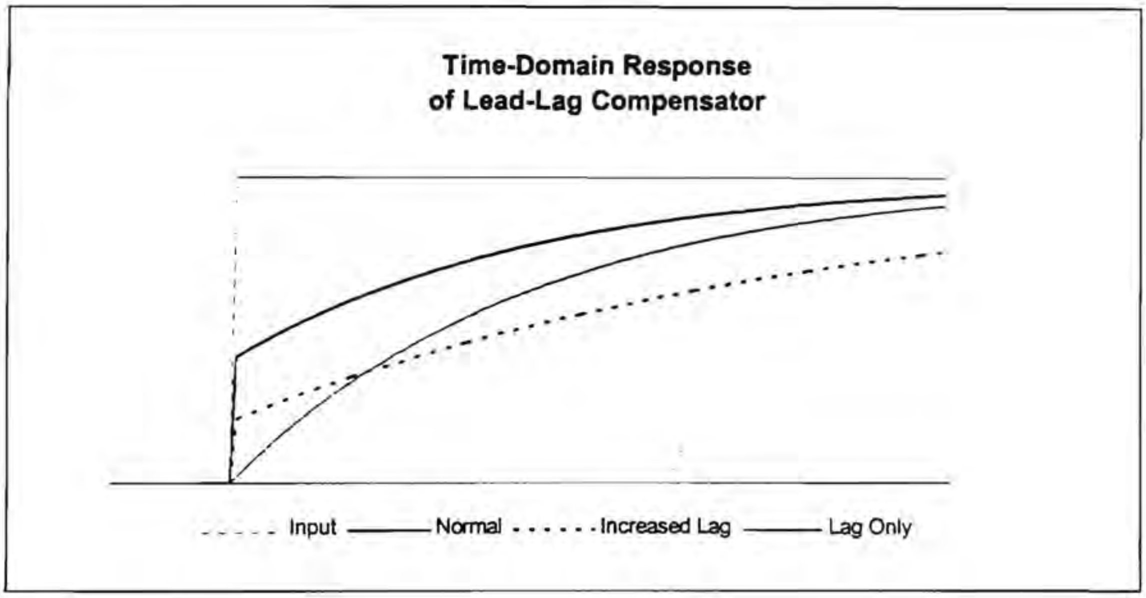


Fig A.2

APPENDIX B: DEAD-BAND AND FILTER CALCULATIONS USED IN THE ORIGINAL REGULATION MODULE

The original regulation module made use of a dynamic dead-band to provide lag filter logic. The dynamic dead-band is calculated by AGC from the static dead-band level, the emergency level and a maximum decay time. It adds the functionality of a first-order lag filter with a time constant equal to the maximum decay time and is defined as:

$$DB_{dynamic} = \left| \begin{array}{ll} DB_{emergency} & \text{... if } |ACE| < DB_{static} \\ DB_{static} + (DT/\ DT_{max}) \times (DB_{emergency} - DB_{static}) & \text{... else} \end{array} \right. \qquad \text{(Eq B.1)}$$

$DB_{dynamic}$ → dynamic ACE dead-band

DB_{static} → static ACE dead-band

DT_{max} → maximum decay time

DT → DT_{max} minus time that ACE is outside static dead-band (≥ 0)

$DB_{emergency}$ → emergency ACE level

The top part of the equation stipulates that the dynamic dead-band stays at the emergency limit as long as the absolute ACE is smaller than the static dead-band. The bottom half of the equation stipulates that when the absolute ACE exceeds the static dead-band, the dynamic dead-band starts decaying until it reaches the static dead-band value. It will remain there until the ACE drops to within the static dead-band, where-after the dynamic dead-band will immediately be expanded to the emergency level again. When the ACE-in exceeds the dynamic dead-band it will be transferred through, without any blocking, as the ACE-out.

ACE-in going into the dead-band filter, dynamic dead-band as calculated using (Eq B.1), and the filtered ACE-out, is plotted in fig B.1 for a typical four-second discrete-time variation of ACE.

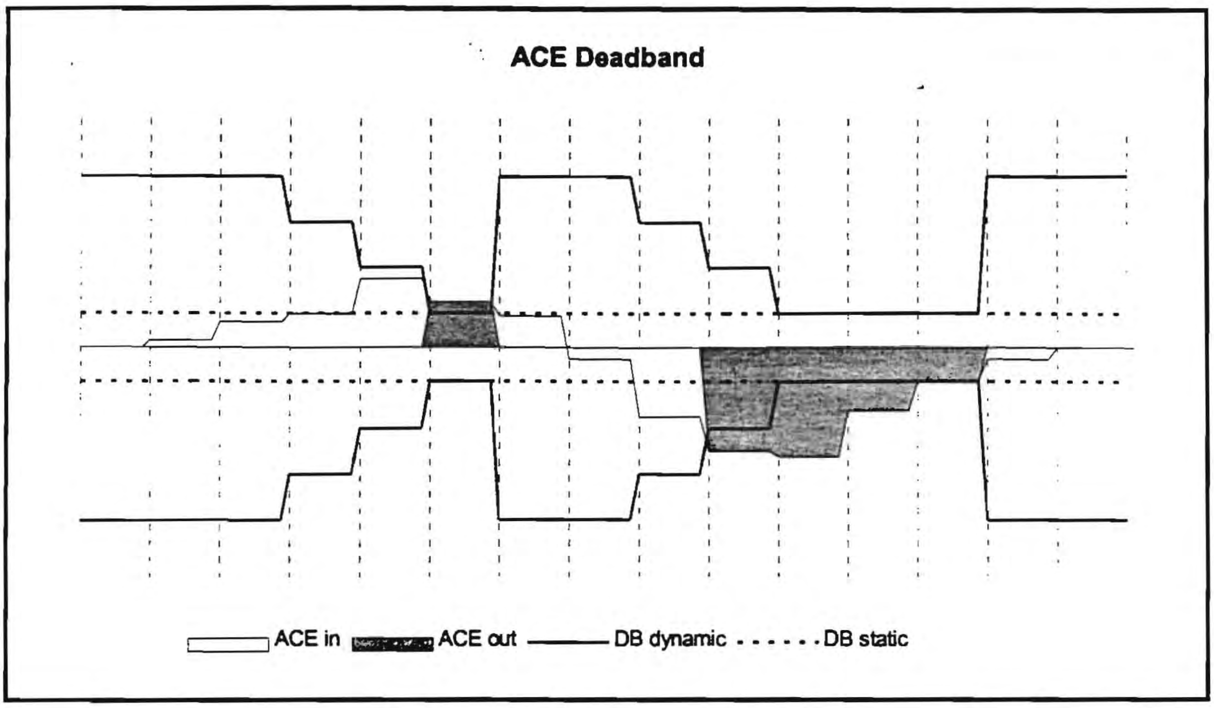


Fig B.1

APPENDIX C: FORTRAN CODE CHANGES IMPLEMENTED

This appendix contains the FORTRAN code changes to the Real-Time Generation module in Encor. It was developed and implemented by RC Hartman, GA Chown and PJJ Swartz during June 1995. Copyright on code changes belongs to Eskom.

C.1. Comment out regulation region calculator resetting of ACE to zero when opposite to integral and temporary dead-band. (4 lines)

AAGC.FOR ACE_PROCESSING (I)

```
c    IF( ( ABS(ACETEMP) .GT. GNOM_OPA(I)* ACEDB)          GOTO 40
c    IF( ACE * ACETEMP .LT. 0.0)                           GOTO 40

c    IF( ( ACETEMP .LT. 0.0) .AND. (ACE .GT. ACEDB))      GOTO 40
c    IF( ( ACETEMP .GT. 0.0) .AND. (ACE .LT. -ACEDB))     GOTO 40
```

C.2. Add code to correct the integral ACE to the maximum allowed integral ACE as set in the parameters. (1 line)

AAGC.FOR ACE_PROCESSING (I)

```
ACEINT_OPA(I) = ACEINT
```

C.3. Add code to filter the total generation to solve for by Control Economic Dispatch with a 45 s time constant. (3 lines)

```
CAED.FOR          GEN_CED_SETUP (IOPA, FLAG)


REAL * 4   MWCED


MWCED =  LDFIL_OPA(IOPA) - FIXED MW + ICHGSK_OPA(IOPA) -

         GENMISC_OPA(IOPA) - LDMISC_OPA(IOPA)


MWCED_OPA(IOPA) =MWCED_OPA(IOPA) + (0.0881 * (MWCED-

                 MWCED_OPA(IOPA)) )
```

C.4. Alter the modification by Bill Gordon to switch all possible units to 'CER' mode when the frequency goes below 49.90 Hz to come in only when the frequency goes below 49.85 Hz. (3 lines)

```
BPT.FOR           SCHEDULED_PLC_BASEPOINTS (I)


IF ( FHZ_OPA(I) .LT. 49.85 ) THEN
    MODED_PLC(J) (1:3) = 'CER'
ENDIF
```

C.5. Comment out code that feeds back unassigned regulation duty to regulating PLCs. (1 line)

CAED.FOR **COMPUTE_PLC_CONTROL_ACTION (I)**

```
c    GENDESI_PLC(J) = GENDESI_PLC(J) + CHNGEX
```

C.6. Add code to allow a negative value in the permissive test parameter. A negative value results in a dead-band effect on the change signals. (7 lines)

AC.FOR **ACE_PERMISSIVE_TEST (I)**

```
IF ( ACEPERM_OPA(I) .LT. 0) THEN
    IF ( ABS(ACE_OPA(I)) .LT. ABS(ACEPERM_OPA(I)) )
        DO J = PLC1, PLC2
            CHNG_PLC(J) = 0.0
        ENDDO
    ENDIF
ENDIF
```

C.7. Alter code to use the total desired generation (load + ACE) instead of only the load to solve for by Control Economic Dispatch . (3 lines)

CAED.FOR **GEN_CED_SETUP (IOPA, FLAG)**

```
MWCED = GENDES_OPA(IOPA) - FIXED MW + ICHGSK_OPA(IOPA) -
        GENMISC_OPA(IOPA) - LDMISC_OPA(IOPA)
```

C.8. **Alter code to include the minimum and maximum generating limits coming from the stations into the control economics routine rather than just the database economic limits. (2 lines)**

```
AAGC.FOR          COMPUTE_UNIT_LIMITS (I)


EMX_UNIT(K)   =    MIN(LMX,EMX)


EMN_UNIT(K)   =    MAX(LMN,EMN)
```

C.9. **Replace the subroutine that calculates the total regulation component with one using fuzzy logic that takes the absolute ACE, integral ACE and direction of movement of the ACE into account.**

```
AAGC.FOR          ACE_PROCESSING (I)


      SUBROUTINE   ACE_PROCESSING( I )

C
C
C
C
C
C

      IMPLICIT NONE
```

```
      INCLUDE '(DF_GENMOM)/NOLIST'
      INCLUDE '(DF_GENMOM_GMGENR)/NOLIST'
      INCLUDE '(DF_GENMOM_GMAGC)/NOLIST'
      INCLUDE '(DF_GENMOM_AGC1)/NOLIST'

      INTEGER*4     I

      REAL*4          ACE,
     X              ACEABS,
     X              ACEAMN,
     X              ACEEMN,
     X              ACEINT,
     X              ACEDB,
     X              ACETEMP,
     X              TREGNOM
     X              DEL,
     X              ACE_NL,
     X              ACE_NS,
     X              ACE_ZE,
     X              ACE_PS,
     X              ACE_PL,
     X              DEL_NL,
     X              DEL_NS,
     X              DEL_ZE,
     X              DEL_PS,
     X              DEL_PL,
     X              DELDB,
     X              DELAMN,
```

```
X               DELEMN,
X               ACEFIL1,
X               ACEFIL2
X               ACEPL,
X               ACEPS,
X               ACENS,
X               ACENL

C Assign new variables

      ACE_NL   = 0.0
      ACE_NS   = 0.0
      ACE_ZE   = 0.0
      ACE_PS   = 0.0
      ACE_PL   = 0.0
      DEL_NL   = 0.0
      DEL_NS   = 0.0
      DEL_ZE   = 0.0
      DEL_PS   = 0.0
      DEL_PL   = 0.0
      DEL = 0.0
      ACEFIL1 = 0.0
      ACEFIL2 = 0.0
      ACEPL    = 0.0
      ACEPS    = 0.0
      ACENS    = 0.0
      ACENL    = 0.0
```

```
      ACE = ACE_OPA(I)

      ACEABS   = ABS( ACE )

      ACEDB    = ACEDB_OPA(I)

      ACEAMN   = ACEAMN_OPA(I) + .001

      ACEEMN   = ACEEMN_OPA(I) + .002

      TREGNOM  = TREGNOM_OPA(I)

      ACEINT   = ACEINT_OPA(I)


C The 0.001 and 0.002 additions added to avoid divide by zero

C in heuristic rules


C Use GINTMX_OPA(I) as multiplier for delta regions

      DELDB    = ACEDB * GINTMX_OPA(I)

      DELAMN   = ACEAMN * GINTMX_OPA(I) + .001

      DELEMN   = ACEEMN * GINTMX_OPA(I) + .002



C              Limit integral of ACE

      IF( ACEINT .GT. ACEINTMX_OPA(I))

X             ACEINT = ACEINTMX_OPA(I)

      IF( ACEINT .LT. (-ACEINTMX_OPA(I)))

X             ACEINT = - ACEINTMX_OPA(I)


      ACEINT_OPA(I) = ACEINT



C---------------------------------------------------------------------

C   Setup the regulation region indicator (RRI)

C       Use dynamic dead-band from last cycle
```

```
C-----------------------------------------------------------------------
C            First reset all rri flags

        QDYN_OPA(I) = QDYN_OPA(I) .AND. .NOT. DBAND$OPA
        QDYN_OPA(I) = QDYN_OPA(I) .AND. .NOT. REGULI$OPA
        QDYN_OPA(I) = QDYN_OPA(I) .AND. .NOT. REGUL$OPA
        QDYN_OPA(I) = QDYN_OPA(I) .AND. .NOT. ASS$OPA
        QDYN_OPA(I) = QDYN_OPA(I) .AND. .NOT. EME$OPA


C Calculate delta ace (DEL) - the direction ace is going


C Slow Filter
C Use the dynamic dead-band value i.e. ACEDYDB_OPA(I) for slow filter
C Tracking/Load time constant DTFTRK_OPA(I)
        ACEFIL2 = ACEDYDB_OPA(I) +
X       (DTFTRK_OPA(I) * (ACE_OPA(I) - ACEDYDB_OPA(I)))
        ACEDYDB_OPA(I)=ACEFIL2


C Fast Filter
C Use regulation/ace filter i.e. ACEFIL_OPA(I) for fast filter
C Regulation/Ace time constant DTFREG_OPA(I)
        ACEFIL1 = ACEFIL_OPA(I) +
X       (DTFREG_OPA(I) * (ACE_OPA(I) - ACEFIL_OPA(I)))
C Fast Filter is allocated in the filter sub routine
C Delta Ace
        DEL = ACEFIL1 - ACEFIL2
```

```
C Default region

        QDYN_OPA(I)  = QDYN_OPA(I) .OR. DBAND$OPA
        ACEREGP_OPA(I)   = 0.0
        ACEREGI_OPA(I)   = 0.0


C Calculate nl,ns,ze,ps,pl for ace

    ACE_NL = MAX(MIN((ACEAMN+ACE)/(ACEAMN-ACEEMN),1.0),0.0)

    IF(ACE .LT. -ACEAMN) THEN
        ACE_NS = MAX(MIN((ACEEMN+ACE)/(ACEEMN-ACEAMN),1.0),0.0)
    ELSE
        ACE_NS = MAX(MIN((ACEDB+ACE)/(ACEDB-ACEAMN),1.0),0.0)
    ENDIF


    IF(ACE .GT. 0.0) THEN
        ACE_ZE = MAX(MIN((ACE-ACEAMN)/(ACEDB-ACEAMN),1.0),0.0)
    ELSE
        ACE_ZE = MAX(MIN((ACEAMN+ACE)/(ACEAMN-ACEDB),1.0),0.0)
    ENDIF


    IF(ACE .GT. ACEAMN) THEN
        ACE_PS = MAX(MIN((ACEEMN-ACE)/(ACEEMN-ACEAMN),1.0),0.0)
    ELSE
```

```
          ACE_PS = MAX(MIN((ACE-ACEDB)/(ACEAMN-ACEDB),1.0),0.0)
      ENDIF


      ACE_PL = MAX(MIN((ACE-ACEAMN)/(ACEEMN-ACEAMN),1.0),0.0)



C Calculate nl,ns,ze,ps,pl for deltaace


      DEL_NL = MAX(MIN((DELAMN+DEL)/(DELAMN-DELEMN),1.0),0.0)


      IF(DEL .LT. -DELAMN) THEN
          DEL_NS = MAX(MIN((DELEMN+DEL)/(DELEMN-DELAMN),1.0),0.0)
      ELSE
          DEL_NS = MAX(MIN((DELDB+DEL)/(DELDB-DELAMN),1.0),0.0)
      ENDIF


      IF(DEL .GT. 0.0) THEN
          DEL_ZE = MAX(MIN((DEL-DELAMN)/(DELDB-DELAMN),1.0),0.0)
      ELSE
          DEL_ZE = MAX(MIN((DELAMN+DEL)/(DELAMN-DELDB),1.0),0.0)
      ENDIF


      IF(DEL .GT. DELAMN) THEN
          DEL_PS = MAX(MIN((DELEMN-DEL)/(DELEMN-DELAMN),1.0),0.0)
      ELSE
          DEL_PS = MAX(MIN((DEL-DELDB)/(DELAMN-DELDB),1.0),0.0)
      ENDIF


      DEL_PL = MAX(MIN((DEL-DELAMN)/(DELEMN-DELAMN),1.0),0.0)
```

```
C Inference rules
C Note ze does not need to be calculated.
C ACE_xx variables will now assigned the combined ACE and DEL outputs.

      ACEPL = MAX( MAX(MIN(ACE_PL,DEL_PL),MIN(ACE_PL,DEL_PS)),
     X   MAX(MIN(ACE_PS,DEL_PL),MIN(ACE_PS,DEL_PS)))

      ACEPS = MAX( MAX( MAX(MIN(ACE_PL,DEL_ZE),MIN(ACE_PS,DEL_ZE)),
     X   MAX(MIN(ACE_ZE,DEL_PL),MIN(ACE_ZE,DEL_PS))),MIN(ACE_NS,DEL_PL))

      ACENL = MAX( MAX(MIN(ACE_NL,DEL_NL),MIN(ACE_NL,DEL_NS)),
     X   MAX(MIN(ACE_NS,DEL_NL),MIN(ACE_NS,DEL_NS)))

      ACENS = MAX( MAX( MAX(MIN(ACE_NL,DEL_ZE),MIN(ACE_NS,DEL_ZE)),
     X   MAX(MIN(ACE_ZE,DEL_NL),MIN(ACE_ZE,DEL_NS))),MIN(ACE_PS,DEL_NL))


C Assign ACEREGP and ACEREGI

      ACEREGP_OPA(I) = 100*((-GASS_OPA(I)*ACE_PL) + (-GNOM_OPA(I)*ACE_PS)
     X          - (-GASS_OPA(I)*ACE_NL) - (-GNOM_OPA(I)*ACE_NS)

      ACEREGI_OPA(I) = - GINTNOM_OPA(I) * ACEINT

C Calculate rri

         IF(ACEABS .GT. ACEEMN) THEN
             QDYN_OPA(I)  = QDYN_OPA(I) .OR. EME$OPA
```

```
          ACEREGP_OPA(I) = -GMX_OPA(I) * ACE
      ELSE IF(ACEABS .GT. ACEAMN) THEN
          QDYN_OPA(I)  = QDYN_OPA(I) .OR. ASS$OPA
      ELSE IF(ACEABS .GT. ACEDB) THEN
          QDYN_OPA(I)  = QDYN_OPA(I) .OR. REGUL$OPA
      ELSE IF(ABS(ACEINT) .GT. ACEINTDB_OPA(I) ) THEN
          QDYN_OPA(I)  = QDYN_OPA(I) .OR. REGULI$OPA
      ENDIF

C-------------------------------------------------------------------
C         Include the inadvertent payback term in ACEREGI
C-------------------------------------------------------------------
      IF( (QDYN_OPA(I) .AND. MIPB$OPA) .NE. 0) THEN
          ACEREGI_OPA(I) = ACEREGI_OPA(I) + MANINPB_OPA(I)
      ELSE IF( (QDYN_OPA(I) .AND. AIPB$OPA) .NE. 0) THEN
          ACEREGI_OPA(I) = ACEREGI_OPA(I) + AUTINPB_OPA(I)
      ENDIF

C-------------------------------------------------------------------
C             Compute ACEREG
C-------------------------------------------------------------------
      ACEREG_OPA(I) = ACEREGP_OPA(I) + ACEREGI_OPA(I)

C-------------------------------------------------------------------
C     Calculate the dynamic ACE dead-band for this time
C-------------------------------------------------------------------
C Dynamic Dead-band is not calculated anymore and is used
C for the slow filtered value of Ace
      TREG_OPA(I) = TREG_OPA(I) - TAGCNOM_OPA(I)
```

```
      IF( TREG_OPA(I) .LT. 0 )  TREG_OPA(I) = 0
      IF( ACEABS .LE. ACEDB )        TREG_OPA(I) = TREGNOM_OPA(I)


C     ACEDYDB_OPA(I) = ACEDB + (ACEEMN - ACEDB) *
CX                   ((FLOAT(TREG_OPA(I))) / TREGNOM )


      RETURN
      END
```

C.10. Alter code to use the actual generation rather than the scheduled base-points when calculating the output of fixed units for Control Economic Dispatch. (1 line)

```
CAED.FOR          GEN_CED_SETUP (IOPA, FLAG)


FIXED UN MW =     GEN_UNIT(IUNIT)
```

APPENDIX D: RESULTS OF SIMULATION IN THE MATHWORKS® MATLAB®

D.1. Introduction

This appendix contains results of the final simulations done by means of the Mathworks® MATLAB® in each category. The development of the simulation models and simulations results can be divided into three groups:

1. Simulations of the AGC system with a step input function, with the original design and with minor design modifications and different configurations.
2. Simulations of the AGC system with a typical real life input signal, on the original design with the minor design modifications and different configurations.
3. Simulations of the AGC system with a typical real life input signal, with the fuzzy logic design modifications and other minor design modifications and different configurations.

The variable input signal to all simulations is the system frequency which has to be controlled satisfactory with the minimum amount of control action to generators. In the first simulations a 0.05 Hz step change in the input frequency signal has to be controlled back to 50 Hz. For the latter simulations, either a 0.05 Hz step change or a 0.10 Hz ramp change over 15 minutes, is induced on a sample of an uncontrolled system frequency, is controlled back to 50 Hz.

D.2. Simulations of the AGC system with a step input function, with the original design and with minor design modifications and different configurations

The first simulations were done by evaluating the response of the control system by means of with a step function as input at time 50s. During the very first simulations only the configuration was adjusted in an effort to improve the system. It was however soon realised that some design modifications were necessary of which results are shown consequently.

Simulation 2.1: Original design without any design modification

Note the high non-linearity in the control integral ACE in fig D.2, which is the result of a function that sets the integral ACE to zero when the sign is opposite to the sign of the ACE. It consequently results in oscillations of the control to generators and the actual ACE.

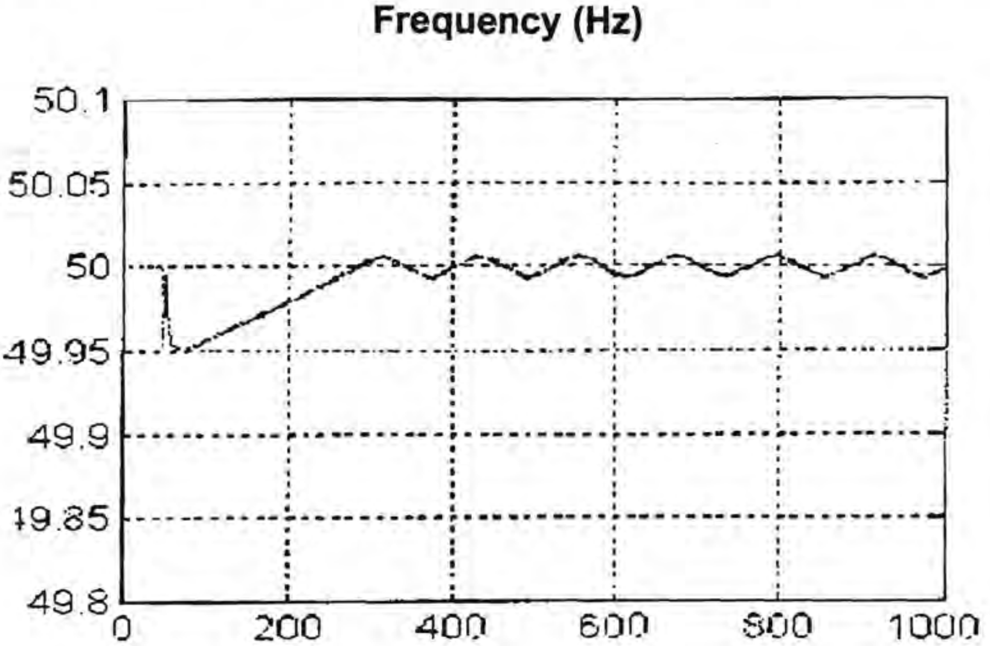


Fig D.1

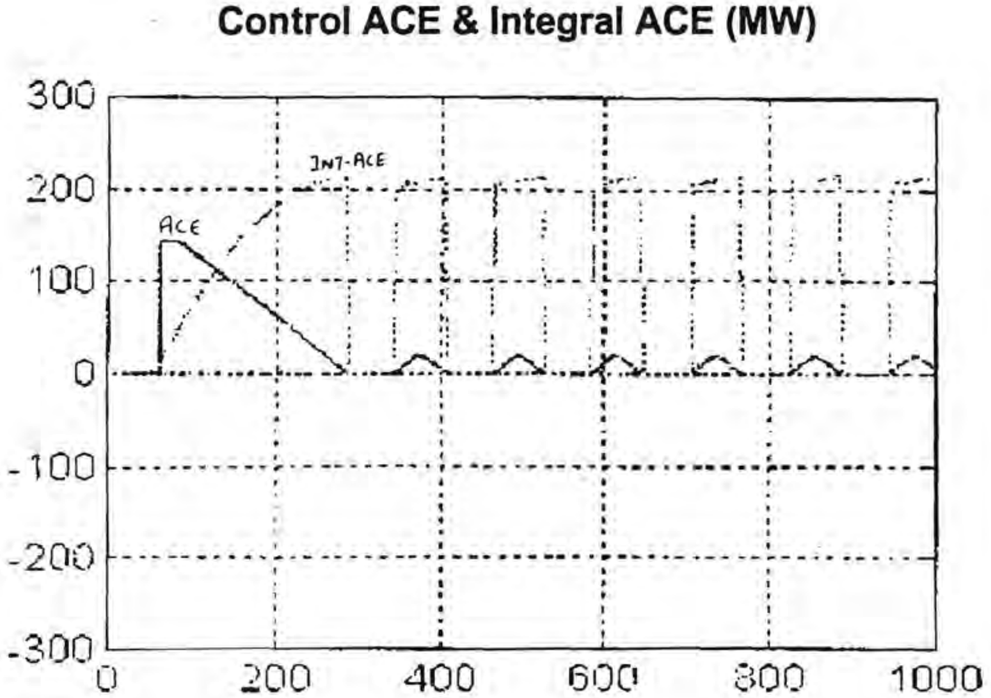
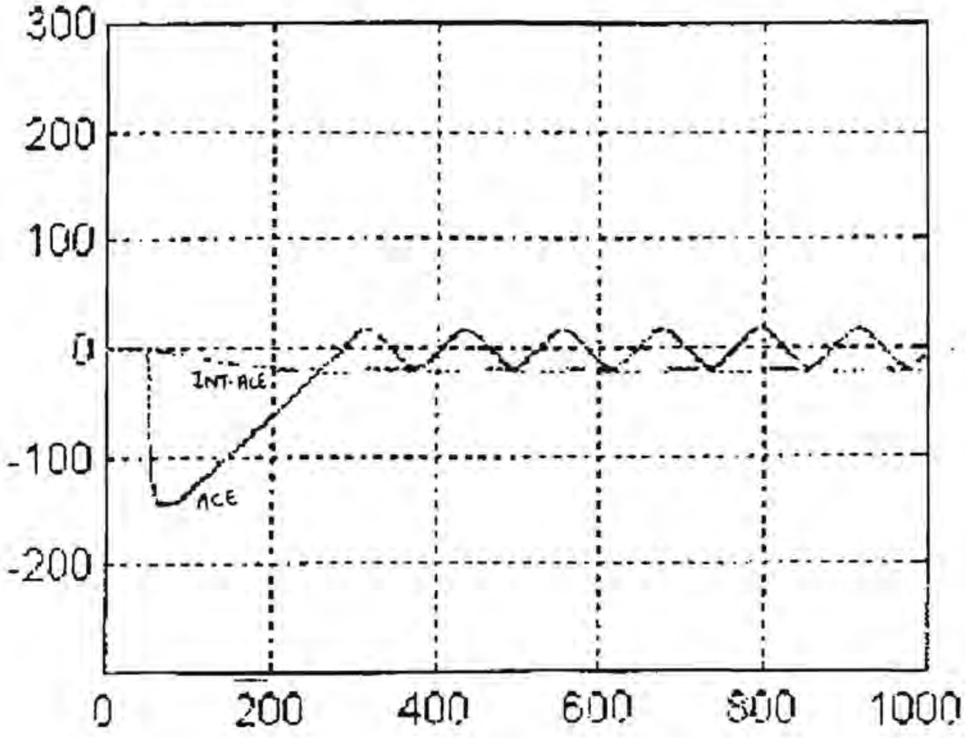
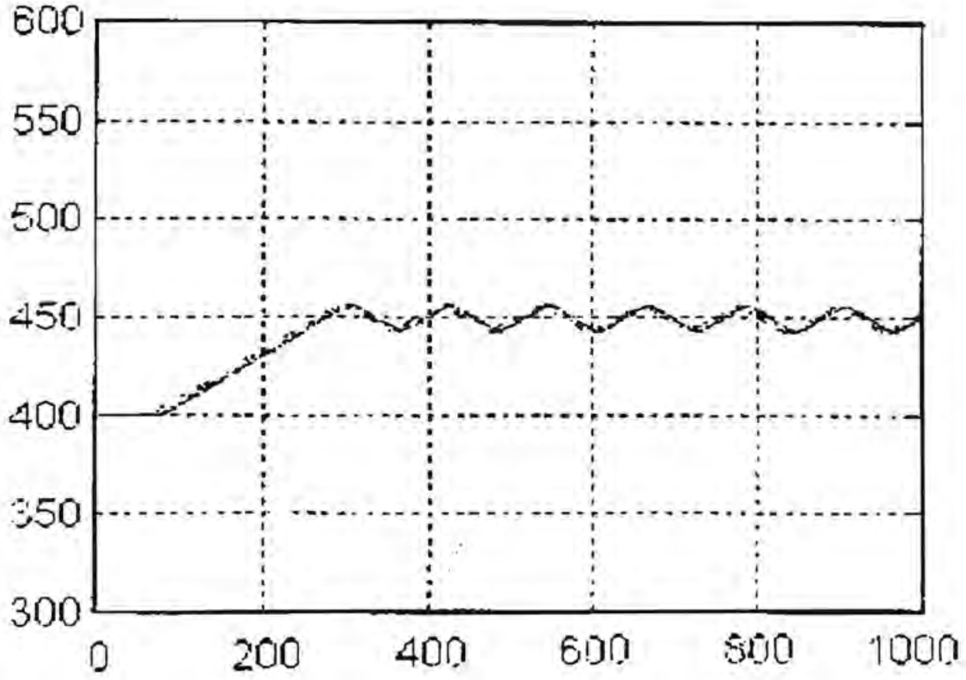


Fig D.2



Actual ACE & Integral ACE (MW)

Fig D.3



Generator Outputs (MW)

Fig D.4

Simulation 2.2: Original design with a modification that prevents the ACE from resetting

The control integral ACE in fig D.7 is much more linear, eliminating most of the resulting oscillations of the control to generators and the actual ACE. The ACE gain is 1 and the integral ACE gain of 10 is too high resulting in an overshoot

Frequency (Hz)

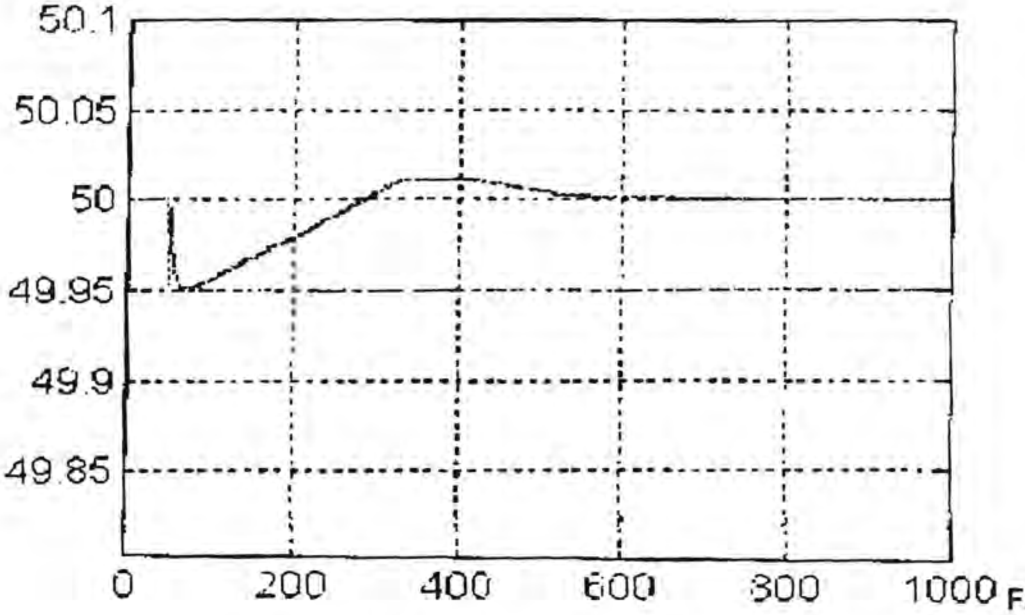


Fig D.5

Control ACE & Integral ACE (MW)

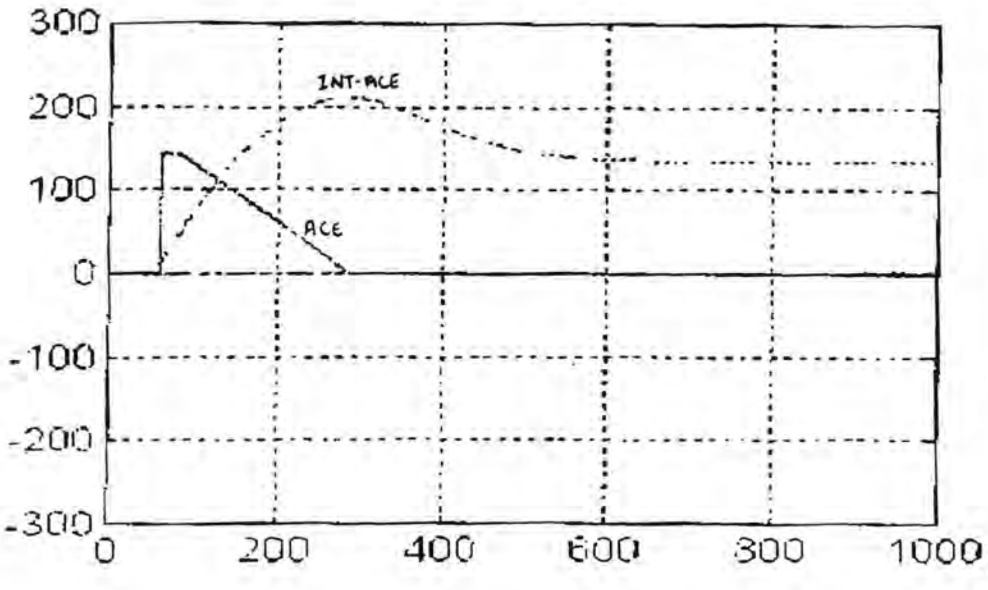


Fig D.6

Actual ACE & Integral ACE (MW)

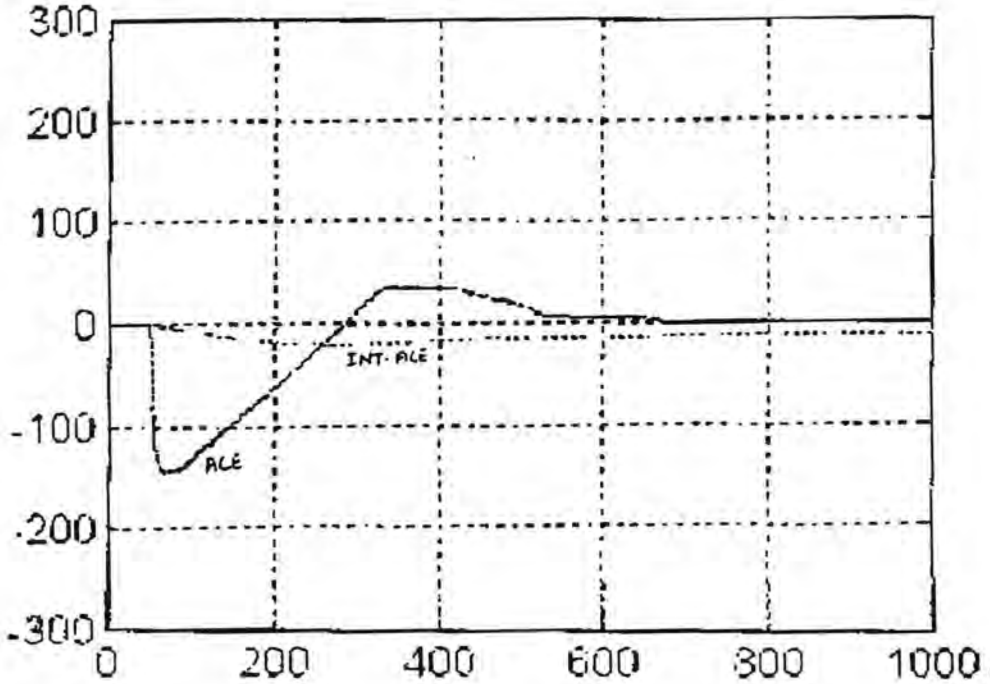


Fig D.7

Generator Outputs (MW)

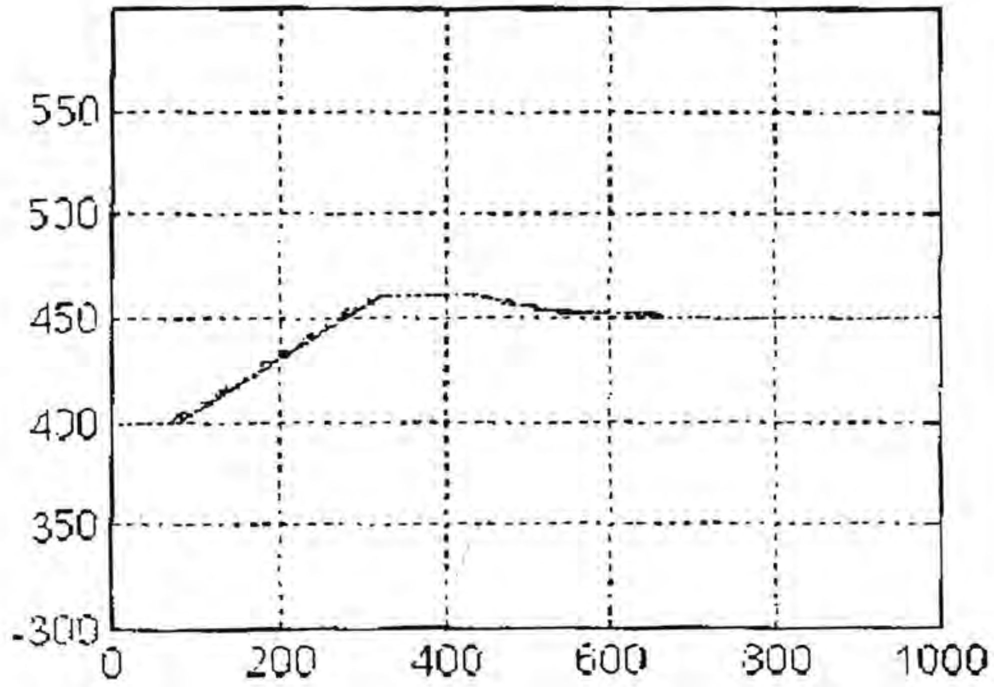


Fig D.8

Simulation 2.3: Modified design as in 2 with an ACE gain of 1 and integral ACE gain of 2

The integral ACE gain of 2 prevents the overshoot but is too slow for larger step changes.

Frequency (Hz)

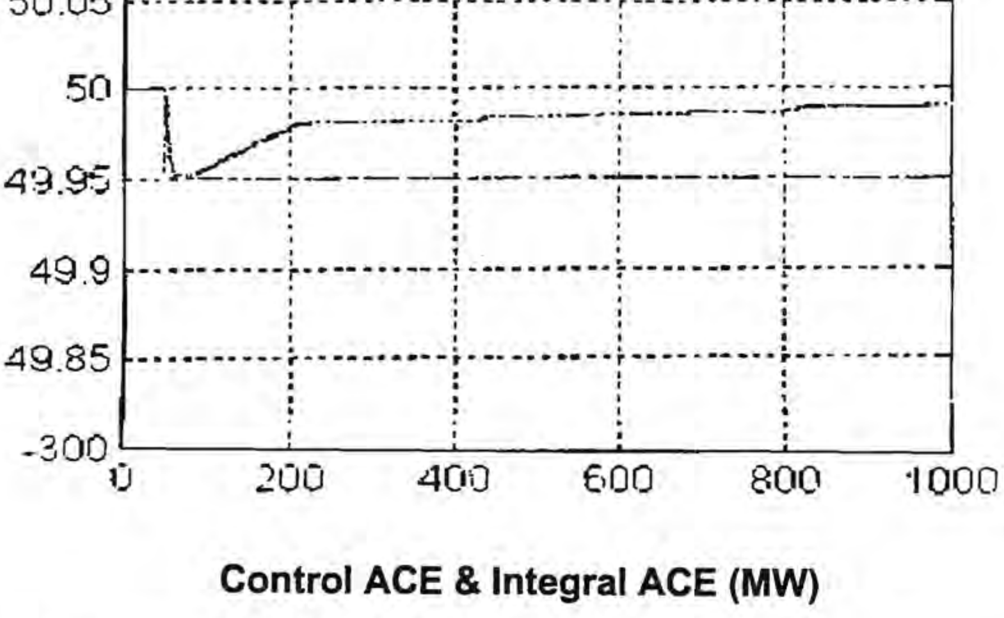


Fig D.9

Control ACE & Integral ACE (MW)

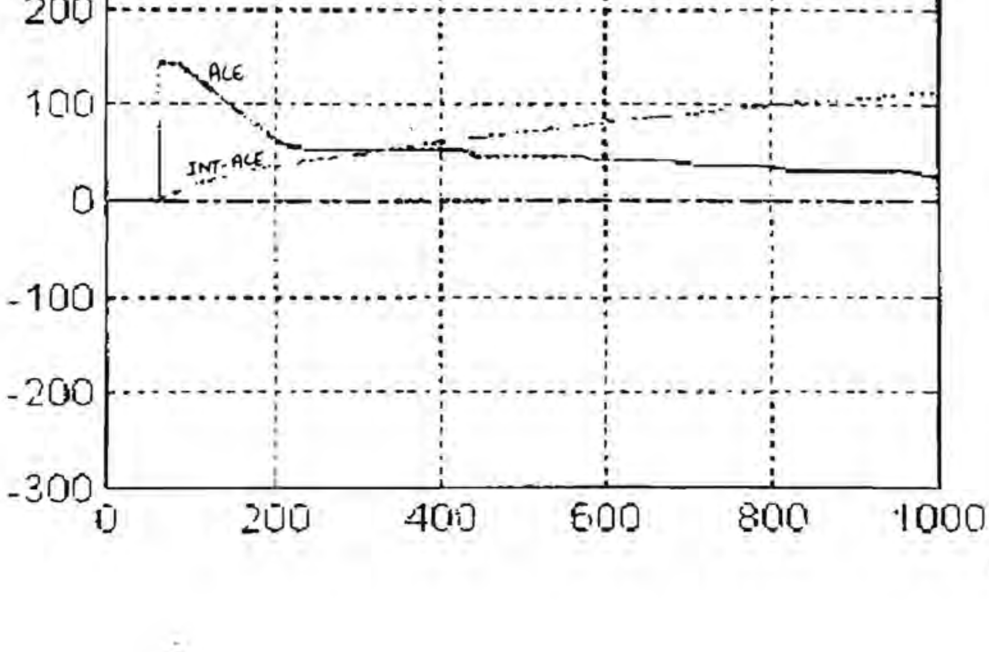


Fig D.10

Actual ACE & Integral ACE (MW)

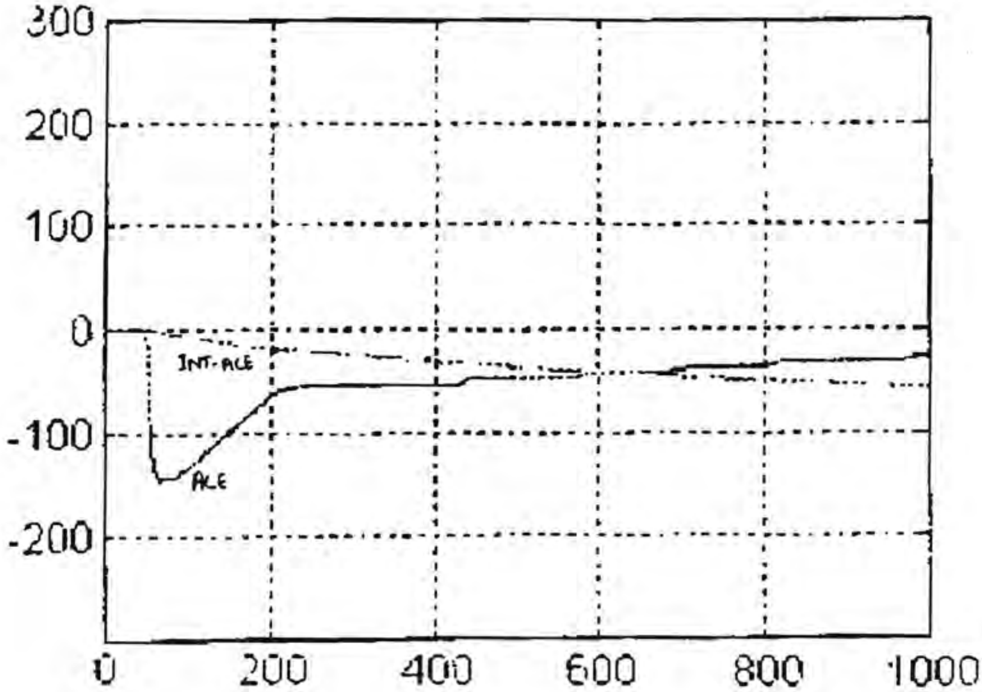


Fig D.11

Generator Outputs (MW)

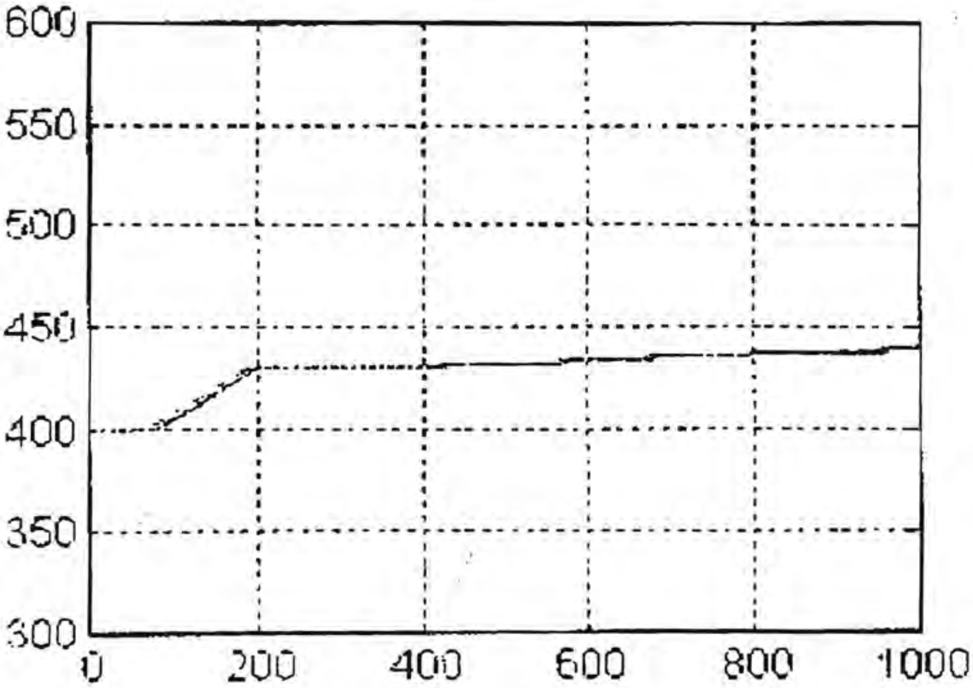
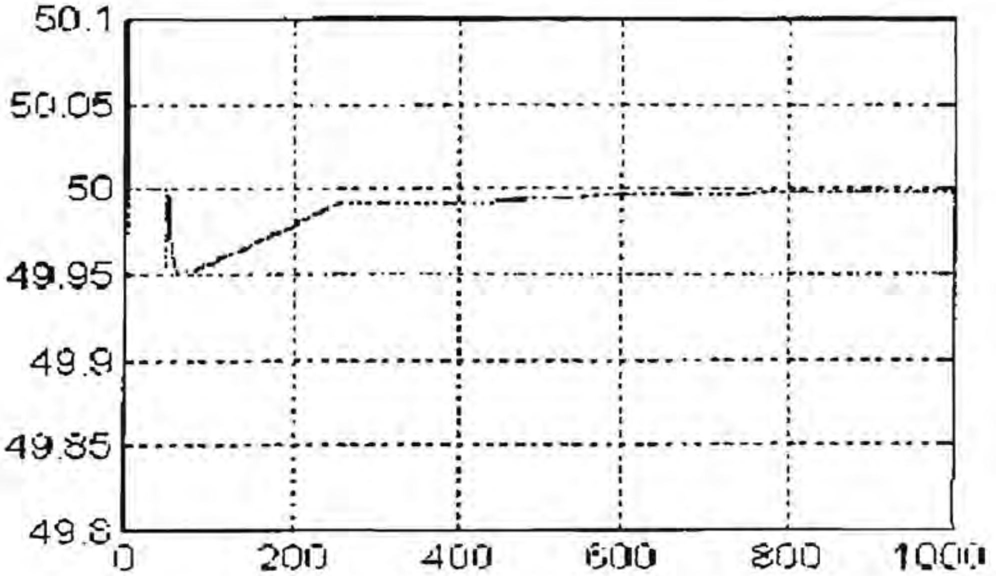


Fig D.12

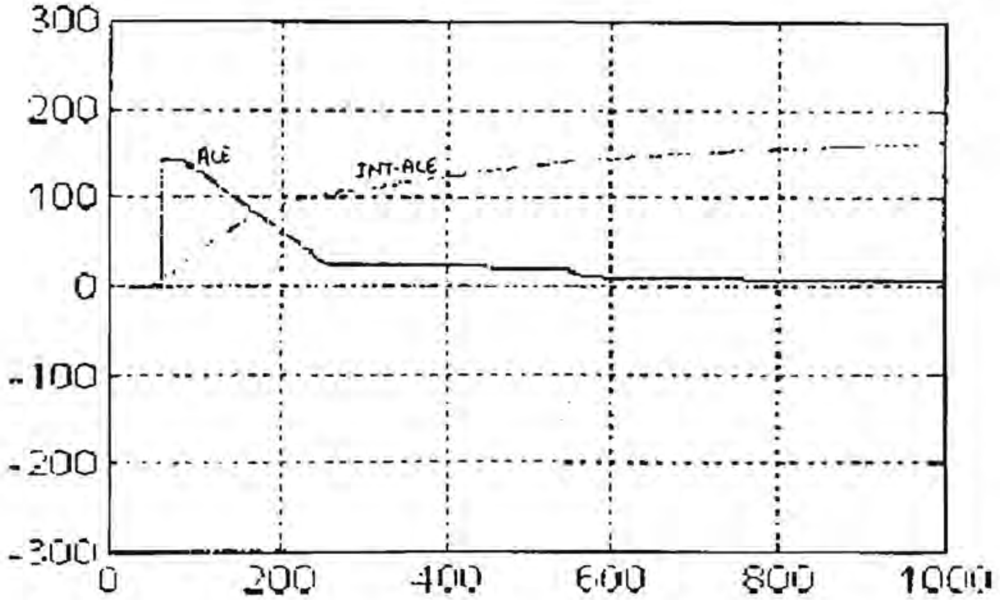
Simulation 2.4: Modified design as in 2 with an ACE gain of 1 and integral ACE gain of 5

The integral ACE gain of 5 results in no overshoot and good enough response for larger step changes.



Frequency (Hz)

Fig D.13



Control ACE & Integral ACE (MW)

Fig D.14

Actual ACE & Integral ACE (MW)

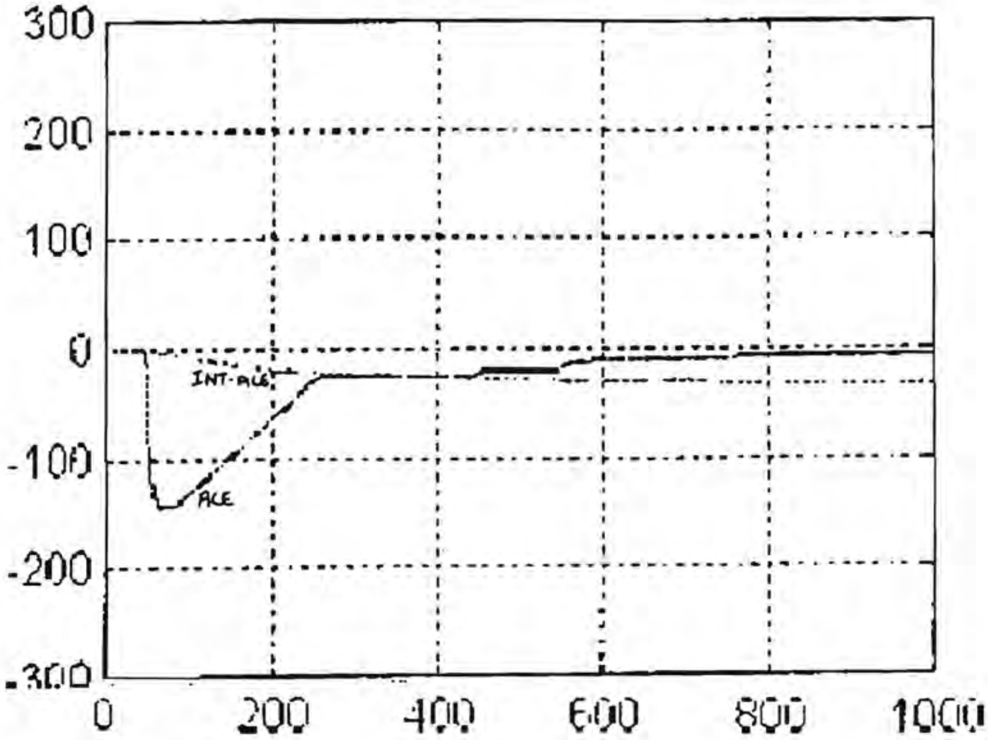


Fig D.15

Generator Outputs (MW)

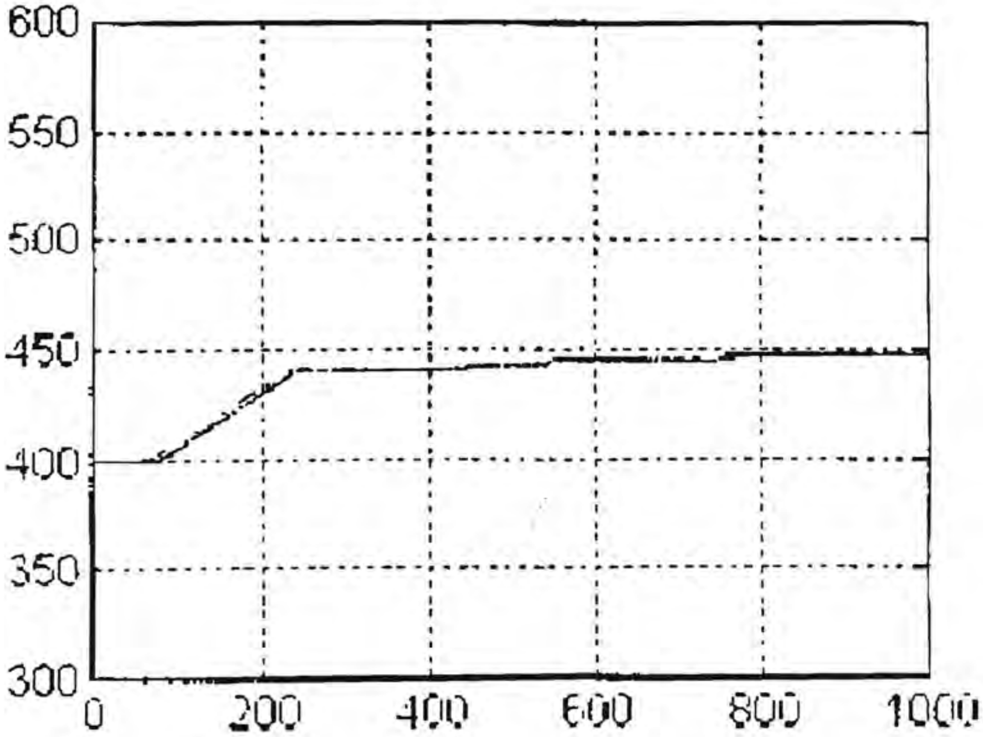


Fig D.16

Simulation 2.5: Modified design as in 4 with more generating units

The recovery is quicker but integral ACE gain is too low for many units.

Frequency (Hz)

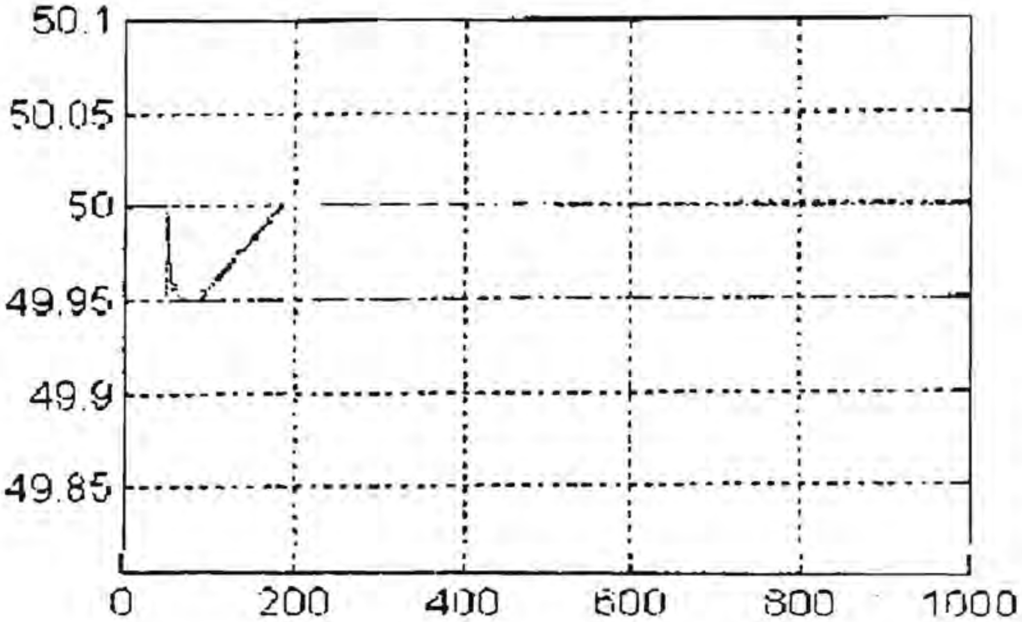


Fig D.17

Control ACE & Integral ACE (MW)

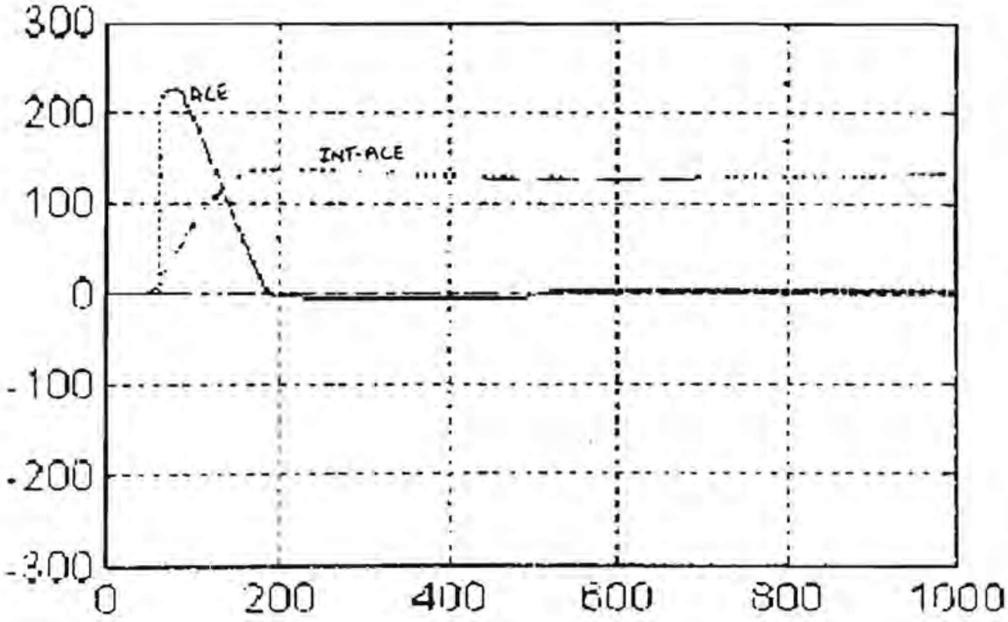


Fig D.18

Actual ACE & Integral ACE (MW)

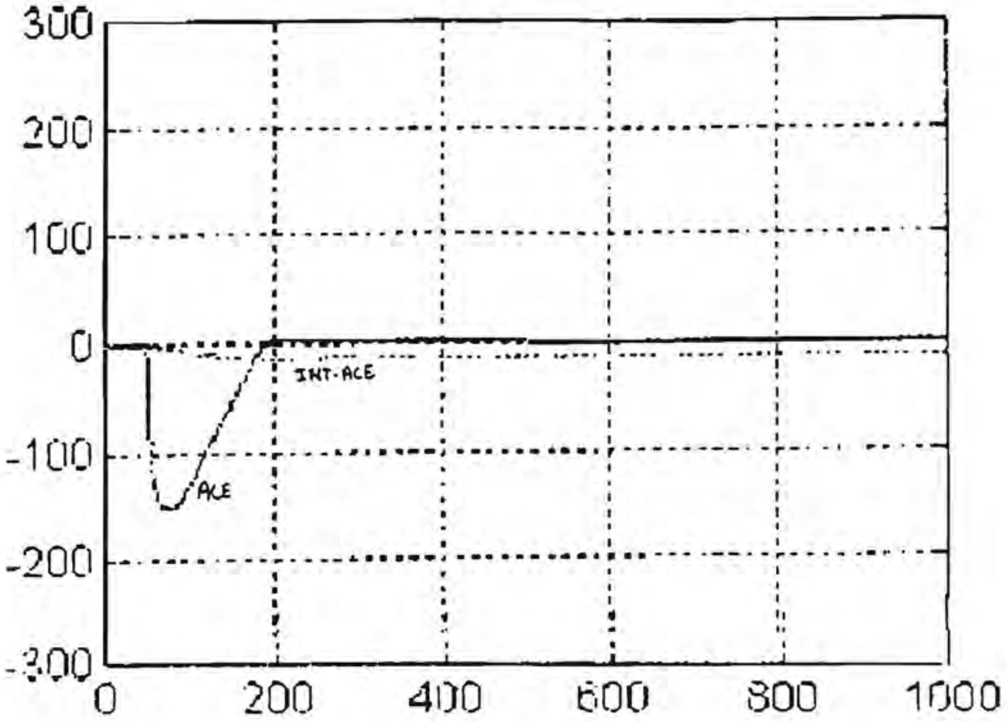


Fig D.19

Generator Outputs (MW)

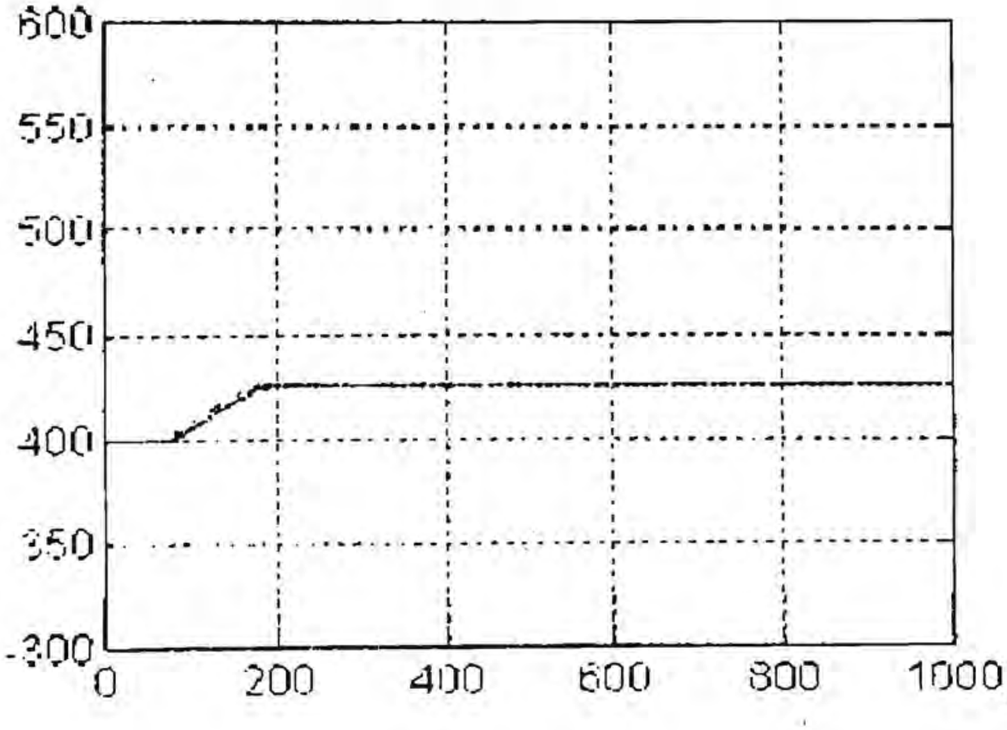


Fig D.20

D.3. Simulations of the AGC system with a typical input signal, on the original design with the minor design modifications and different configurations

These simulations were done by evaluating the response of the controller with a typical input signal which is obtained by taking a sample of the uncontrolled system frequency. A ramp function of 0.1 Hz at 900 MW/min is induced on to this signal.

During the first simulations only the configuration was adjusted in an effort to improve the system. The design modification were then implemented which resulted in fairly good response while reducing the control significantly.

Simulation 3.1: Original design without any modification and with the original configuration

The ACE gain is 4 ,20 ,32 for the different control regions with a dead-band of 30 MW respectively and the integral ACE gain is 2 with a dead-band of 10 MW. Although the frequency control is reasonable the control issued of about 300 MW / unit is unacceptable high. Also note the oscillation in the generator outputs.

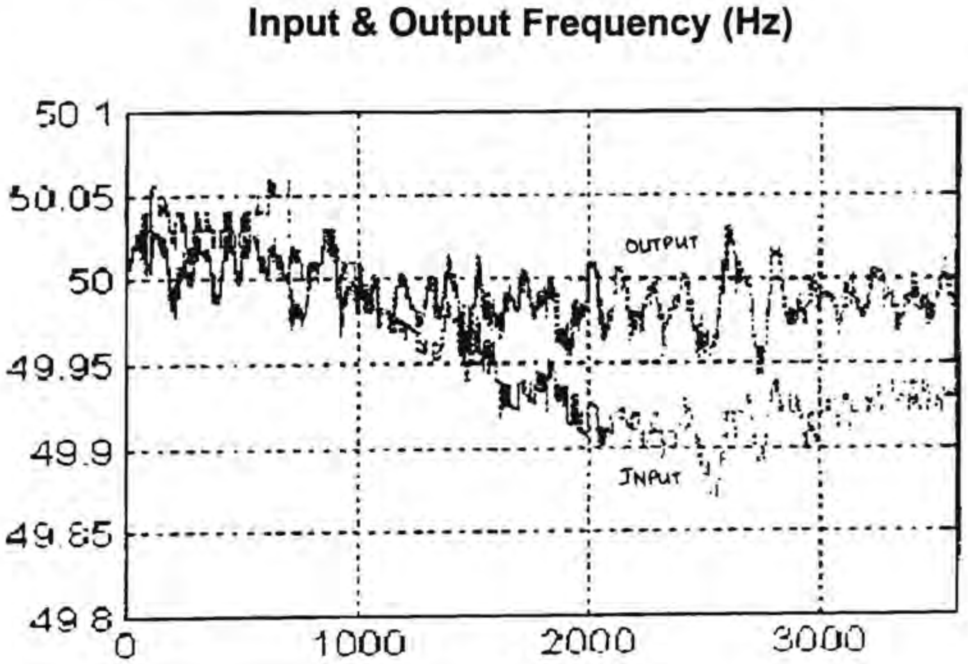

Input & Output Frequency (Hz)

Fig D.21

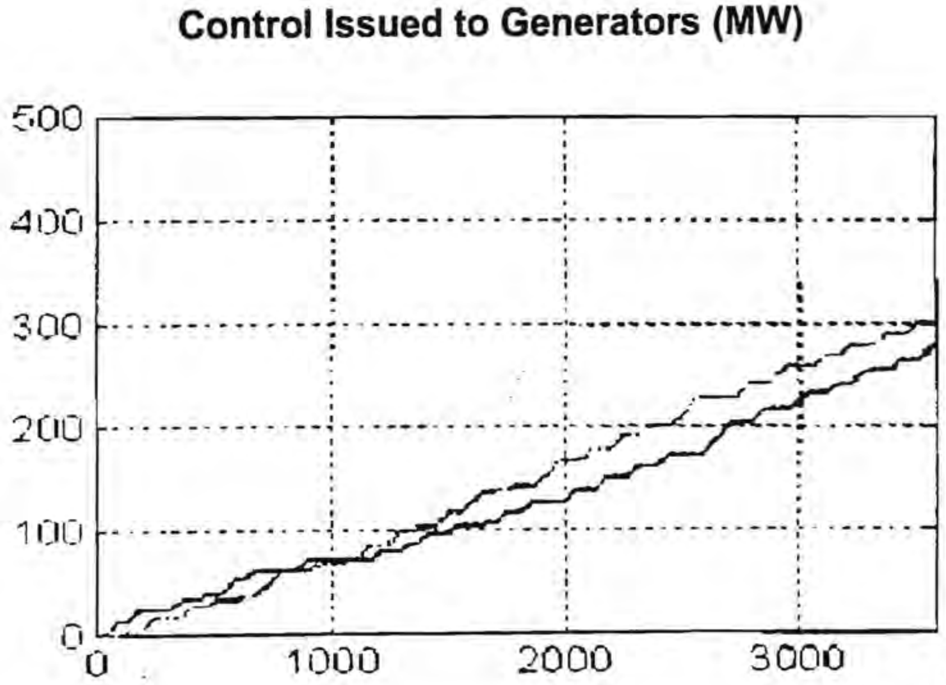
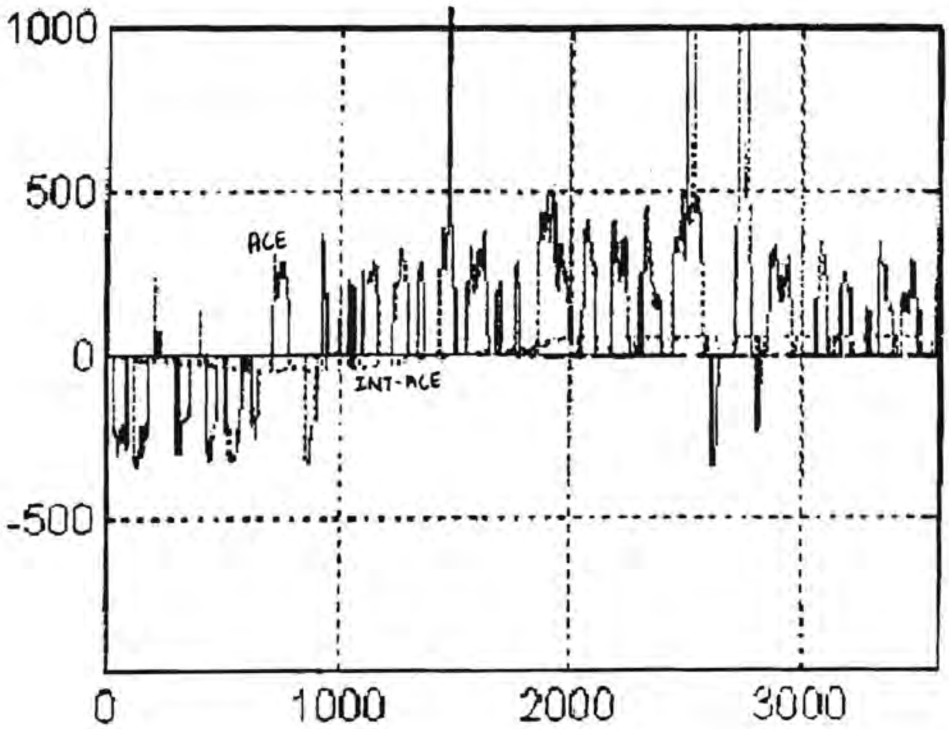
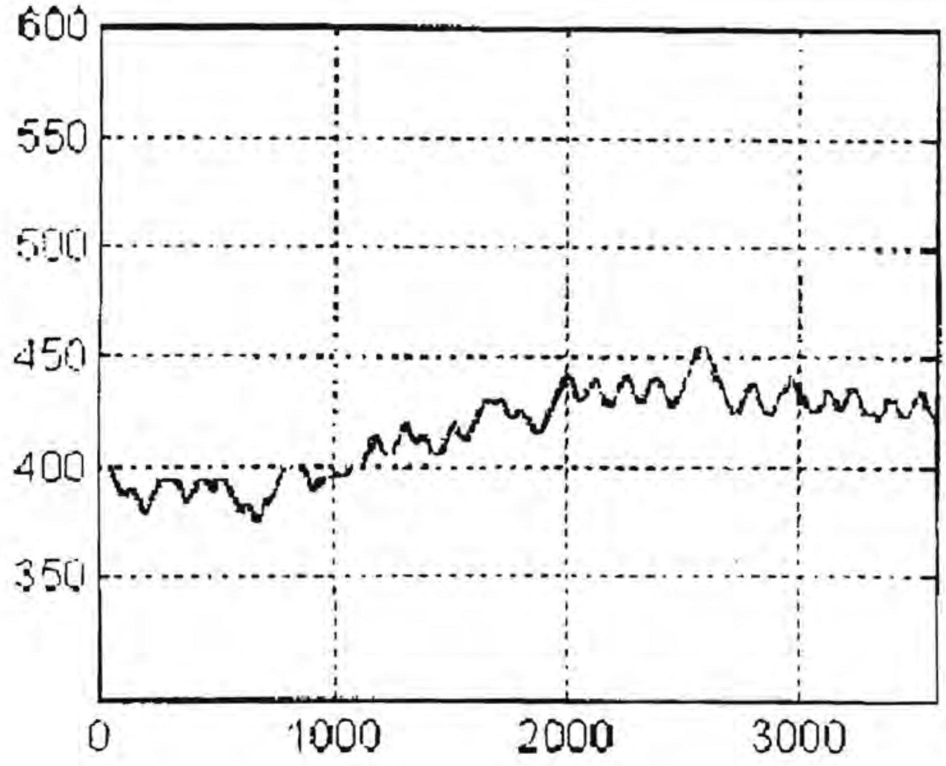

Control Issued to Generators (MW)

Fig D.22



Control ACE & Integral ACE (MW)

Fig D.23



Generator Outputs (MW)

Fig D.24

Simulation 3.2: Original design without modifications but with a different configuration

The amount of control reduces slightly but the control is worse with the frequency remaining belo 50 Hz for 10 minutes. ACE gains are 1 ,2 ,32 respectively with a 60 MW dead-band and th integral ACE gain is 5 with a dead-band of 10 MW.

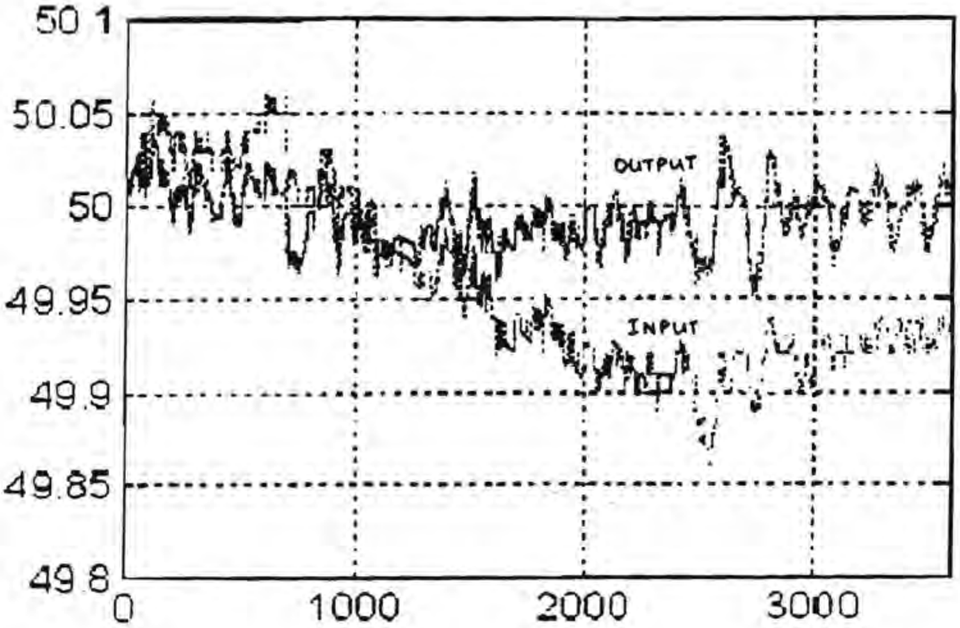

Input & Output Frequency (Hz)

Fig D.25

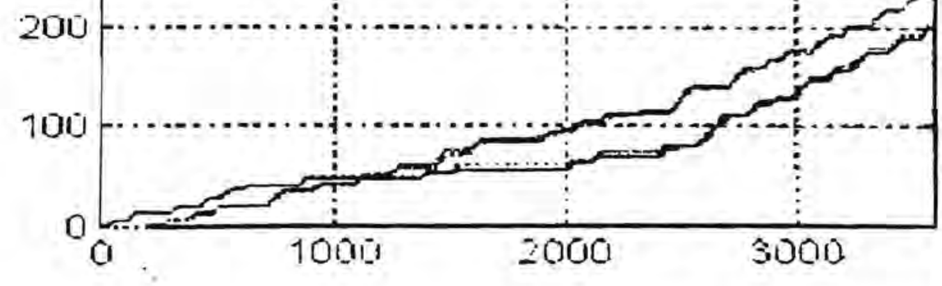

Control Issued to Generators (MW)

Fig D.26

Control ACE & Integral ACE (MW)

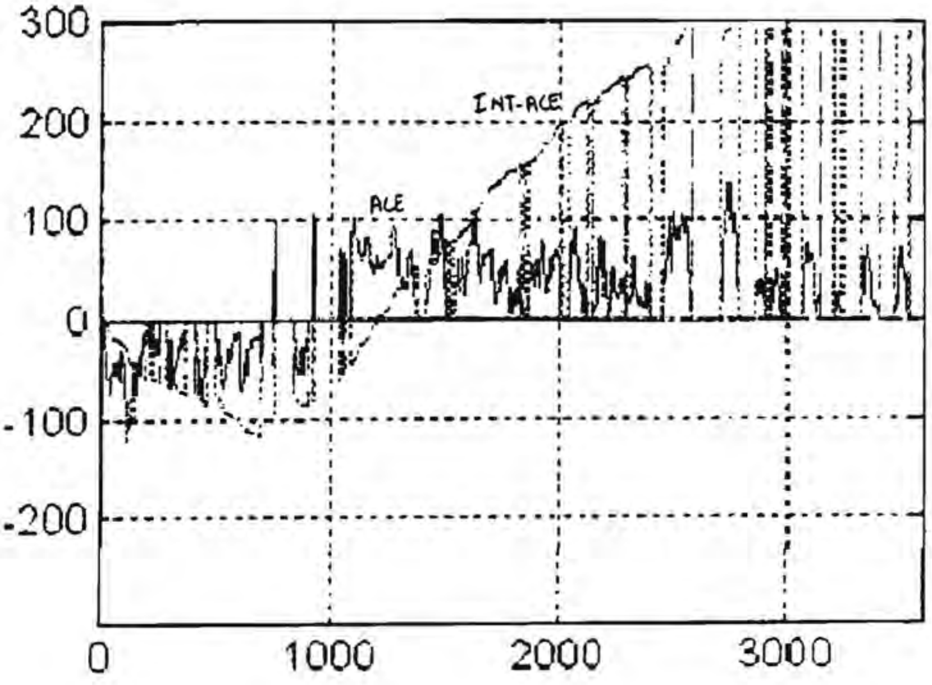


Fig D.27

Generator Outputs (MW)

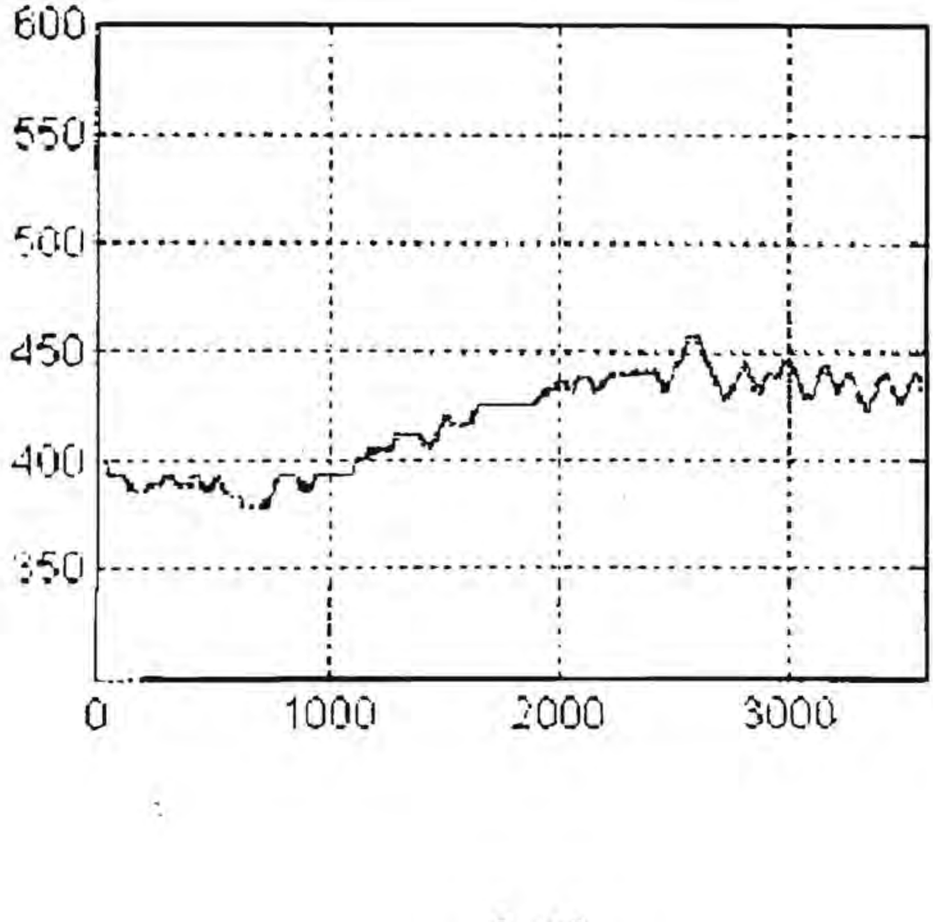


Fig D.28

Simulation 3.3: Original design with minor modifications as in D2.2 and with a differe configuration

The amount of control reduces significantly but the control is worse with the frequency remaini below 50 Hz for 15 minutes. ACE gains are 1 ,2 ,32 respectively with a 60 MW dead-band and t integral ACE gain is 5 with a dead-band of 10 MW.

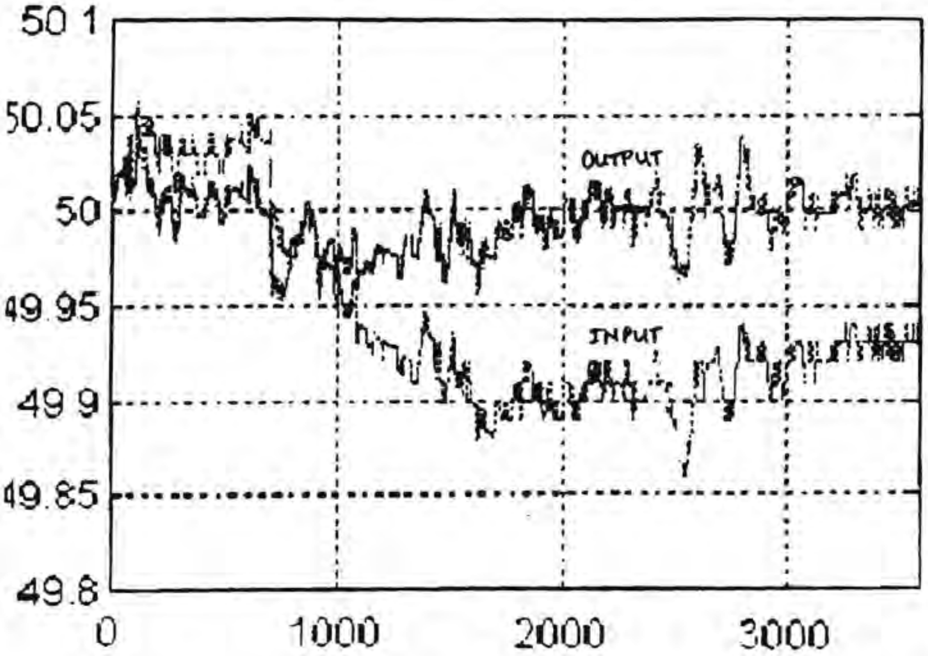

Input & Output Frequency (Hz)

Fig D.29

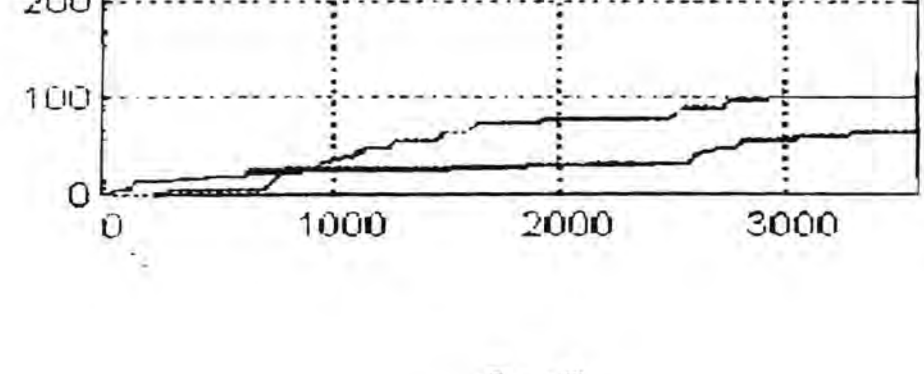

Control Issued to Generators (MW)

Fig D.30

Control ACE & Integral ACE (MW)

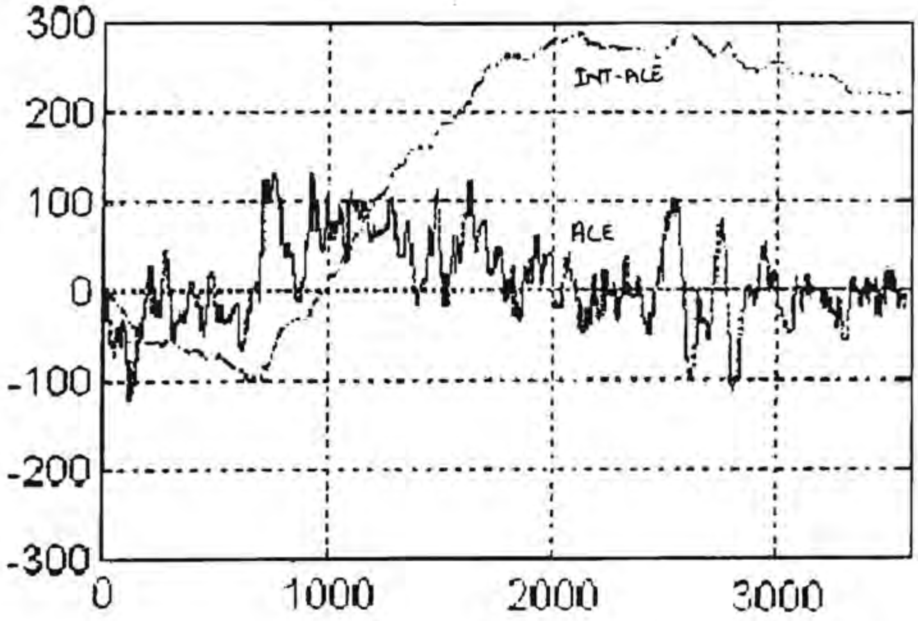


Fig D.31

Generator Outputs (MW)

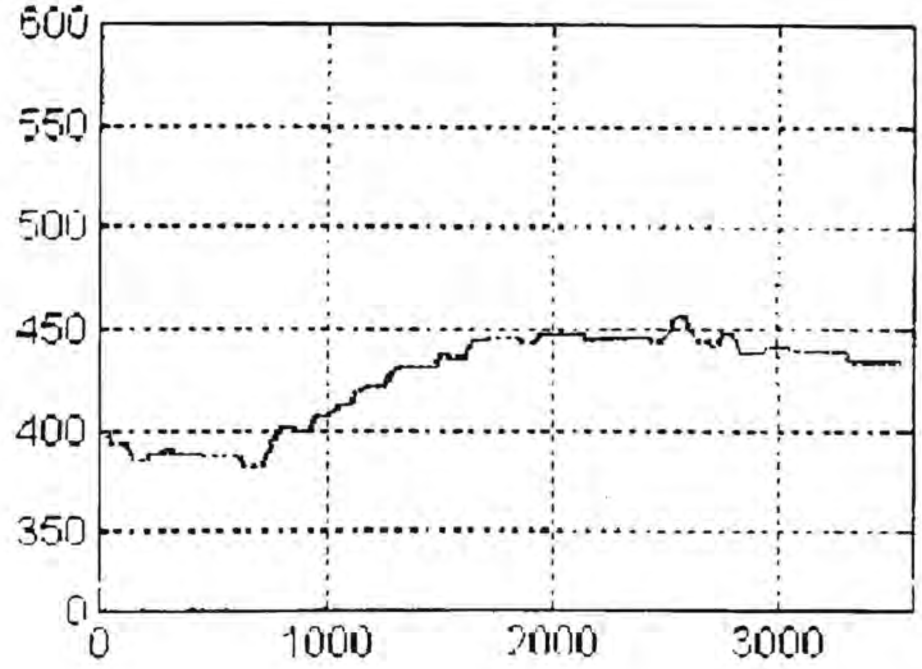


Fig D.32

Simulation 3.4: Original design without modifications with the economic dispatch also modelled running at 180s intervals

The amount of control reduces slightly from the first simulation and the control improves. ACE gains are 1 ,2 ,32 respectively with a 60 MW dead-band and the integral ACE gain is 5 with a dead-band of 30 MW.

Input & Output Frequency (Hz)

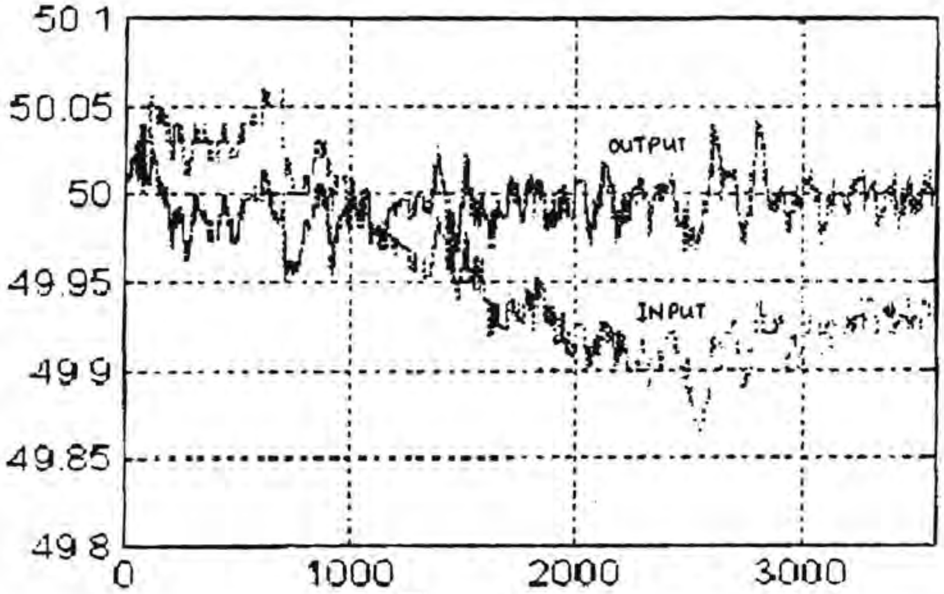


Fig D.33

Control Issued to Generators (MW)

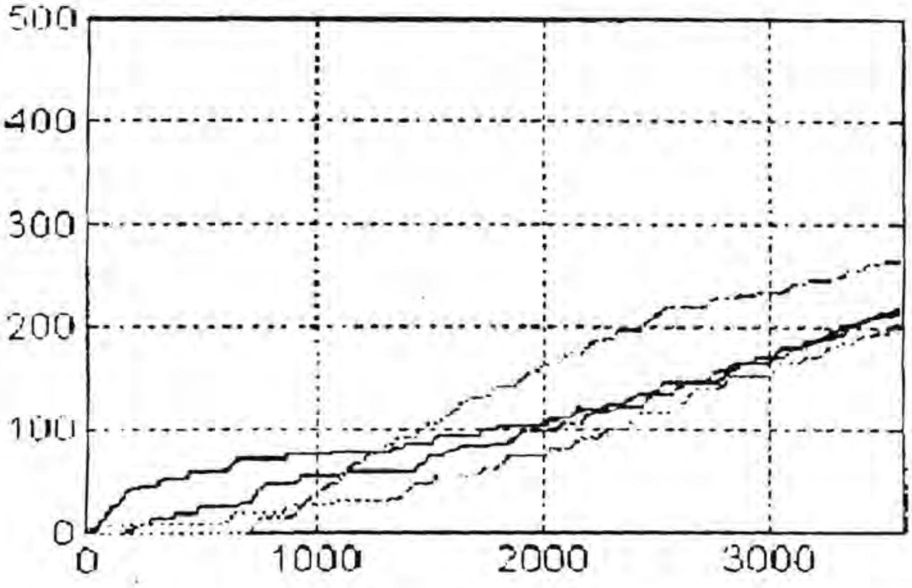


Fig D.34

Control ACE & Integral ACE (MW)

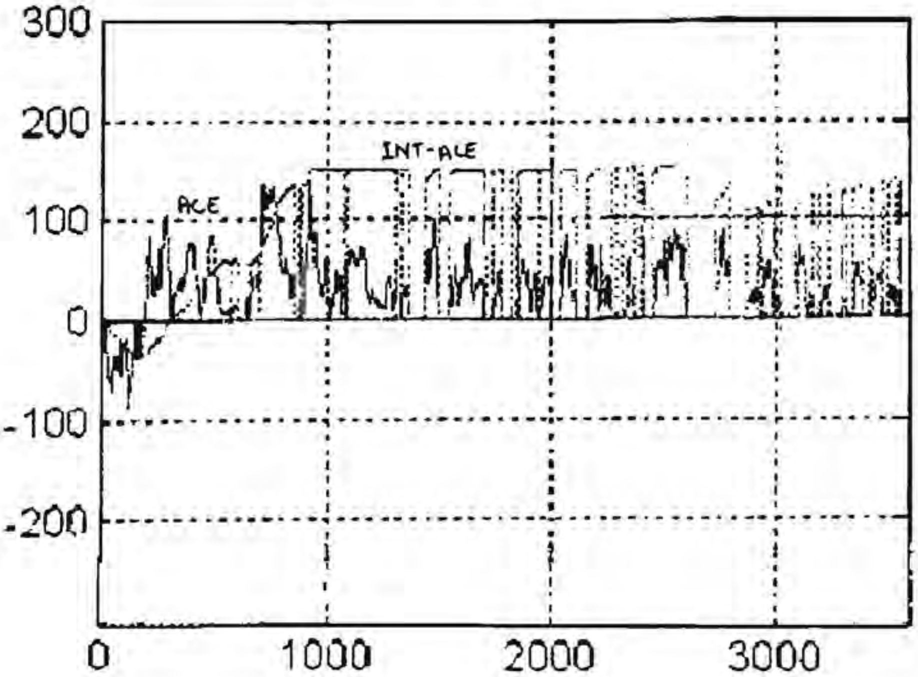


Fig D.35

Generator Outputs (MW)

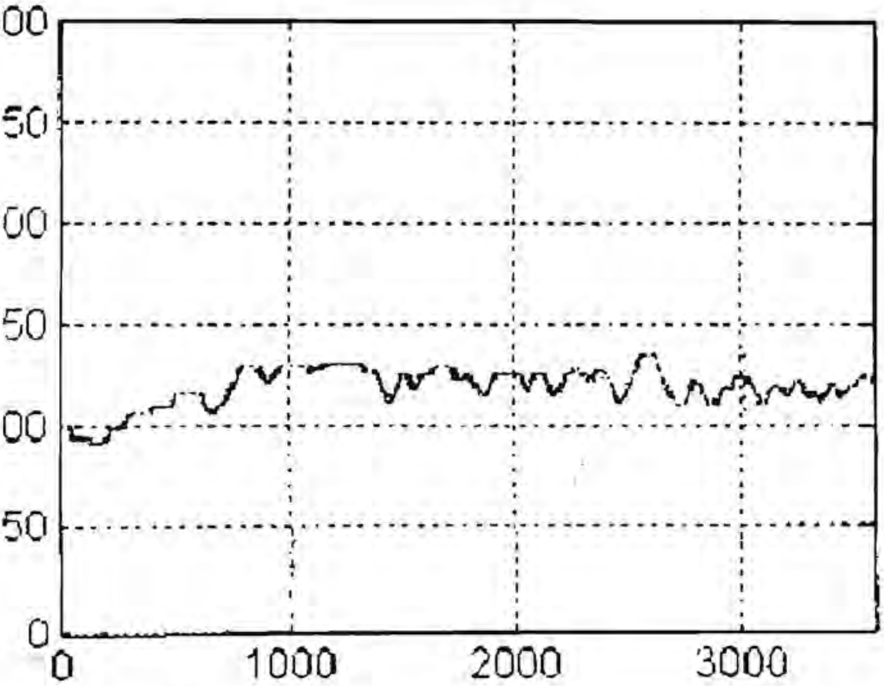


Fig D.36

Simulation 3.5: Original design with minor modifications with the economic dispatch also modelled running at 180s intervals

The amount of control reduces significantly and the control improves. ACE gains are 1 ,2 ,32 respectively with a 60 MW dead-band and the integral ACE gain is 5 with a dead-band of 30 MW. This is the best performance obtainable with the improved original design.

Input & Output Frequency (Hz)

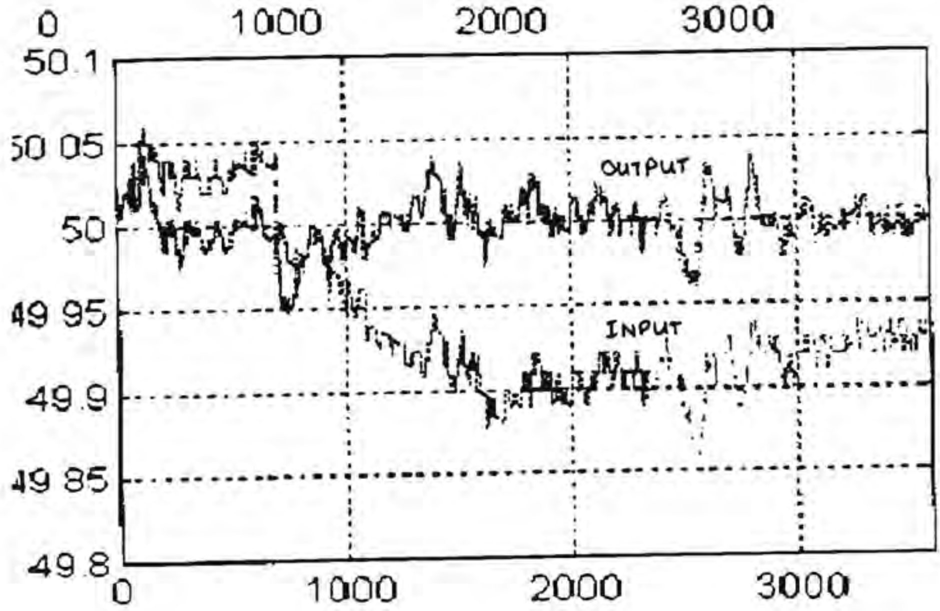


Fig D.37

Control Issued to Generators (MW)

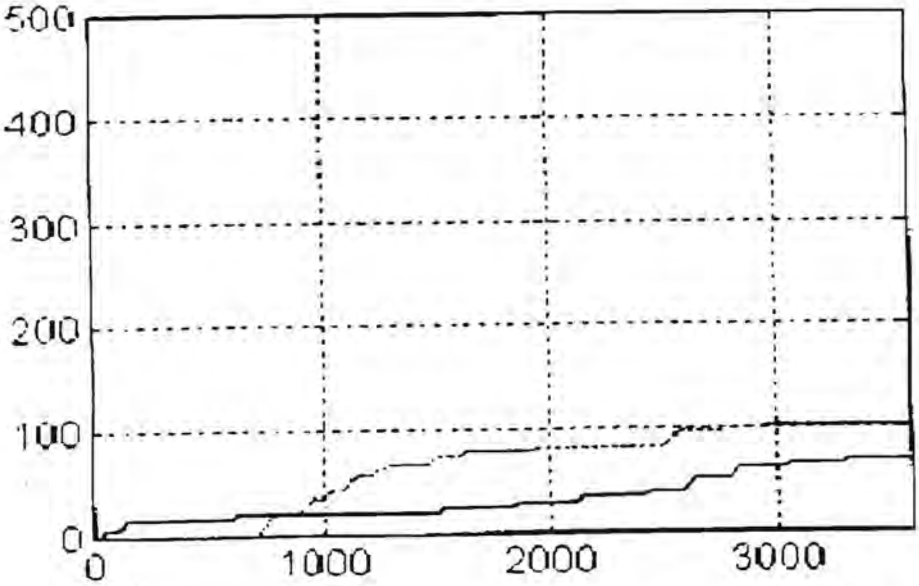


Fig D.38

Actual ACE & Integral ACE (MW)

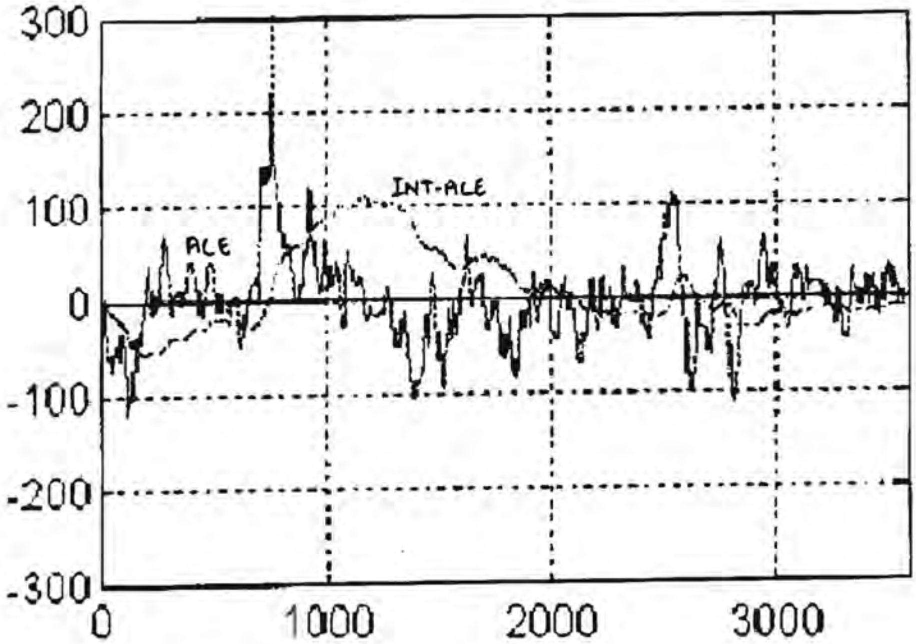


Fig D.39

Generator Outputs (MW)

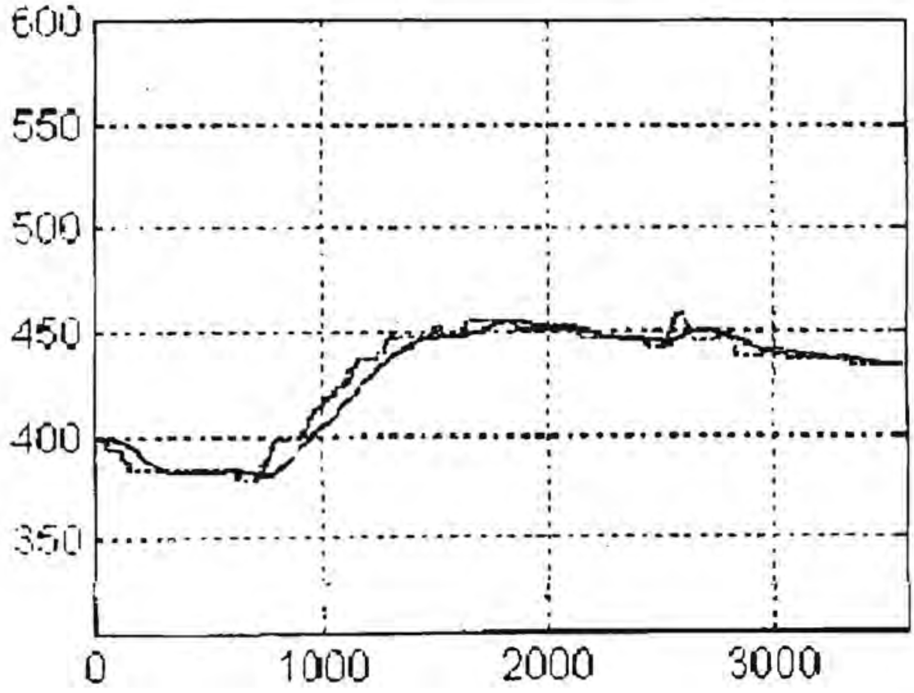


Fig D.40

D.4. Simulations of the AGC system with a typical input signal, with the fuzzy logic design modifications and other minor design modifications and different configurations

These simulations were done by evaluating the response of the fuzzy logic controller with a typical input signal which is obtained by taking a sample of the uncontrolled system frequency Step functions of 0.15 Hz and 0.20 Hz and ramp functions of 0.15 Hz at 750 MW/min are induced on to this signal.

The time constant of the derivative ACE was lowered after the second simulation which resulted in quicker reaction time to large deviations This design was then tested in different scenarios before implementation on the real system.

Simulation 4.1: Fuzzy logic design with step function of 0.15 Hz induced on the input signal

The control is very good and with no overshoot. Note the peaky but fairly linear control ACE resulting from the derivative action. The amount of control issued is low without overshoot in the generator outputs.

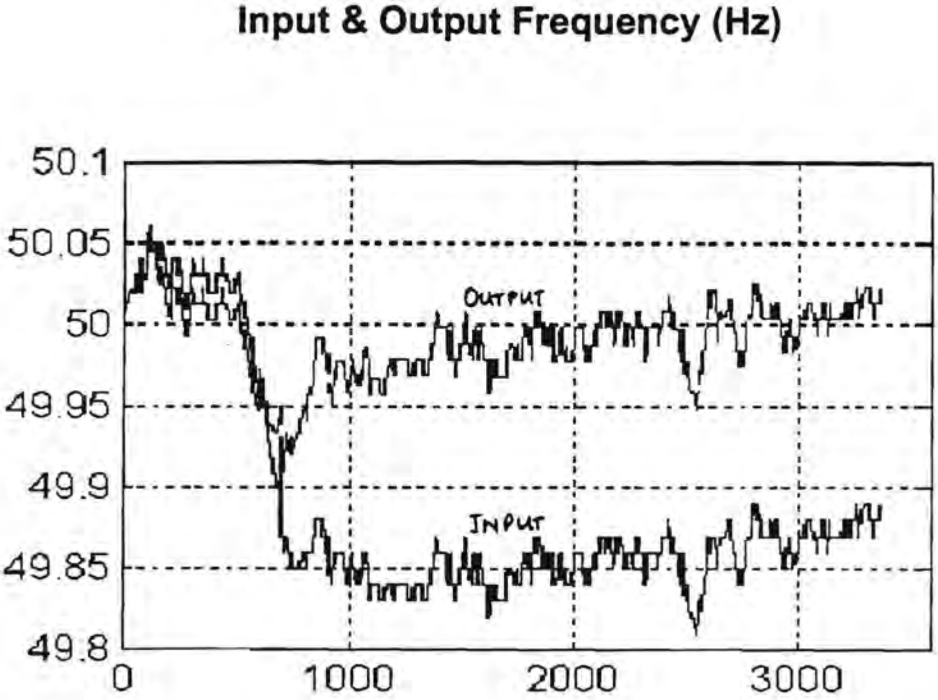


Fig D.41

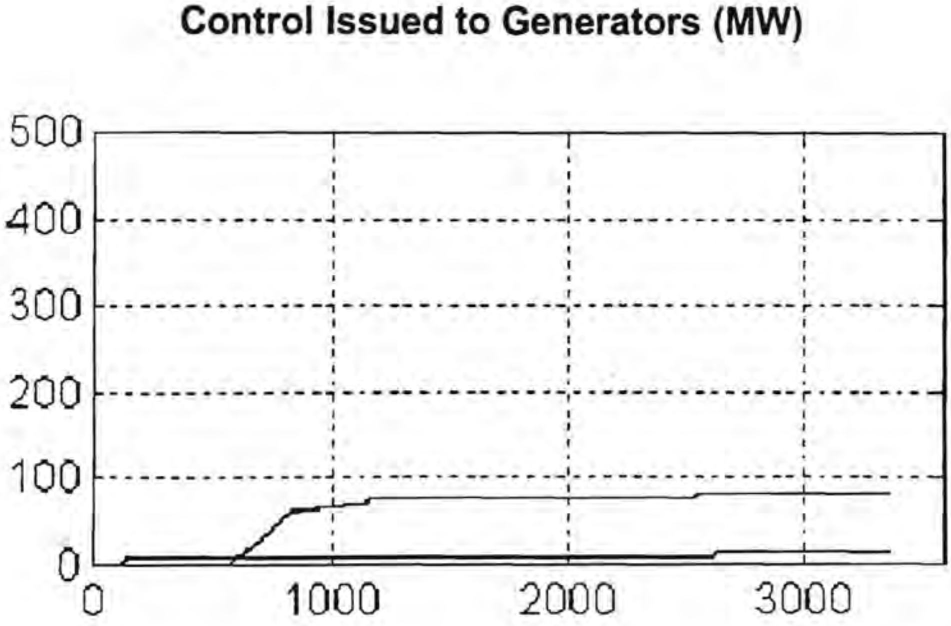


Fig D.42

Control ACE & Integral ACE (MW)

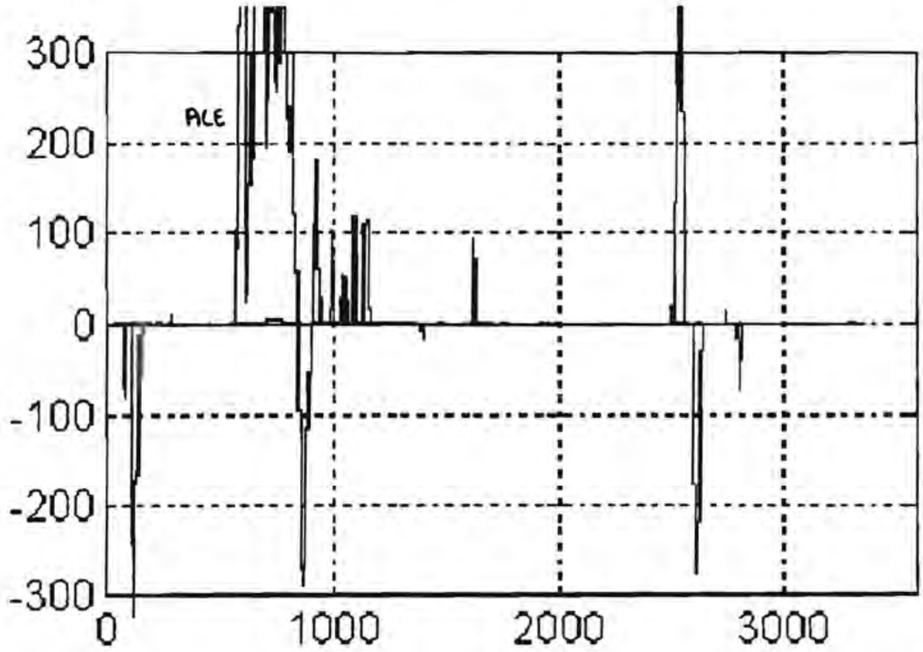


Fig D.43

Generator Outputs (MW)

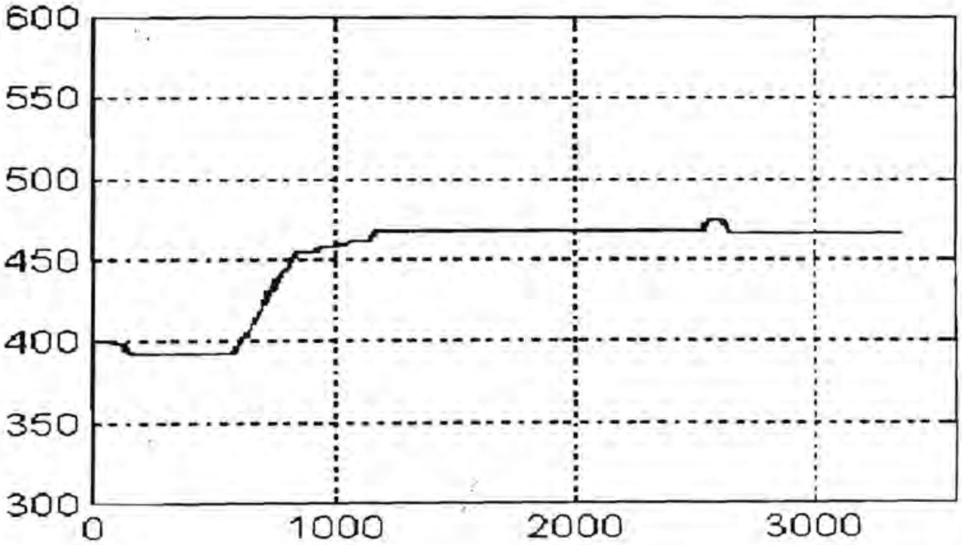


Fig D.44

Simulation 4.2: Fuzzy logic design with step function of 0.15 Hz induced on the input signal and slightly improved configuration

The control is similar to the previous simulation while the amount of control issued is slightly lower.

Input & Output Frequency (Hz)

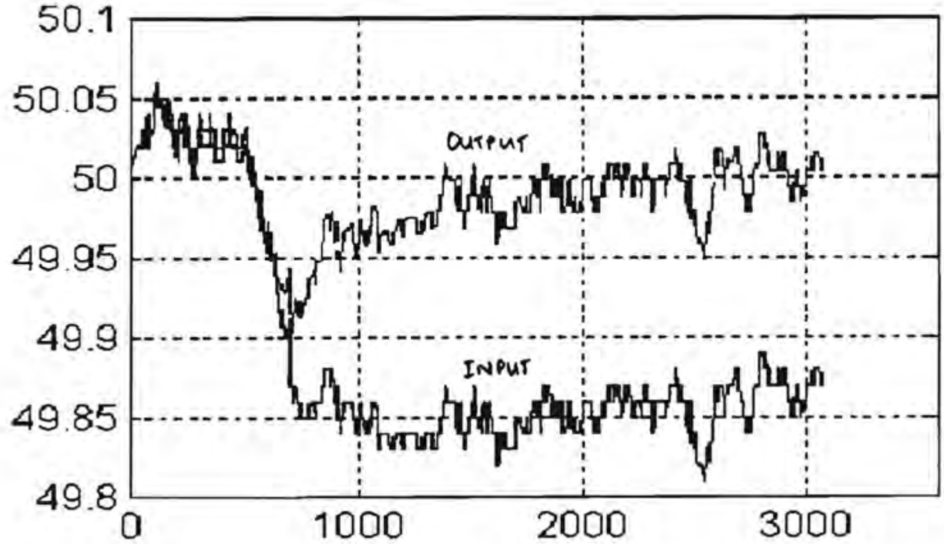


Fig D.45

Control Issued to Generators (MW)

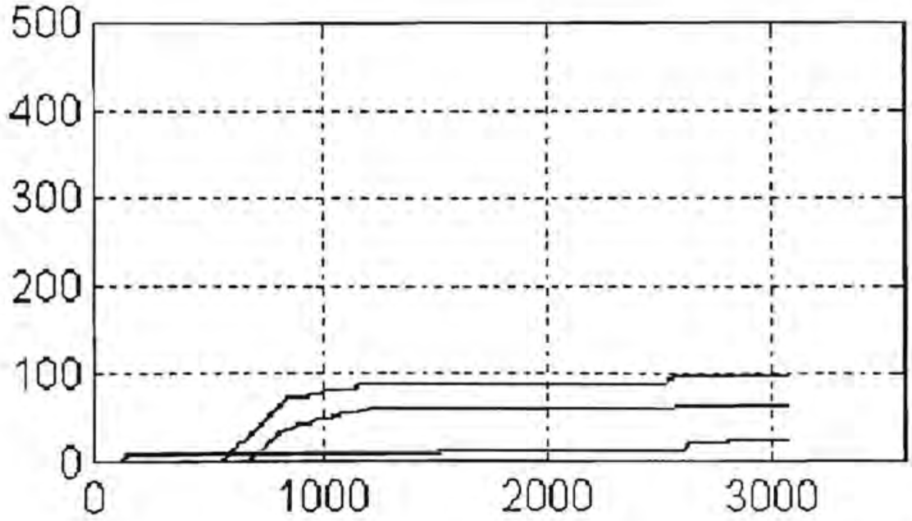
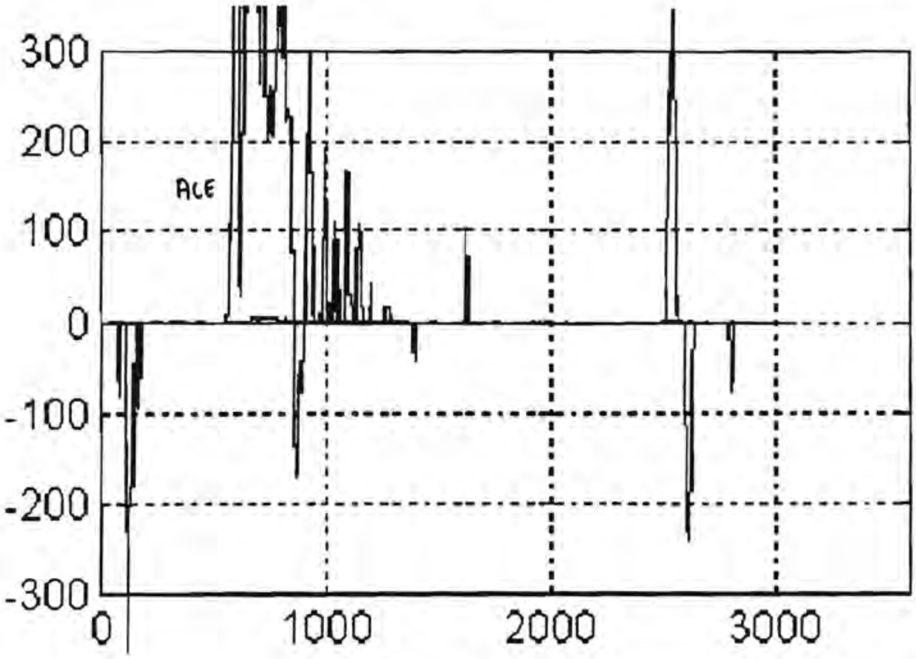
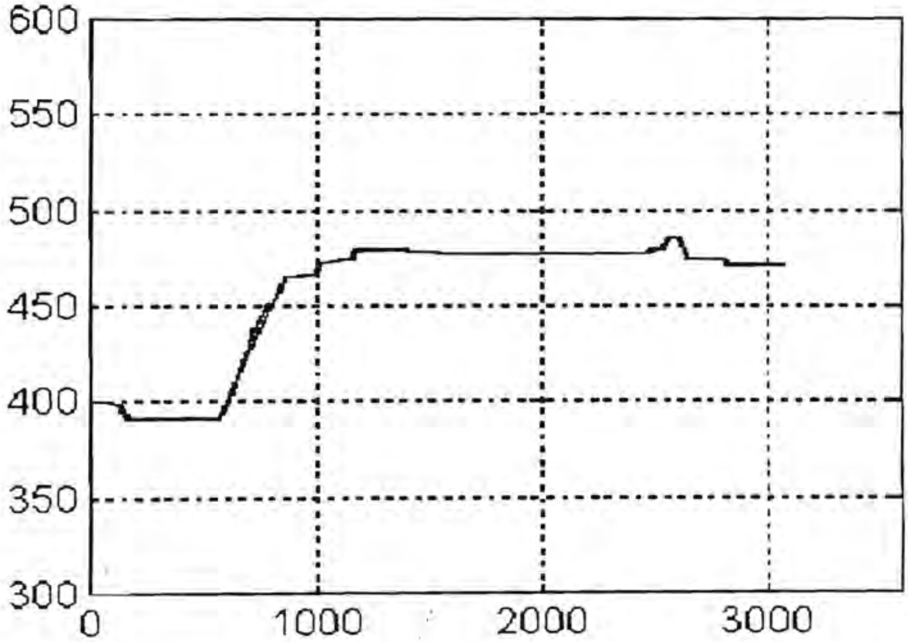


Fig D.46



Actual ACE & Integral ACE (MW)

Fig D.47



Generator Outputs (MW)

Fig D.48

Simulation 4.4: Fuzzy logic design with step function of 0.20 Hz and a ramp fuction in the opposite direction 200s later, induced on the input signal

This test was performed to determine whether overshoot will occur when a pumped storage quick start generator is put on-line after a frequency incident. The ramp function is induced at the worst possible time, but the controller was able to minimise the overshoot very well.

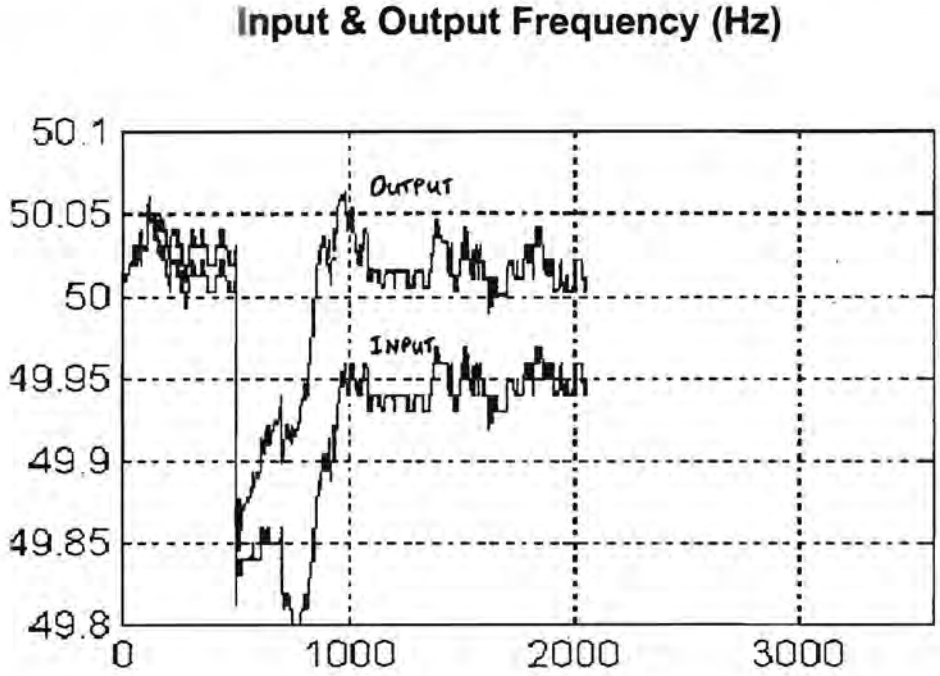

Input & Output Frequency (Hz)

Fig D.53

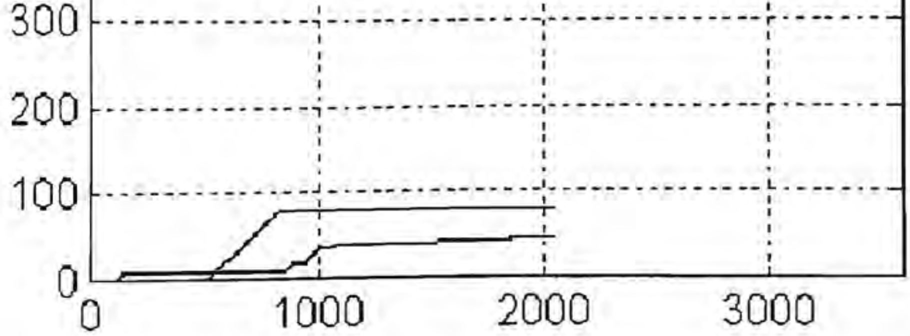
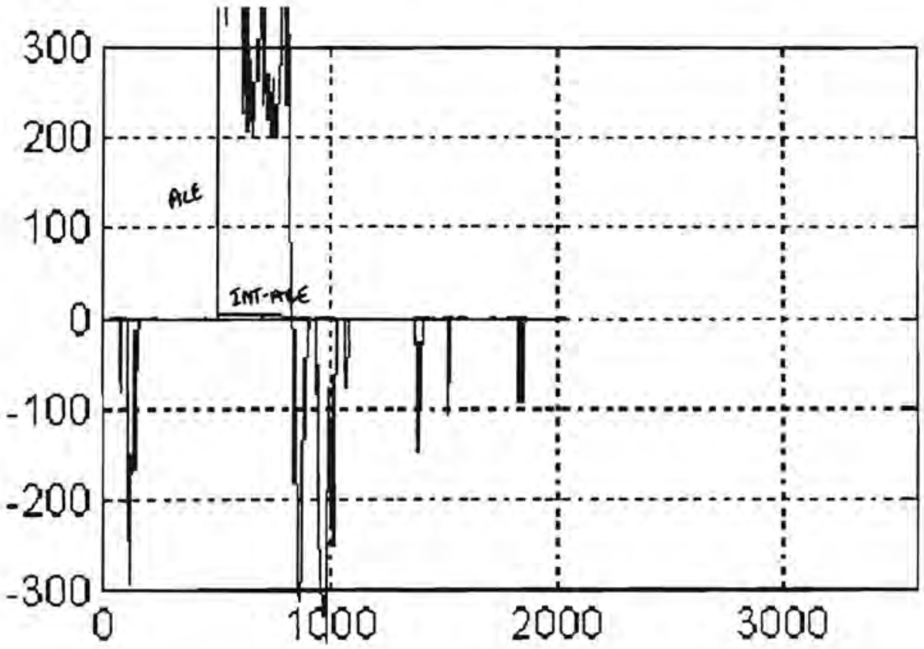
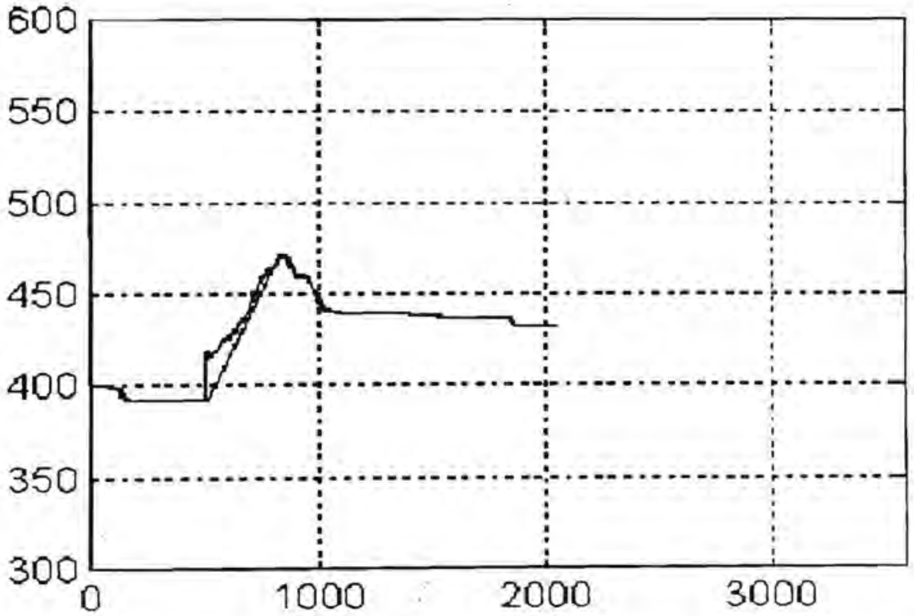

Control Issued to Generators (MW)

Fig D.54



Actual ACE & Integral ACE (MW)

Fig D.55



Generator Outputs (MW)

Fig D.56

Simulation 4.3: Fuzzy logic design with step function of 0.15 Hz induced on the input signal and quicker derivative ACE action

The control is similar to the previous simulation while the amount of control issued improves slightly more.

Input & Output Frequency (Hz)

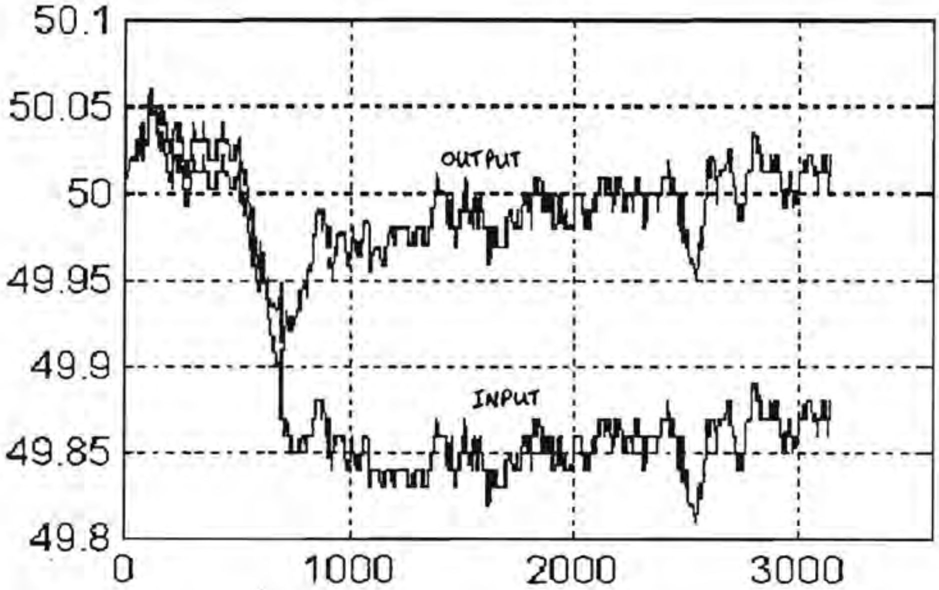


Fig D.49

Control Issued to Generators (MW)

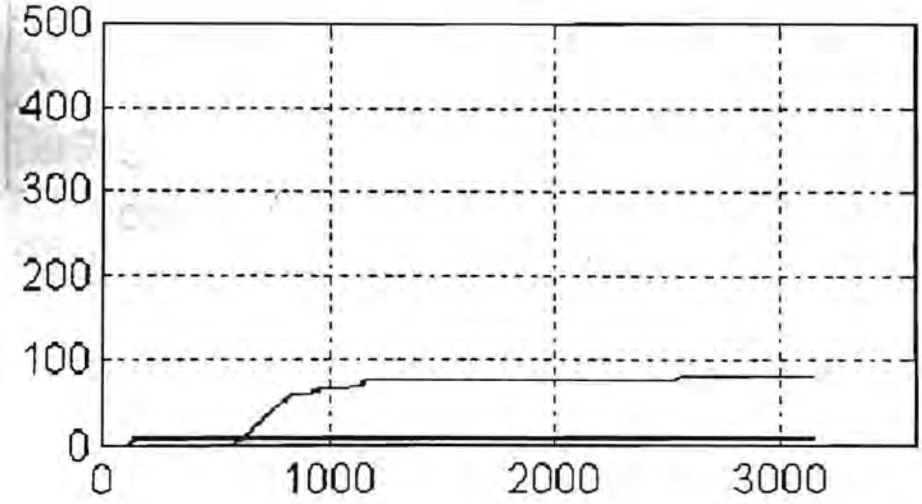


Fig D.50

Control ACE & Integral ACE (MW)

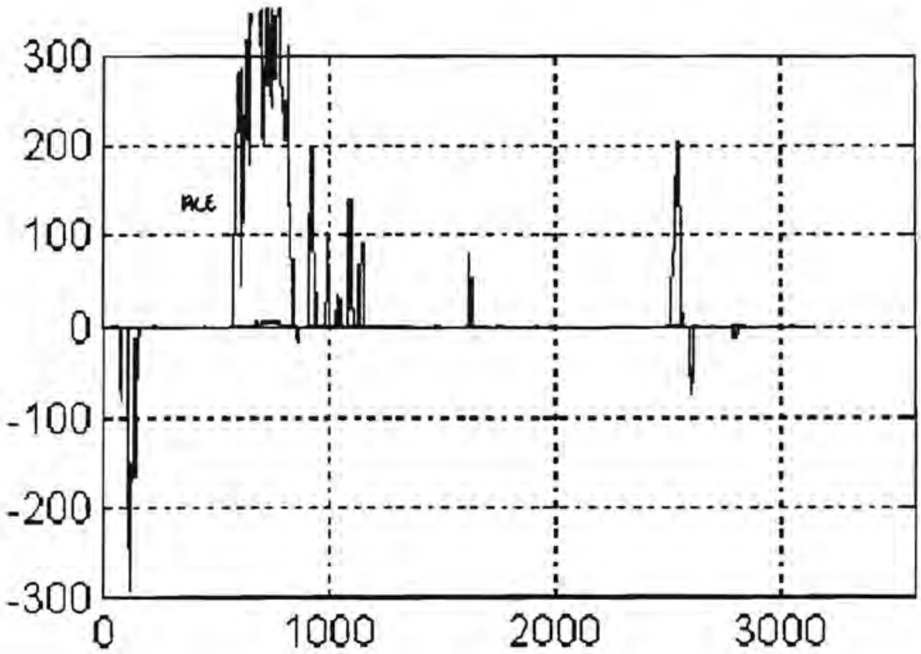


Fig D.51

Generator Outputs (MW)

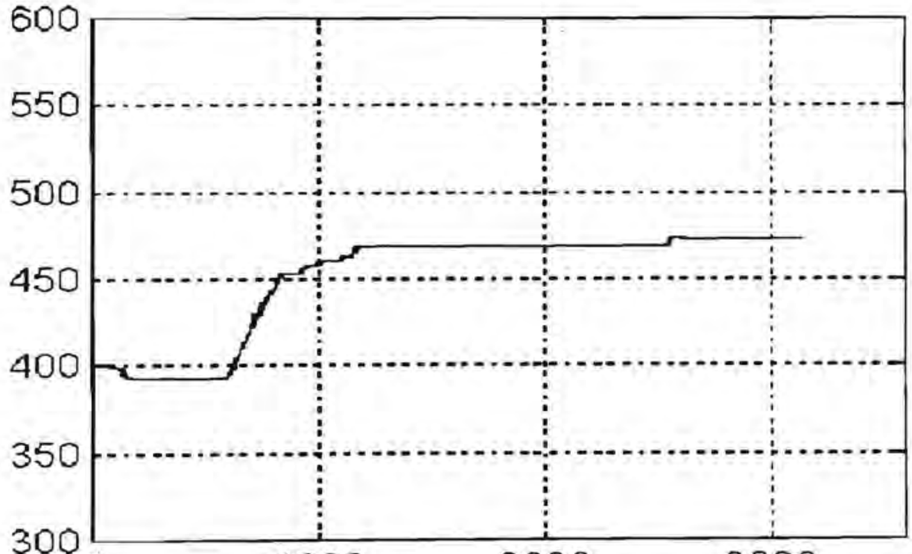


Fig D.52

APPENDIX E: RESPONSIBILITIES OF SAPP POOL MEMBERS (EXAMPLE)

Tie-line scheduling on an interconnected system of the approximate size of the SAPP, consisting of the three areas, is analysed in fig E.1. An example of the large control area C being divided into four smaller control areas with tighter connections to the other areas is then analysed.

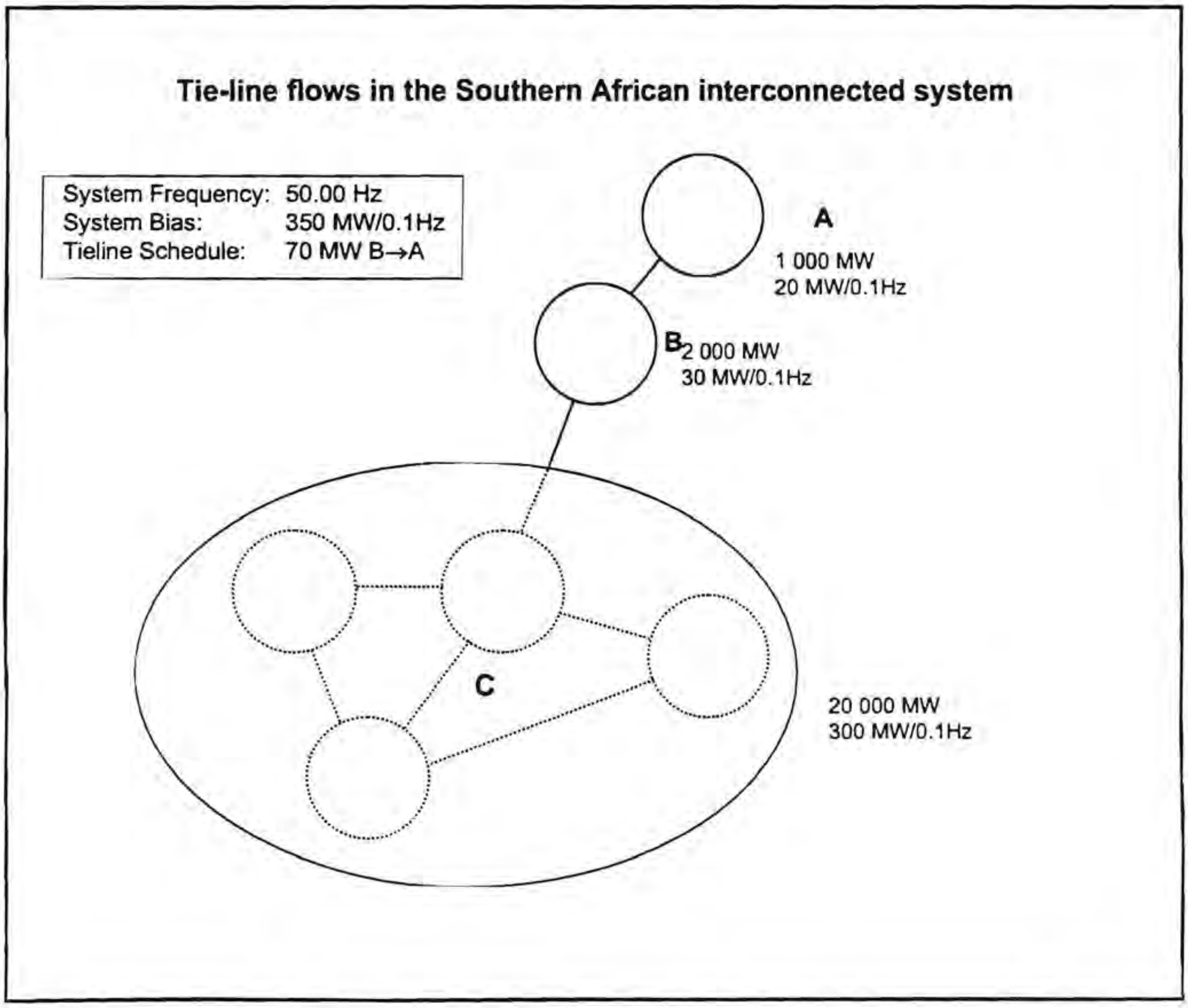


Fig E.1

In both cases the effect of a 70 MW schedule from control area C to control area B (export from C to B) is studied. It is analysed first in terms of scheduling it correctly in both areas and then in terms of scheduling it only at one control area at a time (incorrectly), to determine the sensitivity of the power flow to control from the individual AGC systems. Only steady-state conditions are observed with the initial frequency at 50 Hz and no tie-line schedules in place. Note that areas A and C are connected only to area B.

A. Tie-line scheduling on the Southern African interconnected system

Schedule 70 MW export at control area C to area B, and schedule 70 MW import at control area B from area C and schedule nothing at A.

- The generation in area C increases by 70 MW while that in area B decreases by 70 MW, therefore no change occurs in the total generation of the interconnected system.
- 70 MW will thus flow from area C to area B without a change in the system frequency or errors in the other tie-lines.

Schedule 70 MW export at control area C to area B without scheduling anything at B or A.

- The generation in area C increases by 70 MW, with no change in generation of area A or B, resulting in a change in the total generation of the interconnected system.
- To overcome the transient imbalance of the system generation and demand, the system frequency will increase to 50.02 Hz.

$$\Delta frequency = \Delta generation(MW) \div bias(MW\ /\ 0.1Hz)$$
$$\Delta frequency = 70 \div 350\ /\ 0.1 = 0.02Hz$$

- The demand in every control area will increase in the steady state, according to its individua frequency bias, as a result of the load-frequency characteristic of the demand.

$$\Delta demand = \Delta frequency(Hz) \times area\ bias(MW\ /\ 0.1Hz)$$
$$\Delta demand\ A = 0.02 \times 20\ /\ 0.1 = 4MW$$
$$\Delta demand\ B = 0.02 \times 30\ /\ 0.1 = 6MW$$
$$\Delta demand\ C = 0.02 \times 300\ /\ 0.1 = 60MW$$

- As the change in generation only took place in area C, the changes in demand will be absorbe via the shortest route over the tie-lines, resulting in errors of 4 MW on the B→A tie-line and 1 MW on the C→B tie-line. (Note that the error on B→A is inherently transferred to C→B.)

- Only 10 MW will therefore flow over the correct tie-line C→B with the system frequency changing from 50.00 Hz to 50.02 Hz.

Schedule 70 MW import at control area B from area C without scheduling anything at control area C or area A.

- The generation in area B decreases by 70 MW, with no change in generation in area C or A, resulting in a change in the total generation of the interconnected system.
- To overcome the transient imbalance of the system generation and demand, the system frequency will decrease to 49.98 Hz.

$$\Delta frequency = \Delta generation(MW) \div bias(MW\ /\ 0.1Hz)$$
$$\Delta frequency = -70 \div 350\ /\ 0.1 = -0.02Hz$$

- The demand in every control area will decrease in the steady state according to its individual frequency bias, as a result of the load-frequency characteristic of the demand.

$$\Delta demand = \Delta frequency(Hz) \times area\ bias(MW\ /\ 0.1Hz)$$
$$\Delta demand\ A = -0.02 \times 30\ /\ 0.1 = -4MW$$
$$\Delta demand\ B = -0.02 \times 30\ /\ 0.1 = -6MW$$
$$\Delta demand\ C = -0.02 \times 90\ /\ 0.1 = -60MW$$

- As the change in generation took place only in area B, the changes in demand will be supplied via the shortest route over the tie-lines resulting in errors of 4 MW on the A→B tie-line and 60 MW on the C→B tie-line.
- A total of 60 MW will therefore flow over the correct tie-line C→B and 4 MW over tie-line A→B with the system frequency changing from 50.00 Hz to 49.98 Hz.

B. Tie-line scheduling on a classic interconnected system

Fig E.2 illustrates the Southern African region as it would have been if it had consisted of smaller control areas of similar size.

Schedule 70 MW export at control area C to area B, and schedule 70 MW import at control area B from area C, without scheduling anything else.

- The generation in area C increases by 70 MW while that in area B decreases by 70 MW, therefore no change occurs in the total generation of the interconnected system.

- 70 MW will thus flow from area C to area B without a change in the system frequency or errors in the other tie-lines.

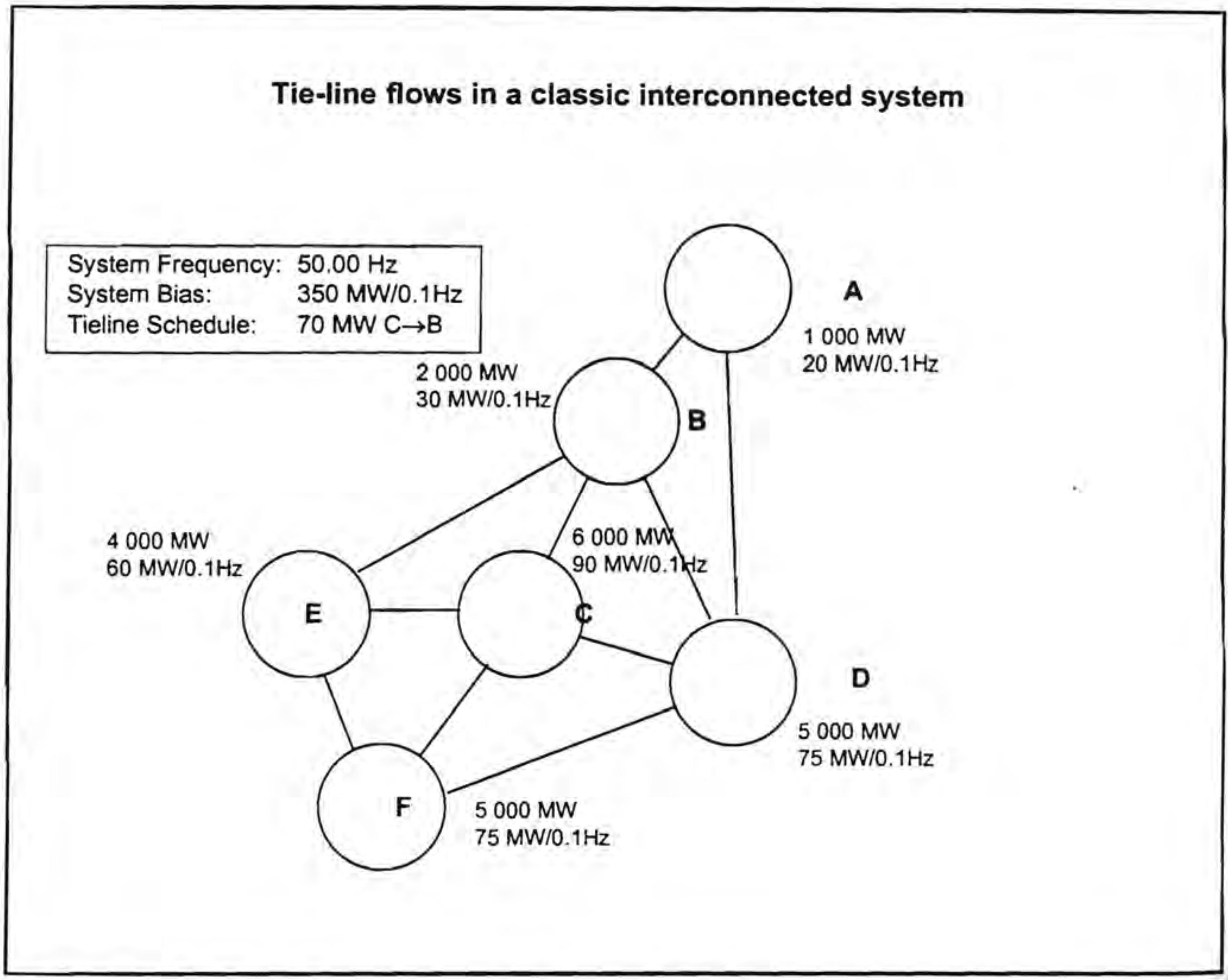


Fig E.2

Schedule 70 MW export at control area C to area B, without scheduling anything else.

- The generation in area C increases by 70 MW, with no change in generation in any of the other areas, resulting in a change in the total generation of the interconnected system.
- To overcome the transient imbalance of the system generation and demand, the system frequency will increase to 50.02 Hz.

$$\Delta frequency = \Delta generation(MW) \div bias(MW\ /\ 0.1Hz)$$
$$\Delta frequency = 70 \div 350\ /\ 0.1 = 0.02Hz$$

- The demand in all control areas will increase in the steady state according to the individual frequency bias of the area, as a result of the load-frequency characteristic of the demand.

$\Delta demand = \Delta frequency(Hz) \times area\ bias(MW\ /\ 0.1Hz)$
$\Delta demand\ A = 0.02 \times 15\ /\ 0.1 = 4MW$
$\Delta demand\ B = 0.02 \times 15\ /\ 0.1 = 6MW$
$\Delta demand\ C = 0.02 \times 90\ /\ 0.1 = 18MW$
$\Delta demand\ D = 0.02 \times 45\ /\ 0.1 = 15MW$
$\Delta demand\ E = 0.02 \times 60\ /\ 0.1 = 12MW$
$\Delta demand\ F = 0.02 \times 75\ /\ 0.1 = 15MW$

- As the change in generation took place only in area C, the changes in demand will be absorbed via the shortest route over all the other tie-lines to C. The error on the C→B tie-line will be a function of the specific load flow at the time.
- Errors totalling 52 MW (70 - 18 = 52) will exist on all the tie-lines to C with the system frequency changing from 50.00 Hz to 50.02 Hz.

Schedule 70 MW import at control area B from area C without scheduling anything else

- The generation in area B decreases by 70 MW, with no change in generation in any of the other areas resulting in a change in the total generation of the interconnected system.
- To overcome the transient imbalance of the system generation and demand, the system frequency will decrease to 49.98 Hz.

$\Delta frequency = \Delta generation(MW) \div bias(MW\ /\ 0.1Hz)$
$\Delta frequency = -70 \div 350\ /\ 0.1 = -0.02Hz$

- The demand in all control areas will decrease in the steady state, according to their individual frequency bias of the area, as a result of the load-frequency characteristic of the demand.

$\Delta demand = \Delta frequency(Hz) \times area\ bias(MW\ /\ 0.1Hz)$
$\Delta demand\ A = -0.02 \times 30\ /\ 0.1 = -4MW$
$\Delta demand\ B = -0.02 \times 30\ /\ 0.1 = -6MW$
$\Delta demand\ C = -0.02 \times 90\ /\ 0.1 = -18MW$
$\Delta demand\ D = -0.02 \times 60\ /\ 0.1 = -15MW$
$\Delta demand\ E = -0.02 \times 45\ /\ 0.1 = -12MW$
$\Delta demand\ F = -0.02 \times 75\ /\ 0.1 = -15MW$

- As the change in generation took place only in area B, the changes in demand will be supplied via the shortest route over all the other tie-lines to area B. The error on the C→B tie-line will be a function of the specific load flow at the time.

- Errors totalling 64 MW (70 - 6 = 74) will exist on all the tie-lines to area B, with the system frequency changing from 50.00 Hz to 49.98 Hz.

C. Conclusions on the responsibilities of pool members created by the physical layout of the Southern African Power Pool

The example discussed in section A indicates that the power flow on the tie-line between Eskom and ZESA is always very sensitive to changes in generation in the small areas, ie ZESA and ZESCO. Conversely it is very insensitive to changes in generation made by Eskom. This differs from the classic interconnected scenario, where errors introduced on a specific tie-line can be transferred to another tie-line as discussed in section B.

ZESA and ZESCO therefore have a specific responsibility to ensure that tie-line errors are limited, while Eskom will mainly control the system frequency and time error.

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