REVIEW OF PRIMARY FREQUENCY CONTROL REQUIREMENTS ON THE GB POWER SYSTEM AGAINST A BACKGROUND OF INCREASING RENEWABLE GENERATION

A thesis submitted for the degree of Doctor of Engineering

by

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Appendix C

Six monthly Reports

1. **First Report:** April 2003

2. **Second Report:** October 2003

3. **Third Report:** April 2004

4. **Forth Report:** October 2004

5. **Fifth Report:** April 2005

6. **Sixth Report:** October 2005

7. **Seventh Report:** April 2006

8. **Eighth Report:** October 2006

This document forms part of an Engineering Doctorate portfolio of evidence for a project conducted on behalf of National Grid in collaboration with Brunel University. It is intended that this report be considered as a stand alone thesis recording the research conducted during the life of the project.

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Impact of railway electrification systems on other electrical systems and civil infrastructures within and outside the railway environment.

Six Monthly Progress Report: First Report

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1.0 Introduction

1.1 The Company

WS Atkins plc is one of the world's leading providers of professional, technologically based consultancy and support services. Sir William Atkins established the original company, WS Atkins & Partners, in 1938 with offices in Westminster, London. It has expanded from its historical base in traditional engineering, management consultancy and property services into related technological consultancy and the management of outsourced facilities with over 15,000 staff in 60 countries.

In 1986 it was decided that WS Atkins Consultants should become an independent company. As a result, two companies were created; WS Atkins Consultants, including the original company, and Atkins Holdings Limited.

WS Atkins provides services for a wide range of organisations through 90 offices all over the UK, and also offices in Continental Europe, Middle East, Asia Pacific and the Americas. WS Atkins provides support for public and private sector clients in a range of markets. Transport accounted for 28% of fiscal 2002 revenues; government services, 25%; international, 22%; commercial services, 15% and industry, 10%.

In 1996 WS Atkins was admitted to the London Stock Exchange and began trading as WS Atkins plc. Since that time, the group has acquired a number of companies; Faithful & Gould, a practice of cost consultants and quantity surveyors; Ventron Technology, a process plant contractor; Lambert Smith Hampton, a property and commercial agency; McCarthy's Consulting Engineers; the Benham Companies, consulting engineers; and Boward Computer Services in July 2001.

1.2 The Research Engineer

Ross Pearmine attended secondary education at BETHS technical high school, Bexley. After leaving with eight GCSE passes and four A-levels in Biology, Maths, Physics and Engineering he join BICC Cables Ltd. During the subsequent year Ross was trained on the companies' internal IEE registered development scheme. He was posted in the heart of the companies research and development sections and continued training during summer secondments whilst at university. He left the employment of the company, now Pirelli Cables Ltd., in 2002 in order to read for a doctorate.

Ross Pearmine read Electrical and Electronic Engineering at Brunel University and graduated in July 2002 with an upper second Bachelors degree. Currently he is working in the capacity of a research engineer on the Environmental Technology Engineering Doctorate scheme at the Brunel University, and is supported by W.S.Atkins.

2.0 Background

2.1 Industrial and Public Drivers

The guided transport electrification system, which includes tramways and railways, is composed of power supplies, the distribution network and traction drives. Built within this network is a system controlling signalling and communication for trains and network operators. These different systems all operate at a range of power levels and are major contributors in the generation of Electro-Magnetic Interference (EMI) both within and outside the railway environment. The design of the railway system and the control of the level of electro-magnetic interference are paramount in relation to the safe operation of the railway. Modelling the electrification system enables predictive assessment of the levels of interference within the railway environment.

Electro-magnetic interference occurs when unwanted electric or magnetic fields from one circuit (normally high power) interfere or couple with another. The severity of the coupling and the magnitude of the interference will determine if any safety critical systems will be affected in the railway network. With a transport system operating in the public domain it is critical that external non-railway sources are also free from interference and maintain a safe level of operation.

Current commercial trends with using problematic EM generating equipment (DC- GHz) force a direct pressure on the environment. It is this projects goal therefore, to enhance the knowledge and the capabilities of engineers designing DC and AC rail systems. In so doing, ensuring that the electrification systems comply with national and international standards and minimise the level of disturbance to the electrical and physical environment.

2.2 Business Requirements for Modelling

Modelling is vital in the design process for a new railway, or the upgrade of an existing railway system. The commercial risks on new projects or upgrades to existing railways, due to interference, can be minimised by the modelling process. Modelling provides detailed information on the performance of the railway system and predictive evidence of compliance with railway and national standards (EMC, control of return currents and earthing).

Simulations will give confidence to the operational side of the business and minimise the risk associated with interference. Careful hazard analysis, simulation studies and design of the system will provide performance characteristics and mitigate against incompatibility.

3.0 The Project Scope of Work

The work will be based around the development of computer software and enhance the capabilities of the specialist engineers within Atkins Rail. This will include investigation into the development of technologies that will have significant impact on the reduction of interference into railway and third parties electrical systems and infrastructures.

A significant amount of research has been performed in this field, however there is a significant amount of work that needs to be built on this research such that the outcomes of this research can be applied into the commercial market place.

4.0 Objectives

4.1 Long-term Objectives:

- Develop necessary information to put together a ‘safety case’.
- Show due diligence in the development of the ‘safety case’, and compliance with E.U./B.S. standards.
- Protect the operating side of the railway business and minimise the technical risk of malfunction of the equipment, reducing the risk of failure due to incompatibility.
- Minimise the commercial risk of the failure of equipment owned by a third party.
- Minimise the commercial risk and loss of revenue due to the failure of equipment.
- Minimise the risk of failure or interruption of safety critical circuits

Impact of railway electrification systems on other electrical systems and civil infrastructures within and outside the railway environment.

4.2 Short-term objectives

- Gain an understanding of the current rail power network operation.
- Attend course modules
- Development of skills

5.0 Research to Date

See separate literature review (Appendix A).

6.0 Next 6 Months

Further study into existing modelling techniques
Research papers in harmonic modelling
Begin development of train modelling software

Possible papers: Impedance of Steel / Aluminium composite rails.
Development of a multi-train computer based power network simulator.

7.0 Summary

This report provides an introduction to the engineering doctorate project located at Atkins Rail. It also presents the desired outcomes of this project from the point of view of the sponsoring company. Included in the report is an outline of the progress carried out to date with research in the field of traction simulation.

Appendix A: **Literature Review**

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List Of Principle Symbols

A	=	Rail cross-sectional area	[m^2]
A_t	=	Cross-sectional area of train	[m^2]
a	=	Chosen sheath radius	[m]
a_T	=	Train acceleration or deceleration	[$m.s^{-2}$]
$\mathbf{A}$	=	Vector potential	[T.m]
δA_m	=	Filament area	[m^2]
B	=	Flux density	[T]
d_{ij}	=	GMD or GMR	[m]
E_I	=	Inverter efficiency	[%]
F_a	=	Acceleration effort	[N]
F_T	=	Tractive effort	[N]
G	=	GMD of the conductor from itself	[m]
g	=	Acceleration due to gravity (9.8)	[$m.s^{-2}$]
H	=	Magnetic field strength	[$A.m^{-1}$]
I	=	Rail current	[A]
I_1	=	Stator motor current, RMS of fundamental	[A]
I_T	=	Train current	[A]
J	=	Current density	[$A.m^{-2}$]
J_s	=	Current density per element	[$A.m^{-2}$]
ℓ	=	Inductance per unit length	[$H.m^{-1}$]
ℓ_m	=	Filament inductance	[H]
ℓ_{ij}	=	Mutual inductance	[H]
m_T	=	Mass of train	[kg]
n	=	Number of sub-conductors	
n_a	=	Number of axles per carriage	
P	=	Rail perimeter	[m]
P_T	=	Tractive power	[$J.s^{-1}$]
P_E	=	Electrical power	[w]
r	=	Equivalent conductor radius	[m]
r_c	=	Radius of track curvature	[m]
R	=	Resistance per unit length	[$\Omega.m^{-1}$]
R_f	=	Resistance of input filter	[Ω]
R_T	=	Train resistance	[N]
Rg	=	Train resistance due to track gradient	[N]
Rc	=	Train resistance due to track curvature	[N]
S	=	Element area	[m^2]
V_T	=	Train voltage	[V]
v_T	=	Train speed	[$m.s^{-1}$]
Z_m	=	Per phase input impedance of motor	[Ω]
ξ	=	The factor to take rotating masses into consideration	
σ	=	Electrical conductivity	[$S.m^{-1}$]
η_m	=	Motor and drive efficiency	[%]
ω	=	Angular frequency	[$rad.s^{-1}$]
μ	=	Permeability	[$H.m^{-1}$]
μ_0	=	Permeability of free space ($1.26x10^{-6}$)	[$H.m^{-1}$]
ε	=	Permittivity	[$F.m^{-1}$]
Φ	=	Airgap flux	[Wb]

α	=	Rolling resistance component independent of train speed	[N]
β	=	Train resistance dependent on speed	[N]
γ	=	Coefficient of air resistance dependent on the square of train speed	[N]
δ	=	Aerodynamic polynomial function	[N]

Impact of railway electrification systems on other electrical systems and civil infrastructures within and outside the railway environment.

1. BACKGROUND OF RAIL TRACTION

Historically the electric railway line began developments in the early nineteenth century when in Scotland, Davidson, and in America, Davenport, experimented with battery propulsion. By the later part of the century practical DC systems became implemented using a DC motor and low voltage supply lines. These systems operated with great simplicity using a switched resistance for speed control. The 1950's introduced new possibilities with the ability to offer high power AC supplies, thanks to the use of the mercury arc rectifier. These AC supplied vehicles used a tapchanger unit to vary drive speeds, but the mercury rectifier was basic and unreliable. Subsequently, it was replaced at the advent of the high power semiconductor diode in 1959, which offered the required electrical operating characteristics.

These maturing technologies allowed for the gradual phasing out of the original DC networks that had existed since the early twentieth century in favour of a standardised 25 kV single-phase 50 Hz system. In 1955 British Rail began the modernisation of UK railways in favour of the 25kV scheme. Currently AC traction supplies are typically employed on lines that cover large distances offering economic benefit on heavy haul and high-speed links. DC lines are more practical in urban traction schemes such as metro and light rail systems because of lower transmission voltages. Voltages of 600 V, 750 V and 1500 V DC are in use on many urban systems although some 3 kV DC main lines are also in operation.

2. DC RAILWAY ELECTRIFICATION

2.1 DC power supplies

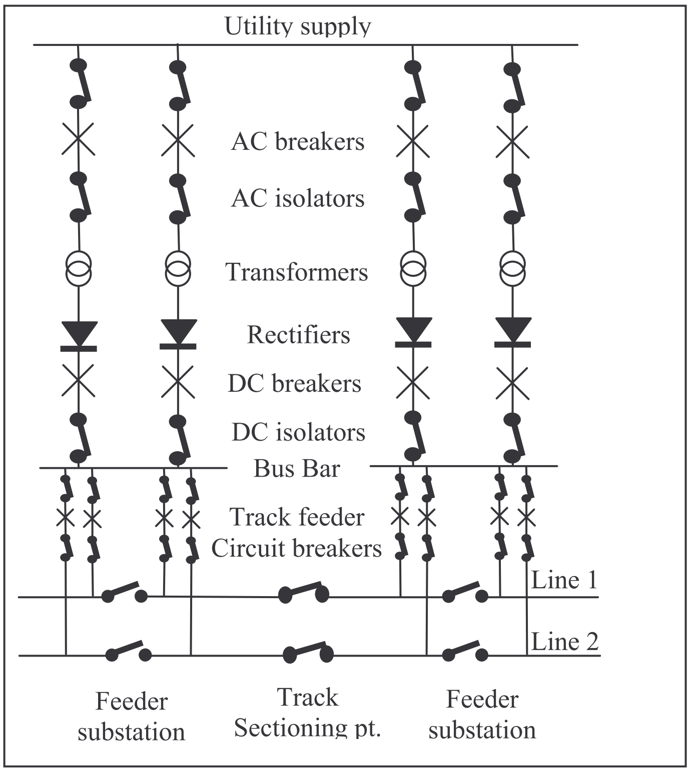


Figure 2.1.1 – DC feeder system

Modern DC railway power supplies chiefly operate at traction voltages of 600-750 V, other voltages exist on older lines that tend to be much higher operating in the order of 1.5 or 3 kV. These voltages are applied to either overhead catenarys (HV) or power rails (LV), in either case a return current generally flows back along the running rails. Some underground utilities choose to run four-rail systems in which the supply and return currents flow though separate supply rail. The four-rail system helps minimize stay currents by providing an isolated path for return alleviating damage to buried metal structures by electrolytic action.

In the standard three-rail system a conductor rail runs parallel with the traction line and current is collected via a shoe contact. The catenary system is slightly more complex with various wire suspension methods and a complicated sprung arm collector known as a pantograph. Power is supplied to the line via substations located at points along the route, these trackside stations are in turn supplied by the local generation companies with mains frequency voltages. A typical rectifier substation is shown in Figure 2.1.1. The substations are spaced at equal distances along the track depending on traction voltage, generally for low voltages the spacing is 3-6 km, 1.5 kV stations at a proximity of 8-13 km and for 3 kV DC 20-30 km.

Track-side substations have typical ratings of 1-10 MW with neighboring feeds sometimes being isolated from each other. They generally operate from 132, 66 or 33 kV three-phase utility supply, which is rectified to DC for traction. Pulse rectifiers employed in the substation can be 6, 12 or 24-pulse varieties depending on the transformer configuration. Six-pulse rectifiers are usually supplied through a transformer secondary arranged in bridge or double-star formation, Figures 2.1.2a and 2.1.2b. Each of the diodes in the bridge circuit conducts full load current for ⅓ of a cycle and those in the double-star arrangement conduct half load currents.

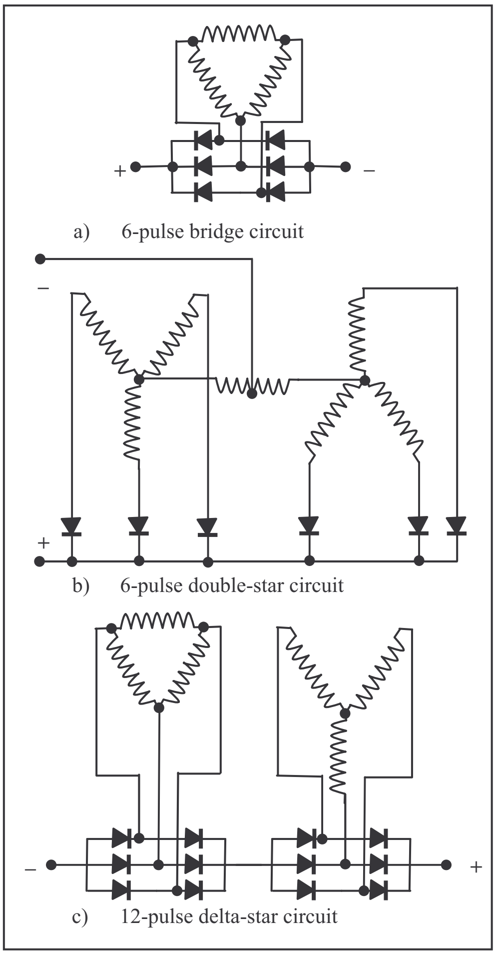


Figure 2.1.2 – Transformer substation arrangements

In the double-star arrangement two separate half-wave rectifiers are connected in parallel with a half-cycle phase difference. The star points are connected via a center tapped inter-phase reactor that provides a path for negative return currents and allow both star circuits to conduct together. A voltage difference between the star points causes a reactor current to flow and sets up a negative load voltage. In both 6-pulse circuits the AC current closely resembles a square waveform.

The 12 pulse rectifier shown in Figure 2.1.2c, consists of a delta and star transformer secondary connected in series each with a separate bridge circuit. The 12-pulse version offers lower harmonics and lower device ratings. Non-uniform current drawn from the utility supply by the substations sets up line harmonics, for each n^{th} order DC harmonic two corresponding AC harmonics are produced. Balanced three-phase supplies eliminate the third multiple harmonics and so for a p-pulse rectifier the input current harmonics occur at (n.p±1) frequency and are of magnitude 1/(n.p±1).

The substation regulation is a vital performance characteristic of the DC electrification system. If the regulation is too high traction motors will not have sufficient volts to accelerate on the line. Raising the substation voltage to compensate may produce excessive rail \ catenary voltages under non-load conditions. Lower regulation is achieved through a compromise between a lower impedance supply transformer and higher fault currents so increasing equipment ratings.

2.2 DC feeding arrangements

With normal feeding arrangements substations are connected in parallel to the traction conductor with a DC circuit breaker at each end of the feeding section to provide protection under fault conditions. Each substation feeds from a common DC busbar via DC circuit breakers where the feeder is separated using a (normally open) bypass isolator.

Double End feeding – All DC circuit breakers are in service to provide double end feeding of the traction supply section. The substation isolators are normally open to provide a separate section that can be easily protected against faults.

Tees feeding – Implemented when a DC feeder at the end of a section is open and is achieved by closing the bypass isolator. This allows the remaining DC circuit breaker to supply the traction sections in both directions.

Single End feeding – Single end feeds on double end feeding sections are temporary feeds following an outage from a track feeder DC circuit breaker. If normal feeding cannot be restored within a reasonable time Tee feeding is usually employed.

Bypass feeding – Occurs when a utility outage or failure of feeder DC circuit breakers in both directions forces the isolator to close. Feed is supplied by DC circuit breakers from adjacent substations.

2.3 DC system grounding

For DC traction, in most cases, running rails are cross-bonded and act as the negative conductor for return currents. Under normal operating conditions there should be no direct connection between the system and ground. In practice however, because of leakage resistance between rails, sleepers and ballast reference to ground is introduced.

The system grounding method employed will affect the systems stray current levels and also the rail-to-ground potential. As such it is obvious that a minimum stray current and a minimum rail-to-ground potential is desired of the system for safety. Stray currents in the system can be minimised by leaving the system ungrounded, but to achieve minimum rail-to-ground potential the system must be grounded to suppress the unwanted voltage. In this situation a compromise between minimum stray current and risk to equipment/human safety is required.

At the present five techniques exist to ground dc systems these are highlighted in a paper by Paul (2002) the schemes and their limitations are reviewed below. (see Figure 2.3.1)

a) **Solidly grounded system**

The negative bus of the substation is grounded to the local earth point with minimal impedance in the grounding circuit. This method effectively grounds the running rails and as a result a proportion of the return current will take a path through ground depending on local soil impedance. The proportion of return current flowing through the ground will increase corrosion to any underground utilities in the vicinity.

b) **Diode grounded system**

The negative bus is ground through a parallel diode array, which has individual protection relays and a shorting contactor. At a predetermined voltage level device 59 energises a contactor to ground the negative system rails. A directional over-current device 32 opens the contactor during periods of low magnitude forward current, but will trip out the system substation if high level faults continue. During normal

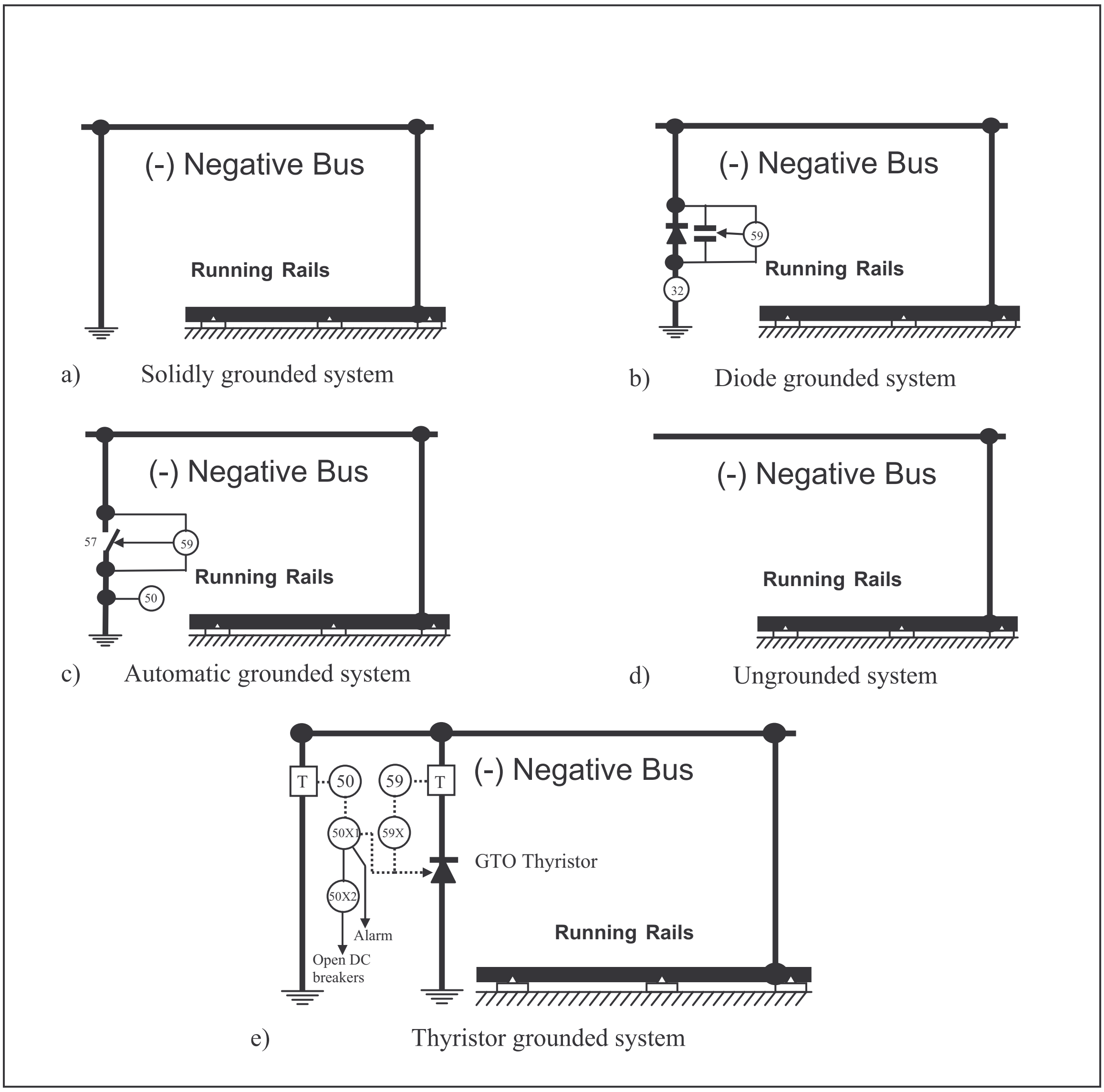


Figure 2.3.1 – DC traction power system grounding methods

operation the rail-to-ground potential is low and thus the diodes are conducting allowing for relatively high stray currents.

c) **Automatic grounded system**

Upon the detection of a predetermined voltage level, over-voltage device 59 causes the mechanical shorting switch device 57 to close grounding the negative bus. Over-current device 50 during periods of short circuit current de-energises the traction substation. Device 50 also serves as remote alarm and local indicator to reset device 57. Due to the nature of device 57 it takes a finite time for the device to activate.

d) **Ungrounded system**

The negative substation bus remains ungrounded at all times. This system provides the lowest stray current levels but increases the risk of high rail-to-ground voltages. During normal running and especially during positive-to-ground faults the vehicle or running rails may be elevated to an unsafe dc voltage.

e) **Thyristor grounded system**

Over-voltage device 59 monitors the negative-to-ground voltage when this exceeds a preset value the thyristor gate is triggered by device 59X grounding the negative bus. Instantaneous current device 50 energises time delay device 50X1 and 50X2. After current levels have reduced device 50X1allows a short delay before a gate turn off signal is applied to the thyristor returning the system to its ungrounded state, at this point an alarm is also triggered. If in the case of a positive-to-ground fault current still flows then after a period set by device 50X2 the dc feeder breakers will be tripped. In some cases a bi-directional GTO will be employed to maximise safety and minimise stray currents. The thyristor scheme has an inherent advantage over the diode scheme in that the thyristor will only ground the system at times of over-voltage trip. Under normal system operation the system will remain ungrounded.

2.4 DC-Fed traction engines

Early traction vehicles used series or separately-excited (SEPEX) DC motors with resistance control, which was developed in the 1970’s by introducing the thyristor DC-DC chopper Figure 2.4.1. Progress in the field of semiconductors has lead to the implementation of the GTO chopper, which has helped to further reduce necessary control circuitry. Many of the current traction systems favour the SEPEX motors over series types because of the ease in which regenerative braking can be harnessed due to the separate field windings. Energy consumption can be greatly improved with regenerative braking, especially with GTO drives in systems when vehicles with high power demands are local concentrated. This situation is typical of metro and light railways when frequent acceleration from stationary can put high power demand on the supply system.

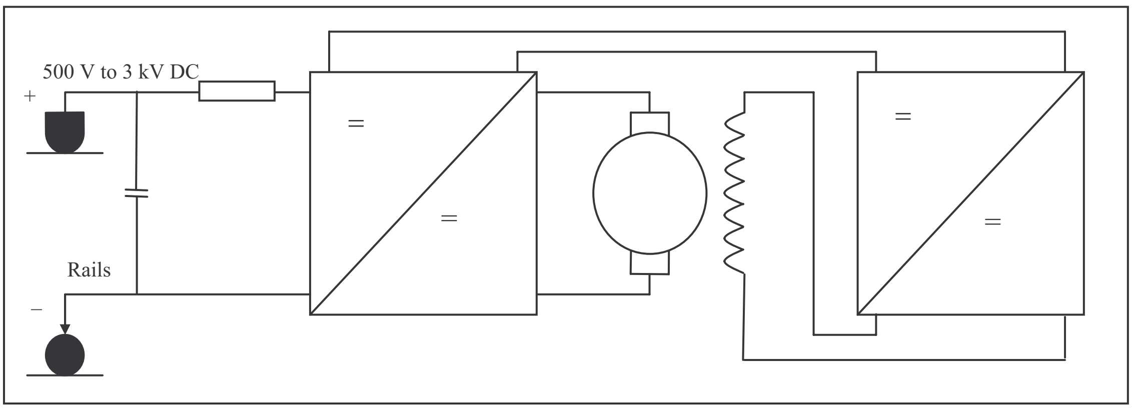


Figure 2.4.1 - DC-DC choppers operating a DC SEPEX motor

The DC-DC chopper can give rise to current harmonics in the supply, particularly when starts up currents in the order of 4 kA are drawn. These harmonic currents can both influence the signalling or communications network and degrade the incoming voltage from the Supply Company. The harmonics are greatest when the mark-space ratio of the chopper is 1:1 with the fundamental at the fixed chopping frequency. A low-pass filter at the power collection terminals is used to attenuate the harmonic content of the line current.

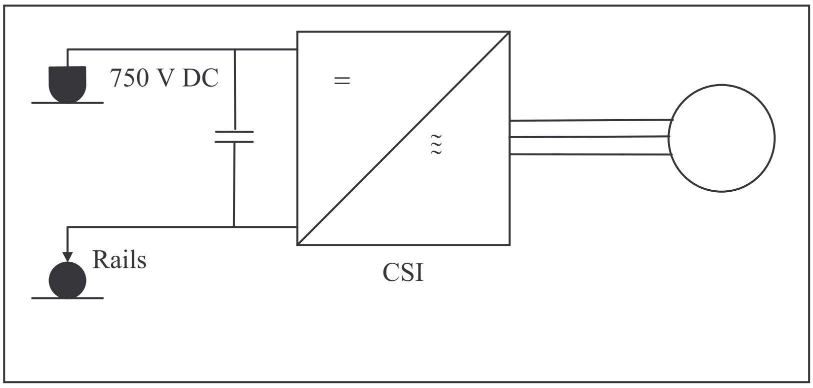


Figure 2.4.2 – DC-3 phase current source inverter operating an induction motor drive

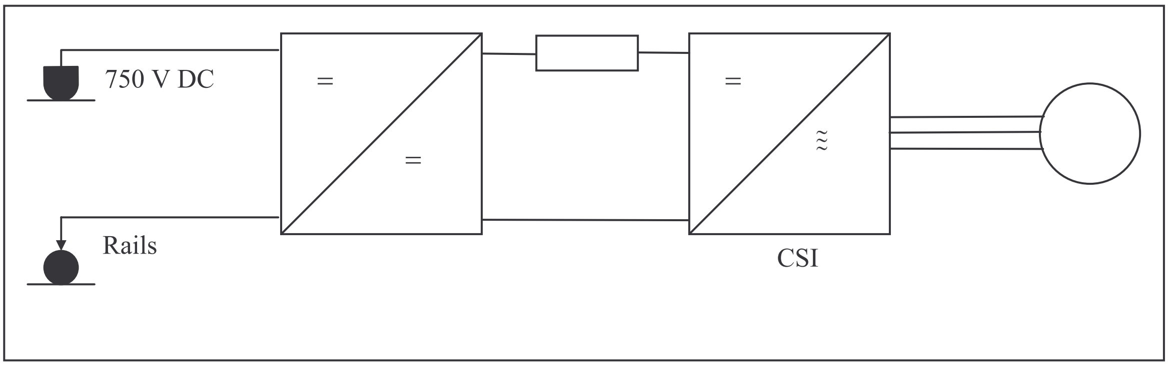


Figure 2.4.3 – DC-DC chopper to 3 phase current source inverter operating an induction motor drive

The development of the power thyristor in the 1970's also lead to the application of induction motors operating from current-source inverter (CSI) systems, Figure 2.4.2 and Figure 2.4.3. These systems evolved into induction motors operating from a voltage-source inverter (VSI) when the fabrication of high power GTO became possible, Figure 2.4.4. The motors themselves can be fed from VSI which is both variable frequency and variable voltage or CSI which require a pre chopper to maintain a constant link current.

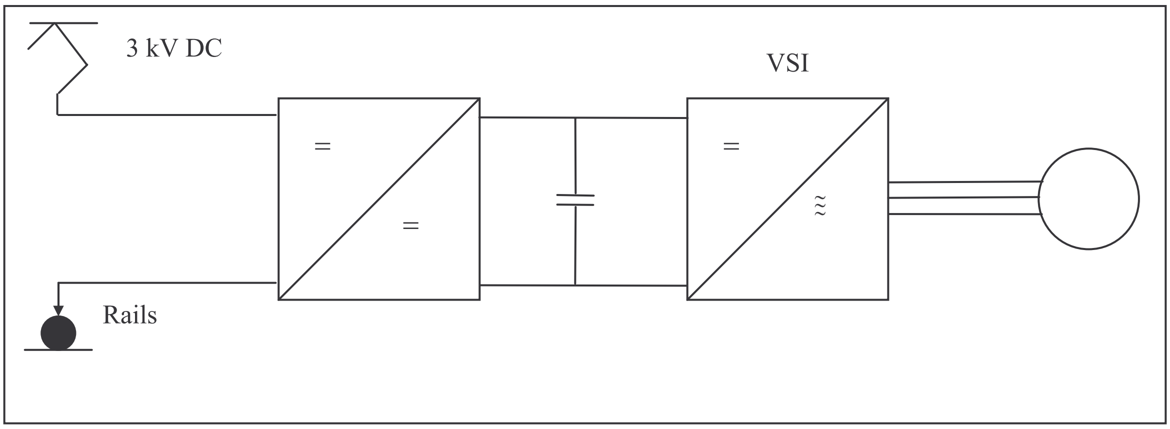


Figure 2.4.4 – DC-DC chopper to 3 phase voltage source inverter operating an induction motor drive

VSIs operating from a DC source can tolerate large fluctuations in supply voltage with the exception of high voltage 3 kV lines where it is necessary to limit reverse voltage to the inverter power devices by use of a chopper. Voltage inverters can use a number of established techniques or combinations of techniques to ensure the correct power characteristics for traction are employed. Of these techniques pulse width modulation (PWM) and Quasi-square wave operations are common.

A CSI operating from a DC source requires constant current achievable from DC chopper with a duty cycle which matches the current demand. Thyristors are implemented in CSI circuits of this type in favour of GTOs devices because of their ability to withstand high reverse voltages.

New technologies are emerging thanks to developments in the transistor markets and IGBT or Integrated Gate Bipolar Transistor packs are now being implemented in four-quadrant converters. The IGBT has the significant advantage of high switching speeds (kHz - GHz) improving the shape of output waveforms, and also a reduction in energy consumption, cost and size.

2.5 UK case studies

London underground Ltd.: 630 V DC fourth-rail top-contact system. Middle earthed arrangement provides a positive conductor rail at +420 V and a negative rail at -210 V DC. Older rolling stock employs series-parallel traction control using resistances. Resistance switching is achieved by the use of cam-operated contactors. All stocks so fitted use camshafts on each motor car, except for the 1967/72 tube stocks and C surface stocks, which use a separate camshaft for series and parallel notching. The two camshaft system was introduced because of the more complex equipment required for rheostatic braking. A larger single camshaft is used on the motoring and braking circuits of stock built since 1973. The 1992 and 1996 tube stocks have modern GTO controlled chopper drives and the 1995 Tube Stock has IGBT traction control.

Figure 2.5.1 – Docklands Light Railway

Figure 2.5.2 – London underground (Hammersmith & city line)

The 1995-6 stocks use 3-phase AC induction motors.

Docklands Light Railway: The line is electrified using a bottom contact 3rd rail at +750 V, with return through the running rails. The propulsion system has two separately excited traction motors with individual field and armature choppers which are controlled by a hybrid microprocessor/conventional electronics control system. Brakes with a single GTO chopper with associated snubbing components and resistors provide rheostatic braking. The two motors are fed in parallel from a two-phase chopper, giving an overall frequency of 528Hz. Each armature chopper has two parrallel GTO thyristors components with snubbing and smoothing. Each field power supply has two series connected GTO thyristors and a four thyristor reversing bridge with smoothing and snubbing components.

Figure 2.5.3 – Class 465 750 V DC traction unit at Waterloo East

Railtrack: +750 V DC third rail top contact system, with return through the running rails; used in urban and suburban railway network in south-eastern zone. 3 phase induction motors with two VSI GTO inverters per driving car, blended regenerative/rheostatic braking with facility to blend with the air brake system. Designed with an ICMU (interference current monitoring unit).

Croydon Tramlink: +750 V DC direct overhead-line driven system, with return through the running rails. Drive system consists of two GTO pulse inverters DPU 251 plus microprocessor controlled drive-brake controller EFB 251 in conjunction with robust and maintenance free transverse, encapsulated, self cooled 3 phase asynchronous traction motors.

Figure 2.5.4 - East Croydon. Croydon Tramlink

Figure 2.5.5 - Lodge Road. Midland Metro

Midland Metro: +750 V DC direct overhead-line driven system, with return through the running rails.

Figure 2.5.6 - Sheffield Supertram

Figure 2.5.7 - Manchester Metrolink

Sheffield Supertram: +750 V DC direct overhead-line driven system, with return through the running rails Tractive effort produced by the conventional Siemens monomotor design, driven by a chopper-controlled DC traction motor. Combined regenerative and rheostatic braking.

Manchester Metrolink: +750 V DC direct overhead-line driven system, with return through the running rails.On Phase I vehicles, traction is provided by four separately - excited DC motors, each motor group is fed from independently controlled choppers utilising gate turn off (GTO) thyristors. The separate field control is also provided on a per bogie basis, and this is achieved using four quadrant inverters with insulated gate bipolar transistor (IGBT) technology reducing the overall component count and weight. In the six new vehicles the motors are AC and utilise IGBTs. Electric braking is regenerative / rheostatic, with the energy being dissipated from naturally - cooled resistors mounted on the roof of the vehicle. A line filter performs three functions: it presents a low impedance source to the chopper and a high impedance to the alternative current voltage component in the overhead 750v supply. It also filters out chopper - generated ripple. The choppers are controlled by a microprocessor and operate at an interlaced chopping frequency of 600 Hz. This frequency does not deviate into signalling frequencies.

Figure 2.5.8 - Newcastle Tyne & Wear Metro

Tyne and Wear Metro: +1.5 kV DC overhead-line driven system, with return through the running rails. It is probably the last of the LRTs to use rheostatic current limiting. Traction system employs Gate Turn Off (GTO) chopper control.

2.6 Outline of DC traction simulation

Modeling is vital in the design process for a new railway, or the upgrade of an existing railway system. The modeling process can minimize the commercial risks on new projects or upgrades to existing railways due to mainly to interference. Modeling provides detailed information on the performance of the railway system and predictive evidence of compliance with railway and national standards (EMC, control of return currents and earthing). Many tasks in simulation are interrelated and manual calculations are laborious and are also highly susceptible to human error. To give a high degree of confidence the systems based on computer programs are being used in the area of railway power systems design. Computer-aided methods are necessary to aid engineers because of the complexity of the DC networks involved. Simulations will give confidence to the operational side of the business and minimize the risk associated with interference. Careful hazard analysis, simulation studies and design of the system will provide performance characteristics and mitigate, against incompatibility.

2.6.1 Review of existing software

To examine the effect of a running train service in terms of timetables and signalling sophisticated simulation software has been developed by many rail companies. The British Rail system is called OSLO (Overhead System Loading) and Balfour Beatty uses its RAILPOWER program, whilst GEC-ALSTHOM software is believed to be based on software developed at Birmingham University.

A well developed simulation suite developed by Mellitt *et al.* (1978) at University of Birmingham utilizes a two part, three stage simulator for DC railways based around train movement and power-network simulation. The suite was specifically developed for simulation studies with chopper drives and regenerative braking although it allows more than energy consumption to be modeled. The simulator makes piecewise calculations over the whole track considering one section at a time. The program uses data arrays to hold information on all sections and all trains between network power calculations. The simulator considers the dc traction motor in one of four operational modes according to tractive effort supplied and models the train as an equivalent circuit according to this mode. The program as explain earlier operates in three stages:

- Movement simulator (part A); establishing the train mode
- Power network solution; simulating node voltages
- Movement simulator (part B); updates train position and velocity

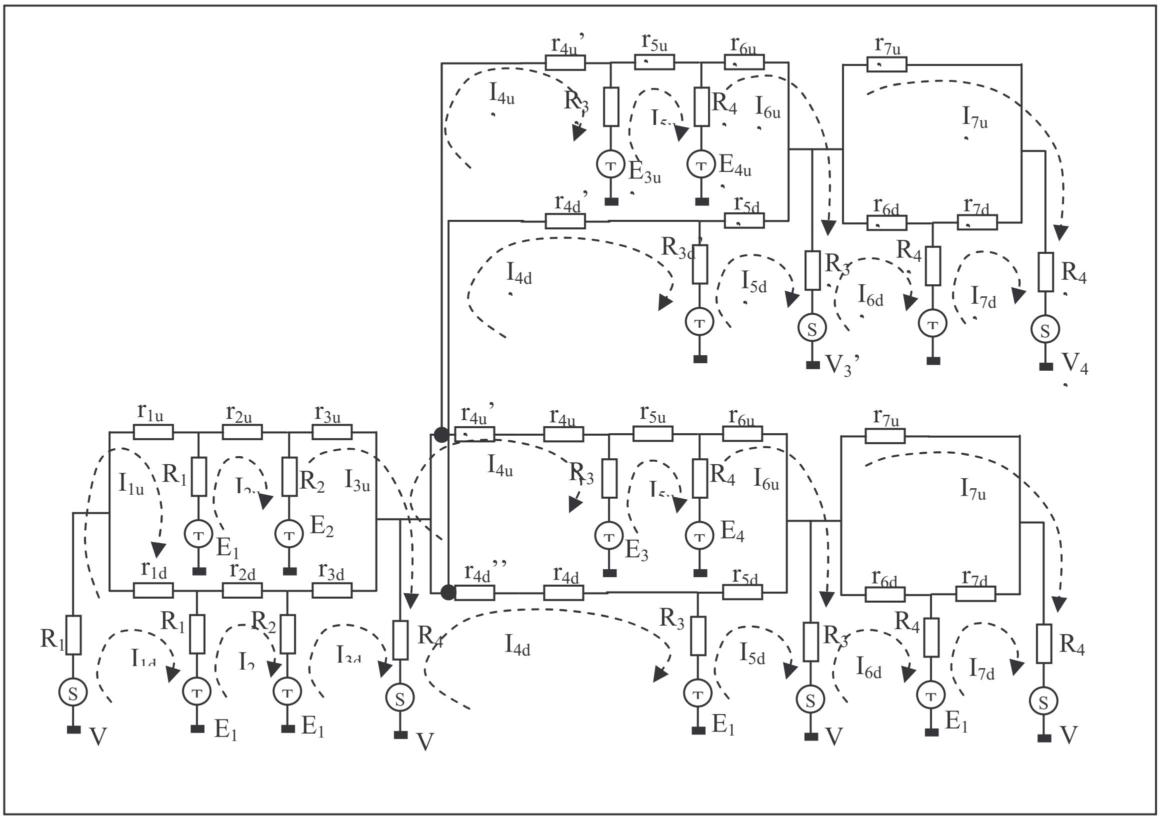


Figure 2.6.1 – Simplified power network with braches

Impact of railway electrification systems on other electrical systems and civil infrastructures within and outside the railway environment.

Jinzenji and Sasaki (1998) base a DC simulator on train behavior, realizing that trains are restricted by signal conditions and passengers. A block system is used to model train movement on the lines, with a simple equivalent circuit to model the system electrically. The simulator attempts to mimic field data in terms of temporal systems loading if not in magnitudes.

Software developed by Ho *et al*.(2002) utilises a set of efficient algorithms in a power network simulator. The simulator assumes all conductive components are linear in nature and the feeder substations are a simple voltage source with series resistance. The substation is replaced with a resistive load when regenerative braking is harnessed. The traction systems are also modelled as a V-R system but values of both characteristics are variable with speed and the units operating mode. The software formulates and solves a matrix equation for the electrical circuit using nodal analysis on the system Figure 2.6.1.

A set of software algorithms are presented by Talukdar and Koo (1977) which are developed for specific use in the railway sector for load flow calculations. Conventional power systems analysis tools cannot be applied to the railway network because of its mobile loads and alternative system frequencies that the system may develop. The work is based on the proposal that traction vehicles do not move fast enough to cause transient effects due to their constantly changing velocities on the supply system. The power network can be assumed to simply change states as power demands alter. A representation of the electrical performance can thus be created from a series of load-flow samples taken in the period of interest. The paper provides methods for the solution of embedded DC traction system in an AC network.

A simulation package that includes regenerative braking was developed at Brunel University for Balfour Beatty by Cai [34] and [35]. The software solves the DC-load-flow problem using iterative techniques based on linear, bi-lateral and lumped circuit parameters. The software developed is adapted for use in both the AC and DC traction environments and is based around the normal two stage program, simulating both movement and also the power network.

Daniels and Jacimovic (1983) develop a design stage power network simulator for use in evaluating the requirements of the utility supply, working voltages, component ratings and harmonic performance. Developed by the International Engineering Company, inc. the package executes a TSP and LFP program to calculate system conditions (see Figures 2.6.2 and 2.6.3).

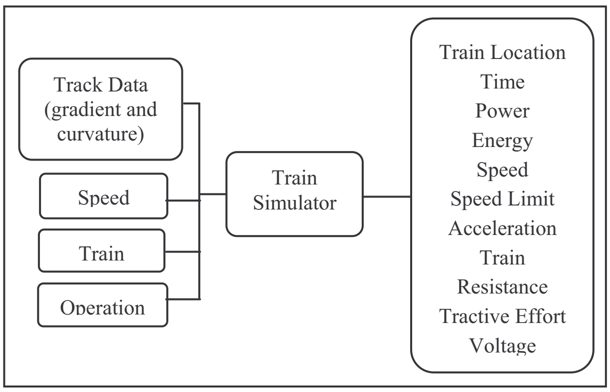


Figure 2.6.2 – Train simulation program (TSP)

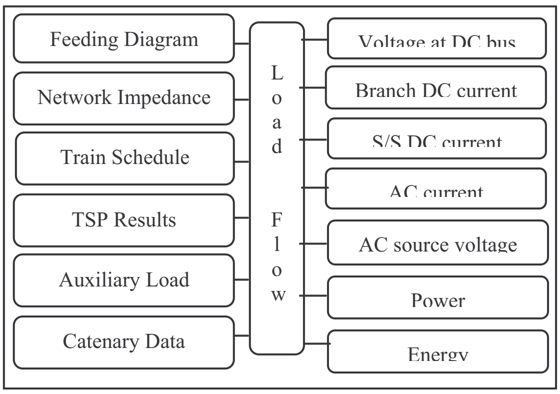


Figure 2.6.3 – Load flow program (LFP)

The result from the LFP is temporal snapshot of:

1. Substation AC and DC volts, amps and watts vs. time

2. DC amps at feeders and catenary vs. time
3. Utility AC voltage fluctuation vs. time
4. AC and DC rms power and currents (peak, off-peak and combined) vs. time
5. Catenary and rail potential vs. distance
6. Energy demand

This data can be saved to a system file or stored graphically and in tabular form in data files.

A program developed by Borwn Boveri (1979) is another design stage simulator for DC traction systems. The program operation is limited to a relatively simple model of a single track but it does allow for a traffic schedule to be implemented on the line. The model calculates line voltages and currents at any point in the schedule and any distance along the track. The program also allows regenerative braking to be employed and so can evaluate the energy levels of the system.

3. AC RAILWAY ELECTRIFICATION

3.1 AC traction lines

For 25 kV networks at 50 Hz supply is directly fed from the electrical utilities via a single-phase transformer substation. Adjacent sections of track are usually supplied from alternate utility phases to keep an equal loading of the three-phase network. The 15 kV, 16⅔ Hz system is more complicated requiring special generators or frequency converter circuits to supply the require feed.

Using a simple transformer arrangement as in Figure 3.3.1a and 3.3.1b is the most economically viable method of supply. In the case of figure 3.3.1a a direct connection to the rails and catenary is made via transformer secondary windings this. This has the disadvantage of large losses, high touch potentials and stray currents that interfere with telecommunications and increase erosion of local metallic pipework. Introducing a cross-bonded return conductor to the system provides a lower impedance path for return currents and its screening effect can also help reduce interference. A more capital-intensive method to reduce interference of traction currents is the addition of booster transformers as shown in Figure 3.3.1c and 3.3.1d. These are unity transformers connected across sectionalized catenary and rails, at intervals of 3-4 km. Return current is forced to flow from the rails and earth into the transformer secondary to equalise the ampere-turns of the primary circuit. In most cases a parallel conductor arrangement is preferred as in figure 3.3.1d to carry the return current. In high voltage AC rail networks the line impedance constitutes most of the total feeding impedance which at power frequency is a result of both physical layout and material properties.

Using an autotransformer system (Figure 3.3.1e) allows an increase in the substation spacing because of the higher transmission voltage involved. The autotranformer is connected across the catenary and an auxiliary feeder with the rails connected to an intermediate point. For 25 kV systems the autotransformers are center-tapped with a unity ratio and a 50 kV supply. A train draws a current, double that of the traction current, through two adjacent autotransformers. Current flows through the autotransformers so that the ampere-turn balance is kept. In an ideal system no current flows along unoccupied rails and so the maximum earth current occurs in-between supplying autotransformers and is a minimum at these transformers.

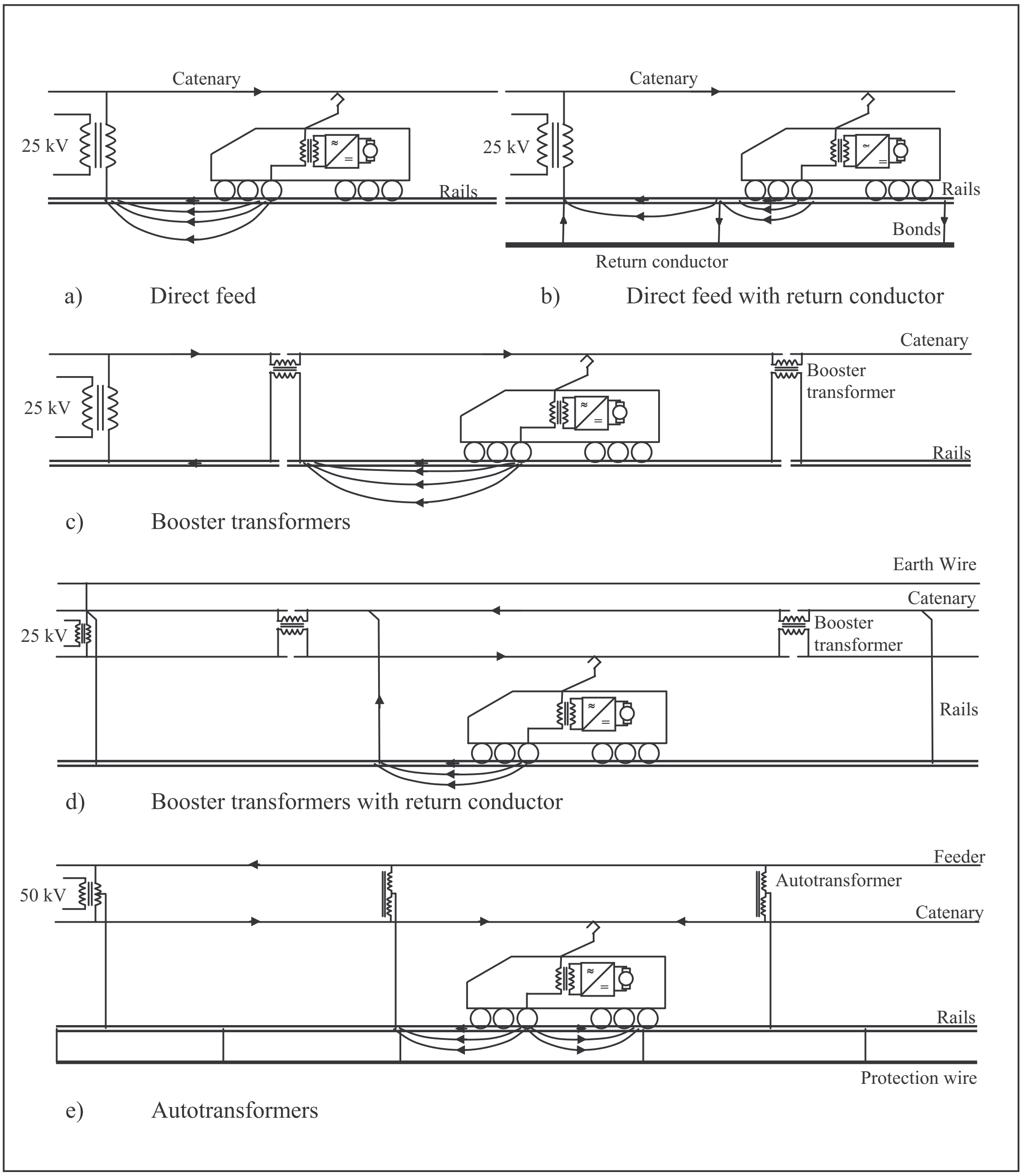
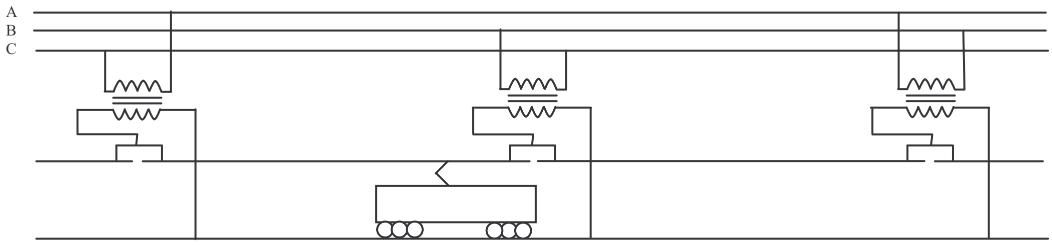


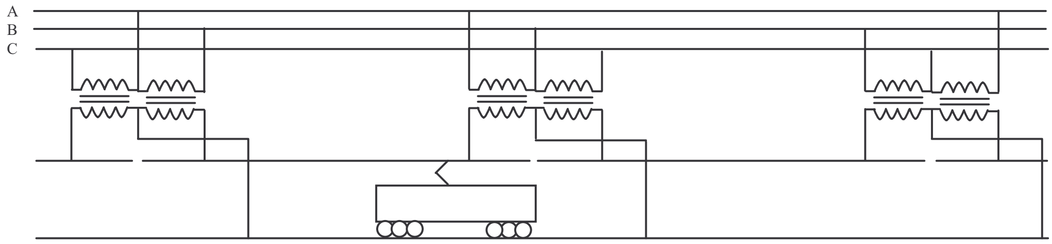
Figure 3.3.1 – AC feeder systems

3.2 AC power supplies

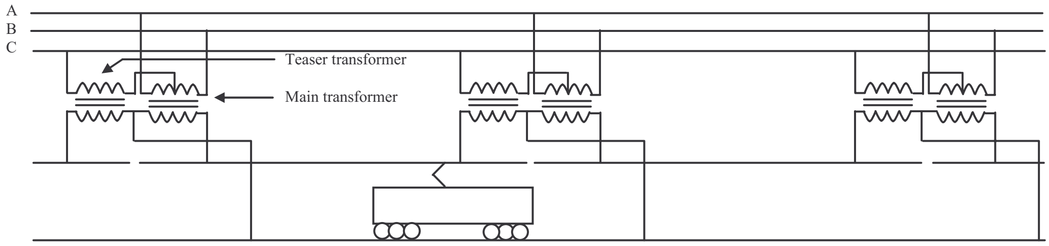
As equal traction currents in reality are unlikely, single-phase supply transformers are usually replaced with special transformer connections or external balancing circuits. Scott, Woodbridge or Le Blanc transformers are commonly used to provide a balanced load on the utility supply, Kneschke (1985) gives these along with other arrangements in a paper on unbalanced traction loads. In the four methods highlighted by Kneschke' paper, balancing is achieved by one or more of the below techniques:



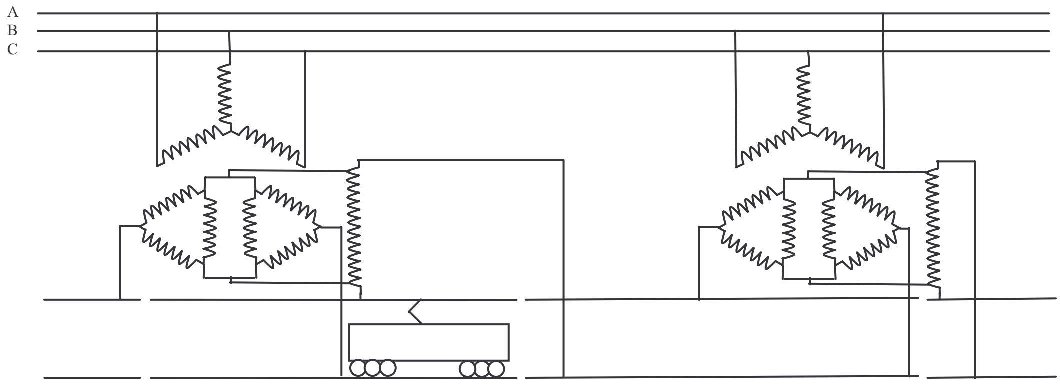
a) Single-phase connection of transformer supply with centre-feed.



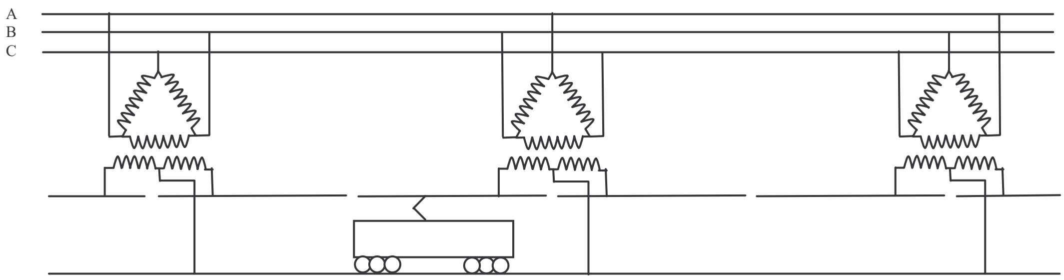
b) V-connection of transformer supply with centre-feed.



c) Scott-connection of transformer supply with centre-feed.



d) Woodbridge-connection of transformer supply with centre-feed.



e) Le Blanc-connection of transformer supply with centre-feed.

Figure 3.2.1 – Transformer substation arrangements

Inherent balancing - successive transformers along the supply line are assigned to alternate phases of the supply network. This is achieved through the sectionalising of the catenary shown in Figure 3.2.1a.

- Local balancing - two-single phase, three-to-two phase and three-phase transformers. Balance is achieved by equally loading the local the supply network at the substation, Figures 3.2.1b through e.
- External balancing - static or rotary balancing equipment.
- Three-phase to single-phase converters - rotary or static converters.

The relative unbalance factor for the V-connected transformer in Figure 3.2.1b compared to that of a single-phase type is 0.5 for the same load. Of the three-two phase types, Scott-connected transformers consist of two sets of windings. The main winding is connected across two supply phases and is centre-tapped, the teaser winding connects the tap point to the remaining phase. The transformer secondary winding voltages are $\sqrt{3}/2.\pi$ degrees out of phase from each other. The main winding is formed from the desired turns ratio, while the teaser winding is a multiple of times the ratio. In the Woodbridge-connection two secondary voltages are supplied, which are again π degrees out of phase but for this arrangement the voltages are unequal. This lower voltage must be raised to match the traction voltage. The secondary windings do not have a common point and as such it is necessary to connect each winding to a different track or to the same track with sectionalised by insulated rail joints. The Le Blanc transformers are similar to Scott types, and the two can be used together in double end-feed systems.

Three-phase transformers can be used for AC traction power supply but they do not produce balance loading of the utility side in symmetrical or asymmetrical arrangements.

In cases where sufficient balancing cannot be accomplished by the choice of transformer connection the use of external equipment can be employed. Static equipment achieves balance of the utility side by the use of capacitor and inductor elements; the system components can also be used for power factor correction. Rotary balancing equipment such as synchronous condensers or induction motors act as a sink for negative sequence currents of the three-phase system. Three-to-two phase converters can be used in situation when no other technique achieves the required balance characteristics. Here a three-phase motor draws balanced current from the utility and can be used to supply torque to a single-phase generator. Static converters can also be employed which utilise semiconductor devices, but they have the draw back of introducing current harmonics into the supply system.

Low power factor is a particular problem in long track sections with single-end feed supply intensified by the use of electronic drives. Power factor can be broken down into two constituent parts displacement factor and distortion factor. The first is governed chiefly by impedance of the traction line, and the later arises due to high levels of harmonics in the line current. Rectifier locomotives can have power factors ranging as low as 40 % during initial acceleration, correction is needed to satisfy specifications imposed by the supply utility. Normally incoming feeders are connected to HV or EHV grid voltages to minimize the effects of harmonics on the utility supply.

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utility. Normally incoming feeders are connected to HV or EHV grid voltages to minimize the effects of harmonics on the utility supply.

Semi-conductor controlled traction equipment and magnetic saturation in transformers and machines can cause resonance in the network creating high frequency currents. These currents can cause increased heating in equipment windings, overcurrents in line capacitors, undervoltages at locomotive pantographs and line overvoltages that exceed safe levels. These effects pose more serious problems in traction systems because of the low impedance of the lines; typically an inductance of 1.33 $mH.km^{-1}$, capacitance of $0.011\mu F.km^{-1}$, and resistance of 0.17 $\Omega.km^{-1}$ which produce resonance at 1 kHz. Traction loads are also high in comparison with the line fault levels, a 10 MW substation may feed a long line with a fault level of 40MW at its termination. Lastly input filters on locomotives interact with the line reactance which may have adverse effects on the problems highlighted above.

3.3 Feeding arrangements

The function of the feeder station, intermediate track sectioning cabin and mid-point track sectioning cabin are to control distribution of the supply to the track. The mid-point cabin as its name suggests is sited between two adjacent feeder stations, whilst the intermediate cabin is approximately halfway between the feeder and mid-point cabin. The mid-point cabin provides electrical isolation for overhead line equipment, neutral sections and track paralleling for the 25 kV systems. The intermediate cabins provide similar functions to the mid-point cabins with the exception tat they cannot terminate feeding sections, both types of cabin increase the systems resilience during loss of supply.

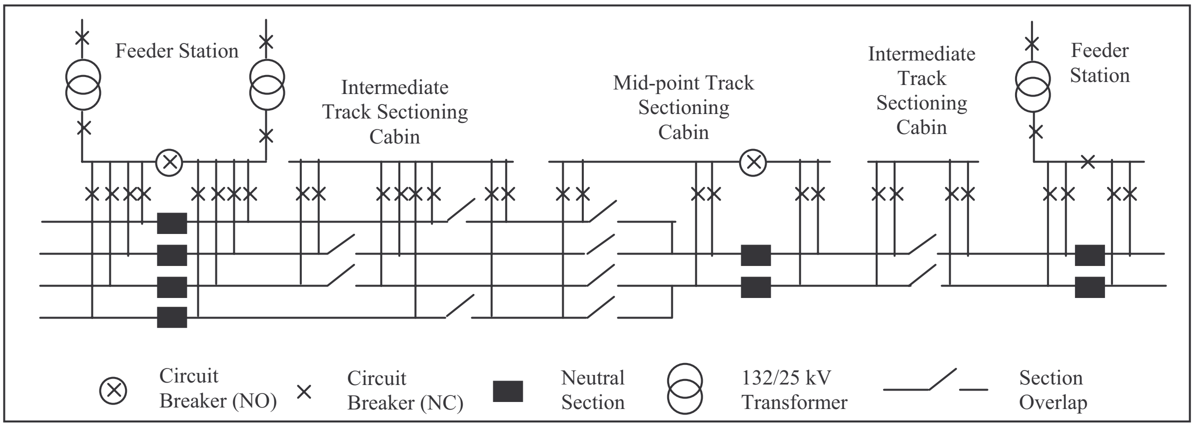

Figure 3.3.1 – Typical 25 kV 'classic' Feeding section

As with DC systems the feeding arrangements can be single-end, double-end or center fed dependant on circuit conditions.

3.4 AC-Fed traction engines

At the introduction of the 25 kV electric supply system, locomotives that used rectifier devices became introduced into service. Figure 3.4.1 shows a typical schematic of the circuitry. It is more common to find the rectifiers in these circuits to be of the semi-controlled bridge type rather than full-bridge. This is due to lower costs and higher operating performance in terms of power factor and armature harmonics. The basic

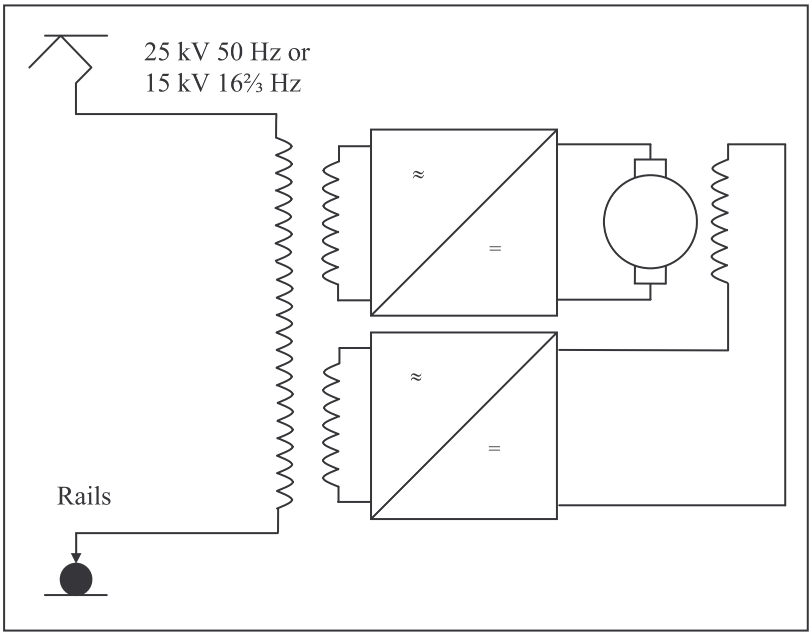

Figure 3.4.1 – AC-DC Rectifier operating a DC SEPEX motor

semi-controlled bridge cannot utilise regenerative braking but this is not usually a problem in long distance lines.

Voltage harmonics created by using the semi-controlled method can be calculated by the use of the Fourier series with the worst voltage harmonic being the second. This harmonic is at a maximum when the firing angle $\alpha = \pi/3$ radians. Approximating the input current as a rectangular waveform allows assessment of the circuit current harmonics, due to the large inductance this is a realistic assumption. The semi-controlled bridge can be shown to reduce the armature current harmonics (beneficial to reduce motor torque ripple) but at a cost of increasing the line harmonics. One method employed to reduce the line harmonics is to switch in more series rectifier circuits. Typically a second bridge with a centre tapped transformer assists in the conduction at half to full supply voltage.

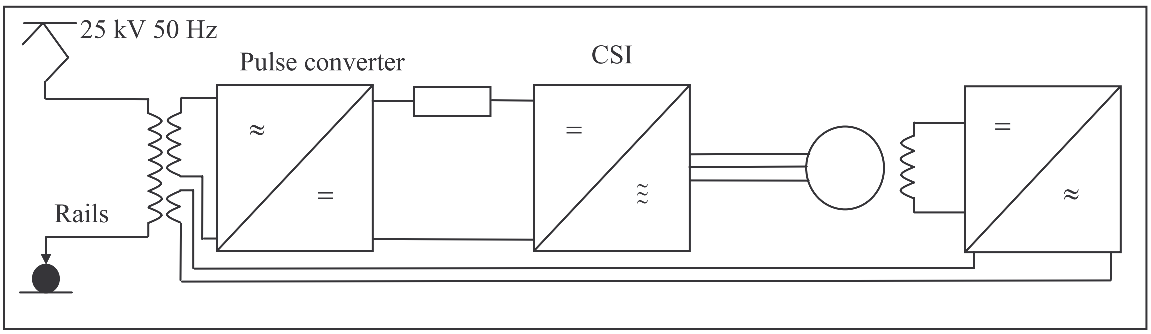

Figure 3.4.2 – AC-DC pulse converter to 3 phase current source inverter operating an induction motor drive rotor, DC-DC chopper feeding motor field winding

In all AC-fed VSI and CSI drives Figure 3.4.2, Figure 3.4.3 and Figure 3.4.4 an AC-DC converter is required to supply the DC link. Commonly a PWM four-quadrant converter is employed which allows for regenerative braking. This type of converter mimics the action of a variable ratio transformer drawing a variable sinusoidal voltage and current at the line frequency. A series filter at twice the supply frequency is required to filter the AC component of the output voltage and the line inductance improves output current ripple. By the careful choice of modulation strategy it is possible to greatly reduce system current harmonics.

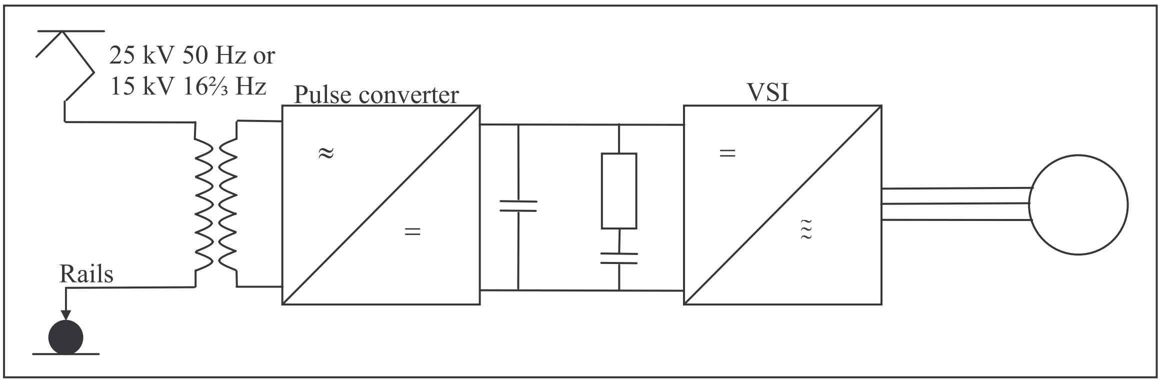

Figure 3.4.3 – AC-DC pulse converter to 3 phase current source inverter operating an induction motor drive

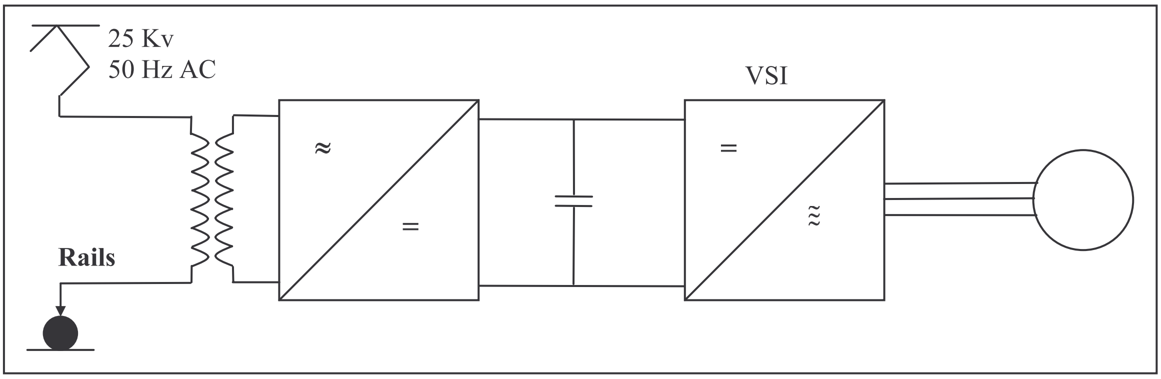

Figure 3.4.4 – AC-DC rectifier to 3 phase current source inverter operating an induction motor drive

3.5 UK case studies

In the UK the 25 kV AC 50 Hz electrification network has steadily grown since the 1960's and the network itself is based largely around the equipment discussed in chapter 3. Overhead catenary wires are now of the simple Mark IIIb type which use a 107 mm^2 copper contact wire. Most UK lines employ single rail return, and these rails are bonded together and also bonded to support structures giving a distributed earth resistance under one ohm.

When booster transformers are installed a separation of 3.2 km is typical, with ratings of 150 A, 200 A and 300 A. Return conductors for two-track lines are normally aluminium and 2x19/4.22mm in cross-section, and four-track lines are normally 4x19/3.25mm.

Typical traction loads are the class 323 EMU, with a double bridge AC/DC converter driving a 3-phase induction motor through a GTO 3-phase VSI inverter. Class 92 dual voltage locomotives (operating from AC or DC traction currents), operating two AC/DC converters which drive two 4-quadrant GTO VSI 3-

Figure 3.5.1 – Class 332 EMU: Heathrow Express

Figure 3.5.2 – Class 323 EMU

phase inverters. Class 332 EMU operating from three parallel 4-quadrant-input AC/DC converters which drive a 3-phase induction motor via two parallel IGBT PWM inverters.

3.6 Review of existing AC traction simulation software

Hsi *et al.* (1999) present an AC simulator which provides a multi-train algorithm for the solution of power flow problems. The paper solves system power flows by decoupling the autotransformer currents into two separate currents the main current and auxiliary current Figure 3.6.1. Treating the upper and lower AT coils separate means that equivalent circuits can be determined for main and auxiliary train currents. The magnitude of the train current supplied by each AT can be found from its inverse aggregate series impedance. Once the currents are quantified the train voltage can be found by considering the voltage drop across each section. For multiple trains the same half-circuit technique can be used and the resulting main and auxiliary currents can be superimposed together. The software developed in this example can solve problems with both constant current and constant power train models.

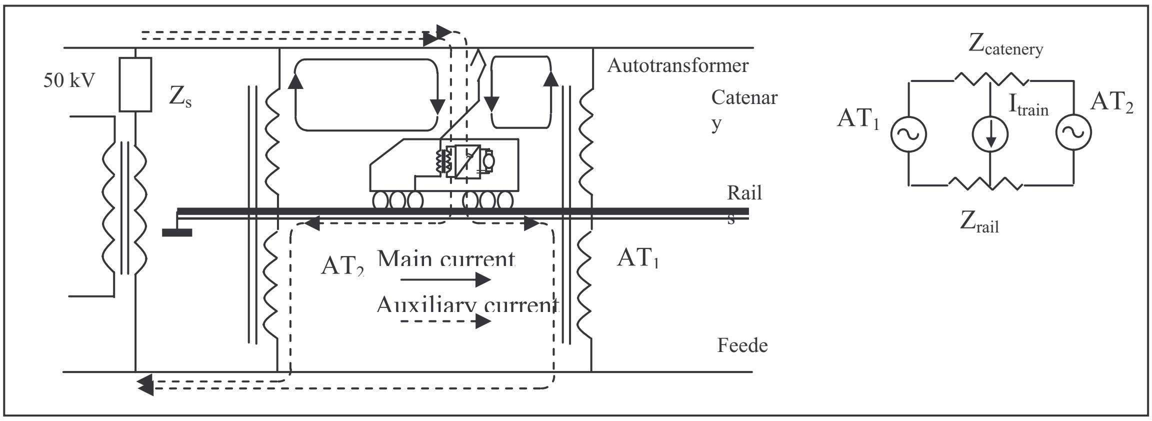

Figure 3.6.1 – Current shared amongst autotransformers

Hill and Cevik (1993) adopt a similar technique to that of Hsi with the addition of modelling a double-end feeding arrangement. The simulator was originally developed for predicting the voltage regulation characteristics of an AC autotransformer system. Current supplied by each AT is assumed on a proportional basis of the train position on the track, the AT closer to the train supplying a higher percentage of the traction current. The package delivers a time varying reading of catenary and rail potentials, and also a voltage history for trains during each run. It provides a design stage tool enabling substation to be place for optimum train and network performance.

Developed at Birmingham University Chan *et al.* (1989) propose a piece by piece model of the railway network. The traction motor and converter are both modelled by a set of known equations and a different set of equations exists for the three modes of train operation employed. For the power network each feeding section is considered individually and as a multi-conductor system. System currents are derived from a mesh equation involving admittance and impedance matrices and voltages similarly can be derived from a nodal equation.

Further work from Birmingham University lead to Mellitt *et al.* (1990) presenting a comprehensive technique to calculate induced voltages in line-side cables. The tool also allows earth current distribution for AT and BT systems to be calculated. The program itself originated because of psophometric voltage limits imposed by the CCITT particularly on lineside telephone cables. The paper compares the accuracy of computer-based approaches with more antiquated mathematical estimates. The software is based around a sectionalized multi-conductor track recorded in terms of impedance and admittance matrices.

Pilo *et al.* (2000) have developed a two part simulator that employs a traffic and AC electrical simulator which provide isolated data that feed into program sub routines. The traffic simulator calculates train motion in terms of distance and time by Newton's second law. A line parameters routine calculates impedance and admittance matrices and then load flow is solved using the Newton-Raphson method. The tool was developed further to calculate unbalanced voltages from direct and inverse sequence voltages, step and touch voltages from equivalent impedances allowing voltages to be obtained by solving nodal equations and induced voltages in parallel lines.

4. CIRCUIT PARAMETERS

In order to simulate any of the railway networks we must have a model for all the basic constituent components. These include conductor rails, overhead pantographs, earth resistance, traction drives, substation feeding and many other items. Some specific components have already been considered in a number of papers.

4.1 Rail impedance

Investigating conductor rails, a paper published by Brown *et al.* (1992) gives an in-depth overview of rail impedances between DC and 60 Hz. The impedance of the rails is shown to be a component of the steel rail resistance, inductance due to internal flux linkage and also inductance due to external flux linked in the air. The paper highlights the influence of both the skin effect and also non-linear magnetic characteristics of the steel and develops an equivalent cylindrical conductor model for each element. Due to the non-uniform shape of the traction rails, variations in DC permeability and the skin effect, standard formulae for resistance and internal inductance cannot be applied.

For DC resistance calculations the cylindrical equivalent conductor has the same cross-sectional area as the rail to maintain resistance. It is defined as:

$$r = \sqrt{\left(\frac{A}{\pi}\right)} \tag{1}$$

For high-frequency AC resistance calculations above 12 Hz, due to the predominant action of skin effect the equivalent conductor must have a circumference that is equal to the perimeter of the rail. Therefore:

$$r = \frac{P}{2.\pi} \tag{2}$$

The paper also attempts to model the inductive properties of the rails but without satisfactory results. It concludes that although the external inductance can be calculated assuming a circular boundary equal to the perimeter of the rail, the internal inductance cannot be modelled correctly by a cylindrical conductor. To determine the internal inductive properties of the rail two methods based around the same technique have been employed in the past. The first technique is that used by Carpenter and Hill (1993), Hill and Carpenter (1993) and Carpenter and Hill (1991) and involves finite element analysis. The technique involves constructing and elemental net base around the rail shape. This net is then used to perform an axisymmetric static and dynamic electromagnetic analysis. The internal inductance can then be obtained by evaluating the stored energy in the material (3) and also the resistance can be found from (4).

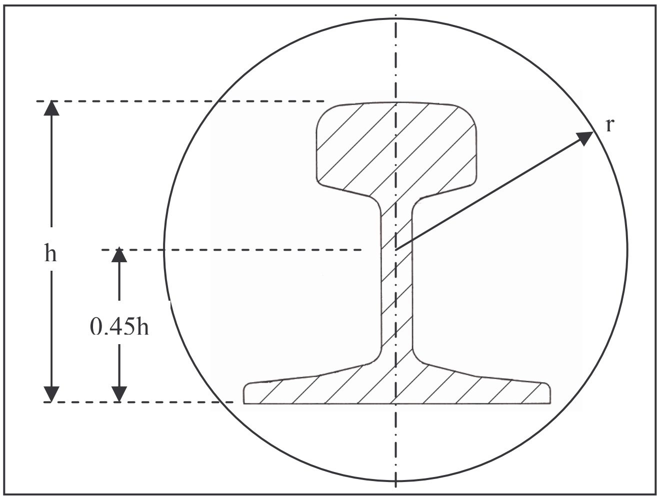

Figure 4.1.1 – Equivalent cylindrical conductor model for rails.

$$\ell = \frac{2}{I^2}\int \mathbf{H}.d\mathbf{B} \tag{3}$$

$$R = \frac{1}{I^2}\sum_{S}\left(\frac{J_s}{\sigma}\right).\delta\mathbf{S} \tag{4}$$

Silvester [14] describes this approach as determining the minimum energy state through the minimisation of a specific function derived from the Helmholtz equation (5).

$$\nabla^2\mathbf{A} + \omega^2.\mu.\varepsilon.\mathbf{A} = -\mu.\mathbf{J} \tag{5}$$

To interpret the irregular shape of the rails as a circular conductor for inductance calculations the geometric mean distance or GMD must be evaluated. This is achieved by evaluating equation (6), which is establishing the GMD of the rail from itself by assessing the effect of a rail composed of many filaments.

$$\ln G = \sum_{m} \frac{\delta A_m . \ln(\ell_m)}{\ell_m} \tag{6}$$

Assuming that all current flows within the skin depth an equivalent conductor annulus must be calculated and converted to a solid cross-section for modeling. This can be achieved through equation (7).

$$\frac{GMD \quad of \quad annulus}{GMD \quad of \quad circle} = 0.7788 \tag{7}$$

The second technique is shown by Lucas and Talukdar (1978), Barr (1991) and also by Wang (1999) and uses a coupled-inductance theory for the modelling of the rail. Slivetser (1966) introduced the basic principle; the theory assumes that the rail is enclosed in a thin cylindrical sheath of radius r in which return current flows, similar to Figure 4.1. The return current is uniformly distributed over the sheath surface and allows not only a defined path for this current but also ensures current distribution in the rail is not affected by proximity effect. The rail cross section is divided into *n* sub-conductors.

The resistance per unit length then becomes (8) and the mutual inductance between the i^{th} and j^{th} sub-conductor is given by (9).

$$r = \frac{n}{\sigma . A} \tag{8}$$

$$\ell_{ij} = \frac{\mu_0}{2.\pi} . \ln\left(\frac{a}{d_{ij}}\right) \tag{9}$$

If i=j then the GMD is substituted as distance d; this can be approximated by their center-to-center distance. If i≠j then the GMR is substituted for d and is obtained from a quadruple integral, Figure 4.1.2 shows the GMR for most common conductor shapes and is taken from a paper by Aguet and Morf (1987).

When the self and mutual inductance for all individual sub-conductors are derived they can be entered into an inductance matrix as highlighted in (7) and a resistance matrix (8) can also be constructed. The voltage current relationship for the conductor can be written in matrix form as (9) where the voltage vector **V** is identical for all the sub-conductors as shown in Figure 4.1.3.

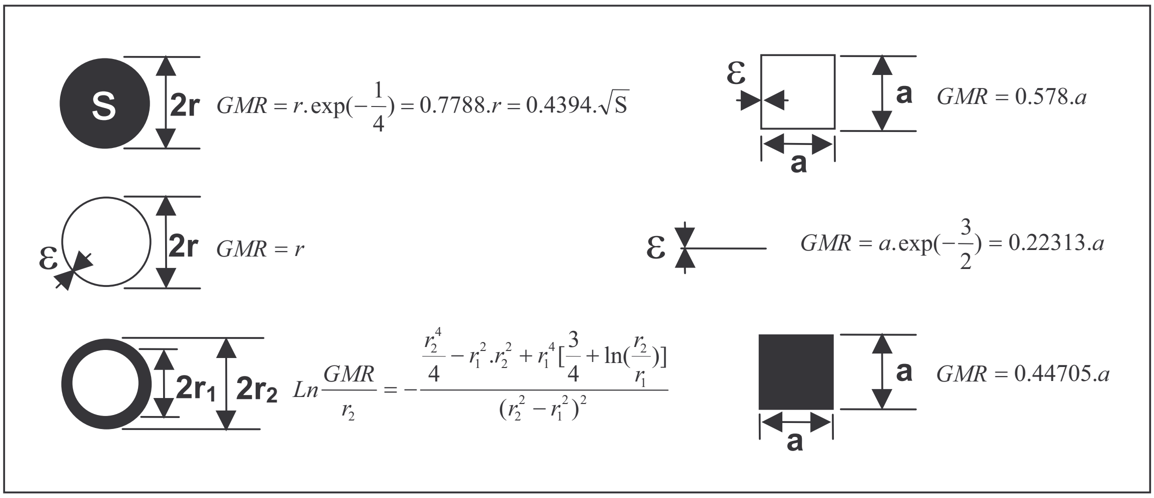

Figure 4.1.2 – GMR of common conductor shapes

$$\mathbf{L} = \begin{bmatrix} \ell_{11} & \ell_{12} & \cdots & \ell_{1j} \\ \ell_{21} & \ell_{22} & & \vdots \\ \vdots & & \ddots & \vdots \\ \ell_{i1} & \cdots & \cdots & \ell_{ij} \end{bmatrix} \qquad (7)$$

$$\mathbf{R} = \begin{bmatrix} r & 0 & \cdots & 0 \\ 0 & r & & \vdots \\ \vdots & & \ddots & 0 \\ 0 & \cdots & 0 & r \end{bmatrix} \qquad (8)$$

$$[\mathbf{V}] = [\mathbf{R}].[\mathbf{I}] + j\omega.[\mathbf{L}].[\mathbf{I}] = [\mathbf{Z}].[\mathbf{I}] \qquad (9)$$

Letting the voltage equal some arbritory value say 1 equation 9 then has only one unknown matrix I , so the solution becomes the inverse impedance matrix $[\mathbf{Z}]^{-1}$. This can be solved by computer program using the LU decomposition technique. For frequency-dependant values of resistance and inductance the sum of the individual currents in all sub-conductors is representative of the total current in the conductor.

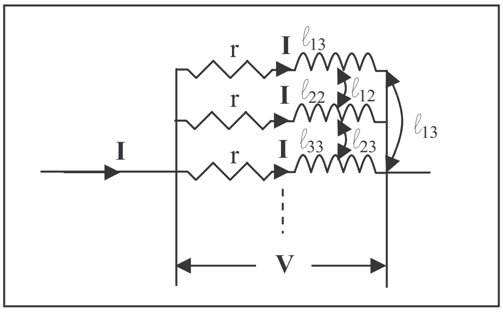

Figure 4.1.3 – Coupled-circuit model of sub-conductors

External inductance due to flux linkage in the air external of the rail can be calculated from the geometrical features of the track layout. The flux boundary between internal and external inductance is given as that of the equivalent conductor radius derived from eqn. (1) acting at a centre that is 0.45 of the rail height above the base.

4.2 Earth impedance

The conductivity of the soil is a significant characteristic when modelling railway or in fact any earthed electrical systems. Not only does the parameter affect ground-return current magnitudes but also significantly influences rail admittance. A paper by Hill *et al.* (1999) collates much information on track parameters and especially those concerning soil conductivity. Table 1 gives a summary of the papers findings in relation to practical ground conductivity levels across a selection of countries including the UK.

Location	Ground Topology	Conductivity Range
Sweden	Rock	0.01 $mS.m^{-1}$ minimum 0.4 $mS.m^{-1}$ nominal
Poland	Alluvial	3.3-77 $mS.m^{-1}$
UK	Rubble stone	20-25 $mS.m^{-1}$
France	General	10 $mS.m^{-1}$
Europe	General	20-40 $mS.m^{-1}$
USA	Coastal region: poorly drained	0.057-4.12 $mS.m^{-1}$

Table 1 – Practical ground conductivity values

4.3 Traction drives

In order to electrical characteristics of traction units it is necessary to obtain a mathematical relationship between the tractive effort supplied by the motor and its voltage. This model can then be used to provide an accurate electrical model for introduction into a power network simulation.

Tractive effort developed by the traction engine mainly depends on the train operation and can either be constant or speed and voltage dependent. Complications develop due to lack in standardisation and the possibility of DC motor or AC induction motor drive systems, both systems are considered.

Current DC motor drive systems are constructed from separately excited DC traction motors because of their inherent capacity for regenerative braking. In current simulators [27], [33] and [24] it is common for electrical drives to be modelled under both armature and field-strength control. This method of motor drive gives rise to the three regions of control as shown in figure 4.3.1. In the speed zone where $0<\omega\leq\omega_1$ the equivalent circuit has the following characteristics; for older rheostat controlled equipment a constant current source is representative. For chopper controllers the input power demand can be evaluated and the motor represented as a constant power term. However, to model this constant power requires use of a negative resistance, which can be problematic to solve in matrix equations. Hence, a constant current model is used as an approximation introducing a small error. In zone $\omega_1<\omega\leq\omega_2$ all equipment draws a line current which is equal to the total motor current this can be represented by a large series resistor and voltage source. The final zone $\omega_2<\omega<\omega_{max}$ provides a linear relationship that can be

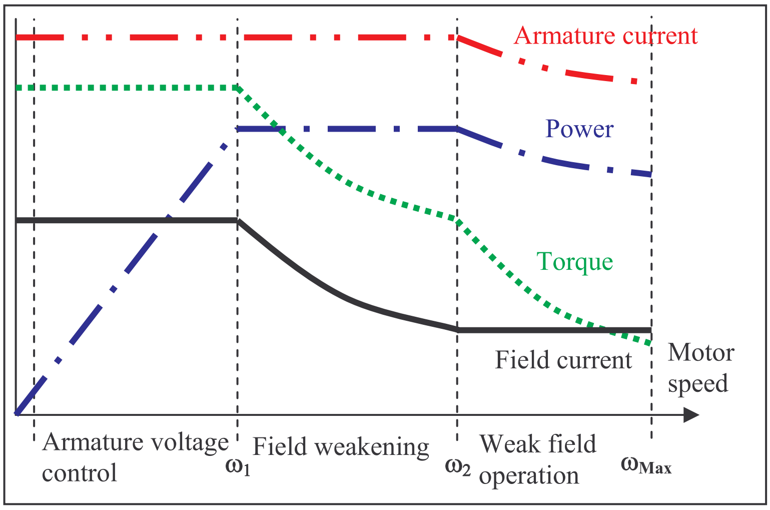

Figure 4.3.1 – DC SEPEX motor drive regimes

modelled by a resistor and voltage source that are both speed dependent. If regenerative braking is employed a straightforward constant power circuit can be used involving a voltage source and series resistor.

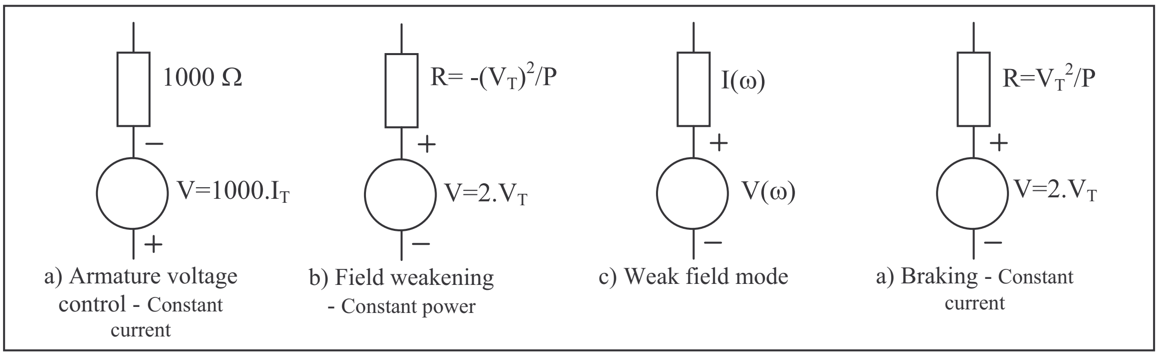

Figure 4.3.2 – Motor equivalent circuits

Changes in recent technologies as highlighted in previous sections have allowed the more appropriate three-phase induction motor to be used in traction applications. Characteristics of the induction motor over the traction duty cycle are given in Figure 4.3.3. Mellitt and Mouneimne (1988) have provided new methods in the electrical representation of AC inverter drive systems for traction applications.

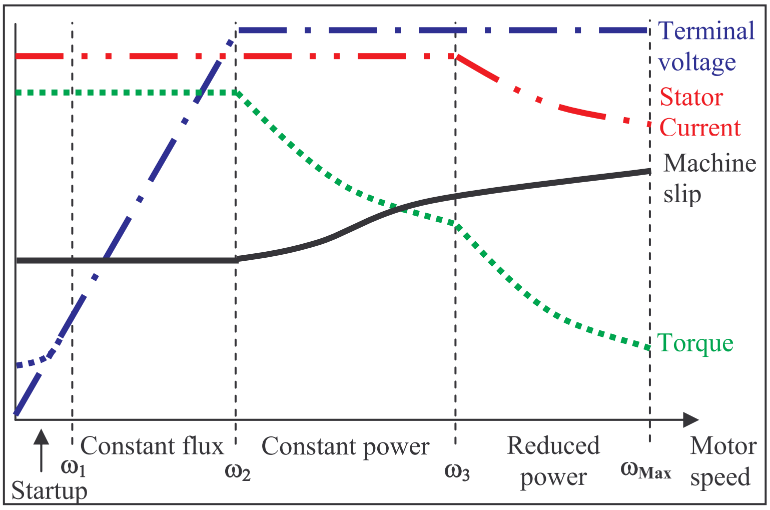

Figure 4.3.3 – Three-phase induction motor drive regimes

The induction motor requires both stator supply frequency and voltage to be control for efficient motoring. Zone $\omega_1 < \omega \leq \omega_2$ is analogous to the armature voltage control in DC motors and so typical representation is as Figure 4.3.2a. I_T can be deduced from the solution of equation 10. Again zone $\omega_2 < \omega \leq \omega_3$ bears very similar resemblance to the field weakening shown in DC motors. A simple constant current representation provides an applicable model. In zone $\omega_3 < \omega \leq \omega_{Max}$ the drive operates with constant input impedance. As both the slip and stator supply frequency are constant all motor circuit components are also constant.

$$P_E = I_T . V_T = I_T{}^2 . R_f + \frac{3 . I_1{}^2 . Z_m . \cos \Phi}{E_i} \tag{10}$$

4.4 Motion simulation

In order so model train movement satisfactorily a Newtonian based equation is needed which relates force mass and acceleration. The following outlines the train resistance formula that can be used for load modelling calculations and simulations. The resistance for train movement on straight and level track can be determined, as proposed by W.J. Davis, as an empirical expression of the form:

$$R_T = \alpha.m_T.n_a + \beta.n_a + \gamma.n_a.v_T + \delta.A_t.v_T^{\ 2} \tag{11}$$

For standard gauge (1435mm separation) railways the formulae listed in Association of American Railways (AAR) recommended practice RP-548 can be used.

The predominant but not exclusive contributors to the α and β coefficients are journal resistances, rolling rotational resistance and track resistance. Coefficient γ consists mainly of flange friction, flange impact, wave action of rail and the wheel to rail rolling resistance. Coefficient δ is composed mainly of head end wind pressure, skin air friction on the side of the train, rear air drag, air turbulence between vehicles and yaw angle of constant wind.

The total train resistance on a level tangent track is the sum of train resistances. When gradients and curves are involved the resistance for the portion of the train length on the curve or gradient is added to the total train resistance on level tangent track to produce a complete train resistance.

As previously stated the formula as listed in AAR RP-548 for locomotive resistance is used:

	Coefficient α	Coefficient β	Coefficient γ	Coefficient δ
Locomotive resistance	.00637	35.833	0.0254	0.0034
Carriage resistance	.00637	89.582	0.0127	0.0073

Table 2 – Coefficient values based on AAR RP-548

The grade or gradient is a measure of the longitudinal inclination of railway track. To determine the grade resistance of an entire train:

$$R_g = \frac{1000}{60}.m_T.g \tag{12}$$

Alternatively grade can be expressed as a percentage, then the resistance can be determined by multiplying the percentage value by a factor of ten to express the resistance in kg/t e.g. 1.67% grade:

$$R_g = (10 \times 1.67).m_T.g \tag{13}$$

Curve resistance is substantially contributed to by the flange contact to rail of the outer leading wheel of a bogie and the slip/slide over the railhead during curving of the two wheels on the same fixed axle. The sharper the curvature the higher the resistance of the portion of the train that is on the curve. The value of curve resistance is calculated in terms of kg/tonne by:

$$R_c = 6.4567.\sin^{-1}\left(\frac{15.24}{r_c}\right) \tag{14}$$

The tractive effort required to accelerate or the braking force to decelerate a train is calculated by multiplication of the train mass/inertia with the acceleration:

$$F_a = a_T.m_T.\xi \tag{15}$$

The total tractive effort required to drive a particular train can therefore be described as:

$$F_T = F_a + R_T + R_g + R_c \tag{16}$$

For the purpose of the electrical simulator a simpler formula can be applied which reduces the dependency on knowing the number of axles per carriage and combines coefficients α and β. This formula is adopted in a thesis by Lukaszewicz, Equation 17 and is the basis of the Lomonossoff equation [1].

$$R_T = A + B.v_T + C.v_T^{\ 2} \tag{17}$$

	Coefficient A / kg	Coefficient B / kg	Coefficient C / kg
Average	10.40497	0.177316	0.033963
Standard Deviation	3.187819	0.087508	0.010554
Chosen Value	10	0.2	0.03

Table 3 – Practical values for coefficients A,B and C in the Lukaszewis Equation

Using practical values from the thesis it is possible to average the terms for various types of locomotives in a per mass equivalent. Table 3 provides chosen values for coefficients A though C where the worst rounding error occurs on coefficient A with a standard deviation of 3.2 which would be acceptable for use in a power network movement simulator.

Using the tractive effort from equation 16 the tractive power supplied to the wheels can be found as:

$$P_T = F_T.v_T \tag{18}$$

Therefore, the electrical power supplied by the motor and drive circuitry can be evaluated as shown in equation 19:

$$P_T = \eta_m.P_E \tag{19}$$

Speed-current and speed-voltage profiles can be employed to determine the instantaneous electrical characteristics of the motor. Also, in much the same way equation 19 may be substituted into equation 10 allowing calculation of motor supply characteristics. These characteristics can then be implemented into the power network model for simulation studies.

5. ELECTROMAGNETIC COMPATIBILITY (EMC) IN RAILWAYS

York services Ltd. have published an extensive report [18] for the Radiocommunications Agency, which looks in-depth into the influence of railway electrification on both internal and external communication systems. The report studies the current EMC regulations and also suggests mitigation techniques that may be adopted. The report itself concentrates mainly on the Radio interference created by railway lines, the disturbances arise mainly because of:

- Arcing between power cable or rails and current collector device
- Arcing on overhead line or power rails
- Transients due to pantograph displacement

Impact of railway electrification systems on other electrical systems and civil infrastructures within and outside the railway environment.

- Interactions of power contacts, wheel-to-rail and rail-to-rail
- Multiple pantographs
- Multiple catenary wires on a single pantograph
- HV power switching
- MHz line resonance
- Excessive voltage stress across insulators
- Intermittent traction current due to poor contacts
- kHz band track circuits

The document goes further to incorporate specific AC EM disturbances:

1. Supply imbalance
2. Supply harmonics
3. Charging the overhead catenary at 1st resonant frequency
4. AC switching
5. Feeding arrangement disturbances
6. Magnetic fields under normal operation
7. Magnetic fields under fault conditions
8. Line resonance due to characteristic impedance
9. Disturbance due to semiconductor traction drives
10. Longitudinal induced voltage due to load or fault current in the catenary
11. Return currents
12. Return current and earth current induced voltages
13. Transverse induced voltage in lineside cables

Another article, which looks at the main internal sources of interference (EMI) in the railway sector, is that given by Hill (1997). The electrical infringements are considered in more depth:

- Rectifier substations – faults, switching transients, harmonics (due to ripple, pulse-type and load current), unbalanced supply.
- Transformer substations – corona, harmonics (due to distorted supply).
- Traction line – corona, transient discharges, changing traction currents, unbalanced magnetic fields.
- Vehicles – switching transients (inverters, pulse converters and choppers), contact arcing (pantographs, collector shoes and DC commutators)
- Signalling equipment – signalling transponders, modulated signals, low-power wheel-rail contacts.

5.1 EMC standards

5.1.1 BS EN 50121-2:2000

BS EN 50121 is the British standard which covers Electromagnetic compatibility for railway applications, part 2 of this standard is concerned with the emissions of the railway system to the outside world. Table 2 gives a general idea of field levels within the vicinity of an electric traction line

System	Frequency	E-field		H-field		Reference conditions	Reference documentation
	Hz	Vm^{-1}	$dB\mu Vm^{-1}$	µT	$dB\mu Am^{-1}$		
750 V to 1200 V conductor rail	0	<10		48	151	I_c =4000 A 50% return current in rails	
600 V to 750 V catenary	0	35		15		I_c =1000 A 50% return current in rails	IEC 61000-2-7
1500 V catenary	0	63	156	111	159	I_c =8000 A U = 1800 V No aerial wire	ITU(T) Directives CIGRE WG 3601
3 kV	0	50	154	28	147	I_c =3000 A U = 3600 V aerial wire	ITU(T) Directives CIGRE WG 3601
15 kV	16⅔	750	177	40	150	I_c =2000 A, RMS U = 17.25 kV No aerial wire	ITU(T) Directives CIGRE WG 3601
25 kV	50	1000	180	16	142	I_c =1500 A, RMS U = 27.5 kV with feeder wire autotransformer	ITU(T) Directives CIGRE WG 3601

Table 4 – Typical maximum electric and magnetic field levels at fundamental system frequency for common rail systems

Figure 5.1.1 shows emission levels measured at 10 meters from the midpoint of the track rails or 3 meters from the substation boundary. The discontinuity of the curves is due to a change in measurement receiver bandwidth. The 80/80 value is the value at which 80% of the passages would not exceed with an 80% certainty.

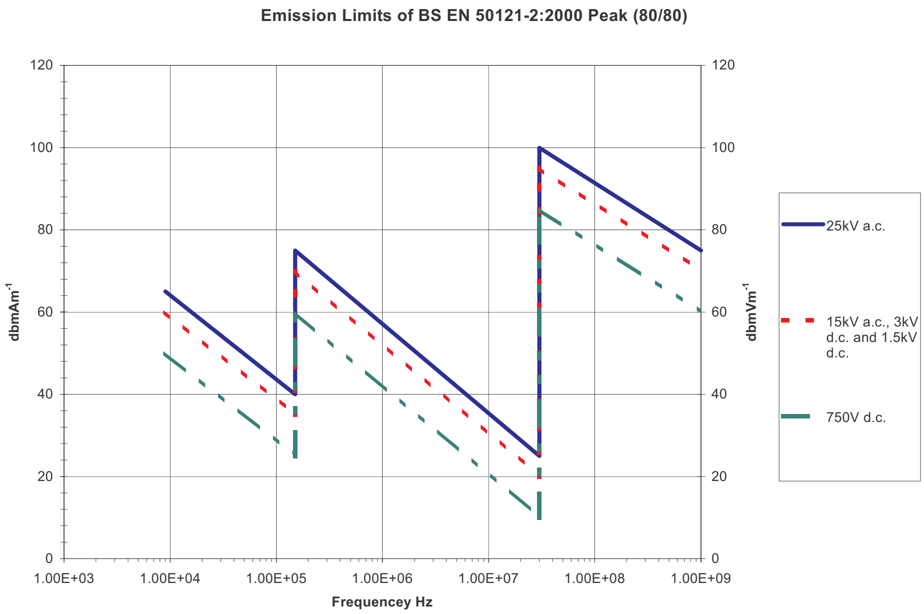

Figure 5.1.1 – Emission limits in the range 9 kHz to 1 GHz

5.1.2 BS EN 50121-3-1:2000

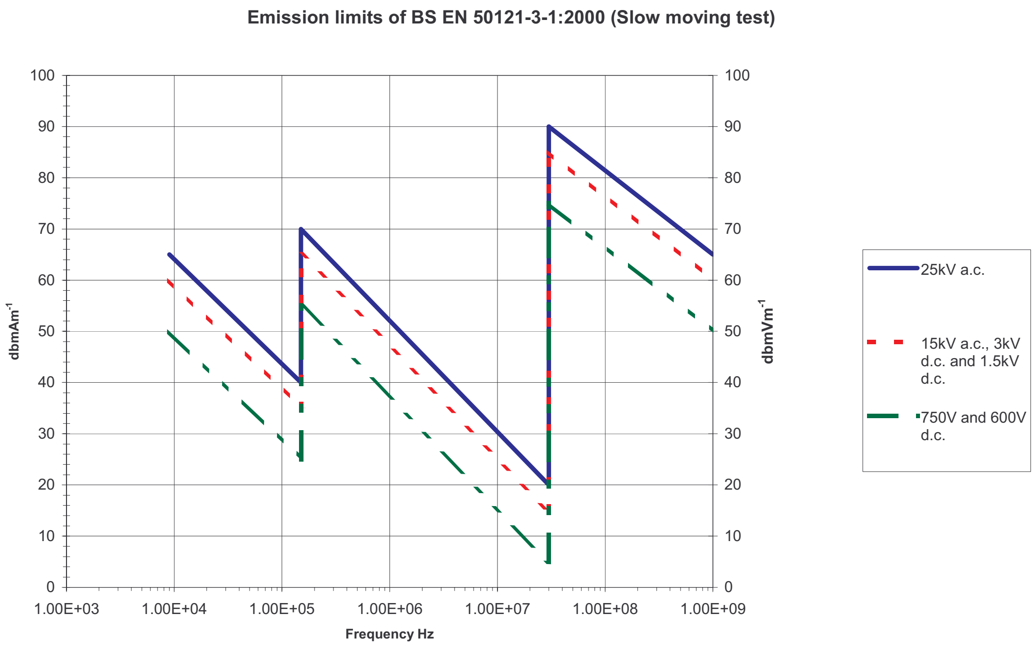

Figure 5.1.2 – Emission limits in the range 9 kHz to 1 GHz

Part 3-1 of the standard is applicable to rolling stock and so covers train and also complete vehicle compatibility. Again emission levels are measured at 10 meters from the midpoint of the track rails. Figure 5.1.2 shows emission limits during the stationary test. For traction locomotives a slow moving test is also required at 20 or 50 kmh^{-1} depending on vehicle type (urban or main line).

5.2 BS EN 50163:1996

This standard limits the supply voltages of traction systems with respect to railway applications. Table 3 shows the limits for the relevant system voltages.

Electrification system	Lowest non-permanent voltage U_{min2}	Lowest permanent voltage U_{min1}	Nominal voltage U_n	Highest permanent voltage U_{max1}	Highest non-permanent voltage U_{max2}
DC(mean values)		400 500 1000 2000	600❶ 750 1500 3000	720 900 1800 3600	770❷ 950❸ 1950 3900
AC (r.m.s. values)	11000 17500	12000 19000	15000 25000	17250 27500	18000❹ 29000

❶ Future DC traction systems for tramways and local railways should conform with system nominal voltage of 750, 1500 or 3000 V.
❷ In case of regenerative braking, a voltage U_{max2} of 800 V may be admissible.
❸ In case of regenerative braking, a voltage U_{max2} of 1000 V may be admissible.
❹ This value has to be confirmed by measurements and might have to be changed.

Table 5 – Supply voltages of traction systems

5.3 Other standards

Further standards which are relevant to the rail sector but do not impose limits on operating equipment are:

BS EN 50207:2001 Railway applications Electronic power converters for rolling stock

BS IEC 61000-2-7:1998 Electromagnetic compatibility (EMC) part 2 environment section 7: low frequency magnetic fields in various environments.

BS EN 50121-1:2000 Railway applications Electromagnetic compatibility Part 1: General

BS EN 50121-3-2:2000 Railway applications Electromagnetic compatibility Part 3-2: Rolling stock - Apparatus

BS EN 50121-4:2000 Railway applications Electromagnetic compatibility Part 4: Emission and immunity of the signaling and telecommunications apparatus

BS EN 50121-5:2000 Railway applications Electromagnetic compatibility Part 5: Emission and immunity of fixed power supply installations and apparatus

BS EN 50155:2001 Railway applications Electronic equipment used on rolling stock

6. SUMMARY

This review highlights the current techniques and apparatus used in the implementation of both AC and DC railway network schemes. Details of utility power supply connection, track feeding methods and motor arrangements are given for both types of supply. Examples of systems currently running in the UK are also included.

The report also details current computer methods used to simulate the electrical characteristics of the AC and DC railway network and its effect on the utility supply companies. A total of twelve programs are described in a modest amount of details. The report briefly identifies some of the parameters used in the computer modeling software and methods used to obtain these parameters.

A final chapter is dedicated to the issues of EMC in railways and the current restrictions imposed on rail projects with regard to EMC.

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Six Monthly Progress Report: Second Report

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1.0 Previous Report

Since the completion of the last six monthly report owing to financial difficulties and commitment issues within W.S.Atkins I have begun a project with National Grid Transco. As a consequence much of the time preceding the last report has been allocated to organisation of the 2002 EngD conference (See EngD Conference Report). Reports were drawn up regarding the development of a network simulator

(Appendix B) and various experimental routines coded in VB were written to perform Matrix inversions, timetable functions and parameter assignments for dynamic train models.

2.0 Introduction - The Company

National Grid Company plc was established on 31 March 1990 as the owner and operator of the high voltage transmission system in England and Wales. When the electricity industry was restructured and then privatised under the terms of the Electricity Act 1989 the National Grid Company plc assumed ownership and control of the transmission system and joint ownership of the interconnectors with Scotland and France.

National Grid, has become the world's largest independent power transmission company. Altogether National Grid employs around 3600 people across England and Wales. That accounts for a vast range of expertise from electrical engineers to accountants, from craftsmen to secretaries.

3.0 Background

National Grid has recently done some work on the response requirement, the amount of response that must be provided to prevent a frequency deviation outside of statutory limits of 50 ±0.5 Hz. Operating experience has showed that the system response is better than expected. This indicated that the contracted system response is probably more than needed. Therefore, by providing a more accurate set of System Response Curves, the costs of Ancillary Services may be reduced. This work has raised a number of issues about how the response requirements should be calculated.

The response requirement has an impact on the environment through the part loading of generators, which increases emissions. Also generator sets operating in a frequency responsive mode run less efficiently than generator sets in other modes.

The increasing usage of renewable generation and the introduction of wind farms into the grid is likely to have an impact on the response requirement.

As well as determining a best estimate of the response requirement NGT must set a margin to allow for errors from various sources. In calculating this response margin a balance must be struck between both the environmental issues and the risk of failing to meet statutory requirements.

As always the public concerns with the company's environmental performance must be satisfied along with their rights to an affordable electricity supply. National Grid Transco is committed to the protection and enhancement of the environment, always seeking new ways to minimise the environmental impacts of present and future activities.

4.0 The Project Scope of Work

The aim of the project would be to improve the calculation of the response requirements so that the most economic response holding can be used which also enables National Grid to meet the statutory limits on frequency deviation.

This will require:

- Improving models of demand and generator behaviour in a transient follow a sudden loss of generation from the system.
- Modelling of how demand changes as a result of changes in frequency following the loss will need to be improved.
- The modelling of plant behaviour over response delivery time scales in event of the loss.
- Validation of the system model against actual loss events.
- Assessing the margin in response requirements needed to allow for modelling errors, failure of plant to deliver response and variation of initial conditions.

Some time may be spent looking at how the response requirements analyses links into the NG processes and how those processes can be improved with a better response requirements calculation.

5.0 Objectives

5.1 Long term Objectives

- Improving models of demand and generator behaviour.
- Manage the risk of failure to meet frequency obligations with cost and environmental impact.
- Modelling of demand-frequency relationship.
- Validation of Eurostag models.
- Statistic analysis of delivery
- Improving the response margin.
- Establish error margins for Generator Mix / Specific plant.

5.2 Short term Objectives

- Gain an understanding of the current methods of calculating the response requirement.
- Complete a literature survey of the current models and to see how response requirements are managed by other countries.
- Learn to use Eurostag modelling software.
- Calculation of physical delivery of actual response primary/secondary during transients.
- Attend Modules.

6.0 Research To Date

See Appendix A

7.0 Next 6 months

- Assess the impact of the location of loss/response holding on response requirement.
- Assess the statistical generator mix of response holding.
- Assess the impact of the generator types on response requirement.
- Assess the impact of the starting frequency on response requirement.
- Begin review of generator models.
- Further study into existing modelling techniques.
- Determine methods to calculate Demand Sensitivity to Frequency index.

8.0 Summary

This Report introduces the current project undertaken by Ross Pearmine at National Grid Transco, Wokingham. Highlighted in the document are the expected objectives for the research to improve the generator response understanding in both the short and long term. Included are details of expected avenues of development that will be explored within the next six months with progress featured in the next report.

Appendix A – Literature Review

Introduction

The safe and secure operation of a complex power system depends largely on the ability of the generators internal to the system to respond to fluctuations and disturbances within the power system. System Frequency on a synchronous system varies with the imbalance between the mechanical energy fed in and the electrical energy taken out. The rate at which the energy is exchanged depends on the energy stored in the components of the overall system. For isolated island power systems such as the UK or Taiwan adequate provision of reserves is essential to maintain system frequency within operational levels.

Currently there is a set of System Response Requirements *vs.* System Demand curves used by the control room to activate ancillary service contracts so that in the event of a generation loss frequency infractions are not experienced. Operating experience shows that the system response is better than what is required. This indicates that the contracted system response is probably more than needed. Therefore, by providing a more accurate model of system response may reduce the financial and environmental impacts of the Ancillary Services.

Frequency Imbalance

National Grid is required to operate the transmission system within the security and quality standards set in the Grid code. The code states (CC6.1.2 & CC6.1.3) that the frequency of the NGT Transmission system shall be normally 50Hz and shall be controlled within the limits of 49.5 and 50.5 Hz unless abnormal circumstances prevail. Under so called abnormal circumstances (credible loss of >1000MW) provisions are made so that the system may deviate from operation frequency by 0.8 Hz. Provisions are made on the grid so that in exceptional circumstances the system frequency may fall between 47 and 52 Hz. In addition National Grid imposes its own operational limits of 50 ± 0.2 Hz which has provisions for 1500 excursions outside frequency targets per annum.

Various methods can be used to correct an imbalance and hence bring frequency back to a target or stop it moving in the first place these include; Manual despatch, Automatic governor control, Automatic Generator Control[1], Low Frequency or High Frequency Relays

Frequency control is achieved through generation response and also demand control. Demand control is fast acting and easy to implement but is only of use for falling frequencies. Generator response is provided by governor action on running machinery, pumped storage, gas turbines and such like. The response is subdivided by National Grid into the terms primary, secondary and high-frequency response. Previous Investigations by national grid [2] also looked at the possibility of providing a pre-primary response system operation in the milli-second time scale.

Very controlled fluctuations as experienced during load changes for example lead to predictable changes in generator operation. These changes can be shown to follow simple mathematical models which in turn can be modeled to predict system behavior.

Response Definitions used in NGT

Primary response – The automatic response to a decrease in system frequency. Machines supplying response in this category are those that provide their full MW generation capability within 10 seconds of the dispatch instruction or frequency deviation. The device is required to maintain the frequency above a 0.8 Hz drop until secondary response becomes available. Full generation capacity should be sustainable for 20 seconds following initiation. Devices may supply some or all of the primary response requirement.

Secondary response – The automatic response to a decrease in system frequency. Machines supplying response in this category are those that provide their full MW response capability within 30 seconds of the dispatch instruction or frequency deviation and hold this for up to 30 minutes. The device is intended to contain and partially recover the frequency after the initial action of the primary response.

High frequency response – The automatic response to an increase in system frequency. Machines supplying response in this category are those that provide their full MW generation capability between 0 to 10 seconds. The device is required to contain frequency change and must assure there is no lesser reduction thereafter.

The discrimination between primary and secondary response is a conceptual one that is best explained through Figure A1. In reality physical separation of the two response types is not straight forward as both may be held on the same unit.

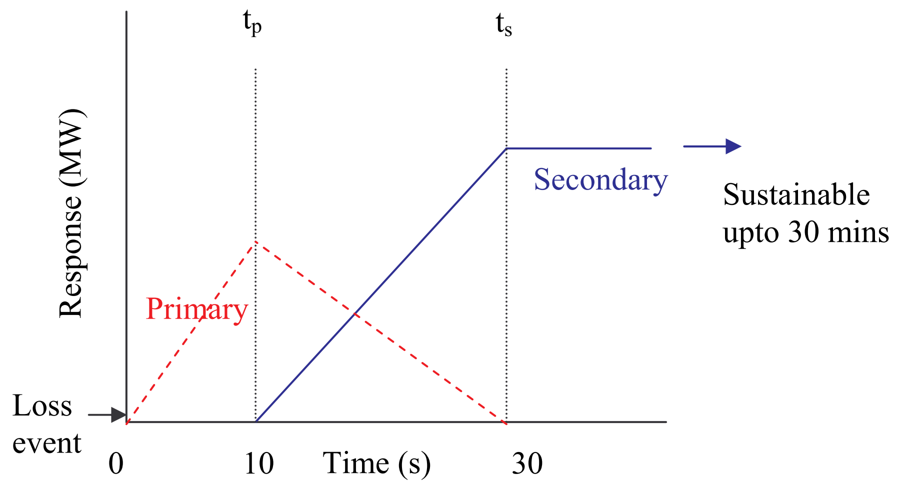

Figure A1 - Assumed 'Primary' and 'Secondary' Response Delivery

Limited High Frequency Response – A response to an increase in system frequency above 50.4Hz which must be at a minimum rate of 2% of output per 0.1Hz above 50.4Hz and be fully available within 10 seconds. This Limited High Frequency Response is for BMUs operating in a Limited Frequency Sensitive Mode

Five minute reserve – machines supplying response in this category are those that provide their full MW generation capability within 5 minutes of the dispatch instruction or frequency deviation. Full generation capacity should be sustainable for 4 hours following initiation.

Spinning Reserve – the response in whole MW at which a generating unit should hold to give maximum capability to provide 5-minute reserve.

Operating Reserve – additional output available from generating plant which must be realizable in real-time operation to respond in order to contain and correct any system frequency deviation in the event of a generation loss.

Generator response

The response of the generators falls into one of three categories [3] autonomous generation response for fast (< seconds) fluctuations, regulation by the AGC (seconds-minutes) or manual load following (minutes-hours).

The differences in the three functions affect the type of generator unit required to respond to the load changes. Generators providing a regulating service must respond quickly to frequent, small load changes. However, the load following generators will respond to large, but slow changing loads.

Response contracts between National Grid and Balancing Mechanism Units (BMUs) are confirmed by response profiles that provide accurate response details for each BMU. These profiles are supplied for a range of frequency deviations from 0.1 to 0.8 Hz.

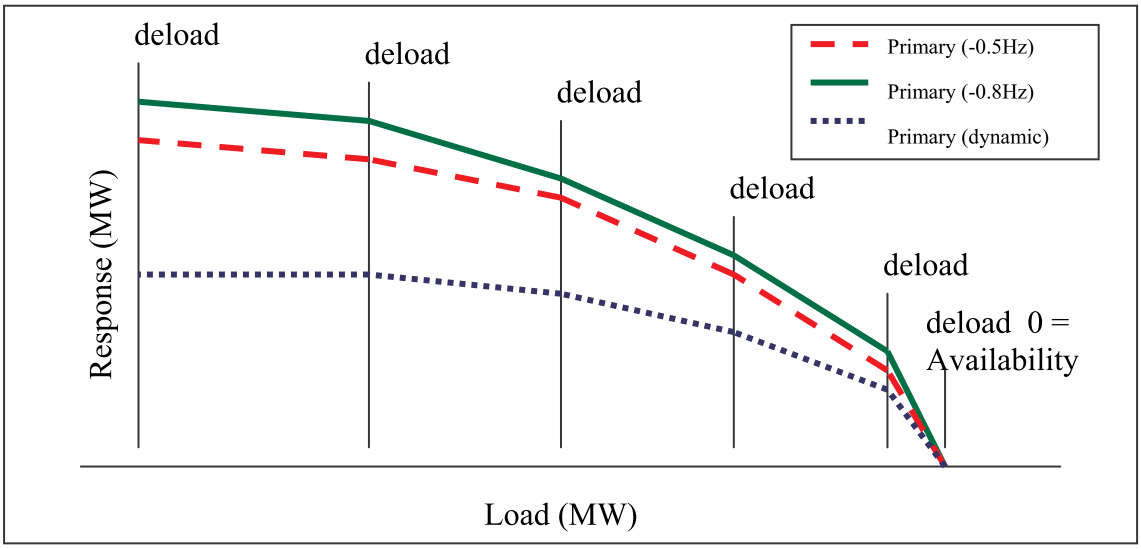

Figure A2 - Sample response curve

Balancing Mechanism Units [4] may be instructed to operate in either a Limited Frequency Sensitive Mode or a Frequency Sensitive Mode (ie. to provide Primary and High Frequency Response or Primary, Secondary and High Frequency

Response). A BMU operating in the Limited Frequency Sensitive Mode will be considered as frequency insensitive unless the system frequency exceeds 50.4Hz when the BMU will be required to provide Limited High Frequency Response.

A BMU may be instructed to provide combinations of Primary, Secondary and High Frequency Response with the combinations permissible, and the value of responses realisable, being defined within the relevant Ancillary Services Agreement. Such an instruction results in the BMU operating in a Frequency Sensitive Mode.

Calculation of Reserves for frequency response

Primary

Previous methods for calculating reserve in national grid [5], use a system network model where all lines are lumped as a single transmission line. All loads were connected to one end of the line and all generators are connected to other end of the line. All MW demand lumped as one load and reactive MVAr demand was set to zero. Generators were grouped into different types, i.e. nuclear, coal, CCGT etc. Each generator type having its own governor/AVR models and the starting frequency set to 50Hz.

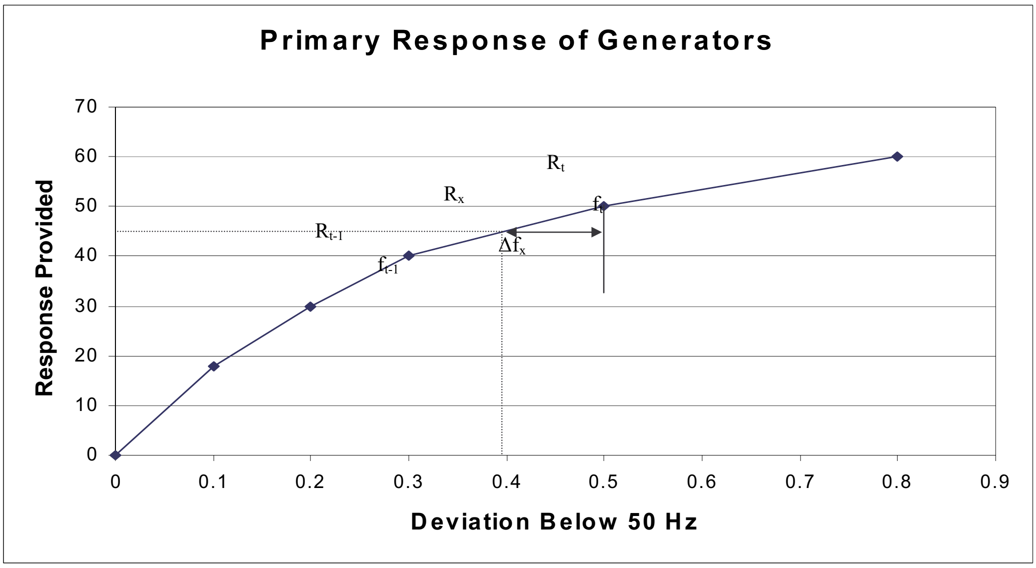

Figure A3 – Primary Response of generators

The newer method employs a more detailed network model and the process outlined in figure A4 and equation 1.

$$R_{prm} = \left(\frac{R_x}{1 - \left(\frac{(1-\kappa)\Delta f_x}{(f_t - f_{t-1})} \right)} \right) \quad Eqn\ 1$$

where

R_{prm}	is the primary response requirement
R_x	is the response calculated at x s (x is a time period defined by National Grid)
κ	is the average of the ratio of response held at the deviation frequency and at target frequency
Δf_x	is the difference in frequency at x s from the target frequency (x is a time period defined by National Grid)
f_{t-1}	is the frequency deviation below 50 Hz at the start of the transient;
f_t	is the target frequency.

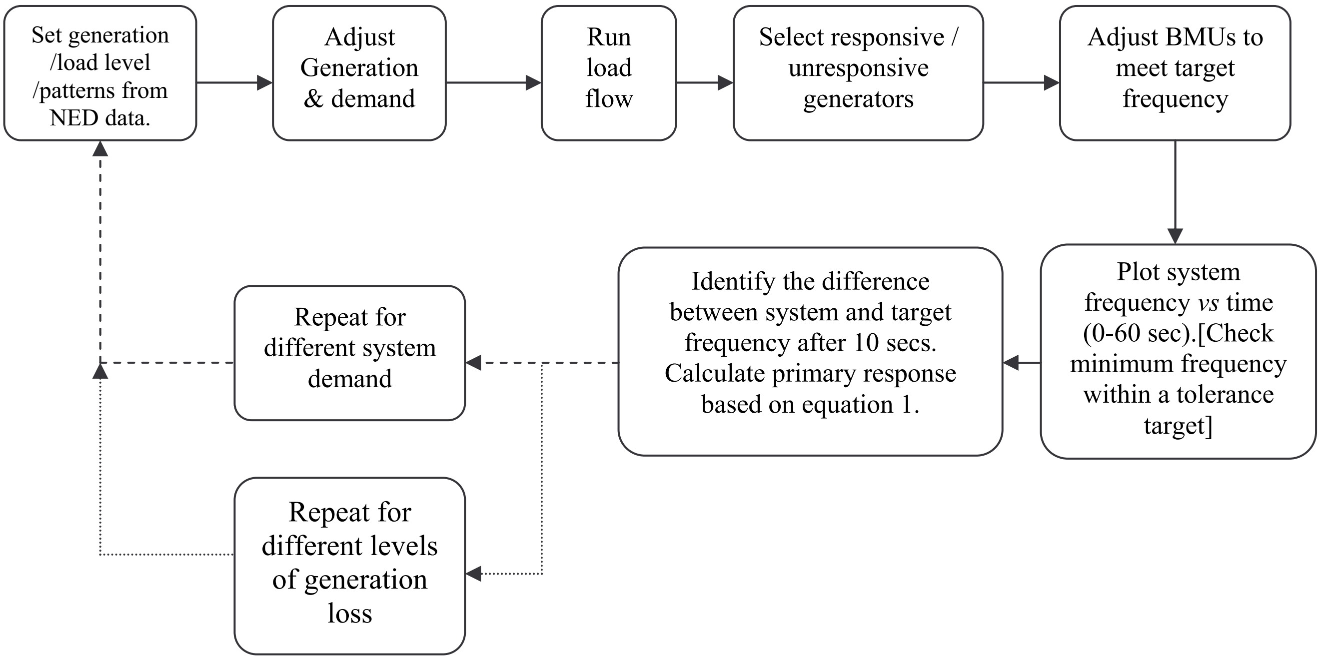

Figure A4 – Calculation of primary response

An error margin is added to final results according to:

$$\text{Margin} = \sqrt{[(\varepsilon \cdot \textit{Response requirements})^2 + \mu^2]} \quad \text{Eqn 2}$$

where

ε	is an error margin
μ	is a weighting factor

Secondary

NGT currently calculate secondary response using the formula:

$$R_{\sec} = (1+\varepsilon)(Risk - \alpha(1+fd_{s\cot})D_{E\&W}\Delta f_{\max,\sec}) \quad Eqn\ 3$$

where

$R_{\sec}$	is the secondary response requirement
ε	is an error margin
$Risk$	is the level of risk for which response is being calculated
α	is the sensitivity of demand to changes in frequency
fd_{scot}	is the Scottish demand as a fraction of NGC demand
$D_{E\&W}$	is the NGC demand
$\Delta f_{max,sec}$	is the maximum frequency deviation allowed on secondary response time scales

Other Approaches to reserve calculation

A paper from Taiwan University [6] looking at the Taiwanese Grid (60Hz) proposes that reserve be divided into four categories; frequency regulating, instantaneous, extended and stand-by reserves. For comparison frequency regulating and instantaneous reserves are equivalent to national grids primary and secondary reserve respectively.

$$\mathrm{RSRR} = \mathrm{Max}[\mathrm{SR}, P_{Gmax}] \quad Eqn\ 4$$

$$\mathrm{SR} = P_{system} \times (\delta P_L/\delta f) \times (60-f_1) \quad Eqn\ 5$$

$$\mathrm{FRR} = P_{system} \times (\delta P_L/\delta f) \times (60-f_2) \quad Eqn\ 6$$

$$\mathrm{IR} = \mathrm{RSRR}-\mathrm{FRR} \quad Eqn\ 7$$

Where

RSRR	is the reasonable spinning reserve
SR	is the spinning reserve
P_{system}	is the system load
$\delta P_L/\delta f$	is the load-frequency sensitivity factor
IR	is the instantaneous reserve
FRR	is the i frequency regulating reserve
f_1	is the frequency of load shedding
f_2	is the margin to f_1
P_{Gmax}	is the output from the largest generator

In these equations FRR and IR are equivalent to National Grid Primary and secondary responses respectively.

Presented in the paper and others [7], [8] is a method for calculation of the value of α, the sensitivity of demand to changes in frequency, equation 8. National Grid currently uses a value of 0.02, which has been developed through operating practice and confidence in the system security. The presented papers employ a statistical approach to calculate the mean (μ) and standard deviation (σ) of the demand sensitivity to frequency based on forced generator outages during a five year period. The factor for each seasonal day is calculated from system data for three separate load periods; hours 0-6, 7-14 and 15-23. Demand sensitivity to frequency is then calculated depending on the rate of change of the system load and the use of pumped storage (Table 1), typical values range from 0.0857 – 0.1212.

$$\alpha = \frac{\delta P}{\partial f} \approx \frac{\Delta P}{\Delta f} \quad [\text{pu.Hz}^{-1}] \qquad \text{Eqn 8}$$

	Pumped storage	No pumped storage
$\frac{dP_{system}}{dt} < 0$	(μ – σ)	(μ)
$\frac{dP_{system}}{dt} \geq 0$	(μ – σ)	(μ + σ)

Table 1 - Criteria for calculating demand sensitivity to frequency

The sensitivity of a system load to frequency can also be expressed by the load damping factor [9], which represents the change in the power for a given change in the frequency in an interconnected system. Typical values of 1% to 2% are common; a value equal to 2 implies that a 1% change in frequency would cause a 2% change in load. The smaller the changes in frequency for a given load change, the stiffer the system. The per unit area transfer function using the total load as power base and 50 Hz as frequency base, can now be represented as follow:

$$\frac{\Delta \overline{F}(s)}{\Delta \overline{P}_G(s) - \Delta \overline{P}_L(s) - \Delta \overline{P}_{tie}(s)} = \frac{1}{\overline{D} + \overline{M}s} \qquad \text{Eqn 9}$$

where

M	is the combined inertia constant of the local machine and the effective rotating inertia of all the other machines connected via the power system
D	is the load damping factor

The inertia constant of the power system can be estimated using the measured transients of the frequency. *Inoue et al* [10] have used frequency transient responses from loss events and load rejection tests to provide an approximation of the transient in estimating the inertia constant. At the onset of an event the change in frequency (Δf) is zero and substituted in equation 10 system inertia becomes:

$$M \frac{d(\Delta f / f_o)}{dt} + K\Delta f = -\Delta P \qquad Eqn\ 10$$

where

M	is the inertia constant of system
ΔP	is the amount of generation loss
K	is the power/frequency characteristic [pu.Hz^{-1}]
Δf	is the change in frequency
f_o	is the rated system frequency

The inertia constant for the Japanese grid system calculated from 10 events is around 14 to 18 seconds. It provides a set of estimated values corresponding to the Japanese Grid for K (-ΔP/Δf) where Δf includes response, ranging from approximately 1.53 to 0.77 at a transiently settled state ≈ 20 seconds after the event. It also suggests that a positive correlation exists between the inertia constant and load damping, which influences the value of system inertia for a given load.

A paper on the Irish electricity grid[11] uses locked governor tests to establish estimates of inertia and load sensitivity to frequency. It approximates the LFSF to in order of 2-2.5% per Hz and gives a system inertia of 5000 MJ or 1.6-1.8 MWs/MVA. The paper also successfully simulates grid responses by use of low order generator models.

Mansoor [12], suggests without speed control governors and tie lines, the inertia and the damping constants can determine the system response to a load change, and the steady state frequency deviation can be calculated as

$$\Delta f_{ss} = \frac{-\Delta P_L}{D} \qquad Eqn\ 15$$

The steady state frequency deviation following a load change for a power system with generator units operating in speed droop mode is given by equation 11.

$$\Delta f_{ss} = \frac{-\Delta P_L}{\left(\frac{1}{R_1} + \cdots + \frac{1}{R_n}\right) + D} = \frac{-\Delta P_L}{\beta} \quad Eqn\ 11$$

where

D	is the frequency characteristic of load damping
$R_{1\ldots n}$	is the speed droop for generators 1 to n
ΔP_L	is the system load change
Δf_{ss}	is the steady state frequency deviation
β	is the power system frequency response (stiffness) [$MW.Hz^{-1}$]

The physical significance of β can be stated as follows; if a power system was subject to a step load change, it would experience a static frequency drop inversely proportional to its stiffness. The smaller the changes in frequency for a given load change the stiffer the system. The steady-state relationship between load change, frequency change and the increase in power output provided by the governor action is shown in figure A6. The power output increase of each individual unit under governor control is given by:

$$\Delta P_T = -\frac{\Delta f_{ss}}{R_{unit}} \quad Eqn\ 12$$

A linear approximation [13] of the frequency response characteristic of the total system can be expressed as.

$$\frac{\Delta P_L}{P_L} = K_L \frac{\Delta f}{f_t} \quad Eqn\ 13$$

$$\frac{\Delta P_T}{P_L} = -K_T \frac{\Delta f}{f_t} = \frac{1}{\rho_T} . \frac{\Delta f}{f_t} \quad Eqn\ 14$$

where

K_L	is the frequency sensitivity of the power demand
K_T	is the reciprocal of droop for the total system generation
ΔP_L	is the system load change
ΔP_T	is the system generation change
ρ_T	is the system droop

K_L relates to the total system demand and tests conducted on actual systems indicate the generation response characteristic is more dependent on frequency than the demand response characteristic. K_L has typical values between 0.5 and 3 while K_T is approximately 20 (ρ_T = 0.05). In the above equations K_T and K_L have the opposite sign meaning an increase in frequency causes a drop in generation and an increase in electrical load. A change in power demand can be expressed as.

$$P_{demand} = \Delta P_T - \Delta P_L = -(K_T + K_L).P_L \frac{\Delta f}{f_t} = -\beta P_L \frac{\Delta f}{f_t} \quad Eqn\ 15$$

The coefficient $\beta = K_T + K_L$ is refered to as the stiffness.

Brief Introduction to Generators

The synchronous a.c. generator consists of two main components a stationary element called a stator and a rotating member known as the rotor. These components are separated by an air-gap and both carry copper windings. A rotating field machine common in larger generators carries a d.c. field winding on its rotor, connection to which is made via slip-rings and brushes.

Under steady state conditions the machine will operate at a synchronous speed but an increase in the output power is only facilitated by an increase in input power to the prime mover. This action will cause the rotor to accelerate above synchronous speed until the new power balance is meet, at which point the machine will return to its synchronous condition. If two or more generators are connected on the same electrical system grid they will operate as if they are on the same shaft. The real power generated depends on the prime mover torque, which is controlled in a hydraulic turbine by the guide vane position.

It is often necessary to respond to changes in load as explained. This is achieved through controlled changes to the operating conditions of a generator and for this two basic control elements are required the Governor and AVR (Automatic Voltage Regulator). The AVR feeds back the generator terminal voltage and compares this with a reference signal. The resulting error signal is amplified and fed into the controller for the field voltage. The purpose of the governor is to control the amount of power transferred to the power system by maintaining a balance between the input shaft power and the exported electrical power.

Two types of control schemes are used for most generator drives; the first is called isochronous control where the governor continues to adjust the generator output until the measured frequency matches a set point precisely. This type of scheme is employed when a generator is supplying an isolated load or is used in a relatively small power system, where only one generator is used to respond to load changes. Isochronous governors are not used in multi-machine as they will counteract each other in trying to control system frequency to their own setting.

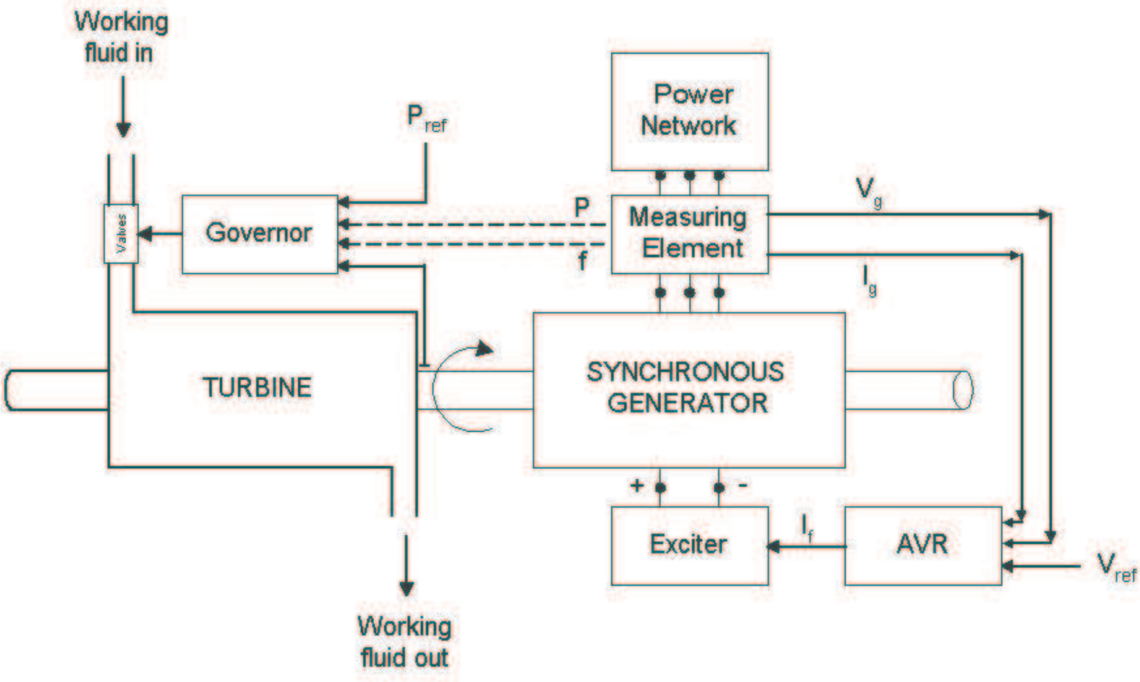

Figure A5 – Generator diagram

The second type is droop control whereby the governor opens the guide vanes to a fixed position determine by the relationship between system frequency and a speed reference. The speed droop operates as a steady state offset with regard to a constant frequency reference. The turbine speed cannot be directly changed once the generator is locked to a power system but it is possible to change the speed reference of the governor. This allows all the control machines to pick up load if the power system frequency falls and likewise deload if the power system frequency rises.

The governor performance is represented by the speed droop characteristic of the generating unit. The speed droop of a unit is defined by equation 16.

$$R\% = \frac{\Delta f(\Delta w)}{\Delta P} = \frac{f_{nl} - f_{fl}}{f_o} \times 100\% \qquad Eqn\ 16$$

where

$R\%$	is the droop
f_{fl}	is the steady state frequency full load
f_o	is the rated frequency
f_{nl}	is the steady state frequency no load
$\Delta\omega$	is the machine speed

A typical droop characteristic for the UK is 4% as specified in the Grid Code

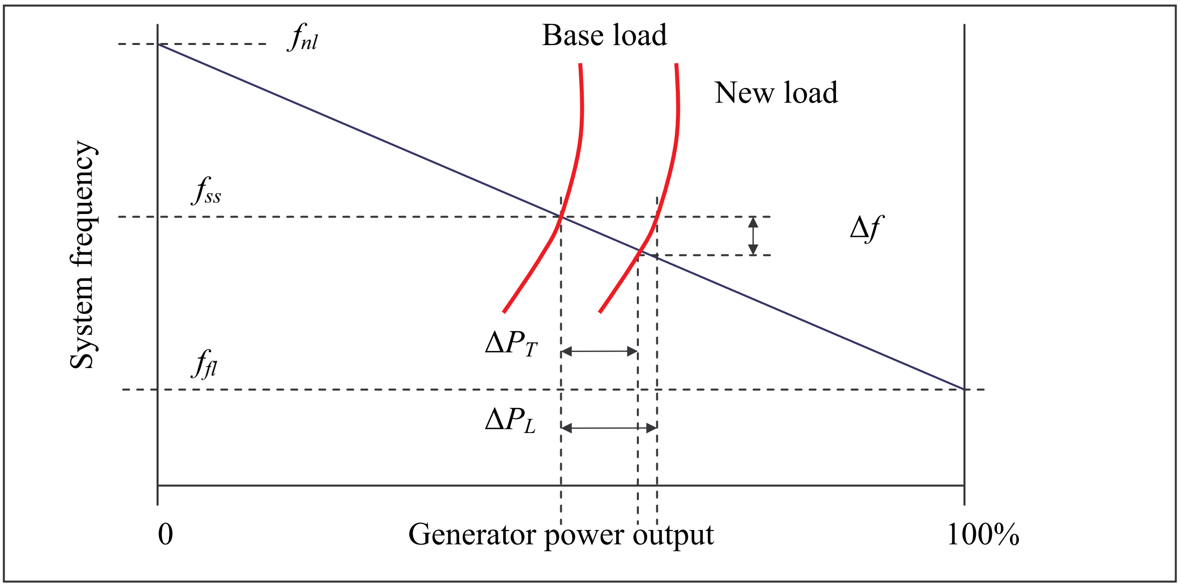

Figure A6 – Generator Characteristics (with speed droop)

CC6.3.7, which means that a frequency deviation of 4% (2 Hz) causes a 100% change in the generator output. The load frequency control characteristic of the power system depends on the collective effects of all the droops of the speed governors and on the frequency characteristics of the load damping.

Basic models for speed governing systems and turbines for power system studies are put forward by a number of IEEE working groups. These include models for steam and hydro turbines [14], hydraulic turbines [15] [16], and also fossil fired plants [17]. The papers define various function block diagrams for turbine controls and when possible provides typical parameters for such models. Adibi *et al* provide models of frequency response and reserve for various generator types.

Summary

In this review an introduction is made into the methods used by National Grid to calculate primary and secondary response. Also included in the document are various methods employed internationally to define a power load-frequency characteristic, and examples of calculated values for those systems.

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Six Monthly Progress Report: Third Report

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1.0 Previous Work

The following sections highlight progress made on objectives set out in the previous six monthly reports (report two).

1.1 Determining methods to calculate Load Sensitivity to Frequency

Review of literature (Appendix A) shows that the value of load sensitivity used by National Grid is in line with that of other systems. After analysis of existing historical data it was found that the sampling period records is not small enough to directly measure the dynamic changes of the load.

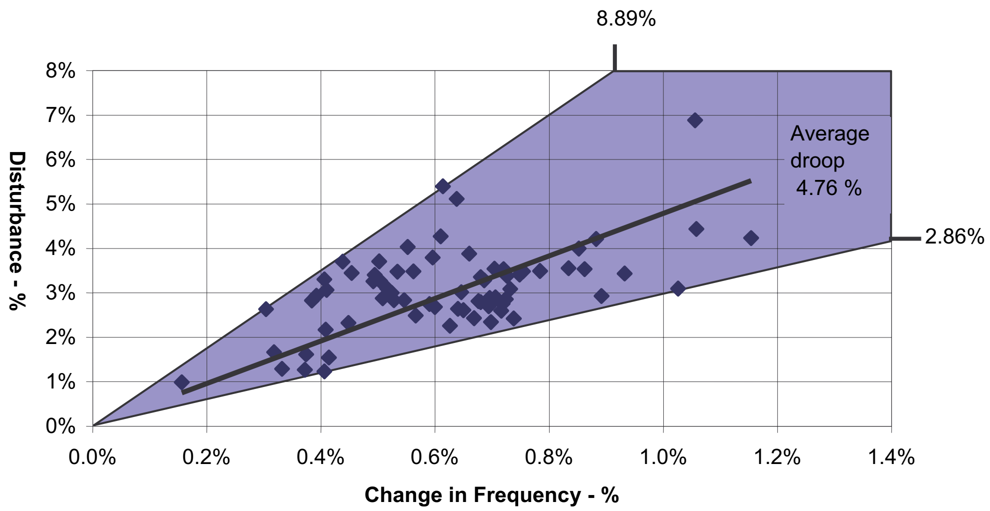


Figure 1.0 Network characteristic for generation losses between 1994 and 2004

Using details of previous generation incidents a plot of minimum frequency against generation disturbance allowed the *network characteristic* (k_T) to be plotted, Figure 1.0. Using Eqn 1 it should be possible to calculate the load response (k_L) if the generation characteristic (k_G) is also known. The generation characteristic can be calculated from knowledge of the total generation, the output of the responsive generators and their droop setting. Figure 1.1 shows the generation characteristic calculated for one of the generation incidents given in Figure 1.0.

$$k_T = (k_G + k_L) \qquad \text{Eqn 1}$$

For the event chosen at the point of generation loss the generation characteristic was 2.93%, and the network characteristic was 4.12%. This gives a Load sensitivity of 1.19%. Calculating the average load sensitivity to frequency for a total of 13 events gives a value of 1.94%, but with a standard deviation of 1.88. This is a very wide range of values.

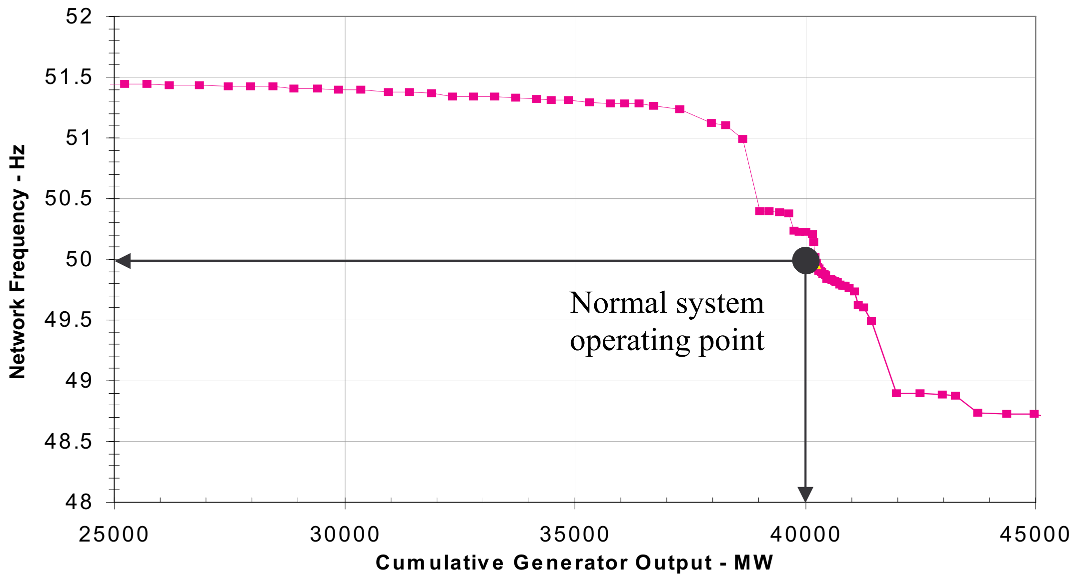


Figure 1.1 – Generation characteristic for UK grid July 2003

On 5th March 2004 the new Integrated Energy Management System (IEMS) went live, replacing the older EMS. The IEMS provides essential facilities to enable the electricity national control centre to manage and control the transmission grid system and for the network operations centre to provide safe access to the system for construction and maintenance. The IEMS interacts with other NGT computer systems as well as having it own database and display facility.

An IEMS change request has been made to allow the logging of load, frequency and generator details at intervals of 3 seconds during a generator loss event. This should allow numerical verification of the load sensitivity to frequency. This is obviously relies on a generator loss taking place and so cannot be given a firm timescale. Typically the grid is affected by approximately six events a year, so it is likely that the next event may occur within the next two months.

DTI energy industry statistics from 2002 illustrate how electric demand is split between the various market sectors. Using the DTI data with that from the literature review in Appendix A, we can get another source of what response to expect from the cumulative UK loads.

Table 1.2 shows the average load-frequency characteristic for the entire network from 2002 to be 1.78-1.94 %, which again is similar to those given in Appendix A.

	Twh	% of total TWh	Load Frequency sensitivity (for load types)
Domestic	114.5	29	0.7 - 1.0
Industry	111.7	28	2.6
Services	98.0	25	1.2 - 1.7
Energy Industry	61.9	16	2.9
Transport	8.5	2	1.2 -1.7
		Total	1.78 - 1.94

Table 1.2 - Load-frequency characteristics of industry sectors

1.2 Assess the statistical generator mix of response holding

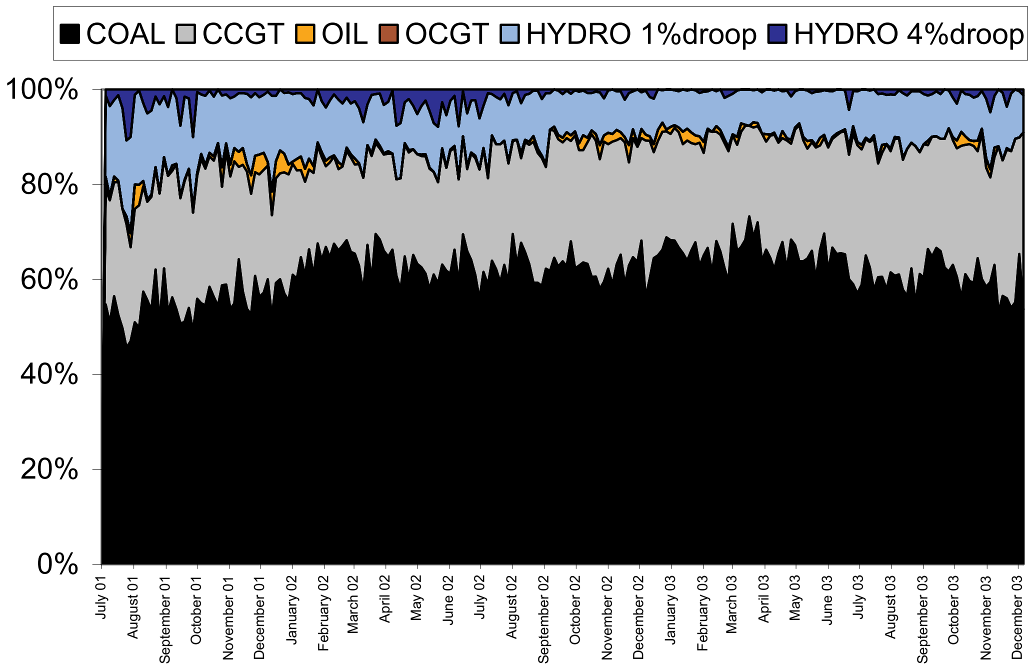


Figure 1.3 – Mix of plant used for Response (July 2001 to December 2003)

Work has begun on this aspect of the project during periods when other work has been suspended pending input from other sources. A plot of the response instructions to balancing plant (Figure 1.3) shows no real noticeable change in trends. It was expected that CCGT plant would gradually be picking up more response. However, a more detailed breakdown showing MW response of the generator types is yet to be completed and this may show otherwise.

1.3 Review of generator models

Currently generators are modelled for some network stability studies in a software package called Eurostag. Each of the generators has a specific governor and voltage regulator model which together with alternator characteristics define its behaviour during transients. During previous network studies it was believed that the responsive generators provided more power than was to be expected. Investigations comparing individual generators on a simple model with test data showed that the generator did seem to be providing more response than was expected from the test data, Figure 1.4 and 1.5.

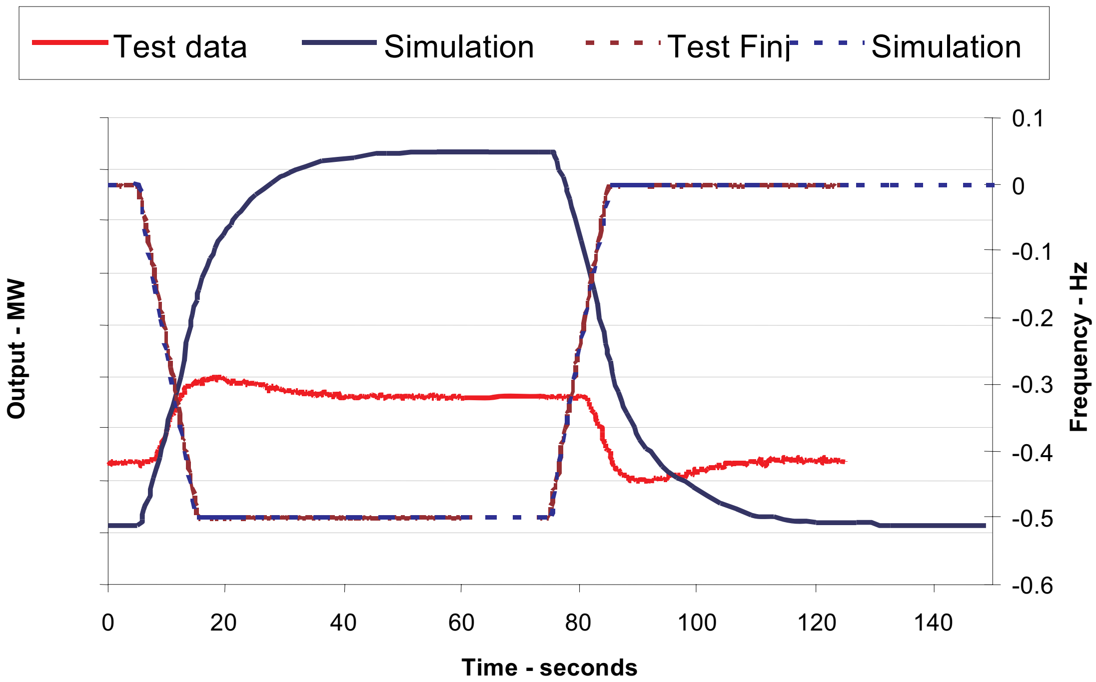


Figure 1.4 – Simulation of X generator against response tests

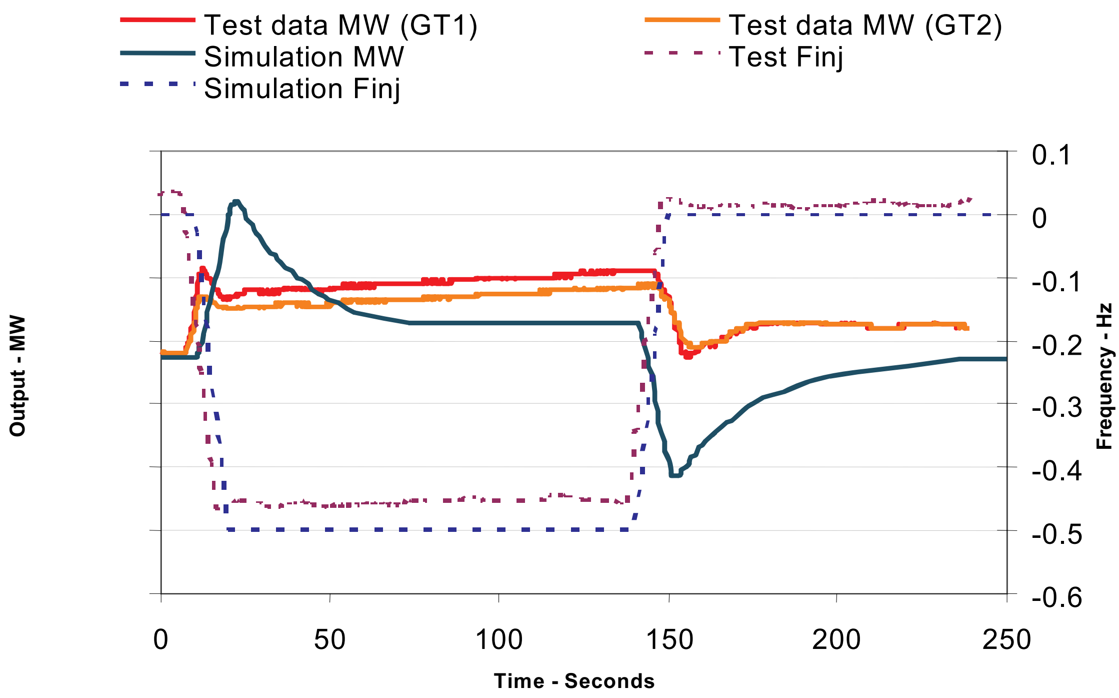


Figure 1.5 - Simulation of Y generators against response tests

However, the small network with only one generator would not necessarily mimic the dynamic effects of both the load and generators of the full UK grid. A database was constructed collating information of a real event which was then implemented into a simulation. The simulation provided a frequency response (Figure 1.6) very close to the one experienced during that event. A closer match may be possible compensating for the fact the some generators deviated from the initial output, due to the system not being in a steady state (hence the initial drop in frequency on the chart). When implementing the different generator outputs to the model it was found not to converge during the load flow calculations. To allow the load flow to converge a simpler network model of only 400kV and 275kV lines is being produced, which will hopefully also decrease computation times.

Further work is to be carried out refining the governor models in Eurostag. Also, further study into modelling techniques using Matlab has been suggested due to its more simplistic components. A simpler model in Matlab would make it possible to use an iterative procedure to calculate the response requirements greatly improving the current process. The model also needs to be maintained for use in future studies.

The benefit of a simple model in this case would be that no specialised technical knowledge would be needed for the upkeep of the model.

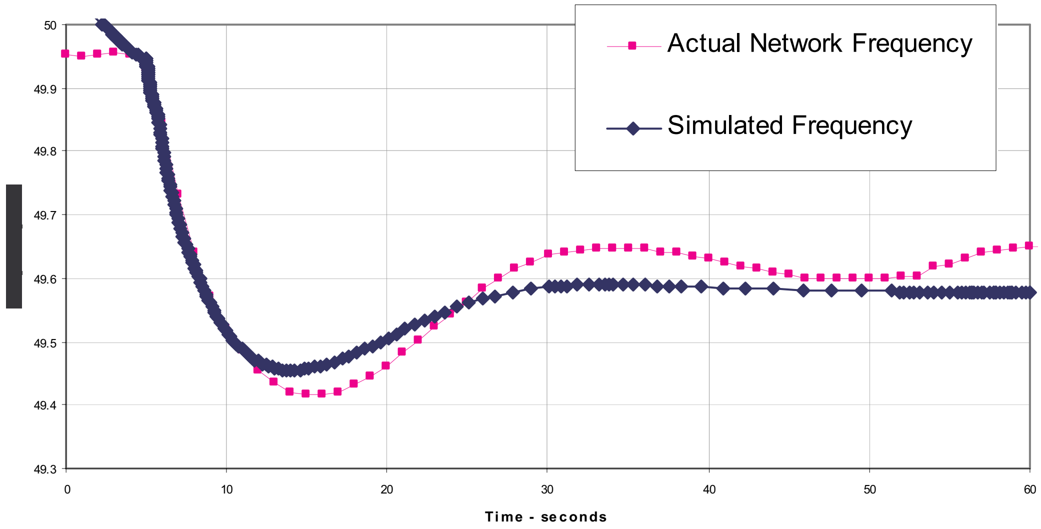


Figure 1.6 - Simulation of generator loss against record of actual event

1.4 Other Objectives

With the exception of assessing the impact of the location of loss/response holding on response requirement no further modelling work can be carried out with the Eurostag software until the generator models are verified. This means that assessing the impact of the generator types and the impact of the starting frequency on response requirement has been postponed until a later date. Time has not permitted any simulations to be carried out to assess the impact of the location of loss and response holding.

2.0 Reviewing the scope of work

As discussed in previous reports the chief aim of this project is to improve the calculation of the response requirements and the understanding behind them. This will allow the most economic (and usually also environmentally) beneficial response holding which also enables National Grid to meet the statutory limits on frequency deviation.

The aim of the current work is to allow an accurate model of the system to be created. This means improving models of demand and generator behaviour in transients. Work has begun in understanding how load changes as a result of changes in frequency following the sudden loss of generation. Review of the Eurostag models aims to provide understanding of plant behaviour over response delivery time scales in event of the loss. Once a complete picture of both these stages is built validation of the system model against actual loss events can be carried out.

With an model that accurately represents the system during transient behaviour it will be possible to assess the margin in response requirements needed to allow for modelling errors, failure of plant to deliver response and variation of initial conditions, such as starting frequency. The model can then be applied to simulate the effects of a changing generation mix. This is of particular interest with the new government initiative to increase the share of renewable generation to 10 % by 2010 and then 15% expected by 2020.

3.0 Review of objectives

- Manage the risk of failure to meet frequency obligations with cost and environmental impact.
- Modelling of demand-frequency relationship.
- Validation of Eurostag models.
- Statistical analysis of response delivery
- Improving the response margin.
- Establish error margins for Generator Mix / Specific plant.
- Calculation of physical delivery of actual response on both primary and secondary timescales.
- Attend Modules

4.0 Next 6 months

- Develop a simple Eurostag network model to use in studies.
- Assess the impact of the location of loss/response holding on response requirement.
- Assess the statistical generator mix of response holding.
- Consider modelling techniques to use Matlab to mimic governor responses.
- Calculate load sensitivity to frequency from network data.
- Produce paper to present at the EngD Conference

5.0 Summary

This report explains the current developments in calculating the load sensitivity to frequency. It holds that the assumed National grid value of 2% seems to be accurate but no quantifiable evidence can be produced to verify this accurately. Initial work on the generator mix used for holding response seems to indicate that the types of plant used have not dramatically changed since the July 2001. However, further work must be carried out on this aspect.

Verification of the governor models used in Eurostag has shown that although seemingly more responsive on an individual basis, if used collectively in a network model results seem to corroborate with recorded data from real events. Further tests are required on the full network model to confirm it is appropriate.

Highlighted in the document are the expected objectives for the research to improve the generator response understanding in both the short and long term. Within the next six months it is hoped that a functional network model will be produced to allow further studies to be completed.

Appendix A – Literature Review

1. Introduction

An electrical supply system comprises of a collection of generating units and also many loads, which are continuously varying over the course of the day in a largely predicable manner. Changes in the consumer demands require an equal change in generator outputs to maintain the system power balance. If a balance is not met stored energy in the loads and/or generators are released, as this release is not instantaneous it is seen as change in system frequency.

The network power-frequency characteristic affects the dynamic behaviour of the power system and defines the ability of the system to compensate for a power imbalance at the cost of a deviation in frequency. The power-frequency characteristic is influenced by two elements; a demand (or load) component and a generator component.

2. Generators

A system with many generator units operating under governor action will have a very large generator characteristic and consequently a large power change will only lead to a very small deviation in frequency. The generation characteristic is largely dependant on the power available in the system, i.e. number of 'responsive' generators operating with their actual load away from their maximum power rating. The generation characteristic of a system is non-linear because of these responsive generating units. When the system power is in equilibrium the generator characteristic can be approximated at the operating point by a linear characteristic equation 1.

$$\frac{\Delta P_T}{P_L} = -K_T \frac{\Delta f}{f_t} = \frac{1}{\rho_T} \cdot \frac{\Delta f}{f_t} \tag{1}$$

where

K_T	is the frequency sensitivity of the total system generation
P_L	is the total system load
ΔP_T	is the system generation change due to frequency
ρ_T	is the system droop
Δf	is the change in system frequency
f_t	is the rated system frequency

3. Loads

System loads are also frequency sensitive and a load-frequency characteristic is required to relate the system demand to the system frequency, equation 2.

$$\frac{\Delta P_L}{P_L} = K_L \frac{\Delta f}{f_t} \tag{2}$$

where

K_L	is the frequency sensitivity of the power demand
ΔP_L	is the system load change due to frequency

4. Power-Frequency Characteristic

In the above equations K_T and K_L have the opposite sign meaning an increase in frequency causes a drop in generation or increase in electrical load. This gives the change in system power demand as:

$$\Delta P_{dist} = \Delta P_T - \Delta P_L = -(K_T + K_L).P_L \frac{\Delta f}{f_t} = -\beta P_L \frac{\Delta f}{f_t} \tag{3}$$

where

β	is the stiffness (sometimes referred to as λ ~ power-frequency characteristic)
ΔP_{dist}	is the disturbance power

5. Assessment of Power-Frequency Characteristic

Appendix A

National Grid currently uses a value of 2 %MW/%Hz for its load-frequency sensitivity, which has been developed through an understanding in operating practice and confidence in the system security.

Papers from Taiwan University [1], [2] and [3] looking at the Taiwanese Grid (peak load 25000MW @60Hz) use a method to calculate the value of the load-frequency sensitivity factor, equation 4. The factor is calculated for each season, with each day split into three separate load periods, Table 1.

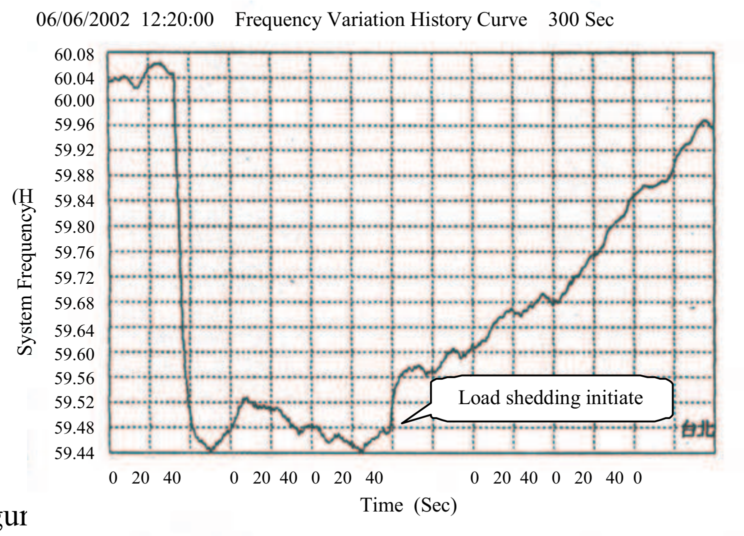
	0:00-7:59 hours	8:00-15:59 hours	16:00-23:59 hours
Spring	0.109109	0.088814	0.087569
Summer	0.097925	0.090716	0.087767
Autumn	0.092095	0.091635	0.085730
Winter	0.106481	0.094925	0.079947

Table 1 – Mean values of Power-Frequency Factor, Taiwanese system

$$Load \quad Frequency \quad Sensitivity \quad Factor = \frac{\delta P}{\partial f} \approx \frac{\Delta P}{\Delta f} \; [\text{pu.Hz}^{-1}] \qquad (4)$$

where

Δf is the maximum frequency deviation
ΔP is the generation loss



Figur

After closer inspection of the methodology it is believed that the calculated factor includes both load and generation characteristics, and relates to the power-frequency characteristic. Figure 1 shows a frequency variation curve used in the paper following the loss of an on-line generator (950MW). The magnitude of system load demand was 21700 MW. The pre-fault frequency was 60.04 Hz and the minimum frequency at the instant following the loss of the generator was 59.44 Hz, so the Δf was taken as 0.6 Hz. These values were substituted in equation (4) to compute the LFSF, which was 0.072965 in this case.

Equation (4) is only a measure of load-sensitivity to frequency if we assume that no generation power is released before the peak deviation. As the frequency peak does not occur until 20 seconds after the disturbance generators are likely to provide or have started to provide response.

Inoue *et al.* [4] have used frequency transient responses from loss events and load rejection tests to provide an estimation of the system inertia constant for the Japanese grid system (14-18 secs). The paper also provides a set of estimated values corresponding to the Japanese Grid (peak load 87400MW @60Hz) for power-frequency characteristic ($-\Delta P/\Delta f$), ranging from approximately 7.7 to 15.3 %MW/%Hz at a transiently settled state 20 seconds after the event.

The Power System Study Committee: Japan [5], also carry out a number of experiments to establish the power-frequency characteristic of Japanese grid. The tests establish a value of 8.5-14.6 %MW/%Hz.

A paper on the Irish electricity grid (peak demand of 4091MW) uses locked governor tests to establish estimates of inertia and load sensitivity to frequency [6]. It approximates the load-frequency characteristic in the order of 2-2.5 %MW per Hz and gives a system inertia of 13-15 GJ equivalent to 5 MW/MVA. Kinetic energy stored in the Load was calculated as 5000 MJ or 1.6-1.8 MW/MVA.

A paper released on behalf of the UCPTE (230 GW @50Hz) [7] gives values for the network power characteristic between 1988 and 1998 as 6.7 - 9.6 %MW/%Hz and Load sensitivities in the order of 0.5 to 2.0 %MW/%Hz (see Figure 2).

A similar paper written by Schulz (1999) describes the network characteristics of the Eastern Interconnector in America. It also provides information on the assumed load characteristic. Load response is assumed to be 1.5 %MW/%Hz, with tests giving the network characteristic a value in the range of 3.9 – 4.4 %MW/%Hz

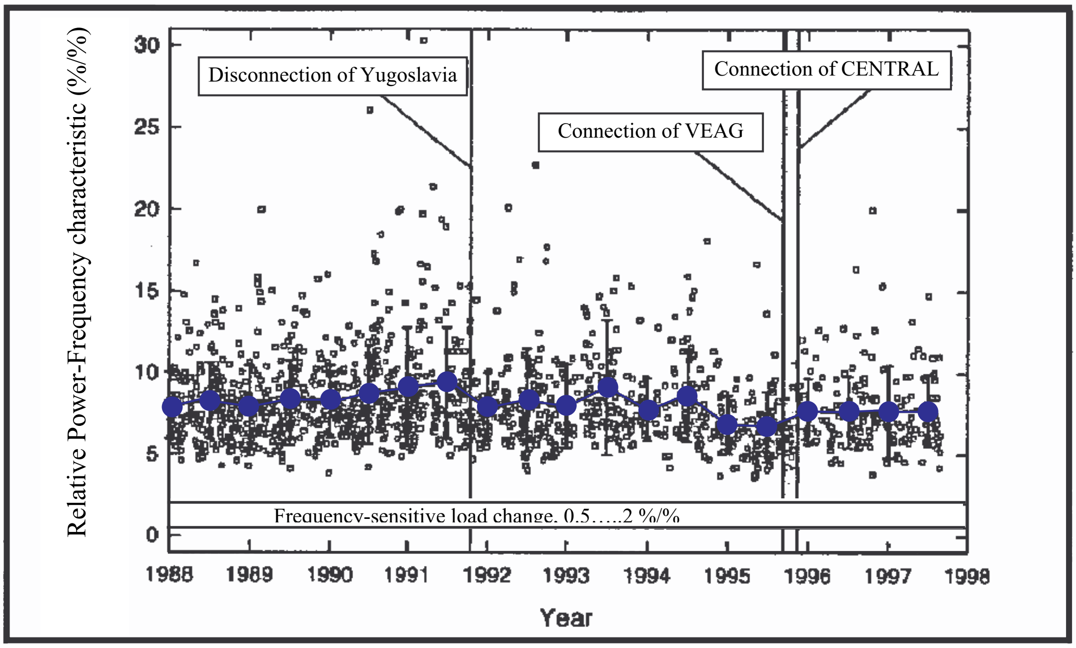


Figure 2 - Observed Relative Power-Frequency characteristic UCPTE/CENTREL half-yearly values and standard deviation

Tests carried out by Berg (1972) on an isolated 2 GW power system in Norway provide more data on Load-frequency characteristic. Tests carried out during generator trips show average values of 0.5 %MW/%Hz for commercial loads and 0.4 %MW/%Hz for a residential load, the paper notes however that a great deal of variation was evident when calculating the average values.

Concordia and Ihara (1982) provide details of measured load characteristics from New York in the years 1941 and 1969 as 1.8 to 1.9 %MW/%Hz and 1.8 to 2.4 %MW/%Hz respectively. Data from residential loads during winter and summer 1980 are also provided ranging from 0.1 to 0.5 %MW/%Hz.

NEMMCO [11] has estimated that the power system demand varies with frequency such that a 1 % change in frequency will cause a 1.5 % change in demand. Conversely, a 1.5 % change in total generation will cause a 1 % change in system frequency, that is 0.5 Hz.

A report published by Eskom in 2000 [12] covers the frequency standards and levels of control for various interconnected systems and the designation of the frequency standard in the Southern African Power Pool. Table 2 gives the summarised results for the African pool, the values are calculated from incidents of significant loss in generation. As the precise methodology for calculations is not given this could mean the data is a measure of the network characteristic rather than the load-frequency characteristic as specified in the report.

Incident	Date	Total Load Frequency Characteristic (MW/Hz)	Load Frequency Characteristic %MW/%Hz Assuming the peak load (30,000MW)	Assuming minimum load (20,000MW)
132	19-Jul	1600	2.7	4
137	27-Jul	1510	2.5	3.8
139	28-Jul	1270	2.1	3.2
144	05-Aug	1140	1.9	2.9
145	05-Aug	950	1.6	2.4
146	05-Aug	1000	1. 7	2.5
	Average	**1250**	**2.1**	**3.1**

Table 2 – Values of Network-characteristic for the Southern African Power Pool

Figures published by an IEEE task force on load representation [13] give constants for frequency sensitivity for both active and reactive power. The findings are given in table 3. Values for residential loads differ from those suggested by Concordia by at least 50%. This discrepancy may be due to the change in load mix within the ten year period.

Load	Power Factor	K_{pv}	K_{qv}	K_{pf}	K_{qf}
Residential					
Elec Heating	0.87 to 0.99	0.9 to 1.7	2.4 to 2.7	0.7 to 1.0	-2.3 to -1.5
Non-Elec Heating	0.89 to 0.97	1.2 to 1.6	2.5 to 3.1	0.7 to 0.9	-2.3 to -1.3
Commercial					
Elec Heating	0.85 to 0.9	0.5 to 0.6	2.5	1.2 to 1.5	-1.1 to -1.6
Non-Elec Heating	0.87 to 0.9	0.7 to 0.8	2.4 to 2.5	1.3 to 1.7	-1.9 to –0.9
Industrial	0.85	0.1	0.6	2.6	1.6
Aluminium	0.9	1.8	2.2	-0.3	0.6
Steel Mill	0.83	0.6	2.0	1.5	0.6
Power Aux. Plant	0.8	0.1	1.6	2.9	1.8
Agricultural Pumps	0.85	1.4	1.4	5.6	4.2

Table 3 – Typical load voltage parameters

Welfonder *et al.* (1989) provide results from load dependency tests carried out on parts of the German grid system. Load monitoring equipment sited at Heidelberg (150MW demand) and Berlin (80MW demand) provide a source of data for measuring the voltage and frequency dependency of the loads. In the respective sites the Load-frequency characteristic is evaluated as 1.2 %MW/%Hz at Heidelberg and 0.8 %MW/%Hz at Berlin. The difference at the sites is attributed to a higher constituent of motor load in the Heidelberg area.

6. Summary

	K_L (%MW/%Hz)	K_T	β (%MW/%Hz)
NGT	2 (assumed)	-	-
Taiwan [1]-[3]	-	-	8.57 - 12.12
Japan [4]	-	-	8.5 - 14.6
Japan [5]	-	-	7.7 - 15.3
Ireland [6]	2 – 2.5	-	-
UCPTE [7]	0.5 – 2	-	6.7 - 9.6
Norway [10]	0.4 - 0.5	-	-
New York [9]	1.8 - 2.4	-	-
America (Eastern Interconnection) [8]	1.5 (assumed)	-	3.9 - 4.4
NEMMCO [11]	1.5 (estimate)	-	-
South Africa [12]	(1250 MW/Hz) ~2.5	-	-
Germany (part system) [13]	08 - 1.2	-	-
Residential Loads [9]	*0.1 - 0.5*	-	-
Residential Loads [14]	*0.7 to 1.0*	-	-
Commercial Loads [14]	*1.2 to 1.7*	-	-
Industrial Loads [14]	*2.6*	-	-
Power Aux. Plant [14]	*2.9*	-	-
Agricultural Pumps [14]	*5.6*	-	-

Table 4 - Sensitivity Factors and Power-frequency characteristics

Results from various sources suggest that the typical power-frequency characteristic of a system will range from 4 to 15 %MW/%Hz. Tests conducted on actual systems indicate the generation response characteristic is far more dependent on frequency than the load response characteristic. K_L has typical values between 0.5 and 2.5 while literature [15] suggests K_T is approximately 20, corresponding to a system droop of 5%. Table 4 summarises the characteristic values given in this report.

Although no numerical background relating to the actual physical network has been used in developing the NGT Load-frequency characteristic, comparisons with values derived from other systems seem to place it within an acceptable band.

The network-frequency characteristic is a parameter that can be control by NGT to provide the most beneficial dynamic response to frequency. Although the Load-frequency characteristic is predetermined by consumer behaviour, generator scheduling solely determines the generation characteristic. Both the number of generators and how the response is held on plant effects the overall generation frequency dependency and hence the network-frequency characteristic.

It would be beneficial to provide a quantitative proof elucidating the NGT load-frequency characteristic, which is used to provide the background for calculating the secondary response requirement. With a loss of generation the reduction in demand with frequency lowers the maximum risk on the network, meaning less response is needed. If the value of the load-frequency characteristic is much greater than anticipate excess response is being allocated to the system and can result in reduced expenditure in that area, typically costing the company £43.5M[1] per year.

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Reducing the environmental impact of frequency control on the UK power system against a background of increasing renewable generation

24th Monthly Progress Report

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Nomenculture

List of Symbols

ACE	area control error	[MW]
A_w	Swept area of the blades	[m^2]
f_{fl}	frequency full load	[Hz]
F_{HP}	HP power fraction	[%]
f_{nl}	frequency no load	[Hz]
f_0	base frequency	[Hz]
g	acceleration due to gravity	[$m.s^{-2}$]
H	inertia constant	[s]
h_H	head height	[m]
I_n	Current	[A]
J	inertia	[$kg.m^2$]
K	Gain	[%]
K_L	load-frequency characteristic	[$\%.Hz^{-1}$]
k_{pf}	demand sensitivity	[$\%.Hz^{-1}$]
K_T	generator-frequency characteristic	[%]
ΔP	power mismatch between load and generation	[MW]
P_{actual}	measured	[MW]
P_E	electrical power	[MW]
P_G	generator power	[MW]
P_i	individual generator outputs	[MW]
P_L	system load	[MW]
P_{Loss}	loss of a known generation	[MW]
P_M	mechanical power	[MW]
$P_{planned}$	planned interchange	[MW]
P_T	system power	[MW]
R	Droop	[%]
T_W	water time constant	[s]
T_{RH}	time constant for re-heaters	[s]

T_{CH}	time constant relating to the steam chest and inlet piping system	[s]
U_b	Voltage	[V]
u_w	Wind speed	[m.s^{-1}]
W	water flow rate	[m^3.s^{-1}]
Y	Admittance	[S]
β	Frequency response	[MW.Hz^{-1}]
η	efficiency	[%]
ρ_a	air density	[kg.m^{-3}]
ρ_G	Generator speed droop characteristic	[%]
ρ_{Gi}	individual generator droops	[%]
ρ_T	system speed droop	[%]
ρ_w	water density	[kg.m^{-3}]
ω	angular rotation	[Rad.s^{-1}]
τ_M	mechanical driving torque	[N.m]
τ_E	electrical torque	[N.m]

List of abbreviations

NGT	National Grid Transco
TSO	Transmission system Operator
UK	United Kingdom
GB	Great Britain
NZ	New Zealand
OHL	Over head lines
HV	High voltage
EMS	Environmental Management Systems
SF_6	Sulphur Hexafluoride
CO_2	Carbon dioxide
NO_x	Nitrogen oxides
CCGT	Combined cycle gas turbine
OCGT	Open cycle gas turbine
SO_2	Sulphur dioxide
PM_{10}	Particulate matter 10μm
CO	Carbon monoxide
CHP	Combined heat and power
UCTE	Union for the co-ordination of transmission of electricity
BMU	Balancing Mechanism Unit

0 Executive Summary

The system frequency of a synchronous power system, such as the GB grid, varies due to the imbalance between the energy supplied to the network and the electrical energy consumed. When large generating blocks are lost the system undergoes a frequency swing with a magnitude relative to the size of loss. Limits are imposed on the magnitude of frequency deviation to prevent, in worst case, collapse of the system. The aim of this research is to develop an increased knowledge to manage the risk of frequency obligations during loss of large portions of power.

Operation of frequency responsive thermal plant results in lower efficiencies and thus increased emissions. The current response requirements must be reviewed to ensure excess response is not being held against the current generation mix. Future increased levels of wind turbines may alter the operational characteristics of the system (primarily system inertia). This is compounded by additional levels of response required because of the unpredictability of wind resources. Environmental implications result from added renewables that increase the response requirement and hence emission levels.

It is the objective of this research to assess the optimum response that must be held to minimise environmental emissions but ensure the operational safety of the system in both the current, and future situations. This research will aid in limiting the environmental impact of frequency response while aiding engineers to implement reserve schemes that do not compromise system security. The project itself looks at two main areas: Modelling Generator response, and Modelling Load response.

0.1 Methodology to be used

Through a series of grid simulations this project will develop an understanding of how the UK transmission network responds to loss in generation. These simulations will be carried out with a set of models, which will be validated against actual conditions, as well as through comprehensive and critical assessment of available literature.

0.2 Contribution to knowledge

World-wide very limited studies have been conducted in the area of frequency response. This is mainly due to the security provided by large interconnected generation areas such as Europe and America. In such systems generator loss leads to a very insignificant deviation in frequency and as such is not a critical issue. Island systems such as the one operating in the UK are more sensitive to the imbalance between generated and consumed power. Anticipated contributions to knowledge of this project include:

- Quantification of the UK load-frequency sensitivity.
- Effect of generator location on frequency response.
- Influence of wind turbines on the frequency response requirement.
- Understanding the environmental impacts of response holding

0.3 Planned papers

The following papers will be written and will be submitted to journals within the next two years:

Load frequency characteristic of the UK grid.

This paper aims to describe the effects of load behaviour on the UK system during frequency disturbances. It will provide examples of generator loss on the system and the drop in frequency as a result. It is hope to include details of generator responses also.

This paper will be submitted to the *IEEE Transactions in power systems.*

Impacts of renewable generation on frequency response.

This paper aims to describe the effects of renewable generation on the UK system especially during frequency disturbances. It will provide results of simulation studies carried on a representative model of the UK transmission network. The paper will highlight potential problems that may arise from the expected increase of renewable sources in the generation mix. This will include the physical impacts due to plant behaviour and the impact due to extra response margin required for their operation.

This paper will be submitted to the *IEEE Transactions in power systems*.

1 Introduction

1.0 Introduction

The system frequency of a synchronous AC power system varies with the imbalance between the energy supplied to the network by generators and the electrical energy consumed by its loads. We will later see that when large generating blocks are lost the system undergoes a frequency drop relative to the size of loss. Limits are imposed on the magnitude of frequency deviation to prevent disconnection of customers from the system or damage to equipment.

The most critical reason for this research is to formulate a response requirement that does not breach National Grid guidelines on security and quality of supply. These requirements define the level of response required to contain specific power losses. If these requirements are over estimated the system becomes very secure against losses and frequency will not deviate considerably from the nominal. This security is delivered at the expense of excess cost and environmental emissions. Conversely, under estimation results in a network at high risk

By the year 2010 it is expected that a considerable increase in renewable generation will occur in the energy sector. Targets suggest that 10 % of energy production will be from renewable sources by the end of the decade. No credible studies have been conducted to investigate what effect this change in generation mix will have on the way the system reacts in terms of frequency response.

With an inevitable change in the future energy mix frequency response studies are required to plan ahead for the introduction of these new generators. Conditional on the effects of introducing a larger percentage of renewable generation operational strategies or procedures may need review.

World-wide very limited literature has been published in the area of frequency response. This is mainly due to the security that is provided by large interconnected generation areas such as Europe. In such systems generator loss leads to a very insignificant deviation in frequency and as such is not a critical issue. Island systems such as the one operating in the UK are more sensitive to the imbalance between generated and consumed power. There is also a vast difference between each HV power transmission network in each country, and also the generation mix supporting it.

With these points in mind this research looks to answer the question; what level of frequency response is currently required to limit environmental impact but not cause undue risk? What will this requirement be in the future?

1.1 Document Structure

The following paragraphs give an explanation of the content of this report:

In Chapter 2 we examine the environmental consequences of frequency response, this includes a summary of the environmental performance of each type of generator. An introduction to renewable generators is also given, with an explanation for the focus on wind turbines in particular.

Chapter 3 highlights the approaches of other countries to frequency response and how the UK differs from those schemes. It also includes the experiences that added renewables has on the running of those systems.

Chapter 4 justifies the need for frequency simulations and the problems associated with alternative techniques to quantify the response requirements. A chosen simulation tool is introduced together with the dynamic components needed for such a tool.

In Chapter 5 we study the main factors that influence frequency response. These include; droop, inertia, load, type of generator and disturbance level. Included in this chapter are preliminary simulations using the response tool to demonstrate the sensitivity of each factor on the frequency response.

Chapter 6 looks at the research carried out to date to improve the accuracy of the chosen simulation tool. This involves the quantification of the load response to frequency, and validation of generator models. Future work to be carried out over the next 2 years of the research is also considered.

Chapter 7 provides a brief summary of the report

2 Environment

2.0 Impact of Frequency Response

Market forces dictate which power stations are called upon to supply generation to the electricity grid to meet consumer demand. This base load of plant is operated to meet the majority of demand. As the system is dynamic NGT, as transmission system operator (TSO) in Great Britain, must balance any short-term differences in generation and demand through the balancing market. A level of backup generation is also required to cover instantaneous loss of the largest generating unit operating at any time. To facilitate this dynamic requirement NGT instructs part-loaded plant to provide the headroom for frequency response, Figure 1. This part loaded generation operates under governor control, and acts to control the grid frequency.

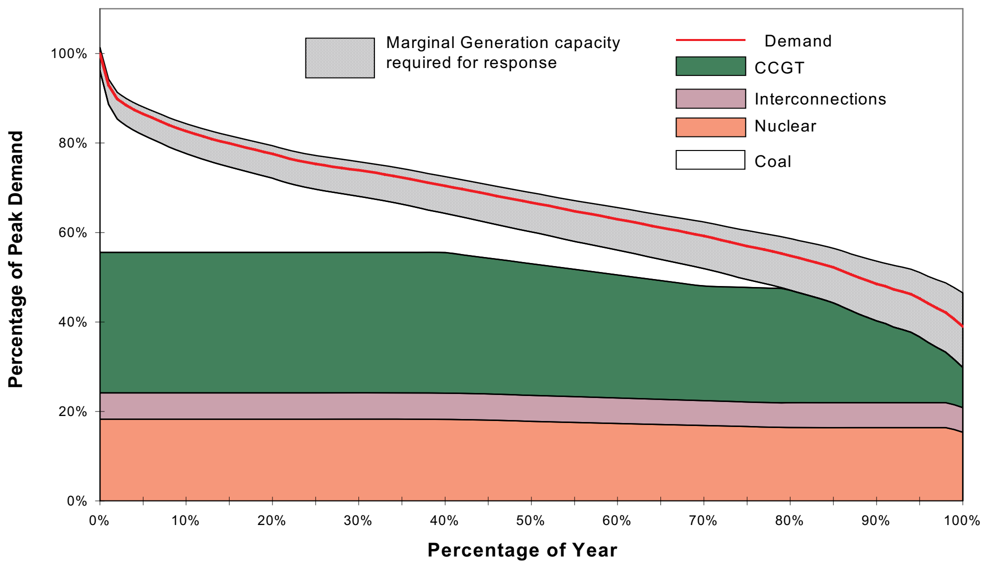

Figure 1 - Load duration curve showing breakdown of grid connected generation

Part load generation or *spinning reserve*, raises environmental concerns because of reduced plant efficiencies (Figure 2), and with the case of gas fired plant results in increased NO_x emissions. A percentage of frequency response is also provided through demand side management, which is facilitated through the disconnection of industrial load. Demand management usually offers minimal environmental impacts but it is dependent on the industrial processes that have been interrupted. Frequency response cannot be held solely by demand side measures as the response is only provided at discrete frequency trigger points.

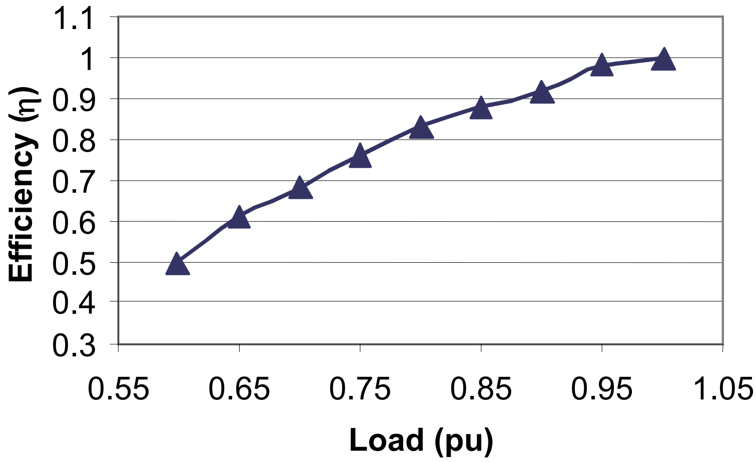

Figure 2 - Part-load efficiency of a CCGT generator

Spinning reserve can be held on any type of plant but in the GB system, the majority is held on coal fired generators as can be seen from Figure 3. As the mix of generating plant connected to the grid changes it is likely that the mix of plant used for response holding will also mirror this change to a certain extent. The differing types of generation also impact the level of loading that is required to provide the same response, due to the transient behaviour of different generator types.

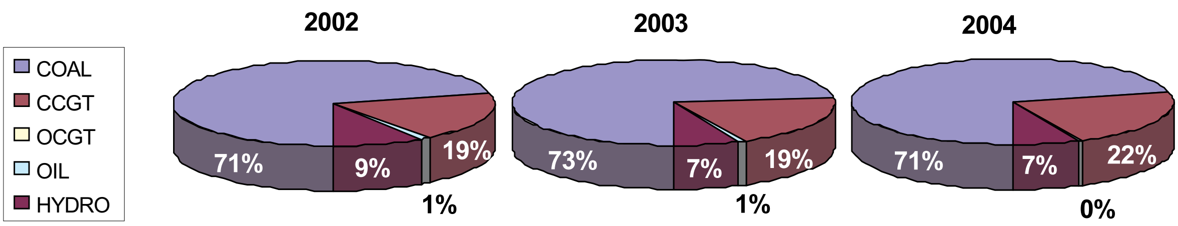

Figure 3 - Instructions issued to spinning plant for frequency response 2002-2004

2.1 Environmental Performance of Grid Connected Generation

The generation mix of the system is a continual evolution of different energy sources and has changed over recent years, Figure 4. An increasing proportion of gas plant has been introduced which has replaced oil, coal and nuclear plants. Projections suggest this trend will continue over the next ten years with renewables also competing for an increased share of capacity. A diverse mix of generation is important for the secure operation of the grid but some generators provide energy at a much greater cost to the environment.

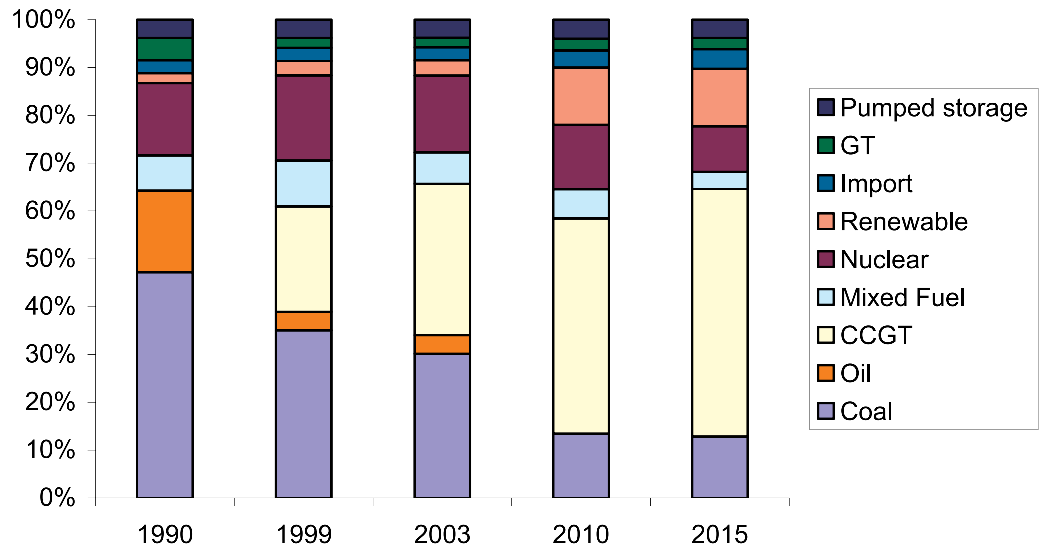

Figure 4 - Generation mix by installed capacity [DTI (2000)]

An ever-increasing demand for electricity has lead to investment in a growing capacity of grid connected generators. Despite this increasing consumption, emission levels of CO_2, SO_2, NO_x and PM_{10} by the industry have fallen in recent years, Figure 5.

The subsequent sections give a brief introduction to the environmental impact of grid based generators during their operational life.

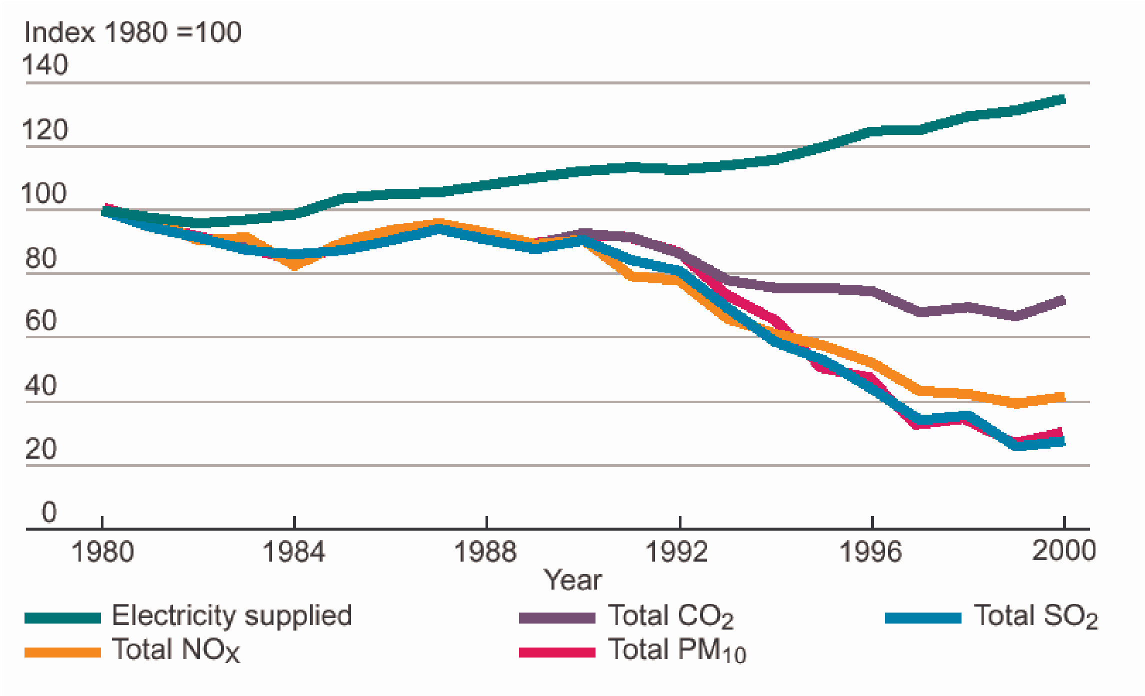

Figure 5 - Gaseous Emissions from UK Electricity [Electricity Association (2003)]

2.1.1 Coal fired power stations

Burning coal releases significant levels of SO_2, NO_x, CO_2, PM, and mercury into the air. Environmental concerns surrounding the use of coal to produce energy include global warming, acid rain, regional and local health issues, and the impacts of coal transport and ash disposal. The goal of newer coal combustion technologies has been to reduce the environmental impacts. In addition to the air emissions, most coal plants have significant community impacts due to the transport and handling of the coal, and a requirement for large quantities of cooling water.

An increasing number of plants have been retrofitted with abatement technologies such as flue gas desulphurisation to help reduce emissions.

2.1.2 Gas fired power stations

The burning of natural gas releases fewer air emissions than coal. Compared to similarly sized coal plants, natural gas plants release 50 percent less CO_2. The greatest emissions are NO_x emissions, which are more significant when plant becomes part loaded. NO_x emissions can be minimised by the use of various control technologies.

Open cycle gas turbine (OCGT) plant efficiency is typically low, approximately 37 percent, so are commonly used as peak load plants or for black start, when high amounts of energy are required very quickly. OCGT emissions include NO_x, CO, and CO_2.

A combined cycle gas turbine (CCGT) is more efficient than a OCGT equivalent because the hot rejected heat gases of the turbine are not vented to the atmosphere, but are used to raise steam for a second electric generator. By combining the gas and steam cycles, the plant can convert approximately 60 percent of the fuel energy into electrical energy. CCGT plants also produce less NO_x and CO_2 emissions than an OCGT plant.

2.1.3 Biomass as a fuel

Emissions from biomass combustion are generally less than from coal or natural gas. Like coal or natural gas combustion, biomass combustion produces CO_2. Biomass can also emit lower amounts of NO_x, produce less ash than coal, and release significantly less toxic material such as mercury. A closed methane digestion system that burns biogas on a farm or landfill would reduce the amount of methane lost to the atmosphere. However, it would release emissions similar to those of a natural gas-fired turbine, but in smaller quantities. Environmental impacts vary with the type of biomass fuel used, although most fuels will have impacts related to burning and storage.

2.1.4 Nuclear Power

The main concern is safety involving the storage and management of highly radioactive spent nuclear fuel. Air emissions are not an issue with nuclear plants.

2.1.5 Hydroelectric and Tidal Power

As Hydroelectric plants use falling water to turn a turbine that drives a generator to produce electricity they produce no air emissions. Their main environmental impacts are related to the flooding of the landscape upstream, changing flows within the stream banks downstream, dividing the stream into separated pools, and damaging or killing young fish. The barriers created by dams constrain fish and other species to specific pools, impacting their ability to survive and reproduce. The turbines have the potential to damage or kill young fish if they are not filtered on the upstream side of the dam

2.1.6 Pumped Storage

Pumped storage is essentially a hydroelectric plant circulating its water supply, hence it is a net user of electricity. In most cases a pumping mode is operated during the night when demands are low, this is beneficial in helping to stabilise the demand profile over the course of a day. Inefficiency in pumping water and also the conversion back to electrical power are a concern with this plant. Ecological impacts regarding the cyclic filling and draining of the reservoir must be considered.

2.1.7 Wind Turbines

Wind power has low environmental impacts (no air or water emissions), but concerns have been raised over aesthetics, noise, and mortality to flying birds and bats.

2.1.8 Solar - Photovoltaic Power

Compared to traditional methods of electric generation, solar power has few environmental concerns. The primary impacts for larger systems are related to land use and aesthetics and may be resolved through appropriate siting.

2.2 Environmental Scope

Assessing the environmental impacts of each and every generation plant and also each type of emission is far beyond the intended scope and life of this research. With CO_2 emission levels being such a dominant issue in the Governments legislation to reduce greenhouse gases it would be reasonable to focus research on the production of this specific gaseous emission. The overall intention would be to assess the levels of CO_2 production corresponding to frequency responsive generation.

2.3 Renewable Generation

Commitment laid down by UK government in the Kyoto agreement (1997) has meant that an increase in renewable generation is necessary to reduce CO_2 levels in the energy sector. The Renewables Obligation Order (2002) calls for electricity suppliers to procure a greater level of electricity from renewable sources. At the moment these generators only account for 1.3 % of the total generation capacity. From Government based targets it is anticipated that this figure will rise to 10 % by 2010, and a further 10 % by 2020.

The impact of this renewable generation on the operation of the grid network is unclear. A critical assessment of the potential impacts these forms of generation will have on the current operation of the grid is needed. Figure 6 shows the current trends in renewables over the past six years and a projection for the year 2010. If the current growth in wind farms is to continue they will account for a large percentage of the renewable mix. A press release from the British Wind Energy Association suggested that by 2010 eight percent of the national capacity would come from wind based sources. This view is also held by the DTI who believe, "Wind power, both on- and off-shore, is presently the only economic scaleable technology and will deliver the majority of the required growth in renewable energy to meet the 2010 target…"

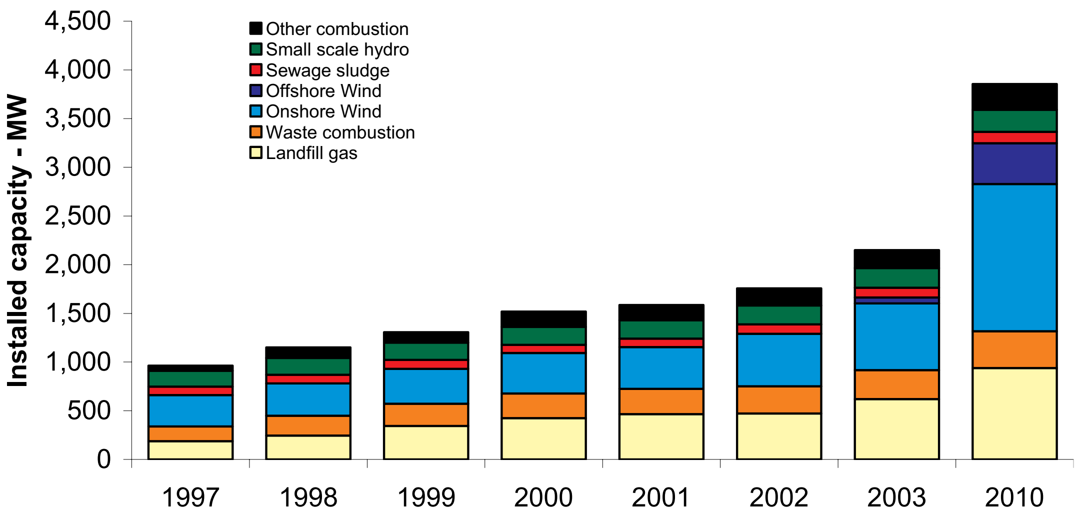

Figure 6 - Growth of renewable generation [DTI (2004)]

In 2003, over 1GW of offshore wind farms where given planning permission, and 328 MW of onshore installations. If these farms are commissioned the current penetration of wind would be more than doubled. At this level of penetration, wind will provide the majority share of grid connected renewables.

Wind turbines are unlike landfill gas or waste combustion, which operate in a similar manner to CCGT/OCGT or coal machines. As wind turbines do not operate like other grid connected generators several frequency control issues arise. The variability of wind sources has a direct influence on the output power from turbines. Any short-term changes in wind speed will lead to a demand generation imbalance, which also effects the instantaneous frequency. The erratic nature of wind means it is hard to forecast, and thus it is possible that extra spinning reserve will be required to maintain the level of frequency deviations on the system.

There are also concerns that electric converters used in variable-speed wind turbines will be seen as inertia-less generators by the grid. Fixed-speed turbines will provide some benefit from their inertia, but this is provided that frequency and voltage remain within their operating limits. If large quantities of variable-speed wind turbines displace conventional generation, the total system inertia will decrease. The grid inertia helps to control the rate at which frequency drops when there is a sudden loss of generation. However, Ekanayake *et al*(2003) have shown that variable-speed turbines could in principal be controlled to provide the equivalent inertia.

With expectation of such a high wind penetration it would be reasonable to concentrate studies only on the effects brought about by additional wind turbines on the system. This gives scope to investigate the variability of wind power and the unknown risks it brings to frequency control in GB. The effect of generator inertia is also a concern that should be addressed in relation to frequency control.

Many papers exist that concentrate on the voltage stability of wind farms, Akhmatov *et al.*(2003) and Rodriguez *et al.*(2002) for example, but limited work exists on the study of frequency stability.

3 Operator experiences in other countries

3.1 Denmark, Sweden, Finland and Norway

The Nordic countries are well known for their continued commitment to sustainable working practices and keenness to minimise environmental impacts. Eltra system operator in Jutland (West Denmark) in particular has one of the highest capacities for wind at 2347 MW, almost 32 % of total generation, Eltra(2003a). Eltra operates as part of the european UCTE system connected through Germany and operates DC links with Norway and Sweden, Figure 7. The neighbouring power systems give Eltra the total import capacity of 3060MW. This is nearly equal to the maximum experienced on the system in 2003.

The balancing of Danish grid is relatively easy in periods of low wind. In high wind situations, large amounts of excess electricity can cause transmission problems on the system especially as it does not have any pumped storage to absorb excess generation. This is compounded by the legal obligation to accept all prioritised electrical energy. Experience has shown that within one to two hours wind speeds can vary in the Great Belt by an amount equivalent to two power stations. The over-production is more likely to occur at night in winter months where it can be aggravated by the output of the many CHP plants. Until very recently, any over-production could always be exported via interconnectors to neighbours.

The large amount of wind electricity produced in Jutland seriously hinders balancing of the Danish electricity supply system. This has lead Jutland to become a net importer of electricity despite its large generation capacity, UCTE(2003).

Figure 7 - Nordic generation mix and interconnector capacities [Nordel (2003)]

As a member of the UCTE Jutland has an obligation to supply 35MW of primary response. Internally it holds ±100 MW of automatic regulating reserve, which must be held on a minimum of three spinning units, Eltra (2003b). Manual upward regulating reserve totalling 420 MW is held as a requirement based on the loss of its largest unit at Enstedvæket (620 MW), this allows recovery of any interconnected power supplied through the UCTE. A further 200MW of downward regulating reserve is held to secure against demand loss. This reserve may be held on units outside of Jutland and supplied through it interconnectors.

The national power systems in the remaining Nordic countries operate as one synchronous system, Elkraft(1996). They are fortunate in having large capacities of hydroelectric power available for frequency response. A primary reserve of at least 600 MW is held on the combined system for controlling the frequency between operational limits (50 ± 0.1 Hz). Contributions to frequency response by each area are made based on the demands experienced in the previous year.

The area control error(ACE) is used to detect the manual frequency control measures that are to be performed. The instantaneous ACE can be calculated from the deviation(ΔP) between measured(P_{actual}) and planned interchange($P_{planned}$) and the frequency deviation(Δf) from 50 Hz, Equation 1. Lindahl(2002) gives the actual frequency response(β) required from each area in 2002, Table 1.

$$ACE = \Delta P + \beta.\Delta f = (P_{actual} - P_{planned}) + \beta.\Delta f$$

Equation 1

Country (Area)	Frequency Response [MW/Hz]
Denmark (Zealand)	270
Finland	1050
Norway	2220
Sweden	2460
Nordel	6000

Table 1 - Contribution to frequency response in the Nordic pool

An *instantaneous disturbance reserve* is activated in reaction to a simultaneous loss of power plant where frequency deviation ranges from –0.1 to –0.5 Hz. The maximum capacity of the loss is assumed to be no more than 1200 MW, it is also assumed that the load will supply 200 MW of self-regulation. Under these conditions the frequency shall not fall below 49.5 Hz.

Operating in this fashion means that the Nordic transmission system can share its frequency response requirements between its member countries. This reduces the number of plant required to hold response and as a consequence increases efficiencies and reduces emissions.

3.2 Germany

Germany is composed of 4 TSOs, and has operational experience with the biggest penetration of wind on any network with a capacity of 14345MW. 6250MW of German's wind turbines are in the E.ON Netz control area, E.ON(2004). This is comparable to the level of wind generation that is to be expected in the UK by 2010. Through operations the TSO has noted that a reliable weather forecast is foremost to maintaining a stable grid frequency.

E.ON's Wind Report highlights the use of reserve capacities of up to 60% of the installed wind power capacity for wind balancing. One occasion when generation dropped 3640MW within six hours, with an average value of 10MW per minute raises particular concerns on wind variability. The report imparts a concern that wind farm construction should be tempered by a realistic recognition of the high costs and serious engineering difficulties experienced during operation.

Germany is connected to the UCTE system via neighbouring states. As such it is required to contribute to the 3000MW primary control that is held on the system. The UCTE operates in a similar manner to the Nordic system, where the proportion of response is calculated based on total demand. Power transfers are required in the event that system frequency drops from nominal 50 Hz and should be limited to ±0.2 Hz.

3.3 New Zealand

New Zealand operates as an island with 170MW of wind turbines, equivalent to 2 % of the total capacity. NZ is very fortunate as over half of its electricity currently comes from hydro dams. This is a useful storage medium when the wind is not blowing, as the volume of water flowing through hydro dams around the country can be reduced. In effect this means that the electricity generated by wind turbines can be stored as potential energy in the hydro and released to generate electricity in periods of calm weather. Hydro turbines are also very good frequency response providers and the majority of response is held either on these generators or as demand management.

The exact methodology behind response holding in NZ cannot be confirmed but assessment of operational records gives an indication of the levels held by the TSO, Transpower. Depending on the time of day between 120 and 300 MW of fast (primary) response is held on the islands with a level of sustained reserve that ranges from 370 to 500 MW (secondary response). Limits on frequency deviation are not as stringent as in the UK, Chown and Coker(2000), permitting frequency deviations down to 47.5 Hz and up to 52 Hz.

3.4 Crete

Crete has a significant level of wind penetration with 69.9 MW against a total system capacity of 640 MW, Papazoglou and Gigandidou (2003). The biggest problem for the system operators is that a minimum level of thermal generation must be kept operating, to provide frequency control and reactive power. To keep this minimum quantity of generation running at times of high wind output and low demand, the wind production is curtailed. The level of curtailment in 2001 was 6% of wind production, and this is expected to rise as more wind is connected. Fortunately the high demands coincide with high winds, and most curtailment occurs in the low-wind season. However, high curtailment clearly has a major effect on the economic and environmental benefits of wind generation.

Details of the Crete frequency response scheme are not available.

3.5 Summary of operator experiences

In Nordic and UCTE systems frequency response levels are held fixed at 1200 MW and 3000 MW respectively chosen only through operator confidence. In GB the primary control requirement is optimised every half hour based on demand and largest loss, and so primary response can range between 400-1320 MW and Secondary response between 400-1250 MW. This avoids unnecessary response holding and ensures a more efficient use of plant. However, this method means that a precise value of the response requirement is necessary.

There are also differences in the frequency criteria for activation of Primary Control. In UCTE a frequency deviation of –0.2 Hz will activate the entire Primary Control reserve. However, in Nordel the amount of Primary Control activated increases with frequency deviation, from –0.1 Hz to –0.5 Hz when the entire reserve is fully activated. In GB, the Primary Control reserve is fully activated for a frequency deviation of -0.8 Hz.

Each of these systems displays a technical variation with the GB system and so none are ideal comparisons with the GB network, which highlights the systems uniqueness. Norwegian, Finish and Swedish networks have similar penetrations of wind power and are of comparable size to GB. However, these systems benefit from the added security of being part of the Nordic system. The German and Danish networks have very high proportions of wind generation but again benefit from connection to the UCTE network. All hold smaller frequency reserves as individual areas when compared to GB.

Both New Zealand and Crete operate as island systems but are somewhat smaller than the GB system. On these islands it is common to experience large swings in frequency compared to GB. NZ benefits from its hydroelectric capability, while Crete favours curtailment to control is wind energy problem.

4 Frequency simulations

4.0 The need for frequency simulations

As discussed in **chapter 3.5**, the response levels in GB are optimised every twenty minutes in the control centre. This results in a more efficient use of resources, but entails a precise value for the requirement based on the instantaneous system characteristics. A set of response requirements allow the appropriate levels of ancillary services to be established, quantifying the reserve needed to limit frequency deviation.

The frequency response of a power system is a complex topic so a large number of approximations and assumptions have to be made to develop workable processes for managing the frequency response requirement. The dynamic behaviour of the GB grid involves a range of unique problems not experienced by most other network operators because of the grids relatively small size, and generation mix. The main areas of concern are large frequency excursions relating to the loss of large individual blocks of energy input to the system.

The dynamic effect of response on the network is also currently poorly understood. Not only does the amount of reserve need to be considered, but also the type of unit holding the response and the possible geographical effect of multiple elements of the reserve to a dynamic change in frequency.

Most of the variables that collectively influence the behaviour of the national grid cannot be exactly quantified by real-time processing, for example, the load behaviour during frequency events. The chief objective must be to ensure that emergency plans to cut off electrical supplies do not operate unnecessarily for events that occur relatively frequently and to avoiding excess environmental impacts on unnecessary reserves.

The complete dynamic process influencing the power system is an interaction between the demand characteristics, all the generators and their control characteristics, and the transmission system performance. The overall system exhibits non-linear behaviour with respect to frequency, and this entails a very complex behaviour.

Existing techniques to model frequency response Adibi *et al.*(1999), Welfonder(1997), Chan *et al.*(1972), Popović and Mijailović(1997), Anderson and Mirheydar(1990), Inoue *et al.*(1997), Weber *et al.*(1997) and Transpower(2000) do not fully represent the impacts of every element of the power system. They assume the system is transiently stable following any generator loss, and so the transmission network can be neglected. This assumption would mean the frequency and voltage have to be uniform throughout the system. Super grid transformers and their associated impedance along with differences in generator rotor angles mean that in reality this is not the case. Assumptions made of the transmission network also mean that any system losses cannot be integrated into the simulations.

Full model simulations which have high level representation of the network are either on smaller networks, as in the case of Kelly *et al.*(1994) and Sharma (1998), or much larger systems Pereira *et al.*(2002). Results here cannot be used as a direct comparison with expected results in GB.

In addition to issues of model complexity, there are some uncertainties that can never be fully simulated like; the exact mix and dynamic nature of demand at any instant in time or the actual behaviour of generated plant. This means that regardless of the sophistication of the models, other factors may influence the actual outcome during a real-time frequency event. For this reason a range of trials are necessary so that operational limits are not breached for the worst case.

4.1 EUROSTAG a solution to model frequency response

Eurostag is an electrical network simulation program developed by Tractebel and Electricité de France, Stubbe *et al.*(1989). It has evolved to allow the study of specific scenarios, of interest here is its capability of simulating networks in the transient time scales (seconds). It uses the same type of component for modelling all forms of network behaviour.

Using an initial user specified network representation a Load-Flow calculation is executed based on the Newton-Raphson method. This produces a detailed voltage map, which is then used in the initialisation phase of the simulation. The on line interactive dynamic simulation program is the core algorithm solving a large number of algebraic and differential system equations simultaneously. The differential element comes from the machines and the control equations, with the algebraic parts originating essentially from the network equations.

Eurostag benefits from a predictor-corrector integration technique, and a variable integration step to solve differential and algebraic equations. The size of the step is calculated after each step and is determined by the user specified truncation error. This means the integration step size changes automatically according to the actual behaviour of the system in a typical range from milliseconds to seconds, this assures a constant accuracy in the integration process.

4.2 Modelling functions

The Eurostag package has extensive modelling capabilities. In addition to the library, which holds detailed models representing basic elements, a graphic data entry program enables the user to directly code custom models. This feature allows voltage regulators, speed governors, turbines and power electronic devices to be implemented.

The electrical network is represented as an equivalent π network under a positive sequence pattern or a full unsymmetrical representation. The bus voltage(U_b) is governed by the relationship between the nodal admittance matrix(Y) and the current(I_n) entering the nodes according to Equation 2.

$$I_n = Y.U_b$$

Equation 2

In the positive sequence, loads are represented by either a non-linear equation as a function of voltage and frequency or by dynamic models using macro-blocks. The dynamic effect of low-voltage level tap changers is also modelled. Reactive compensators are represented as single elements or as banks.

Induction machines may be modelled in two different ways; a "complete" model which assumes the existence of a double rotor cage; or the "simplified model" neglecting rotor transients. The modelling of synchronous machines is done according to Park's classical theory, where the rotor is represented by four equivalent windings.

The machine internal fluxes have been made sensitive to the system frequency and the saturation of the magnetic circuits may be represented using Shackshaft's model. The details of the step-up transformer may also be included in the generator model. The mechanical behaviour of the rotor movements is described by the rotating mass equation, which relates the mechanical and electrical torque to the variation of rotational speed. The user may define the machine by its "external" reactance's and time constants or "internal" mutual and dispersion inductances / resistances.

A Macro-block language is used to represent the dynamic actions of machines to voltage and frequency. Each generator has an associated AVR and governor macro-block. These blocks inject a torque into the shaft of the machine or an excitation voltage across the stator that is determined from the specific transfer function and parameter values contained within the macro file.

Eurostag is also able to simulate automatic control systems. The moment at which these systems de /activate is determined by evaluation of equations describing their behaviour. The equations describing the automations are evaluated after each integration step, based on the value taken by the required state variables. They are used, for example, to represent protective relays, the automatic tap changers of transformers or the automatic load shedding systems.

4.3 The Dynamic Model and Simulation

Synchronous induction machine models are required to capture the dynamics of interest in a simulation. There are three fundamental requirements to represent the dynamic model; the winding dynamics (q-axis damper winding-flux linkage), damper winding dynamics (relating to shaft angel) and shaft dynamics (relating to shaft speed). Details of these parameters are held by NGT for all grid connection generators.

A variable-voltage exciter and a voltage regulator normally supply field current for a synchronous generator and are referred to as an *excitation system*. The excitation system is normally thought of as a control for voltage, but it also indirectly affects the reactive power levels. IEEE periodically issue recommendations for modelling excitation systems(1992) and also *Mummert(1999)*. NGT already has many excitation models developed for specific in-house simulation software such as RASM which have been applied for use in the Eurostag package using custom macroblock models.

All traditional grid connected generators are equipped with governor units which allow frequency response, Figure 8. The turbine and governor model chosen for simulations must take into account the type of unit being operated (i.e. hydro, steam or gas). Literature exists describing the general modelling of hydroelectric turbines; Working Group on prime mover and energy supply models for system dynamic performance studies(1992), Vournas(1990), and Vournas and Daskalakis(1993).

Some papers exist that cover both steam and hydro turbines; IEEE Committee report(1999), Bize and Hurley*(1999)*,and Bourles *et al.*(1997). Models for including boiler dynamics have been presented in a paper by *Mello (1991)*. Steam turbine models have also been published by the Working Group on prime mover and energy supply models for system dynamic performance studies(1991). A derivative of these steam turbine models with boiler dynamics is currently used by NGT for simulating coal and oil fired plant responses.

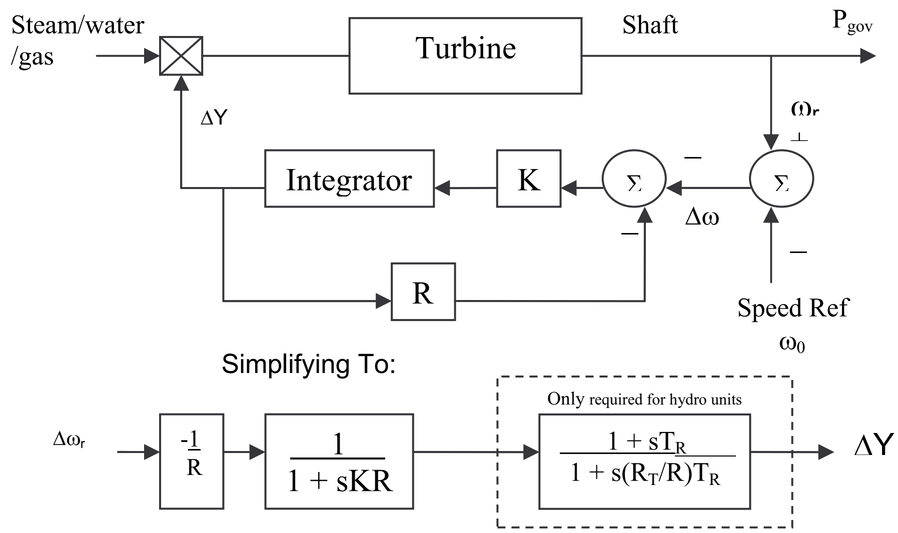

Figure 8 - Governor transfer function

Modelling of CCGT plant is somewhat more complex and is more specific to manufactures chosen control schemes. Kunitomi *et al*.(2003), Working Group on prime mover and energy supply models for system dynamic performance studies(1994), Undrill and Garmendia(2001), and Hannett and Feltes(2001) cover the dynamics of some specific plant. The current model used by NGT to simulate OCGT response in transmission studies was supplied by Siemens and is based on a simple transfer diagram.

Figure 9 gives block diagrams for the most common steam and hydro turbines together with their transfer functions neglecting boiler dynamics.

A useful Cigré brochure, Task Force 38.01.10(2000), gives recommendations for modelling of wind and also photovoltaic generation.

The purpose of carrying out dynamic simulations is to predict the behaviour of the system in response to disturbances. The disturbance itself can be achieved through shutting down one of the generators of appropriate size.

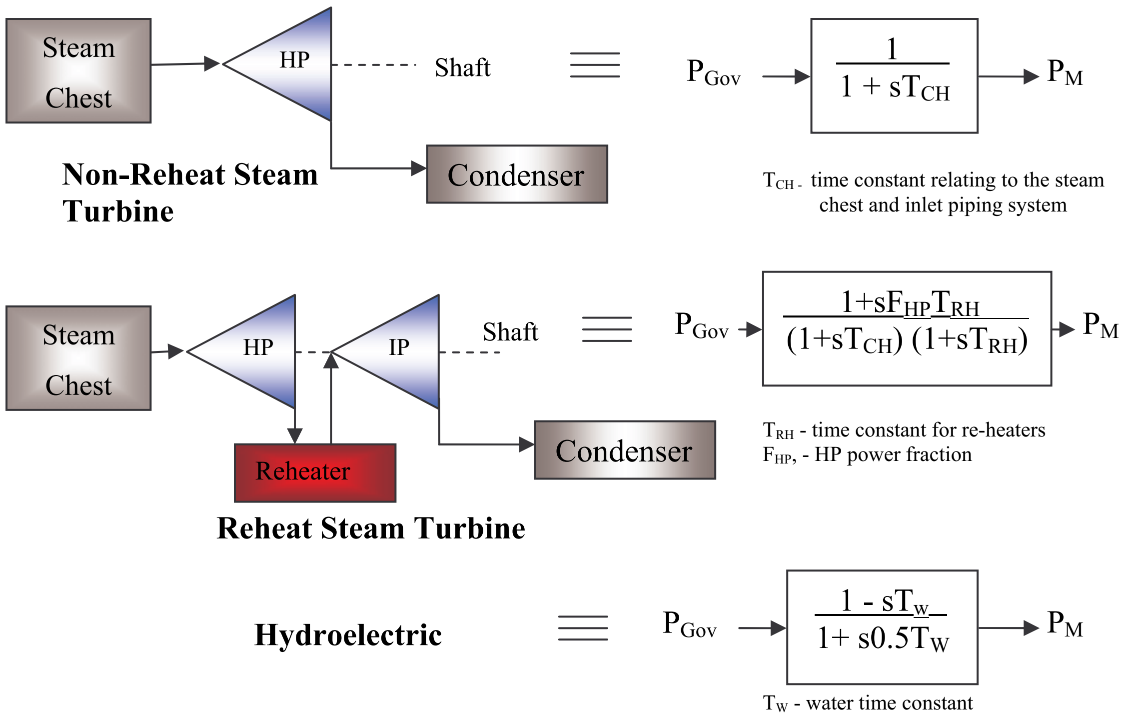

Figure 9 - Various turbine transfer functions

4.4 The Network Model

As recommended in the Cigré report 148, the grid model proposed for use in simulation studies of this project is mainly composed of the 400kV and 275kV transmission system. Some of the 132kV, 66kV and 33 kV infrastructure exists to connect remote generators onto the system keeping the model as close actual grid configuration as is possible.

4.5 Simulations using Eurostag

By using Eurostag to simulate the actions of both generator and load responses it becomes a powerful analytical tool. Simulations can be used to quantify the levels of response needed to contain a frequency disturbance. Operational decisions can be made based on data derived from network models of the physical system that ensure operational limits are not breached.

Simulations can be applied to revisit the current frequency response requirements to ensure excess response, and thus excess emissions are not encountered. Additional simulations can also be implemented to examine the affects of a change in the generation mix on the response requirement. Specifically the affects caused by the operation of more wind turbines on the system. The resulting response holdings translate to machine fuel flows and can be translated to the equivalent emission levels.

Models described in **sections 4.3** and **4.4** have been used in conjunction with Eurostag to examine the effect of some system parameters on system frequency. The results of these disturbance simulations are highlighted in **chapter 5**.

5 System Frequency Response

5.0 Frequency response

The safe and secure operation of a power system party depends on the way it responds to internal power fluctuations and disturbances. The system frequency of a synchronous system varies with the imbalance between the energy fed into the network and the electrical energy taken out by consumers. The rate at which the energy is exchanged depends on the energy stored in the components of the overall system. For isolated island power systems, such as the UK, adequate provision of energy at all times is essential to maintain safe operation of the network.

National Grid operates the UK transmission system to strict quality standards that are set out in the *Grid Code (2004)*. The code states that the frequency of the system shall be normally 50Hz and shall be controlled within the limits of 49.5 and 50.5 Hz unless *abnormal* circumstances prevail. Under *abnormal* circumstances (a credible loss of over 1GW) provisions are made that the system may deviate from operational frequency by 0.8 Hz. In *exceptional* circumstances the system frequency may reach between 47 and 52 Hz. In addition to these safety limits National Grid imposes its own operating limits of 50 ± 0.2 Hz which are strictly monitored.

With these limits in mind it becomes of great importance to understand how components of the overall system effect the dynamic frequency. This is of particular relevance when considering the loss of large portions of generation or load. The main factors which should be considered to influence the minimum frequency of the system include:-

- Magnitude of the contingency event under consideration
- Generator inertia
- Demand frequency sensitivity / Demand inertia
- Reserves available
- Generator response
- Automatic under frequency load shedding -magnitude and settings/response
- Demand management - magnitude and settings
- System losses (i.e. transmission system)
- Frequency at the time of the contingency

The following sections look in detail at some of the system parameters that influence the overall dynamic response of the network.

5.1 Generator Droop

5.1.1 Generators

The power system is composed mainly of synchronous AC generators, which are usually driven by gas, hydro or steam turbines. The main control elements of an electric generator are given in Figure 10. Two basic control elements are required the automatic voltage regulator (AVR), which controls output and the governor, which controls the transfer of mechanical power to the generator shaft.

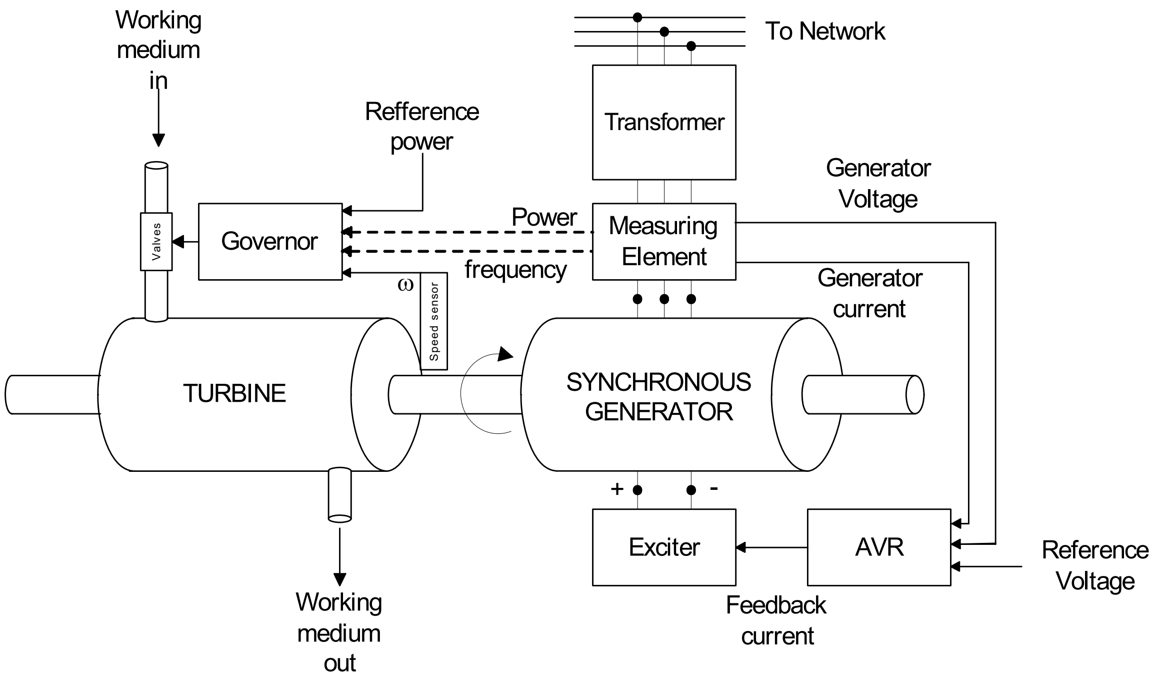

Figure 10 - Block diagram of generator control system

The GB grid uses a droop control scheme to control the power balance on the system and maintain system frequency. The individual machine governors open control valves to a position determine by the relationship between system frequency and a speed reference. This allows all the control machines to pick up load if the power system frequency falls and likewise deload if the power system frequency rises. The turbine speed cannot be directly changed once the generator is locked to a power system but it is possible to change the speed or load reference of the governor.

The governor performance is represent by the speed droop characteristic (ρ_G) of the generating unit. The definition of droop is the amount of speed (or frequency) change that is required to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be equated to the frequency change from no load (f_{nl}) to full load (f_{fl}) relative to base frequency (f_0), Equation 3.

$$\rho_G\% = \frac{f_{nl} - f_{fl}}{f_o} \times 100\%$$

Equation 3

A typical generator droop characteristic for the UK is 4%, which means that a frequency deviation of 2 Hz (4%) causes a 100% change in the generator output. Units that operate with a lower speed droop are more responsive to changes in system frequency.

5.1.2 Impact of Droop on the Power System

Governors respond to a change in system frequency to arrest any change in system power imbalance. However, governors cannot restore the power system frequency to the pre-disturbance level. Supplementary generation must be applied to restore the system to its base frequency of 50 Hz.

$$K_T = \frac{1}{\rho_T} = \frac{\sum_{i=1}^{N_G} \frac{1}{\rho_{Gi}} P_i}{P_L}$$

Equation 4

The system speed droop (ρ_T) can be calculated as the percent steady-state frequency change divided by the per unit steady-state power change. *Kundur(1993)* explains how the system droop can also be calculated from the sum of all the individual generator droops (ρ_{Gi}) and outputs (P_i) given the system load (P_L), Equation 4. The reciprocal of this collective effect is called the generator-frequency characteristic (K_T) of the power system.

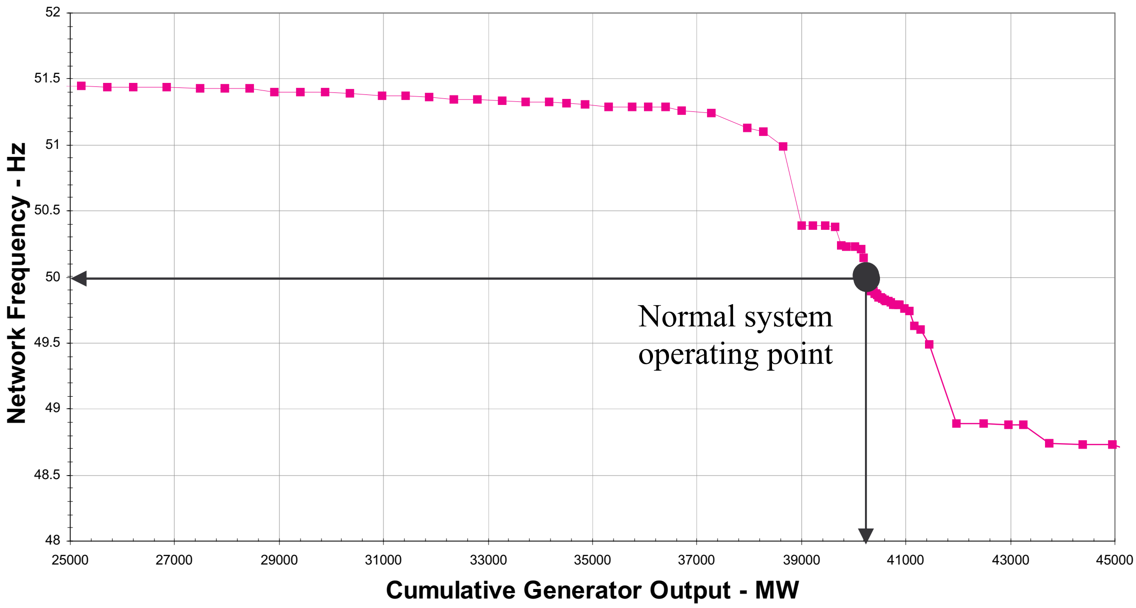

Figure 11 - Generation characteristic from a July morning, 2003

Ordinarily, a system with many generator units will have a very large generator characteristic and consequently a large power change will only lead to a very small deviation in frequency. If a generator is operating at its rated output any further decrease in frequency will not produce a corresponding increase power. This unit no longer contributes to the generation characteristic, and as such causes the system generation characteristic to become non-linear, Figure 11. A fine control zone is developed around the nominal frequency.

If the system power (P_G) is considered as in equilibrium with the system load the generator characteristic can be approximated at the operating point by a linear characteristic Equation 5.

$$\frac{\Delta P_G}{P_L} = -K_T \frac{\Delta f}{f_0} = \frac{1}{\rho_T} \cdot \frac{\Delta f}{f_0}$$

Equation 5

It is important to bear in mind that in the cases discussed in this section we have assumed an ideal relationship between the power supplied by generators and their operational frequency. In reality generators provide a far from ideal characteristic. In the case of steam turbines their control valves have a nonlinear flow area–position characteristic. This causes an incremental speed-droop characteristic. Hydraulic turbines tend to exhibit the speed-droop characteristic shown in Figure 12.

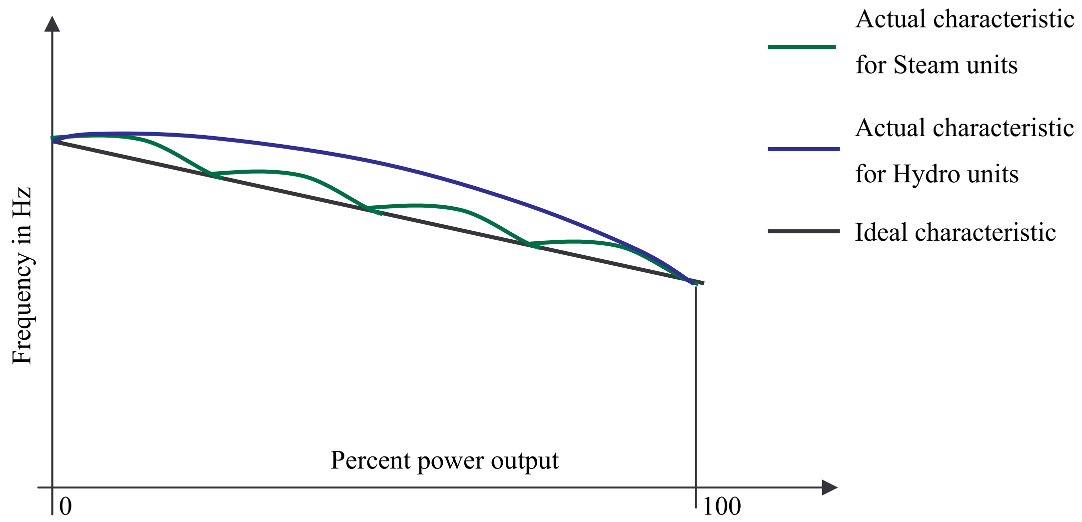

Figure 12 - Speed-droop characteristics of steam and hydro turbines

Figure 13 shows values of system droop during large generation losses between 1994 and 2004. National grid guidelines on security and quality of supply require that loss of system demand or generation the frequency does not breach set limits.

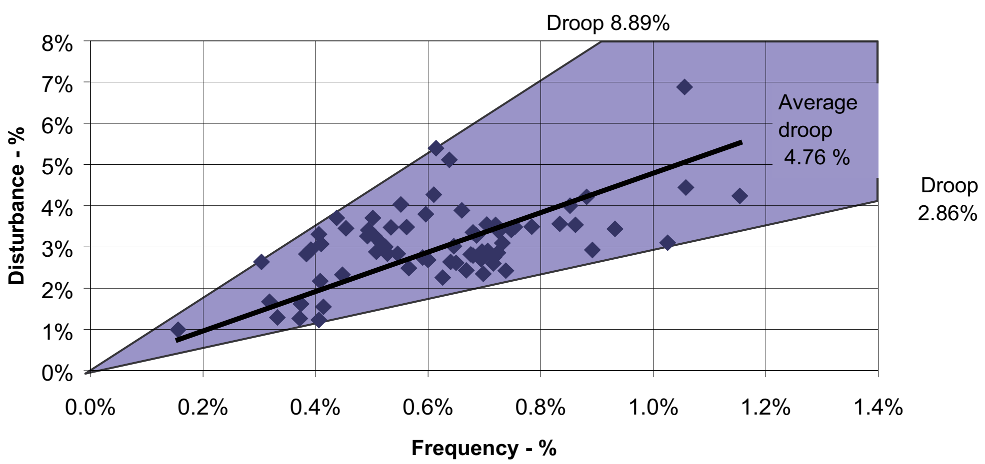

Figure 13 - System droop for generation losses between 1994 and 2004

5.1.3 Generator Droop Simulations

By using a simple power system model of the UK Grid (**Section 3.4**) we can observe the effects of generator droop on the dynamic response of the systems frequency. The example shown is of a 1200MW loss of generation at a network demand level of 25GW. The curves given in Figure 14 show the effect of generator droop on the frequency.

National Grid in the Grid Code specifies that all frequency responsive generating plant must operate with a droop setting of between 3 and 5 %. This has the potential to alter the maximum system frequency deviation seen in the system. Some frequency responsive plants offer a choice of droop settings for the balancing market. This gives greater control over network droop and helps to prevent a maximum deviation from violating operational limits.

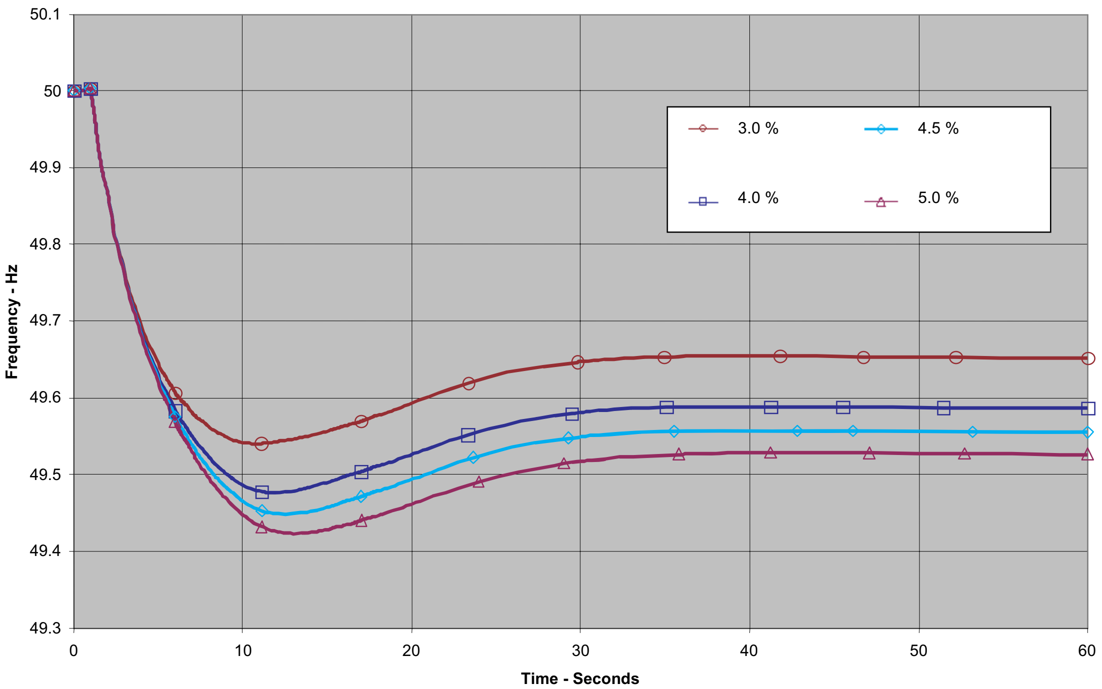

Figure 14 - Effect of Generator droop on System frequency

5.2 Disturbance Magnitude

5.2.1 Typical disturbance levels

On the UK grid the maximum possible loss of generation that is secured against is currently 1320MW, which corresponds to two 660 MW generator units lost via a double switch fault. In 90 % of the *abnormal* events leading to a loss of generation between 1987 and 2003 (Figure 15) the total loss experienced was below the maximum value.

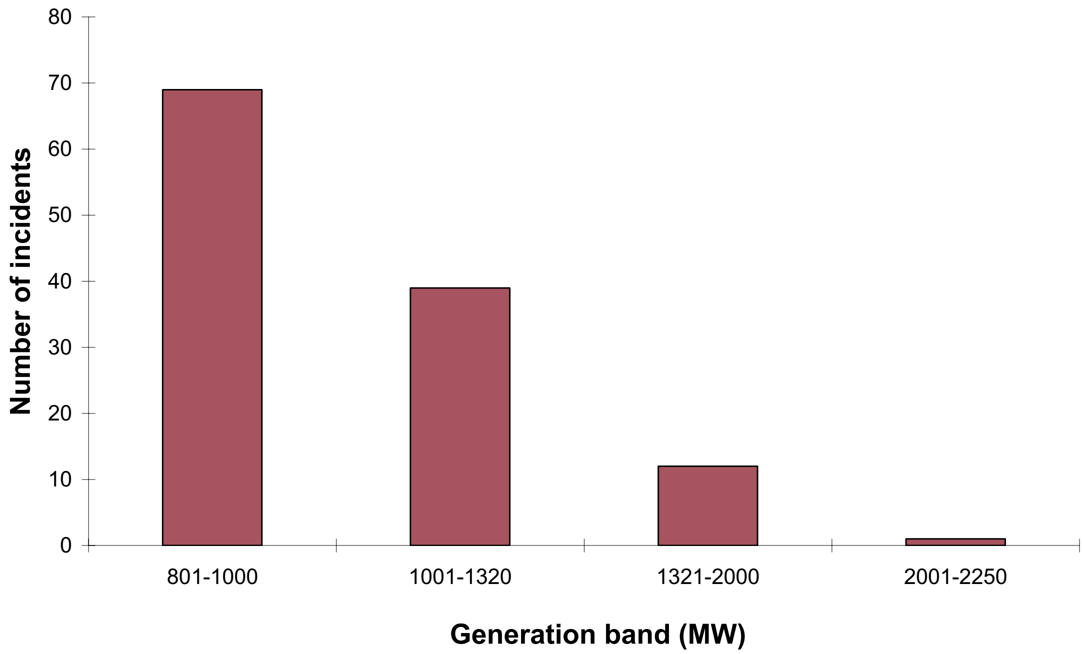

Figure 15 - Distribution of size of abnormal generation loss between 1987-2003

In many cases a loss of a large portion of demand will also have a significant effect on the frequency of the network. The loss of 500 MW of demand would have the same impact on the system as an instantaneous increase of generation by 500 MW causing an increase in frequency. To cater for a loss of demand the normal safety margin of 560MW is allocated in high frequency response, this is equivalent to the loss of two super grid transformers. However, this value may be increased if the anglo-french interconnector is exporting power above this level.

Depending on the time of day and the time of year system demand levels are usually between 18GW and 55GW. Figure 16 places a generation loss of 1320MW at between 6.6 and 2.4 % of the national demand depending on when the event occurs, this is a significant portion of the total power.

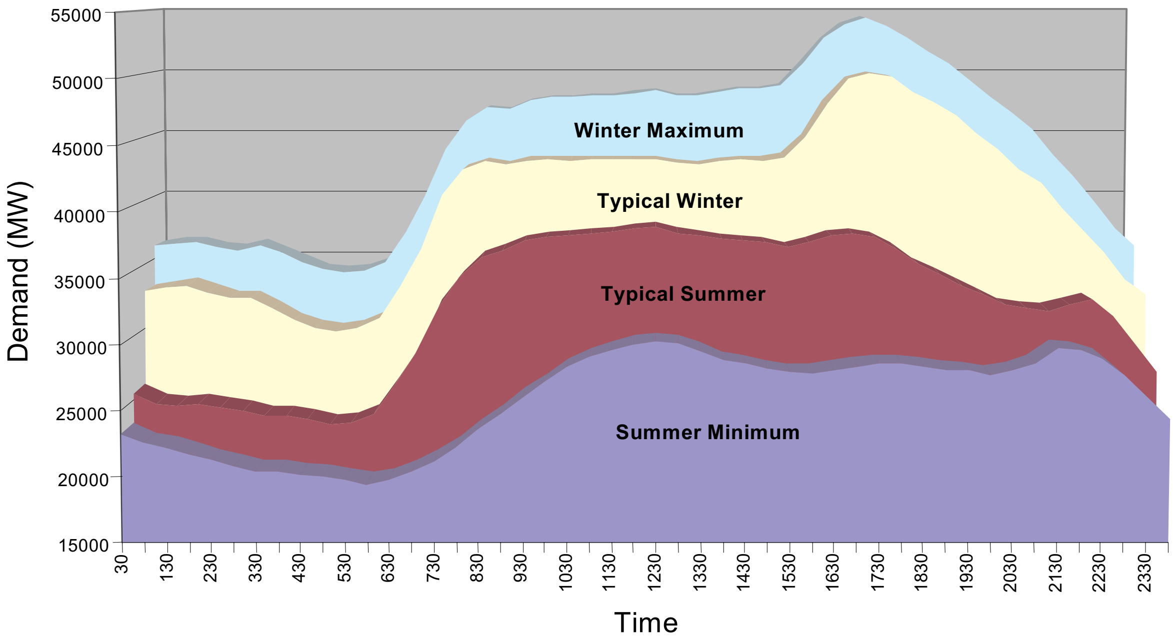

Figure 16 - Typical Grid Demand levels

5.2.2 Disturbance Simulations

Using the same example as in section 4.2.4, it is possible to observe how the magnitude of the disturbance effects the system response. The curves in Figure 17 show the frequency transients at various loss levels. The deficit of power has a direct relation to the maximum deviation, steady state value and initial decay rate of the system frequency as can be seen from the graph.

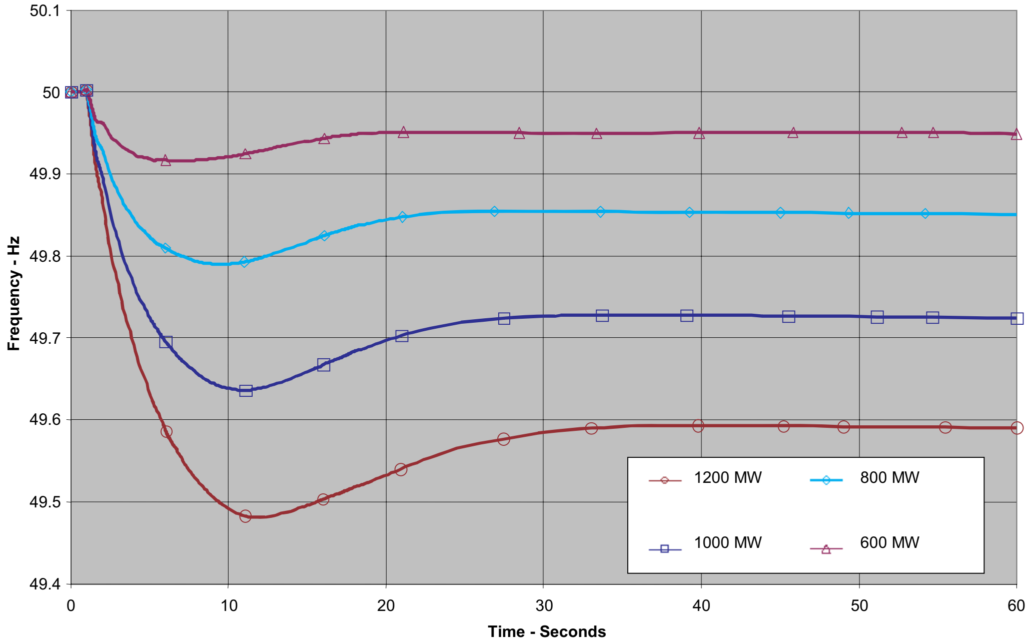

Figure 17 - Effect of disturbance magnitude on system frequency

5.3 Generator inertia

5.3.1 Effects of inertia

According to Newton's laws of motion all objects resist changes in their state of motion. Inertia is the tendency of an object to resist changes in motion and is dependent upon mass of the object. If we consider a simple generator with angular rotation (ω) it has inertia (J) acting against the changing motion and a mechanical driving torque (τ_M) supplied by a turbine with its counter acting electrical torque (τ_E). *Machowski(1998)* gives this relationship as Equation 6.

$$J.\frac{d\omega}{dt} = \tau_M - \tau_E$$

Equation 6

The inertia of a generator is usually normalised as a per unit inertia constant, defined as the kinetic energy at rated speed over the MVA base. The units of the inertia constant are seconds, which represents the time it would take to provide the equivalent amount of stored kinetic energy held in the generator at rated output.

Multiplying the terms in Equation 6 by the normalised speed we have a fundamental description of the rotor dynamics called the *swing equation (*Equation 7*)*. The difference in mechanical power (P_M) and electrical power (P_E) is solely related to the inertia and rate of change of rotation.

$$2H.\frac{d\Delta\omega}{dt} = P_M - P_E$$

Equation 7

A typical thermal generator with 2-poles will have an inertia constant (H) that can range between 2.5 and 6, whilst 4-pole machines have an inertial constant in the order of 4 to 10. Hydro units are normally smaller and so have typical inertia constants of 2 to 4. On the UK grid the inertial values of the individual generators vary between 9.5 and 3.2.

The system inertia as a whole encompasses the inertia of each individual generator connected to the grid. It can be calculated from the weighted average of the all the generators operating on the grid at that particular instant. Scheduling generators in much the same way as with system droop can effect the overall system inertia. By operating more generators the system inertia is raised. It is also worth remembering the load is composed of a percentage of similar rotating machines, albeit of a somewhat smaller scale. These machines will also carry a certain amount of kinetic energy because of their nature, which contributes to resist any change in frequency.

5.3.2 Inertia simulations

System inertia is the main factor that controls the drop in frequency in the two-second period before governor action beings to increase generator output. The example from section 4.2.4 is again used to show inertia properties in Figure 18. Inertia controls the initial decay of frequency, and has a slight influence on the maximum frequency deviation and the time of the maximum deviation. However, its impact is not as significant as for previous parameters.

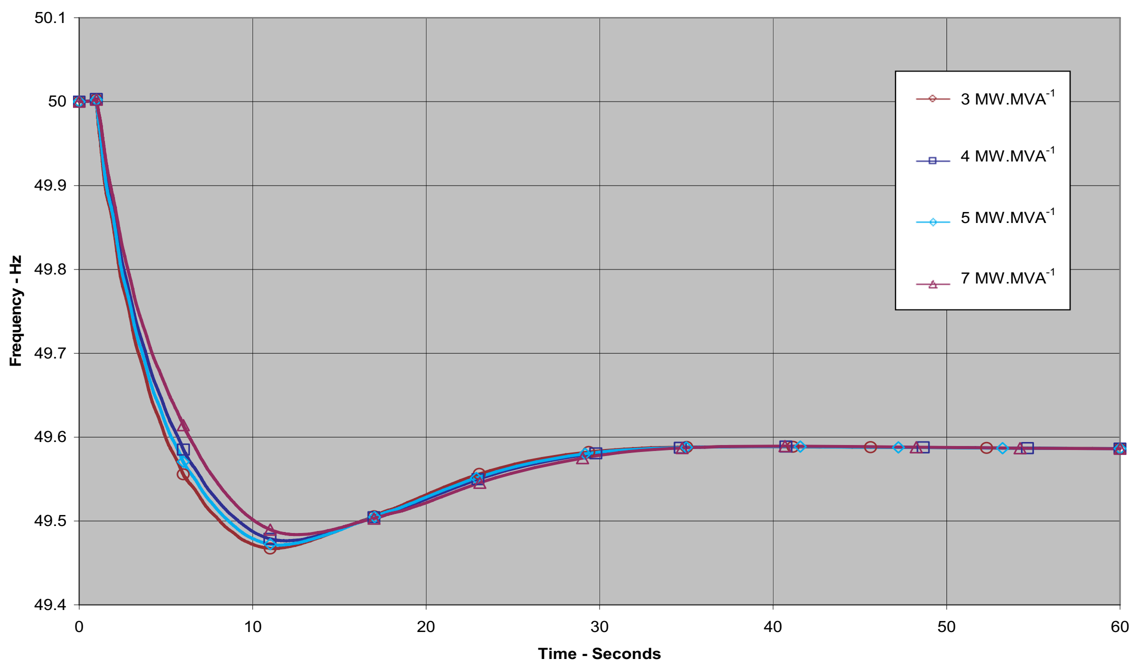

Figure 18 - Effect of inertia on system frequency

5.4 Load Frequency Sensitivity

5.4.1 Load Frequency Characteristic

The total system load is composed of elements of both resistive and inductive load. During an imbalance in generation a net change in load will occur with respect to frequency. This change is due mainly to motor loads, which typically utilise 40 to 60 percent of the network power and will dominate the load-frequency characteristic of the system. A motor load is dependent on the voltage and frequency of the power system to which it is attached. If the system voltage or frequency declines, the connected motor load magnitude will also decline.

Changes in the system frequency have a larger impact on motor load than deviations in the voltage, *Welfonder et al. (1993).* Looking simply at the frequency impact of the motor load an approximate rule of thumb is that the connected motor load magnitude will decrease by 2% if the frequency decreases by 1%. To account for the influence of system loads on frequency a load-frequency characteristic (K_L) relates the two quantities, Equation 8.

$$\frac{\Delta P_L}{P_L} = K_L \frac{\Delta f}{f_0}$$

Equation 8

5.4.2 Load Frequency simulations

The load frequency sensitivity has a considerable influence over the maximum frequency deviation experienced by the system. The example from section 4.2.4 is used to show that a system with a higher load-sensitivity characteristic has a smaller deviation in frequency, Figure 19.

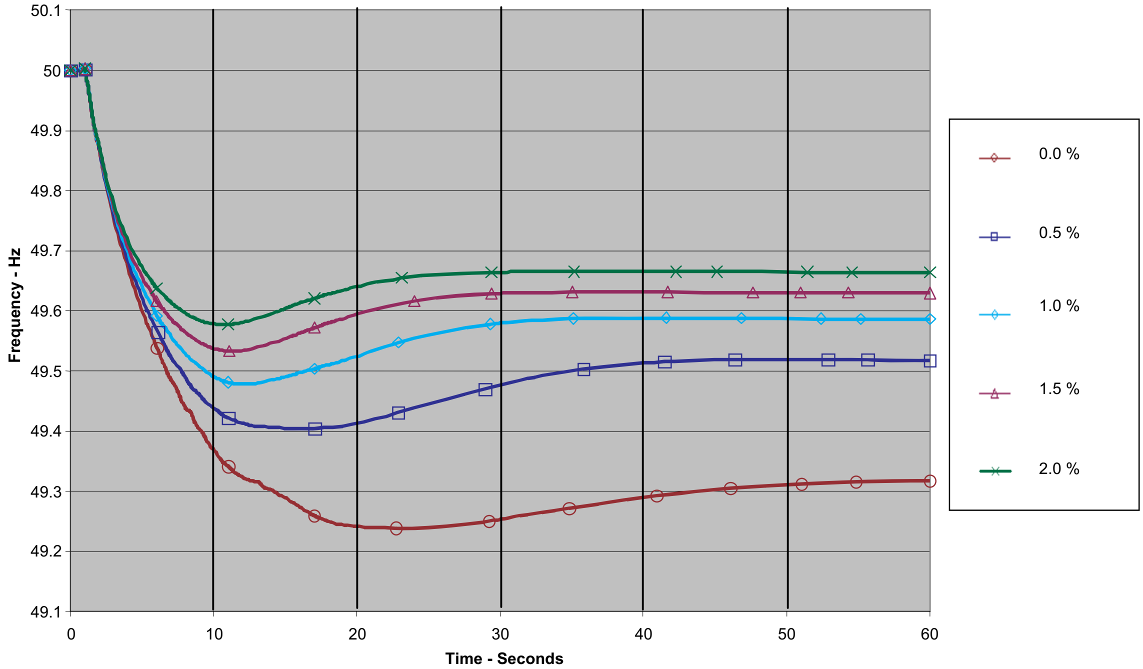

Figure 19 - Effect of load sensitivity on system frequency

5.5 Scheduling Generator Response

The purpose of response and reserve holding are to provide assurance that foreseeable levels of generation failure, shortfall or demand forecast error do not cause involuntary demand disconnection or in worst case system collapse. The allocation of response is an important factor in power systems operation as it determines the shape of the generation characteristic.

Response can be defined as the autonomous reaction to frequency deviation and is required to manage instantaneous imbalances between generation and demand. The response of the generators is grouped by National Grid into one of three categories: Primary response for fast (seconds) under frequency regulation, Secondary response (minutes) to recover the system frequency within operational limits, and High frequency response the equivalent over frequency regulation (on both time scales). These response types enable National Grid to artificially group generators according to their specific transient response characteristics.

Response can be dynamically delivered continuously by part loaded generation operating under governor action or non-dynamic delivered at set frequency trigger points, predominantly provided by demand-side management or fast start gas turbines.

Response is held based on the magnitude of the largest generation supply and secured demand. The response is then offset against the contribution of system inertia and reaction of demand to changing frequency. Generally speaking, as more generation is synchronised to meet increasing demand the disturbance becomes a smaller proportion of the system power, and the system load has more stored kinetic energy in rotating machines meaning less response is required to contain the same disturbance.

In Great Britain dynamic response is provided by de-loaded generators or Balancing Mechanism Units (BMUs). These units may be instructed to operate in either a Limited Frequency Sensitive Mode or a Frequency Sensitive Mode. A BMU operating in the limited frequency sensitive mode will be considered as frequency insensitive unless the system frequency exceeds 50.4Hz when the BMU will be required to provide high frequency response.

A BMU can provide Primary response and/or High frequency response and/or Secondary response at a realisable level of commitment. The magnitude of response required from such a service being defined within the relevant ancillary service agreement. A BMU instructed to deliver any of the above forms of response is operating in a frequency sensitive mode.

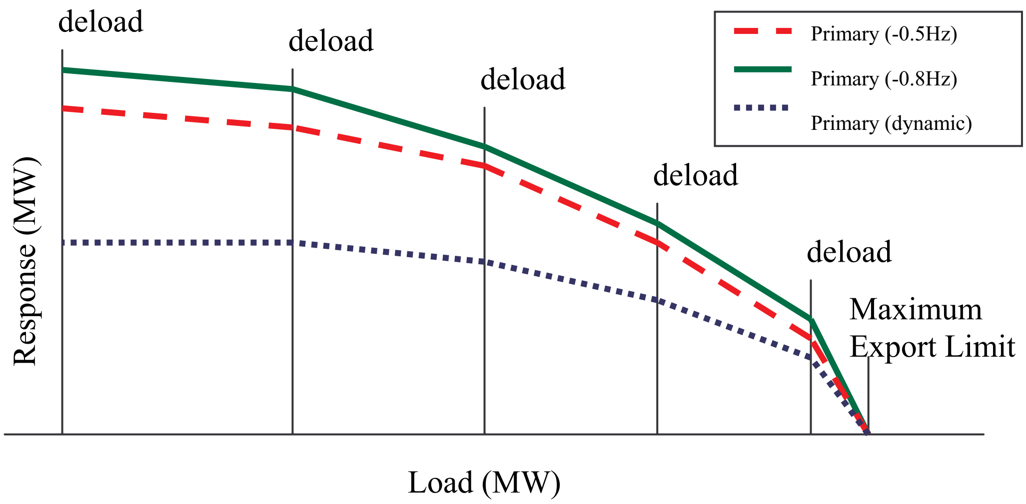

Figure 20 - Example generator response profile curve

Response contracts between National Grid and Balancing Mechanism Units (BMUs) are confirmed by response profiles (Figure 20) that provide accurate response details for each BMU. These profiles are supplied for a range of frequency deviations from 0.1 to 0.8 Hz and are compiled from physical tests carried out on generators.

It is important to realise that deloading a BMU by a certain number of Megawatts does not provide a one for one return of response. Due to the nature of each individual BMU some units will provide a faster response in comparison with other units. For example, open cycle gas turbines will typically out perform steam turbines as is shown in Figure 21. As the delivery of primary response is required by 10 seconds and secondary response by 30 seconds the quantity of response that can be provided at these times is limited by the physical makeup of the plant.

Standing Reserve, is carried by contract to cover short notice plant loss and demand forecasting errors. Following an event that leads to the delivery of response, instructions are given to standing reserve units to recover the level of response holding on the system so that BMUs can be brought back to their respective response holding levels.

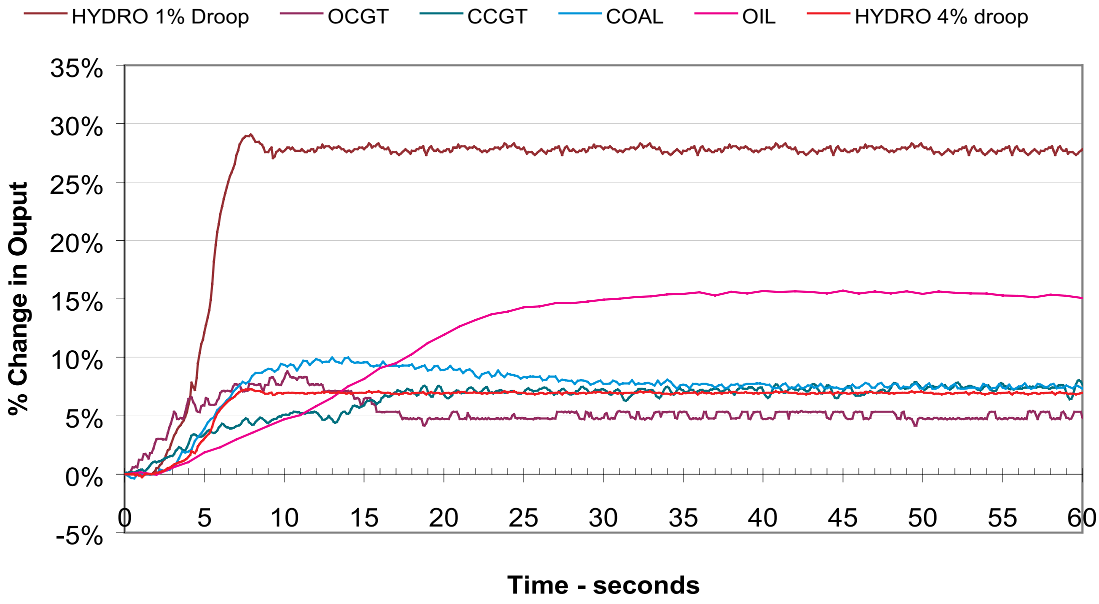

Figure 21 - Generator response to applied test frequency injection signal

5.6 Generators for frequency response

5.6.1 Thermal Plant

Generation plant take advantage of several different forms of energy transfer ranging from traditional coal burning types to modern fuel cell technologies. In all cases a fuel is oxidised to release energy which is then transported to the required load. Every single type of generating set operates with slightly different dynamic properties. The individual plant properties will collectively affect the dynamic response of the system. For this reason knowledge of how the different plant types operate is essential for evaluation of frequency stability.

5.6.1.1 Nuclear Stations

In the UK it is typical operating practise to keep nuclear stations running at a constant power output. This is because of safety concerns with nuclear power; as such they contribute no responsive generation to the system. Some nuclear plant in the UK is configured to provide response if necessary although as explained it has never been called upon to do so.

5.6.1.2 Coal and Oil-fired Stations

In coal-fired stations pulverised fuel is blown into the furnace where it mixes with air and combusts. In the case of an oil-fired station the oil is combusted in a similar process.

Steam is produce from the burning of the primary fuel source in either drum or once-through boilers. Drum boilers, Figure 22a, rely on convection or forced circulation to transfer heat from the furnace walls, to water. In these boilers the steaming rate is a direct function of the heat absorbed in the furnace (i.e. the fuel-firing rate). Drum boilers can still deliver power without any fuel flow into the furnace because of the quantity of stored heat in the water/steam. This system operates at subcritical pressures relying on a density difference between the steam and water phases for circulation.

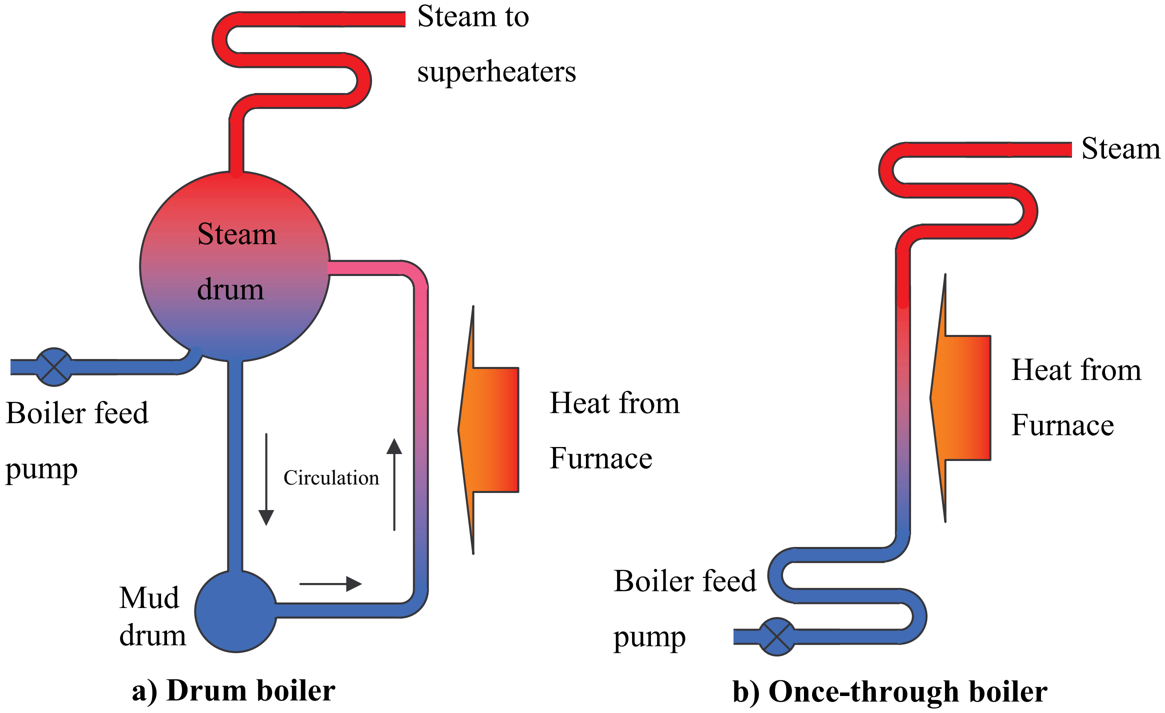

Figure 22 - Typical steam boiler arrangements used in power stations

Once-through boilers, Figure 22b, do not re-circulate water within the furnace; instead, water is feed at pressure into the furnace tubes by a feed pump. The steaming rate for this type of boiler is controlled solely by the feed pump. Since this system does not rely on a density change between steam and water it can operate at supercritical pressures increasing efficiency. A once-through boiler has less stored energy than a similar drum boiler unit, and so it is more responsive to changes in boiler firing.

5.6.1.3 Biofuels

Biofuels are produced from waste vegetable matter or are specifically grown from fast growing, high yield crops. Biofuels can contribute to electrical production by two routes, direct burning in a furnace to raise steam or following fermentation in a bio digester. In either case the method of electrical generation is similar to coal or oil-fired stations.

5.6.2 Steam Turbines

The high pressure, high temperature steam typically from the boilers is feed into sets of axial flow turbines. As the steam passes through the turbines or 'stages' it loses pressure and expands in volume. Between stages the steam can be taped of and reheated to increase operating efficiency.

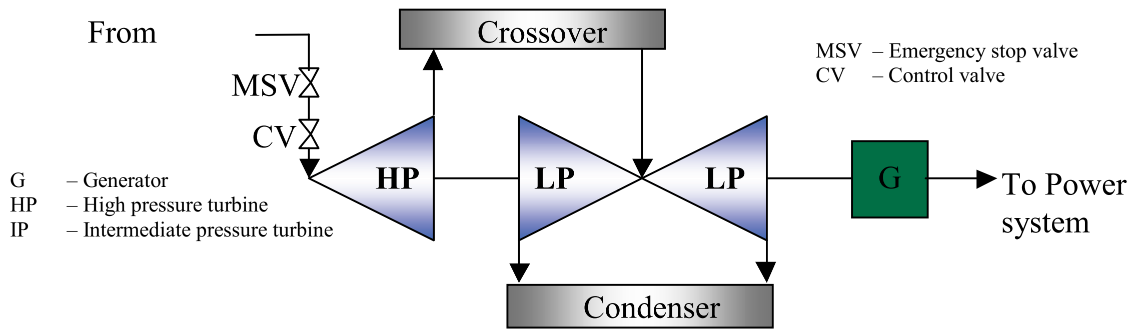

Figure 23 - Non-reheat steam turbine

Steam turbines are categorised by the way in which steam is reheated. Non-reheat turbines like those in Figure 23 usually have one stage and typically operate below 100 MW. The more common arrangement for high power turbines is a reheat configuration where up to three stages mean the turbine has a high operating efficiency. Steam from the boiler passes through the governor control valves and into the high-pressure stage. After the steam has left this stage it is reheated passes through more control valves and does more work in the intermediate stage. At the final stage steam passes from the IP stage by crossover piping for expansion in the low-pressure turbine where it is finally released as exhaust into a condenser.

With most steam turbine configurations relying on more than one pressure stage less than 30% of the output power comes from the initial stage. With such a small proportion of power being extracted from the start of the cycle, reheaters and crossovers become important components in terms of response. Steam supply through the system cannot be instantaneous; the steam travelling through each of the stages introduces a finite delay and the dynamic operation of the unit will be influenced.

5.6.3 Gas Turbines

Open cycle gas turbines (OCGT) directly use combustible natural gas in much the same way as the jet engine on a plane. They are capable of very fast response and start up times (sub three minutes) and are readily employed on emergency low frequency trip relays. A turbine diagram is given in Figure 24, a compressor forces air into a combustion chamber where it mixes with the fuel and ignites. The high pressure, high temperature gases then drive the turbine stage and exhaust is used to pre heat incoming air. The gas turbine drive shaft is connected to the generator to provide the necessary torque for electrical generation.

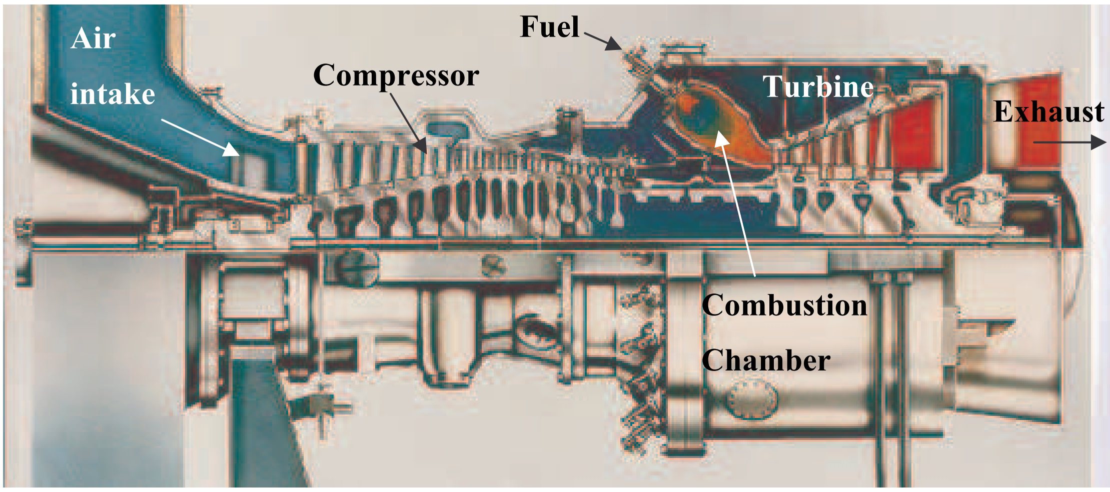

Figure 24 - Diagram of a simple gas turbine

In recent years the CCGT or combined cycle gas turbine has become increasingly dominant in the industry. It uses heat recovered from the gas combustion process to raise steam, which can then be used to drive an addition steam turbine. The steam raised from a typical gas turbine is only sufficient to support a steam turbine unit of half its capacity.

For this reason two distinct plant configurations have evolved.

- Single shaft machines, which have a gas and steam turbine (half the GT rating) on the same drive shaft Figure 25

- Multi shaft plant in which a steam turbine and two gas turbines drive individual generators that are mechanically isolated from each other. Figure 26

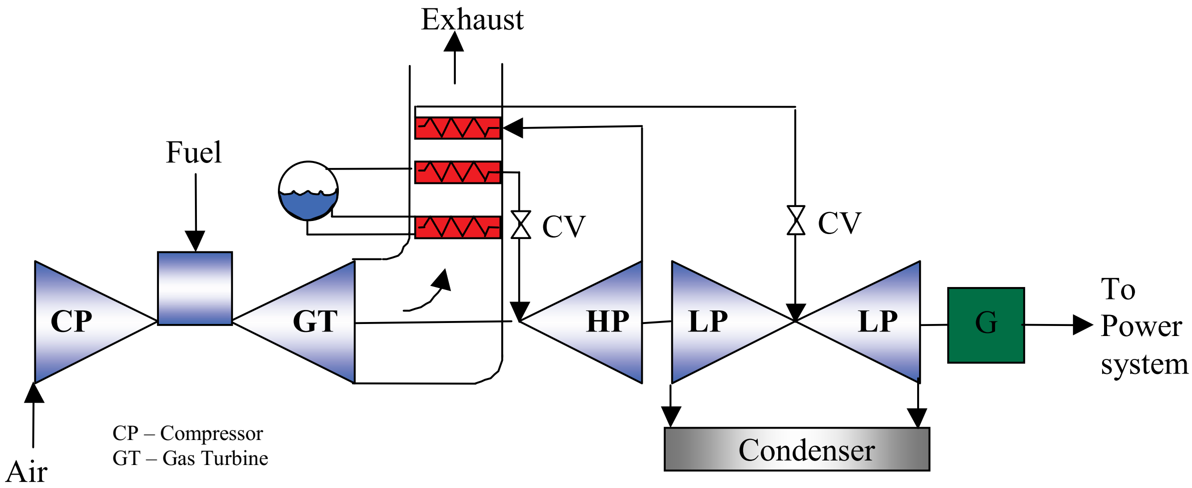

Figure 25 - Single shaft tandem plant configuration

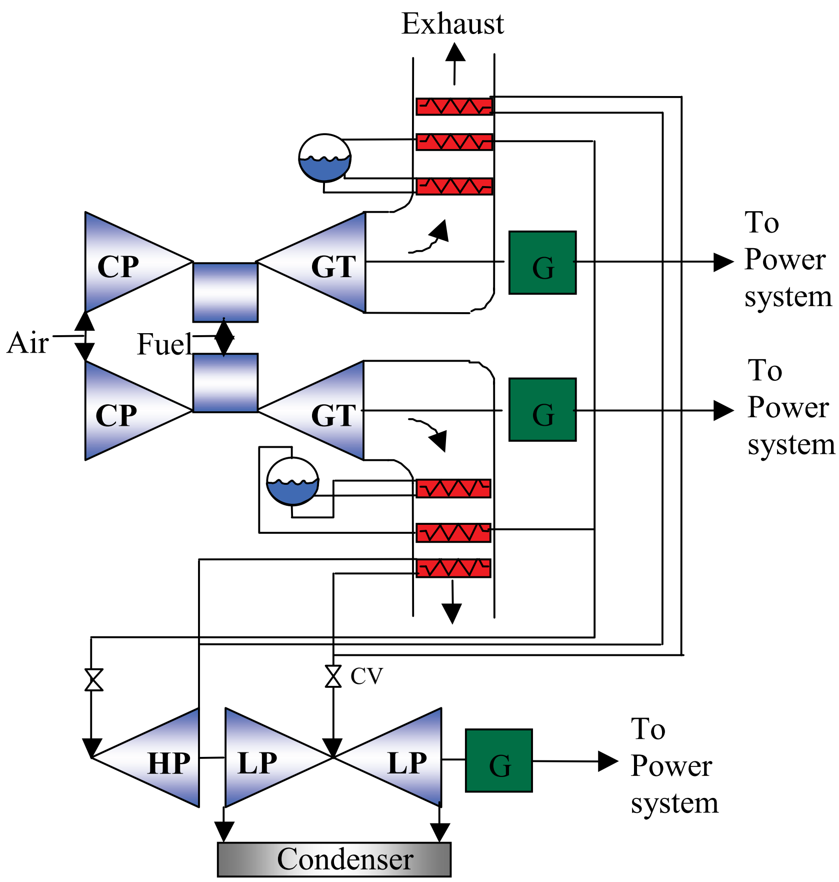

Figure 26 - Multi-shaft plant configuration

Multi-shaft configurations are the most common arrangements to be found connected to the UK grid because they were initially favoured. Newer plant tends to be of the single shaft variety of CCGT. Multi-shaft plants which may consist of HP, IP and LP steam stages can have an extensive and highly complicated steam delivery system. Regulating values may be employed at each stage to manage pressure levels in accordance with the gas turbine output. Electrically each of the turbines drives a separate alternator.

The steam consumed in the steam turbine unit must match the rate of steam production. The rate of steam production is controlled by the exhaust temperature of the gas turbines. To accommodate for this it is more usual for the steam turbine to operate in a “sliding pressure” mode, in which its control valves are in a constant position (normally fully open).

In this arrangement the output from the steam turbine changes at a much slower rate than the gas turbines. The main influences being the storage of steam in the drums, headers and other piping. This means that whilst the GT response is quick with evaporation rates in the boilers being equally quick the storage in the steam delivery system prevents this response from being realised in the steam turbine.

5.6.4 Hydroelectric Generation

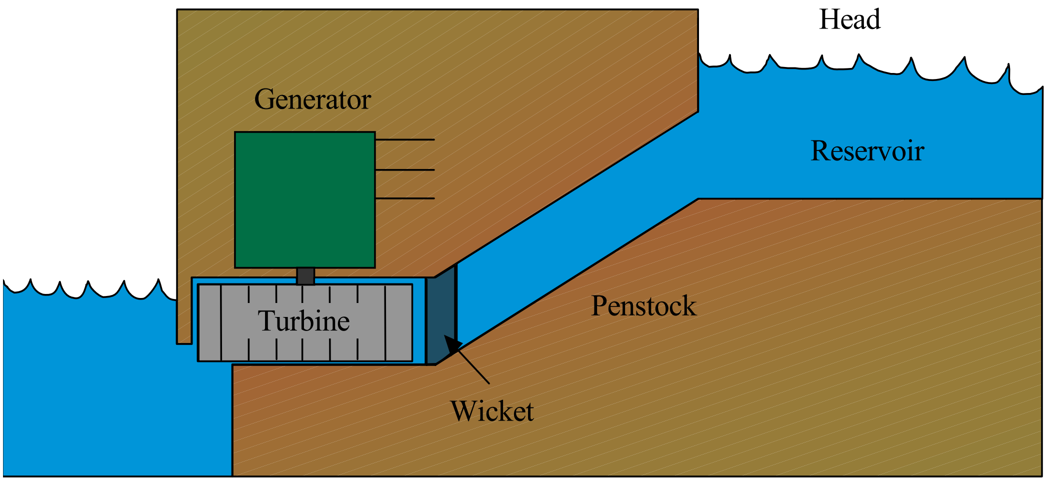

Figure 27 - Hydroelectric turbine arrangement

Hydroelectric generation (Figure 27) is perhaps the simplest form of generation. It relies on a vertical difference between the upper reservoir and the level of the turbines or head (h_H). Kinetic energy gained by the moving water is imparted to the turbine blades, which are used to drive generators. The generator power (P_G) available can be calculated from Equation 9.

$$P_G = \rho_w g W h_H = 9.81 \times W h_H$$

Equation 9

The output power is derived from the water density (ρ_w), acceleration due to gravity (g) and water flow rate (W) through the turbine, which is dependent on the specific design of the system. Detailed representation of turbine design, penstock, surge tanks, water column dynamics and travelling wave effects may be necessary to provide an accurate model of the hydro generator.

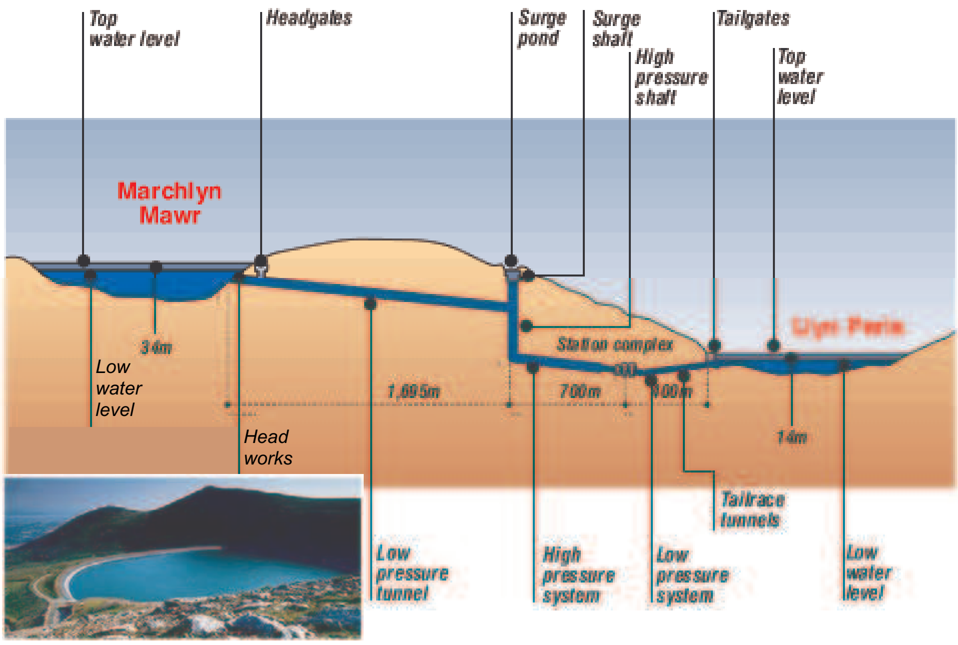

Figure 28 - Dinorwig Hydroelectric pumped storage facility

Scotland operates approximately 200MW of cascade hydro schemes. In England and Wales the hydroelectric generation is mainly utilised in pumped storage facilities such as Ffestiniog and Dinorwig (Figure 28). At these stations water is pumped into a large reservoir during periods of low demand. This store can be released on request and is capable of supplying up to 6 hours of full load generation. The quality of response that can be provided by these machines means that the plant is well suited to use as a fine frequency control tool.

5.6.5 Wind Power

Wind farms provide the most economically feasible source of large-scale renewable generation. The largest development to date is a 60 MW facility operating at North Hoyle Figure 29. Theoretically the maximum power that can be obtained from wind generation is dependant on air density (ρ_a), wind speed (u_w) and swept area of the turbine blades (A_w), Equation 10.

$$P_G = \frac{1}{2}\rho_a A_w u_w^{\ 3} \qquad \textbf{Equation 10}$$

Operation of the wind turbines is only possible at wind speeds above a critical point, usually between 3 and 5 ms^{-1}. The developed power increases with wind speed until the rated output is attained. At rated power blade pitch is altered or the turbine is allowed to stall so as to maintain a constant output with further increase in wind speed. The generators also have a maximum operational speed (typically 20 ms^{-1}), which if breached causes the generator to shut down.

Figure 29 - North Hoyle offshore wind installation

Wind turbines are typically composed of small-scale induction generators with outputs in the order of 2 MW. To reach the required capacity, individual windmills are connected to the grid in banks via transformer sub-stations to create wind farms. The fixed speed types rely on rotor stall to limit the power output at high wind speeds. Typically, variable-speed turbines use aerodynamic blade pitch controls in combination with power electronics to regulate torque, rotor speed and power. The preferred arrangement for larger wind farm projects is the doubly fed induction generator type, Figure 30. These machines have an added benefit that they can be configured by control systems to consume or provide reactive power.

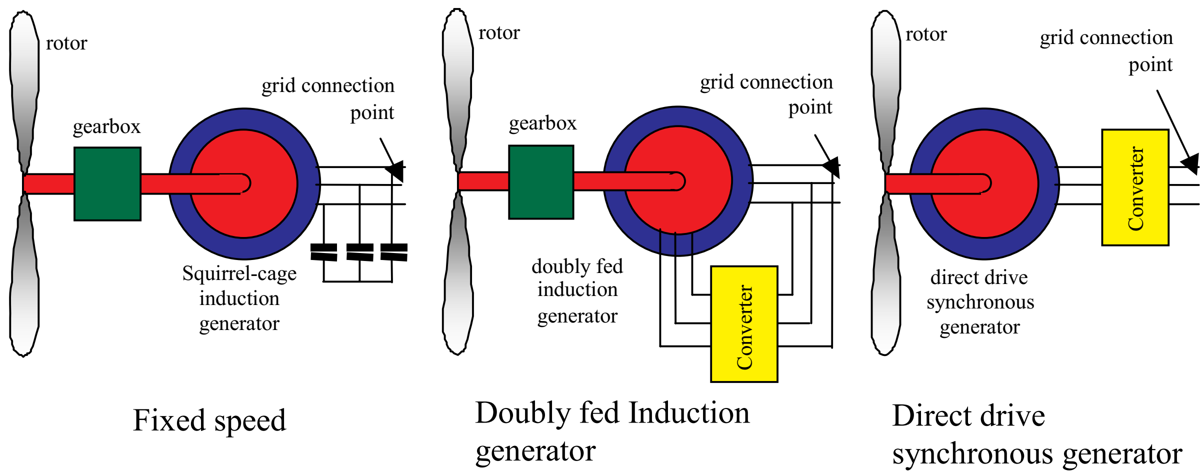

Figure 30 – Wind turbine connection arrangements

The actual turbine power is dependent on a number of physical attributes. Among these attributes the power coefficient versus tip speed ratio defines the aero-mechanical efficiency of the wind turbine. In the case of stall controlled turbines the aerodynamic behaviour of the air at the surface of the blades can also cause transient effects in the mechanical system. The turbine shaft unlike gas or steam turbines is very light and susceptible to twisting, storing energy like a spring. This effect is particularly noticeable during transients when the energy is released.

Wind turbines can be configured with the ability to provide a conventional governor droop and in turn frequency response. This would result in reduced power output in the event of an increase in system frequency. To provide an increase in output power in response to system frequency would require the turbines to be operating at below the optimum power level for the immediate wind conditions. This would in effect waste any potential wind energy. However, if delivery could be guaranteed this form of response would be fast and the response provided would be of the same magnitude as the potential level. This technique is only achievable in pitch regulated turbines, although no turbine manufacturer is offering this function at present.

6 Work to Date

6.0 Modelling Objectives

The most critical objective of the research is to formulate a response requirement that does not breach National Grid guidelines on security and quality of supply. Any loss of demand or generation should not allow frequency to deviate from the nominal by more than 0.5Hz in losses below 1000MW, or 0.8Hz for those 1000-1320MW.

The research should develop a tool to investigate the effect changing system parameters has on system frequency. This tool should provide the added functionality to accommodate various future scenarios. Such scenarios may include losses above 1320 MW (as the system is further stressed by increased electrical demand); or increased penetration of wind turbines.

Chapter 5 detailed some of the more important characteristics that affect frequency response. Of particular significance to achieving an accurate frequency transient after modelling a loss event is selection of an accurate value of load sensitivity. By quantifying the load frequency characteristic on the GB grid this will be achieved. Further optimisation of the response requirement would be possible if daily/seasonal trends can be established in the load frequency characteristic. This could reduce the response holding requirement.

The system frequency was shown in **Chapter 5** to be heavily dependent on the power balance. To ensure the accuracy of simulations all components relating to electrical power which principally includes turbine governor models should be as accurate as possible.

6.1 Load Behaviour

The Load-frequency characteristic is determined by consumer behaviour, which makes direct comparisons between other networks and GB difficult. National Grid currently uses a value of 2 %/Hz for its load-frequency sensitivity, which has been developed through operating practice and confidence in the system security. Many literature sources quote the load sensitivity factor as a percentage value, which is normalised against base frequency and system power. However, we will hold with convention adopted by National Grid and quote sensitivity in % reduction per Hz deviation.

The Irish electricity grid calculates load sensitivity to frequency O'Sullivan and O'Malley(1996) in the order of 2-2.5 %/Hz. The UCPTE, Weber *et al.*(1997), gives values for the load sensitivity in the order of 0.8-3.3 %/Hz. Tests carried out by Berg(1972) on an isolated power system in Norway show average values of load sensitivity as 1.0 %/Hz for commercial loads and 0.8 %/Hz for a residential load, the paper notes however that a great deal of variation was evident when calculating the average values. Concordia and Ihara(1982) provide details of measured load characteristics from New York in the years 1941 and 1969 as 3.0 to 3.2 %/Hz and 3.0 to 4.0 % respectively. Näser and Grebe(1996) use a value of 2 % /Hz in their paper discussing the cost of reserve.

Schulz(1999) assumed the load characteristic of the Eastern Interconnector in America. to be 2.5%/Hz. NEMMCO(2002) has estimated that the power system demand varies with frequency at 2.5 %/Hz. A report published by Chown and Coker(2000) for Eskom gives an average load frequency characteristic of 2.5 %/Hz.

Figures published by an IEEE task force on load representation(1993) give frequency sensitivity for residential loads as 1.4–2.0 %/Hz differing from those suggested by Concordia by at least 50%. This discrepancy may be due to the change in load mix within the ten-year period. Commercial loads are determined to be between 2.0-2.8 %/Hz, with industrial loads 2.2 %/Hz, Aluminium refineries -0.5 %/Hz, Steel Mills 2.5 %/Hz, Power Aux. Plant 4.8 %/Hz, and Agricultural Pumps 9.3%/Hz.

Welfonder *et al.*(1989) provide results from load dependency tests carried out on parts of the German grid system. The Load-frequency characteristic is evaluated as 2.4 %/Hz at Heidelberg and 1.6 %/Hz at Berlin. The difference at the sites is attributed to a higher constituent of motor load in the Heidelberg area. A supplementary paper was also published in 1993 giving details of a further six areas with seasonal dependencies.

	K_L (%MW/Hz)	β or λ (%MW/%Hz)
NGT	**2**	2.86 – 8.89
Ireland	2 – 2.5	-
UCPTE	0.8 – 3.3	6.7 - 9.6
Norway	0.8 - 1	-
New York	3 - 4	-
America (Eastern Interconnection)	2.5	3.9 - 4.4
NEMMCO	2.5	-
South Africa	2.5	-
Germany	2	-
Germany (part system)	1.6 - 2.4	-

Table 2 - Sensitivity Factors and Power-frequency characteristics

In summary the load characteristic is typically represented as a value between 0.8 and 4 %/Hz, Table 2 summarises the characteristic values given in this section. This large variation in accepted values suggests that further investigation into the load frequency sensitivity is required in order to refine our understanding.

6.2 Load Behaviour on the GB grid

Methods have been developed in various countries to quantify a value of load-frequency sensitivity. Hayashi(1988), Davies *et al.*(1958) and Fukuda *et al.*(1989) use tie lines to measure frequency response across two isolated systems. Welfonder *et al.*(1993) measure load characteristics on feeders of small part systems. All these techniques have a similar drawback in that they can only consider part of the system in question. A global sensitivity figure must be scaled up from the part system response and is a source for error.

As part of National Grids data archive it has been continuously recording historical demand and generation values from the network at intervals of one minute since June 1993. However, to quantify the load-frequency sensitivity on the UK grid this data has not been of the resolution needed to capture the dynamic changes of the system. As a consequence a piece of software was developed to allow the continuous logging of an existing real-time data channel at intervals of between 2-10 seconds. With this data it is possible to evaluate the frequency response of the load to a much higher accuracy.

Although not a direct account of demand the technique uses the recorded change in grid-connected generation (ΔP_G) and the loss of a known generation (P_{Loss}) to calculate the power attributed to demand sensitivity (k_{pf}), Equation 11.

$$\Delta P_L = P_G - P_L - \Delta P_G = P_{Loss} - \Delta P_G = k_{pf}.\Delta F$$

Equation 11

Unfortunately, this method requires an instantaneous loss of generation (or increase in load) of a significant magnitude to take place. During operation it has been found that a disturbance greater than 200 MW provides an adequate power mismatch to measure the load sensitivity although higher levels are desirable. From recent incidents it has been possible to calculate a value for the load-frequency sensitivity; Figure 31.

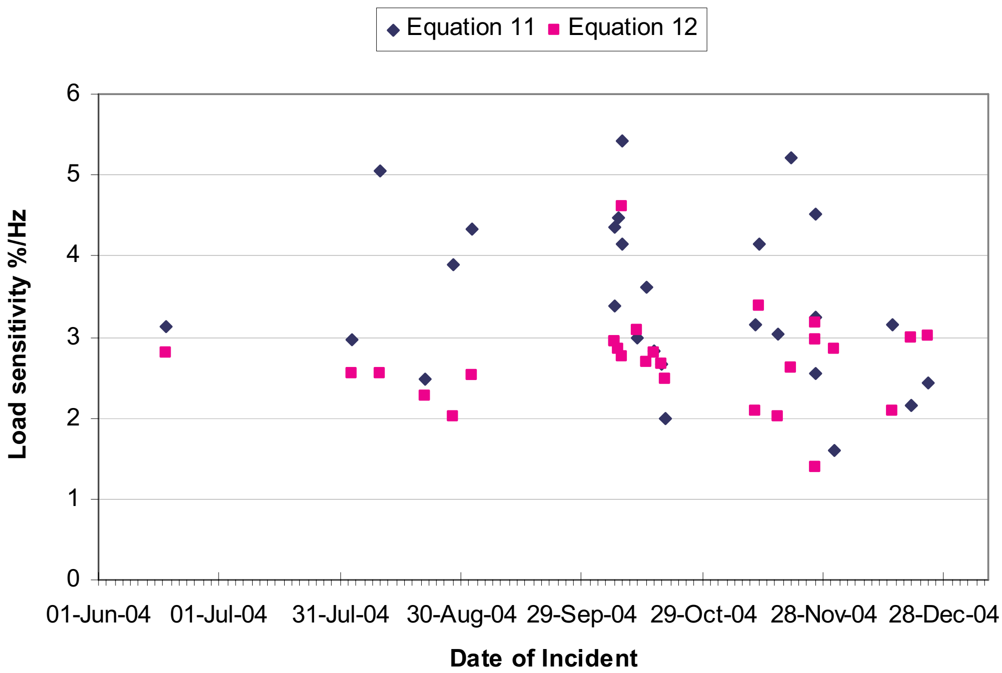

Figure 31 – Recorded Load sensitivity to frequency on the GB system

The weakness of using Equation 11 to calculate demand change, is it requires a steady demand to gain meaningful results. Figure 32 and Figure 33 highlight this weakness with data under a stable demand compared with an increasing demand, which is unpredictable from the generation trace alone.

To corroborate the results a second method was also used involving the initial rate of change of system frequency at the onset of an event, Inoue *et al.*(1999). Using this initial decay rate, the total load and also the system inertia it is possible to calculate the power mismatch between load and generation (ΔP). The formula is given in Equation 12.

$$\frac{2H}{f_0}.\frac{d\Delta f}{dt} = \Delta P$$

Equation 12

The results using this method are however very sensitive to the initial value of frequency decay (which is only recorded to one-second resolution).

Using both methods gives confidence in using a value of 2 %/Hz as a conservative estimate for load frequency sensitivity when modelling simulated loss events. More data is needed for a statistical analysis of the results for seasonal trends.

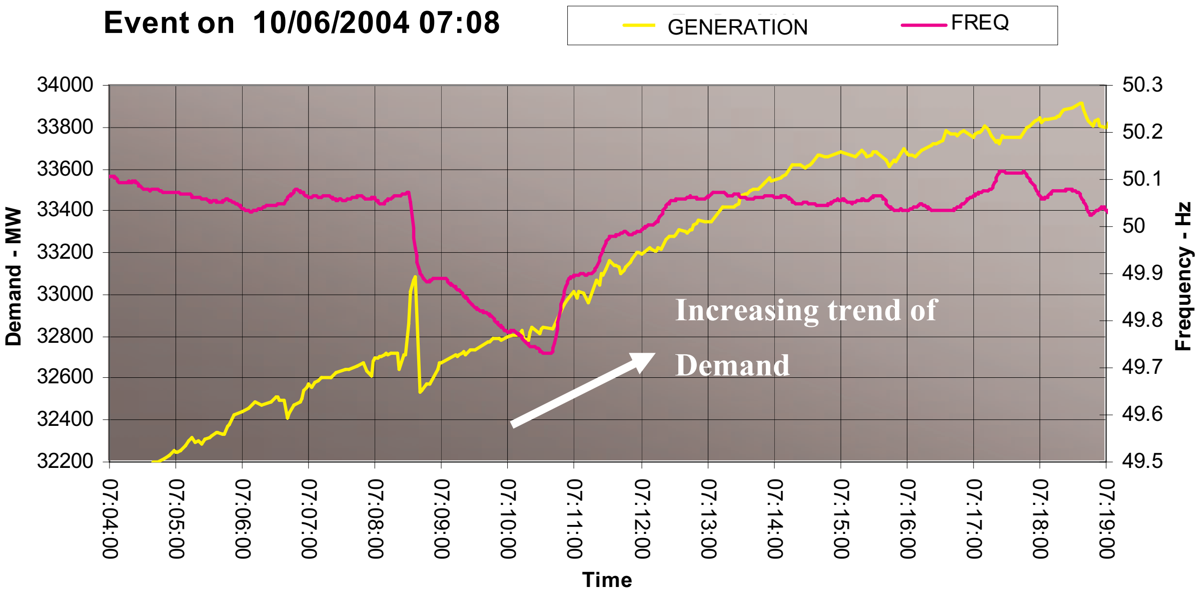

Figure 32 - Generator loss under unclear load conditions

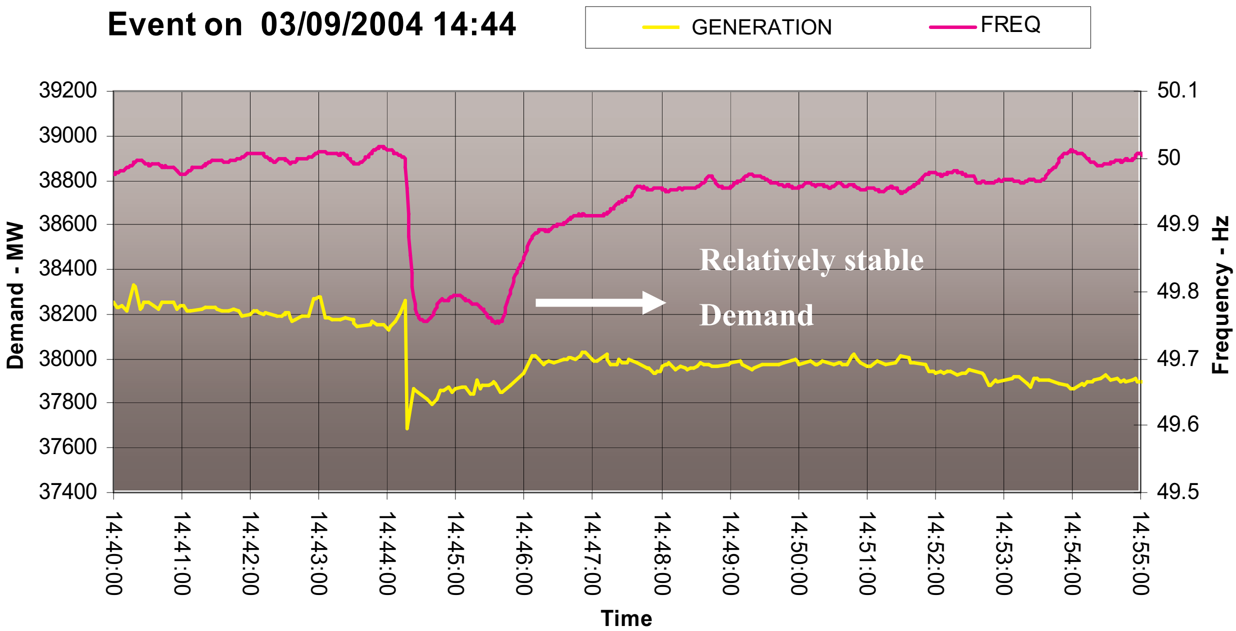

Figure 33 - Generator loss under constant load conditions

6.3 Generator Behaviour on the GB grid

We saw in **chapter 5** that generator droop and generator transient response also has a large impact on the frequency transient, both are inherent in the governor model. From the first studies used to calculate primary response requirement, Williams(2003), it was believed that the response provided by generator models was higher than was to be expected. After investigations comparing individual gas and coal-fired generators on a simple network this project had shown that the generator did seem to be providing marginally more response but not in all cases Figure 34 and Figure 35.

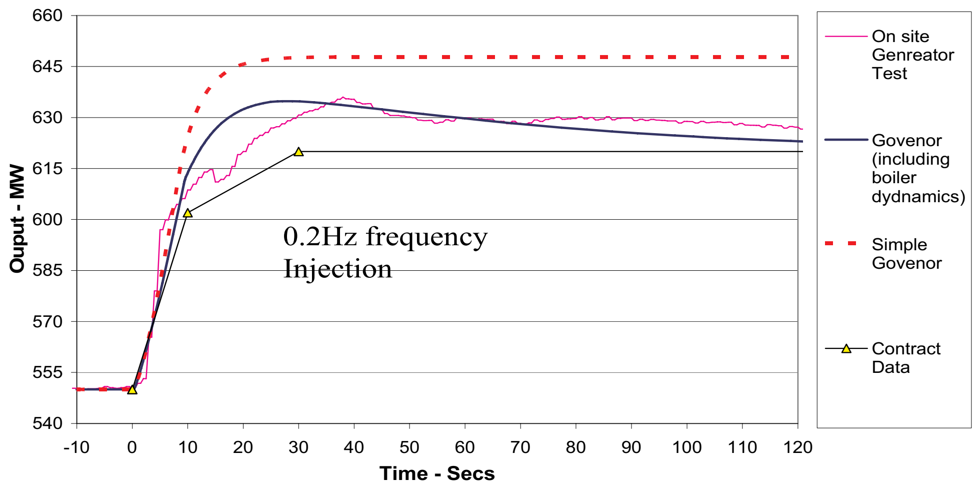

Figure 34 - Simulation of CCGT turbine at deload of 110 MW

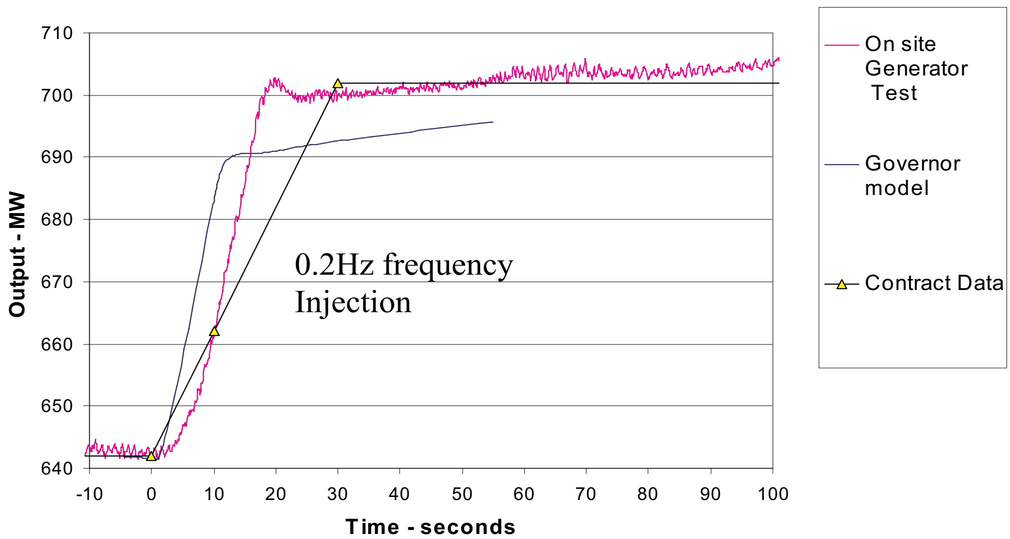

Figure 35 – Simulation of coal fired steam turbine at deload of 95 MW

A simple network with only one generator may not necessarily mimic the dynamic effects experienced by the full GB grid. Simulations on a full network model (Figure 12) of 400 kV and 275 kV lines have highlighted some interesting results. A simulation of a very large generation trip of 1260 MW dated from 26 May 2003 at 00:36 was conducted.

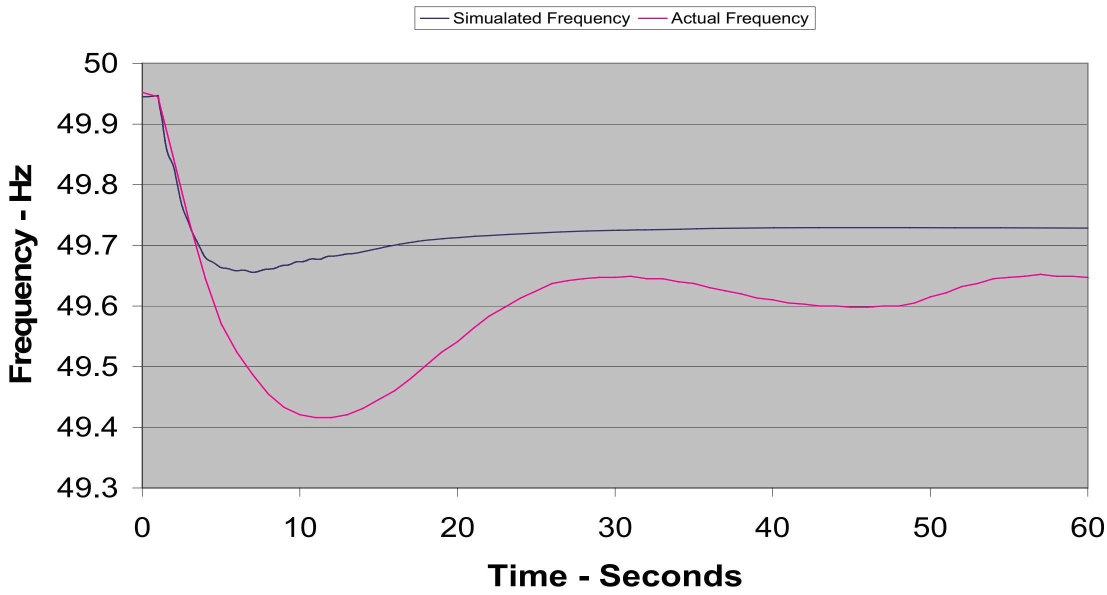

Figure 36.a – Simulation of 1260MW generation loss from 26/05/03 (frequency)

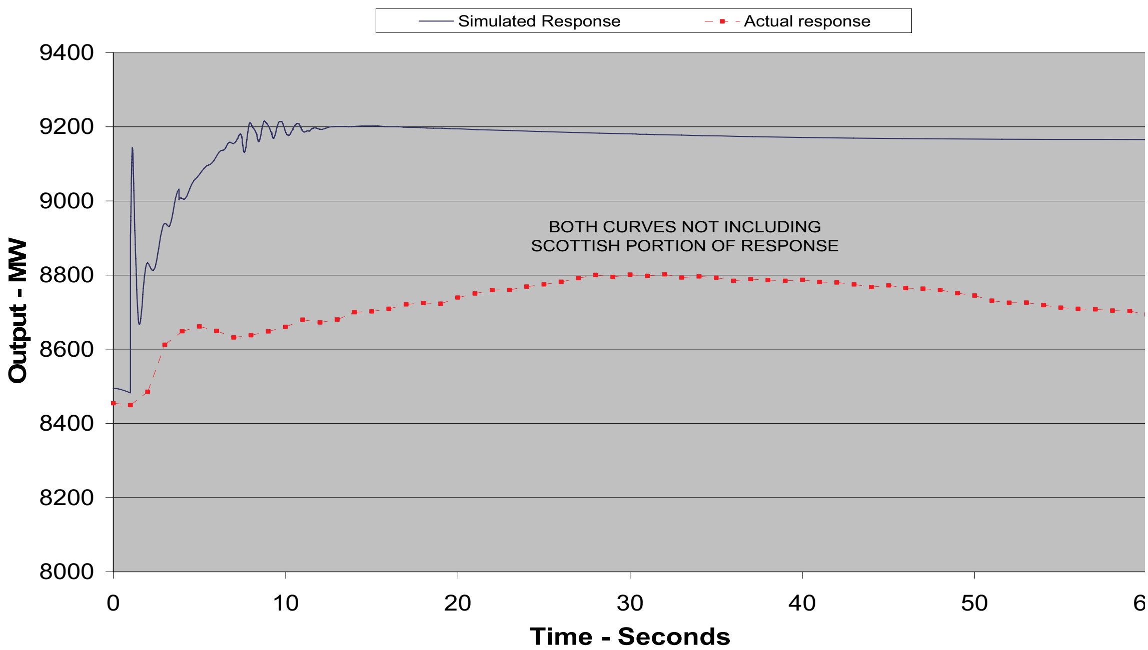

Figure 36.b – Simulation of 1260MW generation loss from 26/05/03 (responsive generation)

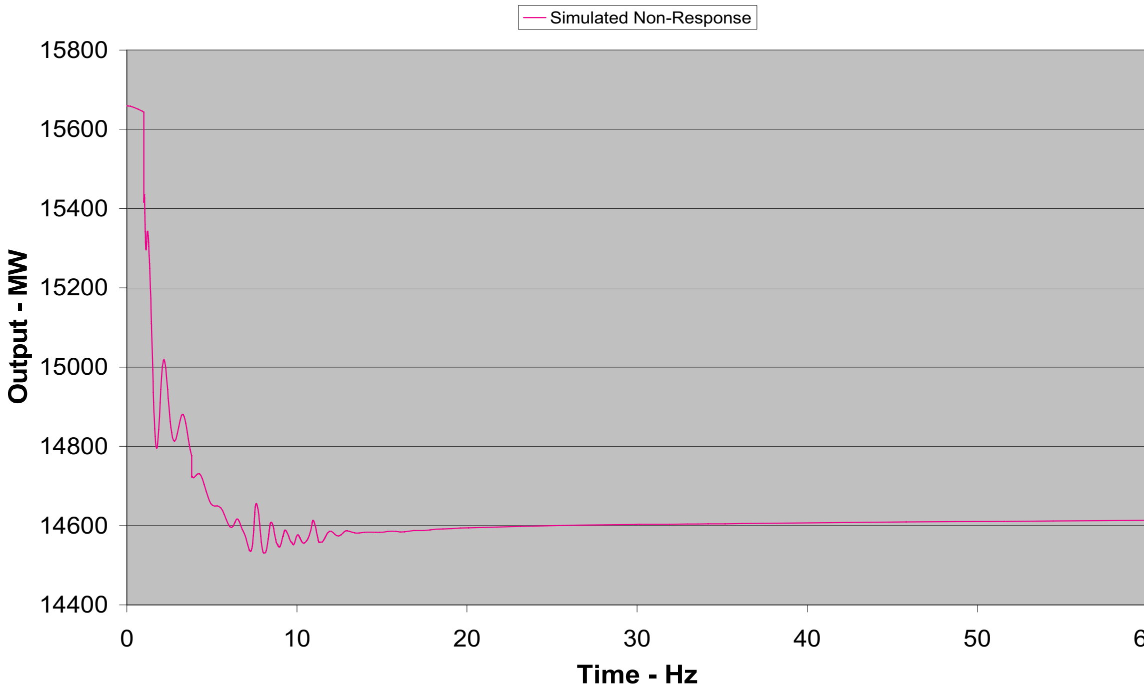

Figure 36.c – Simulation of 1260MW generation loss from 26/05/03 (non-responsive generation)

This simulation showed that the generator response (Figure 36.b**)** to a 0.54 Hz frequency deviation was much greater in the model than in the real event. Post event reports show that 15% of generators failed to supply Primary response (approximatley 70 MW), but this still does not account for the 400 MW difference.

By using data collected from the demand logging system it became possible to get cumulative generation totals of the various types of generator. By simulating another generator loss and comparing the simulated response to the recorded response it is possible to see which generator type is contributing to the inaccuracies. The largest generator loss recorded to date was taken as the test simulation. This was the loss of 615 MW generation on 16 August 2004 at 19:04.

The results given in Figure 37 and Figure 38 show that despite a small discrepancy in the initial levels of the generation, the response of the CCGT turbines is far greater in the simulation that those experienced on the network. In fact, the gas turbines in this case produce a 250 MW peak of response. Coal units also produce a faster response in the simulation compared to real-time data.

Other network operators, Nagpal *et al*(2001), have raised concerns over the use of a similar OCGT model in simulations. The chief issue is with regard to the inability of the model to fully represent temperature control when put into a CCGT mode of operation. The temperature control loop limits power outputs at full load, which is particularly relevant for responsive plant during large frequency deviations. This establishes the need for a specific CCGT model to represent the combined cycle turbines.

All of the plant models used in the simulations are taken from previous transmission study models. Recent discussions with NGT staff revealed that the models used in transmission studies are generic plant models only. They only represent the minimum performance requirement as specified in the Grid Code. This raises the need to review the existing models currently in use against representative real machine data as was confirmed by the simulations from 26/05/03 and 16/08/04.

With an increased confidence in the validated thermal plant models a wind turbine model will be required. Several possible models exist including a generic model developed by Eurostag(2004). The chosen model will require validation in a similar manner to the thermal models, against actual real-time data to ensure its accuracy.

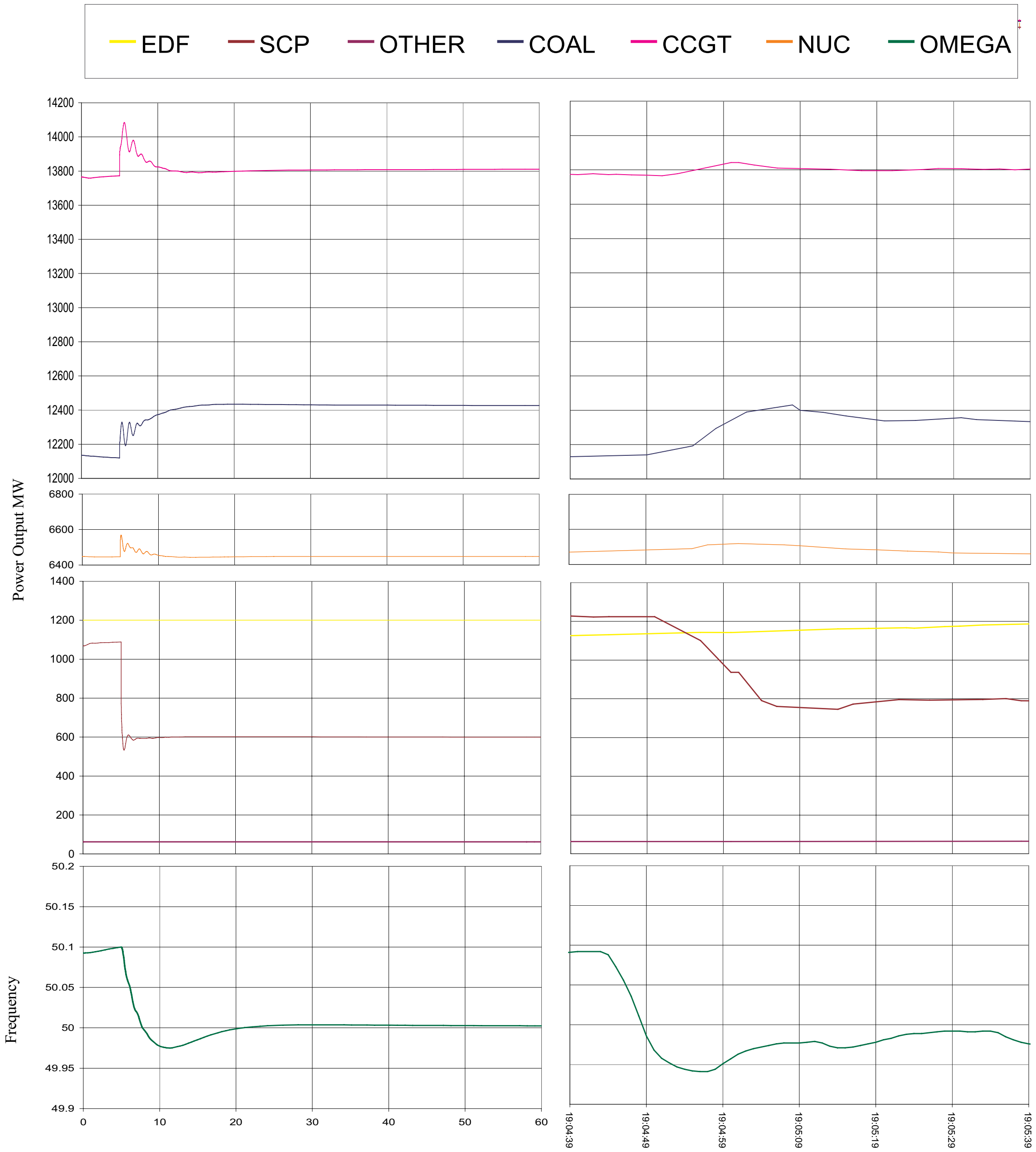

Figure 37 – Simulation of 615MW Generator loss on 16/09/04

Figure 38 – Network response to 615MW Generator loss on 16/09/04

6.4 Future Work

The following paragraphs highlight the work that is to be concluded over the next 2 years of the research project. The timescales of each individual task are shown diagrammatically in the Gantt chart of **section 6.5,** also showing relevant submission dates and course modules.

1. Validate steam turbine models against individual plant

As was discussed in **chapter 6.2**, there is a need to validate existing models of coal, and oil fired plant against actual frequency deviations. This task will use recorded frequency traces from past events to be injected into governor models of frequency responsive plant. The resulting power output simulated by the models can then be verified against the recorded responses during the event. The models can be adjusted where necessary until a satisfactory representation is achieved.

2. Develop CCGT model against individual plant

In **chapter 6.2** issues were raised over the suitability of OCGT models for representing CCGT plant. After reviewing current operating practises and literature on CCGT machines a model to simulate frequency response will be presented. As in the previous task validation of the model against actual frequency deviations is required. This will require following the same methodology as was the case for coal plant.

3. Review existing incidents using validated models

With confidence in the individual thermal plant models (established through tasks 1 and 2), a set of full network simulations can be carried out. This will entail several simulations like those of **chapter 6.2** whereby a specific plant loss is represented fully across every component of the network. This will verify the robustness of the network model components, and the simplification of only using 275kV and 400kV nodes.

4. Add Scottish nodes to grid model

With the onset of BETTA in April 2005, NGT will increase its control operations to include Scotland. Previously Scotland was represented as a lumped element as it did not benefit studies to include the full load and generator contributions of this part of the network. As operational issues will soon include the effects of this network representation should be provided in the network model.

5. Write/Submit paper1

This paper aims to describe the effects of load behaviour on the UK system during frequency disturbances. It will provide examples of generator loss on the system and the drop in frequency as a result. It is hope to include details of generator responses also. This paper will be submitted to the IEEE Transactions in power systems.

6. Review response requirements examining effects of geographic reserve holding

With a full model of the network and accurate governor models it will be possible to assess the level of response required to contain specific losses within frequency limits. Simulations of 300MW loss against a -0.2Hz frequency deviation; 600, 700, 800, 900, 1000MW losses against -0.5Hz deviation; and 1100, 1200, 1260 and 1320MW losses against -0.8Hz deviation will be made. These simulations will be required at demand levels ranging from 15 to 65GW. The simulations will also investigate the effects (if any) that result from situating the reserve in a specific geographic area on the grid.

7. Review literature on modelling of wind turbines

In **chapter 2** we established that the majority of renewable generation to meet government targets would come from wind turbines. In order to simulate the effect of these turbines on the frequency response requirement a model of their control strategy must be represented in the simulations. Much literature has been published recently regarding modelling of individual wind turbines and aggregated farms. To provide a suitable model a review of all current research will be undertaken.

8. Build wind farm model

All grid connected wind farms will be over 50MW in capacity, this results in many individual wind turbines. With a finite processing ability the model established from the previous task will need to be in the form of an aggregate farm or converted to such an arrangement. This will then need to be coded in the Eurostag macroblock language. Once coded it can be fully applied in simulation studies

9. Validate Wind farm model

Once completed the coded the wind farm model will require validating against real data. Even though the turbines at present are unlikely to operate in a frequency responsive mode they will still require validation against a frequency droop incident. This will validate their inertial contribution together with any other control effects imposed by AVR and/or governor actions.

10. Review response requirements with integration of wind model

With a validated wind farm model introduced into the network model a similar trial of simulations as in task 6 will be required. A range of scenarios at different wind penetration levels will be necessary to show the sensitivity of the grid to possible future renewable levels.

11. Translate response requirements into CO_2 emissions

With response requirements defined from simulation studies the annual fuel consumption of thermal plant can be derived from applying the response requirements to anticipated/historic demands. This fuel consumption can then be translated into an estimate of emissions from each type of generator.

12. Write/Submit paper2

This paper aims to describe the effects of renewable generation on the UK system especially during frequency disturbances. It will provide results of simulation studies carried on a representative model of the UK transmission network. The paper will highlight potential problems that may arise from the expected increase of renewable sources in the generation mix. This paper will be submitted to the IEEE Transactions in power systems.

13. Final write up, Corrections/references/prepare for viva

The final task of the research will be to document all findings.

6.5 Time Scales

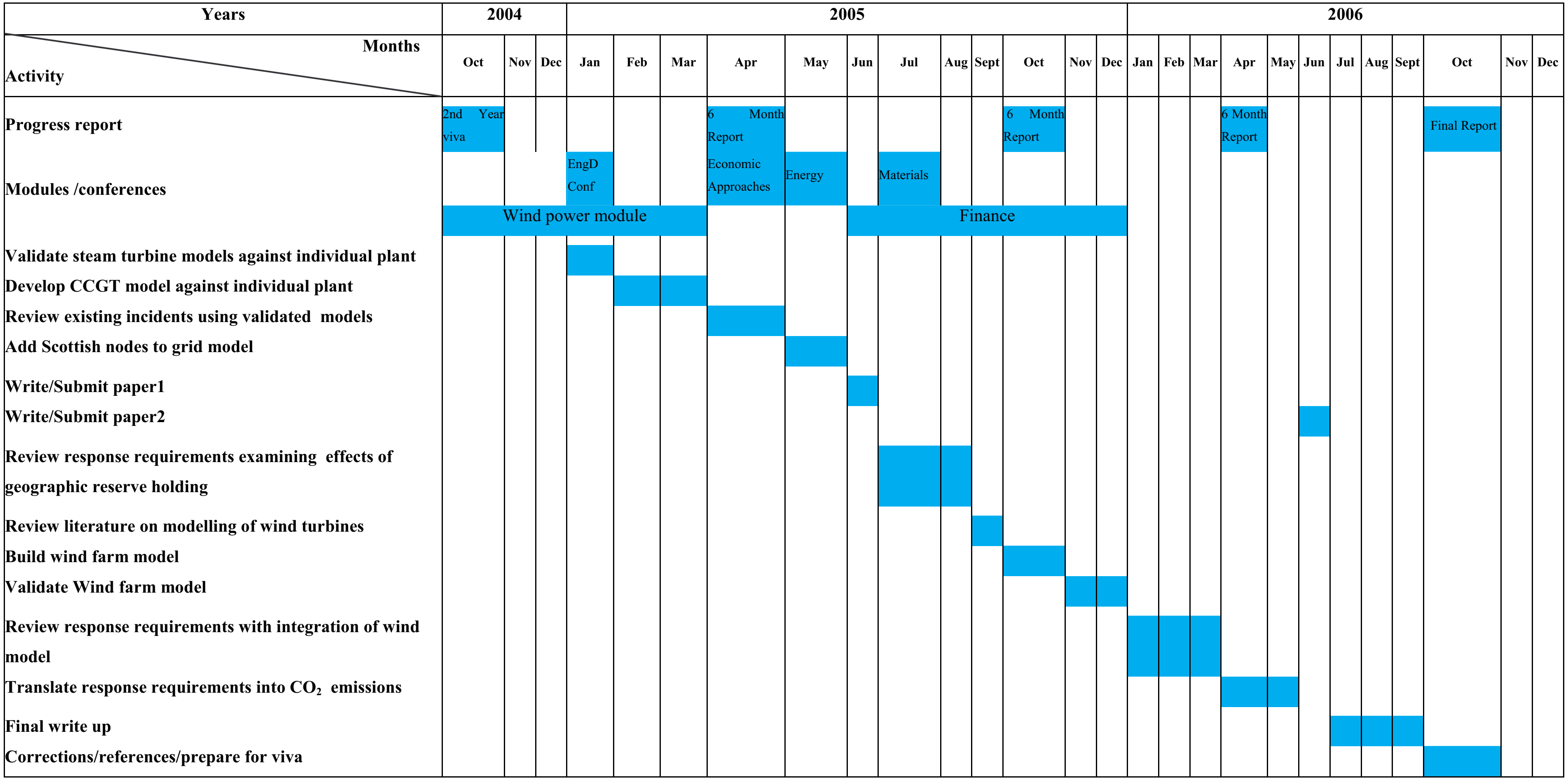

Table 3 - Gantt chart showing expected project deliverables over the final two years of the project

7 Conclusion

7.0 Conclusion

A brief introduction has been given to some of the technical aspects that influence the frequency response of the network. Details are given of the current operating practices for frequency control in GB at the present time, together with a selection of other countries. Frequency responsive generation inherently causes more environmental impact than base load generation. As such, any efforts to reduce the requirement of frequency response holding will decrease environmental impact.

A methodology is proposed to study the effects of frequency response on the transmission grid using a simulation package called Eurostag. The same methodology will allow its impact to be assessed against an increase in wind power. This will lead to a better understanding of how the increase in renewable generation will effect the operation of the transmission system over the next fifteen years.

Current progress has been made in efforts to quantify the Load-Frequency sensitivity of the GB grid, which will continue. Also, simulations involving generating units have helped raised issues regarding model accuracy that must be addressed before further work is possible.

Future work has been discussed with particular attention given to the validation of models against test data and system events to increase simulation accuracy. The next stages of the research will see the development of suitable CCGT and wind turbine model. Once a competent library of models exists it will be possible to assess the current frequency response requirement. Work can then also begin to quantify the level of response that would be required given a significant increase in the number of wind turbines or different system characteristics. This can then be related in terms of CO_2 emissions.

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Six Monthly Progress Report: Fifth Report

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1.0 Work to Date

1.1 Coal Fired Generation

Work preceding this report has been followed according to the Gantt chart given in Section 6.5 of the Transition Viva. As highlighted in the report the precise nature of the macro-blocks used to date in the Eurostag simulations are that of generic models. These models are non-specific to plant and based solely on grid code requirements. To provide some measure of confidence a set of validation trials was conducted on coal fired generating stations operating in responsive mode.

Two main problems were raised upon embarking on the validation trials:

- These trials required monitor data recorded from generation loss events that triggered a large frequency deviation for each generator station. Two of the required stations are not fitted with monitoring equipment capable of supplying data of the required time step resolutions.

- Limited data has been recorded and stored for each of the individual stations. In some cases it was only possible to provide two incidents for validation.

Despite these points validation of the remaining stations continued with available data.

The test methodology was to set up a frequency input in the governor macro-blocks that could be used to inject the experienced system frequency during the events. This injected frequency would cause the generator to respond as would be expected in the real event allowing a comparison with recorded values. An example of two validation tests is given in Figure 1 and Figure 2.

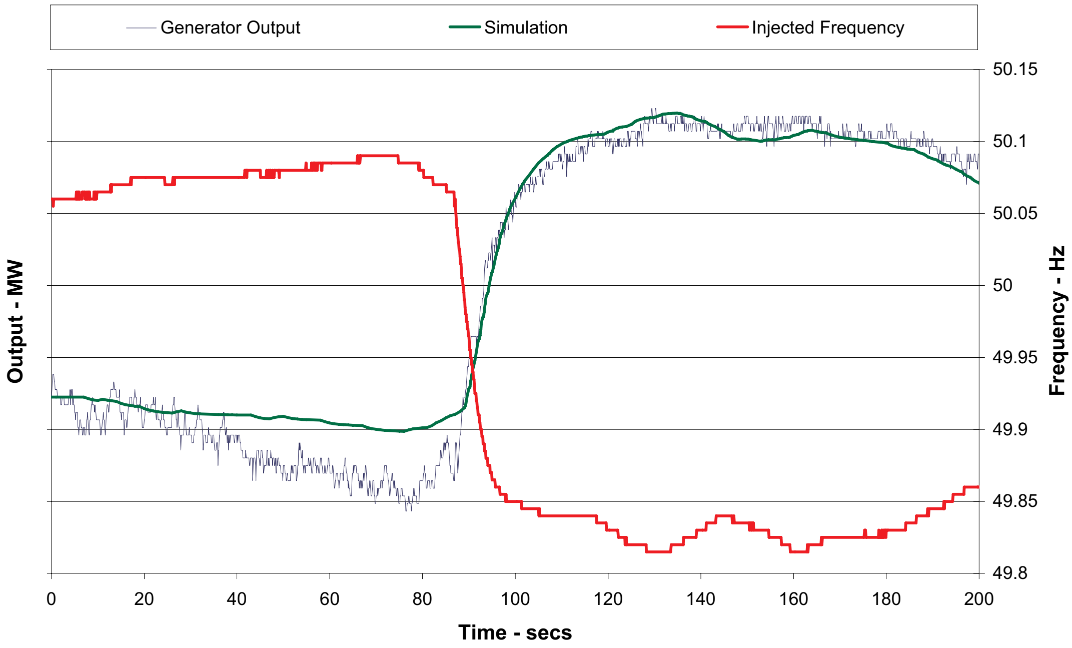


Figure 1 - Response to a 0.26Hz drop in system frequency

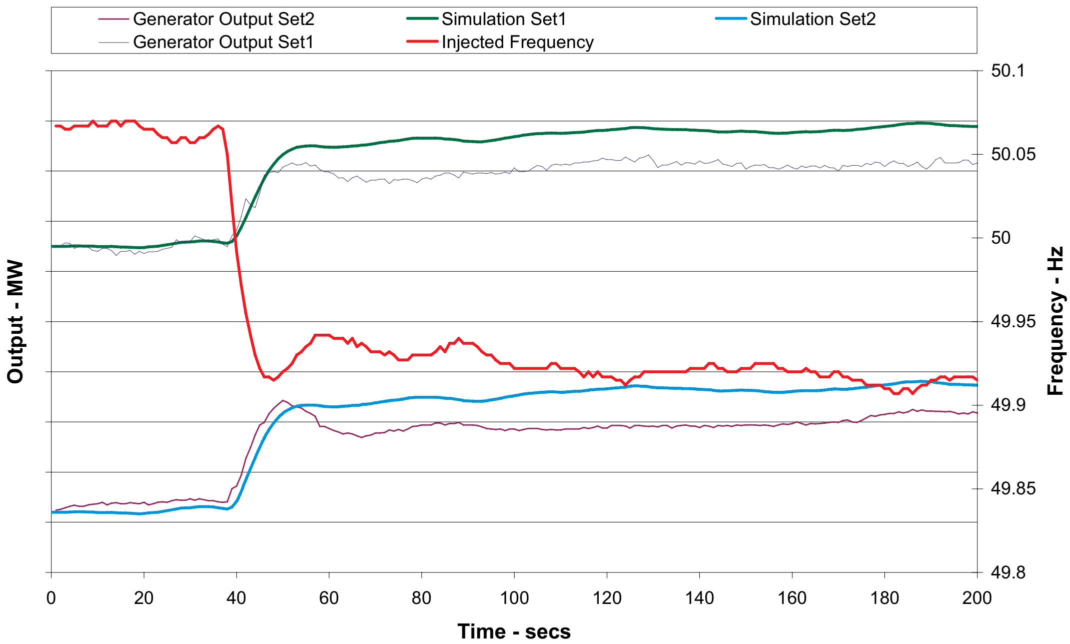


Figure 2 - Response to a 0.15 Hz drop in system frequency

A total of forty tests where carried out on the thirteen coal fired generators. A summary of the results is given in Table 1.

Station	Size(MW)	No of tests	Pass	Comments
TILBURY	4x350	4	√	Droop could be reduced
RATCLIFF	4x500	5	√	OK
KINGSNORTH	4x491	4	√	Droop could be reduced
IRONBRIDGE	2x482	4	X	Rate limited?
HIGH MARNHAM	4x189	0	-	No data
FIFOOTS	3x121	0	-	No data
FIDDLERS FERRY	4x485	4	X	Rate limited?
FERRYBRIDGE	4x490	4	√	OK
EGGBOURGH	4x500	3	√	OK
DRAX	6x645	3	√	OK
DIDCOT A	4x496	3	√	Droop could be reduced
COTT AM	5x507	3	√	OK
ABATHAW	3x500	3	√	OK

Table 1 - Summary of validation results with coal fired generators

From the tests it was apparent that some machines seemed to be showing a rate limited response, Figure 3. After looking at different traces from the same machine it was evident that the rate limit used was not the same for different frequency drops.

Discussions with members of the generator compliance department reviewed the possibility that some generator stations may be programming load controllers with their actual response requirement curves. This would ensure their machines meet required contractual obligations without causing excess stress to their plant.

By simulating one station that seemed to give a limited result it was possible to show that the response was in fact meeting the contract at 10 and 30 seconds (primary and secondary time-scales respectively).

Load Set Point	Primary Response	Secondary Response
355	45 +355 = 400	68 +355 = 423
295	44 +295 = 339	63 +295 = 428
Actual Load	Expected Primary Response	Expected Secondary Response
340	385	426

Table 2 – Response requirement curve for -0.5Hz deviation

shows expected response as defined from the contract matrix. Figure 3 shows these contact values against the expected and modelled results. This would seem to support the idea that some plant is being programmed to meet its requirement.

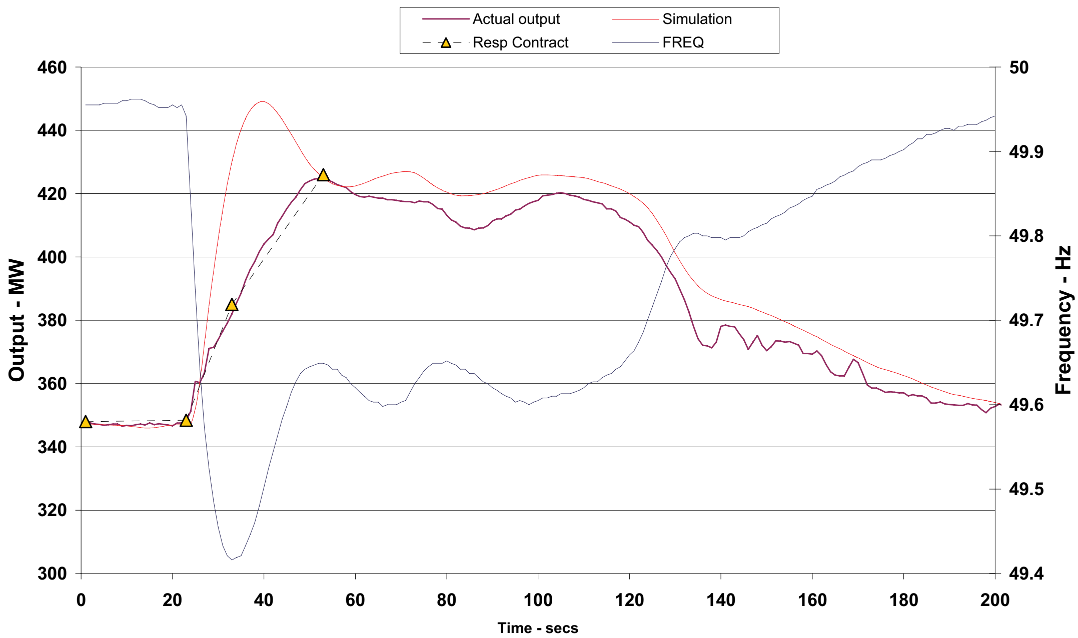


Figure 3 – Modeled and Actual Response to a 0.539 hz Frequency excursion (including contact data)

In the cases where the model is limited an addition is needed to the governor macro-block to confine the output to the response matrix of that machine. In order to determine machines which are running in this type of arrangement it is necessary to observe the machines response to larger frequency drops of 0.3Hz or greater.

1.2 CCGT Plant

The results given in previous reports have show that the response of the CCGT turbines is far greater in the simulations that those experienced on the network. Other network operators, have raised concerns over the use of similar OCGT models in simulations. The chief issue is with regard to the inability of the model to fully represent temperature control when put into a CCGT mode of operation. The temperature control loop limits power outputs at full load, which is particularly relevant for responsive plant during large frequency deviations, Figure 4. This establishes the need for a specific CCGT model to represent the combined cycle turbines.

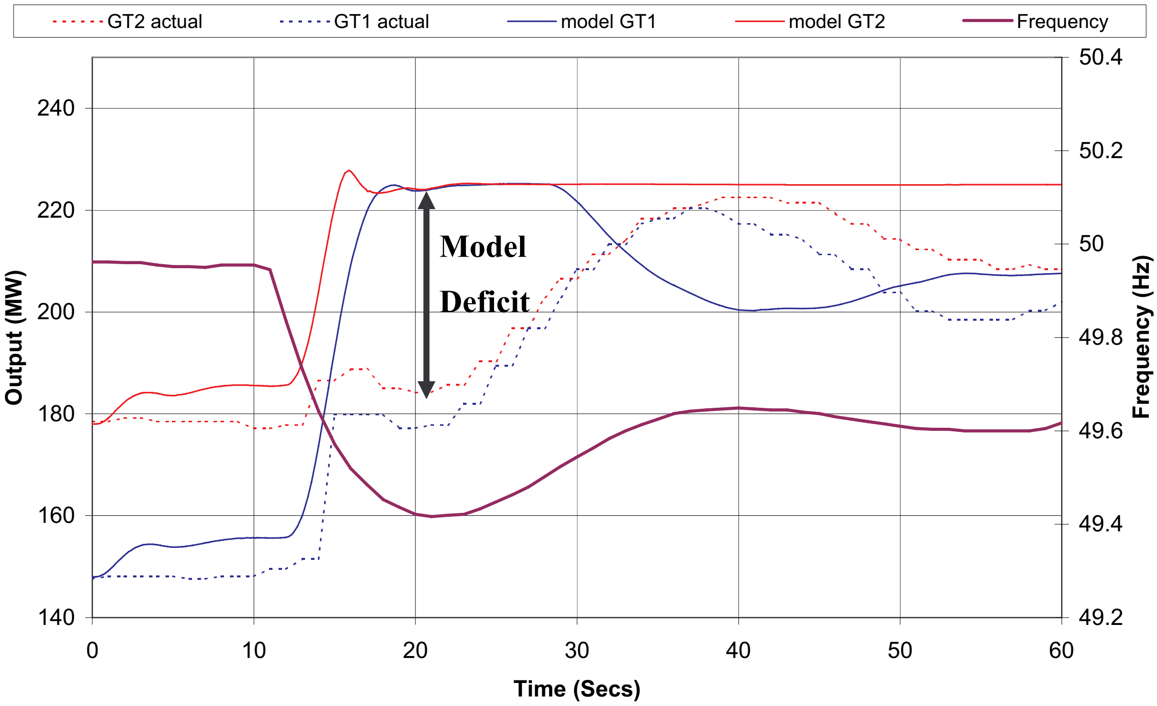


Figure 4 - ABB GT26 CCGT gas turbine response to frequency excursion

Reviewing current operating practises and literature on CCGT machines a model to simulate frequency response will be presented. Most models shown in literature exhibit the same structure, Figure 5.

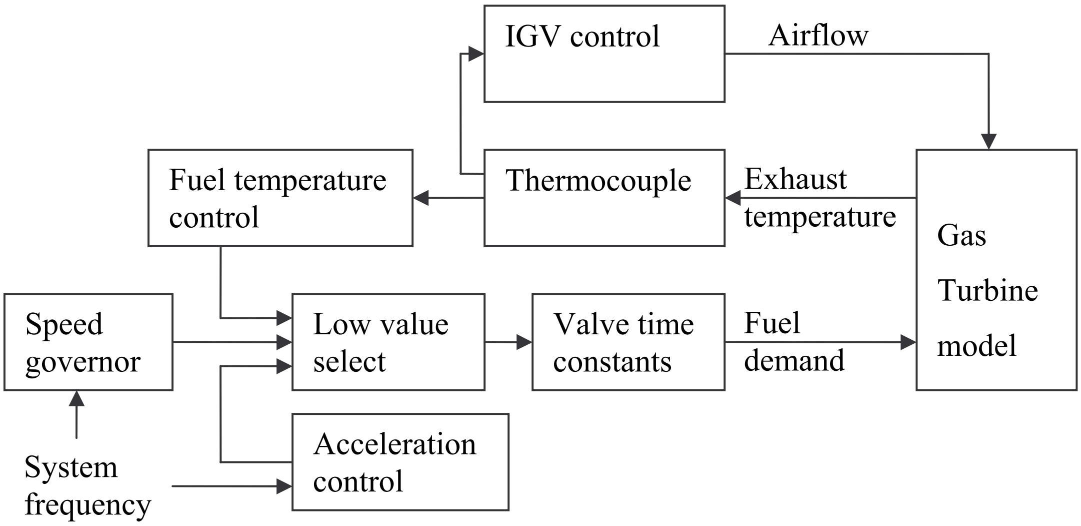


Figure 5 - CCGT model

This model can be considered as composed of seven parts:

1. Simple speed governor model
2. Low value gate
3. Fuel control valve time constants
4. GT model
5. Thermocouple delay
6. Temperature control
7. Airflow (Inlet Guide Vane) control

Parts 1-3, 5 and 6 are simple to implement and are similar for all models. The main variations appear to be in the method used to control airflow and how this interacts with the GT model. The different air control strategies for each turbine manufacturer can be demonstrated through Figure 6 and Figure 7.

The ABB machine operates at rated exhaust temperature from 40% to full load. The airflow though the ABB turbine is managed to hold this temperature constant. In the GE machine airflow is only controlled once the turbine exhaust temperature reaches the rated value, this is at about 80% load.

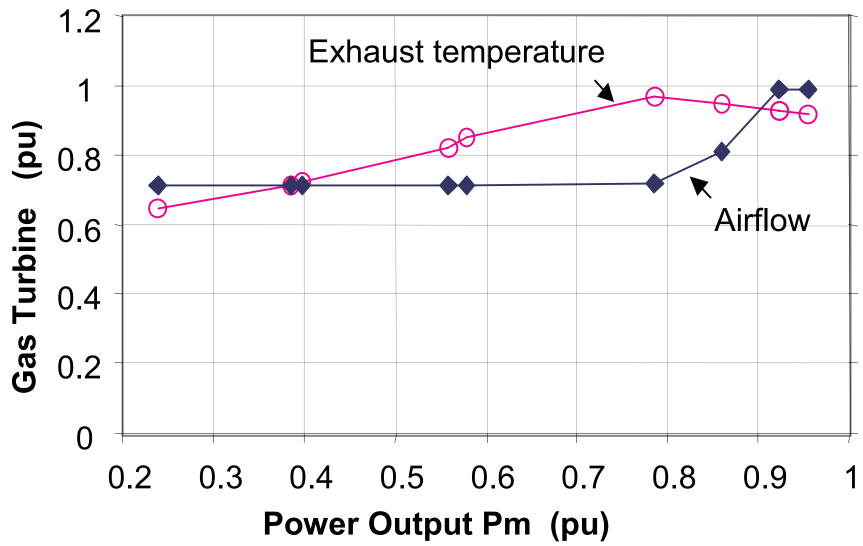


Figure 6 – Part load operation of a GE frame 6 turbine

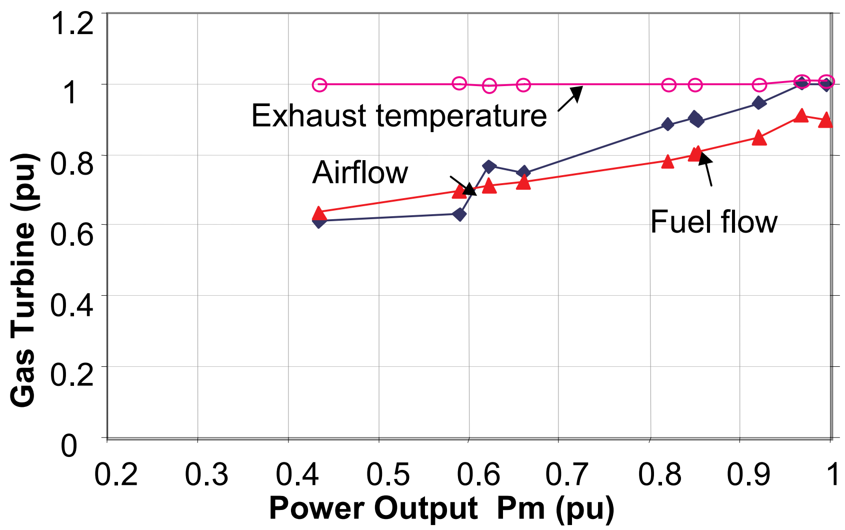


Figure 7 - Part load operation of an ABB GT26 turbine

Figure 8 shows the mix of combined cycle plant on the GB grid. GE manufactures the largest percentage share of CCGT plant, with ABB, Siemens and Misubishi having a similar stake in the remaining share. However, there is no real dominance of manufacture on the grid. This may require the use of four CCGT models to full represent the dynamic characteristics of each manufacture.

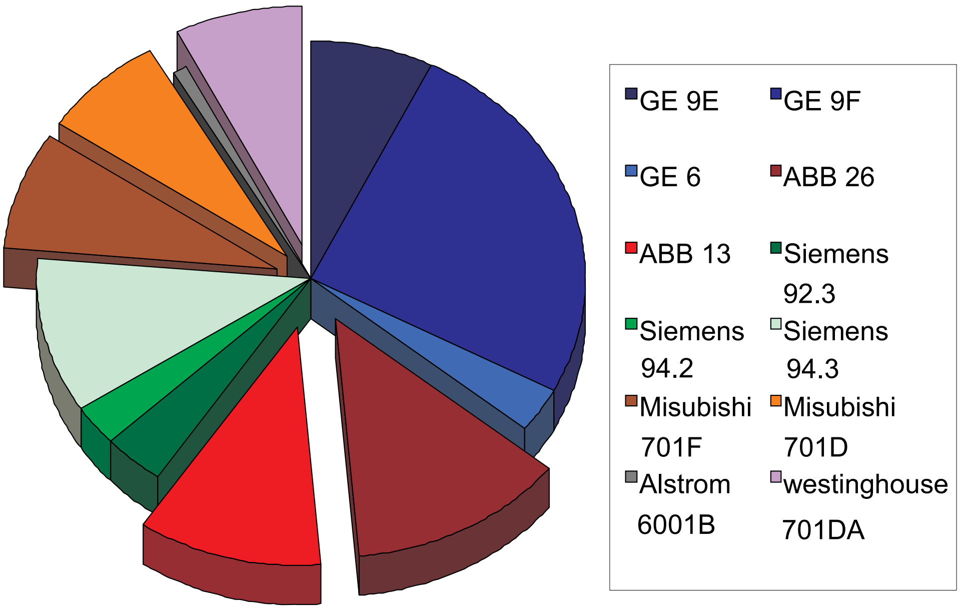


Figure 8 - Capacity of CCGT by machine frame and manufacturers

The gas turbine model coded in Eurostag is based on a number of published papers Rowen(1983), Rowen(1992), Kim *et al.*(2001) and has been derived from GE turbines. A simulation was conducted with this model against an ABB GT26 turbine; the results are shown Figure 9. The model does not fully accommodate the control that seems to be occurring in the real machine however it is an improvement in the right direction from the response in Figure 4.

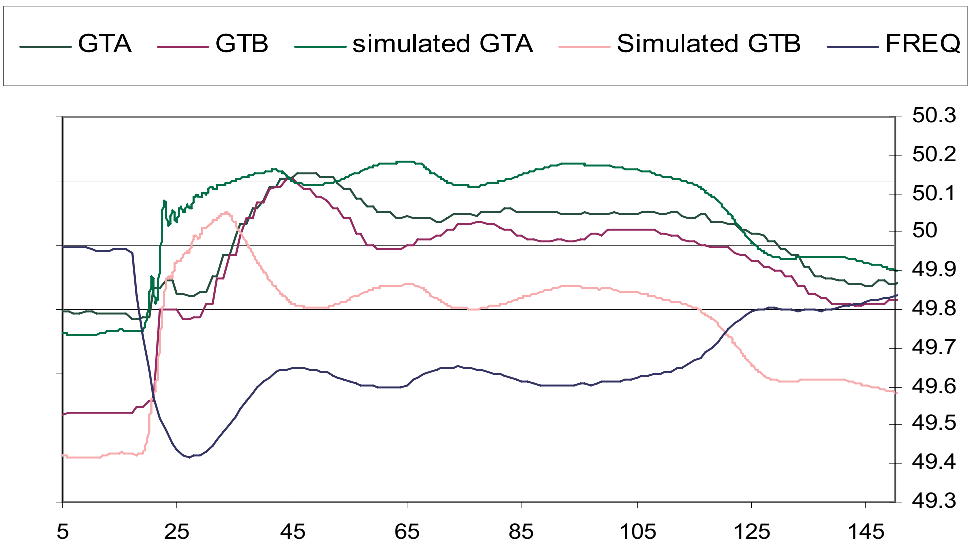


Figure 9 – Modeling a GT26 turbine using a Rowen based governor

To provide a better-suited model a simple CCGT governor was implemented in Matlab to allow easy design iteration. The model was composed using the overall design given in Figure 5 and based on a selection of papers Naoto & Baba(2003), Agüero *et al.*(2001). A simple model was used to represent the gas turbine, Working group on prime mover models(1994) and variations on the airflow control scheme investigated.

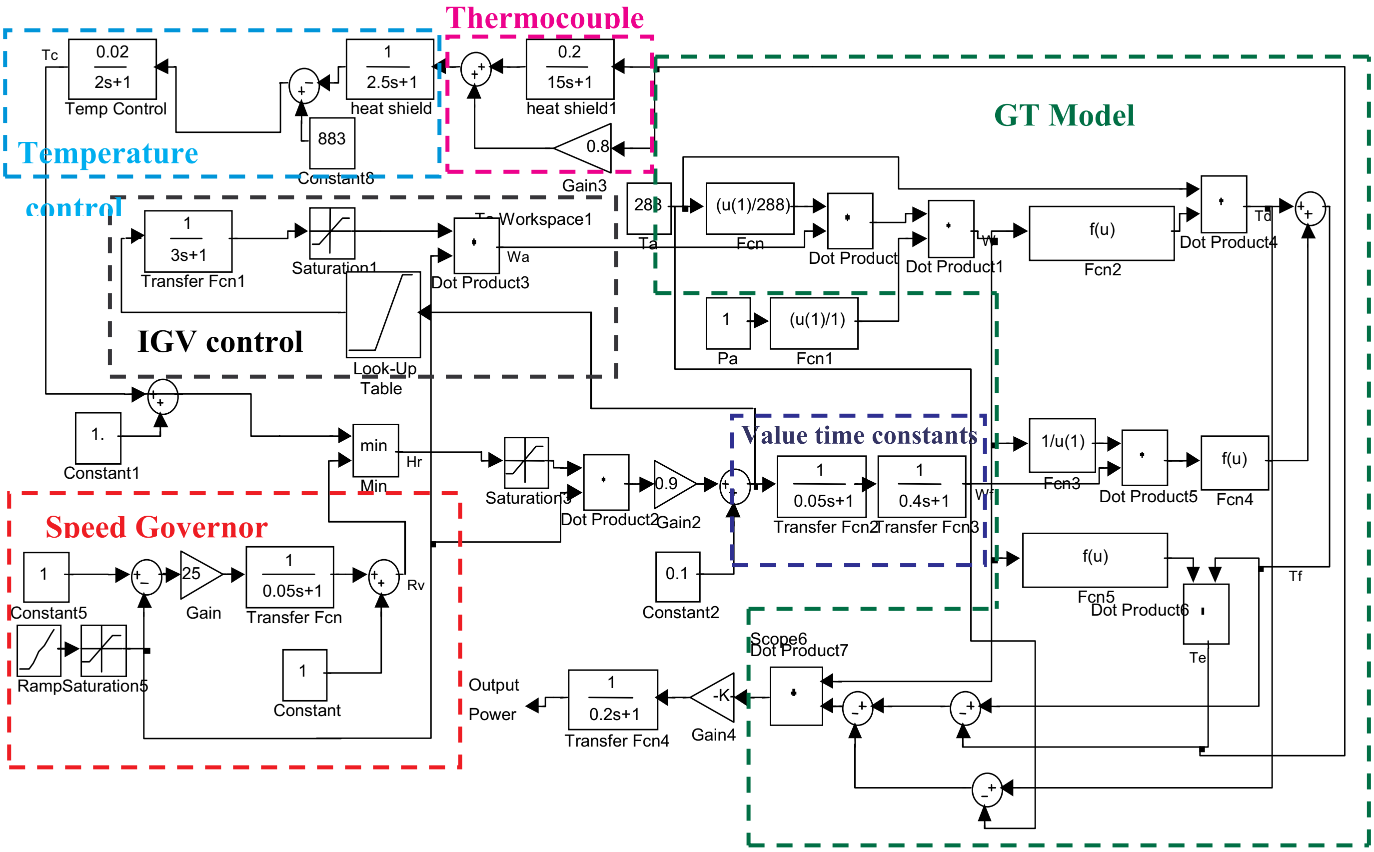


Figure 10 - Block diagram of the CCGT governor model demand based airflow

In the first series of trials the inlet guide vanes were modulated in accordance with the turbine fuel demand signal, Figure 10. A lookup table provided the required IGV position for each load point, a transfer function was used to represent the response of the vane control system.

The response of the model to a simple frequency step injection is given in Figure 11 - Figure 14. The step frequency injection causes an increase in airflow, initial power and also a rise in exhaust temperature as can be seen from the model. This does not mimic the response expected which would be to keep the exhaust temperature stable at rated temperature.

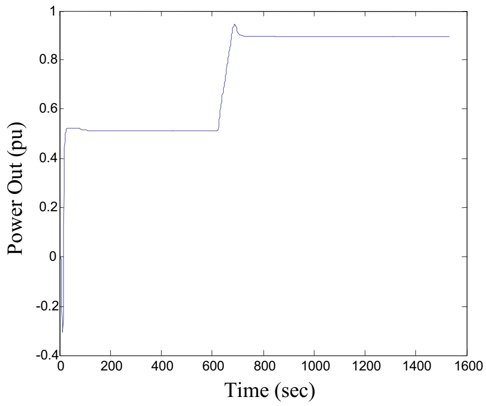


Figure 11 - GT Output

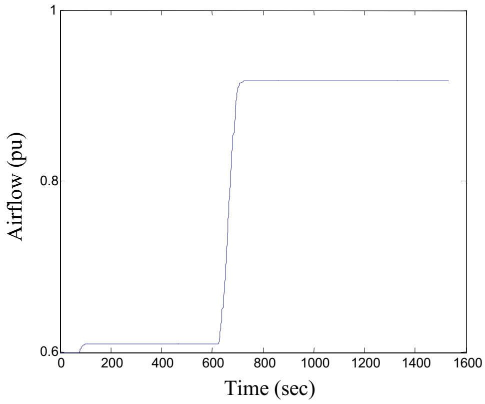
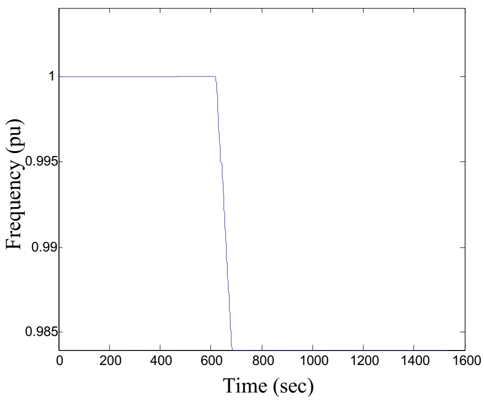


Figure 12 - IGV opening



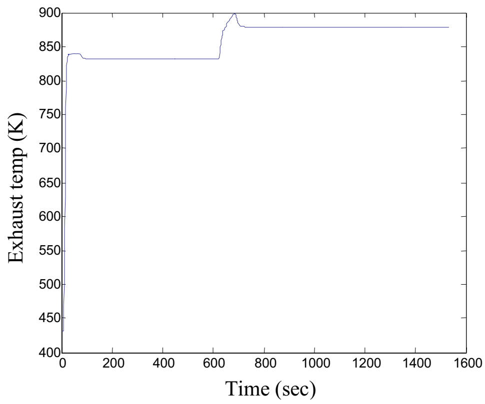


Figure 13 -Frequency inject

Figure 14 - Exhaust temp

A further problem with initialisation is evident from the graphs. An extended initiation time was introduced to allow variables to stabilise before an injection was made. Some web based research has revealed that it is possible to initialise variables in Matlab and this will be incorporated in any further trials.

One other problem that this model seemed to suffer with occurs at full load during a frequency event. With IGV control derived from the GT output (or demand point) at full load IGVs may not be fully open so exhaust temperature can rise above the rated value. This issue was tackled in the next set of trials, which used a temperature error to set the opening of the IGVs. A block diagram on the governor model used in these trials is given in Figure 15.

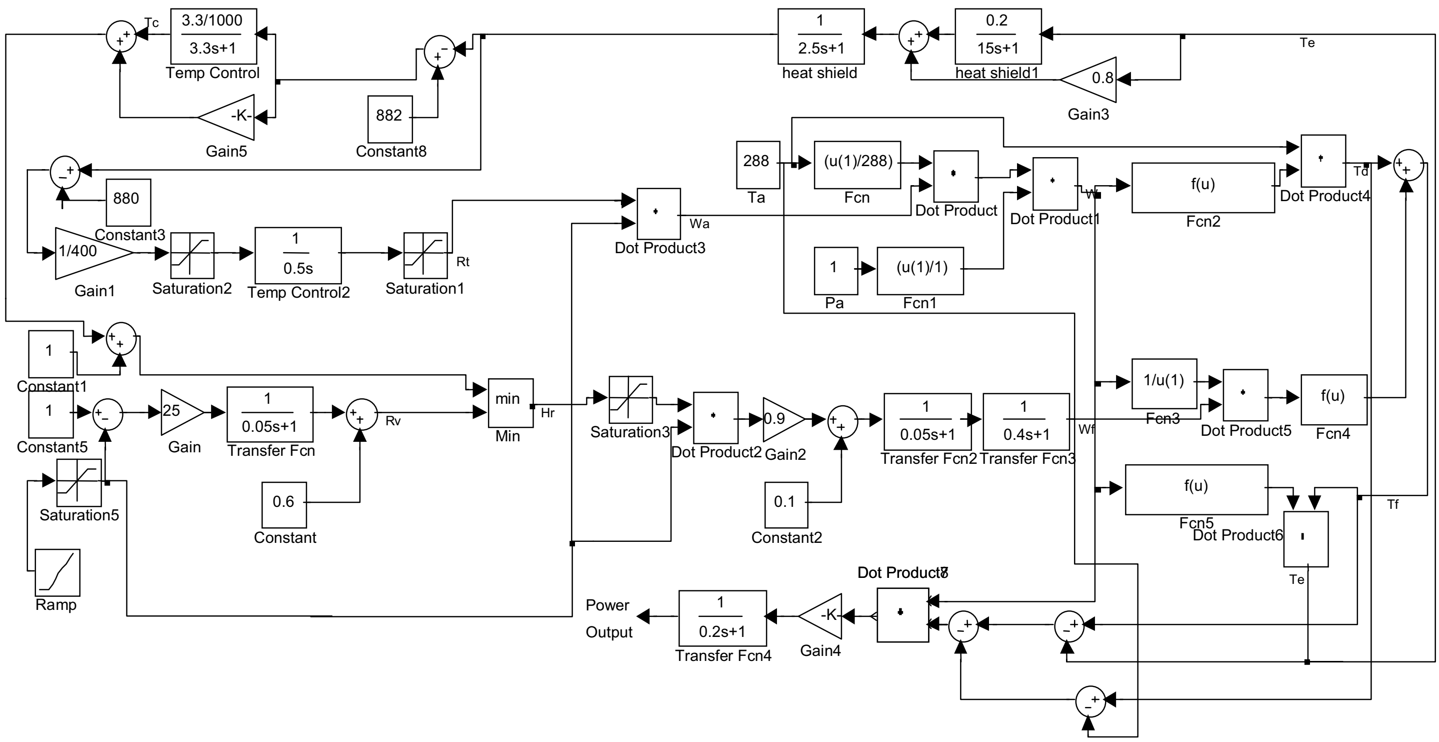


Figure 15 - Block diagram of the CCGT governor model temp based airflow

The same frequency injection was used in this model to represent the drop in system frequency. As before we see and increase in the airflow and output power. However in this instance the exhaust temperature has a more consistent value over the course of the injection. The graphs still exhibit problems due to the initialisation of variables, this is noticeable from the IGV trace as the exhaust temperature rises from 0 to 880 K.

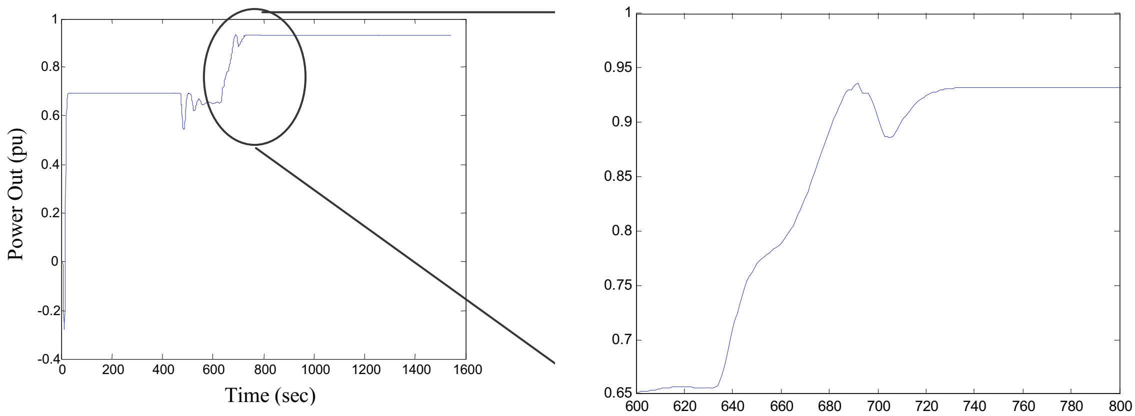


Figure 16 - GT Output (with magnified inset)

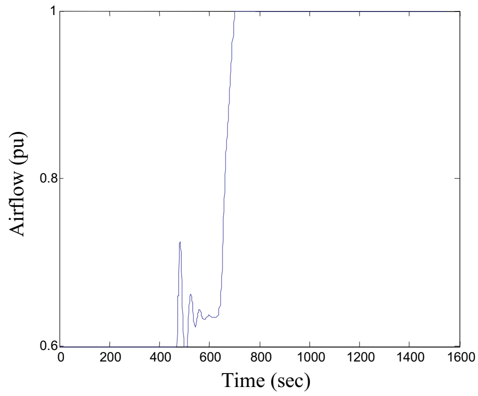


Figure 17 - IGV opening

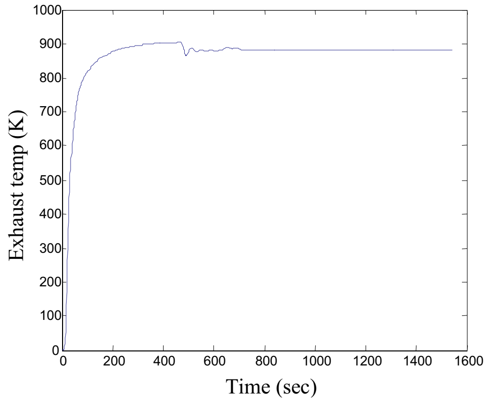


Figure 18 - Exhaust temp

These initial trials offer a degree of coherence with the actual response experienced on the system in Figure 4. Work will continue to develop this models for use with the ABB GT26 machine.

1.3 Demand database

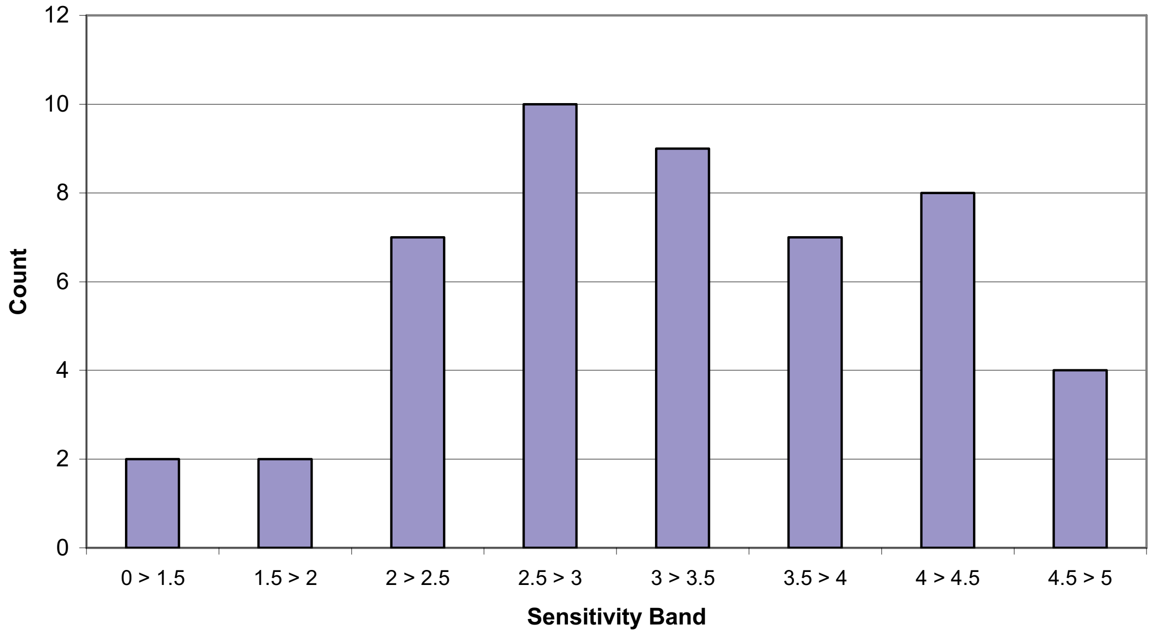
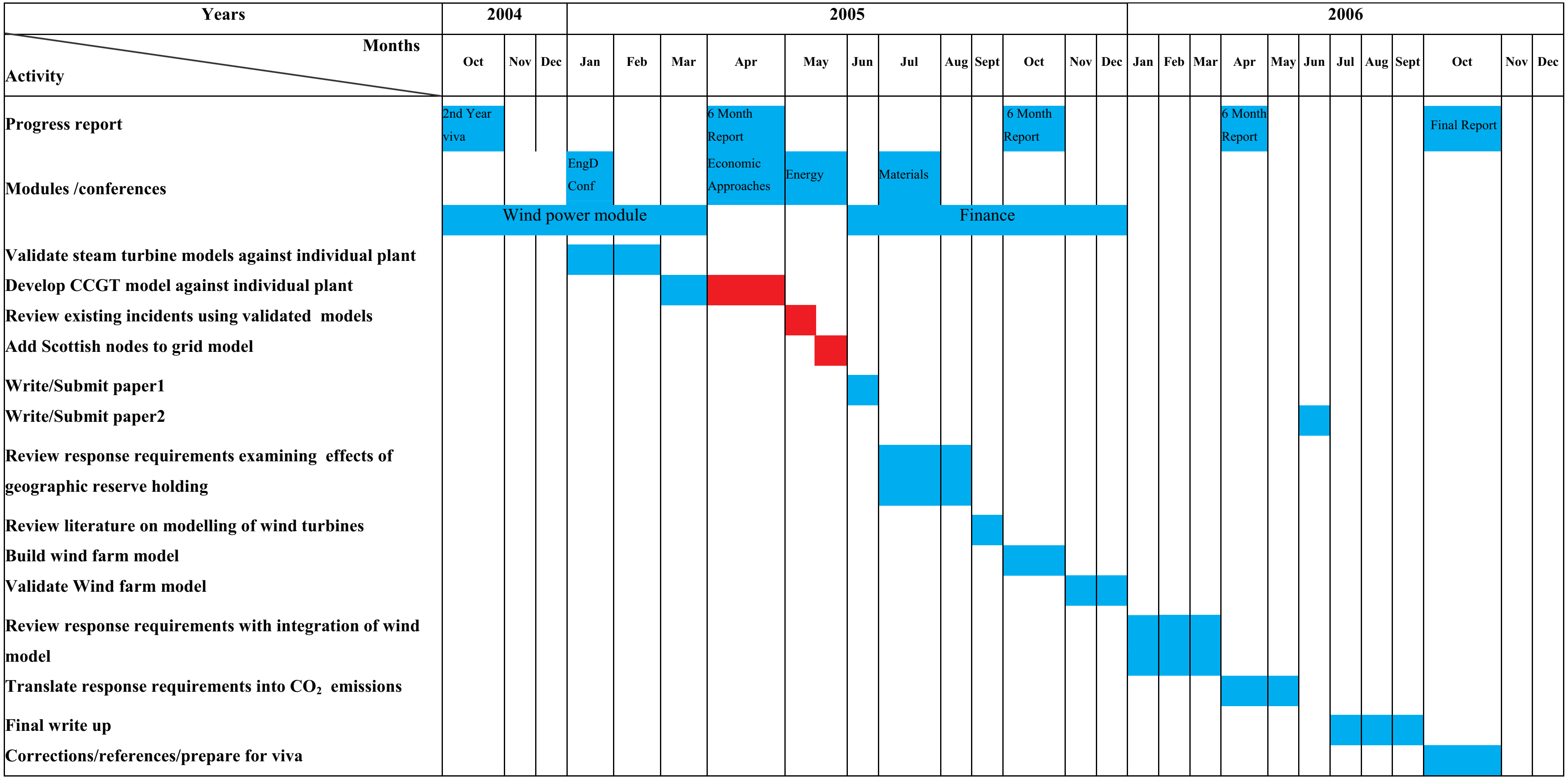


Figure 19 - Cumulative frequency of demand sensitivity as calculated from incidents

Over the course of the last six months there have been a further 51 incidents that have been added to the demand sensitivity database. This has increased the confidence of using a demand sensitivity in the order of 2% per Hz in frequency response requirements. Figure 19 shows a breakdown count of all the recorded sensitivities in intervals of 0.5 %/Hz.

2.0 Next 6 months



Difficulties in developing and implementing of the CCGT governor model have set back the project by approximately one month. In order to keep to the required schedule I have increased development time on the CCGT models by one month and reduced the time devoted to testing against real incidents. I feel this can be achieved by only testing each model in manufacturer range, and not every generating station. This halves the required testing and should not effect the results. A have further reduced the time to implement the Scottish nodes into the network as this can be achieved through importing the network from other existing packages. However the databases that are used to retrieve demand and generation will still need to be reworked.

In the next six months it is hoped that the following can be achieved to the revised schedule.

- Add a response limit to coal fired generation that can be defined by contract values
- Ensure every generator has a simulation from a large frequency drop
- Initialise variables in Matlab to allow further trials with CCGT models
- Model an actual events in Matlab
- Model different types of manufacturer, and implement in Eurostag
- Continue to monitor demand sensitivity
- Review response requirements examining effects of geographic reserve holding
- Write/Submit paper1
- Add Scottish nodes to grid model

3.0 Summary

This report explains the current developments in validating coal fired governor models against real incidents. Work is required to further increase the accuracy of the models in some cases.

Development of a governor model for CCGT plant has also been started. A suitable model has been identified for possible use with ABB GT26 plant. Development of this model is expected for the next six months.

It still holds that the assumed National grid value of 2% seems to be accurate.

Within the next six months it is hoped that a paper will be written to submission to the IEEE.

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1.0 Work to Date

1.1 Coal Fired Generation

Following work set out in the previous progress report in validating coal fired generators it was apparent that some machines seemed to be showing a rate limited response. This response was only apparent during exceptionally large frequency deviations greater than 0.2Hz in most cases. Due to this circumstance the original validation trails needed review to ensure that the machines had been validated against at least two or three large frequency deviations. This would then prove the nature of the response under governor action.

The test methodology followed was the same as in previous examples with a frequency input in the governor macro-blocks that could be used to inject the experienced system frequency during trip events. This injected frequency would cause the generator to respond as would be expected in the real event allowing a comparison with recorded values.

Obtaining a realistic governor response is vital in simulating network frequency during transient disturbances.

1.2 Experiences Validating Coal Fired Governor Models

Analysis of recorded performance data has allowed three distinct groups of governor model to be identified on the system.

a. Standard droop model
b. Limited droop model
c. Rate limited frequency trip model

Examples of each of these generator responses are shown in Figure 1,Figure 2 and Figure 4.

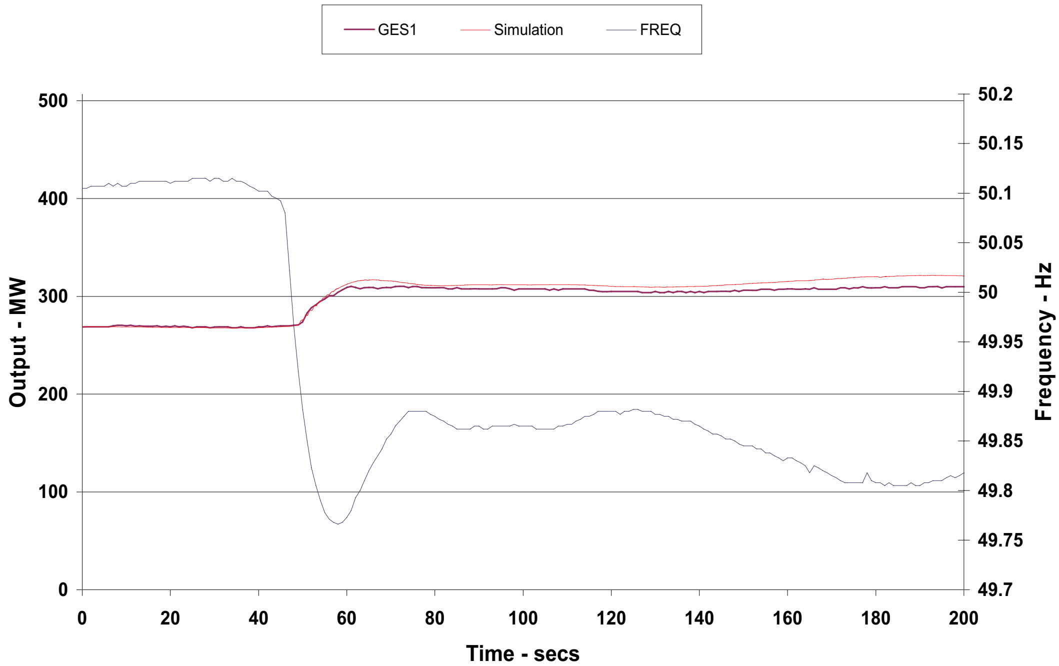


Figure 1 - Standard droop generator response to deviation in frequency.

For standard droop models, no limit is placed on the output control to steam turbines. Machine output can be seen to directly proportional to system frequency with associated pipe delays and boiler dynamics.

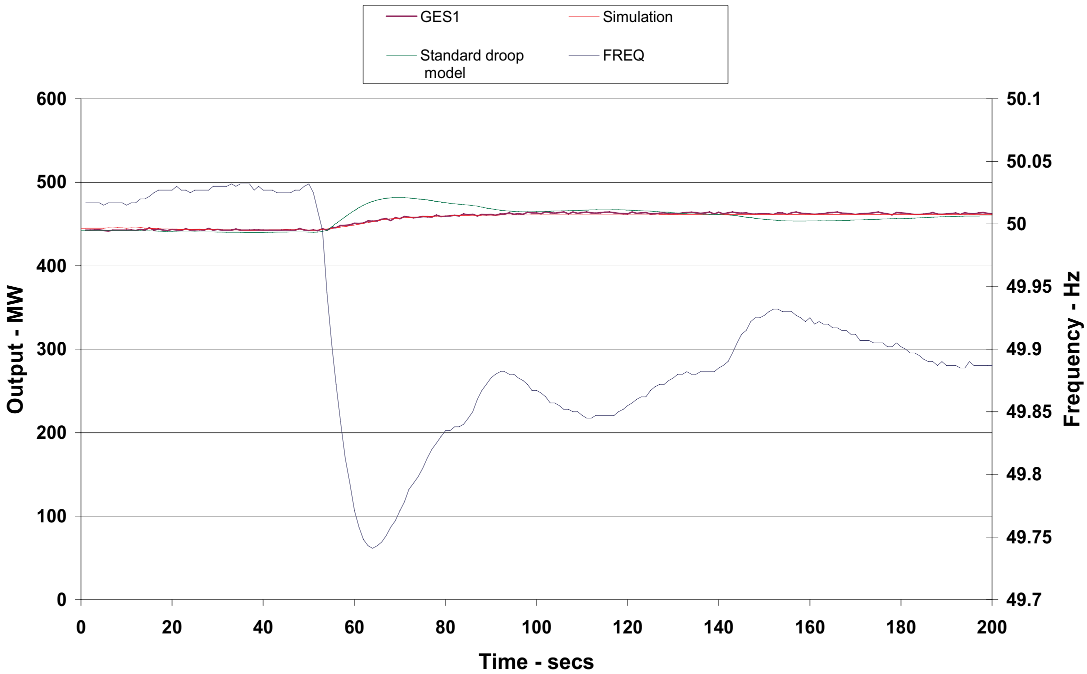


Figure 2 - Limited droop generator response to deviation in frequency.

Limited droop model, in addition to associated pipe delays and boiler dynamics has a limit imposed on the magnitude of response supplied. The limit is related to machine loading levels. The chief reasoning behind operating plant in this manner is to reduce thermal loading in steam pipes and boiler waterwalls. Poor operational decisions can lead to fatigue cracking such as that shown in Figure 3.

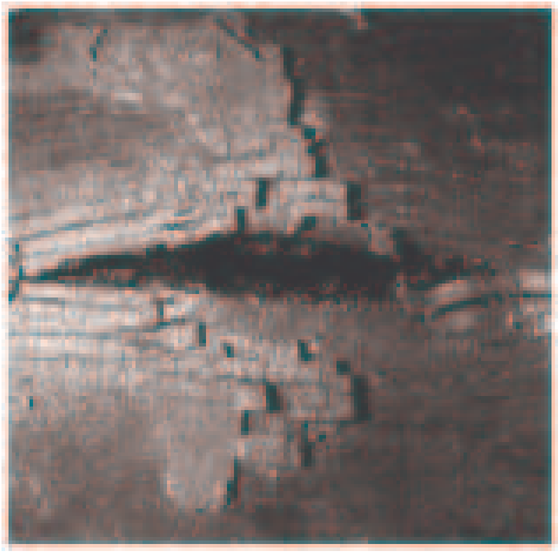


Figure 3 - Fatigue cracks in boiler steam pipes

The output is no longer proportional to system frequency. Comparison with a simulation of the same unit acting under the standard droop model shows the increased error in primary response resulting from incorrect use of the model. This error would have been experienced in early frequency response simulations.

The final governor model in operation on generators is a Rate limited frequency trip model. This controller is similar to the standard droop model for frequency control above 49.8Hz. Below this threshold a limited response is tripped allowing a maximum rate of power increase in the order of 1 MWs^{-1}.

The chief reasoning behind operating plant in this manner is again to reduce thermal loading in steam pipes and the boiler. This has very little influence under secondary response time scales, but a noticeable impact during the primary response interval. As with the previous model, comparison with simulations acting under the standard droop model show the increased error in primary response resulting from incorrect model selection. Again, this error would have been experienced in early frequency response simulations.

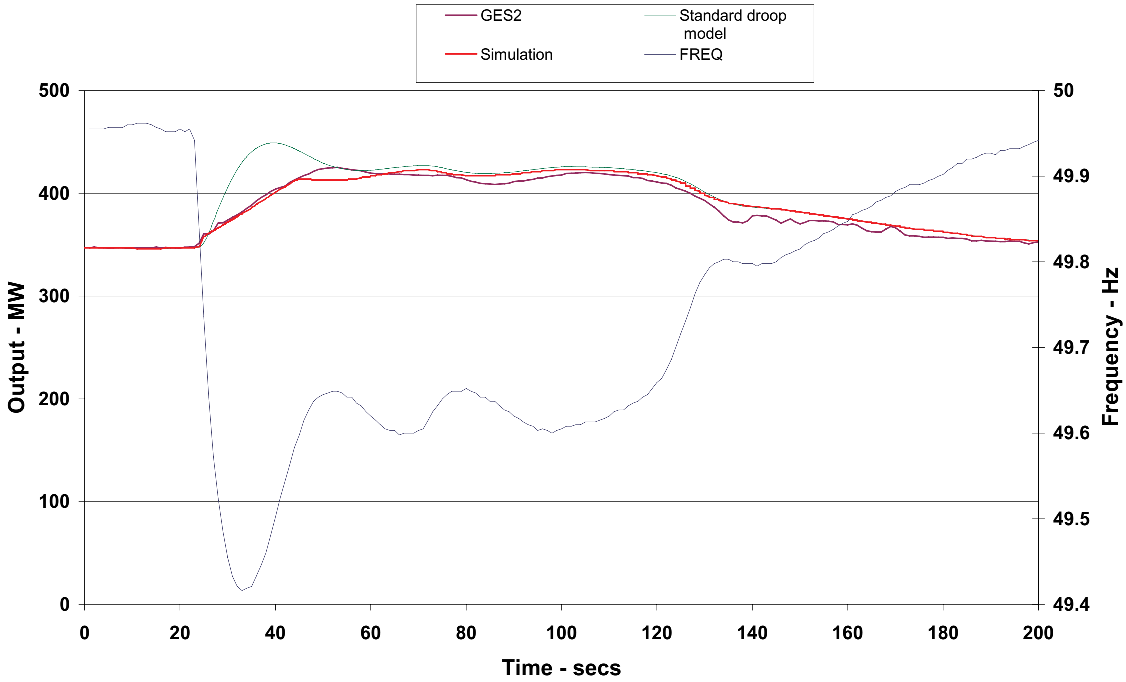


Figure 4 - Rate limited frequency trip generator response to deviation in frequency.

1.3 CCGT Plant

A simple governor model developed in a Matlab environment detailed in a previous report had shown a potential for representation of CCGT response during frequency drops. To provide a governor controller that can be used in system simulation studies the model required coding from Matlab into Eurostag macro block format.

The task of providing a Eurostag macro block was not as straightforward as had been originally thought. Problems occurred in initialising variables, and getting consistency in simulation variables. Valuable experience was gained on how to implement the macro blocks, which will be useful in constructing future CCGT models for different manufacturers.

A block diagram of the implemented model is given in Figure 5a, b and c, with corresponding variables in **Table 1** and **Table 2**.

%FPIGV	-0.1	0.6
	0.7	0.6
	0.765	0.8
	1.	1.
	1.1	1.
KRAD	0.1	
KTEMP	3.3	
MUCOMP	0.91	
MUTURB	0.67	
RC	0.2	
TR	898.	
TRAD	15.	
TTEMP	250.	

Table 1 - GT26 gas turbine governor variables

%FHRSG	0	0
	0.5	0.5
	0.8	0.8
	1.	1.
TB	200	
TS	5	

Table 2 - GT26 heat recover steam generator governor variables

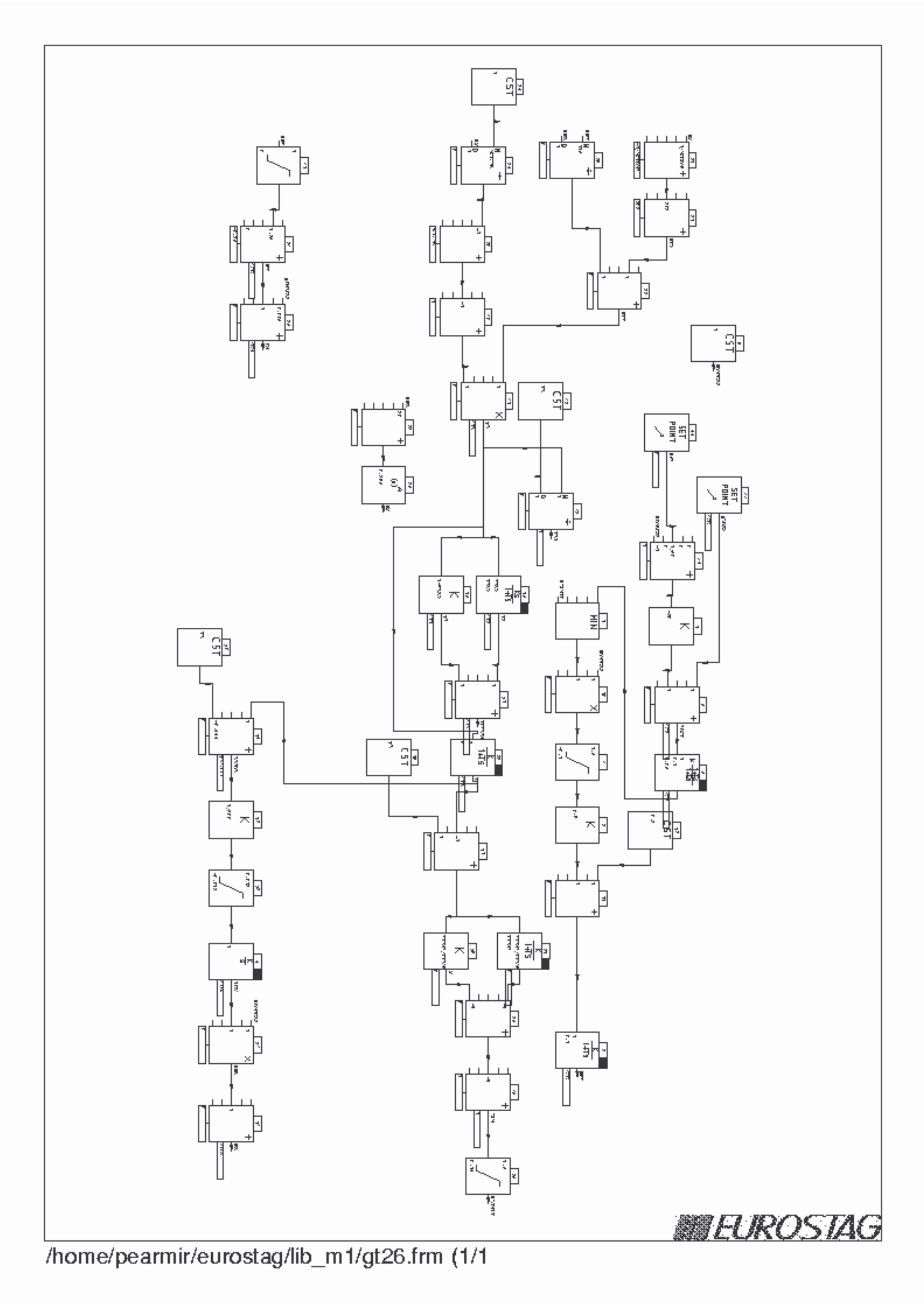


Figure 5a - Block diagram of the GT26 gas turbine governor macro block

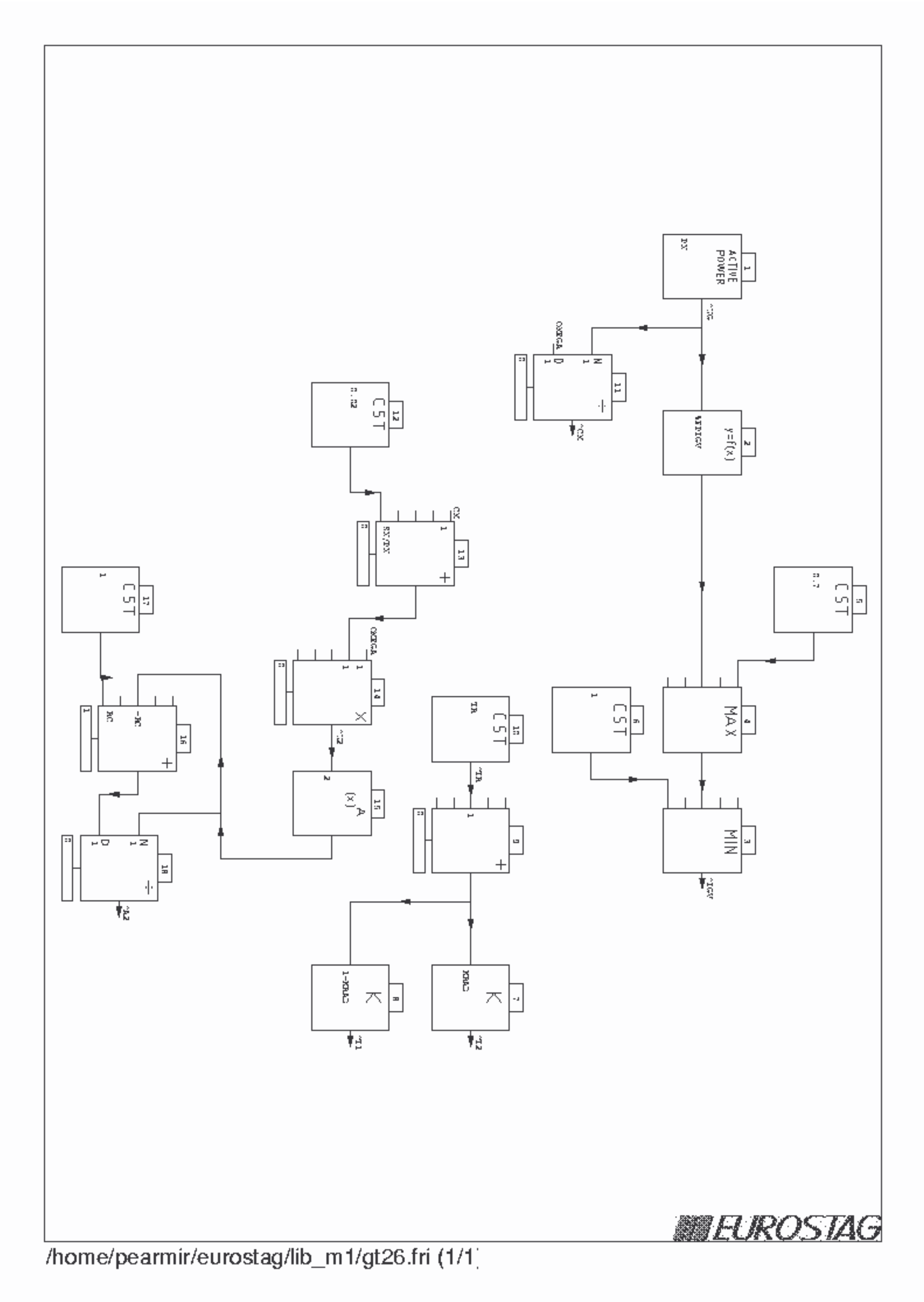


Figure 5b - Block diagram of the GT26 gas turbine governor initialisation blocks

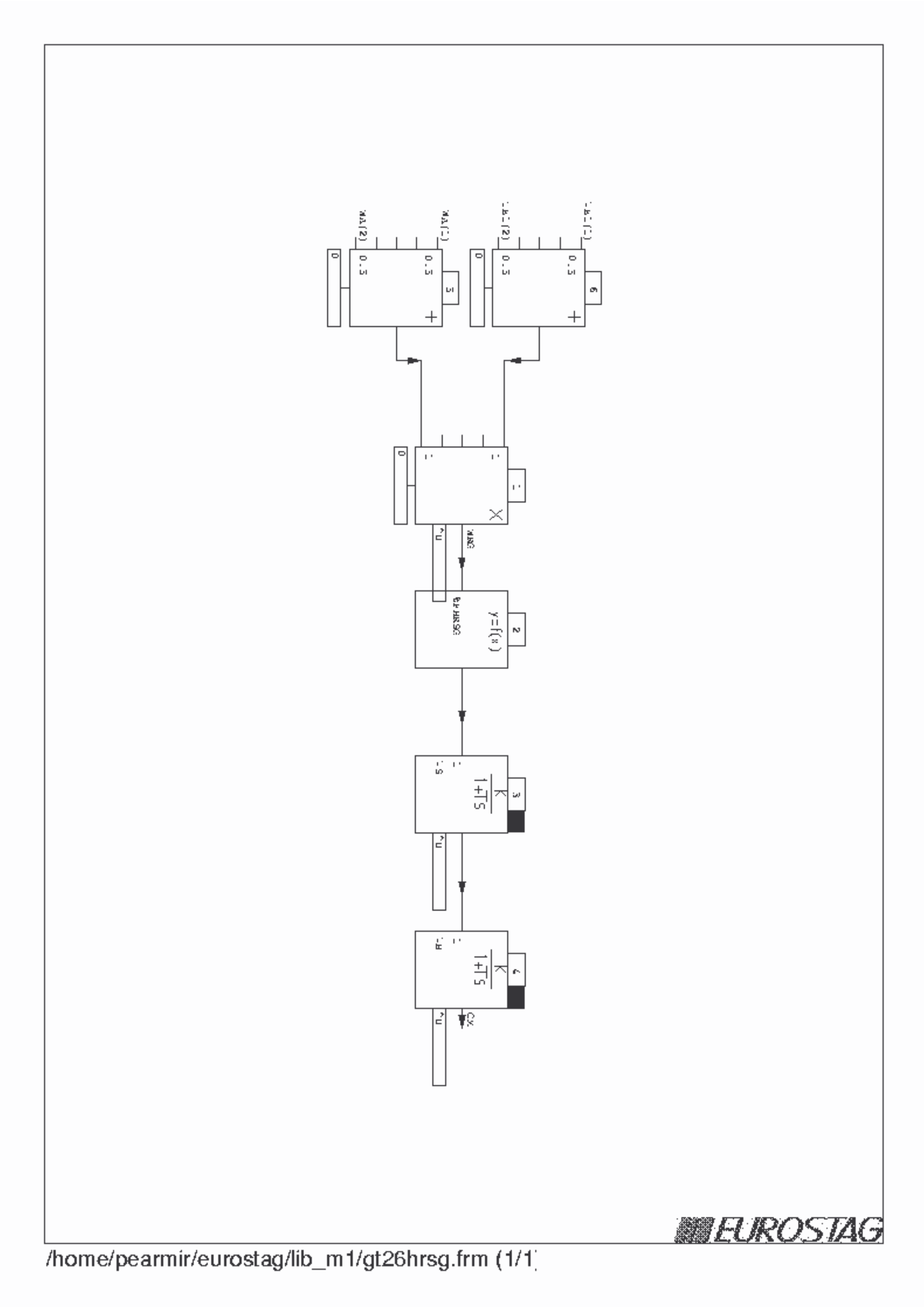


Figure 5c - Block diagram of the GT26 heat recover steam generator governor macro block

Simulations of a frequency event where conducted with the model to validate its response. Figure 6 shows the results of a simulation trial conducted in Eurostag with the updated governor model for GT26 turbines. These models give an improvement on response in the initial stages of the simulation compared to the generic models. However, it is clear that further improvements can be made to increase the accuracy.

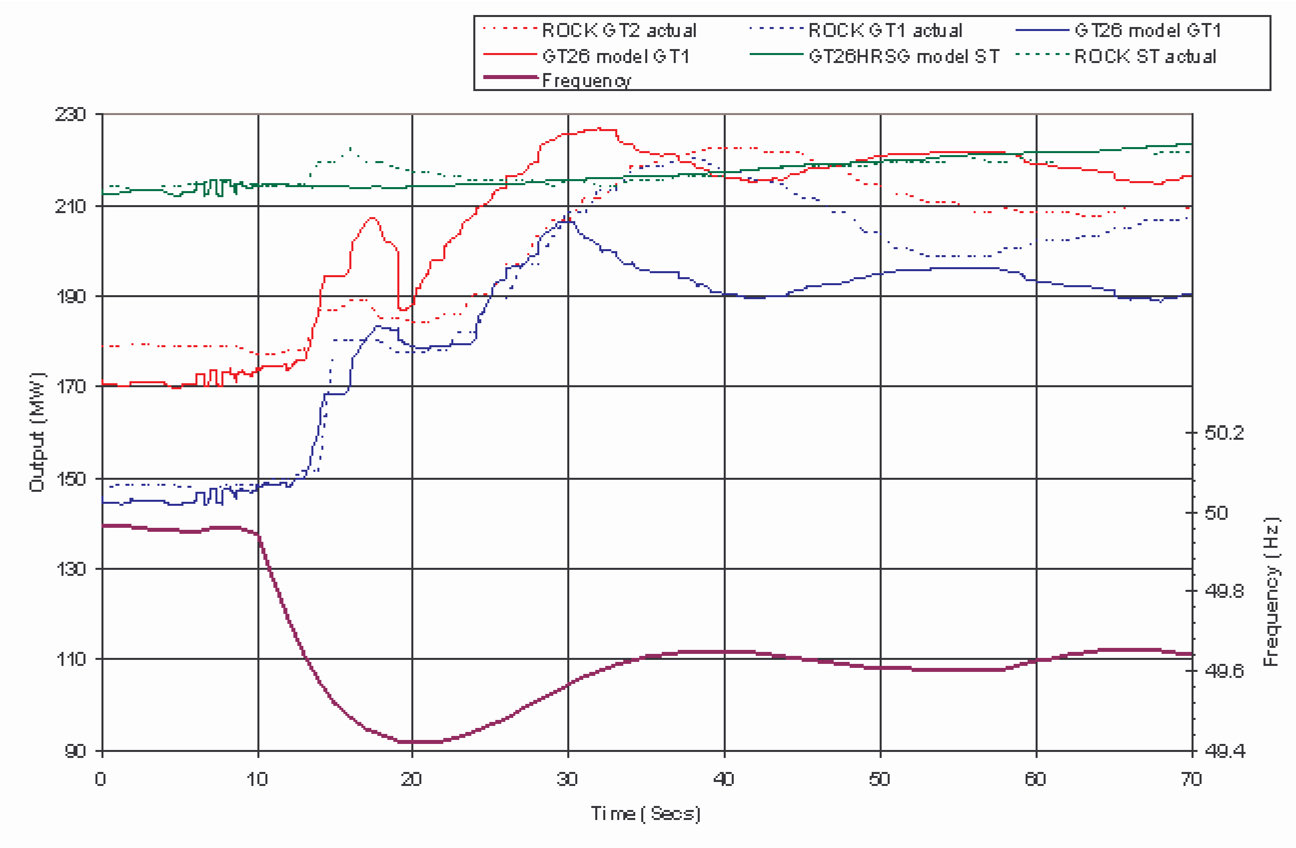


Figure 6 - Simulated GT26 response to an actual -0.6 Hz frequency drop.

In the above example, GT1 does not reach the peak output experienced on the actual unit. This is due to the use of load controllers on the plant. Load controllers monitor the response of the whole plant (two gas turbines and steam turbine) to ensure that the required collective response of the power station is met. In this case the driving signal to both gas turbines would have been greater than the normal 4% droop on other machines because of the slow response of the steam unit.

A simple macro block can be introduced to provide the function of a load controller.

This will be developed and tested against further incidents that led to a considerable deviation in frequency.

1.4 Relevant Literature

A number of papers have been published recently from research conducted on the Irish electricity grid. This research has developed with what seems the same objective set out by National Grid in this project. References to earlier work investigating the load frequency characteristic of the Irish Grid [2] had been made in the transfer viva [1].

Further studies [3][4][5] have progressed with particular attention to frequency response of combined-cycle plant which has been mentioned in section 1.3 of this report. A number of possible problems arise in the methodology adopted by O'Malley. The frequency studies have been conducted using a single bus system to represent the entire Irish grid. The authors are aware that this technique assumes all grid frequency is uniform across the grid. However, studies have shown that this is not the case. Whilst monitoring generator data from the UK grid it is evident the local grid frequencies rarely deviated from each other within a band of 0.1Hz.

In conjunction with homogeneous grid frequency there is also a more significant impact in that the node voltages must also be uniform. This assumption has a greater bearing on the simulations as in many cases the voltages across the network will vary according to node impedances. These impedances are very different for each of the substations on the grid, due to varied components, substation configurations and connections to distribution networks. Generators also act to control these voltages through AVRs which have an impact on the generator dynamic performance.

The second inaccuracy from the view point of the UK grid is the representation of all gas turbines has been made through Rowen's Models [6][7]. It has been shown through this research that the operating characteristics of ABB and GE turbines are critically different (not considering Siemens or Mitsubishi plants). As such the final simulated grid frequency is heavily dependant on the chosen model to represent each turbine. Without looking at the composition of grid connected CCGTs in Ireland it is impossible to say if the published results are affected by this oversight.

The latest research has been conducted in the impacts of increasing proportions of wind turbines on the system [8]. The paper has considered two cases; case one with all variable speed DFIG units, case two all units fixed speed units. The cases represent those units that will not contribute to the inertial response of the system and those that will respectively. The results show an influence on the initial rate of change of frequency as to be expected and also the minimum frequency in both cases. The severity of the disturbance is far greater with all wind turbines being DFIG units.

This results was to be expected in the case of the UK system, however the different makeup of the UK super grid will have an impact on the severity of the disturbance. With the UK grid being much larger in size it requires a large in-feed loss to provide deviations anywhere near those seen on the Irish grid. It is this difference and the use of a 630-bus system model which provides a further contribution to knowledge seen by this project.

2.0 Impacts of Governor Models in grid frequency simulations.

With alterations made to the governor models of thermal plant in section 1.2, and a more accurate representation of GT26 turbines from section 1.3, a frequency incident was revisited. The event chosen was initially studied in the transfer viva and remains one of the largest frequency transients experienced by the National Grid system. For the simulation the network configuration files remained untouched and only the generator data file was altered to include the new validated governor macro blocks. Non-GT26 CCGT gas turbine governor models were replaced with the GE based GASTURB model included in the Eurostag package.

Figure 7and Figure 8 show the output simulations of the event together with the actual recorded system values. The significant improvement in modelling of the generator responses is evident when comparing the charts to the early investigation [1]. Closer inspection of the frequency trace shows good match with the grid frequency in primary time scales. There is a noticeable difference at the secondary time scales of around 0.15Hz. This may be in part still due to the need to validate the CCGT plant and review the models for non-GT26 turbines.

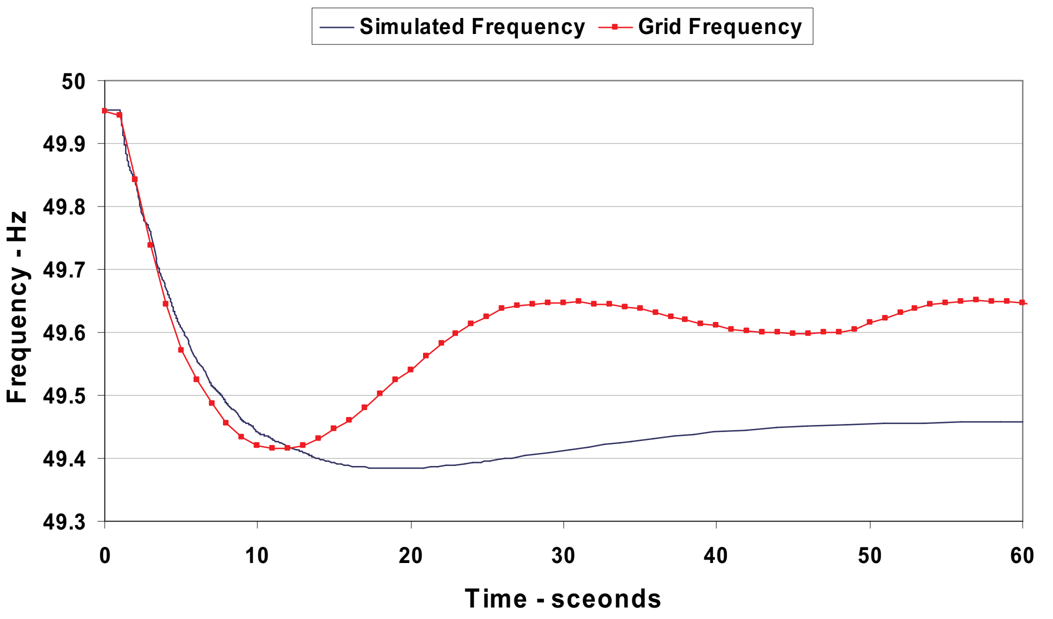


Figure 7 - Simulation of 1260 MW generation loss 26/05/03; Frequency

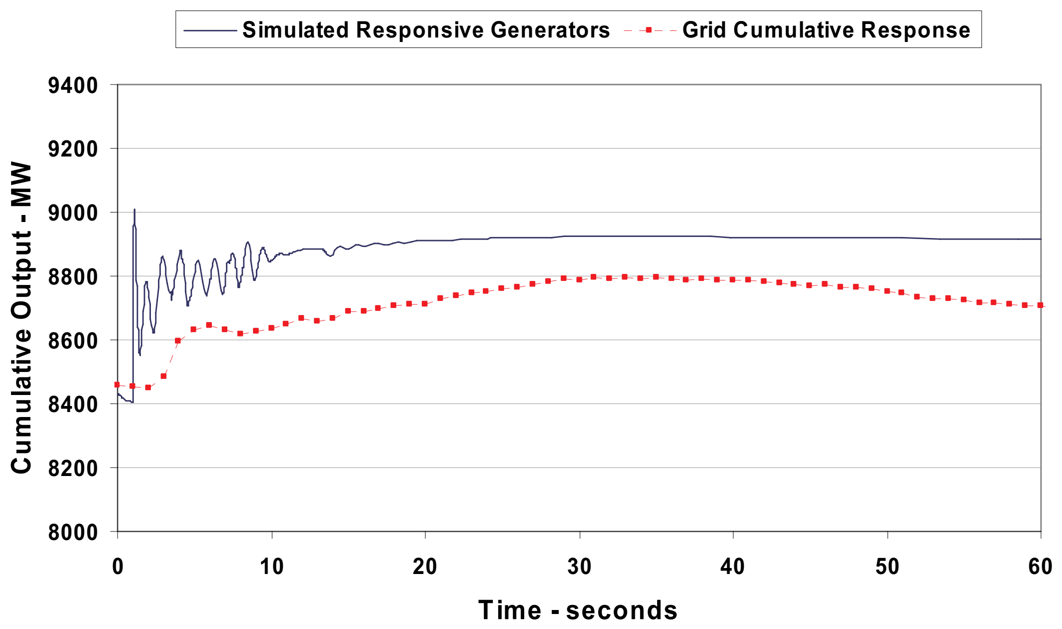


Figure 8 - Simulation of 1260 MW loss 26/05/03; Responsive Generation

However, the initial results showing generator response in Figure 8 look promising, and are certainly an improvement.

3.0 Demand database

Over the course of the last six months the number of recorded frequency incidents rose to 81. This has allowed a journal paper to be submitted to the *IEE Proceedings on Generation, Transmission & Distribution*. Through statistical analysis of the recorded demand sensitivity it has been possible to derive a probability distribution for the values. This enables a minimum expected load response to be identified for network security.

The paper provides further support that the current load frequency sensitivity factor of 2 %MW/Hz is justified. It suggests that the value may even be extended to a value of 2.5 %MW/Hz. Therefore, this value can be substituted into the calculations for response requirements on the electricity grid in Great Britain.

4.0 Targets from previous report

A number of milestones where met from the previous report including:

- Monitoring of demand sensitivity
- Ensure every generator has a simulation from a large frequency drop
- Add a response limit to coal fired generation that can be defined by contract values
- Write/Submit paper1
- Add Scottish nodes to grid model

However, the following tasks where not achieved:

- Model actual events in Matlab

- Model different types of manufacturer, and implement in Eurostag
- Review response requirements examining effects of geographic reserve holding

To ensure that these tasks are completed where necessary and that the project remains on schedule a review of the project plan has been conducted.

5.0 Next 6 months

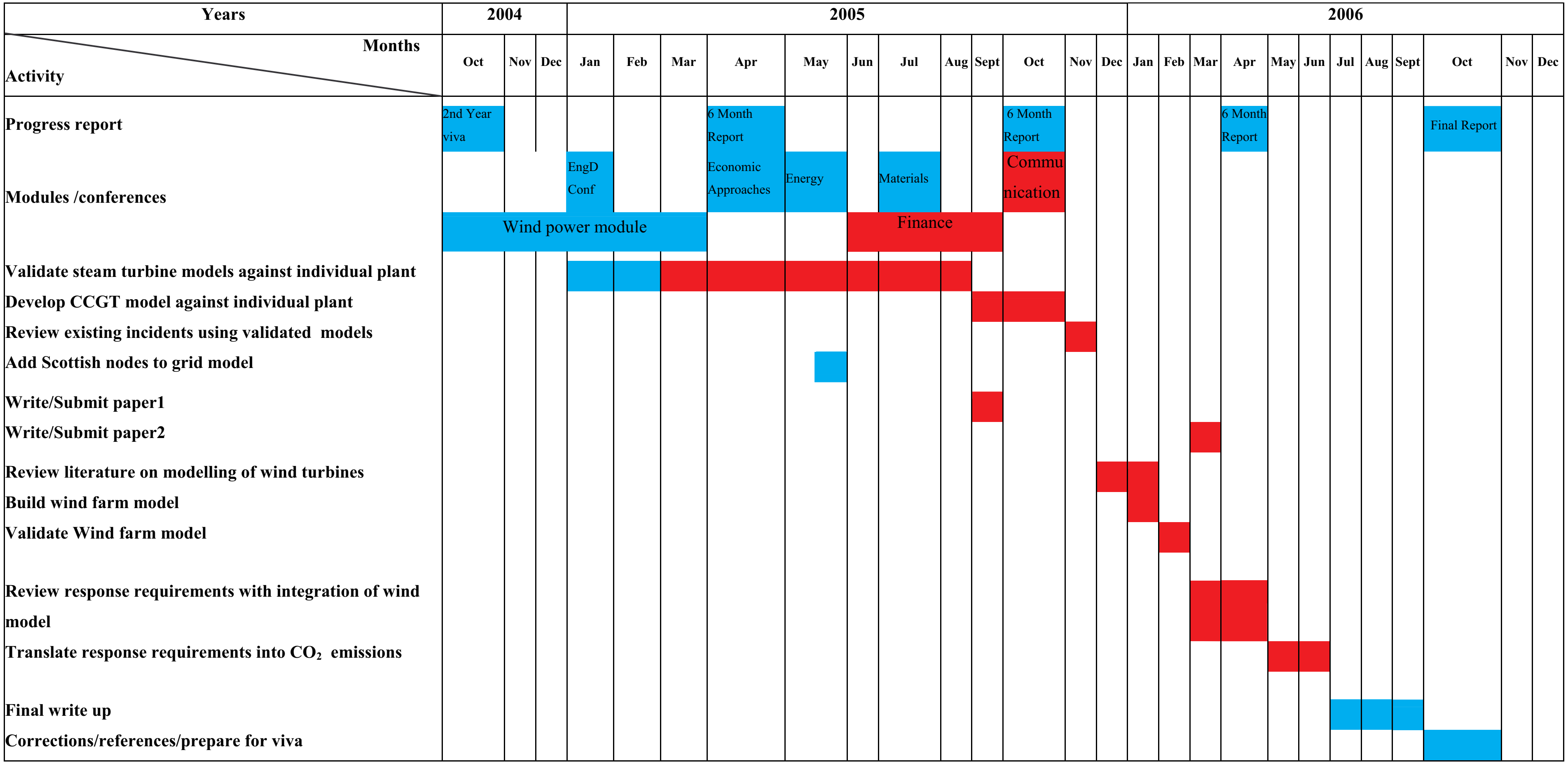
Difficulties in validating and implementing of the coal fired governor model together with unrealistic estimates of the time spent writing up course work for EngD modules have set back the project substantially. In order to keep to the required schedule I have removed the task of reviewing the response requirements examining effects of geographic reserve holding. If time allows at the later stages of the project this task may be reintroduced into the project plan.

I feel this is justified, as the task does not have a great bearing on the objectives of the project. It was originally included as an investigation piece to evaluate if geographic response holding should be a consideration for future policy. With only one further module to attend in the final year a solid twelve-month window exists to complete research. By restructuring the remaining tasks completion of all research in the allotted time scales is reasonable and attainable.

In the next six months it is hoped that the following can be achieved to the revised schedule.

- Validation of CCGT models in Eurostag
- Model actual frequency events in Eurostag
- Obtain data to validate a suitable model for representing wind turbines in simulations studies
- Start review of response requirements

6.0 Project Plan



6.1 Summary

This report explains the current developments in validating coal fired governor models against real incidents. Work is required to further increase the accuracy of the models in some cases.

Development of a governor model for CCGT plant has also been started. A suitable model has been identified for use with ABB GT26 plant. Development of this model will continue for the next month, with validation trails against all grid connected units. Further validation of other CCGT units on the system will also be conducted.

It still holds that the assumed National grid value of 2% seems to be accurate.

Within the next six months it is hoped that a second paper will be written and submitted to the IEEE.

7.0 References

[1] Reducing the environmental impact of frequency control on the UK power system against a background of increasing renewable generation.
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[2] Identification and validation of dynamic global load model parameters for use in power system frequency simulation
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[3] Frequency Control in Competitive Electricity Market Dispatch
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[5] Frequency control on an island power system with increasing proportions of combined cycle gas turbines
Lalor, G.; O'Malley, M.;
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[6] Simplified Mathematical Representations of Heavy-Duty Gas Turbines
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[7] Simplified Mathematical Representations of Single Shaft Gas Turbines in Mechanical Drive Service
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Six Monthly Progress Report: Seventh Report

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1.0 Work to Date

1.1 CCGT Plant validation

The developed model for CCGT plant was validated against tests carried out on existing units or historic data. These tests form a basis to demonstrate compliance with the Grid Code and are conducted on all grid-connected and large embedded plant. As in previous reports the frequency injection signal is provided to the governor to simulate the grid frequency during a real transient. Various injection shapes are tested; the one chosen to validate against in this example is the 0.8Hz ramp over 10 seconds, returning to 0.5 Hz at a load set point of 60 %. Power output, inlet guide vane position, exhaust temperature and fuel valve positions are monitored during the test at sampling intervals of 0.1 seconds. As for the original tests the unit under simulation is synchronised to the full network model as was experienced on the day of tests. The response of a simulation is shown in Figure 1 against compliance test results.

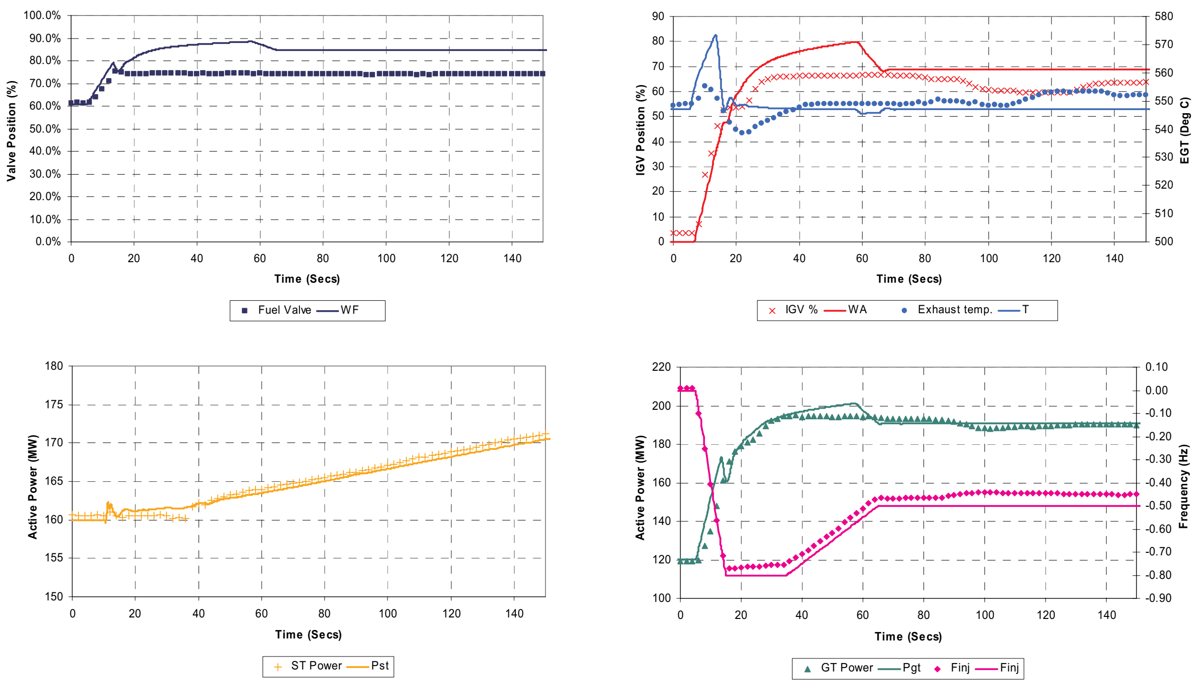

Figure 1 - Validation of a Siemens V94.3A gas turbine governor model at 60% load.

The fuel valve position signal from tests shows an opening from 60 to 73% as frequency is injected, this is met by a rise from 60 to 87% in the model. However, despite this difference the overall power output of the model remains within a tight tolerance of actual unit, suggesting a supplementary fuel valve that was not monitored during tests. The test frequency injection is a summation of grid frequency and injection signal hence the signal is not as crisp as that seen in the simulation due to minor fluctuations in the grid frequency. Figure 2 shows the change in power for the same CCGT unit and model at a slightly higher loading point.

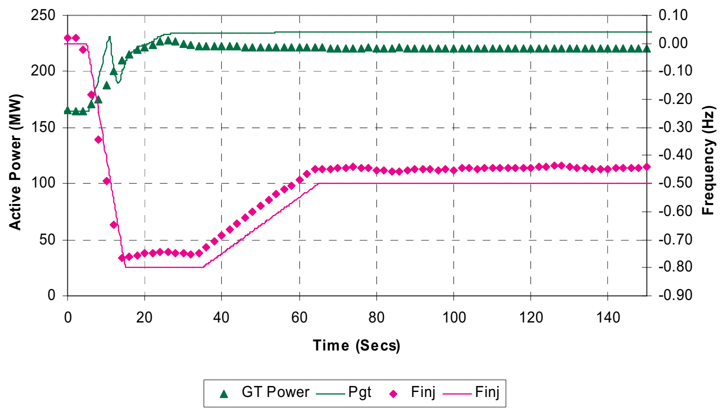

Figure 2 - Power output from Siemens V94.3A gas turbine governor model at 73% load.

Marginal differences between the simulation of inlet guide vane position and exhaust temperature from the test results bring attention to insufficient modelling of temperature limit controls. This is also noticeable in the simulated power output curve as it reaches peak output, which is not limited to the same level as the actual unit. Output power, as simulated by the model, provides a close match to the compliance test in the initial 30 seconds of the trip. This time scale is critical for establishing response levels that curtail the drop in frequency. Response on secondary time scales whilst important to restore system operation back to normality does not critically influence the risks of demand disconnection provided it is sustained from primary levels. Whilst these results show a marked improvement in comparison with the results obtained from standard models there remains an opportunity to improve the model.

Instances where actual historic events can be used to validate models offer the benefit of a real frequency change. However, these events do not provide the opportunity to analyse data on exhaust temperature and airflow simulated by the model. Figure 3 shows a simulation of a historic event against the experienced values.

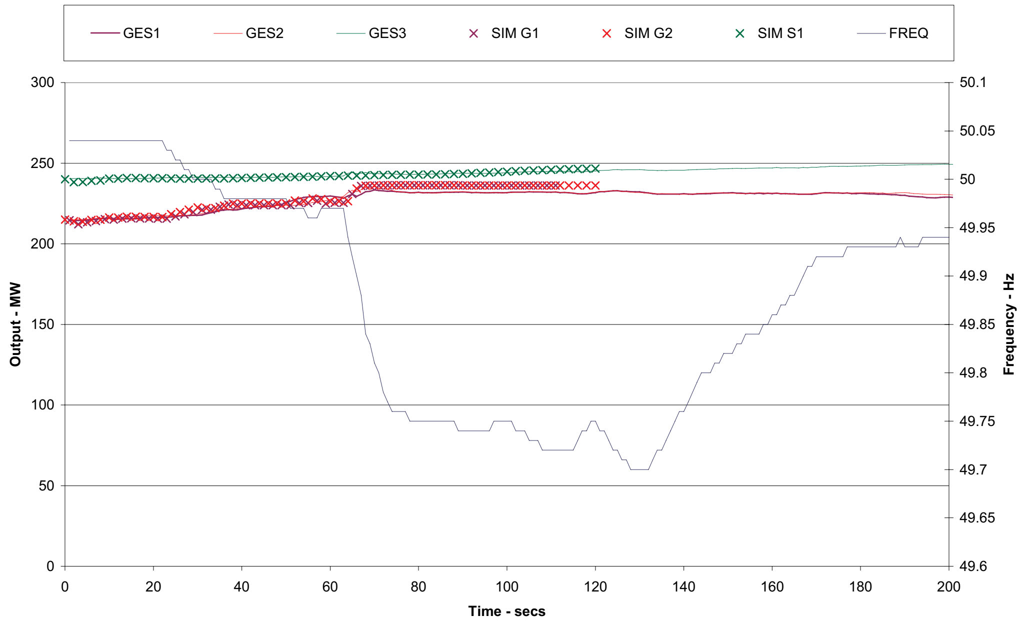

Figure 3 - Simulation of a frequency drop on an ABB GT26 unit

With accurate governor models of Oil, Coal and CCGT units established the project can now progress to running full scale network simulations. The development of a CCGT model and tuning of the generators provides the bulk of the work carried out to date. The models and data collected are unique from all the papers reviewed from literature sources. Considering this information a second draft journal paper has been produced for internal review based on these findings. It is hoped to submit this paper to the to Electric Power Systems Research journal by the end of March.

1.2 Full grid frequency simulations

With a complete library of governor macro blocks the possibility exists to compare the full network response of the simulation model to actual events. Precise reproduction of the transient frequency response in the simulations will highlight the accuracy of the complete model following the developments of the individual generator governors.

Problems obtaining operational data from the Scottish networks and convergence of load flows have meant that a reversion back to a lumped model of Scottish generation and demand was necessary. Building on the simulation carried out in the last report the event from 26 May 2003 was revisited with the full model, Figure 4. Increased accuracy has been obtained in both frequency and generation traces.

A second event from 21 January 2006, following the progressive loss of a CCGT unit totalling 790MW was also simulated, Figure 5. The traces show a very close match to the experienced event. The load response was increased from 2%/Hz to 4%/Hz inline with calculations from the actual event.

A third event from 2nd December 2005 simulates the response during a 1GW bipole trip of the Anglo-French interconnector. During this simulation the lumped Scottish response is somewhat sluggish compared to the actual event, it is this that is the main cause of the difference in experienced and simulated grid frequency. Again the load response was increased from 2%/Hz to 3.7%/Hz inline with the actual event. Also of note is the fact that the frequency does not recover from 49.7Hz due to increasing demands at that time.

These three events demonstrate the accuracy of the post event modelling techniques employed to simulate grid frequency. Now that a high confidence is established in the model a review of the response holding levels can begin.

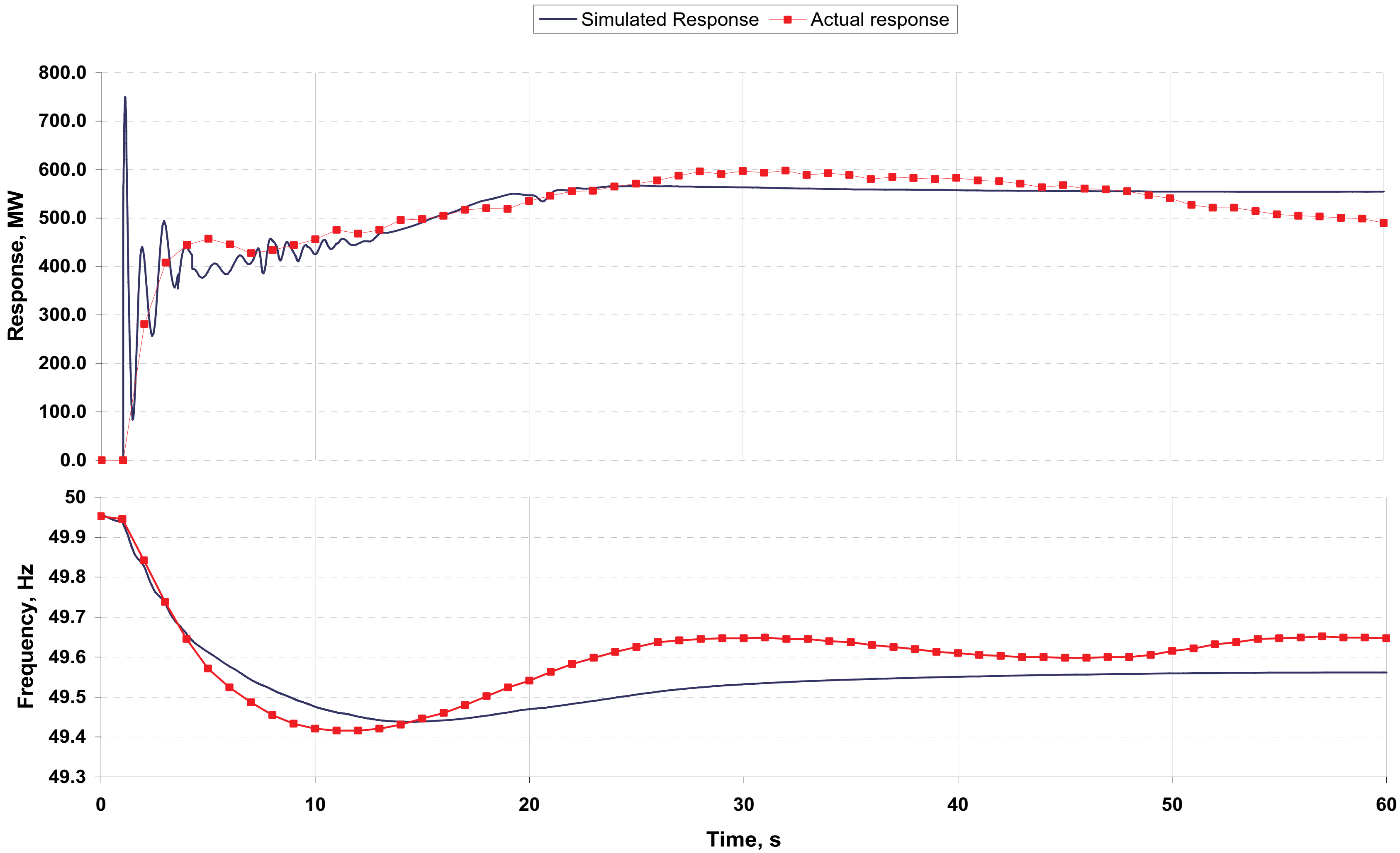

Figure 4 - Network response and simulation to a 1.26GW loss 26/05/03

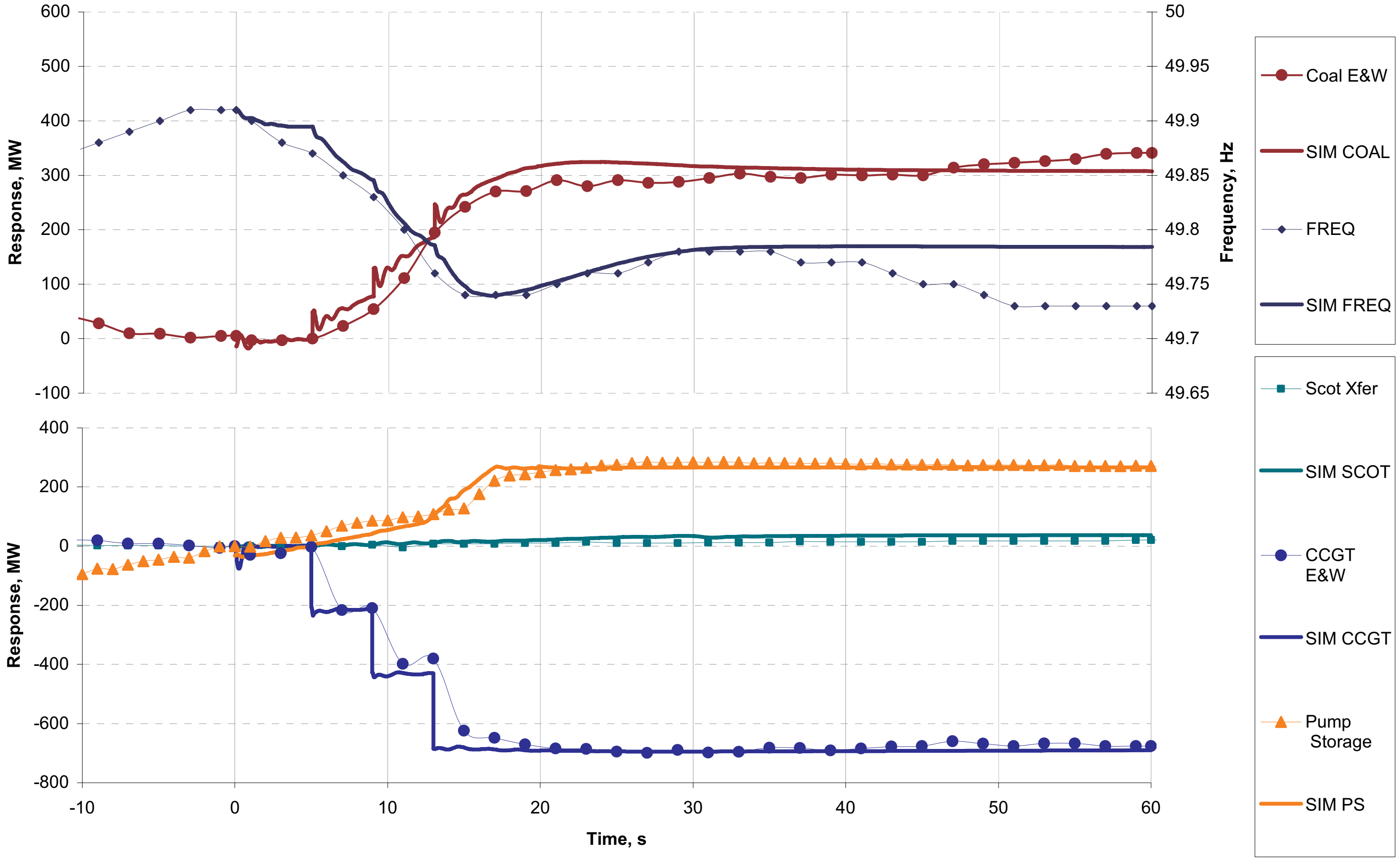

Figure 5 - Network response and simulation to a 790MW loss 21/01/06

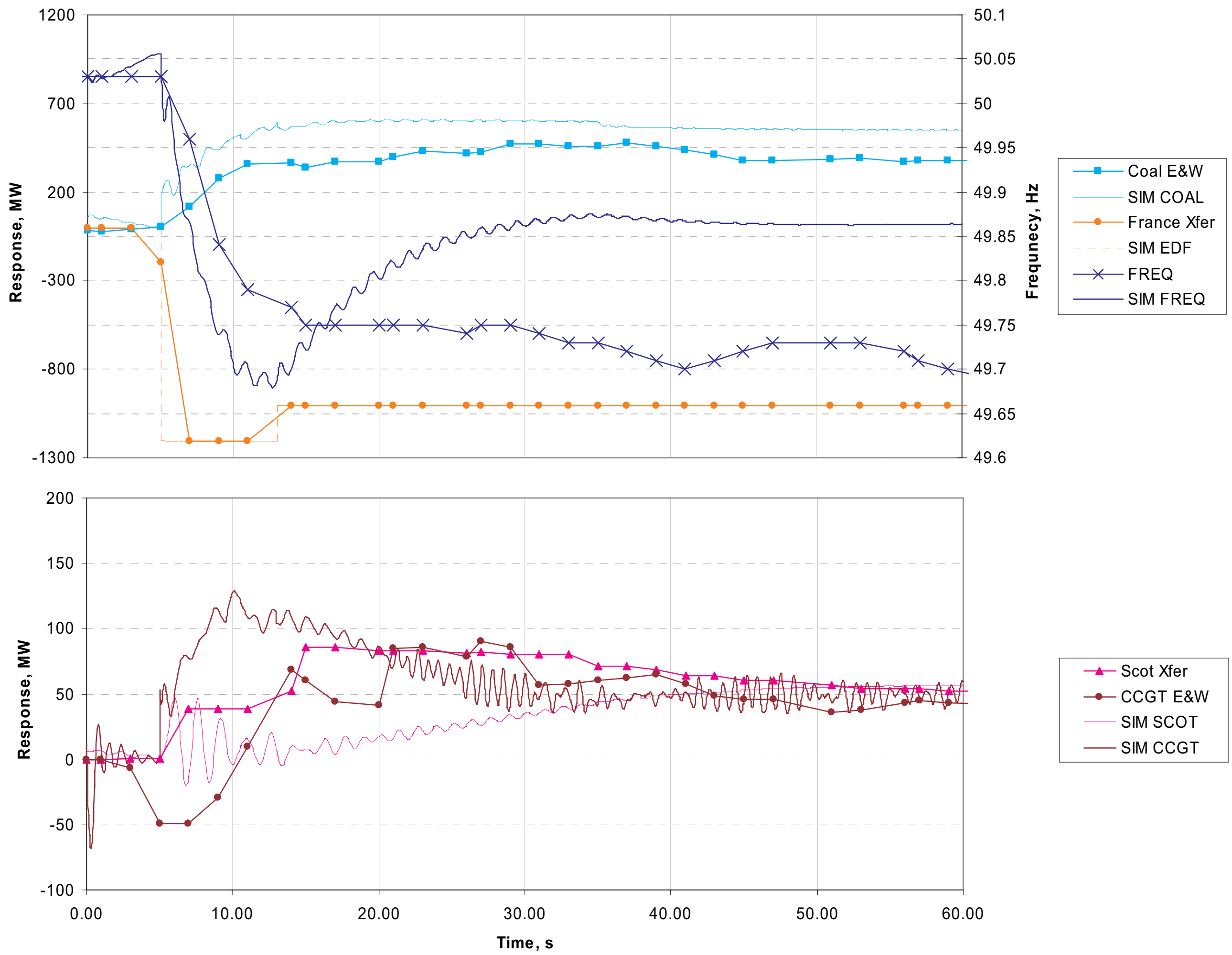

Figure 6 - Network response and simulation to a 1GW loss 02/12/05

1.3 Review of response requirements

The original response requirement curves had been established with a single governor model to represent responsive generation. The dynamic influence of multiple units on the response requirement has not been fully investigated until now. To ensure that holding response on demand side frequency relays would not influence the level of response holding, a simple network model was created with a system demand of 55GW. The loss of 1GW was triggered under three different scenarios:

- Response on Coal Units all with the same governor model + 200MW of demand side management (50% triggered at 49.7Hz, and a further 50% triggered at 49.65Hz)
- Response on Coal Units all with the same governor model
- Response on Coal Units each with specific governor models + 200MW of demand side management

These scenarios would identify differences in response holding levels required to contain the drop in frequency. As the frequency limit under a 1 GW loss is a deviation of -0.5Hz, responsive plant output was adjusted and displaced until frequency fell to 49.5Hz. Figure 7 shows the frequency and cumulative change in response supplied in each of the three scenarios. The frequency minimum was not at the same time for each of the transients, as expect. Due to the difference in dynamic response each frequency trace is unique, however, the traces show that the level of primary and secondary response under each scenario is similar. In fact, further analysis of the three scenarios reveals no significant difference in the levels of response holding at these points.

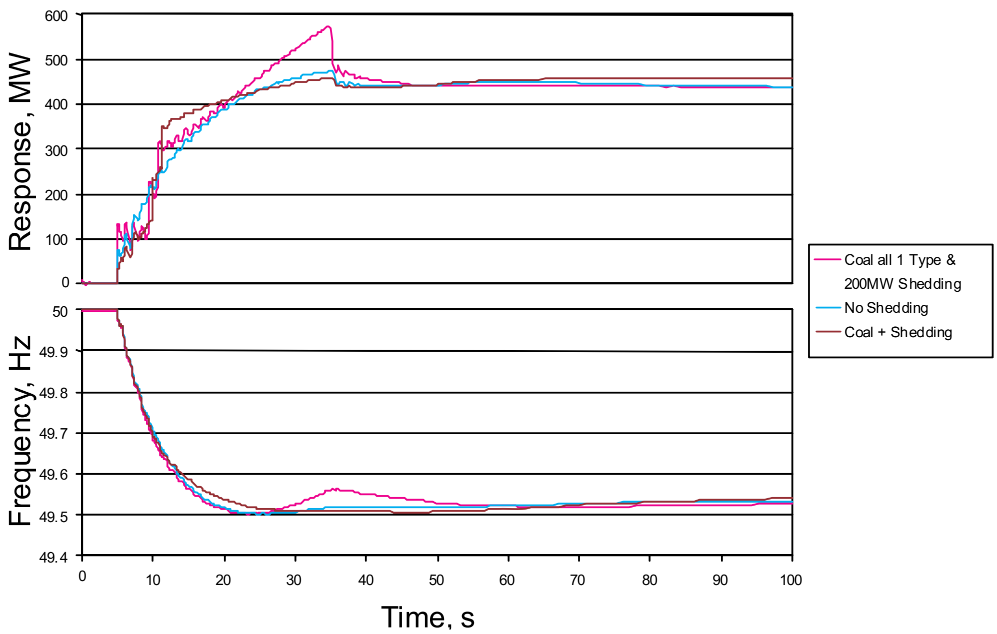

Figure 7 - Response required to contain a 1GW loss under three test scenarios

The conclusion from these studies is that the inclusion of demand management in response trails should have no untoward effect on the net response holding requirement. These results also highlight the similarities in response levels calculated from using machines with varying dynamic responses and simulations when machines have the same dynamic response.

The system quality and security of supply document [1] defines the limits of frequency that must be sustained during system operation. These limits define a maximum permissible deviation of -0.8Hz from nominal during abnormal system incidents. Here abnormal is defined as a generator loss of over 1GW. A second clause to this limit requires that the system frequency must return to 49.5 Hz before a minute after the event. In early response trails on abnormal losses the simulation package was used to define the primary response levels to a deviation reaching 49.2Hz. However, this technique does not necessarily comply with the second part of the SQSS constraint. Secondary response levels are established through Equation 1.

$$R_{SEC} = (1+\varepsilon)(Risk - \alpha.D_{GB}.\Delta F_{\sec,\max})$$

Equation 1

Where;

R_{SEC} = Secondary response holding level

ε = Error margin

Risk = Largest infeed loss

α = Frequency sensitivity to demand

D_{GB} = National Demand

$\Delta F_{sec,max}$ = Maximum permissible deviation under secondary response timescales

This equation will determine the magnitude of the resulting frequency but imposes no relation to the time at which this frequency will be attained. Consequently this may allude to a primary response level which is less than the required power to prevent a breach of legislated limits.

Trials with the full network model at a system demand of 50GW support this conclusion. Figure 8 shows the simulations conducted at a 50GW national demand for both the SQSS requirement and the traditional 0.8Hz deviation. An approximate mismatch of 100MW can be seen in the two situations, with the traditional method conservative on its result. The current (and Pre-BETTA) response holding levels are also shown on the figure, they follow the same pattern as the simulations to 0.8Hz.

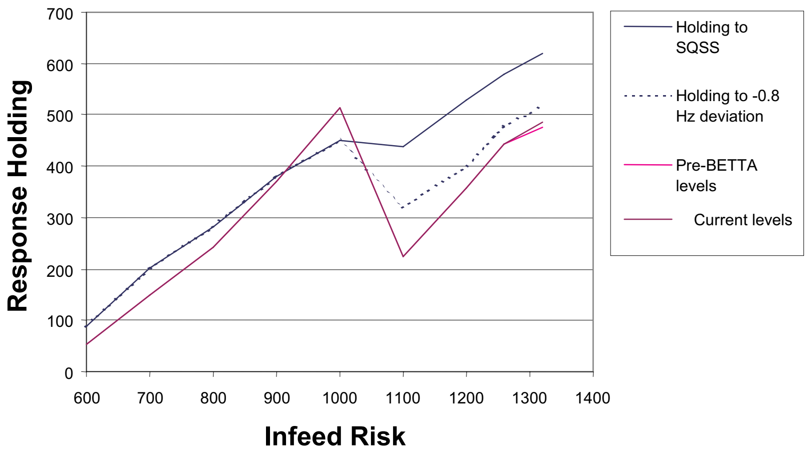

Figure 8 - Primary response requirements at a 50GW national demand

It is unlikely that the control room would have put the system in any jeopardy by operating to these levels. By the nature of the response contracts, balancing units can supply either primary response only or combined primary and secondary response. To meet the desired levels of response holding the secondary contracts cannot be acquired as individual ancillary services. In this situation over commitment of primary response would be more than likely as the secondary requirement is the driving factor. If the contracting arrangement were ever change to allow a secondary response market this situation would become more precarious.

Results under secondary time scales have show that calculating the secondary response requirement using Equation 1 is still acceptable. Further trials are planned to establish a set of requirement curves at national demand levels of between 20 and 65GW at 5GW intervals.

2.0 Demand response paper

A paper entitled "Identification of a Load Frequency Characteristic for allocation of spinning reserves on the UK Electricity Grid" was submitted to the IEE Proceedings Generation, Transmission and Distribution on the 13th of September 2005. Following the submission some major alterations to the paper ensued and a second revision was submitted 9th January 2006, the paper was finally accepted for publication on 11th Febuary 2006.

3.0 Targets from previous report

A number of milestones where met from the previous report including:

- Validation of CCGT models in Eurostag
- Model actual frequency events in Eurostag
- Start review of response requirements

However, the following tasks where not achieved:

- Obtain data to validate a suitable model for representing wind turbines in simulations studies

Several sources in the UK have been approached to provide data of turbine transient response during frequency dips. All avenues of investigation have declined providing information on either technical or commercial grounds. However, if periods of frequency drops can be identified the data may be soured from the Danish grid to at least provide some degree of validation.

4.0 Next 6 months

Following the work plan submitted in the last six monthly report the project is a month behind previous expectations, however, a deadline for completion in October is still realistic. With no further modules expected, and only a conference paper to write, concentration on simulations can be intensified. Minor adjustments have been made to the initial task timing in the schedule (see section 6.0) in order to recover the month lost.

In the next six months it is hoped that the following can be achieved to the revised schedule.

- Implementation and Validation of a wind turbine model in Eurostag
- Conclude review of response requirements
- Complete response requirements adding a degree of wind power
- Conduct sensitivity analysis
- Write final thesis

The possibility may also exist to conduct some live system tests with the update response requirement curves. This would of course lend further credibility to the work carried out this far on the developed system response model.

5.0 Project Plan

Years	2006										
Activity / Months	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov
Progress report				6 Month Report						Final Report	
Modules /conferences									EngD Conference		
Write/Submit paper2											
Write paper for EngD conference											
Review existing response requirements											
Review literature on modelling of wind turbines											
Build wind farm model											
Validate Wind farm model											
Review response requirements with integration of wind model											
Translate response requirements into CO_2 emissions											
Final write up											
Corrections/references/prepare for viva											

6.0 Summary

Validation trials have been conducted on a number of combined cycle gas turbines using both compliance tests and historic events. These tests have been successful in mimicking the dynamic nature of the plants. This data has provided the possibility of writing a second paper which it is hoped will be available to submit to the EPRS by the end of March.

A set of three full network simulations has increased confidence in the response model adopted. In light of these developments initial simulations have begun to identify a response requirement. Trials conducted at a system demand of 50GW have revealed shortcomings in the existing requirement curves. Future work to establish curves for the remaining demand points has been set against project timescales. Implementation of a wind turbine model in Eurostag is required to complete the analysis of future response holding requirements with increased renewables.

The next report will consist of the project thesis, summarising the research conducted over the duration of this project.

7.0 References

1. National Grid: 'GB Security and Quality of Supply Standard - version 1 ', September 22, 2004 Available on-line at http://www.nationalgrid.com/uk/library/documents/pdfs/GB_SQSS_V1.pdf

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1.0 Work to Date

1.1 Review of Response Requirements

Following the developed CCGT model presented in the seventh progress report a full set of response requirements have been produced. These curves are presented in Figure 1 for secondary response and Figure 2 and 3 for the primary requirement.

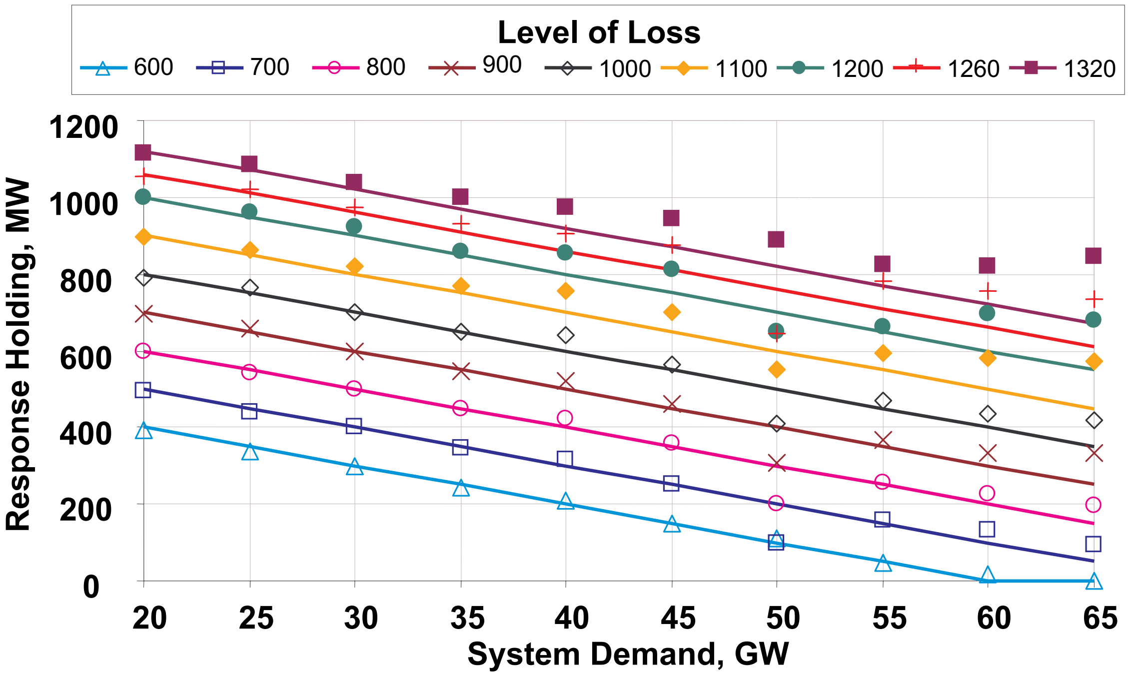

Figure 1 – Secondary response requirements for all losses

Figure 1 gives curves of calculated secondary response levels using the secondary response equation (1) and simulated spot results using the dynamic system model. In most simulations the secondary response levels agree with the calculated values. The larger losses (1320 and 1260 MW) show greater divergence from the calculated values, particularly at the higher demand levels. This excess can be attributed to the over provision of secondary response as envisaged through of selection of appropriate generating plant. In these cases system frequency at the end of simulations was well above the minimum requirement of 49.5 Hz.

Primary response requirement curve values are calculated from simulations of generation losses using the dynamic network model. The starting frequency is assumed to be at 50 Hz. Only coal fired generation and up to 240 MW of demand management have been allowed in the primary response simulations. Figure 2 provides the response holding levels for all significant losses. Curves of best fit have been included to identify spurious results. The correlation factor between curves and measurements is 0.9951, suggesting that spot results do not significantly differ from the lines of best fit.

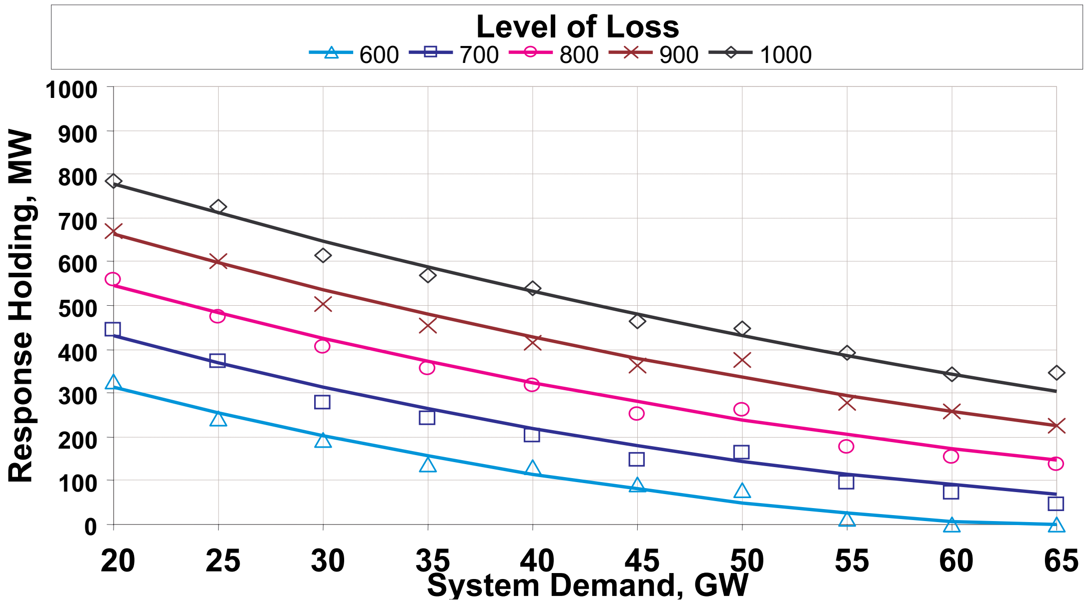

Figure 2 – Primary response requirements for significant losses

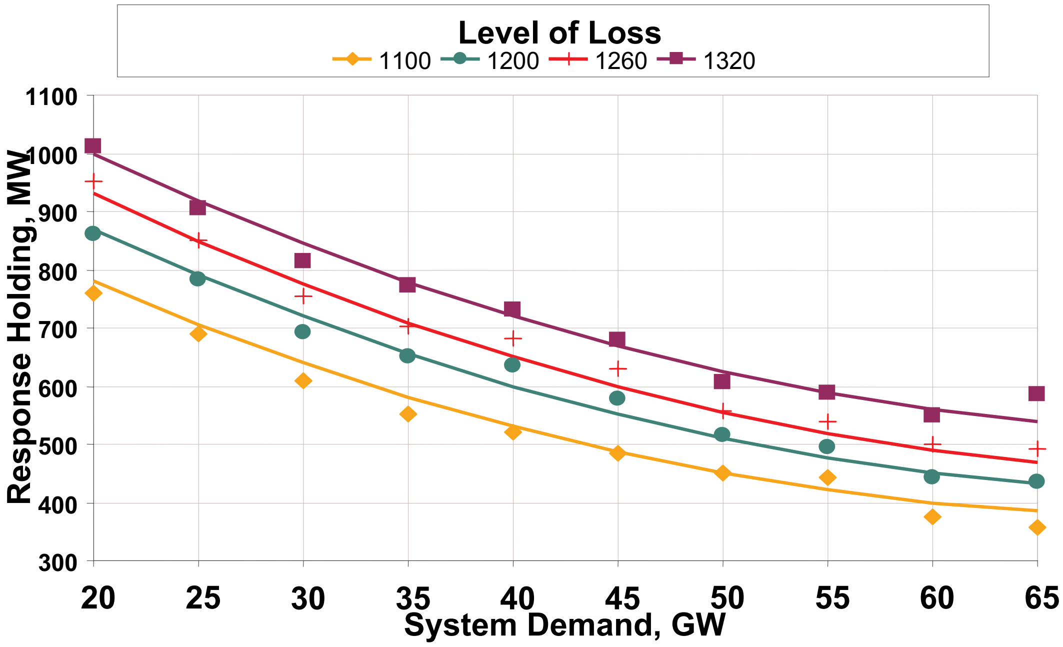

Figure 3 – Primary response requirements for abnormal losses

Figure 3 provides similar response holding levels for abnormal losses. Again the correlation is high at 0.992, again suggesting the curves fit the simulation results.

1.2 Changes in the Response Requirements

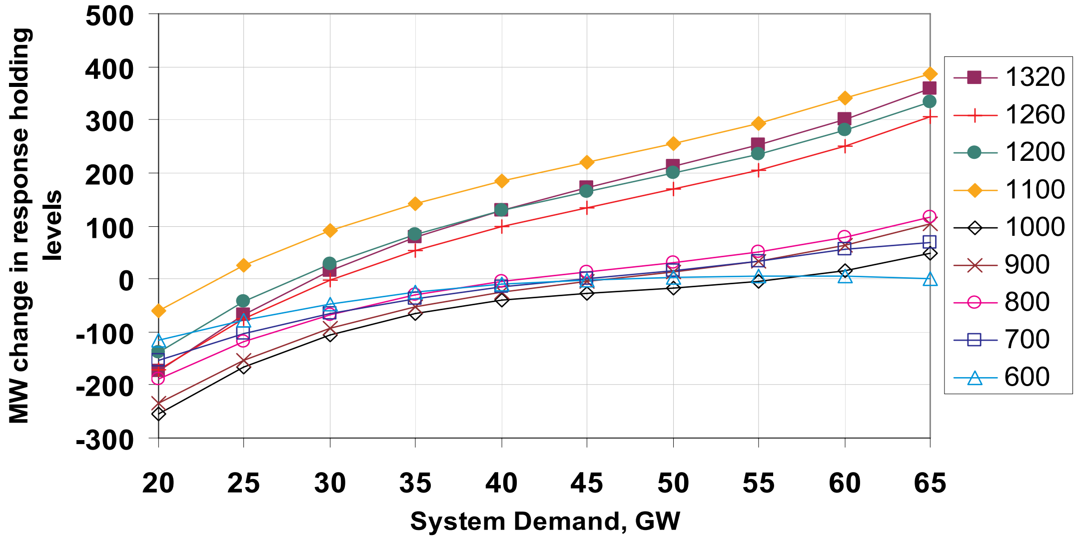

Figure 4 – Changes in primary response requirements (without margin)

Figure 4 shows the general trends of the current primary response requirements not including a margin, against values calculated in this chapter. The simulations show that the lower system demands generally require less primary response than operational requirements suggest at present. In contrast, for the higher system demands response is currently under provided by up to 400MW. Significant losses on the whole show a reduction in requirements or no change at all, except at the higher system demands. Abnormal losses require additional response according to the newly simulated values. Secondary response requirements are identical to current values and so are not considered.

1.3 Wind Turbine Model

The last report established significant problems in obtaining data to validate suitable wind turbine models for simulations studies. The decision to use existing models from literate sources to represent doubly fed induction machines was seen as a suitable compromise. Figure 5 depicts the general structure of the variable speed wind turbine model with a doubly fed induction generator. Each element of the model for the basis of this research is presented in a relatively low level of detail. Full details of the model can be found in

Soens *et al.*(2003). The rotor aerodynamic function was altered to reflect the details presented in Ackermann(2005), which is more representative of variable speed turbines.

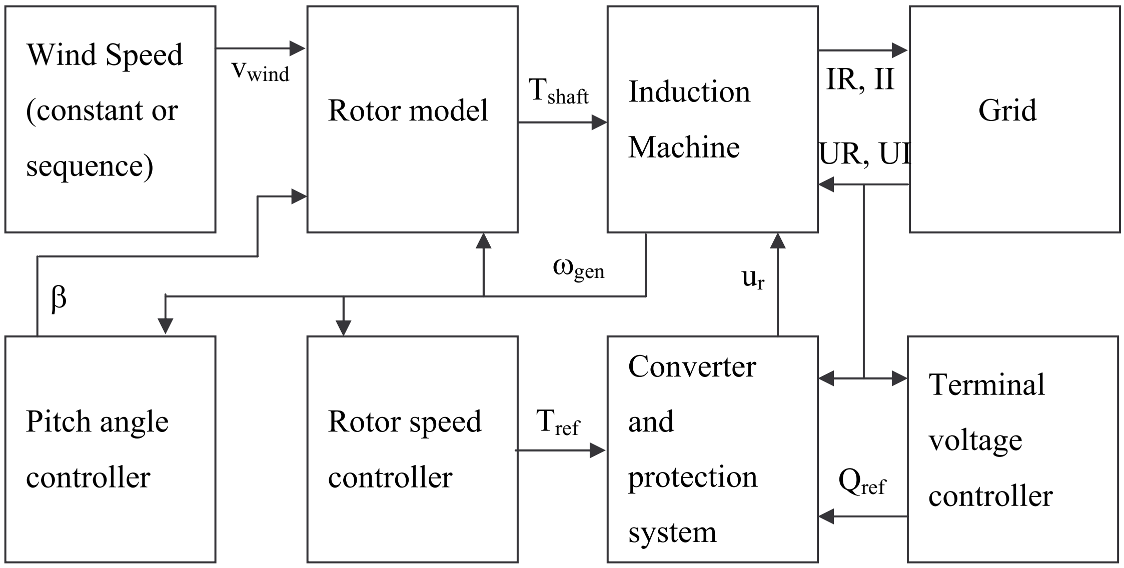

Figure 5 – Variable speed wind turbine model

The shaft and gear train can be modelled as a spring and rotating masses but the simplification was made to remove this assumption. The induction machine model voltage equations are well established and referenced in Kundur(1994). In general variable speed wind turbines operate based on a maximum power tracking strategy and as a result aerodynamic properties of the unit are set at optimum**.** In cases of rotor frequencies below ω_{max}, active power is regulated through speed and current controls. In the case when rotor shaft speed is at maximum, active power is regulated through pitch control, Pöller(2003). The full speed and current control systems are given by Soens *et al.*(2003). An initialisation model has also been implemented which was not present on the original model by Soens. This includes initialisation parameters for Pitch angle, Generator/rotor torque, Generator/rotor speed, which minimises the transients experienced in the early stages of the simulation.

2.0 Influence of Wind Generation on response requirement

Figure 6 shows the changes in primary response requirements with an additional 4 GW of wind generation added to the system. For significant losses the system requires little difference in primary response levels, however, there is a small increase in most cases. The deviations notable in the 50 and 25 GW series are likely to be due to the chosen mix of generation at that particular demand level affecting the system dynamics. Disregarding these data points still allows a dominant trend to be established.

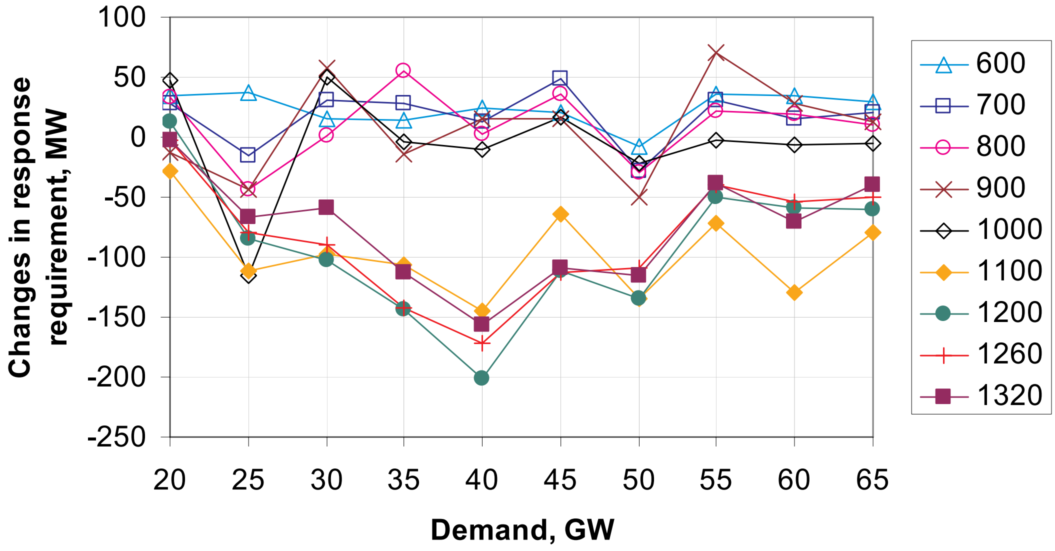

Figure 6 – Changes in primary response requirements

For abnormal losses there is a general decrease in the primary response requirements. This decrease is a result of the obligation to return to 49.5 Hz within one minute. In previous simulations of the response requirements for the current generation mix this factor was limiting the level of response. However, with lower system inertia as a result of wind turbines displacing conventional plant, the system dynamics have changed. The system is more susceptible to changes in frequency, and as a result the full frequency deviation during primary timescales can be harnessed.

The reduction in response peaks at the 40 GW demand point, and falls off as demands increase or reduce. This optimal point again results from the changes in system inertia. At high demands the influence of wind turbine inertia is low due to a dominance of conventional plant on the system. The total system inertia will become similar to the current level experienced on the system as demands increase. Conversely, at low demands the proportion of wind turbines to conventional plant is high. The total system inertia becomes lower and as a result slightly more response is required to contain frequency deviations within limits.

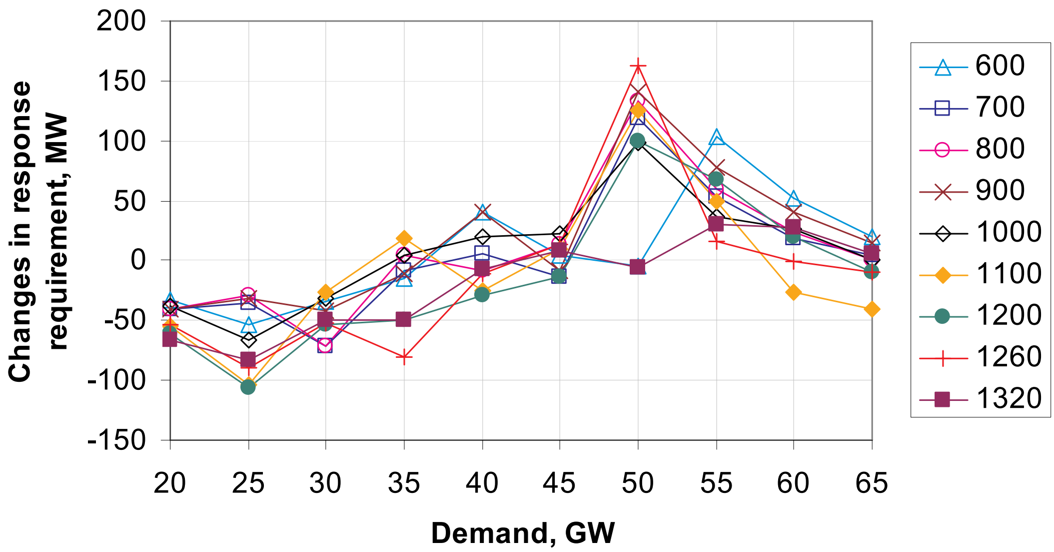

Figure 7 – Changes in secondary response requirements

Figure 7 gives changes in secondary response levels from the simulations with added wind turbines. There is a noticeable peak in the 50 GW results series (except for the 600 and 1320 MW loss), which confirms that something untoward is occurring in this particular system configuration. As explained earlier it is likely to be an effect of the specific generation chosen to meet the demand level. Omitting these results, the general trend of values is within around ±50 MW of the original simulations. This is typical of some of the deviations noted in the simulations of the secondary response requirement in section 1.1. This result is to be expected as the wind turbines should not significantly affect the simulation under steady state conditions.

3.0 Demand Response

Figure 8 details the recorded load sensitivity to frequency from an additional 106 low frequency incidents following generation loss. The results indicate a mean value of 3.43 %MW/Hz, however in the interests of security a worst case must be considered. The 15th percentile from the line of best fit (derived from maximum likelihood estimation) suggests a load sensitivity of 1.99 %MW/Hz, with a 95 percent confidence that the value lies between 1.79 and 2.2. The results have shown that 85 percent of values calculated are above a sensitivity of 2 %MW/Hz. This continues to give assurance in using this value as a minimum response expected from the load when used in conjunction with a margin in the response requirement calculations.

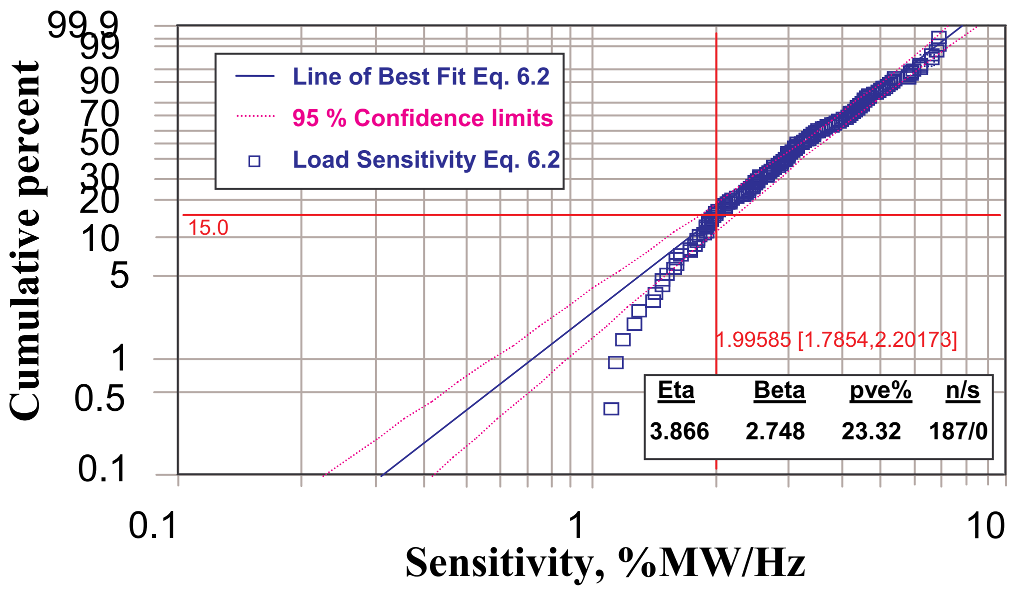

Figure 8 - Distribution of load sensitivity to frequency

4.0 Targets from previous report

A number of milestones where met from the previous report including:

- Implementation and Validation of a wind turbine model in Eurostag
- Conclude review of response requirements
- Complete response requirements adding a degree of wind power
- Conduct sensitivity analysis
- Write final thesis

Unfortunately it was not possible to conduct any live system tests with the updated response requirement curves, due to the time required to give notice to all stakeholders. The decision was also made not to translate response requirements into CO_2 emissions. Based on the work conducted, sufficient environmental benefit had been established. A second paper was also submitted to the to Electric Power Systems Research journal with minor revisions.

5.0 Summary

A complete dynamic response model was used to simulate the system response requirements for safe and secure operation of the network under large infeed losses. These results show some reduction in the primary response requirements is possible at low system demands for significant losses (600-1000 MW). However, the simulations also suggest that an increase in primary response holding is required at high system demands for abnormal losses (>1000 MW). The secondary response requirements show an overall reduction in the holding levels.

These simulations have shown that the existing system obligations under low frequency events limit the potential reduction in primary response holding. The dynamic requirement to return system frequency to 49.5 Hz in 60 seconds, in most cases, prevents the system from reaching the minimum frequency. There is potential to reach the minimum frequency under primary response timescales by allowing generators to provide only secondary response. Alternatively, recommendations to extend the dynamic requirement by a further minute would offer a more suitable transient frequency.

A doubly fed wind generator model was implemented from a number of research projects to represent potential offshore wind farms around the British Isles. The wind farm models were integrated with the complete dynamic model to assess changes in the response requirements. As a result of a net decrease in the total system inertia significant losses require up to 50 MW of additional primary response. The primary response holding for abnormal is shown to be reduced by between 50 and 200 MW, dependant on loss and system demands.

From the perspective of the system security this means there is no urgency in revising the current response requirements as up to 8.5 GW of new wind generators are integrated with the real system. The response margin should easily subsume an additional 50 MW of primary response require in significant events, thus maintaining system security. Under abnormal losses the system security should also be maintained with no further actions. In the interests of system efficiency under abnormal losses, the operational response requirements should be revised to realise any potential reductions in holding levels.

6.0 References

1. Ackermann, T., 'Wind in power systems', John Wiley & sons, Chichester, 2005, Chap 25.
2. Pöller, M., and Achilles, S., 'Aggregated Wind Park Models for Analyzing Power System Dynamics', Proc. 4th International Workshop on Large Scale Integration of Wind Power and Transmission Networks for offshore wind farms, Billund, 2003.
3. Soens, J., Driesen, J., and Belmans, R., 'A comprehensive model of a doubly fed induction generator for dynamic simulations and power system studies', International conference on Renewable energies and power quality (ICREPQ), Vigo, Spain, April 9-12, 2003.