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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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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Abstract

The system frequency of a synchronous power system varies with the imbalance of energy supplied and the electrical energy consumed. When large generating blocks are lost, the system undergoes a frequency swing relative to the size of the loss. Limits imposed on the magnitude of frequency deviation[†] prevent system collapse. Operation of frequency responsive plant to control frequency, results in lower machine efficiencies. Changes to the generation mix on the British transmission system have occurred in the past ten years, when the response requirement was last reviewed. Future increased levels of wind turbines[‡] will alter the operational characteristics of the system and warrant investigation.

A process to optimise the response requirements while maintaining statutory limits on frequency deviation has been identified. The method requires suitable load and generator models to replicate transmission system performance. A value to substitute for current load sensitivity to frequency has been presented from empirical studies. Traditional coal fired generator models have been improved with additional functions to provide a comparable response with existing units. A novel combined cycle gas turbine model using fundamental equations and control blocks has also been developed. A doubly fed induction generator model, based on existing literature, has been introduced for representing wind turbine behaviour in system response studies. Validation of individual models and the complete system against historic loss events has established confidence in the method.

A review of the current system with the dynamic model showed that current primary response requirements are inadequate. The secondary response requirements generally show a slight reduction in the holding levels. Simulations including extra wind generation have shown that there is potential to reduce the primary response requirement in the future. The secondary response requirements are maintained with added wind farms.

Keywords:
Power System Control, Dynamic Simulation, Frequency Reserve, Frequency Response, Governor Modelling, UK

[†] GB Transmission System Quality and Security of Supply Standard, National Grid, 2001.

[‡] Renewable Obligations Order 2002, HMSO: London

Executive Summary

Background

The system frequency of a synchronous AC power system, such as the British transmission grid, varies with the imbalance between generation and load. To maintain system frequency at nominal, a degree of frequency responsive plant is scheduled to allow real-time adjustment of generated power. When large generating blocks are lost the system undergoes a frequency swing of a magnitude relative to the size of loss. Limits are imposed on the magnitude of frequency deviation to prevent plant damage, or in worst case, collapse of the system. Frequency responsive services to recover lost energy are offered mainly by part-load plant, and some demand side management. Part-load plant, or '*spinning reserve*', operates off design specifications, resulting in lower efficiencies, and higher emissions.

The current response requirements are derived from simulations on a simple system model, and were conducted in the 1990's. Owing to changes in generation patterns, particularly increased gas turbine usage, these values need reviewing to preserve the operational safety of the system and ensure efficient use of ancillary services. With the enactment of government legislation to increase the use of renewable generation[§] increased levels of wind turbines are expected. Additional wind farms on and around the British Isles may alter the operational characteristics of the system (primarily system inertia). Environmental implications result from added renewable generation because of an increase in the response requirement and hence emission levels.

As sufficient tests cannot easily be conducted on the real system, simulations representing the system are the key means to establish the response requirements in these cases.

Project objectives

The chief objective of this research is to develop an increased knowledge to manage the risk of frequency obligations during loss of large portions of power. In order to meet this objective several topics were identified for investigation, these include:

- Manage the risk of failure to meet frequency obligations with cost and environmental impact;

[§] Renewable Obligations Order 2002, HMSO: London

- Establish models of demand and generator behaviour;
- Modelling the demand-frequency relationship;
- Validation of existing generator models;
- Improving the response margin;
- Establish error margins for generator mix / specific plant;

These objectives arose following an internal study conducted by National Grid to review the frequency response requirements in 2003.

Contribution to knowledge

A review of a number of existing techniques to manage primary reserve requirements provided a stark contrast between large interconnected and island systems. The island systems presented, employ an optimised strategy for frequency response holding to facilitate the highest efficiency, and thus minimise waste power. A number of existing models used by system operators to define response holding levels were considered. These models generally followed a basic representation of systems, using a simplified model neglecting the transmission network. A simulation method was developed that allowed representation of the network to include system losses and geographic variations in grid frequency. Generator and load behaviour were shown to be influential factors of system dynamics during frequency transients and had already been established as parameters that warranted further investigation.

A number of investigations had been conducted in the late fifties to establish a value for the load sensitivity to frequency on the GB system, but no detailed statistical analysis is documented. A number of empirical studies have also been conducted in other countries, but it cannot be assumed that these values have any correlation with a similar British sensitivity factor. In Pearmine *et al*(2006a), the author presents a method to establish the current load-frequency sensitivity with values calculated from recorded grid data, to an international audience.

A minor but significant contribution to knowledge has occurred as a result of a significant amount of development and testing of generator models. Traditional coal fired plant models have been improved with additional functions to provide a comparable dynamic response with existing units. Also, a novel combined cycle gas turbine model has been produced. Through a set of fundamental equations and control blocks, representation of the newer gas generating stations is possible with this model, referenced in Pearmine *et al*(2006b). These fundamental generator models have been integrated together with the load model into a full transmission system.

This dynamic response model has been validated and used to assess the unique frequency response requirement for the current British grid. An additional margin is also suggested to cover for operational risks.

A doubly fed wind generator model was built 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 the changes necessary to the future response holding requirement.

Implications for practice

Simulations using the complete dynamic model showed some reduction in the primary response requirements is possible at low system demands for significant losses. However, the simulations also suggest that an increase in primary response holding is required at high system demands for abnormal losses. The secondary response requirements show an overall reduction in the holding levels. An improved margin to cover errors in the response modelling process has also been suggested.

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.

As a result of increased offshore wind turbines connected to the system, significant losses require up to 50 MW of additional primary response. The primary response holding for abnormal losses 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 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 required 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.

Conclusions

The work conducted within this research project was aimed at developing an increased knowledge to manage the risk of frequency obligations during infeed losses. Significant work is presented relating to modelling the delivery of frequency response from grid connected generators:

- A number of improvements are suggested on coal fired models to bring outputs inline with real plant;
- A novel combined cycle gas turbine model is given to represent newer responsive thermal plant;
- Models of generating plant have been validated against real events to confirm operational performance;

Work is also presented relating to modelling frequency dependence of the load:

- A methodology to establish a value for the load sensitivity to frequency on the GB system was developed;
- Empirical studies using this method have identified that a value of 2 %/Hz is sufficient in modelling the load dynamic performance;

A dynamic response model, composed of the individual generator models, load model and reduced transmission system was developed that allowed simulations of transient grid frequency. Using the response model, trials to establish the minimum frequency response requirement for the British case were conducted. The model also allowed sensitivity analysis to be performed to establish the influence for different types of responsive plant. A response margin was suggested to cater for errors in the response process and secure operational robustness.

This research has been presented in two international peer reviewed journal papers Pearmine *et al*(2006a, 2006b).

Simulation results have shown that significant reduction to the existing primary response requirements can be made at low demands for losses of 1 GW and below. Some increase is required for the primary response requirement at high demands and larger losses. The secondary requirement can be marginally reduced. With an increased wind penetration, losses of 1 GW or below require additional primary response to maintain frequency limits. However, for losses over 1 GW and up to 1320 MW the primary response holding can actually be reduced. The secondary response requirement is unchanged.

Further work

This research has identified a set of suitable models to represent generators connected to the British transmission system under low frequency events. These models have been applied to study the system response requirements in this case. However, there is significant scope to apply the developed dynamic response model to identify other operational security concerns. One potential investigation is to identify the maximum loss that can be sustained on the system before emergency load shedding is activated. The affect of part load hydro response on the response requirement has not been investigated in any detail here, and is another potential avenue of research. The influence of infeed loss location on the response requirements at present is unknown and also warrants investigation.

There is also potential to investigate greater penetrations of wind turbines on the system, or include models for frequency responsive wind turbines. In this study only a single wind turbine technology was considered, different technologies could be influential in establishing the potential reduction in primary response requirements identified.

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Contents

Volume 1.0

Abstract ii

Executive Summary iii

Acknowledgements viii

Contents x

List of Tables and Figures xiv

Abbreviations xviii

Nomenclature xx

Chapter 1, Introduction 1

1.1 New challenges 1

1.2 Motivation 3

1.3 Objectives and contributions 5

1.4 The engineering doctorate scheme 6

1.5 Outline of the thesis 7

1.6 Publications 9

1.7 Summary 10

Chapter 2, Impact of Frequency Control 11

2.1 Why use frequency control? 11

2.2 General environmental impacts of electricity networks 12

2.2.1 Environmental impact of system losses 14

2.2.2 Environmental impact of insulation materials 15

2.2.3 Environmental impact of generator emissions 17

2.3 Impacts related to response holding 20

2.3.1 Economics of response holding 21

2.3.2 Environmental impact of response holding 22

2.4 Reducing the environmental impact of response holding 25

2.5 Summary 28

Chapter 3, Current International Practises in Frequency Control 29
3.1 Great Britain 29
3.2 Denmark, Sweden, Finland and Norway.. 32
3.3 Germany 35
3.4 New Zealand.. 38
3.5 Ireland.. 40
3.6 Summary 42

Chapter 4, The System Dynamic Response to Instantaneous Infeed Loss......... 44
4.1 Introduction 44
4.2 Grid dynamics 45
4.2.1 Generator droop..46
4.2.2 Magnitude of loss 49
4.2.3 System inertia..50
4.2.4 Load sensitivity to frequency 51
4.2.5 Proportion of response..52
4.3 Techniques to model the response holding requirement 54
4.4 A solution to model frequency response on the British grid 60
4.5 The frequency response model..62
4.5 Summary 63

Chapter 5, Dynamic Generator Models for Response Studies............................ 64
5.1 Overview of types of generation on the GB grid 64
5.2 Dynamic models of thermal plant 66
5.3 Models for coal fired generators..69
5.3.1 Boiler dynamics..69
5.3.2 Steam turbine..71
5.3.3 Frequency responsive coal fired models 74
5.4 Models for combined cycle gas turbines 76
5.4.1 A CCGT and HRSG model 82
5.5 Models for hydroelectric generation 87
5.6 Validation of generator models 90

5.6.1 Modified coal fired models 90
5.6.2 New CCGT model validation..91
5.7 Summary 92

Chapter 6, Load Frequency Sensitivity in Response Studies 94
6.1 Effect of the load on system frequency 94
6.2 Existing quantifications of load sensitivity 97
6.3 Quantifying the load sensitivity to frequency 99
6.3.1 Identifying the load sensitivity to frequency from data 100
6.3.2 Inertial method of calculating load sensitivity 101
6.4 Results from measurements..102
6.5 Load-frequency sensitivity from load components 105
6.6 Potential cost savings of response holding...106
6.7 Summary 108

Chapter 7, Complete Dynamic Response Model 109
7.1 Model validation against historic events 109
7.1.1 Summary of validation events 113
7.2 Procurement of Response 113
7.3 Response requirement trials 115
7.3.1 Secondary response 116
7.3.2 Primary response 118
7.4 Error margins 119
7.4.1 Modelling inaccuracies 120
7.4.2 Margin for variation in choice of units 121
7.4.2.1 CCGT Response 122
7.4.2.2 Frequency control by demand management 123
7.4.3 Margin for system wide parameters 124
7.4.4 Margin for generators failing to supply response 127
7.4.5 Method for combining margins for different errors 128
7.5 Changes in response holding 130
7.6 Summary 132

Chapter 8, Wind Turbine Model 133
8.1 Grid connected wind turbines.. 133
8.2 Model of a wind turbine with a doubly fed induction generator........................ 137
8.2.1 Rotor model.. 138
8.2.2 Induction machine model 139
8.2.3 Pitch control 142
8.2.4 Speed control, current control and converters.................................... 142
8.2.5 Initialisation.. 143
8.3 Wind farm connections 143
8.5 Influence of wind generation on response requirement 147
8.6 Summary 149

Chapter 9. General Conclusions 151
9.1 Summary of the results.. 152
9.2 Future research 153

References 155

Journal and Conference Papers .... Appendix A

Simulation Network and parameters ....Appendix B

Volume 2.0

Six Monthly Progress Reports.. Appendix C

List of Tables and Figures

Table 1 Network Losses 15
Table 2 Contribution to frequency response in the Nordic pool 34
Table 3 Frequency control capability in Germany during 2004 38
Table 4 Variables used in the gas turbine governor model 85
Table 5 Variables used in the HRSG model 87
Table 6 Coefficients of the aerodynamic turbine model 139

Figure 1.1 Components of power system quality 3

Figure 2.1 SF_6 leakage from switch gear and GIS 15
Figure 2.2 Cable oil loss 16
Figure 2.3 CO_2 emissions to air from electricity generators 17
Figure 2.4 Emissions to air from electricity generators indexed to 1990 levels 18
Figure 2.5 Partload efficiency of conventional steam power stations 22
Figure 2.6 Partload operation of F class combined cycle gas turbines 23
Figure 2.7 Distribution of GB frequency response instructions 24
Figure 2.8 Emissions of nitrogen oxides associated with partload operation of F Class Combined Cycle Gas Turbines 24
Figure 2.9 Infeed losses and associated frequency deviations (against operating limits - OS883) 27

Figure 3.1 Generation capacity and national transmission lines of the Great Britain super grid. 30
Figure 3.2 Load duration curve showing breakdown of grid connected generation 31
Figure 3.3 Nordic generation mix and interconnector capacities 33
Figure 3.4 German system operators, generation mix and HV grid network......... 35
Figure 3.5 Frequency model provided by zones and generators within the UCTE 36
Figure 3.6 Associated delivery of response in Germany 37

Figure 3.7 New Zealand transmission grids on north and south islands 39
Figure 3.8 Irish transmission grid 41

Figure 4.1 Generation characteristic from a July morning 47
Figure 4.2 Effect of generator droop on system frequency 48
Figure 4.3 Effect of disturbance magnitude on system frequency 49
Figure 4.4 Effect of inertia on system frequency 50
Figure 4.5 Effect of load sensitivity on system frequency 51
Figure 4.6 Generator response to applied test frequency injection signal 52
Figure 4.7 Example generator response profile curve 53
Figure 4.8 Transient phenomena 55
Figure 4.9 New Zealand, south island dynamic model 56
Figure 4.10 New Zealand, north island dynamic model 56
Figure 4.11 Irish dynamic model 57
Figure 4.12 System transfer function 58
Figure 4.13 Impact of location on grid frequency 59

Figure 5.1 GB generation capacity by fuel types 64
Figure 5.2 Changes in GB generation 2004 to 2012 65
Figure 5.3 Block diagram of generator control system 67
Figure 5.4 Governor transfer function 68
Figure 5.5 Typical steam boiler arrangements used in power stations 70
Figure 5.6 Dynamic behaviour of steam boiler controls 71
Figure 5.7 Model for influence of steam boiler on plant response 71
Figure 5.8 Non-reheat steam turbine 72
Figure 5.9 Single reheat steam turbine 72
Figure 5.10 Double reheat steam turbine 73
Figure 5.11 Simple steam turbine models 73
Figure 5.12 Generic steam turbine model 74
Figure 5.13 Modification to coal governor to allow frequency triggered rate-limit 75
Figure 5.14 Modification to coal governor to allow an output-limit 76
Figure 5.15 Diagram of a simple gas turbine 77
Figure 5.16 Single shaft tandem plant configuration 77

Figure 5.17 Multi-shaft plant configuration 78
Figure 5.18 Open cycle gas turbine model 79
Figure 5.19 Frequency response of a CCGT gas turbine module during an actual incident and the simulated response using OCGT representation 80
Figure 5.20 Exhaust temperature, IGV position and fuel valve position of a number of combined cycle gas turbines 81
Figure 5.21 CCGT model 84
Figure 5.22 HRSG model 86
Figure 5.23 Hydroelectric turbine arrangement 88
Figure 5.24 Dinorwig hydroelectric pumped storage facility 88
Figure 5.25 Hydroelectric turbine model 89
Figure 5.26 Conversion to standard governor model 89
Figure 5.27 Frequency response of a rate-limited generator during an actual incident and the simulated response 90
Figure 5.28 Frequency response of an output-limited generator during an actual incident and the simulated response 91
Figure 5.29 Validation of a combined cycle gas turbine governor model at 60 percent load 92

Figure 6.1 Dynamics of a power imbalance 95
Figure 6.2 Power-frequency effects of motor and non-motor loads 96
Figure 6.3 Generator loss under constant load conditions 101
Figure 6.4 Generator loss under unclear load conditions 101
Figure 6.5 Assumed network response used in the calculation of load sensitivity 102
Figure 6.6 Typical daily variation of measured load sensitivity 103
Figure 6.7 Annual variation of load sensitivity to frequency, months of April 2004 to June 2005 104
Figure 6.8 Magnitude of generator loss against load-sensitivity during April 2004 to June 2005 104
Figure 6.9 Distribution of load sensitivity to frequency 105
Figure 6.10 Electricity demand by sector, 2004 105

Figure 6.11 Changes in response holding when considering a 0.5% increase in load sensitivity against a 1320MW loss 106

Figure 7.1 Simulated 1260 MW loss from 26/05/03 110
Figure 7.2 Simulated 1000 MW loss from 02/12/05 111
Figure 7.3 Simulated 790MW loss from 21/01/06 112
Figure 7.4 Frequency transients for significant and abnormal losses................... 115
Figure 7.5 Response requirements abnormal losses 116
Figure 7.6 Secondary response requirements for all losses.................................. 118
Figure 7.7 Primary response requirements for significant losses 119
Figure 7.8 Primary response requirements for abnormal losses........................... 119
Figure 7.9 Differences in response requirements for CCGT plant....................... 122
Figure 7.10 Differences in response requirements for demand management 123
Figure 7.11 Differences in response requirements for alternate start frequencies (three standard deviations).. 125
Figure 7.12 Differences in response requirements for alternate start frequencies (two standard deviations) 125
Figure 7.13 Differences in response requirements for a minimum load sensitivity to frequency factor 126
Figure 7.14 Secondary Response Requirement (including margin)...................... 129
Figure 7.15 Primary response requirement (including margin) for abnormal losses 129
Figure 7.16 Primary response requirement (including margin) for significant losses 130
Figure 7.17 Changes in primary response requirements (without margin) 130
Figure 7.18 Changes in secondary response requirements with margin 131
Figure 7.19 Changes in primary response requirements with margin 132

Figure 8.1 Installed capacity of wind turbines by type... 134
Figure 8.2 Variable speed wind turbine model.. 137
Figure 8.3 The direct-quadrature reference frame 140
Figure 8.4 Model reference frame 140
Figure 8.5 Block diagram of pitch controller 142

Figure 8.6 Greater Wash off-shore wind farms 144
Figure 8.7 North West off-shore wind farms 145
Figure 8.8 Thames Estuary off-shore wind farms 146
Figure 8.9 Changes in primary response requirements 147
Figure 8.10 Changes in secondary response requirements 148

List of Abbreviations

AC	Alternating Current
ACE	Area Control Error
ACS	Average Cold Spell
AGR	Advanced Gas-cooled Reactors
AVR	Automatic Voltage Regulator
BMU	Balancing Mechanism Unit
BOA	Bid Offer Acceptance
BWEA	British Wind Energy Association
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CIGRE	Conseil International des Grands Réseaux Électriques (International Council on Large Electric Systems)
CO_2	Carbon Dioxide
DC	Direct Current
DFIG	Doubly Fed Induction Generator
DTI	Department of Trade and Industry
EMF	Electro-Magnetic Field
EngD	Engineering Doctorate
EPRI	Electric Power Research Institute
EPSRC	Engineering and Physical Science Research Council
ESBNG	Electricity Supply Board National Grid (Republic of Ireland)
EWEA	European Wind Energy Association
GB	Great Britain
GHG	Green House Gas
GIS	Gas Insulated Substations
GSP	Grid Supply Point
GW	Gigawatt
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HV	High Voltage
HZ	Hertz
IEE	Institute of Electrical Engineers(Great Britain)
IEEE	Institute of Electrical and Electronics Engineers(America)
IGV	Inlet Guide Vanes
IP	Intermediate Pressure
kV	Kilovolt

LF	Low Frequency
LP	Low Pressure
MVA	Megavolt Amperes
MW	Megawatt
NEMMCO	National Electricity Market Management Company Limited
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NI	Northern Ireland
NIE	Northern Ireland Electricity
NO_x	Nitrous Oxides
OCGT	Open Cycle Gas Turbine
PhD	Doctor of Philosophy
PLR	Part Load Response
PM_{10}	Particulate Matter 10μM (or less)
PWR	Pressurised Water Reactors
RASM	Rotor Angle and Machine Stability
ROC	Renewable Obligation Certificates
SEI	Sustainable Energy Ireland
SF6	Sulphur Hexafluoride
SO	System Owner
SO_2	Sulphur Dioxide
SONI	System Operators Northern Ireland
SO_x	Sulphur Oxides
TSO	Transmission System Operator
TWh	Terawatt hour
UCTE	Union for the Coordination of Transmission of Electricity
UK	United Kingdom
VDN	Verband der Netzbetreiber
VHP	Very High Pressure
XLPE	Cross-Linked PolyEthylene

Nomenclature

Chapter 3

ACE	area control error
ΔP	deviation between measured and planned interchange
P_{actual}	measured interchange
$P_{planned}$	planned interchange
Δf	frequency deviation from nominal
β	frequency response requirement
P_{Lmax}	maximum expected system load
P_{sec}	secondary control level

Chapter 4

ω	angular rotation
J	inertia
τ_M	mechanical driving torque
τ_E	electrical torque
H	inertia constant
P_M	mechanical power
P_E	electrical power
P_L	system demand
P_G	system generation levels
Δf	deviation in frequency
f_0	nominal frequency
P_{Loss}	generation loss
K_{resp}	proportion of responsive plant
ρ	governor droop
K_L	load sensitivity to frequency

Chapter 5

ρ_G	speed droop characteristic
f_{nl}	frequency at no load
f_{fl}	frequency at full load
f_0	base frequency
K_g	1/Droop
T_{sr}	Time constant
T_{sm}	Servo time constant
$L_{r1,2}$	rate limit
$L_{p1,2}$	position limit
T_{Boiler}	boiler time constant
P_{gov}	governor power
P_{boiler}	boiler power
T_{CH}	Steam Chest delay

$k_{1\text{-}4}$ Turbine fraction
$T_{1\text{-}3}$ Reheater/Crossover time constant
P_M Output Torque
T_a Atmospheric Air temperature
Cpr Rated pressure ratio
T_d discharge temperature
W_a airflow
η_c isentropic efficiency of the compressor
γ ratio of specific heats
T_f combustion firing temperature
W_f fuel flow
T_{fr} rated firing temperature
T_{dr} discharge temperature
T_e exhaust temperature
η_t isentropic efficiency of the turbine
W water flow rate
H water head height
g acceleration due to gravity
ρ_w density of water
T_W water time constant
$\Delta\omega_{pu}$ per unit change in frequency
$\Delta\omega_{hz}$ change in frequency (in Hertz)

Chapter 6

K_L load-frequency characteristic
ΔP_L change in load
Δf frequency deviation
f_0 nominal frequency
P_L total system demand
P_T system generation
ΔP_T change in system generation
P_{Loss} loss of generation
P_{FCDM} frequency control by demand management
H system inertia
ΔP imbalance between load and generation

Chapter 7

M_U margin for unit modelling
λ_U error for unit modelling
M_V margin for choice of units
λ_V error for choice of units
M_f margin for starting frequency
F_{start} starting frequency
$F_{max,sec}$ frequency limits under secondary response
D_{GB} British system demand
R_{sec} secondary response

K_L load sensitivity to frequency
Risk potential loss of generation
M_D margin for load response
λ_D error for load response
M_G margin for failed response
λ_G error for failed response

Chapter 8

β blade pitch angle
C_p coefficient of performance
v wind speed
ρ_{air} air density
P_w power extracted from the wind
λ tip-speed ratio
ω_{turb} turbine hub rotational speed
H_{turb} turbine inertia
T_{shaft} torsion held in the drive shaft
ω_s rotational speed of the reference frame
ω_{gen} mechanical speed of the rotor
u_{sd} stator voltage (direct component)
u_{sq} stator voltage (quadrature component)
u_{rd} rotor voltage (direct component)
u_{rq} rotor voltage (quadrature component)
r_r rotor resistance
r_s stator resistance
i_{sd} stator current (direct component)
i_{sq} stator current (quadrature component)
i_{rd} rotor current (direct component)
i_{rq} rotor current (quadrature component)
Ψ_{sd} stator flux (direct component)
Ψ_{sq} stator flux (quadrature component)
Ψ_{rd} rotor flux (direct component)
Ψ_{rq} rotor flux (quadrature component)
x_{mq} mutual reactance(quadrature component)
x_{md} mutual reactance (direct component)
x_{sd} stator reactance (direct component)
x_{sq} stator reactance (quadrature component)
x_{rd} rotor reactance (direct component)
x_{rq} rotor reactance (quadrature component)
T_e electromechanical torque
H_{gen} generator inertia
ω_{max} maximum speed of the rotor

Chapter 1

Introduction

Chapter 1 is structure as follows: A brief overview of the current energy sector is given with regards to generation and transmission. The motivation for this research is also highlighted. The aims of the project are discussed, together with the delivered contribution to knowledge. A summary of the remaining document is also provided together with a list of publications.

1.1 New challenges

The UK energy sector has seen a great many changes over the last decade, and the power industry is finding this change to be ongoing. After privatization of the England and Wales power system in 1991, the system was divided to form separate generating and distribution energy companies, as well as a transmission system operator (National Grid Company, NGC). This action was followed in 1997 by the beginnings of liberalisation for electricity markets through NETA, completed in 2001. Consequently, there has been a decrease in the overall rates of network investment. Privatisation has seen a demand for higher profitability, and as a direct result operators are demanding more from their assets.

A steadily increasing network demand on the system is pushing it to its operational limit. Installing new equipment and lines would alleviate this problem. However, this only occurs if it is seen to be profitable or would cause undue risk to the system otherwise. With a ten year lead time to gain planning permission and get consent for new lines, the system is slow to develop to the present needs of customers. Furthermore, environmental issues in relation to the emissions and the location of new generation will limit the construction of new plant, and the expansion of the transmission network. Even with forward thinking, it is difficult to predict forthcoming trends with any accuracy. By optimizing the available resources it is possible, to some degree, to gain the required transfers as a short-term fix but this is always at a compromise to the reliability of the system.

The UK generation patterns over the last decade have changed dramatically, traditional coal burning units have been gradually replaced by combined cycle gas turbines during the so-called “dash for gas” in the eighties. While these units offer highly efficient operating cycles and are also quick to construct, the net effect has changed the operation of the UK gas industry. Britain has now changed its position from being a net exporter of natural gas to a net importer. With security concerns over European gas lines and a high percentage of CCGT generation, we may well see this security of supply issue transferring to the electricity providers. A number of the nuclear power stations are also due for decommission in the next few years and this is also a cause for concern. These stations provide base load for the system offering a clean energy source without the associated emissions of fossil fuels.

With the governments target to minimise carbon dioxide emissions to meet Kyoto levels a large proportion of renewable generation has been incentivised. National Grid has received applications for the connection of some 18GW of wind farms in Scotland. The predicament has arisen because of the advantageous wind speeds in the north. With a peak demand of 6GW, and an interconnector capacity of only 2.2GW, this leaves around 10GW of generation that cannot be exported at present, not including existing plant. The affect of these changes in generation patterns will undoubtedly affect the power flows around the country, adding to congestion.

The drive for renewables has also influenced the levels of distributed generation (solar panels, wind power, fuel cells, micro gas turbines, etc.) installed. These technologies offer the elimination of transmission and distribution line losses and are seen as a cost-effective source of peak demand power. If their growth continues, they will pose a problem to system operation through short term balancing, due to a low degree of transparency being hidden in the distribution levels.

The liberalisation of the balancing market is the latest shake up to the energy system in the UK. Since its onset in early 2006, step rises in prices have been seen in both energy bids and offers. This cost of system balancing is passed through to connection parties that are out of balance with the system. In reality all this means is that customers will pay a higher price for less predictable demands.

1.2 Motivation

Power systems must deliver to customers at grid supply points, electrical power that conforms to high standards of quality. This power quality can be broken down into three main areas of interest as depicted in Figure 1.1. Interruptions are rare in secure systems that typically operate under the (n - 1) criterion and incidents can usually be attributed to random events and unforeseen circumstances. Most system operators extensively scrutinize voltage issues relating to reactive power control through reactive compensation, installation of filtering equipment and carrying out transient stability studies.

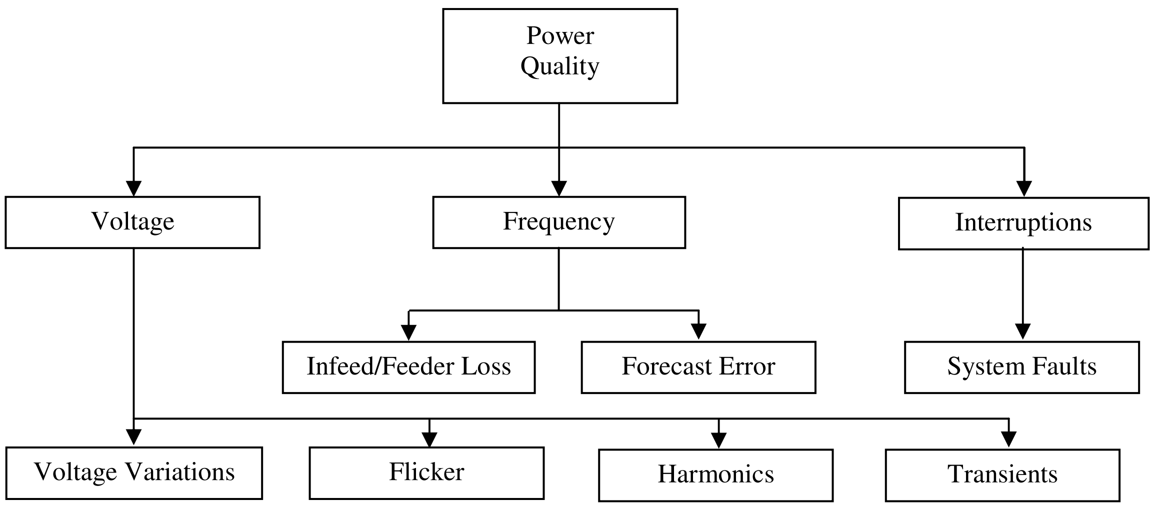


Figure 1.1 – Components of power system quality

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 this frequency deviation to prevent, in worst case, collapse of the system.

Before the introduction of the balancing mechanism all generating plant on the system provided free governor action, so output powers constantly varied relative to system frequency. This often resulted in over provision of balancing power to match system demands. Under market conditions there is a more focussed approach to frequency dispatch with some optimisation. This has resulted in fewer units being selected for frequency response thus improving the overall efficiency of the system. The aim of this research is to develop an increased knowledge to manage the risk of frequency obligations during the loss of large portions of power.

World-wide very limited studies have been conducted in the area of frequency response, especially in recent years. 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. Established working practices in smaller systems are supported through operator confidence in those networks, where system collapse due to severe frequency fluctuations has never transpired. Island systems such as the one operating in Britain are more sensitive to the imbalance between generated and consumed power.

The levels of flexible generation and demand held to provide frequency support services in the British transmission system was last considered in detail by National Grid in 1995. These figures now relate to a somewhat dated system and do not extend to foreseeable system characteristics of the future (such as, a growth in demand, and change in generation mix). In conjunction with these shortcomings the review of frequency response holding levels was conducted on a very basic representation of the system dynamics.

It has been suggested that effects from additional wind generation will include reduced system inertia, and thus impact heavily on system frequency during large infeed losses. It is critical to develop a tool that will assess the impacts of these changes and facilitate the production of a revised set of operational requirements to secure the system. National Grid is also obligated under the Transmission Licence to operate the system in an economic and efficient manner, and therefore is keen to support improvements to its internal processes.

With the balancing market liberalised, there is also a growing requirement to optimise the response held on the system in order to reduce the financial impacts of what may become a more volatile market.

1.3 Objectives and contributions

The overall objective of this work is to provide a process enabling the optimisation of the response requirements so that the minimum level of response holding can be used while maintaining statutory limits on frequency deviation. The thesis mainly deals with modelling the dynamic nature of grid frequency during large instantaneous losses of power. The focus is on the identification of the models and parameters that describe the generator performance, and an active load model. Validation of the complete system model against actual loss events will be required to provide any confidence in the method.

Of particular relevance with regards to contribution to knowledge is the quantification of the load-frequency sensitivity on the British electricity grid. A number of investigations have been conducted in the sixties to establish a value for this parameter on the GB system, but no detailed statistical analysis is documented. A number of empirical studies have also been conducted in other countries but it does not hold that these values have any correlation with a similar British sensitivity factor. In Pearmine *et al*(2006a) the current load frequency sensitivity has been presented from recorded grid data with updated values in chapter 6 of this thesis.

A significant amount of development and testing of generator models has also been undertaken to represent the behaviour of grid connected generators during large frequency transients. Traditional coal fired plant models have been improved with additional functions to provide a comparable dynamic response with existing units. A novel combined cycle gas turbine model has also been produced. Through a set of fundamental equations and control blocks, representation of the newer gas generating stations is possible with this model, Pearmine *et al*(2006b).

These fundamental generator models have been integrated together with the load model into a full transmission system. This dynamic response model has been validated and used to assess the unique frequency response requirement for the current British grid. In conjunction with the individual models further contribution to knowledge has also been provided through the implementation of the full dynamic model specific to the British transmission system. This dynamic model has allowed the production of a set of specific requirements curves to secure the GB transmission system against infeed losses.

A further objective to assess the level of response holding required to secure the system with an increasing proportion of renewable generation has also been met. It is now widely accepted that wind generation will be the most economic and technically feasible source of renewable power to meet UK targets. Further studies have been conducted to assess the influence of future wind turbine installations on the frequency response requirement. A doubly fed induction generator model has been introduced for representing wind turbine behaviour in system response studies. Simulations with this wind model have shown that as the levels of wind turbines increase there may be a need to adjust the response holding requirement.

1.4 The engineering doctorate scheme

An Engineering Doctorate is a four year research degree. Unlike the more traditional theoretical PhD based research, an EngD offers the chance to examine a practical solution to an existing problem. The majority of research is conducted at a sponsor organisation and as such offers a great deal of industrial experience. The sponsor has a direct interest in the study material, and as a result the research becomes more focussed. The project is managed to set timescales with the delivery of set objectives to ensure completion of the project to industrial and academic requirements. These objectives and the project progress are discussed in detail in the additional six monthly reports, Appendix C.

The Brunel/Surrey EngD centre sets their projects in the context of Environmental Technology. As such any project must visibly show an environmental theme. Along with the research matter, a number of taught modules are included to develop students on a professional and technical level. These modules also help to support the student in application to chartered organisations. The chief objective of the scheme is to train graduates for their future careers.

This project is supported by National Grid with the majority of work conducted at the main control centre near Sindlesham.

1.5 Outline of the thesis

Introduction (Chapter 1)

The introduction sets an overview of the UK electricity industry with a description of the motivations of the work described in this thesis. The overall contribution to knowledge is highlighted together with a list of publications produced from the research.

Environmental Impact of Frequency Control (Chapter 2)

Chapter two details some of general environmental impacts caused by electricity networks. The direct implications of frequency control on the environment are also considered with an aim to set an objective for reducing the environment implications.

Current International Practises in Frequency Control (Chapter 3)

In order to assess the suitability of the current methodology used to schedule frequency response in Great Britain we must consider some alternate techniques. This chapter describes operational methods employed in a cross-section of different countries to limit frequency variations. The current technique employed in the British Isles is shown to be appropriately robust.

The System Dynamic Response to Instantaneous Infeed Loss (Chapter 4)

The system dynamics that affect the grid frequency response are a direct result of a number of interacting factors. These factors are considered in chapter four through a number of simulations to demonstrate the relative impact in each case. Current techniques to model the response holding requirement are considered from a number of different sources. A proposed solution to model the response requirement is suggested, which draws from the notions put forward in this chapter.

Dynamic Generator Models for Response Studies (Chapter 5)

An overview of types of generation currently in operation on the British transmission grid is given in chapter five. Following from chapter four, existing models that can be integrated in frequency response studies are discussed. Through validation against real events these traditional models are criticised. A number of appropriate improvements are suggested bringing the models inline with the real case. A novel gas turbine model is also developed to simulate the response provided by combined cycle units.

Load Frequency Sensitivity in Response Studies (Chapter 6)

To complete the chosen dynamic model for response studies, the influence of the load-frequency response in Britain is investigated. A brief synopsis of the characteristic is given, and existing literature discussed. Analysis of system data is used to quantify a value for load sensitivity that can then be used in the overall model. Two further techniques are used to increase confidence in this value.

Complete Dynamic Response Model (Chapter 7)

A complete dynamic response model, consisting of models developed in chapters five and six, is used to replicate several real events. Following satisfactory results, a number of trials are conducted to assess the primary and secondary response holding requirement. Sensitivity analysis is conducted to provide an additional margin to ensure adequate provision of response for the operational case.

Wind Turbine model (Chapter 8)

To assess the impact of future renewables on the frequency response requirement a wind turbine model is proposed. The model is composed from existing literature sources and added to the dynamic response model. Plans for current viable offshore wind generation sites are considered with an increase of 8.5 GW in wind capacity. Response trials are repeated incorporating these wind farms to produce a set of updated response holding curves.

General Conclusions (Chapter 9)

The main conclusions are drawn from this research and suggestions for future work discussed.

1.6 Publications

Some results of this thesis have already been published in the double peer reviewed publications below and are included in Appendix A. The results in [1] are discussed in more detail in Chapter 5. The main results in Chapter 6 are described in [2]. It is hoped that a further paper will be submitted to the IEE to include the influence of added wind penetration [3] as described in Chapter 7.

Reviewed Papers

1. Pearmine, R.S., Song, Y.H., Chebbo, A. and Williams, T.G., 'Identification of a load-frequency characteristic for allocation of spinning reserves on the British electricity grid'
   IEE Proceedings Generation Transmission and Distribution, Issue 6, Nov 2006., pg 633-638.
2. Pearmine, R.S., Song, Y.H. and Chebbo, A., 'Experiences modelling the performance of generating plant for frequency response studies on the British transmission grid'
   Electrical Power Systems Research, Accepted for publication.

Planned Papers

3. Pearmine, R.S., Song, Y.H. and Chebbo, A., 'Effects of increased levels of wind penetration on the GB frequency response requirement' to be submitted to IEE Proceedings Generation Transmission and Distribution

Conferences

4. Pearmine, R.S., Song, Y.H., Bell, K.R.W. and Williams, T.G, 'Wind power and the UK electricity grid', Engineering Doctorate Annual Conference, University of Surrey, 2005.

1.7 Summary

The current energy sector is a highly developed and continually changing entity. Historically, energy sources have moved from traditional coal fired machines to be replaced by gas turbines. While nuclear power is still very much in debate as a clean alternative to fossil fuels, wind farms will certainly form a significant power source in the coming decade.

With such a variable system, studies into effects of these new generation mixes are needed to prepare the system operator in advance. The research presented in this thesis has been supported by the National Grid. It deals with the dynamic modelling of grid frequency; with attention to increasing levels of renewable generation. The main objective is to formulate the level of response holding required to ensure that the system is managed within operational limits.

Chapter 2

Impact of Frequency Control

Chapter 2 indicates a number of environmental problems experienced through the electricity supply industry. A number of general impacts are highlighted together with more specific examples pertaining to frequency response holding. A number of examples are identified that would help reduce the impact of response holding on the environment. The optimisation of response holding levels in this research is justified to reduce the environmental impacts of response holding.

2.1 Why use frequency control?

Frequency control is provided on the British transmission system by part-loaded generators acting under governor action, and frequency triggered load shedding schemes. The action of both services is automatic in relation to the system frequency, Hung *et al.*(1999). To maintain a healthy and stable system frequency generation must match the instantaneous changes in demand.

A stable system frequency is required for many industrial processes that rely on the grid frequency for timing. Any process that uses synchronous motors to control motion is influenced by grid frequency. As a result if frequency falls, so too will motor speed. Ultimately, a production line would suffer from a small, but may be critical reduction in throughput. A further example that is not so common in this digital age is the use of synchronous clocks. These timing devices rely on a constant 50 Hz supply frequency to maintain accuracy. As a result National Grid is still obliged to maintain a clock error of no more than 10 seconds, National Grid(2006a). Lastly, National Grid is also dedicated to becoming the world’s premier network utility, as highlighted in its 2006 Annual Report. With this vision in mind the ethos is to maintain a high standard of network operation, which in terms of frequency control means a stable and predicable supply.

For these reasons the system frequency on the British transmission grid is limited to a narrow operating band of between 49.8 and 50.2 Hz under normal conditions. The extended limits under fault conditions detailed later in the document are established to limit the damage to grid connected plant, such as generators, under exceptional conditions.

2.2 General environmental impacts of electricity networks

The most common environmental impacts related to transmission power lines can be categorised into a number of specific examples. These include effects on existing land use, which can impact land value, damage ecologically sensitive sites or simply interfere with existing local operations. In remote areas improved access for humans and wildlife can be considered a positive effect of transmission power lines as rights of way. As a direct result of pylon construction local areas may also suffer from increased erosion or even interference with local drainage patterns.

Visual intrusion on the landscape is another key impact particularly of over head lines. Large structures such as pylons and wind turbines are inevitably visually intrusive. The complete electricity network in the British Isles, including distribution and transmission systems, consists of around 5% pylons, 36% wood poles and 59% as underground cabling. The aesthetic impact of overhead lines is minimised where possible by using the natural contours of the landscape, and following existing infrastructure, such as motorways.

However, in some situations where routes breach areas of outstanding natural beauty undergrounding of lines is the only possible alternative. At the higher voltages, installing cables underground can be up to twenty times as expensive as overhead lines, with potentially more damaging results to the local ecology.

In order to maintain extra high voltage lines sufficient clearance between lines and earth must be preserved to prevent flashover. This requires stringent vegetation management along the transmission corridor. This can disrupt local flora and fauna populations. The same problem is experienced at distribution voltages but at a much reduced risk. In some cases this type of action can be beneficial to some wildlife species if vegetation control is properly managed.

A more obvious result of electrification is hazard of electrical shock and strike to birds or other wildlife. Human risk is dramatically reduced through raised awareness of danger, and boundary restrictions. Risk is minimised wherever possible for wildlife. For example at the nesting sites for large waterfowl, overhead lines are equipped with large visible balloons on the earth conductor to prevent entanglement. Overhead line towers are sometimes even adopted by birds as convenient structures upon which to roost, often in significant numbers. If bird fouling is a problem a number of methods to dissuade birds from roosting on towers may be used.

A further impact to the local environment is the impact from acoustic noise with particular reference to supergrid transformers. Transformer hum from high rated equipment can be significant. Abatement thorough unit enclosure and sound proofing is usually an affective deterrent. Overhead lines also create some noise in certain circumstances, such as when minor surface damage, dirt or some weather conditions can cause the lines to crackle or hum slightly. The noise is produced as a result of corona discharge, but overhead lines are designed to minimise this effect under normal operation. However, if any noise is produced, the system operator is obliged to kept emissions within statutory limits.

Potential localised human health problems resulting from electric and magnetic fields (EMFs) is of significant concern to the general public. Many research studies have looked for connections between EMF exposure and disease. Some have suggested the presence of a statistical association but overall the weight of evidence is against EMFs causing disease. In 2001, the Advisory Group on Non-Ionizing Radiation of the National Radiological Protection Board reviewed all the scientific evidence on EMFs and cancer and concluded: "for the vast majority of children in the UK there is now considerable evidence that the EMFs levels to which they are exposed do not increase the risk of leukaemia or other malignant disease."

For adults, the report concluded that no link was established between EMFs and leukaemia or brain tumours. However, they also noted that: “the possibility remains that intense and prolonged exposures to magnetic fields can increase the risk of leukaemia in children” but “the epidemiological evidence is currently not strong enough to justify a firm conclusion that such fields cause leukaemia in children.”

Most of the environmental impacts discussed are highly subjective and cannot be quantified by any direct measure. Methods to quantify these impacts through environmental impact assessments have been developed, and are broadly accepted in the academic community. Nevertheless, in the context of this study matter, these impacts will always be apparent in the existing system and will not be considered in any further detail.

2.2.1 Environmental impact of system losses

The British transmission grid is composed of some 23,300 km of transmission lines that are each composed of a resistive element. According to Ohm’s Law the power consumed by these elements will be a function of the current flowing through the lines. As this power heats conductors and is not utilised for any constructive function, it is deemed as a system loss. By its very nature the power system is designed to transport current to demand centres and ultimately, this means that the reduction in system losses is a finite quantity on any high voltage transmission grid.

Generators contribute to these losses as they produce the 400 TWh of energy transported around the country annually, and around 5.56 TWh[**] of this energy is lost from the system. The total system loss equates to the emission of some 2.4 million tonnes of CO_2 based on grid averaged emissions from generators. While the system operator will endeavour to operate the system as efficiently as possible, it is unavoidable that the system will suffer from losses. An incentives scheme, operated by the regulator in the UK, further motivates the system operator to minimise system losses. A breakdown for the projected losses at peak demand for 2005/06 is given in Table 1; these losses signify around 2.3% of the total peak demand.

[**] National Grid - Integrated Energy Management System

Power Loss	**2005/06**
Transmission Heating Losses excluding GSP Transformers (MW)	857.8
Fixed Losses (MW)	266
GSP Transformer Heating Losses (MW)	142.4
Generator Transformer Heating Losses (MW)	157.3
Total Losses (MW)	1423.5
ACS Peak Demand (MW)	62100
Total %	2.2923

Table 1 - Network Losses [National Grid Seven Year Statement (2006)]

These losses can be split into two subcategories, variable and fixed losses. The fixed losses include corona losses due to discharge around high electrical stress components. Super-grid transformers also suffer fixed losses from hysteresis and eddy currents through magnetisation, this leads to so-called iron losses. The variable losses relate to the current flowing through the circuit or transformer windings as discussed previously causing the inevitable heating of network components, and are sometimes referred to as copper losses.

2.2.2 Environmental impact of insulation materials

The extra high voltages of the transmission system used by generators to transport power, requires adequate clearance of transmission components from earth to prevent faults. This can be achieved through sufficient air gaps as seen in overhead lines or the use of highly insulative materials.

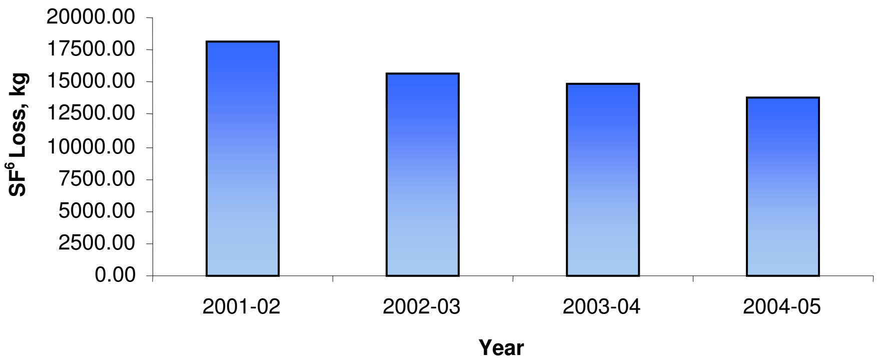


Figure 2.1 - SF6 leakage from switch gear and GIS [NGT environmental report]

Sulphur hexafluoride (SF_6) is an extremely effective electrical insulant and has been adopted for use in the high voltage applications as it offers significant advantages over alternative materials. It is inert, non-flammable, and because of its effectiveness, takes up less volume than an equivalent insulate. SF_6 is used in contact breaker equipment, and at a number of gas insulated substations (GIS). As with any pressurized medium, equipment filled with SF_6 is liable to leak.

SF_6 is a highly damaging greenhouse gas and has an equivalent global warming effect of approximately 23,900 times[††] compared to carbon dioxide. Figure 2.1 shows the levels of gas lost in past years, with the emissions from 2005 totaling approximatly 0.3 millions tonnes equavalent of CO_2. In order to minimise the high impacts of SF_6 as an insulating medium National Grid planning policy gives a preference to air insulated substations, unless space is a critical issue and only a GIS arrangement will suffice. A number of alternative breaker types are also being considered for future operations, Falkingham(2006). Through use of performance targets gas loss as a percentage of inventories has reduced steadily to 4.1% in 2004/05.

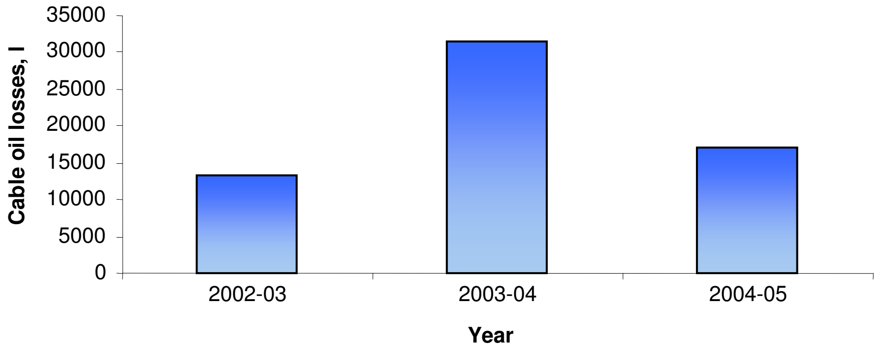


Figure 2.2 - Cable oil loss[NGT environmental report]

In conjunction with gas insulated equipment, a number of mature oil insulated cable circuits also suffer from leakage due to corrosion or impact damage. Similar oil leakage in transformer equipment is usually contained by surrounding concrete bunding, enabling recovery and reprocessing of any lost oil. With many cable

[††] DEFRA

circuits from the sixties reaching the end of service life the asset replacement strategy has seen a move from traditional oil filled types to XLPE insulation on environmental grounds, Evens(2000).

While the loss of cable oil does not contribute directly to global warming, it does posses a significant environmental impact if it cannot be recovered. Figure 2.2 shows the discharge levels of oil in recent years, it reveals a somewhat erratic trend in the volumes lost, attributed to differences in cable designs and cyclic loading.

2.2.3 Environmental impact of generator emissions

Perhaps of more direct significance to the scope of this research are the levels of emissions produced from the combustion on fossil fuels as primary energy sources in thermal generating stations. The chief greenhouse gas produced from traditional power stations in any great quantity is carbon dioxide. The latest Statistics from the Environment Agency show a decreasing trend in the levels of CO_2 emissions since 1990. This is due to the cleaner burn produced by natural gas fired units. The current estimates for emissions by the energy sector are around 176 million tonnes of CO_2, Figure 2.3. The majority of this discharge being attributed to coal fired generating stations.

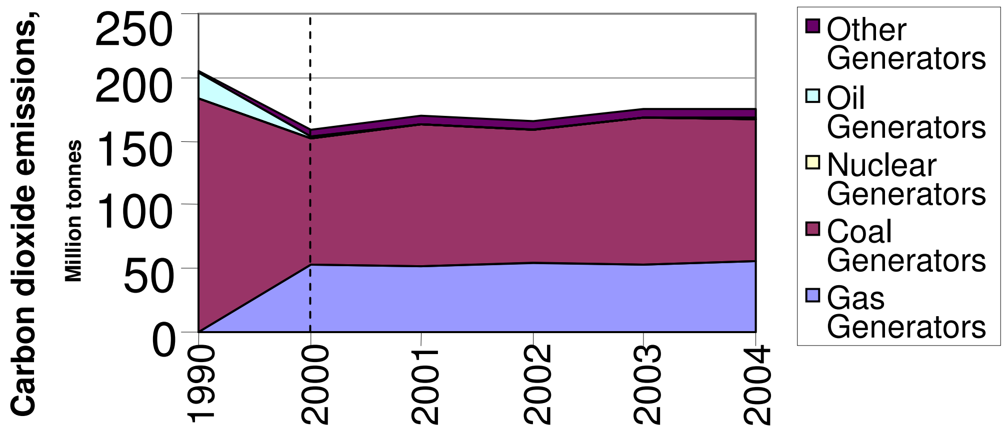


Figure 2.3 – CO_2 emissions to air from electricity generators‡‡

‡‡ Data from 2000-2004 period sourced from DEFRA, 1990-1999 sourced from National Statistics

Along with greenhouse gases fossil fuelled power stations also produce significant levels of both nitrogen oxides and sulphur oxides. These gases combine with moisture in the atmosphere to form acid rain. Prevailing wind conditions often mean that the damaging effects of acid rain are not directly experienced by the source. The bulk of the UK emissions contributed to the environmental problems experienced in Scandinavia (acid lakes and deforestation). Current discharge of NO_x and SO_2 emissions to air for the power generation sector are estimated by government bodies, Figure 2.4.

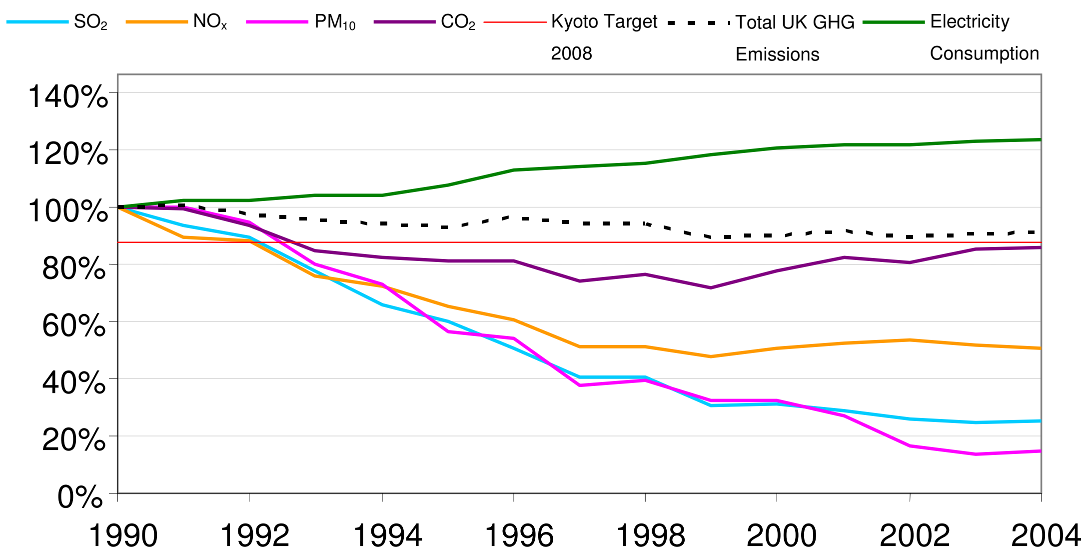


Figure 2.4 – Emissions to air from electricity generators indexed to 1990 levels[‡‡]

As part of the Kyoto agreement, the UK entered a commitment to reduce the levels of greenhouse emissions produced between 2008 and 2012 to below 87.5 % of 1990 levels. With the electricity generators constituting around twenty-eight percent of the total CO_2 emissions share, it was a sensible proposal by UK government to concentrate effort on reducing atmospheric pollution from fossil fuelled generation. The sector has performed well to date with an overall reduction in greenhouse gases (GHG) up until 1999, despite increased electricity consumption. This has mainly been facilitated by the move from coal to natural gas as a fuel source.

There are four main avenues that can be used to achieve a reduction in CO_2 emission levels for electricity generators as identified by Boyle(1990):

1. reducing the need for any type of fuel through a range of energy efficient technologies and techniques
2. Switching to less-carbon intensive fuels
3. Switching from fossil fuels to non-carbon fuels
4. Removing CO2 from flue-gas emissions

These points can each be actively demonstrated through the use of existing examples of technology or policy. Ignoring demand side measures, new generations of power stations are becoming increasingly more efficient as technologies adapt and grow. Since the advent of the steam turbine thermal efficiencies have grown to 40 % with targets of 50 % reachable. The use of natural gas to fuel combined cycle plant push this limit further to 60 %.

The use of renewable technologies as direct replacement for fossil fuel plant is, clearly, the most easily implemented and effective procedure to liberate customers from the CO_2 producing power stations. The introduction of the Renewable Obligation Order in 2002 by UK Parliament was designed to reduce the levels of CO_2 production related to electricity generators. It required large demand sites to obtain a proportion of their metered electricity consumption from renewable sources. In parallel Renewable Obligation Certificates, or ROCs, as they became known helped to incentivise the building of new renewable generation sites, mainly wind turbines.

An alternative fuel source to renewables and fossil fuels that should also be considered is that of nuclear fission. These plants offer clean energy with no direct emissions from power stations. There currently exist some twelve operational nuclear plants in Britain. These sites operate a range of mature technologies including pressurised water reactors (PWR), Magnox and advanced gas cooled reactors (AGR). Over the next few years a number of these sites will be closed; Sizewell A and Dungeness A in 2006, Oldbury and Dungeness B in 2008, and Wylfa in 2010. This will leave a large generating deficit that will need to be filled with new non-fossil sources if the current emission levels are to be maintained. There is still much debate at the present time if new nuclear plants are the best option, and some critics favour replacement by renewables.

A number of coal fired stations Drax, Didcot and Tilbury among others, addressed point two by adopting the joint burning of a more environmentally sustainable fuel mix. While this process still involves the burning of larger proportions of fossil fuels by producing some power from biomass the environmental efforts of the power station is recognised. The generators are eligible to produce Renewables Obligation Certificates and Levy Exempt Certificates, which can be traded.

In conjunction with the additional renewable generation, a number of thermal plants underwent the retrofitting of gas flue desulphurisation units to reduce SO_x emissions. Carbon sequestration techniques are also being considered for the storage of greenhouse gases. One idea is to capture and store carbon dioxide in spent oil fields.

2.3 Impacts related to response holding

The overwhelming problem with the supply of electricity is that it cannot be stored efficiently in any great quantities. Once generated, electrical power must be transported and consumed immediately. In this regard, electricity is perhaps one of the more unique commodities of today's society. The rate of its production must balance the rate with which it is consumed. As the demand for electricity fluctuates sufficient generation capacity must be available to meet demands at different times of the day, days of the week and months of the year. This requires sufficient flexible generation to accommodate the expected changes in power that can occur.

As we will learn in Chapter 4, a portion of this variable generation is held as frequency response to control system frequency under infeed faults. This response must be held at several sites with an additional margin to substitute for poor performance or failure of a unit to operate. This requires that a number of units are operated with sufficient headroom and footroom to increased or decreased outputs.

2.3.1 Economics of response holding

Dynamic response is scheduled by operators in the national control room from the available synchronised plant on the system. There are two main costs associated with the purchase of frequency response, National Grid(2006c)∴. The first is holding payment which is paid to the relevant generator. This holding payment is provided mainly to recover the costs of extra maintenance and lost efficiency associated with the second-by-second changes in balancing power. A responsive unit can provide either Primary and High response or Primary, Secondary and High response. The relevant cost of holding response under each service is agreed in the ancillary service agreement for each unit.

The second cost is a result of positioning generators at the required load points. To create headroom for low frequency response holding, generators must be deloaded through making bids in the market. Once machines have been bid down the energy must then be replaced by increasing the output of other units with corresponding offers in the balancing mechanism. Likewise, to provide high frequency response offers must be taken to put units in the position whereby they can provide a reduction in output.

The bids and offers are normally selected by increasing expense, so that higher trading costs may be avoided. This means that usually response is provided on the machines that have the lowest bid and offer prices. Units do not fully supply all of the power from the load point to maximum output in response, and a return of 55% response is expected on the reduced output. This means that approximately double the volume of bids and offers are required for any volume of response, Pearmine *et al.* (2006a).

Finally generators will also receive an energy payment from the system based on the amount of generation provided on minute timescales. This utilisation payment in the ideal case will be zero because of no plant losses. The payment associated with this

∴ National Grid Confidential Document

energy imbalance exposure is based on a reference price calculated in accordance with agreed methodology using an average system buy and sell price.

All costs relating to system-balancing actions are recovered through the Balancing Services Use of System (BSUoS) charge. Each registered balancing mechanism unit (both suppliers and generators) is liable to pay BSUoS charges determined on imbalance levels.

2.3.2 Environmental impacts of response holding

Operating machines at partload to provide response often implies that generating units are run off design specifications and are consequently not at optimal efficiency. A typical operating efficiency for conventional coal fired steam plant at partload is given in Figure 2.5. The variation is due to heat-rate changes resulting from throttling steam pressure across governor valves and additional auxiliaries. These efficiency losses were confirmed by Kuerten(1998) in studies to identify expense of holding response, later used for auxiliary contract costs. The impact is quite minimal, with a 1.5 % reduction in performance for a 20 % change in output.

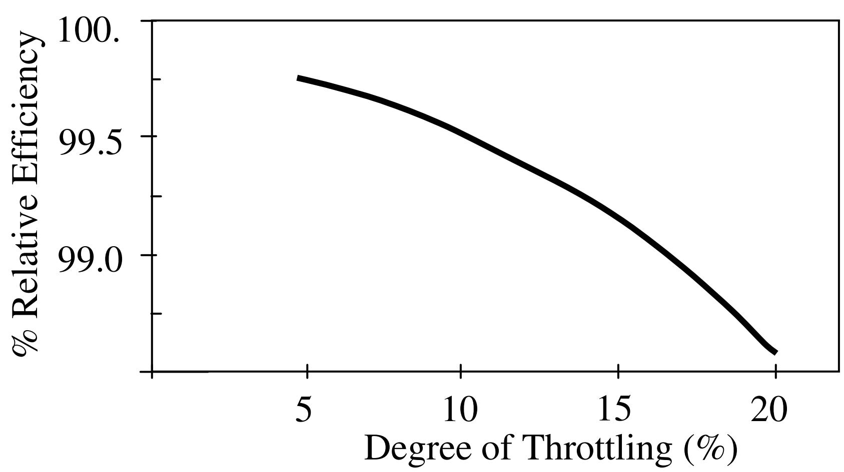


Figure 2.5 – Partload efficiency of conventional steam power stations[Kuerten(1998)]

Combined cycle gas turbines also suffer from similar inefficiencies during operation, being partly composed of steam turbine sections. A typical partload efficiency curve for combined cycle units is given in Figure 2.6. The inefficiency of this type of machine is clearly of more concern than that of coal fired generators. The units sustain a 20 % loss in efficiency if operated at the minimum stable load point. The flow of air through the gas turbine section is controlled to maintain a high output exhaust temperature. This helps to maintain as high a level of efficiency as possible at partload.

These two figures (2.5 and 2.6) demonstrate the necessary evil from the response holding requirement. To hold any response, conventional generators will incur a net loss in plant efficiency. Obviously, that being the case, operating plant at or close to their rated capacities is desirable to minimise this effect.

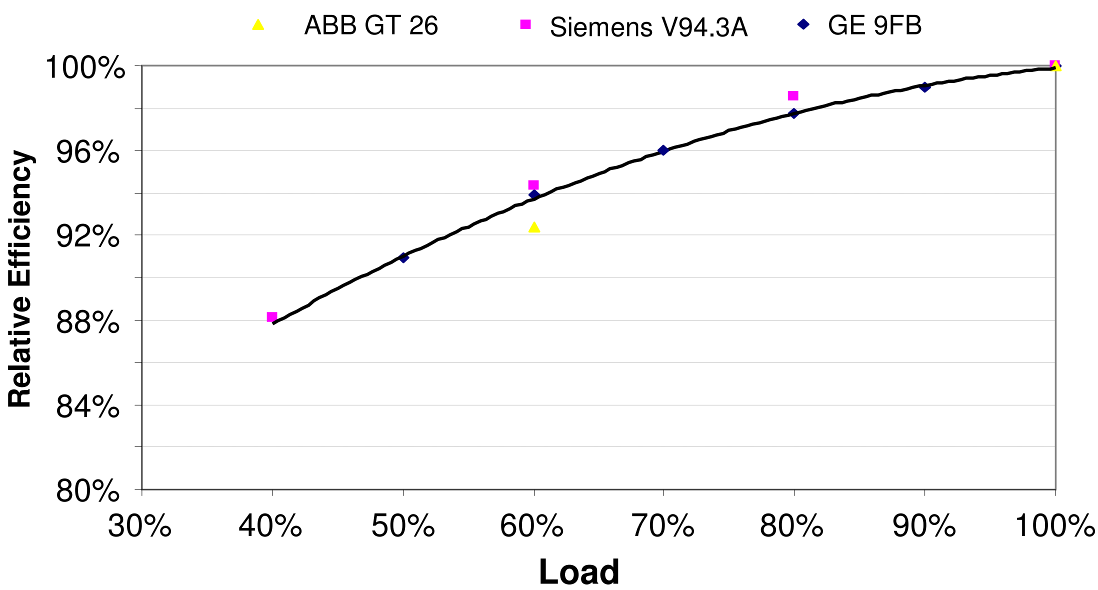


Figure 2.6 – Partload operation of F class combined cycle gas turbines [Tauschitz and Hochfellner(2004)]

Figure 2.7 shows the trend in response instructions given to generating plant on the British transmission system. Data is recorded via the national control room on all machines that are dispatched to provide frequency response. Statistics compiled by the author show that from spring 2002 to summer 2005 a dramatic increase in response holding on gas plant is experienced. With a growing proportion of combined cycle gas turbines utilised for frequency responsive services it becomes important that the level of response be considered in relation to unit efficiency.

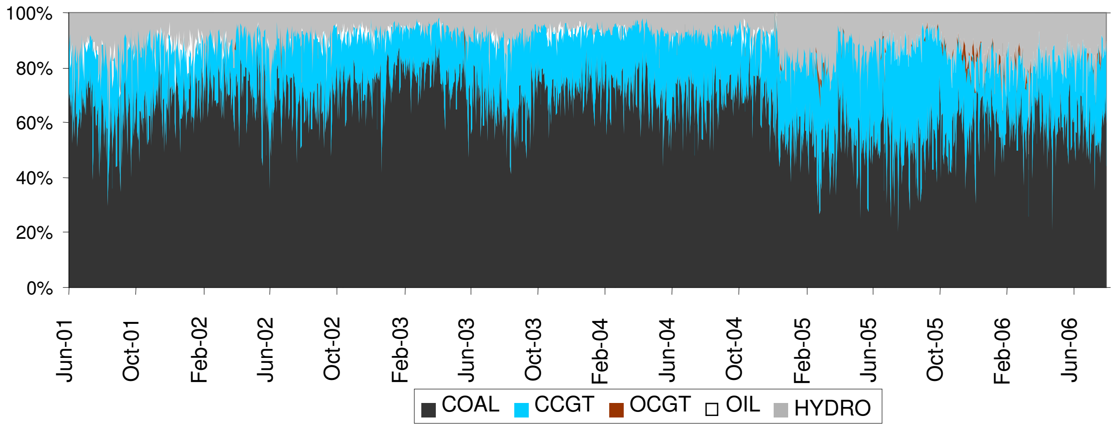


Figure 2.7 – Distribution of GB frequency response instructions

The response holding strategy is further complicated by the response characteristics of generators. The level of response returned from deloading conventional plant is not on a one-for-one basis. Typically, return rates of 55 % are expected, Figure 4.7 demonstrates this on an example unit in a later chapter. Therefore, to get Y MW of response a unit must be deloaded by around 1.8×Y MW. The more response required the lower the machine operating point, the lower the efficiency.

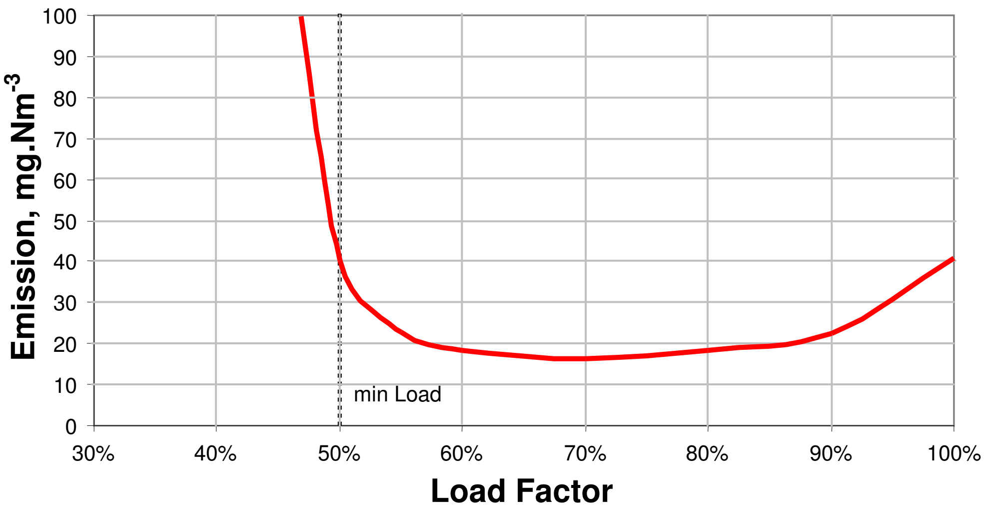


Figure 2.8 – Emissions of nitrogen oxides associated with partload operation of F Class Combined Cycle Gas Turbines [Tauschitz and Hochfellner(2004)]

In conjunction with variable efficiency losses, combined cycle plants also suffer from non-uniform NO_x emissions during partload operation. Figure 2.8 shows typical emission levels for a large CCGT unit. High firing temperatures encourage the production of NO_x within the exhaust gases. The NO_x emission curve follows a bath tub shape with higher emissions produced at the extremes of operation. This suggests that in actual fact emissions of nitrogen oxides associated with combined cycle units are reduced by up to 25% by operating in a frequency responsive mode.

2.4 Reducing the environmental impact of response holding

Reducing greenhouse gas output is the prime objective in all the governments energy policies, therefore this will be the objective considered in this research. Having considered Boyles four suggestions for reducing the environmental impacts from the electricity industry we can define the scope of the research contained herein. From the previous sections we can see that highly efficient use of primary fuel sources is a leading scheme for reducing the environmental impact of frequency control on the British transmission system. Manufactures are constantly improving the operating performance of plant and consequently efficiency.

The open market cannot obstruct inefficient generators from generating electricity; however it is a financial advantage to those plants that use a minimal level of primary energy. The market will therefore eventually undercut the older inefficient plant to the point that operation is no longer economically viable. From the perspective of frequency response holding obviously efficient use of the generators is paramount. The optimum level of response should be scheduled to minimise any excess holding. This optimum level of response should be shared among units so as to minimise the impacts on efficiencies seen in section 2.3.

Switching to less-carbon intensive fuels has two main implications; holding response on renewable technologies, and the real-time balancing requirement. Currently the level of renewable generation on the British transmission system lies at around 2.5 %. As this figure increases it is likely that more dynamic response will be required to balance the fluctuations experienced in wind turbine production. This situation has already been experienced in the German system by operator E.On(2004). This accounts for a proportion of the current reserve capacity but will not be considered in any greater detail.

The alternative implication involves the use of renewable generation in the balancing market. All large scale generation plants are required by the grid code to provide the means to contribute to system balancing. Under beneficial economic circumstances these units will be selected to provide a balancing service. The technological modifications to offer this service have already been considered for wind. However, unlike hydro schemes where water can be stored for later use, wind turbines offering long-term reserves will suffer from a lost energy opportunity. The loss of potential ‘green’ energy would be detrimental to the Kyoto vision; a more robust use would be to store energy in pump storage sites but incur energy losses in conversion.

Variable-speed turbines could in principal be controlled to provide a degree of primary response through energy stored in the rotor. When the rotational speed is reduced so far that the aerodynamic performance of the rotor starts to be seriously impaired, the ‘inertia effect’ would be switched off. Ekanayake *et al.*(2003) and Morren *et al.*(2006) have shown this concept in simulations with variable-speed wind turbines generators. No wind turbines currently connected to the system offer any form of responsive service be it primary or secondary.

If we look historically at past incidents and compare the system response with limits on frequency deviation we see a good record of performance. However, this good performance indicates an overprovision of response. In order to maximise the efficiency of the response process the system should be operating close to its limits. In Figure 2.9 the author uses system data[**] recorded from a number of incidents ranging from 1993 to 2005 and the peak frequency deviations experienced. Also included on the diagram are the limits relating to OS883 which defines the maximum operational deviation of frequency for losses up to 1320 MW. While a number of sub 300MW losses have led to frequency drops close to the limits, incidents above this magnitude show a 0.15-0.2 Hz clearance from the requirement. Even extreme cases well outside the maximum secured condition are easily contained within the operational requirements.

This figure indicates the opportunity to further optimise the response requirement if we assume that the net system droop is linear. The range of incidents given in the figure, especially the smaller losses, are more than likely examples of times when the

1200-1320 MW loss is secured against but a lower loss is experienced. This makes it difficult to establish the potential savings in response during these minor losses. Having considered this fact, the collective droop of the responsive plant means that generally the output power is proportional to frequency. As such, operation along a line of constant gradient from the origin that touches the knee points of OS883 should be possible. The second curve given in figure 2.9 is the line of best fit from the data points, according to this curve there is a potential relax the response holding levels and maintain the OS883 limits.

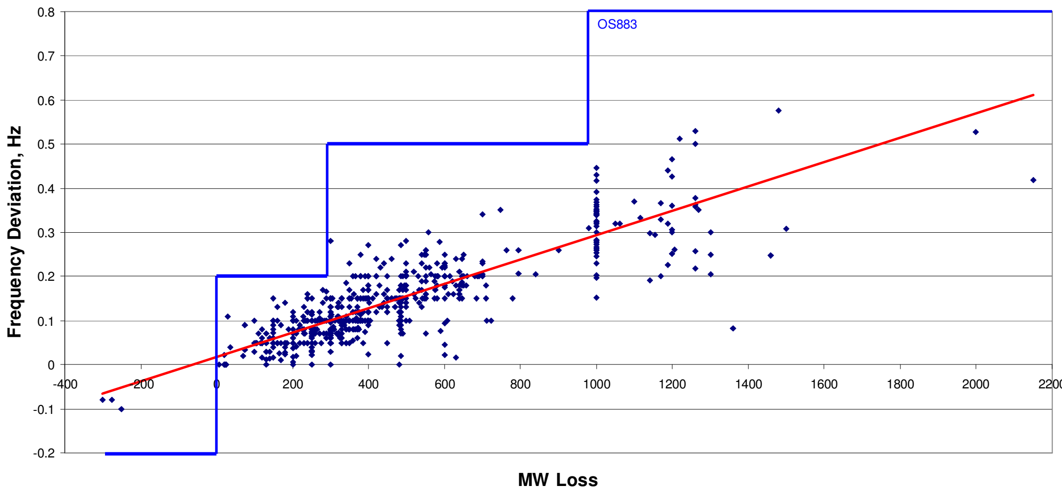


Figure 2.9 Infeed losses and associated frequency deviations (against operating limits - OS883)

The use of the system interconnector as a balancing tool offers access to high levels of renewable generation in Europe. The Baselink interconnector has successfully been implemented with this facility for a number of years, Davies *et al.*(2006). Under the correct technical modifications it would be possible to implement a similar service on the Anglo-French circuit. Suggestions on the use of the Ireland-Scotland link as a response provider have also been documented, SEI(2004). However, both schemes are likely to be some years from implementation.

A substitute to dynamic response holding on generators is the use of demand side management. In this case any large industrial load, ranging between 1 and 120 MW, can be interrupted if system frequency falls below a pre-set trigger point. The trigger point is set outside normal operating ranges, and demand is manually restored when the system has recovered from an incident. This service offers relief at discrete steps and is therefore not suitable for real-time balancing functions. As a result a minimum level of dynamic ‘spinning reserve’ is still required. This technique is heavily reliant on the existence of large industrial demands that can safely withstand interruption.

Research into the use of smaller consumer demands such as fridge-freezers dynamicDemand(2005) or heaters Strbac(2005) have been studied in the past. These types of scheme provide a scaleable demand to shed, and are more suitable for real time balancing. However, results show that as demands are restored they can prove to be as much a balancing problem as the initial incident that tripped them.

2.5 Summary

Generally the electricity industry has a dramatic effect on the gaseous emissions that contribute to the greenhouse effect, and is also responsible for other environmental problems. Even the transport of energy through the network adds to the environmental damage. However, steps can be taken in order to minimise this adverse impact on our planet. The industry endorses the use of renewable generation, and construction of many new wind turbines is currently underway with further expansion planned.

Machine inefficiency in the balancing process is a very important consideration especially with the growing use of new gas fired combined cycle units. Holding less response on multiple units is desirable, but this should not compromise system security. The system operator must also use as much demand side response as possible in order to minimise greenhouse gas emissions. The dynamic requirement of the system limits the total level of load shedding that can be harnessed. In-depth analysis of the system is required to identify the correct level of response required to meet all criteria. However, the existing requirements show scope for significant improvement.

Chapter 3

Current International Practises in Frequency Control

Chapter 3 highlights the operational methods employed in a cross-section of different countries to limit frequency variations on their system. A brief synopsis is also included to highlight the levels of wind generation and give an overview of the system in question.

In the following chapter it will be beneficial to define the differences between the general term of reserves for “Primary Control” as apposed to “Primary and Secondary Response”. Primary Control refers to the automatic measures taken by plant in response to a change in system frequency. This term is useful when describing generic frequency control strategies in all transmission systems. Under the classification of British ancillary services this primary control relates to both Primary and Secondary response, which are defined under different timescales.

3.1 Great Britain

Legislation recently enacted by UK parliament in 2002 has called for an increase in the utilisation of renewable energy sources. The British transmission system is currently equipped with a capacity of approximately 1.9 GW of wind generation with the majority of these units based onshore. A number of large-scale offshore projects have now been approved leases by the Crown Estate and these wind farms are expected to begin construction in the next few years. This will add the necessary capacity to meet government targets of ten percent generation by renewable sources in 2010, providing a capacity in excess of 10 GW by 2015.

With current wind capacity levels so low (2.5 percent) and existing turbines distributed over a wide area, the system has not perceived a noticeable influence on the level of operating reserve to date. The British transmission grid operates as an isolated island system (Figure 3.1) with a peak demand of 65 GW. For system balancing and frequency control the system benefits from a number of pump storage units. In addition, contracts are held with most grid connected generators and also demand side participants to provide frequency responsive services. As an island system, the British grid is secured against a maximum instantaneous power loss of 1320 MW. This is achieved through holding a level of reserve for frequency response.

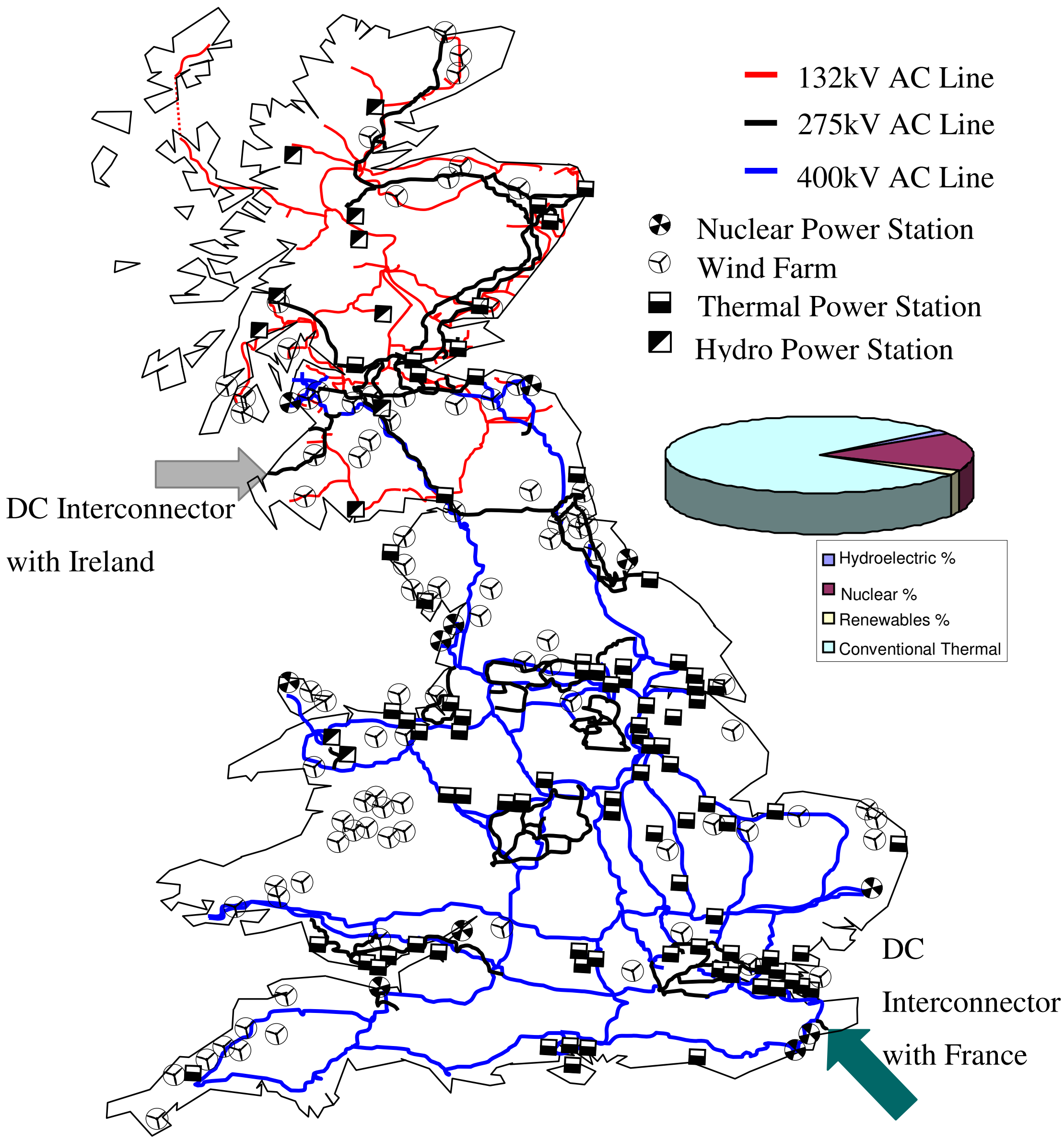


Figure 3.1 – Generation capacity and national transmission lines of the Great Britain super grid.

The frequency response level is optimised during the day against the national demand and maximum potential loss on the system, Hung *et al*(1999). In addition to providing this instantaneous disturbance reserve the response is also held to provide a degree of regulation for the real time balancing of the system. In order to meet operational limits on the standard deviation of system frequency, 300-500 MW of response must be held on spinning units. If feasible, the remainder can be provided by frequency sensitive relays offering bulk relief at discrete frequency intervals, otherwise spinning reserve must be utilised.

The response is split under primary and secondary time-scales; primary being the initial 10 to 30 seconds of the incident and secondary 30 seconds to 30 minutes. This artificial distinction ensures that sufficient response can be scheduled to curtail the initial drop in frequency (where system inertia may vary) and then recover to within minimum limits under steady state. The response is held to limit a power loss greater than 300 MW to within one percent of nominal frequency (50 ± 0.5 Hz), except under *abnormal* conditions defined by National Grid(2004). In the event of an infeed loss greater than 1 GW but below 1320 MW, considered an *abnormal* event, the system frequency may fall to 49.2 Hz but must return to the one percent limits within 60 seconds.

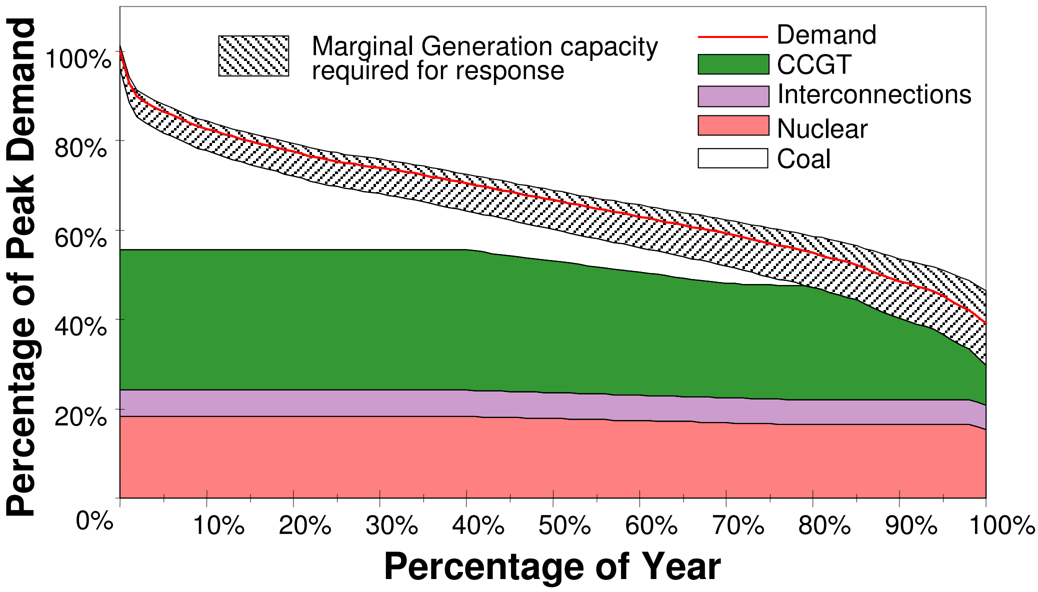


Figure 3.2 - Load duration curve showing breakdown of grid connected generation

The primary response holding currently ranges between 400 and 1500 MW with secondary response levels reaching 1300 MW, depending on system conditions. Figure 3.2 details the allocation of positive and negative margin required to provide frequency responsive services on generating plant.

3.2 Denmark, Sweden, Finland and Norway

Eltra system operator in Jutland (West Denmark) has one of the highest capacities of wind generation at 2347 MW, almost 32 percent of the total generation capacity, Eltra(2003a). Eltra operates as part of the Union for the Coordination of Transmission of Electricity (UCTE) and is synchronously tied through Germany. It also operates DC interconnectors with Norway and Sweden, Figure 3.3. The neighbouring power systems give Eltra the total import capacity of 3060 MW. This is almost equal to the maximum demand experienced on the system.

Balancing the Danish grid is relatively easy in periods of low wind. In high wind, 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. The legal obligation to accept all prioritised electrical energy only intensifies this problem by removing the option to curtail production. Experience has shown that within one or 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 combined heat and power (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.

As a member of the UCTE Jutland has an obligation to supply 35 MW of primary control to the system. 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 200 MW of downward regulating reserve is held to secure against demand loss. This reserve may be held on units outside of Jutland and supplied through interconnector links.

Figure 3.3 - Nordic generation mix and interconnector capacities[§§]

The national power systems in the remaining Nordic countries operate as one synchronous system referenced in Elkraft(1996). This system is comparable with the

[§§] Source: Nordel

British grid with a demand peak of 68.8 GW. The system is fortunate in having large capacities of hydroelectric power available for frequency response. A primary control of at least 600 MW is held on the combined system for controlling the frequency between operational limits of 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 by each country. 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 3.1. The actual frequency response (β) required from each area is given in Table 2, sourced from Lindahl(2002).

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

Equation 3.1

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 a primary control reserve of 1000 MW should control the frequency deviation within 49.5 Hz.

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

Table 2 - Contribution to frequency response in the Nordic pool

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 in each area, and as a consequence increases efficiencies, reducing emissions.

3.3 Germany

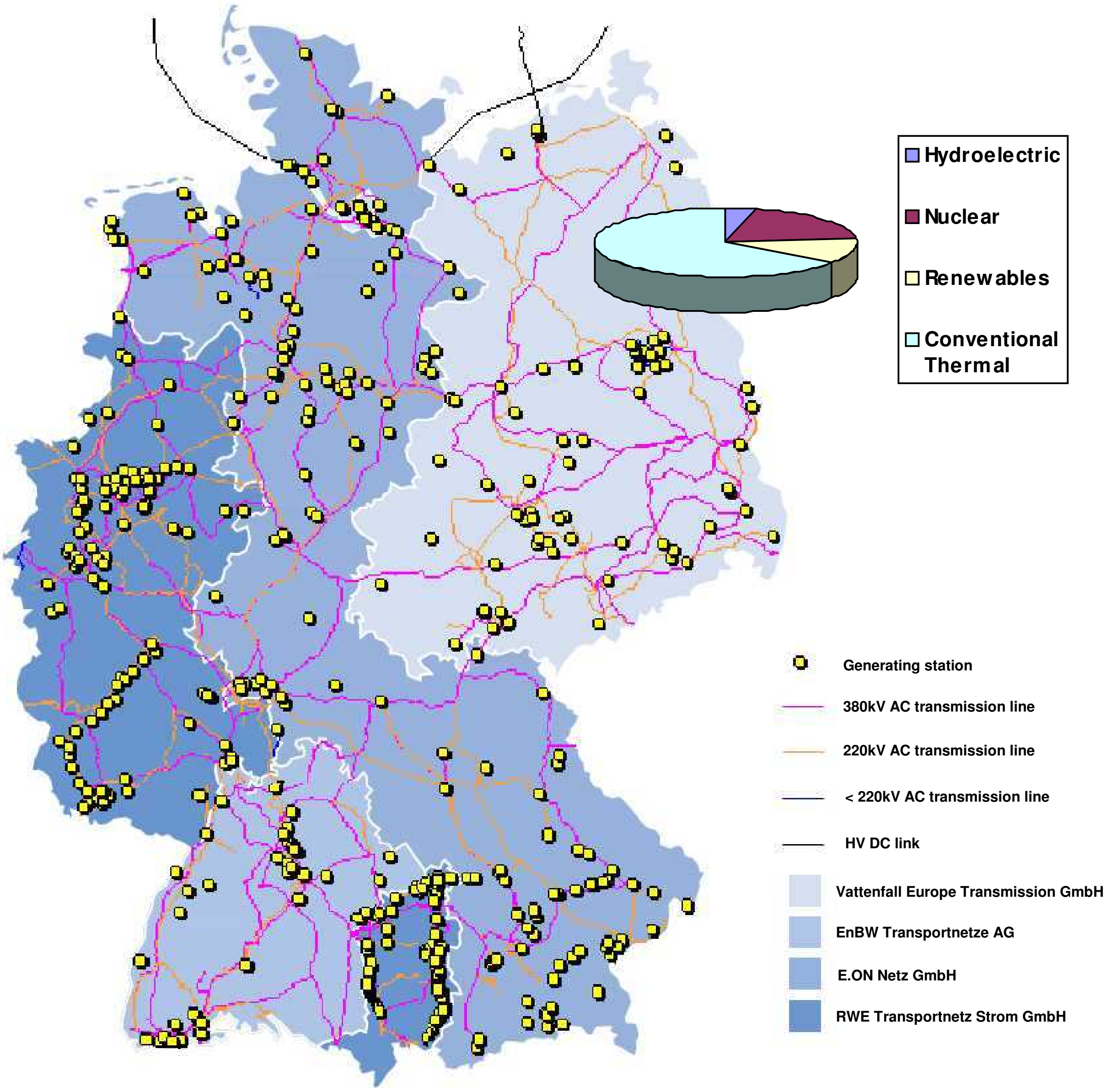


Figure 3.4 - German system operators, generation mix* and HV grid network†††**

*** Source: Energy Information Administration

Germany is composed of four system operators (Figure 3.4), and currently experiences the largest penetration of wind on any network in Europe with a total capacity of 14345 MW. Of that capacity, 6250 MW of the 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. 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 3640 MW within six hours, with an average value of 10 MW per minute raises particular concerns on wind variability.

The Peak demand on the German system reached 77.8 GW[†††] in 2004. The generation plant mix is similar to that of Great Britain with the majority of power supplied through coal fired and CCGT plant. The system also has a comparable percentage of nuclear capacity. Germany is connected to the UCTE system via neighbouring states. As was the case for Jutland, it is required to contribute to the net 3000 MW of primary control that is held on the system.

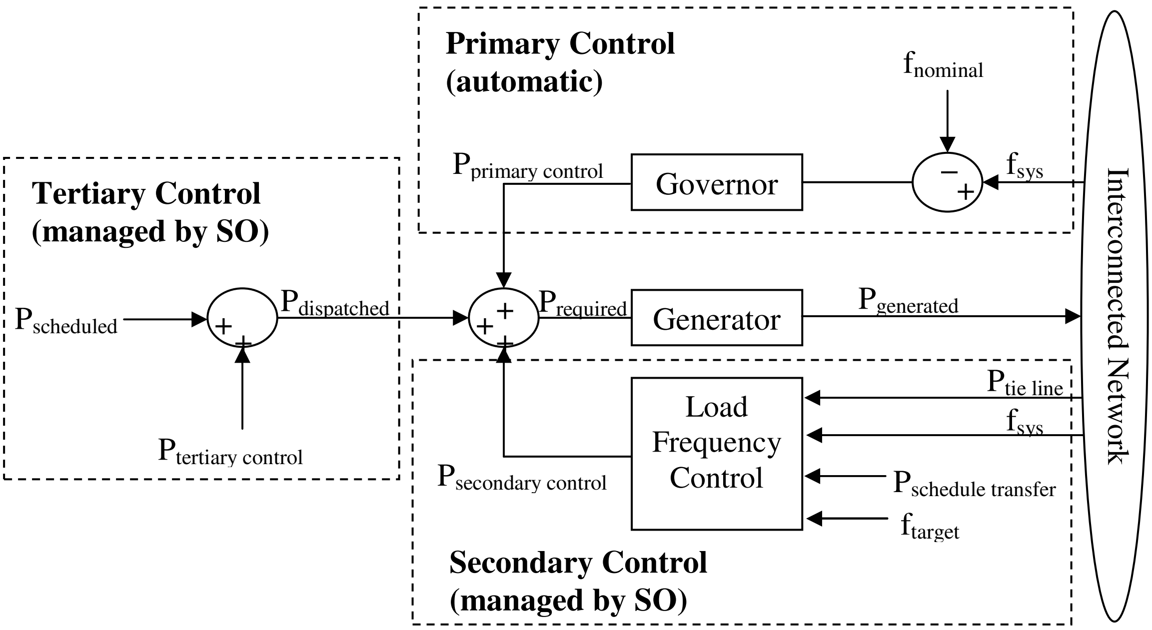


Figure 3.5 - Frequency model provided by zones and generators within the UCTE

[†††] Source: Verband der Netzbetreiber (German association of electricity network operators - VDN)

The UCTE operates in a similar manner to the Nordic system, where the provision of primary control is calculated based on total demand. The frequency control characteristic for Germany in 2003 as set by the UCTE was 5,009 MW/Hz. A simplistic overview of the frequency control process is given in Figure 3.5. Automatic power transfers are required in the event that system frequency drops from nominal 50 Hz and system disturbances are limited within a band of ±0.2 Hz. Secondary control within the disturbance zone restores the reserve levels. The UCTE(2002) recommends a minimum secondary control level calculated on the basis of the expected system load (P_{Lmax}) during each market period as shown in Equation 3.2.

$$P_{\sec} = \sqrt{10.P_{L\max} + 150^2} - 150$$

Equation 3.2

The German transmission system operators procure primary, secondary and tertiary control power. The delivery of these reserves is subject to the time-scales shown diagrammatically in Figure 3.6:

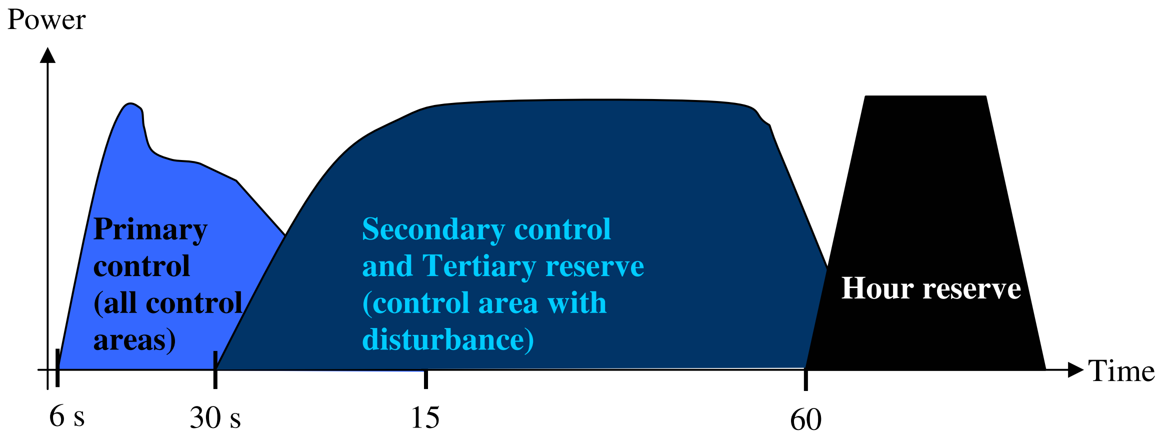


Figure 3.6 - Associated delivery of response in Germany

The total primary control power demand by all German operators amounts to approximately 725 MW. Primary control and secondary control power are procured in a six month cycle, with daily markets for tertiary reserve. Table 3 shows the levels of reserves tendered by the German transmission grid operators in 2003, sourced from Swinder(2004).

	RWE Net AG	E.ON Netz GmbH	EnBW Tronsportnetze AG	Vattenfall Europe Transmission GmbH	Germany Total
Primary Control	+/-310	+/-190	+/-75	+/-150	+/-725
Secondary Control	+/-1230	+800/-400	+720/-390	+/-580	+3330/-2600
Tertiary Control	+1030/-760	+1100/-400	+510/-330	+730/-530	+3370/2020

Table 3 – Frequency control capability in Germany during 2004

3.4 New Zealand

New Zealand operates as an island system, Figure 3.7, the system peak demand to date has been 6513 MW[¤]. The system has approximately 170MW of wind generation, equivalent to around two percent of the total capacity. New Zealand is fortunate like the Nordic pool with typically 60 to 70 percent of all power produced by hydro dams. Geothermal stations meet around six percent of the electrical demand with the remaining power being met by gas and coal fired stations. The majority of the country's hydro generation capacity is located on the South Island, while the majority of the population and industrial demand is located in the North Island. Transfer is controlled via a 1000 MW DC link.

Hydro generation is a useful storage medium when the wind is not blowing, and the volume of water flowing through hydro schemes around the country can be easily controlled. 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 little or no wind. Hydro turbines are also very good frequency response providers and the majority of response is held either on these generators or with interruptible demand sources.

[¤] This record of the highest nationwide demand for electricity (6513 MW) was experienced on 17th August 2004.

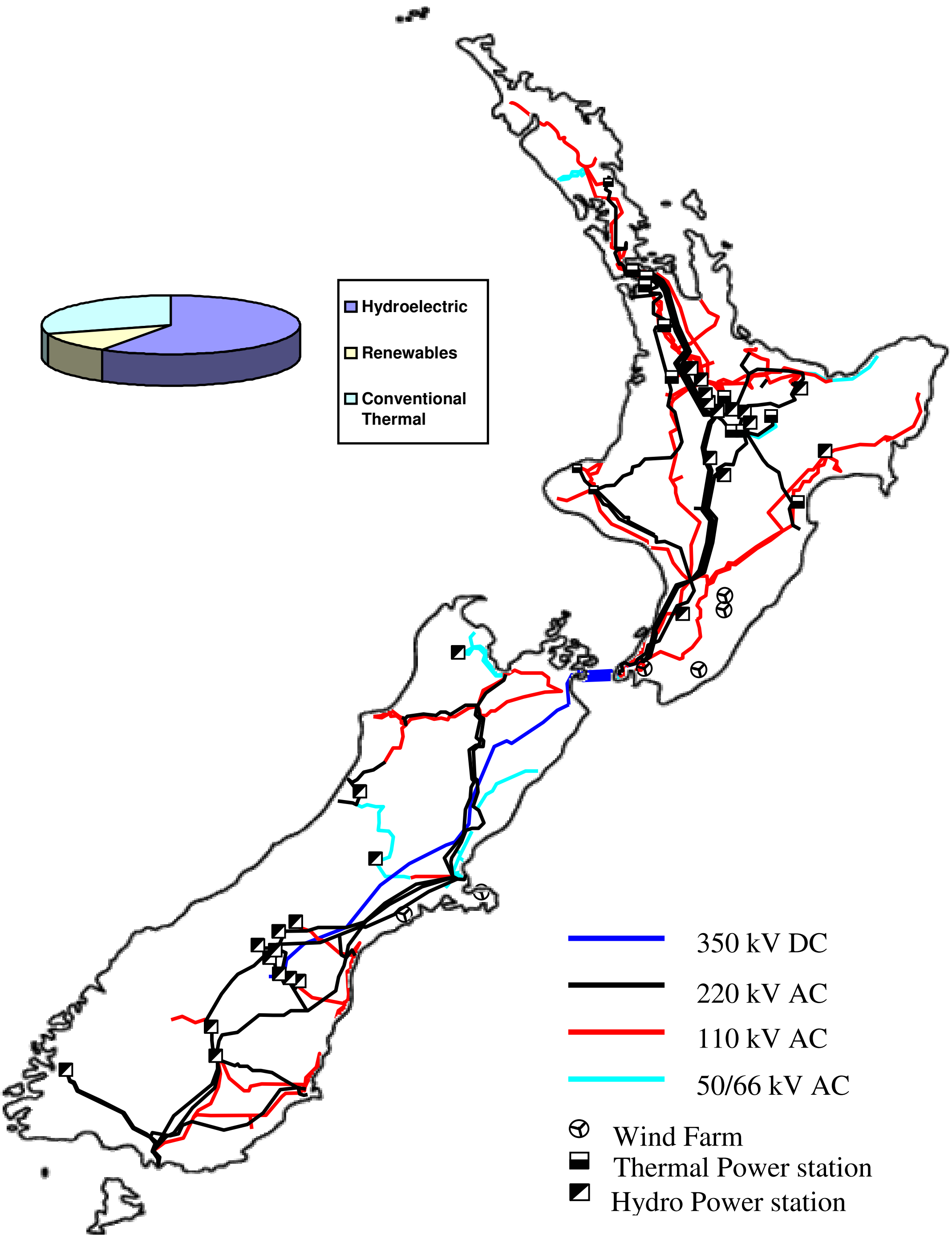


Figure 3.7 – New Zealand transmission grid on north and south islands

The largest single generator contingency is the combined cycle Otahuhu B Station which runs at a maximum output 365 MW; this is likely to rise to 400 MW when the new CCGT plant is commissioned in 2007. The largest credible tripping in terms of MW is the HV DC Bipole Link. This can run at 1000 MW transferring power from the South Island to the North Island, or 600 MW transfer from the North Island to the South Island. This south transfer is limited by the associated AC systems rather than by the capability of the HVDC Link itself. This level of transfer is classed as an "extended contingency" under the System Operator Policy Statement and the Electricity Governance Rules.

The Electricity Governance Rules taken from the Electricity Commission(2005), state that the system operator must provide sufficient reserves, subject to availability, to secure against: "*The maximum amount of MW injection that could be lost, due to the occurrence of a single contingent event; and the extended contingent events, allowing for automatic under-frequency load shedding.*" The frequency levels are managed according to a minimum frequency of 48 Hz for a contingent event on both islands. With these limits reduced to 47 Hz in the north island or 45 Hz in the south island for an extended contingent event.

This large 5% tolerance for frequency deviation is in principal a result of the high proportion of power that can be lost via the DC link. With the system at peak demand and full utilisation of the interconnector capacity a fault on the link can result in a 22 % deficit of the northern island capacity, or 27 % of the southern island capacity. At minimum demands these proportions may even be exasperated if export levels are not curtailed. Also the DC Link displaces a sizeable amount of conventional synchronous generation that in other systems would contribute to system inertia impeding any change in frequency.

Review of operational records from 2005 gives an indication of the response levels held by the system operator Transpower. Depending on the time of day, between 120 MW and 300 MW of fast (equivalent to primary) response is held on the islands; with a level of sustained reserve that ranges from 370 MW to 500 MW, which is comparable with secondary response.

3.5 Ireland

The Irish electricity grid is a small 50 Hz system, Figure 3.8, with a peak load of 6.5 GW[◊]. The system comprises of two AC interconnected power systems, operated by Northern Ireland Electricity (NIE) and ESB National Grid (ESBNG). There is also a

[◊] CER - Commission for Energy Regulation

450 MW DC link connecting Northern Ireland and mainland Scotland, it is expected that this link will provide a frequency triggered responsive service by 2010, Sustainable energy Ireland (2004). This will greatly benefit the system providing added security against instantaneous power loss. The power system has a total installed plant capacity of about 7.6 GW[◊]. At present, there is an installed wind generation capacity of 680 MW, with the majority of connection in the Republic of Ireland. Connection of a further 1000 MW is also currently planned in the near future on the combined Irish system

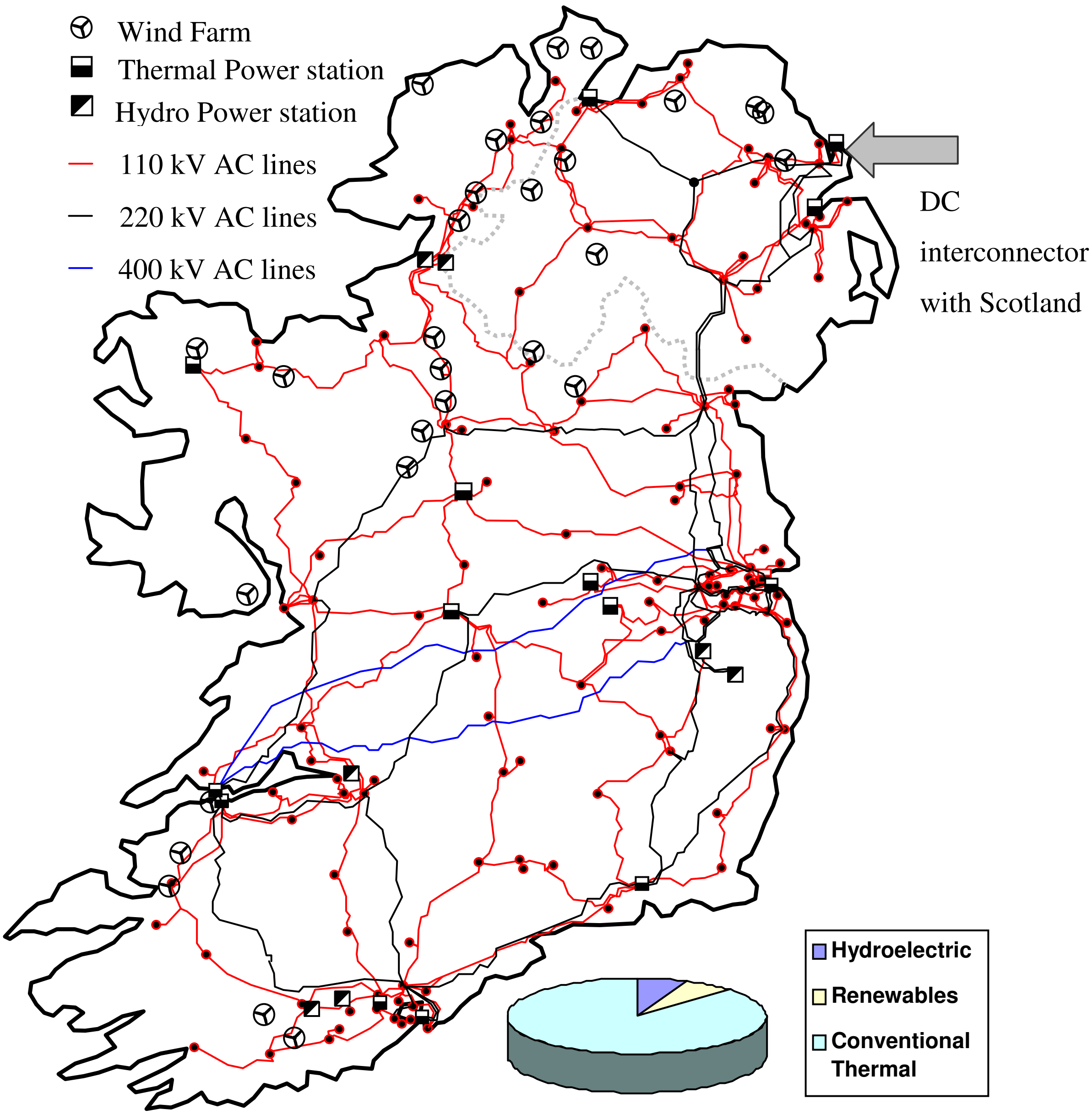


Figure 3.8 – Irish transmission grid

Frequency excursions are often sizeable and at present, a frequency event is to be controlled within the limits of 49.5 to 50.5 Hz on the NIE System. This is in accordance with the Electricity Supply Regulations (N.I.) 1991 as referenced in SONI(2006). Under exceptional circumstances, the system frequency is permitted to deviate between 52 Hz and 47 Hz. The ESBNG grid code requires that the system operates under a normal operating range of 49.8 to 50.2 Hz. During transmission system disturbances this limit may be extended to 48.0 and 52.0 Hz. During exceptional events, as with the NIE system specifications, system frequency may rise to 52 Hz or fall to 47 Hz, ESBNG(2005).

The primary control requirement is to have sufficient interruptible demand relief and spinning reserves, such that there is adequate capacity held in reserve to cover 80% of the largest single generating unit (including interconnectors). This means that the system reserve is typically arranged to recover the loss of 400 MW on the Moyle interconnector or Dublin Bay power station as depicted in EWEA (2005). Under arrangements for sharing emergency cover throughout the all-island system Northern Ireland provides 107MW of this primary control reserve with the Republic of Ireland providing 213MW.

3.6 Summary

In Nordic and UCTE systems frequency response levels are held fixed at 1600 MW and 3000 MW respectively chosen through operator confidence. In GB, New Zeland and Ireland the primary control requirement is optimised against a system dynamic model and the largest potential loss of power. These techniques avoid unnecessary response holding and ensure a more efficient use of generating plant in the respective networks. For island systems holding adequate frequency response capacity only on interconnectors is not feasible, and may not even be possible.

There are also some 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 smaller systems this activation limit is extended. In Nordel the amount of primary control activated increases as frequency deviates from –0.1 Hz to –0.5 Hz, when the entire reserve is fully activated. In GB, the primary response should be established in full for a frequency deviation of -0.8 Hz and secondary response for -0.5 Hz. The all-Ireland system reserve should be triggered by 49.5 Hz. In New Zealand this many be extended to a deviation of 5 Hz from nominal due to the significantly high proportions of generation that can be lost from the system.

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 strong interconnections and high levels of environmentally inert hydro generation.

The German and Danish networks have very high proportions of wind generation but benefit from the security provided through the UCTE network. Both networks hold smaller primary control levels when compared to GB. However, as a direct result of Germany being managed by four TSOs it has a significantly higher level of long-term reserve. Both New Zealand and Ireland 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.

Chapter 4

The System Dynamic Response to Instantaneous Infeed Loss

Chapter 4 is structured as follows: The five main parameters that affect the grid frequency in Great Britain are explained. The review of a number of existing techniques to model the system response is presented. A proposed solution to model grid frequency response is highlighted utilising a full transmission network.

4.1 Introduction

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. The possible geographical effect of multiple elements of the reserve to a dynamic change in frequency must also be considered. Early investigations conducted by National Grid modelled the cumulative response provided by a single type of generator to grid disturbances and more or less neglected the transmission network.

Even if more complex models are used, 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.

4.2 Grid dynamics

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 motion, and is dependent upon the mass of an 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 *et al*(1998) gives this relationship as Equation 4.1.

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

Equation 4.1

The inertia of a generator is usually normalised as a per unit inertia constant, defined as the kinetic energy at rated speed over a rated 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. Machowski shows multiplying the terms in Equation 4.1 by the normalised speed we have a description of the rotor dynamics called the *swing equation* (Equation 4.2).

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

Equation 4.2

The difference in mechanical power (P_M) and electrical power (P_E) is solely related to the inertia and rate of change of rotation. 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 inertia 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 GB grid the inertial values of the conventional generators vary between 9.5 and 3.2.

The author shows the relationship in Equation 4.2 can be extended to represent the dynamic effect of the whole system under the loss of generation, Equation 4.3.

$$2H.\frac{d\Delta f}{dt} = P_G(1 + K_{resp}.\frac{\Delta f}{f_0}.\frac{1}{\rho}) - P_L(1 - K_L.\Delta f) - P_{Loss}$$

Equation 4.3

This fundamental equation explains that when the system demand (P_L) is not in balance with the generation levels (P_G) the system frequency will deviate (Δf) from nominal (f_0). Thus, if a block of generation is lost (P_{Loss}), the system frequency will fall until the proportion of responsive plant (K_{resp}) restores the level of lost energy under governor droop (ρ). The dynamics are also influenced by the self regulating effect of the load (K_L). The system load is sensitive to frequency deviations and load will drop as frequency decreases. A typical value for the equivalent machine inertia for the whole system is approximately 5 and a typical governor droop setting is 4 %.

This simple model described by Equation 4.3 is useful to demonstrate how the system responds to generator loss. It shows that factors affecting the system frequency are:

- Generator droop setting
- Magnitude of power loss
- System inertia
- Load sensitivity to frequency
- Proportion of response

4.2.1 Generator droop

Equation 4.3 is not suitable to represent the system under operational conditions. In reality responsive generators do not all supply response as a linear droop function, and the system experiences non-linear behaviour relative to frequency. In addition, this is further complicated by the different generator operating points selected for frequency control.

Figure 4.1 is the author's demonstration of the non-linear relationship between generation output and system frequency. It is derived from the operating points of all generators connected to the grid at a specific instance in time. Around the operating point (50 Hz) the system exhibits a shallow gradient and a small drop in frequency can release substantial amounts of power. If for example, due to imbalance, the system frequency drops by 0.1 Hz the figure shows that the system will increase generator output by around 400 MW. If however, a loss causes the frequency to fall by 0.5 Hz some 1300 MW of response is released. As the curve moves further away from nominal frequency the potential response is diminished, as plant reaches rated capacity or the minimum load point. This highlights the importance of representing individual generators when looking at grid dynamics, particularly in terms of generator balancing actions.

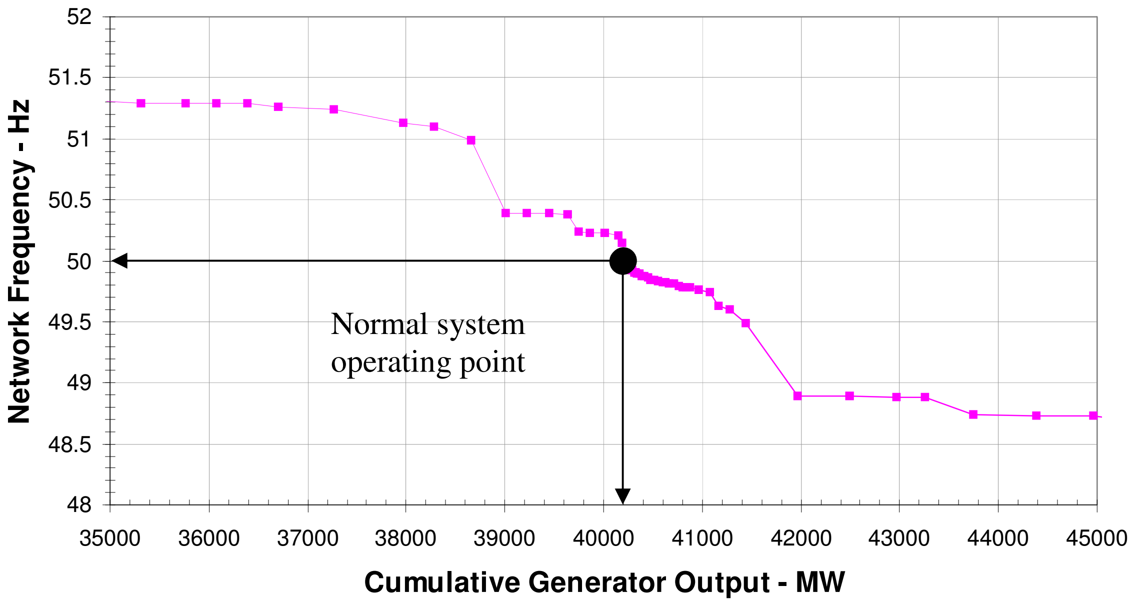


Figure 4.1 - Generation characteristic from a July morning

By using a simple network model of the British Grid (Appendix B), consisting of 275 kV and 400 kV transmission lines and a set of generic governor models, we can observe the effects of generator droop on the dynamic response of the systems frequency. National Grid in the Grid Code specifies that frequency responsive generating plant must operate with a normal droop setting of between 3 and 5 %. Some frequency responsive plant offer enhanced droop settings for the balancing market. This gives greater control over instantaneous changes in frequency during periods of volatile demand.

Simulating the dynamic effect of a 1200 MW instantaneous loss of generation using the simple network model at a system demand level of 25 GW reveals the curves in Figure 4.2. This demand level provides the worst case scenario in the British Isles being at the minimum demand. The low demand means that losses in generation can account for significant proportions of the system power. A loss of 1200 MW represents a typical infeed loss that can be expected from a number of generator sites on the British grid.

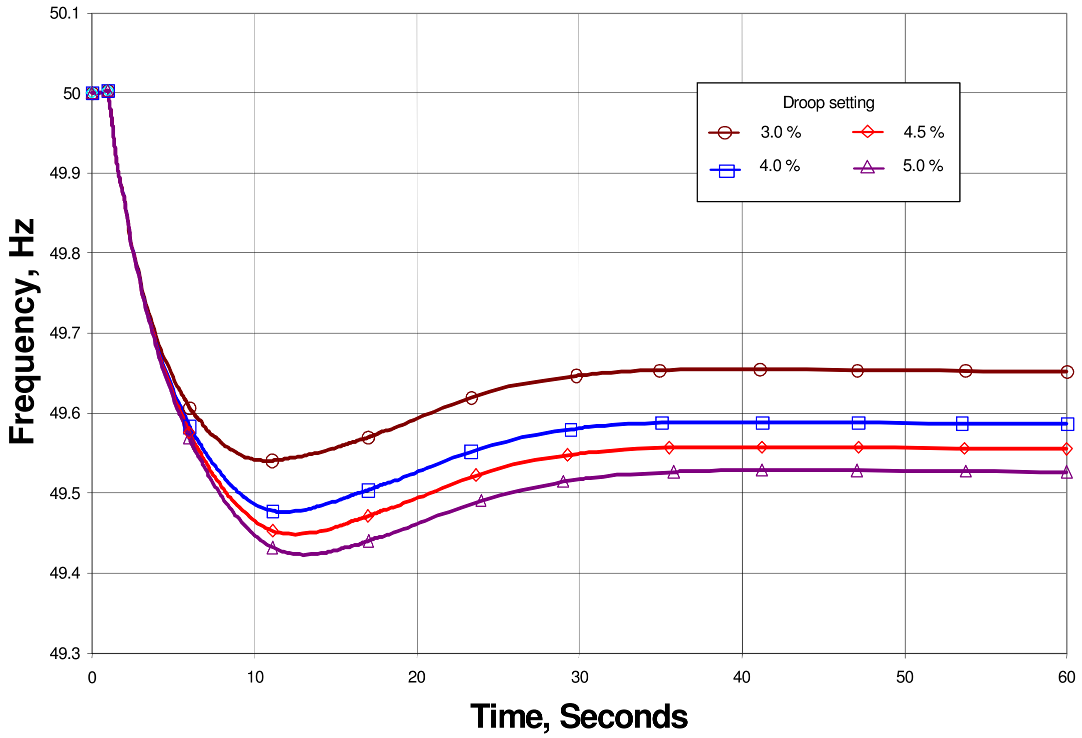


Figure 4.2 - Effect of generator droop on system frequency

In this situation the impact on response is exasperated by the small amount of synchronised generation in operation, resulting in a lower system inertia making frequency swings more volatile. It is not possible to alter the settings of most generators, but the net system droop is controllable to some degree through selective scheduling of high or low droop plant. The net droop setting of the power system has a direct bearing on the maximum and steady state value of the system frequency.

4.2.2 Magnitude of loss

On the UK grid the maximum possible loss of generation that is secured against is currently 1320 MW, which corresponds to two 660 MW generator units lost via a double switch fault. The system is typically secured against an infeed loss of between 1000 MW and 1320 MW.

In most cases a loss of a large portion of demand will 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 losing the demand from two super grid transformers. However, this value may be increased if the Anglo-French interconnector is exporting power above this level. High frequency response is scheduled on generators like primary and secondary response. As it is normally a fixed quantity it is not discussed in any further detail here.

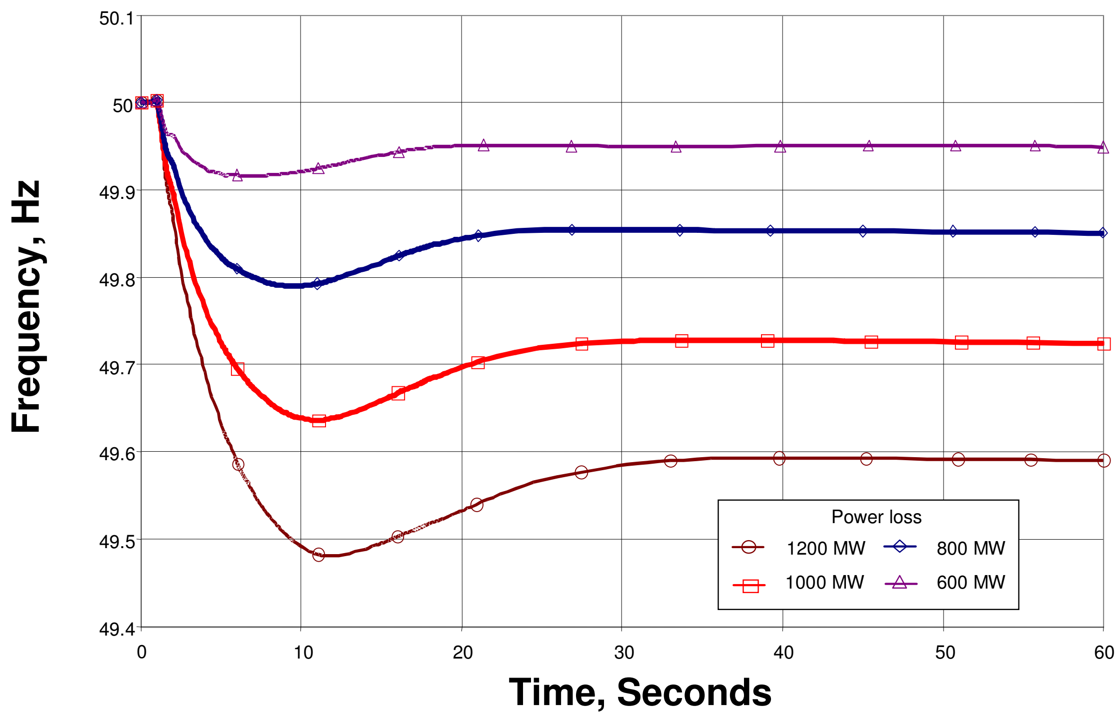


Figure 4.3 - Effect of disturbance magnitude on system frequency

Depending on the time of day, and the time of year, system demand levels can vary between 20 GW and 65 GW. This places a generation loss of 1320 MW at between 6.6 and 2 % of the national demand depending on when the event occurs. At low demands a loss of this size is a significant portion of the total power.

Using the same network model of the British Grid as in section 4.2.1, it is possible to observe how the magnitude of the disturbance affects the system response. The curves in Figure 4.3 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.

4.2.3 System inertia

System inertia is the main factor that controls the drop in frequency in the two-second period before automatic governor action beings to increase generator output.

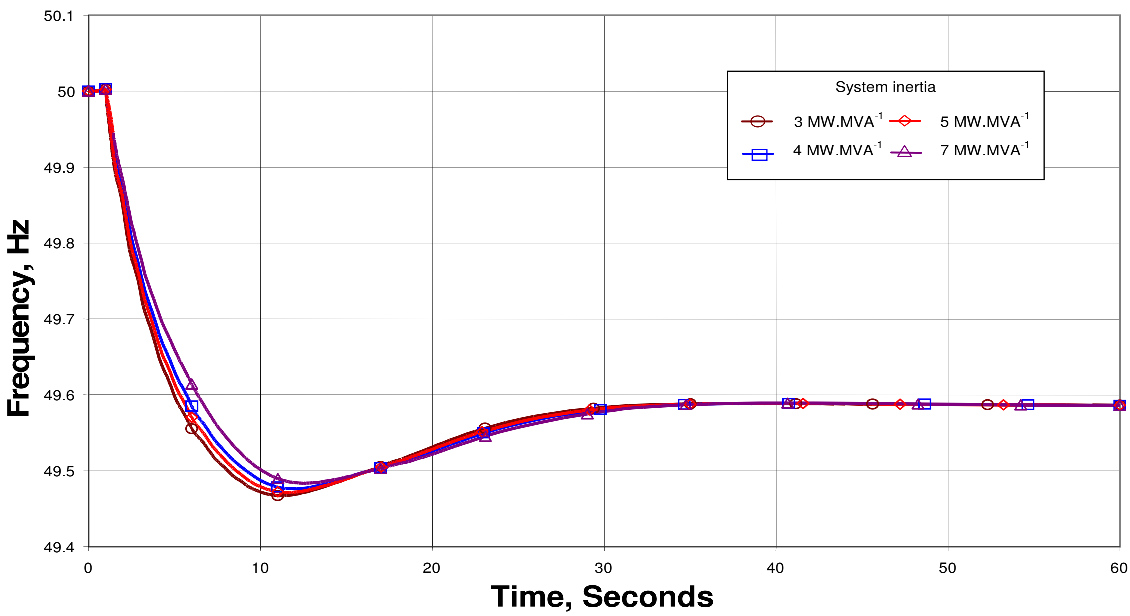


Figure 4.4 - Effect of inertia on system frequency

The simulation model from section 4.2.1 is again used to show inertia properties in Figure 4.4. Inertia controls the initial decay rate of frequency, and has a slight influence on the maximum frequency deviation. This being the case it also influences the time of the maximum deviation. However, it can be seen that the impact of inertia is not as significant as for previous parameters.

4.2.4 Load sensitivity to frequency

The total system load is composed mainly of elements of both resistive and inductive load. During an imbalance in generation a net change in load will occur with respect to frequency. Inductive elements, which are characterize by system frequency, will vary in magnitude during a transient, and in so doing influence the voltage profile. Power consumed by resistive elements of the load will drop as voltage is reduced. Motor loads, which typically utilise 40 to 60 percent of the network power, will also influence the load-frequency characteristic of the system. If the system voltage or frequency declines, the connected motor load magnitude will also decline.

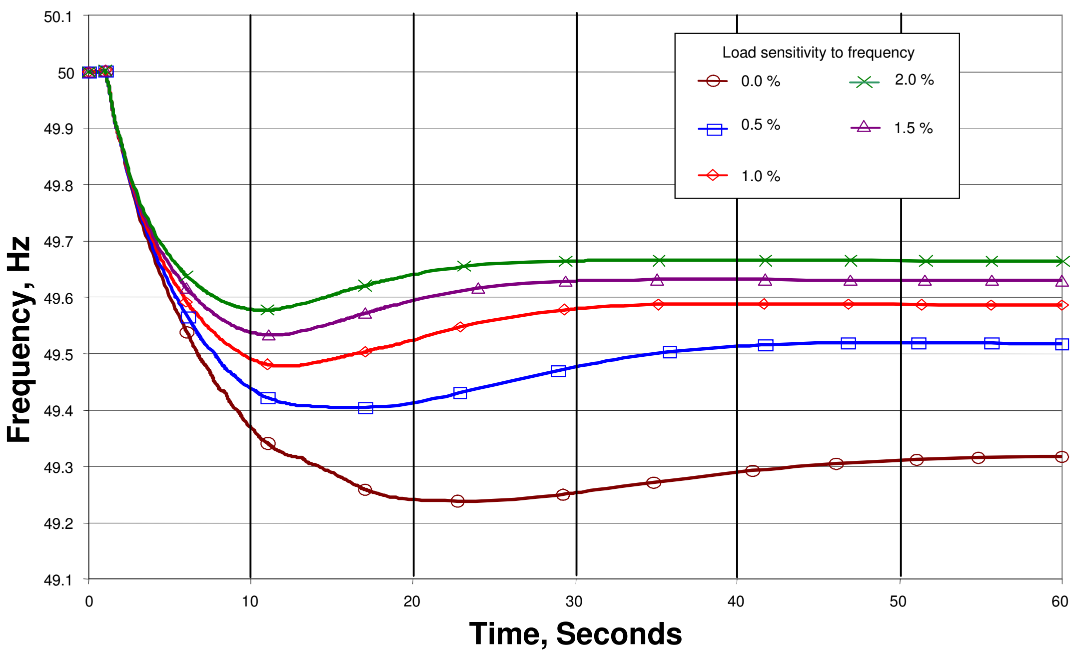


Figure 4.5 - Effect of load sensitivity on system frequency

The load frequency sensitivity has a considerable influence over the maximum frequency deviation experienced by the system. Simulations with the same network model in section 4.2.1, but using lumped frequency dependent static load at each grid supply point, provides detailed information on system behaviour. The load model neglects voltage sensitivity in favour of a simple frequency sensitive relationship.

Varying this relationship across all loads nationally from no dependency to a level of 2 %MW/Hz shows that a system with a higher load-sensitivity characteristic experiences a smaller deviation in frequency, Figure 4.5.

4.2.5 Proportion of response

The final characteristic relevant to grid frequency during disturbances is the generator response. This can be broken down into two additional categories; scheduled response holding levels, and generator dynamic performance. The later can be observed from a set of compliance tests taken from a range of different plant types. In these tests, a ramped frequency discrepancy of -0.5 Hz over 10 seconds is injected into the machine governor, causing a change in output. This change in output represents the desired response required from the generator under a low frequency event.

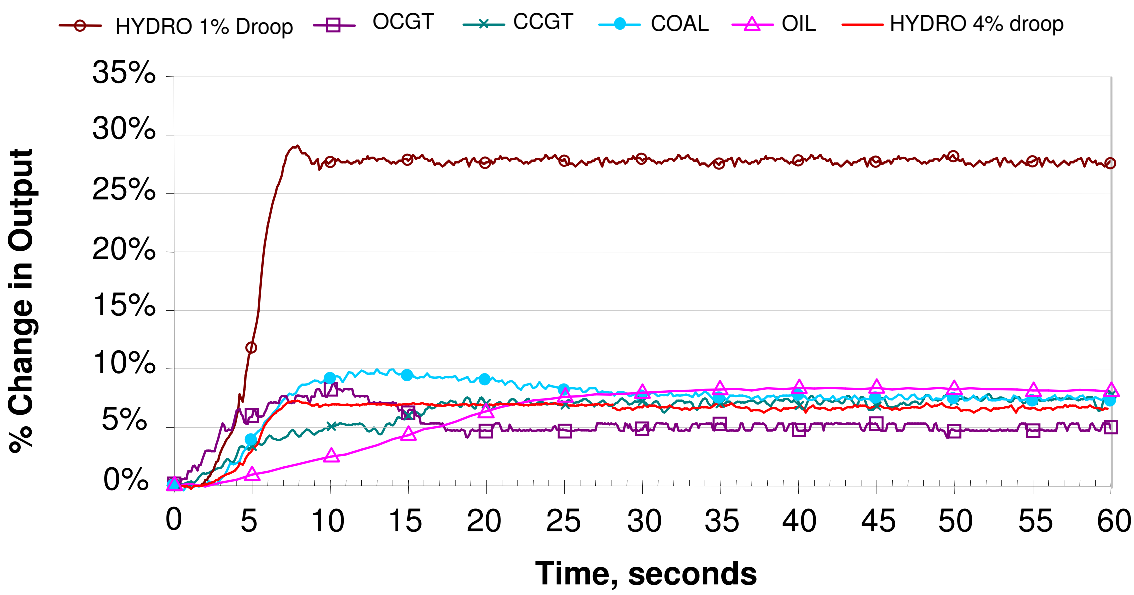


Figure 4.6 - Generator response to applied test frequency injection signal

Figure 4.6 shows the test results of five grid connected generators each of different fuel types. Ignoring the 1% droop hydro curve, all the units considered provide a similar magnitude of response towards the end of the tests. However, during the initial 30 seconds (primary response timescale) the power delivery is significantly different. Interpreting the power delivery through Equation 4.3, we can see that the choice of unit for response based on fuel type will significantly impact the initial frequency following a generator trip.

Dynamic response is scheduled in the control room by zone balancing engineers, through de-loaded generators called 'Balancing Mechanism Units' (BMUs). A BMU can provide either Primary and High response or Primary, Secondary and High response at a realisable level of commitment. The magnitude of response required from such a service is defined within the relevant ancillary service agreement. A BMU instructed to deliver any of the above forms of response is deemed as operating in a frequency sensitive mode.

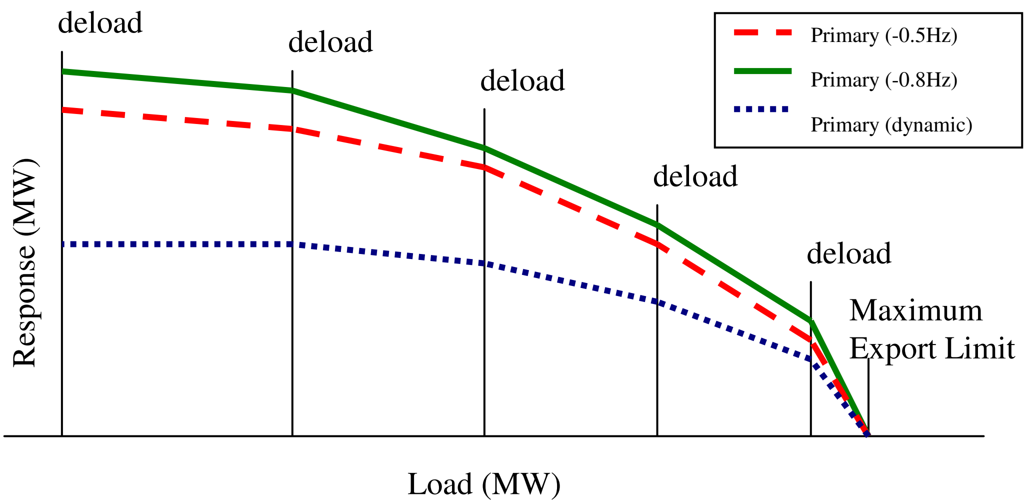


Figure 4.7 - Example generator response profile curve

Response contracts between National Grid and Balancing Mechanism Units are confirmed by response profiles (Figure 4.7) 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 established through compliance 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 more response in comparison with other units, as we have seen. 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.

If an insufficient level of response is held on the system, frequency will drop outside of specified limits thus breaching the operating license. A set of similar curves to Figure 4.3 would be presented if simulations on response levels had been considered.

4.3 Techniques to model the response holding requirement

In a power system, frequency response is a complex topic that unfortunately always has to be considered second place to active generation despatch itself. Operational decisions are made based on data derived from network models of the physical system, these models ensure operational limits are not breached. The complete dynamic process influencing the power system is described by CIGRÉ(1997) as an interaction between the demand characteristics, all the generators with their associated control characteristics, and the transmission system performance. The overall system exhibits non-linear behaviour with respect to frequency, and this entails a very complex model.

The window for frequency balancing has already been established in the British case, and the initial 30 seconds is seen as the optimum time within which to reach the minimum frequency. Consideration of the subsequent few minutes is required to reach a steady state frequency under the secondary response holding. Under these conditions stability is assumed to be inherent. These specific timescales require analysis through programs designed for the study of stability and long term dynamics (Figure 4.8).

A number of existing techniques used to model frequency response are recorded in literature sources. A selected number of these techniques are presented in the following paragraphs.

In modelling reserve requirements in New Zealand, the electricity regulations require that a “Reserves Management Tool” is implemented by the system operator, Transpower(2000). The tool relies on a set of system models, Figure 4.9 and Figure 4.10, to represent the dynamics of the North and South Islands. The model neglects the transmission network favouring a simple single order active load model, which is balanced against generation to provide a measure of frequency. An injected contingency provides the means to assess the level of reserve required from generator governor models to secure the event against appropriate frequency obligations.

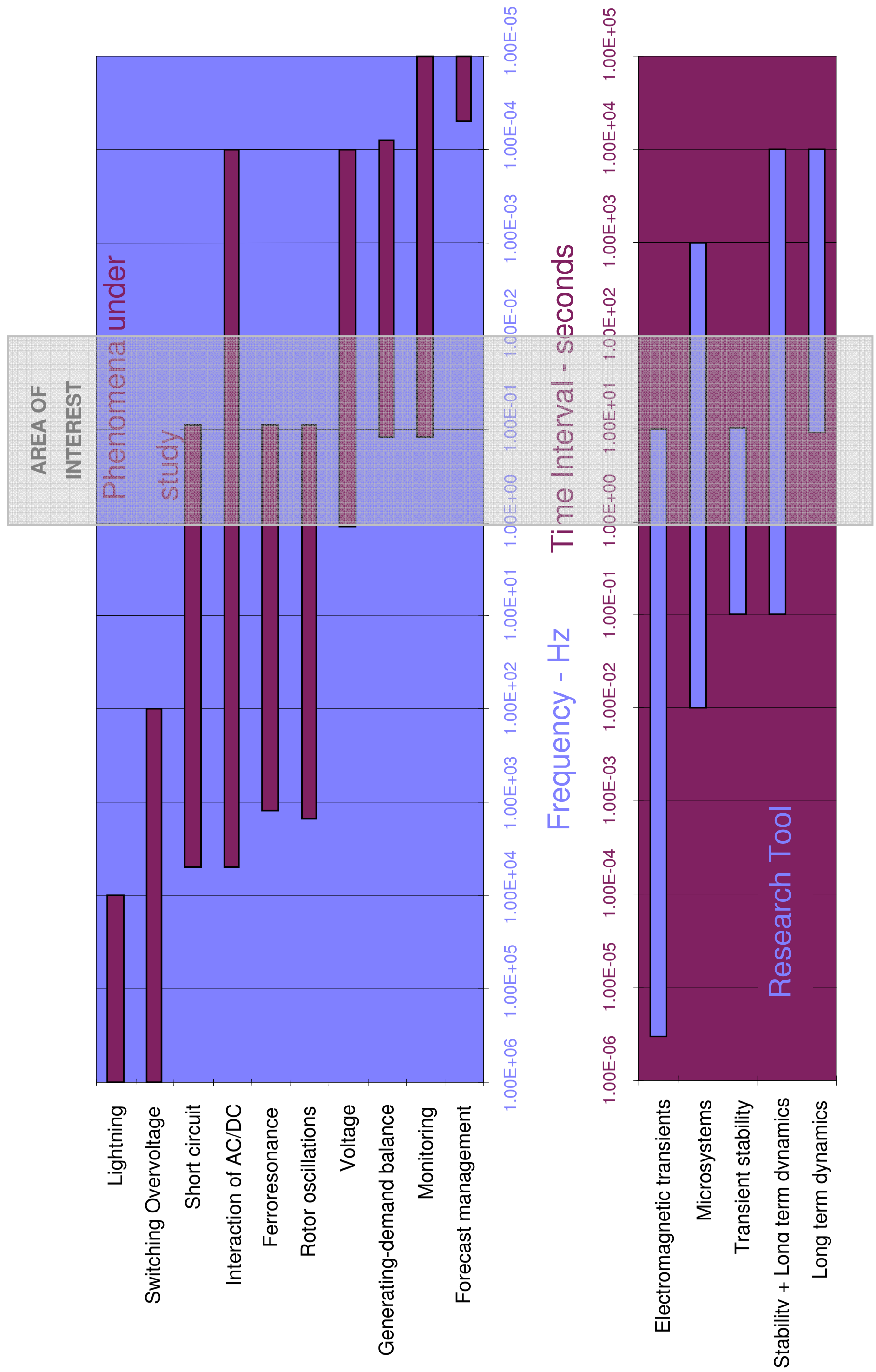


Figure 4.8 – Transient phenomena

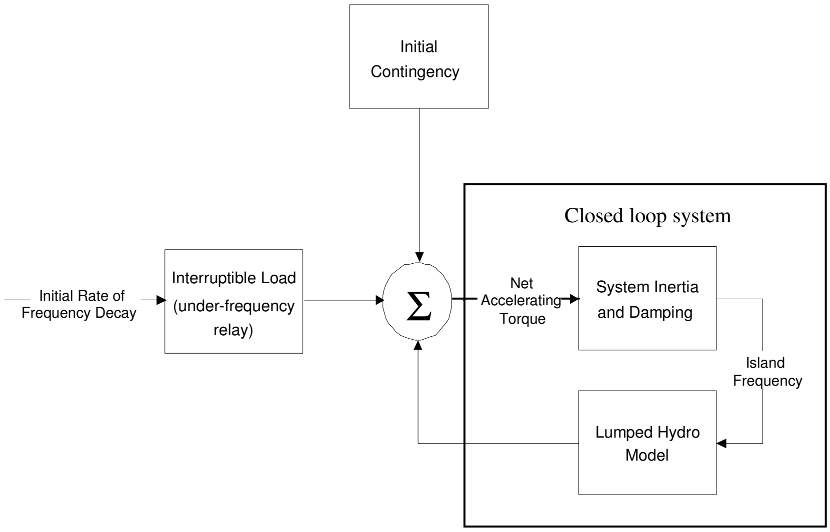


Figure 4.9 - New Zealand, south island dynamic model

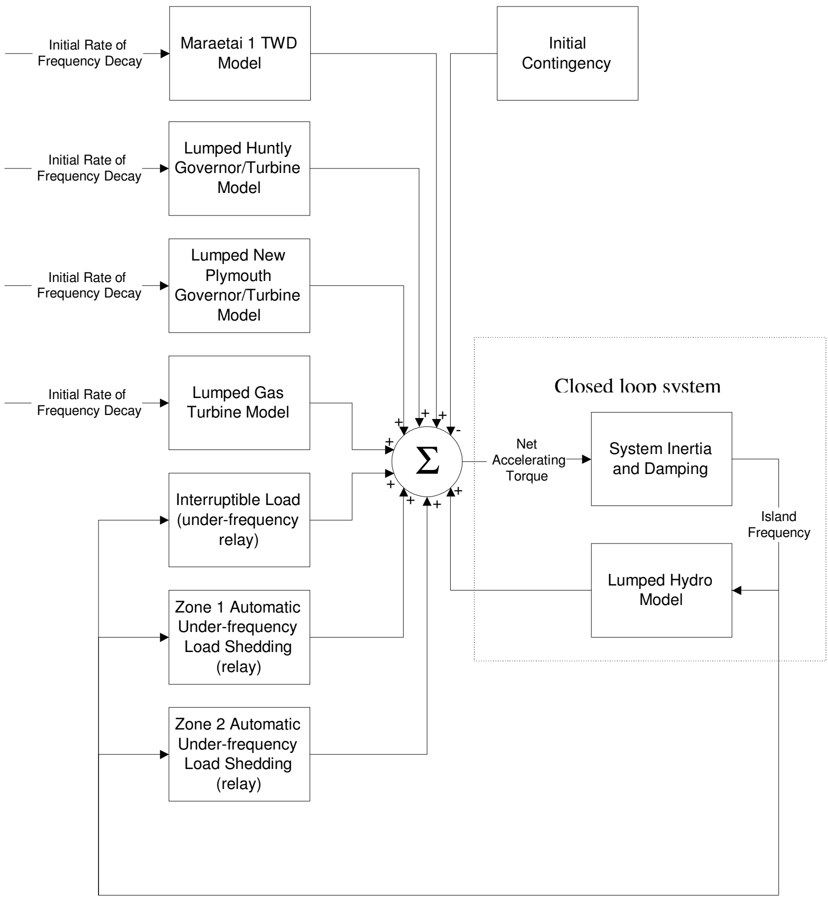


Figure 4.10 – New Zealand, north island dynamic model

In Ireland an initial model of the ESBNG system was developed by O'Sulivan *et al*(1996) and (1999). This model was specifically designed to represent the isolated electricity system in the Republic of Ireland in 1996. The simulations utilised large thermal generators modelled through simple boiler and steam turbine models. Validation was performed using system data from tests and also comparisons with a number of system frequency events. In Northern Ireland a similar model was developed to examine system reliability and response of units to frequency events, Thompson and fox(1994).

The ESBNG model combined with a dynamic model of the NIE system formed an updated model to provide an accurate reproduction of the entire Irish electricity system in research conducted by Lalor *et al* (2005b). The developed model of the all Ireland system, Figure 4.11, is currently being used to study the impact of frequency control on the Irish system.

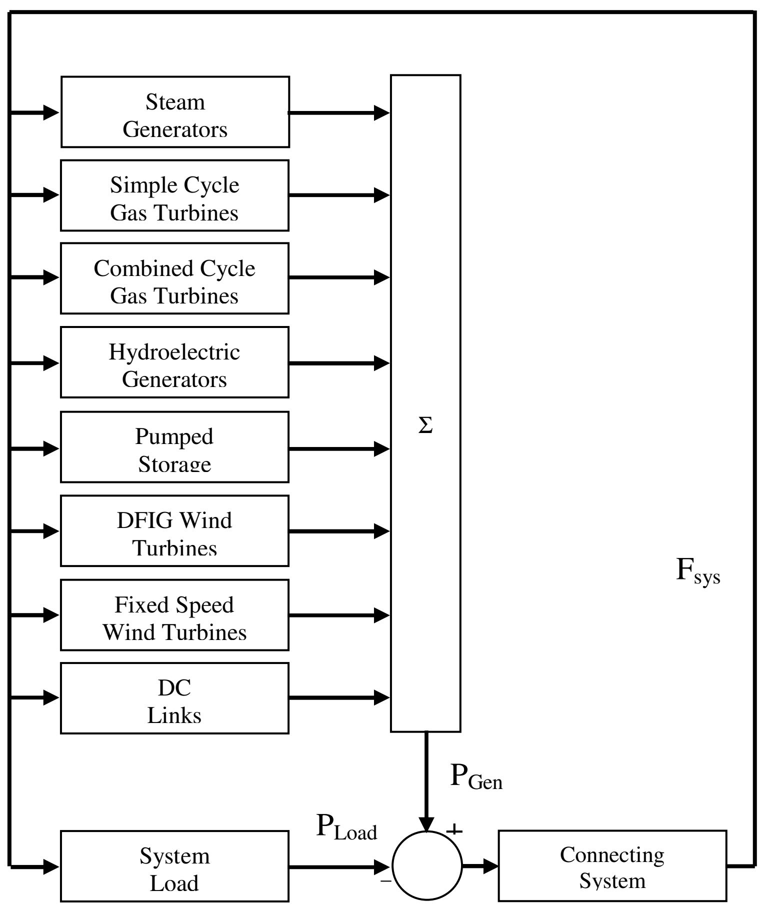


Figure 4.11 - Irish dynamic model

Inoue *et al.*(1997) and Welfonder(1997) provide a similar representation to the previous two models with lumped generator types represented against a simple network load model. Chan *et al.*(1972) have published techniques for analysis of system frequency using the same models but with individual generator representation.

So called low or reduced order models from Adibi *et al.*(1999), Anderson and Mirheydar(1990), Weber *et al.*(1997) or and (1997) generalise the system generator response into a single transfer function. These techniques can all be summarised as simplified equivalent dynamic models for establishing average system frequency. Each can be adapted for use in calculating a frequency response requirement. Stefopoulos *et al* (2005) present a genetic algorithm approach to identify system parameters used in these low-order models. Instead of identification and verification of individual machine parameters the procedure attempts the simultaneous estimation of all system-wide generator parameters. A generic governor model is used to describe the system as in figure 4.12.

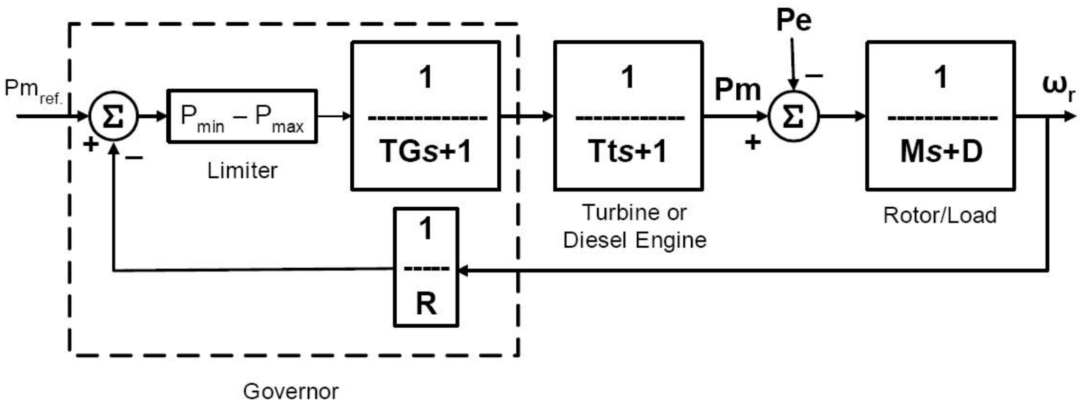


Figure 4.12 – System transfer function

As is the case with all of these models, they do not fully represent the impacts of every element of the power system. The techniques each assume that the system is transiently stable following any generator loss, and so the transmission network can be neglected. This assumption requires a uniform frequency and voltage 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.

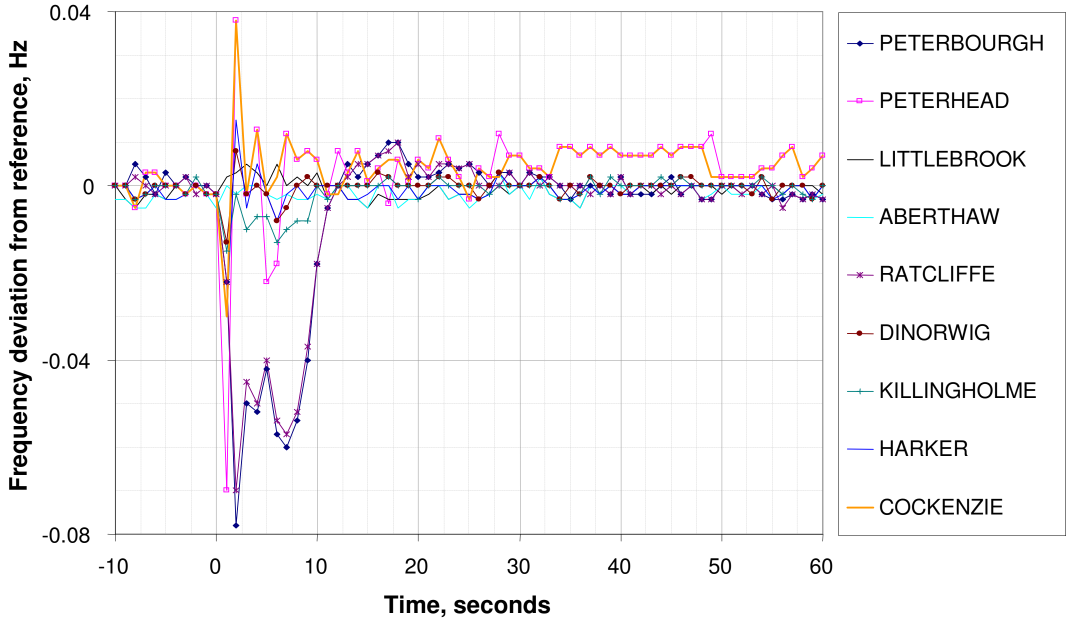


Figure 4.13 – Impact of location on grid frequency

However, it should be recognised that the variation of the voltage following a disturbance is mainly felt locally and on short scales of time. In the same way, the effects of system frequency last only 5 to 10 seconds and are limited geographically. Beyond a certain distance, the instantaneous frequency deviations are similar. Figure 4.13 gives an account of measured deviations from a local grid frequency (Didcot substation) and nine other sites in Britain. The loss of generation in this instance was in Scotland, with Peterhead and Cockenzie experiencing the most volatile frequency swings. The next sites (Ratcliffe and Peterbourgh) going south are also out of sync with the base frequency. The locations are never more than around 0.08 Hz from the system average frequency, with most units never deviating by more than 0.01 Hz.

In neglecting the transmission network these methods also prevent any system losses from being integrated into the simulations.

Benejean(1995) found through studies on the European system, that transfer function representation restricts interactions between the frequency and the voltage, and thus the effects related to the structure of the network cannot be modelled. From his discussion, phenomena related to the network in this context following a disturbance are mainly:

- variations of voltage, generally localized with an area;

- measurements of frequency, dependant on the electric distance between the point of the disturbance and the place of measurement;

- the distribution of power transits in the lines.

Some full model simulations exist with a high level of network representation, these simulations are either on smaller networks, as in the case of Kelly *et al.*(1994) and Sharma (1998), or much larger systems Bondareva *et al.*(2004) and Pereira *et al.*(2002). Results cannot be used as a direct comparison with expected results in Britain.

4.4 A solution to model frequency response on the British grid

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 long term dynamics. Implementing EUROSTAG for the studies of grid frequency, compared to a simpler method using transfer function representation, allows the representation of the network to be incorporated.

This choice of the software is justified following the need to represent factors that have significant effect on the simulation of frequency, as set out by Benejean (1995):

- the dynamics of the generators and the voltage regulators;
- rate of power change of the generators;
- the disruption of the reserves due to modification by transits;
- propagation of the frequency and the voltage which involve reactions different from the generators according to their geographical site compared to the disturbance;
- loads and their sensitivity to the frequency and the voltage.

Using an initial user specified network representation a load-flow calculation can be executed based on the Newton-Raphson method. This produces a detailed voltage map, which can then be used to initialise the simulation. The online interactive dynamic simulation program provides the core algorithm solving a large number of algebraic and differential system equations simultaneously. The differential elements relate to the machines and the control equations, and the algebraic parts originating 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.

The simulation package has extensive modelling capabilities. In addition to the library, 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. Loads are represented by a non-linear equation as a function of voltage and frequency, but dynamic models are also possible via macro-blocks. The dynamic effect of low-voltage level tap changers can also be modelled. Reactive compensators are represented as single elements or as banks.

Induction machines can be modelled as a "complete" model which assumes the existence of a double rotor cage, or a "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 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.

A Macro-block language represents the dynamic actions of machines to voltage and frequency. Each generator has an associated exciter 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 deactivate/activate is determined by evaluation of equations describing their behaviour. The equations describing the automations are evaluated after each integration step, enabling the representation of automatic tap changers for transformers. Automatic load shedding systems for the simulation of demand based response are also possible using these automations.

4.5 The frequency response model

As recommended in the Cigré report 148, the grid model proposed for use in the simulation studies of this project is mainly composed of the 400 kV and 275 kV transmission system, National Grid(2006b). Some of the low voltage infrastructure exists to connect remote generators to the system, keeping the model as close actual grid configuration as is possible. Appendix B contains details of the simulation network and a low level system diagram. The modelling of the loads is traditional, with a set of parameters provided to make them sensitive to the fluctuations of frequency.

The system generators are represented by their exciter, governor and machine parameters. Existing machine parameters can be implemented from generator submission data and similarly exciter models coded into the Eurostag macroblock language. To ensure sufficient representation of active power output a set of governor models are required in the Eurostag code. These models require validation to provide an accurate representation of machines during real events.

Transits simulated by the model will start from a real case with reactive compensation plant switched according to system records. Iterative refinement of the proportion of responsive plant will establish levels of primary and secondary response required to secure the system within limits. This process may then be repeated at alternative national demand levels for a range of different loss scenarios.

4.5 Summary

The network simulations have shown that in modelling grid frequency generator dynamics and the load sensitivity has the most dramatic effect on the final results. A conscious effort must be made to provide realistic representation of these quantities in simulations to minimise any error. Low-order models using transfer functions should be avoided in favour of tools that offer a full network representation.

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. Simulations can be applied to revisit the current frequency response requirements to ensure excess response, and thus excess emissions through poor efficiency levels are not encountered. In Addition, simulations can also be implemented to examine the affect of changing the generation mix. Specifically, the affects caused by the operation of more wind turbines on the system response requirement.

Chapter 5

Dynamic Generator Models for Response Studies

Chapter 5 introduces the main types of generation found on the British grid. The operations of the three major categories of plant used for frequency response services are discussed in detail. Available literature on modelling these generators for response studies is examined. A number of models are presented for the simulation of traditional coal and hydroelectric units building upon existing models from the literature sources. Simulations with an existing gas turbine model highlighted the need for specific models to represent combined cycle units. A novel model developed through three fundamental gas turbine equations is presented. Validation of all the models confirmed levels of frequency response inline with historic data.

5.1 Overview of types of generation on the GB grid

An overview of the British grid was given in section 3.1 together with details of the transmission system. To expand on this, the current grid connected generation capacity of the system is in the order of 74 GW. Figure 5.1 breaks down the generation into various fuel types and shows a diverse portfolio of generation.

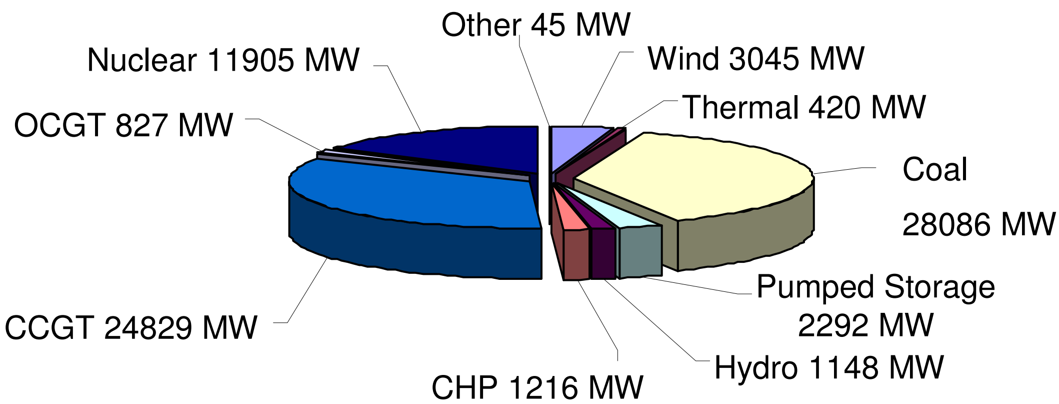


Figure 5.1 - GB generation capacity by fuel types[source from the DTI]

Using data accumulated from plant decommissioning dates, known outages and connection agreements, National Grid(2006b), it is possible to project the generation mix at the turn of the decade. Figure 5.2 shows the projected changes in installed capacity from 2004 to 2012.

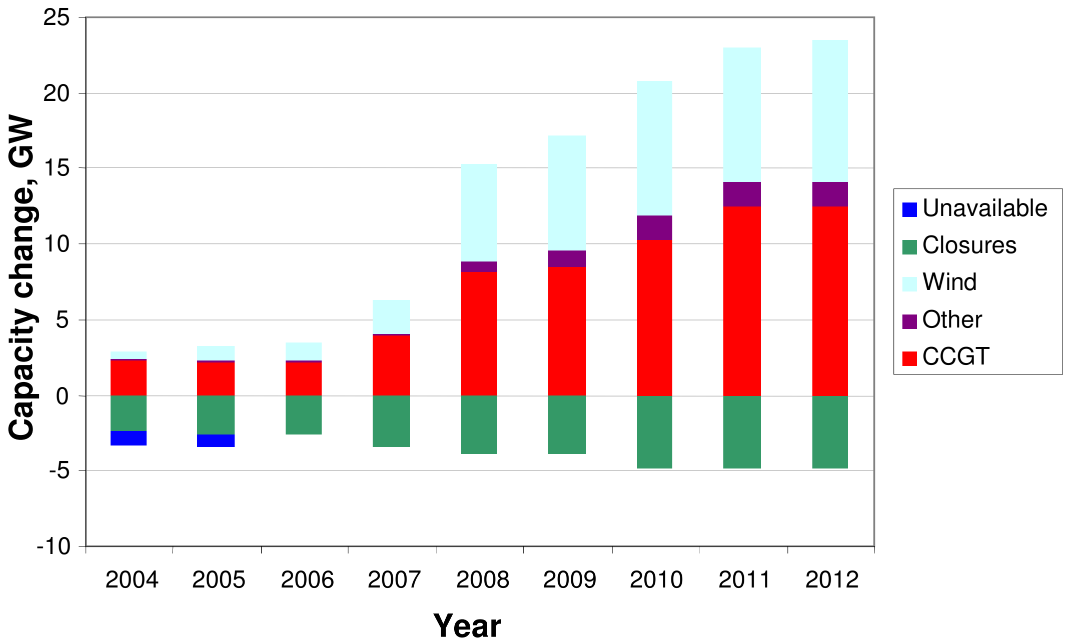


Figure 5.2 – Changes in GB generation 2004 to 2012

Inspection of Figure 5.2 reveals that the aggregate power station capacity rises from 76 GW in 2006 to 94.5 GW by 2012. This is an increase of 18.2 GW (23.8 %), and this net increase is made of the following:

an increase of 9.7GW in CCGT capacity (12.7%);

an increase of 4.9GW in on-shore wind generation capacity (6.4%);

an increase of 3.3GW in off-shore wind generation capacity (4.3%);

an increase of 1.3GW in new import capability (1.7%);

an increase of 601MW in CHP capacity (0.77%);

an increase of 554MW in Pumped Storage and Hydro capacity (0.73%);

an increase of 135MW in Coal capacity (0.18%);

a decrease of 2.3GW in Nuclear Magnox capacity (3.1%).

The largest proportion of the overall increase is due to CCGT plant followed closely by the increase in both on and off-shore wind. On this basis, the capacity of CCGT plant would overtake that of coal in 2008, dominating the generation mix by 2012. Similarly, wind generation capacity (both on-shore and off-shore) is set to rise to 9.4GW by 2012. These capacities do not reflect changes in embedded generation levels. This data is projected from current data and it is not unreasonable to assume that new applications for power station connections may be received. It is also plausible that some existing contracts/power stations may be modified or terminated.

Although currently the main growth in renewable generation is seen as wind power, significant contributions from tidal and wave machines may be possible. Increased investment in research and development of marine renewables has taken place in recent years. It is highly likely that this form of generation will pose a realistic prospect for large scale generation projects after 2010.

5.2 Dynamic models of thermal plant

Synchronous induction machine models are required to capture the dynamics of most grid connected power stations. 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 δ) and shaft dynamics (relating to shaft speed ω). The main control elements of an electric generator are given in Figure 5.3. Two basic control elements are required the automatic voltage regulator (AVR), which controls output voltage, and the governor controlling the transfer of mechanical power to the generator shaft.

The AVR normally supplies field current for a synchronous generator and is sometimes referred to as the *excitation system*. The excitation system is normally thought of as a control for voltage, but it also indirectly affects the reactive power levels. The IEEE periodically issue recommendations for modelling excitation systems (1992), details can also be found in Mummert (1999). National Grid already has many excitation models developed for specific in-house simulation software such as RASM which models network voltage stability. These models are submitted as a condition of plant connection to the grid.

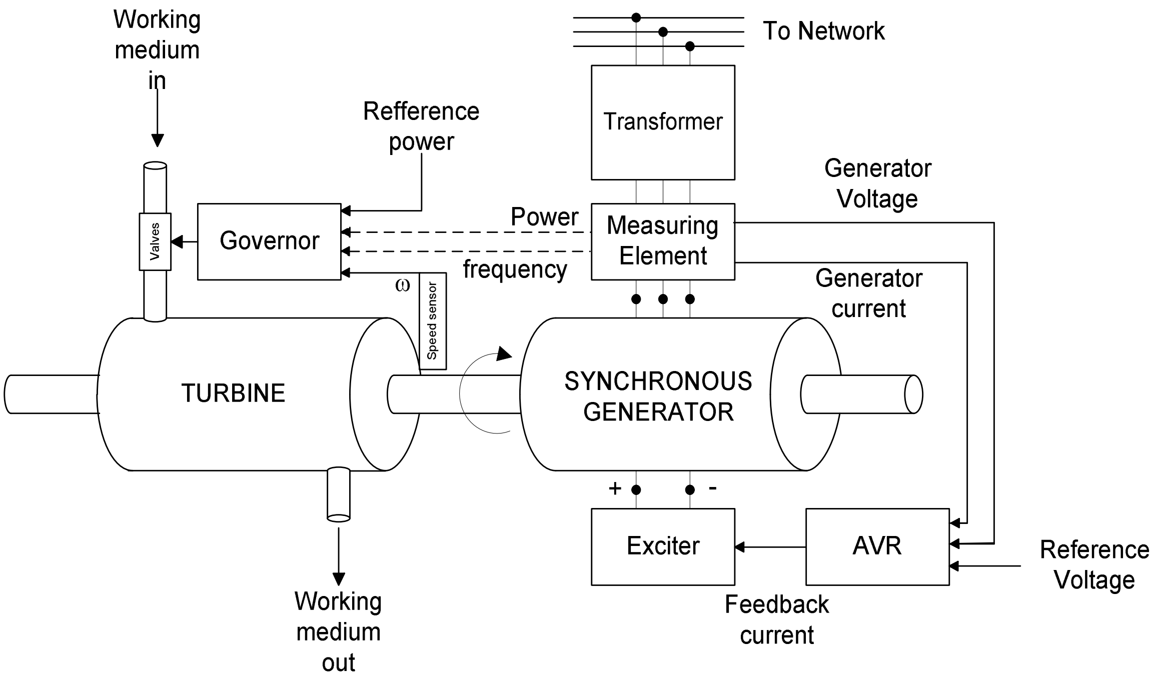


Figure 5.3 - Block diagram of generator control system

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/load reference of the governor.

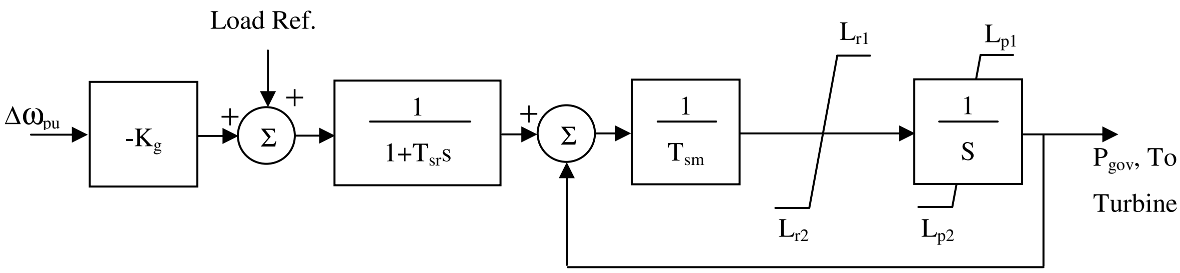
$$\rho_G\% = \frac{f_{nl} - f_{fl}}{f_o} \times 100\%$$

Equation 5.1

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 5.1.

The generator droop characteristic for a UK generator ranges from 3 5 % as defined in the Grid Code. A typical value for plant is 4 %, which means that a frequency deviation of 2 Hz causes a 100 % change in the generator output. Units that operate with a lower speed droop are more responsive to changes in system frequency. All grid connected generators are equipped with governor units, which are ideally matched to specific turbines. As a general rule most stations will provide a secondary response of around 10 15 percent of registered capacity on a frequency deviation of -0.5 Hz.

Figure 5.4, details a typical generating plant governor model. The deviation from system frequency is multiplied by the inverse droop and added to the load reference of the machine. The load reference is the desired machine output at nominal frequency. This error signal is then feed thought a simple lag function and delay due to the servo actuator. The final control signal, which is fed into functions detailing the turbine dynamics, is both rate and position limited.



K_R = 1/Droop T_{sr} = Time constant T_{sm} = Servo time constant L_{r*} = Rate limit L_{p*} = Position limit

Figure 5.4 - Governor transfer function

Generation plants take advantage of several different forms of primary energy sources ranging from the traditional coal burning types to modern fuel cell technologies for distributed generation. In most cases a fuel is oxidised to release energy which is then transported to required the load through the transmission network. Every single generating set is unique and operates with a slightly different dynamic property. The individual plant properties will collectively affect the dynamic response of the system. For this reason, a comprehensive set of models is required to represent how the different plant types operate, and is essential for evaluation of system frequency.

Of all the nuclear units only pressurised water reactors (PWR) can operate at part-load and hence offer responsive services in the balancing market. However, nuclear generation is not called upon to supply reserve for frequency response in Great Britain and so it is not considered here.

5.3 Models for coal fired generators

In coal-fired stations pulverised fuel is blown into the furnace where it mixes with air and combusts. Steam is produce from the burning of the primary fuel source in either drum or once-through boilers.

5.3.1 Boiler dynamics

Drum boilers, Figure 5.5a, rely on convection or forced circulation to transfer heat from the furnace walls to the water. In these boilers the steaming rate is a direct function of the heat absorbed in the furnace (the fuel-firing rate). Drum boilers can still deliver power without any fuel flow into the furnace, useful for supplying primary response. This system operates at sub-critical pressures relying on a density difference between the steam and water phases for circulation.

Once-through boilers, Figure 5.5b, 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.

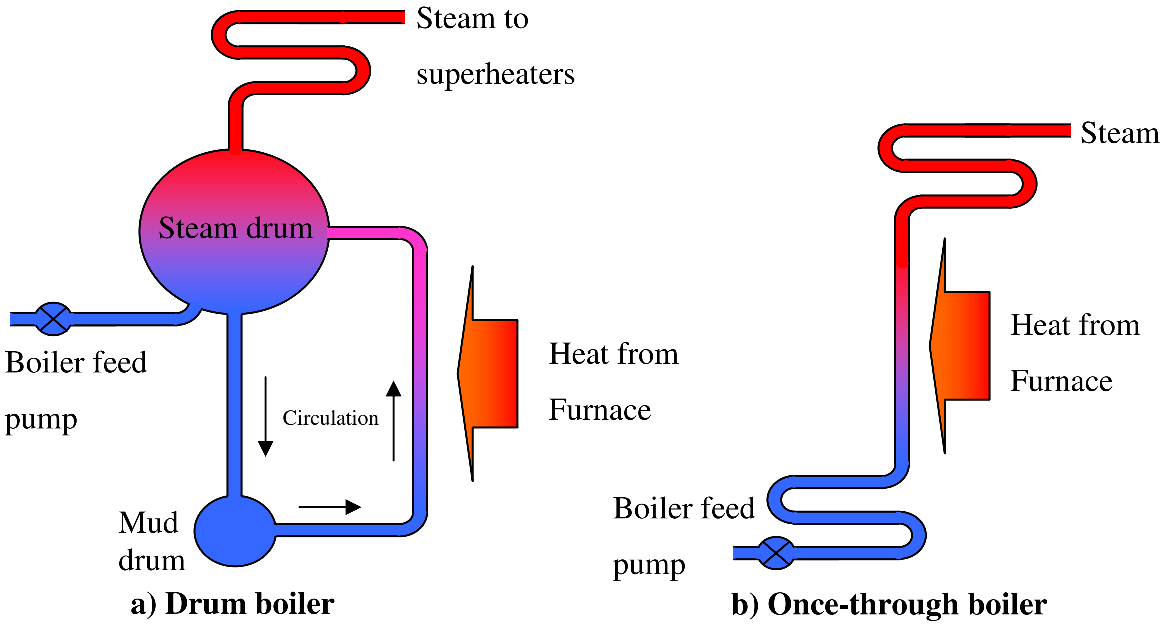


Figure 5.5 - Typical steam boiler arrangements used in power stations

Most of the older coal fired units on the British grid are equipped with the more traditional drum type boilers. As units become modernised it is likely that the once-through boilers will be favoured. The boiler control systems themselves are varied but most can be generalised into two different categories, process parameter control, and more commonly unit control, which includes:

Boiler-following	Generation is controlled by the turbine valves, boiler controls respond to changes in steam pressure by changing steam production. The deviation of throttle pressure from its setpoint provides an error signal feedback into boiler controls.
Turbine-following	Generation is controlled by the boiler input, turbine control valves regulate the boiler pressure.
Integrated	A mix of boiler and turbine following modes
Sliding pressure	Valves are set at optimum points (typically wide open) turbine output is controlled through boiler controls. Similar to boiler-following mode.

In boiler-following mode stored energy is released quickly causing a fast initial response, boiler firing then restores steam levels after an initial pressure drop. In turbine-following mode no use is made of stored boiler energy and steam flow is directly related to generator output Figure 5.6.

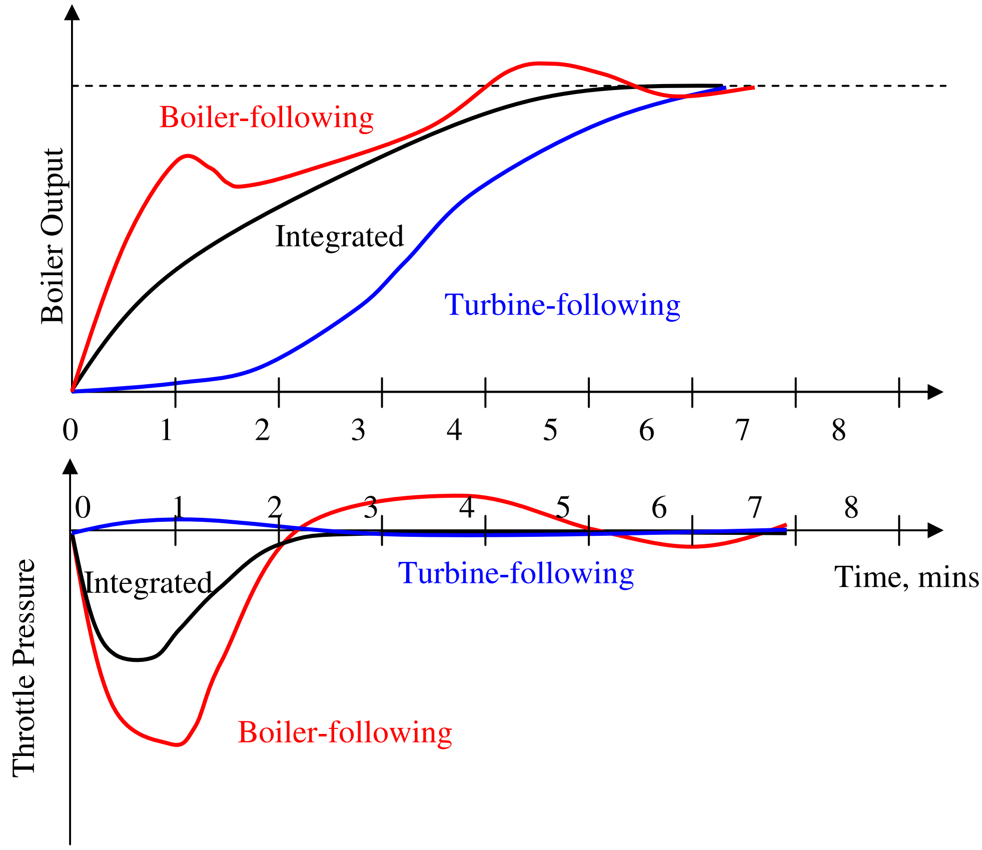


Figure 5.6 - Dynamic behaviour of steam boiler controls

Models for including boiler dynamics have been presented by de Mello(1991). A simple representation for frequency response studies is given in Figure 5.7, a typical boiler time constant (T_{Boiler}) is in the order of 200 seconds.

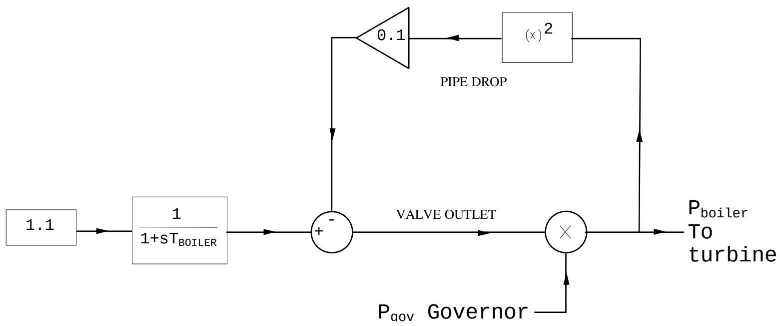


Figure 5.7 - Model for influence of steam boiler on plant response

5.3.2 Steam turbine

The high pressure, high temperature steam raised in the boilers is fed into sets of axial flow turbines. As the steam passes through the turbine stages it looses pressure and expands in volume. Between stages the steam can be taped of and reheated to increase operating efficiency.

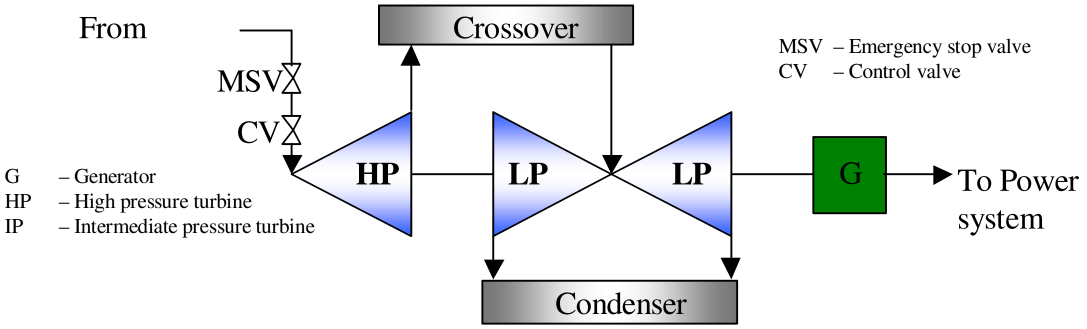


Figure 5.8 - Non-reheat steam turbine

Steam turbines are categorised by the way in which steam is reheated. Non-reheat turbines like those in Figure 5.8 usually have one stage and typically operate below 100 MW. The more common arrangement for high power turbines is the single tandem reheat configuration shown in Figure 5.9.

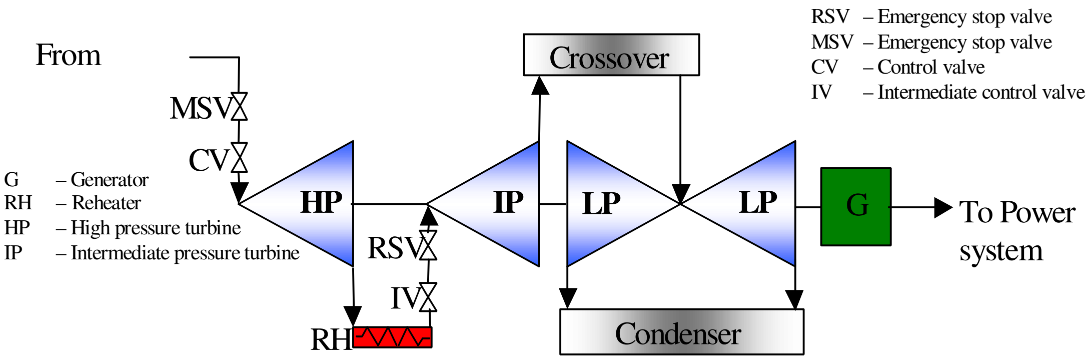


Figure 5.9 - Single reheat steam turbine

Three stages mean the turbine has a high operating efficiency. Steam from the boiler passes through the governor control valves into the high-pressure stage. After the steam is reheated it passes through more control valves to the intermediate stage. Then the steam passes via crossover piping into the low-pressure turbine for the last expansion stage, where it is finally released as exhaust into a condenser. Double reheat turbines are also in use in some generating plant Figure 5.10; these turbines have a very-high-pressure stage at the start of the cycle.

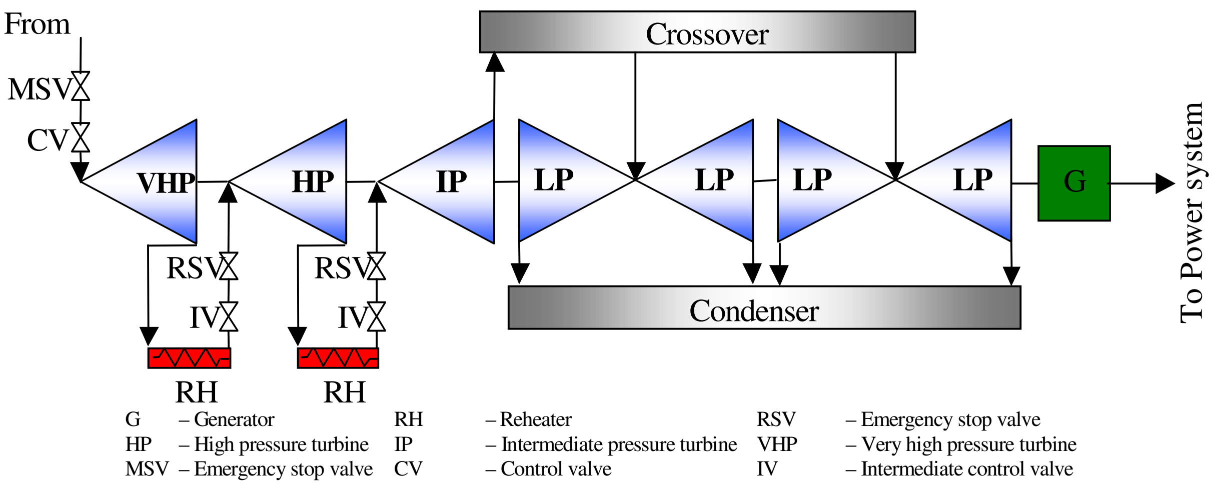


Figure 5.10 - Double reheat steam turbine

Most steam turbine configurations rely on more than one pressure stage with less than 30 percent of the output power coming 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 to the dynamic operation of the unit, and is a significant influence.

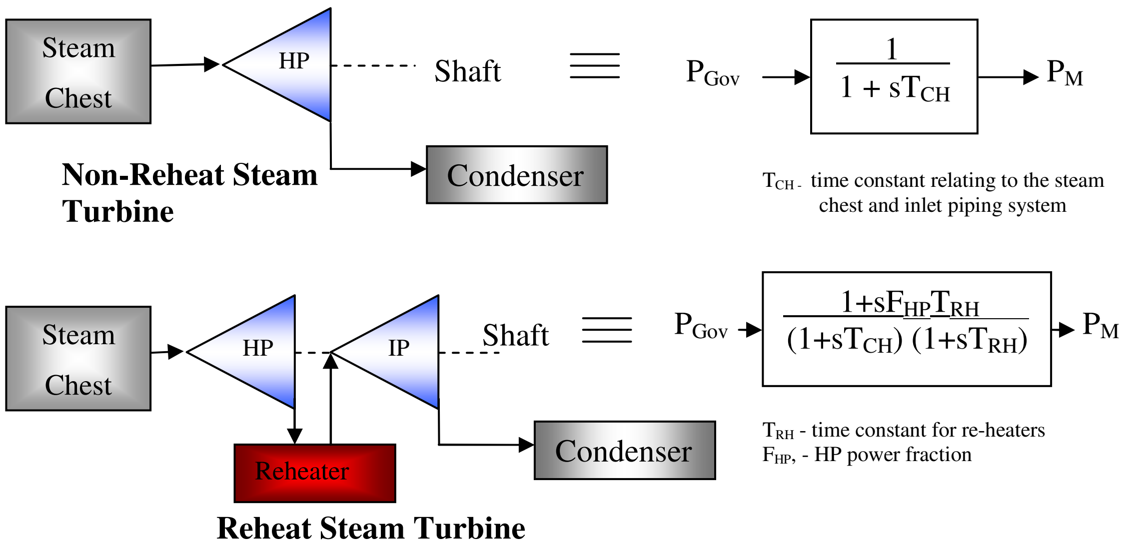


Figure 5.11 – Simple steam turbine models

In modelling a unit the output from the governor model feeds into a steam turbine model. A number of models have been published by the Working Group on prime mover and energy supply models for system dynamic performance studies(1991). Some papers covering steam and hydro turbines are also available; IEEE Committee report(1999), Bize and Hurley(1999*)*, and Bourles *et al.*(1997). Simple transfer models of non-reheat and reheat turbines are given in Figure 5.11.

These two general models can be expanded to Figure 5.12, which by selecting appropriate time constants and values for $k_{1\text{-}4}$, gives a generic model for all plant configurations mentioned previously.

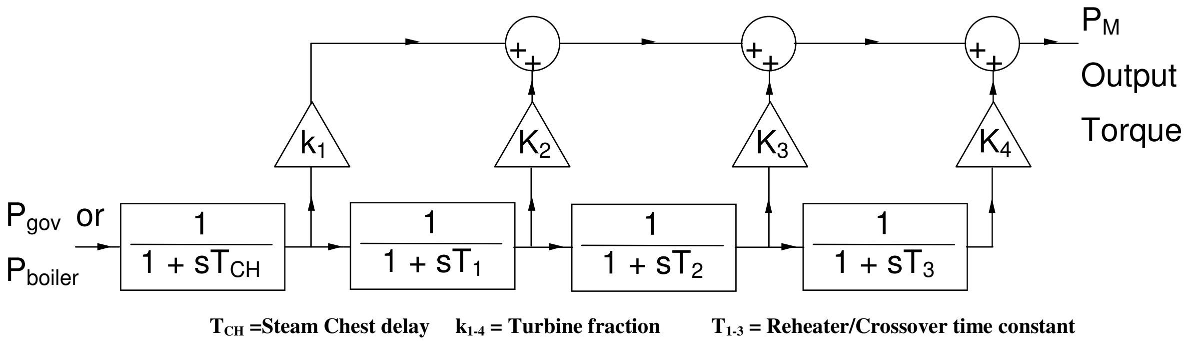


Figure 5.12 – Generic steam turbine model

A typical delay for steam chest and crossovers is in the order of 0.3–0.4 seconds. As re-heaters redirect steam through the boiler a longer period of around 7 seconds is required. The most common configuration on the British grid is the single reheat steam turbine, typical HP/IP/LP fractions are 0.3:0.4:0.3 and can be substituted for k_1, k_2 and k_3 respectively. Double reheat fractions steam are typically 0.22:0.22:0.3:0.26.

5.3.3 Frequency responsive coal fired models

The standard coal fired models, discussed in the preceding section, must conform to real life behaviour if they are to be used for network simulation studies. Simulations against compliance tests can be used to confirm or denied a satisfactory reproduction of plant responses. Compliance tests form a basis to demonstrate alignment with the Grid Code and are conducted on all grid-connected and large embedded plant. Various frequency injection signals are provided to the governor in order to simulate the grid frequency during a real transient. The models are synchronised on a full network simulation, as the generating stations would have been. The output response of the model may then be compared with monitored power from the generator.

In the case of responsive coal fired plant, under normal operation, implementing a governor model from literature sources with associated steam delays provides an adequate representation of performance. However, for the purposes of frequency response, the plant may reach an excursion down to 49.2 Hz. Simulations under these more extreme conditions revealed that a degree of model tuning was required to match the performance seen in actual events. Generally, plant required a droop adjustment of between 0.1 and 0.5 percent on a standardised droop of four percent. This brought a number of generator simulations into tight tolerances with responses recorded from historic events.

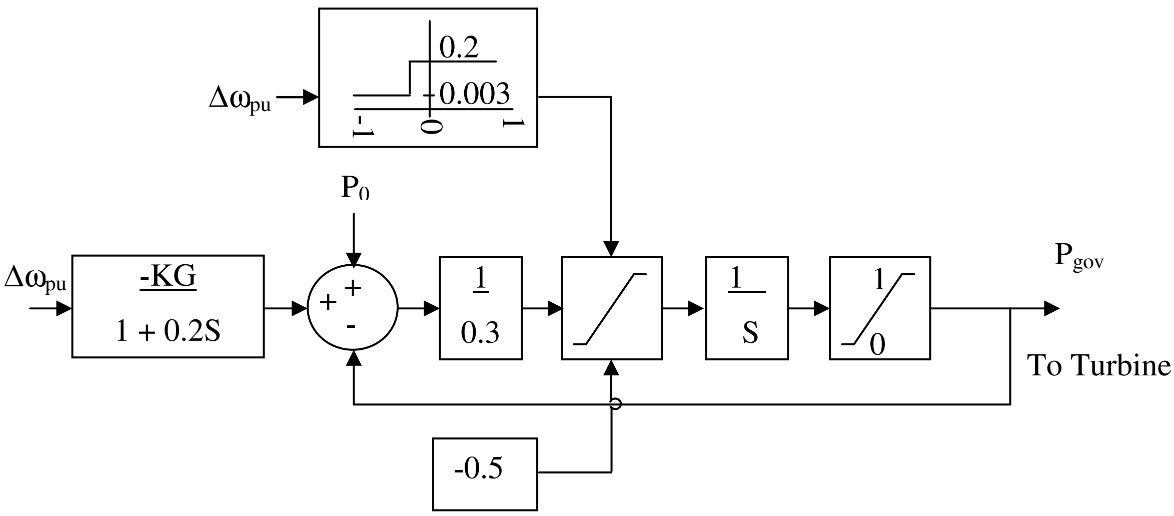


Figure 5.13 - Modification to coal governor to allow frequency triggered rate-limit

It was also observed that a number of coal fired generators operated with a variable rate-limited response. In these cases, a rate limit was seemingly triggered when the minimum operational frequency was breached. To incorporate this strategy, new control blocks were required in the governor model to limit the rate of control valve opening, as shown in Figure 5.13. These rate-limits ranged from 0.01-0.03 pu.s^{-1} among the generating stations that operated under this strategy. The chief reasoning behind operating plant in this manner is to reduce thermal loading in steam pipes and boiler water walls. Operating under this methodology prolongs component life and reduces refurbishment costs for generating stations. Comparisons with Figure 5.4 show the main alterations made in the model.

The remaining coal fired stations that did not respond in line with the rate-limited model or the standard model for the large frequency excursions operated with a limited peak output. This output was proportional to the experienced drop in frequency. Again modification to the governor model was required, this time the position limits (Figure 5.14) were varied according to the load set-point. Again, comparisons against Figure 5.4 show the main alterations made in the model.

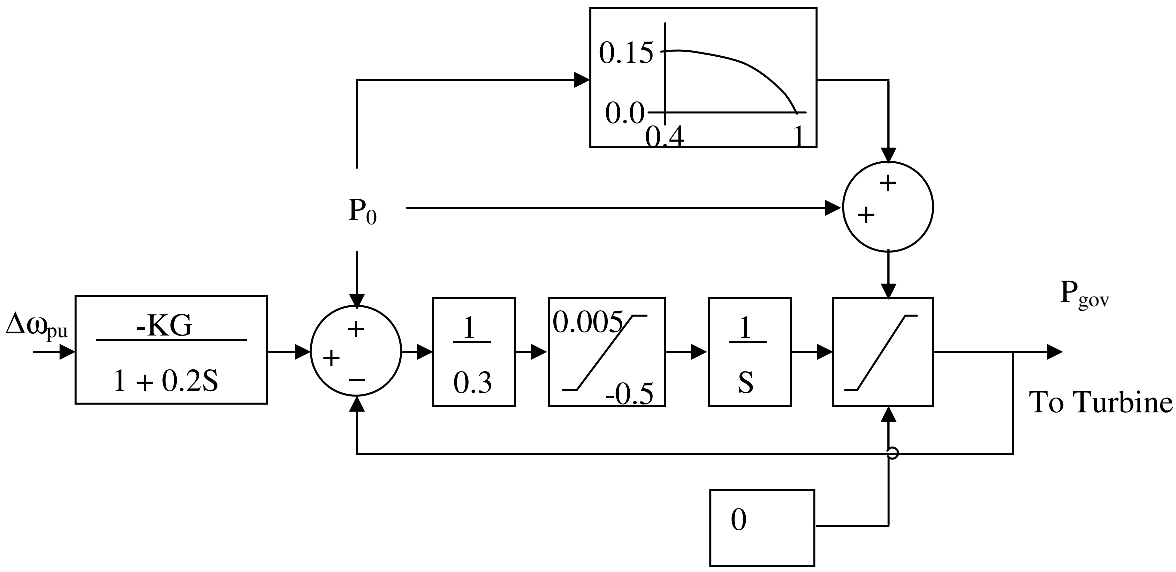


Figure 5.14 - Modification to coal governor to allow an output-limit

These two adaptations together with the standardised model provided good simulation results with all the coal fired BMUs. A number of further trials conducted with system incidents at different operating points increased confidence in the models. A selection of these validation trials are presented in section 5.5.

5.4 Models for combined cycle gas turbines

Open cycle gas turbines (OCGT's) directly combust 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 5.15, 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 may be used to pre-heat incoming air. The gas turbine drive shaft is connected to a generator and provides the necessary torque for electrical generation.

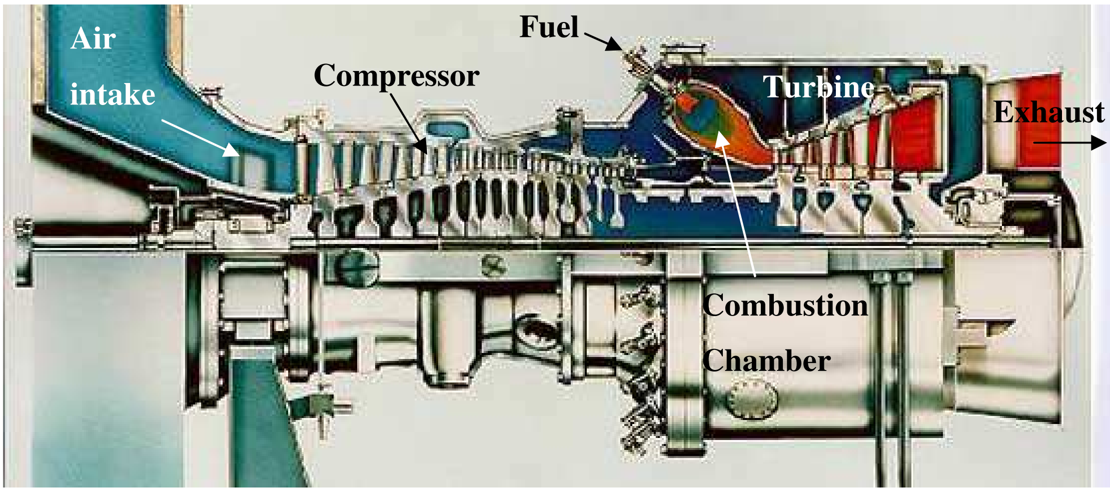


Figure 5.15 - Diagram of a simple gas turbine

In recent years the combined cycle gas turbine or CCGT has become increasingly dominant in the industry. It uses heat recovered from the OCGT process to raise steam, which can then be used to drive an addition steam turbine. Initially CCGT units where developed to provide maximum efficiency and expected to operate as base load plant. In the early stages of deployment National Grid entered discussions with a number of CCGT manufactures to encourage the improvement of part load performance to ensure that plant could offer a frequency response capability.

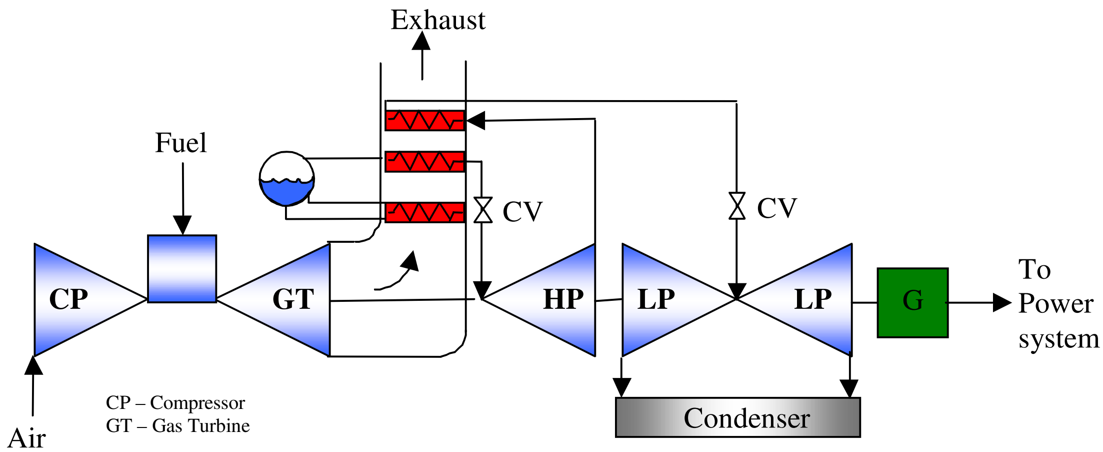


Figure 5.16 - Single shaft tandem plant configuration

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 have a gas and steam turbine (half the gas turbine rating) on the same drive shaft, Figure 5.16. Multi-shaft plants utilise two gas turbines that drive individual generators and are mechanically isolated to support a standalone steam turbine, Figure 5.17. Multi-shaft configurations are the most common arrangements to be found connected to the GB grid because they were initially favoured. Some of the smaller capacity plant is of the single shaft variety of CCGT.

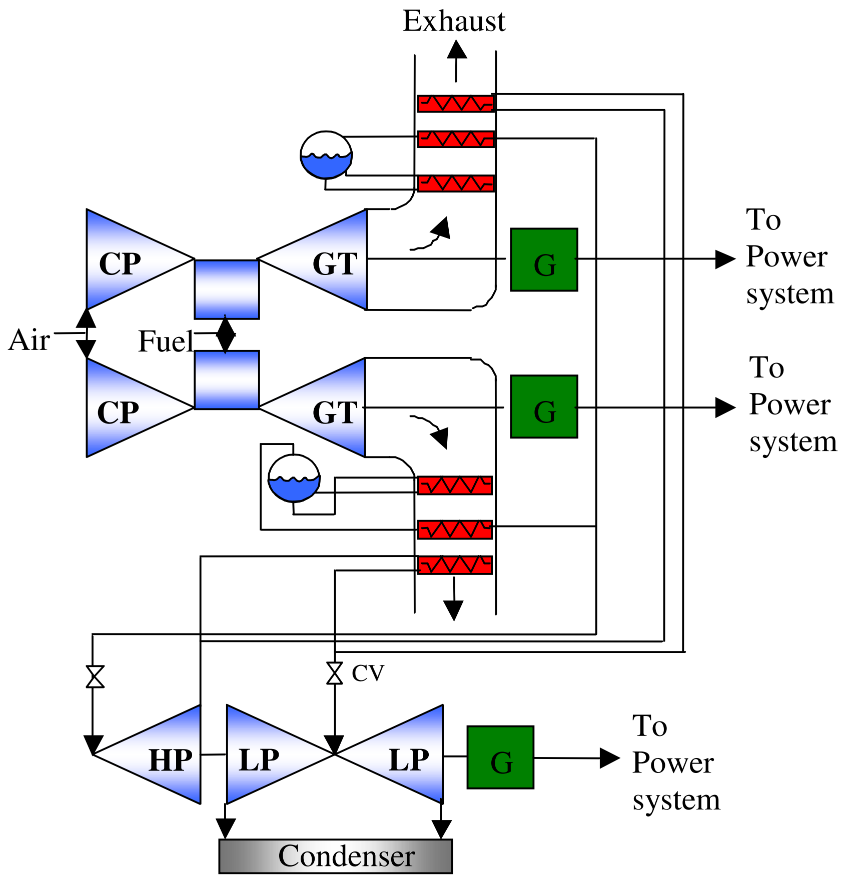


Figure 5.17 - Multi-shaft plant configuration

Multi-shaft plants which may consist of HP, IP and LP steam stages many 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 turbine in both cases operates in a ‘turbine follow’ mode and the steam consumed in the 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 usual for the steam turbine to operate in sliding pressure mode, in which its main control valves are normally fully open. Under this arrangement the output from the steam turbine changes at a much slower rate than the gas turbines. This is mainly due to influences from the storage of steam in the drums, headers and other piping. This means that whilst the gas turbine response is quick with evaporation rates in the boilers being equally quick the storage in the steam delivery system prevents any primary response from being realised in the steam turbine.

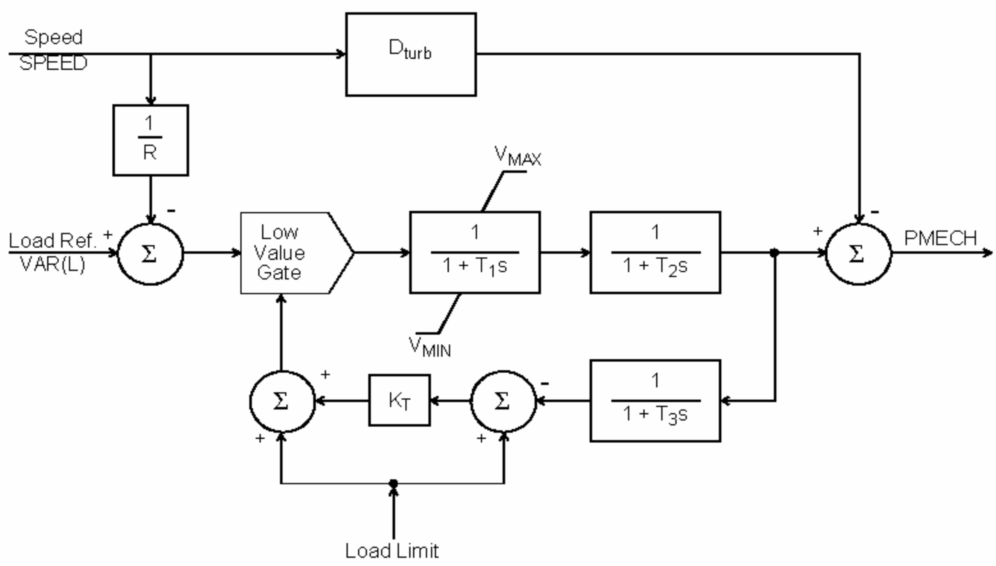


Figure 5.18 – Open cycle gas turbine model

To simplify the model used in frequency response simulations a generic open cycle gas turbine (OCGT) model developed for long-term dynamic transmission studies was employed for all grid-connected CCGT generators, Figure 5.18. It was noted through assessment against large frequency excursions that this model could not adequately represent the nature of the gas plant. Nagpal *et al.*(2001) have also identified concerns over representing gas turbine sections in CCGT modules with a simplified OCGT model. Figure 5.19 shows an exaggerated example of this behaviour. The combined cycle unit in question is deliberately operated with a high degree of temperature limiting, apparent in the initial 30 seconds of the event. This prompted the development of a single model that could be parameterised to represent all the CCGT units and would also provide an appropriate output signal feeding into steam turbine sections.

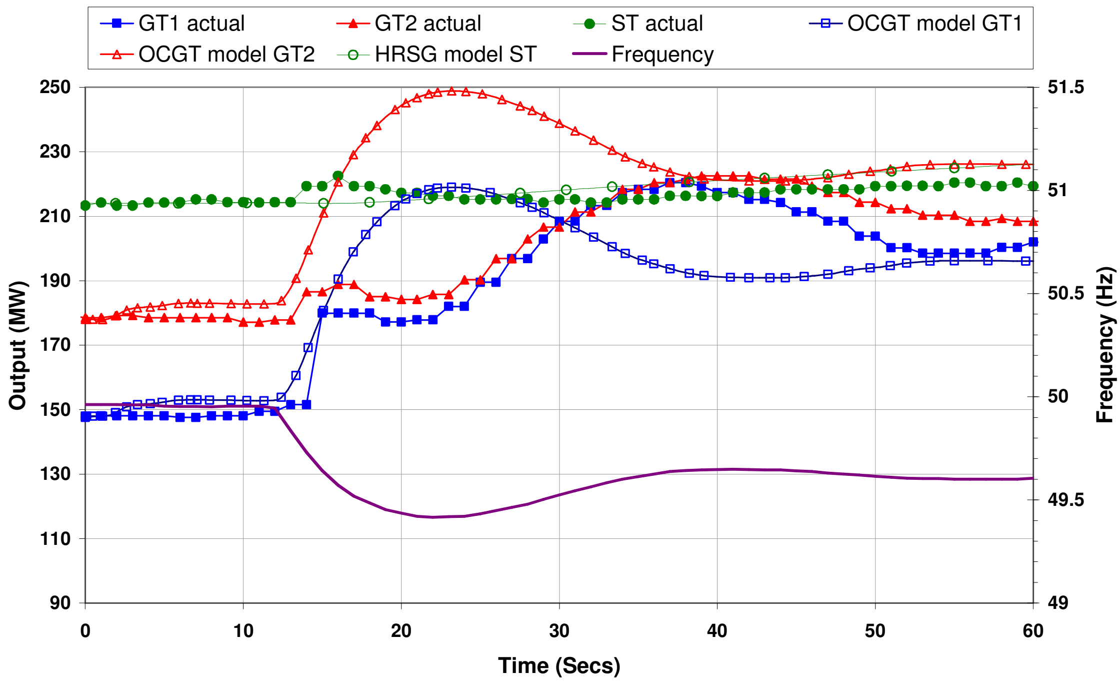


Figure 5.19 - Frequency response of a CCGT gas turbine module during an actual incident and the simulated response using OCGT representation

CCGT units employ inlet guide vanes to control the mass of air flowing through the plant at part load and thus maintain a high output exhaust temperature, keeping efficiencies high. These guide vanes are not modelled in the basic OCGT models and so the main inaccuracy brought by using the OCGT model to represent combined cycle units lies in the control of the exhaust temperature profile. The exhaust gases feeding into heat recovery steam generator (HRSG) are also absent in the OCGT model, which only offers output power to feed into the steam section. In conjunction with inlet guide vanes, the exhaust temperature may also be controlled through limiting the fuel flow to the combustion chamber.

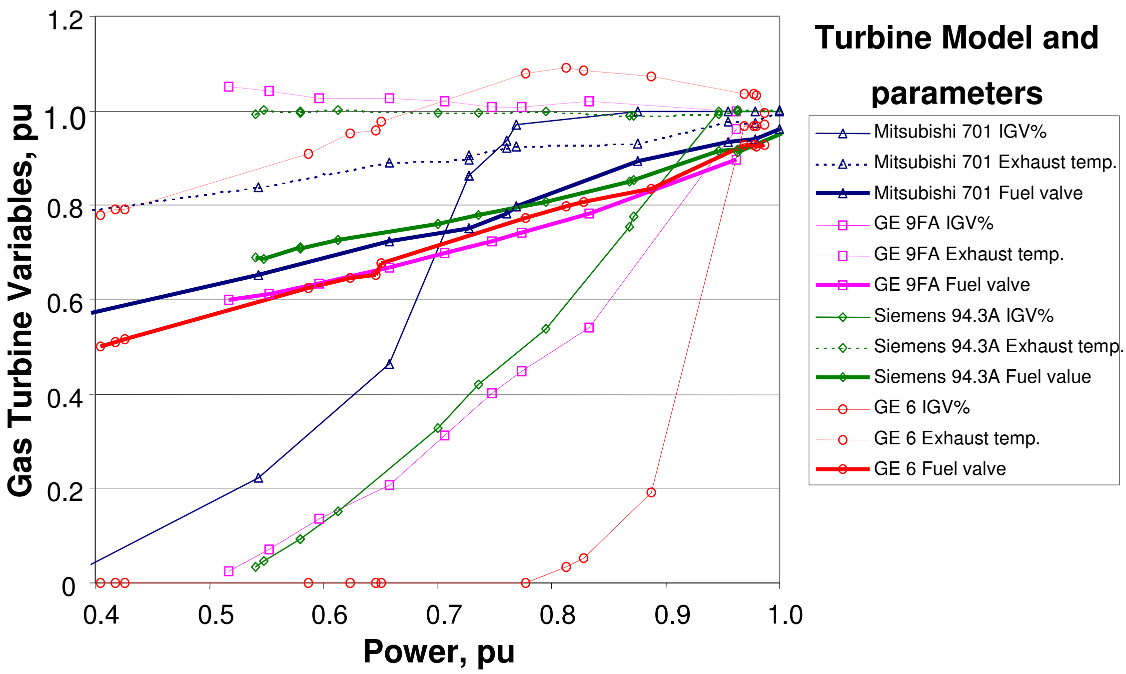


Figure 5.20 - Exhaust temperature, IGV position and fuel valve position of a number of combined cycle gas turbines

To keep the HRSG temperature stable many of the larger CCGT units operate under an almost uniform exhaust temperature profile, which directly influences the control strategy employed. Examples of control strategies for different units are shown in Figure 5.20 compiled from the results of a variety of generator compliance tests.

Literature is available on a large number of models for representing CCGT units, some of these models are developed for small sub 100 MW units as in Kunitomi *et al.*(2003), Hannett and Feltes(2001), Working Group on prime mover and energy supply models for system dynamic performance studies(1994). Other models by Zhang and So(2000), Hannett and Khan(1993), Bagnasco *et al.*(1998), Hajagos and Berube(2001), Kim *et al.*(2001), Lalor and O'Malley(2003) and Lalor *et al.*(2005a) are essentially tuned versions of the established models developed by Rowen(1983, 1992), that assume a constant exhaust temperature. Suzaki *et al.*(2000) present a model for large-scale units but the model itself requires detailed turbine parameters not available to National Grid.

Aguero *et al.(*2001) along with Kakimoto and Baba(2003) have models that are limited by the Eurostag macroblock language and cannot be coded for use in simulations. A promising turbine model by Kunitomi *et al.*(2003) lacks the detail necessary to reproduce a full control systems model. The model described by Undrill and Garmendia(2001) provides a excellent simulation of general electric machines. However, due to confidentiality details of the temperature control systems parameters are again omitted. It was clear no single CCGT model existed that could be tuned for used with a range of different gas turbine manufactures and plant frames. To provide accurate representation of CCGT units operating in a responsive mode a simple model was developed.

5.4.1 A CCGT and HRSG model

The basic gas turbine engine can be modelled as a combustion chamber, compressor and a gas turbine. Variables of interested in terms of temperature control can be calculated though a set of three basic equations, Cohen *et al.*(2001). Air at atmospheric temperature (T_a) is adiabatically compressed by a pressure ratio (*Cpr*) to reach a discharge temperature (T_d) according to Equation 5.2.

$$T_d = T_a\left(1+\frac{(Cpr.W_a)^{\frac{\gamma-1}{\gamma}}-1}{\eta_c}\right)$$

Equation 5.2

The per unit airflow (W_a) through the machine can be controlled by the inlet guide vanes and is also dependent on the ambient temperature and pressure, assumed to be 303K and 1Pa respectively. The compression process is not perfect and the isentropic efficiency of the compressor (η_c) is included to calculate the work done by the compressor. The ratio of specific heats (γ) is assumed to be 1.4.

The combustion firing temperature (T_f) is calculated from the combustor heat balance, Equation 5.3. The fuel flow (W_f) is in per unit of the rated value. The rated firing (T_{fr}) and discharge temperature (T_{dr}) of the turbine is used to calculate the design combustor rise temperature.

$$T_f = T_d + (T_{fr} - T_{dr})\frac{W_f}{W_a}$$

Equation 5.3

The exhaust temperature (T_e) can be calculated from Equation 5.4, where the exhaust gas flow is assumed to be equal to the airflow. The isentropic efficiency of the turbine (η_t) is included to represent turbine inefficiencies. All above temperatures are expressed in Kelvin.

$$T_e = T_f\left(1 - \eta_t\left[1 - \frac{1}{(Cpr.W_a)^{\frac{\gamma-1}{\gamma}}}\right]\right)$$

Equation 5.4

Integrating this basic gas turbine engine model with a control system provides the required governor model for use in frequency response simulation studies. Figure 5.21 shows the complete governor control diagrams that can be integrated into Eurostag simulations. The speed droop (KG) is implemented to provide the fuel demand signal (FD) according to the load reference (Pinit) and machine speed (OMEGA). In accordance with recommendations put forward in the authors work, Pearmine *et al*(2006b), the maximum deviation of fuel valves is limited by a 33% deviation. To supply the minimum expected response against the registered capacity of the station, gas turbine modules are generally set with a higher than normal droop so that the net station droop is in the order of 4 %. The demand signal is rate limited and position limited.

A low value selection occurs between fuel demand and temperature limit(LIMIT), this signal then feeds into the fuel control blocks. It is possible to include frequency dependence in the fuel supply, this is a result of mechanical or electrical pumps with rotational speeds tied into the unit, for most instances no frequency dependence is assumed, and the block can be omitted. The demand is then adjusted inline with the minimum fuel demand at no load and the result is the fuel flow signal (WF).

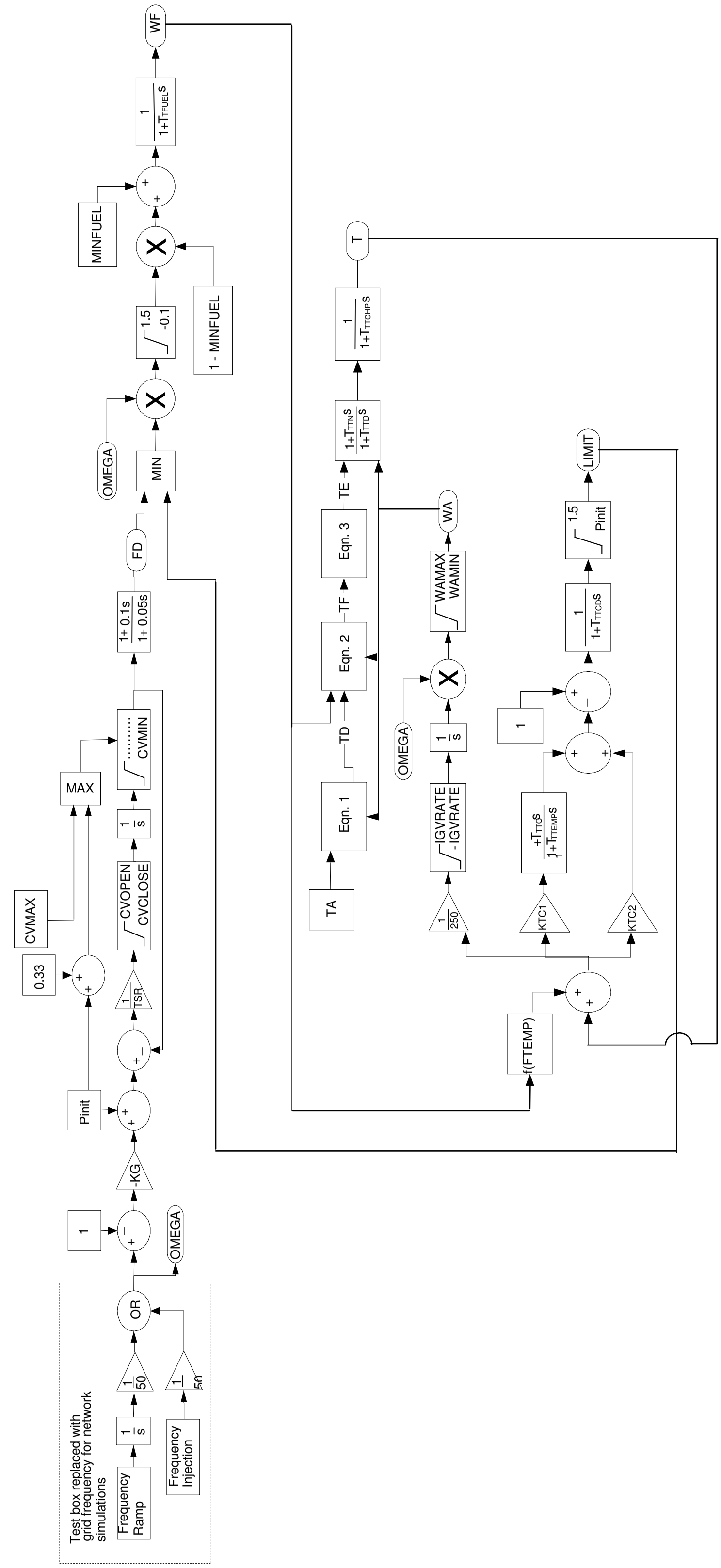


Figure 5.21 – CCGT model

Variable	Description	Value	
KG	1/Droop	31	
TSM	Servo time constant	0.1	
CVOPEN	Governor valve open rate limit	0.02	
CVCLOSE	Governor valve close rate limit	-0.1	
CVMAX	Governor valve open limit	1.0	
CVMIN	Governor valve close limit	0.0	
MINFUEL	Minimum fuel demand at no load	0.2	
TA	Ambient temperature (K)	303	
TD	Rate compressor discharge temperature (K)	660	
TR	Rated exhaust temperature (K)	850	
TF	Rated firing temperature (K)	1598	
TFUEL	Fuel system time constant	0.1	
TTN	Heat transfer lead time constant	15	
TTD	Heat transfer lag time constant	20	
TTCD	Temperature controller delay	5	
TTHCP	Thermocouple time constant	1.1	
KTC1	Temperature controller gain	0.2	
KTC2	Temperature controller gain	0.01	
TTC	Temperature controller time constant	5	
MUCOMP	Compressor efficiency	0.88	
MUTURB	Turbine efficiency	0.85	
TTEMP	Temperature control time constant	200	
IGVRATE	Inlet guide vane open/closing rate	0.018	
WAMAX	Maximum airflow	1.0	
WAMIN	Minimum airflow	0.7	
CPR	Compressor ratio	16.6	
UG	Load Set Point	0.0 - 1.0	
%FTEMP	Exhaust temperature profile function	**WF**	**EXLIM**
		0.0	1.0
		0.5	1.0
		1.0	1.0

Table 4 - Variables used in the gas turbine governor model

The calculated exhaust temperature (T) from the gas turbine engine model is compared to a reference temperature based on fuel valve position. This error signal is then feed to the exhaust temperature limiter and the inlet guide vane control. The inlet guide vane control is adjusted so that the required exhaust temperature is attained. The guide vanes operate to control the airflow at a rate (IGVRATE) slower than the fuel valves, which results in preliminary intervention by the temperature fuel limit under large power fluctuations.

The airflow is adjustable between maximum and minimum limits (WAMAX/ WAMIN). With the compressor directly coupled to the electric generator the airflow (WA) will be influenced by system frequency and will therefore be proportional to the rotor speed. The mechanical torque (TORQUE) derived from the gas turbine is defined as a linear function with respect to the fuel flow over the rotor speed range. A speed dependant term is also included in the machine torque blocks to represent the friction acting on the shaft when fuel flow is stopped. Table 4 details parameters for use in modelling a Siemens 94.3A turbine.

If large frequency deviations below 49.2 Hz are incurred the output power from a gas turbine is significantly reduced due to diminished compressor speed. To overcome this natural power reduction and meet with grid code requirements a degree of over-firing is employed to maintain power levels. If studies are intended to simulate plant behaviour outside the frequency response operating range additional modifications to the temperature controls must be made to include this effect.

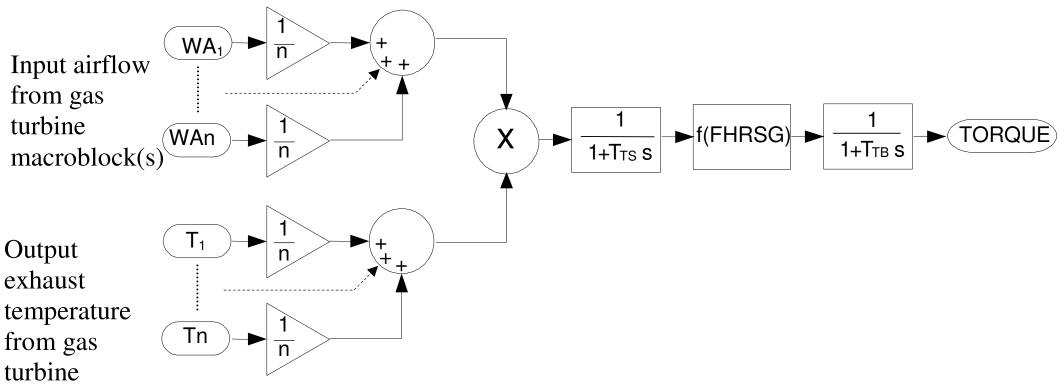


Figure 5.22 – HRSG model

The HRSG module can be modelled based on the output exhaust temperature and the airflow through the gas engine(s). As explained, steam turbine modules are generally operated in sliding pressure mode on the GB grid. This means that the steam is not throttled as in coal based plant, and steam control valves are set fully open. This practise reduces the control scheme complexity in the model, and a basic block diagram is given in Figure 5.22.

Variable	**Description**	**Value**	
TS	Steam pipe time constant	20	
TB	Boiler storage time constant	250	
%FHRSG	Exhaust energy steam turbine output function	**In**	**Out**
		0.0	0.0
		0.5	0.5
		0.8	0.8
		1.0	1.0

Table 5 - Variables used in the HRSG model

Large boiler time constants mean that generally the steam turbine module supplies a small percentage of the overall station response. Table 5 provides typical values for use with the HRSG model in simulation studies.

5.5 Models for hydroelectric generation

Hydroelectric generation (Figure 5.23) 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). Kinetic energy gained by the moving water is imparted to the turbine blades, which are used to drive generators. The power available (P_G) can be calculated from Equation 5.5.

$$P_G = \rho_w gWH = 9.81 \times WH$$

Equation 5.5

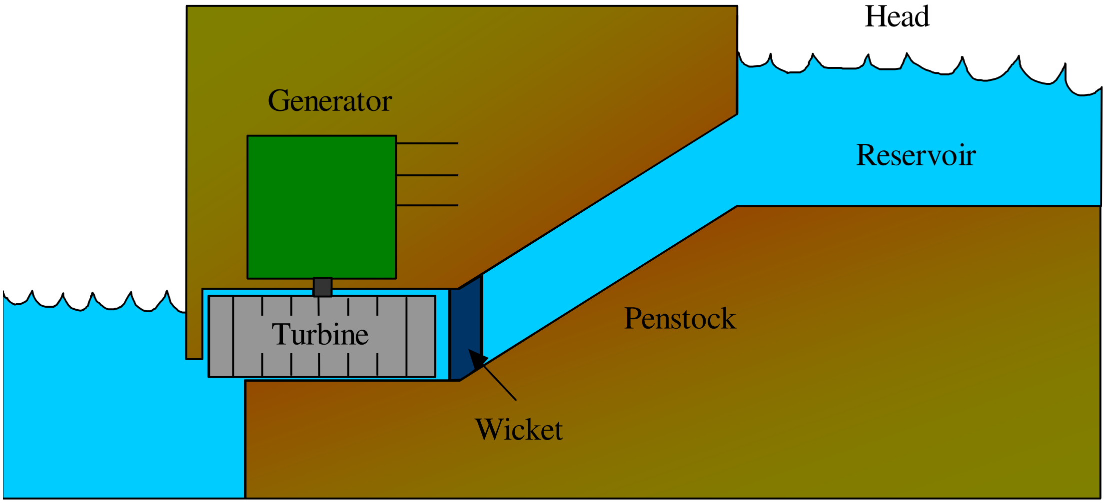


Figure 5.23 - Hydroelectric turbine arrangement

The output power is derived from the 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. In the England and Wales hydroelectric generation is mainly utilised in pumped storage facilities such as Ffestiniog and Dinorwig, Figure 5.24. 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 frequency control tool.

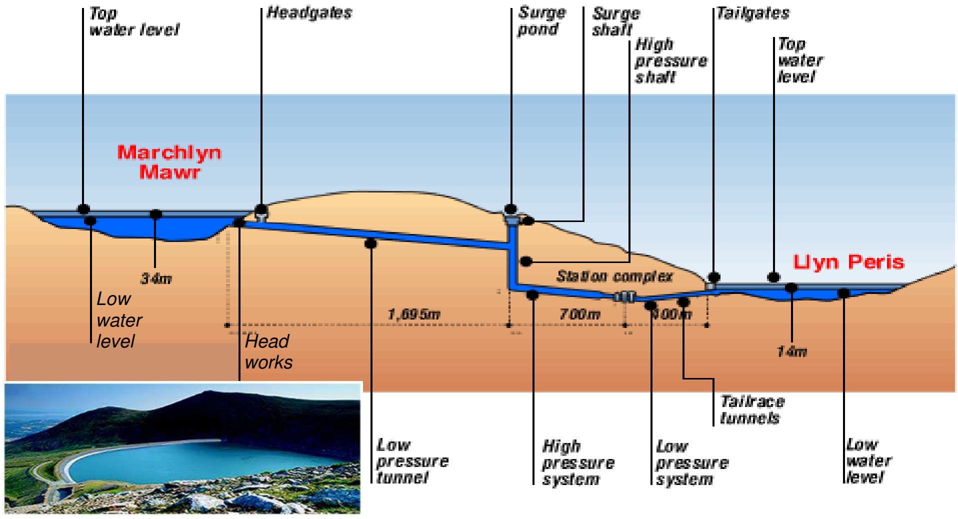


Figure 5.24 - Dinorwig hydroelectric pumped storage facility

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 also cover both types of turbine; IEEE Committee report(1999), Bize and Hurley(1999),and Bourles *et al.*(1997). A generic plant model described by Figure 5.25 is satisfactory for most frequency simulations. Response supplied from pumped storage units can be offered at either 4 or 1 % droop and the governor must reflect the chosen operating point.

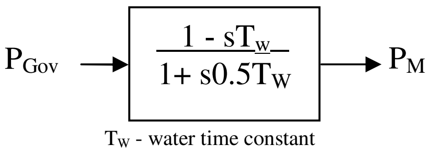


Figure 5.25 – Hydroelectric turbine model

Along with this standard operating mode the pump storage units offer two further modes; part load response (PLR) and low frequency (LF) trip. PLR machines operate at half output capacity during normal system conditions and trip to full output if a frequency event is encountered. LF trip machines operate under the same trip conditions but from zero output. A small modification (Figure 5.26) is required to enable the governor model to instigate the required trip if frequency falls outside tolerance levels.

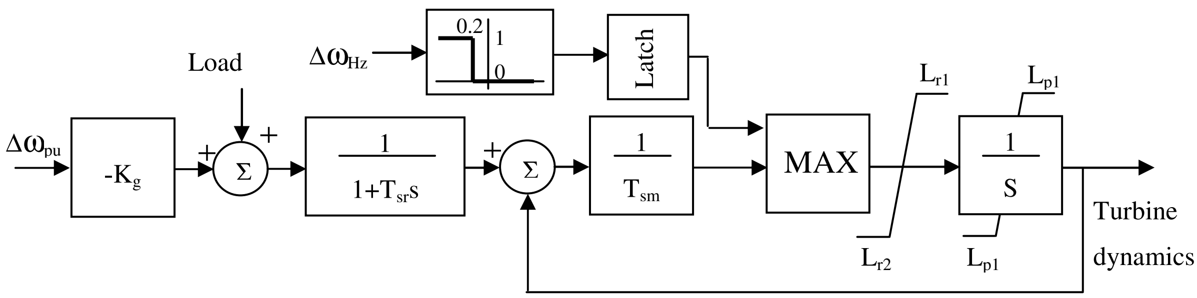


Figure 5.26 – Conversion to standard governor model

5.6 Validation of generator models

5.6.1 Modified coal fired models

The models developed in section 5.3 required validation against real events to provide evidence of their accuracy. In the case of historical incidents, monitored grid frequency data was used as an injection signal into the model. Figure 5.27 shows the results of simulating a rate limited model, as in Figure 5.13, against the real case. Similarly, the output limited mode as illustrated in Figure 5.14 is simulated against the response of the same unit operating with a standardised governor in Figure 5.28.

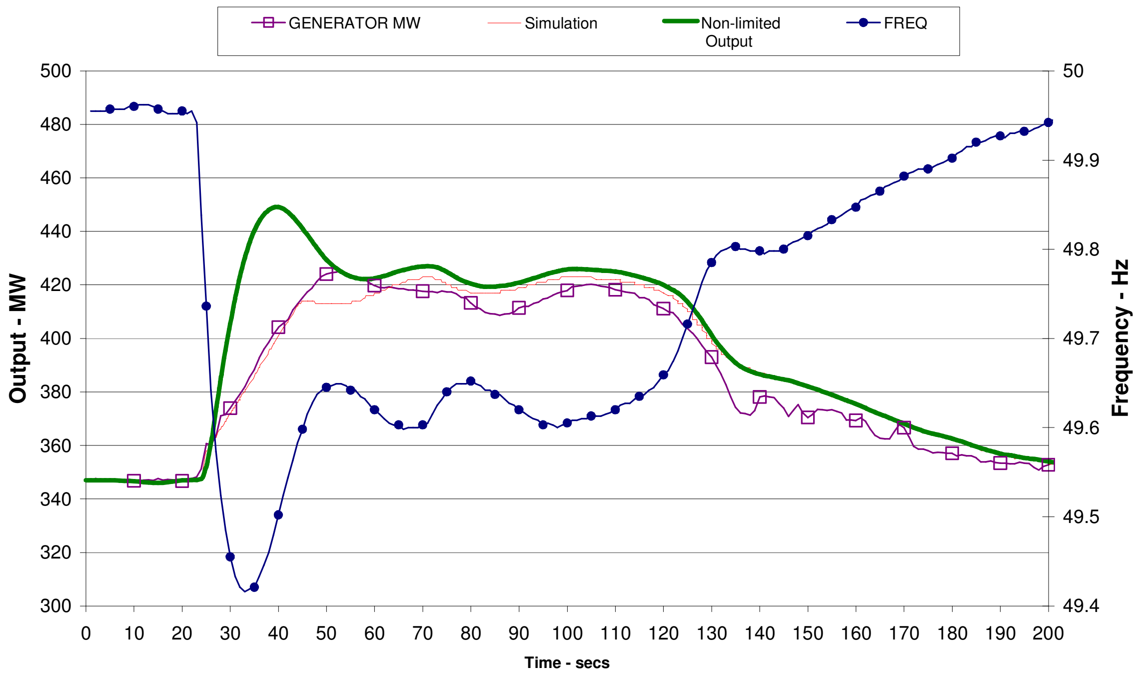


Figure 5.27 - Frequency response of a rate-limited generator during an actual incident and the simulated response

Both examples demonstrate good alignment between model output and the response in the actual events. The significance of miss representation with a standard model can also be seen in the additional curves. For both examples choosing the basic model without limits can result in exaggerated performance especially in the primary response timescales.

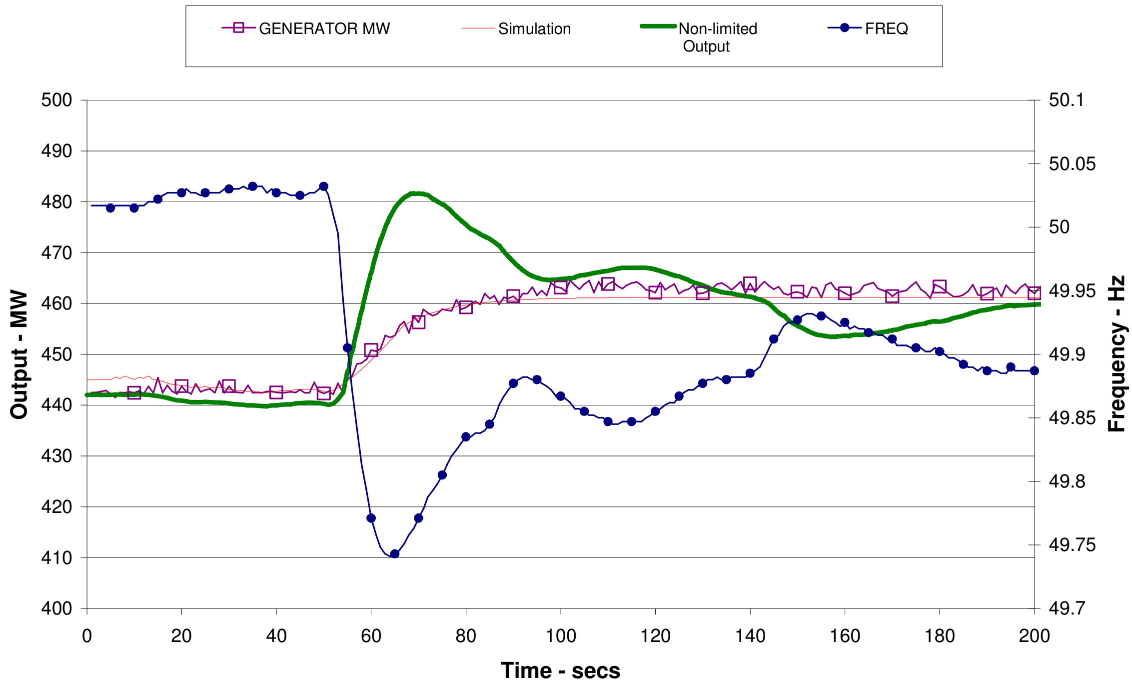


Figure 5.28 - Frequency response of an output-limited generator during an actual incident and the simulated response

5.6.2 New CCGT model validation

As with the coal fired models the developed model for CCGT plant was validated against compliance tests carried out on existing units. Compliance tests provide additional measurements particularly of use for comparisons of CCGT plant. Of the injection shapes tested, the one chosen to validate against is the 0.8 Hz ramp over 10 seconds, returning to 0.5 Hz at a range of load set points. Power output, inlet guide vane position, exhaust temperature and fuel valve positions are monitored during the test at sampling intervals of 0.1 seconds. A frequency injection signal is supplied to the governor model. The response of a simulation is shown in Figure 5.29 against compliance test results.

The fuel valve position signal from tests shows an opening from 60 to 73 % 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.

Marginal differences between the simulation of inlet guide vane position and exhaust temperature from the test results bring attention to differences in the temperature limit controls. Despite minor differences in output power as limits act on the unit at the twenty second mark, the model provides a good match with the compliance results throughout the test. These results show a marked improvement in comparison with the results obtained from OCGT based models. However, there remains an opportunity to further improve the control process of IGVs and thus the exhaust temperature in model.

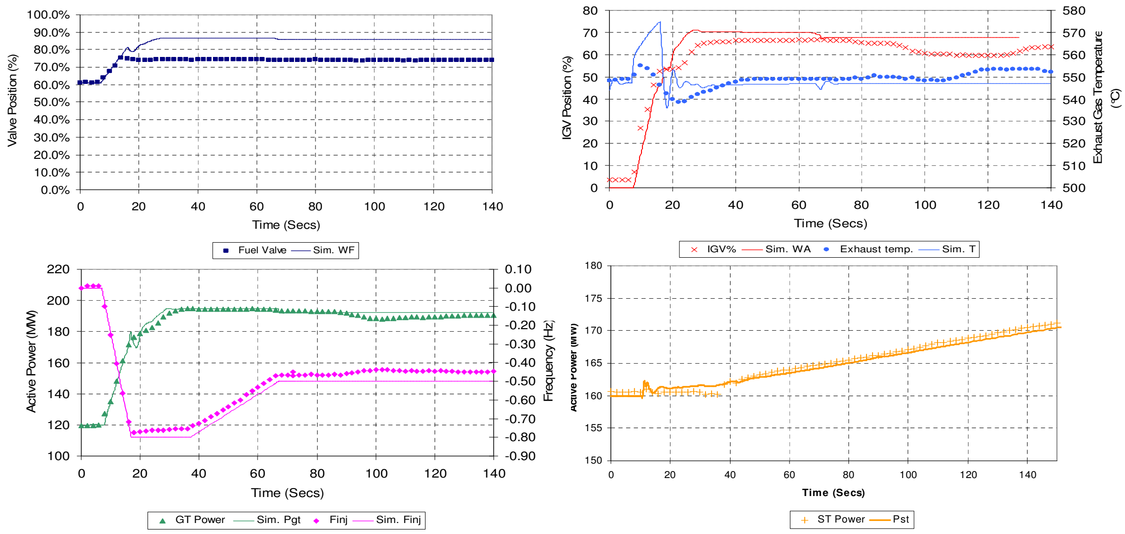


Figure 5.29 - Validation of a combined cycle gas turbine governor model at 60% load

5.7 Summary

The majority of the existing power system in the British Isles is composed of synchronous AC generators driven by gas, hydro or steam turbines. Responsive models of traditional hydro and coal fired plant are well established and validation for real units proves to be a simple exercise. Some traditional models required further development with additional control blocks to adequately represent generator response during frequency transients. Data from grid code compliance tests and historic events can be used to match simulation models against actual plant behaviour.

The nature of combine cycle gas turbines in providing frequency responsive services requires a slightly more complex model. Temperature control provides a critical factor during large frequency deviations and limits the output power from units. These controls vary according to manufacturer and the specific turbine frame studied. A gas turbine model for use in simulation of combined cycle modules was developed by the author and validated against test data. Improvements to the initial model have been demonstrated through further response simulations. The model provides an accurate long-term dynamic model for use in post event analysis and in studies for identification of frequency response holding levels.

Chapter 6

Load Frequency Sensitivity in Response Studies

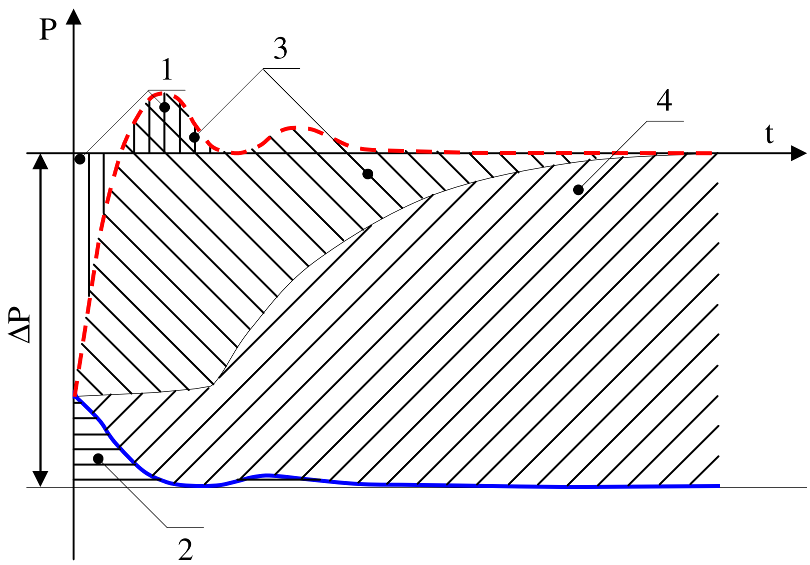
Chapter 6 is structure as follows: A background to the influences of the load-frequency response is discussed building on the dynamics explained in chapter 4. A review of empirical research is examined dating from the 1970's to the present in an attempt to identify the load frequency characteristic. Two techniques are used to evaluate the load characteristic on the British transmission grid using recorded data. A third method is also described using a component-based approach. The latest value for the load frequency sensitivity is proposed for use in the frequency response calculation process.

6.1 Effect of the load on system frequency

The system frequency of a synchronous transmission system will vary due to power imbalance on the network. Figure 6.1 describes this energy balance as a generating unit is lost from the system. The broken curve displays the mechanical power held in the system, while the solid curve describes the electrical power changes in the loads. Any short-term imbalance of energy will result in an instantaneous drop in system frequency as system inertia (area 1 and 2) is harnessed to replace the lost energy. This will occur in the initial few seconds until sufficient reserve is initiated through governor action (area 3 and 4).

The Figure describes a reduction in system load up until a steady-state value is reached. This change in load is attributed mainly to the drop in frequency associated with the energy balance. The influence of this load characteristic with respect to system frequency is a substantial factor in the allocation of response levels. In the calculation of the response requirement National Grid previously used a continuous value of 2 %MW/Hz for its load-frequency sensitivity, which is derived through earlier investigations, Davies *et al.*(1958). National Grid has developed confidence in allocating system response using this value for its load-frequency sensitivity.

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 magnitude of the connected motor load will also decline. Changes in the system frequency have a larger impact on motor load than deviations in the voltage, Welfonder *et al.*(1993).



1 – Generator Rotating masses, 2 – Rotating masses of the loads, 3 – Primary Control, 4 - Secondary Control

Figure 6.1 – Dynamics of a power imbalance from Machowski *et al.*(1997)

Considering the frequency sensitive 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%. Figure 6.2 illustrates, for a 50 Hz network how the motor and non-motor loads vary with frequency. Most non-motor load remains independent of frequency where as the motor load decreases as the frequency decreases. The third curve defined as the “total load characteristic” is the interaction of the two factors.

The load sensitivity can be affected by semiconductor controlled power devices that break the synchronous tie between the power grid and rotating/electrical equipment. Examples of such devices are found in new generations of industrial drive controllers and switch mode power supplies. As proportions of these devices increase, they are also met with changes in customer behaviour, such as an increased motor load due to utilisation of air conditioning. Both of these effects may be reflected in changes of the load response.

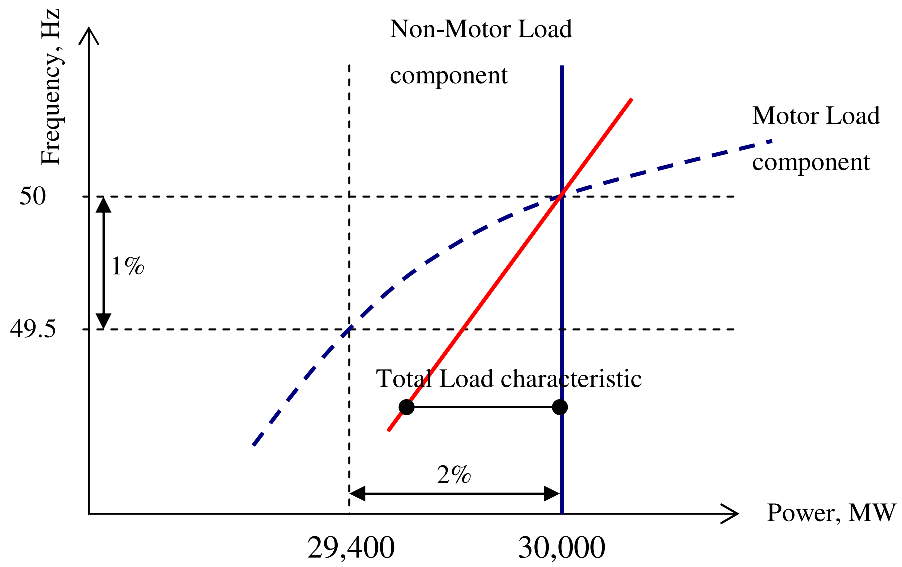


Figure 6.2 - Power-frequency effects of motor and non-motor Loads

Increasing proportions of distributed renewable generation may also influence the load sensitivity seen by the system operator at grid supply points. These generators act to displace demand at these connections, and the inertia and dynamic behaviour as seen by the grid (or not if semiconductor controllers are used) will have bearing on the experienced load sensitivity. The potential change in load mix since early studies means that investigation is required to confirm if this 2 %MW/Hz value is still applicable for response studies. A further possibility exists to optimise the continuous value of load-frequency sensitivity against time of day or seasonal variations.

6.2 Existing quantifications of load sensitivity

The Load-frequency characteristic is determined by load behaviour, which makes direct comparisons between other networks and GB difficult unless a similar load mix can be identified. As the composite load varies in a smooth manner with respect to voltage and frequency it is sufficient to represent loads as static quantities. To account for the influence of system loads on frequency a load-frequency characteristic (K_L) relates the two quantities, Equation 6.1. The change in load (ΔPL) in this equation becomes a self-regulating effect helping to stabilise frequency. This load response is a function of the frequency deviation (Δf) from nominal (f_0) and total system demand (P_L).

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

Equation 6.1

The characteristic is, in part, also a function of supply voltage resulting from the change in impedance of substation components due to frequency (transformers, shunt reactors, etc.). Baghzouz and Quist (1999), among others, identify the specific voltage component of the load response, however, the voltage and frequency portions are consolidated using Equation 6.1.

Many literature sources quote the load sensitivity factor as a percentage value, which is normalised against base frequency and system power. However, in the following comparisons we will hold with convention adopted by National Grid and quote sensitivity in % power reduction per Hz deviation.

Three papers examine the system wide measurement of load sensitivity to frequency. On the Irish electricity grid O'Sullivan and O'Malley(1996) calculate the sensitivity in the order of 2 to 2.5 %MW/Hz. For the UCTE, Weber *et al.*(1997), sets values for the load sensitivity between 0.8 and 3.3 %MW/Hz. The current quantity used by National Grid is centred in the middle of these numbers. A further report published by Chown and Coker(2000) for Eskom gives an average load frequency characteristic of 2.5 %MW/Hz.

More literature sources examine tests carried out on parts of whole systems. Berg(1972) examines an isolated section of the power system in Norway to show average values for load sensitivity as 1.0 %MW/Hz for commercial loads and 0.8 %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 3.0 to 3.2 %MW/Hz and 3.0 to 4.0 %MW/Hz respectively.

Figures published by the IEEE task force on load representation(1993) give frequency sensitivity for residential loads as 1.4–2.0 %MW/Hz differing from those suggested by Concordia by at least 50%. This discrepancy may be due to the change in load mix over the ten-year break between papers. Commercial loads are determined to be between 2.0-2.8 %MW/Hz, with industrial loads 2.2 %MW/Hz, Aluminium refineries -0.5 %MW/Hz, Steel Mills 2.5 %MW/Hz, Power Aux. Plant 4.8 %MW/Hz, and Agricultural Pumps 9.3%MW/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 %MW/Hz at Heidelberg and 1.6 %MW/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.

A number of literature sources estimate the load-frequency sensitivity for use in load modelling. Näser and Grebe(1996) use a value of 2 %MW/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%MW/Hz. NEMMCO(2002) has estimated that the power system demand varies with frequency at 2.5 %MW/Hz.

In summary the load characteristic is typically represented as a value between 0.8 and 4 %MW/Hz. This large variation in anticipated values highlights the importance of investigating the load frequency sensitivity in order to establish a specific value for the British case. Knowledge on the statistical distribution of values would also be of great benefit when attributing supplementary margins to response requirements.

6.3 Quantifying the load sensitivity to frequency

There are two routes to determining the system-load characteristics, Kundar(1993):

- Measurement-based approach
- Component-based approach

In the first, load characteristics are measured at substations during specific periods of operation. These measurements may be based on whole systems, or part-systems then extrapolated to represent the whole system. Parameters based on these types of measurements have been presented in section 6.2. An alternative method was developed by the Electric Power Research Institute(1979, 1981, 1987). The load at each grid supply point is broken-down into constituent load classes such as residential, commercial industrial, and so on. The class is then further divided into components such as lighting, refrigeration and space heating. Characteristics of each component can then be aggregated to represent the full load. This is perhaps the most simplest of methods but requires in-depth knowledge of the demand components at grid supply points.

Techniques concentrating on the measurement based approach include; calculation of the load-frequency sensitivity value through tie lines across two isolated systems and are presented by Hayashi(1988), Davies *et al.*(1958) and Fukuda *et al.*(1989). Welfonder *et al.*(1993) demonstrates a technique to measure the load characteristics on feeders of small part systems.

As part of National Grids data archive the energy management system has been continuously recording historical demand values from the network at intervals of one minute since June 1993. However, investigations to quantify the load-frequency sensitivity found the sampling resolution of this data inadequate to capture the dynamic changes of the system.

6.3.1 Identifying the load sensitivity to frequency from data

To calculate a value for load sensitivity unique to the British grid a method of using measured quantities from the transmission grid, developed by the author was employed, Pearmine *et al*(2006a). In order to gain suitable sampling periods, in the order of seconds, the load measurements must be rejected in favour of generation totals. As a consequence a piece of software was developed to allow the continuous logging of an existing real-time feed from the energy management system at two second intervals. This feed contains system wide generation totals categorised by fuel type.

With this data it is possible to evaluate the frequency response of the load to a much higher accuracy. In order to substitute for system loads, a period of stable frequency is required for the assumption that pre-fault load equals the total system generation (P_T) to hold true. Using this hypothesis the change in load can be represented by the sum of the total change in system generation (ΔP_T), the loss of generation (P_{Loss}) and any frequency control by demand management (P_{FCDM}). The load sensitivity factor can thus be calculated from the relation given in Equation 6.2.

$$k_L = \frac{(\Delta P_T + P_{Loss} + P_{FCDM})}{\Delta f . P_T}$$

Equation 6.2

Unfortunately, this method requires an instantaneous loss of generation (or increase in load) of a significant magnitude to take place. During measurements it was found that a disturbance greater than 200 MW provides an adequate power mismatch to measure the load sensitivity, although higher levels are more desirable. The weakness of using Equation 6.2 to calculate demand change lies in the dependence on a steady demand to gain meaningful results. This restricts the usable data from an already sparse set of system events; Figure 6.3 and Figure 6.4 highlight this point. The figures show recorded traces under a stable demand compared with an increasing demand, which is unpredictable from the generation trace alone.

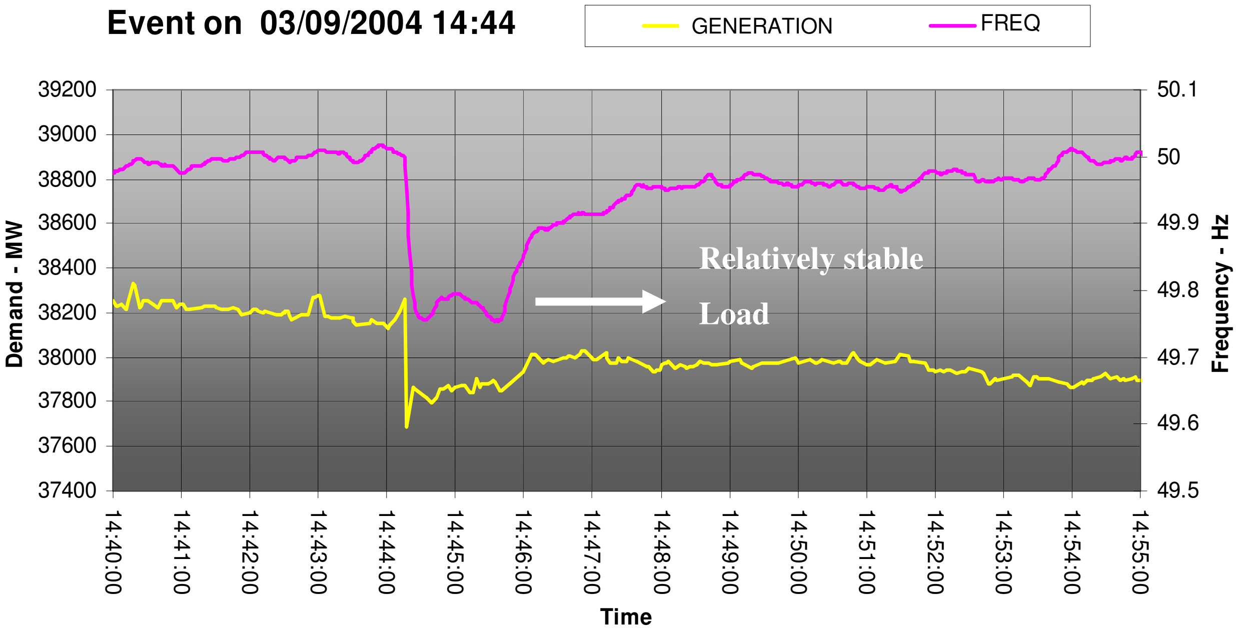


Figure 6.3 - Generator loss under constant load conditions

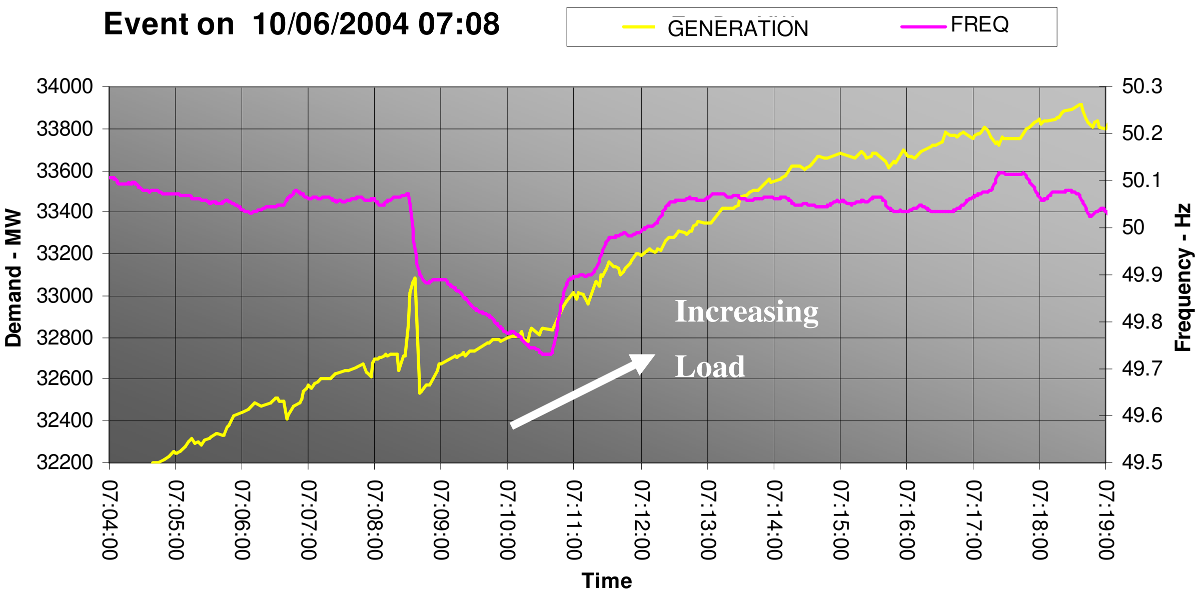


Figure 6.4 - Generator loss under unclear load conditions

6.3.2 Inertial method of calculating load sensitivity

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 (d{Δf}/dt) it is possible to quantify the imbalance between load and generation (ΔP), effectively the load response. For a known system inertia (H) the load sensitivity factor is given by Equation 6.3.

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

Equation 6.3

The results using this method are however very sensitive to the initial value of frequency decay (which is available to one-second resolution). Also, the technique is defined as a measure of the imbalance of load and generation at the instant of loss. As described by Figure 6.5 the load response should fall further if frequency continues to drop, results would therefore be conservative.

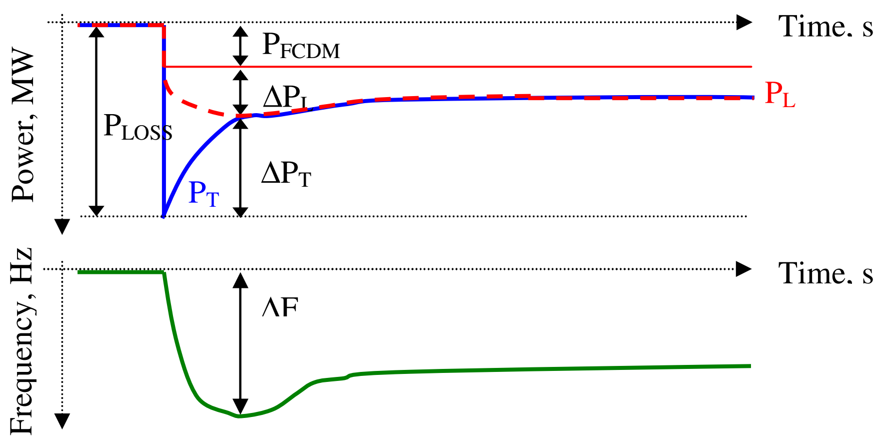


Figure 6.5 - Assumed network response used in the calculation of load sensitivity

6.4 Results from measurements

Figure 6.6 shows the calculated sensitivity factors using Equation 6.2 and the recorded incidents plotted against the time of the day. The distribution of values is over a large range between 1.1 and 6.9 %MW/Hz, this agrees with the sources referenced. This range of values is, in part, due to the changing load mix throughout the day and also seasonal variations. The figure shows low correlation between the sensitivity value and the period of the day. A low correlation is also evident if the data is compared to a typical daily load profile experienced by National Grid. These results are unexpected as we would expect a higher degree of resistive heating load overnight, particularly during winter, in conjunction with less motor load from closed industrial processes. The combined effect of these two situations would be to lower the load-sensitivity value. It is clear from Figure 6.6 that dispersion of values during the day is as widespread as those experienced during the night.

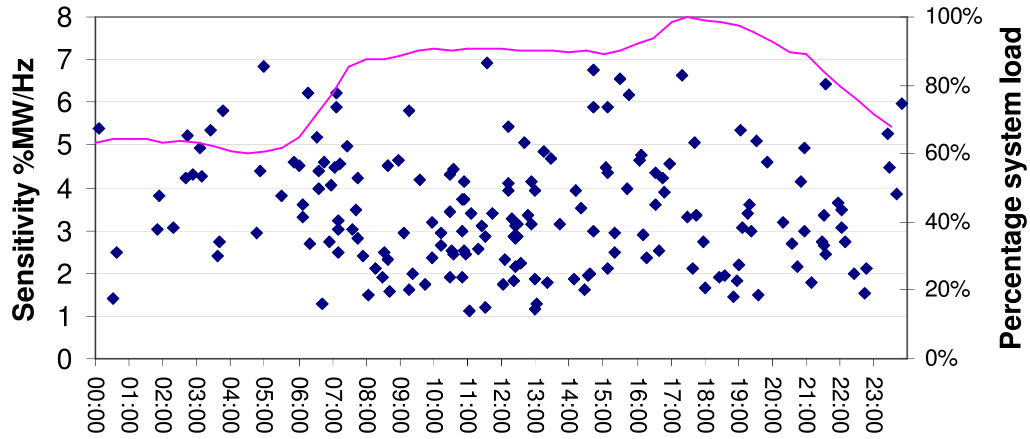


Figure 6.6 - Typical daily variation of measured load sensitivity

Figure 6.7 shows the annual variation of the sensitivity factor using both Equation 6.2 and Equation 6.3. Results from both techniques yield a very similar range of values from the recorded incidents, with a correlation factor of 0.53 between the two methods. Overall, the results from Equation 6.3 are generally lower than those obtained from Equation 6.2 for reasons previously discussed. Instances when this is not the case can be attributed to error introduced through the one second sampling interval or events when the pre-loss load is not completely stable. Figure 6.8 also shows, as expected, that there is no correlation between the size of loss and the sensitivity factor. The data indicates no clear seasonal or daily trends after examination.

Figure 6.9 shows the frequency distribution of results using Equation 6.2, together with lines of 95 percent confidence limits. 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 gives 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. This margin will provide additional security for any instances when full load response is not delivered.

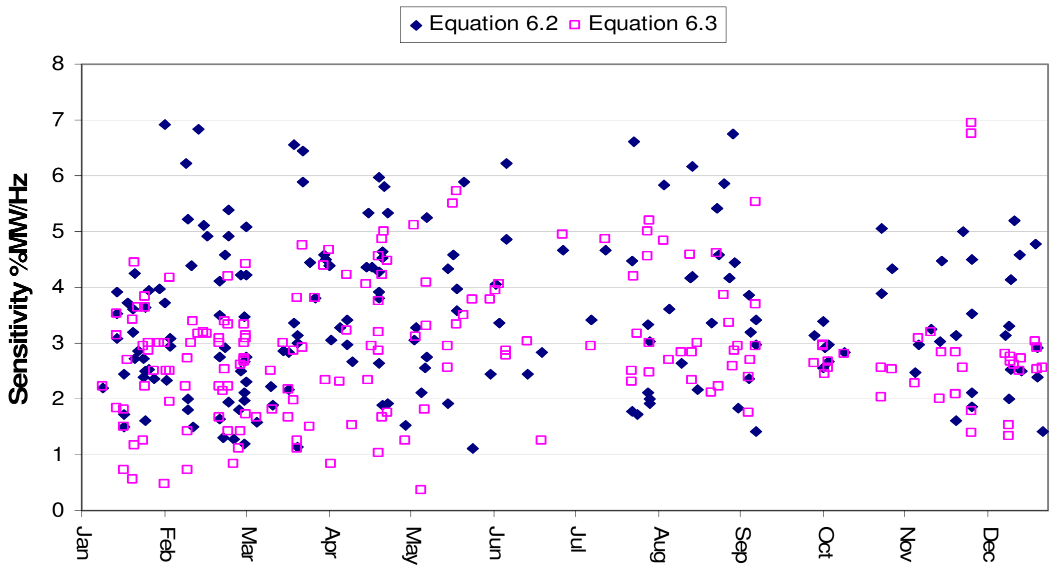


Figure 6.7 - Annual variation of load sensitivity to frequency, April 2004 to June 2005

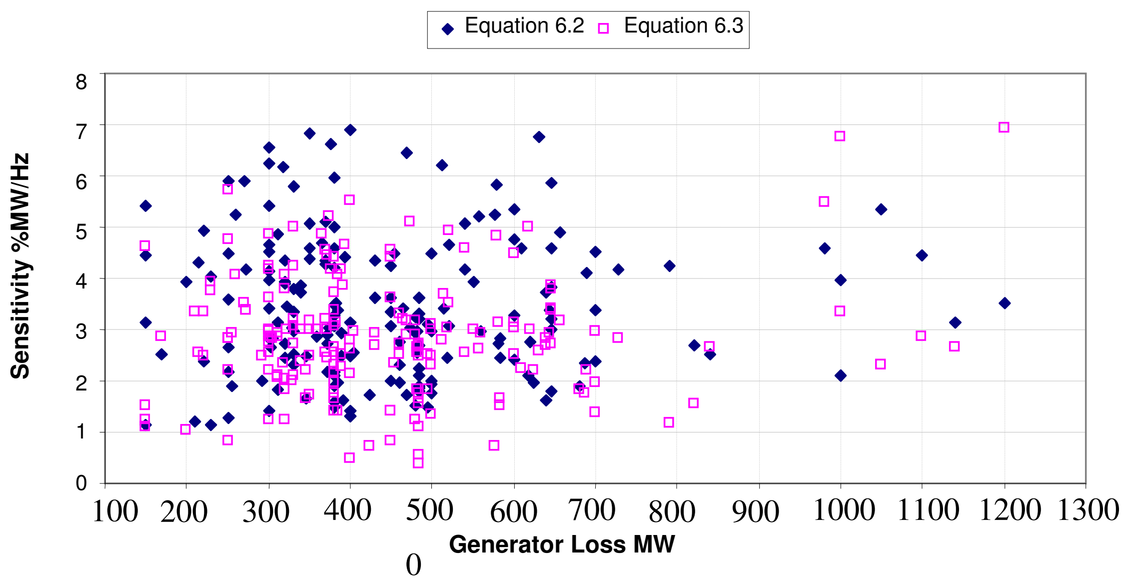


Figure 6.8 – Magnitude of generator loss against load-sensitivity during April 2004 to June 2005

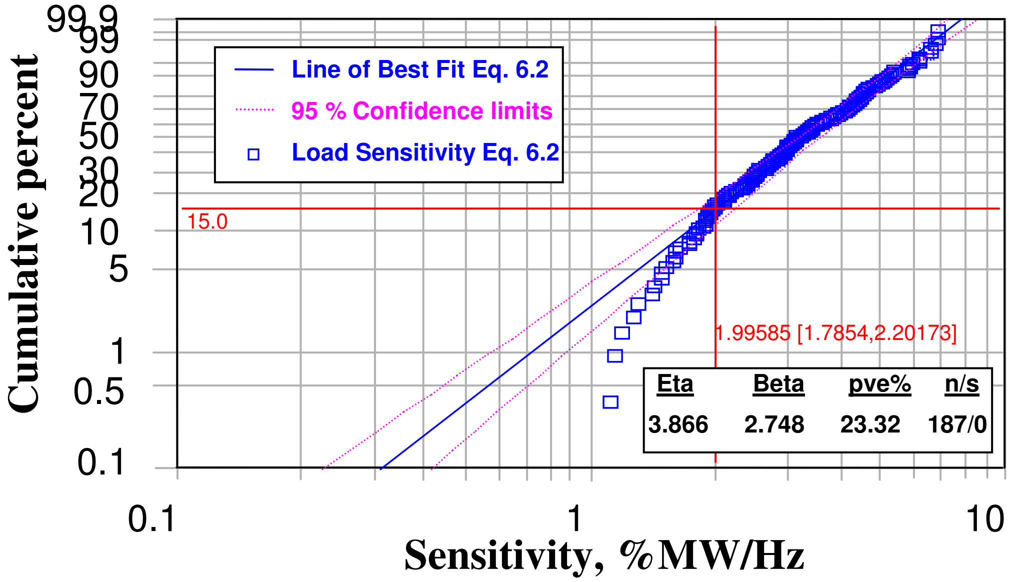


Figure 6.9 - Distribution of load sensitivity to frequency

6.5 Load-frequency sensitivity from load components

The Department of Trade and Industry, DTI(2005), annually submit estimates of the electricity demand by sector. These figures do not breakdown into extreme detail for the end uses of electricity. However, they form an adequate means to estimate load response to frequency using the component-based approach. The measured demand responses suggested by the IEEE Task Force on Load Representation(1993) are used in calculations. By associating these values with the demand proportions from the DTI figures it is possible to calculate a range of possible load response values. Figure 6.10 shows the breakdown of demands for 2004 based on a total demand of 401,811 GWh, DTI(2005).

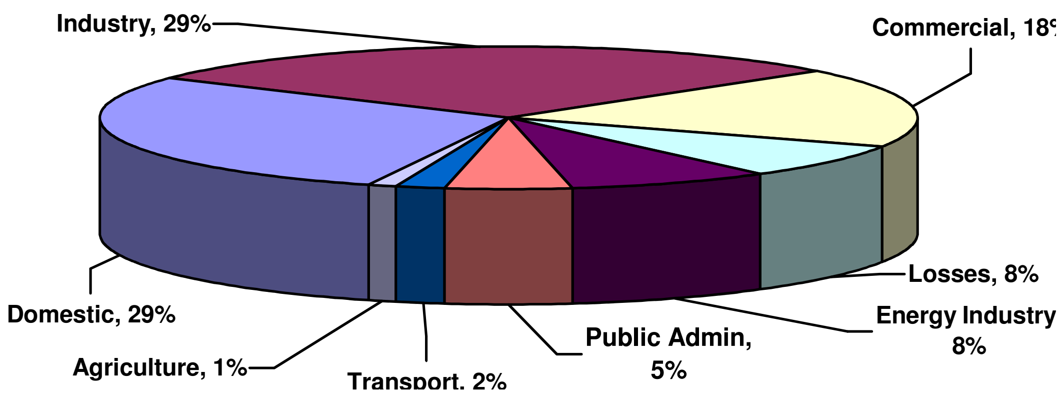


Figure 6.10 – Electricity demand by sector, 2004

For calculations it is assumed a demand response range of 0.7-1 %MW/Hz for residential loads, 1.2-1.7 for commercial loads, 2.6 for industry, 2.9 for energy industry and 5.6 for Agriculture pumps. Lumping transport and public administration with commercial loads gives a system load response value of the order 1.67 to 1.90 %MW/Hz. This value is dependant on the winter/summer season.

A value of load sensitivity to frequency in this range would agree with measurements taken from the system using the alternative methods in section 6.3.1 and 6.3.2.

6.6 Potential cost savings of response holding

To translate a change in response holding into simple cost savings, consider that the system is always secured against the worst foreseeable risk, namely 1320MW. The resulting changes in primary and secondary-resp.onse holding levels for an increase in load-frequency sensitivity factor from 2 to 2.5 %MW/Hz can easily be estimated. Figure 6.12 shows the typical changes in response levels over the course of a normal day. To simplify this dynamic requirement in calculations, consider a median saving of 72MW in primary holding and 160MW for secondary-response. Assume, also, that the plants holding this response capability offer primary and secondary response, and that holding 160MW of secondary means that the obligation of holding 72MW of primary-response is met automatically by the same machines.

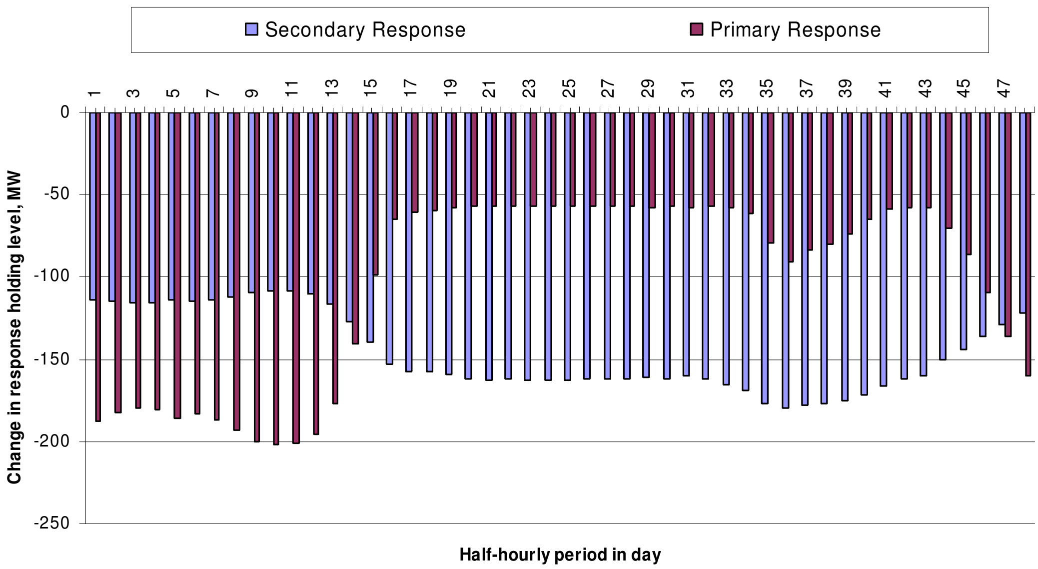


Figure 6.11 – Changes in response holding when considering a 0.5% increase in load sensitivity against a 1320MW loss

Assuming full delivery of generator response at a load response of only 1.3%/Hz, the new frequency-response levels should contain a 1GW loss within limits. On average, three system incidents occur per year with an infeed loss that is greater than 1GW; in the worst case, the load response will under-perform for all three events. In these three events, a supplementary 160MW of energy (to secure back to the old levels) would be required. Based on a balancing mechanism cost of £2,500/MWh, this would require expenditure of around £600,000 on emergency fast reserve, Pearmine *et al*.(2006a).

This cost does not reflect the fact that these fast reserves may not be deliverable in time to limit the fall in frequency. The result may be that the frequency breaches 48.8Hz and automatic disconnection of load begins, to recover the system. If this loss in load exceeds 320MWh, this could cost up to £16.9 million in incentives and result in damage to the operator reputation that cannot easily be assigned a monetary value. The emergency-response cost would be offset against a reduced operating expenditure of £2,719,100 per annum. This is due to changes in the response-holding costs based on average costs from the

To create headroom for response holding, generators must be deloaded through bids and this energy must be replaced by associated offers on other units in the balancing mechanism. Units typically do not supply all of the power from the load point to maximum output in response, and a return of 55% response is expected on the reduced output. This means that approximately double the volume of bids and offers is required for any volume of response.

The differences in system buy and sell price over the period of interest, multiplied by the volume of bids and offers required, is an indication of the cost saving that can be made. The market will therefore see reduced activity on bids and associated offers to the sum of £22,451,083 per annum. This assumes an average cost, but in reality the saving may be greater due to the marginal costing of bids and offers. As the bids and offers are selected by increasing expense, the higher trading costs may be avoided.

Therefore the total cost saving obtained through an increase in the load–frequency characteristic, provided that no demand disconnection occurs, is in the order of £22,451,083 + £2,719,100 - £600,000 = £22,570,183 per annum. These values are speculative and a number of assumptions have been made to simplify the calculation, Pearmine *et al.*(2006a).

6.7 Summary

This chapter has identified a weakness in existing literature to suggest a suitable value of load sensitivity to frequency for use in dynamic simulations of the British grid. A number of techniques have been presented to calculate the actual load response following incidents when large frequency excursions have occurred. Resulting data from these techniques have provided a range of plausible values for use in response studies. The influence of the load sensitivity on the cost of allocating frequency response is also shown to be significant.

Early data published by the author highlighted the possibility of considering an increase in the load sensitivity factor whilst still maintaining a high degree of security, Pearmine *et al.*(2006a). However, after further collection of data the statistical distribution of values changed making the 2.5 %MW/Hz value less favourable. The annual variation of load sensitivity has not been determined from current incidents and it is unlikely that future data would reveal any operational pattern to the data.

The range of possible values measured agrees with using the original load sensitivity factor of 2 %MW/Hz when deriving a frequency response requirement.

Chapter 7

Complete Dynamic Response Model

Chapter 7 investigates the required response holding levels to contain frequency deviations on the current system using the developed simulation tools. The simulations harness the coal fired generator models modified in Chapter 5, together with the new CCGT model. The frequency dependant load model identified in Chapter 6 is also incorporated. The chapter includes detailed tests conducted with the proposed modelling solution against recorded system response during historic events. Updated primary and secondary response holding curves are presented, with additional sensitivity analysis.

7.1 Model validation against historic events

In Chapter 4 the use of a full network model to represent the system in response studies was discussed. Individual plant models simulating balancing actions taken with reference to system frequency where defined and individually tested in Chapter 5. The final piece of the response model was examined in Chapter 6, when a load response was defined as 2 %MW/Hz. Each of these components has until now been studied in isolation. In order to gain confidence in the complete model a number of historic incidents have been chosen from recent years to test the robustness of the complete dynamic model. The simulations are based on a set of relatively large system losses to validate the response model.

The first event simulated dates from the 26th May 2003, the incident occurred at 00:36 at a system demand of 28.4 GW. The drop in frequency was instigated through the loss of some 1260MW of generation. This event was of the largest experienced on the system in recent years and is close to that of the maximum potential loss secured against. Considering the actual event first, the frequency falls to 49.4 Hz reaching a steady state of 49.6 Hz within 60 seconds. This is good response performance; in fact the details would suggest a slight over provision of response in this case.

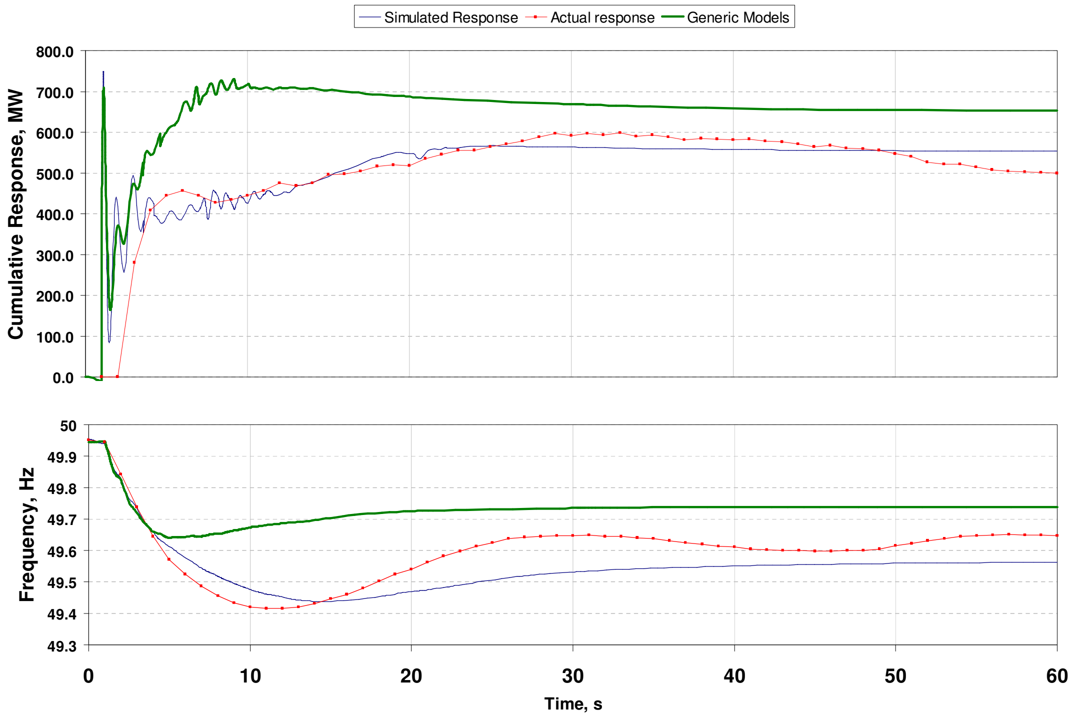


Figure 7.1 – Simulated 1260 MW loss from 26/05/03

The simulation results are given in Figure 7.1 together with metered values during the actual event. The two simulated curves are included to highlight the improvements in performance gained from validating individual plant models. Under the generic models the primary response is heavily exaggerated. This misrepresentation has a dramatic effect on the resulting frequency trace in the initial 30 seconds.

Unfortunately, a comprehensive set of sub-minute metered values was not available for this particular event. National Grids performance team did access remote recording equipment to acquire detailed outputs from individual responsive generation. It is thus a cumulative total response that is presented in the figure not broken down into fuel types.

The simulation model provides a close match to the actual response recorded during the incident. The initial gradient of frequency following the incident is identical for both curves, suggesting the correct system inertia is represented in the simulation model. The frequency falls to a minimum of 49.416 Hz at 10 seconds, represented in the dynamic model as 49.438 Hz after 14 seconds, this is an acceptable error of around 0.05 %. The secondary response is noticeably different in the simulation, with a 34 MW mismatch in generation totals after 30 seconds. A frequency mismatch of 0.04 Hz exists when the model reaches a steady-state value.

The difference in secondary response is largely due to the dynamic nature of the loads. The simulation assumes a static load model which varies with respect to frequency. On the transmission system loads are constantly switched in and out of service and some will vary dynamically. This is shown in the final few seconds of the actual response. As the response falls off the frequency begins to recover, suggesting a reducing demand.

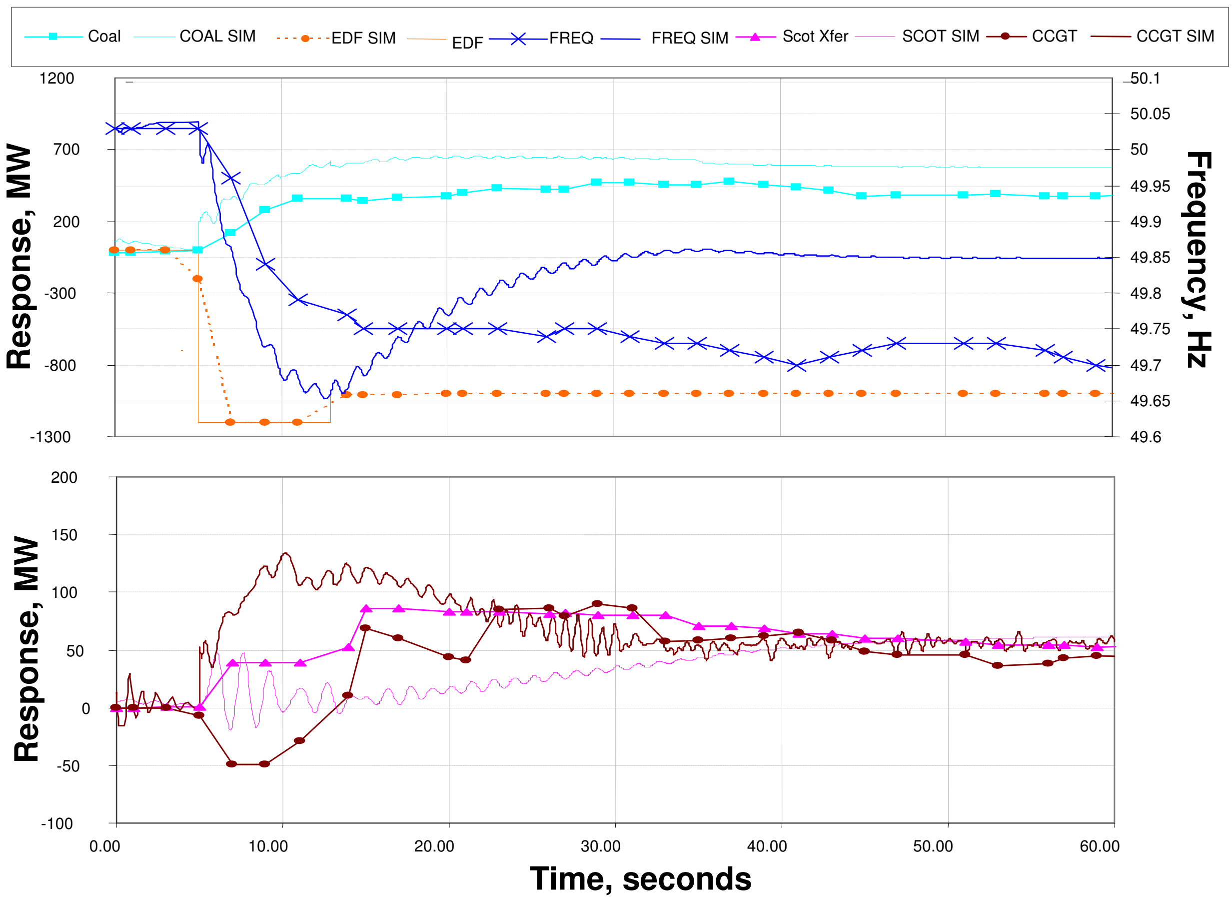


Figure 7.2 – Simulated 1000 MW loss from 02/12/05

The next event dates from the 2nd of December 2005 and occurred in the late evening at 22:48. The incident resulted from a loss of 1000 MW due to a bipole trip on the

Anglo-French interconnector. The system demand was in the order of 37.8 GW, typical for this time of day during the winter months. This event was of quite a significant loss and initially the loss was at 1200 MW before the second bipole took up its full transfer capacity. This event is at a particularly volatile point in the day and the system frequency remains low under secondary time-scales despite a good match in net response output. The fact that the frequency does not recover from 49.7Hz in the real incident indicates an increasing demand at that time.

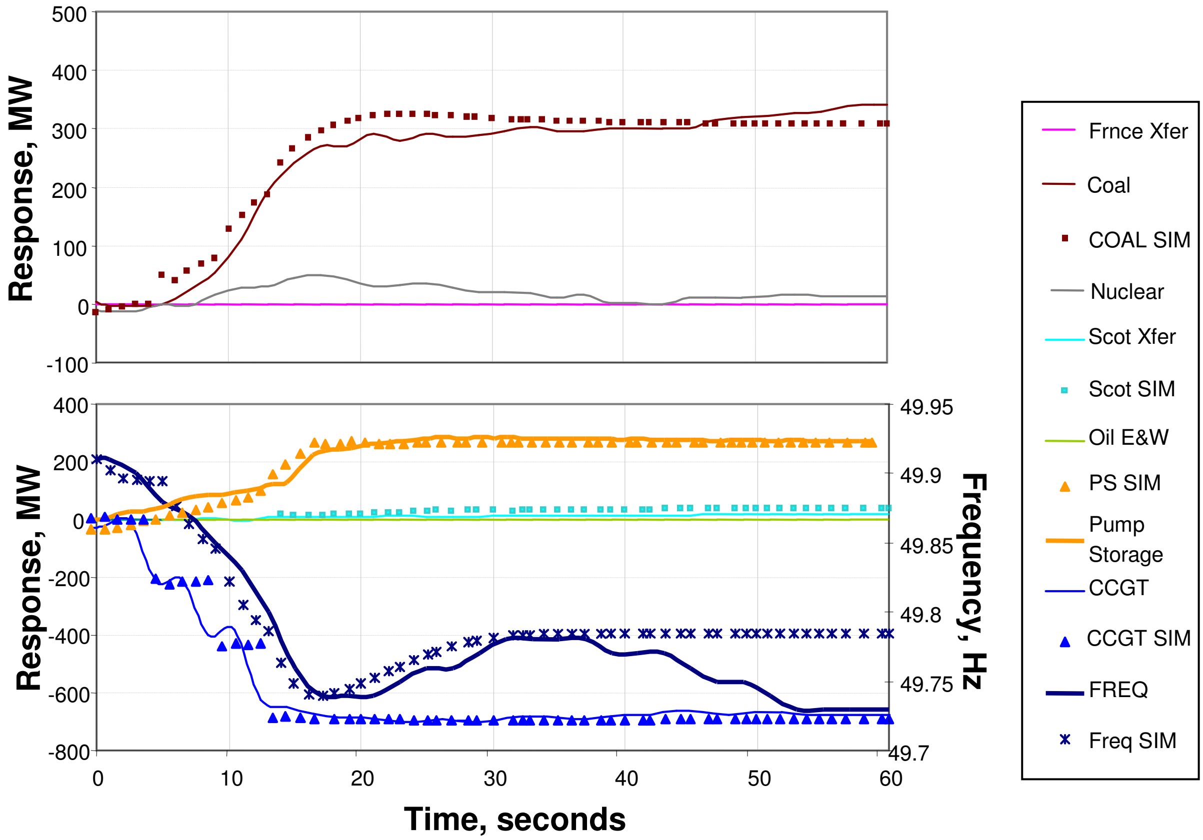


Figure 7.3 – Simulated 790MW loss from 21/01/06

Figure 7.2 shows the simulation (identified by SIM) and system records during the event. No response is held on any nuclear or oil units and so these totals are excluded for clarity. The Scottish response is somewhat sluggish in the simulation compared to the actual event and the CCGT output is initially quite high. These two outputs counter act each other from 10 seconds into the simulation. The coal plant simulation is also over generous by around 100 MW. This means that a difference in simulated grid frequency is experienced in the model. Calculations from the actual event show that the load response in this case was 3.7 %MW/Hz and not the standard 2

%MW/Hz. This would reduce the required generator response and bring the simulated curves more inline with the actual event.

The final event dates from the 21st of January 2006 and occurred at 16:46, following the progressive loss of a CCGT unit in three sections. The national demand at the time was around 46.4 GW. The total loss of generation was 790MW over 12 seconds. Figure 7.3 shows a simulation of the event, the Anglo-French interconnector, nuclear and oil response simulations are excluded for clarity. The traces show a very close match to the experienced event. The load response was increased from 2 %MW/Hz to 4 %MW/Hz inline with calculations from the actual event. The actual frequency trials off in the final 20 seconds for similar reasons to the previous two events

7.1.1 Summary of validation events

The three events discussed in the previous section represent a range of realistic situations experienced on the network. In general the level of representation in the simulations is close to the actual events. The second event does not portray the same state of assurance as the other two events; however, the overall simulation does show good correlation. In conclusion the model gives confidence in representation of the super grid during frequency events. This model should allow identification of the level of responsive generation needed to secure the system.

7.2 Procurement of Response

As explained in Chapter 2.3 frequency response is purchased from BMUs subject to three main costs incurred for mandatory frequency response. This includes payments to de-load plant, hold response and also energy payments, National Grid(2006c).

De-load costs will be incurred by issuing Bid Offer Acceptances (BOAs) to manoeuvre sufficient part loaded plant onto the system as response providers. These costs will be subject to the Balancing Mechanism bid offer costs, which may vary on a minute-by-minute basis, and the amount of part-load plant required.

Capability (holding) payments are based on the response capability at a given de-load, and are paid per hour. The physical response capability is defined in the BMU response contract as defined by compliance tests. The cost element associated with this response holding is set by the generators, who make a monthly submission to National Grid.

Response Energy Payment (Utilisation) costs are paid based upon the power delivery tables defined in the relevant ancillary service contracts. The energy price used for these payments is a weighted average of the imbalance prices from the previous month.

In addition to the above, a number of supplementary response service agreements are held with the First Hydro Company through pump storage generation. There are two forms of frequency response service, Firm and Optional which are reviewed annually. Optional services attract utilisation payments only. The contract allows First Hydro complete freedom of price for optional services, provided notice of change is given within two weeks.

The portfolio of Optional services currently contracted include an enhanced droop setting of 1%, that may be instructed on an opportunistic basis or automatically ramping to full load if system frequency falls to a prescribed value. The rapid release of response either under manual instruction or automatically is also available in Spin-Gen mode, where the unit is synchronised but not exporting generation. Pumping, with automatic de-load if system frequency falls to a prescribed value is a further option. Finally, rapid start, with unit synchronisation within two minutes instruction.

The Firm service provides Part Load Response at a 1% governor droop plus low frequency relay initiated boost. This service is provided for around ten hours in daily PLR service windows. Payments are based on average accepted Bid and Offers prices per settlement period, subject to an annual cap and collar.

Demand-side response provided by demand managers who are prepared for their demand to be interrupted up to 30 minutes several times a week can also be used for frequency response. The normal trend is for interruptions of approximately ten to thirty times per annum. Demand is automatically interrupted when system frequency causes low frequency relays to operate. Payments for this service are made for the availability of the service only (£/MW/h). No payments for delivery of service.

7.3 Response requirement trials

The response requirement after an event is split into two separate timescales, the primary to limit the initial fall in frequency, and the secondary to maintain frequency within limits. The differences in frequency limits between significant and abnormal events mean that two distinct transients are encountered as shown in Figure 7.4.

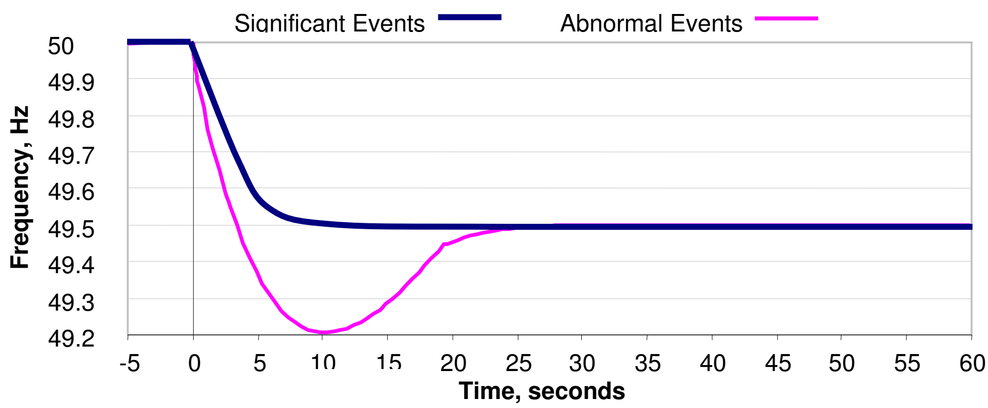


Figure 7.4 – Frequency transients for significant and abnormal losses

Significant loss of generation (1 GW to 300 MW) requires that the system frequency does not fall below 49.5 Hz. A more gradual transient than the one depicted in Figure 7.4 may be possible depending on the level of primary response held. This can generally be established through a single dynamic simulation. Simulating the most abrupt drop in frequency establishes the minimum primary response requirement.

In the past two separate dynamic simulations have been conducted for abnormal losses (above 1GW). One simulation establishes a primary holding level to secure to 49.2 Hz and another for the secondary response requirement against a deviation of 49.5 Hz. This technique has always presumed full conformity with the requirement to return to 49.5 within one minute. Through simulations in chapter 4, we have seen that this assumption will be dependant on a number of factors.

Initial simulations using the dynamic system model showed that presently the system will not meet with this hypothesis. Figure 7.5 shows the simulation results at a system demand of 50 GW, during a 1320 MW generation trip. The bold curves depict the frequency and response using the original assumption and show the response to limit frequency to the minimum 49.2 Hz. The other set of curves ensure the requirement of returning to 49.5 Hz by 60 seconds is met. Under both schemes the secondary response requirement would be identical. However, the primary requirement is shown to be some 100MW higher if the requirement to return to 49.5 Hz inside one minute used. The simulation in the non-bold curves used the minimum level of primary response possible to secure the system at 60 seconds.

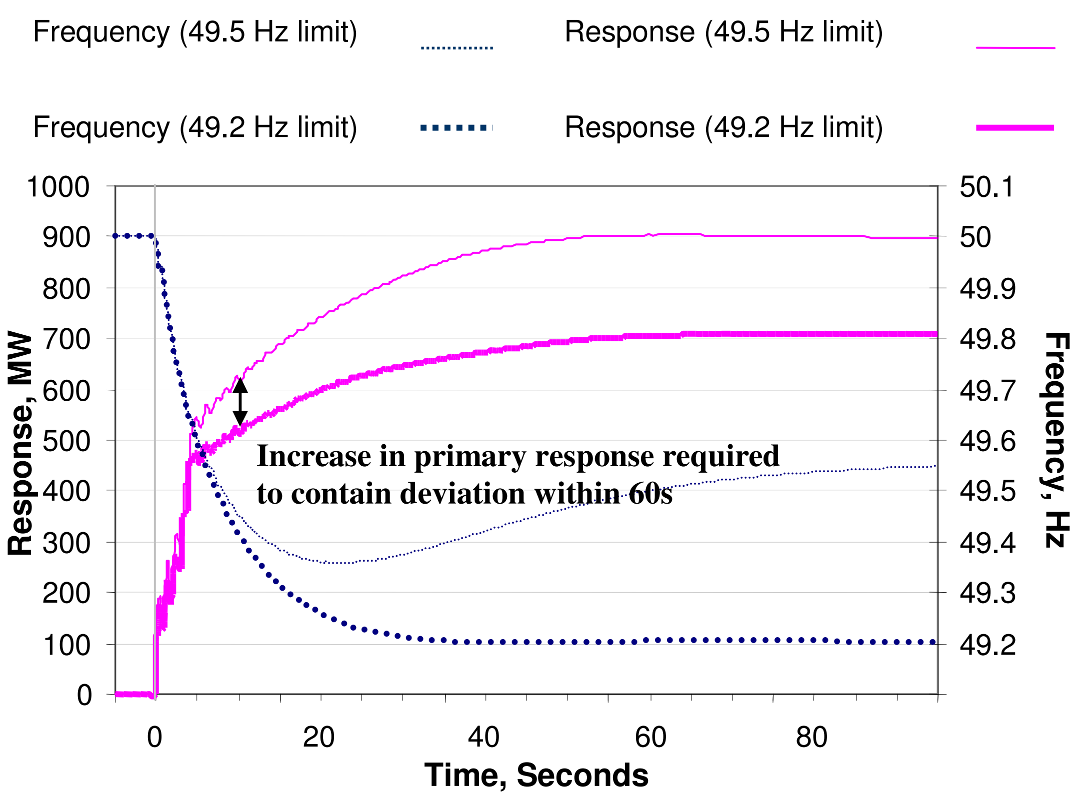


Figure 7.5 – Response requirements abnormal losses

7.3.1 Secondary response

Considering the initial minute of the transient we can see that in actual fact the frequency never has the opportunity of reaching 49.2 Hz. As response contracts for only secondary response cannot be acquired the frequency limits are not fully utilised. Only joint primary/secondary contracts exist, therefore to attain a system frequency of 49.5 Hz at 60 seconds excess primary response must be scheduled. This is one shortfall of the existing response scheduling process. If the timescales for returning the frequency to 49.5 Hz were extended to somewhere in the order of 120 seconds the frequency would have time to recover from 49.2 to 49.5 Hz. Alternatively, the provision of secondary response only contracts would allow the correct level of response to be supplied to meet frequency obligations.

The secondary response requirement is intended to be implemented during steady-state conditions. With the network in a steady-state the response requirement can be approximated by a simple linear function. By considering the level of loss for which response is being calculated the secondary response requirement curves can be calculated for a range of system demand levels using Equation 7.1.

$$R_{\sec} = (Risk - K_L.D_{GB}.\Delta f_{\max,\sec})$$

Equation 7.1

where the secondary response $R_{sec,}$ is required to limit the maximum frequency deviation $\Delta F_{max,sec}$. K_L the recommended load frequency characteristic, Risk is the loss, and the national demand is D_{GB}.

The dynamic response model after 30-60 seconds should agree with results produced using equation 7.1. However, selection of appropriate plant to establish the exact response profile under both primary and secondary timescales sometimes proves to be a difficult task for abnormal events (greater than 1GW). It is therefore suggested that the dynamic response model be used only as guidance to ensure the correct levels are attained under this timescale. The calculated secondary response levels should be within a reasonable tolerance (±10 %) of the dynamic simulation.

Figure 7.6 gives curves of calculated secondary response levels using equation 7.1 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.

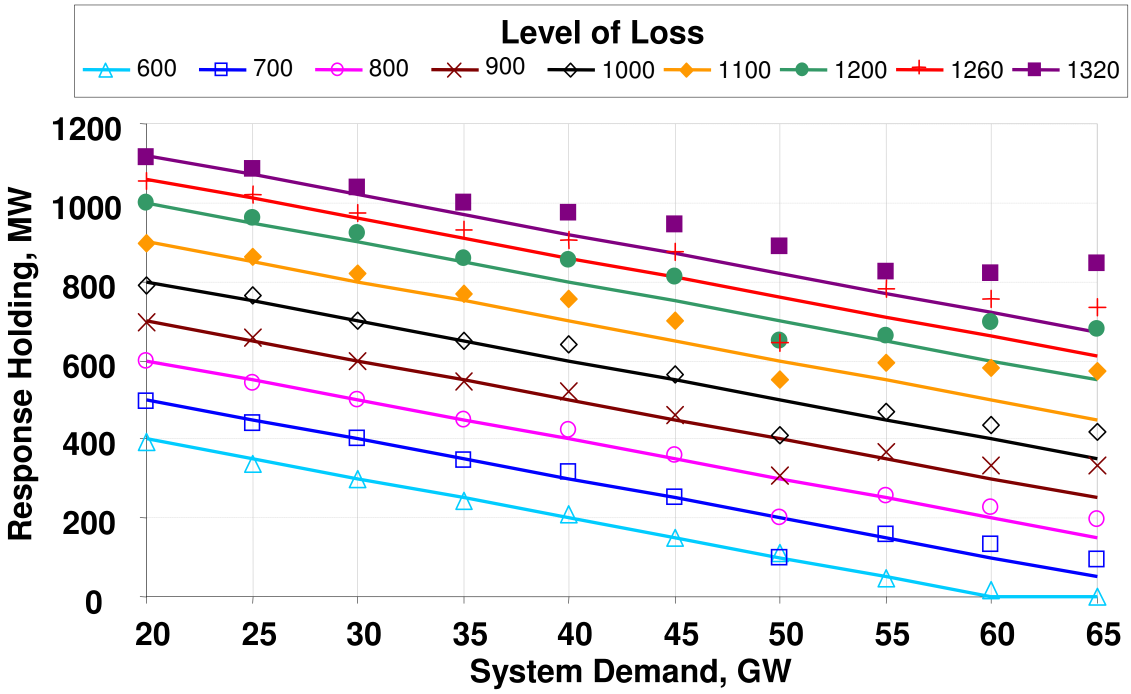


Figure 7.6 – Secondary response requirements for all losses

7.3.2 Primary response

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 7.7 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 7.8 provides similar response holding levels for abnormal losses. Again the correlation is high at 0.992, again suggesting the curves fit the simulation results.

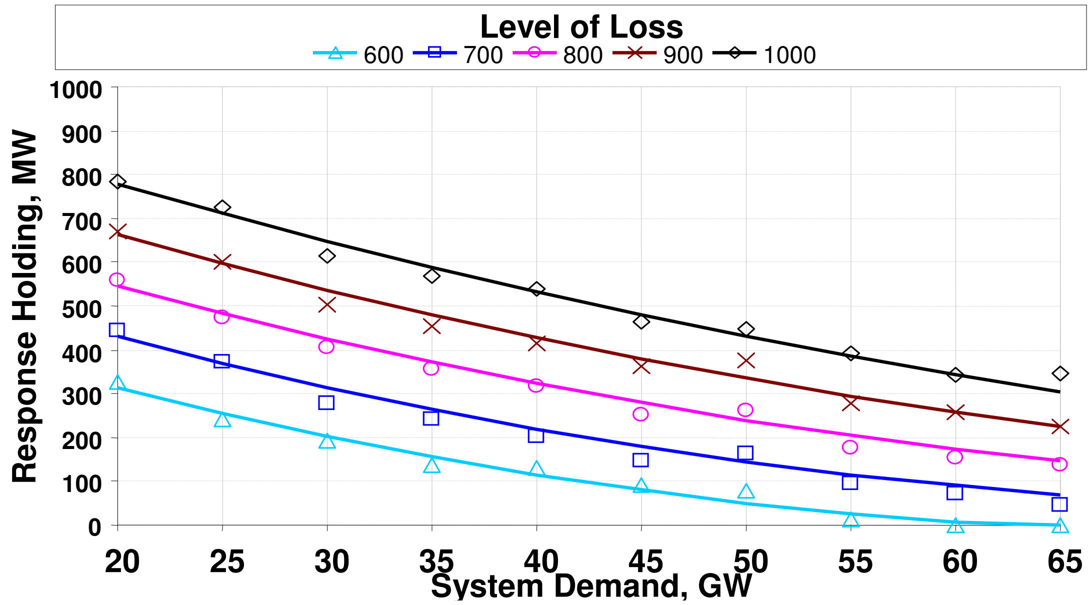


Figure 7.7 – Primary response requirements for significant losses

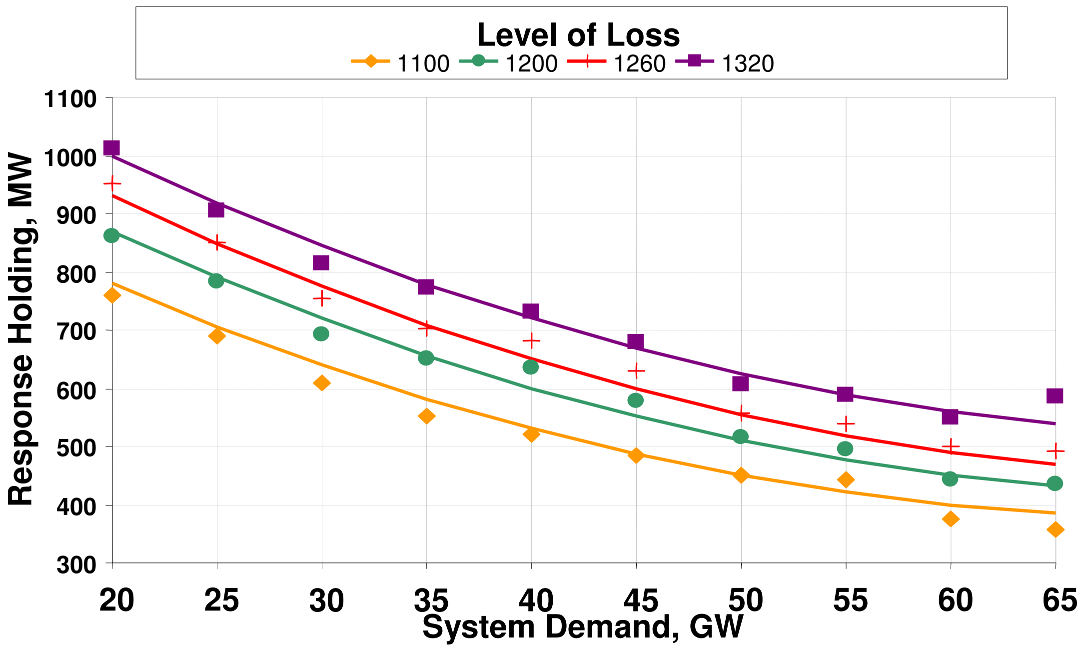


Figure 7.8 – Primary response requirements for abnormal losses

7.4 Error margins

The values of response holding presented in section 7.2 would adequately protect the system during generator loss in the perfect case. From an operational perspective a number of further assumptions should be considered. The main aspects are failure of a generator(s) to supply part or all of response as agreed in contracts. This could be a direct result of a responsive generator being the cause of the frequency incident, or due to operational problems. Performance of the remaining responsive plant, while being generally high is not necessarily guaranteed. A second influence to the response holding is under performance of the load response. We have seen in chapter 6 that the load response varies according to the day, time and system configuration. In order to secure the system fully we must consider the minimum level of load sensitivity to frequency.

To secure the system against these added risks the resulting response requirements derived through Equation 7.1 and simulations are multiplied by a margin. The margin is included to cater for other assumptions made to formulate the response requirement. These assumptions also include:

- Modelling inaccuracies;
- Variation in the choice of units used to provide response;
- Errors in the system wide parameters used, such as starting frequency;
- Operation of rate of change of frequency relays;
- Variation of CCGT output with temperature;

Traditionally a blanket 15 % margin has been added to all response requirements. As a number of factors are independent of response levels this margin is inadequate to fully represent errors in the response calculation process.

7.4.1 Modelling inaccuracies.

Inaccuracies in the modelling of unit response will give a proportional error to the amount of response held. If a single responsive unit has an error of one megawatt, then two similar units with the same response model and starting point will provide an error of two megawatts. Using many units at differing load points with different response characteristics could imply the use of a statistical approach. In this case a reduced margin would be offered as response levels increase. However, since we have a small number of similar generator models taking a statistical approach is not justified. It is assumed that the error from this source is proportional to the response holding.

The accuracy of the modelling of unit response can be determined from calculations against actual loss events on the system. Three such events have been presented in this section. The margin (M_U) for unit modelling takes the form of equation 7.2:

$$M_U = \lambda_U \times \text{Response Requirements} \qquad \textbf{Equation 7.2}$$

Considering a number of system reconstructions, an average error (λ_U) of 0.05 should be substituted. Increased accuracy of the margin would be provided if further post-event simulations are conducted and included in the average.

7.4.2 Margin for variation in choice of units

Two factors must be considered for the margin needed to cover for the variation on the choice on units needed to cover for response:

- The chosen system configuration for response trials may not represent a typical mix of the generator types and powers normally used to provide response.
- The mix of generators used to hold response when a loss occurs may be unusual.

The performance of individual BMUs can have a dramatic effect on the transient frequency experienced during loss scenarios. To investigate the sensitivity of holding response on generators utilising different primary energy sources, a set of simulations were conducted. To reduce the work load required for a complete response holding matrix evaluation, simulations were performed at average daily minimum and maximum demand levels experienced on the system. Secondary response requirements are exempt from this margin, assuming that the generator response has reached a steady state by secondary time-scales. This under steady state the response levels will be identical for all forms of generation.

7.4.2.1 CCGT response

Figure 7.10 shows the changes in primary and secondary response requirement when generation is moved from all coal to all CCGT. For significant events the impact on the primary response holding levels is minimal. A difference of around two to four percent is seen in most trials. Under abnormal losses simulations at both 30 and 50 GW results show a continuous increase in primary response requirement. These results suggest an additional ten percent primary response is required to contain frequencies within limits for losses greater than 1 GW.

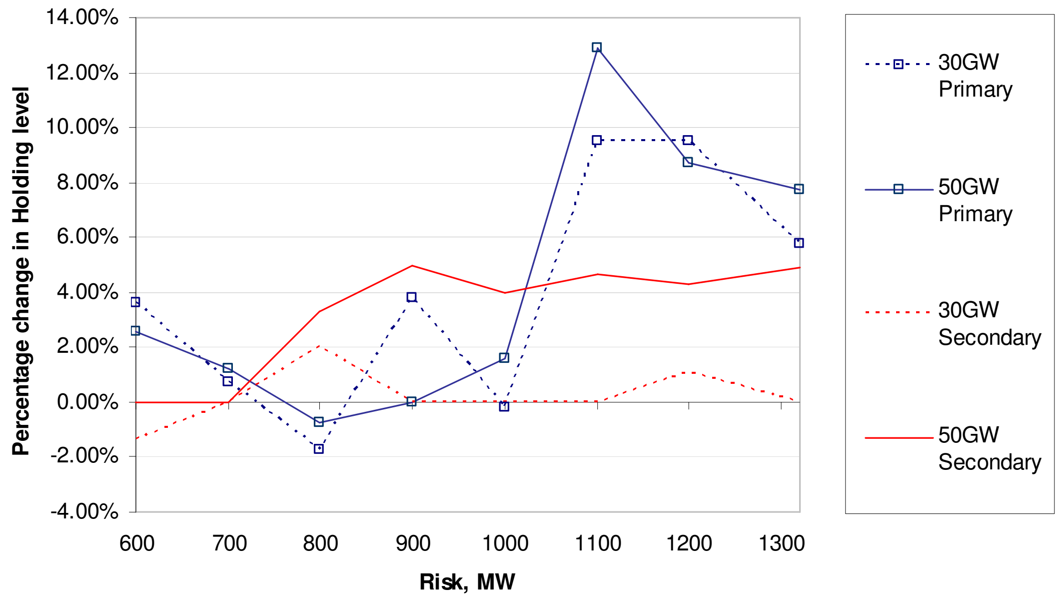


Figure 7.9 – Differences in response requirements for CCGT plant

The error in response requirements introduced by these factors is shown to have greater influence on primary response during abnormal losses. This type of behaviour requires a margin approximately proportion to the response requirement in these instances.

$$M_V = \lambda_V \times \text{Response Requirements} \qquad \textbf{Equation 7.3}$$

The expression given in Equation 7.3 should be used in calculating the margin (M_V) for choice of units under primary response, where λ_V is 0.1 for abnormal events or 0.02 for significant events.

7.4.2.2 Frequency control by demand management

Figure 7.11 shows the changes in primary and secondary response requirement when response is held on demand side tripping and dynamic reserve against purely dynamic reserve. In reality some dynamic response is required by operating guidelines, however to investigate this sensitivity the maximum response is held on demand shedding up to 240 MW after which additional spinning response is allocated.

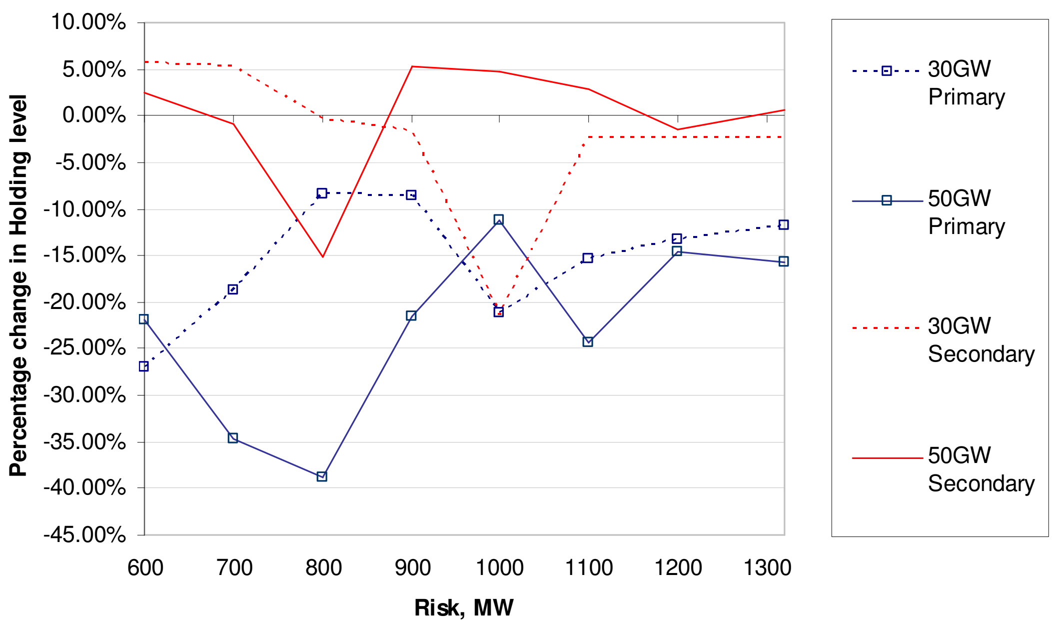


Figure 7.10 – Differences in response requirements for demand management

At 30 GW a general decrease in primary response requirement is shown this is due to the fast response time of the demand. There is potential for 240 MW of response to be provided within two seconds of the incident. This demand based service forms the majority of the primary response requirement in these simulations. The secondary response shows very little change in levels, except for two instances. A similar trend in results is shown in the 50 GW series.

It is suggested that from an operational perspective if demand side response is used primary requirements can be reduced by ten percent or more from pure dynamic requirements. The response holding matrix presented in section 7.2 reflects a typical operational practice, which includes the use of frequency control by demand management particularly for large response volumes. Therefore if the contracted response during operation does include demand side management at least ten percent of additional response should be scheduled.

7.4.3 Margin for system wide values

The system wide parameters are the same for all studies. This implies that the margin to cover for these errors need not be a percentage of the requirement but will relate to how the different system wide parameters affect the response holding.

The starting frequency for the documented holding levels is assumed to be 50 Hz, however the real-time system frequency is constantly changing. As guidance, the standard deviation of system frequency from base is limited to 0.07 Hz. Assuming a normal distribution 99.73 % of frequency values are contained within three standard deviations. Therefore the minimum start frequency we can expect leading into an incident is likely to be no less than 49.79 Hz.

$$M_f = Risk - K_L.D_{GB}.\ (F_{start} - F_{max,sec}) \qquad \textbf{Equation 7.4}$$

Without using the Eurostag model to simulate the margin (M_f) for starting frequency, a formula for secondary response could be based on Equation 7.4. In this case the frequency deviation is the difference between starting frequency (F_{start}) and the frequency limits ($F_{max,sec}$). For secondary response levels this value is, 49.79 – 49.5 = 0.29. Under primary response timescales this method will not account for the timing of the primary response delivery. Taking this interaction into account would require additional simulations to determine the primary response requirements.

Figure 7.12 shows the results of further simulations to identify response holding levels under primary and secondary timescales for a 49.79 Hz starting frequency. Secondary results show broad agreement with Equation 7.4. Interpolating these primary response values across the demand ranges yields margins of up to two and a half times the response requirement. This is well in excess of the current margins used on the system.

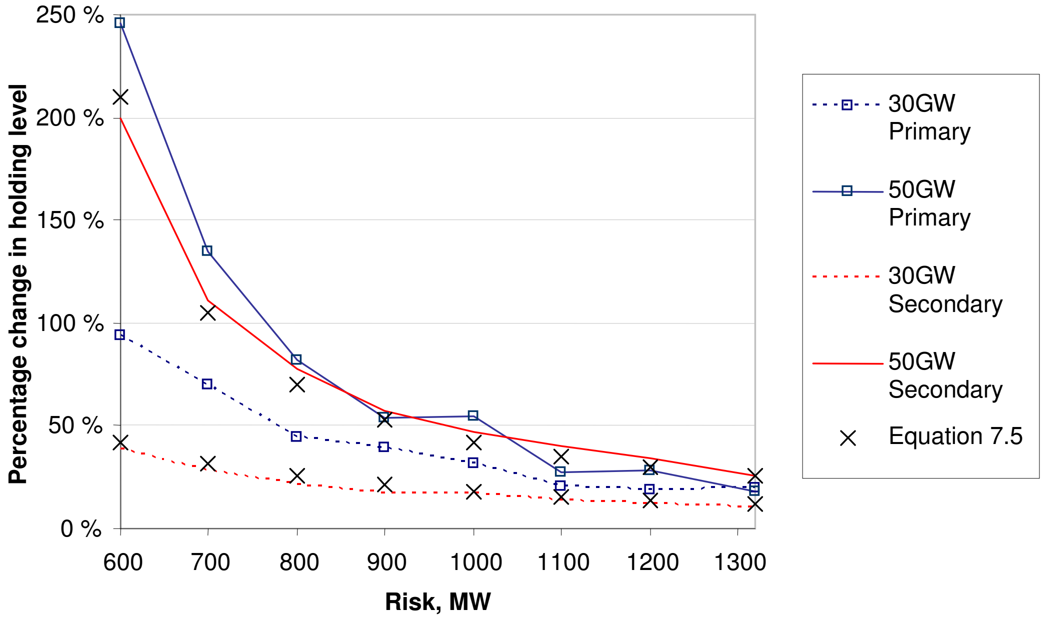


Figure 7.11 – Differences in response requirements for alternate start frequencies (three standard deviations)

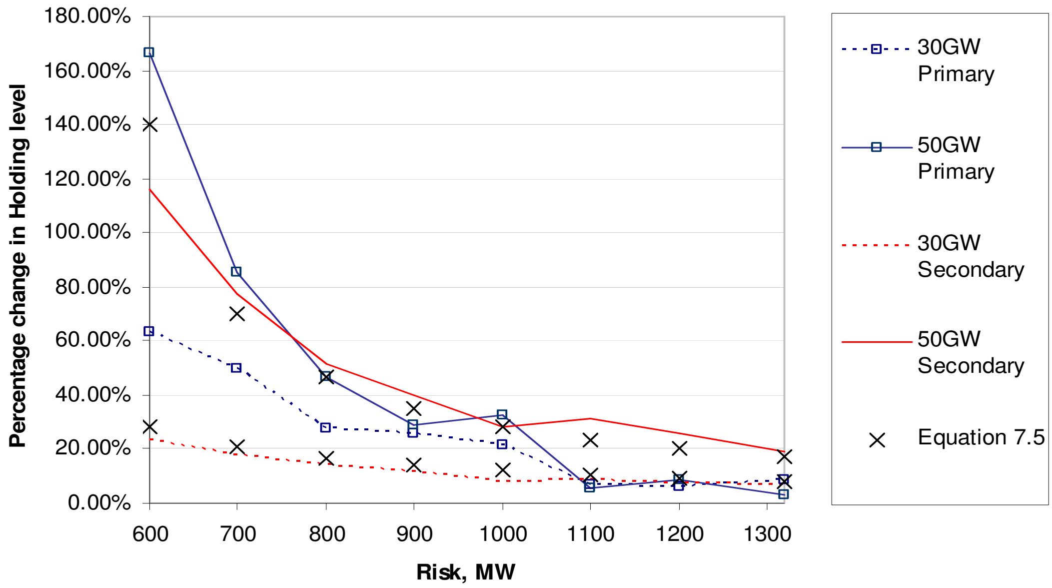


Figure 7.12 – Differences in response requirements for alternate start frequencies (two standard deviations)

If the starting frequency is assumed to be within two standard deviations (95% of the population) the minimum start frequency we can expect is 49.86 Hz. While this compromise reduces the additional margin (Figure 7.13), the risk of a starting frequency outside this value is acceptable. Interpolating the primary margin according to curves in Figure 7.12 requires an additional capacity ranging between 160 and 10 %, which is still particularly high.

The other important global parameter is the demand sensitivity to frequency. This parameter is multiplied by the final frequency deviation hence a basic approach would be to set a margin (M_D) that is dependent on the system demand for both primary and secondary response holding as in Equation 7.6

$$M_D = \lambda_D \times D_{GB} \times \Delta F_{max,sec} \qquad \textbf{Equation 7.6}$$

where λ_D from the minimum recorded data is in the order of: 0.02-0.012 = 0.008.

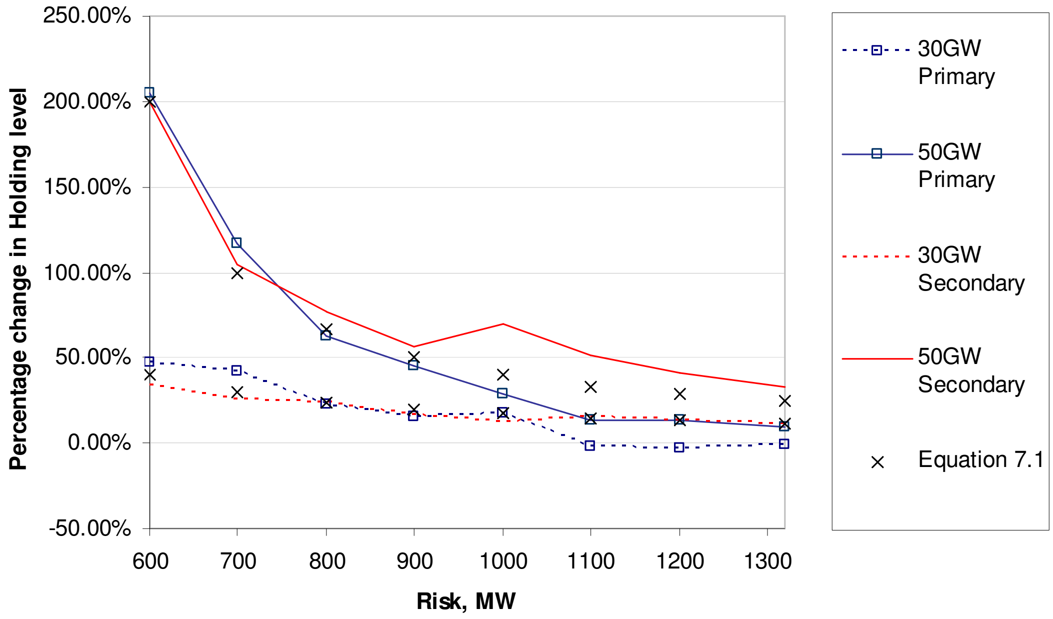


Figure 7.13 – Differences in response requirements for lower demand sensitivity value

Under secondary timescales Equation 7.6 can be used to establish a margin for demand sensitivity at the 1.2 %MW/Hz level. This method will not account for dynamic interactions between the demand sensitivity to frequency and timing of the primary response delivery. Taking this interaction into account again requires additional simulations to determine the primary response requirements at the different demand sensitivity to frequency. Simulations at 50 and 30 GW intervals have been conducted to provide appropriate representation across the demand range, Figure 7.14.

These results also show that a significant margin is required to cater for changes in the load frequency sensitivity.

7.4.4 Margin for generators failing to supply response

The failure of generators to supply response can happen in two ways. The generator can perform slightly differently than expected or the generator could simply not supply any response. The failure of a unit to supply any response can be covered by holding sufficient margin to ensure that a separate unit can be used. If a margin were to be included for complete failure it would simply be a fixed amount of response. By assuming complete failure of response provision partial delivery can be neglected as the worst case has already been considered.

Ideally the performance of individual BMUs would be estimated from historic data and introduced to the requirements as units are scheduled. However, this would result in a cumbersome process which only represents part of the total margin. A suitable alternative is to average the failure rates of all responsive generators and provide a statistical model for delivery. The current failure rate for generators supplying low frequency response is 14 %, however, this factor does not reflect the capacity lost.

At a low response requirement in the order of 25 MW, only one BMU would be needed to hold the full response requirement. For a large response requirement, up to fifteen units would used to hold response. This type of behaviour requires a margin (M_G) that equals the average response held on responsive units at each risk level. This forms a complex relationship which depends on the number of generators scheduled for response. To simplify the calculation, the margin has been represented by a value proportional to the square root of the response requirement, Equation 7.7.

$$M_G = \lambda_G \times \overline{\text{esponse Requirements}}$$ **Equation 7.7**

where λ_G is 2.3 (based on 15 generators sharing the response of a 1320 MW loss at a system demand of 20GW).

7.4.5 Method for combing margins for different errors

The combination the margins from different errors should be based on the statistics of the errors. Assuming that the errors from each source can be treated as independent, and the errors from each source display Gaussian distribution, the combined margin should be written as Equation 7.8.

$$M\arg in = \sqrt{M_U{}^2 + M_V{}^2 + M_f{}^2 + M_G{}^2 + M_D{}^2}$$ **Equation 7.8**

We have already discovered from the load sensitivity measurements that there is an 85 % chance that the value substituted in response calculations is correct. The minimum load sensitivity could actually be a spurious result as only five results are below the 1.5 %MW/Hz value. Furthermore, it is quite common for the standard deviation of system frequency to be less than that detailed in operational procedure. Taking these two points into consideration it is suggested that the margin for starting frequency and load sensitivity both be removed from the total margin calculation until further examination of the distributions are conducted to identify a statistical model.

Applying this updated margin calculation to response values in section 7.2 gives the requirement curves in Figures 7.15 to 7.17.

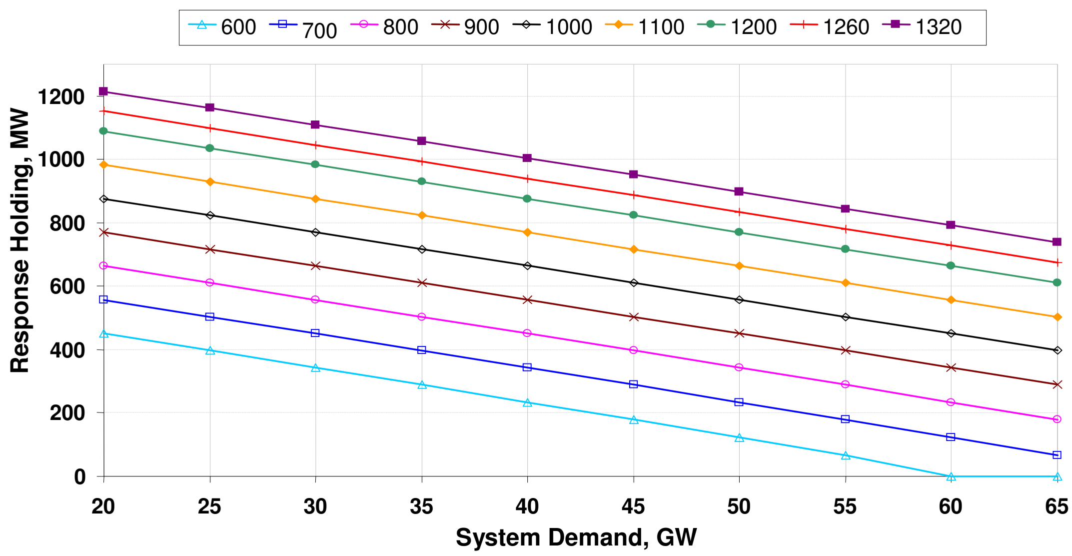


Figure 7.14 – Secondary Response Requirement (including margin)

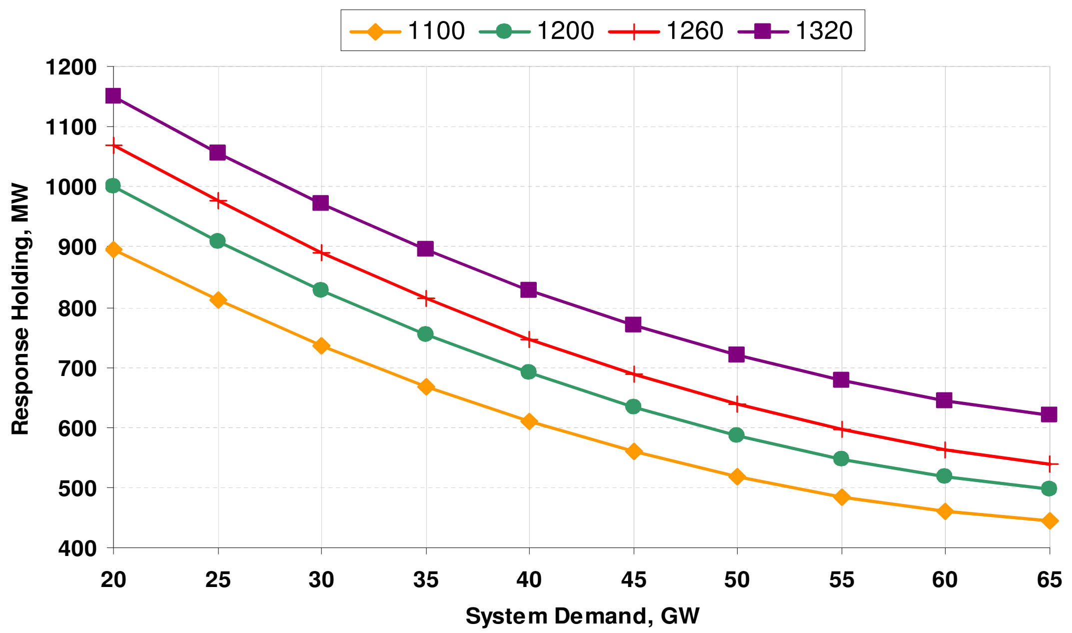


Figure 7.15 – Primary response requirement (including margin) for abnormal losses

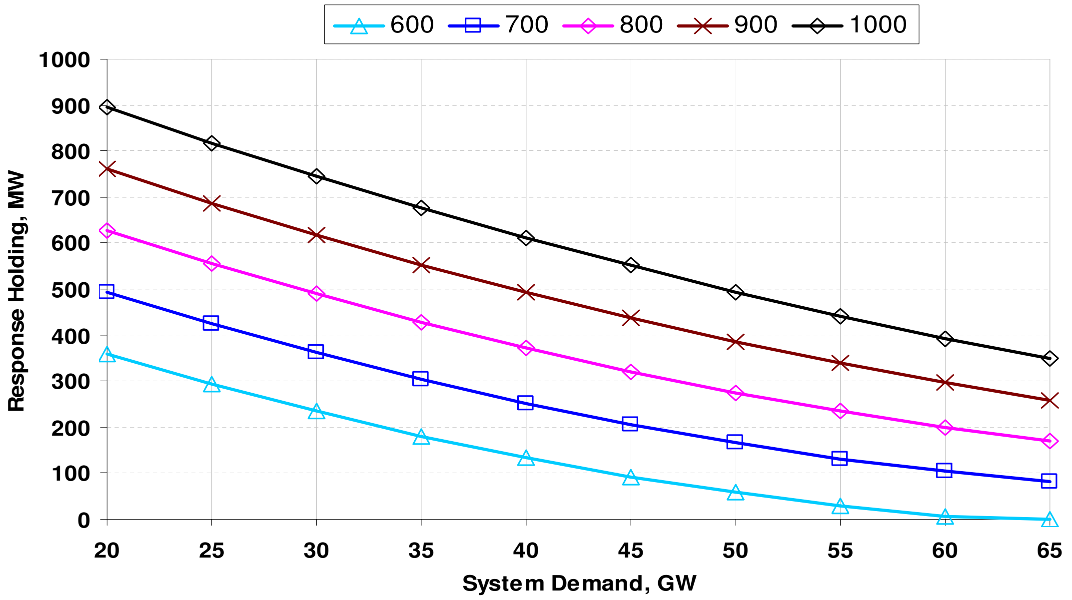


Figure 7.16 – Primary response requirement (including margin) for significant losses

7.5 Changes in response holding

Figure 7.18 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.

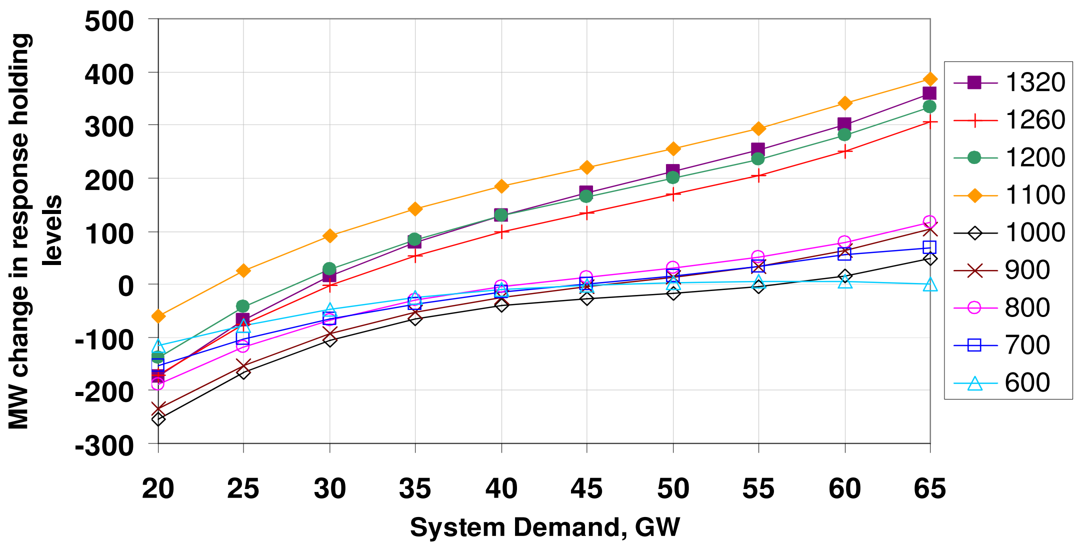


Figure 7.17 – Changes in primary response requirements (without margin)

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.

Differences in the updated requirement curves when including a margin to cater for errors detailed in section 7.4 are considered in Figures 7.19 and 7.20. There is an overall reduction in the response requirement under secondary response, except for 600 to 800 MW losses at higher system demands.

Primary requirement curves show a significant increase in response levels for larger system demands. Abnormal losses above system demands of 30 GW require additional response holding according to simulated values. Significant losses generally require less response at the lower system demand range and more response at the higher range. These facts mimic the results shown in Figure 7.18 suggesting the margin is almost uniform across the response requirements matrix.

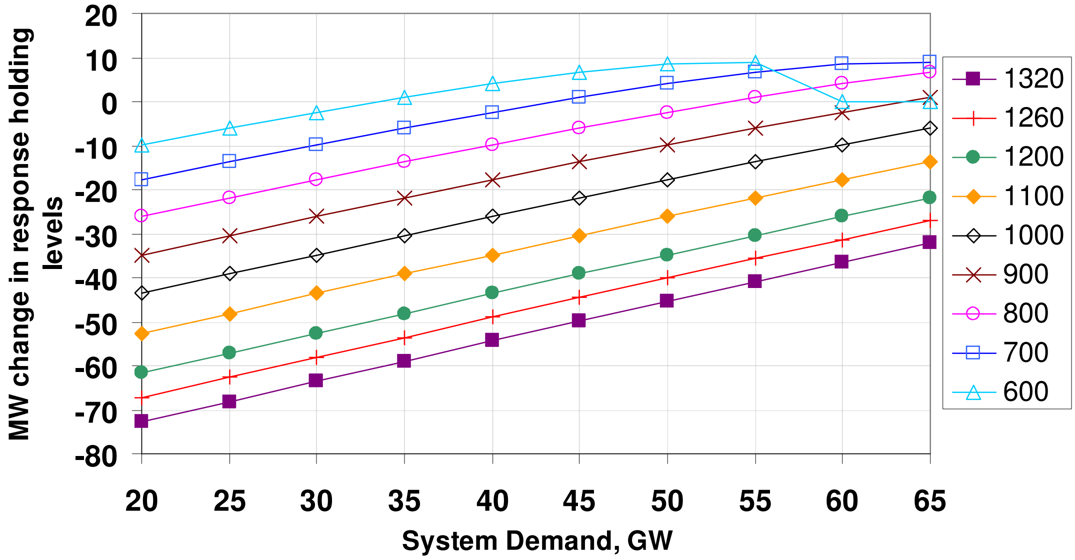


Figure 7.18 – Changes in secondary response requirements with margin

The increase in response holding for abnormal losses can be attributed to the need to return system frequency to 49.5 Hz within one minute. In calculations to establish the current operational response requirements two sets of trials had been conducted as explained in section 7.3. Ignoring the one minute ruling a false primary requirement was set. The system was more than likely never in any risk of being short on primary response because of the additional margin. Also, excess primary response would have been scheduled because the secondary requirement would have dictated the response requirement scheduled in the control room.

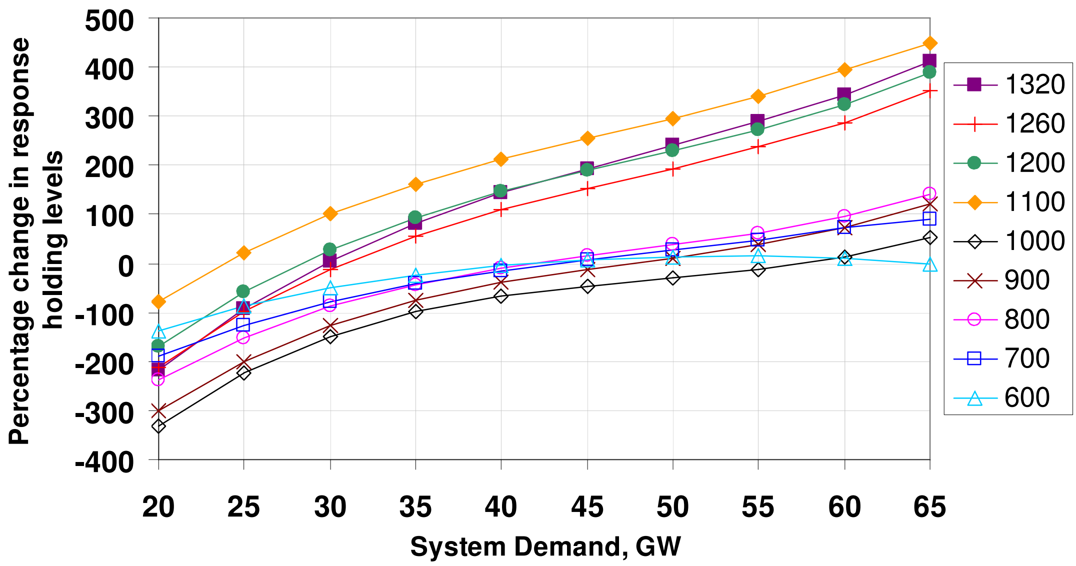


Figure 7.19 – Changes in Primary response requirements with margin

7.6 Summary

Simulations of frequency transients using the developed models and system data from real events has shown good match against records. Using this framework for response trials a set of updated response requirements have been presented.

Simulations have shown an overall increase in the primary response requirements during high system demands with large losses. This increase can be attributed mainly to the requirement for frequency transients to return to 49.5 Hz within one minute. A reduction in primary response requirements is possible at low system demands and for significant losses. The secondary response requirements generally show a reduction in the holding levels.

An improved margin to cover errors in the response modelling process has been suggested. The new method of calculating response margin has little impact on the requirement curves compared to a blanket margin.

Chapter 8

Wind Turbine Model

Chapter 8 investigates the requirements for modelling grid connected wind turbines to study system response. Various types of turbine are discussed on the route to establishing a suitable representation for entire wind farms. A model is presented using a doubly fed induction generator, operating under variable speeds. The distribution and connection of off-shore wind farm sites is detailed with reference to the British transmission grid. Simulations using the established response model and wind park model from this chapter are conducted to discover the effect of increased wind penetration on response holding curves.

8.1 Grid connected wind turbines

As discussed in chapter 2, the levels of renewable generation in the UK are set to increase to an expected ten percent by 2010. The majority of this generation is expected to be supplied through wind farms, BWEA (2004). Large off-shore projects are now receiving consent for construction, and as we will see, three main areas are being developed for this purpose. Presently the Grid Code document, National Grid(2007), has provisions for a frequency response capability on the connection of wind farms (termed Power Park Modules) in section 6 of the Connection Code.

To illuminate, wind parks in operation after January 2006 must be fitted with a suitable proportional frequency control device (i.e. speed governor) to provide frequency response under normal operational conditions in accordance with the Balancing Code. Where required, this means that each wind park must be capable of providing a minimum frequency response of ten percent registered capacity operating below a load point of 80 percent. The response levels above this load point fall proportionally so that no response is required at rated capacity.

These provisions exclude generators in Scotland, England and Wales operating before January 2006, or any farms in Scotland and national embedded plant with a registered capacity below 50MW. For wind farms in England and Wales before January 2006 only the requirements of limited frequency sensitive mode apply. This entails stable active power export between the frequencies of 49.5 Hz and 50.5 Hz, with a reduction in output power by no more than 5% if the system frequency falls to 47 Hz. To avoid unwanted island operation, non-synchronous generating units are tripped if frequency rises above 52 Hz or below 47 Hz for more than 2 seconds.

Wind farms in England and Wales operating after January 2006, and all modules in Scotland irrespective of date, must also be capable of contributing to voltage control through changes in reactive power. With tripping of non-synchronous generation for connection point voltage levels of 80% for more than 2 seconds or 120% (115% for 275kV) for more than 1 second.

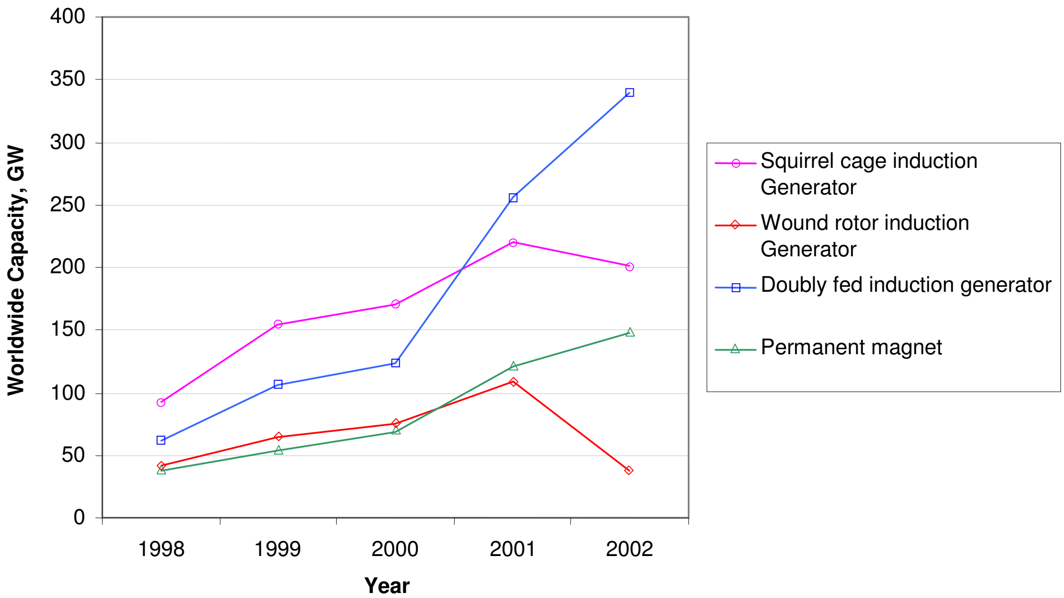


Figure 8.1 – Installed capacity of wind turbines by type [source: Ackermann(2005)]

In order to investigate the effects of these generators on the response requirements, a model for the proposed generation is required. Currently, four main types of generator are used in wind turbines. Figure 8.1 shows the worldwide installed capacity for each example. Wound rotor and squirrel cage machines are now being disregarded in favour of doubly fed induction generators (DFIG) and permanent magnet generators.

DFIG and permanent magnet generators offer improved energy extraction because of variable speed operation. As costs of semiconductor based power converters have fallen over the past few years these turbines have increasingly become the preferred technologies. They also provide more versatile modes of operation, and among other functions, can export reactive power to the system.

The wound rotor and squirrel cage induction generators operate at fixed speed and are normally synchronised with the grid frequency. These two types of generators normally contribute to system inertia, Littler *et al.*(2005), and have no real difference from the electrical properties of conventional generators. The two types of variable speed units are decoupled from the transmission system through power converters. These machines do not contribute to system inertia, and in fact displace other generation that does. Consequently, unless supplementary response is provided, system frequency during generation losses will fall lower and at a quicker initial rate (as seen in chapter 4.2.3).

In order to assess the worst case, that all new off-shore projects are equipped with DFIG type turbines it is necessary to identify adequate models to represent these units. With typical turbine ratings of 2.5-3 MW per machine the wind farms are composed of many individual machines. Modelling some 10 GW of generation would require around 4000 individual machines, beyond the capacity of the simulation software. To sufficiently represent the wind farms, there is a demand for an equivalent site model to analyse the power system interaction with the wind power.

Multiple turbine representation in the form of a corresponding wind park requires that the model embodies the collective behaviour of all the turbines within the wind farm. In the general case this would entail a realistic model, which accounts for the diversity within the wind farm itself. This includes effects due to spatial distribution, different settings and control set-points, control strategies or even different types of wind turbine. Most aggregation techniques require the coherence of wind speed across the farm to be established. Rosa(2003) details appropriate methods to decompose wind speeds across a site.

Akhmatov(2003) recommends clustering of wind turbines according to operational conditions and rescaling to equivalent machines. This approach still requires a significant number of machines, but also assumes comparable operational conditions for clusters of generators. As indicated by Slootweg(2003) this is suitable for aggregation of constant speed wind farms, but not necessarily variable speed wind farms. For the constant speed case, the mechanical power available from the wind can be combined. This allows simulation using a lumped generator model for the farm and further simplifies from the cluster approach. In contrast, Slootweg(2003) suggests that in aggregating variable speed wind turbines the lumped generator model is considered to be unsuitable. Variations in the rotational speed of generators under differing wind speeds mean the operational conditions of the individual units are mixed. Consequently only the electrical power of the wind farm can be summed, resulting in limited aggregation.

The results of different aggregation techniques are compared through steady-state investigations with wind fluctuations and fault analysis by Pöller(2003). The simulations look at both fixed and variable speed turbines. With respect to fixed speed turbines, the conclusion is drawn that a two mass model should be used in representing dynamics. The generator inertia may be lumped in an equivalent model, but shaft oscillations mean that turbine inertia may not. For variable speed units, converters and controls may be collectively modelled along with the electrical representation of the generator. Generator inertia, aerodynamics and pitch controllers should be considered as individual components. However, in cases when variations in wind and mechanical speed may be negligible, application of one lumped generator model representing the complete wind farm delivers satisfying results.

In the proposed generic model we will make assumptions that diversity effects within the wind parks have minimum impact on the simulations, and can thus be ignored. Considering a fixed site wind speed and not a time-varying signal we satisfy the condition set by Pöller(2003). As the simulations themselves consider the entire GB network, a degree of power smoothing would be experienced from variations of wind speed at individual farms. This justifies the use of a constant wind speed to simulate the cumulative effects of the turbine power. Under more advanced simulations for identifying the local impacts of individual farms, in depth representation of units would be essential under recommendation from literature.

8.2 Model of a wind turbine with a doubly fed induction generator

Figure 8.2 depicts the general structure of a variable speed wind turbine with doubly fed induction generator. Each element of the model for the basis of this research is presented in a relatively low level of detail, but the general design may be expanded if specific requirements dictate so.

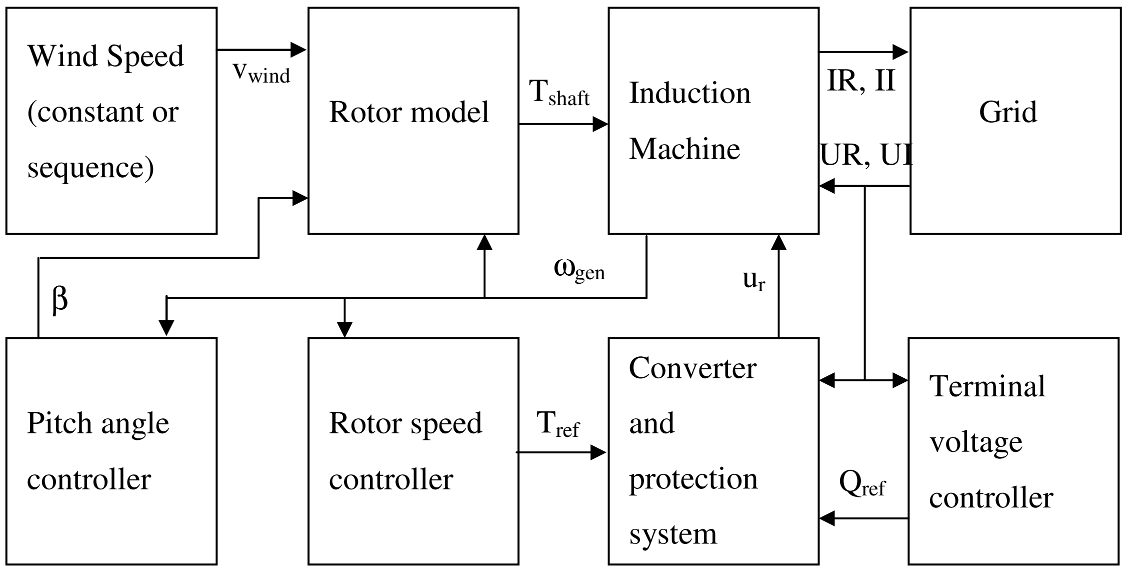


Figure 8.2 – Variable speed wind turbine model

A wind speed model feeds directly into the turbine rotor dynamics. In the case of this research a steady-state value is used, but a pre-recorded time-series may also be introduced. The rotor model consists of a turbine hub and gear train which are represented as a simple lumped-mass. The aerodynamic performance is approximated through an equation which is a function of blade pitch angle and tip-speed ratio. The Induction machine is modelled through a set of differential equations and flux equations in a rotor-orientated reference frame. Pitch and speed controllers ensure maximum power extraction from the wind speed, whilst restricting generator parameters within operational limits. Converters are simplified because of the significantly shorter transient timescales, and protection systems switch off the machine if over/under frequency or voltage events occur.

8.2.1 Rotor model

The maximum power (P_w) that can be extracted from the wind is defined by Equation 8.1.

$$P_w = \frac{\rho_{air} A.Cp.v^3}{2}$$ **Equation 8.1**

Where Cp is equal to the Betz limit (0.593), A is the swept area of the turbine, ρ_{air} is the air density (1.225 kg/m^3) and v is the wind speed. To maximise the energy extraction, variable speed turbines alter the blade pitch angle (β) and hence the speed of hub rotation. This has direct influence on the coefficient of performance (C_p). The original model provides an aerodynamic model for fixed speed units. In order to represent the aerodynamics of a variable speed turbine a general power curve from Ackermann(2005) approximates the relationship, Equation 8.2.

$$Cp(\lambda, \beta) = c_1 . \left(\frac{c_2}{\lambda_i} - c_3 . \beta - c_4 \beta^{c_5} - c_6 \right) \exp\left(\frac{-c_7}{\lambda_i} \right)$$ **Equation 8.2**

where $\lambda_i = \left[\left(\frac{1}{\lambda + c_8 . \beta} \right) - \left(\frac{c_9}{\beta^3 + 1} \right) \right]^{-1}$ and λ is the tip-speed ratio.

Table 6 lists the coefficients used for variable speed units.

Coefficient	c1	c2	c3	c4	c5	c6	C7	c8	c9
Approximation	0.73	151	0.58	0.002	2.14	13.2	18.4	-0.02	-0.003

Table 6 – Coefficients of the aerodynamic turbine model

The turbine hub rotational speed (ω_{turb}) is defined by Equation 8.3, where H_{turb} is the turbine inertia and T_{shaft} is the torsion held in the drive shaft.

$$\frac{d}{dt}\omega_{turb} = \frac{1}{2H_{turb}}(T_{turb} - T_{shaft})$$ **Equation 8.3**

For variable speed turbines the changes in torque associated with wind speed or grid voltage are absorbed by the fluctuations in rotor speed. If required the shaft and gear train can be modelled as a spring and rotating masses. However, as here a constant wind speed is modelled and the relationship has been neglected.

8.2.2 Induction machine model

If a symmetrical and three-phase balanced machine is used to represent the induction generator, a direct-quadrature transformation can be used to decouple the time-variant parameters, helping to simplify the model for vector control. This allows the three-phase system to be converted into phasors through a three-to-two transform.

Eurostag itself uses an orthogonal reference frame to represent voltage and current phasors in the entire network. This allows for straightforward implementation of the model harnessing the real and imaginary phasors in the network simulation. It is assumed the generators are Y-connected without a neutral conductor. Only copper losses are considered in the model and magnetic saturation is neglected. Furthermore, all voltages and current are assumed to be sinusoidal along with the flux distribution.

In addition to a stationary frame (d_s-q_s), an induction machine has two other frames that can be utilised for representation, Figure 8.3. The synchronous rotating frame (d_e-q_e) is aligned with internal flux (stator, air-gap or rotor) and the other rotor frame aligned with a hypothetical shaft rotating at electrical speed (d_e-q_e). The usual approach in modelling is to align the d-axis with the rotor flux, allowing optimal decoupling for control schemes. Here the angle θe is the instantaneous angular position of the flux where the reference frame will be aligned.

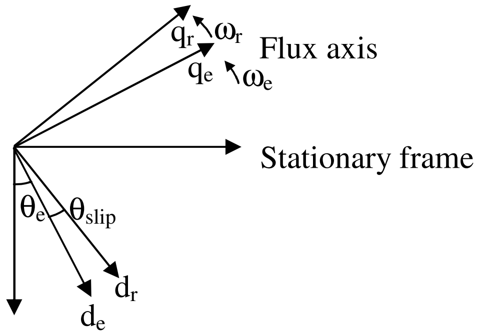


Figure 8.3 – The direct-quadrature reference frame

For doubly fed induction generators it is more beneficial to align the reference frame with the stator voltage, which is the connection node voltage. This allows control by means of the rotor voltage and allows for easy manipulation of active and reactive powers, soens(2005). This implies the stator direct voltage is zero and the quadrature component is the magnitude of the grid voltage, Figure 8.4.

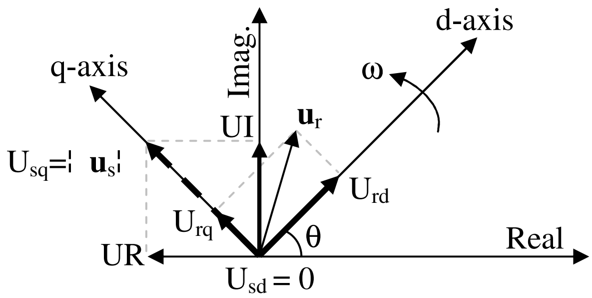


Figure 8.4 – Model reference frame

The voltage equations of an induction generator, using generator convention are well established and referenced in Kundur(1994). Assuming a two pole machine and related in per unit frequency these equations become:

$$u_{sd} = r_s.i_{sd} - \varpi_s.\Psi_{sq} + \frac{1}{2.\pi.50}.\frac{d}{dt}\Psi_{sd}$$ **Equation 8.4**

$$u_{sq} = r_s.i_{sq} + \varpi_s.\Psi_{sd} + \frac{1}{2\pi.50}.\frac{d}{dt}\Psi_{sq}$$ **Equation 8.5**

$$u_{rd} = r_r.i_{rd} - (\varpi_s - \varpi_{gen}).\Psi_{rq} + \frac{1}{2\pi.50}.\frac{d}{dt}\Psi_{rd}$$ **Equation 8.6**

$$u_{rq} = r_r.i_{rq} + (\varpi_s - \varpi_{gen}).\Psi_{rd} + \frac{1}{2\pi.50}.\frac{d}{dt}\Psi_{rq}$$ **Equation 8.7**

in which the subscript *s* and *r* stand for stator and rotor respectively, with *d* and *q* standing for direct and quadrature. ω_s is the rotational speed of the reference frame, and ω_{gen} the mechanical speed of the rotor. Also, *u* is the voltage, *i* the current, *r* the resistance and Ψ the flux. The stator and rotor flux can be defined as:

$$\Psi_{sd} = x_{sd}.i_{sd} + x_{md}.i_{rd}$$ **Equation 8.8**

$$\Psi_{rd} = x_{rd}.i_{rd} + x_{md}.i_{sd}$$ **Equation 8.9**

$$\Psi_{sq} = x_{sq}.i_{sq} + x_{mq}.i_{rq}$$ **Equation 8.10**

$$\Psi_{rq} = x_{rq}.i_{rq} + x_{mq}.i_{sq}$$ **Equation 8.11**

where *x* is the reactance and the mutual reactance is denoted by the subscript *m*.

The electromechanical torque (T_e) is defined in Equation 8.12.

$$T_e = \Psi_{sd}.i_{sq} - \Psi_{sq}.i_{sd}$$ **Equation 8.12**

The motion of the generator is subject to its own inertia (H_{gen}) and this can be represented by Equation 8.13.

$$\frac{d}{dt}\omega_{gen} = \frac{1}{2H_{gen}}(T_e - T_{shaft})$$ **Equation 8.13**

where T_{shaft} is the torsion held in the drive shaft. Equations 8.4 to 8.13 complete the induction machine model.

8.2.3 Pitch control

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 coefficient of performance then limits the maximum power extraction, see Figure 8.5.

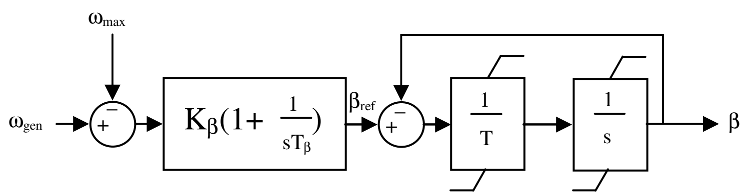


Figure 8.5 – Block diagram of pitch controller

8.2.4 Speed control, current control and converters

Full details of the speed and current control systems are given by Soens *et al.*(2003). The available wind speed is multiplied by the optimal speed-tip ratio to define a rotational speed normalised against base speed. This reference speed is limited between 0.6 and 1.1, and then compared to the actual speed to provide an error signal. The control element is a PI type with anti-windup yielding a reference torque.

The reference stator currents are calculated based on a reactive power reference and reference torque from the speed controller. The actual stator currents are controller through the rotor currents via rotor voltage. A PI-controller with anti-windup is used on the direct and quadrature axis to provide the desired voltage reference.

A simple frequency converter is used to establish rotor voltage with a first order delay of 5 ms on both the d and q axis. In this model it is assumed that the wind farm reactive power exchange is zero.

8.2.5 Initialisation

The electrical models in Eurostag are normally initialised through a user defined macroblock included in the model. If the initialisation is not executed appropriately, the simulation may result in large, fictive transients. These transients must be allowed to decay before the actual dynamics can be simulated resulting in increased simulation time. In some cases the fictive transients even can cause numerical instabilities. An initialisation method is therefore recommended and a specific arrangement has been implemented for this model by the author. This method allows accurate simulation of the dynamic performance, minimising the transients experienced in the initial stages of the simulation. The key parameters that are required for initialisation are:

- Pitch angle
- Generator/rotor torque
- Generator/rotor speed

These three inputs are calculated through the use of lookup tables based on turbine power given in the load flow analysis. Curves presenting typical values for variable speed turbines at part load can be found in Ackermann(2005). For simplicity rotor flux linkage in the q axis is initialised as 1 pu, with all other flux linkage set as zero.

8.3 Wind farm connections

As the majority of the wind turbines are yet to be constructed the studies consider a proposed 6.5 GW of large off-shore wind farms around the British coast. These farms are based on the applications/consent for leasing territorial seabed by the Crown Estate. Also added to this capacity is 2 GW of generation in Scotland to reflect applications for turbine construction and current export limits.

The farms are grid connected in accordance with recommendations from the Econnect(2005) study commissioned by the DTI and the Renewables Advisory Board. The study details recommended connection points and voltage levels for the fifteen offshore sites, of which two have now been rejected, and are removed. Details of a possible DC grid are considered in the document but it is assumed that most farms will connected through 275 kV HV AC sub sea cabling.

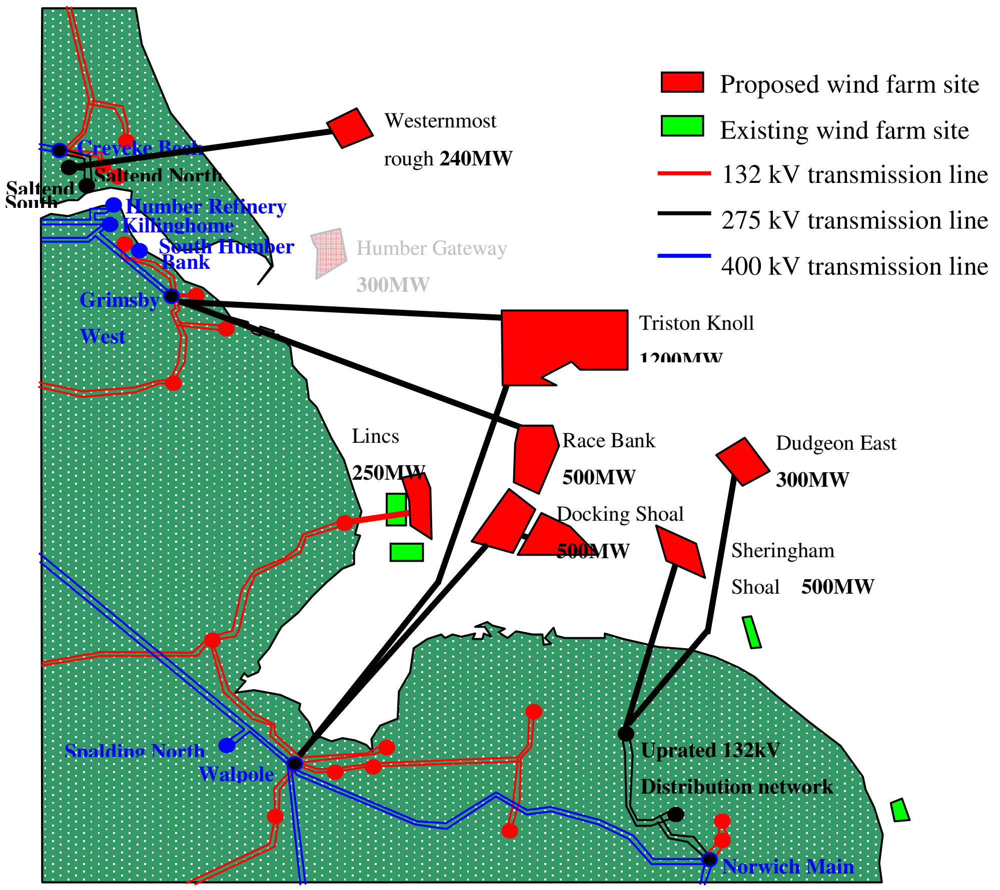


Figure 8.6 – Greater Wash off-shore wind farms

Figures 8.6 to 8.8 show details of the proposed offshore sites used in the study together with suggested network connection points to the exist transmission infrastructure. The additional Scottish generation is lumped and injected at the Eccles transmission node.

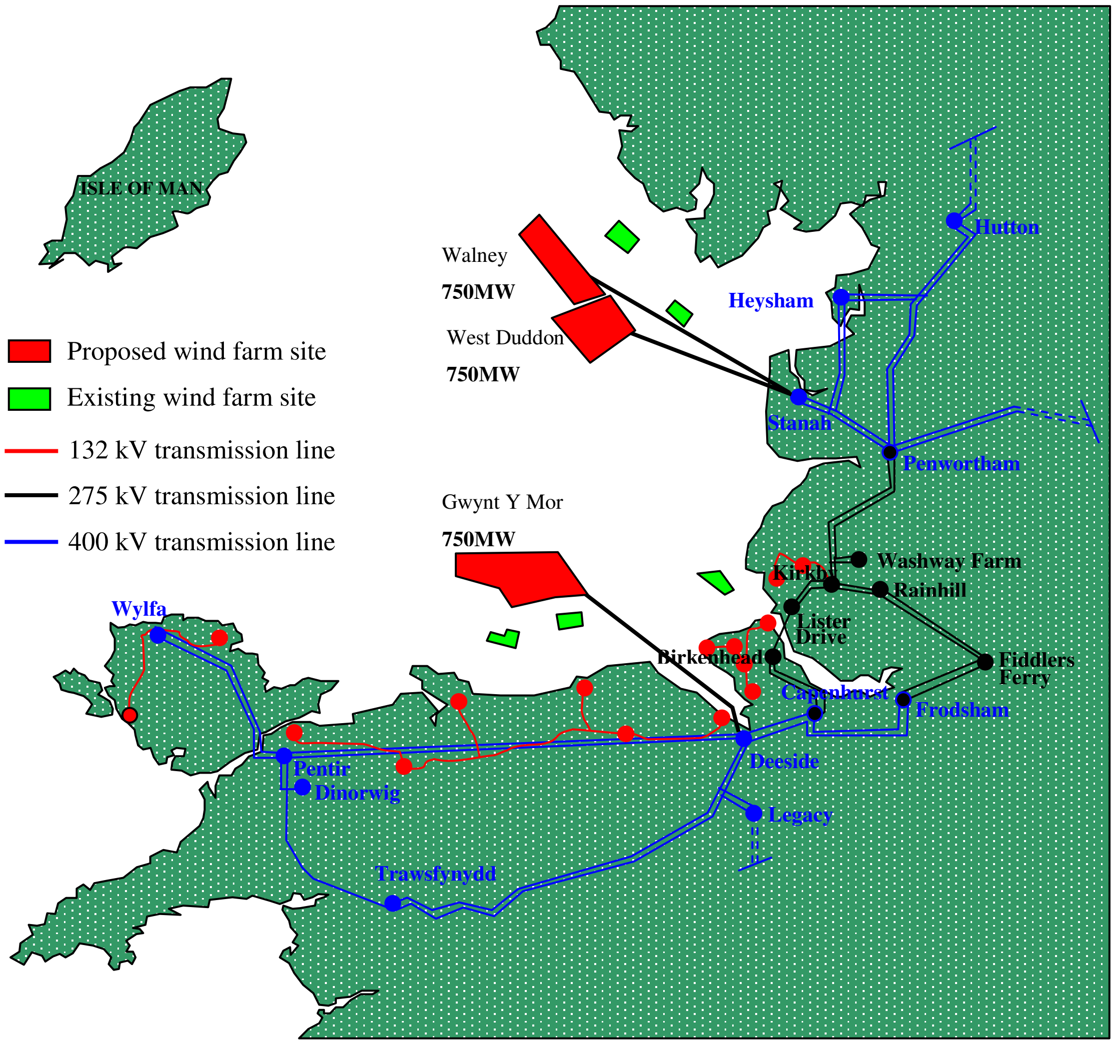


Figure 8.7 –North West off-shore wind farms

It is unlikely that wind generation sites will produce full outputs to coincide with each other across the country. As the author demonstrated in Pearmine *et al*(2005) the correlation between wind speeds across great Britain is actually quite low above 200 km distances. It is very unlikely that if wind farms in Scotland are at rated output the units in the Thames Estuary will experience the same magnitudes of wind speeds. In the same study the output power of turbines was also investigated. The findings relate solely to onshore sites although significant conclusions can be related to offshore sites. The data shows by aggregating areas according to transmission borders, the cumulative generation from wind farms has a ten percent probability of exceeding a maximum of 43 % rated capacity. Conversely, this means there is a ninety percent probability of the outputs being below 43 %.

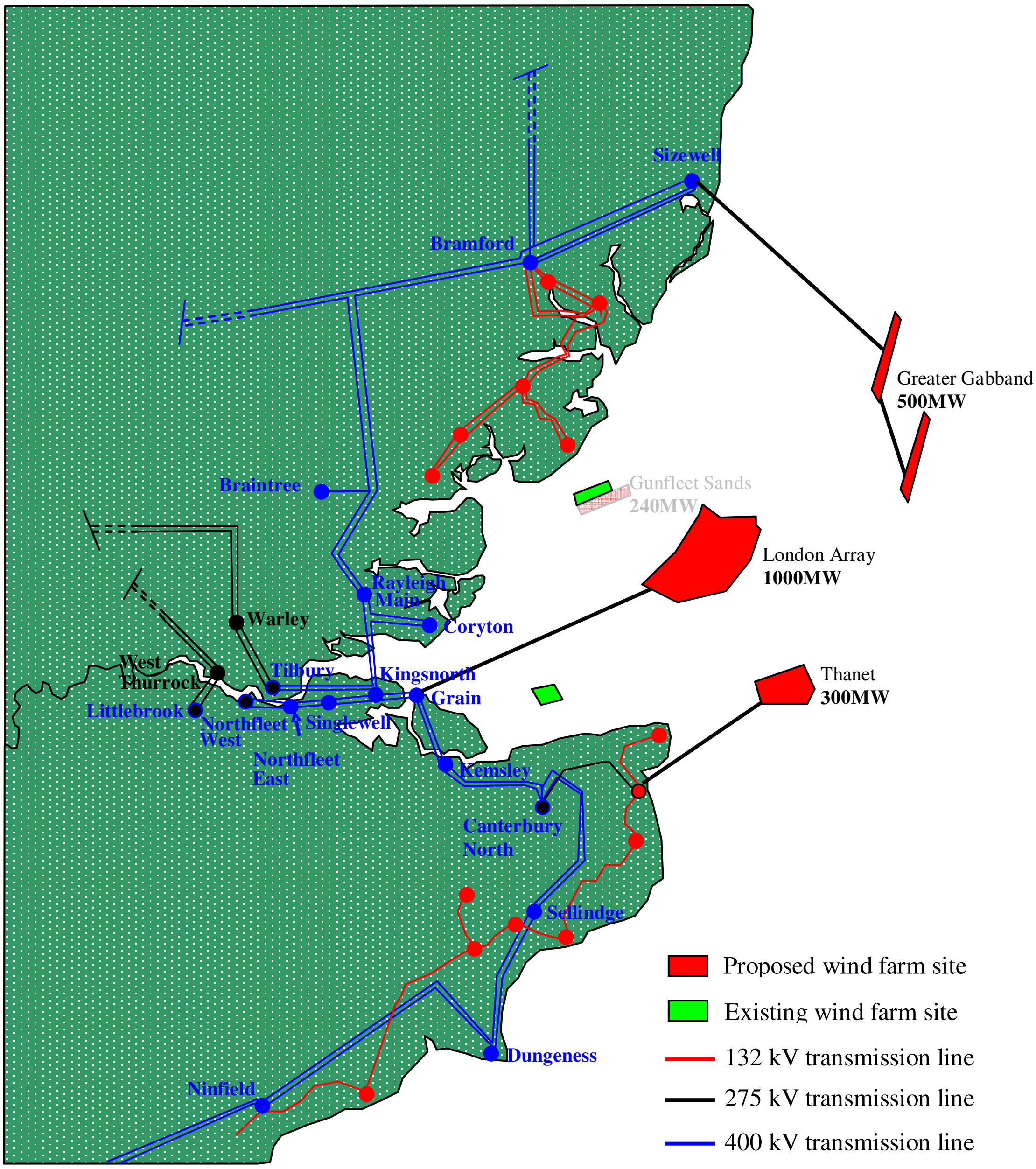


Figure 8.8 – Thames Estuary off-shore wind farms

With the removal of terrain around off-shore sites we would expect the individual sites to experience higher wind speeds, and thus achieve a higher outputs. However, the cumulative national output would remain lower than this value, because of the low correlation between sites. With these points in mind a uniform output power of half rated capacity was chosen for all wind turbine sites. This translates to around 4.25 GW of conventional plant being displaced by wind power plants.

8.5 Influence of wind generation on response requirement

Figure 8.9 shows the changes in primary response requirements with an additional 4.25 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 allows a dominant trend to be established.

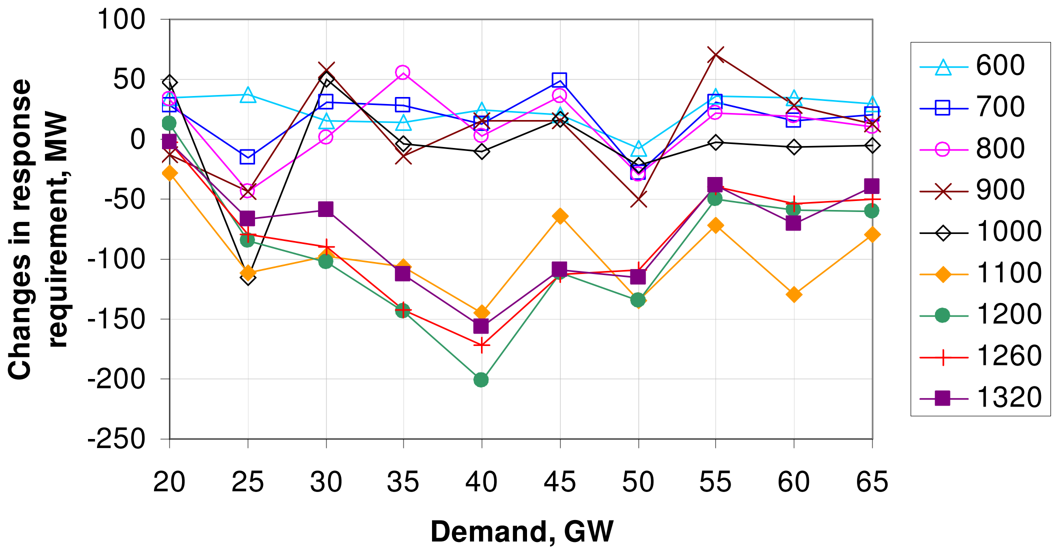


Figure 8.9 – Changes in primary response requirements

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 for the current generation mix in section 7.3, 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.

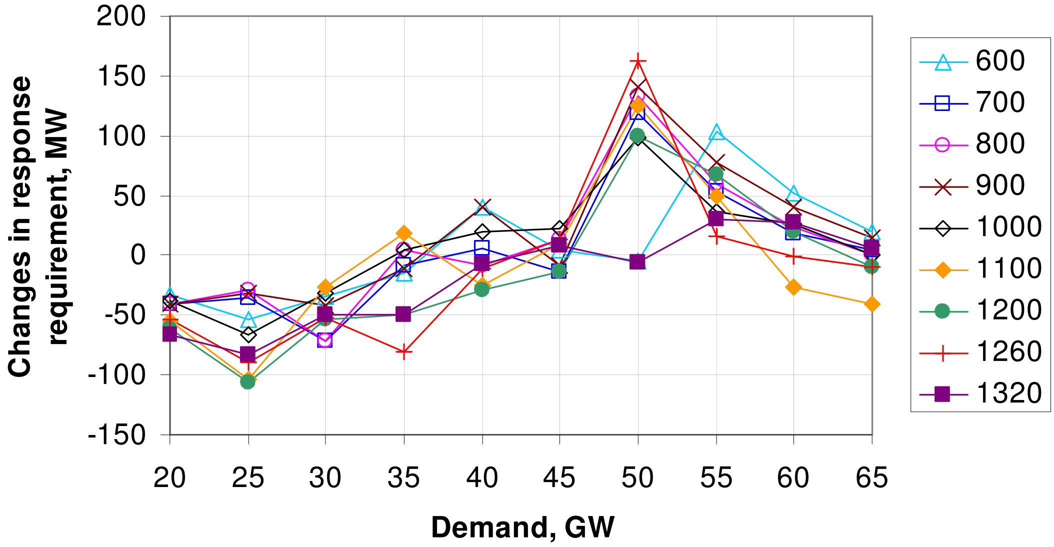


Figure 8.10 – Changes in secondary response requirements

Figure 8.10 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 7.3.1. This result is to be expected as the wind turbines should not significantly affect the simulation under steady state conditions.

8.6 Summary

A model to represent doubly fed induction generators in frequency response studies has been assembled using basic components. Mechanical and control blocks from existing literature sources have been integrated to form a generic wind turbine model. The generic model has been used to represent the expected output power from a number of offshore wind farms around the British Isles during frequency incidents.

Results from studies have shown that as levels of wind turbines with doubly fed induction generators displace existing conventional generation the total system inertia is reduced. For significant losses 1 GW and below, this requires in an increase in the primary response holding of 50 MW. If abnormal losses are encountered the primary response holding can be reduced by between 50 and 200 MW, dependant on loss and system demands.

It is important to note that currently response is held based on the largest requirement on the system. Therefore, if a 600 MW trip requires more response than the largest infeed risk, which may be 1320 MW, the higher response requirement is used. This means the system generation mix requires monitoring so that if wind turbines are not connected to the system old response levels are maintained, whilst if additional wind is exporting the potential savings are realised.

Financial analysis as per Pearmine *et al.*(2006a), can again be applied to estimate the potential expense/savings in response costs through additional DFIG wind generation. In this case little change is experienced in the secondary response levels, and in fact only primary response contracts can be changed, with associated modifications to the holding payments @£4/MW/h (for primary response only). Under sustained significant risks the response holding costs would incur an additional £1,752,000 per annum in response costs. Realistically it is more likely that the potential risks are those leading to abnormal events and hence a saving can be made. Assuming that full utilisation of wind generation can be made inline with these studies the potential savings could be as much as £4,635,500 per annum.

The timing of response has been shown to be a critical factor in the reduction of the primary response requirement by returning the frequency to 49.5 Hz inside sixty seconds.

Chapter 9

General Conclusions

In the opening chapters, this document provides an overview of electricity industry setting a background for the research presented. The environmental impacts of the current system where discussed to provide an objective to minimise the direct influence of frequency response holding in the British case. A number of further systems were investigated and showed that an optimised response requirement is an effective way to manage an isolated systems security to large infeed losses.

Chapter 4 provides details of the main parameters that affect the dynamics of a system during frequency transients. This includes generator droop settings, magnitude of imbalance, the system inertia, the load sensitivity to frequency, and the delivery of response from generators. A number of existing models used by system operators to define response holding levels were discussed. These models generally followed a basic representation of systems, using a simplified model neglecting the transmission network. A method was developed that allowed representation of the network to include system losses and geographic variations in grid frequency.

A number of generator models, required for the modelling solution developed in chapter 4, were offered in a range of literature sources. In chapter 5 the suitability of theses models proved to be sufficient in the general case. However, additional modifications for representing some connected plant were required. Models representing combined cycle gas turbines showed restricted application to specific plant frames. A new universal CCGT model was developed for use in frequency response simulations. Research conducted in this chapter lead to publication of the paper Pearmine *et al*(2006a) in an international journal.

In chapter 4 the importance of not only suitable generator models, but also the correct choice of load frequency sensitivity was established for accurate frequency simulations. In order to establish an appropriate value to use in response trials a set of empirical results were recorded from the system over a two year period. These results from chapter 6 identified a suitable minimum sensitivity to expect during generation loss. Initial research into the load sensitivity value was presented in the international journal paper Pearmine *et al*(2006b). This value was then confirmed by additional results and supplementary methods, and could thus complete the dynamic model to assess the frequency response requirement.

9.1 Summary of results

The complete dynamic model was used to simulate the system response during a number of pre-recorded system incidents. These simulations showed a good match with the dynamic behaviour of the system under the frequency transients. This confirmed the appropriateness of the complete dynamic model for use in response trials.

Simulations using the complete dynamic model to assess the current response requirements were conducted. These results show some reduction in the primary response requirements is possible at low system demands for significant losses. However, the simulations also suggest that an increase in primary response holding is required at high system demands for abnormal losses. The secondary response requirements show an overall reduction in the holding levels. An improved margin to cover errors in the response modelling process has also been suggested.

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 losses 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 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 required 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 that may result.

9.2 Future research

This research has identified a set of suitable models to represent generators connected to the British transmission system under low frequency events. These models have been applied to study the system response requirements in this case. However, there is significant scope to apply the developed dynamic response model to identify other operational security concerns. One potential investigation is to identify the maximum loss that can be sustained on the system before emergency load shedding is activated on the transmission system. The affect of part load hydro response on response requirement has not been investigated in any detail here and is another potential avenue of research.

It was an intention of this research to examine the influence of infeed loss location on the response requirements. The influence of loss location at present is unknown. Studies of different loss locations would be influenced by the line losses and geographic differences in frequency. This is of direct significance for this response model which was purposely intended to satisfy these needs. Sufficient time was not available to conduct the additional simulations to investigate this factor. It is suggested that this is a valuable progression for this research.

As the capacity of wind farms grow it is likely that a number of modifications to turbines will be made to allow for some degree of frequency response. Some of these modifications have already been discussed, but the impacts of these new modifications on the response requirements will need to be considered. There is also the potential for more than 8.5 GW of wind generation to be connected to the system. Further investigations with extra capacity could be conducted to investigate if the conclusions of this research hold at higher levels of wind penetration.

Only a single wind turbine technology was considered in this research, designed to represent the worst case. The impact of different wind turbine technologies mixes could be considered with the introduction of other wind turbine models. This could be influential in establishing the potential reduction in primary response requirements identified in chapter 8.5.

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