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Active Power Flow Management to Facilitate Increased Connection of Renewable and Distributed Generation

by

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Signed:

Date:

I’m truly sorry Man’s dominion
Has broken Nature’s social union,
An’ justifies that ill opinion
    Which makes thee startle
At me, thy poor, earth-born companion
    An’ *fellow mortal!*

Robert Burns
(1759-1796)

For my Mum,

Maureen O'Brien Currie

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List of Abbreviations

ANM	Active Network Management
APFM	Active Power Flow Management
AVC	Automatic Voltage Control
BETTA	British Electricity Transmission and Trading Arrangements
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DFIG	Doubly fed Induction Generator
DG	Distributed Generation
DLR	Dynamic Line Rating
DMS	Distribution Management System
DNO	Distribution Network Operator
DVAR	Dynamic VARs Reactive
EGWG	Embedded Generation Working Group
GDP	Gross Domestic Product
ICT	Information and Communication Technologies
kW	Kilowatt
LIFO	Last In First Out
MW	Megawatt
MWh	Megawatt-hour
NOP	Normally Open Point
OFGEM	Office of Gas and Electricity Markets
OLTC	On-Load Tap Changer
OPF	Optimal Power Flow
ROC	Renewables Obligation Certificate
SCADA	Supervisory Control And Data Acquisition
STATCOM	Static Compensator
SVC	Static VAR Compensator
VAR	Volt Amperes Reactive
RPZ	Registered Power Zone
RTU	Remote Terminal Unit

Abstract

In recent years the power industry has witnessed significant growth in renewable and distributed generator connections to electricity distribution networks. This growth is fuelled by incentives for increasing use of renewable resources. These incentives were introduced by Governments to tackle the challenge of reducing the emission of greenhouse gases from the electricity sector. Much renewable resource exists in remote areas, far from the main demand centres and the accompanying high-voltage transmission infrastructure. The distribution networks in these remote areas were not designed to facilitate the connection of renewable and distributed generation; new methods of planning and operating the distribution network - to take it from being passive to 'active' - are required if these resources are to be accessed in an economically efficient and timely manner.

This thesis proposes an Active Power Flow Management (APFM) scheme to enable increased connection of renewable and distributed generation to electricity networks. The APFM scheme can be incrementally deployed to support multiple generator connections, multiple constraint locations and changes to the network. The APFM scheme manages and coordinates the output of multiple generators within the real-time capacity available on the grid; in doing so, the scheme extends the capacity for generator connections beyond the limits traditionally employed on passive distribution networks. The APFM scheme has completed a successful initial trial and has been deployed on part of the North-Scotland distribution network in 2009.

The design and operation of the proposed APFM scheme is based on the best attributes of methods for increasing generator connections to existing networks. The APFM scheme and accompanying analytical methods are applied to a number of case studies, demonstrating the applicability and suitability of the proposed solution. The means to perform economic assessments of the deployment of the proposed APFM scheme are presented, identifying APFM as economically feasible alternative to network reinforcement for the connection and operation of renewable and distributed generation.

1 Introduction

1.1 Summary of Thesis

This thesis has been conducted at a time of heightened awareness of global environmental issues. A global consensus now exists that links climate change and the corresponding ecological and environmental impacts to human behaviour and the emission of greenhouse gases, mainly that of carbon dioxide, to the Earth's atmosphere. International and national efforts to reduce the emission of greenhouse gases to the atmosphere focus on the electricity sector as one aspect of climate change abatement strategies. Sources of electricity generation are under scrutiny and are now being assessed not only in terms of cost, security and economic viability, but also environmental impact. This is leading a gradual shift towards more sustainable forms of electricity generation, such as that from renewable energy sources. The United Kingdom and Scotland in particular, is rich in renewable energy resource and is experiencing an increase in the connection and operation of renewable energy based generators.

The renewable resource in the UK is abundant in areas remote to the main towns, cities and electrical demand centres. Such areas are also therefore remote to the high voltage transmission network that provides for bulk transfer of electrical energy to consumers. This picture is commonplace in both the developing and developed world. Electricity network infrastructure tends to be more substantial in areas of high population; conversely, long and relatively weak electricity distribution networks serve sparsely populated rural areas. Distributed Generation (DG) is a term used to describe a generator connecting to the distribution network and is synonymous with dispersed and embedded generation. Renewable generators are one type of DG unit; some other examples of DG technology are gas turbines, fuel cells, photovoltaic panels, wind turbines and diesel generators. This thesis presents work relating to increasing the opportunity for, and economic viability of, the connection and operation of DG to existing distribution networks.

Distribution networks have traditionally been viewed as passive power delivery systems, designed to operate with minimal monitoring and operator control intervention and not to accommodate significant generator connections. The traditional approach to connecting DG to such networks has been to require the network to be capable of accommodating the full rated power output of the DG unit during normal operation and even in the event of a first circuit outage. This can be a capital intensive solution and act as a significant barrier to the connection of DG if the developer is to bear the full cost of reinforcement. Renewable energy based generators are often given guaranteed access to capacity in energy markets, which can place an onerous requirement on the developer to invest in infrastructure to accommodate the full rated output of the connecting device. At present, no alternative exists to network reinforcement, although the development of shallow charging principles in the UK and elsewhere is going some way towards addressing the financial burden placed on the developer. Additional complexity in the connection of DG for the Distribution Network Operator (DNO) can arise due to varying network topologies and the timing and nature of DG applications for connections in the same area.

Overcoming technical and commercial barriers to the connection and operation of DG could allow increased access to renewable resource in the near-term. An engineering solution (discounting network reinforcement) to the technical challenges will require a more ‘active’ mode of operation for the distribution network. This will involve taking the existing passive infrastructure and adding monitoring and control functionality to move towards a more active approach to network management. Active Network Management (ANM) involves the application of technology to perform real-time monitoring and control of the network, connected devices and generators to meet prevailing network constraints. ANM schemes are expected to emerge as an economically viable and technically feasible solution to the connection and operation of DG. ANM is a multidisciplinary subject area, requiring recognition and resolution of technical, regulatory and commercial drivers and barriers. A commercial solution to the financial barriers to DG will require due consideration of the nature of the businesses involved (including regulatory incentives and policies), capital costs, operation and maintenance costs, revenue modelling and economic forecasting.

This thesis begins with a thorough discussion of issues relating to the connection and operation of DG, prior to introducing the field and prior art of ANM. The thesis identifies Active Power Flow Management (APFM) as one fundamental component of ANM, prior to introducing a proposed APFM scheme designed to facilitate the expansion of capacity for DG connections to existing distribution networks. The specification of the scheme is presented, followed by detailed design of the control solution and analysis of scheme performance. Case studies are presented to validate the approach to APFM and provide evidence of technical and commercial feasibility in terms of network performance, network security and DG performance. This thesis presents results of a closed-loop trial of the proposed APFM scheme, which is to be fully deployed on the Orkney distribution network in 2009.

The viability of the proposed approach to APFM is assessed through:

- Several case studies of APFM deployment involving different generator technologies and renewable resources
- Consideration of the impact of the APFM scheme on distribution network performance
- The presentation of a methodology to determine the economic cut-off point for new DG connections to the proposed APFM scheme
- Investigation of the impact of the APFM scheme parameters on the economic viability of the DG units
- Analysis of the results of a trial of the APFM scheme on a wind farm connected to the North-Scotland network

1.2 Research Basis and Methodology

The research presented in this thesis took several literature artefacts for its basis, much of the content of these items concern the technical and commercial barriers to connecting DG. Jenkins *et al* (Jenkins et al, 2000) provide an overview of the drivers and types of DG, network impacts and commercial and regulatory issues; this text provides a valuable introduction to DG. Importantly, Jenkins *et al* identify that DG may enjoy a more cost-effective connection by agreeing to restrict operation of the DG plant in certain conditions. The authority of these authors to present this material is without challenge in the UK.

The Embedded Generation Working Group (EGWG) report into network access issues (Embedded Generation Working Group, 2001a; 2001b; 2001c) presents the technical, economic and regulatory challenges associated with increasing levels of DG. The EGWG report is arguably when ANM was first recognised on an industrial platform as a viable route towards connecting and operating DG and therefore accessing renewable energy resources.

In introducing the requirement for ANM, the EGWG (Embedded Generation Working Group, 2001c) also set out a simple vision for the transition from passive distribution networks to active distribution networks. In doing so, this report defines the requirement for Basic Active Management (BAM) solutions as a first step on the path towards a 'fully active' mode of operation. As part of the work of the Distributed Generation Coordination Group (DGCG) (the successor to the EGWG), Collinson *et al* (Collinson et al, 2003) present BAM solutions for the short-term connection and operation of individual DG units. The solutions proposed by Collinson *et al* address power flow management, voltage control and fault level management constraints. Collinson *et al* do not provide solutions for power flow management involving multiple generators, but provide the outline of a solution to manage the power output of a single DG unit in real time based on a single thermal constraint.

The power flow solutions presented by Collinson *et al* were later formalised in Engineering Technical Report 124 by the Energy Networks Association (Energy Networks Association, 2004) that provides guidelines for actively managing the power flows associated with the connection of a single DG unit. These solutions are categorised dependent on the prevailing network conditions at the time of the application of power output constraints: pre-fault, post-fault and real-time constraints. The APFM scheme proposed in this thesis builds upon these foundations for single DG unit solutions and is concerned with multiple generators and multiple network capacity constraints and represents a fully developed APFM scheme.

Roberts (Roberts, 2004), Roberts *et al* (Roberts *et al*, 2003) and Overbeeke (Overbeeke, 2002) identify the use of cellular or zone structures to enable ANM. Overbeeke, in particular, describes how the principles of cell division can support the gradual deployment of ANM. In this thesis, a method of identifying zones for the purposes of applying APFM to an electricity network is presented. The method is scalable and allows further zones to be identified as further generators connect or the network changes.

Kabouris and Vournas (Kabouris and Vournas, 2004) demonstrate the application of interruptible contracts to wind farms and how this approach can support increased generator connections to transmission networks in congested areas. The authors present two strategies for managing power flows from wind farms: preventive and corrective. The preventive approach involves managing the output of wind farms to ensure the N-1 security limit on power flows is not breached. The corrective approach involves curtailing wind farm output only when thermal transfer limits are breached, which would likely only occur during the N-1 contingency. As of 2004, the preventive approach was being applied to the Thrace region of Greece. It was expected that the corrective approach to interruptible contracts would require new regulation and grid code developments and is therefore less favourable in the short term. Kabouris and Vournas also discuss the economic appraisal of the impact of power output constraints on the business of the wind farm developer. The principles of preventive and corrective control actions are further developed in this thesis and incorporated within the proposed APFM scheme.

Based on these foundations, the methodology employed in this research has been to:

- Identify and detail the issues relating to ANM
- Survey the ANM community to determine how ANM is being approached by academic institutions, Governments, Regulators and Industry
- Identify the possible solutions for APFM to expand the connection capacity for DG connections to electricity distribution networks
- Specify the technical elements of an APFM scheme to facilitate increased DG connections
- Develop new techniques to support the modelling, analysis and economic appraisal of the application of the APFM scheme

1.3 Active Power Flow Management

Traditionally, the capacity for generator connections to the distribution network is limited to the 'firm' capacity. Firm Generation (FG) is free to operate when the network is intact and often during the first circuit outage. This is also known as pre-fault constraints; involving limiting DG output to that which the network can accommodate during the worst-case contingency (otherwise known as the N-1 contingency – the loss of the largest one of N lines). This approach imposes a ceiling on the amount of DG able to connect to a network but allows the DNO to preserve and maintain the existing passive mode of operation without risk of breaching network constraints.

The work described in this thesis is concerned with a scheme that manages multiple DG units to meet multiple thermal constraints on the distribution network through APFM. The contributions must be placed in context of existing work, which can be summarised as existing in three main areas:

- Technical and commercial barriers to the connection and operation of DG
- Basic Active Management and other existing solutions for the connection and operation of DG
- Philosophies for integrating ANM solutions within existing communication and control systems

The technical and commercial challenges associated with the connection and operation of DG are summarised by the EGWG (Embedded Generation Working Group, 2001a; 2001b; 2001c). These documents place their focus on the connection of DG, but acknowledge that the challenges identified are applicable to the ANM domain. The EGWG (Embedded Generation Working Group, 2001c) present the transition from passive to active networks, with recognition of the technical elements and commercial drivers required to make the necessary leap and transition towards an active network. The work presented in this thesis is concerned with an APFM scheme that can be gradually implemented, providing a basis for the transition to a more active network.

Ault *et al* (Ault et al, 2003) present a strategic analysis framework to be applied to the appraisal of DG connections. The strategic analysis framework provides a basis for the DNO to assess and understand the implications of DG penetration and support decision making. Ault *et al* present several influence diagrams that provide a comprehensive review and understanding of the interactive nature of technical and commercial issues and the corresponding impacts on the distribution business. This work acts as an excellent reference point for exploring ANM (which is concerned with the connection and operation of DG) and understanding how to identify and interpret the implications of more ‘active’ modes of operation for participants. The work presented in this thesis builds upon these foundations, by providing additional insight in to the unique aspects of ANM, that are in addition to the issues associated with the connection and operation of DG.

In the BAM report, Collinson *et al* (Collinson et al, 2003) present short term solutions for the connection and operation of individual DG units. These solutions address voltage control, fault level management and power flow management. Many of the solutions presented can be considered to be ANM solutions. Several of the power flow management solutions presented have been implemented in UK networks. The power flow solutions presented by Collinson *et al* that can be considered as ANM solutions have been formalised in Engineering Technical Recommendation 124, published by the UK Energy Networks Association (Energy Networks Association, 2004). These solutions are classified according to the approach to managing constraints: pre-fault, post-fault or real-time. The work presented in this thesis builds upon these solutions and presents an APFM solution for multiple generators and multiple constraints, which supports the maximisation of network capacity during either intact network conditions or contingency conditions.

Kabouris and Vournas (Kabouris and Vournas, 2004) demonstrate the application of interruptible contracts to wind farms connected to the Greek Transmission System. The two approaches presented (preventive and corrective) allow the planned capacity of connected generation to exceed the previously enforced FG or N-1 limit. The real-time output of the wind farms and the real-time power flows on the network are monitored and output reduction calculations made based on measured power flow. This system was designed for deployment on Programmable Logic Controllers (PLCs) with emphasis on the simple nature of the scheme and transparency, which provides the required security for the network operator. The scheme acts to reduce wind farm output in proportion to individual wind farm size versus the total portfolio of interruptible contracts. Therefore, each wind farm experiences the same per unit curtailment. The deployment of the scheme is assessed based on historic and probabilistic data and the impact on the estimated portfolio of interruptible contracts for wind farms based on estimates of capacity factor. The scheme is a one-off bespoke solution. The work presented in this thesis goes further by extending the capacity for generator connections beyond the N-1 capability of the network and proposing an APFM solution (with accompanying principles and algorithms) that can be applied to a number of networks and network scenarios.

Liew and Moore (Liew and Moore, 2005) present a power flow constraint approach to facilitate a reduced cost connection for an offshore wind farm to a UK distribution network. The system involves the issuing of ‘turn down’ values to the wind farm (which is performed in 25% steps) based on monitored circuit breaker status and actual power flows on parts of the 132kV distribution system. The constraint system also employs a ‘non-compliance’ trip to disconnect the wind farm from the system should the output reduction level not be achieved. The application of the constraints system allows access to capacity available in real time and is estimated to have saved around £3m in network reinforcement costs. However, no data is available on scheme performance or expected generator curtailment. The APFM scheme presented in this thesis provides a means of identifying network power flow constraints and implements a less crude form of generator output control, which can make better use of available network capacity and evolve as further generators connect or the network changes.

It is unclear how ANM systems will be integrated with existing Supervisory Control and Data Acquisition (SCADA) systems at the distribution level and DG unit control systems. Roberts (Roberts, 2004) provides a comprehensive review of the nature of existing distribution network infrastructure and monitoring and control arrangements in the UK. This report goes on to investigate some ANM possibilities and postulates on how such systems could be integrated within existing SCADA. Roberts identifies the use of a distributed cellular structure for implementing ANM. A method is proposed in this thesis that provides a means of identifying the distributed cellular structure required to deploy the proposed APFM scheme.

Roberts *et al* (Roberts et al, 2003) also identify a hierarchical cellular structure for network control systems deemed to be necessary to support the development of distribution networks, particularly for the connection and operation of DG. Overbeeke (Overbeeke, 2002) identifies the cellular nature of future distribution network control systems and how application of the principles of cell division can support the gradual deployment and development of ANM systems. Overbeeke emphasises the requirement for the evolution of the network to be controlled in a manner that supports a long-term goal. The work presented in this thesis includes a method of identifying cells or zones on the network that can evolve and be gradually implemented as required and integrated within the proposed APFM solution.

Foote *et al* (Foote et al, 2001) investigate the trade-off between network reinforcement and DG output constraints. Indeed, it is argued that accepting constraints will lead to a reduced cost for connecting to and using the distribution network. In assessing curtailed DG connections, Foote *et al* simplify the problem by splitting the electrical load in an area into representative bands. The sum of the load and the export capacity from an area allows the total export permissible from DG to be calculated. This allows the performance of curtailed DG units to be investigated in terms of revenue made and lost. The analysis of the performance of the APFM solution proposed in this thesis goes further by considering the variation of demand and generator outputs at half hour intervals for an annual period.

1.4 Principal Contributions

The principal contributions stemming from this thesis and described therein can be summarised as:

- The design and development of a multi-generator APFM scheme to field trial stage and full implementation. The scheme employs both a preventive and corrective approach to APFM, involving output regulation and tripping of DG units based on real time thermal constraints
- A methodology to identify zones on the network to permit the application of the proposed APFM scheme to manage multiple network constraints and to evolve as further generators connect or the network changes
- The identification of and computational means for defining operating margins for managing power flows as part of an APFM scheme
- An economic assessment methodology for the application of APFM to an existing distribution network. This methodology supports the analysis of DG

connections and provides a means of quantifying the benefits and effects of APFM

1.5 Associated Published Work

1.5.1 Patent Application

Currie, R. A. F., and Ault, G. W.; "Active Network Management", Ref: P15445WO, Filed 16/11/2007

1.5.2 Journal Publications

Currie, R. A. F., Ault, G. W. and McDonald, J. R.; "Methodology for the Determination of the Economic Connection Capacity for Renewable Generator Connections to Distribution Networks Optimised by Active Power Flow Management"; IEE Proceedings, Generation, Transmission and Distribution, May 2006

Currie, R. A. F., Foote, C. E. T., Ault, G. W. and McDonald, J. R.; "Active Power Flow Management Utilising Operating Margins for the Increased Connection of Distributed Generation"; IEE Proceedings, Generation, Transmission and Distribution, January 2007

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1.5.3 Conference Papers

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Currie, R. A. F., Ault, G. W. and McDonald, J. R.; "Initial Design and Specification of a Scheme to Actively Manage the Orkney Distribution Network"; Proceedings 18th International Conference on Electricity Distribution, Turin, Italy, Session 4; 2005

Ault, G. W., Currie, R. A. F. and McDonald, J. R.; "Active Power Flow Management Solutions for Maximising DG Connection Capacity"; IEEE PES General Meeting, Montreal, Invited Panel Paper, 2006

Ault, G. W., Currie, R. A. F. and McDonald, J. R.; "Active Management Solutions to Distributed and Renewable Generation Network Integration Challenges in the UK"; World Renewable Energy Congress, Aberdeen, 2005

Currie, R. A. F., Ault, G. W., MacLeman, D., Smith, M. and McDonald, J. R.; "Active Power Flow Management to Facilitate Increased Connection of Renewable and Distributed Generation to Rural Distribution Networks"; 2nd International Conference on Integration of Renewable and Distributed Energy Resources, Napa, USA, 2006

Currie, R. A. F., Ault, G. W., Fordyce, R.W., MacLeman, D., Smith, M. and McDonald, J. R.; “Design and Trial of an Active Power Flow Management Scheme on the North-Scotland Network”; Proceedings 19th International Conference on Electricity Distribution, Vienna, 21-24 May 2007

Currie, R. A. F., Dolan, M. J., Ault, G. W. and McDonald, J. R.; “Assessing the Impact of Active Power Flow Management on SCADA Alarm Volume”; Proceedings 19th International Conference on Electricity Distribution, Vienna, 21-24 May 2007

Currie, R. A. F., Broadfoot, I. D., Ault, G. W. and McDonald, J. R.; “Towards a Framework for Modelling Active Networks”; Proceedings CIRED Seminar 2008: SmartGrids for Distribution, Frankfurt, 23 - 24 June 2008

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1.5.4 Industrial Reports

Currie, R. A. F., Ault, G.W. and Telford, D.; “Facilitate Generation Connections on Orkney by Automatic Distribution Network Management”; DTI Project Final Report, contract: K/EL/00311/00/00, URN: 05/514, 2005

Currie, R. A. F. and Ault, G.W.; “Register of Active Management Pilots, Trials, Research, Development and Demonstration Activities”; DTI Project Report, April 2006

1.5.5 Articles Referring to the Author's work

The following list presents some articles referring to the author's work:

EA Technology (2006); "A Technical Review and Assessment of Active Network Management Infrastructures and Practices"; United Kingdom Department of Trade and Industry Technology Programme: New and Renewable Energy Contract Number: DG/CG/00068/00/00, URN Number: 06/1196, 2006

KEMA (2009); RPI-X@20: "Technological change in electricity and gas networks. A Sample Survey of International Innovation Projects. Final Report", 2009

Ofgem Press Release R/22 (2006); "Green Light for Scheme to Help Orkney's Renewable Generators"; 13/04/2006

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United Kingdom Department of Business, Enterprise and Regulatory Reform (Contractor: Sinclair Knight Merz) (2008); "Current Technology Issues and Identification of Technical Opportunities for Active Network Management (ANM)"; Contract Number: DG/CG/00104/00/00, 2008

1.5.6 Invited Presentations

The author has given the following invited presentations during the course of this research:

"Renewable Generation Connections and the Network"; DTI 5th Annual Conference on Distributed Generation and the Network, Birmingham, June 2004

"Active Management: New Concepts, Research, Development and Demonstration"; The Institution of Engineering and Technology Seminar: Active Networks Workshop, Austin Court, Birmingham, UK, April 2007

"Orkney – Generator Export Management to Accommodate Infrastructure Constraints – RPZ"; The Institution of Engineering and Technology Seminar: Active Networks Workshop, Austin Court, Birmingham, UK, April 2007

"Active Network Management (ANM): Orkney Registered Power Zone Project"; Control and Power Research Group Internal Power Meeting, Imperial College, London, May 2007

"Active Distribution Management Demonstrations in the UK"; Tutorial: Active Distribution Systems and Integration of Distributed Resources; 20th International Conference on Electricity Distribution, Prague, Czech Republic, June 8, 2009

1.6 Chapter One References

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Embedded Generation Working Group (2001a); "Report into Network Access Issues"; Volume 1, Main Report and Appendices, 2001

Embedded Generation Working Group (2001b); "Assessment of Embedded Generation Contributions to Network Performance"; 2001

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Energy Networks Association (2004); "Guidelines for Actively Managing Power Flows associated with the Connection of a Single Distributed Generation Plant"; Working draft: Engineering Technical Report 124 (ver-005), February 2004

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Liew, S. N. and Moore, T. (2005); "Design and Commission of Active Generator Constraint for an Offshore Windfarm"; Proceedings 18th International Conference on Electricity Distribution, Turin, Italy, 6-9 June, 2005

Overbeeke, F. V. (2002); "Active Networks: Distribution Networks Facilitating Integration of Distributed Generation"; Proceedings Second International Symposium on Distributed Generation: Power System and Market Aspects, Session 9: Active Networks, 2002

Roberts, D. (2004); "Network Management Systems for Active Distribution Networks – A Feasibility Study"; DTI Distributed Generation Programme (Contractor: SP Power Systems LTD); Contract Number: K/EL/00310/00/00, URN Number: 04/1361; 2004

Roberts, V., Collinson, A. and Beddoes, A. (2003); "Active Networks for the Accommodation of Dispersed Generation"; Proceedings 17th International Conference on Electricity Distribution, Barcelona, Spain, Session 4, 2003

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2 Distributed Generation

2.1 Chapter Summary

The goal of this chapter is to provide the reader with an introduction to Distributed Generation (DG). A discussion surrounding a definition of DG is presented, to allow the reader to gain an understanding of the various aspects of the topic. The context for DG, both in terms of the existing electrical infrastructure and drivers for the expansion of DG are discussed. Different types of DG are presented prior to the electricity network constraints and wider system impacts of DG. The value proposition of DG in the context of a liberalised electricity sector is then identified. The chapter concludes with the identification of Active Network Management (ANM) as a means of overcoming constraints on the connection and operation of DG.

2.2 Distributed Generation: A Definition

Distributed Generation (DG) is a term being used internationally to describe smaller, more localised forms of power generation. The term DG is used to refer to different generator technologies and energy sources in different markets and countries. Within this section a definition of DG is presented that is adopted for the purposes of this thesis.

In order to promote a definition of DG it is first necessary to present the nature of typical electricity supply systems. The first electricity supply systems were small in comparison to installed modern infrastructure and characterised by low capacity generators supplying local (and often, industrial) loads and consumers. As the requirement for reliability increased, technology advanced and economies of scale became more apparent, electricity systems became more unified and integrated - a trend that continued over decades to result in the vastly interconnected systems and large-scale generation found in many developed countries today.

The modern approach to electricity supply in the developed world is represented by today's extensive power transmission and distribution networks, market frameworks and consumer quality of supply expectations. The incumbent system is characterised by large centralised generator stations connected to the high voltage transmission network that deliver power through networks of varying voltage levels that are tapered to the point of use. The majority of electrical energy consumed in homes, businesses and factories is generated by large centralised thermal power stations. Thermal power stations combust fossil fuels or utilise nuclear fission to generate electricity. The location of these power stations is usually determined by the proximity and availability of the fuel used to generate electricity, proximity to cooling water and proximity to demand. In the UK, as in other countries, many large thermal stations are located at the coastline and as close to the main electrical demand centres as is aesthetically, politically and practically feasible. Environmental concerns regarding the emissions from large thermal plant and the natural cycles of asset replacement in the power industry are challenging the methods used to plan and operate the existing system.

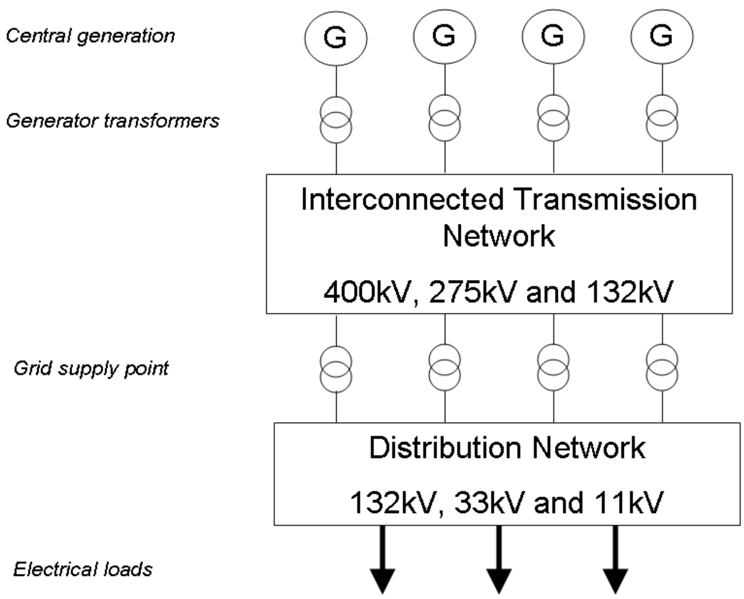

Figure 1: Typical Electricity Supply System with UK voltage levels, according to Jenkins *et al*

As presented by Jenkins *et al* (Jenkins *et al*, 2000), Figure 1 provides a high-level overview of the standard structure of a national electricity supply system. Such systems typically make use of alternating current (AC), operating at frequencies of 50Hz or 60Hz and are comprised of both transmission and distribution networks. Figure 1 is annotated with some voltage levels that are typical of networks in the United Kingdom (UK).

The transmission network is the backbone of the modern electricity supply system and operates in the UK at 400kV, 275kV and 132kV. Large centralised generator units feed power directly into the transmission network, which then transports bulk power to distribution networks through step down transformers at grid supply points (GSPs). The transmission network is typically the subject of extensive monitoring and control and is a dynamically managed system. Distribution networks in the UK operate at 132kV and below in England and Wales and 33kV and below in Scotland. Distribution networks have traditionally been designed to operate as passive power delivery systems, with few generator connections and limited monitoring and control. A combination of fixed and on-load tap changing (OLTC) transformers facilitate the stepping between different voltage levels. Although voltage levels vary per country, much of the same practice exists with regard to this model of electricity supply.

In the UK, as in many other countries, the electricity sector is liberalised. Electricity supply companies buy electricity on the wholesale market and sell it to and bill consumers. There are a number of private companies acting as electricity suppliers in the UK, many of whom also provide gas supplies. The price and package for the electricity and gas supplied by these companies varies and consumers are free to enter into agreements with any one of the established and licensed companies. This approach to electricity supply and the accompanying market and regulatory environment has led to highly efficient and reliable supplies for the vast majority of consumers.

In recent years, the format for supply presented in Figure 1 has been challenged by an increasing trend of decentralisation of generation sources. This has led to increased generator connections at distribution voltages, mainly driven by environmental concerns regarding fossil-based form of electricity generation and incentives for developments in renewable energy sources. The existing distribution network infrastructure and mode of operation places a limit on the opportunity for the connection and operation of DG.

DG is synonymous with embedded generation and often with renewable energy based and combined heat and power (CHP) generating units. DG has been categorised in different ways worldwide, reflecting the variety of technologies and drivers in different countries; for example, the requirement for increased reliability in North America, as opposed to the increased connection of renewable generators in Europe. There are a number of interrelated issues and factors that can lead to a definition of DG; indeed, the term DG is widely used to describe different technologies with different operational characteristics connected at a variety of voltage levels.

Ackermann *et al* (Ackermann *et al*, 2001) pose a number of definitions of DG, including those by other authors, leading to the following definition:

> *"Distributed Generation is an electric power source connected directly to the distribution network or on the customer side of the meter"*

Ackermann et al adopt this definition for the following reasons outlined below, which are consistent with the use of the term DG in this thesis:

- The definition is not specific to a particular technology or energy source (renewable or otherwise)
- DG units can vary in size from several watts to tens of megawatts, therefore it may be misleading to define DG by the rated electrical output of the generator

- Defining DG by voltage level of connection would be misleading due to the varying transmission and distribution voltage levels used in different countries
- The definition can be universally applied due to the established model for electricity supply systems and distinction between transmission and distribution

2.3 Drivers for Distributed Generation

There are a number of drivers for growth in DG; however, there is little doubt that climate change and energy policies that incentivise greater utilisation of renewable energy sources are driving much of the expansion of DG, particularly in Europe. This section discusses climate change and incentives and regulatory measures for increased DG. Hadjsaid *et al* (Hadjsaid *et al*, 1999) present the following drivers for DG:

- Saturation of the existing network and reduction of security margins
- Geographical and ecological constraints
- Stability and security problems (need of expensive preventative measures)
- Continuous growth of demand, especially in developing countries
- Need of investment to sustain increasing power demand, leading to the breaking up of investments (small generation units, cogeneration)
- Privatisation, deregulation and competitive markets
- Emergence of new, rational, generation techniques with small ratings, ecological benefits, increased profitability, and which can be combined with heat generation

It is clear from the factors presented above that the drivers for growth in DG are technical, commercial and ecological. Dugan and McDermott (Dugan and McDermott, 2002) confirm many of these drivers for the expansion of DG, but also identify the following additional factors:

- DG allows utility companies to hedge against high market prices
- The efficient use of energy from combined heat and power (CHP) systems
- Improved reliability is afforded by back-up generation
- Opportunities to sell ancillary services (reactive power, standby capacity, etc)

Some additional factors in favour of the expansion of DG are also identified by Jenkins *et al* (Jenkins *et al*, 2000), the addition of which to the drivers presented above gives a comprehensive perspective on the drivers for the growth of DG:

- Planning permission is often easier to obtain for smaller power stations
- DG is often located closer to demand, potentially reducing overall system losses
- Low or zero emissions technologies can be implemented

It is the opinion of the author that the most important driver for DG is the implementation of low or zero emission technologies as identified above by Jenkins *et al* (Jenkins *et al*, 2000). This driver exists due to the recognition of the role the electricity sector must play in addressing the ecological, environmental and economic impacts of climate change.

2.3.1 Climate Change

A general consensus exists among the global community that the emission of greenhouse gases, mainly CO_2, to the atmosphere is causing the climate of Planet Earth to change. The consequences of climate change are recognised as being, but not limited to, rising sea levels, increasing desertification and extreme and abnormal weather patterns with various implications for plant and animal species and human beings. The following quote is from the Intergovernmental Panel on Climate Change (IPCC) (Intergovernmental Panel on Climate Change, 2007):

"*Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global average sea level*"

The cited implications of climate change for human life are significant, not just in terms of changes to physical geography and the corresponding impact on human geography but also to the economic systems and markets that support and make up the modern age. The Stern Review (Stern, 2006) estimated that the cost of unabated climate change could be between 5% and 20% of GDP. However, Stern estimates that the cost of action now to reduce the impact and onslaught of climate change is nearer 1% of GDP. These numbers suggest a clear economic benefit, in addition to the ecological and environmental benefits, of tackling climate change now.

Climate change has been on the international agenda since the 1980s and was recognised in 1988 with the formation of the Intergovernmental Panel on Climate Change (IPCC). Today, the IPCC is generally regarded as the authority on matters concerning climate change and the potential impacts on human life. The activities of the IPCC led to the United Nations Conference on Environment and Development in Rio de Janeiro in 1992. This meeting, also known as the 'Earth Summit', saw the first global gathering of nations to address global issues relating to, among other things, climate change.

The Earth Summit also witnessed the production of an international environmental treaty: the United Nations Framework Convention on Climate Change (UNFCCC). The UNFCC set no binding limit on the emission of harmful greenhouse gases from signatory countries, but the treaty addressed the issue through the identification of a requirement for binding targets or "protocols" to be implemented at a future date. The subsequent Kyoto Protocol (named after the city of Kyoto in Japan, where the third international meeting of the community occurred in 1997) places mandatory emissions reduction targets on signatory countries. At the present time, over 180 countries have ratified the Kyoto Protocol, including the United Kingdom. Much debate surrounds the effectiveness of the measures contained within the Kyoto

Protocol, particularly as some of the world's largest polluters are yet to sign up, often challenging the science behind climate change, the effectiveness of the proposed arrangements and citing the negative economical implications associated with involvement. The Kyoto Protocol is, however, an unprecedented step towards a global consensus on tackling climate change and has had a marked effect on UK and European Energy Policy.

As a result, one common feature of national energy policies today is a mechanism or incentive program for renewable sources of energy to achieve a gradually increasing level of penetration in the overall energy mix. Such policies are being designed to achieve specific reductions milestones on agreed timelines. This is in recognition of the role of electricity generation in increasing the concentration of GHGs in the atmosphere.

Table 1 provides some data on emissions from some sectors of UK society, as published by the UK Government Office for National Statistics[1]. The supply of electricity, gas and water accounted for 218.6 million tonnes of carbon dioxide equivalent (mtoCO_2e) in 1990, which represented 27.8% of UK emissions. The actual emissions from this sector were reduced in 2003 to 192.6 mtoCO_2e, equivalent to 26.7% of UK emissions. Reductions also occurred in the manufacturing sector, but an increase in emissions from transport and communications has been experienced. Overall, the total UK emissions reduced from 786.3 mtoCO_2e in 1990 to 722.3 mtoCO_2e in 2003. The provision of utilities in the UK is responsible for just under one third of all GHG emissions.

Table 1: Percentage and Million tonnes of CO_2 equivalent emissions from the provision of Electricity, Gas and Water supplies in the UK

	1990 (mtoCO_2e)	**2003 (mtoCO_2e)**
Electricity, Gas and Water Supply	218.6 (27.8%)	192.6 (26.7%)
Total UK emissions	786.3 (100%)	722.3 (100%)

[1] http://www.statistics.gov.uk/cci/nugget.asp?id=901 (Accessed 25/10/2009)

In addition to global agreements such as the Kyoto Protocol, other countries or groups of nations are establishing pacts to address climate change. In Europe this has been done to complement and enforce commitments to meet the Kyoto Protocol. In 2007, the European Council set a binding target for member states to increase the percentage of overall EU energy consumption to be met by renewable energy to 20% by 2020 (Commission of the European Communities, 2007).

A number of other international pacts and treaties have emerged since the Earth Summit in 1992. It is unclear how effective the various targets and measures will be, particularly if the International Community cannot agree on a unified approach. It is out with the scope of this thesis to postulate on the effectiveness of one strategy or another; however, it appears that any mitigation strategy will require an increase in the deployment of renewable energy based electrical generators. Such an increase will require incentives for growth, as discussed in the following section of this thesis.

2.3.2 Incentives and Regulatory Measures

Existing regulatory environments, such as that in the UK, are established to attempt to reduce the cost of electricity to the consumer and increase the reliability and security of supply. Distribution Network Operators (DNOs) are in essence natural and regulated monopolies (and distinct from the Transmission Network Operator), there is at the present time little incentive to connect and operate DG within the existing regulatory environment. Regulated utility companies in the UK are driven towards being asset owning companies, permitted to make a certain return on investments to be recovered from consumers. With consideration of the main goals of regulation concerning demand customers, there is potential for conflicting goals between parties and barriers to block increased deployment of renewable generation.

It is common for renewable generators to have priority access to the grid (also known as a 'must take' policy), Soder *et al* (Soder *et al*, 2007) and Burges and Twele (Burges and Twele, 2005) discuss the application of such a principle in the German power market. There are a number of additional options for incentives and regulatory measures to encourage greater uptake of renewable energy sources. Two of the most common are now briefly introduced: the feed-in tariff and green energy certificate. It is out with the scope of this thesis to consider in detail the effectiveness and breadth of potential approaches to incentivising growth in renewable energy, the following sections are to introduce the reader to some of the context for later discussion of DG value and revenue streams.

A Feed-in Tariff represents a long-term premium payment for electricity produced from renewable energy sources with a designated rate and lifetime. This removes the risks associated with exposure to market variations and as the feed-in tariff results in greater revenue for the generator the renewable project becomes an improved investment option. This approach has been particularly successful at increasing the amount of renewable energy in the German, Danish and Spanish electricity systems (Eriksen *et al*, 2005). Different feed-in tariffs can be applied to different technologies; however, in some countries the feed-in tariff is applied flatly to all technologies. The feed-in tariff represents a significant incentive for renewable energy but does not guarantee that specific targets will be met. In November 2008 the UK Government announced an Energy Bill that requires the implementation of feed-in tariffs for small-scale renewable generators (<5MW).

Green energy certificates are awarded for every unit of renewable energy that is produced and delivered to the grid. In addition, targets for supply companies are set requiring them to purchase a number of certificates that will ensure a percentage of the energy they supply comes from renewable resources. Therefore, the targets in essence become tradable quotas. The renewable developer is given a guaranteed price for the green energy certificate, which is bought by the electricity supply company, therefore supplementing the income of the renewable generator due to revenue from energy sales.

The UK has introduced a Green Energy Certificate programme called the Renewables Obligation, which succeeded its predecessor the Non-Fossil Fuel

Obligation. Under the 1989 UK Electricity Act, five Orders were made requiring Regional Electricity Companies (RECs) to award contracts to supply a certain proportion of electricity from renewable resources. These Orders are known in the UK as the Non-Fossil Fuel Obligations. The Non-Fossil Fuel Obligation was replaced as part of the Utilities Act (2000) by the Renewables Obligation (RO), which came into force in 2002. England and Wales, Scotland and Northern Ireland all have separate RO programmes implemented.

The RO requires suppliers to source a particular amount of the electricity they supply from renewable sources. Each participating renewable generator receives one Renewables Obligation Certificate (ROC) for each MWh of electricity generated. ROCs are then bought buy suppliers to fulfil their required quota. If suppliers do not have the required number of ROCs then the shortfall can be acquired by paying the 'buyout' price. The proceeds from the buyout are then recycled to the suppliers in proportion to the ROCs they have already purchased. Further information on the RO is available on the Ofgem website[2]. Differentiated or 'banded' ROCs now look likely to be implemented in the UK for large-scale generation as a result of the 2008 Energy Bill and as discussed by the UK Government Department for Business, Environment and Regulatory Reform (BERR) (UK Government Department for Business, Environment and Regulatory Reform, 2008). The annual Renewables Obligation targets for the % of total energy supplied from renewable energy between 2006 and 2016 are given in Figure 2.

[2] www.ofgem.gov.uk (accessed 25/10/2009)

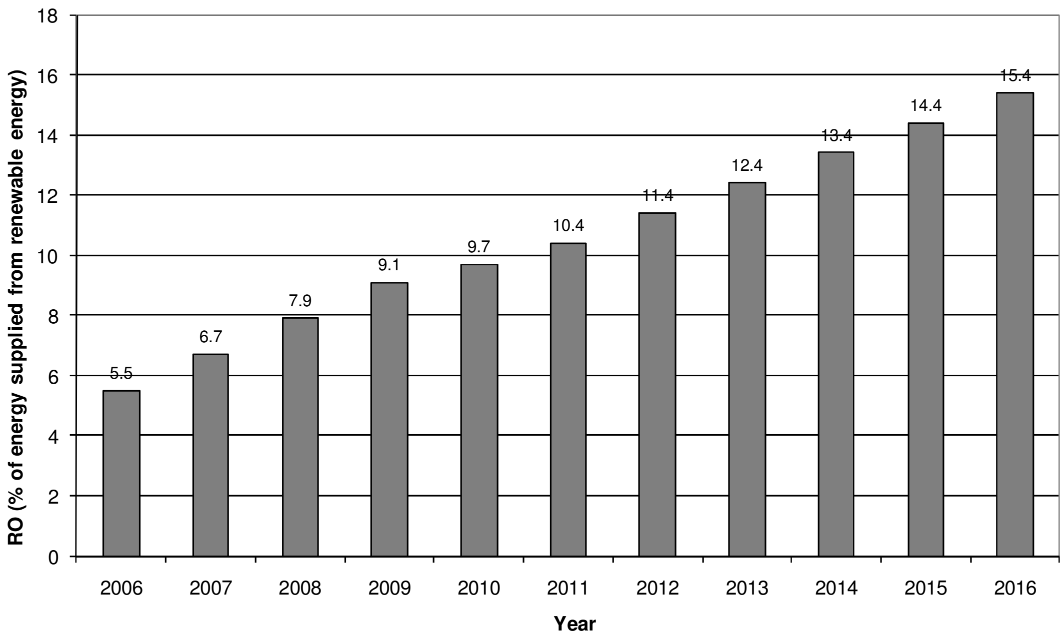

Figure 2: Renewables Obligation targets for renewable energy in the UK

2.4 Types of Distributed Generation

This section briefly presents some different types of DG. Attention is mainly paid to renewable energy sources but technologies that have experienced growth recently and are expected to experience increased connection to electricity networks in the near-term, such as Combined Heat and Power (CHP) systems and Landfill Gas plant, are also discussed.

2.4.1 Wind Energy

As identified by Strbac (Strbac, 2007), the location of the wind energy resource itself presents a significant challenge to accessing this form of renewable energy. It is often the case that large resource exists in areas of low population density, which is served by relatively low capacity electricity networks. Although the number of grid connected wind farms is steadily increasing in many countries, sustaining growth and identifying new sites for wind energy while solving grid access problems remain as significant challenges to the sector.

Twiddel and Weir (Twiddel and Weir, 1990) provide an introduction to wind energy as a resource and the accompanying technological principles of harnessing the energy in the wind. Wind energy is a result of the expansion and convection of air as solar radiation is absorbed on earth. As reported by the British Wind Energy Association (BWEA) (British Wind Energy Association, 2008), wind turbines have been connecting to the grid in the UK since 1989. The BWEA also provide an overview of the growth of the industry and how technology has advanced. Wind generators are currently the most economically viable, available and scalable renewable energy technology. Therefore, wind energy is likely to provide the significant proportion of the growth in renewable energy sources and be the dominant renewable technology within the 2020 timeline.

Matevosyan *et al* (Matevosyan *et al*, 2004) provide the increase in wind power in some European countries in terms of installed MW capacity installed from 1995 to July 2003. There have been significant increases in MW penetration of wind farms in several European countries. Germany, Spain and Denmark have the highest installed capacity; however, Denmark has the highest concentration of wind power in the generation portfolio. According to Soder *et al* (Soder *et al*, 2007) wind power accounts for 58% of the lowest possible net consumption in West Denmark (where net consumption is equivalent to the lowest demand in West Denmark plus export capacity from the area). As reported by Eriksen *et al* (Eriksen *et al*, 2005), in 2004 around 75% of Denmark's installed wind power was located in West Denmark, which therefore experiences the most power system impacts. West Denmark has an installed wind capacity of 2.4GW and East Denmark of 0.7GW, compared with load demand variations of 1.2-3.7GW and 0.9-2.6GW respectively.

In the period since 2003 there has been much connection activity in many developed countries with respect to the grid connection of wind farms. Germany has continued to experience significant growth in wind energy, with approximately 17GW installed in 2005 and Spain with just over 8GW, as reported by Eriksen *et al* (Eriksen *et al*, 2005).

The UK achieved 2GW of installed capacity in 2007 and is now among several countries worldwide that have greater than 4GW of wind energy connected to their electricity supply system. The British Wind Energy Association provides updates of the installed UK wind capacity. According to the European Wind Energy Association (EWEA) (European Wind Energy Association, 2008), wind energy accounted for 7% of the EU energy mix in 2007 and was the second largest growing source of electrical power after natural gas. Sinclair Knight Merz (Sinclair Knight Merz, 2008) present some statistics on the installed capacity and energy production of renewable generators in Europe and the relative implications for the growth of renewable energy within the context of the Scottish generation portfolio; one conclusion from this work is that a significant increase in renewable generation connected to the existing grid is possible.

2.4.2 Wave and Tidal Energy

The global marine energy resource is vast and can be considered to exist in two main forms: wave energy and tidal energy. The marine renewable sector is still in the early stages of development, with many technologies at the research and development stage. Tidal energy devices either make use of fast-flowing tidal stream currents or barrage systems to capture water to release for power generation at a later time. An introduction to the theory behind the marine renewable resource and technology is provided by Twiddel and Weir (Twiddel and Weir, 1990). Bryans *et al* (Bryans *et al*, 2005) discuss tidal generation capacity and its associated impact on the operation of the power system in Ireland, highlighting the benefits of down rating devices due to the cyclical nature of the resource. These benefits include the reduction of power system impacts. The discussion is relevant to the application of similar technology in other power systems.

The UK has been the location for many significant developments in the marine renewables sector. The European Marine Energy Centre (EMEC) was founded on the Orkney Isles off the North-coast of Scotland. More information is available on the EMEC website[3]. EMEC provides several grid-connected wave and tidal device berths to allow testing of new generator technology in some of the harshest and energy intensive seas in Europe. EMEC provides an unprecedented opportunity for developers of new technology to test, demonstrate and prove the grid-connection and operation of new devices.

Wave energy resource, like the wind energy resource, is often located in areas that are remote to main population centres and the main interconnected transmission network. Marine-based renewable generators face the challenge of developing early-stage technology and accessing the wider grid infrastructure in an economically feasible and sustainable manner. The world's first grid-connected wave energy device was the LIMPET, which is located on the Scottish island of Islay, was commissioned in 2000, as discussed in a report by Queens University of Belfast (Queens University of Belfast, 2002).

A recent review of activity in the tidal energy sector by Riddel (Riddel, 2008) provides information on deployments of new technology in the UK. Riddel estimates that the UK possesses 18TWh/year of tidal energy, equivalent to 10-15% of the total known global tidal energy resource. The BWEA's website acts as a good information source for recent developments in the UK wave and tidal energy industry. Both wave and tidal energy are likely to face challenges associated with variability, predictability and uncertainty; although it appears that for tidal energy the cyclical nature of the tide may go some way to addressing this.

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[3] www.emec.org.uk (accessed 25/10/2009)

2.4.3 Combined Heat and Power

Combined Heat and Power (CHP) schemes involve the utilisation of both heat and electricity resulting from the energy conversion process. CHP generators commonly use a combustion process, designed to meet either an electrical or heating load. By making use of both products of the energy conversion process it is possible to increase overall efficiency. Following heating demands results in electricity as a by-product which can be consumed or exported. Following electrical demand ensures that the desired electrical demand is met locally and the resulting heat either replaces part or all of the heating demand of the site or premises.

Many CHP sites are fuelled by natural gas and vary in size from kilowatts to megawatts. As technology advances more fuels are being used in CHP plant, such as wood chips, waste products and other renewable fuels. The UK Government is targetting 10GWe (electrical output) of CHP to be operational by 2010.

2.4.4 Landfill Gas

Landfill Gas can be captured, compressed and combusted for the purposes of generating electricity. Landfill Gas provides a more constant power output profile than many other forms of DG, unless gas is being stored and operation planned differently. Landfill Gas generators typically have a high level of reliability and are often considered as a form of renewable energy. The size and anticipated lifetime of such plants will vary.

2.4.5 Electricity Generation Technology

There are a number of different types of generator technology deployed in existing DG sites and available on the market. The benefit to the generator developers of technology improving performance is clear, but with the proliferation of technology comes added complications for electricity networks and legacy systems. Different generator technologies will perform differently, take control (both automatic and manual) actions differently and respond to system disturbances and events differently. This presents many challenges to utility companies whose job it is to plan and operate the system to high levels of security and reliability.

There are two main types of generator technology: the induction generator and the synchronous generator. Jenkins *et al* (Jenkins *et al*, 2000) provide an overview of these different generator technologies as applied to DG. Most wind turbines utilise induction generator technology; however, in recent years there have been advances in the application of power electronics within Doubly-Fed Induction Generators (DFIGs) for wind applications. It is likely marine based renewables will also employ a variety of generator technology. Both Hydro-Electric and CHP plant generally tend to employ synchronous generators. This section is concerned with the steady-state operation of types of generator technology, rather than the dynamic behaviour and performance during transients.

Most large generator sets are synchronous generators, such as those that utilise combustible fuel as a prime mover. Synchronous generators consist of a stator connected to the three phases of the AC network and a rotor within the stator fed with direct current (DC). The DC supply to the rotor is used to control the resulting rotating magnetic field to allow control of real and reactive power. Synchronous generators are capable of exporting and consuming reactive power, in over-excited and under-excited states respectively.

Induction machines are common on networks; however this is normally as induction motors. The growth of DG and renewable energy sources has led to an increase in the number of induction generators connected to distribution networks, which are essentially induction motors with torque applied to the shaft from some prime mover. Induction generators are used in fixed-speed wind turbines and other renewable energy devices. Induction generators do not provide independent control of real and reactive power, but consume reactive power according to a defined relationship, such as that shown in Figure 3, as discussed by Jenkins *et al* (Jenkins *et al*, 2000). Capacitors are sometimes installed with induction generators to counter the impact on network voltage of the consumption of reactive power by the generator.

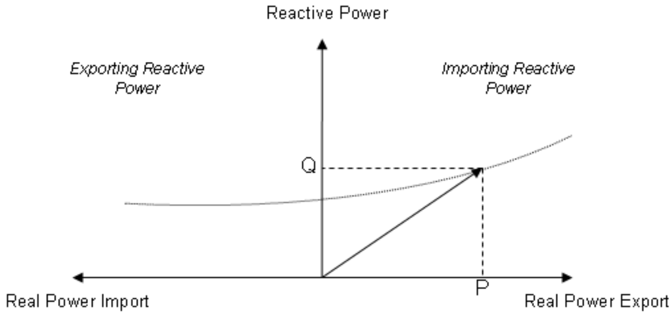

Figure 3: Example of a P-Q chart for an induction generator

Jenkins *et al* discuss some of the benefits of the doubly-fed induction generator, which involves the use of power electronics to partially decouple the rotating generator from the network and allow operation at a speed that is efficient for the input power. There has been significant growth in such variable speed wind turbines, which can produce and consume reactive power. Some modern variable speed wind turbines can operate at unity power factor for all real power export values, as described by Wachtel and Hartge (Wachtel and Hartge, 2007), who also identify that when supplemented by a Static Compensator (STATCOM) it is possible for the reactive power capability of the wind farm to be extended, as shown in Figure 4. Saad-Saoud *et al* (Saad-Saoud *et al*, 1998) describe the application of STATCOMS to wind farms and the associated steady state and dynamic system benefits and impacts. Such benefits are also common to the application of other reactive compensation devices such as the static var compensator (SVC).

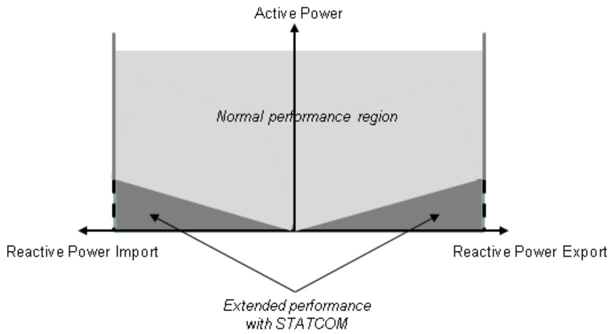

Figure 4: Example of a P-Q chart for a DFIG with/without a STATCOM

Freitas *et al* (Freitas *et al*, 2006) present a comparative analysis of synchronous and induction machines for DG applications, as applied to a simplified test system. The authors discuss the many technical aspects of generator technology; of particular relevance to the work presented in this thesis is the discussion of the impact of either technology on steady state voltage regulation during normal operation (how the different generators affect the voltage profile on the network as load varies) and when the DG unit is disconnected (tripped). An important conclusion from this work is that the best technical choice of generator technology will be determined by the network parameters, topology and characteristics of the load.

Despite the varying capability of different generator technology, Carvalho *et al* (Carvalho *et al*, 2008) identify that many network operators require DG units to operate at either unity power factor (zero reactive power) or fixed power factor, whilst limiting the amount of installed capacity to guarantee an admissible voltage profile for all scenarios of generation and load. Carvalho *et al* give the following reasons for this approach:

1. The capacity of a single DG unit is typically too small to control network voltage
2. Automatic voltage control of a DG unit can interfere with existing arrangements, such as the operation of on-load tap changing transformers

2.5 Distributed Generation and Electricity Networks

Watson *et al* (Watson *et al*, 2003) present a discussion of international activities concerning research and development of the integration of DG to distribution networks. The purpose of this section is not to attempt to repeat such a review and the multiple aspects of it, but to focus on the aspects of DG that relate more closely to ANM. This section explores types of distribution network and the accompanying constraints on DG, planning for DG, operating DG units and the wider electricity system impacts of DG.

2.5.1 Types of Distribution Network

Existing distribution networks are on the whole passive, with minimal monitoring and control functionality; built to deliver power from the transmission network to meet the local demand within certain security, quality and safety standards. Distribution network planning will normally take account of forecasted load growth and other system developments within the lifetime of the assets. The connection of additional load or a generator to such a network will often require investment and an accompanying review of existing infrastructure and operational practices to ensure supply quality and security is maintained or improved.

Figure 5 provides a simple illustration of the distribution network of today; the transmission network feeds power in one direction to serve a number of loads and there are typically few DG connections. The impact of DG unit connections on the distribution network is normally assessed for the minimum demand and maximum generation scenario, which represents the most severe case that could occur on a network that was designed to meet load demand only. The introduction of DG units could have a large impact on power flow, reducing the infeed from the transmission network and potentially reversing the power flow on some distribution circuits.

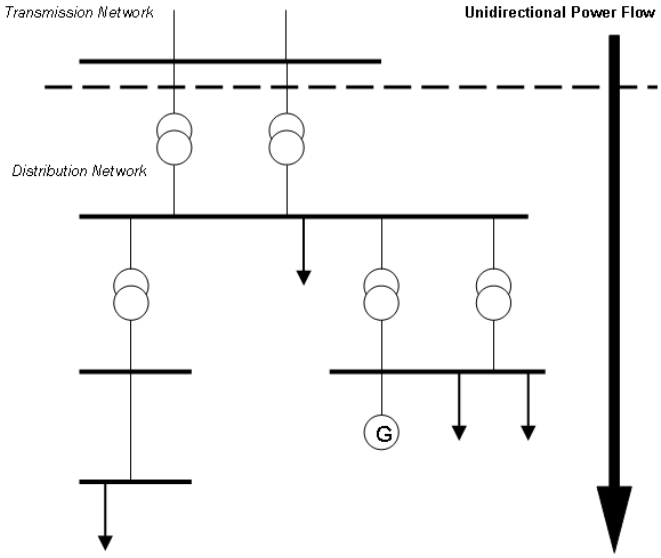

Figure 5: Simple illustration of today's distribution network

The simple illustration given in Figure 5 above does not represent the true complexity and variety of distribution networks. There are many different topologies employed by DNOs according to existing and previous design practice, the nature of network loading and the size and location of electrical demand.

Lackervi and Holmes (Lackervi and Holmes, 2003) identify five types of network configuration for distribution networks; these are illustrated in Figure 6 (substations are represented by circles). DNOs tend to use a number of these configurations and the concepts inherent within to comply with security standards and supply customers.

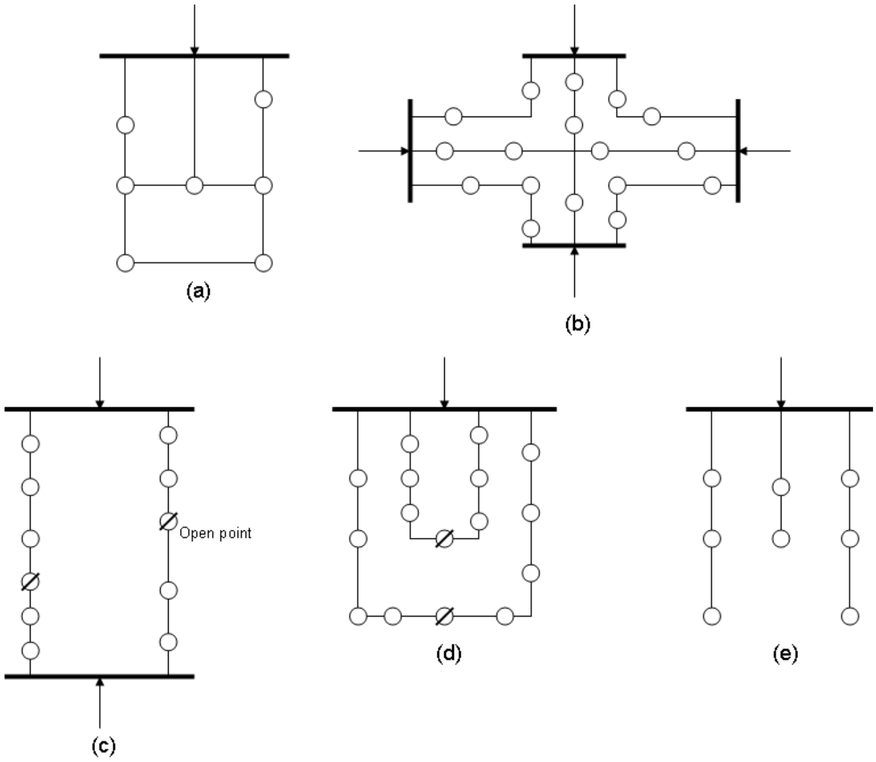

Figure 6: Types of distribution network configuration, as presented by Lackervi and Holmes

Figure 6(a) is a mesh network, the main benefits of which are that security of supply to substations is enhanced due to multiple supply paths. The same can be said for Figure 6(b) which presents an interconnected meshed system. Having redundancy in the network increases reliability and is frequently used in areas of high demand, such as urban demand centres. Figure 6(c) and (d) are different types of ring systems that can be operated split using a Normally Open Point (NOP). This provides some added flexibility in that the NOP can be moved in response to an outage on the system, therefore providing opportunity to reconnect customers once the location of the fault has been identified and the appropriate section of the network isolated. Employing NOPs on the link arrangement in Figure 6(c) and the open loop in Figure 6(d) creates radial circuits to supply load. Figure 6(e) presents a radial distribution network, as typically applied to rural areas and dispersed loads. These circuits typically cover large distances and are designed to operate so that the voltage drop on the radial feeder does not result in the voltage at supply terminals at any point on the network dropping below acceptable or statutory limits.

The work presented in this thesis is mainly concerned with rural distribution networks, such networks are typically characterised by:

- Long radial circuits
- Low observability of the network (sparse measurements and communications)
- Absence of remote control over installed assets and components connected to the network
- Few generator connections
- Potential imbalance due to different phase loads
- Many dispersed loads

2.5.2 Distribution Network Constraints

The introduction of DG has technical implications for the distribution network that have traditionally been addressed by the DNO at the planning stage. Ault *et al* (Ault *et al*, 2003) provide a comprehensive review of the factors affecting DG penetration, the impact of this penetration on the distribution network and ultimately the impact on the business of the DNO. These factors are incorporated within a strategic analysis framework that can be used to analyse DG connections.

The influence diagram of the impact of DG penetration on the distribution network, as proposed by Ault *et al* (Ault et al, 2003), is shown in Figure 7 and demonstrates the many interrelated factors that determine the impact of DG on the distribution network. Other elements of the framework proposed by Ault *et al* are relevant to later chapters of this thesis as other aspects of the deployment and economics of DG are considered.

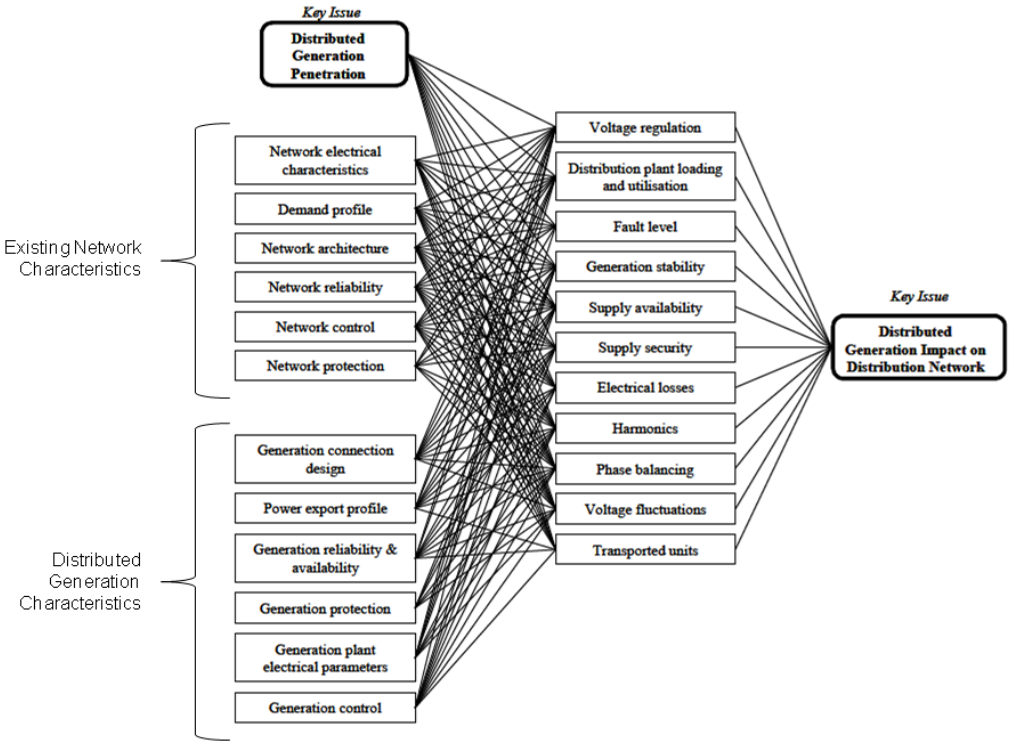

Figure 7: Influence diagram for distributed generation impact on distribution network[4]

In Figure 7 there are three main groups of influence blocks. The first group concerns all aspects of the existing network infrastructure (beginning with network electrical characteristics) including existing demand, control and protection. The block below this is concerned with aspects of the DG unit(s) (beginning with generation connection design) and includes output characteristics, performance and control systems. The two groups feed into the third group of influence blocks, which are concerned with technical aspects of the performance of the distribution network, such as voltage regulation, fault level and electrical losses. The impact of the connection of DG on these and other aspects of the distribution network performance must be considered for each DG connection. When the DG impact on the network exceeds an acceptable level, i.e. reaches a constraint, then it is common practice for network reinforcement or investment to be required to remove that constraint.

[4] Reproduced with kind permission of Dr Graham Ault

As with any system of complex interactions, it is often beneficial to reduce the problem and address it in stages. Thornycroft *et al* (Thornycroft *et al*, 2004) consider different distribution network constraints and the impact of these constraints on the connection and operation of DG. This study lists the following as the main network constraints faced by DG:

- Thermal (including phase imbalance)
- Voltage
- Fault level
- Protection limitations
- Flicker and harmonics

In focusing on these technical challenges, Thornycroft *et al* remove some of the complexity associated with the commercial aspects of DG, for example connection charging and the through-life support and business implications for the host DNO. However, reducing the technical challenges to those presented above still includes a requirement to perform power system analysis, both steady-state, dynamic and/or transient studies of the network. In terms of addressing distribution network constraints for the connection and operation of DG, Thornycroft *et al* present three options:

- The network can be reinforced to solve constraints, or
- DG can be actively managed to minimise the breach of constraints, or
- A combination of reinforcement and active management of DG may provide the best economic option

What Thornycroft *et al* are essentially saying with these three points is that if the connection of a DG unit causes network limits to be violated then the solutions are to invest in the infrastructure (to ensure constraints will never be breached), connect the DG unit anyway and manage its performance to ensure network constraints are not breached in real-time (requiring the implementation of an ANM scheme) or use a combination of network reinforcement and ANM to find the best economic solution to solving network constraints. The decision to combine some form of ANM and network reinforcement would be driven by technically limiting factors, such as the type of ANM solutions available, and commercial factors such as the balance of costs (both capital and operational), benefits and the time to implement solutions.

Collinson *et al* (Collinson *et al*, 2003) and the Embedded Generation Working Group (EGWG) (Embedded Generation Working Group, 2000c) identify the main technical challenges for the connection and operation of DG as:

- Fault level
- Voltage
- Power flow

It is the opinion of the author that these are the three main technical constraints on the connection and operation of DG, whereas those presented by Thornycroft *et al* above are a combination of constraints and system impacts, which will be discussed later in this chapter in addition to other system impacts of DG. The following sections introduce the three main technical constraints on the connection and operation of DG. Although the main focus of the work presented in this thesis is the management of power flow constraints, voltage and fault level constraints are introduced for completeness.

2.5.2.1 Fault Level Constraint

Fault level is a measure of the current that would flow at a certain point in the network at a particular time in the event of a short circuit fault. A change to network topology or generator status can cause fault levels to change. Due to possible variations it is normal to define maximum and minimum fault levels at each point, within which the fault level will vary. It is the responsibility of appropriately deployed switchgear to break fault current. The maximum rating of switchgear is referred to as the design fault level. Jarret *et al* (Jarret *et al*, 2004) present typical design fault levels for common distribution voltages; these are presented in Table 2.

Table 2: Typical design fault levels for common UK distribution voltages

System Voltage (kV)	11	33	132
Design Fault Level (MVA)	250	750	3,500

The connection of DG can have an impact on the fault level experienced in the distribution network, pushing it beyond the capability of existing switchgear and/or render existing protection settings invalid. Uprating switchgear can be an expensive activity and act as a financial barrier to the connection of DG, particularly if the DG developer has to cover the capital costs. Most forms of DG are rotating machines that will contribute to fault level, although other types of DG that are connected through a power electronics interface (such as photovoltaic panels or doubly-fed induction generators) will have a reduced fault contribution.

Collinson *et al* (Collinson *et al*, 2003) provide a number of means to solve fault level constraints. Some of these solutions involve capital expense, such as uprating network components, increasing the impedance of network components, and others involve changes to operational practice (with accompanying expense, of course) such as reconfiguring the network and sequential switching.

2.5.2.2 Voltage Constraint

Network operators are required to ensure that statutory upper and lower limits on network voltages are not breached at supply terminals. Supply to low voltage end users is typically provided through fixed transformers, with the implication that voltage will be regulated by upstream components where control of voltage can be performed, such as at an On-Load Tap Changing transformer (OLTC). Design limits ensure safe operation of equipment within acceptable ratings and timescales and the delivery of power to end users within specified limits. It is typical for the statutory upper and lower limits to vary depending on the voltage level of application.

Jenkins *et al* (Jenkins *et al*, 2000) present a DG unit connected to the end of a radial feeder, as shown in Figure 8. The feeder is supplied by an OLTC transformer and employs a voltage regulator (1:1 ratio transformer) mid way along the feeder to boost the voltage and ensure the level experienced at the end of the feeder is acceptable. The voltage along the feeder is shown for both minimum and maximum loading conditions, not considering the output of the DG unit. It can be seen that the transformers employed on the feeder maintain the voltage within acceptable bounds, irrespective of the demand on the feeder. The existing infrastructure has been designed for this particular situation and takes no account of any DG on the feeder. Due to voltage constraints the installed power output of the DG unit must be limited to that which causes the permissible voltage rise (or less) as identified in Figure 8.

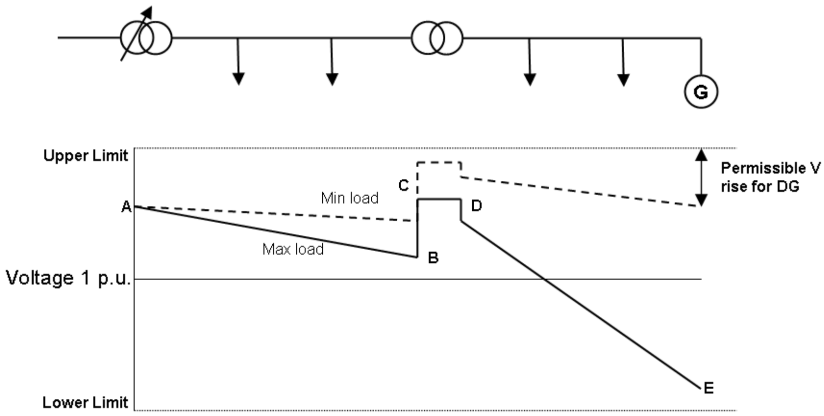

Figure 8: Example of permissible voltage rise for DG unit

Figure 8 only considers a radial feeder example (and it was illustrated earlier that there are other more complex distribution system designs), but provides a useful illustration of the potential voltage constraints on available capacity for DG connections. The following example is provided to further investigate the factors affecting voltage rise due to DG unit connection and operation.

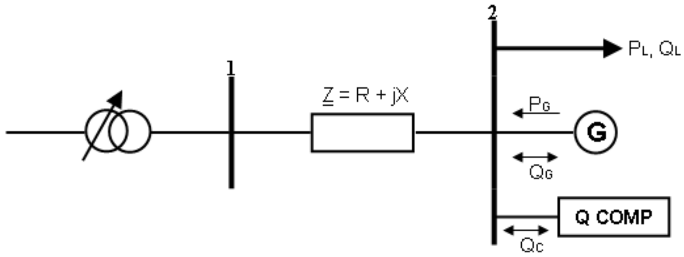

Figure 9: Two busbar example network presented by Liew and Strbac

Liew and Strbac (Liew and Strbac, 2002) provide a two bus example as shown in Figure 9 including a single DG unit, reactive compensation device and load connected at bus 2. The DG unit is capable of injecting real power and injecting or consuming reactive power, the reactive compensation device is capable of injecting or consuming reactive power and the load consumes both real and reactive power. The example network is fed through an OLTC at bus 1. Bus 1 and bus 2 are connected through an overhead line of impedance Z.

The voltage at bus 2 can be calculated using equation (1):

$$V_2 \approx V_1 + R(P_G - P_L) + (\pm Q_G \pm Q_L \pm Q_C)X \tag{1}$$

Where V_1 is the per unit voltage at bus 1 (V_{pu}), V_2 the per unit voltage at bus 2 (V_{pu}), R the per unit resistance of the overhead line (Ω_{pu}), P_G the per unit real power injected by the generator (W_{pu}), P_L the per unit real power consumed by load (W_{pu}), Q_G the per unit reactive power injected or consumed by the generator connected (VAr_{pu}), Q_L the per unit reactive power injected or consumed by the load at bus 2 (VAr_{pu}), Q_C the per unit reactive power injected or consumed by the reactive compensation device (VAr_{pu}) and X the per unit reactance of the overhead line (Ω_{pu}).

As described by equation (1), the voltage at bus 2 is influenced by the voltage at bus 1 and the effects of the net real and reactive power flow through the line resistance and reactance.

It is often the case that the network operator will assess the connection of a DG unit in terms of the minimum load – maximum generation condition. This scenario includes the modelling of all other DG units at maximum rated output. The minimum load condition is normally when the highest voltage will be experienced on a distribution network with no connected generation; therefore, the voltage rise effect due to the output of the DG unit is even more pronounced. Without the presence of DG, the settings on the OLTC will ensure the minimum or maximum voltage permissible on the network is not violated. As we can see in Equation (1), the introduction of real and reactive flows to (or from) the DG unit can push the voltage on the network beyond the levels encountered when no DG is connected.

If we consider a no load condition on the network (P_L =0) and the DG unit operating at unity power factor with the assistance of the reactive compensation device ($\pm Q_G \pm Q_C = 0$), the approximate voltage at bus 2 can be found using Equation (2):

$$V_2 \approx V_1 + RP_G^{MAX} \tag{2}$$

Where P_G^{MAX} is the maximum real power output of the DG unit within the upper voltage limit at bus 2. Rearranging Equation (2) gives Equation (3) for the maximum amount of DG output that can be accommodated within the voltage limit at bus 2;

$$P_G^{MAX} \leq \frac{V_2^{MAX} - V_1}{R} \tag{3}$$

The examples given in Figure 8 and Figure 9 act together as a useful introduction to the challenge of voltage control in the presence of DG. The methods that DNOs make use of to control network voltages can be complex even without the introduction of DG units. Examples of such schemes are:

- Line drop compensation
- Reverse reactance compounding
- Operation of voltage regulators
- Switched or fixed reactive compensation devices
- Under voltage load shedding

The interaction of DG with these schemes can provide the operator with complex problems to solve in real time. Often, DNOs will attempt to solve these issues in planning timescales, implementing solutions that require a minimum of operator intervention during normal operation of the network and no increase in operational costs.

2.5.2.3 Power Flow Constraint

The main limiting factor on power flow is the ampacity of the line – the maximum current carrying capability. This level is set according to assumptions regarding ambient air temperature, conductor parameters and weather conditions. As the amount of current increases in a conductor, the temperature will tend to increase. The increase in temperature of the conductor can cause the line to sag. Regulations regarding the clearance of overhead lines require network operators to carefully plan for the maximum sustained (or cyclical as discussed below) power flow at particular points and the short-term capability of critical sections, to ensure that clearance requirements are met. Other network components, such as transformers, also have maximum and short-term thermal ratings; manufacturers of components will provide details of the thermal capability of the item.

The thermal constraint on power flow is simple: the current in a particular section must not exceed its rated value, as in equation (4). Where the current in line j, I_j (Amps), must not exceed the thermal rating of line j, I_j^{Rated} (Amps). This objective is true for all components of the system (and for different assumptions for the setting of I_j^{Rated}).

$$I_j \leq I_j^{Rated} \tag{4}$$

The introduction of DG units to the distribution network can impact on the magnitude and direction of current and therefore power flow. The impact of these changes will be dependent at any one time on:

- The magnitude of the DG output relative to the real-time demand on the system
- The topology of the network
- The current carrying capability (i.e. thermal capacity or ampacity) of the system:
    - Continuous ratings (static or seasonal)
    - Cyclic or short-term ratings
    - Dynamic real-time ratings
- The real-time performance of other devices or machines connected to the network

The maximum power flow at any point in the network is therefore designed to be accommodated. In addition, standards regarding security of supply often require at least two paths to meet demand, ensuring that the first circuit outage will not result in the loss of load. Figure 10 provides a simplified example of a distribution network designed to meet the maximum electrical demand in the event of the first circuit outage, the demand varies from 5-30MW.

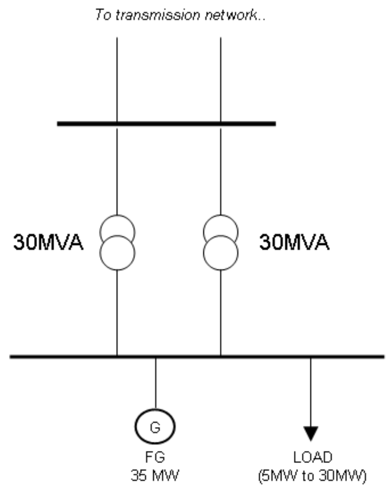

Figure 10: Simplified representation of Firm Generation capacity

The loss of either transformer will not cause the rating of the remaining transformer to be breached in any event. It is also possible that the power flows through either of the two 30MVA transformers could change direction depending on the balance between DG output and local load. If the maximum DG output (35MW) occurs at the same time as the minimum demand condition (5MW) then there will be an export of 15MW through each 30MVA transformer, assuming they are of equal impedance and connected between the same busbars (also the additional complexity of real, reactive and apparent power is ignored for now). The 35MW group of DG included in Figure 10 is termed Firm Generation (FG). By limiting the capacity for DG connections to the FG limit, power flow output control of the FG unit is not required in either the N or N-1 network condition.

There are two approaches to defining the FG capacity, as described by the Electricity Networks Association (ENA) (Electricity Networks Association, 2004) and presented in equation (5) and equation (6). Two simple examples of the application of these methods are now introduced; it should be recognised that the application of these methods to complex network topologies can be more onerous. Equation (5) provides for FG capacity equal to the N-1 capacity of the network, with no recognition of demand. This approach ensures that in the event of the FCO, full rated power output from the DG unit(s) will not result in power flows out with the capability of the remaining network. For the example distribution network in Figure 10, this would result in 30MVA of FG capacity. This method of connecting FG capacity is not reflected in the example in Figure 10.

$$\text{FG Capacity (MVA)} = \text{N-1 capacity (MVA)} \tag{5}$$

Equation (6) presents the second method identified by the ENA to calculate the FG capacity to be calculated on a distribution network. In this case the FG capacity is equal to the N-1 capacity plus the minimum demand on the network, as is the case in Figure 10. In the event of the FCO, if the full rated DG output occurs then the export power flow from the area will be within the capability of the remaining circuit, as for the application of equation (6) and 35MW of FG capacity.

$$\text{FG Capacity (MVA)} = \text{N-1 Capacity (MVA)} + \text{Minimum Demand (MVA)} \tag{6}$$

It has historically been the case that the connection of a DG unit to a network where the FG capacity has been previously fully allocated (according to one of the practices introduced above) will require investment in network infrastructure. The drawback for DG developers is that the cost of connecting to the network where reinforcement is required can be prohibitively high (in the £millions), resulting in projects being shelved.

As discussed by Levi *et al* (Levi *et al*, 2005) when power flows are reversed it is not always the case that OLTC transformers have the same capability as in the original direction of power flow. This may be an additional limiting factor on power flows and should be considered when DG connections result in reverse power flows.

The management of power flows resulting from the connection and operation of DG is the main topic of this thesis. Further chapters will shed more light on the planning and operating challenges associated with increased power flows resulting from increased DG connections.

2.5.3 Planning for Distributed Generation

The main goal of planning and operating distribution networks has traditionally been the supply of load customers. This is unlikely to change in the near term; targets for reducing customer interruptions and the duration of interruptions are key industry drivers in many countries. The incumbent infrastructure, planners and operators are most concerned with security of supply for customers. The connection and operation of DG is a lesser priority and it remains to be seen how future network planners and operators will utilise increased DG activity to complement network security and performance goals.

In the UK, there was a debate in the Industry at the turn of the millennium regarding so called "deep" connection charges for DG units. A deep connection charge involves the DG developer paying for costs associated with making the connection and any other wider system reinforcement costs. The EGWG (Embedded Generation Working Group, 2001a) recognise this issue and also identify that previously DG units were not required to pay a use of system charge to the DNO, which could in turn act as a revenue incentive to the DNO to connect more DG. The UK has now adopted a more "shallow" approach to charging for the connection of DG. Jenkins *et al* (Jenkins *et al*, 2000) discuss the differences between deep and shallow connection charges; notably that a shallow charge involves the developer only paying for the infrastructure required to reach the nearest point of connection. These issues are also discussed by Ekwue *et al* (Ekwue *et al*, 2004) who describe the adoption of shallow charging principles in Germany as a means to reducing the technical and economic barriers to increased DG.

The methods for allocating FG capacity discussed previously are a result of network topologies designed and implemented with redundancy and load security in mind.

Therefore, it is necessary to understand the security of supply planning standards prior to attempting to plan for DG. Engineering Recommendation P2/5 (The Electricity Council, 1978), concerned with security of supply, formed the basis for the planning of much of the existing distribution infrastructure in the UK. The expansion of generation connected to distribution networks has resulted in the review of P2/5 and the adoption of P2/6 (Electricity Networks Association, 2006).

P2/5 specifies the recommended levels of security and capability of a network to meet demand during the first circuit outage and second circuit outage. P2/5 does not recognise the contribution of modern DG technologies (wind turbines, for example) to demand security, only identifying the contribution of steam and gas turbine units. In other words, in order to be compliant with the standard the DNO could not rely on renewable sources of generation to supply load during the first circuit outage or second circuit outage. This can lead to inefficient investment, where the DNO can only consider network solutions to meeting demand, despite the presence of DG units that may be able to (or already do) contribute to the security of the load. If a DNO was to connect DG beyond that which the network could accommodate during the first circuit outage then this would pose a risk to demand customers, (who the DNO has to ensure the appropriate level of security for) and perhaps result in non-compliance.

According to P2/5, for load demand greater than 12MW and less than 60MW (a number of different sizes of load group are considered in P2/5), the smaller of the group demand minus 12MW or 2/3 of group demand should be reconnected within 15 minutes of the first circuit outage. The entire group demand should be reconnected within 3 hours. No demand is to be met after the second circuit outage. P2/5 stipulates that the group demand will normally be supplied by at least two normally open circuits, or by one circuit with other circuits available through manual or automatic switching actions. This note is particularly important in emphasising the topology of existing distribution network infrastructure and the associated issues for DG connection capacity and asset utilisation.

The approach adopted in P2/5 is based on reliability modelling as described in ACE Report No. 51 (Electricity Council, 1979). An example of the approach defined in P2/5 is shown in Figure 11, as discussed by Strbac *et al* (Strbac *et al*, 2007a). Figure 11 presents a distribution network fed through two parallel transformers, each rated at 50MVA. The total group demand is 50MW and there is a 30MW DG unit connected within the distribution network. For the loss of either transformer the situation is P2/5 compliant as the remaining circuit capacity can supply the maximum group demand. According to P2/5, if both circuits were lost then none of the demand is required to be met and the contribution of the 30MW DG unit to the security of the load is not recognised.

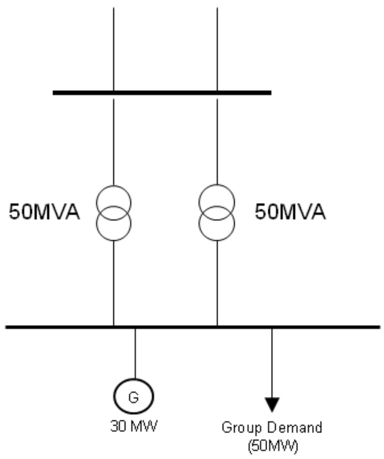

Figure 11: P2/5 compliant base case

With the publication of P2/6 (Electricity Networks Association, 2006) in 2006, there exists a method of incorporating modern DG units within system security planning. P2/6 takes account of a variety of DG technologies of both intermittent and non-intermittent nature. If we consider a scenario where the total group demand of Figure 11 rises to 55MW, the network is no longer P2/5 compliant. Under P2/5 it would be necessary to install a third transformer, as shown in Figure 12(a). The size of this transformer would be selected based on projections of load growth and any other planned asset replacement. Under P2/6, the contribution of the 30MW DG unit to the security of the load can now be recognised, avoiding the requirement for the installation of a third transformer, as shown in Figure 12(b). Assuming the DG unit has an availability that results in a security contribution of 60%, then 18MW can be recognised for network planning purposes. Therefore, the network remains compliant, although if the group demand rose by another 13MW then some form of reinforcement (or increase in generator capacity) would be required for P2/6 compliance.

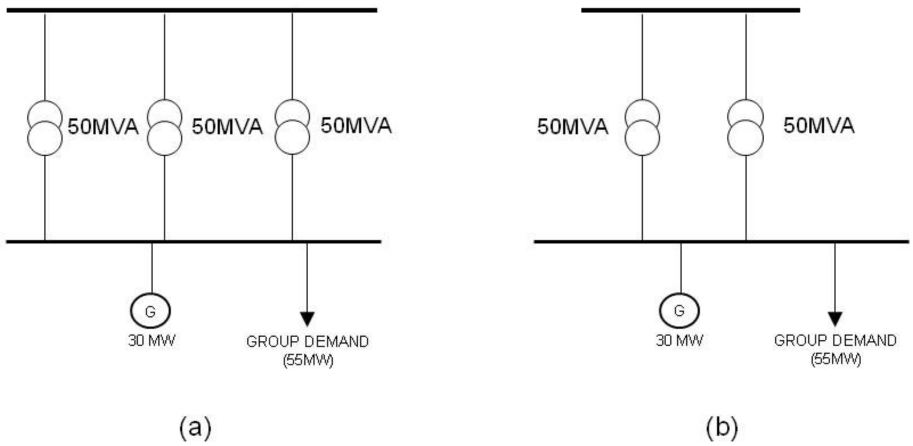

Figure 12: P2/5 and P2/6 compliant solutions for 5MW load growth

This new consideration impacts upon the asset management and replacement strategies employed by the DNO and a balance must be found between investment in reinforcement for the purposes of meeting demand and for accommodating new DG connections. This can be made increasingly challenging when the DNO is faced with multiple interactive DG connection applications, with no guarantee that the DG units will proceed with the offered connection.

P2/6 supports the expansion of wind energy and small hydro-electric stations and the methodology developed to assess the contribution to security can be applied to other renewable resources. However, connecting generation may result in a breach of technical constraints that may require capital investment to resolve. The focus of emerging ANM schemes, and the APFM scheme proposed in this thesis, are the solving of these technical constraints using novel schemes and control architectures.

This represents a significant change in the way that distribution networks are planned and operated, but also requires new methods of assessing the security of supply in distribution networks that are becoming increasingly 'active'.

Research activities are addressing the problem of planning for DG, from a theoretical perspective. Few of the methods in the literature are actually employed by DNOs, either due to regulatory and commercial issues or to lack of commercially available and proven tools. Several authors have presented DG planning as an optimisation problem, where the multiple criteria associated with DG connections can be used to inform the constraints on an objective function, some of these are now discussed.

Harrison and Wallace (Harrison and Wallace, 2005) identify that incorrectly sited or sized DG could potentially saturate available network capacity and have an impact on the rate and volume of renewable generator connections. Harrison and Wallace model fixed power factor generation as negative loads and then use an optimal power flow (OPF) to perform load shedding, identifying available headroom on the network within thermal and voltage constraints. This approach is termed "reverse load-ability" and would require a schedule of locations that were identified as being appropriate for DG connections. Such an approach may not be too far from reality for some countries, but in many markets no means exists yet for DNOs to identify and/or communicate preferred locations for DG units.

Celli et al (Celli et al, 2005) also tackle the issue of siting and sizing DG with respect to accomplishing multiple objectives simultaneously (in terms of constraints on the optimisation problem). The methodology adopted is focused on providing a tool or approach that allows the power system planner to select the most appropriate compromise between the objectives. The objectives considered by Celli *et al* are cost of network reinforcement, cost of purchased energy, cost of energy losses and cost of energy not supplied. Again the potential for this planning approach to be applied is limited due to network operators being unable to define desirable locations for DG connections.

Keane and O'Malley (Keane and O'Malley, 2005) also present a technique for identifying the optimal siting and sizing of DG units, using a linear programming method. In later work, Keane and O'Malley (Keane and O'Malley, 2007) present a methodology to maximise the amount of energy that can be "harvested" from a particular distribution network. Keane and O'Malley study the possibility of extending capacity for DG connections beyond 'firm' levels and define this as holding potential for increasing the collective MWh generated by connected DG units.

It is not the intention to review these works for the purpose of assessing the methods employed in them, but more to identify and gain an understanding of the objectives of existing methods and DG planning approaches being developed. It seems that in the literature, solutions are being presented that are only permissible for use in reality if the siting and sizing of DG units can be influenced or selected by the DNO. Currently in many liberalised markets this is not possible. Without a change to regulation and the resolution of complex commercial interactions it is unlikely that this will change.

2.5.4 Operating Distribution Networks and Distributed Generation

According to Strbac (Strbac, 2007), the increased penetration of wind energy into electricity networks can pose operational problems due to:

- The intermittent nature of the generated power
- The location and remoteness of the resource relative to centres of demand
- The unusual form of generator technology used

It is important to consider these aspects as being related to almost all types of renewable and distributed energy sources.

As has already been discussed, DG units are not normally controlled (i.e. dispatched or constrained) in real-time according to network constraints. This section aims to present a background to the communications and control systems that are used to operate distribution networks and support DG deployment. These systems will become either the platform for delivering more 'active' DG units or at least have to operate in parallel with ANM schemes.

Today's relatively passive distribution networks possess a limited amount of monitoring and control functionality. The full capability of Supervisory Control And Data Acquisition (SCADA) systems is generally only required for high voltage transmission networks where the operator has a number of remote actions at his or her disposal. Decisions can be made regarding these actions based on incoming measurement data and supporting analysis.

Two studies undertaken through the UK Government Department for Trade and Industry New and Renewable Energy Technology Programme are extremely useful for understanding the extent to which DNOs monitor and control their network and also how current practice could be developed to enable further DG connections and ANM. Roberts (Roberts, 2004) provides a comprehensive review of current practice in DNO SCADA systems and considers the feasibility of utilising existing infrastructure for the purposes of ANM. EA Technology (EA Technology, 2006) detail responses received from UK-based DNOs to a questionnaire regarding existing SCADA systems and the deployment of ANM. Some salient points can be extracted regarding existing DNO SCADA systems:

- Existing UK SCADA systems have been in place for a number of years and are tailored towards permitting control from 6.6kV and above, but with reduced functionality available at and below 11kV
- Existing SCADA systems are commercial products, which are updated to meet emerging needs

- Data is collected from Remote Terminal Units (RTUs) and fed back to the control room, occasionally via data concentrators, through a combination of communication circuits at different rates
- Communications deployed vary between each DNO and application; examples include private pilot cables, radio, mobile phone and satellite technology
- RTUs vary in functionality, but typical characteristics include:
    - Time-stamped overview of events, i.e. change of state of circuit breaker
    - Measurement of analogue network data and monitoring of limit and percentage change in value (i.e. report by exception)
    - Digital outputs to allow remote action, e.g. opening or closing circuit breakers
    - Intelligent relay connectivity
    - Some programmable functionality to permit automatic control execution

The SCADA systems that are deployed at the distribution level do not currently perform tasks such as those required if levels of DG are to increase. The integration of more DG units may require faster data acquisition, processing and multi-path links to network components. It is unclear how suitable existing SCADA systems are for supporting the increasing levels of DG being experienced, it has been suggested by Ingram *et al* (Ingram *et al*, 2005) that many DNOs are only familiar with the basic features of deployed systems.

EA Technology (EA Technology, 2006) presents a review of current network infrastructures and best practice. It is clear from this review that there are many different approaches to monitoring network data (both what and where) and a number of different RTUs are deployed on networks. It is clear that to facilitate the widespread connection and operation of DG a platform agnostic approach is key to wider system benefits being realised.

A report by Varming *et al* (Varming *et al*, 2004) presents a wider European perspective on these issues, focusing on the additional requirements that may be placed on SCADA systems to support widespread DG access to electricity networks and markets, particularly the Nordic market. The role of Information and Communication Technologies (ICT) in network management (both for transmission networks and distribution networks and the required interactions of the two) is discussed and some of the applications for ICT in existing SCADA systems are identified, as shown in Table 3. However, it is uncommon for anything other than offline techniques to be applied to distribution networks.

Table 3: Existing ICT Applications for network SCADA systems

• State Estimation • Automatic Generation Control • Short Circuit studies • Load flow • Static stability • Contingency analysis	• Electromagnetic phenomena • Transient stability • Mid-term and long-term dynamics • Economic dispatch • Unit commitment	• Security analysis • Volt/Var scheduling • Optimal power flow • Generator reserve monitoring • Interchange scheduling • Load forecasting

Other reports from the European Union funded projects DISPOWER (Erge, 2003) and ENIRDGnet (Schwaegeri *et al*, 2003) present the communication options available for DG projects and an action plan towards standardisation of communication interfaces. An advance in the communication between intelligent electronic devices (e.g. protection, monitoring and control devices) in substations to support automation is evident with the development of the technical standard IEC61850. How such approaches make it beyond the individual substation and support greater automation at the network level is uncertain.

There is an ongoing discussion in the power industry about the general decentralisation of electricity systems. This is mainly due to the increase in the connection and operation of DG. The decentralisation of sources also brings with it the question of how much the control of the power system can be decentralised.

Traditionally, power system control has been centralised with one main control room (with back up systems on-site or elsewhere) receiving information from the network monitoring systems to support manual control actions. The true extent to which control systems (and decision making) can be decentralised remains to be seen; in fact, it is yet to be adequately demonstrated that it is required at all.

Some key concerns of network operators regarding increased connection of DG are islanding and the performance of the system when exposed to faults. It is imperative that DG protection systems can detect a loss of mains event, which leads to the islanding of the DG unit and nearby circuits and loads. As Knyazkin and Ackermann (Knyazkin and Ackermann, 2003) discuss, there also needs to be sufficient fault current in order for the loss of mains protection to operate, which may be an issue regarding the use of power electronic interfaced DG units, where the rotating mass is electrically decoupled from the system. It is rare for DG units to be permitted to operate in islanded mode due to concerns regarding safety of customers, system control, abnormal feeding arrangements, large variations in frequency and voltage on the islanded system and the safety of personnel undertaking maintenance and field work.

In Denmark the large level of DG resource available in the distribution network (mainly CHP units and wind farms) has resulted in the implementation of a novel method of islanding parts of the distribution network into "cells". Lund *et al* (Lund *et al*, 2005) describe the rationale for this approach, both in terms of the near-term goal of using the method to provide blackstart capability and the more ambitious goal of using the cell controllers to observe network conditions and automatically disconnect and island the distribution network when beneficial.

In summary, it appears that there are limited examples of advanced means of communications and control being applied to distribution networks and DG. The scope of academic research into the area is wide and the features and benefits of the systems deployed at transmission voltages are yet to be experienced at distribution voltages.

2.5.5 Other Electricity System Impacts of Distributed Generation

In previous sections, the network constraints imposed on DG have been considered, as have planning and operating distribution networks with DG. This section describes some of the wider electricity system impacts of DG. These impacts are both technical (affecting transmission and distribution networks) and commercial, and are now presented to provide adequate context for the later discussion of the implications of ANM.

2.5.5.1 Network Losses

The UK regulator Ofgem (Ofgem, 2003) estimate that on average, around 7% of the UK's electricity supplied through distribution networks is lost. It is in the interest of all parties to reduce losses, which occur naturally in an electricity network, but can be minimised through careful planning and operation. Sohn Associates (Sohn Associates, 2005) present some indicative losses for the UK (Table 4) and, while they differ from a total of 7% energy lost as indicated by Ofgem, these figures illustrate the proportional contribution to losses at different voltage levels.

Table 4: Indicative distribution losses in the UK

Voltage Level	Indicative Distribution Loss Levels
132kV	0.5%
33kV	1.5%
11kV	3%
400/230V	7%

The reduction of losses implies a more efficient system and also a reduction in the total generation output required, with the added potential benefit of reduced total emissions and costs. From Table 4 we can see that as the voltage level of the network is reduced the loss level in the network increases. This is due to the current flowing at this voltage level being relatively higher than at transmission and the increased resistance of lower voltage circuits. If DG was load following and connected to the distribution network then there would be a definite reduction in power flows to the distribution network and therefore system-wide losses. The intermittent and variable nature of DG means that this is often not the case, but DG can contribute positively to reduced losses.

EA Technology (EA Technology, 2006) provides a comprehensive review of losses in the entire electricity system and the impact on increased DG penetration. One of the key conclusions of this work is that there are no general rules of thumb to relate increased DG and higher or lower loss levels across the entire electricity system. Localised impacts are dependent on network topologies and characteristics and on the nature of generators and loads.

Mutale *et al* (Mutale *et al*, 2000) discuss the allocation of losses in distribution networks in the presence of DG. The paper provides a good introduction to understanding how losses vary in time and space, prior to performing some investigations on a test network of different loss allocation techniques. Loss allocation and investigation will not be considered in this thesis; however, the adoption of the ANM methods presented in this thesis will impact on the level of distribution network losses, due to the increased connection of DG and the corresponding impact on network power flows.

2.5.5.2 Power Quality

Power quality is a term that is generally used to refer to the magnitude and waveform of current and/or voltage on the network. Jenkins *et al* (Jenkins *et al*, 2000) present the origin of power quality issues as shown in Figure 13.

Power quality effects from the network to a generator or load include voltage sags and swells, harmonic distortions of current and voltage and unbalance between phases. The load or generator can introduce power quality issues to the network in the form of harmonic currents, unbalanced currents, changes to reactive power flows, flicker, increased fault level and changes to active power flows.

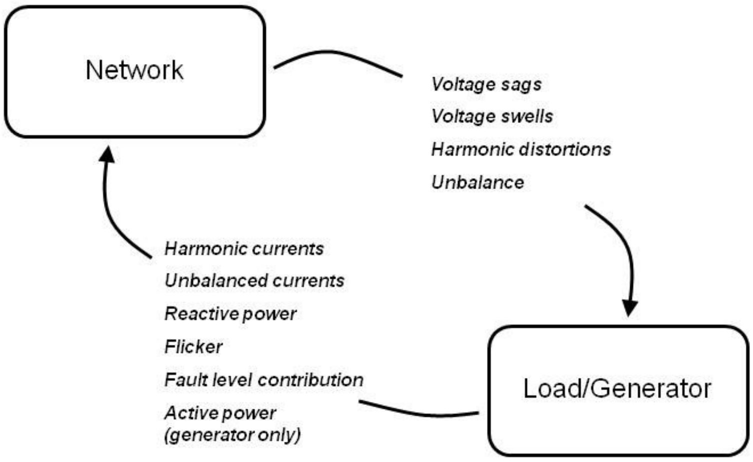

Figure 13: Origin of power quality issues

Ackermann et al (Ackermann *et* al, 1999) address issues relating to connecting DG at 11kV on a distribution network in New Zealand. The study considers the overall integration of the DG unit within network operation and control and investigates the power quality impact on the network voltage of different DG control capabilities. The main conclusion the authors present is that DG units that can control both real and reactive power (i.e. synchronous generators or similar), when properly sized and sited can significantly improve power quality.

Espie *et al* (Espie *et* al, 2003) assess the impact of DG on power quality and investigate the capability of DG to improve power quality. The paper demonstrates how the connection and operation of DG and the pursuit of power quality can be complimentary activities. Espie *et al* also recognise the role that ANM (or coordinated DG control) could play in delivering enhanced power quality,

Some aspects of power quality that are relevant to the work described in this thesis are described in Engineering Recommendation P28 by the UK Electricity Association (Electricity Association, 1989). P28 is concerned with voltage fluctuations, which can be caused by the disconnection or connection of DG units. National Grid (National Grid, 2004) also outline voltage limits for planning and operating UK networks and present voltage step change limits in planning timescales.

2.5.5.3 Protection Systems

As stated by Espie *et al* (Espie *et* al, 2003) the majority of DG units are fitted with either rate of change of frequency (ROCOF) relays or vector shift relays. These relays will remove the DG unit from the system during an oscillatory transient. According to Jenkins *et al* (Jenkins *et al*, 2000), a number of different aspects to protection systems associated with DG can be identified:

- Generator protection against internal faults
- Protection of the distribution network from fault currents supplied by DG
- Anti-islanding or loss-of-mains protection
- Impact of DG on the suitability of existing distribution network protection

There are typically set criteria for generator protection systems that must be installed to comply with regulations. In addition, the network protection systems and settings must be reviewed when new generator units are connected to a network.

For areas with large penetration levels of DG, the implications of approaches to protecting DG units must be put in the context of the wider system. If the settings on protection relays at DG sites are too sensitive then this could result in the loss of large numbers of DG units during a system disturbance. The loss of this generation could in turn worsen the impact of the system disturbance. In this case, the performance of the DG unit and the distribution network in terms of dynamic and transient stability must be considered.

Akhmatov and Knudsen (Akhmatov and Knudsen, 2007) discuss the ride-through capability of different wind generators, both fixed-speed, active-stall types and variable speed, pitch controlled DFIGs. The authors also discuss the use of power ramp (increasing or decreasing wind power generation) to prevent excessive overspeeding of wind farms, after a fault occurring on the system. These factors are now being considered in emerging grid codes to prevent negative system impacts of large scale DG, as discussed by Matevosyan *et al* (Matevosyan *et al*, 2004).

Knyazkin and Ackermann (Knyazkin and Ackermann, 2003) discuss the impact of new DG technologies and note that power electronics interfaces bring a corresponding reduction in the inertia constant (influenced by the kinetic energy in the rotating mass of the generator), which requires faults to be cleared more quickly at the DG site to preserve the stability of wind turbines.

Special Protection Schemes (SPSs) are emerging that are being used to facilitate the connection and operation of increased amounts of DG. An example of such an SPS is an intertripping arrangement, ensuring that a single event somewhere on the system will result in the immediate disconnection of a DG unit. This can add an incremental amount of DG capacity to the network. In future distribution networks, it is anticipated that deployed ANM schemes will operate within the protection envelope.

2.5.5.4 Transmission Network Power Flows

Increased deployment of DG has an impact on the planning and operation of the transmission network. The boundary between transmission and distribution is the Grid Supply Point (GSP) or Bulk Supply Point (BSP). The transmission network is planned to meet the maximum demand required by the distribution network through the GSP and operated to ensure security of supply for the demand being met through the GSP. The connection and operation of DG units in the distribution network will therefore impact on the boundary flows and exchange of power. If the real-time DG output exceeds the real-time load in the distribution network then the conditions at the GSP will change.

The transmission operator therefore requires an understanding of the connections and loads in the distribution network to be able to effectively manage and plan infrastructure. DG has the potential to reduce and increase flows on the transmission network, subsequently changing the voltage and losses positions in the transmission network (and in distribution as discussed previously).

If the installed capacity of DG is high enough, the changes to upstream power flow can be large. Burges and Twele (Burges and Twele, 2005) discuss how the connection of wind generation in parts of Germany has resulted in the thermal constraints on the 110kV network being breached. As a solution to this problem, and to ensure near-term connection of wind energy, the grid operator can curtail all generators participating in a wind generation management system. In the wind generation management system all participating wind farms are curtailed equally to remove the thermal constraints. For example, in Schleswig Holstein, E-on (the network operator) curtail wind farms participating in WGM to 60%, 30% or 0% of rated capacity. Interestingly, the network operator has to provide evidence as to the requirement for wind generation management each time it is used, but the response of each participating wind farm is not monitored to ensure compliance.

2.5.5.5 System Balancing

As will be discussed in section 2.6.1, the electricity system needs to be balanced (i.e. supply to equal demand) on an ongoing, instantaneous basis, if frequency is not to deviate from the nominal level. In the UK, National Grid Company (the single system operator) levies Balancing Services Use of System charges on suppliers and generators to recover the costs associated with balancing the system. DG can impact on the costs associated with balancing the system, particularly when the DG units do not bid into the market and are not visible to the transmission system operator.

The uncertainty regarding overall DG performance in the market could lead to increased balancing costs. Strbac *et al* (Strbac *et al*, 2007b) provide estimated reserve requirements and associated costs of increased total installed capacity in the UK electricity system, as shown in Table 5. It is clear that the growth in installed wind capacity (for the whole electricity system, not just DG) will result in additional reserve requirements to account for the uncertainty in the output of the wind energy portfolio. As more wind capacity is installed, the greater the range of potential additional reserve required. The additional reserve requirements are in the region of 7% to 25%, depending on the installed wind capacity.

Table 5: Estimated reserve requirements and associated costs, according to Strbac *et al*

Installed wind capacity (GW)	Additional Reserve Requirements (MW)		Range of cost of additional reserve (p/kwh)	
	Expected minimum	*Expected maximum*	*Expected minimum*	*Expected maximum*
0	0	0	0.000	0.000
5	340	526	0.002	0.005
10	1172	1716	0.008	0.015
15	2241	3163	0.015	0.027
20	3414	4706	0.022	0.041
25	4640	6300	0.030	0.055

The range of the estimated additional reserve results in a variation in cost from minimum to maximum of 200%, up to an anticipated maximum of 0.055p/kWh at 25GW. Considering that in 2005, the annual traded value for peak power between 7am – 7pm on a weekday was 3.7p/kwh (Ilex Energy Consulting, 2005); this represents a significant (potentially around 10%) increase in the cost of traded electricity.

Gross *et al* (Gross *et al*, 2006) present a study concerned with an investigation of the costs of intermittency due to increased use of renewable resources in the generation portfolio. Intermittency in this regard is taken to mean the variable nature of production from renewable generators that cannot be dispatched to provide full power output at times of peak demand. Gross *et al* identify that the overall cost of intermittency is a combination of the incremental impacts on the short-term balancing of the electricity system and the longer-term costs associated with maintaining desirable levels of reliability and security for customers when more intermittent sources of generation are connected. Gross *et al* estimate intermittency costs to be in the order of £5 to £8/MWh, £2 to £3/MWh of which is due to short-term balancing costs and the remainder to the long-term goal of maintaining reliability.

Soder *et al* (Soder *et al*, 2007) present several case studies of areas of high wind energy penetration. The areas covered include Gotland in Sweden, West Denmark, Schleswig Helstein, Ireland and New Mexico. In particular, Soder *et al* discuss the performance of large wind portfolios in terms of short-term variability and the need for other balancing plant to cater for the change in load on the system and the change in wind power production.

Anaya-Lara *et al* (Anaya-Lara *et al*, 2006) discuss a control strategy to provide short-term frequency regulation from DFIG-based wind turbines. Anaya-Lara *et al* identify that replacing conventional plant with DFIG based wind generation reduces the effective inertia in the system, mainly due to the decoupling of the mechanical and electrical systems in DFIG-based wind turbines. The authors show that it is possible to still achieve a satisfactory response from DFIG-based wind turbines with the implementation of a new controller.

Forecasting of wind power output will become more important to minimising the impact of uncertainty on the balancing of the system. As described by Matevosyan and Soder (Matevosyan and Soder, 2006), when bids are made to the market (which can be up to 38 hours prior to the delivery hour, as in Spain) there are various methods available to forecast wind power production. As installed capacities of wind energy increase, forecasting techniques applied to different timescales are likely to increase in importance.

An increase in the penetration of DG and the proposed approaches to ANM presented in this thesis will have an impact on system balancing. Investigations of this impact are not considered in this thesis, but deserve consideration elsewhere as a separate study. It is worth noting that the implementation of Active Power Flow Management (APFM) provides a means of controlling the output of participating generators, which could be used for system balancing purposes.

2.6 The Value Proposition of Distributed Generation

The value of DG depends not only on capital cost, but also on the size, nature and operating regime of the unit. For example, the presence of on-site DG at an industrial facility could help to secure load or increase reliability – the value of these benefits has to be demonstrable and achievable for the DG developer. In this section the value of DG is discussed, in terms of the tradable and system-wide potential value in a regulated power market. The regulated power market is introduced first with reference to the UK market - to provide context for later chapters of this thesis. The market value of DG is then discussed.

2.6.1 The Regulated Power Market in the United Kingdom

The UK electricity sector was liberalised in the Electricity Act, 1989. Ofgem (Office for Gas and Electricity Markets) is responsible for regulating the electricity and gas markets in the UK. Ofgem also award licenses to electricity network operators and generators. In 2005, the wholesale electricity markets in Scotland, England and Wales were united under the British Electricity Transmission and Trading Arrangements (BETTA), resulting in a single wholesale market in the UK with National Grid Company acting as the single system operator for transmission. A number of companies own and operate more than one distribution license area.

The UK energy market consists of several different mechanisms. The forward/futures contract market and the short term bilateral market (exchange) are known as the bilateral markets. The balancing mechanism facilitates supply meeting demand at each instant, through trading and participation up to an hour prior to the time of use. After the time of use payments are made for energy and services supplied in the settlement period. Participation in the bilateral markets and the balancing mechanism is optional; however, participation in settlements is mandatory for generators. Figure 14 provides an overview of the BETTA market structure with details of the different market mechanisms and how they relate to the actual time of use of electricity, as presented by National Grid (National Grid, 2006).

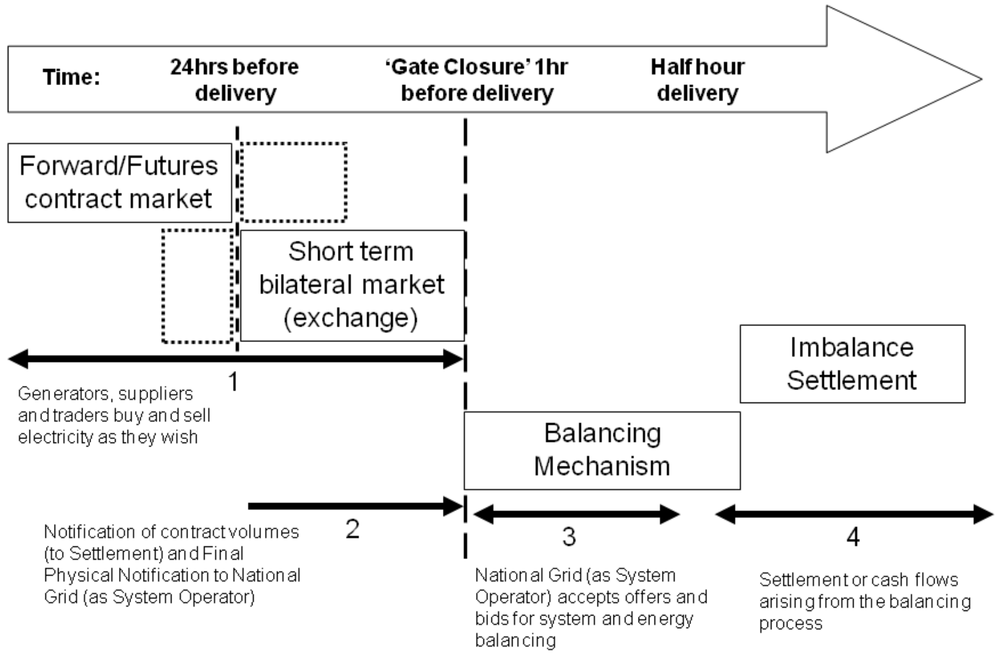

Figure 14: Overview of BETTA Market Structure according to National Grid

The forward and futures market is normally comprised of contracts agreed more than 24hrs ahead of real time. These contracts are between buyers and sellers of electricity and specify the date, quantity and price of electricity. The market typically operates up to a year ahead of real time although trading is possible up to the point of gate closure. Short term bilateral market transactions occur over similar timescales as the forward and futures contract market but tend to be concentrated in the 24hrs ahead of real time (the time from closure to the delivery of electricity varies from market to market). In this region of the market a particular MWh value for a specified period can be traded, allowing buyers and sellers to adjust their portfolios as forecasts of supply and demand become more accurate.

The balancing mechanism is utilised between gate closure and the real time delivery of electricity. National Grid manages the balancing mechanism, which consists of bids to increase generation output (or conversely, to reduce demand) to match supply and demand and solve transmission constraints.

In general, DG units tend to contract with a supplier that agrees to purchase all the energy generated by the unit. Therefore, the DG operator tends to generate as much power as is possible, irrespective of market conditions. This leads to an increased injection of power from renewable energy sources, but could also be seen as providing no incentive for DG to participate in all aspects of the market, either individually or collectively, and introducing added complexity to the challenge of planning, operating the transmission network and balancing the system. In the future, as DG is integrated more into the operation and control of distribution networks, markets are likely to emerge for the provision of ancillary services from the DG unit, such as the provision of reactive power.

2.6.2 The Market Value of Distributed Generation in the United Kingdom

This section addresses the value of DG by first considering typical revenue streams for DG, followed by the costs associated with DG deployment. There are a number of sources of tradable value for DG units in the UK (Ilex Energy Consulting, 2005), although it should be noted that these will change over time and are introduced here at a high-level for the purposes of discussion only:

- Wholesale electricity
- Renewable Obligation Certificates
- Climate Change Levy Exemption Certificates
- Ancillary Services
- European Union Emissions Trading Scheme

The DG developer can receive value for the trading of wholesale electricity, which can vary considerably throughout the year. In general, wholesale prices are arrived at for each half hour period. The value that the DG developer will accrue will be dependent on the time of day, season and predictability of the source.

Green Energy Certificates such as Renewables Obligation Certificates have been discussed earlier in this thesis. Climate Change Levy Exemption Certificates (LECs) are essentially a tax which suppliers must pass on to non-domestic consumers unless they can present the appropriate number of LECs.

The term Ancillary Services describes a number of services that can be provided to the network operator by a DG unit. These services are distinct from the goal of maximising the export of real power, and include such items as the injection or consumption of reactive power, black-start capability and securing demand in a defined network area. These services are either traded for on the market or sold directly to the DNO.

The European Union Emissions Trading Scheme allocates permissible emissions levels to existing generator plant and an automatic quota is provided to all new generators irrespective of source. Renewable generators may be able to trade their allowance, to gain added benefit.

Sohn Associates (Sohn, 2005) provide a case study of a wind farm connecting to part of the 33 kV network in the North of Scotland. This is used as an example here to demonstrate the capital costs and the value to the developer of such a site. The wind farm has 25 turbines, each rated at 2.5 MW, resulting in a total installed capacity of 62.5 MW. The plant for the wind farm was purchased in 2003 at a cost of around £56 million and generates 170,000 MWh per annum (a capacity factor of around 31%). The DG developer has entered into a fixed price structure with a supplier (at a lower value than perhaps could be achieved due to particular aspects of the project but nevertheless worthy of discussion for illustrative purposes) and will receive £32/MWh generated, resulting in annual revenue of £5.5 million. This value includes electricity sales, ROCs and climate change levy exemption certificates. The lower revenue level from the supplier was a result of uncertainty in generation output and an accompanying discounted price due to the location of the wind farm. The long-term fixed contract provided a lower revenue stream to the DG developer but was required in order to raise project finance. The payback period of the wind farm is still likely to be below 10 years despite the lower revenue level. Wind farms in better locations, with higher capacity factors can provide much quicker returns.

In conclusion it appears that even without a good energy sale arrangement and not considering other aspects of realisable value for DG units, an economic case for DG can still exist.

2.7 Chapter Two Conclusions

Modern energy policy and climate change are driving the increased connection and operation of DG, in particular renewable energy sources. Integrating DG within the planning, operation and control of the power system presents several challenges. At the distribution network level, there are several technical constraints on the increased connection of DG to the system. The main technical constraints on the connection and operation of DG are power flow constraints, voltage constraints and fault level constraints. Overcoming these technical constraints in an economically efficient manner - either through network reinforcement, ANM, or a mixture of both - while recognising the risks each participant is exposed to and integrating DG within the market and existing commercial arrangements is required.

The distribution network will need to become more active, both in terms of the number of services available and devices connected, but also in terms of the control philosophy implemented. More active management of the distribution network is required to facilitate the increased connection and operation of DG while making best economic use of available network infrastructure. In order to achieve this, DG units will need to match output to the real-time network capability through the deployment of ANM. In the next chapter, Active Power Flow Management (APFM) is introduced. APFM forms one element of ANM and is the focus of this thesis.

2.8 Chapter Two References

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3 Active Power Flow Management

3.1 Chapter Summary

Active Power Flow Management (APFM) is one component of Active Network Management (ANM) schemes or solutions; others include active voltage management and active fault level management. In this chapter, ANM is presented as a multi-faceted solution to the connection and operation of DG. The drivers for the adoption of ANM systems and technologies are presented and the technical scope of ANM discussed. The chapter then goes on to explore APFM solutions in greater detail, to provide context for the remaining chapters of this thesis, followed by a review of progress to date in the field of APFM. The chapter concludes by summarising the fundamental research challenges for APFM.

3.2 Active Network Management

The term 'Active Network Management' or 'Active Networks' is mainly used in the UK, although is beginning to be recognised internationally as describing more intelligent (or more controllable – autonomously or otherwise) distribution networks. ANM was first raised as an area for investigation to the UK power industry as one of the outcomes of the Embedded Generation Working Group (EGWG) (EGWG, 2001a), which identifies ANM as a route to facilitate near-term connection of distributed and renewable generation. The successor to the EGWG – the Distributed Generation Coordination Group (DGCG) – took the investigation of ANM forward as part of its package of workstreams, resulting in Collinson *et al* (Collinson *et* al, 2003) detailing short-term solutions for the connection and operation of individual DG units. Some of these solutions can be considered to be ANM solutions.

Despite the presentation of these ANM concepts for individual DG units to industry through the DGCG, there are limited examples of deployed ANM systems or technologies enabling the connection and operation of DG. In addition to this, deployable ANM concepts that deal with multiple DG units and multiple network constraints have not been addressed in the prior art. In this thesis, an APFM scheme concerned with multiple DG units and multiple constraints is proposed.

EA Technology (EA Technology, 2006) report that Distribution Network Operators (DNOs) in the UK associate the facilitation of DG, economics and regulation to be the main drivers for ANM, rather than safety, customer minutes lost, customer interruptions and automatic load reduction schemes. So it appears that DNOs see ANM as a solution to the barriers to deployment of DG rather than as a solution to wider technical issues in the network. The drivers for ANM are therefore distinct from many of the existing business drivers for DNOs; regulation and incentives will need to address this balance, if ANM to become business as usual where the cost-benefit can be demonstrated.

EA Technology (EA technology, 2006) reviews and assesses ANM infrastructures and practices through literature searches and completed questionnaires from UK DNOs. For the purposes of this activity it was necessary to define ANM, leading to the following definition used in the report:

> *"ANM is understood to mean systems that operate to take action automatically to maintain networks within their normal operating parameters… ANM operates pre-emptive action to maintain networks within their normal operating parameters."*

This definition highlights the operational and automatic nature of ANM schemes, in addition to defining the goals of ANM as being maintaining the network within normal or acceptable operating limits. Importantly, this definition identifies pre-emptive action as an integral characteristic of an ANM scheme; meaning that maintaining the network within acceptable operating limits is performed in a proactive rather than passive or reactive manner. This is a valid reference point in defining ANM and it can be verified through examination of the first generation of ANM schemes, as discussed later in this chapter.

EA Technology also distinguishes ANM as being separate from, but not independent of network protection systems. It is emphasised that consideration must be given to the impacts of ANM on the protection system components and their required configuration. The coordination and operation of protection systems lies within the remit of Advanced Distribution Automation (ADA). ADA is concerned with reducing customer interruptions and customer minutes lost, but remains a complementary activity to ANM and makes up another facet of many visions of future distribution networks. For the purposes of defining ANM it will be assumed that protection systems fall out with the remit of ANM schemes.

Liew *et al* (Liew *et al*, 2002) propose another definition of an active network:

> *"A network where real-time management of voltage, power flows and even fault levels is achieved through a control system either on site or through a communication system between the network operator and the control devices"*

Liew *et al* identify the technical constraints that can be managed as part of an ANM scheme: voltage, power flows and fault level. In Chapter 2, these were presented as the main technical challenges associated with the connection and operation of DG. In addition to these technical aspects, the commercial elements of different ANM schemes will require the identification of the principles of access for participating DG units to the real-time availability of the network with respect to voltage, thermal and fault level constraints.

Liew *et al* do not define the active network in terms of DG but in terms of control devices; meaning any device that can be controlled to meet the technical constraints on the network. The location of ANM hardware is also introduced; it is anticipated that ANM schemes will require communications links between the network operator and control devices. This can be taken to mean both within electricity substations and between components out on the power system and the network SCADA system.

Based on these foundations and as a result of investigations undertaken during the research behind this thesis, the following factors are recognised as key aspects of ANM:

- ANM is concerned primarily with the connection and operation of DG
- ANM provides network access for DG within network constraints in real-time
- ANM operates pre-emptively to prevent constraint violations during pre-fault and post-fault conditions
- ANM can act correctively to remove technical constraints
- ANM involves decisions that are made automatically and locally
- A number of elements in the distribution network may be subject to control by an ANM scheme, including generators, switchgear and voltage control devices
- Any device or element being controlled by an ANM scheme will require a communications link between an ANM decision making unit and the device or element being controlled
- ANM will require monitoring of primary system parameters and status indications
- Any monitoring device providing data to an ANM scheme will require a communications link to be installed between the location of the ANM system and the monitoring device
- ANM acts in parallel to the existing SCADA system but must be able to interact with such systems, providing remote control over ANM functions as required

The factors presented above provide an adequate overview of the characteristics of an ANM scheme, irrespective of the network constraints being addressed, i.e. power flow, voltage or fault level. It is also worthwhile to note how ANM relates to the wider electricity supply system:

- The key factors for ANM identified above are presented within the context of the existing passive distribution network
- The transmission network encompasses many of these functions and can be considered to be an 'active' system; however, as discussed by Roberts (Roberts, 2004) an active distribution network based on the model for transmission networks where generation is dispatched to meet demand and outage constraints is unlikely to be acceptable for smaller generators on technical and economic grounds.
- The gradual deployment of ANM at distribution and the specific network issues in distribution systems provide ANM with challenges separate from those found at transmission, including:
    - Security planning standards and the application of different levels of security for demand groups
    - The existing transmission network was designed with monitoring and control in mind. At distribution, these functions will have to be retrofitted to support ANM deployment, the cost of which must be recovered by the DNO
    - There are opportunities to make use of capacity available in the N (i.e. network intact) state at distribution, by not limiting power flows to the N-1 capability of the network. This would conflict with existing practice at transmission, where the N-1 planning has not imposed an artificial ceiling on generator connections, but is more concerned with meeting demand securely
- The interface with the transmission network allows the possibility that the distribution network will export power when capable and import power at other times to meet demand

The multifaceted nature of ANM systems, technologies and components make it difficult to settle on any particular definition at the present time. There is also an absence of deployed examples of ANM, which could be used as reference for any definition. The definition presented by Liew *et al* (Liew *et al*, 2002) is deemed sufficient for the purposes of this thesis, but it should be noted that ANM could involve the real-time management of one or all of the constraints mentioned, and that these constraints refer to distribution network constraints.

Distribution networks will gradually become more 'active' as ANM schemes are deployed and new technologies are introduced. These incremental additions to existing networks will likely take place at different times in different networks, only being implemented as needs must. By defining different categories of how 'active' a network is, based around the transition from passive to active, the nature of distribution networks can be considered and the emerging and future characteristics of the active network defined.

The Embedded Generation Working Group (EGWG) (Embedded Generation Working Group, 2001c) defines four transitional levels of ANM: passive, basic, intermediate and fully active. These are characterised by associated operator behaviour and infrastructure requirements, as shown in Table 6.

According to the EGWG, in a 'Passive' network the system operator only reacts to the network during unplanned outages. The infrastructure required to support this level of control involves the monitoring and control of particular critical system components or sections.

A 'Basic' active network is one where the system operator can react to planned abnormalities, such as circuit outages for maintenance. This requires some extension of the existing monitoring and control infrastructure; involving remote control over circuit breakers and the coordinated deployment of field staff to perform manual switching.

The 'Intermediate' active network encompasses real-time monitoring of the system conditions, in addition to some control of connected generation and demand. The interaction between the system operator and the DG unit(s) is performed automatically to satisfy network performance, security or constraints. The infrastructure required for the 'Basic' active network above has been extended to support the 'Intermediate' active network, including the installation of communications links for coordinated control between network devices or components and DG units.

Table 6: Transition from passive to active network management

Level	Operator Behaviour	Infrastructure Requirements
Passive	System operator reacts to abnormal situations, i.e. faults.	Existing monitoring and control at key points on the network. Some remote control facilities, other manual actions available.
Basic	Reactive to planned abnormalities or longer term restrictions (e.g. seasonal).	Selective extension of existing monitoring and control infrastructure on restricted number of circuits
Intermediate	Some real-time network monitoring, scheduling/constraining of generation and load management across parts of the network. Automatic interaction between DNO plant and embedded generation.	Further extension of monitoring and control systems but still on restricted number of circuits. Communication between key network plant and generator for voltage control together with intertripping for load flow and fault level management.
Fully Active	Real time network monitoring, scheduling/constraining of generation, load management across all network.	Monitoring and control at key network nodes, communication with controllable generators and loads. Real time modelling capability of power, active power, voltage, fault levels and security.

The 'Fully' active network is characterised by on-line real-time control of DG units and load demand. Extensive monitoring and control functionality has been added to the network to support the transition to 'Fully' active. In addition, it is suggested in Table 6 that the system operator is able to perform real-time modelling to assist in either the automatic or manual operation of the active network.

The transition from ‘Passive’ to ‘Basic’ is already occurring in many distribution network license areas. The EGWG proposed these transitional levels prior to the deployment of any ANM technologies or systems. The steps from ‘Passive’ to ‘Fully’ active give an idea of the gradual and incremental nature of ANM systems and components. In reality, the transition will not be as exact and as structured in many cases. In the following section the state of the art of ANM at the time of undertaking this research is presented. This is followed by a discussion of the maturity of the APFM prior art and recent developments relevant to APFM. The chapter concludes by presenting the fundamental challenges to APFM, which are in part addressed by the APFM scheme proposed in this thesis.

3.3 Active Network Management State of the Art

This section presents what can be considered the ‘state of the art’ in ANM at the time of undertaking this research, providing a time-stamped view of ANM progress to date. Firstly, the ANM prior art is presented as that which existed in the public domain at the time when this research was conducted. Included within this consideration of prior art is the presentation of results of a study the author conducted for a UK Government and Industry Working Group to compile a register of ANM activities, which was subsequently published. Inspection of the maturity of relevant activities identified and an overview of developments related to APFM between 2006 and 2009 are presented to provide an indication of progress in the field of APFM and at the time of undertaking this research.

3.3.1 Active Network Management Prior Art

In this section, the ANM prior art is presented for the three main technical focus areas of ANM schemes, which are identified by Collinson *et al* (Collinson *et al*, 2003) and Liew and Strbac (Liew and Strbac, 2002) as power flow management, voltage control and fault level management. However, the deployment of ANM schemes in any of these technical focus areas will be dependent on communications and control infrastructure. The focus of the work presented in this thesis is APFM; the prior art for power flow management is therefore presented first; voltage control, fault level management and communications and control are then presented for completeness.

3.3.1.1 Power Flow Management

Several solutions are proposed in the literature for actively managing an individual DG unit to meet power flow constraints. Many of the concepts discussed hold potential for application to managing the power flows from multiple DG units but are not yet developed to meet this requirement. Equation (5) and (6) in section 2.5.2.3 introduced the concept of Firm Generation (FG). Much of the Active Power Flow Management (APFM) prior art is concerned with extending the capacity for generator connections beyond FG limits, into Non-Firm Generation (NFG). This section introduces some of the NFG concepts in the literature, which mainly involve the disconnection or reduction of the output of NFG units during intact network conditions or outages.

The main driver for ANM has been identified above as enabling the connection and operation of DG units; Collinson *et al* (Collinson *et al*, 2003) present the following solutions for actively managing the power flows associated with an individual NFG unit:

- Direct intertripping of DG
- DG trip based on power flow measurements
- DG power output control based on power flow measurements

Post-fault constraints can be implemented through direct intertripping of NFG units. Direct intertripping requires a communications link between branch protection systems and the NFG unit circuit breaker. When branch circuit breakers open, a signal is generated and relayed to the NFG unit circuit breaker to open, removing the output of the NFG unit from the system. The reliability of the approach is dependent on the reliability of the communications link between sites. On occasions when the direct intertripping scheme is unavailable it is likely that the NFG unit will be required to maintain output within pre-fault constraint levels determined by the DNO.

The second power flow management solution involves NFG units being tripped (disconnected) from the network based on measured power flow exceeding an acceptable level. An example of this could be the measurement of power (or current) flow on critical circuits informing an APFM control system that will trip a NFG unit from the system (by opening the metering circuit breaker) when the network firm capacity is breached. Such a solution could involve arming the intertrip facility when the real time flow on the network is greater than the firm capacity of the network.

The third approach suggested by Collinson *et al* involves controlling the power output of a NFG unit based on power flow measurements. This represents a much more dynamic solution that requires real-time monitoring and control. Such a scheme could make use of short-term power ratings of circuits during the operation of the scheme, which could give the NFG unit time to reduce power output in a controlled manner for a sudden change in available network capacity due to an outage on the system. Collinson *et al* suggest that an intertripping scheme is an appropriate back-up to a scheme of this nature. Further work is required to develop methods for relating measurement data to NFG unit output limits and the practical implementation of such a scheme. It is possible that these issues and a lack of clarity regarding how the above solutions could evolve as the network changes or further NFG units connect (i.e. the longer-term issues) are holding up progress in the development of APFM. The APFM scheme proposed in this thesis has been designed to easily incorporate the addition of further generator connections or constraints, to address this issue.

The UK Energy Networks Association (ENA) (Energy Networks Association, 2005a) builds upon the recommendations made above by Collinson *et al*, by categorising APFM solutions for individual DG units in terms of post-fault constraints in Engineering Technical Recommendation 124 (ETR124). ETR124 provides the following solutions for expanding network capacity for the connection of an individual DG unit:

- Post-outage direct intertrip
- Post-outage measured power flow
- Post-outage demand following

These solutions are essentially the same as those suggested by Collinson *et al*. However, ETR124 presents solutions that allow the local electrical demand to be included in the decision making within the APFM solution. The presentation of each of the above solutions in ETR124 is now discussed by way of considering an example network. Figure 15 illustrates an example network with parallel transformers rated at 30 MVA each; feeding a load that varies from 5 MVA to 30 MVA. Various scenarios for allocating NFG capacity are shown.

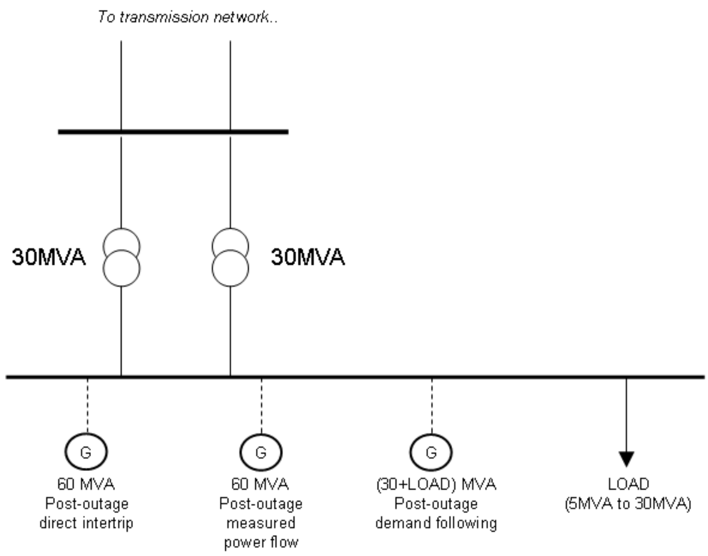

Figure 15: Simplified representation of NFG capacity available to different APFM solutions according to the ENA

The application of the post-outage direct intertrip approach to the distribution network in Figure 15 permits connection of NFG up to the limit of the (N-1) capacity of the network (the loss of one 30 MVA transformer, leaving 30 MVA remaining) plus the maximum demand: 30 + 30 = 60 MVA. In this situation there would be no restriction on NFG output while the network is intact, however if one if the 30 MVA circuits was lost then the NFG would be tripped (as described above for post-fault constraints). Following the removal of the NFG capacity from the system, the DNO may permit reconnection of the NFG unit at a level equivalent to the (N-1) capacity of the network plus the minimum demand: 30 + 5 = 35 MVA.

The post-outage measured power flow approach involves the allocation of NFG to the (N-1) capacity of the network (i.e. the capacity of the network based on the loss of one 30 MVA transformer, leaving 30 MVA remaining) plus the maximum demand of 30 MVA: 30 + 30 = 60 MVA. As described above for the post-outage direct intertrip approach, this results in 60 MVA of DG capacity for the network presented in Figure 15, although the method of capacity allocation and the operational delivery of the strategy is different. For the application of the post-outage measured power flow approach, the NFG unit is only disconnected when the measured power flow on the network is greater than the (N-1) capability, which will only occur when the NFG output minus the demand is greater than the (N-1) capacity. Therefore the NFG unit gains the benefit of not automatically being disconnected for the (N-1) contingency, but only if the power flow on the network exceeds the (N-1) capability of the system in real-time.

The post-outage demand following solution involves automatically limiting the output of the NFG unit to the (N-1) capacity of the network plus the actual demand on the network at any given time, resulting in a maximum installed capacity of 60 MVA on the network in Figure 15. This solution will require monitoring of the demand on the network or of power flow at critical circuits. In the event of the (N-1) contingency, the NFG unit would not be tripped if the output can be controlled in a timely enough fashion to reduce the power flows on the system within acceptable timescales. ETR 124 does not provide further details of how to practically implement such a solution, which is inherently more complex than the other APFM solutions for individual NFG units that are based around the disconnection of NFG units in the event of the N-1 condition. The requirement for a solution to the post-outage demand following problem is addressed by the APFM scheme proposed in this thesis, which can be extended to incorporate multiple DG units and distribution network power flow constraints at multiple locations.

Liew and Moore (Liew and Moore, 2005) present a post-outage demand following connection solution for an offshore wind farm. In this case, the application of APFM formed the basis for the connection of the 76MW generator. The constraint is delivered to the wind farm during outages on the network in the form of a number of "turn down" instructions. In the application of the rules relating to curtailment of the wind farm it is noted that existing access arrangements for other generation connected in the area (in this case combined cycle gas turbine plant) should be honoured. The "turn down" instructions are issued to the wind farm in 25% blocks depending on the power flow being measured. The system includes a non-compliance trip, where the wind farm is tripped for not achieving the issued "turn down" instruction. The application of the "turn down" signals by Liew and Moore represents one of the few APFM schemes in existence that has been described publicly and is not bound by confidentiality. It is assumed that other versions of the solutions proposed by Collinson *et al* (Collinson *et al*, 2003) are operating on networks in the UK and beyond for the connection and operation of individual DG units, however little detailed information is available in the public domain.

Kabouris and Vournas (Kabouris and Vournas, 2004) demonstrate the application of interruptible contracts to wind farms and how this approach can support increased generator connections to transmission networks in congested areas. The approach is essentially a post-outage demand following solution. The authors present two strategies for managing power flows from wind farms: preventive and corrective. The preventive approach involves managing the output of wind farms to ensure the N-1 security limit on power flows is not breached; this method is being applied to the Thrace region of Greece. The corrective approach involves curtailing wind farm output only when thermal transfer limits are breached, which would likely only occur during the N-1 contingency. It was expected that the corrective approach to interruptible contracts would require new regulation and grid code developments and is therefore less favourable in the short term.

Kabouris and Vournas also discuss the economic appraisal of the impact of power output constraints on the business of the wind farm developer, identifying that it is important to forecast the level of constraint to be experienced by each participant in a given year. Such information can be used for financial planning purposes and could also help evaluate the benefits of different wind farm locations. This system was designed for deployment on Programmable Logic Controllers (PLCs) with emphasis on the simple nature of the scheme and transparency, which provides the required security for the network operator. The scheme acts to reduce wind farm output in proportion to individual wind farm size versus the total portfolio of interruptible contracts. Therefore, each wind farm experiences the same per unit curtailment. This shared access can be considered to be one approach to "principles of access" that relate the output of multiple DG units to each other and the network constraints being managed. Other principles of access exist, as will be discussed later in this chapter. The performance of the scheme presented by Kabouris and Vournas is assessed using historic and probabilistic data and the impact on the estimated portfolio of interruptible contracts for participating wind farms is based on estimates of capacity factor.

Kabouris and Vournas present a method applicable to multiple DG units and provide a means to assess the economic viability of each participant. These two aspects of this work are crucial to the practical success of the Active Power Flow Management (APFM) scheme. It is clear that the next generation of APFM schemes can learn from the nature of the solution described by Kabouris and Vournas and the type of analysis performed to support deployment. The elements required to achieve practical success and the accompanying criteria for assessing the performance of generators connecting to an APFM scheme are incorporated within the work presented in this thesis. The APFM scheme presented by Kabouris and Vournas is bespoke and has not been implemented in other network areas to date. The APFM scheme proposed in this thesis provides the basis for implementation on different network types and for different generation scenarios, moving beyond bespoke APFM solutions to meet specific network needs in a single area.

Foote *et al* (Foote *et al*, 2001) investigate the cost benefit of trading network reinforcement against operational constraints on DG output to reduce the requirement for network reinforcement. Some simplified cost data is used and a single day scenario is multiplied by 365 to estimate the annual cost and operational implications of curtailment. The main conclusion is that a combination of constraints and reinforcement can be the most cost effective solution for the connection and operation of DG. It is clear that such cost-benefit analysis will be required for assessing the deployment of APFM solutions and comparing alternative solutions.

The solutions presented above are mainly concerned with individual DG units - limited progress has been made with multiple DG unit APFM schemes. It is clear that the aspects of the more mature solutions that are attractive to network operators need to be identified and factored into the design of APFM schemes. Such consideration will be supported by assessing the progress made (or maturity) of these projects, as discussed later in section 3.4.

3.3.1.2 Voltage Control

ANM solutions for managing the voltage on the network due to the connection of individual DG units have been identified by Collinson *et al* (Collinson *et al*, 2003). Subsequently, the Energy Networks Association (ENA) in the UK published guidelines for actively managing a single DG unit for the purposes of voltage control (Energy Networks Association, 2004b) in Engineering Technical Recommendation 126 (ETR126), which is based on the solutions presented by Collinson *et al*. The solutions presented in ETR126 are mainly focused on maintaining the steady state voltage of the distribution network within +/-6% of the nominal voltage at the nominal frequency, but also identify step voltage concerns as being relevant to the planner. ETR126 presents the following four solutions:

- Generator real power control
- Generator reactive power control
- Line voltage regulator
- Active voltage control with remote sensing

As was described in Chapter 2, the maximum permissible or acceptable voltage on the distribution network can be a limiting factor on the capacity for DG connection(s). However, if the real power output of the DG unit can be managed to ensure voltage constraints are not violated then a greater total installed capacity is possible. The impact on the economic viability of the DG unit is of concern as real power is normally the source of DG income; therefore, as with other APFM solutions, the energy curtailment experienced must not be prohibitively high for this to be considered as a solution. As was the case for APFM schemes in the previous section, DG developers will require an indication of likely constraint levels in order to perform financial appraisal of projects and raise project capital.

Using the same two bus example given in Chapter 2 in Figure 9 and presented by Liew and Strbac (Liew and Strbac, 2002), if the output of the DG unit is curtailed to satisfy the voltage constraints on the network then the amount of curtailment at any given time is determined by equation (7):

$$P_G^{CUR} \approx P_G^{MAX} - \frac{V_2^{MAX} - V_1}{R} \tag{7}$$

Where P_G^{CUR} = Required per unit real power curtailment from DG unit (W_{pu}) and P_G^{MAX} = Maximum per unit real power rating of DG unit (W_{pu}).

The rated power output of the DG unit, the maximum output at any instant and the required curtailment are related by equation (8):

$$P_G^{MAX} \approx P_G^{CUR} + P_G^{ACTUAL} \tag{8}$$

Where P_G^{ACTUAL} = The real-time per unit power output of the generator being curtailed (W_{pu}).

For other network types and situations the complexity of the relationship between voltage levels on sections of the network and the output of DG unit(s) will increase. This will require monitoring or estimation of the voltage at various parts of the network and a method of translating knowledge of the location and size of constraints into a set-point for the acceptable MW production from DG units.

Another solution to solving voltage constraints for individual DG units is managing reactive power flows. This is likely to be preferable to the developer provided there is no impact on real power production, which provides the DG developer with their main source of income. The DNO can also make use of OLTCs on the network at one or more GSPs to achieve an increase or decrease in distribution system voltage profile. Modern DG technologies such as Doubly-Fed Induction Generators (DFIGs) permit operation at a range of power factors, typically from 0.95 leading to 0.95 lagging – as is the requirement in many grid codes (Matevosyan *et al*, 2006). If the DG unit can absorb more reactive power to reduce the voltage on the network then this can lead to the network being capable of accommodating increased real power production, as described in equation (9):

$$P_G^{MAX} \approx \frac{V_2^{MAX} - V_1}{R} + \frac{Q_{import} X}{R} \tag{9}$$

Where Q_{import} = Per unit reactive power imported (VAr_{pu}).

Line voltage regulators can be placed between the DG unit and the upstream substation; therefore decoupling the feeder with DG on it from the voltage control performed by the OLTC in the substation, which serves the rest of the passive network. This technique has been deployed on part of the rural 11kV North-Wales network, as described by Collinson *et al* (Collinson *et al*, 2003).

The final recommended solution from ETR126 is active voltage control with remote sensing. This solution is very much tailored towards the approach adopted by the company Econnect, in the development of their voltage control product GenAVC. Hird *et al* (Hird *et al*, 2004) and Collinson *et al* (Collinson *et al*, 2003) present block diagrams that describe the functions to be performed by a scheme to perform active voltage control by incorporating remote sensing. Strbac *et al* (Strbac *et al*, 2002) also present the same system of function blocks, with slightly differing terminology.

The main elements of the function blocks required in software to perform active voltage control with remote sensing are shown in Figure 16. A combination of measurements from the network, pseudo measurements (values not taken from real-time monitoring, but required to perform state estimation, such as estimated load values) and network data are required to support the approach. The outputs from the state estimator are a set of busbar voltages for the network. These estimates of network conditions are combined with knowledge of constraints and commercial contracts as inputs into an algorithm that schedules a set of control actions to meet the prevailing conditions. These actions could include the control of voltage control relays, DG units, loads, reactive compensation devices and circuit breakers.

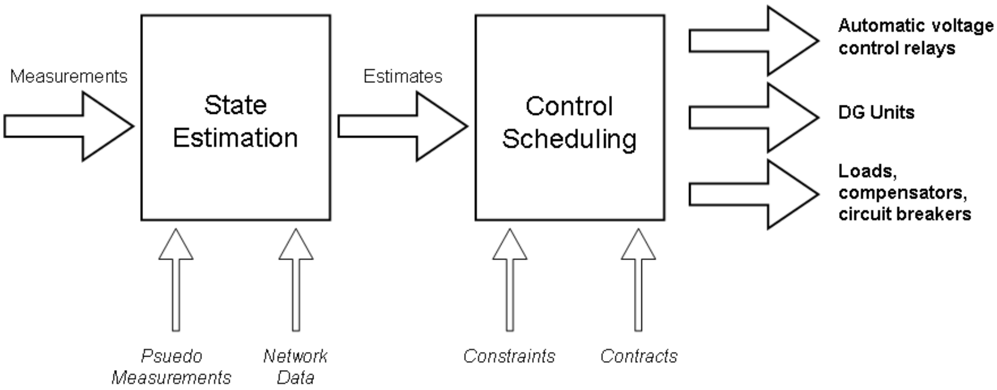

Figure 16: Summary of function blocks required by software to perform active voltage control with remote sensing, according to Hird *et al*, Strbac *et al* and the ENA

Figure 16 is useful for considering the processes undertaken by any ANM scheme. A combination of online and offline data must be processed and subject to algorithms that recognise the control actions available to the ANM scheme to solve network constraints.

Strbac *et al* (Strbac *et al*, 2002) investigate a number of the options for managing the voltage rise effect associated with DG by integrating the operation of DG with the operation of the distribution network. These include, generation curtailment, reactive compensation and coordinated voltage control. These solutions are implemented using an Optimal Power Flow (OPF); the objective function of the OPF being to minimise generator curtailment. The OPF achieves this by searching through the space of possible solutions, bound by optimisation constraints and the cost functions of the various controllable resources to satisfy the voltage constraints on the system. In this manner, OPF is a planning tool applied to determine the potential 'resource' in terms of MWh that each solution will provide from the DG units included in the modelling scenarios. Strbac *et al* also discuss the option of adopting a rule-based 'priority list' approach to solving voltage constraints, but this approach is not adopted and studied. It is suggested however, that such approaches are likely to be implemented in early ANM installations, rather than the more complex combination of state estimation and OPF. For the example network considered by Strbac *et al*, it is found that area-based coordinated voltage control is the best means of reducing real power curtailment of DG units; the authors do not address issues relating to the practical implementation of an ANM scheme to perform area-based coordinated voltage control. Liew and Strbac (Liew and Strbac, 2002) perform similar studies on a different test network using OPF and arrive at a similar solution; that area-based coordination of voltage control, including OLTC transformers, achieves the greatest penetration of DG within voltage constraints.

Kiprakis and Wallace (Kiprakis and Wallace, 2004) describe two methods to solve voltage constraints due to the introduction of synchronous generators at the remote ends of a radial distribution network. The first of which is a deterministic or rule based system that decides when to switch between power factor control (fixed power factor) and voltage control (DG unit varies reactive power consumption/injection to achieve target voltage at terminals) modes. The second method is a fuzzy inference system that adjusts the power factor of the DG unit in response to the terminal voltage at the DG site. Both methods hold promise for increasing the amount of DG connected to the network when voltage constraints are preventing further passive DG connections.

Zhou and Bialek (Zhou and Bialek, 2007) investigate the curtailment of DG units based on the contribution of DG units to voltage constraints as quantified by voltage sensitivity factors. Zhou and Bialek correctly identify that the transmission network is an example of an actively managed system where grid congestion is managed, but that for a similar philosophy for congestion management to be applied at the distribution network would require full information about the status of the network, connected generators and loads. As was discussed earlier in Chapter 2 and is confirmed by Zhou and Bialek, this information is rarely available and even if it was available, DNOs are not accustomed to such network operation duties or systems and lack the required tools and resources to manage such a network scenario. Zhou and Bialek investigate the application of real power constraints imposed on participating DG units to meet network voltage constraints at 11kV. It is stated that voltage constraints are normally the binding constraint on DG connections at 11kV.

Zhou and Bialek view real power constraints as the last option to solve voltage constraints, once other avenues (reactive compensation, voltage regulators and OLTC transformers) have been exhausted. The sensitivities of network voltages to the injection of real and reactive power are found through inspection of the Jacobian matrix, which it is recognised will vary in real-time as network conditions evolve. As was this case with Strbac *et al*, Zhou and Bialek use an OPF to solve the voltage constraints. The authors do not discuss the practical implementation of such a scheme (despite touching on some of the commercial considerations that would be required), in particular it would be required to assess the validity of updating the Jacobian matrix in response to real-time measurements and status indications, validating and verifying suggested control action(s) and the effectiveness of the OPF approach to online control when the network and voltage constraints are dynamically changing.

Carvalho *et al* (Carvalho *et al*, 2007) propose to not put the DG unit in charge of regulating the voltage at the connection point, but to implement a system that ensures that DG unit injections do not cause voltage excursions with respect to statutory limits. This is to be achieved with occasional communication between the DNO and the DG site. The required reactive power operating point of participating DG units is found through direct calculation based on the impedance of the network between the DG unit and the bulk supply point. It is noted that using reactive power control can result in increased losses and OLTC positions that are vulnerable for the network should DG units trip off the system, as compared with a fixed power factor approach. However, the approach allows the voltage profile of the network to be similar to that for the 'no DG' scenario. It is unclear how such an approach could be implemented in a practical sense and, in particular, the authors do not discuss the commercial factors that may affect the implementation of the computational method suggested for multiple DG units and more complex network topologies with multiple DG sources and loads.

Crabtree *et al* (Crabtree *et al*, 2001) investigate some methods to accommodate DG without degrading network voltage regulation. Similar solutions to those identified above are discussed, particularly with respect to the 'actors' (those being the devices, generators or loads) that can be controlled for the purposes of voltage regulation. In addition, the authors identify the on-line adjustment of the fixed tap settings for 11kV/400V transformers, as an option to provide greater access for DG units. The tap settings on such devices are normally only changed off-line in response to unsatisfactory voltage profiles being observed and may require the installation of tap-changing equipment. Crabtree *et al* provide a useful overview of the challenges of integrating a new voltage control solution within the array of existing techniques available for employment at distribution voltages.

It is clear that the methods in the literature concerned with voltage control do in some cases involve the control of real and/or reactive power at generator terminals. Some of these methods could hold potential for their application to solving power flow management constraints on networks. In the future, ANM schemes will be required that allow the goals of voltage management and power flow management to be achieved in tandem.

3.3.1.3 Fault Level Management

Collinson *et al* (Collinson *et al*, 2003) propose some short term ANM solutions for fault level management, including:

- Converter technology for generation
- Network reconfiguration
- Is Limiter
- Sequential switching

Converter technology applied to DG units, such as in DFIGs for wind applications, can increase costs but lead to operational benefits and lower fault current contribution from DG units, as opposed to that from more traditional rotating machines. The reduction in fault contribution can be beneficial as compared with another generator technology, particularly in areas where the fault level is near or approaching the maximum capability of the network.

The distribution network can be reconfigured to ensure that fault levels are within acceptable limits. The extent to which this can be achieved will depend on how interconnected the network is. Some network types, e.g. radial systems, provide little opportunity for reconfiguration. Network splitting is one option that is commonly available for reducing fault level.

Collinson *et al* discuss the installation of fault current limiting devices such as the Is limiter at critical points on the network. Such devices act to clear high fault currents but have failed to be widely deployed in UK networks, although Collinson *et al* report that they have been installed on the German network. Once significant challenge associated with such devices is that the explosive link can operate only once, then must be replaced, which means they cannot be tested. Such a device could be viewed as incorporating high-risk for a network operator.

Sequential switching involves the separation of multiple paths that are contributing to a fault prior to the faulted section being cleared. This can be performed to ensure the fault current is within the rating of the final faulted section to be cleared. Careful coordination of devices is required to ensure that the fault current that all switchgear are required to break is within the rating of the device, which could otherwise lead to equipment damage and more importantly, a number of safety implications for humans. Such coordination is dependent on having the appropriate communications and control infrastructure in place.

Although there is less prior art concerned with fault level management, there will be situations where the management of power flows will require due consideration of the fault level restrictions on the network, particularly when connecting new generator units and reconfiguring the network to maximise access for generators. It is possible that fault level management techniques could be deployed in tandem with APFM schemes in such situations.

3.3.1.4 Communications and Control

It was discussed in Chapter 2 how the incumbent distribution network is essentially 'passive' - there are little monitoring, communication and control functions available to the network operator. This is in stark contrast to the anticipated nature of future networks, as described by Varming *et al* (Varming *et al*, 2004):

> *"Every node in the electrical network of the future will be awake, responsive, adaptive, price-smart, eco-sensitive, real-time, flexible, humming – and interconnected with everything else"*

Varming *et al* describe a system of significant complexity. There will be a gradual shift towards increased visibility and control of networks, but the achievement of the vision above is some way off as of yet. Particularly as developments tend to be incremental and driven by specific needs, not rolled out to entire distribution networks until network operators are convinced of the need and the suitability of the solution.

Communications and control is different from the other areas of ANM previously discussed. There is a general requirement to address communications and control issues for the implementation of any ANM system; therefore, this section considers activities relating to general distribution monitoring, communications and control. It is anticipated that such systems are key to 'unlocking' the true potential of ANM.

Roberts (Roberts, 2004) presents a feasibility study regarding the deployment of ANM on the existing SCADA infrastructure. One of the key conclusions that Roberts presents is that there are fundamental limitations of existing SCADA systems associated with speed of operation, reliability and resilience that would limit their applicability where the consequences associated with the failure of the system are large. Roberts also argues for simple, modular ANM schemes to be developed, that provide a route through the complexity associated with implementing ANM solutions for many individual DG units. This suggests that emerging ANM systems will be required to operate in parallel with existing SCADA systems and their accompanying communications links, likely requiring independent communications links to be established for ANM. This is an important practical point to note for the development of ANM and is factored into the design and operation of the APFM scheme proposed in this thesis.

The findings presented by Roberts (Roberts, 2004) are mostly confirmed by EA Technology (EA Technology, 2006), who provide a technical review and assessment of ANM infrastructures and practices in which it is identified that existing SCADA systems possess some of the functionality expected to be required by ANM systems. It is noted that DNOs seem reluctant to utilise this existing capability and that there is a general lack of trust in deploying ANM technologies, whether through SCADA or not. Gaining the trust of DNOs through testing and trial of ANM systems that are deployed on trusted hardware platforms will be crucial, as will ensuring that simple measures are adopted first that can be easily understood, monitored and verified. This is confirmed by inspection of the multiple generator APFM scheme, as described by Kabouris and Vournas (Kabouris and Vournas, 2004), which uses Programmable Logic Controllers (PLCs); the PLC is an established and trusted source of control in the power industry. This observation is incorporated within the work presented in this thesis and the practical aspects of the proposed APFM scheme.

3.3.2 Progress in the Field of Active Power Flow Management

While conducting the research presented in this thesis, the author undertook a research project for a UK Government and Industry working group to compile a register of activities in the area of ANM. This resulted in a register of 105 projects, covering a variety of the technical aspects of ANM at differing stages of maturity. Inspection of the contents of the register allows conclusions to be drawn about the maturity of the ANM domain, in terms of deployed and commercially available systems. The ANM register was first published online at the end of 2006;

subsequent revisions have also been published. The following sections introduce some of the register's contents and investigate the more relevant projects of the 2006 ANM Register to provide context for the contributions of this thesis and build upon the prior art introduced in the previous section. ANM activities undertaken from 2007 onwards that are relevant to this thesis are presented later in this chapter.

The ANM register includes activities that are ongoing or completed and are either pilots, trials, research, demonstration or deployment activities. By considering the type and technical focus of each activity it can be demonstrated where much focus had been directed, where solutions had been implemented and where solutions were emerging. As a result, technical areas which experienced little or less activity, either due to the lack of a pressing need or due to uncertainty regarding the future market and technical environment were identified. The analysis of the content of the register allows the implications of the spread of all activities to be considered.

Government and Industry reports, press releases, web searches, journal and conference publications and magazine articles were searched for activities valid for inclusion in the ANM Register. In particular, Ingram *et al* (Ingram et al, 2005) provide a useful overview of technology developments relevant to ANM, in terms of primary and secondary system plant to support increased penetration of DG.

The 2006 ANM register is available as a table with entry categories as columns and unique register entries as separate rows. Each project has a unique identification number and a brief summary of each project is included within the register. The first page of the register is shown in Figure 17, which shows the level of information provided on all the ANM activities found.

Project ID	Project Title	Lead Organisation	Partner Organisations	Funding Source	Activity Type	Activity Status	Start and completion dates	Country	Classification of technical focus	Brief Summary of Activity	Contact details	Report Link (URL)
01	"Embedded Controller" for Active Management of LV Distribution Networks	Econnect Ltd	University of Northumbria at Newcastle, VA Tech and T&D UK Ltd and YEDL	DTI Technology Programme: New and Renewable Energy. Contract number: K/EL/00334	R&D	O	2004 - 2007	UK	VC FLM PFM	To research and develop a small-scale "embedded controller", model and evaluate its performance. To develop design specifications for a full-scale "embedded controller" suitable for LV distribution networks.	http://www.econnect.co.uk/	http://www.dti.gov.uk/renewables/publications_pdfs/pp204.pdf
02	Skegness / Boston Registered Power Zone	Central Networks	-	Registered Power Zones Initiative, Ofgem, UK	T	O	2005	UK	PFM	Dynamic ratings are calculated using real-time load and local temperature information. This allows the thermal capacity of the network to be utilised more effectively for accommodating increased connections of wind energy. An additional 90MW of generation may connect, which will be subject to curtailment based on the breaching of the dynamic thermal capacity.	Jeff Douglas Jeff.Douglas@central-networks.co.uk	http://central-networks.co.uk/Content/Media/media_press_detail.aspx?NewsId=387
03	Facilitate Increased Generator Connections to the Orkney Distribution Network	Scottish Hydro Electric Power Distribution Ltd	University of Strathclyde	DTI Technology Programme: New and Renewable Energy. Contract number: K/EL/00311	R	C	2003 - 2004	UK	PFM	Initial specification of active power flow management scheme. Scheme works through the identification of control zones and available capacity for export from the Orkney distribution network. Power flows are managed using operating margins and generator output regulation and tripping. Results in capacity for around 3x firm generation to connect.	David.Telford@scottish-southern.co.uk	www.dti.gov.uk/renewables/publications_pdfs/kel00311.pdf
04	Voltage Control Policy Assessment Tool	EATL	Central Networks, EDF Energy, Central Electric, Scottish Power, United Utilities	EATL STP Project	D	C	2004	UK	VC	Develop effective policies for applying voltage control technologies for enabling increasing connections of small generators. This project is developing a tool for DNOs to assess new approaches and find the best that allows maximum connections at the lowest cost for the developer, customer and DNO.	http://www.eatechnology.com/	http://www.eatechnology.com/STP_Home.asp

Figure 17: First page of ANM Register

Figure 18 is concerned with analysing the contents of the ANM register to demonstrate the technical focus spread across the activities. It is not surprising to see many projects in communications and control (27% of all projects) as the lack of existing monitoring and control of distribution networks is a potential barrier to ANM. After communications and control, the main technical areas of activity are voltage control (19%), power flow management (14%) and fault level management (10%). These areas correlate to the main technical challenges facing the connection and operation of DG and therefore ANM, as discussed previously.

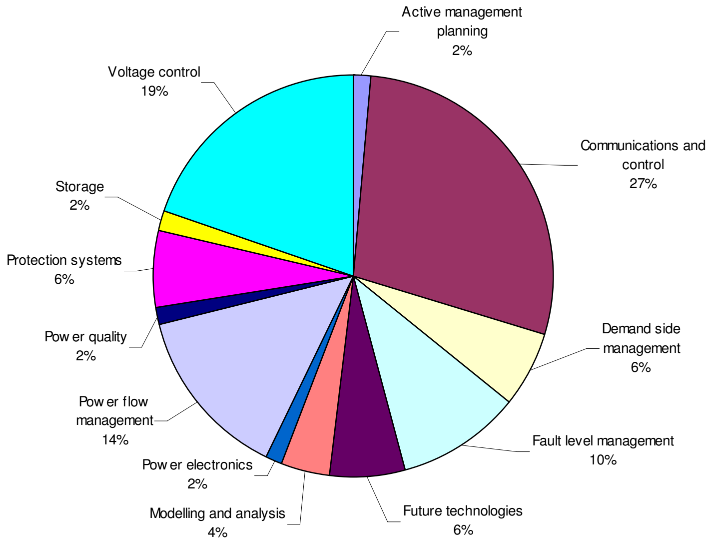

Figure 18: 2006 ANM Register content by classification of technical focus

As shown in Figure 19, 65% of the projects included within the ANM register are research activities; in total, 78% of all activities are in the research and/or development phase. Figure 19 shows that 8% of the projects in the register have made it to a stage where the project can be tested and assessed in a trial or pilot. Fully deployed projects account for 14% of the register's content. These results show that the majority of activities are not likely to be rolled out in the near term. Indeed, normal timescales from research to full deployment are in the order of 10 years, according to Ingram *et al* (Ingram *et al*, 2005).

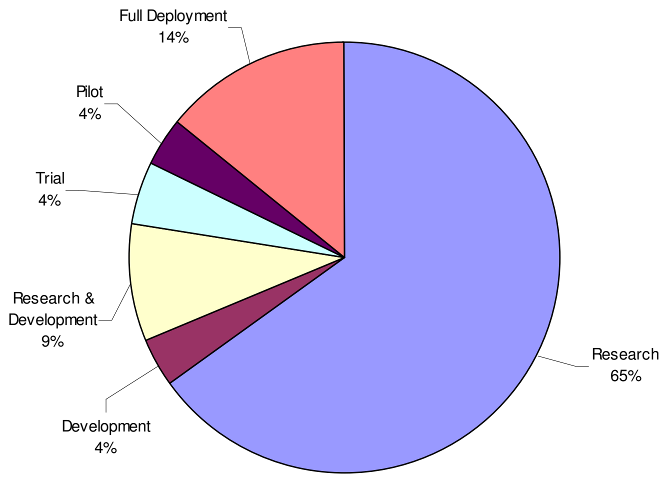

Figure 19: Register content by each activity type

If ANM is to play a role in meeting targets for the connection and operation of renewable and distributed generation then firstly the systems or technologies that are available for deployment and anticipated timescales for other projects need to be identified. To investigate the type and status of the register contents a 'Project Maturity Index' (PMI) was introduced. The PMI is a value that represents the activity type and activity status. At the lower end of the scale will be ongoing research activities; the top end will comprise of completed, fully deployed projects. Projects that encompass both research and development activities will be given either a PMI of 3 or 4 (for ongoing and completed projects respectively). The project maturity indices are shown in Table 7.

Table 7: Project Maturity Index for all types and status of projects

Project Maturity Index	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Activity Status	Ongoing	Completed	Ongoing	Completed	Ongoing	Completed	Ongoing	Completed	Ongoing	Completed
Activity Type	Research		Development		Trial		Pilot		Full Deployment	

In the previous sections of this chapter the ANM prior art was introduced, the following sections provide insight into the maturity of power flow management and communications and control activities as these are of most relevance to the work presented in this thesis.

3.3.2.1 The Maturity of Active Power Flow Management Activities

It can be seen in Figure 20 that many of the power flow management projects are still in the research and development stage. However, there are five projects fully deployed that are installed to perform APFM.

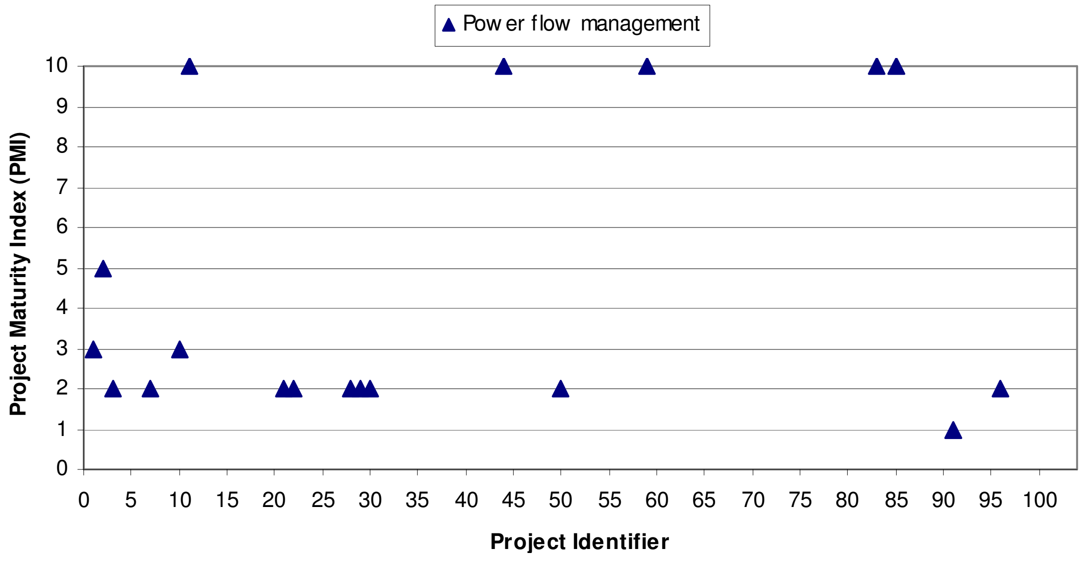

Figure 20: Active power flow management projects versus project maturity index

There is a deployed system on the Scottish transmission network that acts in accordance with the post-outage measured power flow solution described in ETR 124 (project identifier number 11 in Figure 20). The participating wind farm is disconnected from the network when measured power flow exceeds the (N-1) capability of the network. Little information of this project is available in the public domain; the author was provided with some information regarding this scheme by the network operator (Scottish and Southern Energy plc) but is unable to reveal further details of the scheme due to confidentiality.

The active constraint system for an offshore wind farm as described by Liew and Moore (Liew and Moore, 2005) and discussed previously is a fully deployed APFM activity (project identifier number 44 in Figure 20). The constraint management system in Greece that was discussed previously that is presented by Kabouris and Vournas (Kabouris and Vournas, 2004) is also a fully deployed system (project identifier number 59 in Figure 20).

The other deployed activities are related to systems for monitoring temperature and loading of transformers and cables to facilitate the calculation of a real-time or dynamic rating. These devices to not constitute an APFM scheme but could form one constituent element, requiring an APFM scheme to control the output of participating generators to meet the dynamic ratings rather than the static or seasonal rating.

Project 2 is concerned with the work of the author of this thesis with respect to the trial of an APFM scheme to actively manage power flows on part of the North-Scotland network. This is discussed in more detail in subsequent chapters of this thesis.

The APFM solutions included in the 2006 ANM Register that are fully deployed are bespoke systems, tailored to a specific network need. If more APFM solutions are to be deployed on distribution networks then more generic control architectures, platforms and algorithms are required, that can be gradually adopted and implemented as the needs of the network operator and DG developers evolve.

It appears that despite the presentation of short-term solutions by Collinson *et al* (Collinson *et al*, 2003) there has been little or no adoption of such solutions. The deployed systems that involve regulating the output of participating generators are simplistic, but the cost-benefit is clear and can be demonstrated, for example, through curtailment modelling by Kabouris and Vournas (Kabouris and Vournas, 2004). The simple approach and the supporting analysis are important lessons to be taken into the development of any APFM solution and are factored into the work presented in this thesis.

It is clear from Figure 20 that a gulf exists between the deployed systems for APFM and the projects that remain at the research and development stage. Emerging research and development concepts and solutions that are suitable for trials need to be identified; in addition, DNOs need to be incentivised to try out new solutions without being exposed to unacceptable risk.

The implementation of an APFM solution will ultimately be reliant upon a suitable communications and control infrastructure. Therefore, the next section explores the maturity of activities identified in the 2006 ANM Register relating to communications and control.

3.3.2.2 The Maturity of Communications and Control Activities

Communications and control projects form the largest area of technical focus of ongoing ANM activities, accounting for 27% of all the projects reviewed. As can be seen in Figure 21, many of the projects concerned with this technical area are at the research and development stage (i.e. Project Maturity Index 1-4).

Communications and control is a difficult area for realising the outcomes of research as the SCADA systems currently employed by DNOs are established products. These products are developed to meet the existing needs of the DNOs by individual manufacturers. Therefore, it can be difficult for new systems to be tested on existing networks, due to perceived risk by the DNO and the high costs associated with such an activity. It seems that SCADA system providers are unlikely to develop ANM capability and have not been involved in research and development in this area, but it is likely that all will eventually explore offering ANM capability within core SCADA offerings. This makes it more likely that initial ANM schemes will be independent of existing SCADA solutions.

Figure 21 presents the maturity of the communications and control projects included within the 2006 ANM Register. It can be seen that there are a number of projects at varying stages of development, including some that are deployed.

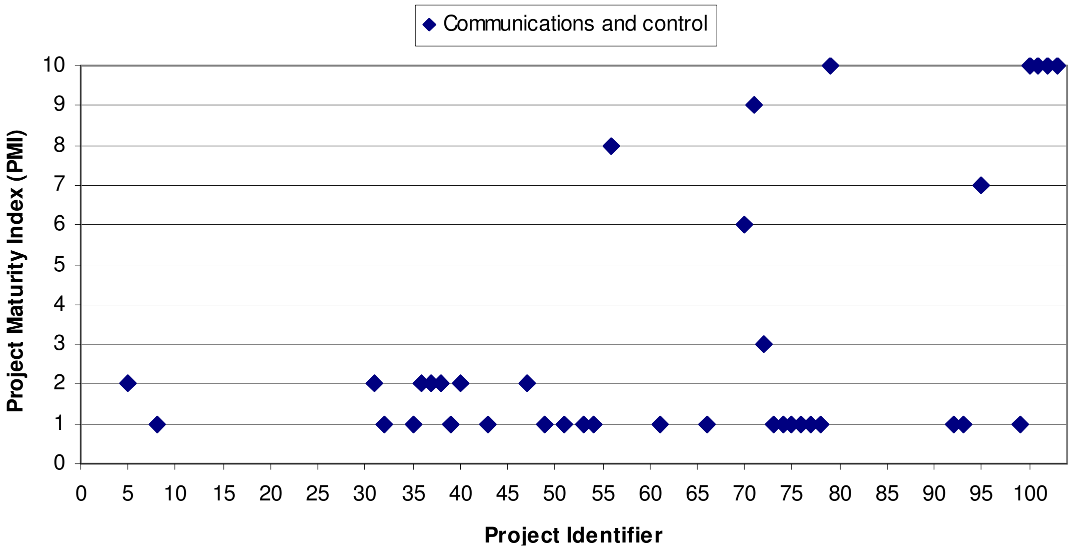

Figure 21: Communications and control projects versus project maturity index

Smith (Smith, 2001) describes the outcome of a project concerning a generic SCADA system that can be applied to individual wind farms, irrespective of technology or manufacturer (project identifier number 56 in Figure 21). The generic SCADA system allows local and remote control of wind farm functions and gathering and analysis of operational data. Effective operation, monitoring, control and reporting of wind farms (and other forms of DG) will be crucial to the successful deployment of ANM schemes and technologies.

Liss *et al* (Liss *et al*, 2002) describe the development of innovative distributed power interconnection and control systems (project identifier number 70 in Figure 21). This work was undertaken as part of the programme of activities of the National Renewable Energy Laboratory through the United States Department of Energy. The goal of this project, which was completed in 2002, was to develop and demonstrate cost-effective solutions in terms of products, software and communications to improve the economic case for greater use of distributed energy resources. In addition, the provision of operational benefits to the network operator through participation in resource planning and ancillary services is identified as a crucial goal. Liss *et al* report on the outcomes of the first year of a three year programme of activities to manage multiple DG units as a virtual power plant, with the goal of better economic performance and efficiency. The focus of the activities appears to be on-site small-scale generation (<2MW) and the proving of establishing monitoring and communications links. The method of decision making to support the control of the participating DG units is not discussed in detail but appears to be logic based. Such systems operating in tandem with ANM could be an effective method of deploying multiple small-scale resources in areas where grid constraints exist.

Regan *et al* (Regan *et al*, 2003) describe the Distributed Energy Neural Network Integration System (DENNIS) project, which is also undertaken by the National Renewable Energy Laboratory through the United States Department of Energy (project identifier number 71 in Figure 21). The purpose of DENNIS is to demonstrate a neural network control system for managing multiple small DG units (at the household level) as a virtual power plant. The aggregated community of DG units is managed by an intelligent "neighbourhood controller" to meet individual power requirements and to sell power or other services to a utility. DENNIS is mainly focused on predicting and understanding the energy requirements of a building (e.g. dwelling, office etc) and how on-site generation should best be matched to these requirements, considering the conditions on the grid and prevailing weather conditions. One may conclude that DENNIS is therefore not likely to play a role in the large-scale integration of DG units at higher voltage levels. It is unclear how effective the training of the neural network proved to be or how scalable the approach is for application to wider system problems. ANM schemes may have to interact with such systems in the future.

Encorp[5] have brought to market multi-site remote dispatching software for virtual power plants (project identifier number 79 in Figure 21). This work is also based in North America and is focused on the integration of small-scale generation at the household or building level. The Encorp software allows multiple sites to be grouped by the network operator and treated as a virtual power plant. Different groups can be formed for different purposes. It is unclear how the operation of such

[5] www.encorp.com (accessed 25/10/2009)

a scheme can be made equitable and be implemented fairly for all participants. The accompanying pay and reward mechanisms will likely be very complex and are not discussed in the literature. However, the software communicates to the network operator what the current generation level is, how much capacity can be brought online and how much can be shed if necessary. Such information will be required by ANM schemes, accompanied by understandable and automated decision making.

The remaining deployed systems in Figure 21 are all SCADA systems available from different manufacturers as products. All claim to be able to perform ANM functions within the existing SCADA systems but there is little or no evidence of this. It has been recognised by Ingram *et al* (Ingram *et al*, 2005) that existing SCADA systems may possess characteristics required for ANM but that network operators are either unaware of the potential or are choosing to implement separate solutions.

Further work is required in order to ascertain the actual capabilities of existing SCADA systems, and the desired requirements of communication and control schemes for ANM that are in development. Considering this and the results presented in Figure 21, it appears that tried and tested communications and control solutions for ANM are not available to the market. Much effort has been directed, particularly in North-America, towards the integration of multiple distributed energy resources through virtual power plants. Deployed virtual power plant systems will provide valuable lessons regarding data management and communication and control integration, ANM schemes may have to interface with such systems in the future.

3.3.3 Recent Developments in Active Power Flow Management

Several activities relating to APFM have taken place in the last two years (i.e. since 2007) when the ANM register was generated and published; the significant elements of these activities are described in this section.

The Autonomous Regional Active Network Management System (Aura-NMS) project is concerned with the development of an advanced Distribution Management System (DMS). Aura-NMS is developing algorithms to support automatic restoration, voltage control and power flow management. At the core of the DMS is a multi-agent system that arbitrates between the goals of the different algorithms, which are essentially separate and use different techniques, as described by Davidson *et al* (Davidson *et al,* 2009a; 2009b).

As part of the Aura-NMS project, Dolan *et al* (Dolan *et al*, 2009a) discuss two candidate techniques for power flow management; approaching the problem as a constraint satisfaction problem (solved using constraint programming techniques) and as a current tracing approach. Dolan *et al* compare the two approaches in terms of the magnitude of resulting curtailment imposed on generators and total computation time. When using the constraint programming technique, the authors define bands (in MWs) of generator output that the algorithm uses to create a list of possible solutions to the prevailing thermal constraints. The results show that the banding of the generator outputs for the constraint programming technique is a determining factor in the level of curtailment experienced – the larger the band, the greater the curtailment, as would be expected. The current tracing approach, on the other hand, generates a single result, which is in the mid range of the curtailment results for constraint programming. All solutions are found in less than one second of computation time; therefore, it can be concluded that computation time is not anticipated to be a serious issue for the use of such techniques. Davidson *et al* (Davidson *et al*, 2009c) provide a closer look at the constraint programming technique considered in Aura-NMS.

In another paper published on the Aura-NMS project, Dolan *et al* (Dolan *et al*, 2009b) discuss the use of an Optimal Power Flow (OPF) technique for APFM. The authors identify several limitations of existing OPF techniques, including flexibility, adaptability and performance. It is also discussed how OPF techniques require 'good' data to provide a robust solution – such data is often not available at distribution and the performance of the OPF may suffer as a result. It is also recognised that in general, the network operator cannot normally regulate the output of DG units connected to the distribution network (indeed, control is often limited to on/off requests during system outages) and that the distribution network operator (DNO) is likely to prefer robustness to optimality. Despite these issues, the authors identify OPF as warranting consideration for application to APFM. The authors investigate the use of a linear programming technique to perform Thermal Optimal Power Flow Management (TOPFM). As part of the investigation of TOPFM, the authors consider the Last In First Out (LIFO) principle of access, by assigning increasing cost parameters to each generator to connect (making the last to connect the most expensive and therefore the first to be curtailed when thermal constraints are breached). The outcomes of the study show that TOPFM has promise for application to the APFM problem; in particular the ability of the technique to cope with a variety of network topologies is noted as significant. The authors identify future work relating to how the TOPFM technique relies on an accurate power system model (that reflects the real-time topology of the system), measurement error (including state estimation error) and data skew, amongst others.

Yip *et al* (Yip *et al*, 2008) describe the application of a Dynamic Line Rating (DLR) system applied to a 132kV circuit between Boston and Skegness in England. The deployment of the system permits a larger penetration of wind energy, as the rating of the circuit is calculated based on real-time weather conditions. An automatic system instructs a wind farm to regulate output to meet the prevailing dynamic thermal rating of the circuit; if the wind farm does not respond appropriately then the system will trip the wind farm off the system. The authors state that the deployment of such a system can enable around 30% more generation when compared to the fixed seasonal rating.

Jupe *et al* (Jupe *et al*, 2008) assess a number of different approaches to APFM. The internal workings of the APFM scheme are based on the use of power flow derivatives (i.e. sensitivity factors). The authors compare traditional network reinforcement, a basic tripping solution and three types of APFM scheme to a fairly simple single generator unit example. The APFM schemes consider both regulating and tripping generator units and also the application of static, seasonal or dynamic line ratings. As would be expected, the authors show that the application of DLR increases the MWh performance of the generator.

Jupe and Taylor (Jupe and Taylor, 2009) discuss and assess several commercial strategies that could be utilised by Active Constrained Connection Managers (ACCM), which in essence deliver the application of APFM. In this thesis, the author refers to such strategies as 'Principles of Access'. Jupe and Taylor present the following principles of access:

- Last In First Off
- Percentage of total DG output
- Equal percentage reduction of present power output
- Most appropriate technical strategy

'Last In First Off' involves giving priority access to those generators that connect (or sign their connection agreements) first. 'Percentage of total DG output' involves curtailing the output of participating DG units based on their percentage share of the total actual output of all DG units under the control of the APFM scheme. 'Equal percentage reduction of present power output' means the curtailing of all participating DG units by the same percentage of their full rated output. 'Most appropriate technical strategy' would involve the curtailing of the DG unit that the power flow at the constraint location is most sensitive to.

Jupe and Taylor (Jupe and Taylor, 2009) found that constraining the DG unit according to the 'most appropriate technical strategy' resulted in the greatest overall benefit in terms of aggregate group energy production. The authors recognise that APFM schemes are required that support a number of contractual arrangements with regard to principles of access. For example, the authors present the idea that cross-payments could be established between DG units to support the 'most appropriate technical strategy'. This is further indication of the potential changes to the commercial environment that could provide the context for APFM.

Neumann *et al* (Neumann *et al*, 2008) describe work to integrate the ACCM approach presented by Jupe and Taylor (Jupe and Taylor, 2009) with a dynamic thermal rating system. The application of dynamic thermal ratings allows the real-time thermal capability of the distribution network to be accessed by DG units that are subject to APFM. Once the weather dependent thermal capability of sections of overhead lines is known, the authors describe the allocation of real and reactive power set-points to participating generators (calculated using a load flow solution), either from controllers installed on the network or in the network operator's control room. The system has been designed to intertrip participating generators if the capacity of the network is breached at any time. The authors anticipate an open-loop trial of the approach to APFM in 2009. The outcomes of this trial will be of significant interest to the ANM community.

Michiorri and Taylor (Michiorri and Taylor, 2009) describe an extension to the dynamic thermal ratings approach outlined by Neumann *et al* (Neumann *et al*, 2008), which involves forecasting the real-time thermal ratings of an area of network using weather forecasting data. By treating each component of the network in isolation and taking due consideration of the surrounding terrain and weather forecasts, the authors are able to use 'thermal state estimation' to determine the ratings of circuits across a wide geographical area. The implication of this technique is that if the error in the estimation algorithm can be identified and factored into how the network operator uses the information in a satisfactory way, then there is a reduced requirement for new instrumentation of the network and greater visibility is afforded of existing infrastructure. Such novel techniques hold promise for facilitating APFM and maximising the use of existing network infrastructure.

3.4 Research Challenges for Active Power Flow Management

This thesis and the contributions described herein are concerned with Active Power Flow Management (APFM). Building upon the discussion presented previously regarding the state of the art in ANM, the following section describes the fundamental challenges for APFM that require to be addressed. Not all of these are addressed by the completed work of the author; some will form the basis for future work and are also relevant to other aspects of ANM.

3.4.1 Identification of Suitable Algorithms and Control Techniques

Methods of translating the breaching of power flow constraints (i.e. the maximum current carrying capability of a section of the network) to DG output reduction signals are required. Such control algorithms must take account of network topology, the nature and operating point of participating DG units and the commercial relationships between the network operator and each participating DG unit, and between the DG units themselves. This is one of the greatest research challenges associated with APFM; the relationship between constraints and the multiple parties or ‘actors’ that can be controlled to remove constraints is applicable to the entire ANM domain. Some possible APFM algorithms or techniques that could be employed to allocate power flow constraints to one or more participating DG units are:

- Allocation based on direct measurement
- Allocation based on sensitivity factors
- Allocation based on current tracing
- Allocation based on OPF or another optimisation technique
- Artificial Intelligence techniques

Allocating curtailment to participating DG units based on direct measurement is the method adopted by both Liew and Moore (Liew and Moore, 2005) and Kabouris and Vournas (Kabouris and Vournas, 2004) and the only technique currently deployed to perform APFM. The simplicity of this type of deterministic approach (based on a set of simple rules) makes it favourable to the DNO and participating DG developers. The first generation of APFM schemes exhibit this form of direct measurement of the constraint breach and the allocation of the required reduction to one or more DG units. For these reasons, the use of direct measurements is the focus of the work presented in this thesis.

The allocation of real power curtailment to participating DG units could be performed according to sensitivity factors. This would be similar in theory to the approach to solving voltage constraints described by Zhou and Bialek (Zhou and Bialek, 2007) or described by Jupe *et al* (Jupe *et al*, 2008) with regard to APFM. There is an added online computational burden associated with the adoption of such a scheme, which would be reliant on an accurate distribution model and some form of state estimation, if enough measurements were not available, to allow load flow solutions to be performed and sensitivity factors calculated. The use of sensitivity factors within an APFM scheme is a useful means of associating DG units with constraints, although such a purely technical solution would require a thorough investigation of commercial factors. However, sensitivity factors could be utilised by a direct measurement scheme to translate measured constraint breaches to required reduction signals. This is not considered within this thesis as the author is firstly tackling the issues associated with the use of direct measurement.

Current tracing could be performed to calculate the contribution of individual DG units to overloaded sections of the network. Bialek (Bialek, 1996), Kirschen and Strbac (Kirschen and Strbac, 1999) and Kirschen *et al* (Kirschen *et al*, 1997) provide a sound starting point for investigating such techniques, although the authors are more concerned with identifying flows for the purposes of allocating costs and supporting market operation. A current tracing approach to APFM results in a greater analytical burden and requirement for monitoring or estimating all real-time DG output and load on the network. Once the contribution of each DG unit to a constraint is known, the appropriate set-point for real power production can be calculated and issued to each DG unit. As with sensitivity factors, a number of issues remain to be resolved for current tracing to be used within an APFM scheme, which warrant further investigation, as discussed by Dolan *et al* (Dolan *et al*, 2009a).

Strbac *et al* (Strbac *et al*, 2002) investigate the use of OPF to regulate DG units within the prevailing constraints on a test network. Such analytical techniques require further exploration and adaptation to be used in an online APFM system. OPF will provide benefit in situations where multiple constraints (i.e. voltage and thermal) are to be met through one set of control actions. OPF engines will produce a single solution to each scenario, although could be run with adjusted objective values to produce multiple solutions. There are several issues that remain to be resolved concerning the use of OPF in an APFM scheme, which were presented by Dolan *et al* (Dolan *et al*, 2009b) and discussed previously. The use of OPF within an APFM scheme warrants further investigation but is not considered within this thesis.

It is also likely that techniques employed in communications networks and computer science, particularly Artificial Intelligence techniques, warrant investigation for their application to ANM. For example, Davidson *et al* (Davidson *et* al, 2009c) describe the use of constraint satisfaction programming as a means to identifying solutions to remove multiple prevailing voltage and thermal constraints. This thesis does not consider the application of artificial intelligence techniques, which are identified as a possible area of future work.

The work presented in this thesis stems from the perspective of the author that simple APFM schemes can be developed, without the use of artificial intelligence techniques or other complex methods. The development of simple, but well thought through solutions will stand a better chance of achieving deployment, contributing to the development of distribution networks and opening the door for the application of more advanced and holistic schemes in the future.

3.4.2 Active Power Flow Management Schemes for Multiple DG Units

Previously in this chapter the solutions for actively managing individual DG units were presented. There is a much greater degree of complexity involved in specifying and implementing multi-generator APFM schemes and there are no generally accepted means of providing such a solution. The following challenges remain to be addressed for the connection and operation of multiple DG units through APFM:

- Existing APFM schemes for individual DG units need to be assessed in terms of the elements that are applicable to the multiple DG unit problem
- Technical and commercial factors need to be considered in the design of APFM schemes
- APFM architectures need to be devised that allow different algorithms, control techniques and multiple DG units to be deployed to meet commercial contracts
- The evolution of APFM schemes due to network or generator developments must be incorporated within the proposed architectures, this will allow the 'short-term' solutions in the prior art to become more standard business as usual applications
- Principles of access are required that define how an APFM scheme will allocate curtailment to multiple DG units

3.4.3 Principles of Access to Capacity

APFM is concerned with managing the access of DG units to the network within network constraints. This implies that either the behaviour of the DG unit will be modified or ultimately that the real power production of the DG unit will be modified based on network constraints. 'Principles of Access' are an integral part of an APFM scheme and define how the output of one or more DG units is related to the constraints on the network. In the document 'Options for Operational Rules to Curtail Wind Generation', the Electricity Supply Business (ESB) in Ireland (ESB National Grid, 2004) discuss the options for curtailing multiple wind generators. These rules are also applicable to other forms of DG units participating in an active network. ESB identify that any adopted operational rules for curtailment should:

- Facilitate the operation of a safe, secure and reliable power system

- Be equitable
- Be efficient
- Be clear and transparent
- Support compliance with both the Grid Code and Distribution Code
- Be feasible to implement for all curtailment scenarios
- Comply with relevant laws

In addition to these criteria, there is a requirement for operational rules for curtailment to be sustainable, meaning that the rules implemented can be adjusted or developed to permit expansion of the APFM scheme, due to further generator connections or changes to the network. This and the conditions presented by ESB are the criteria that should be used to assess principles of access.

Some principles of access were discussed in section 3.3.3 in the context of the work undertaken by Jupe and Taylor (Jupe and Taylor, 2009). The principles of access presented by ESB are more complete and incorporate those presented by Jupe and Taylor; ESB present the following five operational rules for curtailment:

1. In order of size
2. Equal percentage basis
3. Market generated
4. Based on connection date
5. Based on shedding rota/auction

'In order of size' involves curtailing the participating DG units in accordance with their relative size to each other, i.e. either the largest or smallest first. This may be useful in some situations as infrastructure could be installed for a small number of large DG units, rather than a large number of small DG units. The commercial aspects of such a principle could be complex, requiring some form of compensation payments for those curtailed. As the likelihood of experiencing curtailment for one DG unit would be dependent on the surrounding DG connection activity. 'Equal percentage basis' can be considered to be equivalent to the 'Percentage of total DG output' or 'Equal percentage reduction of present power output' principles discussed in section 3.3.3 in the context of the work undertaken by Jupe and Taylor (Jupe and Taylor, 2009). 'Based on connection date' can also be considered to be the same as Last In First Off (LIFO) that is also discussed with reference to the work of Jupe and Taylor. 'Market generated' rules for curtailing DG units would require the implementation of a new market mechanism, perhaps based on the lowest overall constraint cost. Such a mechanism does not currently exist and could not be implemented easily. Similarly, 'Based on a shedding rota/auction' could require similar new commercial and regulatory arrangements that would prevent its near term use.

The principles of access presented by ESB are interestingly separated from the algorithms or techniques available to perform curtailment of DG units. The implication is that such commercial rules require independence from the technical method of delivering APFM, e.g. allocation based on direct measurement, sensitivity factors, current tracing or optimisation techniques. This has implications for the overall architecture of APFM solutions, which must be adaptable to different commercial agreements and environments.

3.4.4 Planning for Active Power Flow Management

Traditional methods of planning distribution networks have been mainly concerned with security of supply and cost minimisation. There is much activity in the research community regarding the issues associated with planning for the connection and operation of DG, some of which was discussed in Chapter 2. However, these analytical techniques do not allow the DG developer or DNO to fully understand how any APFM scheme will work in real time and the implications for commercial arrangements. The main challenges for APFM planning are:

- 'APFM in the loop' planning tools that address the operation of an APFM scheme and accompanying network performance, DG units and network components over different time periods
- To allow trade-offs between operational expenditure and capital expenditure to be explored
- Through-life cost comparison of different APFM solutions and conventional network reinforcement (it may be that network reinforcement represents the preferable long-term economic (through-life) solution for connecting a large amount of renewable energy)
- The steps from passive to active distribution networks need to be studied and understood to allow DNOs to keep sight of the development and evolution of their network
- A framework for modelling and simulating APFM should be developed that details the necessary data flows and steps required to identify, appraise and deliver an APFM solution
- Planning departments of network utility companies require the resource, time and incentive to consider APFM beyond the requirement to offer the lowest cost connection solution to the DG developer. It is often the case that existing arrangements leave little room for considering, and recovering the costs of considering, alternative connection solutions such as APFM

3.4.5 Incorporating Active Power Flow Management within the Existing Distributed Generation Connection Process

This section considers more closely how APFM impacts on the various stages of the DG connection process, by considering the impacts of ANM in general. Jarret *et al* (Jarret *et al*, 2004) provide a guide and route map to DG developers looking to connect to a distribution network in the UK. The guide provides an overview of costs, timescales, competition (contestable and non-contestable works) and goes into some detail on technical aspects and system effects of DG in the appendices to the guide. Jarret *et al* present a high level overview of the connection process, as shown on the left hand side of Figure 22.

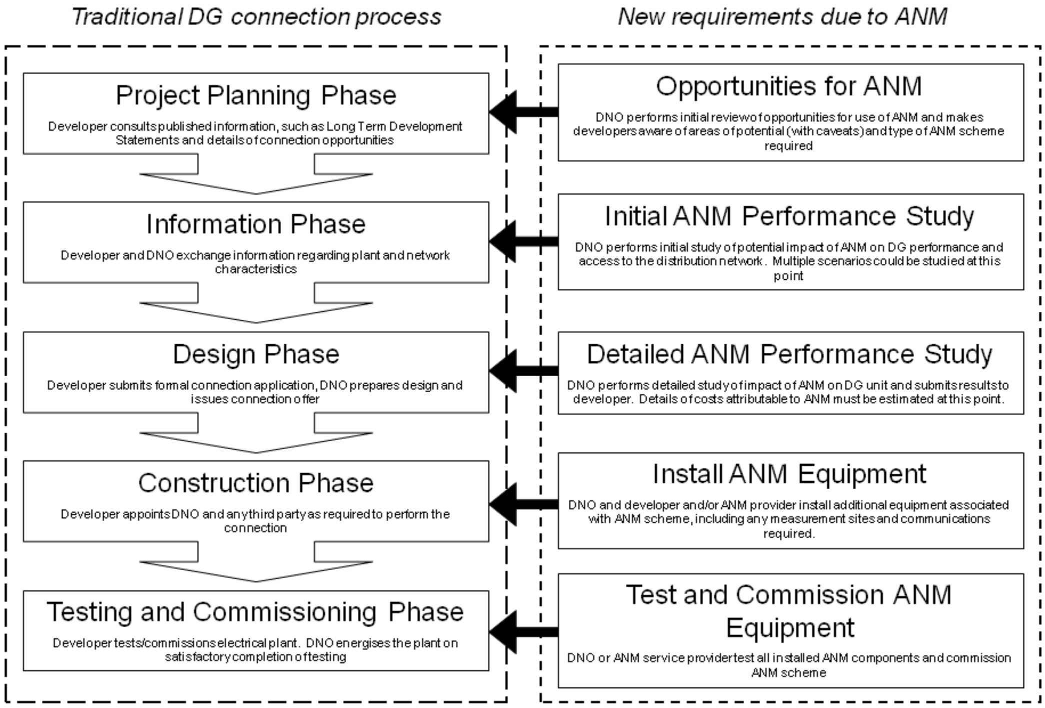

Figure 22: Traditional DG connection process and new requirements due to ANM

Based on the process identified by Jarret *et al* and the work undertaken in this thesis, the author identifies the new requirements due to ANM on the right hand side of Figure 22. At each stage of the traditional connection process for DG, ANM introduces new challenges. As was discussed above for APFM planning, a significant challenge lies in determining how DNOs will consider ANM as one of the options available to them when considering new generator connections.

The opportunity for ANM needs to be identified at the 'Project Planning Phase'. This will require an indication of the scope and likely costs for ANM to be made available to the DG developer, in addition to the likely implications, such as generator curtailment. It is unclear whether DNOs in the UK are able to proactively identify opportunities for ANM prior to receiving generator connection applications (to encourage uptake in a particular network area) or only identify potential ANM solutions on a project by project basis. At present, DG developers refer to the Long

Term Development Statement of the DNO for information and network data, and then use this to identify issues associated with connecting to the network at a particular location and voltage level. This may or may not identify areas where there is no grid capacity available for new DG connections.

At the 'Information Phase' the DNO and DG developer exchange information relating to the nature of the connection and technical equipment involved. If ANM is to be considered, there is a new requirement on the DNO (or a 3rd party) to support an initial appraisal by performing a simple study of the ANM scheme and the impact on the proposed connection. This will allow the DG developer to decide whether to proceed with the connection process.

At the 'Design Phase' the DNO reviews all the details of the connection, performs the appropriate power system studies and issues a connection offer to the DG developer. If ANM is to be considered as a connection option, the DNO (or a 3rd party) will be required to perform a more comprehensive study of the impact of ANM on the DG unit, including a description and cost details of the additional components required to support ANM, such as measurement devices and communications links.

At the 'Construction Phase' all electrical and civil works are undertaken to build the project. If additional ANM equipment is required it may have to be installed at several sites on the DNO's network (the DG substation, measurement points on the network and other substations). Dedicated communications paths between ANM sites may have to be installed, separate from the normal communications route between the DNO and the DG site.

The installation of ANM will add an additional burden during 'Testing and Commissioning Phase'. All ANM functions and associated communications paths and measurements will be required to be tested, as will the fail safe nature of the ANM scheme.

3.4.6 Quantifying the Benefits and Effects of Active Power Flow Management

As described above, there is a requirement during the 'Design Phase' to analyse and consider the implications of adopting APFM. The economic benefits to all parties must be evident for APFM to be the preferred connection option. The following challenges exist for quantifying the benefits and effects of APFM:

- Analytical tools are required that allow DG developers to easily determine the impact of curtailment on project revenue streams. Such tools could consider the sensitivity of the DG project to changes in financial incentives, future electricity prices and various network scenarios.
- Capital and operational costs are required to allow the long term suitability of APFM solutions to be determined and compared to network reinforcement solutions
- Strbac *et al* (Strbac *et al*, 2007) speculate that the wider system benefit of deploying APFM is in a reduced requirement for generation capacity and network capacity. The wider transmission system impacts of increased DG have been discussed previously in Chapter 2; however, several areas require further work:
    - Identifying the role of active networks in the market from the perspective of individual or collective DG units, contracts with suppliers and interaction with different market mechanisms
    - Active networks providing network services such as system balancing, frequency response, islanding and reactive power support
    - The coordination of multiple active networks and the management of power exchanges between distribution and transmission
    - The impact of APFM adoption on total system losses
    - The potential of APFM to improve network reliability and security

3.4.7 Deployment of Active Power Flow Management

The gradual deployment of APFM is likely as there are no universally accepted systems or technologies that can manage all the technical constraints associated with DG connection. Therefore, individual systems that manage one or more DG units within one technical constraint are likely to emerge first. However, DNOs are unlikely to deploy APFM systems for individual DG connections unless the installation can evolve to include other DG units and accommodate future changes to the network (e.g. reconfiguration, load increase/decrease, reinforcement etc). The problem of supporting this gradual evolution can be supported by employing an appropriate APFM control architecture.

Both Overbeeke (Overbeeke, 2002) and Roberts *et al* (Roberts *et al*, 2003) propose the identification of a cellular or zonal ANM architecture. Each cell or zone is defined by locally occurring control actions, communications and measurements and is interconnected to the rest of the distribution network and potentially to other cells or zones. Therefore, the cells or zones can operate independently or collectively. In particular, Roberts *et al* discuss how the cell or zone concept can support gradual and incremental deployment of ANM. Overbeeke discusses the nature of such cells, that they are self-managing but not necessarily responsible for providing all of their own energy requirements. Overbeeke also borrows from biology the notion of cells acting independently and collectively, but also gradually evolving and cell division occurring as needs emerge or operating limits are reached. This is considered by the author of this thesis to be an appropriate manner in which to consider the deployment and subsequent development of APFM schemes.

As has been discussed previously, many of the APFM solutions found in the literature are untested and remain to be deployed on actual distribution networks; a number of challenges remain for APFM deployment:

- An APFM architecture involving the application of zones or cells is required to support the resolution of individual and coincident constraints

- A method of identifying and evolving control zones or cells is required to incorporate future DG connections and changes to the network
- The APFM schemes for individual DG units need to be tested and endorsed by the industry to ensure best practice is shared and both technical and commercial lessons are learned
- The different options for principles of access to network capacity need to be considered by the industry to ensure a fair operating regime for all actively managed generators and network operators who deploy APFM, this will prevent the commercial complexities holding up APFM deployment
- The design, installation, servicing and warranty of APFM schemes falls out with the existing DNO capability and needs to be provided or resourced
- APFM solutions must be comparable to other connection solutions, namely network reinforcement
- The real and potential benefits for each party must be demonstrated and regulatory policy evolve to recognise potential system-wide and societal benefits
- New commercial and contractual arrangements are required to deploy APFM solutions, to allow the DNO to act more as a Distribution System Operator, who contracts with DG units and other customers to provide services to assist in network operation

3.5 Chapter Three Conclusions

This chapter has provided an overview of APFM, presenting it as a fundamental component of ANM. It has been found that the majority of activities relating to APFM are at the research and development stage. Despite the relatively large amount of activity in the area of APFM, there are few implemented solutions for the connection and operation of DG. It is anticipated that the first generation of APFM schemes will focus on solving one type of network technical constraint, in a manner that allows gradual deployment and the inclusion of additional DG units or changes in the network. Therefore, ANM schemes concerned with only one aspect of ANM (i.e. power flow management, voltage control and fault level management) are likely to emerge first.

The focus of the research described in this thesis is APFM. APFM schemes are required when the thermal capacity constraints of the distribution network are put under pressure due to the connection and operation of DG. The state of the art in APFM has been presented in this chapter; some conclusions have been drawn from the literature reviewed. These have been used to direct research focus and are now discussed.

The use of direct measurement of overload and the allocation of the output reduction required to remove the overload to DG units in the form of curtailment is a method which is simple and understandable, which is likely to increase the likelihood of adoption. This should be explored further for the application of APFM to real-time constraints for multiple DG units.

The impact of APFM on network performance should be considered and studied as part of evaluating the suitability of APFM as a solution to meeting thermal capacity constraints.

A combination of preventive and corrective control actions can be utilised to perform APFM and provide the network operator with an appropriate level of network security. The principles of preventive and corrective control require new operational strategies to be developed that support the connection and operation of multiple DG units.

As APFM is gradually implemented, zones should be identified on the distribution network to perform APFM control. Such zones aid in the process of defining the transition of the network to becoming increasingly ‘active’. APFM zones will likely require monitoring, communications and control facilities and will exist independently, interactively or be nested within each other. A method of defining and characterising APFM zones is required.

Analysis tools are required that demonstrate the installed capacity (MW) and energy produced (MWh) and energy curtailed (MWh) by DG units connecting to the distribution network through APFM. Such information should be considered in terms of the impact on the cash flows associated with the participating DG unit.

APFM systems should be subject to trial and testing to prove the algorithms and demonstrate the workings and reduce some of the risk to the host DNO, and the perceived risk by the power industry. This risk can be further reduced by implementing APFM separately from existing SCADA systems on hardware that DNOs are used to working with, such as Programmable Logic Controllers (PLCs). The simpler the APFM algorithm the better, allowing DNOs to understand and influence the operation of the APFM scheme as required and therefore not allowing complexity and the associated risks of new complex systems to become a barrier to deployment.

3.6 Chapter Three References

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4 Specification of an Active Power Flow Management Scheme

4.1 Chapter Summary

An Active Power Flow Management (APFM) scheme is presented in this chapter that is concerned with the connection and operation of multiple DG units within the real-time thermal constraints of the network. The APFM scheme can be applied to existing networks, newly built network infrastructure and different voltage levels. The focus of the APFM scheme is the connection and operation of DG units beyond the NFG capacities identified in Chapter 3, into Regulated Non-Firm Generation (RNFG) capacity. The chapter begins by reiterating the high-level principles of APFM, followed by an introduction to RNFG units. The APFM control philosophy is then presented, including APFM zones, principles of access to capacity, APFM algorithms (for preventive and corrective control) and APFM operating margins. The practical operation of the APFM scheme is then discussed.

4.2 High-Level Active Power Flow Management Specification

In Chapter 3 the fundamental research challenges for APFM were introduced, stemming from the technical and commercial challenges associated with the connection and operation of DG presented in Chapter 2. Based on these foundations, a high-level specification for APFM exists, comprised of the following elements:

- APFM involves the real-time regulation and/or tripping of DG units
- APFM can make use of capacity beyond the N-1 capacity of the network
- APFM takes account of real-time variation in demand, rather than assuming the minimum or maximum demand condition

- APFM involves preventive and corrective control actions to manage network constraints
- APFM can support different principles of access to capacity
- APFM can be implemented gradually, according to a zonal structure, with zones emerging as further DG units connect to the network or the network changes

The APFM scheme presented in this thesis meets this high-level specification through the connection and operation of Regulated Non-Firm Generation (RNFG). The introduction of RNFG units provides a means of increasing the amount of generation that can connect to existing or planned electricity networks and the principles can be applied to existing generator connections. RNFG units are introduced in the following section.

4.3 Regulated Non-Firm Generation

Chapter 2 presented the limits on the capacity for the connection of Firm Generation (FG) units. In Chapter 3 some methods were presented for extending the capacity for DG connections into Non-Firm Generation (NFG) capacity. These solutions were concerned with individual DG units and typically involved the disconnection (tripping) of the DG unit when capacity constraints were breached, e.g. when a circuit outage occurs. Regulated Non-Firm Generation (RNFG) units are proposed here as DG units that have their real power output varied in real-time to meet the prevailing thermal constraints on the distribution network. RNFG capacity can be allocated in addition to FG and/or NFG, or as a means to connect DG units to part of a network that previously had no DG units connected.

A simplified example network was used in Chapter 2 and Chapter 3 to demonstrate firm and non-firm generation capacities. In Figure 23, this same network example provides an example of theoretical capacity that could be allocated to RNFG units.

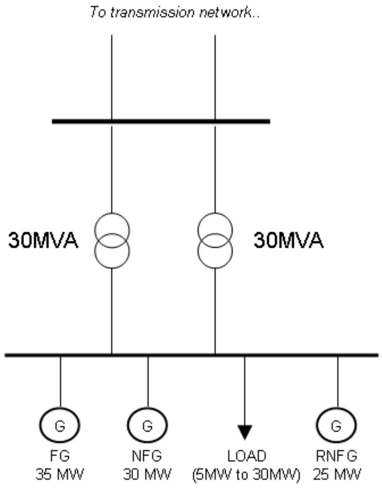

Figure 23: Simplified representation of FG, NFG and RNFG capacity

If the RNFG capacity present on the network in Figure 23 was to be allocated based on the variation in load demand only, there would be 25MW of RNFG capacity available on the network. Due to the approach to allocating FG and NFG capacities, this 25MW is also equal to the N (i.e. intact) capacity of the network (60MVA) plus the maximum demand on the network (30MW) minus the FG and NFG capacities (35MW and 30MW, respectively). This theoretical definition of RNFG capacity takes no account of diversity (i.e. non-coincidence) in output between FG, NFG and RNFG units.

The output of the RNFG units at any given time will be dependent on the local demand, the output of FG and NFG units, principles of access to capacity and the thermal constraints on the network. Assuming the full capacity of the circuits can be harnessed, it is possible to define the collective real-time access of the RNFG units, according to Equation (10):

$$S_{RNFG} = S_N + S_{Demand} - S_{FG} - S_{NFG} \tag{10}$$

Where, S_{RNFG} = Real-time maximum permissible output from RNFG unit(s) (MVA), S_N = The N capacity of the network (MVA), S_{Demand} = The real-time electrical demand on the network (MVA), S_{FG} = The real-time output of the FG unit(s) (MVA) and S_{NFG} = The real-time output of the NFG unit(s) (MVA).

The following key points arise from inspection of Equation (10).

- If FG and NFG output remains constant and demand increases, the network capacity available to RNFG increases
- If FG and NFG output remains constant and demand decreases, the capacity available to RNFG decreases
- If FG or NFG output increases, the capacity available to RNFG decreases, provided demand does not change
- If FG or NFG output decreases, the capacity available to RNFG increases, provided demand does not change
- If FG and NFG output decreases and demand increases, the capacity available to RNFG increases
- If FG and NFG output increases and demand decreases, the capacity available to RNFG decreases

There are other combinations and variations of the above examples; the purpose of those presented is to clearly highlight the real-time and varying nature of the constraint on the output of RNFG units. The relationship between RNFG output and the demand, FG output and NFG output remains the same for the intact network and during contingencies (i.e. N in equation (10) would become N-1, etc). If RNFG units remain online in a contingency to access the remaining network capacity and NFG units are disconnected during a contingency then the contribution of the NFG units can be discounted from Equation (10). This may occur if NFG units have been connected based on an intertripping arrangement that does not provide for real-time regulation of NFG output.

When managing the output of RNFG units to meet thermal constraints on the network, the operator has three main options available, depending on prevailing network conditions:

- Reduce/trim output from DG unit(s)
- Increase output from DG unit(s)
- Disconnect/trip DG unit(s)

If an APFM scheme requires a reduction in real-time output (i.e. trimming) and the generator technology deployed is capable of providing this response, then the APFM algorithm will need to calculate the reduction required to remove the breach of associated thermal constraints.

If we consider RNFG units to be mainly comprised of renewable (and therefore intermittent) forms of generation, it is less likely that the RNFG unit will be able to increase power production when required. It is certainly feasible that a renewable generator may be able to increase output, but this would be reliant on an increase in the primary renewable energy resource or would only be possible if the generator was already operating at a constrained level and not making full use of the renewable energy resource available to it.

Any type of DG unit can be disconnected from the network by the network operator if the appropriate control facility is available. DG units will disconnect themselves from the network during system disturbances to prevent damage to the generator and satisfy safety concerns. An APFM scheme could make use of tripping where appropriate; but this should be viewed as the last available option to the APFM scheme, as the main goal is increased access for RNFG units.

4.4 A Control Philosophy for Active Power Flow Management

The APFM scheme proposed in this section adopts an algorithm and architecture based around the concept of APFM zones. APFM zones are only defined on the connection and operation of RNFG units, based on the identification of circuits where thermal constraints are breached. An introduction to the APFM algorithm, APFM operating margins and APFM zones is now provided.

4.4.1 Active Power Flow Management Algorithm

A high-level overview of the APFM algorithm is now presented, a more detailed look at the functional elements of the APFM scheme is presented in the Appendix. As discussed in section 4.3, there are three options for controlling RNFG units as part of an APFM scheme. The main goal of the proposed APFM scheme is the connection and operation of RNFG units to rural distribution networks, which tend to be radial in nature. As RNFG units will generally exist in areas where the installed generation capacity is greater than the load demand, the two options of reducing (or trimming) RNFG output and disconnecting (or tripping) RNFG units will be included within the APFM scheme.

Collinson *et al* (Collinson *et al*, 2003) and the Energy Networks Association (ENA) (Energy Networks Association, 2004) present the approach to intertripping a DG unit in the event of the first circuit outage on the distribution network. Tripping DG in the event of the first circuit outage and also for the measured breaching of the post-fault thermal constraint is discussed by the authors. These solutions were discussed in detail in Chapter 3. Collinson *et al* (Collinson *et al*, 2003) present a requirement for an APFM scheme to perform real-time regulation of individual DG output to match available network capacity. Details of the solution and an in depth analysis of the requirement and justification for such a solution are not provided in the report by Collinson et al or the ENA. The APFM scheme presented in this thesis directly addresses these points and in addition, addresses the challenges associated with multiple DG units.

Collinson *et al* (Collinson *et al*, 2003), Liew and Moore (Liew and Moore, 2005), Kabouris and Vournas (Kabouris and Vournas, 2004) and Engineering Technical Recommendation ETR124 (Energy Networks Association, 2004) all identify that tripping DG units can act as a final action to preserve network security when other control actions have failed. This philosophy has been adopted by the APFM scheme and modified for application to multiple DG units.

Kabouris and Vournas (Kabouris and Vournas, 2004) present the idea that an individual scheme can be either 'preventive' or 'corrective' in its approach to managing thermal constraints. The APFM scheme presented here represents further development of these ideas by employing and coordinating both preventive and corrective control actions. Preventive action involves the regulation of the output of one or more RNFG units. Corrective action involves the tripping of one or more RNFG units. The APFM algorithm and accompanying control techniques provide a means of deciding when to perform preventive and corrective actions and when more than one RNFG unit should be subject to those control actions.

The trimming of RNFG output represents the 'preventive' part of the APFM algorithm in Figure 24. The APFM scheme measures the export from a defined area, when the export breaches a pre-defined threshold an alarm is sent to one or more RNFG units warning that a trim is imminent. One or more RNFG units are then trimmed by the APFM scheme, by issuing of a set-point to each individual RNFG unit for permitted maximum output. If each RNFG unit achieves the issued set-point and the export is below the threshold then the APFM scheme will begin increasing the output of RNFG units when capacity is available (not shown in Figure 24). After a set time period, if the export has not returned to within safe limits the APFM scheme enters the corrective mode of operation.

The tripping of RNFG units represents the 'corrective' part of the APFM algorithm in Figure 24. If trimming RNFG output has not succeeded in reducing export below the pre-defined threshold then the APFM scheme will trip the RNFG circuit breaker, disconnecting the RNFG unit from the network. The APFM scheme then issues an alarm to the RNFG unit that communicates the cause of the trip. If this action does not return the network to within acceptable operating limits then an alarm is raised to warn the DNO. If the corrective action achieves the desired reduction in export then the scheme can be automatically or manually reset.

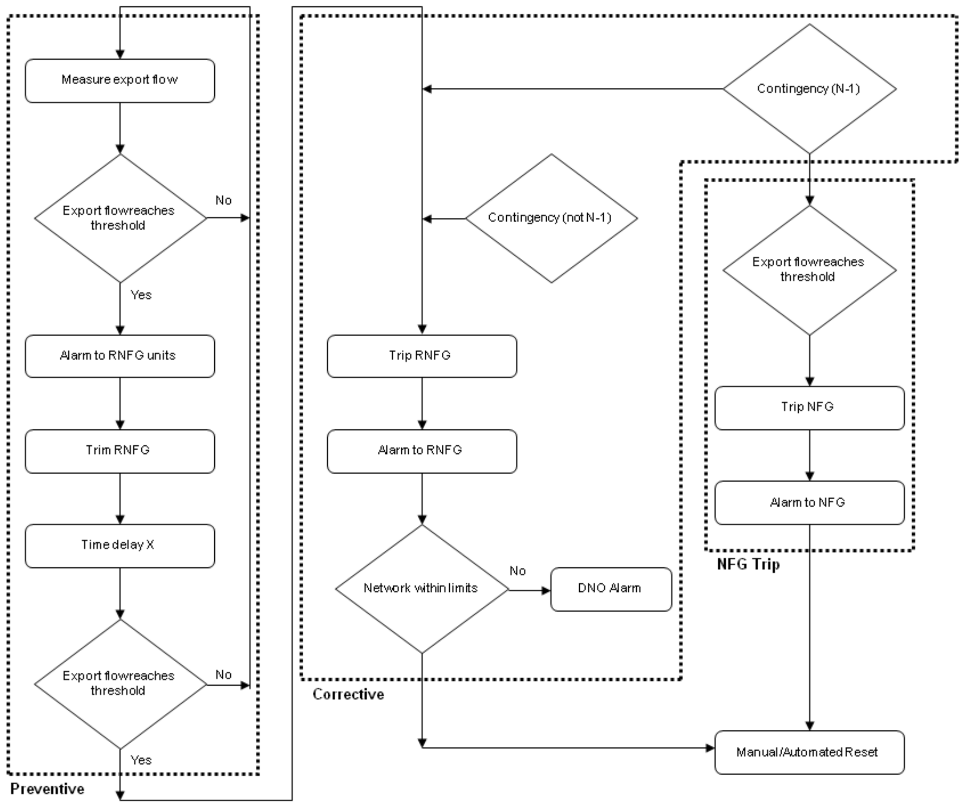

Figure 24: High level Active Power Flow Management Algorithm

Separate from the ‘trim then trip’ aspects of the APFM scheme presented above, the N-1 contingency or another contingency could result in RNFG units being tripped. In parallel to the ‘corrective’ element of the APFM scheme is the NFG intertrip scheme. When the N-1 contingency occurs, the NFG may be tripped if the export breaches a pre-defined limit. The operation of NFG units can then either be automatically or manually reset. This is commensurate with the post-fault direct intertripping approaches of Collinson *et al* (Collinson *et al*, 2003) and Engineering Technical Recommendation ETR124 (Energy Networks Association, 2004) described in Chapter 3.

The following example presents a narrative of the proposed APFM scheme and considers RNFG units connected in addition to FG and NFG units. Through the presentation of a sequence of events, the example describes how trim and trip control actions are initiated by the breaching of thresholds:

An APFM scheme has a number of connected and operational RNFG units (assumed to be wind turbine generators in this example). At time T_1, the system load demand increases, allowing RNFG units to increase their power output without the power flow on the network violating thermal limits. At time T_2 the load demand decreases and coincidentally the wind speed increases and the output from FG, NFG and RNFG wind generating units increase. This causes the power flow on the network to reach the pre-defined 'trim' threshold. The RNFG unit with lowest priority in terms of access to capacity (possibly the last to connect) is sent a control instruction to trim power output. After a time delay, TD_1, or if before the effects of this instruction materialise, a second, higher 'trip' threshold is reached then this lowest priority RNFG unit is tripped. If the breach of power export threshold persists, then the next lowest priority RNFG unit is instructed in the same manner. This process continues until the power export is within the threshold once again. RNFG units increase output again or reconnect through automated reset signals.

In the example sequence of events above, the curtailment of the RNFG unit(s) only persists when the output of generation is high and the demand on the network is low. In other words, the RNFG unit(s) can operate freely until there is the breaching of a threshold on the network; therefore allowing the APFM scheme to take full account of diversity in generator output (whether it be FG, NFG or RNFG output) and of the variation in demand on the network.

Aspects of the narrative presented above are explored further in the rest of this chapter. The 'operating margins' required to define the thresholds that trigger the actions of the APFM scheme are presented. The 'trim' and 'trip' thresholds noted above are set at particular export levels (or 'trigger' levels) relative to the maximum thermal rating of the circuit in question. Operating margins are used to define the size of the gap between different trigger levels; the APFM scheme employs several different trigger levels and accompanying operating margins, which are presented in the following section. The chapter goes on to then present the APFM algorithms that act on the breaching of the operating margins and other measurements.

4.4.2 Operating Margins for Active Power Flow Management

Operating margins are a crucial part of the APFM scheme, providing security to the network operator by limiting the allowed current at constraint locations within the capability of the network to a degree that can be actively managed by the APFM scheme. The different types of operating margins proposed for the APFM scheme are now introduced, as are the computational means for calculating them.

The setting of the APFM operating margins is concerned with the rate of change of the power flow (and therefore the current) at the constraint locations and the time it takes the APFM to measure the constraint, process the logic, deliver the control signal and get a response from an RNFG unit. In summary, the following factors affect the size of the APFM operating margins:

- Local load behaviour
- RNFG unit ramp rates
- Existing DG behaviour
- Communication delays
- Turnaround time for control actions

Figure 25 presents the operating margins required by the APFM scheme to fulfil the control goals of trimming, tripping and releasing capacity back to RNFG units within the thermal constraints of the distribution network. The APFM operating margins are set relative to other significant levels of current in the circuit, as is now discussed.

There are six export levels or margins of interest, the highest portraying power flows on the network that resemble the system approaching real danger, i.e. a dangerously high current is flowing in the circuit with potential implications for safety of utility personnel and the public, continuity of service, asset health and asset lifetime. At this point, the current on the network has breached all trigger levels, and the APFM scheme, NFG intertripping and protection systems have all failed to act, exposing the asset to extremely high current. This is an extreme condition that the distribution network is designed to not reach through careful coordination and setting of protection systems, irrespective of the deployment of APFM.

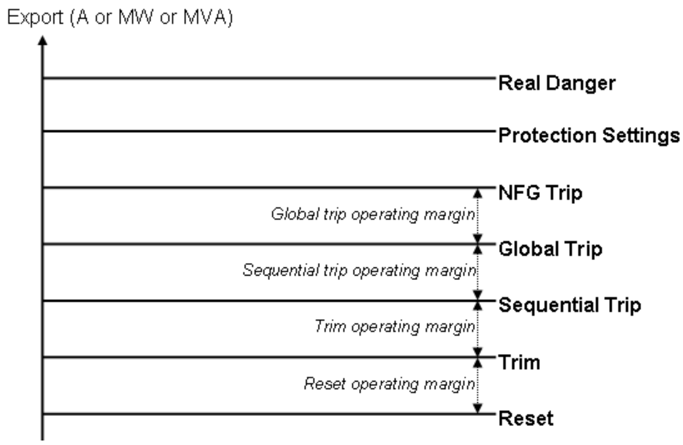

Figure 25: Operating margins employed in the APFM scheme

The second export level or margin is defined as the level at which protection systems will act to open circuit breakers and remove the circuit from operation. This level is set as part of a coordinated protection scheme for overcurrent protection and the circuit is tripped by branch protection systems due to the measurement of a persistent overcurrent. The real danger and protection settings levels are employed on existing systems; it is the operating margins and the trigger levels defined below these points that are the focus of the APFM scheme.

The third margin is the NFG intertrip trigger level. When this is exceeded, NFG units are tripped to remove any subsequent overload due to a fault on a parallel circuit or due to the net current or power flow in excess of the margin. The NFG trigger point must be applied to both circuits in the case of two parallel circuits (circuit 1 and circuit 2), as described in Equations (11) and (12).

$$S_{NFG1} = S_{Total} - S_{(N-1)_2} \tag{11}$$

$$S_{NFG2} = S_{Total} - S_{(N-1)_1} \tag{12}$$

Where, S_{NFG1} = Level of export in circuit 1 to trigger intertrip of NFG if circuit 2 is on outage (A or MW or MVA), S_{NFG2} = Level of export in circuit 2 to trigger intertrip of NFG if circuit 1 is on outage (A or MW or MVA), S_{Total} = Total combined capacity of intact circuits (A or MW or MVA), $S_{(N-1)_2}$ = Export capacity lost due to outage on circuit 1 (A or MW or MVA) and $S_{(N-1)_1}$ = Export capacity lost due to outage on circuit 2 (A or MW or MVA).

Figure 26 is a simple representation of the network capacity, generation group capacity and demand variation on the Orkney Isles distribution network. The Orkney distribution network forms part of the north-Scotland network and will be used several times in this thesis to demonstrate the application of the proposed APFM scheme. The APFM scheme proposed in this thesis will be deployed on the Orkney distribution network in 2009 to facilitate increased connection of renewable generation.

The remaining operating margins are those that relate to the operation of the APFM scheme. These are now introduced in more detail and the computational means of calculating each are presented for the simple example network in Figure 26. Some examples of calculated APFM operating margins are then provided. The operating margins theory and examples presented are concerned with real power only (MWs), although the methods could be applied to current (Amps) and apparent power (MVA).

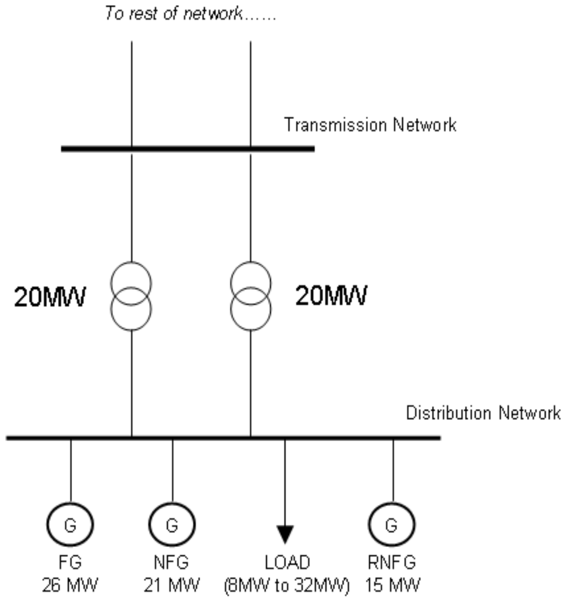

Figure 26: Simplified network example to demonstrate APFM operating margins

4.4.2.1 Global Trip

The ‘Global trip’ is the level at which all RNFG units are tripped to prevent the NFG units being tripped as a result of persistent and excessive RNFG output. The global trip could therefore also trip all RNFG units for the loss of a parallel circuit at a zone boundary. The trigger level must be applied to each circuit in Figure 26. Equations (13) and (14) can be used to calculate the global RNFG trigger level for the example of parallel circuits given above.

$$S_{GlobTrip1} = S_{NFG1} - OM_{Trip} \tag{13}$$

$$S_{GlobTrip2} = S_{NFG2} - OM_{Trip} \tag{14}$$

Where, $S_{GlobTrip1}$ = Level of export in circuit 1 that will cause a global trip of RNFG units (A or MW or MVA), $S_{GlobTrip2}$ = Level of export in circuit 2 that will cause a global trip of RNFG units (A or MW or MVA) and OM_{Trip} = Trip Operating Margin (A or MW or MVA).

For real power flow (MW) management, the trip operating margin can be calculated for a worst case scenario in terms of how quickly the export at the constraint location can rise. Equation (15) provides a method of calculating the trip operating margin. The maximum increase in export will occur when the FG, NFG and RNFG units are ramping up at the maximum rate and there is a drop in electrical demand on the network at the maximum rate that can be experienced. The addition of these rate-of-change values for all DG units and loads provides the rate of change of the total current or power at the constraint location. This gradient is multiplied by the total time taken to achieve the desired control response. This is a combination of the time it takes the APFM scheme to measure and process the breach of the trip margin (the APFM time delay, TD) and the time it takes to trip the RNFG units (TT).

$$OM_{Trip} = \begin{bmatrix} \left(\sum_{FG=1}^{n}\left(\frac{dP_{FG}}{dt}\right)\right) + \left(\sum_{NFG=1}^{n}\left(\frac{dP_{NFG}}{dt}\right)\right) \\ + \left(\sum_{RNFG=1}^{n}\left(\frac{dP_{RNFG}}{dt}\right)\right) + \left(\sum_{L=1}^{n}\left(\frac{dP_{L}}{dt}\right)\right) \end{bmatrix} \times \left(TD + TT\right) \tag{15}$$

Where, $\sum_{FG=1}^{n}\left(\frac{dP_{FG}}{dt}\right)$ = Maximum FG ramp rate (MW/min), $\sum_{NFG=1}^{n}\left(\frac{dP_{NFG}}{dt}\right)$ = Maximum NFG ramp rate (MW/min), $\sum_{RNFG=1}^{n}\left(\frac{dP_{RNFG}}{dt}\right)$ = Minimum RNFG ramp rate (MW/min), $\sum_{L=1}^{n}\left(\frac{dP_{L}}{dt}\right)$ = Maximum load drop (MW/min), TD = APFM time delay (minutes) and TT = Trip time (minutes).

4.4.2.2 Sequential Trip

The 'Sequential Trip' trigger level is used to trip individual RNFG units in consecutive order of priority, thus preventing the failure of one RNFG unit to respond to a curtailment instruction causing the global trip level to be exceeded. This can occur when efforts to trim the RNFG units have failed to reduce the export and the export continues to rise towards the 'Global Trip'. The sequential trip trigger levels on the parallel circuits in Figure 26 are defined by Equations (16) and (17):

$$S_{Seq.Trip1} = S_{Glob.Trip1} - OM_{seq} \tag{16}$$

$$S_{Seq.Trip2} = S_{Glob.Trip2} - OM_{seq} \tag{17}$$

Where, $S_{SeqTrip1}$ = Trigger point in circuit 1 when the APFM scheme begins sequentially tripping one or more RNFG units (A or MW or MVA), $S_{SeqTrip2}$ = Trigger point in circuit 2 when the APFM scheme begins sequentially tripping one or more RNFG units (A or MW or MVA) and OM_{seq} = Sequential trip operating margin (A or MW or MVA).

Equation (18) provides a method of calculating the sequential trip margin. Equation (18) is in the same format as Equation (15) but instead of the trip time the sequential trip time (ST) is added to the APFM time delay (TD). The sequential trip time is the time it takes the APFM scheme to trip an individual RNFG unit, which may be staged at particular time intervals.

$$OM_{Seq} = \begin{bmatrix} \left(\sum_{FG=1}^{n} \left(\frac{dP_{FG}}{dt} \right) \right) + \left(\sum_{NFG=1}^{n} \left(\frac{dP_{NFG}}{dt} \right) \right) \\ + \left(\sum_{RNFG=1}^{n} \left(\frac{dP_{RNFG}}{dt} \right) \right) + \left(\sum_{L=1}^{n} \left(\frac{dP_{L}}{dt} \right) \right) \end{bmatrix} \times (TD + ST) \tag{18}$$

Where, ST = Sequential trip time (minutes).

The breaching of the sequential trip margin will result in the sequential disconnection of RNFG units until the measured export drops to an acceptable pre-defined level. The time between the sequential tripping of RNFG units (ST) is a configurable parameter within the APFM scheme.

4.4.2.3 Trim Margin

When the export at the constraint location breaches the ‘Trim’ level, the set-point issued to participating units is changed to curtail the RNFG units with the goal of reducing the export at the constraint location to below the ‘Reset level’. The RNFG units are approached individually or collectively as required, the trim RNFG trigger level in each circuit in Figure 26 is defined by Equations (19) and (20):

$$S_{Trim1} = S_{SeqTrip1} - OM_{Trim} \tag{19}$$

$$S_{Trim2} = S_{SeqTrip2} - OM_{Trim} \tag{20}$$

Where, S_{Trim1} = Trigger point in circuit 1 when the APFM scheme begins trimming one or more RNFG units (A or MW or MVA), S_{Trim2} = Trigger point in circuit 2 when the APFM scheme begins trimming one or more RNFG units (A or MW or MVA) and OM_{Trim} = Trim operating margin (A or MW or MVA).

The trim operating margin can be calculated using Equation (21), which acknowledges that when the APFM scheme is taking measurements, processing data and issuing control instructions there is no reduction from the RNFG units. There is also the inherent time delay introduced by the generator control scheme prior to achieving a set point reduction. The maximum increasing gradient of the export from a zone is multiplied by the APFM time delay (TD) plus the time it takes the RNFG unit to begin ramping down power production, defined here as the ramp time delay (RTD). Added to this value is the export gradient from the zone when the RNFG is ramping down at full capability, which is then multiplied by the time allocated to the ramp response, defined here as the ramping time factor (RTF). This means that the trim operating margin accounts for how long the APFM scheme takes to measure, process and issue a set point then provide the RNFG unit(s) with time to respond.

$$OM_{Trim} = \left[\left[\begin{array}{l} \left(\sum_{FG=1}^{n} \left(\frac{dP_{FG}}{dt} \right) \right) + \left(\sum_{NFG=1}^{n} \left(\frac{dP_{NFG}}{dt} \right) \right) \\ + \left(\sum_{RNFG=1}^{n} \left(\frac{dP_{RNFG}}{dt} \right) \right) + \left(\sum_{L=1}^{n} \left(\frac{dP_{L}}{dt} \right) \right) \end{array} \right] \times (TD + RTD) \right] +$$

$$\left[\left[\begin{array}{l} \left(\sum_{FG=1}^{n} \left(\frac{dP_{FG}}{dt} \right) \right) + \left(\sum_{NFG=1}^{n} \left(\frac{dP_{NFG}}{dt} \right) \right) \\ - \left(\sum_{RNFG=1}^{n} \left(\frac{dP_{RNFG}}{dt} \right) \right) + \left(\sum_{L=1}^{n} \left(\frac{dP_{L}}{dt} \right) \right) \end{array} \right] \times RTF \right] \tag{21}$$

Where, RTD = Ramp time delay (minutes) and RTF = Ramp time factor (minutes).

4.4.2.4 Reset Margin

The last of the margins is the 'Reset' margin, the target for the trimming of RNFG units and designed to prevent hunting around the trim RNFG export level. The reset trigger levels in the parallel circuits in Figure 26 are defined by Equations (22) and (23):

$$S_{reset1} = S_{Trim1} - OM_{\mathrm{Re}set} \tag{22}$$

$$S_{reset2} = S_{Trim2} - OM_{\mathrm{Re}set} \tag{23}$$

Where, S_{reset1} = Level of export in circuit 1 that will initiate the release of capacity to one or more RNFG units (A or MW or MVA), S_{reset2} = Level of export in circuit 2 that will initiate the release of capacity to one or more RNFG units (A or MW or MVA) and $OM_{\mathrm{Re}set}$ = Reset operating margin (A or MW or MVA).

The reset-operating margin is calculated using equation (24), which adopts the same approach as the trip and sequential trip margin, except this time the reset time (RT) is added to the APFM time delay (TD). The reset time ensures that the RNFG units are not released too close to the trim trigger level. The reset-operating margin will ensure that the time between the RNFG units being released and the trim operating margin being breached will be at least equal to the reset time.

$$OM_{\mathrm{Re}\,set} = \left[\begin{array}{l} \left(\sum_{FG=1}^{n} \left(\frac{dP_{FG}}{dt} \right) \right) + \left(\sum_{NFG=1}^{n} \left(\frac{dP_{NFG}}{dt} \right) \right) \\ + \left(\sum_{RNFG=1}^{n} \left(\frac{dP_{RNFG}}{dt} \right) \right) + \left(\sum_{L=1}^{n} \left(\frac{dP_{L}}{dt} \right) \right) \end{array} \right] \times (TD + RT) \qquad (24)$$

Where RT = Reset time.

4.4.2.5 Application of Active Power Flow Management Operating Margins

As was stated earlier in section 4.4.2, the distribution network that was presented in Figure 4 is a simplified version of the Orkney Isles distribution network, which forms part of the North-Scotland network. The Orkney distribution network will be used several times in this thesis to demonstrate the application of the APFM methods presented. The simplified version of the Orkney distribution network will now be used to demonstrate the calculation of operating margins and trigger levels for the APFM scheme. The limit of the existing FG connection capacity in the distribution network is 26MW, based on a previous minimum local demand of 6MW (the network has since experienced load growth) and an outage of one of the two largest circuits (each with a capacity of roughly 20MW). Additional generation connection capacity (21MW) beyond this limit has been made available to NFG, whereby NFG will only be permitted to operate when both of the circuits are in service. Inter-tripping arrangements will disconnect NFG for loss of either largest circuit and if the total export exceeds the capacity of the remaining cable (as described in the existing solutions for APFM in chapter 3). Thus, further generator connections are constrained by a lack of available connection capacity according to established practice.

Figure 4 in section 4.4.2 illustrated the FG, NFG and RNFG unit capacities being considered in this example. Provision of a similar level of capacity increase by conventional means would require installation of new circuit capacity. The cost associated with this could pose a significant financial barrier to further DG connections. The size of time delay and operating margins employed can impact on the economic viability of RNFG connections, as will be shown in a later chapter of this thesis. Equations (11)-(24) are now applied to the scenarios shown in Table 8 to demonstrate how to set the operating margins and trigger levels required for the APFM scheme.

Table 8: Scenarios used to calculate examples of APFM Operating Margins

Ramp rate	Scenario 1	Scenario 2	Scenario 3	Scenario 4
$\sum_{FG=1}^{n}\left(\frac{dP_{FG}}{dt}\right)$	5%/min	10%/min	20%/min	40%/min
$\sum_{NFG=1}^{n}\left(\frac{dP_{NFG}}{dt}\right)$	5%/min	10%/min	20%/min	40%/min
$\sum_{L=1}^{n}\left(\frac{dP_{L}}{dt}\right)$	5%/min	10%/min	20%/min	40%/min
$\sum_{RNFG=1}^{n}\left(\frac{dP_{RNFG}}{dt}\right)$	5, 10, 20 and 40%/min for each scenario			

In scenario 1, the variability of the existing FG units, NFG units and demand on the network is low at 5%/min, allowing the effect of different ramp rates of the RNFG units to be investigated. Ramp rates for RNFG units of 5%/min, 10%/min, 20%/min and 40%/min are considered, representing a reasonable range of realistic values that will demonstrate the impact of an increase in the ramp rate of RNFG units on the sizes of operating margins employed. Scenario 2, 3 and 4 consider values of 10%/min, 20%/min and 40%/min respectively for the ramp rates of the FG units, NFG units and demand, and the same range of ramp rates for RNFG units as in scenario 1.

The assumptions regarding the various APFM time factors used in equations (11)-(24) are provided in Table 9. These time factors have been selected based on typical communications delays in power systems and the effects of varying sizes of time delays on the APFM scheme will be considered in Chapter 6. The capacity of FG units, NFG units and RNFG units used in the calculations are as shown previously in Figure 4.

Table 9: Time delays used to calculate examples of APFM Operating Margins

ANM Time Factor	Time (Seconds)
TD	2
TT	1
ST	1
RTD	10
RTF	30
RT	20

Table 10 presents the results of the application of the equations for APFM operating margins to scenario 1 and shows that a low variability of FG, NFG and local load (5%/min) allows the network to be operated close to its full rated capacity. The trim trigger level varies between 92.5% and 95.1% for RNFG ramp rates of 5%/min and 40%/min respectively. The APFM scheme will start releasing capacity back to RNFG units at 86% to 88.2% of rated capacity dependent on the ramp rate of the RNFG units. Interestingly, the highest reset trigger point occurs at the lowest trim RNFG trigger point. This is also the case for scenarios 2 to 4. This means that the higher ramp rate of the RNFG unit(s) then the higher the export can be prior to taking action, but the lower the reset trigger due to the quicker ramp-up of RNFG unit(s) post-curtailment. The effects of which could be tempered by the adaptation of the APFM algorithm to release RNFG unit output at a reduced rate in the post-trim situation.

Table 10: Trigger levels for scenario 1

Trigger Point (% of rated capacity)	RNFG 5%/min	RNFG 10%/min	RNFG 20%/min	RNFG 40%/min
NFG Intertrip	100.0	100.0	100.0	100.0
Global RNFG Trip	99.4	99.3	99.1	98.8
Seq. RNFG Trip	98.8	98.6	98.3	97.5
Trim RNFG	92.5	92.9	93.6	95.1
Reset	88.2	87.9	87.2	86.0

Table 11 presents the results of the analysis of scenario 2. Scenario 2 considers a more variable FG unit and NFG unit output and local load of 10%. It can be seen that this results in larger operating margins and lower trigger levels for tripping, trimming and releasing RNFG units. The trim trigger level now varies from 84.6% to 87.2%, around 8% lower than for scenario 1. The reset trigger level has reduced by a similar amount to a range of 74.5% to 76.6%. Therefore, RNFG units in scenario 2 would be likely to experience more curtailment than those in scenario 1.

Table 11: Trigger levels for scenario 2

Trigger Point (% of rated capacity)	RNFG 5%/min	RNFG 10%/min	RNFG 20%/min	RNFG 40%/min
NFG Intertrip	100.0	100.0	100.0	100.0
Global RNFG Trip	98.9	98.8	98.6	98.3
Seq. RNFG Trip	97.8	97.7	97.3	96.5
Trim RNFG	84.6	85.0	85.7	87.2
Reset	76.6	76.3	75.7	74.5

Scenario 3 considers an even more variable FG unit output, NFG unit output and local load. It can be seen that this results in much reduced trigger levels due to the requirement for larger operating margins. As can be seen in Table 12, the global RNFG trip and sequential RNFG trip are still above or around 95% but the trim and reset trigger levels are much reduced. The trim trigger level varies from 68.8% to 71.4% and the reset trigger level from 51.4% to 53.6%.

Table 12: Trigger levels for scenario 3

Trigger Point (% of rated capacity)	RNFG 5%/min	RNFG 10%/min	RNFG 20%/min	RNFG 40%/min
NFG Intertrip	100.0	100.0	100.0	100.0
Global RNFG Trip	97.9	97.8	97.7	97.3
Seq. RNFG Trip	95.9	95.7	95.3	94.6
Trim RNFG	68.8	69.2	69.9	71.4
Reset	53.6	53.3	52.7	51.4

Scenario 4 is the most extreme in terms of the variability in FG and NFG output and local load. For each of the RNFG ramp rates specified it is assumed that the FG units, NFG units and local load vary at 40%/min. It can be seen in Table 13 that this results in greatly reduced trigger levels for the APFM scheme. The global and sequential RNFG trip trigger levels are still above 90%, but the trim trigger level varies from 37.2% to 39.8%. This shows that if the FG units, NFG units and local load are highly variable then the capability of the RNFG units does not impact much on the size of trim operating margin required. It can also be seen in Table 13 that the situation is so severe that capacity will not be released to the RNFG units until an export is measured of 5.3% to 7.5%. The viability of the APFM scheme would be in doubt in these circumstances due to such low access levels.

Table 13: Trigger levels for scenario 4

Trigger Point (% of rated capacity)	RNFG 5%/min	RNFG 10%/min	RNFG 20%/min	RNFG 40%/min
NFG Intertrip	100.0	100.0	100.0	100.0
Global RNFG Trip	96.0	95.9	95.7	95.3
Seq. RNFG Trip	91.9	91.7	91.4	90.6
Trim RNFG	37.2	37.6	38.3	39.8
Reset	7.5	7.2	6.6	5.3

The results of scenarios 1-4 show that the behaviour of existing DG units and load has a large bearing on the size of operating margins employed by the ANM scheme. For faster ramp rates of RNFG units the higher the trigger levels are for trimming RNFG in any scenario, implying a greater energy yield by the RNFG units. Smaller operating margins than those identified could be employed at the discretion of the network operator but may result in increased tripping of participating RNFG units. The implications of this for network performance and the participating generators would need to be considered.

4.4.3 Active Power Flow Management Control Zones and Principles of Access

As was discussed in Chapter 3, Overbeeke (Overbeeke, 2002), Roberts (Roberts, 2004) and Roberts *et al* (Roberts *et al*, 2003) propose the identification of a cellular or zonal architecture for the gradual deployment of an ANM scheme. In this thesis, these shall be termed as APFM zones, as applied to the APFM scheme proposed herein. Each APFM zone is defined by locally occurring control actions, communications and measurements and is interconnected to the rest of the distribution network and potentially to other zones. Therefore, the APFM zones can operate independently or collectively. Neither Overbeeke, Roberts nor Roberts *et al* identify a method of identifying or practically utilising such zones for the purpose of APFM.

The method of identifying APFM control zones presented here is a means of identifying the location of constraints that need to be measured for the purposes of APFM. The APFM zones also allow one or more RNFG units in a zone to be associated with a measurement point and actively managed according to defined principles of access.

The first step to identifying APFM control zones is to identify the first new RNFG unit and the node to which it is to be connected. Then power import/export routes and the power produced/consumed at the electrical node are determined and an

APFM zone boundary condition applied to assess whether the export route node capacity could be exceeded. By comparing the maximum power/current that can be transmitted with the maximum capacity of the node being considered, zones that have to be actively managed can be identified. This method takes as its formulation the application of Kirchoff's current law. In doing so the method addresses issues relating to coincident constraints on an electricity network. The method for determining the boundaries of APFM control zones can be expressed using the APFM zone boundary condition, in Equation (25):

$$\sum_{i=1}^{n} P_{transfer} + \sum_{i=1}^{n} P_{produced} - \sum_{i=1}^{n} P_{consumed} > P_{\max} \tag{25}$$

Where, $\sum_{i=1}^{n} P_{transfer}$ = Maximum transfers or contributions from n nested APFM zones or other network areas (MW), $\sum_{i=1}^{n} P_{produced}$ = Maximum summated rated output of n RNFG units within APFM zone (MW), $\sum_{i=1}^{n} P_{consumed}$ = Summated minimum demand of n energy RNFG units within APFM zone (MW), $P_{\max}$ = Maximum capacity at APFM zone import/export boundary (MW).

If the resulting net transfer is greater than the static, seasonal or dynamically determined export capacity from the node being considered ($P_{\max}$) then an APFM zone is defined. If the net transfer is below the static, seasonal or dynamically determined export level then an APFM zone is not required.

Once the first node is assessed, the next node in direction of power export has to be considered and the process repeated until the Grid Supply Point (GSP) or logical extent of the network is reached. This process is then repeated for each export route for current and power from the electrical node being considered and each new RNFG unit. This provides a comprehensive and logical approach that identifies possible thermal capacity constraint breaches for the connection of one or more RNFG units.

At this stage, an APFM configuration is defined according to principles of access to capacity in each APFM zone. To ensure that the principles of access are adhered to, power system studies are performed for the connecting RNFG unit(s), in addition to auditing of APFM scheme performance once installed.

APFM zones can be nested within one another, or exist in isolation. The contribution of nested zones or other network areas to the net transmittable current or power from an APFM zone is recognised in equation (25) by the term $\sum_{i=1}^{n} P_{transfer}$. This relates to any current or power flowing into or out of the electrical node being considered and so can be a positive or negative value. While the electrical notation for real power (P) is used here, the above method can be extended to make use of apparent power (S). The most general meaning of S is implied through reference to current (A), real power (MW) and apparent power (MVA). The actual calculations for S in equation (1) and subsequent equations, expressions and explanations would have to take into account the vector form of S. The maximum rating of a component (for example $S_{\max}$ if apparent power is being used) may be determined by the static, seasonal or dynamic rating of the circuit.

Establishing APFM zones for specific network types will now be described in detail with reference to an example radial network and an interconnected distribution system, although the method can be applied to different networks and network topologies. The APFM zoning method can be performed at the planning stage or as and when new RNFG units are to be added to the network and can also be performed online to respond to changes to network topology. At the planning stage, power system analysis is undertaken to identify any impacts of different network paths and reactive power flows on the location of the APFM zones.

4.4.3.1 A Radial Network Example

Figure 27 shows a typical radial distribution network that has three FG units connected to a feeder at buses 1, 3 and 4. The maximum capacity for export for this network is 12MW (neglecting reactive power flows for now). The three FG units are: FG1 (10MW) at bus 4, FG2 (2MW) at bus 3 and FG3 (6MW) at bus 1. The maximum rated FG output is equal to the capacity for export (12MW) plus the minimum load (6MW), which gives a total of 18MW. The operation of all or any FG units will not overload the thermal rating of the distribution network on any section of the feeder.

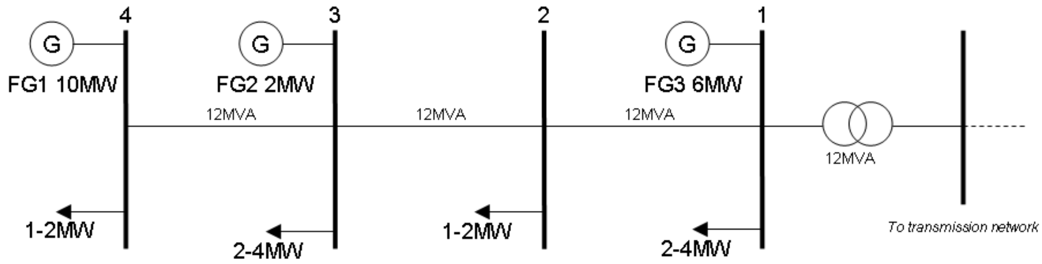

Figure 27: Radial feeder example with FG units connected

RNFG1, RNFG2 and RNFG3 are to be connected to the radial distribution network. The first unit RNFG1 (2MW) is to be connected at bus 4, RNFG2 (4MW) at bus 3 and the RNFG3 (4MW) at bus 1. It will be assumed that RNFG1 is the first to connect, followed by RNFG2 then RNFG3. To identify the APFM zones to be actively managed in Figure 27, RNFG1 is added to the network at bus 4, as shown in Figure 28, where FG1 (10MW) is already connected. Equation (25) is then applied to bus 4 giving 12-1=11 MW. Since this is less than the maximum capacity for export, an APFM zone is not required at bus 4. Next, equation (25) is applied to all of the electrical branches connected to the feeder, in the direction of export from bus 4. Doing this for buses 3 and 2 also results in no APFM zone being required, i.e. no condition of generation or load demand could result in the export from bus 3 or bus 2 exceeding the circuit thermal rating of 12MW. However, for bus 1 equation (25) results in 10+6-2=14 MW, which is more than the maximum export capacity from bus 1, and so an APFM zone boundary is required at bus 1. This and the location of RNFG1 define a zone, which will be referred to as zone 1, as shown in Figure 28, requiring APFM to be deployed.

Consider now the addition of RNFG2 (4MW) at bus 3. The application of equation (24) at bus 3 gives: 11+6-2=15 MW and 15>12 MW, resulting in the requirement for an APFM zone, zone 2, which is nested within zone 1, as shown in Figure 28. Following the export path from bus 3 involves the application of equation (25) at bus 2 and bus 1. This identifies that RNFG2 also contributes to the overloading of the export from bus 1. Therefore, RNFG2 has to be actively managed for access to available export capacity from bus 1 and bus 3. Consider now, the addition of RNFG3 (4MW) at bus 1. Application of equation (25) identifies that RNFG3 compounds the existing overloading on the export circuits from bus 1. Therefore, RNFG3 has to be actively managed for access to capacity in zone 1.

At each zone boundary, a measurement device is located or an existing device in the appropriate position used, so that the net power and/or current can be monitored in real time. These key measurements are used to ensure that the maximum capacity at the network pinch point is never exceeded.

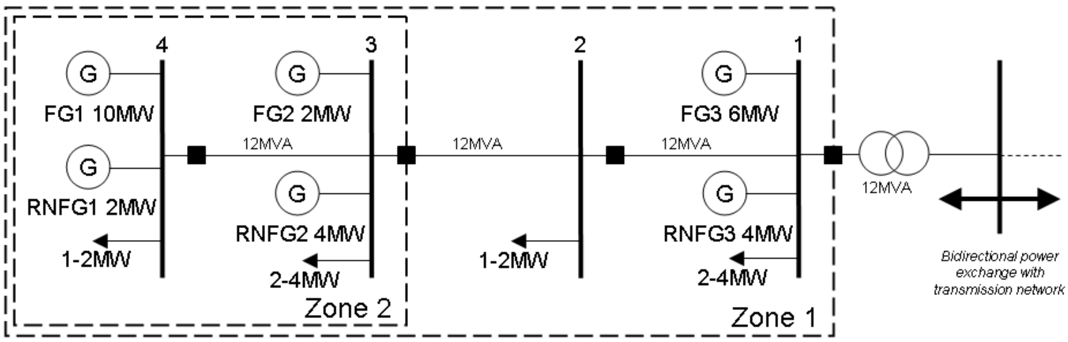

Figure 28: Radial feeder example with FG units, RNFG units and APFM zones defined

Once the zones are defined, an APFM configuration is determined based on access to capacity criteria and the entire network is subject to power system analysis. This is performed individually, consecutively or collectively for each energy producing/consuming device connecting to the APFM scheme depending on the principles of access to capacity. Power system analysis also allows the performance of the network in terms of voltage profile and the real and reactive power flows on the system to be addressed. In addition, the power flow studies will aid in the identification of potential conflicts to the principles of access. Different options that could be applied to the principles of access to capacity were introduced in Chapter 3. For the application to the APFM scheme presented here, the Last-In First-Out (LIFO) principle will be adopted, for the following reasons:

- Through the application of LIFO within APFM control zones, it is possible to offer individual RNFG units a connection with a clear indication of the associated network constraints and the accompanying impact on the performance of the network
- The LIFO approach means that all RNFG units can be studied to provide estimates of MWh generated and MWh curtailed, which will allow individual RNFG units to perform an economic assessment of the benefits of APFM, which will not be impacted upon by the connection of additional RNFG units
- Adopting LIFO as the principle of access means that the location, size and nature of RNFG units, relative to each other, will not impact on the treatment of each by the APFM scheme

There are other aspects of LIFO that are less favourable, such as the risk of network sterilisation due to the location and size of an RNFG unit preventing the connection of other RNFG units. However, this is a risk that exists in the current commercial and regulatory environment in many countries and is a common challenge to gaining economic efficiency from generator connections and network investment.

In Figure 28, RNFG1 is the first unit connected and is only liable for curtailment based on the measured export from bus 1 and is the last of the three RNFGs to be curtailed for the constraint at this location. In contrast, RNFG2 will be curtailed before RNFG1, and RNFG3 will be curtailed before either of RNFG1 and RNFG2. Based on a LIFO scheme, the RNFG priority stack for curtailment in either zone of Figure 28 is given below in Table 14.

Table 14: RNFG Priority Stack for Zone 1 and Zone 2 in Figure 28

Zone	RNFG Stack
1	RNFG3 RNFG2 RNFG1
2	RNFG2

In this scenario, when the export from bus 1 is measured as exceeding the allowable limit, and so the constraint at zone 1 is breached, then the RNFG units will be curtailed individually or collectively according to LIFO in the order RNFG3, RNFG2 then RNFG1. RNFG3 will be curtailed first; RNFG2 may be curtailed at the same time as RNFG3 (if RNFG3 is to be fully reduced) or after RNFG3 has been fully curtailed. RNFG1 may be curtailed at the same time as RNFG2 (if RNFG2 is to be fully reduced) or after RNFG2 has been fully curtailed. RNFG2 will be curtailed for a breach of the constraint at zone 2. In order to decide the level of reduction or curtailment, an APFM scheme is required that will calculate a reduction in output from the RNFG units that will return the export to satisfactory levels. The delivery of the output reduction signal will involve the application of operating margins implemented within an APFM scheme, such as those described in the previous section of this thesis.

4.4.3.2 An Interconnected Network Example

Figure 29 shows another network to which APFM can be applied. This is an interconnected distribution network. The electrical load at buses 3, 5 and 6 (a total peak of 15MW) can be met for the loss of either circuit between buses 3 and 2, or buses 6 and 7. There is additional electrical load at bus 2 (a peak of 14MW). Firm Generation (FG) has been allocated on the network at bus 6 (FG1, 15MW) and bus 3 (FG2, 8MW), these FG units can operate for the loss of either circuit between buses 3 and 2, or buses 6 and 7 without overloading the remaining circuits on the distribution network.

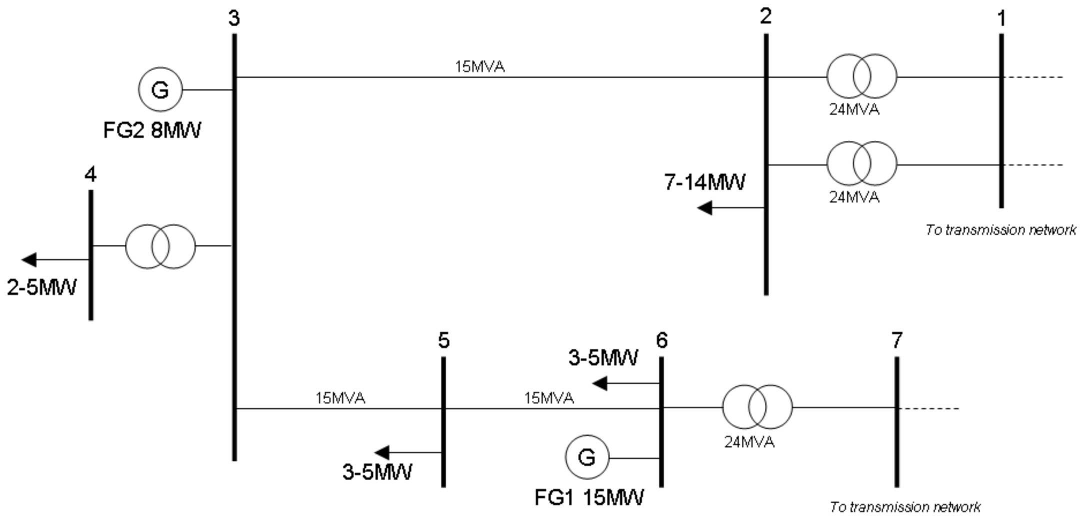

Figure 29: Interconnected network example with FG units connected

RNFG units are to connect to the network at bus 3 (RNFG1, 30MW) and at bus 5 (RNFG2, 10MW), as shown in Figure 30. RNFG1 is first to connect, followed by RNFG2. The size of RNFG1 and RNFG2 require them to have their output regulated in real-time during normal operation and not just be inter-tripped during the first circuit outage.

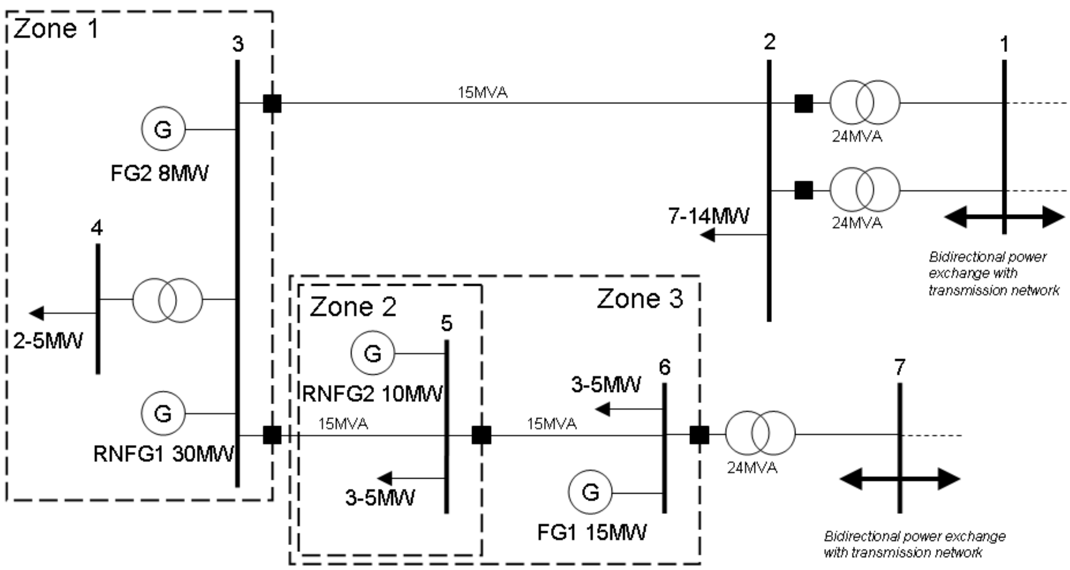

Figure 30: Interconnected network example with FG units and RNFG units connected

To identify APFM zones, equation (25) is applied to each RNFG unit in turn. Consider firstly connection of RNFG1. In this case, 30MW of generation capacity is added to bus 3. In this case, there are two possible export routes either between bus 3 and bus 2 or bus 3 and bus 5. Applying Equation (25) to the export from bus 3 to bus 2 gives -15+38–2 = 21 MW. Since the maximum capacity is exceeded, an APFM zone is required on the export route between buses 2 and 3. This APFM zone is shown in Figure 30 as zone 1. Applying Equation (25) to the export from bus 3 to bus 5 gives a similar result and so zone 1 is extended to cover this boundary, with measurement points defined on the export route from bus 3 to bus 5 and bus 3 to bus 2. Following each export route to each of the GSPs and applying Equation (25) at each bus in turn, there are no further APFM zones required on the interconnected network for the connection of RNFG1.

Consider now the connection of RNFG2 at bus 5; equation (25) is applied to bus 5. The maximum export from bus 5 includes the full export from bus 3 of 15MW and so is 15+10–3 = 22 MW. This is greater than the maximum capacity of 15 and so an APFM zone - zone 2 - is required at bus 5, as indicated in Figure 30. Moving one node in the direction of power export, bus 6 has to be considered. According to equation (25), the maximum export = 15+15–3 = 27 MW. This is greater than the maximum capacity of 24. Therefore, an APFM zone, zone 3, is required at bus 6, as shown in Figure 30. During intact network operation, no other APFM zones are required on the network for the RNFG units considered.

At each zone boundary, a measurement device is located or an existing device in the appropriate position used, so that the net power and/or current can be monitored in real time, for example between buses 3 and 2, buses 3 and 5 and buses 5 and 6. These key measurements are used to ensure that the constraints at the network pinch points are met. For example, when the export from bus 5 and/or bus 6 is measured as exceeding the allowable limit, the APFM calculates a reduction in output from RNFG2 based on the level of overload experienced. According to the LIFO principle of access to capacity, the RNFG stack for curtailment in the zones of Figure 30 is given in Table 15.

Table 15: RNFG Priority Stack for Zone 1, Zone 2 and zone 3 in Figure 30

Zone	RNFG Stack
1	RNFG1
2	RNFG2
3	RNFG2

In this scenario, when the export from bus 3 is measured as exceeding the allowable limit, and so the constraint at zone 1 is breached, then RNFG1 is curtailed. If export from bus 5, or zone 2, is exceeded, RNFG2 is curtailed. Likewise, if export from bus 6, or zone 3, is exceeded, RNFG2 is curtailed. Both RNFG1 and RNFG2 could also require to be disconnected in the event of an outage on the system, through an intertripping arrangement from branch protection systems.

4.5 Practical Aspects of Proposed Active Power Flow Management Scheme

The proposed APFM scheme has been designed to suit near-term deployment; therefore it is worthwhile to consider the platform for delivery of the APFM scheme. Various components are required to deliver an active network; ranging from processing units to measurement devices, circuit breakers, communications links and RNFG units. The APFM scheme presented in this thesis has been designed for implementation on Programmable Logic Controllers (PLCs) (but it should be clear that the algorithms could actually be translated to other platforms as well). PLCs have been selected for a number of reasons:

- PLCs are used extensively in the power industry; DNOs are well aware of their operation and trust them to perform in substation environments – this is particularly pertinent as there is a natural reluctance in the electricity industry to adopt untried and untested technology that could affect the quality of supply or cause failures of supply

- The reactionary manner in which the APFM scheme operates seems suited to PLCs, which are capable of reacting to a variety of analogue and digital inputs and provide signals to plant on-site or through communications links
- Although there is complexity associated with the APFM scheme, it is possible to devolve the software into relatively simple routines and sub-routines that can be implemented on modern PLCs
- PLCs are off-the-shelf technology, no new hardware developments are required to implement the scheme, which could be installed on a number of available PLC platforms at the preference of the host utility company
- PLCs have been employed in Greece, as described by Kabouris and Vournas (Kabouris and Vournas, 2004) to implement real-time pre-fault constraints on wind farms and are common components in wind farm control systems, meaning the generation developers also are comfortable with the application of such technology

The following sections introduce the initial hardware required for the deployment of the APFM scheme, assuming that each APFM scheme will include at least one RNFG unit, one measurement point and a central APFM controller. In addition to what is required as far as APFM hardware is concerned, a variety of communications and measurements will be required. Communications and measurements are not considered directly in this work.

4.5.1 Central Active Power Flow Management Controller

The Central APFM Programmable Logic Controller (PLC) will receive data on all measurement points, circuit breakers and RNFG units. The Central APFM PLC will be the main intelligent hub of the APFM scheme and be responsible for taking decisions regarding the output regulation of all RNFG units. This is one of the main reasons that the APFM scheme has a central controller; so that the measurement point PLCs and RNFG unit PLCs can be added incrementally with minor adjustments to the Central APFM PLC code. The Central APFM PLC will receive measurements from the network, process those measurements, then issue control instructions to RNFG PLCs, who will then provide the control instruction to the RNFG unit control system. It is therefore imperative that the central APFM PLC has communications links to all measurement points and RNFG units.

The Central APFM PLC could comprise a central processing unit with the option for multiple modules to provide additional I/O functionality. This will ensure that as the number of RNFG units increase, the PLC will be able to handle the operational complexity and communications requirements. The software in the Central APFM PLC will exist in a ‘building block’ fashion, allowing it to be gradually updated when new measurement points or RNFG units are connected.

It will be a requirement for the Central APFM PLC to have a configurable data logging facility to allow retrospective analysis of the performance of the APFM scheme. This could also be achieved through a data link to the host utility’s SCADA system or another type of electronic data repository.

4.5.2 Regulated Non-Firm Generator Controller

Controllers known as RNFG PLCs will be located at each RNFG site. The RNFG PLC will issue set-points to the RNFG unit and also be responsible for monitoring the response of the RNFG unit to any change in set-point. The RNFG unit will also be capable of tripping the RNFG circuit breaker, due to a loss of communications, lack of response to a trim signal or continued breach of the issued set point. The set point will be determined by the Central APFM PLC and communicated to the RNFG PLC. The RNFG PLC is the route through which the APFM scheme communicates with the RNFG generator control systems.

The RNFG PLC does not perform any intensive calculations and could realistically be implemented within the Central APFM PLC if that was suitable for the host network operator and RNFG developer. However, the RNFG PLC gives the network operator confidence that they have equipment installed that will gracefully back-off RNFG unit output if communications are lost.

4.5.3 Network Measurement Unit Controller

Network Measurement Unit (NMU) PLCs will receive data from measurement devices on the network at locations where the thermal capacity of the network could be breached due to the connection of RNFG units. A variety of existing signals may be available depending on the location of the pinch point and the NMU PLC. NMU PLCs should be able to accept analogue representations or data streams of current, voltage, power and reactive power as required. In addition, circuit breaker status data and reactive compensation device status data can also be provided to the NMU PLC as a digital input.

If the measurement device that provides data to the NMU PLC has a means of communicating to the central APFM PLC then the NMU PLC may not be required. This can be determined at the time of installation.

4.6 Active power Flow Management Scheme Operation

The APFM control scheme will make use of the various components and the high-level algorithm presented above to effectively operate and perform the following core functions:

- Monitoring primary system parameters
- Network topology identification
- Output regulation of RNFG units
- Releasing capacity back to RNFG units post-trim
- Tripping of RNFG units
- Releasing capacity back to RNFG units post-trim

- Loss of communications
- Lockouts and enables

A significant amount of developmental work has been undertaken regarding the practical operation of the proposed APFM scheme. The items presented above are further explored in the Appendices to this thesis by way of logic flow charts to provide the reader with an overview of the operation of the APFM scheme.

4.7 Chapter Four Conclusions

In this chapter, a specification for an APFM scheme has been presented. The APFM scheme takes as its foundation the literature reviewed previously in Chapter 3 and has been designed to address the fundamental challenges to APFM. The algorithms and methods generated in the research and presented in the thesis have been designed for implementation on PLCs; however, another platform could be easily adopted.

Whereas the prior art of APFM is mainly concerned with single DG units and single network constraints, the proposed APFM scheme manages the output of multiple RNFG units to meet multiple network constraints, through a distributed zonal structure. The distributed zonal structure can evolve as further DG units connect, allowing the APFM scheme to evolve with the needs of the DNO. Operating margins for APFM have been introduced and defined as a means to perform preventive and corrective control for APFM. The practical aspects of the APFM scheme have been discussed and are presented in Appendices through the use of logic flow charts.

The main aspects of the APFM scheme, the APFM control zones, operating margins and preventive and corrective control actions are significant contributions to knowledge and are the subject of several academic papers, including Currie *et al* (Currie *et al*, 2006), (Currie *et al*, 2007a), (Currie *et al*, 2007b), (Currie *et al*, 2008) and a patent application (Currie and Ault, 2007).

4.8 Chapter Four References

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5 Initial Trial of Active Power Flow Management Scheme

5.1 Chapter Summary

This chapter presents an initial trial of the APFM scheme, performed on a wind farm connected to the North-Scotland network. As part of the validation of the proposed specification for the APFM scheme it is necessary to confirm that the output of renewable generators can be regulated to meet prevailing thermal constraints on the network. The APFM prior art identified in Chapter 3 does not include the presentation of the practical response of a wind farm to output regulation instructions as part of an APFM scheme. Therefore, the presentation of the results of the trial is a necessary step towards proving and validating the proposed approach to APFM.

The trial of the APFM scheme allowed the processes concerned with the output regulation of an individual RNFG unit to be tested using a number of Programmable Logic Controllers (PLCs). SCADA data of wind farm power output and status indications retrieved from PLC data logs were used to analyse the performance of the APFM scheme and wind farm during the trial. In addition to the investigation of the results of the trial, historical wind farm output data was investigated to provide further understanding of the temporal aspects of existing wind farm behaviour.

The wind farm used for the APFM trial was previously running at a capped maximum output, below the maximum rated MW capability of the wind farm, due to network constraints. The application of the APFM scheme allowed the wind farm to increase MW output above the constrained limit; therefore, the APFM scheme provided access to the real-time capacity available on the network for increased power output from the wind farm, as described by Currie *et al* (Currie *et al,* 2007) and Currie *et al* (Currie *et al,* 2008).

5.2 Objectives of Trial

The initial trial of the APFM scheme had the following main objectives:

- Measure primary system parameters at a constraint location
- Confirm the suitability of the communications solution and PLCs employed
- Prove control logic for the output regulation of an individual RNFG unit
- Determine the response characteristics of the wind farm to output regulation instructions

Although all of the above factors were important, the last two objectives were crucial to the success of the trial. The trial took place on a wind farm connected to the Orkney Isles distribution network. Due to the limited opportunity for performing a trial of an APFM scheme, the impact on the power flows at the measurement could not be observed as it could not be guaranteed that the constraints on the network would occur during the time the trial was permitted to last for. Therefore, the measured current that was fed into the Central APFM PLC that represented the current in the circuits at the constraint location was scaled up to allow the operation of the APFM scheme to be monitored. It was also not possible to test the tripping of RNFG units or a loss of communications event.

5.3 Active Power Flow Management Controllers

Two Allen Bradley Micrologix 1100 PLCs were used in the trial. The PLCs were programmed using RSLogix500 and witness tested prior to installation by the host DNO, Scottish Hydro Electric Power Distribution (SHEPD) Ltd. The PLCs support both RS232 and Ethernet communications. The embedded I/O functionality of the Micrologix 1100 - 10 digital and 2 analogue inputs, 6 digital outputs - was extended through the addition of analogue and digital modules.

5.4 Active Power Flow Management Trial Communications

Two PLCs were used in the trial; one located at a pinch point on the Orkney distribution network and the other at the wind farm substation. The PLCs exchanged message (MSG) instructions through a private wire link between the two sites. This was done using the RS232 port on the PLCs and modems for communication through a four wire private wire circuit. The Ethernet port of the PLCs were used to interface the PLCs with laptop computers, permitting online changes to the program as required, monitoring of the status of the APFM scheme, checking of the control instructions issued by the PLCs and downloading of the data log. The PLC at the wind farm site issued instructions to the wind farm control systems through SHEPD's SCADA system (i.e. through the local Remote Terminal Unit (RTU)).

Figure 31 provides an illustration of the APFM trial. The Central APFM PLC and the RNFG PLC were operated in a master-slave configuration. Therefore, the RNFG PLC could not initiate communications with the Central APFM PLC. Due to technical difficulties with the server at the wind farm, the trial involved the passing of set-point instructions from the RNFG PLC to the host network operators SCADA system, which were then passed to the RNFG control systems. The full deployment of the APFM scheme is not likely to require set point indications to be passed to RNFG units through the host utility SCADA system. The RNFG PLC will have direct links to the control system of the RNFG unit. These links or data relating to these links will be monitored by the host utility SCADA system as required.

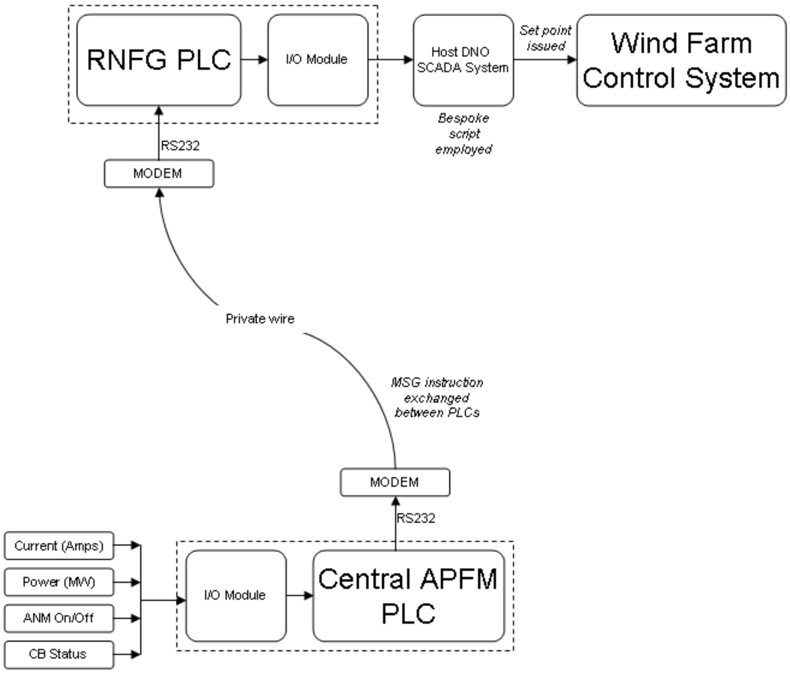

Figure 31: Information flows in the APFM trial

The installed RNFG PLC cabinet at the wind farm substation is shown in Figure 32.

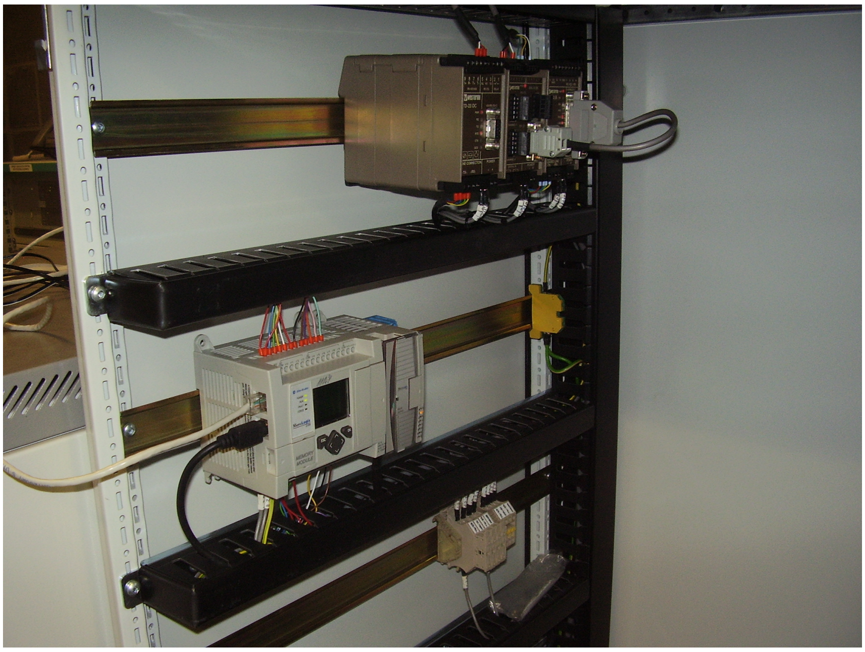

Figure 32: RNFG PLC installed at wind farm substation

5.5 Active Power Flow Management Logic Codes

The trial of the APFM scheme involved a single measurement point and a single RNFG unit. Therefore, the Central APFM PLC was located at the site of the measurement point and an RNFG PLC at the wind farm substation. This section describes the APFM logic codes used in the trial of the APFM scheme.

The MSG instruction issued by the Central APFM PLC to the RNFG PLC involves the sending of words, in this case the bits within the words represented set-point instructions and status indications. The number of MSG instructions in a defined time period was checked to determine the communications status. In the event of a loss of communications the RNFG PLC issued the lowest set-point to the wind farm to remove any risk of overloading the distribution network. In this case, this involved returning the output of the wind farm to a constrained level, not 0 MW.

Table 16 provides the input/output (I/O) list for each site in the trial. At the Central APFM PLC, the inputs are analogue representations (4-20mA analogue signal) of current and power in the measured circuits, and digital inputs (10V DC signal) representing the circuit breaker status indications, an on/off signal from SHEPD's SCADA system and a local on/off switch in the substation. The on-site outputs from the Central APFM PLC are digital outputs that act as local indications (e.g. RNFG set-points, alarms, status indications, etc). The Central APFM PLC also issues a MSG instruction to the RNFG unit, comprised of status indications and the set-point to be passed to the RNFG unit.

At the RNFG PLC, the inputs to the PLC are digital on/off inputs from SHEPD's SCADA system and a local switch, in addition to the MSG instruction received from the Central APFM PLC. The RNFG PLC provides digital outputs that represent set-points to the RNFG unit (via the host network operator's SCADA system, as described above) of 0.733pu, 0.77pu, 0.8pu, 0.84pu and 0.866pu, in addition to local alarms and status indications.

Table 16: APFM Digital Input/Output list

PLC	INPUTS	OUTPUTS
Central APFM PLC	• Analogue representations of current and power • Circuit Breaker Status Indications • APFM on/off indication from SCADA • APFM on/off local switch	• Local indications. • MSG instruction.
RNFG PLC	• APFM on/off from SCADA • APFM on/off local switch • MSG instruction from Central APFM PLC	• Local indications. • 0.733pu set point • 0.77pu set point • 0.80pu set point • 0.84pu set point • 0.866pu set point

5.6 Results of Active Power Flow Management Scheme Trial

The following sections present the results obtained from the trial of the APFM scheme. The goal of the trial was to investigate the time delays associated with APFM control and the suitability of and timescales for the hardware and software achieving output regulation of the RNFG unit.

5.6.1 Communication Delays

The time taken for set-point control instructions to be communicated by the Central APFM PLC to the RNFG PLC, then to the wind farm control system, was tested during a period of low wind speed. Table 17 presents the results of these tests.

Table 17: Results of communications testing during APFM trial

Time of set-point issue by Central APFM PLC	Set-point issued to wind farm by SCADA	Wind Farm control system registers and responds to instruction	Total time taken
16:39:46	16:39:50	16:39:51	00:00:05
16:40:49	16:40:52	16:40:54	00:00:05
16:41:49	16:41:52	16:41:53	00:00:04
16:42:03	16:42:10	16:42:11	00:00:08
16:43:41	16:43:43	16:43:45	00:00:04

Table 17 shows that the majority of the delay associated with communications is due to the combined delay of issuing the MSG instruction from the Central APFM PLC to the RNFG PLC, then from the RNFG PLC to the SCADA system and then from the SCADA system to the wind farm control system. The total time for this part of the communications takes between three and seven seconds.

It can be seen in Table 17 that the wind farm takes one to two seconds to register and respond to the set-point issued after it is received by the wind farm control system. The main delay in the communications employed in the trial is in the SCADA system issuing the set-point to the wind farm. It is important to note that this delay will not be present in the full APFM scheme. The total time for the APFM scheme to send an instruction and have the RNFG unit register the signal and confirm receipt of the instruction varies from four to eight seconds.

5.6.2 Response of Regulated Non-Firm Generation Unit to Curtailment Instruction

SCADA system data was retrieved for the output of the wind farm during the trial of the APFM scheme. Figure 33 provides this data and indications of when the RNFG PLC issued set points to the wind farm (via the SHEPD SCADA system). This illustrates the performance of the wind farm during a period of high wind speed when subject to constraint from the APFM scheme.

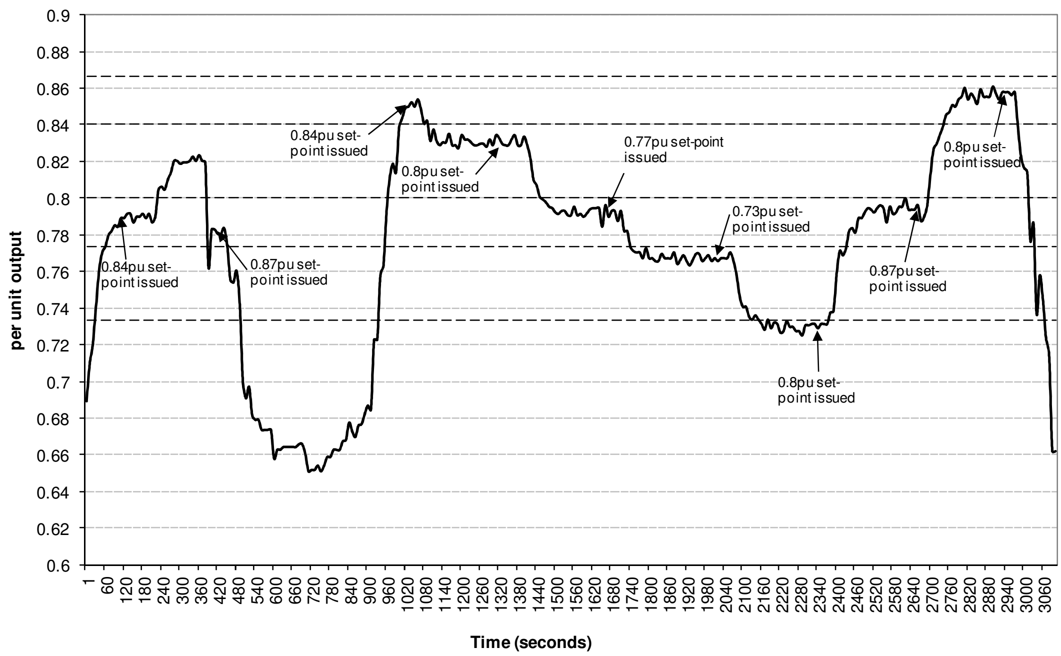

Figure 33: Timing of APFM scheme set-points and corresponding wind farm response

At the start of Figure 33 the wind farm is operating at a set-point of 0.8pu issued by the RNFG PLC. At 150 seconds the APFM scheme permitted an increase in output to 0.84pu. The output rises accordingly in the period from 240 seconds to around 400 seconds. The output of the wind farm then drops due to a drop in wind speed despite a set-point of 0.866pu being issued by the APFM scheme. This 0.866pu set-point is maintained through a period of reduced wind farm output for around ten minutes until the output rises above 0.84pu after around 1020 seconds. Over the next twenty minutes the wind farm output is stepped down sequentially at five-minute intervals through set-points of 0.84pu, 0.8pu, 0.77pu and 0.733pu. Output reduction instructions are sent from the Central APFM PLC to the RNFG PLC in response to current breaching pre-defined thresholds at the measurement point.

It can be seen that the wind farm output remains below the set-point after reducing from the initial higher value in each case over this twenty minute period. This holds true for the release of capacity to the wind farm towards the end of the trace when a 0.8pu set-point is issued at around 2340 seconds and a 0.866pu set-point issued at around 2640 seconds.

Figure 33 demonstrated several occasions where the wind farm output was constrained, beginning at around 1100 seconds. It is important to consider the following factors when interpreting the response of the wind farm to the issued set-points:

- The results are dependent on the wind conditions at the time of testing
- The ramp rate response of the generator is specific to the manufacturer's model and control system parameters
- The wind farm being considered was not designed to perform this function or adjusted to facilitate a quicker response to APFM control instructions
- It may be possible to reduce the inertia within the wind farm control system, to support faster regulation of the turbine output

Each of the output regulation events shown in Figure 33 are now discussed in more detail, prior to summary results of the APFM trial being presented.

Figure 34 presents a closer inspection of changes in wind farm output in response to the changing of the set-point from 0.866pu to 0.84pu. It can be seen that there is a delay prior to the output reduction occurring due to the inertia within the wind farm control system. The wind farm achieves the desired set-point 73 seconds after the RNFG PLC provides the new set-point to the SCADA system. It appears from Figure 34 that the wind farm does not start reducing its output for 40 seconds, then takes an additional 33 seconds to achieve the reduction. The ramp rate of the turbine can be identified through inspection of Figure 34, which illustrates the response of the wind farm from 1060 seconds to 1093 seconds. The response time of 33 seconds to reduce MW production to 0.84pu equates to a ramp-down rate of approximately 5% of rated output per minute.

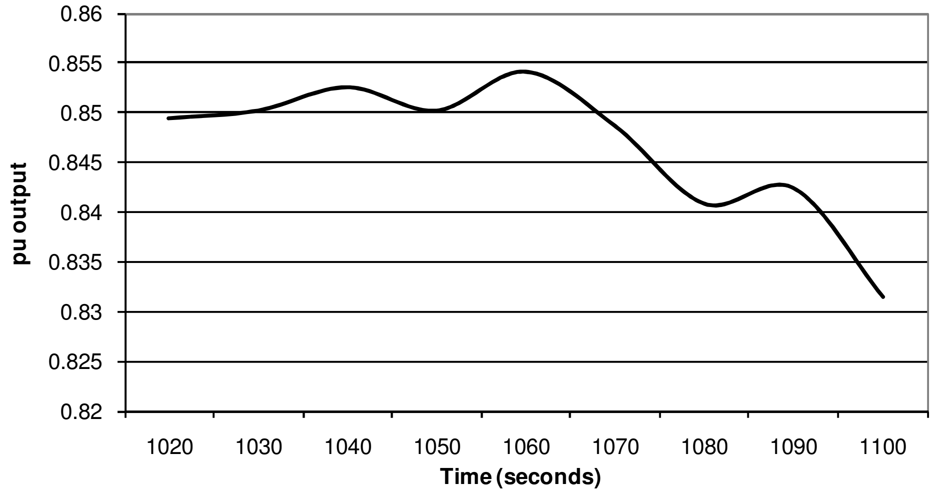

Figure 34: Wind farm response to a set-point change from 0.866pu to 0.84pu

Figure 35 illustrates the reduction of wind farm output from 0.84pu to 0.80pu. Figure 35 provides the trace from the instant that the RNFG PLC requests the change in set-point. It can be seen that around 80 seconds pass before the wind farm begins to reduce output at 1400 seconds. After this occurs, the wind farm achieves the set-point of 0.80pu after 50 seconds. This corresponds to a ramp-down rate of approximately 5% of rated output per minute.

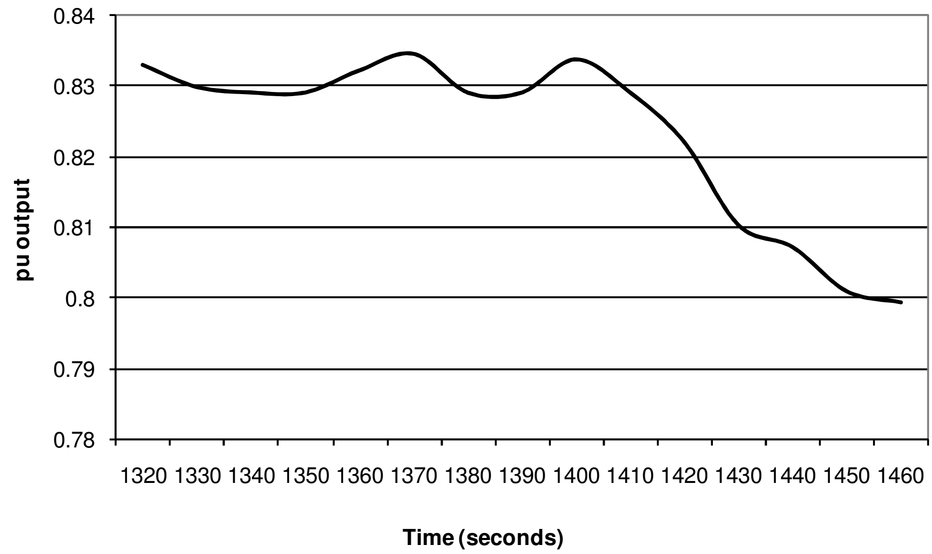

Figure 35: Wind farm response to a set-point change from 0.84pu to 0.80pu

Figure 36 considers a set-point change from 0.80pu to 0.773pu. It can be seen that the wind farm takes 30 seconds from the time when the set-point is issued (1680 seconds) to begin reducing power output at 1710 seconds. The set-point is achieved after 35 seconds at 1745 seconds. This gives a total time from the issue of the control instruction to the meeting of the set-point of 65 seconds. The meeting of the set-point in 35 seconds by the wind farm corresponds to a ramp-down rate of approximately 5% of rated output per minute.

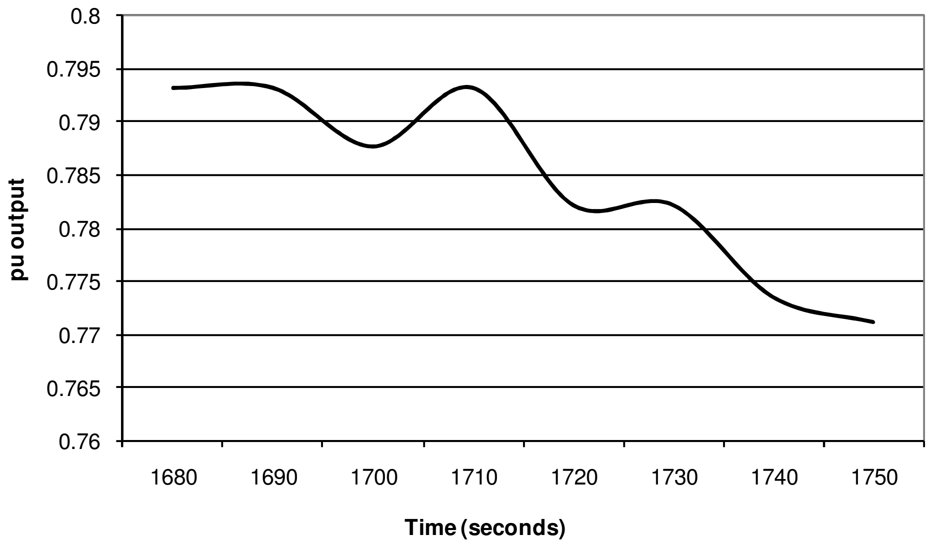

Figure 36: Wind farm response to a set-point change from 0.80pu to 0.773pu

Figure 37 provides the response of the wind farm operating at 0.773pu to the issue of a 0.733pu set-point, the total time taken to achieve output reduction is 110 seconds. 20 seconds pass after the issued set-point before the wind turbine begins reducing power output. Figure 37 shows the wind farm reducing output over a 90 second period, corresponding to a ramp-down rate of around 3% of rated output per minute.

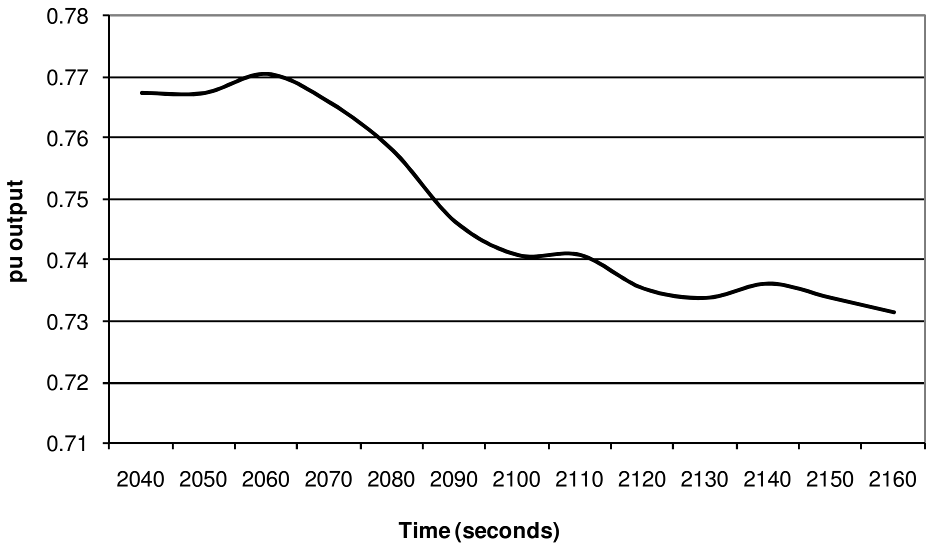

Figure 37: Wind farm response to a set-point change from 0.773pu to 0.733pu

Figure 38 shows the response of the wind farm to the APFM scheme increasing the permitted wind farm output from 0.733pu to 0.80pu. It can be seen that the wind farm begins to increase MW production at 2390 seconds; 40 seconds after the RNFG PLC issued the set-point. It is unclear whether the increase is delayed due to the delays inherent within the communications and control schemes or due to wind conditions. As can be seen in Figure 38, from 2390 seconds to 2490 seconds the wind farm gradually increases MW production until the set-point is achieved. It is difficult to interpret the response of the wind farm for this scenario as the previous examples for trimming the wind farm suggest that the wind farm control systems restrict the combined output from all turbines to below the set-point issued, therefore it is questionable when the set-point target is achieved. Once the power production starts increasing it takes around 100 seconds for the wind farm to achieve a 6.66% increase, representing a ramp-up rate of around 4% of rated output per minute.

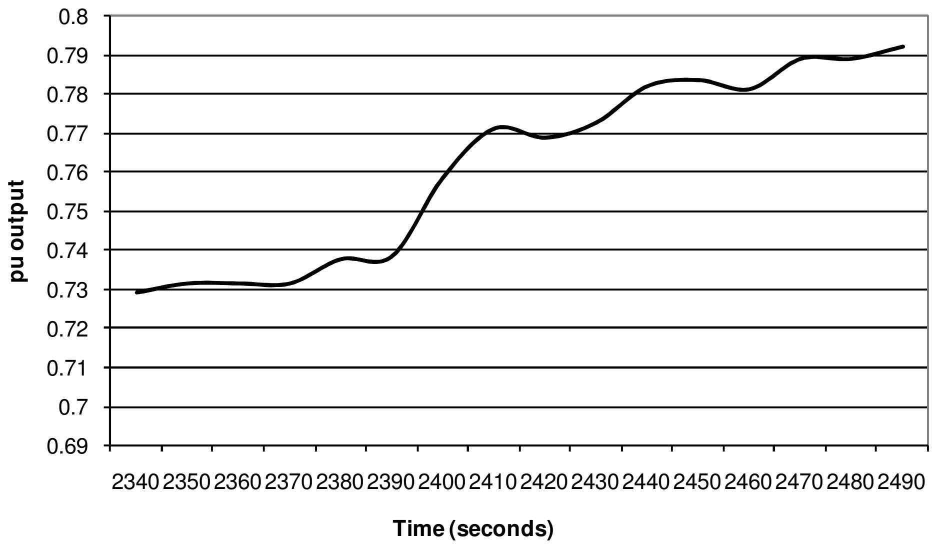

Figure 38: Wind farm response to a set-point change from 0.733pu to 0.80pu

Figure 39 presents the result of increasing the wind farm output from 0.8pu to 0.866pu. The time taken for the APFM scheme to issue the control instruction plus the time taken for the wind farm to respond is 150 seconds. The wind farm starts increasing MW production at 2080 seconds, 40 seconds after the initial control instruction was issued by the RNFG PLC. The MW output then stabilises below the set-point target after 110 seconds at 2190 seconds, as shown in Figure 39. This represents a 6.6% increase in wind farm output in a 110 second period; equating approximately top a ramp-up rate of around 4% of rated output per minute.

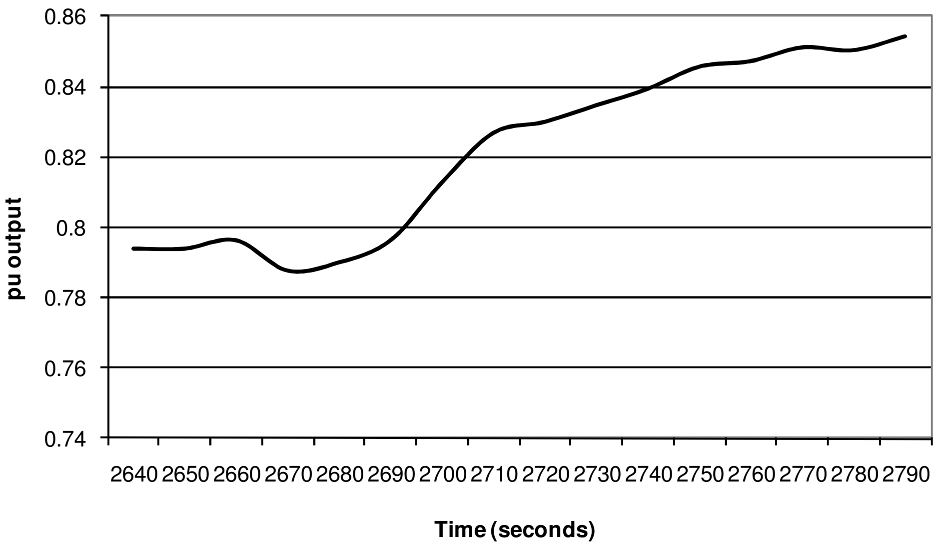

Figure 39: Wind farm response to a set-point change from 0.80pu to 0.866pu

5.6.3 Summary Results of Active Power Flow Management Scheme Trial

Table 18 provides a summary of the results of the trial of the APFM scheme. The total time taken for the APFM scheme to measure, process and send a control instruction is provided. The time taken for the wind farm to regulate MW production to the desired set-point is presented, resulting in an approximate ramp rate for the wind farm for each set-point change discussed previously.

The communications and control delay identified in Table 18 does not distinguish between the communications delay and the inherent delay within the wind farm control system. According to the results presented previously in Table 17 (concerned with communications delays), it would appear that the wind farm control system is mainly responsible for the delays identified in Table 18.

Table 18: Summary of response characteristics of wind farm

Approximate initial wind farm output (pu)	Set point issued (pu)	Communications/ control delay (seconds)	Ramp time (seconds)	Total time for control (seconds)	Approximate ramp rate %/minute (rounded to nearest whole number)
0.866	0.84	40	33	73	5
0.84	0.80	80	50	130	5
0.80	0.773	30	35	65	5
0.773	0.733	20	90	110	3
0.733	0.80	50	100	150	4
0.80	0.866	40	110	150	4

5.7 Lessons Learned from Trial of Active Power Flow Management Scheme

Interpreting the performance of the APFM scheme and the wind farm in the trial are essential tasks, which will validate and inform the practical implementation of the APFM scheme. The following sections detail the lessons learned from the trial of the APFM scheme.

5.7.1 Wind Farm Output Regulation Capability Confirmed

The APFM trial has shown that a wind farm can achieve a desired set-point and therefore be controlled for the purposes of APFM. It appears that the response characteristic of the wind farm can vary over a relatively short period of time, in terms of how long it takes the wind farm to begin reacting to an issued set-point. However, once it is actually responding, it appears that the ramp rate is fairly consistent between 3%/min and 5%/min. It has also been shown that the MW output from the wind farm can remain consistently below the set-point issued. This confirms that the output of a wind farm can be managed in accordance with the requirements of the APFM scheme, provided the communications, control and ramp times can be accounted for. The APFM operating margins directly address dealing with this uncertainty.

Setting the ramp rate of participating RNFG units to a higher value will benefit the operation of RNFG units in the full scheme as the size of operating margins employed will be reduced (the full benefit of which will depend on the relative ramp rate behaviours of other connected generators and loads), which in turn will reduce the curtailment experienced by each RNFG unit. A desirable ramp rate for RNFG units should be communicated to the generator developers at the planning stage.

5.7.2 Integrating the Active Power Flow Management Scheme with the Network Operator SCADA System

PLCs can perform data logging and support remote access, although security concerns are likely to reduce the opportunity for off-site access to an automatically operating control scheme. The following issues must be considered when looking to integrate the APFM scheme with the host network operator SCADA system:

- The network operator DNO should be able to remotely turn the APFM scheme on/off
- The network operator DNO will need to identify which data (analogue measurements, digital values) should be brought back through the SCADA system to operator terminals
- The network operator DNO will need to identify which APFM functions should be accessible by the control room
- The host network operator will need to view some of the data associated with the APFM scheme on the normal screen for the network area, where the details of the other generators and measurements are displayed. Issues will arise due to the routes available for data to reach the control engineer,

confirming data, performing actions etc, such issues will need to be resolved for each installation.

- A separate SCADA screen will likely be required to allow the control engineer to access more information on the APFM scheme than that displayed on the normal screen for the network area. The APFM SCADA screen could be based on a schematic of the network and the locations of controllers, measurements and RNFG units.

The results of the trial provide insight into how the wind farm would respond if controlled by the APFM scheme. Historical data of the performance of the wind farm is now investigated to provide an understanding of the normal operating behaviour of the wind farm, which essentially represents the behaviour of wind farms that could be either FG units or NFG units connected to the network.

5.8 Analysis of Wind Farm Historical Data

One of the lessons learned from the trial of the APFM scheme was that the temporal aspects of the wind farm performance will impact on the effectiveness of controlling wind farm output through APFM. To gain further understanding of the behaviour of the wind farm in the trial of the APFM scheme, analysis of variations in wind farm output over different time periods was performed.

Investigation of a wind power output profile to identify trends in data is an onerous and potentially complex task. The results of such an analysis are also dependent on the profile fed into the analysis process (which for wind generation is subject to seasonal variations) and could change significantly as different data or generator technologies are considered. For this reason it was decided to consider a simple frequency distribution of the variations in wind farm output over different time periods. This was done for a period of high wind speed and therefore high wind farm output. This is useful as it is likely that the RNFG units will be curtailed at times of high wind speed.

Three data sets of power produced by the wind farm in the trial of the APFM scheme were studied. The data was provided by Scottish Hydro Electric Power Distribution Ltd (SHEPD) - the network operator - and consists of one second, 10 second and hourly profiles of MW output. The one second time series data was from an eight hour period in November 2005, the 10 second time series was from a three day period in November 2005 and the one minute time series covered the period from November 2005 to June 2006. A profile of one minute variations in output was created using time stamped data from the 10 second profile. Analysis of the profiles and the change in wind farm output over different time periods provides some insight into how existing wind generating units may behave.

5.8.1 One Second Variations in Wind Farm Power Output

A profile of wind farm power output at one second intervals for a six hour period of high wind speed was used to investigate the second by second variations in power output. A histogram of the change in power output per second (ΔP/sec) for the 28,800 data points considered is presented in Figure 40.

It is clear from inspection of Figure 40 that the output of the wind farm does not change over a one second period for 93% of the six hour period considered. There are a few occasions where the wind farm experiences a 0.007pu or 0.008pu increase in one second, but this happens for less than 1% of the time considered. Similarly, the wind farm experiences a reduction in output of 0.006pu or 0.007pu for less than 1% of the six hour period considered.

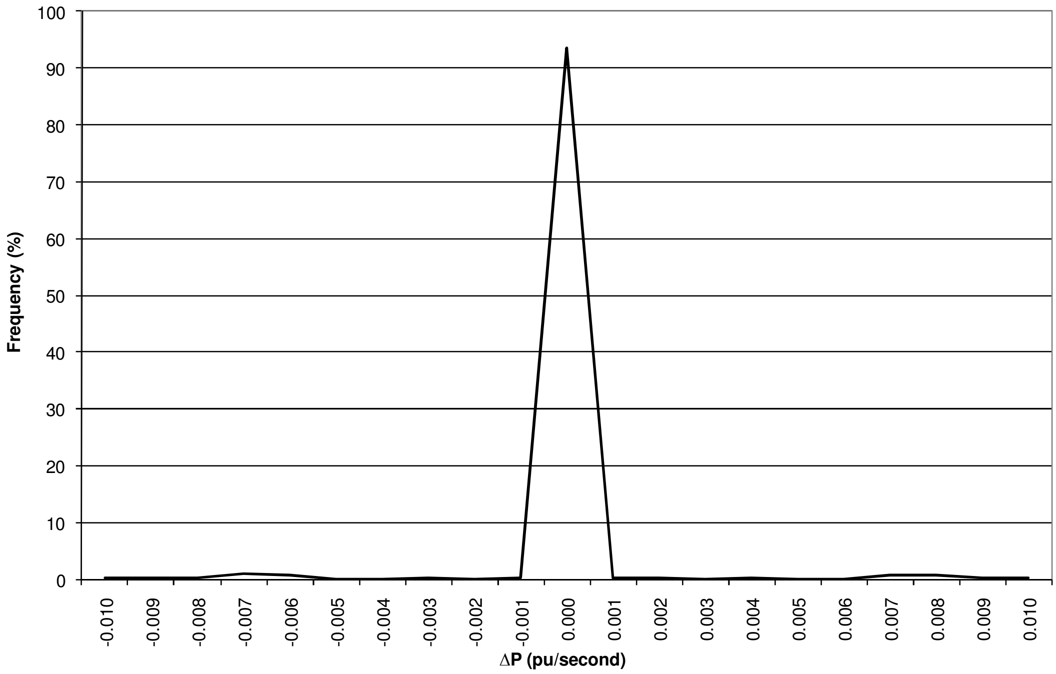

Figure 40: Histogram of per unit changes in wind farm output for one second intervals over a six hour period

5.8.2 10 Second Variations in Wind Farm Power Output

Figure 41 presents a histogram of the change in wind farm output over 10 second time intervals ($\Delta P/10s$) for a three day period, consisting of 25,920 data points.

The most frequent change in power output over a 10 second period is an increase of 0.01pu (i.e. a 1% increase in wind farm power output), rather than 0.00pu as identified previously. For 62.2% of the data points considered, there was a 1% increase in wind farm output over a 10 second period. Either side of this peak the frequency of $\Delta P/10s$ reduces to 1% of the data set.

There are two smaller spikes in frequency of similar shape and size at +0.05pu (6.6%) and -0.04pu (6.4%). These trends suggest one of two things: there are different modal aspects to how the wind farm behaves or there is some kind of filtering action inherent to the data capture process. There are also positive and negative ΔP/10s that are of greater magnitude, but these do not occur in more than 1% of the data set.

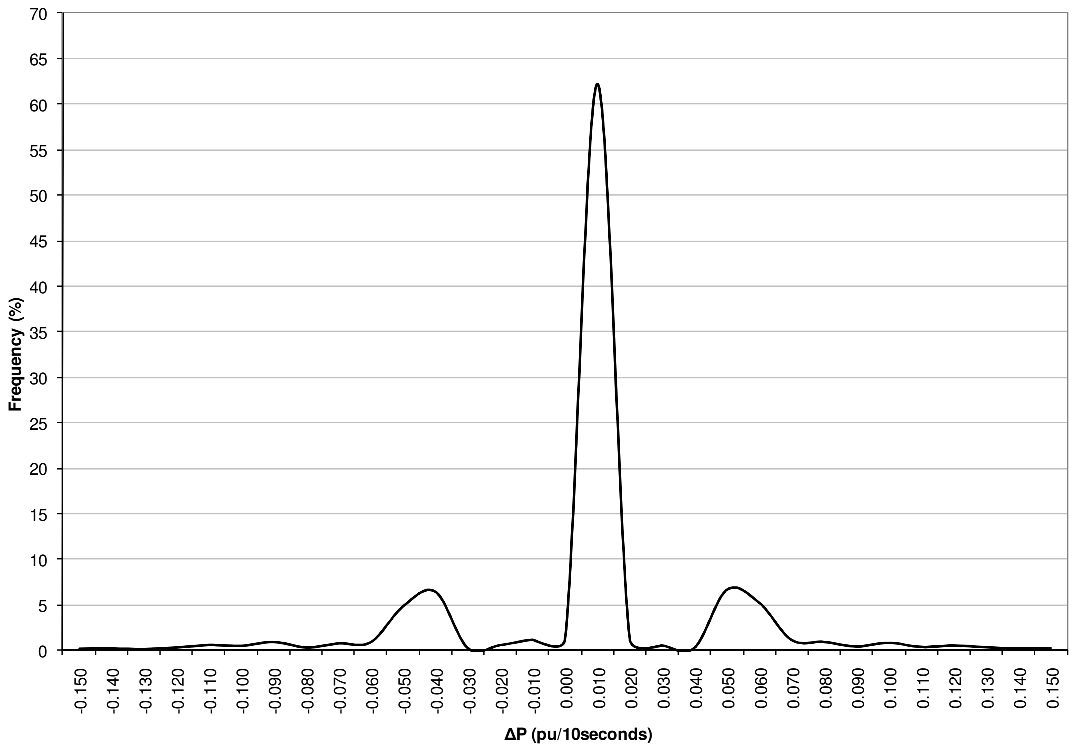

Figure 41: Histogram of per unit changes in wind farm output over ten second intervals over a three day period.

In summary, Figure 41 suggests that over 10 second periods of high wind speed it is more likely that the wind farm will experience an increase in output. This increase will more often than not be 1% of rated output; however, higher increases of 4-5% will occur on occasion.

5.8.3 One Minute Variations in Wind Farm Power Output

One minute time series data was created using the existing 10 second data as described previously. The 10 second data set was reduced to a data set consisting of one minute average values, resulting in 4320 data points. Decimation of a data set such as this requires careful consideration, averaging has been used here but consideration must be given to anti-aliasing and Nyquist sampling criteria when reducing large data sets, as discussed by Ifeachor & Jervis (Ifeachor & Jervis, 2002). The results of the analysis of the resulting average 1 minute profile are shown in Figure 42.

Figure 42 shows that the range of wind farm output variations at one minute intervals is dominated by 0.001pu (0.001% of rated output), which is experienced for over 43.5% of the data set. Either side of this peak, there are no changes in average wind farm output from one minute to the next for around 13.5% of the time and an increase of 0.002pu for just over 15.5% of the time period.

Figure 42 shows that the majority of changes in wind farm output over a 1 minute interval appear to be positive. A negative average change in power output (-ΔP/min) of 0.001pu occurs more often than no change whatsoever, with a frequency of around 14.65%.

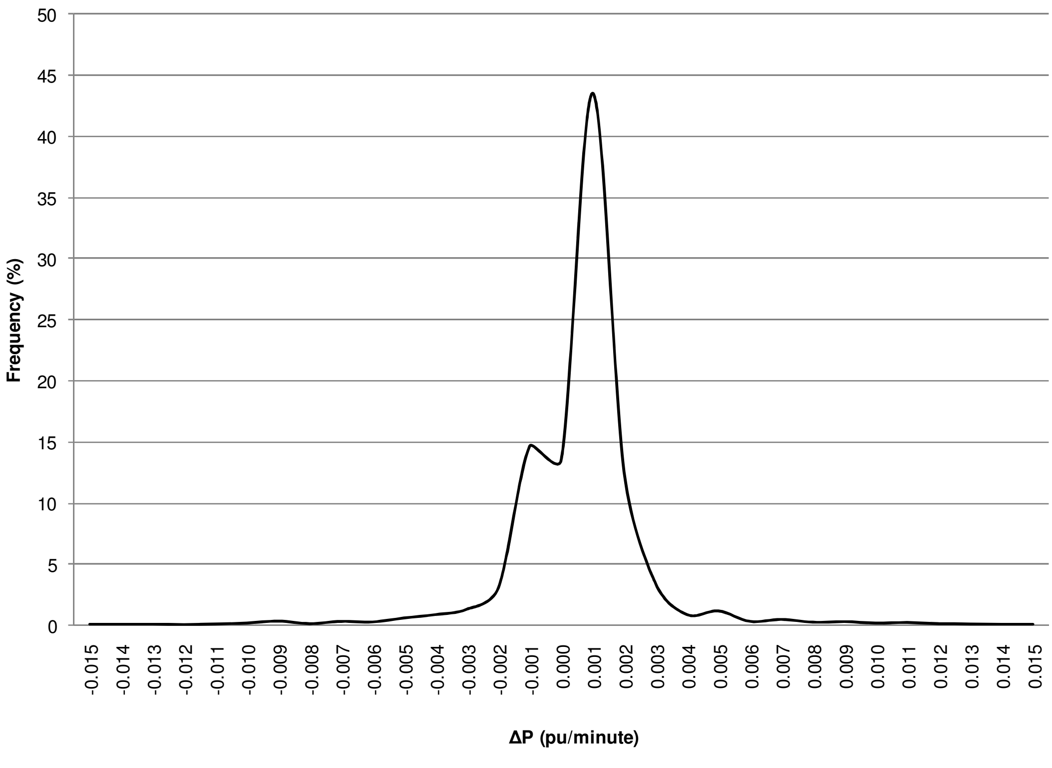

Figure 42: Histogram of average per unit changes in wind farm output over one minute intervals over a three day period

5.8.4 One Hour Variations in Wind Farm Power Output

Power output data at one hour intervals over a 7½ month period (November to mid-June) was analysed. A histogram of the variation of wind farm power output over these one hour periods is shown in Figure 43.

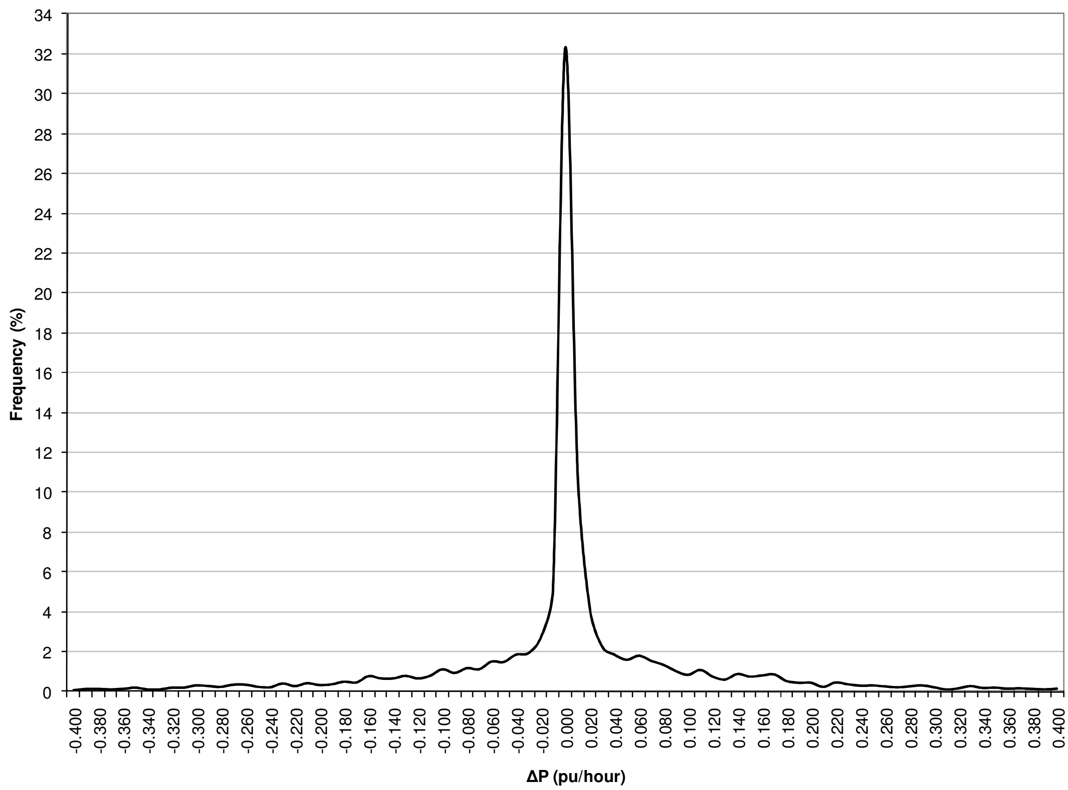

Figure 43: Histogram of per unit changes in wind farm output over one hour periods for 7½ months

Figure 43 shows that the most frequent change in wind farm output over one hour periods for the 7 ½ months considered is 0.00pu, which accounts for 32.3% of the data set. This spike in frequency dominates the histogram, but some other trends are noticeable.

There are more small increases in power output than there are decreases; indeed, the side of the spike on the negative part of the x-axis has a steeper slope than that on the positive side. Apart from this trend, the distribution is fairly even and both positive and negative changes in wind farm power output appear to be similarly common.

It is assumed that this could be due to the inherent inertia of the rotating mass that will reduce the rate of power output reduction. It is also assumed that if the same length of investigation (i.e. several months) were investigated for the other time-series data (e.g. one second data) then the histogram would appear more even, as is the case in Figure 43.

5.8.5 Discussion of Wind Farm Data Analysis Results

The results presented in the histograms closely resemble results published in a report by CIGRE (CIGRE, 2005). This report presents variations in wind farm power output over different time series in terms of magnitude. The main difference between the work presented by CIGRE and that presented here lies in the distinction between positive and negative variations, rather than just the magnitude of the variation.

Another study of wind farm behaviour by the National Renewable Energy Laboratory (NREL) (National Renewable Energy Laboratory, 1999) identifies a similar trend in one minute variations in wind power output. This report also states that data such as that presented in the previous sections tends to present more significant trends when individual or smaller numbers of turbines are considered, as opposed to a larger, wider geographical spread of wind farms. With reference to the APFM scheme presented in this thesis, the diversity in RNFG unit output due to geographical location will benefit the operation of the APFM scheme, as all generator units (FG, NFG and RNFG) will not ramp at the same time and at their maximum ramp rate values.

It is worth noting that no study has been identified where a similar type of analysis has been performed with a view towards informing the integration of the control of a wind farm with a distribution network control scheme. On the whole, studies tend to focus on the large scale integration of wind farms in terms of regulation, load following, reactive power support, voltage control and frequency-responding spinning reserve.

The maximum and average increase and decrease values in wind farm output for the different time series considered in this study are summarised in Table 19.

Table 19: Maximum and average variations in Wind Farm output for four different time series

Time Series Profile	Maximum Increase (%)	Maximum Decrease (%)	Average Increase (%)	Average Decrease (%)
1 Second	2.89	2.42	0.03	0.03
10 Second	5.54	3.36	0.17	0.16
1 Minute	5.02	4.71	0.07	0.07
1 Hour	87.99	79.71	3.32	3.31

It can be seen that the maximum increase and decrease in wind farm power output over each time series is high compared with the average values. One second time series data has a maximum increase in power output of 2.89% and a decrease of 2.42%. However, the average change in output over one second is +/-0.03%.

10 second time series data has a maximum increase of 5.54% and decrease of 3.36%. These values are significantly higher in magnitude than the average increase and decrease of 0.17% and 0.16% respectively.

One minute time series data experiences a maximum increase of 5.02% and decrease of 4.71%. These values are significantly higher than the average increase and decrease of 0.07% and 0.07% respectively. These results show that as the width of the window for monitoring is increased the average variation remains low.

The results for one hour time series data shows that the maximum increase and decrease in wind farm output to be 87.99% and 79.71% respectively, this is very large in comparison to the other time series data. Interestingly, the average values for these variations are 3.32% and 3.31% respectively. This result is very close to the average variation results for the 1 minute time series data.

Investigation of wind farm power output over different time periods has shed light on the performance characteristics of the wind generator studied. The results are, however, specific to the wind farm in question and the data set considered. Further analysis of seasonal variations in short term power fluctuations will provide further insight, as will investigation of the effects of geographically and electrically diverse wind farm locations. The results presented in Table 19 are required to inform the setting of time delays and operating margins within the proposed APFM scheme; however, it may be necessary to perform further data analysis of profiles of load and other generators, including generators with firm, non-firm or regulated non-firm status. The requirement for further analysis will be dependent on the background generation and demand and the type of new RNFG units connecting to the APFM scheme.

The time delays and operating margins used in the APFM scheme will be set based on an appraisal of the maximum increase/decrease in load and the output of FG, NFG and RNFG units over the time period in question. The average value experienced over this time period will also be considered. Setting the operating margin to account for the worst case scenario will ensure that the individual RNFG units have the best possible chance to avoid being individually tripped during normal operation. This will also, however, result in the largest operating margin and more curtailed MWh output per annum for participating RNFG units. Therefore a balance will need to be struck, which will be informed by the results presented above and further analysis of existing generation and load in the application area.

5.9 Further Work to Prove the Practicality of the Proposed Active Power Flow Management Scheme

Despite the success of the APFM trial meeting its objectives, several pieces of further work are required to verify the practicality of the APFM solution. These are now discussed.

5.9.1 Modifications to the Active Power Flow Management Scheme

The time delays and operating margins employed by the APFM scheme will be reviewed with each new RNFG unit connection or change to the network and the response of the system monitored until it can be confirmed that the scheme is providing sufficient access to capacity for the RNFG. Changes to these settings will be made by changing values within the Central APFM PLC. It may be possible for such changes to be made locally or remotely; however, it will be necessary to implement a change procedure irrespective of how the change is delivered.

The automatic or manual changing of the APFM topology will need to be tested and investigated. It may be that pre-programmed topologies can be agreed with the host utility companies and implemented automatically for a change in network topology. This will be addressed at the implementation stage but may require additional algorithms to be installed, depending on the complexity of the network.

5.9.2 Verification of Active Power Flow Management Functions

The other core functions performed by the APFM scheme will need to be tested, particularly those relating to the provision of network security (i.e. RNFG tripping and the logic associated with a loss of communications event). In addition to achieving set-point control, as was the case in the initial trial of the APFM scheme, it will be necessary to evaluate the effectiveness of the actions taken by the APFM scheme on reducing the measured current at the site of the thermal constraint on the network.

The communications deployed with the APFM scheme could have an impact on the operation of the scheme. The performance of the functions when subject to different latencies of communications routes will need to be considered.

5.9.3 Behaviour of Existing Generator Units and Loads

The behaviour of existing generation and load can be determined through analysis of historic profiles and the outcomes of the APFM trial. Data will be required over different time periods that will provide further insight into the temporal aspects of behaviour of both generators and loads. The results of data analysis will be used to set APFM time delays to filter out short term variations that breach operating margins, and to set the size of the operating margins themselves.

5.10 Chapter Five Conclusions

An initial trial of the APFM scheme has been completed on an existing wind farm. The initial trial has proven the hardware, software and communications systems chosen are effective for performing APFM. Although there are limitations associated with the trial, it has confirmed that a wind farm can be controlled to meet prevailing network constraints by the APFM scheme provided the response characteristic of the participating generators can be factored into the operation of the APFM scheme. The results of the trial are an important contribution to the field of APFM and are a significant step toward the validation of the proposed approach to APFM, including the suitability of the proposed algorithm and associated operating margins. Further work has been identified to prove the practicality of the APFM solution and to explore the behaviour of demand and FG, NFG and RNFG units through analysis of historic data.

It is now necessary to assess the proposed APFM scheme in terms of the impact on network performance, the installed capacity of RNFG units likely to connect (MW) and the performance of the RNFG units in terms of energy generated (MWh) and energy curtailed (MWh). This will be addressed in the next chapter of this thesis.

5.11 Chapter Five References

CIGRE (2005); "Electric Power System Planning with the Uncertainty of Wind Generation"; The First Report of Working Group C1.3, 2005

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Currie, R. A. F., Ault, G. W., Fordyce, R.W., MacLeman, D., Smith, M. and McDonald, J. R. (2008); "Actively Managing Wind Farm Output"; IEEE Letter, Transactions on Power Systems, Volume: 23, Issue: 3, 1523-1524, August 2008

Ifeachor, E. C. And Jervis, B. W. (2002); "Digital Signal Processing: A Practical Approach"; Second Edition, Pearson Education Limited, ISBN 0201-59619-9, 2002

National Renewable Energy Laboratory (NREL) (1999); "Short-Term Power Fluctuation of Wind Turbines: Analyzing Data from the German 250MW Measurement Program from the Ancillary Service Viewpoint"; Proceedings of Windpower '99, 1999

6 Economics of Active Power Flow Management

6.1 Chapter Summary

This chapter presents several economic assessments of the APFM scheme proposed in this thesis. The results of the economic assessments of the proposed APFM scheme address the requirements of both the DNO and RNFG developer, providing the necessary information to allow decisions to be taken regarding APFM scheme deployment. Such assessment methodologies and results are fundamentally required to support the deployment of the proposed APFM scheme and provide a point of reference for other ANM and APFM schemes and technologies. Case studies are used to support the application of the economic assessment methodologies and demonstrate that the proposed APFM scheme can support the economically viable connection of significantly higher installed capacities of renewable and distributed generation.

Firstly, a methodology is presented to determine the economic cut-off point for RNFG unit connections to the APFM scheme, based on break-even economics. A case study of the Orkney Isles distribution network is then presented to demonstrate the application of the methodology. Secondly, Generator Constraint Analysis Tool (GenCAT) is presented, which is a spreadsheet based program to study scenarios of RNFG unit connections and nested zonal constraints and estimate levels of generation and curtailment experienced by RNFG units connecting to the APFM scheme. The Orkney Isles distribution network is again used a case study, this time to demonstrate the application of GenCAT. Finally, the impact of varying APFM time delays on operating margins and the performance of RNFG units is investigated; a network from the United Kingdom Generic Distribution System project – UKGDS-EHV1 – is used as a case study to demonstrate the impacts on RNFG performance.

6.2 Economic Cut-Off Point for Regulated Non-Firm Generation Unit Connections

The RNFG units that connect to the APFM scheme will have their output curtailed when power flow on the network breaches the trim margin. As the APFM scheme adopts a LIFO approach to the principles of access, each additional RNFG unit should experience more curtailment than the previous (although this may not be true in all cases as a proportion of full output actually curtailed). In this section, a methodology is presented as described by Currie *et al* (Currie *et al*, 2006) to allow the economic cut-off point for further RNFG unit connections to the APFM scheme to be identified. The methodology is based on break-even economics, that is, the point at which the revenue lost due to curtailment is large enough to make the RNFG unit unviable.

6.2.1 Methodology for determining the Economic Cut-Off Point for Regulated Non-Firm Generation Units

The issue of constraints for generators connected to the transmission network often involves some discussion of constraint payments. Payments for constraints at the distribution network are not explored here, as it is assumed that the economic benefit for the RNFG developer lies in the avoidance of large capital costs associated with network reinforcement. Therefore, the RNFG owner can accept constraints up to the point where the benefits outweigh the revenue lost due to constraints. A methodology consisting of 13 distinct steps is now presented to identify the cut-off point for new RNFG unit connections.

STEP 1: Network capability for generation export at incremental load levels from minimum to maximum demand for the control zone is determined through power flow analysis.

In Step 1, the maximum generator export from the APFM zone is determined through power system analysis. This involves the modelling of real and reactive power flows and the corresponding voltage profile on the network. The load flow studies are performed for incremental levels of load (e.g. 1MW blocks) and the output of RNFG units is increased each time until the thermal rating of the network is reached. The result of this exercise is a set of maximum RNFG output levels for each incremental load level.

STEP 2: Gross available network capacity for export in each half-hour interval is calculated using historic half-hourly load demand data for one year.

In Step 2, the available network capacity at each half-hour for an annual period is calculated. Historic load data for each half-hour period of an annual period and the outcome of Step 1 is used to determine the gross capacity available for generator output on the network at each half-hour interval of the annual period.

STEP 3: APFM scheme trim threshold for each half-hour interval is determined by subtracting the pre-defined operating margin from the gross network export capability.

In Step 3, the trim margin to be applied as part of the APFM scheme is then subtracted from the gross capacity available to generators in each half-hour period of the year, resulting in the capacity available to generation through the application of APFM being calculated. The trim margin is subtracted as this is the target level for the APFM scheme and will be the level achieved if output regulation of RNFG units is achieved.

STEP 4: Generation portfolio output energy (MWh) is estimated for half-hour intervals for incremental RNFG capacity (i.e. MWh/MW of RNFG capacity) based on a historic generation power output time series for the same period as the load demand series (or from other energy resource assessments).

In Step 4, historic profiles of generation are used to create RNFG unit profiles. These profiles and the historic profiles of FG and NFG units can then be used to create a profile of energy (MWh) generated by the entire generation portfolio for different RNFG unit scenarios.

STEP 5: Generation portfolio output energy (MWh) that does not breach the trim threshold is summated over the full period of interest for all RNFG portfolio capacity levels (MW) from zero to some notional upper limit based on each individual half-hour interval in one year.

Step 5 involves the comparison of all scenarios of total generation portfolio output (MWh) with the available capacity (calculated in Step 3). The generator output that does not breach the trim threshold is summated for the annual period (or other time period being considered).

STEP 6: Constrained RNFG portfolio energy output (MWh) that breaches the trim threshold is summated for all RNFG portfolio capacity levels (MW) from zero to some notional upper limit based on each individual half-hour interval in one year.

Step 6 involves the comparison of the total generation portfolio output (MWh) with the available capacity (calculated in Step 3), as in Step 5. However, this time the generator output that does breach the trim threshold is summated for the annual period (or other time period being considered).

STEP 7: Typical cost of RNFG connection is estimated using Equation (26), including cost of connecting to APFM scheme:

$$C_c = C_c^{Gen} + C_c^{EC} + C_c^{SC} \tag{26}$$

Where, C_c = Annualised capital cost (£/MW), C_c^{Gen} = Annualised capital cost of generation plant (£/MW), C_c^{EG} = Annualised capital cost of electrical connection (£) and C_c^{SC} = Annualised capital cost of APFM scheme connection (£).

Step 7 involves calculating the total annualised capital cost of the connection to the network (including generator plant costs and electrical connection costs) and the APFM scheme on a per MW basis. These costs can then be applied to the scenarios of RNFG capacity as required.

STEP 8: Set renewable certificate (RC) price and electricity market price (both in £/MWh).

The revenue available to the RNFG unit(s) is determined in Step 8 according to the price the generator will get for each unit of electricity from the market and also from any renewable certificates that the developer may be able to access for each unit of energy generated.

STEP 9: Calculate revenue for all RNFG capacity levels:

$$R_T = E(RC + p^E) \tag{27}$$

Where, R_T = Total revenue accrued by increment of RNFG capacity (£), E = Annual RNFG energy output (MWh), RC = Renewable certificates unit price – if applicable (£/MWh) and p^E = Average energy market unit price (£/MWh).

In Step 9, the total revenue received by each incremental MW of RNFG capacity is calculated using Equation (27). The total energy produced in the year (MWh) is multiplied by the renewable certificate price plus the market price for electricity.

STEP 10: Calculate lost revenue for all RNFG capacity levels:

$$R_L = E_c(RC + p^E) \tag{28}$$

Where, R_L = Total revenue lost by increment of RNFG capacity (£) under APFM scheme and E_C = Curtailed annual RNFG energy output (MWh) under APFM scheme.

In Step 10, the total revenue lost for each incremental MW of RNFG capacity added is calculated using Equation (28). The total energy curtailed in the year (MWh) is multiplied by the renewable certificate price plus the market price for electricity.

STEP 11: Calculate the break-even revenue required for RNFG according to Equation (29):

$$R_{BE} = C_{RP}^{C} + C_{OP} + P \tag{29}$$

Where, R_{BE} = Revenue required by increment of RNFG capacity to break even (£), C_{RP}^{C} = Annualised capital repayment (£), C_{OP} = Operating charge (£) and P = Normal profit (£).

In Step 11, the total revenue required for the RNFG capacity being studied is calculated using Equation (29), which involves the summation of the annualised capital repayment, any operating costs and the normal profit required by the RNFG unit.

STEP 12: Divide revenue required by increment of RNFG to break even by the total revenue (£/MWh):

$$E_{RNFG} = \frac{R_{BE}}{R_T} \tag{30}$$

Where E_{RNFG} = Annual RNFG energy output required to break even (MWh).

In Step 12, the annual energy production required by the RNFG capacity being considered is determined by dividing the revenue required by the RNFG (according to Equation (30)) by the total revenue accrued by the RNFG per MW of capacity (according to Equation (27)).

STEP 13: Match E_{RNFG} result from STEP 12 to the outcome from STEP 5 to derive the Economic Cut-Off Point (ECOP) in MW of additional RNFG enabled by the APFM scheme.

In Step 13, the annual energy production required is matched to the MWh generated by incremental MWs of RNFG capacity. This allows the economic cut-off point to be identified for RNFG capacity (MW).

Following Steps 1 - 13 provides a number of useful results for analysis of the APFM scheme. For a given increment of RNFG (and taking account of higher priority RNFG already connected) the annual energy output and annual energy curtailed can be identified. In addition, an overall upper limit on RNFG connections can be estimated based on the operation of the APFM scheme and RNFG generation portfolio economics.

The method proposed does not address planned (maintenance) or unplanned wind generating unit outages that could increase the curtailment experienced by RNFG units and therefore lower the ECOP. The application of the methodology is now presented using a case study.

6.2.2 Case Study – Economic Cut-Off Point for Regulated Non-Firm Generator Connections

The Orkney distribution network forms part of the North-Scotland network, operated by Scottish and Southern Energy plc. The north and west coasts of Scotland are rich in renewable energy and are the focus of significant interest from renewable energy developers. Orkney has a long association with wind energy in particular and was home to some of the first grid connected wind turbines in the UK.

This section describes the application of the APFM scheme to the Orkney Isles and the determination of the ECOP for a number of scenarios of operating margins and revenue levels.

6.2.2.1 The Orkney Situation

The Orkney electrical demand varies from around 8MW to 32MW. The Islands that comprise the Orkney Isles are connected through a combination of overhead lines and submarine cables. The network is connected to the Scottish mainland through two submarine cables with a combined import/export capability of around 40MW.

26MW of Firm Generation (FG) and 21MW of Non-Firm Generation (NFG) has been connected to the network. Existing FG are a mixture of renewable and non-renewable sources that have priority access to network capacity and are unconstrained during normal operating conditions and the N-1 contingency. The NFG are inter-tripped for the N-1 contingency (loss of a submarine cable to the mainland) if the power export breaches a pre-defined threshold. As a result of the FG and NFG (a mixture of wind energy, marine energy and gas generation) there are times when Orkney exports power to the mainland.

A dynamic reactive compensation device and several shunt reactors have been installed by the network operator to alleviate short-term and long-term voltage fluctuations on the local network. The Orkney Isles' distribution network is shown in Figure 44.

The FG, consisting of a mixture of wind generation, marine energy sources and gas turbine generation, accounts for 26MW. An additional 21MW of NFG capacity has been allocated by the network operator, meaning further generator connections are constrained by a lack of available capacity.

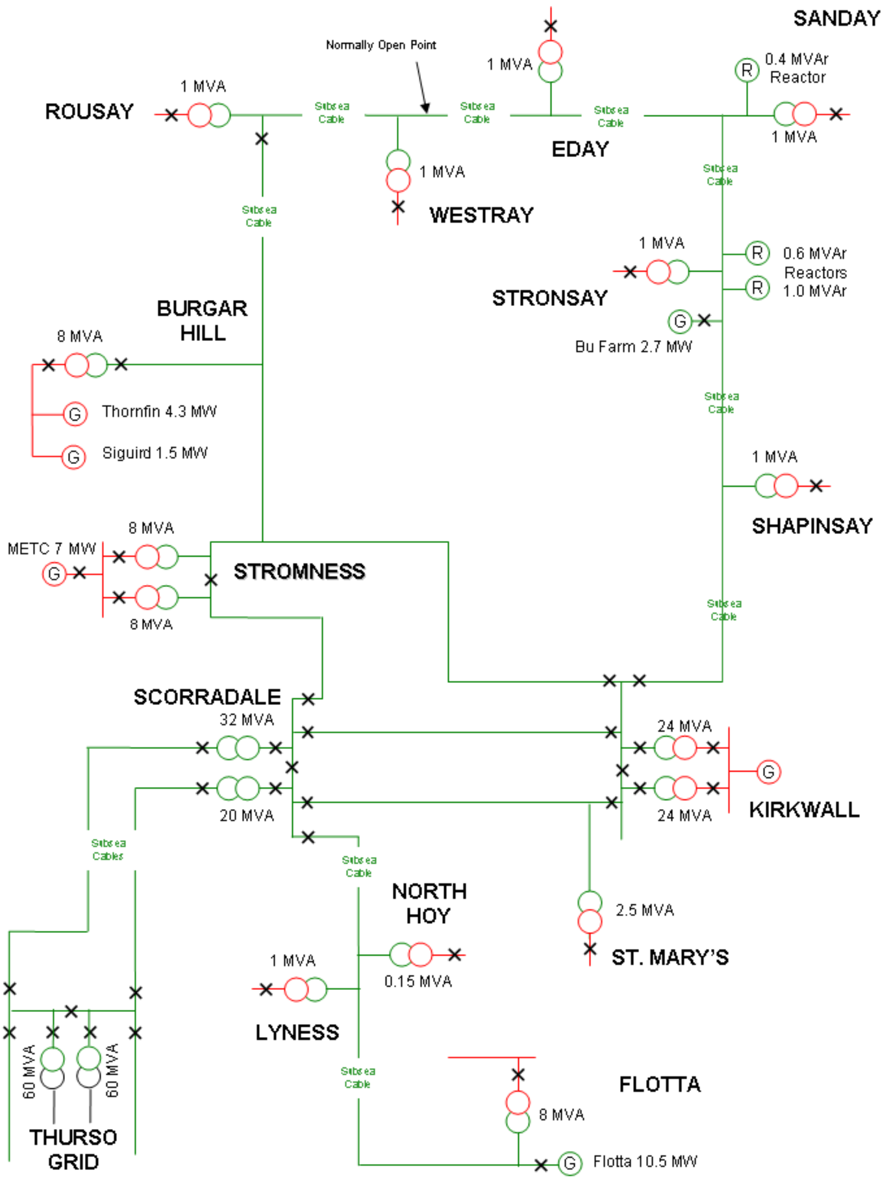

Figure 44: Orkney Isles Distribution Network

6.2.2.2 The requirement for Active Power Flow Management

The installation of voltage control equipment has resulted in thermal capacity constraints on the Orkney network being the main impediment to further generator connections. The application of the APFM scheme presented in Chapter 4 will facilitate increased DG connections to the Orkney network.

The size and location of RNFG units will determine the location of thermal constraints and also the levels of constraint experienced by RNFG units. The methodology presented can be applied to the addition of incremental additional capacity for the entire Orkney network (taken as one APFM zone) without the exact location of RNFG units being known.

6.2.2.3 Economic Cut-Off Point for new Regulated Non-Firm Generator Connections to the Orkney Network

The maximum theoretical amount of generation that can connect to the Orkney network is 72MW (based on the export capacity to the Scottish mainland plus the maximum demand on the Orkney network). Therefore, after the FG and NFG capacities are allocated the RNFG accounts for the remaining 25MW. By considering break-even economics, the methodology presented in section 6.2.1 will determine if the economic range for RNFG units connected to the network is above or below this theoretical level.

Existing profiles of wind generation were normalised and scaled to create the RNFG generation portfolio of varying sizes. The RNFG units are subject to coincidental constraint (when wind generation in the FG and NFG units coincides with the output from the RNFG units and so the RNFG units must regulate down their power output). This coincidental constraint issue along with the varying load demand, impacts heavily on the constraint experienced by the RNFG.

Following the methodology for the evaluation of the ECOP outlined above, and using a range of values for the trim operating margin (from 1MVA to 10MVA) a set of results for the Orkney network are generated. Figure 45 shows the results for energy output for incremental RNFG capacity from the 47MW lower limit (based on FG plus NFG capacity) after thermal constraints are satisfied. This is effectively the output from STEP 5 in the process outlined in section 6.2.1. The energy output of the incremental RNFG portfolio has been calculated up to a total generation portfolio (FG + NFG + RNFG) of 102MW. This level is beyond the theoretical RNFG capacity defined above to ensure that a large enough range is considered and also to allow the effects of increasing curtailment to be visualised.

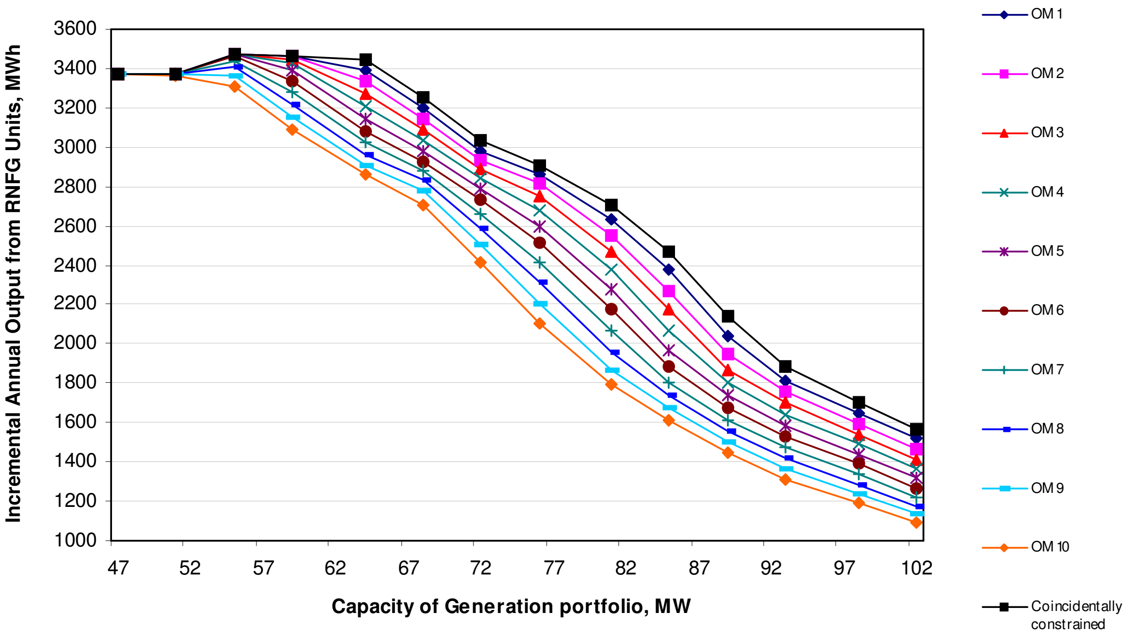

Figure 45: Incremental energy output from RNFG connected to the APFM scheme

Figure 45 shows a general decrease in annual energy output for each incremental unit of RNFG capacity. The first few MWs of incremental RNFG capacity produce around 3400 MWh of energy in one year (a load factor of 39%) and they are almost totally unconstrained throughout the year. The slight increase in MWh around 52MW is due to the value for 47MW being an average of the entire FG + NFG units; the additional RNFG profiles were created using wind energy only. The profiles used for wind energy had a higher capacity factor than the average for all generation sources that comprised the FG and NFG units.

Higher increments of RNFG capacity produce less and less output as the constraints of the APFM scheme take effect (with the major effect from the existing generation and the load demand profile). The ten options for operating margin studied also have a significant effect on annual energy output from RNFG units. If the capacity increment at 81MW is taken as an example: the theoretical maximum annual output for this RNFG increment (shown by the coincidentally constrained curve) is approximately 2700MWh per year. If the largest operating margin (represented by the OM10 curve) is assumed then the annual energy output drops to 1800MWh. This difference of 900MWh per year demonstrates the significance of setting the operating margin: the operating margin clearly must be set at an appropriate level to ensure secure network operation, but if it is set too high then the generation curtailment becomes significant.

The next stage in this case study analysis follows STEP 7 through to STEP 13 in the methodology. The cost of electrical connection and connection to the APFM scheme will be specific to each individual generator. In the case of the communications equipment necessary for integration with the APFM scheme there are different options with different associated costs. For example, digital radio may be a favourable choice of communications on Orkney, but in the absence of a suitable digital radio link (≈£20,000) it may be necessary to install pilot wires which may have a capital cost in the region of £120,000. The variation in these costs will be related to site specific arrangements, available measurements and the cost of communications.

The costs presented in Table 20 will be used to complete the remaining steps of the methodology.

Table 20: Assumed costs for connection to APFM scheme.

Capital Cost Component	Capital Cost
Generator installation	750 £/kW
Electrical connection to distribution network	£150,000 + component dependent on circumstances
Integration with ANM scheme communications	£20,000 + component dependent on circumstances

Using equation (25) and the approximate parameter values for wind generation capital costs given in Table 20, the total capital cost is calculated at:

$$C_c = \underline{£920{,}000 \,/\, \mathrm{MW}}$$

Assuming 10% of this total capital cost for wind generation is required per annum to service the capital outlay then the minimum annual revenue for economic break even is 92,000 £/MW of connected wind generation.

Two levels of total revenue from combined energy sales and renewable certificate sales will be considered (based on GB Renewable Obligation Certificate prices): 40 £/MWh and 60 £/MWh. Given that 92,000 £/MW must be recovered to break-even then the energy output required is 2300 MWh at a revenue per unit of 40 £/MWh and 1533 MWh at a revenue per unit 60 £/MWh (based on STEP 12). If these break-even energy outputs are now used with reference to Figure 45 then an indicative upper economic limit on generation development can be identified (STEP 13).

Figure 46 illustrates the ECOP based on the assumptions presented above for each of the operating margin levels and for the two realistic examples of energy and renewable certificates revenues.

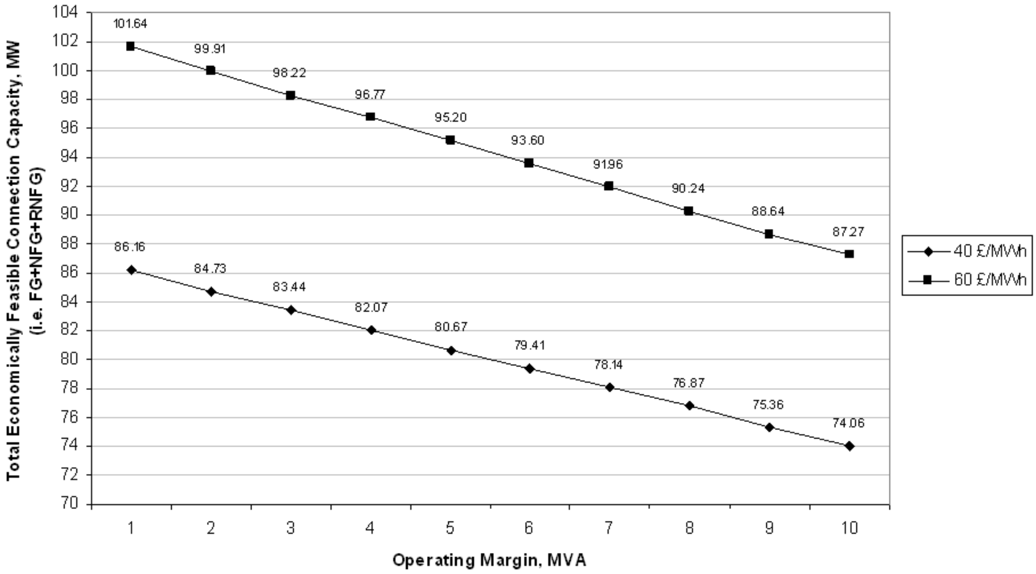

Figure 46: Economic cut-off point for RNFG connections

The results in Figure 46 show the significant impact on the economic viability of a connection due to uncertainty regarding the revenue accrued from ROCs and energy sales. Generation developers will have to assess whether a potential generation investment has enough merit through careful consideration of the operational constraints of the scheme and also the potential future prices for energy and renewable certificates.

Figure 46 shows that the APFM scheme has the potential to increase the capacity of generation connected by upwards of three times the FG connection capacity, from a FG capacity of 26MW to 74MW (being the lowest ECOP value calculated for the scenarios considered).

These results are tremendously valuable to DNO and generation developer alike as they give a clear indication of the economically feasible generation capacity enabled by the APFM scheme for the assumptions made.

6.3 Generator Constraint Analysis Tool

In the previous section, the economic limit of connections to the APFM scheme was investigated. This was done for incremental levels of RNFG capacity. In this section a tool is described that allows constraints for individual or multiple RNFG units to be calculated. A Generator Constraint Analysis Tool (GenCAT) is used to assess multiple network constraints and provide an indication of curtailment for RNFG units located in one or more APFM zones. Power system studies of the network are required as an input to GenCAT, which is a profile-based analysis tool.

If the APFM scheme is to be considered as a viable alternative to network reinforcement for connecting generation, then an effective GenCAT software tool is required. There is added complexity associated with the creation and use of such a tool, in comparison with the approach outlined previously for the methodology to determine the ECOP. The following factors provide the added complexity:

- The actual location of the RNFG units and the corresponding constraints and curtailment will need to be more closely analysed. This information will be required for raising project finance and to create confidence in the commercial opportunity for each RNFG development.
- The tool will need to be flexible to cater for multiple RNFG units
- The tool will need to allow the user to select the location and nature of RNFG units (i.e. 5 MW wind farm in Zone 1, 3 MW tidal generator in Zone 3, etc)
- The tool will need to be flexible to cater for multiple measurement points

The user can enter the number, size, location and nature of RNFG connections into GenCAT. GenCAT will provide results of energy produced and curtailed for each connection, through an iterative process at half-hour intervals for an annual period, solving all nested constraints.

Although not directly interfaced with a power systems simulation package, GenCAT allows the user to specify values that are informed by data or power systems analysis, such as operating margins and profiles of generation and load.

The operation of GenCAT requires the following three main steps:

1. Establish GenCAT programme structure
2. Characterise RNFG unit(s)
3. Solve all zone and nested zone constraints

6.3.1 Generator Constraint Analysis Tool Program Structure

Figure 47 provides an overview of the process required to establish the structure of the GenCAT programme. Due to results of power system studies (of the proposed connection of one or more RNFG units) and the method described in Chapter 4 for identifying APFM zones, the user has identified the need for an APFM zone. Therefore, the location of the constraint is known and the capacity of the network at that location is known. The user creates a worksheet for the APFM zone being defined, this zone is then characterised in terms of the size (MW), nature and ramp behaviour of FG, NFG and load in the zone. The profiles of existing generation and load are then created for each half-hour of an annual period. This information and knowledge of the constraints allows the capacity available at each half-hour period to be calculated. If the zone is to be nested within another zone then zone boundary exchanges are calculated, i.e. the export or import from the zone based on existing generation and load. A new APFM zone is then defined (being the zone that the previous zone is nested within) and the same process undertaken until the appropriate programme structure is achieved, based on the APFM zones identified according to the method outlined in Chapter 4.

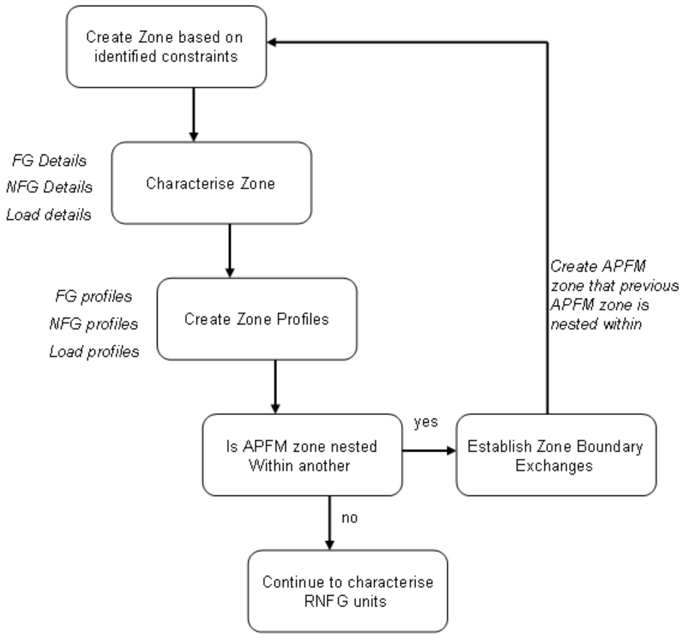

Figure 47: Overview of process to establish GenCAT programme structure

6.3.2 Characterising Regulated Non-Firm Generation Units

Once the required structure of the GenCAT programme is defined, the RNFG units to be modelled need to be added. Each RNFG unit has data associated with it that must be entered by the user, including size (MW), zone of location and nature. At the present time, GenCAT supports the modelling of wind, wave and tidal based renewable generators as will be discussed in the next section. The RNFG units are added to GenCAT in the order of highest priority first, to create a stack of RNFG units that are ordered to fit with the Last In First Off (LIFO) principle. Once the RNFG units have been defined in this manner, GenCAT then separates the units by zone of location. The ramp rates and time delays associated with the RNFG units and APFM scheme (in addition to previous information regarding the FG units, NFG units and load in the zone) are then used to define the APFM operating margins required at each zone. This process is shown in Figure 48. Approaching the definition of the RNFG units in this manner allows the nested constraints to be addressed in the next stage of the operation of GenCAT.

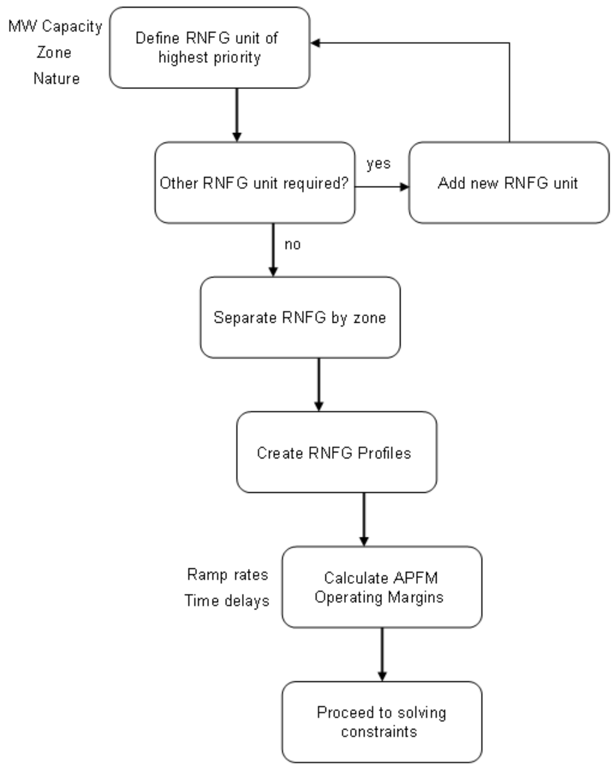

Figure 48: Overview of process to define RNFG unit(s) in GenCAT

6.3.3 Solving Zone and Nested Zone Constraints

The final process undertaken by GenCAT is the solving of all zone and nested zone constraints for the RNFG units and accompanying GenCAT programme structure defined by the user. This process is shown in Figure 49. The most nested zone is considered first; the curtailment required in each half-hour period is calculated. The total curtailment for the zone is then allocated to each RNFG unit according to LIFO, i.e. if after allocating the total curtailment to the first RNFG unit there is remaining curtailment (due to the required curtailment being greater than the output of the RNFG unit at that instance) then this curtailment is allocated to the next RNFG unit according to LIFO, and so on.

After the final RNFG unit profiles have been defined for the zone constraints, the zone boundary exchanges are recalculated, as if the zone is nested within another then the boundary exchange will need to be considered when the constraints in the other zone are being calculated. In this way, the RNFG units in the nested zone will still be liable for curtailment, but the calculation for required curtailment will only include the zone boundary exchange and the load and generation (FG, NFG and RNFG) in the zone. This will generate another set of new RNFG profiles in the nested zone and the first curtailed profile for the RNFG units in the zone being considered.

Finally, once constraints in all zones have been studied, the final profiles will provide the energy (MWh) generated by the RNFG units and the summation of all curtailment imposed on each RNFG unit for all associated zones will provide the total energy (MWh) curtailed.

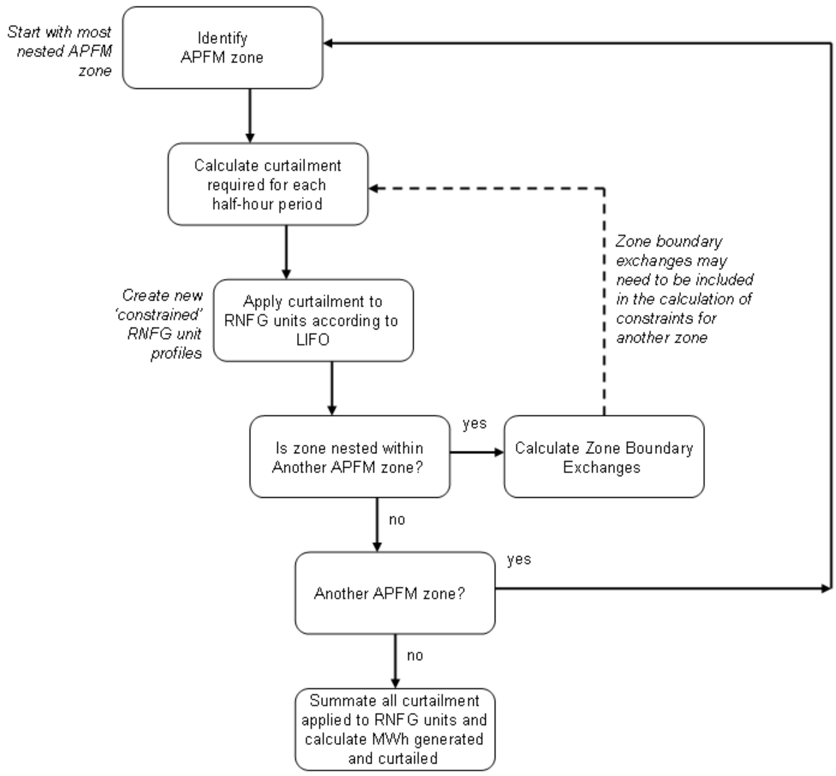

Figure 49: Process undertaken by GenCAT to solve all zone and nested zone APFM constraints

6.3.4 Case Study: Constraint Analysis on the Orkney Distribution Network

The application of the APFM scheme proposed in this thesis to the Orkney Isles distribution network formed the basis for an application by the network operator – Scottish Hydro Electric Power Distribution Ltd (SHEPD) – to the UK regulator (Ofgem) to designate Orkney as a Registered Power Zone (RPZ). The RPZ mechanism was introduced by Ofgem to encourage the uptake of innovative methods of connecting and operating DG. Due to the RPZ status, SHEPD are permitted to recover a significant proportion of the costs expended in delivering the RPZ and also have access to an additional incentive per MW of generation that is enabled by the RPZ.

SHEPD required an analysis tool to model the prospective RNFG connections to the Orkney distribution network. GenCAT was used to model over thirty applications to connect through the APFM scheme. In the following sections, the application of GenCAT to the Orkney RPZ is presented. Further insight is gained into the operation of GenCAT through this case study.

6.3.4.1 Generator Constraint Analysis Tool Program Structure for Orkney

Based on the topology of the Orkney network and the RNFG applications, GenCAT was structured to provide analysis of four zones nested within the Orkney 'Core Zone', as shown in Figure 50.

Each zone identified in Figure 50 was characterised in terms of existing generation, load and network capacity constraints. Each zone was given its own worksheet in Excel, with the associated data for each half-hour period in an annual period. Two versions of this GenCAT program structure were created; one for a year when there was high output from wind energy connected on Orkney (2003-4) and one when there was a relatively low output from the same wind energy (2005-6). This allowed a range of results to be provided on prospective RNFG connections. The basic structure of GenCAT configured for the Orkney RPZ is summarised in Figure 51.

Further zones can easily be added to GenCAT through the duplication of worksheets in excel and the modification and addition of limited Visual Basic for Applications (VBA) code.

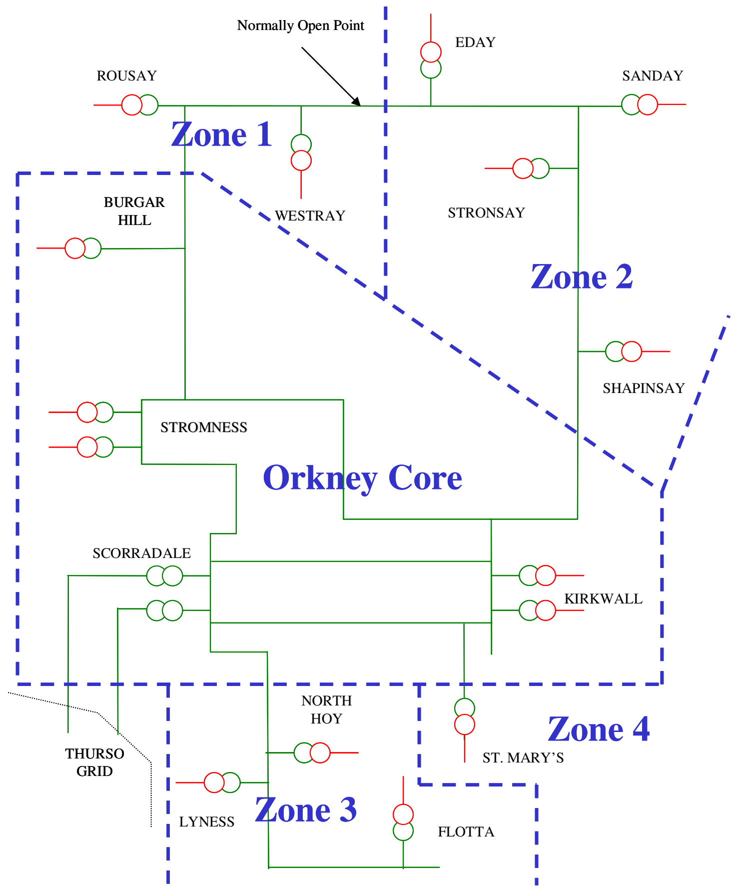

Figure 50: APFM Zones identified on Orkney network relative to GenCAT program structure

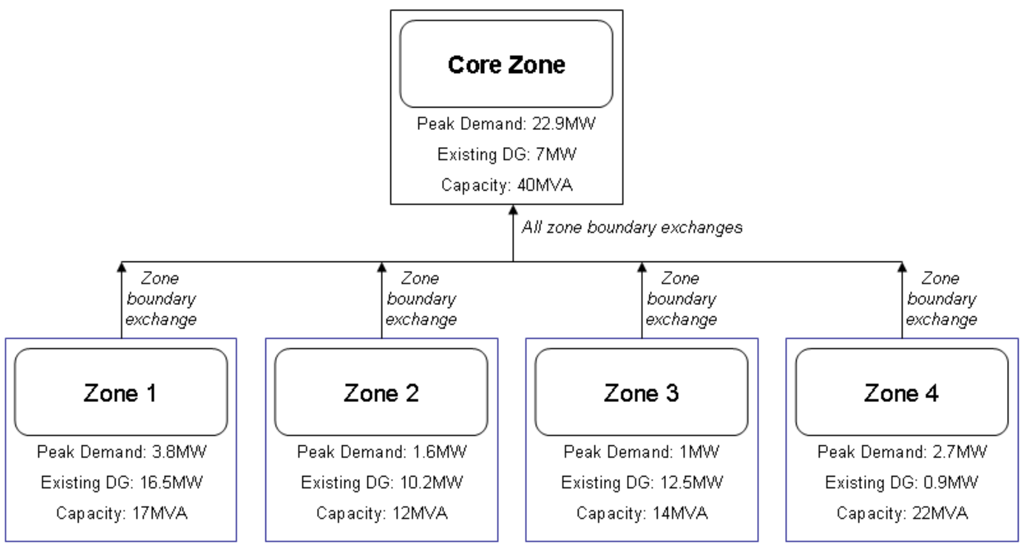

Figure 51: Summary of GenCAT Program Structure for the Orkney network

The front worksheet of GenCAT configured for the Orkney RPZ is shown in Figure 52. The user can click on the 'Click to begin' button in the bottom right hand corner of Figure 52 and will be provided with a pop-up display and user-form, shown in Figure 53. The details of the RNFG units are then entered in the user-form which allows the selection of the RNFG i.d. (representing the position in the priority stack of the RNFG unit), the size of the RNFG unit (in MWs), the zone of location (Zones 1-4 or Core) and the nature of the unit (wind, wave or tidal). The rest of the GenCAT analysis process is undertaken from the user-form and results can be extracted once constraints have been solved.

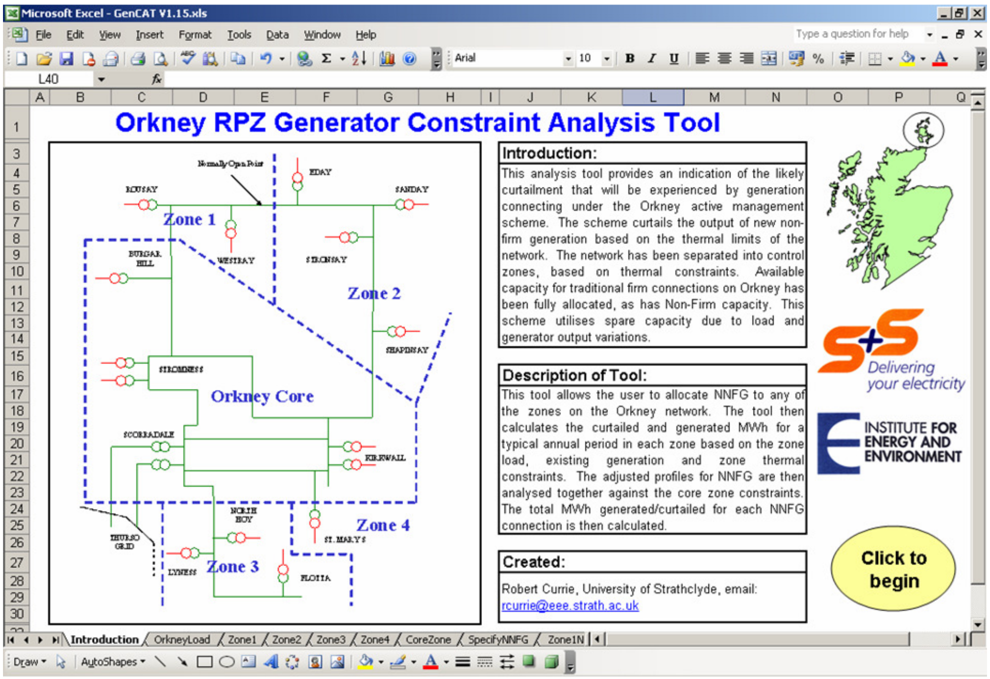

Figure 52: Screenshot of GenCAT configured for the Orkney network

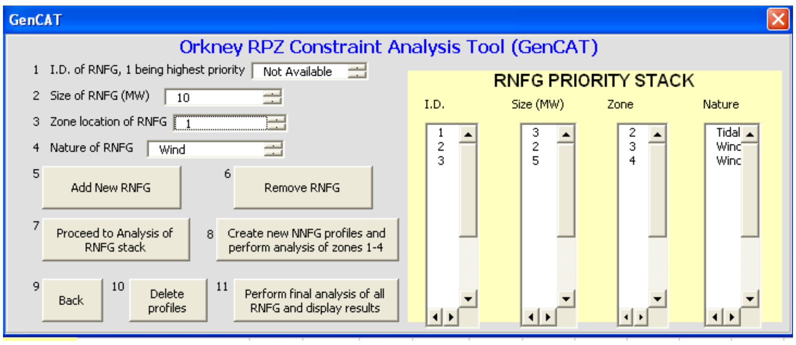

Figure 53: User interface for GenCAT including Orkney RNFG priority stack

6.3.4.2 Load and Generator Data

Historic profiles of generator output and total demand on Orkney were used as inputs to GenCAT, for both the 2003-4 and 2005-6 periods. Historic profiles of wind generation are preferable to generic profile data and if the wind data is from the same time period as the load data then the results of the simulation may be considered to be more representative of reality. The existing wind profiles from FG and NFG units in each zone were used to create normalised profiles for RNFG units being added to each zone. If no existing profile existed for a zone, then a wind profile from a nearby zone was used to create the normalised RNFG unit profile. Wind energy profiles vary by location but generally have a capacity factor within 0.3 – 0.45.

Despite the existence of the European Marine Energy Centre on Orkney, which has a test facility for wave energy devices, no wave energy output profiles were available as inputs to GenCAT. Generic half-hourly profiles for wave energy devices are not widely available as many devices are still to reach the market. Based on consultation with the network operator, Scottish Hydro Electric Power Distribution (SHEPD), it was decided that wave energy profiles should be created by lagging a wind energy profile by 4 hours, providing an approximate wave energy profile. The performance of the generator provides further uncertainty due to the lack of maturity in generation technology in the marine renewables sector. Therefore, the profiles used in this analysis are likely to be larger than that in reality. Future studies could make use of profiles supplied by the developer or site specific wave data and published technical information.

As with wave energy, half-hourly profiles for tidal energy devices are not widely available as many devices are still to reach the market. Due to the dependency on local geography, it would be beneficial if a power output profile was provided by the generator developer for further, more detailed studies. In consultation with SHEPD, tidal device profiles were created using the power curve of the 1MW MCT SeaGen device, as described by Boehme *et al* (Boehme *et al*, 2006). Water speed and tidal height data for Ullapool was supplied by the Energy Systems Research Unit at the University of Strathclyde, this data was adjusted for the tidal variation and height at Orkney. This data was used to map power output to the tidal cycles in 2003-4 and 2005-6. The profile data for tidal energy has a low capacity factor (of around 15%), which was agreed with SHEPD to be a reasonable starting point for modelling a generator technology which is yet to be commercially deployed.

6.3.4.3 Generator Curtailment Simulations

In order to demonstrate the simulation of RNFG connections to the Orkney network, the RNFG units in Table 21 are presented as an example of the type of study that can be performed by GenCAT. Several wind farms, a wave generator and tidal generator are modelled, providing a total RNFG capacity of 23.2 MW.

Table 21: RNFG Units considered in GenCAT simulations of the Orkney network

RNFG i.d.	Location	Technology	Size
1	Core Zone	Wind	0.9
2	Zone 1	Wind	2.3
3	Core Zone	Wave	10
4	Zone 2	Tidal	3
5	Zone 3	Wind	2
6	Zone 4	Wind	5

The operating margin employed for the export from each zone was calculated based on typical real and reactive power flows identified through steady state simulation and the maximum thermal rating (MVA) of the circuit in question. This resulted in the following conditions being agreed with SHEPD for each zone for the purposes of simulation; the actual operating margins implemented will depend on which RNFG units connect to the APFM scheme.

Table 22: Parameters used for performing constraint analysis

APFM Zone	Operating Margin (MVA)
Zone 1	2
Zone 2	3
Zone 3	3
Zone 4	4
Core Zone	8 (4MVA on each circuit)

6.3.4.4 Generator Curtailment Results for High-Wind Year

The results of curtailment studies of the high-wind year for the RNFG units shown in Table 21, are now introduced in terms of the results of constraints being applied to zones 1 – 4, then the Core Zone (with the other zone nested within). Finally, the total MWh generated and curtailed by each RNFG unit (i.e. not just details relating to one set of solved zone constraints) and the capacity factor generated and curtailed are presented.

In Table 23, the results for the 2.3 MW wind generator in zone 1 are presented. It can be seen that based on the constraints in zone 1 only, RNFG 2 produces 8262.15 MWh and is curtailed by 174.49 MWh.

Table 23: GenCAT results for RNFG 2 for Zone 1 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
2	Zone 1	Wind	2.3	8262.15	174.49

In Table 24, the results for the 3 MW tidal generator in zone 2 are presented. It can be seen that based on the constraints in zone 2 only, RNFG 4 produces 3562.89 MWh and is curtailed by 149.46 MWh.

Table 24: GenCAT results for RNFG 4 for Zone 2 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
4	Zone 2	Tidal	3	3562.89	149.46

In Table 25, the results for the 2 MW wind generator in zone 3 are presented. It can be seen that based on the constraints in zone 3 only, RNFG 5 produces 7336.2 MWh and experiences no curtailment.

Table 25: GenCAT results for RNFG 5 for Zone 3 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
5	Zone 3	Wind	2	7336.20	0.00

In Table 26, the results for the 5 MW wind generator in zone 4 are presented. It can be seen that based on the constraints in zone 4 only, RNFG 6 produces 18340.51 MWh and experiences no curtailment.

Table 26: GenCAT results for RNFG 6 for Zone 4 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
6	Zone 4	Wind	5	18340.51	0.00

The final results for all RNFG units are shown in Table 27. The MWh generated by RNFG units located in nested zones is increased due to the core zone constraints (i.e. the constraints on the submarine cables from Orkney to the Scottish mainland). All RNFG units experience some curtailment due to core zone constraints.

Table 27: GenCAT results for all RNFG units

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
1	Core	Wind	0.9	3259.75	41.54
2	1	Wind	2.3	8149.75	286.89
3	Core	Wave	10	33856.58	2808.35
4	2	Tidal	3	3296.87	415.48
5	3	Wind	2	6047.95	1288.26
6	4	Wind	5	14206.47	4134.04

RNFG 1 is a 0.9 MW wind generator located in the core zone. RNFG 1 generates 3259.75 MWh and is curtailed 41.54 MWh. This is equivalent to reducing the capacity factor of RNFG 1 from 0.42 to 0.41.

RNFG 2 is a 2.3MW wind generator located in zone 1. As zone 1 is nested within the core zone, RNFG 2 experiences additional curtailment to that provided in Table 23. The total energy generated by RNFG 2 reduces to 8149.75 MWh from 8262.15 MWh and the curtailed energy increases from 174.49 MWh to 286.89MWh. The total curtailment on RNFG 2 is equivalent to reducing the capacity factor from 0.42 to 0.40.

RNFG 3 is a 10 MW wave generator located in the core zone. RNFG 3 generates 33856.58 MWh and is curtailed 2808.35 MWh. This is equivalent to reducing the capacity factor of RNFG 3 from 0.42 to 0.39.

RNFG 4 is a 3MW tidal generator located in zone 2. As zone 2 is nested within the core zone, RNFG 4 experiences additional curtailment to that provided in Table 24. The total energy generated by RNFG 4 reduces to 3296.87 MWh from 3562.89 MWh and the curtailed energy increases from 149.46 MWh to 415.48 MWh. The total curtailment on RNFG 4 is equivalent to reducing the capacity factor from 0.14 to 0.12.

RNFG 5 is a 2MW wind generator located in zone 3. Despite zone 3 being nested within the core zone, RNFG 5 only experiences curtailment due to core zone constraints, as no zone 3 curtailment is required, as was shown in Table 25. RNFG 5 generates 6047.95 MWh and is curtailed 1288.26 MWh. This is equivalent to reducing the capacity factor of RNFG 3 from 0.42 to 0.35.

RNFG 6 is a 5MW wind generator located in zone 4. Despite zone 4 being nested within the core zone, RNFG 6 only experiences curtailment due to core zone constraints, as no zone 4 curtailment is required, as was shown in Table 26. RNFG 6 generates 14206.47 MWh and is curtailed 4134.04 MWh. This is equivalent to reducing the capacity factor of RNFG 6 from 0.42 to 0.32 and represents the loss of around one quarter of the output of RNFG 6. This is due to the fact that RNFG 6 is the unit of least priority.

6.3.4.5 Generator Curtailment Results for Low-Wind Year

The results of curtailment studies of the low-wind year for the RNFG units shown in Table 21, are now introduced in terms of the results of constraints being applied to zones 1 – 4, then the Core Zone (with the other zone nested within). Finally, the total MWh generated and curtailed by each RNFG unit (i.e. not just details relating to one set of solved zone constraints) and the capacity factor generated and curtailed are presented.

In Table 28, the results for the 2.3 MW wind generator in zone 1 are presented. It can be seen that based on the constraints in zone 1 only, RNFG 2 produces 7717.03 MWh and is curtailed by 2.29 MWh.

Table 28: GenCAT results for RNFG 2 for Zone 1 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
2	Zone 1	Wind	2.3	7717.03	2.29

In Table 29, the results for the 3 MW tidal generator in zone 2 are presented. It can be seen that based on the constraints in zone 2 only, RNFG 4 produces 3684.47 MWh and is curtailed by 18.46 MWh.

Table 29: GenCAT results for RNFG 4 for Zone 2 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
4	Zone 2	Tidal	3	3684.47	18.46

In Table 30, the results for the 2 MW wind generator in zone 3 are presented. It can be seen that based on the constraints in zone 3 only, RNFG 5 produces 6175.46 MWh and experiences no curtailment.

Table 30: GenCAT results for RNFG 5 for Zone 3 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
5	Zone 3	Wind	2	6175.46	0.00

In Table 31, the results for the 5 MW wind generator in zone 4 are presented. It can be seen that based on the constraints in zone 4 only, RNFG 6 produces 15438.64 MWh and experiences no curtailment.

Table 31: GenCAT results for RNFG 6 for Zone 4 constraints only

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
6	Zone 4	Wind	5	15438.64	0.00

The final results for all RNFG units are shown in Table 32. The MWh generated by RNFG units located in nested zones is increased due to the core zone constraints (i.e.

the constraints on the submarine cables from Orkney to the Scottish mainland). Due to the lower output from existing wind farms (both FG and NFG units), the results in Table 32 suggest that Core Zone constraints are no longer as active as in the high-wind year; therefore, the curtailment experienced by RNFG units is more dependent on the placement of the unit and local zone characteristics.

Table 32: GenCAT results all RNFG units

RNFG i.d.	Location	Nature	Size (MW)	Energy Generated (MWh)	Energy Curtailed (MWh)
1	Core	Wind	0.9	2778.96	0.00
2	1	Wind	2.3	7717.03	2.29
3	Core	Wave	10	30877.29	0.00
4	2	Tidal	3	3684.47	18.46
5	3	Wind	2	6175.46	0.00
6	4	Wind	5	15425.39	13.25

RNFG 1 is a 0.9 MW wind generator located in the core zone. RNFG 1 generates 2778.96 MWh and experiences no curtailment. This is equivalent to RNFG 1 having a capacity factor of 0.35.

RNFG 2 is a 2.3MW wind generator located in zone 1. Zone 1 is nested within the core zone, but RNFG 2 experiences no additional curtailment to that provided in Table 28. The total energy generated by RNFG 2 is 7717.03 MWh the curtailed energy is 2.29 MWh. This is equivalent to RNFG 2 having a capacity factor of 0.38 (curtailment is minimal).

RNFG 3 is a 10 MW wave generator located in the core zone. RNFG 3 generates 33856.58 MWh and experiences no curtailment. This is equivalent to RNFG 3 having a capacity factor of 0.35.

RNFG 4 is a 3MW tidal generator located in zone 2. Zone 2 is nested within the core zone, but RNFG 4 experiences no additional curtailment to that provided in Table 29.

The total energy generated by RNFG 4 is 3684.47 MWh the curtailed energy is 18.46 MWh. This is equivalent to RNFG 4 having a capacity factor of 0.14 (curtailment is minimal).

RNFG 5 is a 2MW wind generator located in zone 3. Despite zone 3 being nested within the core zone, RNFG 5 only experiences curtailment due to core zone constraints, as no zone 3 curtailment is required, as was shown in Table 30. RNFG 5 generates 6175.46 MWh. This is equivalent to a capacity factor for RNFG 3 of 0.35.

RNFG 6 is a 5MW wind generator located in zone 4. Despite zone 4 being nested within the core zone, RNFG 6 only experiences curtailment due to core zone constraints, as no zone 4 curtailment is required, as was shown in Table 31. RNFG 6 generates 15425.39 MWh and is curtailed 13.25 MWh. This is equivalent to RNFG 6 having a capacity factor of 0.35 (curtailment is minimal).

6.3.4.6 Discussion of Generator Curtailment Results

A summary of the results of GenCAT analysis of a high-wind output and low-wind output annual period for the connection of the identified RNFG units to the Orkney distribution network is provided in Table 33.

Close inspection of the results presented in Table 33 provide some interesting results. In general, the output of RNFG units that are wind generators is reduced in the low-wind year (2005-6), but this is not always the case. As a low-wind year means the FG and NFG energy production from wind farms will also be reduced; which has the effect of completely removing the constraints due to the core zone imposed on RNFG units during the high-wind year. Where an RNFG unit experiences more curtailment than one of lower priority, it is due to nested zone constraints particular to the location of each RNFG unit, LIFO will still be adhered to for the core zone constraints.

Table 33: Summary results of GenCAT analysis of the Orkney network

RNFG i.d.	Location	Nature	Size (MW)	High-Wind Year (2003-4)		Low-Wind Year (2005-6)	
				Generated (MWh / Capacity Factor)	*Curtailed (MWh / Capacity Factor)*	*Generated (MWh / Capacity Factor)*	*Curtailed (MWh / Capacity Factor)*
1	Core	Wind	0.9	3259.75 / 0.41	41.54 / 0.01	2778.96 / 0.35	0.00 / 0.00
2	1	Wind	2.3	8149.75 / 0.4	286.89 / 0.01	7717.03 / 0.38	2.29 / 0.00
3	Core	Wave	10	33856.58 / 0.39	2808.35 / 0.03	30877.29 / 0.35	0.00 / 0.00
4	2	Tidal	3	3296.87 / 0.12	415.48 / 0.02	3684.47 / 0.14	18.46 / 0.00
5	3	Wind	2	6047.95 / 0.35	1288.26 / 0.07	6175.46 / 0.35	0.00 / 0.00
6	4	Wind	5	14206.47 / 0.32	4134.04 / 0.09	15425.39 / 0.35	13.25 / 0.00

RNFG 6 – the RNFG unit of lowest priority – has a higher overall capacity factor in the low-wind year of 0.35, as in the high-wind year the capacity factor of the curtailment experienced by RNFG 6 is 0.09 (over one quarter of the energy production of RNFG 6, which has a capacity factor of 0.32 for the high-wind year).

RNFG 5 is second last in the RNFG priority stack. RNFG 5 generates roughly the same amount of power in the high-wind and low-wind year, equivalent to a capacity factor of 0.35. RNFG 5 experiences curtailment with a capacity factor of 0.09 in the high-wind year and no curtailment in the low-wind year.

RNFG 4 is a tidal device, therefore the potential energy production of RNFG 4 is unaffected by the consideration of either a high-wind or low-wind year. However, RNFG 4 produces more energy in the low-wind year due to an absence of curtailment as a result of reduced power flow injection from wind farms on Orkney.

The capacity factor of RNFG 4 increases from 0.12 to 0.14, when comparing the high-wind and low-wind scenarios.

RNFG 3 is a wave generator, the output of the wave generator is closely correlated with the wind conditions on Orkney; therefore, RNFG 3 generates less energy in the low-wind year. In a high-wind year, RNFG 3 generates energy equivalent to a capacity factor of 0.39, due to curtailment equivalent to 0.03. In the low-wind year, RNFG 3 generates energy equivalent to a capacity factor of 0.35 and experiences no curtailment.

RNFG 2 produces less power in the low-wind year as it is a wind generator. However, it generates at a slightly higher capacity factor than other wind farms at 0.38 in the low-wind year with only slight curtailment. This is due to better performance of wind farms in this zone of the Orkney network than in other zones in 2005-6, and the profiles of these wind farms were used to create the RNFG 2 profile. In the high-wind year, RNFG 2 generates energy equivalent to a capacity factor of 0.4 and is curtailed equivalent to 0.01.

RNFG 1 is the RNFG unit of highest priority and experiences little curtailment in either scenario. IN the high-wind year, RNFG 1 generates energy equivalent to a capacity factor of 0.41 and is curtailed equivalent to 0.01, compared with production equivalent to 0.35 in the low-wind year with no curtailment.

In conclusion, there does not appear to be a fixed pattern to curtailment, which is ultimately dependent on the output of existing generation, the location of constraints and the position in the LIFO priority stack of RNFG units. However, RNFG units of varying technology benefit from increased diversity and those low down in the priority stack may produce at a consistent capacity factor despite the amount of curtailment varying. The results presented, however, should provide enough information for generator developers to assess the economics of a connection to the Orkney RPZ as a RNFG unit and raise project finance.

6.4 Active Power Flow Management Time Delays and Regulated Non-Firm Generation Curtailment

This section takes a closer look at the role that communications and control delays can play with regard to the curtailment experienced by RNFG units. These time factors influence the setting of the operating margins required for the implementation of the APFM scheme, as described in section 4.4.2. This is demonstrated by way of a case study of the application of the proposed APFM scheme, as described by Currie *et al* (Currie *et al*, 2007a).

6.4.1 UKGDS-EHV1 Case Study

The network and profiles used in this case study were obtained from the UK Generic Distribution System project[6], which provides resources to support modelling and analysis of UK-style distribution networks. The UKGDS-EHV1 network is representative of a typical rural distribution network in the UK and encompasses 3 voltage levels: 132kV, 33kV and 11kV, as shown in Figure 54.

The load on the network varies from a summer minimum of 5.7MW to a winter maximum of 36.89MW. The parallel circuits connecting the 132kV (bus 100) to the 33kV bus (bus 302) are each rated at 30MVA. The transmission network is modelled as an equivalent swing bus generating unit.

A variety of sizes and types of generators were added to the network and allocated firm or non-firm (intertrip for loss of either 132/33kV transformer) capacity. Power system studies were performed using PSS/E v29 to assess the impact on the voltage profile of the network for the addition of FG units and NFG units. Without any DG connected, the voltage on the network is low, reaching around 0.9pu on the 33kV network in places. All 11kV supply terminal voltages were within +/- 3% of 1pu. The addition of FG units improves the voltage profile of the network. Indeed, the

[6] www.sedg.ac.uk (accessed 25/10/2009)

further addition of NFG units raised the voltage above 1.03pu at NFG terminals; therefore, reactive compensation was added at NFG sites where necessary in 2 MVAr inductive blocks until voltages were below 1.03pu. The location and characteristics of the FG units and NFG units are shown in Table 34.

Table 34: Location and characteristics of firm and non-firm generation

Category	Bus Number	Size (MW)	Generator type	Nature
FG	307	7	Induction	Wind
FG	1107	10	Synchronous	Gas CHP
FG	314	4	Induction	Wind
FG	1114	4	Induction	Wind
FG	335	6	Induction	Marine
FG	332	4	Induction	Micro Hydro
NFG	1102	2	Inverter connected	Solar
NFG	316	6	Doubly fed	Wind
NFG	311	7	Induction	Wind
NFG	323	3	Induction	Wind
NFG	326	5	Doubly fed	Wind
NFG	331	1	Induction	Wind

6.4.1.1 Addition of Regulated Non-Firm Generation Units

The theoretical capacity RNFG capacity on the UKGDS-EHV1 network is equivalent to the capacity of both 132/33kV transformers, plus the maximum demand minus the FG and NFG capacity (30+30+36.89-35.7-30), which equals 31.19 MW. APFM zones 1-3 in Figure 54 were identified as areas where capacity for connection existed; however, it is clear that other potential APFM zones exist on the network, depending on the location of RNFG units.

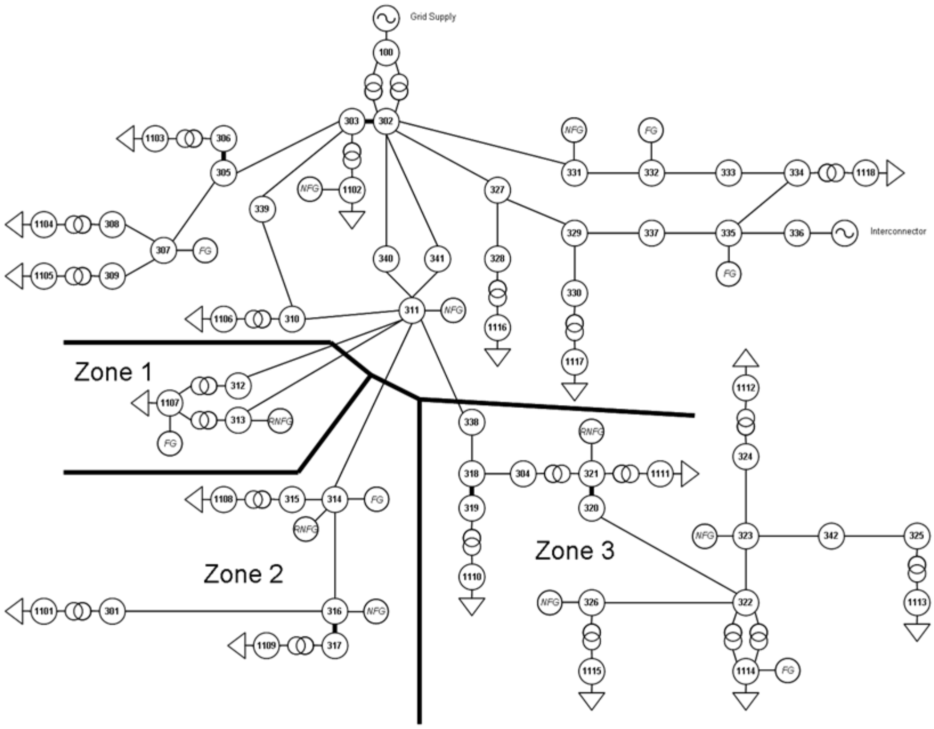

Figure 54: UKGDS-EHV1 network with APFM control zones 1-3 identified

RNFG units were added to the network (while at the maximum load condition) in zones 1-3 as shown in Table 35: Location, size and nature of until the export from each zone, or export to the transmission network, reached the thermal capacity. This takes the total amount of generation connected (FG + NFG + RNFG) to 90MW, which remains below the total theoretical level of 96.89MW. This is due to the transport of reactive power and the influence of FG, NFG and RNFG size and location on the utilisation of available capacity.

Table 35: Location, size and nature of RNFG units

Bus Number	Size (MW)	Generator type	Nature
313	22	Doubly fed	Wind
314	2	Doubly fed	Wind
321	7	Induction	Marine

Power system studies of RNFG units were performed as for the addition of FG and NFG units. The two doubly fed induction wind generators were modelled in voltage control mode, regulating the voltage at the bus of connection to 1pu. No unacceptable step voltages occur through the tripping of any individual RNFG by the APFM scheme during normal operating conditions.

Now that all DG units are specified for the network, a range of operating margins need to be set so that investigations of communications and control delays can be performed.

6.4.1.2 Setting the Trip Margin

For the purposes of this analysis, the sequential trip margin will be aligned with the thermal capacity of the network. If the control instruction to trip is not instantaneous then there will be a time lag before the generator is tripped, this may result in circuits being overloaded - short term or cyclic ratings could be employed. However, for the case study presented it will be assumed that the RNFG units meet the curtailment instruction provided to them, in order to allow the energy generated and curtailed by each RNFG unit to be estimated

6.4.1.3 Setting the Trim Margin

As discussed by Sinclair Knight Merz (SKM) (Sinclair Knight Merz, 2004), it is likely that the revision of grid code requirements in the UK will result in generation larger than 15MW being limited to a maximum permissible ramp rate of 20% of rated capacity per minute for a one minute average. The following assumptions were used in the calculation of the trim margins in Table 36.

- A ramp rate of 20% of rated capacity per minute for the FG, NFG and RNFG
- A maximum load drop of 5% of peak load per minute

- Various time factors of 1 minute, 45 seconds, 30 seconds and 15 seconds considered.

Table 36: Time factors and resultant trim operating margins

Operating Margin Identifier	OM1	OM2	OM3	OM4
Time Factor (minutes)	1	0.75	0.5	0.25
Trim Operating Margin (MVA)	6	4.5	3	1.5

These 15 second variations in the time factor to be applied to the calculation of the trim margin will allow the impact of an increase/decrease in the amount of time it takes the APFM scheme to measure constraints, communicate those constraints, process all data and communicate a set-point to an RNFG unit, on the RNFG unit energy production.

6.4.1.4 Case Study Results

A profile based analysis of half-hourly data for generation and load allowed an assessment of the impact of the APFM scheme on the annual output from the RNFG units. Following on from which, an economic analysis of the APFM scheme was performed to demonstrate the impact of the different time factors (and therefore operating margins) and APFM integration costs on the viability of RNFG connections.

As described for the determination of the economic cut-off point earlier in this chapter, the RNFG units were modelled in incremental MW blocks. The RNFG units are unconstrained until the level of connected generation reaches the 17-23MW range (dependent on the time factor (TF) and thus the size of the trim operating margin employed), as shown in Figure 55. Therefore, little curtailment is experienced by the first RNFG unit to connect – the 22MW generator at bus 313. The curtailment experienced by the RNFG units connecting beyond the 17-23MW range (again, dependent on time delay and trim operating margin employed) increases exponentially as shown in Figure 56. Figure 55 shows that for the last incremental MW of RNFG connected, the largest operating margin employed (OM1 = 6MVA) results in an incremental output of 2333MWh/MW, as opposed to 2366MWh/MW for the use of the smallest operating margin (OM4 = 1.5MVA).

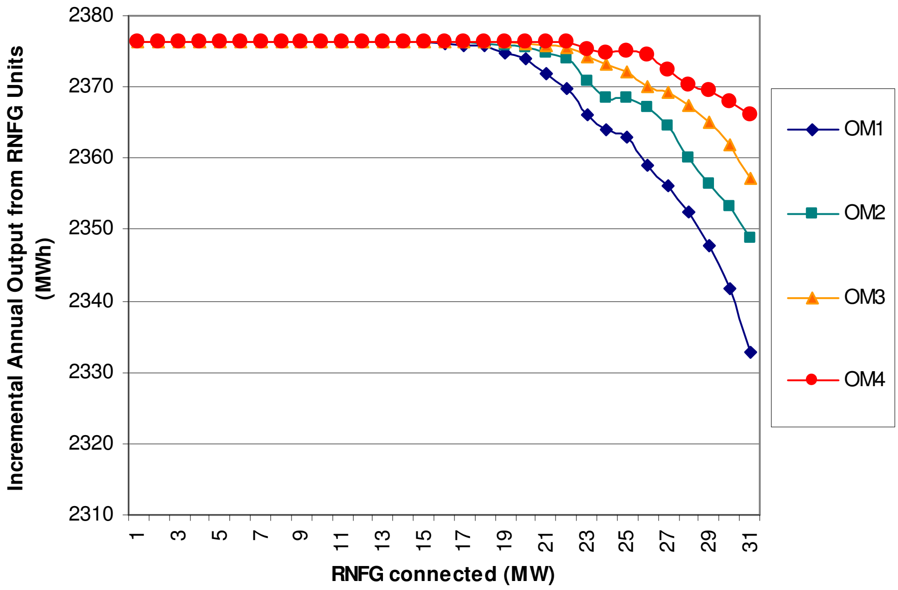

Figure 55: Incremental annual output from RNFG units for different sizes of time delay and trim operating margin

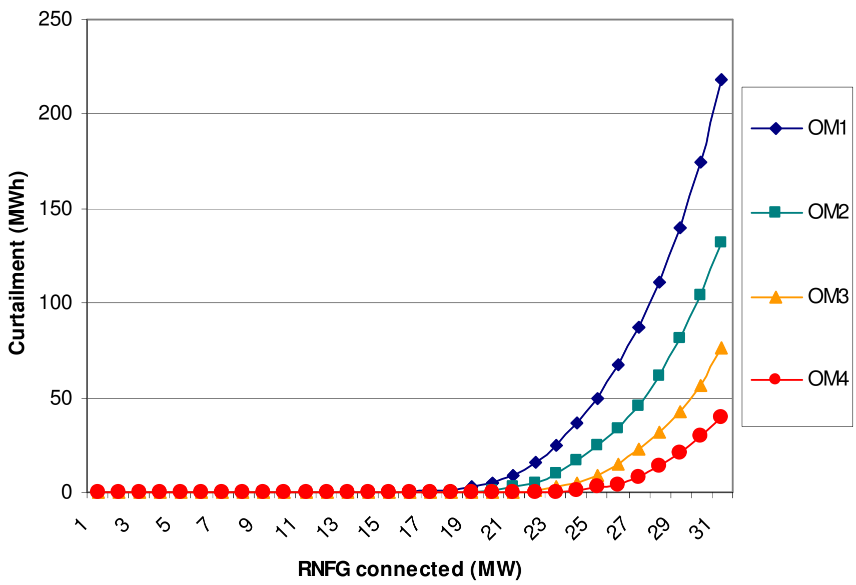

Figure 56: MWh curtailment experienced at each MW of RNFG connected for different sizes of time delay and trim operating margin

6.4.1.5 Economic Analysis of Regulated Non-Firm Generator Connections

An economic analysis of each RNFG unit connection has been performed. The analysis considers the performance of the RNFG assuming all trimming instructions have been obeyed and no tripping due to lack of RNFG response occurs. An economic analysis of each RNFG unit was performed using the assumptions regarding time factors and operating margins shown previously in Table 36. The economic viability of each RNFG unit has been assessed using a minimum annual revenue level of 10% of the initial capital outlay. This represents a typical capital recovery factor and normal profit at current interest rates.

Table 37: Assumptions for economic analysis of RNFG unit connections

Generator installation (£/kW)	750
Electrical connection (£)	150,000
Additional APFM costs (£)	100,000
Combined energy certificate plus energy sales revenue (£/MWh)	70

Based on the assumptions above, each RNFG unit has an economically viable connection option through the APFM scheme irrespective of additional APFM scheme integration costs and revenue lost due to curtailment. The RNFG unit at bus 321 experiences the greatest curtailment and therefore is more sensitive to changes in the size of the time delay and operating margin. Figure 57 shows the results of the economic analysis of the RNFG unit at bus 321 for a typical annual period. The revenue accrued by this RNFG unit ranges from £1,151,676 to £1,161,701, shown in Figure 57 to be above the minimum annual revenue required of £550,000. The revenue lost for the RNFG unit at bus 321 is the greatest of all RNFG, ranging from £8,352 to £59,460 again dependent on size of time delay and trim operating margin employed. Despite this lost revenue, the connection of the RNFG unit at bus 321 remains economically viable.

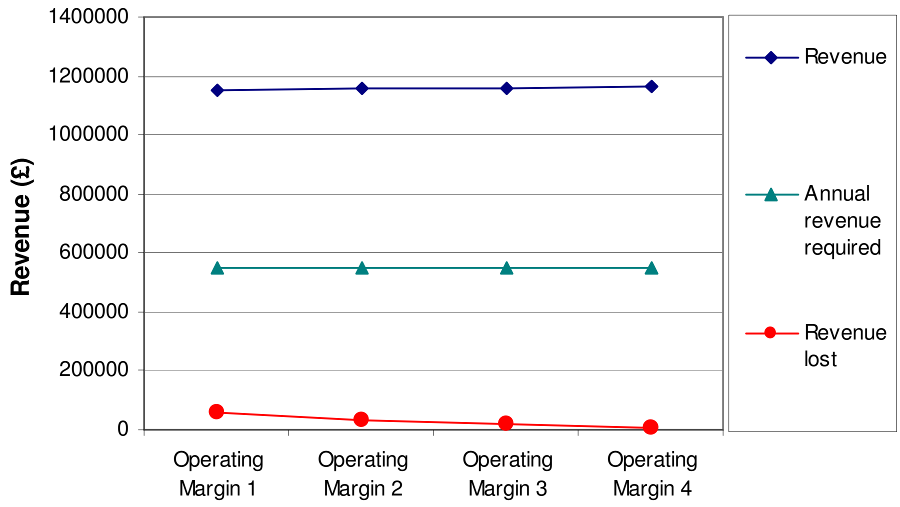

Figure 57: Results of economic analysis of typical annual period for RNFG unit at Bus 321

6.4.1.6 Conclusions of UKGDS-EHV1 network case study

For the UKGDS-EHV1 network, the application of the APFM scheme and the connection of RNFG units up to 17-23MW (depending on the size of the time delay and trim operating margin) will result in little curtailment of RNFG units and provide generator developers with an economically attractive alternative to network reinforcement. Extending RNFG connections beyond 17-23MW results in increased curtailment of RNFG output; however, the revenue lost does not impact on the economic viability of any RNFG project.

The different time delays employed in the case study can increase the revenue lost by a RNFG unit by around £50,000. In the case study presented the RNFG units remain economically viable. If more RNFG units were to connect then the implication of the larger time delay is greater curtailment, which has already been shown to rise exponentially. However, even for the RNFG units presented, £50,000 is a significant amount of lost income and the setting of the operating margin is therefore a sensitive commercial issue as well as being of technical interest to the DNO.

6.5 Chapter Six Conclusions

This chapter has explored the economics of the proposed APFM scheme through a number of case studies of APFM deployment. A methodology has been presented to determine the Economic Cut-Off Point for new RNFG unit connections. Using break even economics and real network data and real profiles of generation and load, it was found that the proposed APFM scheme enabled a significant additional component of capacity to connect. The magnitude of the additional component varies dependent on the cost and revenue assumptions of the study, but in the worst case was found to result in a total generation portfolio of around three times the conventional FG limit. The results of such an economic assessment are fundamental to informing the decision by the network operator to deploy the APFM scheme and are crucial to validating the application of the proposed APFM scheme.

Studies of RNFG unit performance when connected to the proposed APFM scheme have been performed both for an actual distribution network using historical data and on a generic distribution network using generic profile data. A number of different situations and generator technologies have been studied to explore the potential curtailment experienced by RNFG units connecting to the proposed APFM scheme. It has been shown that in most cases, a significant portion of capacity exists on the existing network infrastructure that could be accessed through the deployment of the proposed APFM scheme without significant curtailment of RNFG units.

6.6 Chapter Six References

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7 Conclusions and Future Work

7.1 Chapter Summary

This chapter presents a summary of the main conclusions stemming from the presentation of the research in this thesis and identifies several avenues for further work.

7.2 Conclusions

The growth of renewable and distributed generation is seen as a key component of strategies to reduce the greenhouse gas emissions resulting from the generation, transport and use of electricity. This thesis has explored the drivers and growth in such generation sources, while identifying the significant challenges associated with grid connections to distribution networks. It has been discussed how the renewable resource tends to exist in remote areas, where mainly passive distribution networks supply low and disperse loads. Such areas are not served by the high-voltage transmission networks that transport bulk power throughout the electricity supply system. If renewable resources are to be accessed in the near-term, there is a need to take the existing passive distribution network and make it more 'active'. Active Network Management (ANM) provides a means to overcome connection hurdles, permitting greater connections to existing networks through the addition of advanced monitoring and control systems. One crucial aspect of ANM is Active Power Flow Management (APFM). This thesis has specified, formulated and demonstrated one of the first multiple generator and multiple constraint APFM schemes:

- Distributed Generation (DG) connections to existing distribution networks are normally limited to the Firm Generation (FG) of the network. It has been shown in this thesis how this conservative approach to allocating generator capacity is driven by distribution network planning standards and the existing regulatory framework, which was established to achieve high levels of supply reliability and security, rather than to connect DG. APFM prior art is mainly concerned with the connection of Non-Firm Generation (NFG). NFG connect in addition to FG and are often tripped from the network during an outage, to ensure that no overloading of network components occurs. The solutions for NFG have not been adopted by many Distribution Network Operators (DNOs). One explanation for this is that the existing solutions are crude and are concerned with tripping individual generators, while not providing the flexibility desired by DNOs with regard to multiple generators, multiple constraints and the ability to evolve as needs emerge. In addition, the issue of real-time regulation of DG power output has not been addressed in the literature; this challenge has been addressed in this thesis, including some of the accompanying commercial challenges. This thesis tackles these issues and proposes the connection and operation of Regulated Non-Firm Generation (RNFG) in addition to FG and NFG. The proposed APFM scheme provides the means for the connection and operation of RNFG units.

- The proposed APFM scheme takes as its basis various literature sources and examples of deployed systems, mainly concerned with management of power flows from individual DG units. Multiple DG APFM schemes have been suggested in the literature but none presented in the detail required and with the accompanying analytical tools and methods required to allow them to be tested, demonstrated or deployed more widely. The APFM scheme proposed in this thesis tackles these challenges and evolves the concepts of preventive and corrective control to the power flow management problem through the implementation of operating margins and zones. Such concepts are crucial to the provision of network security and are a key aspect of the proposed APFM scheme. DG connections to the APFM scheme are subject to output regulation to prevent thermal overloads occurring in zones on the network. If this preventive measure is not successful, the APFM scheme will take corrective action; tripping one or more DG units from the network to protect the system and maintain security of supply. The proposed APFM scheme has completed a successful initial field trial involving the regulation of the output of an actual wind farm connected to the Orkney distribution network. This is believed to be one of the first occurrences of real-time regulation of wind farm power production by an APFM scheme. The APFM scheme has been fully deployed in 2009 (November) as the basis for two RNFG unit connections and is expected to connect upwards of ten additional generators to the Orkney distribution network.

- The proposed APFM scheme takes a zonal approach to control. APFM zones have been introduced in this thesis as a means to facilitate RNFG units and also to allow the APFM scheme to evolve with the definition of further zones on the network as further RNFG units connect or the network changes. Computational means and an accompanying methodology have been presented that allow APFM zones to be identified and implemented. These methods have been applied to a number of case studies, thereby demonstrating their practical use. The adoption of cellular or zonal architectures for ANM have been proposed previously, but the methods presented in this thesis are the first to identify zones for APFM and the accompanying control architectures that evolve and support gradual deployment of an APFM scheme.

- Within the APFM zone structure, it has been identified that 'Principles of Access' are required that relate RNFG units to the constraints as they are reached in real-time. A number of different principles of access have been identified, each of which could be implemented within the proposed APFM scheme. The principle of 'Last In First Out' (LIFO) was chosen for inclusion within the scheme as it was identified as being the most appropriate for near-term deployment and the most likely to endure tests of a commercial nature at the present time. The APFM scheme can be easily modified to accept different principles of access. This is important as APFM may be required to implement different Principles of Access in the future.

- Operating margins for APFM have been introduced as a means to implement preventive and corrective control in active networks. The computational means for setting the suite of APFM operating margins have been presented, providing a systematic means of applying sound engineering principles. The operating margins provide the basis for reducing individual and/or collective RNFG output, tripping individual or collective RNFG units and releasing capacity back to RNFG units. The sensitivity of the operating margins to changes in generator behaviour and to time delays associated with APFM communications and control has been identified. Through case studies on a generic network, it has been shown how the magnitude of the operating margins implemented in the APFM scheme can impact on the energy produced by the RNFG units, demonstrating the importance of setting the operating margins appropriately. APFM operating margins and the accompanying control algorithm are what provide the DNO with the comfort that the APFM scheme will act to improve or maintain existing security and quality of supply standards. Incorporating such control philosophies within APFM schemes is crucial to achieving deployment.

- The proposed APFM scheme curtails the output of RNFG units connected to the distribution network. It has been shown that a methodology can be applied to determine the Economic Cut-Off Point (ECOP) for further RNFG connections. The ECOP methodology presented is based on break even economics and the incremental addition of RNFG unit capacity. The ECOP methodology can be utilised to investigate the true potential for the application of the APFM scheme to a particular network area (i.e. APFM zone) and this is of particular interest to the network operators in making APFM deployment decisions. The methodology has been demonstrated through a case study of the Orkney distribution network, which identifies economically viable RNFG unit capacity the results in the combined FG, NFG and RNFG capacity being nearly three times the original FG limit. This suggests that deployment of the APFM scheme can treble the amount of installed renewable generator capacity on parts of the existing grid. The identification of the ECOP provides the DNO with a means of assessing the feasible levels of RNFG units that could connect to an APFM scheme, providing valuable information to assist in the decision to deploy the proposed APFM scheme.

- Generator Constraint Analysis Tool (GenCAT) has been presented as a means for modelling and estimating the performance of defined scenarios of RNFG unit connections during two annual periods; one of high wind resource and one of low wind resource. GenCAT is the first analysis tool of its kind, allowing the user to define the number, type, size and location of RNFG units, within the APFM zone architecture. GenCAT then uses historic ½ hourly profiles and provides estimates of the energy (MWh) both generated and curtailed by each RNFG unit in the scenario. Providing a means of assessing the economic implications for the RNFG developer of connecting to the APFM scheme. This is crucial to informing the decision making process for the RNFG developer considering a connection to the proposed APFM scheme.

In summary, the principal contributions stemming from this thesis can be summarised as:

- The design and development of a multi-generator APFM scheme to field trial stage and full deployment. The scheme employs both a preventive and corrective approach to APFM, involving output regulation and tripping of DG units based on real time thermal constraints
- A methodology to identify zones on the network to permit the application of the proposed APFM scheme to manage multiple network constraints and to evolve as further generators connect or the network changes
- The identification of and computational means for defining operating margins for managing power flows as part of an APFM scheme
- An economic assessment methodology for the application of APFM to an existing distribution network. This methodology supports the analysis of DG

connections and provides a means of quantifying the benefits and effects of APFM

- The proposed APFM scheme provides a sound technical and commercial solution to increasing the number and capacity of renewable and distributed generation connections to existing electricity networks

Several case studies of the proposed APFM scheme have demonstrated the suitability for application to electricity distribution networks. Case studies have shown that the application of the APFM scheme can increase the capacity for renewable and distributed generator connections to around three times the conventional limit. In addition, it has been shown that the first generators (depending on size and location) that connect to the network through APFM experience little or no curtailment. It has been demonstrated that it is possible to model the curtailment experienced by further generator connections to the APFM scheme. This allows the network operator and generators to make informed investment decisions and such information is fundamentally required to support deployment of the APFM scheme. The APFM scheme and accompanying methods and analysis are repeatable for many networks and generator locations and technologies.

To conclude, the APFM scheme proposed in this thesis has been shown to provide a technically and commercially feasible alternative to conventional network reinforcement to enable increased connection of renewable and distributed generation.

7.3 Future Work

In undertaking this work, several items of future work have been identified:

- The operating margins that have been presented in this thesis require the magnitude of the various ramp-rates and time delays to be decided upon when setting the margins. As has been shown in various case studies, this can lead to overly excessive operating margins, which can result in increased curtailment for the RNFG units. In reality, the various factors that affect the magnitude of the operating margins will vary with time. Moving to an APFM regime based on flexible operating margins would allow enhanced access for RNFG units. The operating margins could be set based on the real-time or forecast behaviour of connected DG units and on the time delays associated with APFM, or could be set periodically based on a review of data and consideration of the probability of DG ramp rates and time delays coincidentally occurring. This area warrants further exploration and assessment of these options, which would allow APFM schemes to become more efficient and further maximise the use of available network capacity.

- The performance of RNFG units connected to the APFM scheme has been estimated using ½ hourly historic profile data. The data have been sourced either from the DNO or from published resources. Where such data is unavailable, it will be beneficial to perform some probabilistic assessment of the curtailment experienced by RNFG units in the future. This could be performed by way of a Monte Carlo simulation, using probability distributions as inputs to describe the performance of both generators and loads. Further thought will need to be given to the interactive nature of the data sets and the correlation between data associated with different generators and loads that could be lost as a Monte Carlo simulation is undertaken. The probabilistic analysis tool will be required to honour the zone architecture implemented for APFM and could likely be implemented in a similar manner to the existing GenCAT.

- It has been shown in the literature review of this thesis that Dynamic Line Rating (DLR) systems are an emerging area of technical focus. At the present time, the APFM scheme makes use of the fixed or seasonal ratings of components on the distribution network. It would be possible to interface to a device that provides DLR values for the components located at constraints at zone boundaries in real-time, based on weather conditions. This could be performed for overhead lines with the anticipated greatest benefit, although dynamic ratings can be applied to underground cables, submarine cables and transformers. Various issues remain to be resolved for the merging of the APFM scheme with DLR, but the software and hardware aspects are not anticipated to be onerous. The main challenges will be in deciding upon the location of DLR, the implications for network operation - increasing the rating of one section of line could cause another to become overloaded - and modelling the impact on RNFG unit curtailment.

- The principles developed for APFM hold potential for application to voltage management. The real and/or reactive power output of RNFG units could be managed within the voltage constraints on the network by making use of operating margins to implement preventive and corrective actions. For example, the breaching of a voltage trigger level on the network could result in the reduction of real power output from one or more RNFG unit. If the voltage continues to rise towards another trigger level then the RNFG units could be individually or collectively tripped. There are additional challenges associated with voltage management due to the differences in nature between voltage and current, and the interaction with devices that already perform voltage control on the network, such as transformers. At the present time, DNOs prefer to perform voltage control through installed equipment, rather than rely on generators to provide response. A similar set of research, practical and commercial challenges require to be addressed as have been for the APFM scheme proposed in this thesis. It is suggested that these be explored and that the resulting voltage management scheme be designed to work in tandem with the APFM scheme.

- Energy Storage Systems (ESS) could be deployed on future distribution networks and may need to be controlled by the APFM scheme. If located behind a constraint location (i.e. in an APFM zone) then the APFM scheme could control the charging and discharging of the ESS to attempt to reduce the curtailment of RNFG units in the zone. When discharging the ESS, the

APFM scheme would need to ensure that the increased power flows did not contribute to upstream APFM zones that the current zone may be nested within. When not being used to reduce curtailment, the ESS could be used to achieve other power system operational goals, such as reducing losses, improving voltage profile or even islanding parts of the distribution network. This area warrants further investigation.

- As distribution networks evolve to become more active, the way that control room operators interact with the distribution network will change. At the present time, there is little monitoring and control functionality available to the distribution control operator. Existing duties involve dealing with planned and unplanned outages on the network and the secure supply of demand to as many customers as possible, while keeping down the number and duration of supply interruptions. The previous model involves the transition between static security states (i.e. secure, restorative, etc). ANM deployments (including APFM and voltage management) will require the definition of new static security states that will aid the control room engineer in determining when to interact with an ANM scheme of any type. This will allow ANM schemes that act automatically to be managed properly, with alarms and indications categorised appropriately to engage the operator at the correct times. Resolving this issue will aid the adoption of new ANM schemes from a wider network control perspective.

- Finally, the distribution network will evolve to encompass a number of new services and technologies. The days of passive distribution networks with the sole purpose of delivering electricity to consumers are coming to an end; distribution networks will become more active, more information and communications technology will be deployed, different types of ANM algorithms will coordinate and control network connected devices. The coordination of a number of complex systems, data management issues and human interaction point toward the use of intelligent systems and it is recommended that this be explored as a significant area for future work.

8 Epilogue

The research presented in this thesis has been commercially deployed as part of the Orkney Registered Power Zone (RPZ). The APFM scheme was commissioned into operation at the end of November 2009. This represents one of the first fully deployed APFM schemes anywhere in the world. The vehicle for this commercial deployment was the creation of a spin-out company from the University of Strathclyde – Smarter Grid Solutions Ltd (SGS). I left my Research Fellow position at the University to take up full-time employment in SGS in 2008. SGS raised £500,000 in venture capital to commercialise the research contained within this thesis. As a founding member of the company and the Operations Director, I am currently pursuing the future work items identified in this thesis with SGS colleagues.

At the Scottish Green Energy Awards in 2009, SGS received the "Best New Business" award and the "Best Renewable Innovation" award for the Orkney RPZ project. These surprising and welcome accolades have raised the profile of this work and are a testament to the team who have worked to realise the deployment of the APFM scheme on Orkney, including colleagues at the University of Strathclyde, Scottish and Southern Energy and more recently at SGS.

Bob Currie

December 2009

9 Appendices: Operation of APFM Scheme

9.1 Appendix A: Logic to Monitor Primary System Parameters

Each NMU PLC will receive analogue representations of current (Amps) and/or power (Megawatts) from measurement devices installed on the network. The Central APFM PLC will read specific data locations in the NMU PLC and transfer the data to the appropriate addresses in the Central APFM PLC. If the export breaches the trim margin, the Central APFM PLC will read the data more regularly. This will continue until a timer has expired. This process is illustrated in Figure 58.

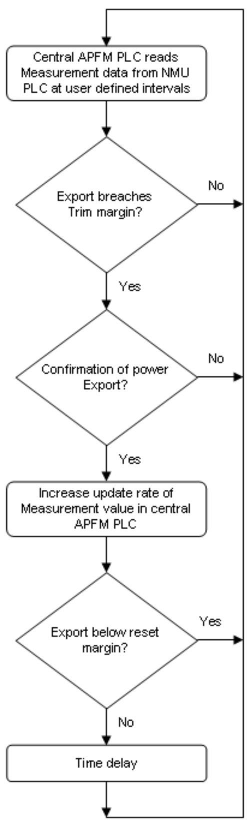

Figure 58: Processes undertaken by APFM scheme to measure current and power

Measurements will be performed on each individual asset; meaning limits will be applied to all circuits that could potentially be overloaded, including those that are parallel. This will mean that if a parallel circuit is lost then the overloading of the remaining circuit will trigger the appropriate course of action, based on the capacity available on the remaining circuit.

9.2 Appendix B: Logic to Perform Active Power Flow Management Scheme Topology Identification

The topology of the APFM scheme is directly related to the actual network topology, the location of RNFG units and the principles of access. A change in network topology, such as the opening or closing of a circuit breaker can result in a change to the topology of the APFM scheme. The topology of the APFM scheme reveals the relationship between each NMU PLC and each RNFG PLC, and can be presented in a look-up table format. This allows some pre-planned scenarios to be catered for. If digital signals are provided representing circuit breaker status, then a change in this data can trigger a change in APFM topology. This approach will cater for different network topologies but not all and in some instances it may not be possible to operate RNFG units. This will occur during individual or multiple unplanned outages. It is common during such events for DG units to be disconnected from the network unless being explicitly asked to operate by the network operator.

The APFM scheme topologies are represented in data tables, associating measurement points (or NMU PLCs) with RNFG units (and therefore RNFG PLCs). A change in network topology results in a look-up table approach to defining the topology of the APFM scheme and the suitable APFM operating margins to be used. The process required for APFM scheme topology selection is shown in Figure 59.

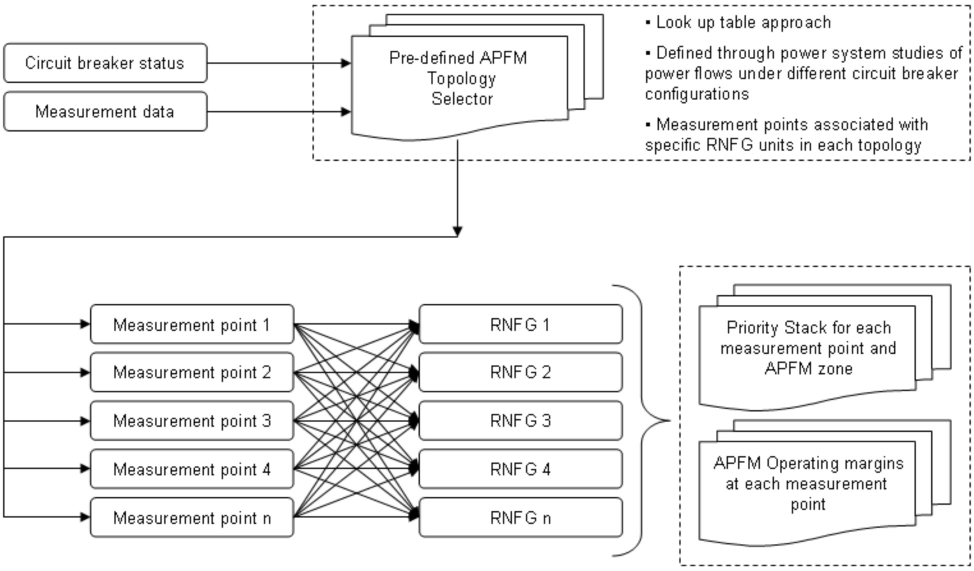

Figure 59: Processes required for APFM topology identification

The circuit breaker status indications and actual measurement values can be used to identify the RNFG units that should be associated with each measurement point. It may be possible to infer the export at a location if a measurement is unavailable for that specific location. Once the measurement points and associated RNFG units are known, a priority stack for each measurement point (i.e. APFM zone) is created, representing the APFM topology. The corresponding operating margins to be employed at each measurement point can then be specified.

9.3 Appendix C: Logic to Perform Output Regulation of Regulated Non-Firm Generation Units

In the APFM scheme proposed in this thesis, the measurement of current or power breaching the trim operating margin will initiate a chain of events leading to the reduction of output from one or several RNFG units. The RNFG units may experience curtailment based on the level of export from their zone of location and the export at any external measurement points they are associated with. The logic that controls the trimming of RNFG units must be capable of coping with coincident overloading of network locations and be able to identify when more than one RNFG unit must be curtailed.

The following sections provide an overview of the logic processes required for trimming the output of RNFG units: issuing trim control instructions to RNFG units and monitoring the response of RNFG units to the trim control instruction. The control algorithms presented adhere to the principles set out in Chapter 3, concerned with the research and development of an APFM scheme that maintains simplicity, repeatable principles and logical processes, and network security.

9.3.1 Issuing Trim Control Instructions to Regulated Non-Firm Generation

The Central APFM PLC will take the incoming measurement value from an NMU PLC and, if the trim margin at that site has been exceeded, issue trim set-point instructions to the associated RNFG units, as shown in Figure 60.

After the Central APFM PLC has identified that the trim margin has been exceeded at a measurement point, a timer is started. After the timer elapses, the Central APFM PLC calculates the reduction required (X MWs in the example in Figure 60) to return the measured value back to the reset margin. The timer is employed to filter out any small excursions above the trim margin that are short in duration. After the Central APFM PLC calculates the reduction required it will then consider the RNFG units associated with the measurement point in accordance with LIFO. In Figure 60, three RNFG units are used as an example: RNFG1, RNFG2 and RNFG3. RNFG1 has highest priority, followed by RNFG2 then RNFG3.

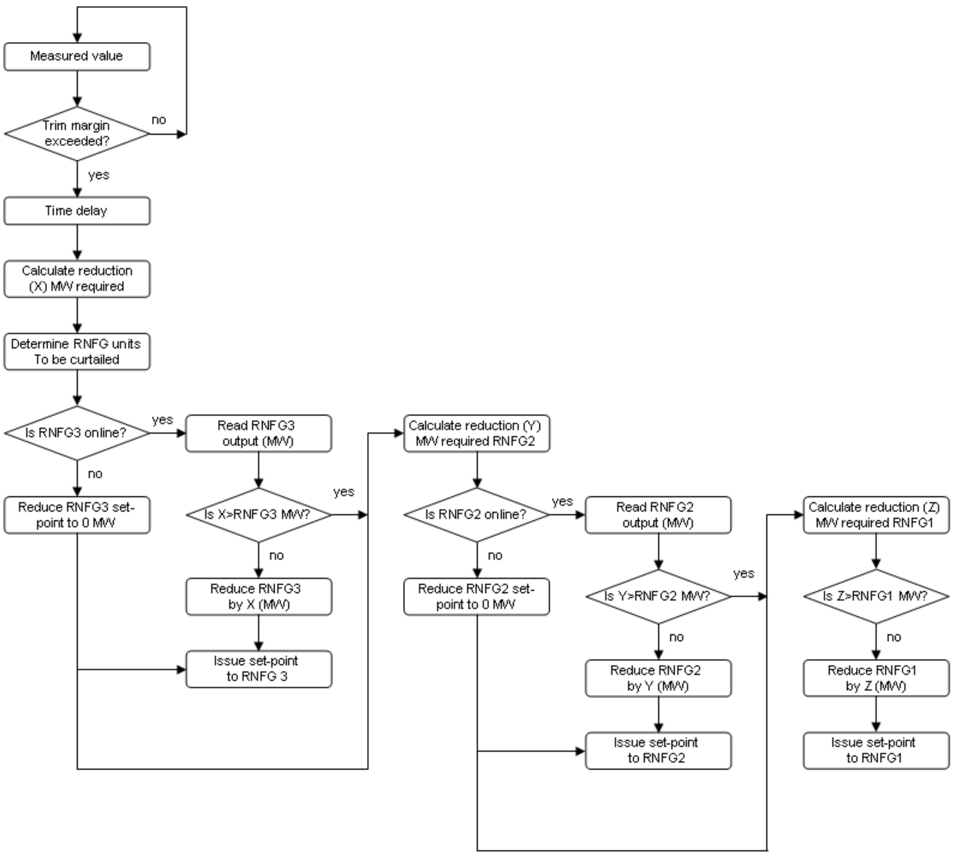

Figure 60: Overview of processes required to issue trim control instructions to RNFG units

The Central APFM PLC firstly checks that RNFG3 (the unit of least priority) is online. If RNFG3 is not online the Central ANM PLC still issues a full output reduction signal to ensure that RNFG3 does not subsequently come online and increase output (therefore LIFO will be adhered to when the next RNFG unit is curtailed). If RNFG3 is online, the Central APFM PLC will read the MW output of RNFG3 from the RNFG PLC located at the generator site. If the required curtailment is not greater than the output of RNFG3 then RNFG3 has its output reduced by X MW, if the required curtailment is greater than RNFG3 output then X MW is still subtracted from the permitted RNFG3 output, leading to a set-point being issued for a full output reduction.

If X is greater than the output of RNFG3 then curtailment of RNFG2 is required. The remaining curtailment (Y MWs in the example in Figure 60) is then applied to RNFG2. The same logic processes are undertaken for RNFG2 as were for RNFG3, any residual curtailment (Z MWs in the example in Figure 60) is passed on to RNFG1. As only three RNFG units are in place, the curtailment required must be fully applied to the output of RNFG1; therefore Z is subtracted from the permitted output of RNFG1.

When a RNFG unit is associated with more than one measurement point, the Central APFM PLC will issue the largest curtailment required by any measurement point that the RNFG unit is associated with. When calculating the amount of curtailment to be issued to each RNFG unit, the APFM scheme will apply a multiplication factor (similar to a sensitivity factor) to ensure that the reduction in RNFG output will be proportional to the reduction required.

The curtailment of RNFG units can be performed at intervals once the first curtailment is applied, allowing the curtailment instruction to be updated to reflect prevailing system conditions.

9.3.2 Monitoring the Response of Regulated Non-Firm Generation Units to a Trim Control Instruction

The RNFG PLC is responsible for monitoring the response of the RNFG unit to the set-point issued. This could be performed by the Central APFM PLC but represents a relatively simple task for the RNFG PLC.

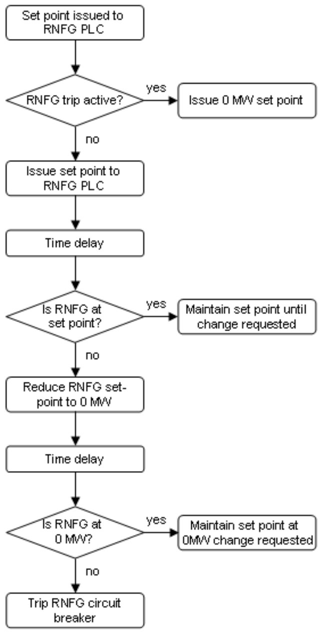

Figure 61: Process undertaken by RNFG PLC on receipt of set-point from Central APFM PLC

When the RNFG PLC receives a new set-point instruction from the Central APFM PLC it firsts checks that a trip of the RNFG unit is not active. This is to avoid spurious APFM signals. If a trip is active, the RNFG PLC will automatically issue a set-point equivalent to 0 MW. If a trip is not active then the set-point is issued to the RNFG control system by the RNFG PLC. After a defined time period the output of the RNFG unit is checked to ensure it is not breaching the set-point issued. If the set-point has been met then the RNFG PLC continues to issue the set-point until the Central APFM PLC requests a change. If the set-point has not been achieved the RNFG PLC will issue a full reduction signal to the RNFG unit to go to 0 MW. After a time delay the RNFG PLC checks to see if the RNFG unit has met the 0 MW set-point. If it has, the 0 MW set-point is continued until the RNFG PLC is instructed otherwise by the Central APFM PLC. If the RNFG unit is generating more than 0 MW the RNFG PLC will trip the RNFG circuit breaker to remove the output of the RNFG unit from the network.

9.4 Appendix D: Logic to Increase the Output of Constrained Regulated Non-Firm Generation

The APFM scheme begins releasing network capacity access back to the RNFG units when the export at the measurement point drops below the reset margin. A time delay is used to filter out momentary reductions in export that result in the export falling below the reset margin. As was the case for trimming RNFG units, the use of this time delay prevents spurious signals from the APFM scheme, but also prevents hunting of RNFG output around the reset margin.

After the export has been below the reset margin for a period of time, the headroom between the real-time export value and the trim margin is measured. This calculated capacity is released to the highest priority RNFG unit. After a period of time, the APFM scheme compares the issued RNFG unit (RNFG1 in this example – the highest priority unit) set point with the maximum set point. If RNFG1 is not at full rated output then the APFM scheme releases the measured available headroom to RNFG1. If RNFG1 is at full rated output then a time delay is employed prior to the APFM scheme re-calculating the available headroom to the trim margin and releasing this capacity to the next highest RNFG unit in the priority stack – RNFG2 in this case.

The same logic processes are repeated for RNFG 2 until it reaches full rated output, at which point the APFM scheme follows the same procedure to releasing capacity to the RNFG3 – the final RNFG unit in the example given in Figure 62.

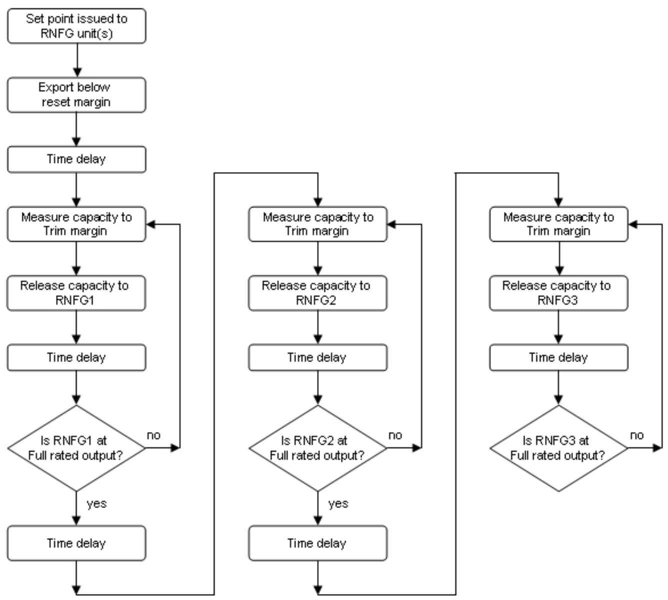

Figure 62: Logic processes required to release capacity back to RNFG after trimming

9.5 Appendix E: Logic to Perform Tripping of Regulated Non-Firm Generation

Events that are external to the APFM scheme can cause the tripping of the RNFG units, such as a system disturbance resulting in the DG protection systems removing the generator from the system. The APFM scheme must be able to cater for and react to this situation. On the other hand, the RNFG units can be tripped by the APFM scheme for the following three main reasons:

- The RNFG unit output has been above the set-point issued by the APFM scheme for a period of time
- The RNFG unit has not responded adequately to a trim signal and the export has breached the sequential trip margin
- Current at an associated measurement point breaches the global trip margin

Although the first two points above are distinct, they are very similar from the perspective of the functional elements of the APFM scheme; non-compliance will result in RNFG units being tripped. The RNFG units may be tripped individually or collectively by the APFM scheme, the following sections deal with both of these possibilities.

9.5.1 Tripping Individual Regulated Non-Firm Generation

Figure 63 presents the logic processes for tripping individual RNFG units when the RNFG unit is not complying with a set-point instruction (i.e. the real-time output has been above the permitted set-point for a period of time) or the sequential trip margin is breached.

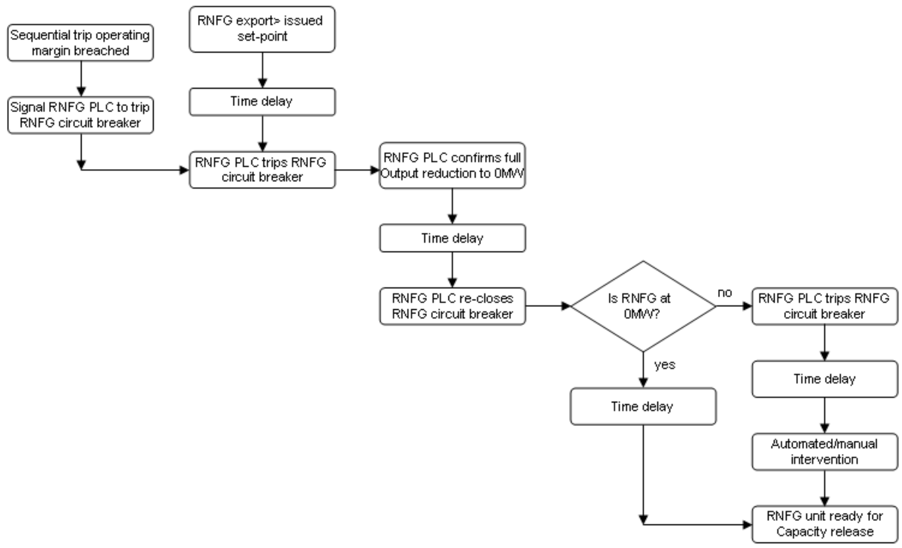

Figure 63: Logic processes undertaken by APFM scheme to trip an individual RNFG unit

The RNFG PLC will trip the RNFG circuit breaker if the export has been above the issued set-point for a pre-defined time period or if the instruction to perform a trip has been issued to the RNFG PLC. After tripping the circuit breaker, the RNFG PLC monitors the output of the RNFG unit to ensure it is at 0 MW. Once it is confirmed that no power is being produced by the RNFG unit, a timer is started, at the end of which the RNFG PLC will re-close the RNFG circuit breaker. Once the breaker has re-closed, the APFM scheme will check that the output of the RNFG unit remains at 0 MW. If the RNFG unit is at 0 MW then the APFM scheme will identify the RNFG unit as being ready to have its set-point increased after a period of time of being held at 0 MW. If after re-closing the RNFG PLC measures that the RNFG unit is generating power then the RNFG PLC will trip the circuit breaker again. After a period of time, the APFM scheme will then await automated or manual intervention to allow the APFM scheme to identify the RNFG unit as being ready to have its set-point increased.

9.5.2 Global Trip of Regulated Non-Firm Generation

A global trip of RNFG units will occur when the 'Global RNFG Trip' level is breached at a measurement point. The logic processes undertaken by the APFM scheme will be the same irrespective of the location of the overload and applied to the RNFG units associated with the measurement point.

When the Global RNFG Trip margin is breached the Central APFM PLC will start a timer. As is the case for other operating margins, this timer allows short-term variations that may cause the margin to be breached momentarily to be filtered out. At the end of the timer the APFM scheme will determine which RNFG units should be tripped to reduce the loading at the measurement point. The Central APFM PLC will then issue the control instructions to the RNFG PLCs associated with the measurement point to trip the RNFG circuit breaker. After this process is initiated, the APFM scheme performs the same checking procedure as described above for the tripping of an individual RNFG unit.

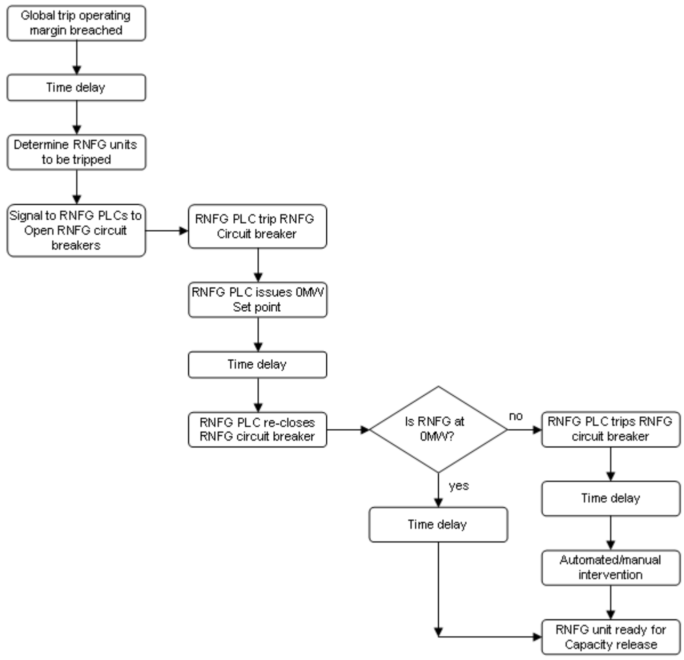

Figure 64: Logic processes undertaken for global trip of RNFG units

9.6 Appendix F: Logic to Increase the Output of Regulated Non-Firm Generation after Tripping

The following sections provide an overview of the logic processes required to increase the set-point issued to RNFG units (i.e. release capacity back to the RNFG units) that have been collectively or individually tripped.

9.6.1.1 Increasing the Output of Regulated Non-Firm Generation after an Individual Trip

It is necessary to determine what capacity is available prior to releasing capacity back to a RNFG unit that has been individually tripped by the APFM scheme. Such a calculation will give due consideration to the output of RNFG units of less priority. Figure 65 presents the main logic processes associated with increasing the output of RNFG units that have been individually tripped. At the beginning of the process the RNFG unit must be operating at full constraint, i.e. 0 MW. A time delay is employed so that the APFM scheme will consider raising the set-point after defined time periods, e.g. every five minutes. If the export is below the trim margin and there is no RNFG of less priority to the RNFG unit online then the APFM scheme continues to issue the full output reduction signal of 0 MW.

If the export is not under the trim margin but a RNFG unit of lesser priority is generating power then the APFM scheme allocates the capacity being utilised by the export from the RNFG unit of lesser priority to the RNFG unit that has been previously tripped. After a time delay the APFM scheme assesses the export again to determine if the export is below the trim margin. If the export is under the trim margin and there is no RNFG unit of lesser priority generating power then the APFM scheme calculates the capacity available and releases it to the RNFG unit. If in this situation there is a RNFG unit of lesser priority online then the APFM scheme calculates the capacity available plus the output of the lesser priority RNFG units. This capacity is released to the RNFG unit up to its full rated output if necessary, at a pre-defined ramp rate. After a time delay the APFM scheme assesses the export again to determine whether any additional capacity is available for the RNFG unit to access, this is repeated until the RNFG unit is unconstrained. The logic processes associated with trimming will reduce the output of the lesser priority RNFG units as required while RNFG units of greater priority increase their output.

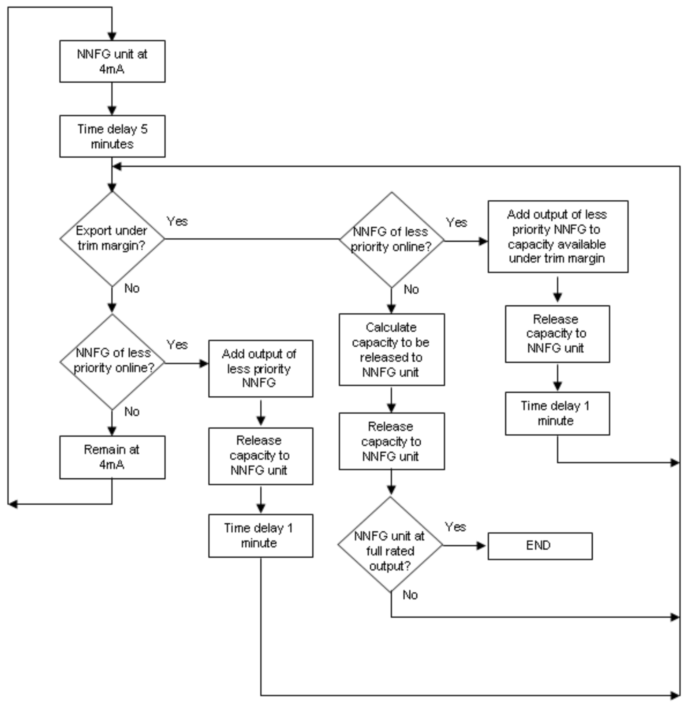

Figure 65: Logic process to release capacity to a RNFG unit that has been tripped individually

9.6.2 Increasing the Output of Regulated Non-Firm Generation after a Global Trip

The global trip of RNFG could occur during normal operation if the tripping of individual RNFG units on the breach of the sequential trip margin failed to reduce the export at a measurement point to an acceptable level. This could also be cause by the loss of one or more parallel circuits at a measurement point.

After all RNFG units have been tripped and are fully constrained off by the APFM scheme, the output of RNFG units is increased according to the order of the priority stack. As shown in Figure 66, the Central APFM PLC determines the priority stack of RNFG units for the measurement point in question and then allows the RNFG units online at pre-defined intervals (e.g. five minutes) and at a pre-defined ramp rate, after checking for violations of the trim operating margin. If there is a violation of the trim margin, the other RNFG units will be prevented from exporting power through the control logic associated with trimming and RNFG output regulation.

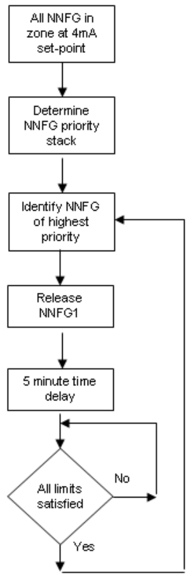

Figure 66: Logic process to release capacity to RNFG stack after a global trip

9.7 Appendix G: Logic for Loss of APFM Communications

It is crucial that the APFM scheme fails safe and can cope with the loss of a communications link. This is significant as it is common for communications systems to experience disruption and the network control systems must be designed to limit the impact of this on the security of supply. As was discussed earlier in this chapter, the RNFG PLC is fundamental to meeting this requirement and is responsible for reducing the output of the RNFG units during such an event. There is no requirement placed on the NMU PLC to act on a loss of communications with the Central APFM PLC; therefore, the following sections present the logic required in the Central APFM PLC and RNFG PLC.

9.7.1 Loss of Communications at Central Active Power Flow Management Controller

The Central APFM PLC will be communicating regularly with all measurement and RNFG PLCs. The Central APFM PLC will check for the status of each communications link by counting the number of successful message (MSG) instructions in a time period. This is demonstrated in Figure 67 using an example time period of 60 seconds and discussed in the following paragraphs.

If the number of successful MSG instructions to the NMU PLC is below the target level (X messages, in this case), then the Central APFM PLC will identify this as a loss of communications event. The Central APFM PLC will then issue a full output reduction signal to each RNFG PLC associated with the NMU PLC. Each RNFG PLC will then pass the set-point to the RNFG control system and monitor the response of the RNFG unit, as was discussed previously.

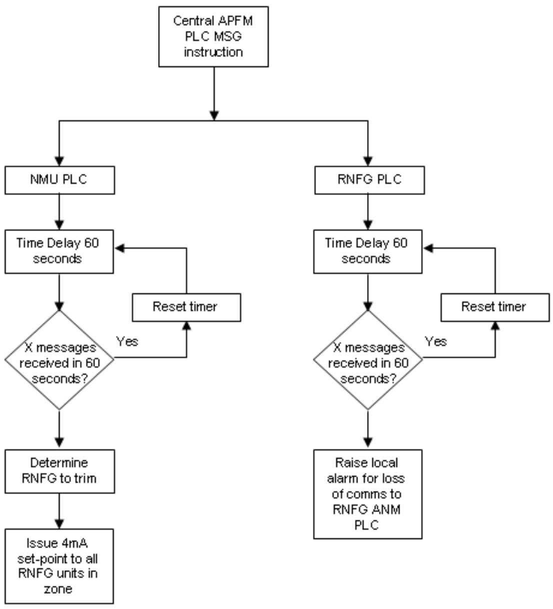

Figure 67: Logic process undertaken at Central APFM PLC for loss of communications to a NMU PLC or RNFG PLC

The Central APFM PLC will approach the monitoring of the communications links to RNFG PLCs in the same way as for NMU PLCs; however, the main outcome now becomes the raising of an alarm. This is due to the Central APFM PLC having no means of controlling the RNFG unit output during a loss of communications, which becomes the responsibility of the RNFG PLC.

9.7.2 RNFG PLC Logic for Loss of Communications

The RNFG PLCs will be equipped with logic processes to ensure the safe operation of the system if the communications link to the Central APFM PLC is lost – the requirement for this is fundamental to the APFM scheme providing security of operation to the network operator. The RNFG PLC will monitor the number of successful MSG instructions from the Central APFM PLC, if this does not meet the minimum requirement (again, the example of X messages in a 60 second period is used), the RNFG PLC will issue the RNFG control system with a full output reduction signal of 0 MW. The RNFG unit will then be subject to meeting the issued set-point as described previously.

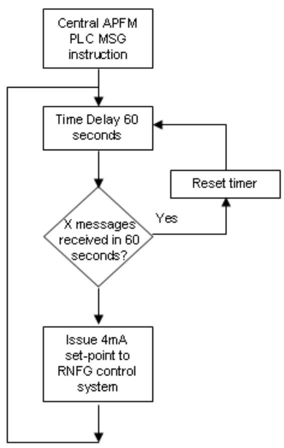

Figure 68: Logic processes undertaken by RNFG PLC for loss of communications

9.8 Appendix H: Logic for Lockouts and Enables

The Central APFM PLC will require status indications from each RNFG PLC to show when each RNFG unit is on or off-line, generating power or not, and the set-point issued to the RNFG unit by the RNFG PLC. In addition to this the Central APFM PLC will require regular representations of the output (MW) of the RNFG units. All of this data will be passed to the Central APFM PLC through the use of the MSG instruction. If some of this information is not available it could affect the smooth running of the scheme. Therefore the logic must provide some lockout and enable functionality to ensure the APFM scheme operates properly and can be controlled when not operating properly.

The Central APFM PLC will be equipped with the ability to restrict and enable the operation of the APFM scheme. This will allow a control engineer to reduce the output of all RNFG units to zero – equivalent to switching the APFM scheme off. The central APFM PLC will require a link to the SCADA system of the host network operator to support remote control and visualisation of the APFM scheme.

When the APFM scheme is switched off the RNFG PLCs will receive an instruction to ensure that the RNFG units achieve a full output reduction within a defined period of time.