Ofgem 2008 National Report to the European Commission

Date of submission: 31 July 2008

Overview:

The Directives on gas and electricity liberalisation stipulate a monitoring and reporting obligation for Member States as well as for regulators. To that end, this report covers Ofgem's annual reporting requirements to the European Commission, in accordance with Directives 2003/54/EC (electricity) and 2003/55/EC (gas). This report covers only Great Britain (GB) and not N. Ireland.

In terms of content, the report covers:

- The organisation and structure of the Gas and Electricity Market Authority (GEMA)
- Developments in the GB energy markets in the last 12 months
- The regulation and performance of the GB electricity market
- The regulation and performance of the GB gas market
- Security of supply
- Public service issues

Since GB energy markets have been fully liberalised and the regulatory structures in place for a number of years, this report is intended as an updated version of the submissions to DG TREN in 2006 and 2007. Much of the information remains unchanged, although latest data is supplied where relevant. It should be noted that not all of this information is under Ofgem's jurisdiction, and where external sources are used references are provided.

Finally, for further information on Ofgem's activities, we would draw attention to our **2007/08 Annual Report**. This is the report of the Gas and Electricity Markets Authority for the period 1 April 2007 to 31 March 2008 to the Secretary of State for Business, Enterprise and Regulatory Reform. The report is made under section 5(1) of the Utilities Act 2000, and also sets out information on impact assessments as required by section 5A(9) of the Utilities Act 2000, as introduced by section 6 of the Sustainable Energy Act 2003. The Ofgem Annual Report 2007-08 is available at:

http://www.ofgem.gov.uk/About%20us/annlrprt/Pages/AnnualReport.aspx

Contact person:
Adhir Ramdarshan
Ofgem, European Strategy & Environment
9 Millbank, London, SW1P 3GE
Adhir.Ramdarshan@ofgem.gov.uk
0207-901-7340

Table of Contents

1. Foreword

This has been a particularly difficult year for energy consumers given the anxiety about the cost of energy that has pervaded the period. Given our principal objective to protect the interests of consumers, we have been acutely aware of the impact rising prices have had on Britain's households and businesses. In response we have focused our efforts to ease the impact of rising global commodity prices. That focus has been particularly sharp given that the rising cost of energy sector measures to tackle climate change is also adding to Britain's energy bills. Meanwhile we hold our course on the environmental challenges and social issues at the heart of sustainable development.

To help navigate this course, I chaired a fuel poverty summit in April of ministers, industry, consumer groups and other key stakeholders to consider the hardships faced by consumers struggling to pay their energy bills. The summit produced a fuel poverty action plan – a raft of commitments to practical measures to help the fuel poor principally through better targeting of existing resources.

Ofgem's growing role in sustainable development has been demonstrated this year in the greater profile of sustainability in its price controls. The price controls set the maximum amount of revenue which energy network owners can take through charges they levy on users of their networks to cover their costs and earn them a return in line with agreed expectations. The controls include curbs on networks' expenditure as well as incentives to be efficient and to innovate technically. Networks are, in effect, the trade routes that will carry renewable energy to consumers. So Ofgem has devised ways to enable this sector of the industry to prepare to connect the new renewable generation needed if Britain is to meet European renewable targets. We have provided networks with incentives to boost their own environmental performance. We have this year proposed smarter ways to use the power transmission grid to speed up connection of renewables projects currently stalled in a queue and we have started to consult on ways to streamline the codes governing connections and use of the energy grids.

Greater integration of energy markets and cross-border flows has meant that the operation of wider European markets has an impact on GB consumers. Wholesale gas prices in Britain are affected by those in neighbouring markets in which competition may be less well-established or liberalisation less complete. The commercial and physical links between British and other gas markets are being strengthened significantly by plans for new gas pipelines and LNG import terminals, and European rules and regulations increasingly affect Britain's markets.

For these reasons, Ofgem considers that the European Commission's report on the functioning of gas and electricity markets across Europe is an important opportunity to take stock of progress towards the single market, and to review barriers to further progress so as to ensure these are addressed in the future legislation.

Our voice in Europe has helped to guide the European Commission in its quest to inject competition into energy markets and to create a single internal energy market. This is obviously particularly important this year, as we build on the progress being made by the ERGEG Regional Initiatives and move into the second phase of the so-called "3rd legislative package". In this context, the need to inject competition into EU energy markets has taken on greater than ever importance and Ofgem welcomes these initiatives.

Britain's acknowledged lead in energy regulatory practice in Europe has not prevented Ofgem from asking searching questions of its own practices. We have set out this year an appraisal of the incentive-based approach at the core of our regulatory regime to ensure it is still fit for purpose. And we have responded to consumer concern over price increases with a probe into whether Britain's energy retail market is working for all consumers during these difficult times.

The year has been a perfect illustration of the growing complexity of the demands on the energy sector which has been reflected in the demands on the regulator. The promotion of markets, where appropriate, alongside economic regulation of network monopolies remains a powerfully effective combination for tackling these demands. But in the face of escalating global fuel prices, coupled with the costs of tackling climate change, Ofgem has dug deep into its reserves of expertise to rise to what are unprecedented challenges.

Lord Mogg
Chairman

2. Summary \ Major Developments in the last year

2.1 Basic organisational structure of the regulatory agency

1. The Office of Gas and Electricity Markets (Ofgem) supports the Gas and Electricity Markets Authority (the "Authority"), the regulator of the gas and electricity markets in Great Britain. The Authority consists of non-executive and executive members and a non-executive chair. [1] Non-executive members bring experience and expertise from a range of areas including industry, social policy, environmental work, finance and Europe. The Executive members of the Authority are Ofgem's Chief Executive and three Managing Directors.

2. The Authority determines strategy, sets policy priorities and takes decisions on a range of matters, including price controls and enforcement. The Authority's powers are provided for under the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly applicable European Community legislation.

3. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and has powers under the Gas and Electricity Acts to take action for breaches of the obligations imposed under this legislation. It is a designated National Competition Authority under the EC Modernisation Regulation and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading (OFT) in respect of market investigation references to the Competition Commission.

4. In terms of funding, Ofgem recovers costs from the licensed companies it regulates. Licensees are obliged to pay an annual licence fee. Ofgem is independent of the regulated companies.

5. For a detailed explanation of Ofgem's competencies, please see Appendix 1 – The Authority's Powers & Duties.

6. For an explanation of the changes to consumer representation in GB, please see Appendix 2.

7. Please note that since June 2007 responsibility for energy policy within the UK government has passed from the former DTI to the new Department for Business, Enterprise and Regulatory Reform (BERR).

2.2 Main developments in the gas and electricity markets

Energy markets

8. In 2007/08, rising wholesale energy prices have been a key driver behind increases in household and industry energy bills. After retail price reductions in 2007, rising global energy prices resulted in a spate of price rises in early 2008.

[1] Ofgem and the "Authority" are used interchangeably in this report.

9. The prices of coal, oil, gas and electricity, (which are the four main energy sources), have increased significantly between April 2007 and now. Global Liquefied Natural Gas (LNG) markets were also much tighter than winter 2006/07 due to higher global LNG demand, particularly from Asian markets such as Japan.

10. High world oil prices are reflected in wholesale gas prices, particularly since the GB market is now increasingly exposed to the European markets where oil and gas prices are closely linked as a result of the market's structure (notably through predominant indexation of gas prices to oil price in long term contracts for gas).

11. Electricity wholesale prices have been subject to further upward pressure from environmental measures. The European Union Emissions Trading Scheme has moved into a higher impact second phase while the EU's Large Combustion Plant Directive has restricted the use of high sulphur emitting power stations. Suppliers have also had to increase the power bought from renewable energy sources under the UK renewables obligation.

12. The amount of energy from renewable sources will increase following the agreement in spring 2008 by Member States to an EU-wide target of 20% renewable energy by 2020. The European Commission has proposed that the UK share of this target would be to achieve 15% of the UK's energy from renewables by 2020 which is equivalent to almost a ten-fold increase in renewable energy consumption from current levels.

13. From early 2008, all major suppliers increased their prices to customers. This led to public concern among customers that Ofgem considered may undermine confidence in competition. On 21 February 2008, Ofgem decided to launch a probe (sector review) into retail markets in electricity and gas for households and small businesses.

14. Ofgem's routine monitoring of the GB retail market has shown there were five million account switches in 2007.

Infrastructure

15. New infrastructure projects have been announced or confirmed during 2007/8. These include electricity interconnection and LNG import capacity.

16. The following electricity interconnection projects between the GB and other markets have been announced or confirmed during 2007/8:

    a. interconnection with the Netherlands: in July 2007 Ofgem issued an electricity interconnector licence and an exemption order from Third Party Access and Use of Revenue requirements, thereby enabling BritNed Development Ltd to build a high voltage DC electricity cable of 1320MW capacity between Great Britain and the Netherlands. The exemption order was amended in November 2007 to meet additional requirements of the European Commission in relation to it;

    b. interconnection with Ireland: in July 2008 Ofgem has consulted on its proposal to grant East West Cable One Ltd (formally Imera Power Ltd) an exemption from Third Party Access and Use of Revenue requirements for each of their proposed two 350MW interconnectors between Wales and the Republic of Ireland; and

c. interconnection with Ireland; In September 2006 the Irish government requested CER (the Irish Regulator) to arrange for the design of a tender for the construction of a 500MW DC interconnector between Ireland and GB to be owned by EirGrid. CER has confirmed that work on this tender is well under way. The interconnector is scheduled to be commissioned in late 2011.

17. During 2007, BBL Company announced its intention to increase capacity on the Balgzand-Bacton Line (BBL) gas interconnector with the Netherlands from 15bcm to 18bcm. This additional capacity is expected to become available to the market between 2010-2012.

18. In April 2007, Ofgem granted an exemption from regulated Third Party Access requirements in relation to the third phase of the Isle of Grain LNG importation terminal. This will allow for the expansion of the terminal capacity by up to 7 bcm/y in 2010.

19. It is anticipated that the second phase Isle of Grain LNG importation terminal as well as the South Hook and Dragon LNG terminals will commence operation this year. This would provide an additional 25.5bcm to the market for winter 2008/09.

20. In August 2007, SSEHL and Statoil Hydro were granted exemptions from the Gas Act requirements to offer negotiated third party access to the Aldbrough storage facility. Access to this facility was considered not to be technically and/or economically necessary for providing efficient access to the system for the supply of customers (Article 19 of the gas Directive). It is anticipated that this facility, which has a total operational capacity of 4,550GWh and maximum deliverability of 421GwH will be in operation for Winter 2008/09.

21. In addition, during the last year a number of potential storage operators have met with Ofgem to discuss proposals to construct additional storage facilities for the GB market.

Security of Supply

22. The keystone for security of energy supply is an energy sector that can attract investment. Through its maintenance and promotion of competitive wholesale and retail markets in Britain and its sound regulation of network monopolies Ofgem has laid the foundations for investment in energy infrastructure.

23. Among key mechanisms and measures for improving the UK's security of supply, the following are included:

24. <u>Long term Electricity Network Scenarios (LENS)</u> - Commenced in June 2007, the main objective of the LENS project is to pave the way for debate on the outlook for electricity networks. It is developing a range of plausible electricity network scenarios for Great Britain for 2050, around which industry participants, government, Ofgem and other stakeholders can discuss future network issues.

25. <u>Energy Markets Outlook (EMO)</u> - Ofgem and the UK government have launched a yearly programme to produce energy market information and analysis which made its first report in autumn 2007. The programme reviews prospects for the medium- and long-term security of supply, looking at infrastructure planning and other constraints. In a way that mirrors the LENS programme, EMO will provide credible long-term market scenarios to assist industry in strategic planning.

26. Emergency arrangements - Having been the driving force behind the creation of the industry Energy Emergencies Executive which supervises emergency planning arrangements, Ofgem continues to play a key role in ensuring the industry is well prepared to deal with emergency situations. Ofgem took part in an industry-wide, government-led simulation of a 'black start' following national power losses in summer 2007 to test plans to deal with such an event in the future. The exercise was drawn up by the Energy Emergencies Executive.

2.3 Major issues dealt with by the regulator

Markets

Retail market probe

27. Ofgem launched a Retail Market Probe in February 2008 to address public concern about whether the electricity and gas retail markets are working effectively for all customers, in particular vulnerable customers. The aim of the probe is to take a more detailed look at whether the gas and electricity retail markets are working for all customers. The Probe covers households and small businesses and is being carried out under Ofgem's Enterprise Act 2002 powers, which allow the regulator to access information that is not routinely made available.[2]

28. The investigation will cover:

- the customer's perspective and experience of the market including access to information and barriers to switching supplier;
- suppliers' market shares and switching rates for different customer groups;
- the competitiveness of suppliers' pricing in the different market segments and customer movement between payment types as well as suppliers;
- the relationship between retail and wholesale energy prices; and
- the economics of new entry and the experience of companies trying to enter the energy market.

29. Initial findings for the probe are scheduled for publication by the end of September 2008. Possible outcomes of the probe range from a referral of the market to the Competition Commission, to enforcement under Ofgem's own powers, campaigns to promote customer awareness and participation in the market, recommendation to government for legislative changes or a clean bill of health for the market.

Other consumer-related issues

30. Ofgem continues to encourage suppliers to take a proactive approach to helping their fuel poor and vulnerable customers. In August 2007, we published information highlighting suppliers' initiatives to help their vulnerable customers. Following the 2008 budget announcement, the government secured an agreement with suppliers to triple their collective expenditure on these initiatives to at least £150m per year by

[2] Section 174 of the Enterprise Act 2002.

2011, providing an additional £225m over the next three years. Ofgem has agreed to monitor and report on suppliers' progress against this commitment. Ofgem also hosted an Energy Summit on Fuel Poverty in April 2008 where attendees agreed a programme of practical action to improve the targeting of existing help to those in fuel poverty and to help vulnerable customers participate more effectively in the energy market.

31. New obligations in suppliers' licences to increase protection for vulnerable consumers took effect on 1 August 2007. For example, a ban on gas suppliers from disconnecting older customers over winter (bringing this into line with existing protection in electricity) and new obligations to require the timely recalibration of gas and electricity prepayment meters, to ensure these apply the right charges after a price change and prepayment customers are not unduly overcharged.

32. Ofgem also launched its Consumer First programme at the start of 2007, which gathered momentum in the spring. The programme seeks to improve the regulator's understanding of the developing interests and concerns of household energy consumers. Work under Consumer First included workshops to test consumer attitudes to environmental considerations. Other valuable areas of research included studies related to:

- customers' experiences, expectations and willingness to pay for quality of service improvements by the electricity distribution businesses;
- customers' views of suppliers' complaint handling processes;
- debt and disconnection;
- green tariffs;
- understanding behaviour of vulnerable consumers when switching supplier; and
- setting up the consumer panel and consumer challenge group to boost customer involvement in Ofgem policy making.

33. On the back of the above research, Ofgem published a Debt and Disconnection Best Practice Review in January 2008 which identified best practice among suppliers and set benchmarks for suppliers' performance in this area. It included strong messages for businesses to step up to the mark and maintain their focus in this area to ensure their customers, particularly their vulnerable customers, have adequate assistance to help them manage their energy bills.

34. Ofgem has taken action as necessary to ensure suppliers are compliant with licence obligations. It has recently launched an investigation into allegations of mis-selling of gas and electricity contracts by the supplier npower. Earlier in the year, Ofgem took informal action to ensure all suppliers were providing the necessary information to customers on the benefits and disadvantages of prepayment meters.

Networks

Review of the regulatory regime for energy networks

35. In March 2008, Ofgem opened a review of the 20-year-old regime governing its regulation of the gas and electricity networks. The two-year review will seek to establish whether the existing approach - based on pegging increases below the retail price increase (RPI) - is still the best way to ensure that networks are well-run and provide a good service to customers. The need for the review arises out of the new challenges faced by the energy network companies in financing and running their business. The challenges for the future include ambitious new government renewables targets for 2020, proposals for greater power network interconnection in Europe, a greater emphasis on small-scale distributed generation and growth in gas imports.

Transmission

36. Transmission Access Review - Anticipated growth in renewable energy will place new demands on the electricity transmission grids. In Scotland alone there is 12GW of mostly wind plant awaiting connection to the networks. In conjunction with government and industry, Ofgem commenced a major project in July 2007 looking at the possible reform of transmission access arrangements to identify areas for improvement. This will, inter alia, look at ways in which the current access arrangements can be improved to enable more flexible and quicker access to the transmission system. It has the potential to play a key role in delivering the EU's 20 per cent renewable target. It is hoped the changes proposed to the Secretary of State in the final report to this project will be facilitated by industry and in place by 1 April 2010.

37. Offshore Transmission regime - Ofgem has continued to work towards facilitating the connection of increased amounts of renewable generation to the transmission networks, in particular the development of an offshore transmission licensing and charging regime. This will facilitate the development of a sustainable and competitive offshore wind industry. These offshore transmission networks are pivotal to the UK's objectives for renewable energy and will add to the security of UK energy supplies.

Distribution

38. Gas price control - The gas distribution industry went through a major restructure in 2005 after National Grid divested four of the eight gas distribution networks (GDNs) in England, Scotland and Wales to three separate buyers. The creation of new companies in the sector meant that, in the gas distribution price control review that concluded in March 2008, Ofgem was able to make comparisons between them and force the poorest performers to work towards the efficiency of the best. Before this time Ofgem had no such comparisons available with all the companies in the ownership of one group.

39. Electricity price control - Ofgem launched its fifth electricity distribution price control review with the initial consultation in March 2008. Ofgem's proposals include the following key priorities:

- encouraging distribution network operators (DNOs) to be more responsive to the needs of customers not least because of the growing customer interest in managing their own energy use through forms of so-called microgeneration;
- giving DNOs strong financial incentives to help tackle climate change; and
- delivering good value for consumers by ensuring that DNOs provide secure and more sustainable networks.

40. Structure of charges **-** The structure of charges which DNOs apply determines how allowed revenue is recovered from different customer groups. Ofgem is consulting fully and working with DNOs to encourage them to adopt better approaches to charging. In particular, we are concerned that current charging structures do not properly reflect the impact and benefits from generation connected to their networks and could be standing in the way of more small scale low carbon generation coming onto the system.

Sanctions

41. There were sanctions imposed by Ofgem during 2007/2008, the major one being a fine of National Grid - £41.6 million (€60.8million)[3] for a breach of competition law that restricted the development of competition in the domestic gas meter market. It is the biggest fine imposed in the GB for anti-competitive behaviour. This decision is currently the subject of an appeal to the Competition Appeals Tribunal.

Other policy actions

42. In addition, we carried out a lot of policy groundwork in 2007/8 which should become evident in the coming year. Some of the areas where we have carried out such work include:

- in Europe, we will continue to play a proactive role alongside our EU colleagues in CEER and ERGEG, including through Lord John Mogg's chairmanship, as the "Regional Initiatives" develop further and the formal negotiations on the "3rd legislative package" enter the second reading;
- Ofgem is increasingly contributing towards transparency in energy markets. For example, we are leading on the implementation of a project for TSOs to improve network data release in the context of the North West Gas Regional Initiative;
- the government published its Energy White Paper in May 2007, which, among other issues, set out the potential role of Distributed Energy (DE) in meeting the UK's energy policy objectives. This led to the publication of a joint Ofgem/BERR consultation in December 2007 on initial options for introducing greater flexibility to the market, regulatory, and licensing arrangements for DE. On the back of responses, Ofgem/BERR published preferred proposals in June 2008 for implementation by the end of 2008;
- Ofgem has initiated a major overhaul of the rules governing participation in the gas and electricity markets (Governance Review). The review aims to speed up the delivery of major policy changes and reduce Ofgem's role in routine amendments. It will take out complexities that create obstacles for small players and new entrants;
- we continue to manage the government's energy demand reduction project. This is co-funded by government and industry participants and involves several energy saving trials with about 50,000 households participating. The trials will compare the efficiency of smart meters, clip on real time display units and other ways of information provision to save energy use. The trials will end in 2010; and
- we have introduced new complaint handling standards for suppliers and network companies and have approved a statutory redress scheme which the companies must be members of under new Government legislation. These new arrangements come into force from 1 October 2008.

[3] The Bank of England's 2007 average annual exchange rate of £1 to €1.4619 is used throughout this report unless otherwise stated.

43. Further information on recent activities in GB energy markets, and on the activities of Ofgem can be found in the Ofgem Annual Report 2007-08, which is available at:

    http://www.ofgem.gov.uk/About us/annlrprt/Pages/AnnualReport.aspx

3. Regulation and Performance of the Electricity Market

3.1 Regulatory Issues [Article 23(1) except "h"]

Overview

This section describes the regulatory framework for the GB electricity market. It covers:

- Management and allocation of interconnection capacity and mechanisms to deal with congestion
- The regulation of the tasks of transmission and distribution companies:
  - Price controls and incentives
  - Standards of performance and quality of service
  - Network tariffs
  - Balancing arrangements
- The regulation of effective unbundling

3.1.1 General

44. Gas and electricity markets in Great Britain are fully liberalised.

3.1.2 Management and allocation of interconnection capacity and mechanisms to deal with congestion

Management of congestion on interconnectors

45. The GB electricity system is connected with France and Northern Ireland via the IFA[4] and Moyle[5] interconnectors respectively. The existence of these interconnectors and the current proposals for new interconnectors suggests that new interconnection capacity will be provided to the market when it is economic to do so. One new interconnector link to the Netherlands (BritNed[6]) is under construction. Ofgem have also granted licences for the construction of three interconnectors with the Republic of Ireland, one interconnection with Belgium and two with France although none of these are yet under construction.

46. The requirements of the Directives and the electricity Regulation regarding interconnectors have been implemented into GB legislation through our licensing framework, and in particular through the standard conditions of the electricity interconnector licence[7]. The use of revenue requirements are set out in standard licence condition (SLC) 9, charging methodology requirements are set out in SLC 10

[4] Interconnexion France Angleterre (IFA) is a 2,000MW HVDC interconnector link between France and GB. It is jointly owned by National Grid Interconnector Limited (NGIL) and RTE.
[5] Moyle is a 500MW interconnector between Scotland and Northern Ireland. Capable of exporting at 500MW to Northern Ireland and importing at 80MW. It is owned by Moyle Interconnector Ltd.
[6] BritNed is a 1,000MW interconnector jointly owned by NGIL and TenneT.
[7] Interconnector Licence: http://epr.ofgem.gov.uk/document_fetch.php?documentid=8790

whilst obligations relating to third party access are set out on SLC 11. Ofgem's ability to grant an exemption from all of part of the requirements of SLC 9, 10 and 11 is set out in SLC 12. It is an offence to participate in the operation of an interconnector without first being granted a licence by Ofgem.

47. Ofgem considers that effective secondary trading and anti-hoarding mechanisms are required, with each interconnector operator needing to demonstrate that there is a transparent mechanism that allows spare capacity to be made available to the market. Our objective is to ensure that capacity is not hoarded and that unused capacity can be obtained in a transparent market based manner by third parties so as to maximise the use of the interconnector concerned. The actual methodology under which interconnector capacity is made available in both the primary and secondary market is for the interconnector owner/operator to decide.

48. This requirement is underpinned by a licence obligation. SLC 13 of the interconnector licence requires the licensee to make available the maximum capacity of its interconnector. This includes the development of procedures on the primary market to facilitate the secondary trade of capacity and the requirement to allow and facilitate the trading of capacity rights on the secondary market. If capacity is reduced for technical reasons the mechanism for reducing the capacity allocation should be open, transparent and non-discriminatory.

49. If the interconnector licence holder does not meet the requirements of the licence the Authority would anticipate being informed by market participants or through our own monitoring. Ofgem would then investigate and take any appropriate action. Ofgem's enforcement powers include the ability to impose a financial penalty of such amount as is reasonable in the circumstances of the case (not exceeding 10% of the licensee's applicable turnover).

50. In 2007 BritNed was issued an electricity interconnector licence and an exemption stating that that SLCs 9, 10 and 11 of the interconnector licence and Article 6(6) of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity should not apply for a period of 25 years. As part of its exemption application BritNed set out its commitment to comply with the Congestion Management Guidelines and to put in place effective anti-hoarding use-it-or-lose-it (UIoLI) measures. Were these measures not to be put in place then the Authority would investigate and may have grounds to amend or revoke the exemption. Consideration would also be given to compliance with SLC 13 (described above) which is in force in the licences of exempt interconnectors.

51. Under the current regulatory and contractual framework, the risk of contractual congestion on the interconnector with France is addressed by UIoLI provisions which aim to prevent the hoarding of capacity.

52. Market fundamentals are such that the interconnector with Northern Ireland typically exports from GB however, on occasions imports are received.

Management of congestion on national networks

53. Electricity transmission owners (TOs) are under a statutory obligation to develop and maintain efficient systems, as are electricity distributors. In accordance with planning and operational standards, the TOs build assets to ensure that demand on the network can be served.

54. In addition to the TO role of building infrastructure, there is also a GB System Operator (SO) whose role it is to balance the transmission system in real time. In addition to licence requirements to operate the transmission system in an economic, efficient and coordinated manner, the SO is incentivised to reduce the cost of congestion under its system operation incentive scheme, whereby it may pay, or be paid, a proportion of the costs incurred relevant to target set by Ofgem (both subject to caps/ floors and sharing factors). Further details of this incentive scheme and recent developments are provided in the discussion of regulation of the tasks of distribution and transmission companies (section 3.1.3).

55. The management of congestion is integrated with the functioning of the wholesale market. Access to the transmission network is financially firm and as such the SO must pay (through the balancing system) to constrain generators on or off in order to manage network congestion.

56. The electricity SO is required to publish information about the longer-term development of the network that will allow new customers to assess the opportunities for connecting to the network in various locations.

57. Congestion on electricity distribution networks is not an operational issue because networks are passively operated. Distribution network owners are required to make available information about their networks that will allow new customers to assess the opportunities for connecting to the network in various locations.

3.1.3 The regulation of the tasks of transmission and distribution companies

58. There are three transmission system owners in Great Britain:

- National Grid Electricity Transmission Ltd (NGET), which owns the high voltage transmission system in England and Wales;
- Scottish Power Transmission Ltd, which owns the high voltage transmission system in the South of Scotland; and
- Scottish Hydro-Electric Transmission Ltd, which owns the transmission system in the North of Scotland.

59. NGET is the designated SO for all of the transmission systems in Great Britain.

60. There are fourteen licensed distribution network operators (DNOs)[8] in Great Britain. These DNOs were established as part of the privatisation process in 1990 and were the only providers of distribution network services in each geographic area for several years. However, the Utilities Act 2000 changed the legislative and regulatory framework to enable each DNO to own and operate network assets in any area of Great Britain. These changes have also facilitated the entry of new DNOs which build, own and operate networks connected within existing distribution systems. As a result, there exist an additional four much smaller independent distribution network operators (IDNOs). Therefore, there are 18 licensed electricity distributors in total.

[8] So-called because they have Section B standard conditions – distribution services obligations dating back to 2001 - in effect in their licence.

61. Ofgem regulates the level and structure of charges levied for using the monopoly transmission networks. The charges that users of the transmission system pay are set at a level to recover the revenue that Ofgem approves in the price control process. However, it is the SO that deals with administration of these charges. Whilst charges are set annually, there is a degree of predictability and stability regarding the level of charges users pay. In terms of the structure of charges, there is currently a cost reflective (locationally-varying) system which is kept under review by the SO. Any proposed changes to the charging methodology are subject to veto by Ofgem. At present only National Grid is allowed to propose changes to the charging methodologies, although issues can be raised for consideration by National Grid. Furthermore, there is a proposal going through the industry codes process, whereby other parties would be entitled to raise charging methodology changes.

62. In addition to the transmission licence obligations, the transmission system owners are all incentivised financially to minimise loss of supply. Furthermore, the planning and operational standards include a de minimis level of asset build which provides a high level of reliability.

Price controls and incentives

63. The level of distribution and transmission charges and the quality of service provided by these companies are regulated using price controls and various incentive regimes. These price controls typically last for five years. The price controls are established by Ofgem independently of other government departments. Nevertheless, Ofgem is required to have regard to the social and environmental guidance issued by government and any orders issued in respect of assistance for areas with high distribution costs.

64. For the fourteen DNOs established at privatisation and the transmission network companies, establishing these price controls and incentive regimes involves collating a range of information on operating costs, capital expenditure, financial issues and performance outputs for each of the companies which is then analysed. Where applicable, the information that is collected from each network company is normalised to ensure as far as possible comparability across companies and then it is used to assist in determining the relative performance of each network company and to establish efficient cost and performance benchmarks using a variety of statistical techniques.

65. In addition to the benchmarking process, Ofgem also uses independent consultants to undertake efficiency studies on specific aspects of costs and network performance. These studies will typically examine the scope for improvements in costs or performance. For example, during the recent transmission price control review, Ofgem commissioned a study of efficiency and forecast operational expenditure (Opex)[9] for the current price control period 2007/12.

66. Setting cost allowances or performance targets in this manner is not a purely quantitative process. Ofgem will also consider a number of other factors to ensure that the resultant cost allowances or performance targets are both sustainable and robust.

---

9 TPCR Efficiency Study and Forecast Opex: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultantsReports/Documents1/15836-TPCR_tpareport.pdf

67. Quality of supply targets (discussed below) are also set for each licensee, and, where relevant, efficient costs of achieving these targets are included in the cost assessment.

68. Based upon our assessment of costs and outputs, Ofgem establishes cost allowances and performance targets which form the basis of the price controls and incentive framework. Together, these elements determine the total amount of revenue (allowed revenue) that each network company may earn in each year of the control period. The company is required by the regulatory regime to set charges for use of the network such that it complies with the limits on allowed revenue that have been set.

69. The business information available for new entrant electricity distributors is limited and the costs of undertaking detailed efficiency studies to establish cost allowances and performance targets often outweigh the benefits to consumers. Ofgem has therefore introduced a system of relative price regulation to ensure that the charges for use of these networks are no more than the charges that would be paid by an equivalent customer that is connected to the incumbent regional network.

Transmission

70. Since the British Electricity Trading and Transmission Arrangements (BETTA)[10] became effective on 1st April 2005 and, by virtue of the Energy Act 2004 (Designation of System Operator) Order 2004, NGET has been designated by the Secretary of State to the role of SO across the whole of GB – i.e. it is Great Britain SO. The two Scottish Transmission Licensees assume the sole role of TOs. The interactions between the SO and TOs are governed by the SO TO Code (STC).

Transmission Asset Owner

71. The following section focuses on NGET's price control as similar arrangements apply to Scottish Power Transmission and Scottish Hydro-electric Transmission, following the introduction of BETTA.

72. As the holders of transmission licences in Great Britain, the GB transmission licensees are each required by the Electricity Act 1989, as amended by the Utilities Act 2000 and the Energy Act 2004, to develop and maintain an efficient, co-ordinated and economic system of electricity transmission and to facilitate competition in the generation and supply of electricity. Under Schedule 9 of the Electricity Act, all licensees, including transmission licensees, are also required to have regard to the effects of their activities on the environment, more specifically on the "preservation of amenity and fisheries".

73. The Maximum Allowed Revenue (MAR) for TOs is set by the Authority at the time of a Transmission Price Control Review (TPCR). Ofgem traditionally undertakes the TPCR every 5 years. In order to align the electricity price control review dates with those for gas transmission, NGET's previous price control arrangements were extended for one year until 31 March 2007. The current electricity and gas transmission price control period started on 1 April 2007 and expires on 31 March 2012.

---

[10] BETTA, proposed by Ofgem and the Department of Trade and Industry (now BERR), created a fully competitive British-wide (bringing together England & Wales and Scotland) wholesale electricity market for the first time.

74. The main components of price controls are Opex, capital expenditure and depreciation and the cost of capital. The price control also includes incentive mechanisms to encourage companies to deliver what customers require. At the start of any TPCR, the company submits all the relevant data to the regulator in the form of Business Plan Questionnaire (BPQ).

75. During the price control review process, Ofgem uses the BPQ information whilst also making use of independent consultants to undertake studies on specific aspects of cost and network performance. These studies will typically examine the scope for improvements in costs or performance given the business practise of the companies as well as the prevailing commercial, operational and market situation.

System Operator

76. NGET is the SO for the high voltage electricity system in Great Britain. NGET buys and sells electricity and other related services from generators, suppliers and large customers to keep the system balanced and secure. Ofgem sets incentive schemes on an annual basis to encourage NGET to manage and reduce these costs to the end user. There is a separate scheme for the external and internal SO costs. Since the introduction of the New Electricity Trading Arrangements (NETA) in 2001 there has been an external incentive scheme in place each year except for 2006/07.

77. In March 2007, NGET consented to the Authority's proposals for an external SO incentive scheme for one year's duration from 1 April 2007 which expired on 31 March 2008. In March 2008, NGET consented to the Authority's proposals for an SO incentive scheme for one year's duration for 2008/09. The 2008/09 incentive has been set with a 'deadband' of £15 million, ranging from £529 million to £544 million. In the event that outturn Incentivised Balancing Costs (IBC) fall within this range, no payments are made through the incentive scheme.

78. NGET started consulting in June 2008 on proposed options for the external incentive scheme to apply from April 2009. As part of this consultation consideration will be given to the appropriateness of setting elements of or all of the scheme for a longer term period than the current one year.

Standards of performance

79. Transmission network companies must provide the Authority with an annual report which covers the electricity transmission system's performance in terms of availability, system security and quality of service[11]. This GB System Performance Report is required under Standard Condition C17 of the transmission licence. Further information is provided to the Authority under the licence in a range of broad areas relating to licensee performance.

80. Most outputs are specified in the licence. If NGET does not meet its requirement to operate an efficient and reliable network it can face financial penalties of up to 10% of its annual revenue.

---

[11] See Report to the Authority for the Gas & Electricity Markets 2006/2007 - http://www.nationalgrid.com/uk/Electricity/Info/performance/

81. In addition, NGET is subject to a "Reliability Incentive"[12]. This sets a target for the "quantity of unsupplied energy in MWh". Whenever there is a black-out or fault, it is estimated how high demand would have been. These hypothetical demands are summed up to give the total quantity of unsupplied energy. Ofgem set a target level for this for the current price control period and NGET is rewarded/ penalised if it over/underperforms relative to the target. For the report period of 2007/08 the maximum penalty is £15.74m while the maximum reward is £10.49m.

Network Tariffs

Structure of charges

82. The GB transmission licence requires that Ofgem does not veto the form of the transmission charging methodologies and thereafter decide on modifications made to them. Following extensive industry consultation, Ofgem approved the form of the Transmission Network Use of System (TNUoS) charging methodology when it was introduced across the integrated GB market in 2005. The structure of charges is designed to be cost reflective so that efficient signals are provide to the market and generators can site their projects in the most cost effective areas.

83. The transmission licence requires that NGET updates the charging methodologies to reflect changes to the regulated business. In addition any proposed changes to the charging regime must be consistent with the various licence obligations. These charging proposals are submitted to Ofgem for consideration. If the Authority considers that the proposal is consistent with the various licence requirements and does not veto it, the charging amendment can be implemented. However, as mentioned above, this process is currently being reviewed under the auspices of the industry codes governance.

84. NGET calculates annual transmission charges using the approved methodologies. Ofgem has no role in calculating or approving the annual levels of TNUoS charges.

85. The regulatory period over which the TOs' maximum allowed revenue is calculated is 5 years. The settlement allows the transmission licensees a level of revenue which Ofgem calculates is sufficient for them to maintain and develop existing network in an economic and efficient manner. It is this Maximum Allowed Revenue (MAR) which is collected through TNUoS.

86. As SO, NGET levies TNUoS charges on the behalf of all the three transmission licensees. Total TNUoS revenue collection is split 27:73 between generators and demand. There are separate generation and demand tariff methodologies.

87. The underlying rationale behind TNUoS charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. In calculating the level of TNUoS charge, the SO uses a simplified DC Load Flow (DCLF) model of the transmission system to represent the long run marginal cost of providing a network infrastructure at different geographical locations. Therefore the model produces locationally differentiated charges for both generation and demand, based on actual costs that users incur on the system, which are

[12] See Electricity transmission network reliability incentive schemes. Final proposals. December 2004 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/9001-tx_incentives.pdf

expressed in £/kW of capacity. The SO runs the model annually and updates its transmission charges on 1 April every year.

88. To ensure adequate revenue recovery, there is also a non-locational residual tariff levied on both generation and demand users. It is applied to the transport tariffs so that the correct generation/demand revenue split is maintained and the total revenue is achieved.

89. There are 21 charging zones for generation and 14 for demand. For 2007/08 the demand charge varies between €2.11/kW and €34.75/kW whereas the generation charge varies between €-12.53/kW and €31.56/kW. Five generation zones have a negative TNUoS charge. This means that generators in these zones are paid by the SO for using the transmission system.

90. Connection charges enable National Grid to recover, with a reasonable rate of return, the costs involved in providing the assets that afford connection to the GB transmission system. Connection charges relate to the costs of assets required to connect an individual User to the GB transmission system, which are not and would not normally be used by any other connected party ("shallow" basis).[13] Certain connection assets may be provided by users themselves.

Distribution

Structure of charges

91. In July 2004, Ofgem implemented changes to the regulatory framework to establish an obligation on all DNOs to produce separate connection and use of system charging methodologies to be approved by Ofgem. Each methodology must meet four relevant objectives:

- that compliance with the charging methodology facilitates the efficient discharge by the licensee of the obligations imposed upon it under the Electricity Act and by the licence;
- that compliance with the charging methodology facilitates effective competition in the generation and supply of electricity, and does not restrict, distort or prevent competition in the transmission or distribution of electricity;
- that compliance with the charging methodology results in charges which reflect, as far as is reasonably practicable (taking account of implementation costs), the costs incurred by the distribution business; and
- that the charging methodology, as far as is reasonably practicable, properly takes account of the developments in the distribution business.

92. Ofgem launched the structure of charges project in 2000, with the aim of reviewing charging methodologies used to calculate distribution network charges by all DNOs. Owing to repeated delays in delivering revised charging methodologies, Ofgem recently consulted on placing a formal licence condition on DNOs to deliver appropriate charging methodologies by 1 October 2009.

[13] See The Statement of the Connection Charging Methodology, http://www.nationalgrid.com/NR/rdonlyres/D46B7CF7-946B-4A0E-A418-97B83E77131D/6651/GBCCMI2R0Final.pdf

93. In terms of background, in October 2004, Ofgem consulted with the electricity industry on the form and content of the draft use of system and connection charging methodologies submitted by each DNO. In light of response to the consultation, DNOs then submitted revised charging methodology statements to the Authority for approval at the end of November 2004. Each methodology was assessed against the relevant objectives and in February 2005, the Authority approved the initial charging methodologies to take effect from 1 April 2005.

94. Ofgem has put in place a process for modifying the approved charging methodologies where the modifications can be demonstrated to better meet the relevant objectives. DNOs consult with interested parties on proposed modifications and consider the views expressed. Once the consultation process has been concluded, the proposed modification of the methodology is submitted to the Authority, which decides whether or not to veto the proposal. The Authority also has the option of consulting.

95. Each DNO must comply with its approved charging methodologies when setting charges for connection and use of system. Ofgem has also imposed obligations on each DNO to publish statements of these charges in an approved form and made available to interested parties and any other person that requests the information. In addition to setting out the charges that may be levied for use of or connection to the distribution system. The use of system and connection charging statement will also set out the general terms and conditions associated with use of the distribution system, the network charges, terms and processes for obtaining a connection.

Assistance for high cost distribution areas

96. The Energy Act 2004 established statutory provisions that enable the Secretary of State to make orders that charges levied by the SO shall be set to recover an amount of money from all suppliers that will be passed on to consumers connected to a distribution system on which the costs of distributing electricity are relatively high. These arrangements are focused largely at those customers connected to largely rural networks to ensure that they are not unduly disadvantaged by high electricity costs.

97. These arrangements are established by the Secretary of State independently of Ofgem.

Level of charges [2006/7]

Table 3.1 Average network charge payable by different customer groups in Great Britain:

Customer type	**Transmission charges (c/kWh)**	**Distribution charges (c/kWh)**	**Total network charge (c/kWh)**
Domestic customer[1]	TBC	1.95 – 3.89	TBC
Small industrial customer[2]	TBC	1.23 – 2.69 (E&W) 3.06 – 5.05 (Scot)	TBC
Large industrial customer[3]	TBC	0.12 – 1.72	TBC

Notes:

Distribution network charges change once or twice a year: the table above represents 2006/7 charges at an exchange rate appropriate at that time. The differential in tariffs between customer types is expected to be broadly the same year on year within the same price control period.
1) Domestic customer – is a household customer with annual consumption of 3 500 KWh/ year
2) Small industrial customer – is a commercial customer with annual consumption of 50 MWh / year, subscribed maximum power 50 KW
3) Large industrial customer – is an industrial customer with annual consumption of 24 GWh/ year, subscribed maximum power 4000 KW, assumed to be connected at 11kV
5) Exchange rate of £1 = €1.48

Outputs reporting framework

98. Ofgem introduced output reporting for the electricity distribution companies from 1 April 2001, following the third electricity distribution price control review. Under the relevant licence conditions, Ofgem drew up Regulatory Instructions and Guidance ("RIGs") which defined the outputs and provided the framework under which the data is collected and reported.

99. The 18 licensed DNOs are required to report annually on:

- the number and duration of interruptions to supply;
- the speed of telephone response;
- medium-term performance (fault rates and causes);
- connections performance; and
- environmental issues.

100. In addition the companies are required to provide details of customers on a weekly basis who have contacted them during an interruption or to report an emergency. This enables Ofgem to carry out surveys of the quality of telephone response provided by DNOs.

101. The current version of the RIGs is version 5, which was published in March 2005. The key difference with this version is the introduction of more detailed reporting on supply interruptions and new reporting for connections and environmental performance.

Quality of service incentives

102. Ofgem first introduced an initial incentive scheme for quality of service from 1 April 2002 to 31 March 2005. The scheme linked companies' revenue to three key areas of quality of service:

- the number of interruptions to customers' supplies;
- the duration of interruptions to customers' supplies; and
- the quality of telephone response provided to customers.

103. Each of the distribution businesses could be penalised annually, by up to 1.75 per cent of revenue if it failed to meet its targets for the number and duration of interruptions. Companies could earn additional revenue if they outperformed their targets for 2004/05 based on their rate of performance up to that date.

104. Companies could be rewarded or penalised by up to 0.125% of price controlled revenue dependent on their relative performance in a monthly customer survey of the quality of telephone response.

105. A revised incentive scheme was introduced as part of the current Distribution Price Control Review (DPCR) from 1 April 2005 until March 2010. Ofgem has increased financial exposure to the interruption incentives to 3 per cent of revenue and introduced tighter interruption targets. On average the DNOs are required to achieve a 4% improvement in the number of interruptions and 13% in the duration by 2010. The worst performers from DPCR 2005-10 have significantly larger improvements to make so there should be a narrowing of performance differences over time.

106. Since the introduction of the interruptions incentive scheme in April 2002 the underlying number of customer interruptions per 100 customers has fallen by 1.3% (2002/3 to 2006/7) (excluding the impact of exceptional events). Interim figures for 2007/8 show a downturn in both customer interruptions and customer minutes lost compared to the previous year. On average a customer experiences 0.81 interruptions per year and is interrupted for approximately 83 minutes excluding exceptional events.

107. With exceptional events included the picture is less clear, as changes are far more variable depending on the year chosen due to the impact of major events such as the October 2002 storms and further storms and flooding in January 2005 in many parts of Great Britain. In 2007/8 there was a moderate amount of exceptional event claims. Storms were less prevalent than in 2006/7 but there were a number of floods in June 2007 resulting in several large claims.

Standards of Performance

108. The Standards of Performance for electricity DNOs were first introduced in 1991. Since then they have been revised on a number of occasions to tighten the standards, increase compensation payments or to introduce new standards.

109. Guaranteed Standards of Performance ("GSOPs") set service levels that must be met in each individual case. If a DNO fails to provide the level of service specified, it must make a payment to the customer affected (e.g. for not restoring supply within a specified timeframe). This is subject to a number of exemptions.

110. The latest GSOPs for DNOs came into effect from 1 April 2005 as part of the current electricity distribution price control. They are summarised in Table 3.2.

Table 3.2: Guaranteed standards of performance

Reporting code	Service	Performance Level	Penalty Payment
GS1	Respond to failure of distributors fuse (Regulation 10)	All DNOs to respond within 3 hours on a working day (at least) 7 am to 7 pm, and within 4 hours on other days between (at least) 9 am to 5 pm , otherwise a payment must be made	€30 for domestic and non- domestic customers
GS2*	Supply restoration: normal conditions (Regulation 5)	Supply must be restored within 18 hours, otherwise a payment must be made	€73 for domestic customers and €146 for non-domestic customers, plus €37 for each further 12 hours
GS2A*	Supply restoration: multiple interruptions (Regulation 9)	If four or more interruptions each lasting 3 or more hours occur in any single year (1 April – 31 March) , a payment must be made	€73 for domestic and non- domestic customers
GS3	Estimate of charges for connection (Regulation 11)	5 working days for simple work and 15 working days for significant work, otherwise a payment must be made	€58 for domestic and non- domestic customers
GS4*	Notice of planned interruption to supply (Regulation 12)	Customers must be given at least 2 days notice, otherwise a payment must be made	€30 for domestic and non- domestic customers
GS5	Investigation of voltage complaints (Regulation 13)	Visit customer's premises within 7 working days or dispatch an explanation of the probable reason for the complaint within 5 working days, otherwise a payment must be made	€30 for domestic and non- domestic customers
GS8	Making and keeping appointments (Regulation 17)	Companies must offer and keep a timed appointment, or offer and keep a timed appointment where requested by the customer, otherwise a payment must be made	€30 for domestic and non- domestic customers
GS9	Payments owed under the standards (Regulation 19)	Payment to be made within 10 working days, otherwise a payment must be made	€30 for domestic and non- domestic customers
GS11A*	Supply restoration: Category 1 severe weather conditions (Regulation 6)	Supplies must be restored within 24 hours (see table 2.2 below), otherwise a payment must be made	€37 for domestic and non domestic customers, plus €37 for each further 12 hours up to a cap of €292 per customer
GS11B*	Supply	Supplies must be restored	€37 for domestic and

	restoration: Category 2 severe weather conditions (Regulation 6)	within 48 hours, otherwise a payment must be made	non domestic customers, plus €37 for each further 12 hours up to a cap of €292 per customer
GS11C*	Supply restoration: Category 3 severe weather conditions (Regulation 6)	Supplies must be restored within the period calculated using the following formula: $48 \times \left(\frac{\text{total number of customers interrupted}}{\text{category 3 threshold number of customers}} \right)^2$	€37 for domestic and non domestic customers, plus €37 for each further 12 hours up to a cap of €292 per customer
GS12*	Supply restoration: Highlands and Islands (Regulation 7)	Supply must be restored within 18 hours, otherwise a payment must be made	€73 for domestic customers and €146 for non-domestic customers, plus €37 for each further 12 hours

* Customers need to claim under these standards, for the remaining standards payments are automatic

Table 3.3: Thresholds for normal and severe weather conditions

Designated electricity distributor	Category 1 Eight times the mean daily faults at distribution higher voltage	Category 2 Thirteen times the mean daily faults at distribution higher voltage	Category 3 threshold number of customers	Upper threshold number of customers
Central Networks West plc	63	103	348,000	597,000
Central Networks East plc	58	95	410,000	703,000
Electricity North West Limited	47	77	262,000	449,000
Northern Electric Distribution Limited	36	59	218,000	374,000
Yorkshire Electricity Distribution plc	35	57	347,000	595,000
Western Power Distribution (South West) plc	54	88	270,000	463,000
Western Power Distribution (South Wales) plc	46	73	208,000	357,000
EDF Energy Networks (LPN) plc	10	17	331,000	567,000
EDF Energy Networks (SPN) plc	46	74	284,000	487,000
EDF Energy Networks (EPN) plc	72	117	484,000	830,000
SP Distribution Limited	79	129	226,000	387,000
SP Manweb plc	61	99	188,000	322,000
Scottish Hydro-Electric Power Distribution Limited	61	99	119,000	204,000
Southern Electric Power Distribution plc	62	101	417,000	715,000

Ofgem collects performance data from DNOs on an annual basis. The data is verified and then forwarded to the Consumer Council (“energywatch”) for publication, in accordance with the Electricity Act 1989.

Quality of service reports

111. To date, Ofgem has published six reports on the quality of service in electricity distribution. These reports set out information on how the DNOs have performed against their targets for the number and duration of supply interruptions and against other performance benchmarks that Ofgem has calculated. They also set out information on fault rates and the quality of telephone response. Ofgem will continue to publish annual reports on the quality of service in future.

Balancing of the transmission system

112. The current electricity balancing arrangements are designed to provide commercial incentives for generators (suppliers) to physically match the amount they are going to deliver (offtake) to or from the system. Generators' (suppliers) imbalance relates to difference in the amount they physically deliver and their notified contracted position.

- NGET, as GBSO has a role as residual energy balancer for operating the high voltage transmission system. NGET buys or sells electricity from generators (or large customers who are able to quickly reduce their demand) to bring the system back into balance. NGET also contracts with generators and large suppliers to hold 'reserve' to keep the system in balance if, for example, there is a sudden loss of generation and/or a sudden, unexpected increase in demand. In addition to its role as residual energy balancer, NGET is also responsible for system balancing i.e. keeping the transmission system within safe technical limits. Market participants are obliged to provide a minimum level of balancing (ancillary) services but most of these services are provided either via competitive tenders for contracts (held on an annual, semi-annual or monthly basis) or the acceptance of (locational) bids and offers in the Balancing Mechanism. Note that Ofgem includes congestion management as part of system balancing.

Structure of charges

113. NGET, as GBSO, recovers the costs of balancing the System through Balancing Services Use of System (BSUoS) charges. BSUoS charges are levied on the basis of metered volume to participants, with overall charges split 50:50 between generation and demand.

114. As described in table 3.4 below, imbalances between participants' contracted and metered volumes are settled at imbalance or cash-out prices. The net surplus or deficit cashflow resulting from imbalance settlement is returned to or recovered from all participants on a metered volume basis.

115. The general principle behind these charging arrangements is that the system operator's costs of energy balancing are targeted via cash-out prices to those participants that are out-of-balance, whereas all participants contribute to system balancing costs via BSUoS charges.

Summary of key components of cash out

116. We summarise the main features of the cash out arrangements below before explaining the key developments in the balancing market arrangements since our last report to DG TREN.

Table 3.4: High-level summary of main features of balancing arrangements in GB

Balancing mechanism indicators	**Description**
Balancing interval	**Half hourly**
Description of relevant balancing area	**Great Britain National Grid** –the cash-out arrangements provide a commercial incentive for generators and supplier are required to balance physically against their notified contracted position. Except in the case of Trading Units (see below), separate imbalance calculations are carried out for generation and consumption. This means that vertically integrated companies with generation and supply arms cannot net off their generation and consumption imbalances but have to pay for them separately. [14]
Interaction with other areas	**Yes** - the GB market is connected with other geographic areas (refer to section 3.1.2). Participants in these markets can trade in GB and participate in the BM via special arrangements for interconnector trading.[15]
Time of gate closure	**1 hour** – final physical notification (FPN) of contracted demand or supply notified one hour ahead of relevant settlement period.
Opportunities for intra-day trading	**Yes –** market participants are free to contract bilaterally with each other up to gate closure for each settlement period, which occurs one hour before the start of the period. Intra-day trading occurs between market participants, either on a bilateral basis, via brokers (such as Spectron[16]) or on organised exchanges (such as the APX Power UK[17]). There are a range of products traded, for example based on half hourly or 4 hourly blocks.
Opportunities for revision of nominations	**Market participants are free to amend nominations up to gate closure** - Initial physical notifications are submitted at least day-ahead (and potentially earlier) and may be amended up to gate closure. Final physical notifications (FPN) are fixed at gate closure, after which market participants cannot

[14] For example, if a market participant's generation portfolio provided insufficient energy to the system relative to what it was contracted to deliver and at the same time its customer demand was lower than it had contracted to offtake then the market participant would face imbalance charges for delivering insufficient energy (short) and for demand being lower than it was contracted to deliver.

[15] Like all other market participants, interconnector users are exposed to the cash-out arrangements. However, the settlement arrangements are slightly different to those for other parties in that the imbalance exposure for the interconnector as a whole is assigned to a so-called Interconnector Error Administrator, who is then responsible for allocating it to individual interconnector users. The basis on which this allocation is done does not fall within the remit of the BSC. Interconnector users can submit Bids and Offers to the BM in the same way as other parties, but they can only be accepted with the consent of both NCG and RTE.

[16] See http://www.spectrongroup.com/ for more details.

[17] See www.ukpx.co.uk for more details.

	amend their notified contracted position against which their imbalance position will be calculated. Participants should also notify any variation in notified physical input or output, other than variations arising from the issue of Bid-Offer Acceptances, at and after gate closure.
Typical prices charged to network users to resolve imbalances	**A 'dual' cash out price system** that applies in respect of electricity imbalances based on a System Buy Price (SBP) and the System Sell Price (SSP). Parties that are short are charged SBP for their imbalance volumes and Parties that are long receive SSP for their imbalance volumes. How the SBP and the SSP are derived depends on whether the transmission system, as a whole, was long or short. Participants who are out of balance in the same direction as the system (i.e. their individual imbalance exacerbates the aggregate imbalance of the system in that half hour balancing period) incur the main imbalance price. The main price is derived from the cost of actions taken by NGET to resolve the overall imbalance. Participants who are out of balance in the opposite direction as the system incur the reverse price. The reverse price is derived from a market price based on short-term energy trades in the forward and spot market
Process and timetable for settlement of imbalances	**5 to 288 working days after settlement period:** an initial calculation of imbalance occurs after 5 days. Further reconciliation occurs once updated information on metered volumes and balancing actions becomes available. Final reconciliation occurs after 288 days, reflecting the timeframes over which metering data from smaller customers may be available. To reduce the number of transactions, given 48 settlement periods per day, market participants' settlement is based on the first and second half of each month.
Arrangements for small generators and new entrants	Any grouping of suppliers and small generators within the same distribution network may (optionally) elect to be considered as a single entity (a Trading Unit) for balancing purposes. This means that it is the net exports or imports of the Trading Unit that are used to calculate its imbalance exposure. The balancing rules also allow consolidation services, whereby the output of a number of small generators are aggregated together thus leading to a likely reduction in their combined imbalance exposure. There are no specific arrangements for new entrants.
Information provision	Information in relation to the operation of the BM is provided on the Balancing Mechanism Reporting

	Service (BMRS) website[18] by the Balancing Mechanism Reporting Agent (BMRA). The BMRS website provides near real time and historic data about the BM. NGET is required to send a variety of data items (defined in the Grid Code) to the BMRA and to ELEXON (for publication on the BMRS) for reporting purposes.

Developments in the balancing arrangements

Information on imbalance prices

117. Table 3.5 provides updated data for 2007/08 on average annual SSP and SBP values and the average spread between SSP and SBP since NETA go-live.

Table 3.5: Average annual energy imbalance prices

(€/MWh)	Average SSP	Average SBP	Average SSP-SBP spread
2001/02[19]	13.44	56.52	43.07
2002/03	16.03	42.50	26.46
2003/04	22.73	34.01	11.30
2004/05	27.95	40.67	12.71
2005/06	50.62	73.75	23.14
2006/07	36.74	55.86	19.12
2007/08	44.60	68.73	24.13

118. As can be seen in table 3.5, imbalance prices increased in 2007/08 following the decline during 2006/07. This is primarily related to higher commodity prices (notably gas and coal) feeding through into generators and suppliers' bids and offers in the balancing mechanism. Environmental regulations having also been a factor driving increased balancing costs from January 2008 due to the implementation of the Large Combustion Plant Directive (LCPD) and the second phase of the EU Emissions Trading Scheme (ETS).

Modifications to cash out arrangements in 2007/08

119. No changes have been made to the cash out arrangements since the implementation of the modification to move to a more marginal main cash out price (as described in the 2006 report). However, Ofgem rejected a proposal in February 2008 to base the main cash out price on the market price (current reverse price) with a fixed 5% premium/discount. In addition, two proposals are currently being assessed which, if approved, would also amend the calculation of the main imbalance price. One proposal is to calculate the main cash out price from the cheapest actions submitted to the SO (not necessarily those accepted). This is intended to be a proxy for the actions that the SO would have taken if the network was unconstrained. The second proposal would remove from the stack of actions on which the main price is

[18] See www.bmreports.com.

[19] 2001/02 data also includes the period from 27 March 2001 (NETA go-live) until 31 March 2001 inclusive.

based all actions identified by NGET as being within a constrained area. This is intended to prevent actions taken for "system balancing" purposes from influencing the cash out price. Ofgem intends to make decisions on both modifications by mid-October 2008.

Interactions with other Member States

120. As stated in section 3.1.2, the GB electricity system is connected with France and Northern Ireland via the IFA[20] and Moyle[21] interconnectors respectively. The existence of these interconnectors and the current proposals for new interconnectors suggests that new interconnection capacity will be provided to the market when it is economic to do so. One new interconnector link to the Netherlands (BritNed[22]) is under construction. Ofgem has also granted licences for the construction of three interconnectors with the Republic of Ireland, one interconnection with Belgium and two with France although none of these are yet under construction. We have also spoken with parties regarding the potential construction of two further interconnectors with Europe.

121. The ERGEG Electricity Regional Initiative has set up seven electricity regional initiative projects. The overall aim is for each regional market to identify specific problematic impediments to trade or distortions to trade, and introduce practical improvements that will contribute to removing them. GB is part of a region which also includes France and Ireland – The France - UK - Ireland Region (FUI). Ofgem is closely involved with this work and is the lead Regulator for the FUI Region.

3.1.4 Effective unbundling

Table 3.6 Ownership structure of DNO companies in Great Britain

Network company	Activity	Owner
CE NEDL (Northern Electricity Distribution Ltd)	Electricity Distribution	Mid American Holdings
CE YEDL (Yorkshire Electricity Distribution Ltd)	Electricity Distribution	Mid American Holdings
Central Networks East plc	Electricity Distribution	E-on
Central Networks West plc	Electricity Distribution	E-on
EDF Energy (EPN) plc	Electricity Distribution	Electricite de France
EDF Energy (LPN) plc	Electricity Distribution	Electricite de France
EDF Energy (SPN) plc	Electricity Distribution	Electricite de France
SP Manweb plc	Electricity Distribution	Iberdrola
SP Distribution plc	Electricity Distribution	Iberdrola

[20] Interconnexion France Angleterre (IFA) is a 2,000MW HVDC interconnector link between France and GB. It is jointly owned by National Grid Interconnector Limited (NGIL) and RTE.
[21] Moyle is a 500MW interconnector between Scotland and Northern Ireland. Capable of exporting at 500MW to Northern Ireland and importing at 80MW. It is owned by Moyle Interconnector Ltd.
[22] BritNed is a 1,000MW interconnector jointly owned by NGIL and TenneT.

Western Power Distribution (South Wales) plc	Electricity Distribution	PPL Corporation
Western Power Distribution (South West) plc	Electricity Distribution	PPL Corporation
Electricity North West Ltd	Electricity Distribution	Colonial First State Asset Management and Infrastructure and Investment Funds
Scottish Hydro-Electric Power Distribution plc	Electricity Distribution	Scottish & Southern Energy plc
Southern Electric Power Distribution plc	Electricity Distribution	Scottish & Southern Energy plc
Energetics Electricity Ltd	Electricity Distribution	Cannon Kirk Ltd
ESP Electricity Limited	Electricity Distribution	Terra Firma Capital Partners Limited
Independent Power Networks Ltd	Electricity Distribution	Challenger Infrastructure Fund
The Energy Networks Company Ltd	Electricity Distribution	Babcock and Brown Infrastructure Ltd

122. The licences of distribution and transmission companies require that they:

- do not undertake transactions that create a cross-subsidy with another entity;
- enter into agreements on an arm's length basis and on normal commercial terms; and
- carry out activities only for the purposes of distribution or transmission (whichever is appropriate), subject to the *de minimis* activities provisions which allow a small amount of non distribution or transmission activities (whichever is appropriate) to be undertaken.

123. In addition, the transmission licence of NGC (who operates the GB transmission system) prevents NGC and all affiliated and related undertakings from owning electricity supply or generation interests.[23]

124. Infringement of these and other licence obligations may result, after going through due process, in enforcement action and financial penalties. The financial penalty cannot exceed 10% of annual turnover.

125. In setting price controls for distribution and transmission companies an important issue for Ofgem is to consider the costs that a network company shares with other companies within its group. This includes head office costs and the activities it has outsourced to other entities. These costs must be charged according to the principles listed above. However, Ofgem leaves it to the distribution and transmission companies concerned to determine how it organises its business in relation to outsourcing work and sharing of common costs within the framework of obligations imposed by its licence.

[23] The licensee cannot purchase or otherwise acquire electricity except for system operation purposes, and it must procure that no affiliate or related undertaking purchases or otherwise acquires electricity.

126. The fourteen DNOs established at privatisation and the transmission network companies have financial ring-fence conditions in their licence. One of these conditions has the effect, subject to a *de minimis* provision, of restricting the business activities that the company can carry out, to those for which it is licensed e.g. distribution. As a consequence, each company's company law accounts will largely only include the activities of the network company. In addition for the fourteen DNOs established at privatisation and the transmission network companies, the licences also include specific regulatory accounts conditions. For example, amongst other things, these obligations require that the regulatory accounts are published, are subject to audit requirements and must be accompanied by an audit opinion, addressed to the Authority, from an appropriate auditor setting out that the accounts have been prepared in accordance with the requirements of the relevant network licence. For most companies Ofgem has also introduced another licence condition in relation to price control review information that requires the companies to prepare detailed information on their activities in accordance with published guidelines.

127. The licences of the fourteen DNOs established at privatisation require that licensees must maintain managerial and operational systems preventing any relevant (i.e., affiliated or related) supplier or shipper having access to confidential information except in certain specified circumstances (which are detailed in the licence condition). The network company must always be managed and operated to ensure it does not restrict, prevent or distort competition in the supply of electricity or gas or the shipping of gas or the generation of electricity. The transmission network companies responsible for transmission ownership activities in Scotland (who have affiliated generation and supply interests) are required by Special Conditions C, D and E of their respective transmission licences to restrict the use of transmission related information and to introduce arrangements to provide for the managerial and operational independence of the transmission network business.

128. The licences of the fourteen DNOs established at privatisation and the transmission network companies also require that the licensees appoint a compliance officer who will facilitate compliance by the licensee with the licence conditions relating to the restriction on the use of certain information and the independence of the network business.

129. A distribution licensee is required to use reasonable endeavours to comply with a statement that it produces setting out how it intends to comply with, amongst other things, the requirement not to restrict, prevent or distort competition. This compliance statement must also set out how the licensee shall maintain the branding of the distribution business so that it is fully independent from the branding used by any relevant supplier or shipper.

130. During 2003 and early 2004 several energy groups owning both electricity distribution and supply businesses proposed changes to their supply and/or distribution brands. In many cases these proposals reduced the difference between the branding of their respective supply and distribution businesses. Some of these proposed changes have now been implemented. These changes gave rise to concerns that competition in energy supply may be adversely affected by the re-branding that was occurring. In response to these concerns, Ofgem reviewed whether the approaches to branding by a number of distribution licensees with supply businesses complied with the relevant electricity distribution licence condition concerning brand separation. As part of this review, it was necessary to consider what, if any, the effect of any similarity of any such branding may have had on competition.

131. As explained in Ofgem's open letter summarising the outcome of this review[24], there did not appear to be robust evidence to suggest that the current branding practices adopted by supply and distribution businesses had operated to restrict, prevent or distort competition in the domestic electricity supply market.

[24] Open letter: http://www.ofgem.gov.uk/Markets/RetMkts/Compet/Documents1/9471-branding_open_letter.pdf

3.2 Competition Issues [Article 23(8) and 23(1)(h)]

Overview

This section provides an overview of the GB wholesale and retail electricity markets. It covers the following issues and relevant data:

Wholesale market:
- General description of the market
- Ancillary services
- Demand side participation
- Member State integration
- Recent mergers and acquisitions

Retail market:
- General description of the market
- Market shares and new entry
- Integration between the retail and wholesale markets
- Independence from network companies
- Customer switching
- Competition issues
- Current retail price levels

Measures to avoid abuse of dominance:
- Ofgem’s role and powers in wholesale and retail markets

3.2.1 Description of the wholesale market

132. There has been a single GB wholesale market since 1 April 2005 as a result of wholesale market arrangements for England and Wales (introduced in April 2001) being extended to also include Scotland. These market arrangements are designed to provide:

- a common set of trading rules allowing electricity to be traded freely across GB;
- rules for access to, and charging for, the transmission network; and
- a GB wide SO independent of generation and supply interests.

133. The GB wholesale market is based on bilateral trading between generators, suppliers, traders and customers across a series of markets. Consequently, generators are required to self-despatch their plant rather than have them centrally dispatched by the SO. Broadly speaking, the wholesale market can be broken down principally into over the counter trading and power exchange trading, followed by Balancing Mechanism (BM) activity and imbalance settlement.

Over the counter trading (OTC)

134. Over the counter trading (i.e. bilateral trading between two market participants or where an intermediary (the broker) brings together a buyer and seller) typically

operates from a year or more ahead of real time up until 24 hours ahead of real-time.[25]

Power exchanges

135. Although power exchanges can extend out as far as the contract market, trading on them tends to be concentrated in the final 24 hours preceding Gate Closure. Generators and suppliers trade short term on power exchanges to fine tune their positions as their demand and supply forecasts become more accurate in the run-up to real time. Trading on power exchanges is via a set of standardised contracts on a spot, prompt and forwards basis: (this includes half-Hour to four hour contracts; base load and peak load contracts; weekly, monthly and seasonal contracts).

Balancing mechanism (BM)

136. In the GB electricity market gate closure occurs one hour ahead of a settlement period. Market participants can no longer adjust their contracted positions against what they are expecting to physically deliver or consume, but may provide balancing services to NGET. The BM is the mechanism where NGET may accept bids and offers to increase or decrease electricity to assist it in balancing the system. Details relating to the operation of the BM and imbalance settlement have been provided in the 'balancing' section of part 3.1.3 of this report and so are not repeated here.

Consumption and demand

137. Actual peak demand for electricity in GB during 2007/08 was 60.7GW[26] (including transmission and distribution losses) whilst demand over the course of the year was 348TWh.[27]

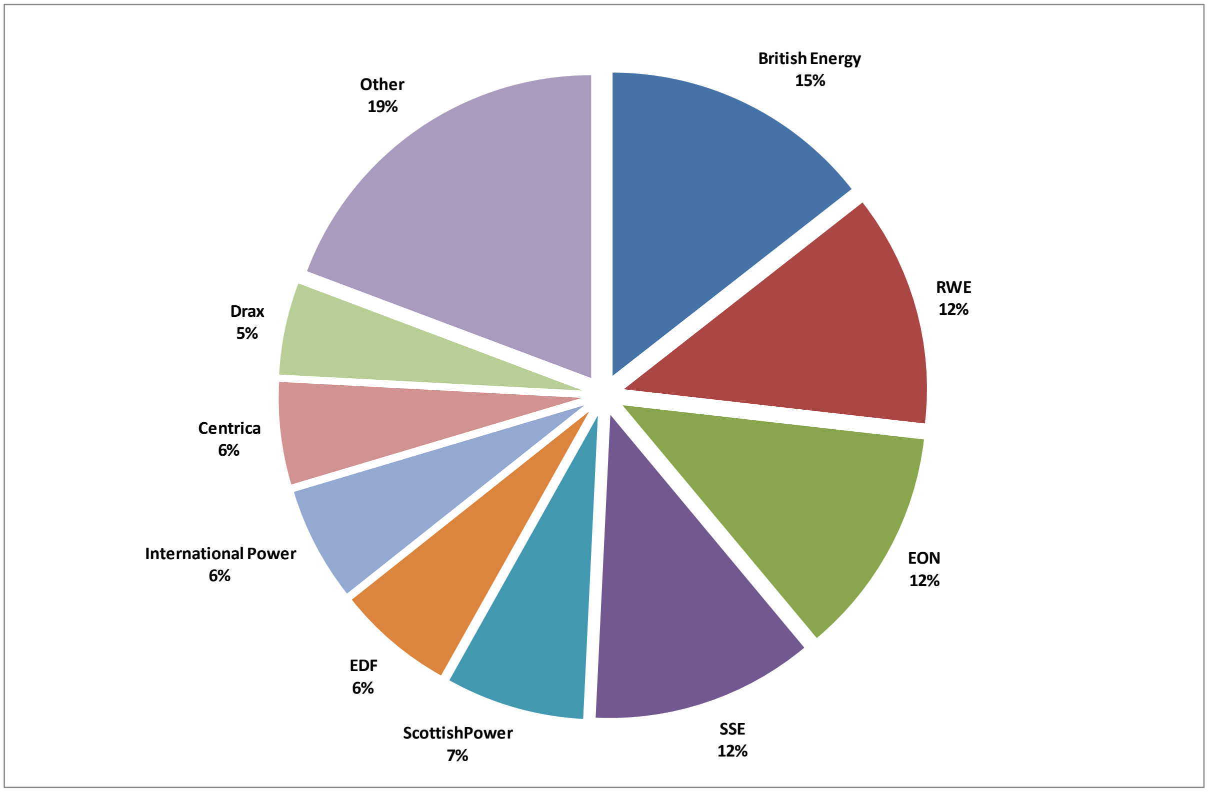
Generation capacity

138. The total installed capacity on the GB system at the beginning of 2007/08 was 78.4 GW. This had risen to 79.9GW by the start of 2008/09 (NGET's May 2008 Seven Year Statement). As illustrated in figure 3.7 below, seven companies had market shares exceeding 5% and, of these, the largest three companies held 39% of the installed capacity. It is worth noting that contractual arrangements are important as ownership of capacity does not necessarily equate fully with the dispatch rights, which depend on the contractual arrangements in place.

Figure 3.7: 2008/9 - Percentage of capacity (based on Transmission Entry Capacity (TEC) Values) by Generation Owner (source: NG Seven Year Statement, table 3.5)

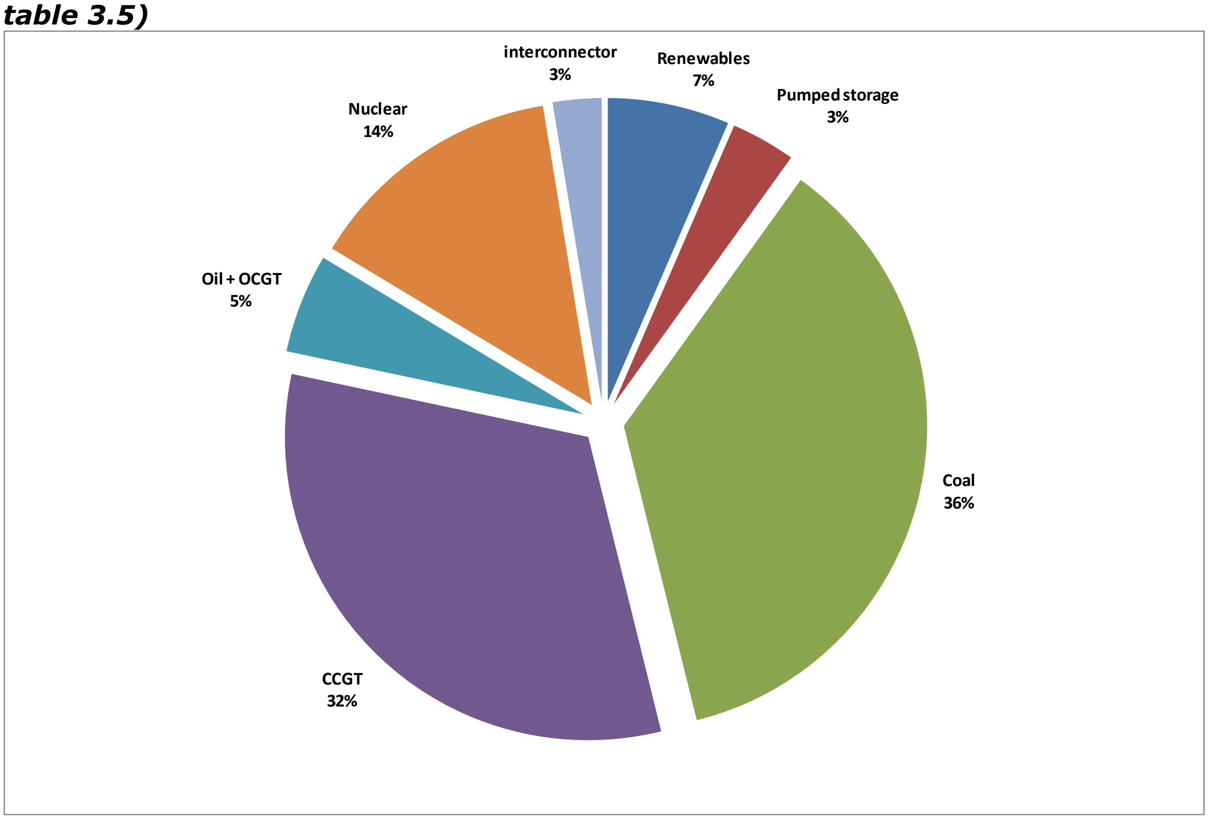
---

[25] Examples of typical contracts include annual contracts (contracts for the delivery of a given volume of power at a specified price throughout a year), seasonal contracts (summer/winter), quarterly contracts and monthly contracts. However, this market is also used for non-standard contracts designed to match a consumer's anticipated demand profile.
[26] This information is taken from NG's Seven Year Statement, May 2008.
[27] This information is taken from NG's Seven Year Statement, May 2008.



139. A breakdown of the wholesale electricity market by fuel type is outlined in figure 3.8.

Figure 3.8: 2008/09 TEC Values by fuel type (source: NG Seven Year Statement, table 3.5)



HHI by volume and capacity

140. Table 3.9 provides Herfindahl-Hirschman Index (HHI) analysis based upon capacity and output owned by different companies in GB.

Table 3.9: Herfindahl-Hirschman Index (HHI) analysis based upon capacity and output[28] (source: NG Seven Year Statement, table 3.6)

Company	Capacity (HHI)	Output (HHI)
British Energy	208	327
RWE	153	94
EON	147	162
SSE	140	157
ScottishPower	54	40
EDF	38	75
International Power	37	27
Centrica	30	21
Drax	24	55
Other	34	28

141. The largest individual HHI by capacity and output is British Energy which owns and operates a large number of nuclear plants in GB.

Volume of electricity traded

Exchange trade

142. Total traded volume on the UKPX for the 2007/8 was 17.1 TWh for all packages, where the total traded volume comprises half hour and four hour (EFA) block trades – this is around 2TWh higher than 2006/7.

Balancing Mechanism

143. NGET's actions in the Balancing Mechanism over financial year 2007/08 amounted to around 4TWh of offer acceptances to increase generation, and around 6.1TWh of bids to reduce generation (around 2TWh lower than the previous year).

Over-the-counter trade

144. On the basis of analysis undertaken by the Financial Services Authority (FSA)[29] it is possible to estimate total OTC trade in 2006/7 (Aug 06 to Jul 07) to be around 966TWh (this excludes exchange based trading).

---

[28] Where the station capacity is owned by a number of equity owners, capacity and output have been allocated to each party on the basis of their % equity holding.
[29] http://www.fsa.gov.uk/pubs/other/analysis_energy_2007.pdf

145. Using trade data from industry participants OTC delivered volume in 07/08 928TWh.

Long-term contract trade

146. Ofgem has no non-confidential information on the extent of long-term contracting.

Ancillary services

147. As discussed in section 3.1.3 NGET makes use of a range of balancing services including:

- contracted balancing services for technical system requirements such as frequency response, reserve, reactive power and black start. These are typically in option contract format;
- forward energy contracts; and
- offers and bids in the Balancing Mechanism.

148. In this section, we focus on contracted balancing services, which are classified as either mandatory or commercial. As part of the terms for their connection to the system, generators are required to provide mandatory contracted balancing services according to the terms set out in the Grid Code. The mandatory services cover basic levels of reactive power and frequency response. Commercial services are either directly negotiated between NGET and the service provider or procured via a tender process. They include: reserve (BM start up and fast) reactive power, frequency response, black start, congestion management and intertrip arrangements (which allow NGET automatically to reduce generation or demand). In addition to these longer term arrangements, NGET enters into short-term Pre-Gate closure Balancing Trades (PGBTs), which it can use for energy or system balancing purposes.

149. Further detailed information in relation to NGET's balancing services can be found at http://www.nationalgrid.com/uk/Electricity/Balancing/

150. Information in relation to each market participant's share of the various ancillary services markets is commercially sensitive and is not publicly available. However, NGET publishes aggregate information regarding the balancing services that it has procured on both a monthly and an annual basis. In addition, for some of the services (those that influence cash out prices), NGET provides utilisation reports. These reports can be found on NGET's website at http://www.nationalgrid.com/uk/Electricity/Balancing/services/

151. As an illustration of the extent to which NGET makes use of different balancing services, Table 3.10 is reproduced from NGET's May 2008 Procurement Guidelines Report, which provides a summary of the volume of each service it has utilised and the costs it has incurred.

Table 3.10: NGET balancing services summary (source: NGET Procurement Guidelines Report 2007/08, May 2008)

Balancing Service	Info Provision	Value
Reactive Power Market	Utilisation Volume (MA) Utilisation Volume (DefaultPM) Total Spend (MA) Total Spend (Default PM)	33,32GVArh 18,520 GVArh €13.03m €55.60m
Short term Operating Reserve (STOR) Including MB and NBM	Average availability payments: Non-Working Days Working Days Total Spend Total Volume	 6.41 6.41 €71.65m 29,017 MWh
Mandatory Frequency Response	Holding Volumes & Prices: Average Volume held MW Average price €/MW/h Total Holding Spend Total Response Energy Payment Spend	Primary / Sec / High 398/ 271/ 759 €4.14/€2.51/€12.37 €102.63m -€1.59m
Commercial Frequency Response	No. Of Contracts Total Spend	5 (Apr-Jun, Oct-Mar) 6 (Jul-Sep) €83.91m
Fast Start	Total Spend	€6.20m
Black Start	Total Spend	€19.85m
BM start up	Total Cost of BM Start Up Number of Instructions	€21.55m 617
Fast Reserve Tendered	Total Spend on Availability and Utilisation[30]	€11.51m
Fast Reserve Non-Tendered	Total Spend on Availability	€52.88m
SO to SO	Volume Imported Volume Exported Total spend	293 GWh -182 GWh €45.25m
System to generator Operational Intertrips	Capability payments Utilisation payment	€0.57m 0.00
Commercial intertrip service	Total Spend	€17.02m
Ancillary Constraint Contracts	Total Spend	€23.70m
Maximum Generation Service	Total Spend	€0.00
All Other Services	Total Spend	€0.00
Forward Trading	Traded gross volume Net cost of forward trading OTC – Power Exchange & Energy Buy Volume Sell Volume OTC – BMU Specific Buy Volume Sell Volume	825,968 MWh €64.40m 270,874 MWh -14,368 MWh 461,092 MWh -79,634 MWh

[30] Other than Fast Reserve utilisation achieved through acceptance of bids and offers.

PGBT's	No. of PGBT's entered into: Sourced Agreed Average PGBT Prices £/MWh: Buy Sell Volume MWh: Buy Sell Total Cost of PGBT's	 46 37 €88.96/MWh €1.10/MWh 46,974 MWh -47,960 MWh €8.23m

152. Contracted balancing services represent a significant proportion of overall system operation costs totally £408 million in 2007/8.

Demand side participation

153. Suppliers provide demand side pressure in price formation by partaking directly in the wholesale market as they contract with generators and traders. The demand side can also participate in the Balancing Mechanism and compete with generators to provide balancing services.

154. Removing barriers to demand side participation in the electricity market has been a focus of collaborative effects by the industry in GB. These efforts have mainly sought to improve the transparency of information in the electricity market, with the creation of an electricity daily summary page which seeks to bring together the most important pieces of electricity data, currently housed on various platforms, into one User friendly page[31]. Ongoing industry meetings have also allowed participants to provide input and feedback to National Grid's informal electricity information transparency consultation.

Member State integration

155. The GB electricity system is connected with France and Northern Ireland via the IFA[32] and Moyle[33] interconnectors respectively. The existence of these interconnectors and the current proposals for new interconnectors suggests that new interconnection capacity will be provided to the market when it is economic to do so. One new interconnector link to the Netherlands (BritNed[34]) is under construction. Ofgem have also granted licences for the construction of three interconnectors with the Republic of Ireland, one interconnection with Belgium and two with France although none of these are yet under construction.

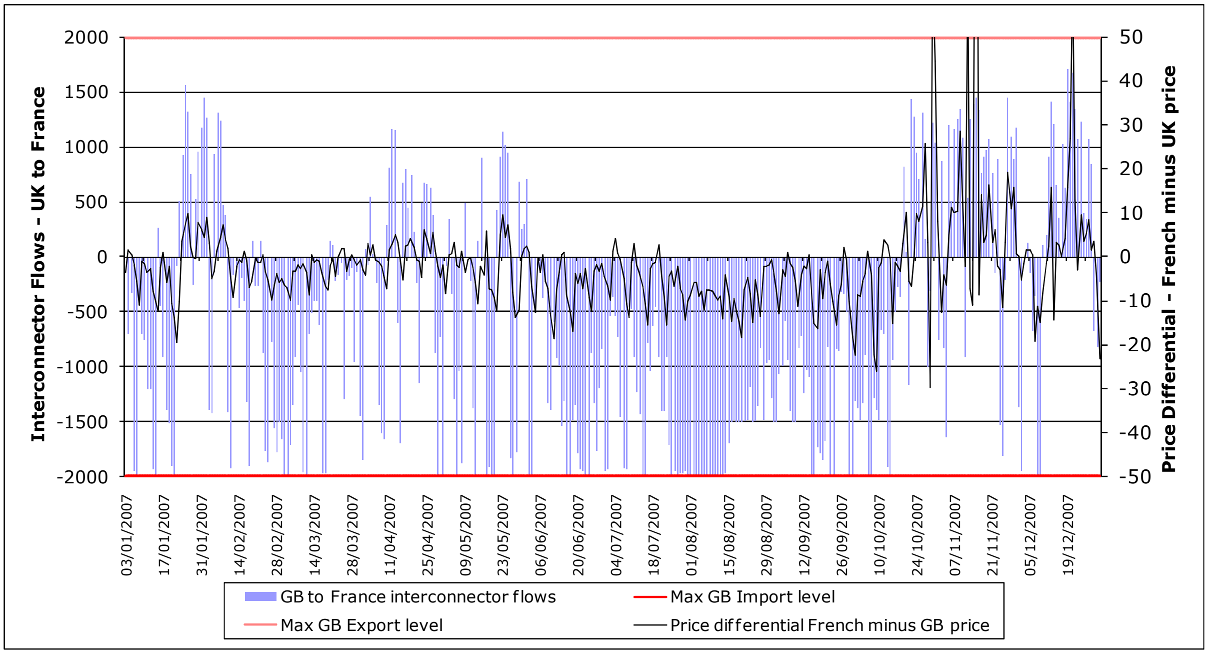
156. GB typically imports from France and exports to Northern Ireland. Total imports into GB were 8,927TWh and 21GWh respectively, whilst exports were 2,025GWh and

[31] http://www.nationalgrid.com/NR/rdonlyres/4B98082B-2548-4601-9F57-AA5CF7D45F10/22654/Electricity_Info_update_DSWG_Livemeeting_14Jan08.pdf
[32] Interconnexion France Angleterre (IFA) is a 2,000MW HVDC interconnector link between France and GB. It is jointly owned by National Grid Interconnector Limited (NGIL) and RTE.
[33] Moyle is a 500MW interconnector between Scotland and Northern Ireland. Capable of exporting at 500MW to Northern Ireland and importing at 80MW. It is owned by Moyle Interconnector Ltd.
[34] BritNed is a 1,000MW interconnector jointly owned by NGIL and TenneT.

1,423GWh respectively. Prices for access to interconnectors reflect the market dynamics, with non-discriminatory auctions regularly held for daily, weekend, monthly, quarterly, seasonally and annual capacity.[35]

157. Figure 3.11 shows total interconnector flow across the GB-France interconnector. It shows that flows across the interconnector broadly followed the price differential between GB and Europe. On 48 days during 2007, flows on the interconnector were with 1% of full capacity (imports into GB).

Figure: 3.11: Flows across the GB-France interconnector during 2007



158. In broad terms, the GB market is integrated with neighbouring markets to the extent that market parties are able to trade between them, with prices for such trade established using market based methods (see descriptions of interconnector arrangements above). This is not to say that there are not further issues or impediments to address. It is the case, for example, that interconnector flows do not always mirror market fundamentals, and this may be symptomatic of some cross border distortions in trade.

159. Going forward, GB expects to analyse and address further the possibilities for enhanced cross border trade and market integration. In the first instance this will be through ERGEG's "Electricity Regional Initiative". Under this, Ofgem is working with regulators in Republic of Ireland, Northern Ireland, and France to lead a process designed to identify and rectify impediments to trade. The process is designed to involve: TSOs, stakeholders, the European Commission, and national governments.

Recent mergers and acquisitions

[35] National Grid's website (http://www.nationalgrid.com) contains information on prices from these auctions.

160. Under the Enterprise Act 2002 the Office of Fair Trading (OFT)[36] has a function to obtain and review information relating to merger situations, and a duty to refer to the Competition Commission (CC) for further investigation any relevant merger situations[37] which it believes have resulted or may be expected to result in a substantial lessening of competition in the UK.

161. There were no merger and acquisition cases in relation to energy markets presented to the OFT in 2007.

162. Under the EC Merger Regulation 2004, the European Commission investigates any concentration[38] which is deemed to have a Community dimension[39]; to determine whether the concentration might significantly impede effective competition in the common market.

163. There were no new merger and acquisition cases in relation to GB energy market presented to the Commission since the 2006/07 National Report.

3.2.2 Description of the retail market

Electricity retail markets

164. In the electricity supply licence, customers are classified as "domestic" where they use energy for domestic purposes at domestic premises; they are classified as "non-domestic" where they use energy for business and industrial purposes.

165. Ofgem published a Domestic Retail Market Report in June 2007. The report is designed to inform the debate about the health of residential energy markets in Great Britain.[40] As discussed in Section 2, a more detailed look at retail markets in gas and electricity is currently underway, and we expect an initial report on these findings to be published in the autumn.

166. Presently, there are six large supplier groups participating in the domestic market - E.ON (formerly Powergen), npower (owned by RWE AG), EDF Energy (owned by Electricité de France), Scottish and Southern Energy (SSE), Scottish Power (owned by Iberdrola) and Centrica (which owns British Gas).

167. There are approximately 27.1million customers in the domestic electricity sector of which the six large supply companies account for about 99% of the market. There are also four supply companies who are independent[41] of these groups supplying electricity to domestic customers.

168. Table 3.12 below shows the most recent national market shares of the six large supplier groups in the domestic electricity markets.

---

[36] See www.oft.gov.uk
[37] 'Relevant merger situations' is defined in s23 of the Enterprise Act 2002.
[38] 'Concentration' is defined in Article 3 of the EC Merger Regulation.
[39] 'Community dimension' is defined in Article 1 of the EC Merger Regulation. Whether a concentration has a Community dimension depends on the turnover of the undertakings concerned.
[40] This document is available from the Ofgem website at: http://www.ofgem.gov.uk/Markets/RetMkts/Compet/Documents1/DRMR%20March%202007doc%20v9%20-%20FINAL.pdf
[41] Independent retailers are defined as new entrant firms. They are typically not vertically integrated.

Table 3.12: GB domestic electricity retail market shares – March 2008

Group	**Electricity**
Centrica	22%
Scottish and Southern Energy	19%
E.ON	18%
Npower	15%
EDF Energy	13%
Scottish Power	12%

Source: Electricity distribution companies

169. In November 2007, SSE overtook E.ON to obtain the second largest electricity market share in the domestic sector.

170. The information Ofgem collects on market shares in the non-domestic markets is acquired from a third party, who collects the data from suppliers. This data is presented in Table 3.13 below.

Table 3.13: GB non domestic electricity retail market shares by volume of supplied electricity (Feb 07)

	Non HH[42] (sub 100kW)	HH[43] (100 kW, 1MW)
Centrica	17%	-
npower	17%	17%
Powergen	19%	11%
SSE	16%	12%
EDF Energy	18%	19%
ScottishPower	7%	5%
British Energy	-	18%
GdF	-	7%

Source: Datamonitor

Market shares and new entry

171. In domestic electricity, there are six main supplier groups all with a share of above 5%. Since the market opened to competition, at least twenty suppliers have entered and exited since April 1999.

172. Centrica, the former gas monopoly supplier is the largest entrant in the market and has a significant presence with a national market share of 22%. It has gained its

[42] Non-HH represents customers that are not metered on a half hourly basis. This group can be categorised as all those with a consumption below 100kW.
[43] HH represents customers that are metered on a half hourly basis. This group can be categorised as all those with consumption above 100kW.

customers mostly through organic growth. The former Public Electricity Suppliers (PESs, the former retail incumbents) have also entered into regions other than their former monopoly areas. On average, these new entrants have gained about 49.5% of the regional incumbents' market share. The incumbents still have, on average, about 50.5% of the domestic customers in their former monopoly areas. Entry by the independent suppliers has been on a less significant scale. They have in total less than 1% of the national market.

173. The three suppliers with the highest domestic national market shares are Centrica, Scottish and Southern Energy and EON (formerly Powergen), who together have 59% of the market.

174. In each of the sectors of the non-domestic market there are at least six suppliers with a market share above 5%, as shown in table 3.14. The three suppliers with the highest market shares in the non-half hourly sector are Centrica, EDF and E.ON who together have a 55% share of the sector. In the half hourly sector EDF Energy, British Energy and npower are the three suppliers with the highest market shares, which together have a 54% share of the sector.

175. In the non-domestic markets there have been at least 9 new entrants since 2001. Although we observe some independent new entry, in general successful new entrants tend to be large firms active in other product or regional markets/countries and tend to build market share relatively quickly. In the domestic market, around 20 suppliers have entered the market since the introduction of competition.

Integration between wholesale and retail markets

176. The 6 large supplier groups in the domestic market are vertically integrated, i.e. they are part of a corporate group that is active in both the wholesale and retail markets. Between them, the six supplier groups account for 54% of generation output (this figure is based on equity share and does not include contractual arrangements between generators and suppliers). None of the independent domestic suppliers are vertically integrated. In addition to the six large supplier groups, other non-domestic suppliers are also vertically-integrated (such as British Energy). About 70% of generation output is accounted for by vertically-integrated suppliers in the non-domestic markets.

Independence from network companies

177. The GB transmission system operator's transmission licence prohibits it from having an interest in electricity wholesale or retail markets, either directly or through an affiliate company.

178. The Utilities Act 2000 amended the Gas Act 1986 and the Electricity Act 1989 and prohibited a supply licence holder from holding a distribution or transmission licence in a single legal entity. Apart from npower and Centrica all the large suppliers have an affiliate connection to electricity DNOs, in that they belong to company groups that own distribution companies. In addition, SSE and Scottish Power belong to groups that own transmission assets (but do not operate their respective transmission systems as this is undertaken by National Grid).

179. None of the independent new entrants since the introduction of competition have had affiliations to either TSOs or DNOs.

Customer switching

180. Ofgem primarily collects data on the number of customers switching between suppliers in the domestic electricity retail market. It therefore does not have switching data for the non-domestic markets.

181. Between May 2007 and April 2008, on average, 439,500 domestic customers changed electricity supplier each month. Table 3.14 shows the number of domestic customers who switched in electricity over the last 12 months.

Table 3.14: Number of GB domestic electricity customers who switched between May 2007 and April 2008

May-07	451,535
Jun-07	425,657
Jul-07	441,492
Aug-07	500,630
Sep-07	396,523
Oct-07	477,419
Nov-07	476,704
Dec-07	411,269
Jan-08	335,134
Feb-08	440,642
Mar-08	476,149
Apr-08	441,342

Source: Electricity distribution companies

182. There has been a steady increase in the level of switching between electricity suppliers, with the level in 2008 exceeding that seen in 2007. Table 3.15 below shows the number of monthly and annual transfers of domestic electricity customers.

Table 3.15: Total annual transfers in electricity

Total Transfers	Jan – Dec 04	Jan – Dec 05	Jan – Dec 06	Jan – Dec 07
Electricity	4,229,023	4,316,401	4,820,756	5,157,028

Source: Electricity distribution companies

Summary of switching procedures

183. The Customer Switching Processes used in the retail electricity market are initiated following agreement between a supplier and a customer to enter into a contract. Once the customer has decided that they wish to switch supplier, they can either directly approach an alternative supplier, use a third party supplier price comparison service

(energywatch has put in place processes to accredit these comparison services) or delegate the responsibility for negotiation to a broker or consultant (which is used in the case of a number of non domestic customers). Alternatively, the customer may be contacted directly by the supplier, e.g. on the doorstep, and asked whether they want to transfer supplier.

184. The rules and processes used with regard to customer switching in the electricity market are found pre-dominantly in a supplier's SLCs, the Master Registration Agreement (MRA) and its subsidiary documents. Other supporting processes are found in the Balancing and Settlement Code (BSC).

185. Once the terms and conditions for supply are agreed, the customer has a period of time to consider the contract and decide whether to cancel it – the Cooling Off Period. This period is a legal obligation with regard to domestic customers and is seven business days. However, many domestic suppliers have extended this period to 14 days and some I&C suppliers have also adopted the cooling off period. If the customer does not cancel the contract, the new supplier using a shared network called the Data Transfer Network notifies the relevant distributor of the intended transfer who then performs a simple validation check. If successful the distributor stores the transfer details on a central system called MPAS (Metering Point Administration Service) and then contacts the old supplier to notify them of the specific meter point (MPAN – meter point administration number) to be transferred and the intended supply start date. The old supplier then has five business days to object to the transfer. If no objection is raised then the transfer and intended supply start date are agreed and the new supplier must appoint agents (e.g. a meter reader, data aggregator and meter operator) to fulfil its duties (i.e. collecting meter readings, provision and maintenance of a meter etc) as prescribed in the supplier's SLCs, the BSC and the MRA.

186. The last task the new supplier must complete is to procure and submit a change of supplier meter reading that falls within +/- 5 working days of the Supply Start Date (SSD) and submit that read to the DNO's meter point admin system within eight working days (SSD +8 days).

Competition Issues

187. Ofgem has concurrent powers with the OFT to apply and enforce certain provisions of the Competition Act 1998 (CA 98) and the Enterprise Act 2002.

188. Ofgem along with the OFT has issued advice and information explaining how the CA 98 will be applied and enforced in the energy sector[44].

189. Ofgem is currently undertaking an in-depth investigation under the Enterprise Act 2002 in the electricity retail market energy for households and small businesses.

Current retail price levels

190. Ofgem monitors domestic suppliers' prices across GB. All final prices in the GB wide retail energy markets are determined by market forces as all price controls on

[44] This document is available on the OFT website at:
http://www.oft.gov.uk/shared_oft/business_leaflets/ca98_guidelines/oft428.pdf
OFT Competition Law Guidelines: Application in the energy sector.

final prices were lifted by April 2002. However, there are elements of the final price which are attributable to the regulated aspects of the market, in particular distribution, metering and transmission charges, and as such continue to be price controlled.

191. There are three main methods of payment offered by suppliers. Customers on standard credit receive a bill, typically on a quarterly basis, for the energy they have already consumed. The bill can be settled by cash, cheque, debit or credit cards. Customers that pay by prepayment generally use a card, key or token meter to pay upfront for the electricity they consume. This tends to be the most expensive payment method. Where customers pay by direct debit, the payment is taken directly from their bank account each month. This method of payment tends to the cheapest.

192. Domestic suppliers set prices on a regional basis, mirroring the DNO territories and pricing levels. A region's incumbent supplier is generally the most expensive supplier in a region with entrants pricing at varying discounts to this price. On average, the competitors' annual electricity standard credit bill is about €41 per year cheaper than the incumbent. The average incumbent standard credit electricity bill is €636 per year – across the 14 regions, the incumbent bill ranges between €571 and €695 per year. Table 3.16 provides a summary of electricity prices in the domestic sector.

Table 3.16: GB domestic electricity annual bills – 1 July 2008[45]

	Range of supplier national average prices	Average Incumbent Price across all regions	Average of Best Offer across all regions
Direct Debit	€ 536 - 590	€ 603	€ 528
Standard Credit	€ 563 - 631	€ 636	€ 555
Prepayment	€ 563 - 663	€ 642	€ 559

Source: Ofgem

193. The breakdown of the average domestic electricity bill consists of the following components: distribution and metering costs (where metering is a very small proportion), transmission costs, environmental costs (which include the Carbon Emissions Reduction Target [46] and the Renewables Obligation[47]), and Value Added Tax (VAT). Generation costs, retail costs (including, for example, marketing, billing and call centres) and margin make up the remainder of the bill. Table 3.17 provides the estimated breakdown of the domestic bill into these components.

Table 3.17: Estimated breakdown of domestic electricity bill as of January 2008[48]

[45] Bills are based on an average annual consumption of 3,300 kWh.
[46] The Carbon Emissions Reduction Target (CERT), previously the Energy Efficiency Commitment (EEC2), is the government's main policy instrument for reducing carbon emissions from existing households. CERT is due to run from 2008 to 2011, and requires certain gas and electricity suppliers to meet a carbon emissions reduction obligation (carbon obligation). The target is 154 million tonnes of carbon dioxide (lifetime).
[47] The Renewables Obligation is the government's main mechanism for supporting renewable energy. It aims to provide a substantial market incentive for all eligible forms of renewable energy.
[48] Ofgem's January 2008 publication, 'Updated – Household Energy Bills Explained', has a more detailed discussion of the bill breakdown.
http://www.ofgem.gov.uk/Media/FactSheets/Documents1/energy%20prices%20jan08.pdf

Components of bill	**Proportion of bill**
Energy, supply costs and margin	66%
Distribution and metering costs	17%
Transmission costs	4%
Environment	8%
VAT	5%

Source: Ofgem

194. Ofgem does not actively collect data on prices in the non-domestic sector; therefore we are unable to provide up-to-date data on prices and a breakdown of non-domestic bills. BERR publish a digest of non-domestic prices on their website. The most recent publication is for March 2008 which is available at: http://www.BERR.gov.uk/energy/statistics/publications/prices/index.html

3.2.3 Measures to avoid abuses of dominance

Market surveillance

195. Ofgem's market surveillance team monitors the gas and electricity markets, including the wholesale electricity market and the Balancing Mechanism. They routinely assess whether there is any evidence of anti-competitive behaviour or breaches of statutory or licence provisions. On the basis of active surveillance and monitoring of the markets, Ofgem can investigate the behaviour of market participants if anti-competitive conduct is suspected and, where necessary, enforce domestic and European competition law.

196. Additionally, the Financial Services Authority (FSA)[49] has responsibilities for the operation of financial markets in the UK. The FSA works to prevent abuse or distortion of financial markets, including power exchanges such as the IPE. The FSA has the power to fine persons who have abused the market, where "market abuse" is defined under the Financial Services Market Act 2000.

General competition law framework

197. Ofgem has concurrent powers with the Office of Free Trading (OFT) to apply and enforce certain provisions of the Competition Act 1998 (CA 98). Specifically, Ofgem can enforce provisions prohibiting:

a. anticompetitive agreements under Article 81 of the EC Treaty and Chapter I of the CA 1998; and

b. the abuse of dominance under Article 82 of the EC Treaty and Chapter II of the CA 98,

in the electricity sector.

198. Ofgem has the power to:

[49] http://www.fsa.gov.uk/

- investigate suspected infringements;
- impose interim measures;
- give directions to bring an infringement to an end;
- accept binding commitments to address competition concerns, where appropriate; and
- impose financial penalties on undertakings of up to 10 per cent of an undertaking's turnover in the relevant market affected by the infringement in the business year preceding the date of the decision.

199. The Authority also has concurrent jurisdiction with the OFT under the Enterprise Act 2002 to make market investigation references in the electricity sector.

Generation licences

200. The electricity generation licences contain some conditions that could be used to tackle certain types of anti-competitive conduct on the part of generators. Certain conditions prohibit discrimination in the sale of electricity and cross-subsidisation.

Market information and transparency

201. Ofgem's submission to the European Commission (DGTREN) Report 2005 contained a detailed explanation of general market information and transparency requirements.

202. In summary, licensed generators are obliged to comply with the Grid Code.[50] The Grid Code places certain obligations on signatories to submit accurate estimates of the physical properties of its generating units. The details are split into two main operating codes known as OC1 and OC2. OC1 covers short term, medium term and long term demand forecasts. Users are required to provide NGET with their planned MW operational profiles for their stations. OC2 is concerned with the exchange of specified information to facilitate and co-ordinate the planning for the safe, secure and efficient operation of generation units and the network, such as outages and current estimates of usable output.

203. As stated in section 3.1 in relation to the Balancing Mechanism, market participants are required by the balancing market arrangements to notify NGET of their contracted positions over various timeframes.

Reporting obligations on NGET

204. Information in relation to the operation of the BM is provided on the Balancing Mechanism Reporting Service (BMRS) website[51] by the Balancing Mechanism Reporting Agent (BMRA). The BMRS website provides near real time and historic data about the BM.

205. NGET is required to send a variety of data items (defined in the Grid Code) to the BMRA and to ELEXON (for publication on the BMRS) for reporting purposes. The

[50] The Grid Code is an industry code covering all material technical aspects relating to connections, operation and use of the GB transmission system and lines and plant connected to that system.

[51] See www.bmreports.com.

specific data items required to be sent are listed in Section Q of the Balancing and Settlement Code (BSC). Generally, the type of data that NGET is required to send includes zonal and national demand forecasts, zonal and national generation forecasts, zonal and national imbalances and information in relation to the actions that it has taken to balance the system.

206. There are a number of reporting obligations placed on NGET directly via its licence or more indirectly reflecting its responsibilities to operate and efficient, economic and coordinated system.

Bidding behaviour

207. In cases where Ofgem considers that generators' bidding strategies suggest that the market manipulation may be occurring, Ofgem would seek to investigate and, where appropriate, take enforcement action under its competition law powers.

Virtual power plant auctions

208. There have been no virtual power plant auctions in GB.

Retail Market

Transparency

209. Standard licence conditions (SLCs) in the electricity supply licence are the principal means by which Ofgem requires suppliers to meet minimum requirements for the provision of information and contract terms.

Contract structure

210. SLC 22 of the electricity supply licence stipulates that a licensee may not supply a domestic premises except under a domestic supply contract or a deemed contract. The domestic supply contract must be in writing and set out all terms and conditions.

211. SLC 24 of the electricity supply licence provides that the terms of a domestic supply contract must allow the customer to terminate that contract. The supplier may charge a termination fee, except in certain defined circumstances including:

- the contract is of an indefinite length;
- the contract allows for both a fixed term period and a period of indefinite length and is brought to an end during the period of indefinite length; or
- the licensee gives notice of a unilateral variation of a term of the contract.

Provision of information

212. SLC 23 of the electricity supply licence obliges suppliers to take all reasonable steps to draw the customer's attention to the principal terms of the supply contract.

213. SLC 31 of the electricity supply licence obliges suppliers to provide their customers with information on:

- how to contact the Consumer Council;
- the Consumer Council's role in resolving customer complaints;
- the efficient use of electricity; and
- the procedure the licensee will follow to deal with any complaints.

Competition policy actions

214. Last year, the Gas and Electricity Markets Authority issued a non-infringement decision further to an investigation under the Competition Act 1998 in the retail sector (specifically an investigation into the supply of meter data services).

215. In April 2008 Ofgem launched an investigation into Scottish Power Limited and Scottish and Southern Energy plc, under section 18 of the Competition Act 1998 (the Chapter II prohibition) and Article 82 of the EC Treaty. This decision was based on a formal complaint alleging abuse of a dominant position in the electricity generation sector arising from constrained capacity on the transmission network, as well as informal enquiries.

4. Regulation and Performance of the Natural Gas Market

4.1 Regulatory Issues [Article 25(1)]

Overview

This section describes the regulatory framework for the GB gas market. It covers:

- Management and allocation of interconnection capacity and mechanisms to deal with congestion
- The regulation of the tasks of transmission and distribution companies:
  - Price controls
  - Standards of performance and quality of service
  - Network tariffs
  - Balancing arrangements
  - Access to storage, linepack and other balancing services
- The regulation of effective unbundling

4.1.1 General

216. Gas and electricity markets in Great Britain are fully liberalised.

4.1.2 Management and allocation of interconnection capacity and mechanisms to deal with congestion

217. The GB gas system is interconnected with Belgium, Northern Ireland, the Republic of Ireland and the Netherlands. An increase in capacity of the Belgium interconnector was completed in 2007. The existence of these interconnectors and the current proposals for capacity increases in the interconnector between the Netherlands and the UK and recent actual capacity increases suggest that the interconnection system is responding well to market signals.

218. The requirements of the Directives and the gas Regulation regarding interconnectors can be found in GB law in the licences to participate in the operation of interconnectors. Standard licence condition 10 of the interconnector licence requires the Authority to approve the charging methodology for access to an interconnector; SLC 11 requires the licensee to offer to enter into agreements for access to its interconnector on transparent, objective and non-discriminatory terms. Standard licence condition 13 requires the licensee to make available the maximum capacity of its interconnector. This includes the development of procedures on the primary market to facilitate the secondary trade of capacity and the requirement to allow and facilitate capacity rights to be traded on the secondary market. If capacity is reduced for technical reasons the mechanism for reducing the capacity allocation should also be open, transparent and non-discriminatory.

219. Ofgem is of the view that each interconnector operator must demonstrate that it has a transparent mechanism in place that allows spare capacity to be made available to the market. The ultimate objective is to ensure that capacity is not hoarded and that unused capacity can be obtained in a transparent market based manner by third parties so as to maximise the use of the interconnector concerned. The actual methodology under which interconnector capacity is made available in both the primary and secondary market is for the interconnector owner/operator to decide.

220. Under the current regulatory and contractual framework, there are no use-it-or-lose-it provisions on the interconnector with Belgium. However, the interconnector operator currently facilitates the secondary trading of unwanted capacity by way of a bulletin board on its website. Ofgem does not routinely analyse physical congestion on interconnectors in the absence of complaints from market participants. However, data from 2004 suggests that physical congestion on the interconnector with Belgium was very low: for around 1% of the time flows were above 95% of maximum capacity at times when gas prices suggest that additional capacity would have been used. Based on analysis of data from 1 April 05 to 8 Jul 06, physical capacity was only ever breached on two days (when the IC was exporting) and only came close on one day when importing (99%).

221. Prevailing wholesale prices in the two markets are such that the interconnector with Ireland only exports from GB. Therefore, any congestion on this interconnector would have no adverse consequences on consumers in GB.

Management of congestion on national networks

222. The GB gas system is interconnected with Belgium, Northern Ireland, the Republic of Ireland and the Netherlands. An increase in capacity of the Belgium interconnector was completed in 2007. The existence of these interconnectors and the current proposals for capacity increases in the interconnector between the Netherlands and the UK and recent actual capacity increases suggest that the interconnection system is responding well to market signals.

223. The requirements of the Directives and the gas Regulation regarding interconnectors are being met in GB by issuing licences to participate in the operation of interconnectors. For example, SLC 11 of the interconnector license requires the licensee to offer to enter into agreements for access to its interconnector on transparent, objective and non-discriminatory terms. Standard licence condition 13 requires the licensee to make available the maximum capacity of its interconnector. This includes the development of procedures on the primary market to facilitate the secondary trade of capacity and the requirement to allow and facilitate capacity rights to be traded on the secondary market. If capacity is reduced for technical reasons the mechanism for reducing the capacity allocation should also be open, transparent and non-discriminatory.

224. The BERR (or DTI as it was known then) published a consultation document in June 2005[52] on the licensing and exemption regimes that it proposed to introduce for existing interconnectors, in line with the requirements of the Energy Act 2004. After considering the responses to this consultation, minor drafting changes to some of the licences' terms and conditions and to the draft exemption order were made. While

[52] Licensing of existing gas and electricity interconnectors under the terms of the Gas Act 1986, the Electricity Act 1989 and the Energy Act 2004.

most changes were concerned with the electricity interconnectors, some small drafting amendments were proposed for the UK/Republic of Ireland gas interconnectors and the UK Belgian gas interconnector. These changes primarily sought to address concerns regarding the differential treatment of individual interconnectors and the risk of conflicting demands from the two different regulators involved. The BERR is satisfied that the changes made are fully compliant with the EU legislation.

225. Ofgem considers that effective secondary trading and anti-hoarding mechanisms are required, with each interconnector operator needing to demonstrate that there is a transparent mechanism that allows spare capacity to be made available to the market. The ultimate objective is to ensure that capacity is not hoarded and that unused capacity can be obtained in a transparent market based manner by third parties so as to maximise the use of the interconnector concerned. The actual methodology under which interconnector capacity is made available in both the primary and secondary market is for the interconnector owner/operator to decide.

226. Once the interconnector licences are in place this methodology will need to meet the requirements of the relevant conditions of the interconnector licences. If this were not to be the case, Ofgem would expect the affected prospective interconnector users to make Ofgem aware of the situation, which Ofgem would then investigate and take any appropriate action.

227. In terms of publication requirements for this information, the BERR and Ofgem consider that there should be equivalent information requirements on LNG and interconnectors as required of similar facilities in gas and electricity markets respectively, for example, generators in electricity or other connection points to the NTS in gas (wholesale market information requirements are discussed below).

228. Under the current regulatory and contractual framework, there are no use-it-or-lose-it provisions on the interconnector with Belgium. However, the interconnector operator currently facilitates the secondary trading of unwanted capacity by way of a bulletin board on its website. Ofgem does not routinely analyse physical congestion on interconnectors in the absence of complaints from market participants. However, data from 2004 suggests that physical congestion on the interconnector with Belgium was very low: for around 1% of the time flows were above 95% of maximum capacity at times when gas prices suggest that additional capacity would have been used. Based on analysis of data from 1 April 05 to 8 Jul 06, physical capacity was only ever breached on two days (when the IC was exporting) and only came close on one day when importing (99%).

229. Prevailing wholesale prices in the two markets are such that the interconnector with Ireland only exports from GB. As such, any congestion on this interconnector would have no adverse consequences on consumers in GB. Ofgem does not routinely collect or analyse data relating to this interconnector.

Management of congestion on national networks

230. Transmission system operators are responsible for managing congestion on their networks. Both gas and electricity system operators are under a statutory obligation to develop and maintain economic and efficient systems, as are gas and electricity distributors.

231. The gas national transmission SO faces commercial incentives to reduce the cost of congestion at entry points as it is required to auction firm access rights and to fund a proportion of the cost of buying back any rights to network access that it has sold but which cannot be delivered due to congestion. Under the SO price control, there are separate commercial incentives to reduce the costs of congestion associated with existing (operational) capacity and new (incremental) capacity.

- Under the operational incentive scheme, the SO has an implicit target allowance of £21m per annum for capacity congestion management associated with existing capacity (net of certain revenues[53] it earns). It is allowed to keep a proportion of any savings made relative to this target allowance, but must fund a proportion of the costs it incurs above the target allowance. Its potential gain (or loss) from this incentive scheme is capped at £18m (or -£18m) per annum. The operational incentive scheme will be reviewed and potentially reset after the first two years of the new price control (starting in April 2007).

- Under the incremental incentive scheme, the SO must fund all of the cost of capacity congestion management associated with the late delivery of new capacity (i.e., above an implicit target allowance of £0m per annum). However its potential loss from this scheme is subject to a cap of -£4m per month and -£36m per annum. There is no potential gain to the SO from this scheme. In addition, there is an "entry permits" scheme whereby the SO can vary the lead time for delivery of any new capacity (around a default lead time of 42 months). Through this scheme, the SO can potentially receive an additional revenue allowance at the end of the five-year price control period, if it commits in advance of the auctions to delivering capacity earlier than the default lead time or if it does not use up (by delivering capacity later than the default lead time) its initial endowment of permits set at the start of the period. The total gains from this scheme to the SO are capped at £36m.

232. These mechanisms are intended to incentivise the SO to maximise the technical availability of its network and ensure timely delivery of the capacity.

233. Under its price control the transmission SO is required to offer for sale a defined (baseline) volume of firm entry capacity at each entry point, but may also make additional entry volumes available as either "non-obligated" firm capacity or interruptible capacity. In addition, it is obliged to make additional capacity available if the auction results satisfy the requirements of a specified capacity release mechanism, when the results of this mechanism demonstrate a sustained demand above the baseline.

234. To date there have been several examples where auction results have demonstrated a sustained demand (i.e. demand above the baselines volume) at existing entry points, including Isle of Grain, Easington and Hornsea and new entry points including Cheshire. Therefore, the SO has been obliged to release incremental capacity at these entry points.

235. There have also been auction signals demonstrating a sustained demand at various new entry points. Consequently, the SO is currently investing in new infrastructure to enable access to its network at the new entry point of Milford Haven.

[53] These include revenues from sales of interruptible capacity and "non-obligated" capacity. If the SO earns revenues from the sales of non-obligated capacity because of earlier than planned delivery of new (incremental) capacity, then it is allowed to retain all of these revenues as additional revenues. All other revenues are treated as described in the main text.

- At Milford Haven this is in response to demand for access from the LNG terminals under construction there. Entry capacity at Milford Haven has been sold to start from the last quarter of 2007. Ofgem has developed specific incentive arrangements for the SO in relation to the provision of the first tranche of gas transmission capacity (which was due for delivery from October 2007) at Milford Haven. Under this incentive scheme, for each month over a period lasting one year, the SO must fund a proportion of the cost of capacity congestion management associated with the potential late delivery of the first tranche of capacity. Its potential loss from the scheme is capped at -£2m to -£6m per month (depending on the month).

236. A number of large industrial and commercial gas consumers pay a reduced gas transportation charge in return for allowing the SO to interrupt their gas supplies, typically for up to 15 days per year. This provides the transmission SO with an important tool to manage network congestion. Any customers interrupted on more than 15 days receive an additional payment, which is funded from the transmission SO incentive scheme. However, the total costs of the additional interruption are small (the incentive target is around £1.68m per annum for 2008/9).

237. The transmission SO can also constrain the use of Liquefied Natural Gas (LNG) in certain storage facilities. Shippers that book capacity in these constrained LNG sites undertake an obligation to provide transmission support gas to the SO on days of very high demand. In recognition of this, shippers get a discount from the charge for the storage service. The target cost for constrained LNG costs incurred by the SO are currently £2.1m.

238. The combined target costs of congestion management facing the transmission SO under the current arrangements are therefore in the order of £23m per annum (excluding the costs of interruption up to 15 days per site which do not fall on the SO but are recovered from all customers under the current arrangements). This is small in comparison with the total cost of the gas transmission network, which is around £0.6 billion (the total allowed revenue from charges to network users for use of the transmission network).

4.1.3 The regulation of the tasks of transmission and distribution companies

239. There is one gas transmission network, the National Transmission System (NTS), which is owned and operated by National Grid Gas plc (NGG). There are eight gas distribution networks (GDNs)[54] in Great Britain. These eight networks are operated by four GDN operators (National Grid Gas Plc, Scotia Gas Networks Plc, Northern Gas Networks Ltd and Wales & West Utilities Ltd). GDN operators transport gas from the NTS using a low pressure system to serve domestic customers, business consumers and Independent Gas Transporters (IGTs).

240. In 1995 the Gas Act 1986 was amended to allow for the creation of Independent Gas Transporters (IGTs) which develop, operate and maintain local gas transportation network extensions onto the GDNs (or other IGTs). There are sixteen licensed IGTs organised in ten groups.

---

[54] In gas distribution, there is no distinction between asset owners and system operators. DN owners both own and operate the system.

Price controls

241. Ofgem regulates the level and structure of charges levied for using the monopoly GDNs and the quality of service provided by these companies. The level of charges and quality of service provided by gas transporters, with the exception of IGTs, is regulated using price controls and various incentive regimes. Relative Price Control (RPC) was introduced to regulate Independent Gas Transporter transportation charges in January 2004. RPC requires that IGT charges to all new customers should be capped at a level broadly consistent with the GDN equivalent charge.

242. In establishing price controls and incentive regimes, a range of information is collected on operating costs, capital expenditure, financial issues and performance outputs for the NTS and each GDN which is then analysed.

243. Ofgem also uses independent consultants to undertake efficiency studies on specific aspects of costs and network performance. These studies will typically examine the scope for improvements in costs or performance. Setting cost allowances or performance targets in this manner is not a purely mechanistic process. Ofgem will also consider a number of other factors to ensure that the resultant cost allowances or performance targets are both sustainable and robust.

244. Based upon our assessment of costs and outputs, Ofgem establishes cost allowances and performance targets which form the basis of the price controls and incentive framework. Together, these elements determine the total amount of revenue (allowed revenue) that each network company may earn in each year and the network company is required by the regulatory regime to set charges for use of the network such that it complies with the limits on allowed revenue that have been set.

245. The current five year price control began on 1 April 2008 and ends 31 March 2013. GDNs in total will be allowed to recover on average £2,470 million (in 2005-06 prices) for each of the five years. For the average domestic customer this represents a real increase of approximately £2 per annum.

246. Ofgem sets price controls which are typically five years long. The current gas and electricity transmission price controls began on 1 April 2007.

247. On 1 June 2005, Transco Plc (now NGG) completed the sale of four GDNs including Scotland, North of England, Wales and West, and the South of England. Now that four of the GDNs are no longer owned by NGG, Ofgem is better able to use comparative regulation in its gas distribution price controls.

248. As part of the next price control review for GDNs, information will be collected from the NTS and each GDN company and where applicable normalised to ensure as far as possible comparability across companies and then it will be used to assist in determining the relative performance of each GDN and to establish efficient cost and performance benchmarks using a variety of statistical techniques.

249. The price control establishes allowed revenue for the NTS and each GDN to be recovered through transportation charges.

250. The NTS, GDN and IGT licensees are responsible for establishing a set of network charges in accordance with the principles set out in their GT licence. The NTS, GDN

and the IGT licensees must adhere to the obligations in their charging methodology[55], the licence and the Gas Act.

251. Periodic reviews are undertaken on the structure of charges to ensure the distribution charging boundary and distribution charging methods are in accordance with the requirements of the licences[56]. The charging boundary is the boundary between transportation activities and connection activities. The distribution charges are sub-divided into system related and customer related activities. The structure of distribution charges affects the behaviour of a wide range of consumers and, for this reason, it is important for it to provide appropriate incentives to use GDN assets effectively. Improvements to the charging models have the potential to lead to a more efficient use of GDN assets, thus reducing the costs of developing and maintaining them. These lower costs would then be reflected in reduced distribution charges for all consumers.

252. The business information available for IGTs is limited and the costs of undertaking detailed efficiency studies to establish cost allowances and performance targets often outweigh the benefits to consumers. Ofgem has therefore introduced a system of relative price regulation to ensure that the charges for the use of these networks are no more than the charges that would be paid by an equivalent customer that is connected to a GDN. The Relative Price Control came into effect on 1 January 2004[57].

Outputs reporting framework

253. Ofgem introduced output reporting for Great Britain's eight Gas Distribution Networks ("GDNs") in April 2002, as part of the 2002-07 price control review. Under the relevant licence conditions, Ofgem published Regulatory Instructions and Guidance ("RIGs") which defines the outputs and provides the framework under which the data is collected and reported.

254. The original framework required GDNs to report on (i) the number and duration of non-contractual interruptions to supply, (ii) the resolution of shipper queries, (iii) the reliability of the M-number CD-ROM service and (iv) some environmental outputs. Since 2002, the reporting framework (via the RIGs) has been amended three times.

255. Version 3 of the RIGs, which was published in March 2005, introduced a requirement for all GDNs to undertake customer surveys of a sample of those customers that have experienced a non-contractual interruption to supply, and report the results of these surveys to Ofgem. The surveys cover performance in three key areas – (i) communication, (ii) the inconvenience caused to customers by the interruption and (iii) the efficiency and professionalism with which the work was carried out to restore supplies.

256. Ofgem has developed an updated RIGs document as a part of the gas distribution price control review ("GDPCR"). The main changes from the previous version will be to introduce reporting on the accuracy of pipe-line records and to extend the customer

---

55 Standard Special Condition A5 of current GT licence.

56 Conclusions on the review of the structure of gas distribution charges: Conclusions Document, 28 February 2006

57 See pages 23-28 for an overview of RPC in The Regulation of Independent Gas Transporter Charging; Final Proposals, Ofgem, July 2003.

satisfaction survey requirements to include customers who have experienced an emergency or service from the GDNs' connection businesses.

257. The requirement to report the number and duration of interruptions remains. However, the data reported under this output to date has not been as robust as expected. In 2004, Ofgem commissioned an assessment of the systems used to record and report the interruptions information which highlighted that the reported number of interruptions was understated and the duration of interruptions significantly overstated due to problems with the data and the way that it is collected. Some progress has been made in the reporting arrangements to ensure that data is more robust through changes to the RIGs which came into effect on 1 April 2005. For this reason, Ofgem cannot provide trend data for continuity. Nevertheless, the data conforms to broad industry estimates for the number and duration of interruptions of around 1 customer in every 100 experiencing an interruption, lasting for around 12 hours.

258. As part of the current GDPCR Ofgem has reviewed the existing outputs and quality of service arrangements and are proposing a number of improvements to ensure they remain relevant, address any gaps identified and provide an appropriate level of protection for consumers. We consider the changes will result in the following benefits:

- simplification of the outputs and quality of service arrangements;
- improved protection for consumers;
- improved accuracy and reliability of data recorded and reported by GDNs;
- enhanced comparative competition between the GDNs; and
- improved ability to monitor how performance is improving both over time and between different GDNs.

Further reading: please see appendix 3 – Further reading – 4.1.3 – Gas – Outputs reporting framework

Quality of service indicators (Standards of Performance)

259. Ofgem introduced Standards of Performance for gas transporters (“GTs”) to further protect the interests of customers in 2002. Guaranteed Standards of Performance (“GSOPs”) set service levels that must be met in each individual case. Currently GSOPs cover areas such as restoring supplies after an unplanned interruption, reinstating premises after works, providing quotations and the scheduling of connections works etc within a specified timeframe. If a GT fails to provide the level of service specified, it must make a payment, or payments, to the customer affected subject to certain exemptions.

260. In previous years, Overall Standards of Performance (“OSOPs”) were used to set minimum average levels of performance for a 12 month period. These standards covered areas such as answering telephone calls and notifying customers of planned interruptions, responding to complaints and attending gas emergencies.

261. As a part of the most recent GDPCR, Ofgem decided to remove the OSOPs from the quality of service regime. The OSOPs were replaced (where appropriate) with guaranteed standards or licence conditions. These changes are outlined in more detail in the GDPCR Final Proposals document published in December 2007.

262. The current guaranteed standards of performance are summarised in the table below.

Table 4.1: Current Guaranteed Standards of Performance

No.	Guaranteed standard	Compensation if not met
GS1	GT must restore customer's gas supply within 24 hours following an unplanned interruption. Further compensation must be paid for each additional period of 24 hours until supply is restored, subject to a cap. If the interruption is caused by another GT, the other GT is either required to make the payment to the GT to whose network the customer is connected or to the customer directly.	£30 (domestic) £50 (small nondomestic).[58] Cap of £1000.
GS2	GT must reinstate customer's premises within 5 working days. Further compensation must be paid for each additional period of 5 working days.	£50 (domestic) £100 (nondomestic).
GS3	GT must provide alternative cooking and heating facilities to priority domestic customers when supply to the customers' premises is discontinued. GT must provide these facilities within 4 hours for planned and unplanned interruptions affecting less than 250 consumers, or within 8 hours for an unplanned interruption affecting 250 or more customers.	£24 (domestic) if claimed by the customer within 3 months.
GS4-6	GTs must provide a quotation for providing a new or altering an existing connection within: • 6 working days for standard connections • 11 working days for non standard ≤275kWh connections • 21 working days non standard >275kWh connections. Further compensation must be paid for each additional day that failure continues subject to a cap. If the quotation is inaccurate it is treated as if it was not provided on time.	£10, or £20 for non standard >275 kWh connections. Cap is lesser of £250 (or £500 for non standard >275 kWh connections) or contract sum.
GS7	Where a customer challenges a quotation under the GT's published accuracy scheme and the quotation is found to be inaccurate the GT shall refund the amount of any overcharge.	Amount of any overcharge.
GS8	GT must respond to land enquiries in respect of a new connection or alteration of an existing connection within 5 working days. Further compensation must be paid for each additional day that failure continues subject to a cap.	£40. Cap is £250 (or £500 for >275 kWh customers).
GS9-10	GT must offer a date for commencement of the work and substantial completion within 20 working days of the customer accepting the quotation. Further compensation must be paid for each additional day that failure continues subject to a cap.	£20 (≤275 kWh) £40 (>275 kWh) Cap is lesser of £250 (or £500 for >275 kWh customers) or contract sum.
GS11	GT must substantially complete a connection on the date agreed with the customer. Further compensation must be paid for each additional day that failure continues	Initial payment between £20-£150 (depending on quotation amount).

[58] The standard does not apply to consumers that consume more than 73,200 kWh per year or where the interruption affects more than 30,000 consumers. Larger consumers are protected by the Uniform Network Code.

	subject to a cap.	Cap varies depending on quotation amount, up to £9000 for quotes between £50k-£100k.
GS12	GTs must make payment required under the guaranteed standards to the customer within 20 working days from when the payment became due. Payments to other GTs under Reg. 7 (Supply restoration) must be made within 10 working days of receiving notification of the interruption.	£20
GS13	GTs must notify consumers at least 5 working days in advance of a planned supply interruption.	£20 (domestic) £50 (non-domestic) if claimed by the customer within 3 months.
GS14	GTs must respond to a complaint within 10 or 20 working days depending on whether a site visit or making enquiries of third parties is required. Further compensation must be paid for each additional period of 5 working days until the substantive response is provided, subject to a cap.	£20 (domestic and non-domestic). Cap of £100.

263. Ofgem collects data from gas transporters on a quarterly basis. Performance is measured annually for GDNs and over a three year period for IGTs because of size relativities. The data is then forwarded to the consumer council ("energywatch") for publication, in accordance with the Gas Act 1986. These reports are available on energywatch's website (www.energywatch.org.uk).

264. A penalty of £25,000 (€36,548) was imposed on Northern Gas Networks for failing to meet service standards for provision of gas connections.

Further reading: please see appendix 3 – Further reading – 4.1.4 – Quality of service indicators (Standards of Performance)

Quality of service reports

265. To date, Ofgem has published five reports on the quality of service in gas distribution. These reports have put into the public domain information on how GDNs performed with respect to the quality of service output measures set out in the RIGs. However, so far, these have only included high level summary information on the number and duration of interruptions due to poor quality data reported under this output. Ofgem expects to be in a position to publish more robust data in future reports.

Further reading: please see appendix 3 – Further reading – 4.1.4 – Quality of service reports

Network tariffs

266. The standard LDZ system charges comprise capacity and commodity charges with separate functions for directly connected supply points and connected system exit points (CSEPS). Where LDZ charges are based on functions, these functions use Supply Point Offtake Quantity (SOQ) in the determination of the charges. At daily

metered (DM) firm supply points the SOQ is the registered supply point capacity. For non-daily metered (NDM) supply points, the SOQ is calculated using the supply point End User Category (EUC) and the appropriate load factor.

267. A separate charging function for transportation to Connected System Exit Points (CSEPs) was introduced from 1st October 2000. This function reflects the view that transportation to CSEP loads typically makes less use of the LDZ system than to other similar-sized loads. In the calculation of LDZ charges payable, the unit commodity and capacity charges are based on the supply point capacity equal to the CSEP peak day load for the completed development irrespective of the actual stage of development. The SOQ used is therefore the estimated SOQ for the completed development as provided in the appropriate Network Exit Agreement (NExA). For any particular CSEP, each shipper will pay identical LDZ unit charges regardless of the proportion of gas shipped. Reference needs to be made to the relevant NExA or CSEP ancillary agreement to determine the completed supply point capacity.

268. Transportation charges are derived in relation to a price control formula which is set by Ofgem, the gas and electricity market regulator for the transportation of gas. This formula dictates the maximum revenue that can be earned from the transportation of gas. Should more or less than the maximum permitted revenue be earned in any formula year, then a compensating adjustment is made in the following year.

269. Alterations to the charges can only occur once a year on 1 October. Ofgem is not required to approve the unit rate changes to charges with the price control acting as the restriction on over-recovery of revenue. Changes to the actual charging methodology must be approved by Ofgem.

Table 4.2: Annual Quantity 150000 MWh

DN	Distribution Charges[59] (€ per annum)	Transmission Charges[60] (€ per annum)
South of England	202013	106,151
Scotland	184256	31,650
North of England	187142	33,534
West Midlands	202862	62,997
North West	200948	66,300
East of England	191899	56,179
Wales & the West	160059	106,826
London	209077	105,729
Average	192282	69,987

Table 4.3: Annual Quantity 150 MWh

DN	Distribution charges	Transmission Charges
South of England	1156	153.86

[59] Current Charges effective from 1 October 2007.
[60] Charges effective from 1st October 2007 until 30 September 2008. These figures include exit charges only.

Scotland	1003	32.79
North of England	1030	35.85
West Midlands	1108	83.73
North West	1052	89.10
East of England	1009	72.65
Wales & the West	1041	154.95
London	1208	153.17
Average	1076	95.09

Table 4.4: Annual Quantity 19 MWh

DN	Distribution Charges	Transmission Charges
South of England	147	17.74
Scotland	127	4.11
North of England	131	4.46
West Midlands	140	9.85
North West	133	10.45
East of England	128	8.60
Wales & the West	132	17.87
London	153	17.67
Average	136	11.13

270. Since the sale of four DNs by Transco in June 2005, regional differences in network charges have begun to emerge. The DNs have introduced charges which reflect different allowed revenue under the price control. The charges used in the above table are the most recent available (2008)

271. The regional variation in distribution charges for small users (19 MWh) ranges from €127 per annum in Scotland to €153 in the London. For medium sized user (150MWh) charges range from €1,003 in Scotland to €1,208 in London. Larges user charges (150,000MWh) charges range from €160,059 in Wales and the West to €209,077 in London. Transmission charges incorporate regional differences determined by DN exit zones.

Balancing

272. Ofgem's submission to the European Commission (DGTREN) Report 2005 contained a detailed explanation of the balancing market arrangements. These have not changed significantly over the past three years so what follows is primarily a summary of the information contained in the previous submission.

273. In GB, the primary responsibility for balancing lies with gas shippers. The current gas balancing arrangements are designed to provide shippers with commercial incentives to balance their inputs to and offtakes from the GB high-pressure national gas transmission system (NTS) over the course of each daily balancing period, which corresponds to a gas day[61]. A shipper's imbalance volume is equal to the difference

[61] That is, in each 24 hour period beginning at 6am each day.

between its aggregated final inputs and offtakes and this is cashed-out at prices determined by trades on the on-the-day commodity market (OCM).

274. NGG, in its role as SO for the NTS, has a role as residual balancer and, as such, it can buy and sell gas to correct residual imbalances and thus ensure that the system remains in balance at all times. The primary tool that NGG uses to balance the system is the OCM. In this market it, can physically purchase gas (either at the notional National Balancing Point – NBP – or at a specific location) or take title to gas (the name on the contract becomes NGG's).[62] NGG can also use a range of other tools to help it balance the system. For example, it can trade forward to alleviate imbalances, although it has not yet exercised this ability to any extent. It can also buy-back transmission capacity entry rights that it has previously sold, thus reducing the volumes of gas that shippers can inject into the system. Ofgem has oversight over the types of balancing tools that NGG can use and their tendering processes.

275. A high-level summary of the main parameters of the balancing arrangements in GB is set out in table 4.5.

276. ***Table 4.5 – summary of gas market balancing arrangements in GB***

Balancing mechanism indicators	**Description**
Balancing interval	**Daily balancing -** market participants can continue trading throughout each daily balancing period and, indeed, can continue to trade out their imbalance volumes for up to 15 days after the end of the month in which the relevant gas day occurs[63]. However, participants have to notify their intended inputs and off takes to NGG ahead of time.
Description of relevant balancing area	**Great Britain**
Calculation of imbalance prices	A shipper's imbalance volume is equal to the difference between its aggregated final inputs and off takes over the balancing period.
Definition of system needs	In determining what balancing actions it needs to take, NGG, as SO of the NTS, is bound by its safety case, and the provisions of the Uniform Network Code (UNC).[64]
Typical prices charged to network users to resolve imbalances	Different imbalance prices apply depending on whether a shipper is short gas (its offtakes are greater than its inputs) or long gas (its offtakes are less than its inputs). A shipper that is short gas pays the system marginal buy price (SMPbuy) and a shipper that is long gas is paid the system marginal sell (SMPsell). For SMPbuy (sell) this is the higher (lower) of • the highest (lowest) price of any trade to which NGG is a party on the OCM, excluding any trades

[62] Note that National Grid Gas is only allowed to trade gas for balancing purposes, it is not allowed to trade speculatively.
[63] After the day trading is a concept that does not exist in the electricity arrangements.
[64] All gas transporters, including gas distribution network owners, are bound by the terms of the UNC.

	that it takes for locational reasons; or • the average price of gas traded on the OCM (SAP) plus a fixed value £/KWh uplift. If NGG does not purchase (sell) any gas, SMP buy (sell) defaults to this price. In addition to imbalance charges, the cash out arrangements in gas include a scheduling charge. The scheduling charge is designed to provide incentives for shippers to make accurate input and offtake nominations, irrespective of whether the nominations match. Over the past four years, SMPbuy have on average been close to spot (day ahead) prices with both of these typically around 9-15% higher than SMP sell prices.
Tolerance levels	**None –** reforms to gas trading introduced improved incentives on shippers to balance their own positions through a phased reduction of imbalance tolerances.[65]
Opportunities for pooling imbalances	**Yes across a shipper's portfolio** - a shipper's imbalance volume is equal to the difference between its aggregated final inputs and offtakes. Shipper's may also 'trade' out their imbalances up to 15 days after the imbalance period.
Interaction with other areas	The GB gas market is interconnected to the gas markets in Ireland (the Republic of Ireland and Northern Ireland), Belgium and the Netherlands. The Irish interconnectors have, so far, been exclusively used to export gas from GB. The Netherlands interconnector is unidirectional and has only been used to import gas to GB. Gas has flowed in both directions across the interconnector to Belgium.
Process and timetable for settlement of imbalances	See 2005 report.
Arrangements for small generators and new entrants.	None
Information that must be provided to market participants by the TSOs regarding the balancing mechanism.	See below

277. In terms of gas nominations, users nominate quantities of gas for delivery to and offtake from the transmission system each day in accordance with the UNC for the purposes of enabling NGG to plan and carry out the operation of the NTS and Operational Balancing.

278. The following timetable, as detailed in section C of the UNC provides the key points in the preceding gas day by which users are required to provide certain nomination information for the following gas flow day.

[65] A shipper whose imbalance volume was less than its imbalance tolerance was exposed to an average rather than a marginal cash out price.

279. ***Table 4.6 – nomination timetable (source: Joint Office of Gas Transporters (UNC))***

Daily Metered Output Nomination Time:	13:00
Non-Daily Metered Output Nomination Time:	14:00
Input Nomination Time:	14:30
Renomination Start Time	15:00

Developments in the balancing arrangements

Information on imbalance prices

280. Table 4.7 below shows average annual SMP Sell, SAP and SMP Buy values since 1 April 2001 and compares them to the average annual spot (day-ahead) prices.

281. ***Table 4.7 – Average annual energy imbalance prices***[66]

(c/therm)	Average SMP Sell	Average SAP	Average SMP Buy	Day-ahead prices
2001/02	25.97	27.67	29.27	28.64
2002/03	20.67	22.29	23.77	23.43
2003/04	27.82	29.54	31.13	30.37
2004/05	35.89	37.98	39.58	39.70
2005/06	60.60	64.38	67.06	69.85
2006/07	39.48	41.85	43.91	43.41
2007/08	52.04	53.82	55.39	54.22

Transparency and market information

282. A number of initiatives designed to increase transparency have been completed over the past three years and others are still on-going. These initiatives include:

- improvements to the NGG website, including the publishing of a Daily Summary Report, which draws together essential information about the gas supply/demand position;
- the introduction of "gas balancing alerts" which NGG will issue when its day-ahead forecast of gas demand is greater than or equal to anticipated available gas supplies;
- the publication by NGG of information (on almost real time basis) of deliveries into National Transmission System entry sub-terminals, in accordance with Uniform Network Code modification 006;
- approval by Ofgem of a further Uniform Network Code modification (104) requiring publication (with a 10 hour and 1 minute lag) of the aggregate physical LNG in store at LNG importation facilities at the close of the previous gas day;
- the setting up by Grain LNG, the owner of the first large scale LNG import terminal in the UK, of a website to provide information on exports on the terminal and the availability of spare slots at the terminal; and
- the publication of proposals to introduce incentives on NGG to improve its demand forecasts and to publish information on its website in a timely manner.

[66] All the values in this table have been converted from sterling to Euros using an exchange rate of 1.44 EUR/£.

Access to storage, linepack and other balancing services

283. Ofgem's submission to the European Commission (DGTREN) Report 2005 contained a detailed explanation of the access to storage, linepack and other ancillary services.

Storage services

284. The two largest storage facilities in GB (Rough and Hornsea) are required to offer TPA, whilst the other facilities are exempt from this requirement. Table 4.8 presents details on the size and scope of existing storage facilities in GB.

285. ***Table 4.8 Storage facilities in GB.***

Facility name	Owner	Space (mcm)	Deliverability (mcm/day)	Injectability (mcm/day)
Rough	Centrica Storage Ltd	3067	49	15
Hornsea	Scottish and Southern Energy Hornsea Limited (SSEHL)	316	18	2
Total TPA under Article 19		3383	67	17
TPA % share of total storage		83%	52%	46%
Other non TPA storage				
Hatfield Moor	Scottish Power	116	2	2
Humbly Grove	Star Energy	290	7	8
Hole House	Energy Merchants Gas Storage (UK)	42	6	9
Avonmouth LNG	National Grid	81	14	(>1)
Glenmavis LNG	National Grid	47	9	(>1)
Partington LNG	National Grid	104	20	(>1)
Dynevor Arms LNG	National Grid	28	5	(>1)
Total storage (non-LNG)		3831	82	36
Total storage (LNG)		259	48	1
Total Storage (All)		4090	130	37

286. All of the storage sites offering TPA provide storage services on the basis of a standard bundled unit (SBU) of space, deliverability, and injection. Firm and interruptible products are offered. In addition, unbundled rights may be traded on the secondary market.

287. The price of a SBU in the Rough storage facility is usually indexed to published summer\winter differential in the price of gas. National Grid LNG holds annual auctions for the sale of storage capacity on a pay-as-bid basis and publishes the weighted average price paid to the wider market. SSEHL does not publish prices; it negotiates with each customer on a case by case basis.

288. Ofgem understands that all the non-exempt storage facility owners sell capacity in a non discriminatory fashion and Ofgem has not received any complaints to indicate otherwise. In the case of Rough, a number of new entrants to both the gas and electricity markets have secured capacity.

4.1.4 Effective Unbundling

Unbundling requirements on the network companies

289. The NTS, DN and IGT licences require that licence holders:

- do not undertake transactions that create a cross-subsidy with another entity;
- only enter into agreements on an arm's length basis and on normal commercial terms; and
- carry out activities only for the purposes of gas transportation, metering and meter reading subject to the de minimis activities provisions which allow a small amount of non gas transportation, metering and meter reading activities to be undertaken.

Legal ownership for DSOs and TSOs

290. The fully integrated monopoly British Gas was privatised in 1986. In 1993, following a Monopolies and Mergers Commission report the company was re-structured. In 1997, the company demerged into two separate companies, BG plc and Centrica. Transco was part of BG plc and in 1999 Transco became a public limited company - BG Transco plc. In 2000, Transco demerged from BG plc becoming part of the Lattice Group plc as Transco plc. In 2002, Lattice Group plc merged with National Grid to form National Grid Transco plc - the UK's largest utility. In October 2005 Transco plc changed its name to NGG.

291. NGG owns the NTS and has retained four DNs in Great Britain. NGG has a separate licence for the NTS business and the four retained DN businesses but there is no legal separation between the licensees. Special Conditions and Standard Special Conditions in the licences have been designed to replicate the effects of legal separation[67]. The other four DNs that were sold are owned by Scotia Gas Networks Ltd (who own two), Wales & West Utilities Ltd and Northern Gas Networks Ltd. In addition, there are also sixteen licensed Independent Gas Transporters (IGTs).

292. NGG's NTS licence (but not the other gas transportation licences) contains conditions which have the effect of precluding NGT and any other related or affiliated

[67] For the NTS business Special Conditions C19, C20 and C21 require business separation statements, appointments of compliance officer and separate managerial boards. The RDN Special conditions E9 and E10 in the licence seeks to ensure NGG NTS and NGG RDN act as separate entities and enter into quasi-contractual relationships.

company from having commercial interests in the sale of gas in GB, thereby guaranteeing the independence of the TSO from commercial interests in the wholesale market.

Ownership structure of TSOs and DSOs

293. Until 1 June 2005, NGG owned the vast majority of the gas network across Great Britain, constituting the NTS and eight DNs transporting gas to over twenty million customers across GB. In May 2003 NGG announced it would consider the sale of one or more of its DNs if the transaction maximised shareholder value. On 1 June 2005 the transaction was completed having gained the consent of the Gas and Electricity Markets Authority.[68] The decision followed an extensive consultation process undertaken by Ofgem from July 2003[69].

294. There are currently over nine hundred thousand customers connected to IGTs. This figure is projected to surpass one million during 2008.[70]

Independence of production and supply affiliates

295. The licence of the national transmission SO prevents the licensee and all affiliated companies from having an interest in gas supply or trading (except for system balancing purposes).

296. The transportation licences of the NTS and the eight DN companies require full managerial and operational systems independence preventing any relevant supplier or shipper, any trading business, its meter-related service business, and its meter reading business from having access to confidential information except in certain specified circumstances. The network company must always be managed and operated to ensure it does not restrict, prevent or distort competition in the supply of electricity or gas or the shipping of gas or the generation of electricity.

297. With the exception of Scottish and Southern Energy, (which is owned by Scotia Gas Plc) and Corona Energy (which is owned by Macquarie Group, who part own Wales and West Utilities Ltd) the owners of the NTS and DNs do not have production or supply affiliates.

298. The NTS and the DNs are required by their gas transportation licence to use best endeavours to comply with a statement that they produce setting out how it intends to comply with, amongst other things, the requirement not to restrict, prevent or distort competition.[71] This compliance statement must also set out how the licensee shall maintain the branding of the transportation business so that it is fully independent from the branding used by any relevant supplier or shipper, trading

---

[68] National Grid Transco- Sale of gas distribution networks: Transco plc applications to dispose of four gas distribution networks, Authority Decision, Ofgem, February 2005.

[69] National Grid Transco- Potential sale of gas distribution network businesses, Final Impact Assessment, Ofgem, November 2004, 255/04a. For other documents on the distribution network sale consultation process go to Ofgem's website www.ofgem.gov.uk and select under Area of Work: gas distribution network sale.

[70] Xoserve data 2008.

[71] Standard Special Condition A33: Restriction on Use of Information and Independence of the Transportation Business.

business, its meter-related services business and its meter reading business (Ofgem may consent to a relaxation of this requirement).

299. Ofgem has not been required to address in detail the issue of branding separation between a gas transporter and a relevant gas supplier. However, during 2003 and early 2004 several energy groups owning both electricity distribution and supply businesses proposed changes to their supply and/or distribution brands. In many cases these proposals reduced the difference between the branding of their respective supply and electricity distribution businesses. Some of these proposed changes have now been implemented. These changes gave rise to concerns that competition in energy supply may be adversely affected by the re-branding that was occurring. In response to these concerns, Ofgem reviewed whether the approaches to branding by a number of distribution licensees with supply businesses complied with the relevant electricity distribution licence condition concerning brand separation. As part of this review, it was necessary to consider what, if any, the effect of any similarity of any such branding may have had on competition. Further information on this issue may be found in section 3.1.4.

300. The NTS, DN and IGT licensees have an activity and financial ring-fence condition in their licence. This condition has the effect, subject to a de minimis provision, of restricting the business activities that the company can carry out to those for which it is permitted.

301. The NTS and DN licensee's are also required to maintain such accounting systems as are necessary to facilitate the publication of Regulatory Accounts. The accounts include the production:

- Profit and Loss Statement / Income statement;
- Balance Sheet;
- Cashflow Statement;
- Statement of total recognised gains and losses / statement of changes in equity;
- Corporate Governance Statement;
- Directors Report; and
- Operating and Financial Review.

302. Furthermore under the terms of the licence the regulatory accounting statements are also required to be accompanied by an auditor's report. The preparation of this information assists in the monitoring of the entities obligations

303. Ofgem has also introduced another licence condition in relation to price control review information. This requires the companies to prepare detailed information on their activities in accordance with published guidelines[72] and enables Ofgem to monitor effectively the licensees' spend of allowances determined in price controls.

304. The prohibition of cross subsidies licence condition[73] in the gas transporters licences requires that there cannot be cross subsidies between the licensee and any other affiliate or related business of the licensee. In addition, it also requires that there cannot be cross subsidies between the four DNs retained by NGG.

Role of the compliance officer

---

[72] Standard Special Condition A30: Regulatory Accounts. Part C.

[73] Standard Special Condition A35: Prohibition of Cross Subsidies.

305. The NTS and the DNs are required by their licences to have a compliance officer[74] whose duties include facilitating compliance by the licensee with the licence conditions relating to the restriction on the use of certain information and the independence of the transportation business[75].

306. The NTS and the DN licensees must maintain managerial and operational systems preventing any relevant shippers, relevant suppliers, any trading business, its metering services and its meter reading businesses having access to confidential information except in certain specified circumstances (which are set out in the licence). The transportation business must always be managed and operated to ensure it does not restrict, prevent or distort competition in the supply of electricity or gas, the shipping of gas, generation of electricity, any trading business or the supply of meter-related services or meter reading.

Shared costs and outsourcing

307. In setting price controls for the NTS and the DN companies an important issue for Ofgem to consider is the costs that the network company shares with other companies in its group e.g. head office costs and the activities it outsources to other entities. However, Ofgem leaves it to the NTS or DN company concerned to determine how it organises its business in relation to the outsourcing of work and sharing of common costs, subject to them remaining compliant with their licence which requires them:

- not to undertake transactions that create a cross subsidy with another entity;
- to only enter into agreements on an arm's length basis and on normal commercial terms (except with our prior agreement); and
- to carry out activities only for the purposes of gas transportation, metering and meter reading subject to a *de minimis* limit.

308. Ofgem also requires the NTS and DN companies to have an audit on their allocation methodology.

Failure to comply with management or accounts unbundling requirements

309. If a gas transporter breaches its licence, Ofgem can take enforcement action. Enforcement action for a breach of a licence could include, after going through due process, the imposition of a financial penalty on the licensee. The financial penalty cannot exceed 10% of the gas transporter's annual turnover.

Further reading: please see appendix 3 – Further reading 4.1.4 – Gas – Effective Unbundling

---

[74] Standard Special Condition A34. Appointment of the Compliance Officer.

[75] Standard Special Condition: A33. Restriction on Use of Information and Independence of the Transportation business.

4.2 Competition Issues [Article 25(1)(h)]

Overview

This section provides an overview of the GB wholesale and retail gas markets. It covers the following issues and relevant data:

Wholesale market:
- General description of the market
- Member State integration
- Interactions via global LNG markets
- Conduct in the wholesale market
- Availability of gas to the market
- Market information and transparency

Retail market:
- General description of the retail market
- Market shares and new entry
- Customer switching
- Competition issues
- Retail prices

Measures to avoid abuses of dominance:
- Ofgem's role and powers in wholesale and retail markets

4.2.1 Description of the wholesale market[76]

310. In summary, the GB wholesale market is based on bilateral trading between gas producers, shippers, suppliers, traders and customers across a series of markets. Broadly speaking, the wholesale market can be broken down into over the counter trading and power exchange trading. Unlike the electricity market there is no gate closure period, hence any adjustment to positions and actions taken by National Grid may occur throughout the day via the OCM.

Over the counter trading (OTC)

311. Over the counter trading (i.e. bilateral deals between two market participants, including via an intermediary (the broker) brings together a buyer and seller) typically operates from a year or more ahead of real time up until 24 hours ahead of real-time.[77]

[76] Defined as covering any transaction of gas between market participants other than final end use customers.

[77] Examples of typical contracts include annual contracts (contracts for the delivery of a given volume of gas at a specified price throughout a year), seasonal contracts (summer/winter), quarterly contracts and monthly contracts. However, this market is also used for non-standard contracts designed to match a consumer's anticipated demand profile.

Exchanges, including the OCM

312. Although trading on exchanges can extend out as far as the contract market, trading on them tends to be concentrated towards real-time. Shippers trade short term on the exchanges to keep in balance as their demand and supply forecasts become more accurate in the run-up to real time. Trading on exchanges is via a set of standardised contracts.

Wholesale gas market

Consumption and demand

313. NGG's Ten Year Statement[78] provides information in relation to forecast and actual annual gas demand. For 2007, annual gas domestic demand was 99.8bcm – this excludes exports through the interconnector with Belgium. The forecast for 2008 is 99.7bcm.

Gas supply

314. Information in relation to actual and forecast annual gas supplies is also provided in National Grid's Ten Year Statement 2007.

Table 4.9: Potential UK Peak Supply Capacity (mcm/d)[79]

	2006/07	2007/08	2008/09
UKCS (90%)	212	227	210
Import Projects (90%)	164	287	335
Existing & Potential Storage	63	141	149
Other Imports	0	0	0
1:20 Peak Day Demand	439	541	549

315. In terms of annual supplies, for 2008/09, National Grid anticipated supply capacity of 60bcm could be provided by UK Continental Shelf (UKCS) production and 49bcm could be provided by imports[80].

316. Apart from imports from Norway (projected at 31bcm for 2008/09), which reach GB via dedicated lines, it is difficult to determine the ultimate source of the GB's continental imports (via the Interconnector UK and Balgzand-Bacton Line), because gas arrives at Zeebrugge and Balgzand from many different locations. Since 2005/06 onwards, GB has also imported LNG via the Isle of Grain which received its first supplies in July 2005 (IoG capacity is expected to increase to 9bcm per year in 2008/9). In addition, there are two further LNG terminals due to come online during 2008/9 which could add up to 27bcm per year.

---

78 References to National Grid's Ten Year Statement refer to the version published in December 2007, which is available at http://www.nationalgrid.com/uk/Gas/TYS/tys07chart.htm

79 See Figure 4.6C in http://www.nationalgrid.com/uk/Gas/TYS/current/tys_charts2006.htm

80 Anticipated actual supply is provided in Figure 4.6D of National Grid's Ten Year Statement.

Market shares of companies

317. The GB market receives its gas supplies from a variety of different sources encompassing indigenous supplies for the UKCS, imports from Norway (via the Vesterled and Langeled pipelines), imports from the Continent (via the Interconnector UK and BBL pipelines) and other imports which arrive through the Isle of Grain LNG importation terminal.

318. In terms of gas from the UKCS, there are five companies whose market share of production exceeds 5 per cent. Market share relating to import pipelines is more difficult to assess, as shippers trade their capacity on secondary markets making individual imports by companies harder to trace. For example, there are 16 shippers who hold primary capacity on the Interconnector IUK, and 7 main shippers on the Langeled pipeline. In contrast, since December 2006 when BBL became operational, it has typically been used by two to three shippers. Finally, there are two shippers (BP and Sonatrach) who import gas through the Isle of Grain although this will increase to four shippers following the increase to IoG capacity in 2008.

319. In terms of market share for gas storage, around 50% of capacity in Rough, the largest gas storage facility in GB, is held by five parties (Rough has a capacity of around 3.2bcm (42mcm/d)). However, market share figures are liable to change as capacity can be traded on a secondary market.

320. Taking these factors into account, it is extremely difficult to make precise quantitative evaluations in terms of market shares in the GB wholesale gas market.

Exchange trading

321. Trade of the natural gas futures contract on the Intercontinental Exchange (ICE) reached around 1.15 million lots in 2007. In physical terms, total traded volume amounts to around 150 million therms per day.

322. 84 customers were identified as transacting directly on the platform during the year, a net increase of 24% from the previous year. In April 2007 the period over which parties could trade forward was extended to over four and a half years.

On-the-day commodity market trade

Total traded volume on the OCM for the in the calendar year 2007 totalled 129.0TWh, down from 152.9TWh in 2006.

Over-the-counter trade

323. On the basis of data provided by the FSA total traded volume in 2006/7 (Aug 06 to Jul 07) was around 437,042 million therms (around 1,182bcm). This makes the GB gas market one of the most liquid gas markets in Europe.

324. Around 10,000TWh of trades were registered on NG systems for balancing purposes in 2007 (trade data is based on month of gas flow rather than month of trade). This is significantly up from 6,800TWh in 2006. This represents a churn of

trades to total throughput of around 10 (the number of times each unit of gas is traded prior to delivery).

Long-term contract trade

325. Ofgem has no non-confidential information on the extent of long-term contracts.

Member State integration

326. The GB market is becoming increasingly reliant on imports from other countries, given that its demand for gas is now outstripping its domestic supplies.

Table 4.10: Forecast import requirements

bcm	2005/06	2006/07	2007/08	2008/09	2009/10
UKCS Forecast	82	71	66	60	55
Demand Forecast (ex IUK)	93	98	97	98	100
%age Import Requirement	12.46%	27.68%	32.46%	38.84%	44.58%

327. At present, there are two gas interconnectors linking the UK to the continent, the IUK and BBL. IUK allows up to 20bcm/year of exports from and around 23.5bcm/year imports into the UK. The BBL connects the UK with the Netherlands, is unidirectional[81] and allows up to 15bcm/year to be imported to the UK. In addition, gas can be supplied from the Norwegian continental shelf (NCS) into the St Fergus gas processing sub terminal via the Vesterled pipeline. The Langeled pipeline connects GB with the Ormen Lange field in the NCS and has a capacity of around 25bcm/year.

328. In terms of the IUK, each shipper has a share of the Forward Flow and Reverse Flow Standard Capacity. Originally, 9 Shippers acquired Capacity Rights in the UK/Zeebrugge interconnector for a period of 20 years from 1 October 1998 through to 30 September 2018. These Capacity Rights can be permanently transferred (in whole or in part) to another party through an Assignment, or temporarily transferred to another party for a specified period of time via either a Sub-Let or a Capacity Transfer[82]. Currently 16 Shippers hold primary capacity rights to the interconnector.

329. Although, in aggregate, the interconnector is either in Forward Flow or Reverse Flow, an individual Shipper can utilise their Capacity Rights in the opposite direction such that they are “flowing” as a counter-flow. Subject to the physical Flow Direction of the Interconnector and operational conditions, the IUK may make additional Interruptible Capacity available to Shippers. Interruptible Capacity is shared between Shippers in proportion to their Standard Capacity.

330. The BBL commenced operation in December 2006 and has three foundation shippers with contracted capacity for periods of up to 15 years. Use it or lose it provisions are applied to capacity allocations and temporary capacity is advertised and traded if and when available through mechanisms established by BBL. BBL is installing

[81] BBL Company intends to introduce non-physical reverse flow services on a first come first served basis by 1 September 2008.

[82] See http://www.interconnector.com for more details.

a 4th compressor to upgrade capacity by 3bcm, BBL also intends to introduce a non-physical reverse flow service late in 2008.

331. Given the existing interconnections, prices in the GB gas market are closely correlated with those on continental Europe, which, in turn, are typically linked to oil-product prices. The commencement of BBL and Langeled has strengthened this relationship, as previously when the Interconnector IUK was full or not operational, GB prices may de-couple from those elsewhere in Europe. The close correlation between prices at Zeebrugge (ZEE), TTF in the Netherlands and the National Balancing Point (NBP).

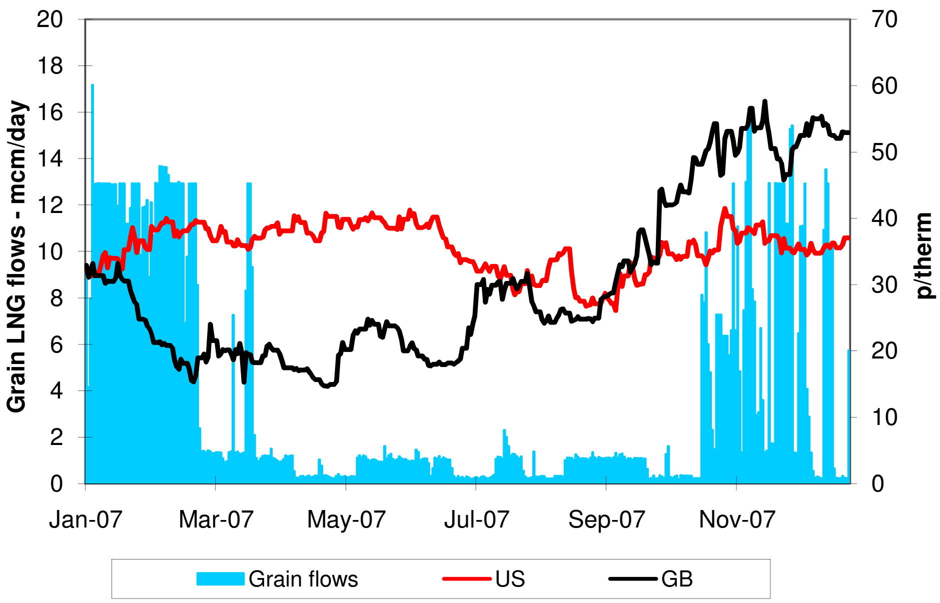
Interactions via Global LNG markets

332. Since the completion of the LNG import facility at the Isle of Grain at the start of winter 2005/06, the scope of the GB gas market has been extended to include a more direct interaction with global market. As an illustration, figure 4.15 compares the GB and US month ahead prices with flows at the Isle of Grain over the 2007 calendar year.

333. It can be seen that for the first nine months of 2007 GB month ahead gas prices were below those seen in the US. Although there are a number of factors that can determine the destination of LNG cargoes, these price signals would indicate the GB market to be a less attractive destination for LNG than the US. This is confirmed by the fact that, during most of the period flows from Grain were relatively low. In contrast flows from the terminal during 2006, when the GB price generally exceeded that in the US, were much higher.

334. Additionally, there is increasing evidence that the relevant market for LNG is becoming a global one, with many Atlantic Basin Cargoes diverted to Asia during winter 2007/08. This can be attributed to a combination of higher Asian demand, global supply shortages, and lower shipping costs.

Figure 4.11: LNG flows and comparison of GB and US prices



Conduct in the wholesale gas market

Competition law

335. Ofgem's competition law powers are set out in section 3.2.3.

Shippers' licence

336. The gas shippers licence prohibits shippers from knowingly or recklessly pursuing any course of conduct that is likely to prejudice the safe and efficient operation by a relevant transporter of its pipe-line system, the safe, economic, and efficient balancing by that transporter of its system, or the due functioning of the arrangements provided for in the UNC.

Availability of gas to the market

337. Whilst all market participants who wish physically to transport gas on the NTS require a shipper's licence to do so, they are able to participate on the traded markets, simply by signing up to the UNC and agreeing to abide by its balancing provisions. It is through access to the traded markets that non-incumbents, including new entrants, can purchase gas. There are no other mechanisms (such as gas release programmes) to ensure the availability of gas to non-incumbents – given the volumes of gas that are traded on a daily basis.

Market information and transparency

338. Experience over the past few years, including the large price spikes observed, have highlighted the need for increased transparency in the GB market. They clearly

indicated that limitations on the information available to market participants can lead to significant unnecessary costs. In the extreme, a lack of appropriate information could have an impact on the security of gas supplies.

339. Many of the key market information and transparency issues have already been discussed in the section on regulation, since it is largely through regulatory requirements that most market data is published. For example, shippers' licences prohibit them from providing a false impression of the amount of gas they will deliver. They also have to provide operational data i.e. on their intended inputs to and offtakes from the NTS, under the terms of the UNC. Shippers are also subject to specific requirements to inform the relevant transporter with regard to metering, premises served and gas illegally taken. These regulatory requirements are backed up by financial incentives to accurately nominate their intended inputs to and offtakes from the NTS. The information provided by shippers over operational timeframes in support of NGG's role as residual gas balancer was identified above.

340. NGG, on its website, publishes a broad range of data that is intended to provide market participants with an appreciation of the state of the system and any constraints or problems that are or may be likely to affect it. Following changes to the UNC in October 2006, this set of information to be published now includes data on gas intakes throughout the day from each of the NTS entry points. For customers without daily meters, NGG is responsible for producing demand forecasts and nominations, against which their imbalances are measured.

4.2.2 Description of the retail market

Gas retail markets

341. Under the gas supply licence, customers are classified as "domestic" where they use energy for domestic purposes at domestic premises; they are classified as "non-domestic" where they use energy for business and industrial purposes.

342. There are currently six large supplier groups in the domestic retail gas market; which are the same as the six largest domestic suppliers in the electricity market. All but one are new entrants to the gas retail market. Centrica owns the former monopoly, and incumbent gas supplier, British Gas.

343. There are approximately 21.9 million domestic gas customers in GB, of which the six supply groups account for nearly 100% of the market.

344. Table 4.12 shows the most recent national market share data of the supplier groups in gas.

Table 4.12: GB domestic gas retail market shares - March 2008

Group	**Gas**
Centrica	45.5%
SSE	14%
EON	13%
Npower	11.5%

Scottish Power	9%
EDF Energy	7%

Source: Domestic gas suppliers

345. The information Ofgem collects on market shares in the non-domestic markets is acquired from a third party, who collects the data from suppliers. This data is presented in Table 4.13.

Table 4.13: GB non domestic gas retail market shares by volume supplied - February 2007[83]

	Non daily metered	Daily metered[84] (large firm / Interruptible)
Powergen	22%	5%
Centrica	20%	6%
Shell Gas Direct	5%	14%
TotalFina Elf	18%	17%
Npower	6%	3%
GdF	-	19%
BP Gas	-	6%
Statoil UK	-	17%
Corona	13%	-
ENI	-	8%
SSE	6%	-

Source: Datamonitor

Market shares and new entry

346. In the domestic gas retail markets, there are six large supplier groups all with a share of above 5%. The market share of the top three domestic suppliers, namely Centrica, SSE and EON (formerly Powergen), is 72.5%.

347. Since the introduction of competition there have been about twenty new entrants including all the former monopoly electricity suppliers. The former monopoly electricity suppliers have been the most successful entrants.

348. At present there are two independent companies (i.e. excluding the former monopoly electricity suppliers) in the domestic gas market. Penetration by these independent entrants has been on a relatively smaller scale compared to the large supplier groups. They have never accounted for more than 1% of the national domestic gas market.

349. Since the acquisition of the portfolio of Telecom Plus by npower in February 2006, there has been no further consolidation in the domestic gas market.

---

[83] The market shares shown in this table only cover gas suppliers with a market share of greater than 3%.

[84] Daily Metered – A supply point with an annual consumption greater than 58,600,000 kWh.

350. On 1 June 2005, NGG sold four of their eight Gas Distribution Networks. Scotia Gas Networks, who are owned by a consortium that includes SSE, purchased two of these networks

Vertical integration

351. Five of the six large gas suppliers in the domestic retail market have gas production interests; either contractually or by equity. In the non domestic market, all the large suppliers are gas producers.

Customer switching

352. Ofgem collects data on the number of customers switching between suppliers in the domestic gas retail market, but we do not have switching data for the non-domestic markets.

353. In response to competition on price and the introduction of new products, there has been a steady increase in the level of switching between gas suppliers. Table 4.14 shows the number of annual transfers of domestic gas customers.

Table 4.14: Total annual transfers in gas

Total Transfers	Jan – Dec 04	Jan – Dec 05	Jan – Dec 06	Jan – Dec 07
Gas	3,588,634	3,510,976	3,915,480	3,982,207

Source: Ofgem

354. Customer switching figures include those switching away from the incumbent to new entrants, switching between new entrants and switching back to the incumbent. On average, around 331,200 domestic gas customers changed supplier each month between April 2007 and March 2008. Table 4.15 illustrates the number of domestic gas customers that switched each month between April 2007 and April 2008.

Table 4.15: Number of domestic gas customers that switched supplier between April 2007 and April 2008

Apr-07	301,465
May-07	333,867
Jun-07	378,374
Jul-07	352,128
Aug-07	335,546
Sep-07	289,298
Oct-07	382,801
Nov-07	343,441
Dec-07	321,811
Jan-08	343,837
Feb-08	278,173
Mar-08	313,306

Apr-08	388,391

Source: Gas suppliers

Summary of switching procedures

355. The rules and processes used with regard to customer switching in the gas market are found predominantly in a supplier's SLCs, the Unified Network Code, and its subsidiary documents.

356. Once the terms and conditions for supply are agreed, the customer has a period of time to consider the contract and decide whether to cancel it – the "Cooling Off Period". A cooling off period of seven days is a legal obligation with regard to domestic customers. However, many domestic suppliers have extended this period to 14 days and some I&C suppliers have also adopted the cooling off period. If the customer does not cancel the contract, the new supplier (via its shipper) notifies the relevant transporter of the intended transfer. The transporter performs a simple validation check and if successful contacts the old supplier to notify them of the specific meter point (MPRN – meter point registration number) to be transferred and the intended supply start date. The old supplier then has seven business days to object to the transfer. If no objection is raised then the transfer and intended supply start date are agreed. The last task the new supplier must complete is to procure and submit a change of supplier meter reading that falls within +/- 5 working days of the Supply Start Date (SSD) by SSD +10 days.

Competition issues

357. Ofgem has concurrent powers with the OFT to apply and enforce the Competition Act 1998 (CA 98) and the Enterprise Act 2002. Ofgem along with the OFT has issued advice and information explaining how the CA 98 will be applied and enforced in the energy sector[85].

358. Ofgem is currently undertaking an in-depth investigation under the Enterprise Act 2002 in the gas retail market for households and small businesses.

Retail prices

359. Ofgem monitors domestic suppliers' prices across GB. As with electricity, all final prices in GB wide retail energy markets are determined by market forces as price controls on final prices were all lifted by April 2002. However, there are elements of the final price which are attributable to the regulated aspects of the market, in particular transportation and metering charges, and as such they continue to be price controlled.

360. As with electricity, there are three main methods of payment offered by domestic gas suppliers, known as standard credit, direct debit and prepayment[86]. The incumbent's bill for an average domestic customer paying by standard credit is around €822. Competitors' bills can be up to €47 cheaper. Of the three payment methods,

---

[85] The "OFT Competition Law Guidelines: Application in the energy sector" is available at: http://www.oft.gov.uk/shared_oft/business_leaflets/ca98_guidelines/oft428.pdf

[86] Each of these payment methods is explained in the electricity retail section of this report.

direct debit tends to be the cheapest and customers can make further savings by switching to this method of payment.

4.2.3 Measures to avoid abuses of dominance

Market surveillance

361. Ofgem's market surveillance team monitors the gas and electricity markets, including the wholesale gas market and the Balancing Mechanism. They routinely assess whether there is any evidence of anti-competitive behaviour or breaches of statutory or licence provisions. On the basis of active surveillance and monitoring of the markets, Ofgem can investigate the behaviour of market participants if anti-competitive conduct is suspected and, where necessary, enforce domestic and European competition law.

362. Additionally, the Financial Services Authority (FSA)[87] has responsibilities for the operation of financial markets in the UK. The FSA works to prevent abuse or distortion of financial markets. The FSA has the power to fine persons who have abused the market, where "market abuse" is defined under the Financial Services Market Act 2000.

General competition law framework

363. Ofgem has concurrent powers with the Office of Free Trading (OFT) to apply and enforce certain provisions of the Competition Act 1998 (CA 98). Specifically, Ofgem can enforce provisions prohibiting:

a. anticompetitive agreements under Article 81 of the EC Treaty and Chapter I of the CA 1998; and

b. the abuse of dominance under Article 82 of the EC Treaty and Chapter II of the CA 98,

in the gas sector.

364. Ofgem has the power to:

- investigate suspected infringements;
- impose interim measures;
- give directions to bring an infringement to an end;
- accept binding commitments to address competition concerns, where appropriate; and
- impose financial penalties on undertakings of up to 10 per cent of an undertaking's turnover in the relevant market affected by the infringement in the business year preceding the date of the decision.

The Authority also has concurrent jurisdiction with the OFT under the Enterprise Act 2002 to make market investigation references in the gas sector.

[87] http://www.fsa.gov.uk/

Retail Market

Competition policy actions

365. On 21 February 2008, the Authority issued an infringement decision under the Competition Act 1998. The Authority found that National Grid had abused a position of dominance in the market for domestic-sized gas meters. The Authority directed that National Grid must bring the breach to an end and has imposed a penalty of £41.6 million (€60.8million). National Grid has entered into long-term exclusive contracts for the provision of domestic gas meters with energy suppliers. The contracts are considered to lock suppliers into National Grid for a significant share of their gas meter requirements and thereby restrict the development of competition. National Grid has launched an appeal against the Authority’s decision.

5. Security of Supply

Overview

This section provides further data and information on:

Electricity security of supply:
- Peak electricity demand conditions
- Generation capacity, investment and mix
- Infrastructure projects

Much of the information in this section is drawn from NGET's Seven Year Statement (see reference below)

Gas security of supply:
- Ongoing supply-demand capacity
- Production and import investment
- Security of supply standards
- Gas emergency measures

Much of the information in this section is drawn from NGG's Ten Year Statement (see reference below)

5.1 Electricity [Article 4]

Ongoing supply-demand situation

Peak electricity demand conditions

366. NGET's Seven Year Statement[88] provides information in relation to outturn and forecast peak electricity demand levels. In its latest statement, NGET outlines that actual GB peak demand in the winter of 2007/08 (at 60.6GW) was over 2,000MW higher than in the previous winter and equalled the previous highest GB peak which had occurred 5 years earlier. Correcting historical actual demands to Average Cold Spell (ACS) conditions eliminates the weather effects and gives a better indication of the underlying pattern of annual peak demand. Correcting winter weekday peak demands in 2007/08 to ACS conditions yields a provisional 'unrestricted' peak of 61.4GW; a decline of 400MW on the previous winter's ACS peak

367. On the basis of the information provided in NGET's Seven Year Statement, current levels of peak electricity demand and expectations up until 2014/15 are shown in Table 5.1.

Table 5.1 – ACS peak demand forecasts (source: NGET Seven Year Statement, table 2.1)

[88] References to NGET's Seven Year Statement refer to the version published in May 2008, which is available at http://www.nationalgrid.com/uk/Electricity/SYS/

Forecast (GW)	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
ACS Peak Demand incl. Station Demand	61.4	62.7	63.6	64.3	65.6	66.2	66.8	67.3
ACS Peak Demand excl Station Demand	60.8	62.1	63	63.7	65	65.6	66.2	66.7

Generation capacity

368. NGET's Seven Year Statement provides information in relation to the Transmission Entry Capacity (TEC)[89] at each power station for each year between 2008/09 and 2014/15. On the basis of the information provided in NGET's Seven Year Statement, TEC expectations up until 2014/15 are shown in Table 5.2.

Table 5.2 – Power Station Transmission Entry Capacities (source: NGET Seven Year Statement, table 3.5)

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
TEC (GW)	79.9	87.8	92.6	97.8	100.0	104.1	110.1

Generation investment

369. Section 36 of the Electricity Act 1989 specifies that a generating station of over 50MW capacity shall not be constructed, extended or operated except in accordance with a consent granted by the Secretary of State within England and Wales and the Scottish Executive in Scotland. The relevant office takes into account views on particular applications, including views of the local planning authority and, in certain circumstances, may call a public inquiry into a proposal. When granted, consent lasts for five years within which time a project must show signs of construction.

370. The Seven Year Statement prepared by NGET provides details of those generation projects for which Section 36 consent has been granted as well as details of those generation projects for which Section 36 consent is being considered. Currently 8.79 GW of new generating capacity has been proposed and is awaiting Section 36 consent. A further 10.8 GW of generation projects have received Section 36 consent. Wind farms (both on- and off-shore) account for 7.3 GW of the proposed capacity, whilst the capacity of proposed CCGT's is 10.64 GW.

371. The NGET Seven Year Statement also provides information in relation to forthcoming generation projects which are actually in the process of construction. As can be seen from Table 5.3 below, a total of 22.3 GW of new generation capacity is scheduled to be completed over the next three years.

---

89 The Transmission Entry Capacity of a power station is the maximum amount of active power deliverable by the Power Station at the Grid Entry Point (or in the case of an Embedded Power Station at the User System Entry Point), as declared by the Generator, expressed in whole MW. The maximum active power deliverable is the maximum amount deliverable simultaneously by the Generating Units and/or CCGT Modules less the MW consumed by the Generating Units and/or CCGT Modules in producing that active power and less any auxiliary demand supplied through the station transformers.

Table 5.3 – Changes in Power Station Capacity (TEC (MW)) (source: NGET Seven Year Statement, table 3.7)

2009		**2010**		**2011**	
Station	**Capacity MW**	**Station**	**Capacity MW**	**Station**	**Capacity MW**
Netherlands Interconnector Stage 1	0	**Barmoor**	30	**Causeymire Phase 2**	6.9
Millenium Wind Ceannacroc Stage 3	15	**Drone Hill**	37.8	**Newfield**	60
Kilbraur Wind Farm Stage 2	19.5	**Auchencorth**	45	**Ewe Hill**	66
Kingsburn Wind farm Fintry Stirling	20	**Andershaw**	45	**Dersalloch**	69
Akron Wind (Caithness)	20	**Rothes Biopower Plant**	52	**Waterhead Moor**	120
Ballindalloch Muir Wind Farm Balfron	20.8	**Carraig Gheal (Fernoch)**	60	**Harrows Law**	140
Whitelee Stage 3	28.6	**Limmer Hill**	80	**Gwynt Y Mor Stage 1**	294
Dun Law extension	29.8	**HearthStanes B Windfarm**	81	**Rhigos**	299
Tormywheel	32.4	**Earlshaugh**	108	**Kyle**	300
Toddleburn	36	**London Array Stage 1**	200	**Humber Gateway**	300
Longpark	38	**Harestanes**	213	**Port Talbot**	350
Fairburn Wind Farm	42	**Griffin Windfarm**	216	**Grain Stage 2**	430
Edinbane Wind Skye	42	**Sheringham Shoal**	315	**East-West Interconnector Project**	500
Lairg - Achany Wind Farm	62	**Severn Power Stage 2**	425	**Docking Shoal Wind Farm Ltd**	500
Gordonbush Wind	87.5	**West Burton B Stage 2**	435	**Hatfield**	800
Fallago	144	**West Burton B Stage 3**	435	**Brine Field**	1020
Arecleoch	150	**Netherlands Interconnector Stage 3**	520	**Netherlands Interconnector Stage 3**	520
Crystal Rig 2	200	**Netherlands Interconnector Stage 2**	800	**Netherlands Interconnector Stage 2**	800
Lincs Offshore Wind Farm	250	**London Array Stage 2**	800	**London Array Stage 3**	800
Thanet	300	**Grain Stage 1**	860	**Grain Stage 2**	860
Severn Power Stage 1	425				
Staythorpe C Stage 1	425				
Staythorpe C Stage 2	425				
West Burton B Stage 1	435				
Greater Gabbard Offshore Wind Farm	500				
Clyde	519				
Pembroke 1 Stage 1	800				
Staythorpe C Stage 3	850				
Pembroke 1 Stage 2	1200				
Drakelow D	1230				
Total MW	**8346.6**	**Total MW**	**5757.8**	**Total MW**	**8234.9**

372. Over the last twenty years, the planning process in the UK has delayed the development of a number of gas and electricity infrastructure projects. The government is seeking to address these planning issues through a Planning Bill, with one of its key objectives being the improvement of the way in which the planning process deals with important new energy infrastructure development. The Planning Bill is currently being considered by the House of Lords.

Evaluation of operational network security

373. Network security in its simplest terms is ensured by the obligation on the transmission operators to ensure all reasonable demands for electricity are met. This, in conjunction with licence conditions in relation to developing, maintaining and operating the transmission system in an economic, efficient and coordinated manner set the broad framework in which the detailed technical requirements are applied. The GB Security and Quality of Supply Standards (GBSQSS) ensure that the transmission system meets defined minimum security criteria, such that there is a degree of redundancy in the transmission system that ensures that the transmission system can accommodate peak flows without risk to the security of supply.

374. In terms of generation adequacy to meet demand, the regime in GB is largely non-interventionist, with the market deciding the amount of installed generation capacity to meet demand. A comprehensive suite of information is released to the market in a number of different areas so that efficient decisions in generation investment can be made. In addition, whilst the broad adequacy of generation to meet demand is provided for by market signals and associated responses, the SO has a major role in procuring balancing services to ensure the real time balancing of the transmission system. The SO holds a range of balancing services it can call on to give it the flexibility it needs in operational timescales to cater for the failure of generation and fluctuations in demand, and is therefore charged with the residual balancer function.

Generation mix

375. The generation fuel mix in 2007/08 across a total TEC of 79.9GW, based on information provided in NGET's Seven Year Statement, is displayed in Table 5.4 below.

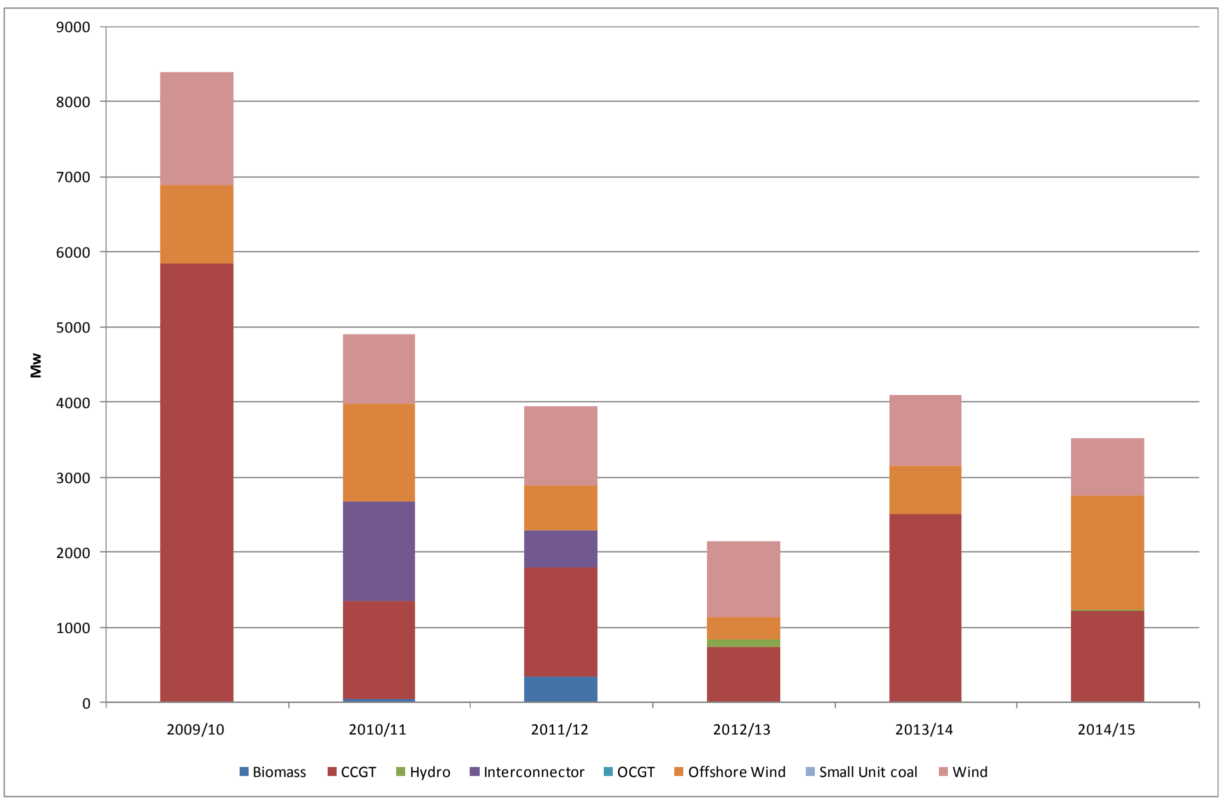
Table 5.4 – Generation mix by plant type (source: NGET Seven Year Statement, table 3.14)

Plant Type	TEC GW	% of Total TEC
Biomass	0.05	0.06
CCGT	25.74	32.21
CHP	2.33	2.91
Hydro	1.03	1.29
ICGCCT	0.00	0.00
IGCC with CCS	0.00	0.00
Interconnector	2.07	2.59
Large Unit Coal	4.41	5.52
Large Unit Coal + AGT	21.46	26.86

Medium Unit Coal	1.15	1.44
Medium Unit Coal + AGT	1.12	1.40
Nuclear AGR	8.37	10.47
Nuclear Magnox	1.45	1.81
Nuclear PWR	1.20	1.50
OCGT	0.59	0.74
Offshore Wind	0.14	0.18
Oil + AGT	3.64	4.55
Pumped Storage	2.74	3.43
Small Unit Coal	0.78	0.98
Wind	1.65	2.07
Total GW	79.92	100.00

376. Figure 5.5 shows that the proposed new generating capacity is predominantly gas fired CCGTs. This combined with scheduled nuclear retirements and possible coal-fired retirements, will make the GB electricity market increasingly dependent on gas and renewables.

Figure 5.5 – Anticipated additions to transmission entry capacities by plant type (source: NGET Seven Year Statement, table 3.5)



Generation commissions/retirements

377. On the basis of information in NGET's Seven Year Statement[90], between 2007 and 2008 there were 424.8 MW of wind generation capacity additions and 1805 MW of CCGT capacity addition. 0 MW of nuclear capacity is to be disconnected in 2008[91]. No units are scheduled to be mothballed i.e. reversibly closed, during 2008[92]. Therefore, the net position is an overall increase of 2229.8 MW of capacity.

Infrastructure projects

378. The GB electricity system is connected with France and Northern Ireland via the IFA[93] and Moyle[94] interconnectors respectively. The existence of these interconnectors and the current proposals for new interconnectors suggests that new interconnection capacity will be provided to the market when it is economic to do so. One new interconnector link to the Netherlands (BritNed[95]) is under construction. Ofgem has also granted licences for the construction of three interconnectors with the Republic of Ireland, one interconnection with Belgium and two with France although none of these are yet under construction. We have also spoken with parties regarding the potential construction of two further interconnectors with Europe.

The Netherlands

379. National Grid Interconnector Ltd and NLink - a subsidiary of TenneT, the transmission SO in the Netherlands - are constructing a 1000MW interconnector (BritNed) between Britain and the Netherlands. On 12 July 2007 Ofgem issued an electricity interconnector licence to BritNed and an exemption order stating that the third party access and use of revenue requirements should not apply for a period of 25 years. The exemption order was amended by the European Commission in order to take on board its further concerns.

Ireland

380. There are two proposed interconnector projects between GB and Ireland. One 500MW interconnector has been proposed by the Irish TSO Eirgrid, and East West Cable One Limited (EWC) has proposed to build two 350MW links on a merchant basis. EWC has been granted two electricity interconnector licences by the Gas and Electricity Markets Authority. EWC has applied for a full exemption from the application of rules relating to third party access and use of revenue requirements for each interconnector. On 2 July 2008, Ofgem issued a consultation document[96] requesting views on the assessment of EWC's reasons for requesting an exemption and our initial view that EWC should be granted an exemption from the application of

---

[90] Source: Table 3.7 of NGET's Seven Year Statement.
[91] Source: Table 3.10 of NGET's Seven Year Statement.
[92] Source: Table 3.11 of NGET's Seven Year Statement.
[93] Interconnexion France Angleterre (IFA) is a 2,000MW HVDC interconnector link between France and GB. It is jointly owned by National Grid Interconnector Limited (NGIL) and RTE.
[94] Moyle is a 500MW interconnector between Scotland and Northern Ireland. Capable of exporting at 500MW to Northern Ireland and importing at 80MW. It is owned by Moyle Interconnector Ltd.
[95] BritNed is a 1,000MW interconnector jointly owned by NGIL and TenneT.
[96] Available at: www.ofgem.gov.uk

rules relating to third party access and use of revenue requirements for each licensed interconnector.

Regulatory framework for interconnectors

381. The EU Electricity and Gas Directives and Electricity Regulation introduce, amongst other things, the requirement for a regulated third party access (RTPA) regime for interconnectors. These requirements were implemented in Great Britain via the Energy Act 2004. The Energy Act 2004 introduced a licensing regime for all gas and electricity interconnectors, which is administered by Ofgem.

382. The requirements of the EU legislation concerning third party access and, where appropriate, exemptions from these requirements are given effect via this licensing route. Where exemption from these requirements is granted, this is done by "switching off" certain of the interconnector licence conditions via an exemption order. BERR has now issued licences to all relevant interconnectors to GB.

5.2 Gas [Article 5] and 2004/67/EC [Article 5]

Ongoing supply-demand situation

383. NGG's Ten Year Statement[97] provides information in relation to forecast and actual annual gas demand and supply. Relevant data is reproduced below.

Table 5.6: Base Case Gas Demand Forecast[98]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
bcm	98	106	108	110	111	112	114	116	119	120	123	125	126	127	129	131	133
Mtoe	81	88	89	91	92	93	94	96	98	99	102	103	104	106	107	109	111

Table 5.7: Potential Gas Supply[99]:

	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Bcm	125	121	125	119	112	117	159	182	196	191	198	209	207	230	225	220	215
Mtoe	104	101	104	99	93	97	132	151	162	159	165	173	171	191	187	183	178

Table 5.8: Potential gas supply after load factor[100] has been applied[101]

	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
bcm	117	113	117	111	104	104	127	142	151	147	151	158	156	172	167	162	157
Mtoe	97	94	97	92	86	86	105	118	126	122	125	131	129	143	139	134	130

Supply Demand balance:

[97] References to NGG's Ten Year Statement refer to the version published in December 2007, which is available at: http://www.nationalgrid.com/uk/Gas/TYS/
[98] Source: National Grid Ten Year Statement Table 3.8A. Available at: http://www.nationalgrid.com/uk/Gas/TYS/tys07chart.htm
[99] Source: National Grid Ten Year Statement Table 4.6B. Available at: http://www.nationalgrid.com/uk/Gas/TYS/tys07chart.htm
[100] continent 50%, Norway 75%, LNG 75%, other 75%, UKCS 100
[101] Source: National Grid Ten Year Statement Table 4.6B. Available at: http://www.nationalgrid.com/uk/Gas/TYS/tys07chart.htm

384. Figure 5.9 illustrates the supply and demand outlook for the GB from 2000 to 2017.

Figure 5.9: Potential UK annual supply capacity[102]

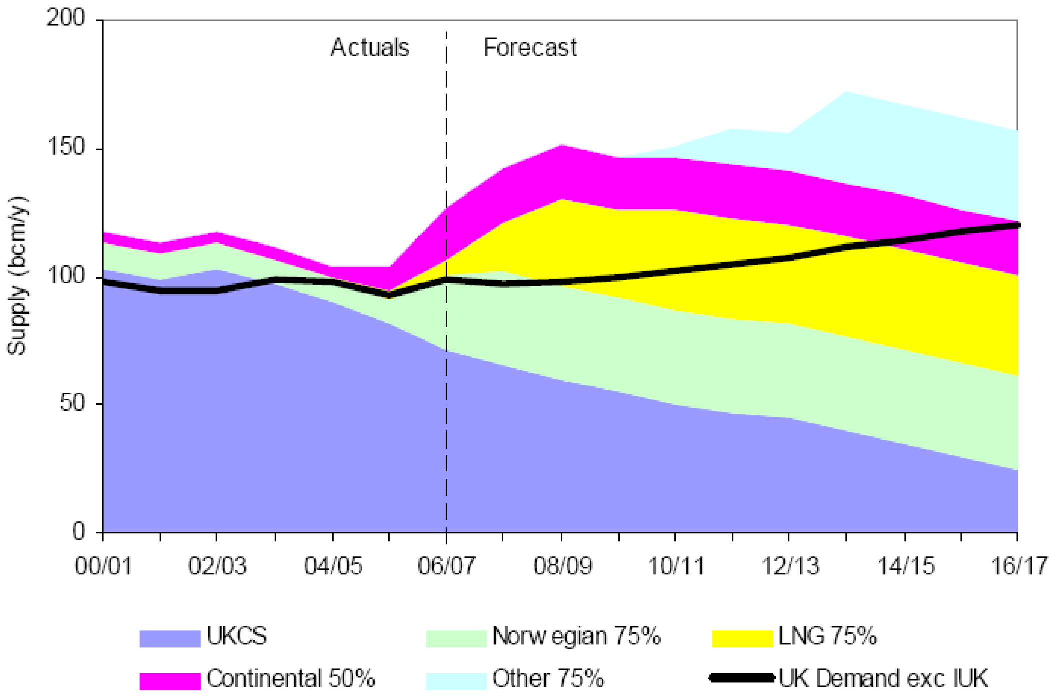


Table 5.10 –UKCS Forecast and Import Requirements[103]

bcm		06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
2006 UKCS Forecast		71	66	60	55	50	47	45	40	35	30	25
Demand excl. Belgian IC		98	97	98	100	102	105	108	111	114	117	120
% Import Requirement		27.68%	32.46%	38.84%	44.58%	50.91%	55.13%	58.15%	63.92%	69.09%	74.51%	79.32%

Table 5.11 – Potential UK Annual Supply Capacity[104]

[102] Source: NGG Ten year statement figure 4.6B http://www.nationalgrid.com/NR/rdonlyres/F085FC32-8C53-4999-AF88-80388A29AE2C/22103/TYS2007.pdf
[103] Source NGG Ten Year Statement Table 4.6A http://www.nationalgrid.com/NR/rdonlyres/8D8CEA4A-9E81-4170-A84A-B8CA92AA6F70/14983/TYS_2006_Charts.xls#FIGURE_4.6D___Base_Case_Annual_Supply
[104] Source NG Ten Year Statement Table 4.6B

bcm	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
UKCS	71	66	60	55	50	47	45	40	35	30	25
Norwegian	29	37	37	37	37	37	37	37	37	37	37
LNG	7	19	34	34	39	39	39	39	39	39	39
Continental	20	21	21	21	21	21	21	21	21	21	21
Other	0	0	0	0	4	14	14	36	36	36	36

Production and import investment

385. NGG's Ten Year Statement provides information in relation to proposed import and storage projects. Table 5.12 outlines the proposed import projects expected over the course of the next four years. A number of import projects were completed in 2007, including the Belgian Interconnector Expansion (total 25.5bcm/y), the Teesside GasPort LNG importation facility (4bcm/y) and the TampenLink pipeline (10bcm/y). These projects together with existing import facilities mean that the UK now has around 98bcm/y of importation capacity.

Table 5.12 – UK import projects[105]

Import Project	Developer	Location	Capacity (bcm/yr)	Date	Status
BBL Expansion	BBL	Bacton	Up to 8	2010+	Interest being Sought
South Hook I	Qatar Petroleum/ ExxonMobil	Milford Haven	10.5	2008	Under Construction
South Hook II	Qatar Petroleum/ ExxonMobil	Milford Haven	10.5	2008/09	Under Construction
Dragon	BG Group/ Petronas	Milford Haven	6	2008	Under Construction, further expansion possible
Isle of Grain II	Grain LNG	Isle of Grain	9	2008/09	Under Construction
Isle of Grain III	Grain LNG	Isle of Grain	7	2010/11	Under Construction
Conoco Phillips	Partners	Teesside		2012+	Planning submitted
Canvey LNG	Partners	Canvey island	5.4+	2012+	Planning rejected, appeal pending
Amlwch	Canatxx LNG	Amlwch/ Fleetwood			On-shore consents granted, re-gas facility linked by sub-sea pipe to Canatxx Storage.
Other LNG	Various	N/a		2012+	Conceptual

[105] Source: NGG Ten Year Statement, table 4.5B

386. Regarding the quality and level of maintenance of the networks NGG has a duty as a licensed gas transporter under section 9(1)(a) of the Gas Act (1986) to develop and maintain an efficient and economical pipe-line system. This duty to maintain an efficient and economical network should ensure NGG maintains the network at a sufficient level of quality as this is more economic and efficient than the alternative of allowing the network to run down and then developing a new one.

387. Table 5.13 shows storage facilities and their development status.

Table 5.13 – UK storage projects[106]

Storage Project	Developer	Location	Size(mcm)	Date	Status
Rough	Centrica Storage Ltd	Offshore	3400		Operational
Hornsea	SSE	Yorkshire	320		Operational
Hatfield Moor	SP	Yorkshire	120		Operational
Hole House Farm	EdF	Cheshire	40		Operational
Humbly Grove	Star Energy	Hampshire	290		Operational
Avonmouth	National Grid	South West	80		Operational
Dynevor	National Grid	South Wales	30		Operational
Glenmavis	National Grid	Scotland	50		Operational
Partington	National Grid	North West	100		Operational
Aldbrough	SSE/Statoil	Aldbrough	420	2008	Under construction, phased build up
Aldbrough (Phase II)	SSE/Statoil	Aldbrough	420	2011+	Planning consents granted
Holford Gas Storage	E.ON	Byley	160	2010-12	Under construction, phased build up
Whitehill Gas Storage	E.ON	Aldbrough	420	2012-13	In final stages of gaining consents
Stublach	GDF	Cheshire	550	2012+	Planning granted
Caythorpe Gas Storage	Caythorpe Gas Storage Limited	Yorkshire	210	2009/10	Planning appeal pending
Saltfleetby	Wingas	Lincolnshire	700	2012/13	Planning consents

[106] Source: NGG Ten Year Statement, table 4.5D

					rejected
Portland	Portland Gas	Dorset	1000	2011	Pending planning approval
Gateway Storage	Stag Energy Development Co. Ltd	East Irish Sea	1100	2011-2013	Pending planning approval
British Salt	British Salt	Cheshire	1000	2010+	Proposed, pre-planning
Welton	Star Energy	Lincolnshire	440		Planning to be sought 2008
Bletchingley	Star Energy	Surrey	~1 bcm		Planning to be sought 2009
Albury I	Star Energy	Surrey	~0.2 bcm		Planning applied for in 2007
Albury II	Star Energy	Surrey	~0.7 bcm		Planning to be sought 2009
Gainsborough	Star Energy	Lincolnshire	~0.2 bcm		Planning to be sought 2008
Esmond / Gordon	Star Energy	Off-shore	~4 bcm		Planning to be sought 2009
Fleetwood	Canatxx	Lancashire	~1 bcm		Planning consents rejected by Secretary of State
Others	Various	Various		2011+	Conceptual projects at early stages

Liquidity[107]

388. A liquid market will feature a large number of buyers and sellers ready and willing to participate in the market at all times. Liquid markets are important in ensuring that price signals to participants are accurate and to allow participants to adjust contractual positions without materially altering the prevailing price. Short term exchange liquidity might also lower barriers to entry for new suppliers.[108] It is important to note that a high level of liquidity is not an end in itself, and is merely one indicator of a healthy market as it makes new entry relatively easy.

[107] Liquidity refers to the ability to quickly buy or sell a particular item without causing a significant movement in the price.
[108] Since the financial risk of not being able to buy generation to meeting their supplier obligations could be reduced.

389. It is worth noting that there may be a number of benign explanations for falls in liquidity, for example improvements in initial contracting, supply-demand balancing and forecasting may cause liquidity to fall. In addition, more sophisticated products (e.g. options) are a substitute for direct trading in physical products. However, at very low levels of liquidity, confidence in traded prices can be undermined.

390. There are a wide range of measures of liquidity, including number of market participants, number of trades, volumes traded and churn (the number of times a single unit is traded).

Gas

391. The majority of total volume traded in the UK is traded over-the-counter (OTC), with most activity observed close to real time and close to the delivery of the product, i.e. volumes are highest for near term products (day-ahead, week-ahead, month-ahead).

392. The Financial Services Authority (FSA) conducts an annual survey of energy brokers in the UK to determine total OTC traded volumes, these are reported below.

Table 5.14: Estimated value of UK Gas market

	Volume traded (billion therms)	Est.value of market (£billion)
2006/07	437	134
2005/06	209	108
Increase on 2005/06	*226 (109%)*	*26 (24%)*

Source: Financial Services Authority

393. According to the FSA, the total volume of forward traded gas through electronic or voice brokered services year from 1 August 2006 to 31 July 2007 was 437 billion therms, an increase of 109 per cent on the previous year.[109]

Incentives for new investment

394. We would expect a properly functioning market to send price signals to investors encouraging them to build the generation capacity to meet required future demand. Below we assess some of the evidence on market signals for investment.

Security of supply standards

395. BERR issued a consultation document in March 2006 seeking views on the measures needed to implement Directive 2004/67/EC concerning measures to safeguard security of natural gas supply. In January 2007 BERR published the conclusions of this consultation which are that with the exception of the requirement to report long-term gas supply contracts under Article 5.1(c), the Government believes that Great Britain complies with the terms of Directive 2004/67/EC.

[109] As some voice and electronic brokered services are cleared through exchanges, energy traded on exchanges are excluded from this analysis to avoid double counting.

396. The decline of the UKCS has presented a major challenge for Great Britain's liberalised gas market. The market is responding and developing a diverse and flexible gas supply portfolio with access to gas from a range of countries and a significant increase in our storage capacity indicating that over the longer term, the market will deliver security of supply if the supply/ demand fundamentals and price signals support this.

397. Given the lead times for planning and building new investment and the current market outlook there does not currently appear to be a requirement for further government intervention to provide incentives to deliver more import capacity. However it is important for the government and Ofgem to monitor investment and the supply/demand balance to make sure that the energy markets are bringing forward projects in a timely way. The Energy Markets Outlook (EMO) was announced as part of the Energy White Paper and will be a successor to the report produced by the Joint Energy Security of Supply Working Group (JESS). The publication of EMO in October 2007 was the first stage in delivery of the government's undertaking to introduce a new information service providing forward looking energy market information relating to security of supply. The government also launched a website[110] containing additional detail that is updated on an ongoing basis.

398. Over the last twenty years, the planning process in the UK has delayed the development of a number of gas and electricity infrastructure projects. The government is seeking to address these planning issues through a Planning Bill, with one of its key objectives being the improvement of the way in which the planning process deals with important new energy infrastructure development. The Planning Bill gets its first reading in the House of Lords on 15 July 2008.

Gas Emergency Measures

399. The government has a number of methods that it can use to stop a shortfall of either gas or electricity causing a situation to deteriorate into an emergency. In the first instance government would invoke powers available to it under the Fuel Security Code. This enables it to direct generators (power stations) to use alternative sources of fuel to generate electricity.

400. However, unforeseen circumstances such as disruption caused by severe weather or damage to certain parts of the gas or electricity infrastructure could lead to an emergency situation developing. Emergency plans are in place to deal with gas and/or electricity emergencies, these have been agreed with industry and tested on a regular basis to insure that they are robust and fit for purpose.

401. In the event of a gas supply emergency, the Network Emergency Co-ordinator (NEC), an industry senior manager, can use powers under the Gas Safety (Management) Regulations GS(M)R to control supply and demand. The NEC can direct five stages of a network gas supply emergency;

Table 5.15: Five stages of a network gas supply emergency[111]

[110] Refer to the Department for Business, Enterprise and Regulatory Reform (BERR) web site at: http://www.berr.gov.uk/energy/energymarketsoutlook/page41839.html

[111] Source: UK Resilience Website - A service of the cabinet Office. Available at: http://www.ukresilience.gov.uk/response/recovery_guidance/infrastructure_issues/utilities.aspx

Stage	Description	Power
1	Potential Emergency	Isolation of supplies to large non-domestic consumers with interruptible supply contracts
2	Actual Emergency	Maximisation of beach gas and storage. Suspension of the commercial arrangements.
3	Firm Load Shedding	Isolation of supplies to large non-domestic consumers with firm supply contracts.
4	Network Isolation	Isolation of local gas networks including domestic and non-domestic consumers.
5	Restoration	Phased restoration of gas supplies.

402. In the event of a gas supply emergency, there are three categories of priority (protected) consumer;

Category A – vital for public safety including hospitals.
Category B – as above but with interruptible supply contracts.
Category C – industrial sites that would suffer £50M damage.

403. Priority users receive limited protection and are not protected against a local supply failure or damage to the service pipe work and associated equipment.

404. The priority user lists were updated in 2006 to ensure the right users are protected under these arrangements. Further information can be found on the BERR website[112].

[112] Available at: http://www.berr.gov.uk/energy/reliability/downstream/page30313.html

6. Public Service Issues [Article 3(9) electricity and 3(6) gas]

Overview

This section describes the relevant statutory requirements and licence conditions on transmission, distribution and supply activities which Ofgem oversees. It covers:

- Statutory requirements for networks
- Fuel mix disclosure
- Appropriate treatment of vulnerable customers
- Disconnections for non-payment
- Transparent terms and conditions for supply contracts

405. Activities such as transmission/transportation, distribution and supply are licensed activities. The concept of public service obligations is not explicitly defined, but the licences place obligations on the holder. One of Ofgem's duties is to act in a manner best calculated to secure that licence holders are able to finance the carrying out of the activities which they are authorised or required by their licence to carry on.

406. These duties for non-network activities are placed in a non-discriminatory manner on all relevant licensees in the context of a fully liberalised market. Duties placed in respect of network activities are taken account of in setting price controls.

407. The notion of 'services of general economic interest' exists in the UK as an exclusion to the Chapter I and Chapter II prohibitions of the Competition Act 1998.

408. The relevant statutory requirements and licence conditions are outlined below

Statutory Requirements for Networks

- Under section 9(2) of the Electricity Act 1989 the holder of a transmission licence must develop and maintain an efficient, coordinated and economical system of electricity transmission and facilitate competition in the supply and generation of electricity;
- Under section 9(1) of the Electricity Act 1989 distribution licensees are obliged to develop and maintain an efficient, coordinated and economical electricity system and facilitate competition in the supply and generation of electricity;
- Under Section 10 of the Gas Act 1986 there is a duty to connect premises within 23 metres of the gas main without charge; and
- Under section 9(1) and (1A) of the Gas Act 1986 a gas transporter has a duty to develop and maintain an efficient and economical pipe-line system and facilitate competition in the supply of gas.

Fuel Mix disclosure

409. In March 2005, a new SLC was inserted into electricity supply licences to implement the requirements of Directive 2003/54/EC, requiring each electricity supplier to provide details to its customers of the mix of fuels used to produce the electricity it supplies together with certain environmental information.

410. In summary, suppliers are required to provide customers, at least once per year, with details of the fuels used to generate the electricity that they supply. These are categorised as coal, natural gas, nuclear, renewable and other. They must also provide information on the environmental impact of this generation (carbon dioxide emissions and radioactive waste).

411. In June 2005 Ofgem consulted upon a draft set of non-binding guidelines regarding the fuel mix disclosure obligations and, following consideration of the responses received to this consultation as well as the experience of disclosure for the first year, a final version of the guidelines was published in December 2005. The purpose of the guidelines is to encourage good practice by suppliers and help them with the presentation of the fuel mix information in order to ensure that customers can understand the information provided.

Appropriate treatment of vulnerable customers

412. Ofgem is obliged, through its statutory duties, to have regard to the interests of customers who are disabled, chronically sick, of pensionable age, on low incomes or living in rural areas, and to have regard to the need for sustainable development. Ofgem is also obliged to have regard to statutory guidance issued by government on social issues which, amongst other things, requires Ofgem to help the government in meetings its targets to eliminate fuel poverty.

413. In October 2005, Ofgem launched its Social Action Strategy which describes how it seeks to meet these social responsibilities and help the government to meet its targets for eradicating fuel poverty. The 2008 annual update to the Strategy, reviewing progress over the past year and identifying areas for the coming year, has recently been published on the Ofgem website.

414. The Strategy supplements Ofgem's broad approach of promoting competitive energy markets and regulating network monopolies, by focussing on four key areas:

- securing compliance with regulatory obligations and effective monitoring and reporting by the companies;
- encouraging best practice among energy suppliers, using research to identify effective ways to address fuel poverty and help vulnerable customers;
- influencing the debate about measures to help tackle fuel poverty, working with other stakeholders, helping to promote a joined up and holistic approach; and
- informing consumers about ways to lower their energy bills.

415. Energy suppliers have a range of regulatory obligations towards vulnerable consumers. For example, in the gas and electricity supply licences:

- SLC 26 provides for the provision of special services (e.g. passwords for callers, frequent meter reads, the provision of certain information and the provision of services under the Priority Services Register) for domestic customers who are of pensionable age, disabled or chronically sick;
- SLC 27 deals with payments, security deposits and disconnections. Amongst other things, it requires suppliers to offer customers a wide choice of payment methods which should include payment by cash or through a PPM; and it provides protection for customers in payment difficulty;

- SLC 28 deals with prepayment meters and, amongst other things, provides that suppliers must take all reasonable steps to ensure that PPMs are reset within a reasonable period of time after a change in charges; and
- SLC31 contains obligations in relation to the provision of certain information to domestic customers (including information about the efficient use of energy).

416. Electricity distribution and gas transportation licensees are also subject to licence obligations relating to the provision of services to vulnerable customers.

417. Ofgem continues to encourage suppliers to take a proactive approach to helping their fuel poor and vulnerable customers, in particular by developing their social programmes and through the promotion of best practice in the area of debt and disconnection. We have published reviews in both of these areas to shine a light on suppliers' initiatives in this area and to encourage an exchange of best practice across the industry.

418. On a related note, environmental policy is also being used to target key consumer groups. The government's Carbon Emissions Reduction Target (CERT), previously the Energy Efficiency Commitment (EEC2), is the government's main policy instrument for reducing carbon emissions from existing households. Under EEC2, suppliers had to meet at least 50% of their target with a "Priority Group" of customers including those receiving income related benefits or tax credits. With CERT (which began on 1 April this year) the Priority Group was expanded to include those over 70 (as well as those on income related benefits or tax credits). For CERT, suppliers are required to meet at least 40% of their target with measures to this group.

419. Ofgem also works to ensure that vulnerable customers are able to access the benefits of the competitive energy market, in terms of price, quality and service, identifying barriers and removing them. Ofgem is conducting an Energy Supply Markets Probe which will analyse whether the retail market is operating effectively and meeting the interests of all consumers. It will identify and report initial finding in September 2008.

420. Ofgem also hosted an Energy Summit on Fuel Poverty in April 2008. Its objective was to agree a programme of practical action to improve the targeting of existing help to those in fuel poverty and help more vulnerable customers participate more effectively in the energy market.

Disconnections for non-payment

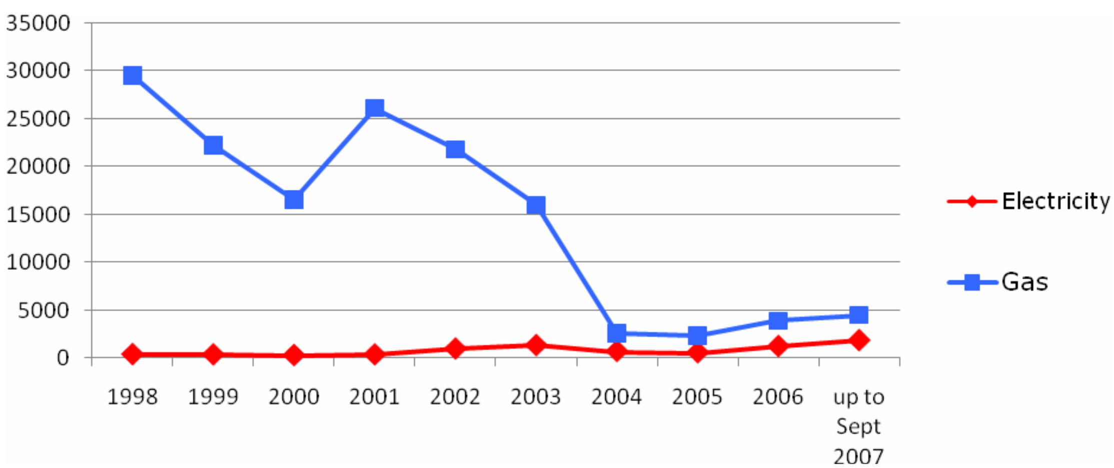
421. Suppliers are subject to a number of obligations with regard to dealing with customers in payment difficulties. These include preventing disconnection in certain circumstances and procedures designed to secure prepayment meter installation as an alternative to disconnection.

422. From 2001 until 2005, the total number of customers disconnected for non-payment of their energy bill decreased sharply, as highlighted in the chart below. There are a number of factors behind this trend including:

- pressure on suppliers to only disconnect customers as a last resort;
- suppliers increasing the number of PPMs installed to recover debt as an alternative to disconnection;

- the voluntary safety net introduced by suppliers to not disconnect vulnerable customers; and
- the decision by British Gas to temporarily stop disconnecting customers.

Figure 6.1: Total number of electricity and gas disconnections



423. The figures for 2006 showed a slight increase in the number of disconnections, with 3,859 gas customers and 1,258 electricity customers being disconnected, compared with 2,309 and 604 (respectively) in 2005. The figures also show that disconnections in gas remain higher than in electricity. This may be in part be due to the inability to install gas PPMs in some instances, as an alternative to disconnection, because of safety reasons.

424. Suppliers have advised that the increase in the total number of disconnections is because they are more confident in the debt and disconnection processes they have in place. This should ensure they are only disconnecting those customers who refuse to pay bills after all attempts to resolve a debt issue have been exhausted and who are not vulnerable. Ofgem's Debt and Disconnection Best Practice Review publish in January 2008 included a number of examples of best practice on which suppliers can draw to further improve the way they respond to and help customers who face debt or the risk of disconnection.

Ongoing maintenance of end user price regulation

425. Supply price controls were completely lifted in April 2002. Retail prices are determined through competition in the market, although a significant proportion of suppliers cost base, recovered through unregulated changes to end users, consists of regulated tariffs such as transportation and metering costs paid by suppliers paid to the network monopolies.

Transparent terms and conditions for supply contracts

426. The gas and electricity supply licences include the following conditions:

- SLC 22 stipulates that a licensee may not supply a domestic premises except under a domestic supply contract or a deemed contract. The domestic supply contract must be in writing and set out all terms and conditions;

- SLC 23 obliges suppliers to take all reasonable steps to draw the customer's attention to the principal terms of the supply contract;

- SLC 31 obliges suppliers to provide their customers with information on:

    - how to contact the Consumer Council;
    - the Consumer Council's role in resolving customer complaints;
    - the efficient use of electricity; and
    - the procedure the licensee will follow to deal with any complaints;

- SLC 7 obliges the supplier to ensure that the terms of its deemed contracts are not unduly onerous.

Appendix 1 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. The Authority also has other statutory duties in respect of the environment as set out in various other Acts.[113] References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[114]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[115].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[116]; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[117]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[118] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;

[113] For example, the Environment Act 1995 and the Countryside and Rights of Way Act 2000.
[114] Entitled "Gas Supply" and "Electricity Supply" respectively.
[115] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[116] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[117] The Authority may have regard to other descriptions of consumers.
[118] Or persons authorised by exemptions to carry on any activity.

- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- contribute to the achievement of sustainable development; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[119] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

1.9. The Authority has regard to all of its duties when carrying out its functions.

1.10. The Energy Supply Ombudsman (ESO) was established in July 2006 (at the request of Ofgem) by the six largest suppliers to resolve billing and transfer disputes and provide redress where domestic energy customer complaints had not been adequately addressed by suppliers. Since the establishment of the ESO, Parliament has introduced new measures through the Consumers, Estate Agents and Redress Act 2007 (the CEAR Act) to require energy suppliers and network operators to be a member of an Ofgem approved redress scheme to resolve the complaints of domestic and small business energy customers' complaints.

1.11. The CEAR Act will see energywatch – the current energy consumer body - replaced with a single point of contact for consumers for information and advice covering all markets (Consumer Direct), the extension of redress schemes potentially to cover all energy complaints, and a new consumer advocacy body (the new NCC). The CEAR Act also provides for the same changes to apply to postwatch, energywatch's equivalent in the postal market. These new arrangements will take effect from 1 October 2008. The CEAR Act places a statutory requirement on Ofgem to make regulations which set standards for complaint handling by the companies we regulate.

[119] Council Regulation (EC) 1/2003

Appendix 2 – Changes to Consumer Representation

1.12. The Energy Supply Ombudsman (ESO) was established in July 2006 (at the request of Ofgem) by the six largest suppliers to resolve billing and transfer disputes and provide redress where domestic energy customer complaints had not been adequately addressed by suppliers. Since the establishment of the ESO, Parliament has introduced new measures through the Consumers, Estate Agents and Redress Act 2007 (the CEAR Act) to require energy suppliers and network operators to be a member of an Ofgem approved redress scheme to resolve the complaints of domestic and small business energy customers' complaints.

1.13. The CEAR Act will see energywatch – the current energy consumer body - replaced with a single point of contact for consumers for information and advice covering all markets (Consumer Direct), the extension of redress schemes potentially to cover all energy complaints, and a new consumer advocacy body (the new NCC). The CEAR Act also provides for the same changes to apply to postwatch, energywatch's equivalent in the postal market. These new arrangements will take effect from 1 October 2008. The CEAR Act places a statutory requirement on Ofgem to make regulations which set standards for complaint handling by the companies we regulate.

Appendix 3 – Further Reading

Further reading – 4.1.3 – Outputs reporting framework

'Gas Distribution Quality of Service Regulatory Instructions and Guidance – version 4'; Draft; April 2007[120]
http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/Gas%20Distribution%20Quality%20of%20Service%20Regulatory%20Instructions%20and%20Guidance%20latest.pdf

'Gas Distribution Quality of Service Report'; Ofgem document 210/06; December 2006
http://www.ofgem.gov.uk/Networks/GasDistr/QoS/Documents1/16406-210_06.pdf

Gas Distribution Price Control Review, Final Proposals; Ofgem document 285/07; December 2007
http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/final%20proposals.pdf

Further reading – 4.1.3 – Quality of service indicators (Standards of Performance)

'Guidance for reporting on standards of performance and standard special licence condition D10 for gas distribution network operators and independent gas transporters'; Ofgem publication 254/05; November 2005[121]
http://www.ofgem.gov.uk/Networks/GasDistr/QoS/Documents1/12143-254_05.pdf

Letter on the Gas (Standards of Performance) (Amendment) Regulations 2008; March 2008
http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/The%20gas%20standards%20of%20performance%20regulations%202008.pdf

Further reading – 4.1.3 – Quality of service reports

'2006/07 Gas distribution quality of supply report'; Ofgem publication 294/07; December 2007
http://www.ofgem.gov.uk/Networks/GasDistr/QoS/Documents1/Gas%20Distribution%20QoS%20report%200607%20Final.pdf

'2005-06 Gas distribution quality of service report'; Ofgem publication 210/06; December 2006
http://www.ofgem.gov.uk/Networks/GasDistr/QoS/Documents1/16406-210_06.pdf

'2004/05 Gas distribution quality of service report'; Ofgem publication 280/05; December 2005

[120] At the time of writing, version 4 of the RIGs has not been formally published. No changes to the current draft are anticipated and Ofgem expects to publish the final version in the near future.
[121] An update to this document is currently in development.

http://www.ofgem.gov.uk/Networks/GasDistr/QoS/Documents1/12338-280_05.pdf

Further reading – 4.1.4 – Gas – Effective Unbundling

Gas Distribution Price Control Review, Final Proposals, December 2007
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=final%20proposals.pdf&refer=Networks/GasDistr/GDPCR7-13

Transmission Price Control Review, Initial Proposals
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/14439-104-06AMEND.pdf

http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/14435-060623_MainAppendices%20final.pdf

http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/14436-OfftakeAppendix%20104c-06.pdf

http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/14437-060623_OfftakeAppendix_IA.pdf

Transmission Price Control Review: Final Proposals, December 2007
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/16342-20061201_TPCR%20Final%20Proposals_in_v71%206%20Final.pdf

http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/16341-20061129_TPCR%20FP%20Supplementary%20Appendices_in_final.pdf

The role of regulatory accounts in regulated industries, final proposals, April 2001
http://www.ofwat.gov.uk/aptrix/ofwat/publish.nsf/AttachmentsByTitle/regacc_0401.pdf/$FILE/regacc_10april01.pdf

Regulatory Accounts, Final Proposals, November 2000
http://www.ofgem.gov.uk/About%20us/enforcement/mergers/oft/Documents1/mergersandaquisitions%2068.pdf