OXERA

OXFORD ECONOMIC RESEARCH ASSOCIATES

THE COAL AUTHORITY

THE COST OF FLEXIBILITY PROVISION BY ELECTRICITY GENERATORS

NOVEMBER 2003

Blue Boar Court
Alfred Street
Oxford OX1 4EH
Tel: +44 (0) 1865 253000
Fax: +44 (0) 1865 251172
Email: Enquiries@oxera.co.uk

Executive Summary

Ensuring reliability of energy supplies is a key goal of the UK government's new energy policy. Such reliability has several dimensions, ranging from long-term strategic security of fuel sources through network resilience to real-time balancing of the energy system. In electricity, the lack of storability and the inelasticity of demand mean that short-term, real-time balancing is of particular importance, requiring a system with sufficient flexibility in its generation portfolio to be able to match potential changes in demand, or to 'load follow'.

Looking forward, various commercial and policy changes can be anticipated that may substantially change the generation mix, including:

- a reduction in coal's contribution to the fuel mix as environmental constraints bind; and
- an increase in the level of wind power in the fuel mix as a result of continued support for the renewables sector.

Since different types of generation offer different levels of flexibility, or impose varying demands for flexibility on the system, the reliability of electricity supply will be affected by these broad trends in the market.

In this study, which OXERA has undertaken in conjunction with Power Planning Associates, a methodology for assessing the cost of load-following has been developed in order to analyse the implications of alternative future generation scenarios. The scenarios, derived from OXERA's wholesale electricity market model, have been constructed to allow comparison of diverse generation mixes that may emerge by 2010 and to assess their impact on the cost of providing system flexibility, as shown in the table below.

2010 generation scenario summary (GW)

	Scenario 1 (High Wind)	Scenario 2 (Low Coal)	Scenario 3 (Low Wind)
Coal	24.9	9.8	24.9
Gas	23.4	38.4	25.6
Nuclear	8.7	8.7	8.7
Wind	6.7	6.7	1.0
Other	7.8	7.1	7.8
Total	71.5	70.7	68.0

Source: OXERA.

Technical and operational generator flexibility

One of the main inputs to the analysis is an assessment of the technical capability of different types of generation to provide load-following flexibility to the system and the cost of such provision. The results used are shown below, where the flexibility is defined according to the ramp range (ie, what change in output level a generator would typically be willing or able to provide for load-following purposes) and the ramp rate (ie, how quickly the change in output level could be achieved).

Typical load-following capabilities for different plant types

Plant Type	Typical unit size (MW)	Typical ramp range up or down (% capacity)	Ramp rate (%/minute)	Constrained ramp rate (%/minute)
Simple gas turbine (normal)	157	20	7	2.9
Simple gas turbine (fast)	157	20	20	2.9
Combined-cycle gas turbine (CCGT) (pre-1998)	233	20	5	3.1
CCGT (post 1998)	390	20	8	2
Coal (1970s—constant pressure)	500	20	5	n/a
Coal (1970s—sliding pressure)	500	20	3	n/a
Coal (2005+)	600	20	7	n/a
Nuclear advanced gas-cooled reactor (AGR)	1,200	10	2	n/a
Nuclear UK pressurised water reactor (PWR)	1,260	20	0.5–3	n/a
Small hydro	1,260[1]	20	7.5	n/a
Pumped storage	1,728[2]	100	375	n/a

Note: [1] This represents the total installed capacity of small hydro plant in Great Britain. [2] Based on the total size of the Dinorwig pumped-storage plant in North Wales.
Source: Power Planning Associates.

There are three interesting points to draw from this information.

- The technical flexibility of CCGT and coal-fired generators is very similar, thereby suggesting that there is no obvious comparative advantage of one type of technology over the other.

- The operational flexibility of gas-fired stations is, on average, significantly lower than the technical flexibility because of constraints imposed on the gas system through Network Exit Agreements.

- Due to lack of controllability in its output, wind power is not considered a viable source of generation flexibility.

The modelling focuses on supply-side responses and does not account for any potential demand-side activity. However, although the demand side could potentially provide a significant volume of reserve and response, it would be unlikely to offer any real ramping capability.

Costs of load-following

When generators adjust their output to respond to changes in electricity demand, they can incur a number of costs. Broadly speaking, these costs consist of:

- *reduced fuel efficiency*—due to not operating at the most efficient output level;
- *further reduction in efficiency*—as plant are ramped up or down;
- *increased maintenance costs*—due to additional strains on machinery.

The cost incurred by different types of generator when altering output will depend on the efficiency rate and technical characteristics of the plant and the cost of fuel used. As shown in the following table, the ramping costs for normal simple gas turbines, CCGTs and constant-pressure coal plant are all quite similar. However, the costs for gas-fired plant are driven primarily by additional maintenance costs, while the ramping costs for coal-fired plant are based more on variable efficiency and fuel costs.

Ramping costs

Plant Type	Ramping cost (£/MW changed output)	
	Unconstrained	Constrained
Simple gas turbine (normal)	11.49	8.61
Simple gas turbine (fast)	42.51	8.61
CCGT (pre-1998)	12.95	11.97
CCGT (post-1998)	11.49	18.21
Coal (1970s—constant pressure)	11.01	–
Coal (1970s—sliding pressure)	18.36	–
Coal (2005+)	8.21	–
Nuclear AGR	–	–
Nuclear UK PWR	–	–
Small hydro	–	–
Pumped storage	5.01 up, 0 down	–

Source: Power Planning Associates.

Categories of load-following

Load-following requirements vary across the day and throughout the year in response to the overall pattern and predictability of demand. In this report, load-following requirements are broken down into three broad categories:

- following the expected profile of demand throughout each day;
- balancing residual energy imbalances resulting from errors in forecasting demand and generator output; and
- ensuring system security through providing frequency response and standing reserve services.

This separation enables the drivers of the volume of load-following required to be identified more easily. The first component is dependent on the assumed load profile, which defines the necessary ramp rate to meet anticipated changes in demand at different times of the day. The residual balancing from forecast error estimates the additional costs of ensuring the supply–demand balance which are incurred through uncertainty in demand levels and in the precision with which different generation types can control their output levels and profiles across the day. Finally, system security refers to the forecast levels of standing reserve and frequency-response services that the transmission system operator (TSO) may have to contract for.

Scenario comparisons

The comparison between the scenarios (High Wind, Low Coal and Low Wind) draws on the understanding of the drivers of load-following requirements and the capabilities and costs of different generators of providing the services. The estimated costs for meeting each type of load-following under each scenario are reported below, using the constrained gas ramp rates. Although the absolute magnitude of the costs associated with each type of load-following are sensitive to underlying assumptions, the relative magnitudes provide some interesting results.

- In terms of ramping costs, a greater reliance on wind generation and a lower level of coal-fired capacity increases the underlying cost.
- Energy-balancing costs are lower when existing coal stations are closed, reflecting the increased ability of new generation to maintain a given output level or profile in comparison with the existing coal station technology.
- Security costs increase with higher levels of wind generation because there is an increased requirement for reserve due to the intermittent nature of wind generation.

Summary of load-following costs (£m per year)

Scenario	Ramping costs	Energy-balancing costs	System security costs	Total load-following costs
High wind	215.2	246.9	93.1	555.2
Low coal	224.1	204.7	96.6	525.4
Low wind	207.9	241.7	86.6	536.2

Source: OXERA and Power Planning Associates calculations.

Conclusions

Without significant advances in either electricity-storage technologies or demand-side behaviour, load-following requirements on generators will continue to increase. However, this is likely to occur against a background of a generation mix that differs considerably from that which exists at present, with greater reliance on gas-fired generation and a larger contribution from wind power within the overall mix.

The analysis in this report indicates that wind generation can be expected to increase the cost of load-following on the system because of the lack of controllability in this source. However, it also shows that replacing old coal-fired stations may reduce the likelihood of generator output error from conventional plant, thereby reducing energy-balancing costs.

Flexibility of the gas-fired generators is constrained by the limitations on offtake arrangements with the gas network operator, Transco. Therefore, in the longer term, the cost of providing flexibility from generation, and even the ability of the system to cope with the increasing load-following requirements, will be largely dependent on the degree of flexibility that can be offered from the gas network.

Contents

1. Introduction

In February 2003 the government published its Energy White Paper, 'Our Energy Future—Creating a Low Carbon Economy', which set out four goals of energy policy:

- putting the economy on a path to deliver 60% reductions in CO_2 emissions by 2050, as recommended by the Royal Commission on Environmental Pollution;[1]
- maintaining the reliability of energy supplies;
- promoting competitive markets to help improve productivity and sustainable economic growth;
- ensuring that every home is adequately and affordably heated.

These goals are set against the background of an energy sector that is facing substantive changes over the next decade or so, including:

- a shift from energy self-sufficiency to import-dependence;
- closure of the current nuclear generators, which represent around 20% of generation capacity;
- continued growth in the share of gas-fired generation in the generation mix;
- a commitment to increasing the contribution of renewable generation (in particular, wind generation) to electricity supply.

As a consequence of these trends, the generation mix in the longer term will look significantly different than at present, with implications for security of electricity supply. Some of these implications have already been anticipated in the new energy policy—for example, in relation to the medium- to long-term security concerns surrounding access to fuel sources and major investment programmes in generation and transmission infrastructure.

However, there is a further short-term security concern that may arise with the changing generation mix—whether the combination of generation technologies chosen will provide sufficient flexibility to enable the electricity system to cope with short-term variations in electricity demand (ie, load-following).

This report, undertaken by OXERA in conjunction with Power Planning Associates, develops a framework to investigate the issue of system flexibility and the implications for flexibility of changes in the generation mix. In particular, the analysis focuses on quantifying how the cost of following electricity-demand load would vary as a result of changes to the generation mix. The analysis is divided into three components:

- investigating the future requirements for system flexibility, taking into account the effect that the generation mix will have on these requirements;
- assessing the flexibility of different types of generation technology, taking into account the technical characteristics, costs of flexibility and infrastructure considerations for different types of generation;
- estimating the cost of meeting requirements for flexibility under pre-defined scenarios for the future generation mix.

[1] RECP (2000), 'Energy—The Changing Climate', June.

With reference to the final point, three scenarios have been defined to describe the potential mix of generation technologies that might emerge in the future. As the purpose of the study is to investigate the effect of different generation mixes, the scenarios deliberately span a wide range of outcomes, encompassing the effect of both strong growth in wind generation and potential closure of a significant number of coal-fired plant under stricter environmental constraints.

The structure of this report is as follows:

- section 2 provides background information on issues of electricity system control, describing the need for flexible generation and current mechanisms used to manage the system. This section also provides brief descriptions of the generation technology mix scenarios used later in the analysis;
- section 3 discusses ways of providing flexibility and states the capabilities and costs of providing flexibility for different generation technologies;
- section 4 describes the requirement for system flexibility under three separate categories based on the nature of the flexibility required and the arrangements used to ensure its delivery;
- section 5 details the analysis used to estimate the costs of meeting system flexibility requirements and how these costs change under the three scenarios;
- section 6 concludes.

2. Background

The pattern of electricity demand is influenced by several factors, including:

- weather conditions;
- commercial and industrial operating patterns;
- domestic consumption needs (including lighting and heating).

As a consequence, there is significant variation in electricity demand throughout the day, much (though not all) of which is predictable. Since electricity is not a storable commodity, all changes in electricity demand need to be met by corresponding changes in generation on a real-time, second-by-second basis. Load-following is the process of adjusting generator outputs in order to match changes in demand. This balance is achieved through a combination of market mechanisms and active management of the system.

2.1 System-balancing mechanisms

In Great Britain the overall responsibility for ensuring the real-time balance between electricity generation and demand falls on the TSO under the terms of its Transmission Licence. There are currently three separate TSOs in Great Britain;[2] however, it is expected that National Grid Company (NGC) will take on the role of GB-wide TSO with the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in April 2005. The introduction of BETTA will result in a common set of electricity trading arrangements being applied throughout Great Britain. It is expected that these arrangements will encompass many of the features of the New Electricity Trading Arrangements (NETA), which were introduced in England and Wales in March 2001 and on which this analysis is based.

Under NETA, the balance of electricity generation and demand is facilitated through two broad mechanisms:

- the wholesale electricity market;
- active management of generation and demand by the TSO.

In the first instance, the electricity trading arrangements encourage energy balancing as suppliers enter into firm energy contracts with generators in order to meet their expected energy requirements. Energy is traded as a series of half-hourly blocks and participants are incentivised, through an imbalance-pricing regime, to ensure that the volume of energy that they physically produce or consume is consistent with their contractual commitments.[3] This encourages energy market participants to trade in the wholesale markets so as to ensure that sufficient energy is generated in each period to meet demand requirements. However, even with these incentives, there may be errors made by suppliers in forecasting customer demand, or technical difficulties for generators in meeting their contracted output targets. Furthermore, the energy imbalance regime is

---

[2] The TSO for England and Wales is the National Grid Company, while there are two TSOs in Scotland: SP Transmission plc (a subsidiary of Scottish Power) and Scottish Hydro Electricity Transmission Ltd (a subsidiary of Scottish and Southern Energy).

[3] In each half-hour trading period, the difference between a market participant's contracted and actual volumes is cashed out at an imbalance price based on the costs incurred by the TSO in resolving energy imbalances across the system.

based on the total imbalance over a half-hourly period; within a given half-hour, residual differences between supply and demand will remain.

Active management of the system by the TSO is required in order to resolve the residual energy imbalance remaining after market trading.[4] The primary tool used by the TSO to manage the system is the Balancing Mechanism, whereby generators and demand-side participants indicate the prices at which they are willing to change their generation or demand away from their intended levels. By accepting 'Bids' to reduce output (or increase demand) and 'Offers' to increase generation (or reduce demand), the TSO can control the overall balance of generation and demand on the system at any given time. In deciding to take actions in the Balancing Mechanism the TSO must take into account a number of factors, including:

- the expected size of the overall energy imbalance that must be managed;
- the volume and prices of Bids and Offers submitted;
- the speed and rate at which Balancing Mechanism participants can react to instructions from the TSO.

In addition to activities in the Balancing Mechanism, the TSO relies on a number of contractual and statutory arrangements to aid with system-balancing. These arrangements can include buying and selling energy on the forward markets and contracting ahead of time to ensure that sufficient volumes of energy are made available in the Balancing Mechanism.

The costs that the TSO incurs in system-balancing are recovered through the Balancing Services Use of System charge, levied on all market participants on the basis of their metered generation and demand.[5]

2.2 Generation-mix scenarios

OXERA has developed three broad scenarios of the possible mix of generation technologies that might be in operation by 2010. These scenarios reflect three quite different assumptions of outturn trends in the operation or introduction of various forms of generation over the period. Each scenario is derived from OXERA's wholesale electricity model, which analyses the rational economic response of electricity market participants to various influencing factors such as input fuel prices and the strength of environmental constraints. However, the assumptions used to develop these scenarios were selected so as to result in large differences in the generation technologies used across each scenario, and therefore may not necessarily reflect the generation mix that is most likely to emerge.

2.2.1 Scenario 1: High Wind

Under Scenario 1, it is assumed that the generation mix in 2010 remains fundamentally the same as at present, with the exception of the introduction of 6GW of new wind-

[4] One hour prior to the start of a half-hour trading period, the market for electricity in that period closes (referred to as gate closure) and participants are required to inform the TSO of the volume of energy they intend to produce or consume.

[5] Since the beginning of NETA on March 27th 2001, the cost incurred by NGC in taking actions in the Balancing Mechanism has averaged £5.44m per month, while the monthly cost of balancing-services contracts has averaged £13.76m. For the 2002 calendar year, total Balancing Mechanism costs were £52.49m, while balancing-services contract costs were £214.21m. These figures are contained in Ofgem (2003), 'NGC System Operator Incentive Scheme 1 April 2003—31 March 2004 , Final Proposals and Statutory Licence Consultation', March.

powered generation to meet forecast growth in demand. This assumption is consistent with the recent announcements by the government concerning making sites available for up to 6GW of new offshore wind generation by 2010.[6]

2.2.2 Scenario 2: Low Coal

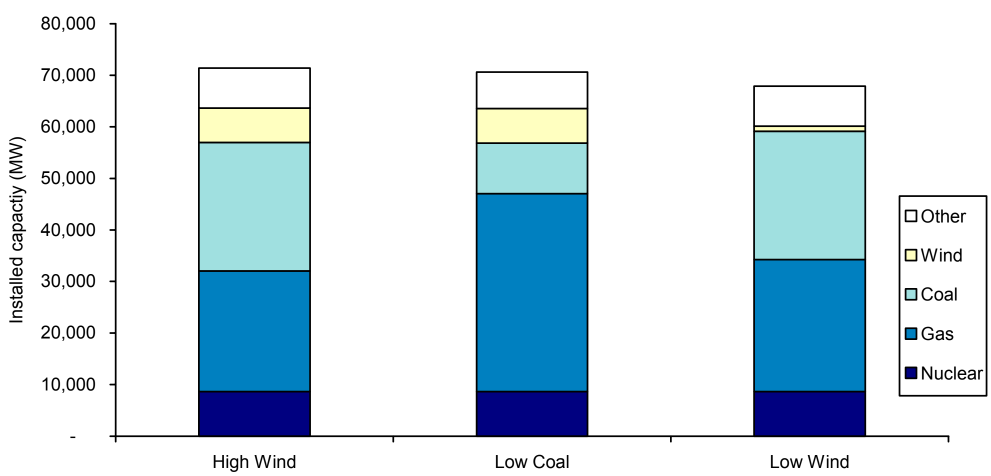
This scenario is based on the premise that, by 2010, environmental constraints and tariffs have forced a significant number of coal-fired generators to close. Under this scenario it is assumed that all coal plant without appropriate emission-abatement technology installed (some 15GW of capacity) would be forced to close. This capacity would be replaced by a combination of new gas-fired generators and the 6GW of new wind generation already assumed in scenario 1.

2.2.3 Scenario 3: Low Wind

Under this final scenario, it has been assumed that there will be little increase in wind generation by 2010 and that growth in electricity demand will be met through additional gas-fired generation.

The installed capacity of different types of generation technology under each scenario is illustrated in Figure 2.1. It should be noted that, in the two scenarios containing high levels of wind generation (scenarios 1 and 2), the overall capacity of generating plant is higher than in scenario 3, which has low wind penetration. The reason for this is that the average output of wind generation in Great Britain is estimated to be less than 40% of maximum capacity.[7] Therefore, a greater overall generation capacity is required to provide a given level of electricity output for wind plant than other sources of generation.

Figure 2.1: Installed capacity of generating plant (2010, MW)



Source: OXERA modelling.

[6] On July 14th, Patricia Hewitt, Secretary of State for Trade and Industry, announced the second round of leasing for offshore wind-farm development, in which sites in the Thames Estuary, the Greater Wash and the north-west were identified as being appropriate for development. See DTI (2003), 'Hewitt Announces Biggest Ever Expansion in Renewable Energy', July 14th.

[7] Natural variations in wind speed affect the output from wind generators, resulting in a range of generation output from zero to full capacity. Therefore the average output over time will be much less than the maximum capacity. For further discussion, see OXERA (2003), 'The Non-market Value of Generation Technologies', June.

3. Load-following capabilities and costs

All generating plant capable of controlling their output, and demand sources capable of adjusting their consumption, have the potential to contribute to load-following. Currently, the majority of load-following is provided by generators; however, the level of flexibility provided by demand-side participants has been increasing in recent years to the extent that Ofgem now estimates that up to 29% of some system-balancing services are provided by the demand side.[8]

For generation load-following, the technical characteristics of each type of plant determine the volume of load-following that it can provide, and the rate at which it is able to alter output. Table 3.1 provides a summary of typical load-following capabilities of various types of generating plant. The figures are indicative only and individual stations may have different degrees of flexibility to that used to describe their generic plant-type.

The typical ramp ranges provided describe the usual range over which a generator would be willing to change output up or down when providing load-following services. For example, a 500 MW coal unit operating at 80% capacity would usually be able to reduce output to 60% or increase it to 100%. The typical range for most types of plant is 20%, with the exception of some nuclear plant, which were assessed to have a tighter output range, and pumped storage, which is designed to be able to adjust output rapidly across its entire output range.

The ramp rate refers to the maximum rate at which output can be increased or decreased, expressed as a percentage of unit size per minute. The greatest flexibility is provided by pumped-storage plant, which is able to ramp up from zero to full output in approximately 60 seconds. Fast-reacting gas turbines are also able to change output quickly, responding at a rate of 20% per minute.

On the whole, CCGTs appear to be able to change output faster than coal-fired plant. However, two different ramp-rate estimates have been given for gas-fired plant. The unconstrained ramp rate refers to the technical ability of the plant to change output, while the constrained ramp rate refers to the rate of change possible within the constraints of the National Transmission System (NTS) for gas.[9] Furthermore, the ramp rate for CCGTs built before 1998 is lower than that for post-1998 plant because the earlier plant were typically built without the capability to bypass the steam generator when fast changes in output were required.

[8] Ofgem (2003), 'England and Wales Wholesale Market—2 Years On', presentation by Sonia Brown, June 20th, available at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/3654_neta_sonia.pdf.

[9] Under the standard Network Exit Agreements for the NTS, the rate at which gas users may change their off-take rate is constrained.

Table 3.1: Typical load-following capabilities for different plant types

Plant Type	Typical unit size (MW)	Typical ramp range up or down (% capacity)	Ramp rate (%/minute)	Constrained ramp rate (%/minute)
Simple gas turbine (normal)	157	20	7	2.9
Simple gas turbine (fast)	157	20	20	2.9
CCGT (pre-1998)	233	20	5	3.1
CCGT (post-1998)	390	20	8	2
Coal (1970s—constant pressure)	500	20	5	n/a
Coal (1970s—sliding pressure)	500	20	3	n/a
Coal (2005+)	600	20	7	n/a
Nuclear AGR	1,200	10	2	n/a
Nuclear UK PWR	1,260	20	0.5–3	n/a
Small hydro	1,260[1]	20	7.5	n/a
Pumped storage	1,728[2]	100	375	n/a

Note: [1] This represents the total installed capacity of small hydro plant in Great Britain. [2] Based on the total size of the Dinorwig pumped-storage plant in North Wales.
Source: Power Planning Associates.

3.1 Costs of altering generator output

Most generating plant are designed with an optimal output level to ensure maximum efficiency. When generators adjust their output to respond to changes in electricity demand they can incur a number of costs. Broadly speaking these costs consist of:

- reduced fuel efficiency due to not operating at the most efficient output level;
- further reduction in efficiency as plant are ramped up or down;
- increased maintenance costs due to additional strains on machinery.

The cost incurred by different types of generator in order to alter output will depend on the efficiency rate and technical characteristics of the plant and the cost of fuel used. Table 3.2 is based on assumed prices of 21.8 p/therm for gas and £45.5/tonne for coal (including the costs of transportation and expected carbon taxes), and estimates of plant efficiencies and maintenance costs as a result of ramping. The ramping cost for pumped storage was based on an estimate of the cost of having previously pumped sufficient water uphill in order to allow pumped-storage plant to ramp up. Pumped-storage plant incur no costs when ramping down. The ramping costs for nuclear plant were not estimated due to lack of available data.

The ramping costs for normal simple gas turbines, CCGTs and constant-pressure coal plant are all quite similar. However, the costs for gas-fired plant were driven primarily by additional maintenance costs, while the ramping costs for coal-fired plant were based more on efficiency and fuel costs.

Table 3.2: Ramping costs

Plant Type	Ramping cost (£/MW changed output)	
	Unconstrained	Constrained
Simple gas turbine (normal)	11.49	8.61
Simple gas turbine (fast)	42.51	8.61
CCGT (pre-1998)	12.95	11.97
CCGT (post-1998)	11.49	18.21
Coal (1970s—constant pressure)	11.01	–
Coal (1970s—sliding pressure)	18.36	–
Coal (2005+)	8.21	–
Nuclear AGR	–	–
Nuclear UK PWR	–	–
Small hydro	–	–
Pumped storage	5.01 up, 0 down	–

Source: Power Planning Associates.

4. Load-following Requirements

The requirement for load-following varies across the day and throughout the year in response to the overall pattern and predictability of demand. Generally speaking, load-following requirements can be broken down into three broad categories:

- following the expected profile of demand throughout each day;
- balancing residual energy imbalances resulting from errors in forecasting demand and generator output;
- ensuring system security through providing frequency response and standing-reserve services.

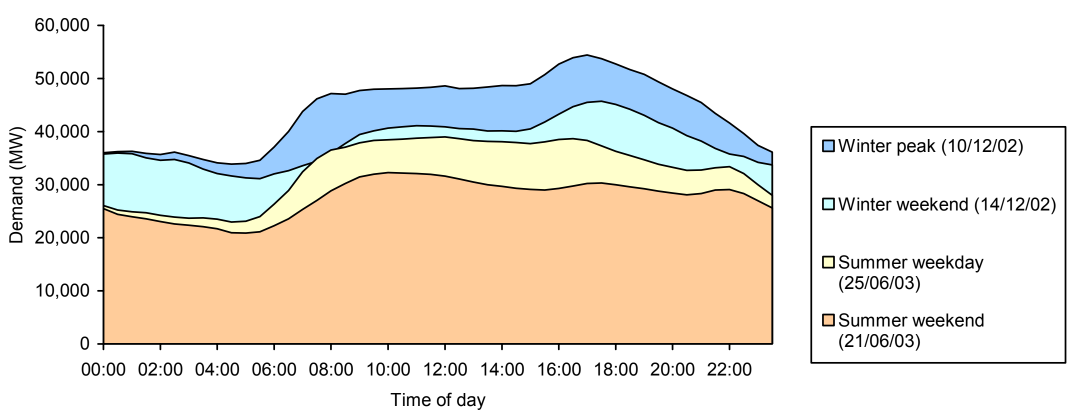
Across these categories, different measures and mechanisms may be employed to satisfy the load-following requirement. For example, changes in the expected load profile throughout the day are dealt with mostly by market participants trading in forward electricity markets. By contrast, short-term errors in demand forecasting and generator output are usually compensated for by the TSO taking actions in the Balancing Mechanism.

Similarly the dynamic characteristics of different types of generation and demand influence the type of load-following service they can provide. Some forms of generation, such as nuclear reactors, prefer to operate at fixed steady levels and therefore do not generally get called on by the TSO. Other generators, such as the pumped storage hydro plant in Dinorwig, can rapidly alter their output and therefore provide a useful tool for balancing short-term fluctuations in the energy balance.

4.1 Following the expected demand profile

The demand for electricity varies significantly over the course of a year and throughout each day, and total electricity production must follow this profile. As an example, Figure 4.1 shows several daily demand profiles for the England and Wales system.

Figure 4.1: Daily demand profiles for England and Wales



Source: Balancing Mechanism Reporting System, 'Initial Demand Out-turn'.

These profiles illustrate some key features of electricity demand.

- The greatest changes in demand occur in the morning between approximately 5.30am and 8am as people wake up and begin switching on electrical equipment.
- On a peak winter weekday, demand can rise by more than 36% (from 36.4 GW to 47.1 GW) between 5.30am and 8am. Although overall demand is lower during the summer, the change in demand during weekday mornings is virtually the same as in the winter peak.
- The change in demand is lower on weekend mornings reflecting lower commercial and industrial loads and a more staggered start to the day for many people.
- During winter afternoons, demand increases in response to heating and lighting requirements; however, by 6pm this is offset by reductions in commercial and industrial loads. For example, on December 10th 2002, from 5.30pm to midnight, demand dropped by 17.6 GW.

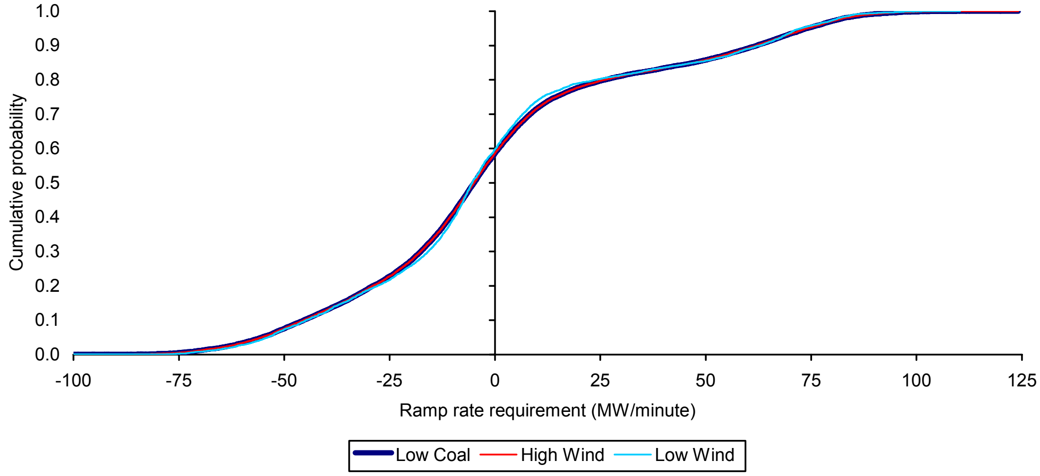
Based on changes in half-hourly demand, it is possible to determine the rate at which total generator output would need to change (the system ramp rate) at different times of the day and year in order to follow the expected load profile. The rate of change required by controllable generation will also be affected by the variable output of wind generators. Because wind generation is uncontrollable and subject to fluctuation, controllable generation will be required to follow not only the changes in total demand but also changes in wind generator output. This would increase the overall rate of change required in periods when wind output falls, and reduce the requirement when wind output rises.

4.2 Estimating future requirement for following load profiles

Over time, changing patterns of energy use will influence the overall level and shape of the demand profile, and therefore the rate at which total output must change. Consideration of how generation will be required to meet this load-following requirement will in turn be influenced by the mix of generation technology employed. For example, the introduction of significant volumes of wind generation is likely to increase the overall ramp rate required from controllable generation, while the introduction of plant with faster individual ramp rates may reduced the number of plant required for load-following.

Using predictions of the overall level and shape of Great Britain electricity demand for 2010, a set of ramp-rate requirements have been calculated under each of the three generation-mix scenarios. These rates estimate the overall rate of demand change to be compensated for by flexible generation after taking into account fluctuation in wind generator output. Figure 4.2 illustrates these ramping requirements as a set of cumulative probability curves. These show the proportion of time for which the required ramp rate is expected to be less than a given level. For example, under all three scenarios the expected ramp rate is expected to be less than 25MW per minute for 80% of the year.

Figure 4.2: Distribution of ramp-rate requirements



Source: Power Planning Associates.

The ramp rate requirements estimated for the High Wind and Low Coal scenarios are identical, reflecting the same assumptions on demand profiles and wind generation volume. The Low Wind scenario results in a slightly tighter distribution of ramp-rate requirements due to the lower volume of wind generation assumed.

4.3 Residual energy balancing

Under NETA, participants in the electricity market must provide the TSO with at least one hour's notice of their intended patterns of generation and consumption. Although these notifications must be an accurate reflection of their intentions, differences can arise between the intended profiles and the actual generation and demand observed. Such differences can be described as demand estimation errors and generator output errors. Demand estimation errors are caused by the inability to forecast exactly the level of demand and fluctuations in that level on a minute-by-minute basis and by uncertainty in the exact timing of changes in demand.[10] Sources of generator output errors include uncontrollable fluctuations in generator output and the effect of generator plant failures.

The TSO will need to adjust the balance of generation and demand in order to account for these demand estimation and generator output errors. This is usually achieved by utilising Bids and Offers in the Balancing Mechanism to adjust the overall level of generation and demand to bring the system into balance.[11] NGC estimates that it takes in excess of 500 balancing actions each day. On a monthly basis the volume of balancing actions taken represents between 3.5% and 7.5% of total demand.[12]

4.3.1 Estimating residual energy-balancing requirements

Demand estimation error is influenced by the level and rate of change of demand as well as the proportion of industrial, commercial and domestic load contributing to the overall

[10] Typical examples of this phenomenon include the effect of advertisement breaks during popular television programmes and televised sporting events.
[11] Other mechanisms can be used by the TSO to ensure energy balancing such as pre-gate-closure balancing transactions. For more details see NGC (2003), 'Balancing Principles Statement', May.
[12] Ofgem (2003), 'England and Wales Wholesale Market—2 Years On', presentation by Sonia Brown, June 20th, available at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/3654_neta_sonia.pdf.

demand level. Generator output error is also influenced by demand level and rate of change; however, the technical characteristics of different plant types will also have an effect on the overall magnitude of the error. As these errors represent positive and negative deviations from a given level, they are often expressed in terms of a root mean square (RMS) value, which gives a measure of the average expected magnitude of the error, independent of the direction of error. Combining the demand and generator errors gives an estimate of the volume of the energy-balancing requirement.

Estimated levels of demand estimation and generator output error have been calculated for each generation mix scenario, taking into account predicted demand profiles and the generator mix assumptions. These are shown in Table 4.1.

Table 4.1: Estimated total demand estimation and generator output error

Scenario	Average total net demand estimation error (MW)	Average total conventional generator output error (MW)
High Wind	679.7	467.4
Low Coal	679.7	410.1
Low Wind	683.6	465.2

Source: Power Planning Associates and OXERA calculations.

The demand levels used to calculate these estimation errors were based on the net demand after removing the contribution of simulated wind generation. Therefore, although the High Wind and Low Coal scenarios appear to have lower levels of Demand Estimation error, this is because they are based on a lower overall net demand than the Low Wind scenario.[13] Looking at the values for Generator Output error, the main difference occurs under the Low Coal scenario where the error is significantly smaller. This is because this scenario assumes that significant volumes of older generation with less-stable output characteristics would be replaced by newer, more consistent generation. However, it was not possible to estimate the generator estimation error of wind generation within the timeframe for this study. The difference in generator estimation error between the High Wind and Low Wind scenarios therefore represents only the change in error of controllable generation.

4.4 Providing frequency response and standing reserve

Frequency response and standing reserve are methods of ensuring the quality and security of the electricity system. Frequency response refers to the automatic change in demand or generator output in response to a change in the system frequency. Equipment connected to the electricity system is designed to operate within a tight frequency range. If, at any given point in time, demand exceeds generation, the frequency of the system will fall. Similarly, system frequency will rise when generation exceeds demand. In order to facilitate the safe operation of the network and the equipment connected to it, the TSO must ensure that system frequency remains within a set range.[14]

It is currently a condition of connection to National Grid's transmission system that all generators are able to provide a minimum level of frequency response. However, in order

[13] This leads to the level of demand estimation error for the High Wind and Low Coal scenarios being slightly underestimated.

[14] Under the Electricity Supply Regulations 1988, NGC is required to maintain system frequency at 50.00Hz +/– 1%, unless exceptional circumstances prevail.

to provide frequency response, a generator must be synchronised with the system and operating at less than full capacity. Demand-side participants are also able to provide frequency response by automatically curtailing consumption in response to a decrease in system frequency.

Standing reserve is required to ensure that the TSO has sufficient levels of flexible generation or demand available to cope with unexpected events. It is provided by generation that can increase output, or demand that can decrease consumption, within 20 minutes' notice and that can sustain this deviation for at least two hours. Standing reserve costs relate to the cost of keeping capacity available and the costs of utilising this capacity if required. The requirement for standing reserve availability used in this analysis was based on the expected maximum level of demand under each scenario, after taking into account the intermittent wind generation. The expected level of utilisation was assumed to be proportionally similar to current levels. The standing reserve requirements assumed under each scenario are shown in Table 4.2.

Table 4.2: Standing reserve requirements

Scenario	Availability requirement (MW)	Expected utilisation (GWh)
High Wind	2,147	85
Low Coal	2,148	85
Low Wind	1,970	78

Source: Power Planning Associates and OXERA calculations.

5. Estimating the Cost of Load-following

Clearly, the volume and type of generating technology will influence the overall cost of load-following. As old plant reach the end of their economic life and are replaced, it is important to ensure that the resultant generation mix provides sufficient flexibility to the system. Using the generation-mix scenarios described in section 2.2, the cost of load-following was estimated under each of the three main categories of load-following, acknowledging, as discussed in section 4.3, the fact that the treatment of wind generation in the model may slightly underestimate the cost associated with this form of generation in terms of residual energy balancing.

5.1 Following load profile

The cost of following the overall profile of demand is determined by the rate of change of demand and the costs of the generating plant used to match these demands. Using the rate-of-change requirements outlined in section 4.2, a calculation was made of the number and type of units that would be required to meet each level of requirement. This calculation takes into account the expected output and estimated ramp rates for each type of plant under each level of ramping requirement. For the purposes of this analysis the constrained ramp rates for gas-fired plant were used as they reflect more closely the practical limitations on gas-fired stations that exist at present, and any change in these limitations would require a cost–benefit analysis to be undertaken. The number and type of units needed to meet each level of the ramping requirement determine the overall cost of following the load profile. Table 5.1 summarises the average ramping requirements and total ramping costs under each scenario.

Table 5.1: Ramping requirements and costs

	Average number of units required	Average ramp rate of units used (MW/minute)	Total ramping cost (£m)
High Wind	2.5	15.6	215.2
Low Coal	3.3	10.0	224.1
Low Wind	2.5	15.6	207.9

Source: Power Planning Associates and OXERA calculations.

Costs vary between the scenarios based on differences in the number of plant required and the costs of the plant used to provide load-following. Total ramping costs are lowest under the Low Wind scenario, reflecting the higher level of flexible and controllable generation available than under the High Wind and Low Coal scenarios. Despite the average number of units being the same under the High Wind and Low Wind scenarios, average ramping cost per MW increase under the High Wind scenario due to the reduced volume of controllable generation available.

Ramping costs are highest under the Low Coal scenario as a result of the lower average ramping rates achievable. This in turn is due to the significant volume of constrained gas-fired plant replacing coal-fired plant.

5.2 Residual energy balancing

Estimates of the load-following costs incurred for energy balancing are obtained by multiplying the Demand Estimation and Generator Output error requirements described in section 4 with estimates of the price of purchasing balancing energy. The price of balancing energy was assumed to reflect the operational and running costs of plant expected to be part-loaded (and hence able to provide flexibility) in each period of the analysis. This is a cost-based assessment of the price of balancing energy. The price at which participants make capacity available within the Balancing Mechanism may be higher than the cost-based price, reflecting their views on the market value of flexibility.

Table 5.2 Energy-balancing requirements and costs

	Average demand estimation error (MW)	Average generator output error (MW)	Average energy balancing price (£/MWh)	Total energy balancing cost (£m)
High Wind	679.7	467.4	24.6	246.9
Low Coal	679.7	410.1	21.4	204.7
Low Wind	683.6	465.2	24.0	241.7

Source: Power Planning Associates and OXERA calculations.

Table 5.2 provides estimates of the energy-balancing requirement and cost under each generation-mix scenario. Energy-balancing costs are highest under the High Wind scenario as a result of higher energy-balancing prices. This effect can be explained by the lower volume of flexible plant available in this scenario. Costs are lower under the Low Wind scenario as the higher level of controllable plant available results in a lower average balancing price.

In the Low Coal scenario, there is a marked reduction in balancing costs reflecting the large reduction in generator output error, as explained in section 4, and a significantly lower average balancing price. This lower balancing price can be accounted for by the larger volume of cheap gas-fired generation assumed under this scenario.

5.3 Frequency response and standing reserve

Frequency response and standing reserve costs were estimated for each scenario, based on the cost of part-loading plant providing frequency response and the expected volume standing reserve required. Part-loading costs were calculated by assessing the impact of reduced plant efficiency as well as the additional plant start-up costs resulting from the part-loading requirements.

Table 5.3 shows the frequency response and standing reserve costs estimated under each scenario. The assumption of significant volumes of wind generation under the High Wind and Low Coal scenarios results in a greater requirement for part-loaded plant due to the variability of wind generation. However, the assumed plant costs under each scenario have a greater impact on the overall frequency response and standing reserve costs.

Table 5.3: Standing reserve requirements and costs

Scenario	Cost of part-loading for frequency response (£m)	Total standing reserve cost (£m)	System security costs (£m)
High Wind	47.6	45.5	93.1
Low Coal	50.9	45.7	96.6
Low Wind	46.0	40.6	86.6

Source: Power Planning Associates and OXERA calculations.

6. Conclusions

The primary aim of this study was to look at the impact that the mix of generation technology used in the future could have on the capability of the system to follow variations in demand. In each scenario, the system was capable of meeting the load-following requirement, but there were differences in the costs of achieving this.

A summary of the total estimated load-following costs is provided in Table 6.1. These cost estimates provide a useful means of assessing the effect of changes in generation mix; however, the values are highly dependent on assumptions regarding the relative prices of different fuels—in particular, differences in cost between producing electricity from gas-fired and coal-fired plant. Therefore, it is more useful to look at the changes in load-following costs across scenarios rather than the costs themselves.

Table 6.1: Summary of load-following costs (£m per year)

Scenario	Ramping costs	Energy-balancing costs	System security costs	Total load-following costs
High wind	215.2	246.9	93.1	555.2
Low coal	224.1	204.7	96.6	525.4
Low wind	207.9	241.7	86.6	536.2

Source: OXERA and Power Planning Associates calculations.

The results of the analysis indicate that the introduction of significant volumes of new wind generation would result in increased load-following costs. Wind generation increases the volume of load-following required from other sources of generation and demand across each of the three load-following categories. Both the rate of change of the residual demand profile (after subtracting wind generation from total demand) and the level of forecasting error increase in relation to the volume of wind generation on the system, this also results in an increase in the volume of frequency response required.

Another significant factor is the impact of replacing coal-fired generation with new CCGT plant. Technically, the load-following capabilities and costs of CCGT plant are not significantly different to those of existing coal plant; however, constraints on the gas transmission system could limit the flexibility that gas-fired plant are able to provide. Although this does not prevent gas-fired plant providing load-following capabilities, more plant would be required and hence greater costs would be incurred.

There are other factors that could have an impact on load-following capabilities and costs in the future, which have not been considered in this analysis. Not least of these is the potential role that interconnectors could play both in terms of providing load-following capability and contributing to load-following requirements. Traditionally, the flow of energy into the UK via the French interconnector has remained relatively constant, reflecting the low cost of French imports relative to local generation. However, the development of electricity trading across Europe, and changes in relative prices, could result in more variable flows across the interconnector.

Currently, the costs incurred by generators in providing load-following are reflected partly in short-term electricity prices and partly in the prices charged for providing flexibility through the Balancing Mechanism or balancing-services contracts. Ultimately, these costs are borne by electricity consumers. The implication of this study is that future load-following costs will be influenced by the mix of generation technology used in the future and therefore should be considered in the formulation of energy policy.