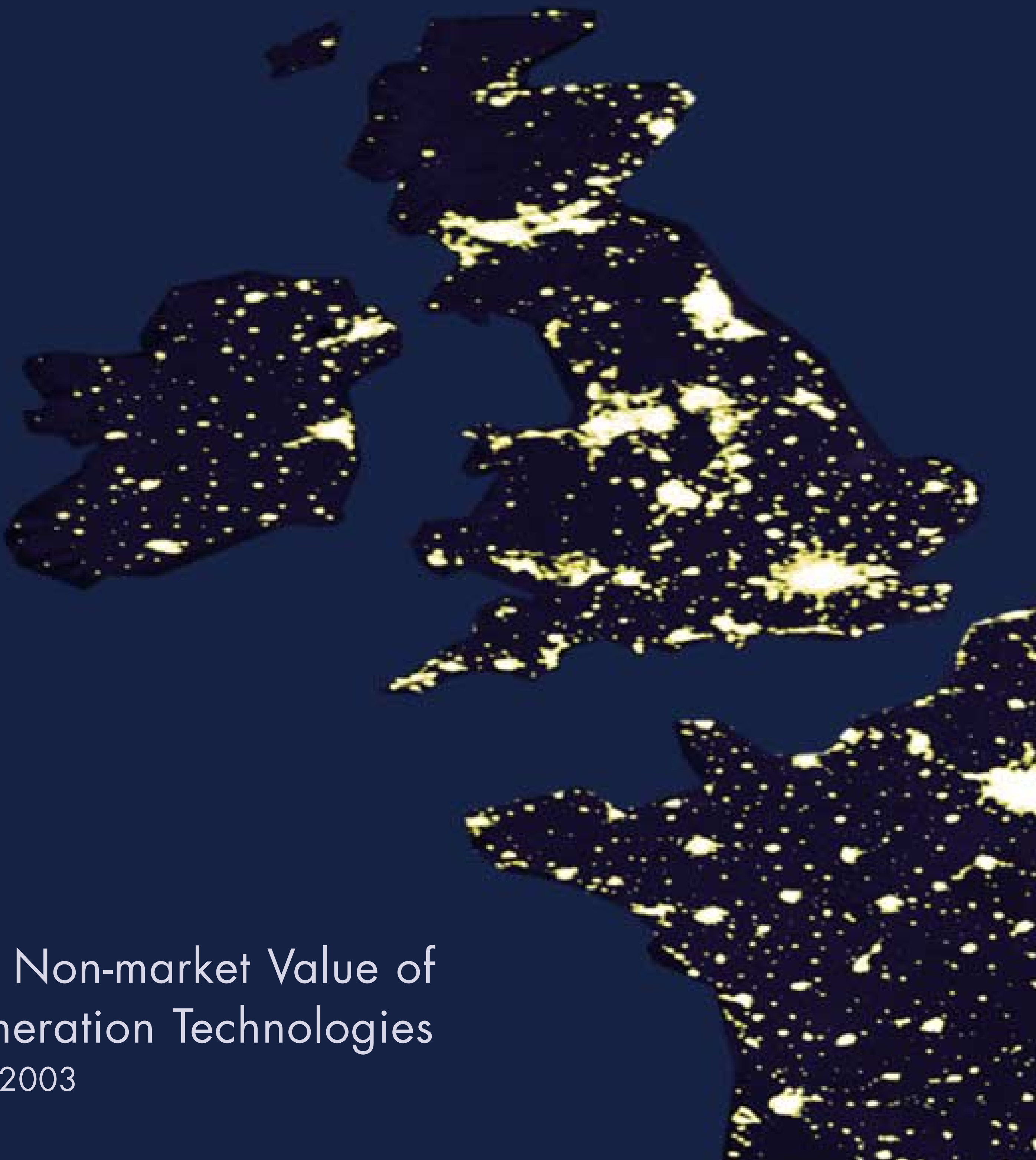
OXERA

Oxford Economic Research Associates



The Non-market Value of Generation Technologies

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Contents

The Energy White Paper, 'Our Energy Future—Creating a Low Carbon Economy', published by the Department of Trade and Industry (DTI) in February 2003, establishes the key goals for a new energy policy:

- to place the UK on a path to achieve 60% reductions in carbon-dioxide (CO_2) levels by 2050;
- to maintain the reliability of energy supplies;
- to promote competitive markets; and
- to ensure that all homes are adequately and affordably heated.

Giving priority to these new objectives does not automatically imply that they will be delivered in the most cost-effective and efficient manner in the electricity sector, since the environmental and energy-security costs and benefits associated with different generation types are not necessarily reflected accurately in market prices.

Most market assessments of generation technologies focus on the relative costs of generating electricity in terms of input fuel costs, conversion efficiencies, and operating and maintenance costs. What is not evident in these operational costs are the impacts on electricity supply security, environmental emissions, and incremental infrastructure requirements implied by additions of different generation types to the current fuel mix.

In this report, OXERA has undertaken an assessment of the major non-market costs and benefits associated with different types of generation and fuel mixes. The analysis draws on scenarios produced from OXERA's wholesale electricity market model and a new methodology developed by OXERA for assessing the security-of-supply implications of different fuel mixes. In addition to setting out this new framework, which includes appropriately assessed non-market costs, this report provides a useful contribution to the debate on how best to achieve the long-term energy policy goals.

Modelling Security of Electricity Supply

Concerns over security of supply in the electricity sector have, in the past, centred on the adequacy of the network infrastructure for delivering electricity. Although this remains an area for regulatory and political scrutiny, expected developments in the generation fuel mix are beginning to raise concerns about the reliability of generation in addition to transmission and distribution. In particular:

- support for renewable generation in the UK is expected to lead to significant increases in the capacity of wind generation both onshore and offshore, requiring the system to deal with a higher degree of short-term intermittency;
- a growing dependence on gas-fired generation is forecast up to 2020—OXERA's base scenarios suggest an increase from 42% in 2003 to 53% in 2020—at the same time as the UK is expected to become a net gas importer, with long-term reliance on regions such as the former Soviet Union and the Middle East.

The implications of increased reliance on wind generation have been modelled explicitly by OXERA using historical wind-speed data for specific geographic regions over the past 20 years. This approach has enabled profiles of potential wind generation to be estimated and compared with current demand profiles. The conclusions of this analysis are that:

- there is significant daily and monthly variation in the achievable load factors of wind; and
- the peaks in wind generation are generally not fully coincident with electricity demand—ie, wind generation is not necessarily available at times of peak demand.

Table 1 illustrates the impact of this second conclusion. The table shows the number of hours in a year in which defined levels of demand and wind capacity are available. It indicates that, on average, wind generation is only producing at peak for five days of the year, only eight hours of which coincide with the period when demand is at its peak.

However, security of supply from the perspective of the consumer is dependent not on the profile of an individual generation type, but on the profile of the overall portfolio. Thus, although wind may not contribute much to meeting peak demand, it may not necessarily lead to significant periods of excess demand on the system if there is sufficient capacity available from other generation sources to meet this reliably.

Table 1: Coincident hours of wind generation and electricity demand

Percent of maximum output	40%	50%	60%	70%	80%	90%	100%
	Percent of peak demand						
10%	0	276	517	399	339	88	23
20%	0	123	420	437	472	140	23
30%	0	73	264	348	396	86	55
40%	0	39	177	263	338	174	29
50%	0	27	103	196	259	161	34
60%	0	17	74	205	201	181	38
70%	0	7	61	201	214	230	33
80%	0	1	46	125	152	161	21
90%	0	0	14	87	86	103	17
100%	0	0	1	30	39	43	8

Source: OXERA.

In order to capture this portfolio effect, OXERA has developed a methodology that estimates the reliability of all generation types present in the fuel mix. The reliability of an individual type of generation can be represented by two components:

- input fuel interruption—the probability that the input fuel source is available to the generator, covering both political risks of non-delivery and transit risks; and
- plant failure—the probability that the plant will not be able to operate because of technical problems/constraints, or as a result of terrorist action.

Estimates of these probabilities for all the major generation types have been acquired from insurance market data provided from an independent source. The market data draws on knowledge of existing insurance contracts (for example, those underwriting existing liquefied natural gas (LNG) tanker transportation) and on proxies for politically motivated interruptions (for example, the political risk indices used by many insurers). This data has also been supplemented to include not only the probability of an interruption, but also the duration and proportion of the generation type that would be affected.

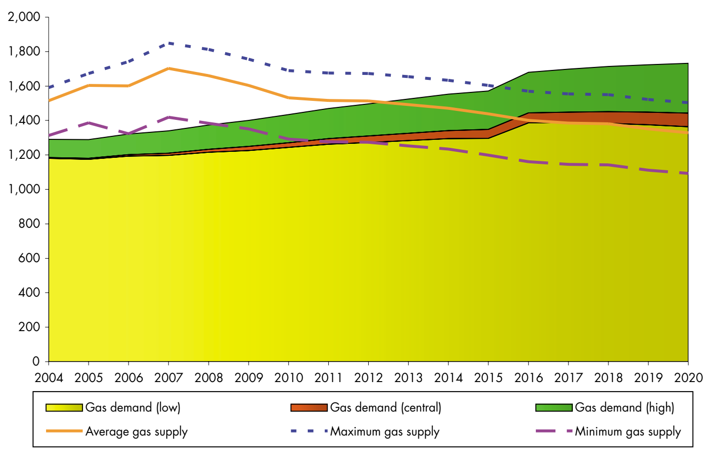
Particular attention has been given to the input fuel risk for gas-fired generation, since the strategic risks associated with natural gas importation are new for the UK and have potentially significant implications, given the expected dominance of gas in the fuel mix.

OXERA's analysis of the natural gas market has concentrated on modelling the impact of different supply (in terms of available infrastructure and the source of the gas) and demand scenarios. In particular, the supply scenarios assume specific storage, LNG import and pipeline capacities, together with estimates of the potential division of supply between the major producers (including indigenous production and imports from Norway, the Netherlands, Russia and LNG suppliers, principally Qatar and Algeria).

As with the generation sector, insurance market forecasts have been acquired to allow modelling of the probability of interruptions to supply from the different sources or as a result of infrastructure failure.

Figure 1 highlights some of the scenarios that may occur. These have been translated into probabilities that the generation sector, as opposed to the domestic or industrial sectors, may have insufficient gas supplies to meet generation requirements in the future.

Figure 1: UK gas supply and demand, 2004–20 (TWh)



Source: OXERA.

Because the events affecting different generation types may occur concurrently, OXERA undertook a Monte Carlo simulation to derive an annual profile of generation capacity availability based on a scenario for the generation capacity mix in 2020 consisting of 45% conventional gas-fired generation, 13% coal, 5% nuclear, 13% renewables, 13% domestic CHP (dCHP), and 11% 'other' generation (including interconnectors and pumped storage). This enabled calculation of a system-wide security measure, as shown in Table 2. Similarly to Table 1, the numbers represent hours in a year where demand and supply can be expected to be at their respective levels (for example, the 133 in the bottom right of the table means that there are 133 hours where demand net of wind will be 70 GW and available capacity will be greater than 70 GW). The shading in the table indicates that capacity is more than adequate to meet demand.

What this shows is that, for the assumed generation mix in 2020, there are 10 hours where demand can be expected to be greater than available capacity (implying lost supply equivalent to around 100 GWh).

Table 2: **Implied supply security in 2020 (base-case scenario)**

	Demand net of wind (GW)				
	20–29	30–39	40–49	50–59	60–69
Capacity (GW)					
30–39	–	–	–	–	–
40–49	0	1	1	0	0
50–59	1	7	11	4	0
60–69	16	103	144	62	5
70+	398	2,623	3,679	1,572	133

Source: OXERA.

This result is dependent on the overall fuel mix assumed in the market. For comparison, the methodology has also been run for two alternative fuel mixes: one with higher wind generation and one with a new nuclear build programme. Tables 3 and 4 show the implied security risk under the nuclear and high-wind scenarios respectively. As can be seen, the number of hours of potential interruption is reduced by to only 4 (or 40 GWh) in the nuclear scenario and 6 (or 60 GWh) in the high-wind scenario.

This illustrates the generic potential of the approach to assess the security inherent in different electricity market scenarios of generation or demand, and to map how this security varies over time, as new investment occurs.

Table 3: **Implied supply security (new nuclear build)**

	Demand net of wind (GW)				
	20–29	30–39	40–49	50–59	60–69
Capacity (GW)					
30–39	–	–	–	–	–
40–49	0	0	0	0	0
50–59	1	7	11	4	0
60–69	1	10	13	6	0
70+	413	2,716	3,810	1,628	137

Source: OXERA.

Table 4: **Implied supply security (high wind)**

	Demand net of wind (GW)				
	20–29	30–39	40–49	50–59	60–69
Capacity (GW)					
30–39	–	–	–	–	–
40–49	0	0	0	0	0
50–59	3	9	9	3	0
60–69	34	126	130	36	3
70+	877	3,231	3,316	914	69

Source: OXERA.

The quantification of the degree of security of supply associated with a given fuel mix can be crudely transformed into a monetary benefit for certain types of generation, which can be expressed in £/MWh, comparable to the standard generation cost comparisons. In the report, the additional value of improved security of supply is linked to the value of lost load (VOLL) used previously in the Electricity Pool of England and Wales. Applying this value to the two alternative scenarios presented implies a security-of-supply benefit to wind generation of £5.1/MWh and to nuclear of £3.7/MWh in 2020.

The testing of other options for improving security of supply within this framework—for example, reinforcement of the gas delivery infrastructure via additional LNG terminals or increased storage capacity—may indicate that these are more cost-effective. However, what has been illustrated is that there are potentially substantial benefits that may not be explicitly accounted for in the base generation costs.

Carbon and Other Emissions

In quantifying the environmental costs and benefits, OXERA has drawn on the range of independent estimates of the damage costs of carbon and other emissions. OXERA's assessment of these studies suggests an appropriate central carbon damage cost figure of £25/tC and a damage cost for NOx of £3,484/tonne and for SO2 of £2,800/tonne.

For consistency with the security-of-supply analysis, OXERA has assessed the relative changes in emissions between different generation mixes, rather than introducing a specific cost adjuster to individual generators.

Because OXERA's wholesale market model already simulates the operation of a carbon trading market, with an assumed carbon price of £10/tC, the full cost of carbon damage is not captured by the implied generation cost faced by consumers. Thus, any reduction in carbon emissions as a consequence of the use of alternative fuel sources provides an additional benefit of £15/tC saved. Because estimates of carbon damage costs vary, a range has been used in the main report—from £17/tC to £40/tC.

Therefore, the additional value that the above-mentioned nuclear or wind scenarios provide in terms of lower carbon and other emissions should also be captured as non-market benefits of these generation types. Table 5 presents the total reductions in the three emission categories over the base case and the implied benefit. As can be seen, in terms of their environmental benefit, nuclear's contribution is more significant than that of wind, mainly because wind generation relies more heavily on fossil-fuel generation at peaks.

Table 5: **Emissions benefits in 2020**

	Base case	High wind	New nuclear
Carbon emissions (mt)	37.9	35.9	30.8
NO_x emissions (kt)	121.6	119.6	98.9
SO_2 emissions (kt)	51.6	52.7	40.2
Total saving (£/MWh)	–	1.1–2.2	3.8–5.6

Source: OXERA.

Network Infrastructure Costs

As well as assessing the benefits of different generation types, the incremental costs must be taken into account. Therefore, in analysing the cost of renewables, it is necessary to consider the incremental network infrastructure costs incurred. These do not include the cost of connection to the network, which is covered by the generation cost, but do include the network reinforcement and management costs associated with renewable generation. These costs arise in both the transmission network and the distribution network.

In this study, OXERA has estimated the incremental investment costs associated with a growth in wind generation. Given uncertainty over actual capital costs, a range of potential costs has been assumed. These indicate that the incremental costs of network infrastructure in the high wind scenario are in the order of £3.8/MWh to £9.9/MWh. The implication of this is that network infrastructure costs effectively negate a large proportion of the non-market benefits already associated with the high wind scenario

Summary of the Overall Costs of Generation

Throughout this study OXERA has sought to integrate the market and non-market costs associated with different forms of generation, which must be incorporated if appropriate investment decisions are to be taken in the marketplace to ensure that the government's policy objectives are efficiently met. Table 6 shows the main quantification of the non-market benefits for the indicative scenarios analysed in the study. Taking into account these benefits may significantly alter the perception of the most cost-effective means of meeting the government's policy objectives.

Table 6: **Summary non-market generation value, 2020 (£/MWh)**[1]

	Electricity network infrastructure	Carbon emissions	Security of supply	Other emissions	System cost	Total
Wind	–3.8 to –9.9	0.9 to 2.0	5.1	0.2	0.1	**–3.6 to 3.6**
Nuclear	0	1.5 to 3.4	3.7	2.3	0.6	**8.1 to 10.0**

Note: [1] Negative value is a cost of the generation type.

Source: OXERA.

1. Introduction

The recently published Energy White Paper, 'Our Energy Future—Creating a Low Carbon Economy' (DTI, 2003) establishes a new set of goals for energy policy, reflecting the new environmental and energy-security challenges that the UK economy will face over the medium to long term. These goals are to:

- put the economy on a path to deliver 60% reductions in CO_2 emissions by 2050, as recommended by the Royal Commission on Environmental Pollution (RCEP, 2000);
- maintain the reliability of energy supplies;
- promote competitive markets to help improve productivity and sustainable economic growth; and
- ensure that every home is adequately and affordably heated.

Most standard analyses of the costs associated with different forms of generation focus on the underlying operational costs of the stations (defined against a baseload operating profile). However, the priority afforded to environmental impact and supply security in energy policy suggests that the actual value of generation in the fuel mix should consider the incremental effect of that particular type of generation on these key goals.

By failing to account for:

- the impact of the generation type on overall supply security in the market;
- the additional infrastructure investment costs associated with connection; and
- the environmental impact, most notably on overall emissions, but also encompassing other external costs;

the market may favour certain generation types, thereby leading ultimately to an inefficient fuel mix in the longer term.

To address these issues, OXERA has undertaken a series of studies aimed at providing a methodology for establishing the value of generation within a long-term energy policy. The analysis has largely focused on three areas:

- establishing a quantitative assessment of overall electricity security of supply—with specific reference to the impact of increased reliance on intermittent renewable sources (ie, onshore and offshore wind generation) and on gas-fired generation over a period when the UK will become a net gas importer;
- providing a quantification of the additional system costs associated with renewable generation; and
- valuing emission damage costs or benefits attributable to different generation sources.

Because the additional costs or benefits may vary over time, the costs and benefits of different forms of generation are compared between scenarios that rely more heavily on one or other of the fuel sources. Essentially, this involves comparing a scenario of high wind generation or of new nuclear build with a base-case scenario that imposes no real constraints on carbon emissions or levels of supply security.

Improvements or detriments to emissions and security performance associated with these alternative scenarios are then translated into costs or benefits in terms of £/MWh, which can then be applied to the base operating cost figure in order to derive an implied cost of the generation type in the economy.

The report is structured as follows:

- section 2 describes the main scenarios, detailing the core assumptions underlying the base case, where reliance on gas-fired generation continues to grow, and presenting a high-level comparison with the alternative scenarios;
- section 3 discusses the quantification of the implied security-of-supply benefits associated with each scenario, with particular reference to the characteristics of wind generation and the gas supply market as determinants of future security in power generation;
- section 4 focuses on the operation of renewable generation, the implication for short-term coincidence of wind generation and load, and the additional infrastructure costs associated with renewable generation;
- section 5 provides a means of quantifying the emissions benefits and costs associated with the different generation sources, focusing on CO_2, NOx and SO_2;
- section 6 concludes.

2. Market Scenarios

The analysis of the value of different forms of generation has been carried out on the basis of three potential generation scenarios up to 2020: a base case and two alternative fuel-mix scenarios.

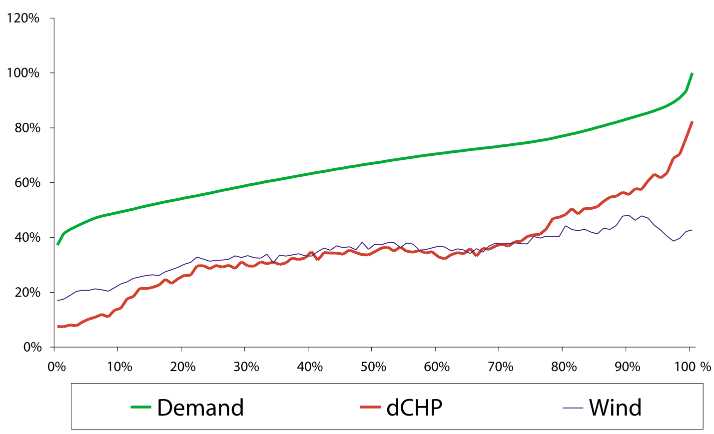
2.1 Scenario descriptions

2.1.1 Base case

This scenario forms the baseline for development of the generation sector up to 2020, and contains a number of assumptions for various aspects of the sector.

- **Renewables**—in this scenario, wind generation develops as detailed in the low growth trend described in section 4, reaching a total installed capacity of 6.5 GW by 2020, of which 4 GW is in Scotland. At the same time, energy-from-waste generation grows to a total of 2.5 GW over the same period.
- **CHP**—dCHP penetration reaches a level of 9.6 GW by 2020. Industrial CHP is as assumed in the National Grid Transco Seven Year Statement 2002.
- **Demand**—this continues to grow at the rate suggested by National Grid Transco in its 2002 Seven Year Statement, and increases after 2008 at a rate of 0.4% pa. The overall relationship between the level of demand and the volume of wind and dCHP output is shown in Figure 2.1.

Figure 2.1: **Annual coincident load–duration curves**



Source: OXERA.

- **Nuclear**—the current fleet of nuclear generators retires at their current announced closure dates and there is no replacement build programme.
- **Coal**—the introduction of the EC Large Combustion Plants Directive (LCPD) has a major impact on the operations of coal-fired power stations from 2008. Plant that opt out are required to limit their operations to 20,000 hours between 2008 and 2015, and those that remain open thereafter face strict emission limits. The implications of this are discussed later in this section.
- **Gas-fired generation**—the remainder of the demand is met by a mix of combined-cycle gas-turbine (CCGT) and open-cycle gas-turbine (OCGT) generation.
- **Fuel costs**—fuel prices are assumed to carry forward at relatively flat levels. The price of coal is assumed to be an average of £30/tonne delivered to power stations throughout Great Britain, with transportation costs providing geographical variations. The gas price is assumed to fall from current levels of ~20p/therm to 18p/therm over the next few years, until increased transportation costs and marginal gas prices result in the price rising to 20p/therm again between 2013 and 2015, where it will remain until the end of the modelling horizon. Fuel costs have been maintained between scenarios.
- **Carbon costs**—the model assumes that an EU emission trading scheme is in place from 2005, and that the price of carbon is set within that market. While there are discussions in section 5 on the damage costs of carbon, it is assumed that price the determined under market forces is £10/tC.

2.1.2 High-wind scenario

In this scenario, wind sees greater penetration in the generation sector, and reaches a total installed capacity of 14.2 GW by 2020, again with 4 GW installed in Scotland. This delivers 20% of electricity from renewable sources in 2020, a possible policy target proposed in the White Paper. All other parameters are as in the base case.

2.1.3 Nuclear

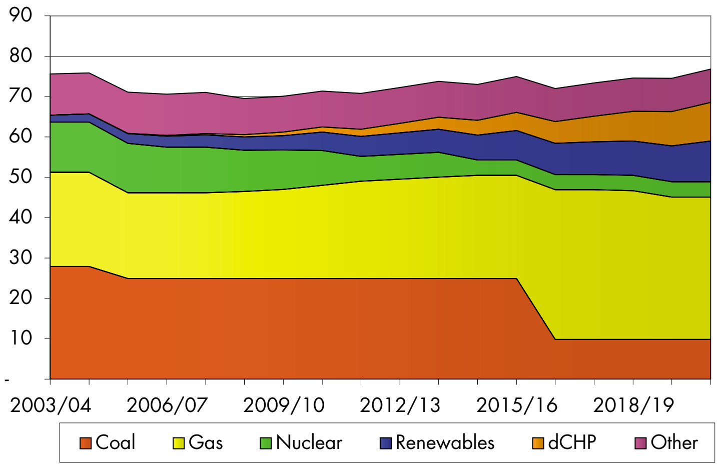
As in the base case, but with the instigation of a new nuclear build programme, commissioning 10 GW of new reactors between 2012 and 2025, sufficient to replace the 8.6 GW retiring between now and 2020. By 2020, 6 GW are on line.

2.2 Scenario results

2.2.1 Base case

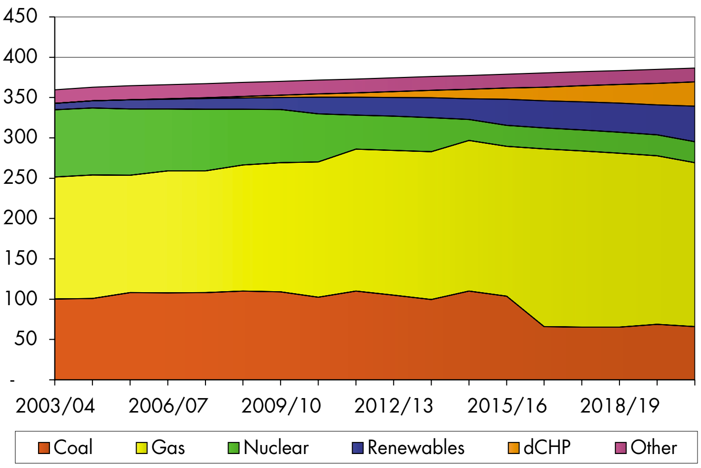
Figures 2.2 and 2.3 show the installed capacity and annual output for the different types of generation in the base case.

Figure 2.2: Installed capacity (GW) in the base-case scenario



Source: OXERA.

Figure 2.3: Total output (TWh) in the base-case scenario



Source: OXERA.

In 2005, capacity falls as the market reacts to reduce capacity headroom in response to low wholesale prices.

The largest year-on-year change in all of the scenarios is between 2015/16 and 2016/17. Here, the much stricter emission constraints set out in the LCPD result in significant closures of coal-fired generation. The Directive also limits generation from opted-out plant to 20,000 hours between 2008 and 2015, whether the UK chooses the emission limit values (ELV) or the National Plan (NP) option. After 2015, the OXERA modelling suggests that only 9.8 GW of coal remain on the system. This figure is as high as it is because the remaining coal stations are elevated to higher load factors, as they move from peakier generation patterns to more of a mid-merit position, and can subsequently recover the investment costs of selective catalytic reduction (SCR) technology required to reduce NOx emissions to allowed limits. There is a build programme of OCGT that plays a large role in peak generation after 2015.

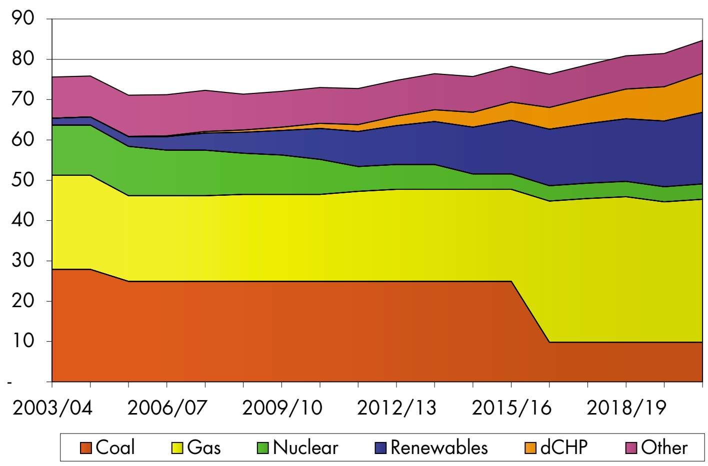
New CCGT build in the base case totals 5 GW by 2014, after which the increase in wind and energy-from-waste capacity, coupled with the introduction of OCGT peaking capacity, removes the need for further developments. In total there is a requirement for 11 GW of new OCGT generation (the majority of which is needed after 2015) to replace the retired coal and to support the penetration of wind generation.

Finally, closure of uneconomic gas-fired generation begins to be seen by 2019, with 1.5 GW potentially closing in the years 2019 and 2020, bringing the total to 4.7 GW.

2.2.2 High-wind scenario

This scenario has a higher penetration of wind generation capacity in England and Wales (10.2 GW compared with 6.5 GW), but maintains 4 GW of wind in Scotland. Figures 2.4 and 2.5 show the installed capacity and resultant output across the modelling horizon.

Figure 2.4: Installed capacity (GW) in the high-wind scenario

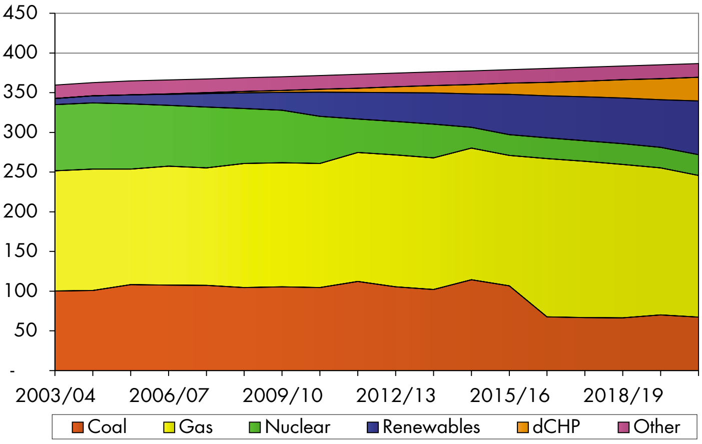


Source: OXERA.

In the high-wind scenario, not only has the volume of wind capacity increased, but so has the volume of back-up capacity, with a further 4 GW of OCGT capacity being introduced onto the system to provide appropriate levels of system support. The introduction of higher quantities of wind has displaced a quantity of conventional gas-fired new build—this scenario sees only 2.25 GW of CCGT built by 2016. Furthermore, the continued build in later years of wind generation sees slightly greater closure of existing CCGT stations, with a further 400 MW of closure up to 2020.

As the capacity of wind is higher than in the base case, coal generation plays a more significant role in providing flexibility and a back-up role across the portfolio, and subsequently has a slightly higher fuel-burn during 2008–15.

Figure 2.5: **Total output (TWh) in the high-wind scenario**

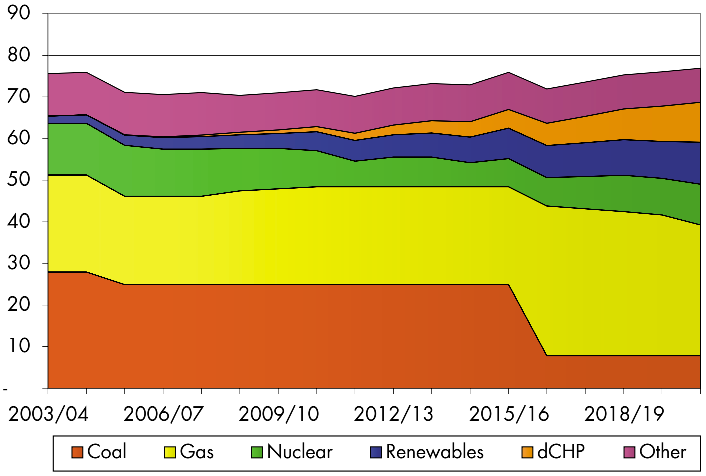


Source: OXERA.

2.2.3 New nuclear build

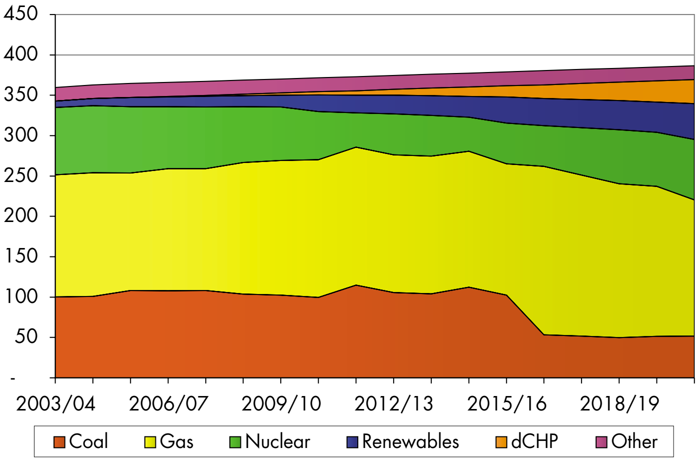
The nuclear scenario consists of the introduction of a new build programme of nuclear power stations to replace the existing fleet. The programme is to build 10 GW of nuclear capacity, with 1 GW units coming on line at a rate of approximately one every 18 months between 2012 and 2025. By 2020, there has been 6 GW of build completed. Figures 2.6 and 2.7 show the generation mix and total output up to 2020.

Figure 2.6: **Installed capacity (GW) in the nuclear scenario**



Source: OXERA.

Figure 2.7: **Total output (TWh) in the nuclear scenario**



Source: OXERA.

As the new nuclear build programme does not require the same degree of reserve capacity on the system as an equivalent volume of wind, there is less new OCGT build than in the high-wind scenario. However, there is slightly more build than in the base case (1.1 GW). This results from the closure of a further 2 GW of coal capacity, as the imposition of nuclear at the bottom of the merit order means that some coal is relegated to load factors which make it uneconomic to remain open after 2015. Indeed, the timing of the arrival of the nuclear capacity means that some opted-out plant operate at higher load factors earlier in the 2008–15 period, and therefore close early. Similarly, the introduction of more base-load capacity has accelerated the closure of older gas capacity: a further 2.8 GW is retired by 2020.

2.3 Scenario comparisons

2.3.1 Entry and exit

Tables 2.1 and 2.2 summarise the change in the generation mix between scenarios, showing the total GW of closures and new build by 2020 in each of the scenarios.

Table 2.1: **GW of closure by 2020**

	Base	High wind	Nuclear
Coal	20.0	20.0	22.0
Nuclear	8.6	8.6	8.6
CCGT	4.8	5.1	7.5

Source: OXERA calculations.

Table 2.2: GW of new build by 2020

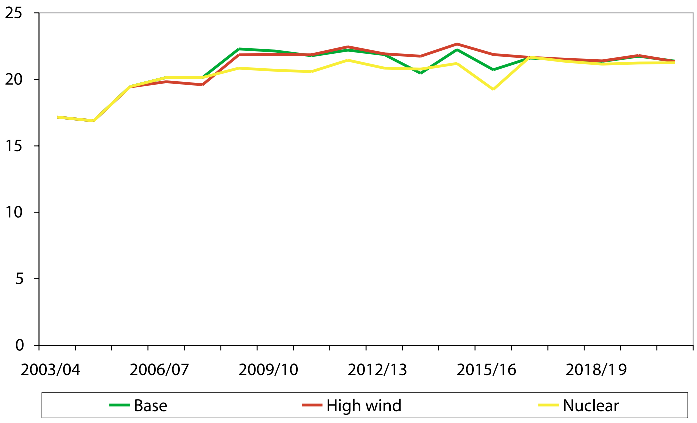
	Base	High wind	Nuclear
Wind	6.5	14.2	6.5
Nuclear	0	0	6.0
OCGT	10.9	14.9	12
CCGT	5	2.25	2.75

Source: OXERA calculations.

2.3.2 Wholesale prices

Prices in the various scenarios are expected to remain at relatively constant levels, trending towards the new-entry price for CCGT and remaining there.

Figure 2.8: Scenario out-turn prices (£/MWh)



Source: OXERA.

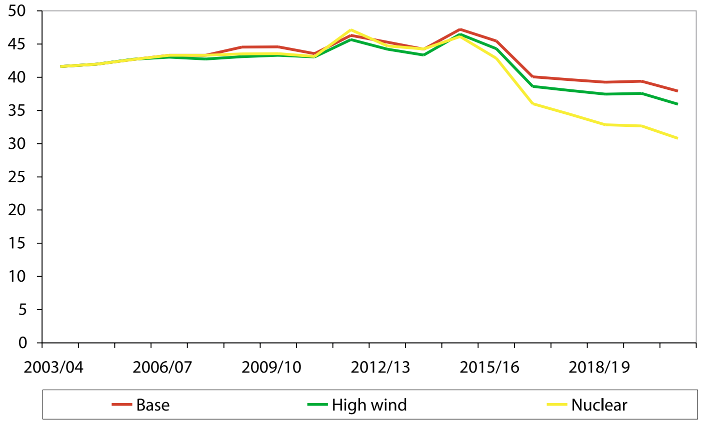
2.3.3 Carbon emissions

While both the high-wind and nuclear scenarios result in lower carbon emissions in 2020, the nuclear scenario sees higher coal burn, and hence higher emissions, in some of the years in the period 2008–12 because of the accelerated closure of coal stations. Figure 2.9 shows the carbon emissions in each of the scenarios.

2.3.4 Other emissions

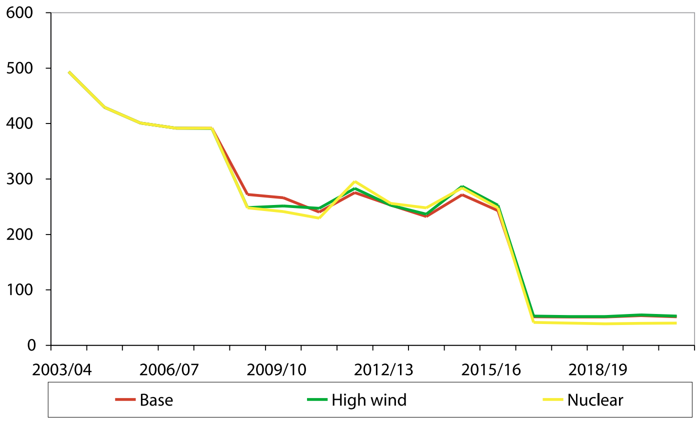
As well as carbon, the modelling estimates the total emissions for SO_2 and NOx. Figures 2.10 and 2.11 show these emissions respectively.

Figure 2.9: Carbon emissions (Mt) by scenario



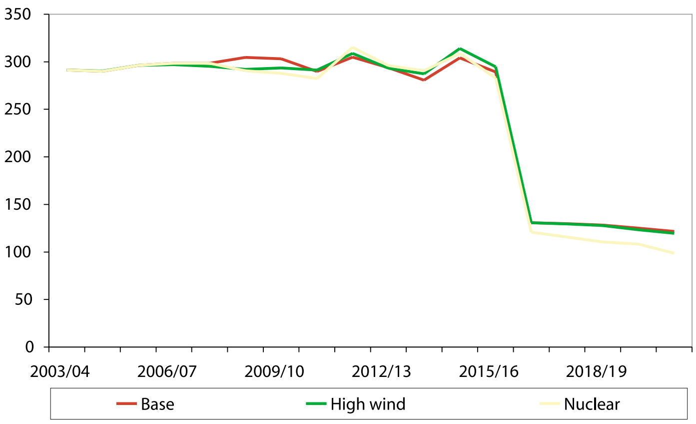
Source: OXERA.

Figure 2.10: SO_2 emissions (kt) by scenario



Source: OXERA.

Figure 2.11: NOx emissions (kt) by scenario



Source: OXERA.

3. Security of Supply

Maintaining the reliability of the UK's energy supplies is one of the four central objectives for government energy policy announced in the Energy White Paper. Concern over supply security has been increasing both as a result of recent events, such as the petrol protests in 2000 and the Californian electricity crisis in 2001, and because of potential implications of the predicted structural change in the UK's energy position, from a net exporter of fuel to a net importer.

In the period up to 2020, the UK exhibits two linked trends that will have an impact on electricity supply security:

- an increasing reliance on gas-fired generation—OXERA's base-case scenario shows the share of gas-fired generation rising from 42% in 2003 to 53% in 2020; and
- a switch from the UK being a net exporter of natural gas to being a net importer somewhere between 2006 and 2008.

The implication of these trends is that security of electricity supply will become increasingly dependent on the reliability of imported gas sources and the associated delivery infrastructure.

Furthermore, this increased dependence on gas is expected to occur simultaneously with a substantive change in the structure of the residual generation mix:

- continued government support for renewable generation—of which onshore and offshore wind appear to be the most cost-effective forms of generation at present—increases the importance of this form of generation in the fuel mix;
- the current baseload nuclear fleet is decommissioned; and
- coal-fired generation is anticipated to be adversely affected by harsher environmental constraints.

This section presents an analysis of the potential impact on electricity supply security of the different generation mixes associated with the scenarios described in section 2. It also assesses the potential costs of addressing any security problems that may become apparent. The additional cost imposed on the electricity system as a whole by different forms of generation is estimated. The methodology uses data, derived from insurance market information, on the likelihood of various political and technical risks.

3.1 General approach

Supply security can be defined across multiple dimensions. For example, the Energy White Paper, which uses the term 'energy reliability', refers to security issues across a number of time horizons (ie, responding to short-term contingencies and long-term fuel adequacy), and in respect of both commodity and infrastructure risk. The ultimate goal of any supply-security policy is to reduce the damage costs of interruptions to supply as far as can be justified by the cost of doing so.

In order to describe security of supply, this analysis focuses on levels of supply insecurity, with the degree of *insecurity* in the electricity system being defined by the following factors:

- the probability of a supply interruption—ie, the probability that load (L) on the system exceeds available capacity (C);
- the magnitude of the interruption—ie, the value (L – C); and
- the duration of the interruption.

Assuming that the load to be met is fixed (ie, there is no demand-side peak management additional to that already implicit in the demand figures in the scenarios), the central determinant of security is the available capacity. The effective capacity (C) available to satisfy a predefined load profile is a function of the volume and reliability of the generation on the system. The factors influencing the reliability of different forms of generation vary, but can generally be categorised as follows:

- plant failure (whether through technical or operational constraints/problems, or as a result of terrorism); and
- input fuel interruption (for example, gas interruptions, wind intermittency).

Although some of these out-turns may not be perceived as being very likely, they may still represent a significant risk for the UK economy if they do occur, since they may cause large-scale disruptions. In order to predict this impact, OXERA has applied interruption-frequency data from insurance market sources for all technologies and fuel sources to derive an expected profile for interruptions of different duration and magnitude.

One of the major sources of potential interruption is input fuel supplies. In particular, for gas supply, the likelihood of interruptions to imported gas has been analysed. This independent analysis then informs the proportion of gas capacity lost for any given interruption identified in the data provided.

Data for all individual events that could lead to an interruption was input into a model, together with their probability of occurrence and the proportion of capacity of a specific generation type that the event would render unavailable. An event simulation was undertaken over a hypothetical 1,000-year period to establish a generic pattern of potential outages by fuel type. This pattern was then applied to the out-turn capacity figures in 2020 for each of the three scenarios analysed, in order to estimate the expected capacity availability throughout the year. Comparing this with the load–duration curve (LDC) then produced the likelihood of supply shortfall.

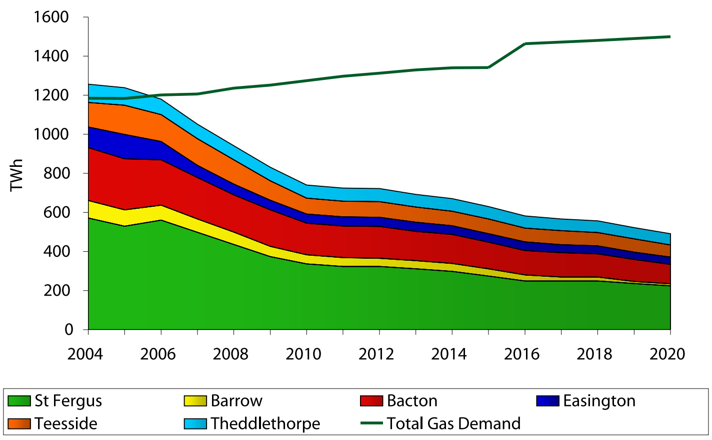
3.2 Gas

The UK was largely self-sufficient in gas during the period of rapid expansion of gas-fired generation in the 1990s. Although the introduction of the UK–Continent Interconnector between Bacton and Zeebrugge led to short periods of import (or 'reverse flow'), the overall position has been one of export. However, going forward, the increased demand for gas from power generation, together with significant domestic and industrial demand, means that the UK's existing and as yet unexploited or undiscovered reserves will not be sufficient to meet demand.

Figure 3.1 illustrates a central forecast based on Transco's 2002 Ten Year Statement forecasts of firm residential and industrial demand, together with projected gas-burn from the base-case scenario. There is a step change in gas demand in 2015/16 when the restrictions from the LCPD trigger a substitution from coal to gas generation.

As Figure 3.1 shows, using current projections of UK gas resources (proved and probable), physical reliance on imported gas (as opposed to commercial) will begin around 2006, and imports can be expected to account for around 42% of total supply by 2010 and 66% by 2020.[1] The sources of this gas will be Norway, the Netherlands, Russia and various LNG producers active in the global market, particularly Algeria and Qatar.[2]

Figure 3.1: UK Continental Shelf supply and UK demand, 2004–20 (TWh)



Source: OXERA.

The reliance on the individual sources changes over time, reflecting the growth in new input capacity and the overall reserves of the different nations.[3] Potential import composition in 2010 is shown in Figure 3.2*a*, and that in 2020 in Figure 3.2*b*. As can be seen, Russia plays a greater role going forward.

[1] This figure for import dependence is below that suggested as likely by the Performance and Innovation Unit in the 'Energy Review' report (PIU, 2002), which suggested around 80% import dependence by 2020. The differences are accounted for partly by lower expected gas use for power generation, exclusion of non-firm industrial gas demand and relatively optimistic assumptions on UKCS production potential used here.

[2] There is no UK LNG terminal at present, but it is anticipated that at least one terminal will be operational by 2006/07 when Qatar Gas expects to be delivering its first LNG train to the UK under contract with ExxonMobil (http://www.exxonmobil.com/Corporate/Newsroom/Newsreleases/xom_nr_240602.asp)

[3] Russia alone accounts for around one-third of global gas reserves, with a further third being located in the Middle East.

Figure 3.2a: **Import shares, 2010**

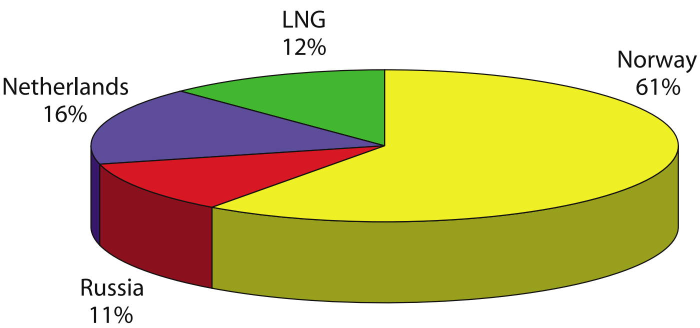
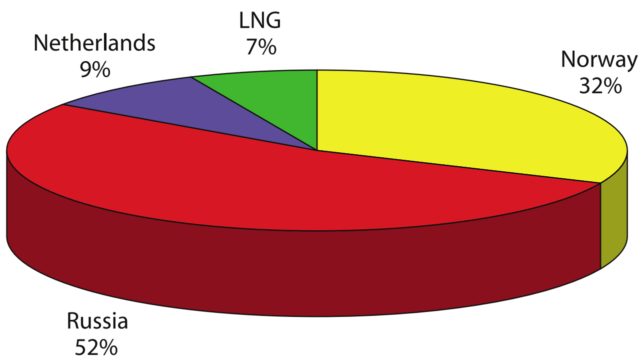


Figure 3.2b: **Import shares, 2020**



Source: OXERA.

According to the insurance market data provided, there may be a significant political risk of disruption in Russian gas supplies. Potentially significant interruptions of up to 180 days have been identified as possible through disruption to the transportation infrastructure (notably the Yamal–Europe pipeline) caused by political or terrorist action. Using political risk data provided from the insurance sector suggests that politically motivated risks of interruption, accounting for around half of the potential flows of Russian gas to the UK, could occur once every eight years. The data also indicates that LNG supplies, while less prone to political disruption, may have higher probabilities of infrastructure or transportation risks.

These risks of disruption suggest that an alternative examination of the supply sources is needed, taking account of potential interruptions, their likelihood and duration. Additional information provided from the insurance markets has been used to analyse the potential for shortfalls in gas supply for generation purposes, as both gas-burn in the generation sector increases and the sector becomes more reliant on imports.

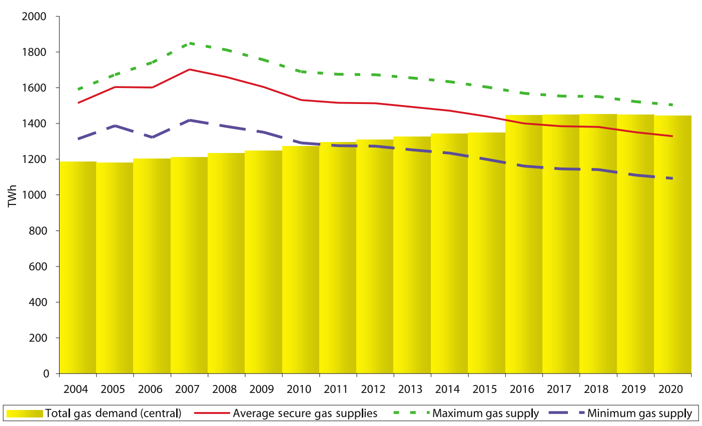
The data represents an independent assessment of the frequency and duration of a large number of potentially significant interruptions to supply, covering technical failures, political risks and major accidents. This data has been used to analyse the expectation of security-of-supply shortfalls of gas relative to the base case, and to investigate the wider implications of alternative methods of mitigating security concerns.

Potential gas flows from different suppliers have been identified, together with the likely entry point to the UK's transmission system (be it a beach terminal, storage site or LNG import terminal). Capacity constraints have been assumed at each entry point, together with a probability of additional capacity restrictions as a result of technical failure. These restrictions are dependent on the number of sub-terminals at each entry point, since it is assumed that, at most, one sub-terminal could be interrupted at any time.

The supply sources are then adjusted for possible interruptions at source or in transit, whether these are technical/operational or political risks. This framework allows an assessment of both 'average' and 'worst case' scenarios for gas supply interruptions. The worst-case scenario assumes that the two major interruptions to supply that could occur (ie, to Russian gas and LNG imports) happen simultaneously, whereas the average supply scenario applies the average expected loss per annum to the available supplies.[4]

Figure 3.3 shows the maximum, minimum and central gas supply available at any point in time under these scenarios.

Figure 3.3: **UK gas supply and demand (TWh)**



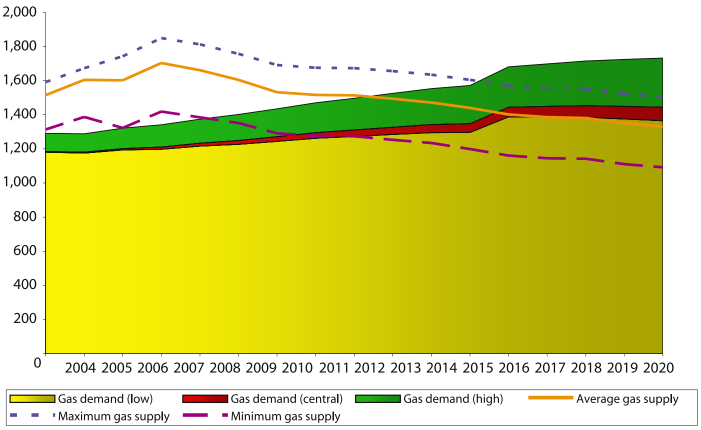
Source: OXERA.

[4] Thus, if there were a 5% probability of a loss of 50% of Russian gas and a 10% probability of a loss of 100% of LNG imports, the average scenario would assume that 2.5% of Russian gas is lost per year and 10% of LNG imports; whereas the worst-case scenario would report a 50% reduction in Russian imports and a 100% loss of LNG imports.

As can be seen, using the average secure gas supplies scenario, although, on average, supply shortfalls may not occur until 2016, the worst-case scenario (the minimum line in Figure 3.3) could see gas supply shortfalls as early as 2011. Conversely, if there were no interruptions, although the UK's gas demand continues to increase, a shortfall is unlikely to emerge before 2020.

Alternative gas demand assumptions, such as assuming a non-power-generation gas demand growth of around 0.5% per annum or a high growth rate of 1.25% per annum, change the outlook, as shown in Figure 3.4. Furthermore, if incremental supplies from the UKCS or Norway were also available, the adverse impact might be mitigated even further.

Figure 3.4: UK gas supply and demand (TWh)



Source: OXERA.

3.3 Valuing supply security

Using the predicted occurrence of the independent, individual supply interruptions for each generation type, a picture of supply security under the base case can be developed. Table 3.1*a* shows the number of security interruptions (of different duration) within the numerical simulation. As can be seen, there were 50 events of 180 days or longer (around 1 every 20 years), during which 5–15 GW of capacity were unavailable for generation.

Table 3.1*a*: Likelihood of interruptions of set duration over 1,000 years (base case)

	7–27 days	28–179 days	≥180 days
>5 GW	63	41	50
>15 GW	59	8	0
>30 GW	4	1	0

Source: OXERA.

Table 3.1*b* shows the implied electricity security of supply in 2020 under the base-case scenario as the number of hours when particular combinations of demand (L) and capacity (C) are available in the market. For example, there are 103 hours in a year when capacity is 60–70 GW and demand (net of wind output) is 40 GW. Thus, all the shaded areas represent periods where supply of electricity will be secure. As can be seen, there are 10 hours in a year when the system is likely to experience shortfalls in capacity.

Table 3.1*b*: Implied supply security in 2020 (base case)

	Demand net of wind (GW)				
	20–29	30–39	40–49	50–59	60–69
Capacity (GW)					
30–39	–	–	–	–	–
40–49	0	1	1	0	0
50–59	1	7	11	4	0
60–69	16	103	144	62	5
70+	398	2,623	3,679	1,572	133

Source: OXERA.

3.3.1 Alternative supply-security scenarios

The level of supply security implied by the high wind and new nuclear scenarios was also assessed—the results are presented in Tables 3.2*a* and b and 3.3*a* and *b*, respectively. As can be seen in Tables 3.2*b* and 3.3*b*, both scenarios result in an improvement in implied security of supply in 2020, with the high-wind scenario reducing the expected number of hours of shortfall ($L - C < 0$) to six, and the nuclear scenario reducing the number to four.

However, the more important comparison is between Tables 3.1*a*, 3.2*a* and 3.3*a*. What is significant here is that a programme of new nuclear build removes the occurrence of long interruptions, since the reliance on Russian gas is substantially lower than in the other scenarios.

The longest periods of interruption (ie, of over 180 days) affect only up to 50% of Russian gas imports. Under the nuclear scenario, total gas-burn is 343 TWh, compared with 409 TWh in the base case and 364 TWh in the high-wind scenario. Given expected gas availability from other sources, this reduces the proportion of total gas-fired generation that would be adversely affected by a Russian outage, thereby removing the occurrence of long interruptions in excess of 5 GW.

Table 3.2*a*: Likelihood of interruptions of set duration over 1,000 years (high wind)

	7–27 days	28–179 days	≥180 days
>5 GW	63	41	50
>15 GW	59	8	0
>30 GW	1	0	0

Source: OXERA.

Table 3.2*b*: Implied supply security (high wind)

	Demand net of wind (GW)				
	20–29	30–39	40–49	50–59	60–69
Capacity (GW)					
30–39	–	–	–	–	–
40–49	0	0	0	0	0
50–59	3	9	9	3	0
60–69	34	126	130	36	3
70+	877	3,231	3,316	914	69

Source: OXERA.

Table 3.3*a*: Likelihood of interruptions of set duration over 1,000 years (new nuclear build)

	7–27 days	28–179 days	≥180 days
>5 GW	59	11	0
>15 GW	59	8	0
>30 GW	1	0	0

Source: OXERA.

Table 3.3*b*: Implied supply security (new nuclear build)

	Demand net of wind (GW)				
	20–29	30–39	40–49	50–59	60–69
Capacity (GW)					
30–39	–	–	–	–	–
40–49	0	0	0	0	0
50–59	1	7	11	4	0
60–69	1	10	13	6	0
70+	413	2,716	3,810	1,628	137

Source: OXERA.

These results can be used to provide an estimate of the contribution to supply security provided by both wind and nuclear. Assuming the cost of an interruption can be thought of as equivalent to a value of lost load (VOLL) figure,[5] and with the knowledge of the number of hours of interruption, and their magnitude, the lost-load cost saving relative to the base case for wind and nuclear can be measured.

The electricity sector has used a range of VOLL figures. The Electricity Pool of England and Wales used a figure of £2,816/MWh in 2000/01 prices, equivalent to around £3,000/MWh in 2003/04 prices. Although higher levels of VOLL have been used (for example, in Australia and New Zealand), the analysis below uses the England and Wales figure.

As Table 3.4 shows, additional wind or nuclear build reduces the costs of interruption by £120m and £180m per annum respectively. This is achieved through different incremental volumes of output from each generation type: 23.5 TWh from wind and 48.9 TWh from nuclear. Thus, when the security-of-supply benefit is expressed in £/MWh, the high-wind option produces a larger benefit (£5.1/MWh) than nuclear (£3.7/MWh).

Table 3.4: Security-of-supply comparisons, 2020

	Base case	High wind	Nuclear
Expected hours of interruption	10	6	4
Expected GWh lost	100	60	40
Forecast cost of interruptions (£m)			
VOLL @ £3,000/MWh	300	180 1	20
Cost saving over base case (£m)	–	120	180
Additional output from new generation (TWh)	–	23.5	48.9
Security-of-supply benefit over base case (£/MWh)	–	5.1	3.7

Source: OXERA.

[5] This assumes that the VOLL is not dependent on the length of outages or their magnitude. There is little discussion of this in the initial derivation of VOLL in the UK in 1990, although the fact that it was applied to a half-hourly price may be thought of as indicating a short-term loss valuation. If this is the case, the VOLL figure may actually underestimate the implications of lengthy interruptions, such as those identified in Tables 3.1*a* to 3.3*a*.

There are two elements of the supply security provided by the two forms of generation that may not be captured in this initial valuation:

- additional impacts caused by the duration of interruption—as Tables 3.1*a*, 3.2*a* and 3.3*a* show, it is likely that there will be longer interruptions under the base-case and high-wind scenarios than under a new nuclear scenario;
- potential system back-up costs—the costs of maintaining an adequate level of conventional fossil-fired generation in order to meet peak demands.

3.4 Assessing system costs

The system costs associated with the two alternative scenarios were calculated from the base data. The analysis assesses the difference in the average system costs (forward-looking operating costs, and capital costs for new investment) from fossil-fired generation (ie, CCGT, OCGT and coal) in each of the three scenarios, since non-fossil-fuel generation does not change between scenarios. The difference in these costs between the base case and the alternative scenarios provides an indication of the cost or saving associated with the generation options.

Table 3.5 shows the average system cost in £/MWh under each of the three scenarios. The nuclear and wind scenarios both require a lower level of investment in conventional generation than the base case. However, the benefit is greater for nuclear than for wind.

Table 3.5: **System costs (£/MWh) in 2020**

	Base case	High wind	Nuclear
System costs	15.1	15.0	14.5
Reduction in system cost	–	0.1	0.6

Although wind generation might be expected to exhibit significant additional costs, this does not emerge in the high-wind scenario. This is because operating patterns under the high-wind scenario enable 2 GW of coal-fired generation to be maintained on the system, requiring less incremental investment in OCGT during this period than under the nuclear scenario.

3.5 Alternative supply-security options

The option of replacing increased reliance on gas with a more diverse generation mix is, however, not the only one available. An alternative is to invest in means of enhancing the security of the gas supplies coming into the UK. This could be achieved by investing in additional storage infrastructure or further LNG terminals, reducing reliance on a single import point and increasing the volumes of LNG that can be imported. Within the basic gas-security analysis underlying the figures in Tables 3.1*a* and 3.1*b* only one LNG terminal was assumed to exist in the UK.

Table 3.6 shows how supply security in 2020 in the base case could be enhanced by investment in additional gas infrastructure. As can be seen, the alternative supply source removes the likelihood of interruptions under the base case.

These results must be read with some caution, however. In particular, the reliance on gas-fired generation and on unreliable supply sources will continue to increase after 2020, and so LNG may not prevent more severe shortages in the longer term.

Table 3.6: **Implied supply security (base case with extra LNG)**

Capacity (GW) \ Demand net of wind (GW)	20–29	30–39	40–49	50–59	60–69
30–39	–	–	–	–	–
40–49	–	–	–	–	–
50–59	0	0	0	0	0
60–69	1	7	11	4	0
70+	414	2,726	3,824	1,634	138

Source: OXERA.

4. Wind and Other Renewable Generation

One of the main tasks in modelling the future lower-carbon energy mix is to capture the pattern of generation from wind generators, taking into account daily, seasonal and regional variations in wind speed. This data-incentive exercise is modelled below.

4.1 Wind generation modelling

Hourly electricity output from three offshore locations in England and two onshore locations in Scotland was modelled for two wind energy development scenarios, using the method described below.[6]

4.1.1 Site selection

The wind-generated electricity profile for England and Wales is based on onshore (coastal) wind-speed measurements at six sites located within the coastal zone of the three Proposed Strategic Areas identified in 'Future Offshore' (DTI, 2002). A description of the sites recommended at each location is given below.

- Thames Estuary—two wind-speed sites were used, both of which fall within the Thames Estuary Strategic Area: Shoeburyness and Walton-on-the-Naze.
- The Wash—two wind-speed sites were used, both of which fall within The Wash Strategic Area: Weybourne and Wainfleet.
- North West—there are a number of wind-speed sites within the North West Strategic Area. The following two sites offer the widest geographic spread, providing a more realistic range of variability in the site: St Bees Head and Squires Gate.
- North West Scotland—two sites were identified at this location, one in close proximity to an existing wind farm, and the other is a coastal site near land identified for potential wind-farm development: Tain Range Saws and Wick Airport.
- South West Scotland—a number of sites were available at this location; two were selected for their proximity to existing wind farms and to land modelled as potential wind-farm development areas: West Freugh and Machrihanish.

[6] OXERA is grateful to Graham Sinden of Trinity College, Oxford University, for his assistance with this work.

The data for these sites was obtained under licence from the Meteorological Office, and covered a period of 20 years, of which the most recent 10 years were used in the market modelling.

4.1.2 Turbine selection

The hourly electricity output from each location was modelled using the following two turbine types:

- offshore: the three offshore locations were modelled using the performance characteristics of the Nordex N80/2500 turbine. This is a dedicated offshore turbine with a hub height of 80 metres, and a rated maximum output of 2.5 MW per turbine;
- onshore: the two onshore locations were modelled using the performance characteristics of the Vestas V80-2.0 turbine. This is an onshore turbine with a hub height of up to 78 metres (the height used in this modelling), and a rated maximum output of 2 MW per turbine.

4.1.3 Gust assessment

Wind gusts may affect the performance of wind turbines, particularly at higher wind speeds. Both the turbines used in this modelling have a cut-out speed of 25 metres per second (m/s), meaning that the turbine will stop operating when the average wind speed exceeds 25m/s, or the gust speed exceeds 28m/s (Nordex N80). Once a turbine has shut down, it will not restart again until the average wind speed has dropped to 22m/s.

In normal operation, these rules are applied at a very short timescale, typically seconds or minutes. However, the highest-resolution wind data available for this project was hourly—this presents a limitation on the accuracy of modelling turbine output in high winds, as wind speeds are averaged over an hour, and gusts are reported as the largest gust occurring in the hour.

One approach to this problem is to use the average hourly wind-speed data, and hourly gust-speed data, and apply the operational rules to this. However, using this approach will result in the impact of high average winds and gusts being overstated, especially as it is unlikely that all wind turbines in a wind farm will experience exactly the same conditions and respond in an identical manner.

To overcome this limitation of the available data, the results of a previous analysis of 10-minute data have been adapted for this modelling work. It has been shown that there is a relationship between hourly average wind speed and the occurrence of gusts that would cause a turbine to shut down. This analysis determined the probability of a wind turbine shutting down and not restarting during a one-hour period for a range of average hourly wind speeds.

4.2 Wind data analysis method

The following procedure was used to generate the modelled electricity output from each of the five locations.

- **Error checking**—the raw wind-speed data files were screened for error records and missing records. Error records were removed, and missing data remained as null values in the dataset.
- **Aggregation of datasets**—at a number of sites, more than one source of wind-speed data was available. At these sites, a primary data source was identified, and records from the secondary data source were included where they were missing in the primary data source.
- **Missing-value estimation**—where hourly wind-speed measurements at a site were missing from the dataset, inferred data was used. The process used to complete each dataset was:
  - (i) fill the missing values with the average wind speed experienced for that hour, as calculated from all the available data at that site;
  - (ii) identify a secondary source of wind-speed data (from another site in the region) which has wind-speed records for time periods missing at the primary site; and
  - (iii) correct the average wind-speed values used in (i) with the data from the secondary site (ii).

  Varying degrees of completeness of the datasets result in significant levels of inferred data at some sites. Overall, 77% of all hourly wind speeds were measured at the sites, with the remaining 23% of data being inferred according to the method described above. The proportion of actual data at any one location varied from 55% to 97%, with the majority of missing data occurring in the early 1980s.
- **Correct for location**—wind speeds at the three offshore locations were corrected for the difference in surface roughness between the onshore site where the wind speed was measured and the offshore location of the modelled wind farm.
- **Correct for height**—for all sites, wind-speed measurement was assumed to occur at 10 metres, while the hub height of the turbines was 78 or 80 metres. Wind speed was corrected to compensate for this difference in height between measurement and turbine location.
- **Estimate electricity output**—wind speed at hub height was converted to electricity output using the wind-speed/-power relationship for the two turbines. The electricity output of both onshore and offshore wind turbines at high wind speeds was then modified to account for gusts, and the average hourly output from each pair of sites at a location formed the modelled electricity output from that location.

  Onshore wind turbines typically operate at a capacity factor of around 30–35% (higher in optimum locations, such as offshore wind farms), while it is unlikely that a wind farm would be developed at a site with a significantly lower capacity factor. It is reasonable to expect that the modelled capacity factor for the onshore locations would be in the region of 30–35% and for the offshore location in the region of 38%. An iterative process was used to achieve a realistic capacity factor at each location, with minor variations in surface roughness at the wind-measurement site being used to achieve the final capacity factor.

4.3 Application of scenarios

Two scenarios for wind-generating-capacity development, as shown in Table 4.1, were evaluated. The final hourly electricity output from each location was then calculated by applying the installed generating capacity figures shown in Table 4.1 to the modelled electricity output for the location.

Table 4.1: **Scenarios for wind-generating-capacity development, 2020 (MW installed)**

	Low scenario	High scenario
Offshore wind		
Greater Wash	950	5,800
Thames Estuary	750	2,800
North West	700	1,600
Onshore wind		
Scotland total (50% south-west, 50% north-west)	4,000	4,000

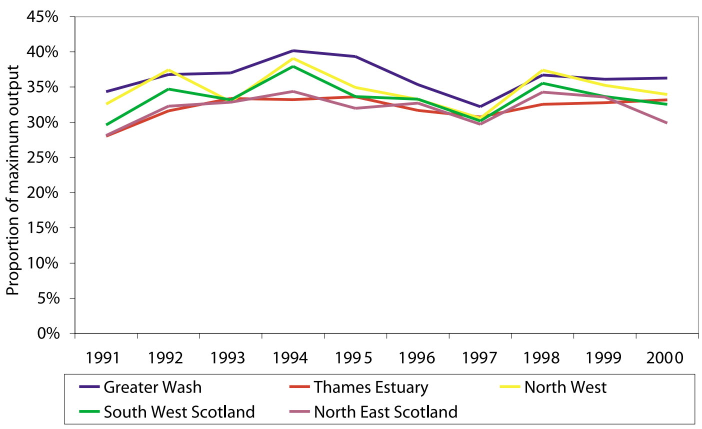
Source: OXERA.

4.4 Modelling results

4.4.1 Variation in output

The results from analysis of the wind output modelling are shown below. Figure 4.1 shows the variation in total output from each of the five sites over the past 10 years (for which the dataset is most complete). The average annual output varies by about ±4% from the average load factor over the 10-year period.

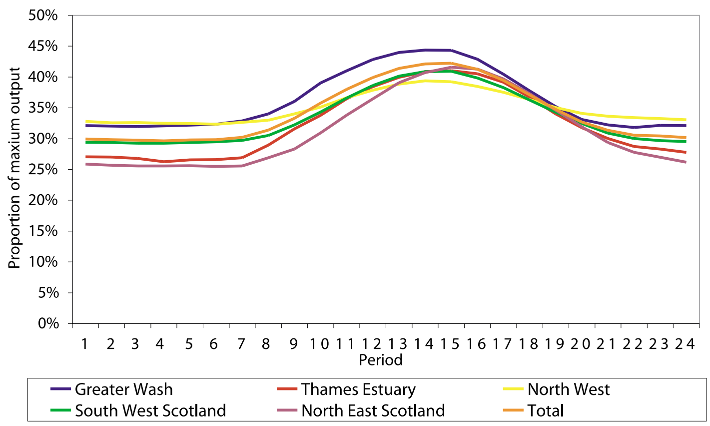
Figure 4.1: **Annual variations**



Source: OXERA calculations using Met Office data.

All the sites show a diurnal variation in generation of around 10% or more of capacity, plotted in Figure 4.2. The effect is more pronounced for some sites than others, and does not coincide with the morning or evening peak of electricity demand, since it occurs mid-afternoon and has receded by evening.

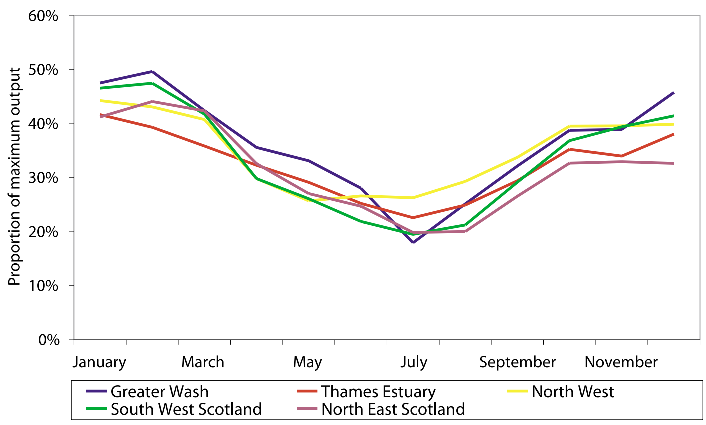
Figure 4.2: **Daily variation**



Source: OXERA calculations using Met Office data.

There is also a marked seasonal pattern of output, shown in Figure 4.3, with output in the winter months being double that in the summer months.

Figure 4.3: **Monthly variation**



Source: OXERA calculations using Met Office data.

The overall pattern in Table 4.2 is constructed by combining all these patterns together, and comparing the output of the wind portfolio against demand for electricity. This table has been derived from 10 years of hourly UK electricity demand data and 10 years of simulated wind generation data, with each actual hour of wind speed matched to each actual hour of demand. The results reveal that there are significant periods in an average year when demand is high and wind output is low. For example, in a typical year there will be 23 one-hour periods when the output from wind turbines for the whole of Great Britain is less than 10% of declared net capacity, and demand is between 90% and 100% of peak demand.

Similarly, there will be 186 periods when wind output is between 10% and 30% of capacity, and demand is between 80% and 90% of peak demand.

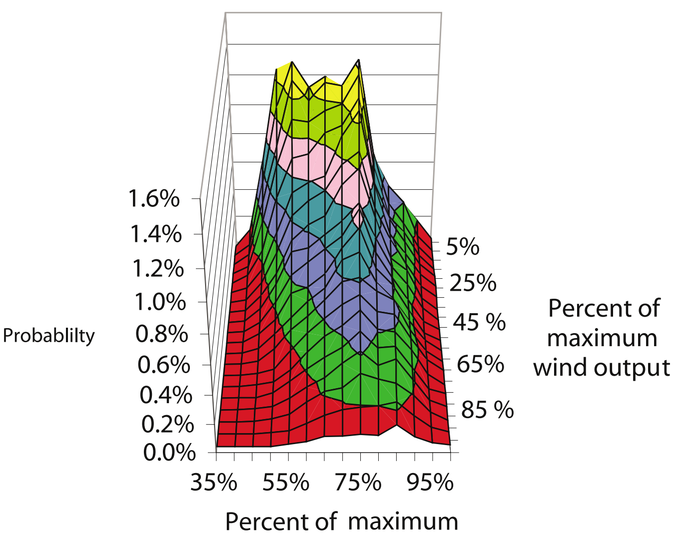
Table 4.2: Coincident hours

Percent of maximum output	Percent of peak demand 40%	50%	60%	70%	80%	90%	100%
10%	0	276	517	399	339	88	23
20%	0	123	420	437	472	140	23
30%	0	73	264	348	396	86	55
40%	0	39	177	263	338	174	29
50%	0	27	103	196	259	161	34
60%	0	17	74	205	201	181	38
70%	0	7	61	201	214	230	33
80%	0	1	46	125	152	161	21
90%	0	0	14	87	86	103	17
100%	0	0	1	30	39	43	8

Source: OXERA calculations.

The data shown in Table 4.2 is presented as a three-dimensional surface in Figure 4.4.

Figure 4.4: Correlation between demand and wind output



Source: OXERA calculations.

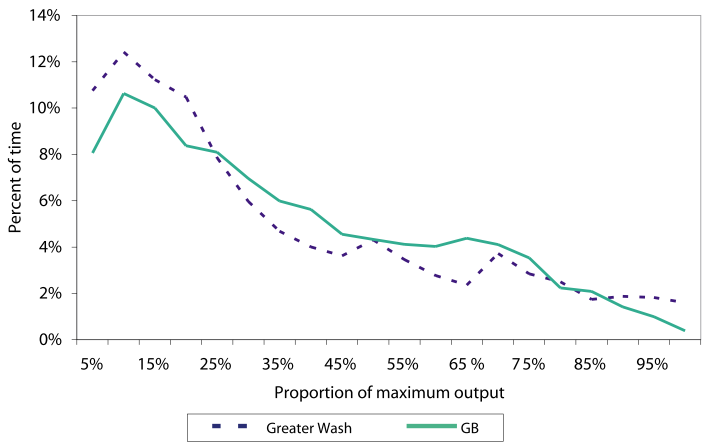
4.4.2 Portfolio effect

One of the effects reported in the academic literature is a smoothing of variations in output from a geographically dispersed set of turbines compared with a set that is concentrated in a small area. The extent of this smoothing depends on the correlation of wind speeds between sites.

A few studies have examined aspects of the portfolio effect (eg, Milborrow, 2001), but some (eg, Wan and Bucaneg, 2002) have concentrated on short-timescale power fluctuations. Ernst et al. (1999) showed the variation in output with separation of wind turbines averaged over different time periods. Similar information could be extracted from the OXERA dataset.

The output–duration curve for a single site (the dotted line in Figure 4.5) shows a greater proportion of time with extreme (low or high) levels of output than the whole Great Britain portfolio (the solid line).

Figure 4.5: Portfolio effect



Source: OXERA calculations.

This pattern is similar to the output–duration curve produced by NGC in its submission to the Performance and Innovation Unit's (PIU) Energy Policy Review in 2001 (see Laughton, 2001).

4.5 Costs

4.5.1 Network infrastructure

The network infrastructure costs comprise network reinforcement and management costs associated with renewable generation. These costs fall on both the transmission network and the distribution network, but do not include the cost of the connection to the network, which is included in the generation cost.

The OXERA scenarios assume that the vast majority of renewables is wind generation, and that almost all of the wind generation is connected to the transmission network. In contrast, Ilex, in its report for the DTI, assumed a greater proportion of distribution-connected generation (Ilex, 2002, table 17, p. 63). The Ilex distribution network cost scenario most comparable with the OXERA scenario for the penetration of renewables +appears to be either North Wind Low 20%, or Wind and Biomass Low 20%. These give distribution network capital costs of between £100m and £320m. Hence, a mid-range figure of £200m is assumed here.

For transmission costs, the DTI's Transmission Issues Working Group examined the results of studies of transmission capital costs, quoted in Ilex (2002), to support 4 GW of renewables in Scotland, which is the basis of both OXERA renewables scenarios, and found this to be £1,235m. This is a provisional figure based on high-level studies by the transmission network operators. A similar study was carried out by National Grid Transco in 2002, examining costs in England and Wales for accommodating up to 4 GW of offshore wind. This found that up to 4 GW could be accommodated along the east coast of England at a total cost of about £80m, but no figures for higher volumes were produced. Ilex had access to further estimates (see Ilex 2002, table 26, p. 53), which suggest that the OXERA high-wind scenario might involve transmission system capital expenditure of £2.4 billion to £4.3 billion.

These CAPEX figures are translated into £/MWh figures in Table 4.3. They equate to a total network reinforcement cost of £4.4–£7.6/MWh on average for offshore and onshore wind generation for the high-wind scenario in 2020.

Table 4.3: **Network reinforcement costs (high-wind scenario)**

	Low	High
Distribution capital cost (£m)	200	200
Transmission capital cost (£m)	2,400	4,300
Annualised distribution cost (£m)	16	16
Annualised transmission cost (£m)	188	336
Distribution cost (£/MWh)	0.34	0.34
Transmission cost (£/MWh)	4.06	7.27
Total network cost (£/MWh)	4.40	7.61

Note: Assuming 25-year depreciation of network assets and 6% cost of capital.

Source: OXERA calculations.

However, of note for the comparative analysis being undertaken is the extent of the increase in the network reinforcement costs in expanding the wind generation capacity on the system. Table 4.4 presents this comparison, providing a range of incremental network reinforcement costs (depending on the assumed capital costs) of between £3.8/MWh and £9.9/MWh.

Table 4.4: **Incremental network infrastructure costs, 2020 (high-wind)**

	Low-cost case	High-cost case
Increase in wind output (GWh)	23,483	23,483
Increase in total investment cost (£m per annum)	88.8	233.5
Cost per unit of wind generation (£/MWh)	3.8	9.9

4.5.2 System response

System response costs, which involve the maintenance of part-loaded capacity to provide frequency and voltage control services on short timescales (minutes and seconds), have not been estimated in this study.

4.5.3 System balancing

System balancing costs, which involve the provision of system capacity available at less than four hours' notice, are incorporated into the general system costs presented in section 3.4. OXERA considers that there is sufficient non-wind generation capacity with a start-up capability of under four hours within the scenarios that have been developed in this study to provide system balancing services.

4.5.4 Curtailment costs

With 4 GW of wind capacity forecast for Scotland, and a peak demand for power in the region of about 6 GW, there is a prospect that wind output might exceed demand from time to time. When it does, it might have to be constrained off in order to balance the system. OXERA looked at the likelihood of this happening, and how much wind output might be lost as a result.

It seems unlikely that wind power would provide all of the power consumed in Scotland at any single time. One reason is that other forms of generation would be needed to load-follow and provide system services, another reason is that nuclear generation, totalling 1.25 GW (once Hunterston has closed), is likely to be constrained on.

However, there is some relief from the constraints of supplying only Scottish demand through the interconnectors to England and Wales and Northern Ireland, which allow up to 2.65 GW to be exported from Scotland.

OXERA modelled these effects and found that the proportion of wind output that would be curtailed is just 0.1% if the constrained-on non-nuclear conventional capacity in Scotland totals 1 GW. The effect of curtailment is to raise the cost of generating power from wind turbines in proportion to the lost output. In Scotland, therefore, it appears likely that wind generation costs are barely changed by the effect of curtailment, although the actual adjustment should be determined by a study of system management requirements and the volume of plant that might be constrained on.

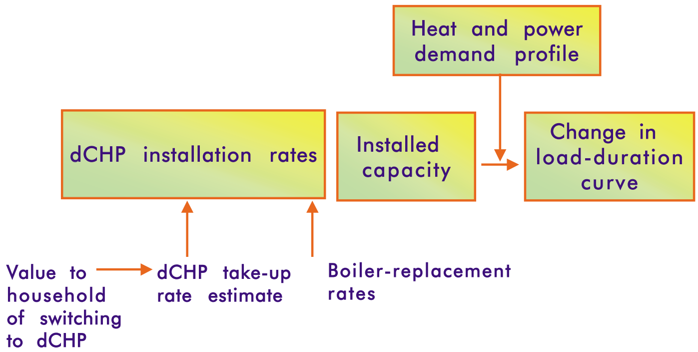
4.6 Domestic CHP

OXERA constructed a model to estimate the change in the LDC, and the expected change in electricity demand in each hour through the year as a result of autogeneration by households using dCHP. This is a new technology that has been tested but not yet released into the market in the UK. The first technology to be released into the mass market will be the Stirling cycle dCHP units, such as those marketed by Microgen and Whispagen. These produce power whenever the unit is called upon to deliver heat for space heating or hot water. At around 6 kW_{th} of heat output, they typically produce around 1.5 kW_e electricity. This is not the only size: other products may be brought to market to serve different households with higher demand.

In the long term, fuel cells may offer an alternative to the Stirling cycle. PlugPower already offers larger fuel-cell CHP units, which have a quite different electricity-to-heat ratio: about 20% heat and 80% electricity. They would therefore produce about 16 times more electricity than the Stirling cycle engine for the same heat load. In the modelling described below, dCHP is assumed to use the Stirling cycle.

The model follows the pattern shown in Figure 4.6. One part of the model estimates the heat and electricity demand profile, and the other the rate of dCHP installation.

Figure 4.6: Schematic of model



Datasets of the annual electricity and heat demand for 3,500 households across England and Wales were used, taken from the 1996 Housing Condition Survey[7] and the Electricity Association. For each household, the profile of electricity and heat demand hour by hour through the year is estimated. It is then assumed that, in each hour that heat is demanded, electricity production is 25% of the heat load, and no more than 1.5 kW_e. Across the whole year, when electricity production exceeds a household's demand, the value of the power produced is assumed to be £30/MWh; when demand exceeds production, the value of the power produced is assumed to be £70/MWh. This differential in value is because exported power is only expected to receive the wholesale price plus avoided transmission costs, which total about £30/MWh, whereas power that reduces imports is equivalent in value to the price of standard domestic electricity purchases, which is around £70/MWh.

The total value of power production over the year is estimated for each household, and compared with the premium cost of replacing a boiler with a dCHP boiler. The premium is expected to be £600, initially, but to fall to £275 by 2020. It is then assumed:

- first, that households only replace their boiler when their existing boiler one reaches the end of its life (a rate of replacement of once every 15 years), or when a new house is built; and
- second, that households only fit a dCHP unit in preference to a conventional boiler if the payback period is a few years.

[7] Available on the web site of the Office of the Deputy Prime Minister, at www.housing.odpm.gov.uk/research/ehcs96/.

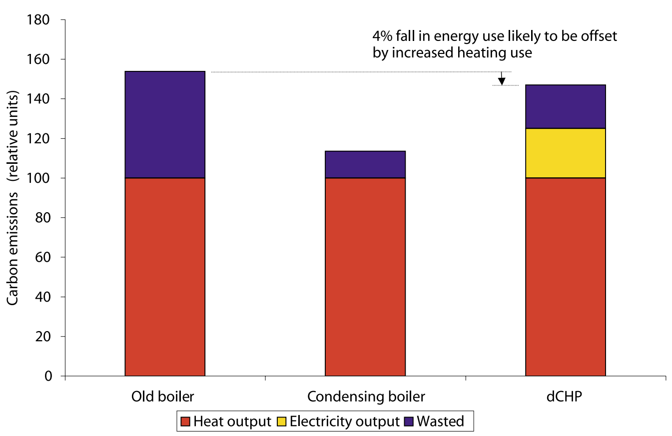
The new profile of total household demand is estimated from the profiles of those households who choose dCHP and those who do not, and it in turn is used to estimate the LDC.

4.6.1 Change in carbon emissions

When gas-equipped households switch from a conventional boiler to a dCHP unit, their gas consumption may change, which may alter their household carbon emissions. Until recently, household gas boiler efficiency has generally been about 65% (and 55% for older, heavy-weight boilers). In the period up to 2020, it is mostly boilers of this type that will be replaced by dCHP. New non-condensing boilers can achieve 75% efficiency, but condensing boilers, which offer 88% efficiency, only represent a small fraction of boilers installed. Thus, in this modelling, it is assumed that the dCHP units will replace boilers of average 65% efficiency.[8]

The energy efficiency of dCHP units is 85–90%. Figure 4.7 shows the total energy used by different boilers with the same heat output (indexed to 100). It illustrates that, when a dCHP unit provides the same heat output as an old conventional boiler, there is approximately a 4% fall in energy (gas) demand by the household. This is a negligible amount, given that households may spend part of their energy bill savings on consuming more energy.

Figure 4.7: **Comparison of gas use of different boilers to achieve the same heating effect**



Note: Assuming that the efficiency of an old boiler is 65%, the efficiency of the condensing boiler and dCHP are each 88%, and that the ratio of electricity to heat output of a dCHP unit is 25%.

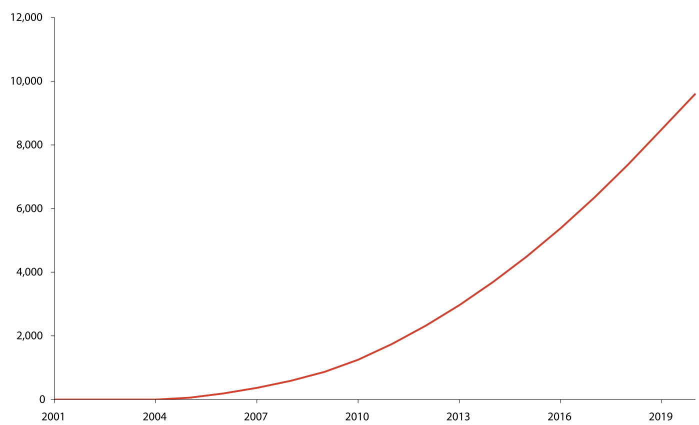
Source: OXERA calculations.

Based on the calculation above, it is assumed that the carbon emissions of a household do not change when it switches from an old boiler to a dCHP unit.

4.6.2 Model results

Using assumptions on the value of electricity exported by a household, a scenario of dCHP penetration were generated, as shown in Figure 4.8.

Figure 4.8: **Capacity of dCHP installations (MW)**



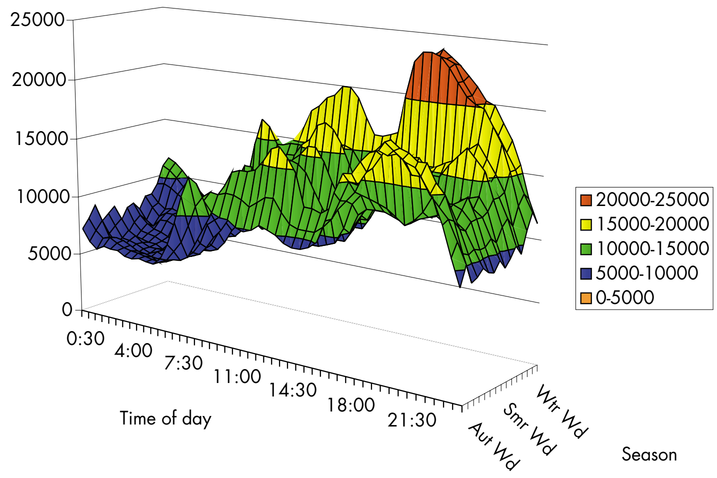
Source: OXERA.

This scenario is used in all the modelling reported in this paper.

Prior to the introduction of dCHP, the daily demand profiles for typical weekdays and weekend days through the year are estimated as shown in Figure 4.9, expressed in MW. The front of the chart shows days in autumn, and progressively moving towards the back of the chart, spring, summer and winter are shown.

[8] Figures for boiler efficiency are taken from Defra's Standard Efficiency Database for Boilers in the UK.

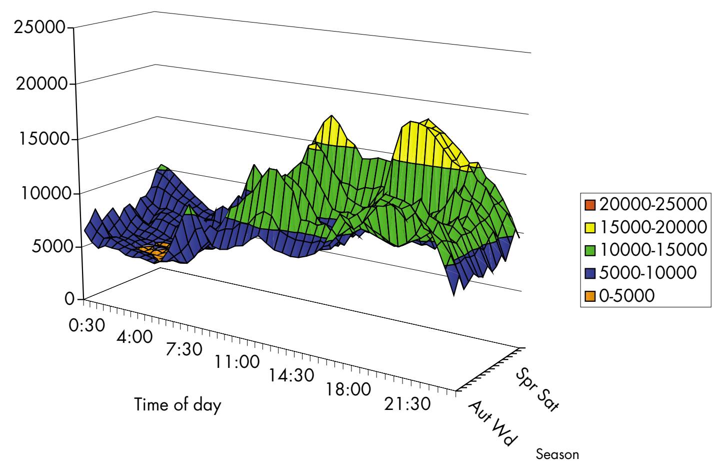
Figure 4.9: **Demand for electricity for all UK households prior to the introduction of dCHP**



Source: OXERA.

Figure 4.10 shows the equivalent data in 2020 under the baseline take-up of dCHP. There is a significant change in net household demand, with demand greatly reduced, especially in the morning and evening, and in the winter.

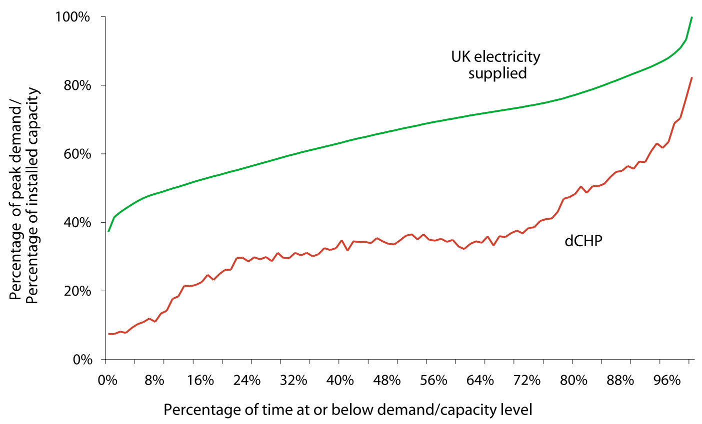
Figure 4.10: **Demand for electricity for all UK households in 2020, with baseline-scenario take-up of dCHP**



Source: OXERA.

Because there is a strong coincidence between the level of dCHP output and the level of electricity demand, as shown in Figure 4.11, a substantive programme of dCHP build would not only reduce the demand for transmission-connected generation, but would also significantly flatten the residual LDC.

Figure 4.11: **Coincident LDC for electricity demand and dCHP output**



Source: OXERA.

4.7 Industrial CHP

As highlighted in section 2, industrial CHP growth is already accounted for in the demand forecast.

4.8 Summary

The CHP scenarios modify the LDC and thus affect the baseline fuel mix. The future volume of CHP is quite uncertain, but it has been reasonably straightforward to model the likely pattern of generation, especially from dCHP.

5. Carbon and Other Emissions Benefits

The social cost[9] of greenhouse gas emissions is an important figure because, adopting a welfare-economic approach to public policy, it should be used to inform decisions on climate change policy, including energy taxation, subsidies and regulatory standards, and hence, investments. So far, the estimation of the social cost of greenhouse gas emissions has remained a relatively academic pursuit, and the negotiation of domestic and international policy on climate change has sought to achieve agreement first on the science, and second on steps towards controlling atmospheric concentrations of greenhouse gases. While the Kyoto Protocol will deliver some action in the medium term, further ahead, policy may be increasingly influenced by *economic* assessments of the impact of climate change and the cost of its mitigation. Such an assessment would balance the costs of damage with the costs of emission abatement, and the estimate of the cost of damage could then become a benchmark for the incentives for investment in emission abatement.

This section reviews the studies that estimate the marginal damage cost from the emission of greenhouse gases and present their findings in units of cost per tonne of emissions. It explains the main differences between the studies, and suggests a best estimate that lies within the range of current damage estimates. Even so, these estimates contain a great deal of uncertainty.

The section draws out conclusions on:

- the effect of adaptation, which lessens the damage caused by global warming;
- the weighting applied to damage visited on poorer nations and that affecting the rich when the damage cost is aggregated across nations;
- the effect of the discount rate chosen, and the recent change in UK policy on discounting;
- recent developments in the scientific understanding of climate change.

5.1 General approach

Although not all the studies on the social cost of greenhouse gas emissions adopt similar approaches, a review of one study will give a sufficient introduction to the processes involved in these studies. The study chosen as the example is Tol (2002). For a review of all the major studies, the reader may wish to refer to Tol (2003).

Tol (2002) presents the results of studies that show the global impact of climate change on human activities (such as agriculture, forestry, water, and energy consumption), land use (due to loss of land as a result of flooding), ecosystems, vector-borne diseases, and health effects of heat and cold stress. The impacts are recorded by global region, largely based around continental land masses. The main models include the Open Framework model, and versions of the FUND model—version 1.6 (an older version), and version 2.0, a newer version which covers a larger number of impacts and incorporates adaptation. The impacts covered in the FUND 2.0 model, used in Tol (2002), are detailed below.

- For agriculture, the results cover changes in yield or land productivity, including the adaptation of farmers to different crops and crop management. Tol examined the relationship between changes in output and temperature, and postulated an optimum temperature for each region. In all the cases, the changes in output did not exceed 0.1% of GDP.
- For forestry, the impact is positive, at least for the initial increases in global temperature. Although global warming increases forestry output, its impact on GDP is negligible.
- For water, Tol relies upon a single study, and reaches an estimate of –0.5% to –1.5% of GDP.
- For energy consumption, Tol considers the change in heat demand arising from growth in income levels and in population. He takes a similar approach to the demand for cooling, which has relatively low utilisation at present. He estimates a saving in heating of about 1% of GDP, and an increased cost of cooling of about 0.6%.
- For land loss due to flooding, Tol uses a number of studies to provide estimates of the area of land loss. He then assumes an income density of land in each region and estimates the income loss when land becomes flooded. Flooding causes migration, and this is assumed to have a cost equivalent to three times the regional per-capita income per migrant. These figures are adjusted for the adaptation of flood defence, and the costs of flood defence are included.

[9] In this context, social cost means the cost to society–ie, the reduction in economic welfare aggregated across all individuals.

- For vector-borne diseases, such as malaria, a number of studies on the change in prevalence with temperature are used to derive a relationship between the health costs (mortality and morbidity) and temperature. Mortality is valued at 200 times per capita income. Wealthy populations are not susceptible to these diseases because they invest in preventative measures. The models suggest that the number of fatalities does not exceed 10,000 per annum, which translates into a small fraction of world GDP.
- The effect of heat and cold stress is taken from studies and applied to population projections for persons aged 65 or over, since it may bring forward the deaths of those with cardiovascular or respiratory illness.

Tol expresses the results as functions of temperature, and shows the movement of the damage costs over a time horizon of several hundred years. The net present value of the costs can thus be obtained by discounting. Furthermore, by differentiating the damage function with respect to temperature, and then substituting into the equation the relationship between carbon emissions and atmospheric concentration of greenhouse gases, and between atmospheric concentration and temperature, the marginal damage cost of emissions can be obtained. These steps are important because recent changes in scientific understanding may have altered the relationships since the valuation studies were written.

These last steps in the calculations are not presented by Tol (2002), but Pearce (2003) explains their derivation, and provides a survey of the literature where all the damage cost estimates have been presented in this most useful form. These are the estimates that will be used in this paper.

5.2 Summary of the studies reviewed in this report

The studies reviewed in this report are the same as those referenced in Pearce (2003). Most are also reviewed in the Government Economic Service Working Paper by Clarkson and Deyes (2002), which was published to coincide with the Cabinet Office's Energy Policy Review. That paper compares the assumptions made in the studies in order to identify the reasons for the variation in the estimates of damage costs.

The main choices to be made between the studies are between their assumptions for the following elements of the calculation:

- integrated climate impact models used—Open Framework, FUND 1.6 or FUND 2.0, or other;
- equity weighting employed;
- value of a statistical life;
- temperature-rise profile;
- categories of impact included;
- discount rate assumed;
- extent of adaptation assumed.

The more recent studies build upon a wider body of work on individual impact areas, such as agriculture, and use newer versions of the models, incorporating, for example, adaptation and more up-to-date scientific assumptions. There is, however, a lag of several years between the scientific developments and their incorporation into the economic assessments.

5.2.1 The choice of model

The Open Framework model (Downing et al., 1996) is based on a doubling of atmospheric CO_2 concentrations leading to temperature and sea-level changes, as forecast by Wigley et al., 1993. The model covers the period 1990 to 2100. Non-market damages are assumed to be a factor of the damages calculated in the sectoral models (flooding, agriculture, energy and water).

The FUND 1.6 model (Climate Framework for Uncertainty, Negotiation and Distribution) operates on nine regions for the period 1950 to 2200. This model was used within the ExternE programme to devise the value of damage from greenhouse gas emissions (see Eyre et al., 1998).

The FUND model version 2.0 is a major revision of version 1.6. It had not been peer-reviewed at the time of the publication of Tol and Downing (2000), but includes updated assumptions about climate change (which suggested lower damage than previously forecast), the effect of adaptation (which is to reduce the damage estimates), and additional categories of damage. The Tol and Downing (2000) paper is of particular value because it compares the results of the FUND 1.6 and 2.0 versions under a number of assumptions about weighting of damages and discounting.

5.2.2 Mortality

In adding up the damage costs in terms of early death—mortality—the cost associated with an early death has typically in the past been estimated crudely as the value of a statistical life lost, where the values have been derived from observed behaviour or lifetime earnings—this is known as the value of a statistical life (VSL). However, the individuals whose lives are foreshortened are often not representative of the groups for whom these values were calculated, and an improved method is to estimate the number of years by which a life has been foreshortened, which gives the value of life years lost (VOLY). VOLY—or, even better, quality-adjusted life years—can be used to provide a more accurate representation of the mixture of acute and chronic health impacts on a population.

Tol and Downing (2000) offer estimates using both VSL and VOLY. As a value of VSL, they take 200 times the per-capita income in the relevant region at the relevant time for each fatality. For VOLY, they take 10 times per-capita income, relating this to VSL, and thereby not accounting for the mixture of chronic and acute health effects. While this is not ideal, no better estimate is currently available for climate change impacts. Their calculations show that the carbon damage cost estimated using the former approach is about 1.4 times the equivalent value of the latter approach.

5.2.3 Adaptation

Of the studies surveyed in Clarkson and Deyes (2002), six were published before 1995 and use early versions of the climate impact models. They also surveyed two more recent studies, by Tol and Downing (2000) and Eyre et al. (1998). Of these two studies, Eyre used FUND 1.6, and Tol and Downing compared results obtained using FUND 1.6, FUND 2.0, and the Open Framework. Tol and Downing's work, as Pearce (2003) shows, reveals the effect of *adaptation* on the estimate of carbon damage cost. It is very significant.

Pearce adds a further recent study to his review, that of Nordhaus and Boyer (2000), incorporating some catastrophic events. These are short-term catastrophies such as drought and storms, but not major climatic system shifts, such as a weakening of the North Atlantic Ocean Circulation (Gulf Stream). In 2002, Tol published a new study, which also uses FUND 2.0.

Using data from Pearce (2003), adaptive and non-adaptive models of climate change impacts can be compared. The models that allow adaptation result in much lower damage estimates.

Table 5.1: **The effect of adaptation on carbon damage cost estimates ($/tC)**

Discount rate	Adaptation	No adaptation
3%	4–9	40–50
5%	–7 to –15	20–37

5.2.4 Equity weighting

The damages and benefits arising from climate change are spread around the globe. They are estimated as changes in GDP and are derived partly from figures such as output per head and per hectare. These output figures vary greatly between countries—rich countries have higher productivity than poorer countries, and also have more assets. This leads to much higher unit values of damage, such as value for a life foreshortened, in the rich countries than in poor countries. For the sake of equity, the authors of some of the studies adjust the damage values of all countries to a world or EU benchmark level of income. For example, when Tol and Downing (2000) make this adjustment, the damage figure is increased by about 1.75 times.

An adjustment for relative income alone is not sufficient to correct for differences in welfare, because income generates utility in diminishing marginal amounts. In other words, an extra pound of income (or climate change damages) is worth more in terms of welfare to a poor person than to a rich person, even after scaling for their relative absolute income (or consumption).

Clarkson and Deyes (2002) apply an equity weight, and Pearce (2003) also offers a discussion of the topic and reviews the literature. Pearce concludes that an equity weight should be based on a value for the elasticity of marginal utility of income of between 0.5 and 1.2. The value of 1.0 chosen by Clarkson and Deyes (2002) falls within this range, and they show that it roughly doubles the unweighted estimates of carbon damage. OXERA uses the Tol and Downing (2000) cost estimates, which have not been adjusted for income or welfare, and applies a multiplying factor of 2 to the damage cost to reflect the equity adjustment.

5.2.5 Discounting

The discount rate chosen to aggregate damages across time is important. This is because, if a high discount rate is used, the resulting discount factor can reduce distant-future impacts to an inconsequential value. The subject of what discount rate to use is fairly complex, and has recently been thoroughly reviewed and applied to climate change by OXERA (2003). The conclusion of this review, which has been incorporated into the Treasury's official guidance on economic appraisal in government (HM Treasury, 2003), is that a discount rate of 3.5%, declining over time towards 1%, should be used.

All the damage costs cited in the literature on integrated assessment models assume constant discount rates, not declining ones. Although Tol and Downing (2000) report damage costs for several discount rates, all are constant over time. In common with many other authors, they express the discount rate as a pure time preference rate (to which has to be added about 2% to generate the social time preference rate used in policy analysis).

OXERA (2003) shows that the effect of switching from a social time preference rate of 3.5% constant to one of 3.5% declining to 1% is to increase the estimated carbon cost damages by about 1.9 times. Therefore, OXERA applies this multiplying factor to the damage costs estimated by Tol and Downing (2000), who previously used a pure rate of time preference of 1%.

The FUND 2.0 model used by Tol and Downing extends only as far as the year 2200, whereas the damages from greenhouse gas emissions persist for longer, and would make a greater contribution to the damage estimate under a declining discount rate. Ideally, damages up to about the year 2400 should be included. However, since this has not been possible using the literature available, it is simply noted that the actual damages may be higher than estimated for this reason.

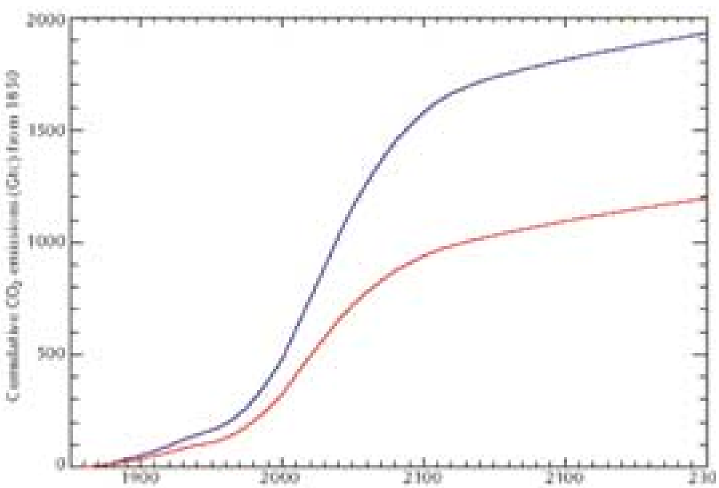
5.2.6 Climate modelling

Recent climate modelling studies have tended to produce similar estimates of temperature changes to the original Intergovernmental Panel on Climate Change (IPPC) studies. There are, however, two aspects of more recent and future work which may lead to significant changes in the carbon damage cost estimates.

The first is the incorporation of non-linear climate changes. The climate model results used by economists to date have been average or expected outcomes, which mask the range of possible outcomes. The damage costs averaged over a range of outcomes may not equal those associated with the average outcome. There is still no full set of probabilistic climate change outcomes available, but the Met Office expects that such results will become available within two to three years (Met Office, 2003).

The second aspect is that the Met Office reports a change in the understanding of the relationship between anthropogenic carbon emissions and total carbon emissions (Met Office, 2002). This recent research shows that, for every 1 tonne of CO_2 released into the atmosphere by human activity, the rise in global temperature causes further release of tonnes of CO_2 previously stored in soils and vegetation. Figure 5.1 shows how this effect changes the expected trend in the atmospheric concentration of CO_2.

Figure 5.1: **The augmentation of climate change due to non-anthropogenic release of CO_2**



Cumulative emissions that are consistent with the WRE550 CO_2 concentration scenario.

Source: Met Office, 2002. Reproduced with kind permission.

As the Hadley Centre points out, while its model without carbon-cycle feedback matches the WRE (Wigley, Richels and Edmonds) model used by the IPCC, the feedback significantly changes the results.

> The figure above shows two cumulative emissions profiles that eventually stabilise CO_2 at 550 ppm. The blue line shows the result from the Hadley Centre model without any carbon cycle feedbacks. The results are similar to the original WRE emissions scenario. The red line shows the result when the carbon cycle feedback is included. Thus, emissions may need to be reduced by much more than originally thought to meet a specific concentration level.

Using the Hadley Centre's data, therefore, the damage cost caused by 1 tonne of CO_2 appears to be about 1.6–1.8 times as great as previously thought because of the carbon-cycle feedback. It then seems appropriate to apply this factor to the carbon damage cost. However, as OXERA found no reference to these recent scientific results in the economic literature, the approach suggested in this report has not been subject to peer review.

5.3 Summary

Because of its incorporation of adaptation, wide coverage of sectors, adjustment for income, and use of VOLY, Tol and Downing (2000) should be chosen as the base estimate of damage cost, although it does not account for gains in amenity due to climate change.

The Tol and Downing (2000) estimate of damage cost should be adjusted in three ways, to reflect:

- the application of welfare weights (as well as income adjustments), as adopted by Clarkson and Deyes (2002) and Pearce (2003);
- the Treasury's recommendations on discounting, involving a social time preference rate which starts at 3.5% and declines to 1%;
- the effect of the carbon-cycle feedback modelled by the Met Office (2002).

Taking Tol and Downing (2000), the damage cost to which these adjustments are made is $4–$9/tC, with a central estimate of $5.1/tC (see Table 5.2 for conversion to sterling). This is identical to the value observed most frequently in the meta-analysis by Tol (2003), which, he notes, can be adjusted for equity weighting and the use of a low discount rate.

Table 5.2: **Calculation of carbon damage cost (2000 prices, £/tC)**

	Multiplying factor	Damage cost
Initial estimate	–	($/tC) 4–9
Conversion to sterling	0.67	2.7–6.0
Equity adjustment	2	5.4–12.0
Discount-rate adjustment	1.9	10.3–22.8
Carbon-cycle feedback adjustment	1.7	17.5–38.8

Source: Tol & Downing (2000), table 5.

The effect of the adjustments is to give a carbon damage cost range of £17–£39/tC in 2003 money, and a best estimate of £22/tC based on Tol and Downing's best estimate of $5.1/tC. A value of £25/tC has been used for the sake of simplicity.

Given that the base case simulates the operation of a carbon trading market, with a forecast carbon price of £10/tC, the full cost of carbon damage is not captured by the implied generation cost faced by consumers. This reflects that the contribution to long-term emissions abatement from a carbon trading market will still result in an increase in atmospheric greenhouse gas emissions concentrations and associated damage costs.

This figure can be compared with the conclusions of Clarkson and Deyes (2002), who based their calculation on Eyre (1998). They concluded that:

> a value of approximately £70/tC (2000 prices, with equity weighting), seems like a defensible illustrative value for carbon emissions in 2000. This figure should then be raised by £1/tC for each subsequent year.

They also suggested that:

> it is still important to note the huge uncertainty surrounding this estimates and to bear in mind the fact that it takes no account of the probability of so-called 'climate catastrophe'. As such a pragmatic solution may be to employ two other values in sensitivity analysis. One of which could be half the size of the central estimate (i.e. £35 [/tC]) and another twice as big as the central estimate (i.e. 140), thereby representing the disproportional upside risk.

5.4 Valuation of carbon savings

OXERA's analysis suggests a carbon damage cost figure of £25/tC. Given that the base case simulates the operation of a carbon trading market, with a forecast carbon price of £10/tC, the full cost of carbon damage is not captured by the implied generation cost faced by consumers. Thus, any reduction in carbon emissions as a consequence of the use of alternative fuel sources provides an additional benefit of £15/tC saved.

Therefore, the additional value that nuclear or wind provides in terms of reduced carbon emissions must be calculated. Table 5.3 presents the total carbon reductions over the base case and the implied carbon benefit. As can be seen, nuclear has a greater carbon benefit than wind, mainly due to the fact that wind generation relies more heavily on fossil-fuel generation at peaks.

5.5 Other emissions

In addition to carbon savings, there are savings in other emissions, specifically NOx and SO_2, as shown in Table 5.4.[10] These have been calculated in the same way as the carbon savings in Table 5.3, and are based on a damage cost for NOx of £3,500/tonne and for SO_2 of £2,800/tonne (European Commission, 2002).

Table 5.3: **Carbon benefit in 2020**

	Base case	High wind	New nuclear
Carbon emissions (mt)	37.9	35.9	30.8
Carbon saving (£/MWh)	–	0.9–2.0 (1.3 central)	1.5–3.3 (2.2 central)

Source: OXERA.

Table 5.4: **Benefits in other emissions, 2020**

	Base case	High wind	New nuclear
NOx emissions (kt)	121.6	119.6	98.9
SO_2 emissions (kt)	51.6	52.7	40.2
Total saving (£/MWh)	–	0.2	2.3

Source: OXERA.

[10] Adjustments may also be made for radioactive emissions. However, initial calculations have suggested that the incremental impact on radioactive emissions from a new nuclear build programme is minimal relative to the potential benefits from savings in other emission types.

6. Conclusions

In this report, OXERA has assessed the major non-market costs and benefits for different types of generation. Using scenarios produced by OXERA's wholesale electricity market model and a new methodology for assessing the security-of-supply implications of different fuel mixes, the study has highlighted some important results.

As Table 6.1 shows, the non-market values associated with wind and nuclear generation, for the indicative scenarios analysed in the study, are potentially significant:

- there are large benefits from improved security of supply—in the order of £5.1/MWh for wind and £3.7/MWh for nuclear;
- the reduction in carbon and other emissions from nuclear and wind provide additional benefits to the economy of £3.8–£5.7/MWh and £1.1–£2.2/MWh respectively;
- for wind generation, these benefits are achieved at the expense of substantive infrastructure costs of between £3.8 and 9.9/MWh.

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Since these values are directly relevant to the government's main policy objectives, they must be accounted for if appropriate investment decisions are to be taken to ensure that these are efficiently met. The framework developed as part of this research establishes a methodology for achieving this and is published as a new contribution to the long-term energy policy debate.

Table 6.1: **Summary non-market generation value, 2020 (£/MWh)**[1]

	Electricity network infrastructure	Carbon emissions	Security of supply	Other emissions	System cost	Total
Wind	–3.8 to –9.9	0.9 to 2.0	5.1	0.2	0.1	-3.6 to 3.6
Nuclear	0	1.5 to 3.4	3.7	2.3	0.6	10 to 13.5

Note: [1] Negative value is a cost of the generation type.
Source: OXERA.

Appendix: Generation Costs

The majority of this paper deals with costs of generation that may not be captured in the marketplace or recognised as part of a 'traditional' investment analysis. These costs and benefits combine with the classic 'generation' costs of different technologies to provide an overall view of the total cost of a particular type of generation within a given generation mix. This appendix looks briefly at these engineering costs for a number of potential new build types, and provides central estimates used in the overall valuation.

A1.1 Wind

As more wind farms are developed, it is expected that the turbine cost and the balance of plant costs will fall because of economies of scale and specialisation in the supply chain. This expectation is formalised in the learning-curve methodology, which projects future costs on the basis of current costs and assumptions about the amount of development. [11]

OXERA has applied learning curves to the cost of on- and offshore wind. The estimates are based on a detailed analysis of the turbine, the balance of plant, and the operating and maintenance costs. Prices ranges were established of £27–£39/MWh for onshore and £37–£50/MWh for offshore for the year 2002. It was assumed that the cost of turbines was driven by the capacity growth at the European level, whereas the balance of plant costs were driven by the development of UK capacity. Capacity development projections were based on OXERA modelling and European wind energy data (*WINDDirections*, July and November 2001). Table A.1 and A.2 summarise these assumptions.

Table A.1: **Assumptions of future development growth**

	2002 wind electricity price range (£/MWh)	Assumed capacity built in UK (EU) in 2010 (GW)	Assumed capacity built in UK (EU) in 2020 (GW)
Onshore wind	27–39	4.3 (40.5)	7.5 (70)
Offshore wind	37–50	2.5 (7)	10.0 (50)

Source: OXERA.

Table A.2: **Assumptions about cost components and learning rates**

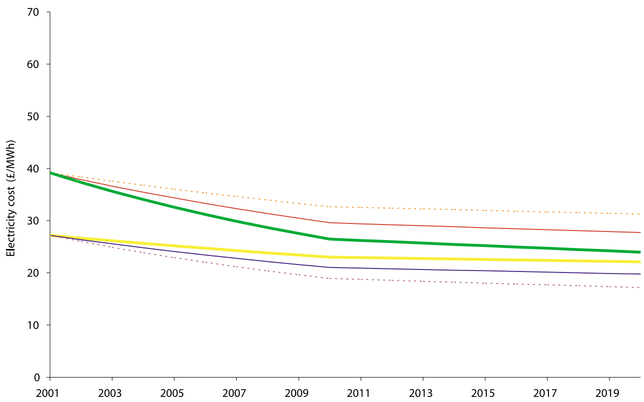
	Cost of capital (%)	Amortisation lifetime (years)	Load factor (%)	Experience parameter (learning rate)	Capital cost, 2003 (£/kW)	Operating and maintenance costs (£/kW/yr)
Offshore wind	8–10	15–20	35–38	0.05–0.15[1] 0.15–0.37[2]	900–1,000	25–35
Onshore wind	8–10	15–20	31–33	0.05–0.15[1] 0.15–0.32[2]	600–760	17–29

Note: [1] Capital cost; [2] operating and maintenance cost.
Source: OXERA.

[11] See IEA (2000) and Roberts, P. (1983).

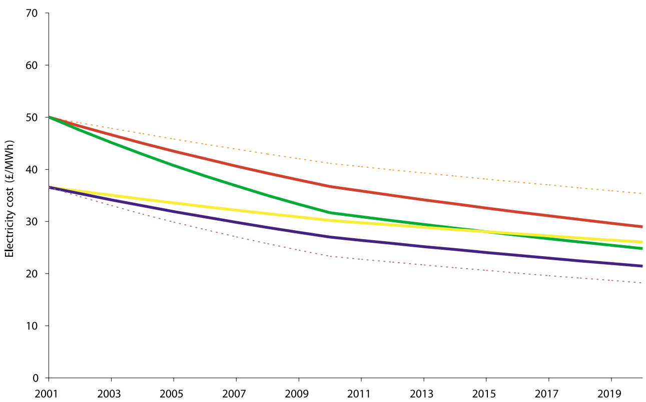
Figures A1.1 and A1.2 show wind cost forecasts to 2020. Onshore wind electricity costs could be in the range £20–£25/MWh by 2020. Offshore wind capacity growth rates are potentially much higher, yielding greater cost decreases. Offshore wind electricity costs could be in the range of £21–£29/MWh by 2020. The figures show a range of assumptions on learning rates and capacities built. The bold lines indicate central assumptions.

Figure A1.1: Onshore wind costs over time (2001–20)



Source: OXERA.

Figure A1.2: Offshore wind costs over time (2001–2020)



Source: OXERA (2002)

The PIU in its 'Energy Review' report used ranges of the cost of wind of £15–£25/MWh for onshore wind and £20–£30/MWh for offshore wind (PIU, 2002).

A1.2 Nuclear

There are a number of potential technologies for the next generation of nuclear generation plant being proposed or developed. BNFL and British Energy undertook a joint feasibility study of the BNFL/Westinghouse AP1000 reactor, based on the AP600 design, for suitability as replacements for British Energy's existing fleet of reactors in the UK.[12] Other possible technologies include the Canadian CANDU reactor, the pebble bed modular reactor (PBMR), the European passive reactor (EPR), and GE's boiling water reactor (BWR).

For the purposes of this study, the AP1000 is used. BNFL/Westinghouse have released a document outlining the main points of the AP1000 design and associated costs (BNFL/Westinghouse). In this initial assessment, the production costs range from £30/MWh for a first-of-a-kind single unit, to £22/MWh for the fourth in the series. More recent estimates based on a series of twin-unit reactors range from £25/MWh for the first units to £20/MWh for the fifth set.

The PIU also looked at the issue of new nuclear build, based on a single unit assessment, and, making adjustments for operating availability, construction times and regulatory stability, arrived at a cost of £30–£40/MWh (PIU, 2002).

A1.3 Combined-Cycle gas turbine

Capital cost

Capital costs for recent CCGT projects have been reported in the range £400–500/kW, with £400/kW being reported as the cost of CCGT in *Power UK* (Platts, 2003). The expectation is that these costs will fall during the years between now and 2020.

This contrasts with the views of the PIU report, of current capital costs of £270/kW falling to £260/kW in 2020 (PIU, 2002).

12 BNFL/Westinghouse, 'AP1000… the reactor technology ready now', www.bnfl.com/website.nsf/images/energyreview_ap1000_summary/$file/Energy_Consultation_AP1000_summary.doc.

Fuel costs

The future price of gas is uncertain. Production of gas on the UK Continental Shelf will decline, which will mean that imports will increase, from Norway in the first instance, but from as far away as Russia in the longer term. While the marginal cost of gas production is likely to remain the same, the costs of transportation mean that gas will increase in price as supplies are sourced further afield. Currently, National Balancing Point prices are approximately 20p/therm for the next two years, although this is linked to current high oil prices. Therefore, prices could be expected to fall in the medium term (as oil prices settle to lower values), before increasing on the back of higher transportation charges. The price in 2020 could therefore be expected to be in the range of 18–25p/therm.

Efficiency

Current plant efficiencies are above 55%, having increased from efficiencies below 45% in the early 1990s. The increase in efficiency is slowing, but is still expected to reach 60% for future CCGTs.

Total

Bringing all these elements together, with an assumed annual fixed operating and maintenance cost of £15/kW/yr, gives a range of new entry costs in 2020 of £18–£25/MWh with a central estimate of £21/MWh, compared with the PIU's estimate of £20–23/MWh. Note, however, that this does not include a cost of carbon emissions. If the cost of carbon is included, the above estimates increase at a rate of ~£1/MWh per £10/tC, moving the range to £19–£26/MWh for the assumed price of £10/tC.

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