PARSONS BRINCKERHOFF

Powering the Future

Mapping our low-carbon path to 2050

Full Report

December 2009

Contents

Appendices

1. Introduction

To protect the wellbeing of future generations, immediate action is vital to manage carbon dioxide (CO_2) emissions worldwide and minimise potential climate change. The UK government has adopted a position of leadership, making a climate change commitment to reduce these emissions by 80% by 2050 compared with 1990 levels.

Such a commitment presents a major challenge to the UK and its economy. We are already facing a serious shortfall in electricity generating capacity, given that many of our power stations are scheduled to retire in the next decade. Rapid replacement of power plant is a challenge, but it also represents an opportunity to make an earlier transition to infrastructure with lower carbon emissions.

The UK government has consulted on various strategies necessary to deliver the climate change commitment, initiating work by the Climate Change Committee and prompting contributions from a wide range of interest groups and consultancies. The recently published UK Low Carbon Transition Plan and the UK Renewable Energy Strategy define a way forward to delivering the 34% reduction required to meet the first carbon budget for 2020. A roadmap for the period from 2020 to 2050 is being developed within government. Changes will be required in all sectors of the economy to deliver the major reductions in CO_2 emissions by 2050. Powering the Future has been prepared as a contribution to this debate, evaluating opportunities in each sector for emission reduction while taking a holistic approach to energy consumption and CO_2 emissions in the UK economy.

A key feature of Powering the Future is the recognition of potential interactions between sectors. Acknowledging and exploiting the opportunities afforded by these interactions is fundamental to the UK achieving its CO_2 emissions targets in an economically efficient manner. For example, if the UK began to produce significant amounts of its electricity from intermittent renewable sources without compensatory actions, the reliability of electricity supply would be degraded. However, wide adoption of electric vehicles in the transport sector would provide opportunities for the control of charging demand to maximise the value of the renewable generation without degrading reliability.

In moving forward its strategy, the UK has to deliver:

- compliance with 2050 CO_2 reduction commitments
- compliance with the 15% renewable energy target agreed with the EU by 2020
- reliable electricity supply throughout the period to 2050 and beyond
- technically feasible changes in each sector, including those needed to take account of interactions between sectors
- diversity of electricity generation technologies to minimise risks of overreliance on any one technology
- diversity of energy supplies, keeping imported fuels to a reasonable minimum

The adopted strategy has to consider the future availability of fuels. The security of fuel supply is clearly affected by the finite nature of many of the resources. It is also affected by commercial and political pressures, with the UK continuing to import most of its fossil fuel supplies for the foreseeable future. Sustainable fuel resources, such as biomass derived from plant materials and animal waste, will play a significant role in reducing CO_2 emissions despite the modest scale of the available resource.

As a leading international consultancy, Parsons Brinckerhoff recognised the essential need for a comprehensive strategic approach to reducing CO_2 emissions. Our involvement in major infrastructure projects in all sectors enabled us to adopt a broad view in assessing the implications to the UK economy of meeting the 80% CO_2 reduction commitment. In particular, we wanted to assess the effectiveness of alternative strategies in achieving the reduction commitment while minimising risks from excessive dependence on critical technologies or fuels.

Powering the Future evaluates options for CO_2 emissions reduction across all sectors of the UK economy. Incorporating government published statistics on the current energy consumption and CO_2 emissions of each sector, it creates models that allow each improvement option to be analysed and evaluated. Scenario analysis is used to apply a consistent set of such options across all the sectors to evaluate overall CO_2 emissions and to compare the value of the different options.

2. Approach

2.1 Objectives

The main objectives of Powering the Future are to:

- provide a coherent response to the UK government on the implications of the climate change commitments across the whole economy
- assess the types and scale of change required in each sector to meet the commitments
- compare the impact of alternative strategies for emissions reduction, to identify which are critical to achieving compliance
- identify the implications of adopting alternative strategies, with regard to UK dependence on critical technologies or fuels

2.2 Scope

The intent of Powering the Future is to assess the impact of adopting different sets of technologies and measures to achieve the targeted CO_2 reductions across the whole of the UK economy, so that further work can be directed towards delivering results consistently across all sectors.

Powering the Future addresses the major emitting sectors to assess the technical feasibility of alternative means of delivering the reductions commitment. The implications of the necessary changes are put into perspective in terms of the scale and rate of implementation. However they are not costed, since the first step must be to identify effective feasible options. Cost is an important issue for any choices to be made in the subsequent implementation of selected measures.

A variety of cost estimates are available in other reports such as the Stern Review[1] and McKinsey[2]. In 2006, Parsons Brinckerhoff published a report entitled Powering the Nation which provided detailed costs for alternative power generation technologies. This report will be updated and reissued in early 2010 to take account of the significant changes in the costs of fuels and plant since 2006.

The transition from identifying potential solutions to their progressive and timely implementation requires significant further work. A number of areas for further work are suggested in appendix A7 of this report.

2.3 Basic assumptions

Powering the Future makes the following assumptions:

- the 2050 commitment is the appropriate target for CO_2 reduction
- the effects of climate change on heating or cooling demand will be limited
- there will be no radical changes in lifestyle, ie most people will live in houses and will travel to work outside the home; families will have an average of two children; life expectancies will not change significantly
- economic growth will average 1.5% over the period to 2050
- the limitations of the electricity transmission and distribution networks will not restrict the outcomes of particular scenarios

Readers should also note that the options considered only use technologies that are either currently established or are close to large-scale application.

2.4 Methodology

Powering the Future divides the UK economy into five sectors:

- transport
- domestic
- industry
- commercial
- electricity

It analyses these sectors for potential responses to the CO_2 emissions reduction target. Drawing upon government published statistics, it reviews the current energy consumption and CO_2 emissions of each sector and prepares a forecast to 2050. The resulting information is incorporated into a sector model that allows improvement options to be analysed and evaluated.

These options fall into four general types:

- demand reduction
- efficiency improvement
- substitution of alternative fuels or energy source
- capture and storage of CO_2 emissions

Each type of solution can contribute to a reduction in CO_2 emissions. The first three types can be applied to every sector, while carbon capture and storage (CCS) is more appropriate for large fixed-point sources of CO_2 emissions such as a steel works or power plant.

1 Stern N, 'The Economics of Climate Change' 2006.
2 McKinsey & Company, 'Pathways to a Low-Carbon Economy, version 2 of the Global Greenhouse Gas Abatement Cost Curve' 2009.

Following the analyses of each sector, a scenario analysis (section 10) applies a consistent set of measures across the sectors, for example improved insulation of buildings or the application of renewable heat, to evaluate the overall impact on the UK. This analysis allows the alternative strategies to be compared and critical measures to be identified.

Figure 2.4.1 shows the process used to analyse each sector of the UK economy using data from government statistics to create a series of sector models which are then subjected to alternative carbon reduction measures. Scenarios are used to explore the implications of attempting to achieve the 80% reduction target with alternative sets of measures.

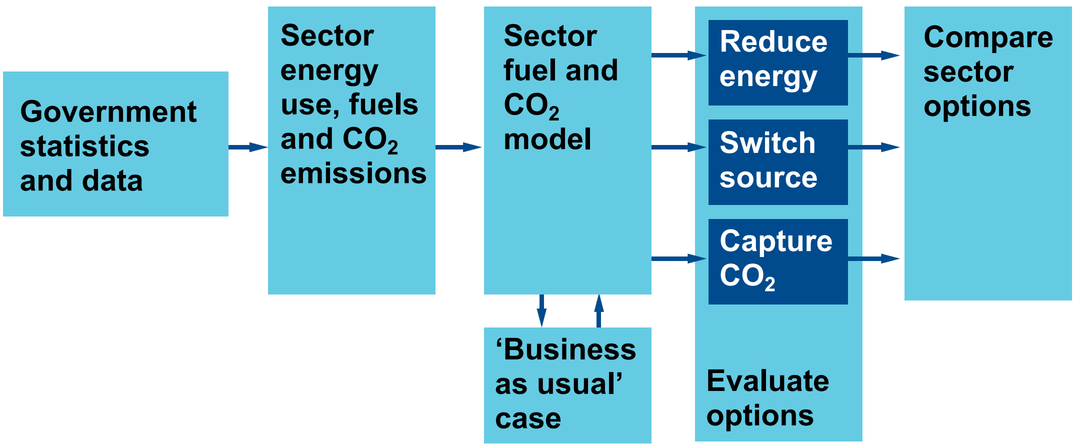
Figure 2.4.2 shows the scenario analysis process used in Powering the Future. The scenario analysis allows the impact of alternative strategies across all sectors to be visualised and compared. The scenarios considered in this report include a reference scenario together with alternative scenarios that change different elements of the reference scenario.

The scenarios are intended to investigate the value of the following measures: renewable heat, industrial combined heat and power (CHP), nuclear programme, CCS, wind generation, building insulation, vehicle conversion to electricity, and photovoltaic (PV) generation. The value of these measures is put into context by the yardstick of a 1% change of the economic growth rate.

2.5 Structure

Section 4 of Powering the Future summarises the recent trends of fuel use and CO_2 emissions by the UK economy and outlines the general principles by which CO_2 emissions can be reduced. Sections 5 to 8 review the status and analyse the measures for reduction of CO_2 emissions in the transport, domestic, industry and commercial sectors. Following consideration of the consuming sectors, the current and future capability of the electricity sector is reviewed in section 9. This section includes an assessment of the measures available for new power generating plant to meet the future electricity demand with minimum CO_2 emissions.

Figure 2.4.1 Sector analysis process

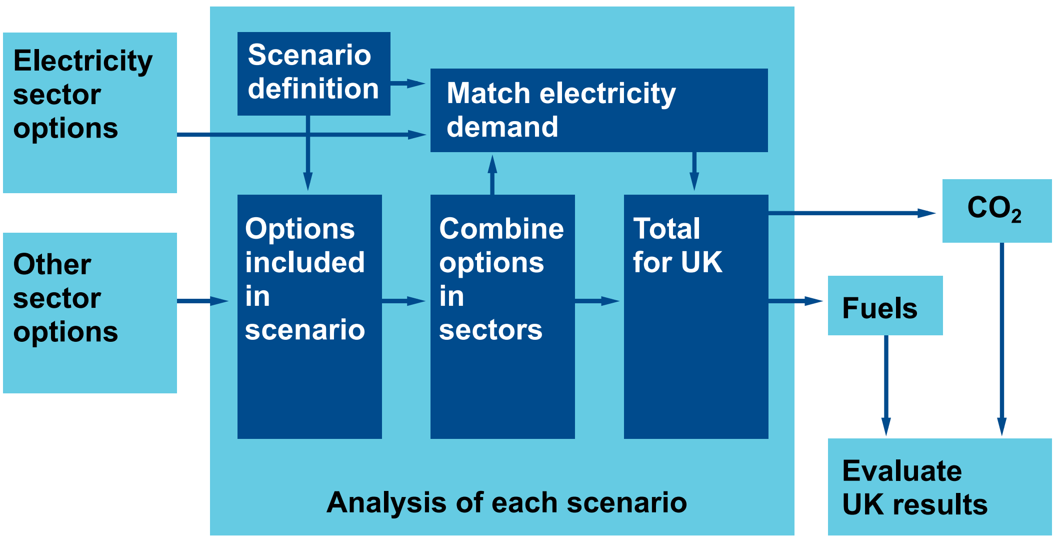


Section 10 describes the process of scenario analysis and evaluates the outcome of the alternative scenarios. It assesses the reduction in CO_2 emissions offered by each scenario, identifying the most effective measures and highlighting dependence of the UK economy on critical technologies or fuel supplies, where appropriate.

Findings are presented at the end of each sector section, and the major study findings are presented in section 3.

Abridged references are given in footnotes, with full references in appendix A8.

Figure 2.4.2 Scenario analysis process



3. Findings

1. The scale and urgency of the challenge. Achieving the 80% reduction in CO_2 emissions mandated by the Climate Change Act 2008 is feasible but extraordinarily challenging. It will require urgent and large-scale effort in every sector of the UK, and a delay in any sector will jeopardise the commitment.

2. Leadership. The scale and rate of change required across all sectors to achieve the desired reductions in CO_2 emissions are such that market mechanisms will require strong leadership from government to be effective.

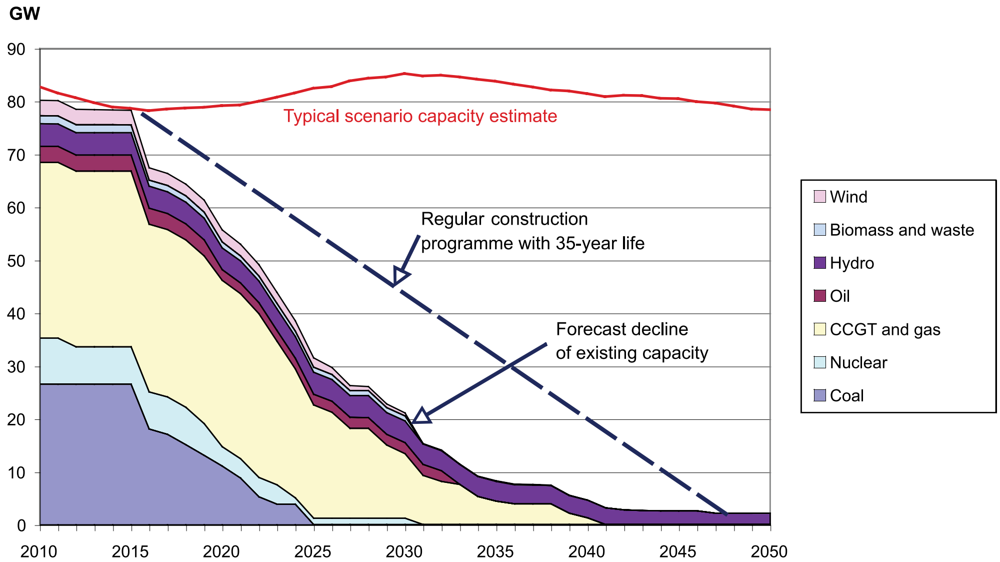
3. UK generation capacity trends. UK electricity generating capacity is forecast to fall to half of its current value by 2023, but it is unlikely that there will be a significant reduction in demand (see figure 3.1). In order to maintain adequate capacity from 2020 onwards, new plant would have to be built at a rate that is at least equal to the highest historical rate achieved by the UK – this at a time when the capacity of the indigenous UK power plant industry is greatly reduced.

4. Sector coordination. Analysing the alternative solutions shows there are strong interactions between sectors and measures. All sectors must therefore be addressed in a coordinated way to avoid wasted investments and failed commitments.

5. Sequence of interventions. There is a risk that decisions and actions taken now to meet the EU 2020 renewables target will have undesired and adverse impacts on the UK's ability to meet the 2050 carbon obligations. For example, the early and widespread adoption of wind power could severely undermine the viability of other low-carbon technologies, making it difficult to meet carbon targets and longer-term commitments.

6. Maintaining industrial competitiveness. Funding the requirements for substantial reductions in CO_2 emissions and improvements in energy efficiency necessary from UK industry – without undermining its competitiveness – will require significant interventions at both the UK and European levels.

Figure 3.1 Forward capacity of existing and committed plant



7. Primary reduction measures. The scenario analysis results summarised in figure 3.2 show that the following measures are essential to achieve the CO_2 reduction targets:

- rapid and large-scale switch of cars and light goods vehicles (LGVs) to electric battery power
- radical improvement in industry energy efficiency
- large-scale application of renewable heat using solar energy and making maximum use of available biomass
- intensive and substantial improvement in the insulation of new and existing houses and buildings
- development and application of CCS for large emitters in the industry sector, in addition to its application for coal-burning power plant

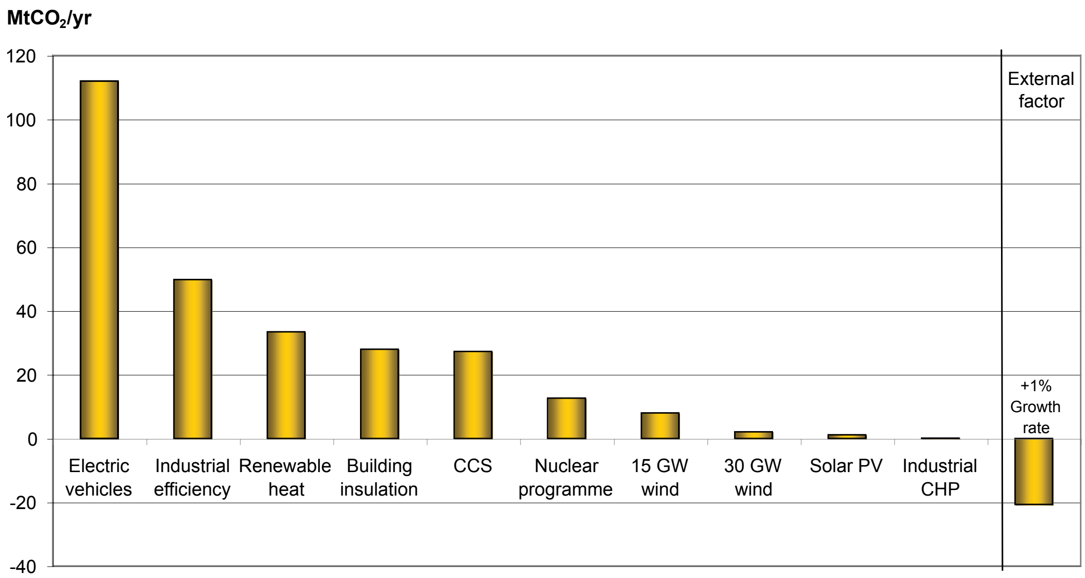
8. Secondary reduction measures. Wind power, nuclear power and solar PV are collectively essential to the decarbonisation of electricity production, reducing CO_2 emissions by over 100 $MtCO_2$/yr from current levels. However, as electricity will be largely decarbonised by 2050, the value of any individual low-carbon power generating measure will be low, as shown in figure 3.2. The choice of the final mix of these alternatives must therefore be made on operational, economic and energy security grounds.

9. Avoiding technology dependence. Choices between alternative measures can result in excessive dependence on key technologies. For example, the omission of a nuclear programme would result in heavy dependence on CCS technology, which is currently unproven at the scale required for a major power plant.

10. Avoiding fuel dependence. Fuel diversity issues can be managed if a holistic view of UK energy use is taken. The reference scenario (the base case for evaluation of alternative options) achieves a good diversity of fuels by substituting electricity for oil in the transport sector, and by having a flexible electricity generation mix.

11. Quick wins. Because of the scale of the measures, improved building insulation, improved industry energy efficiency, and greater use of electric vehicles all offer valuable reductions in carbon emissions by 2020. Early action is needed to deliver these reductions.

Figure 3.2 Value of CO_2 reduction measures in 2050



4. UK economy, energy resources and consumption, and CO_2 emissions

4.1 Sector introduction

This section introduces the context in which all policies for CO_2 emissions and power generation must be considered. Energy consumption for each sector is reviewed and sources of energy are examined at the UK level.

Energy resources are briefly discussed in terms of their future availability, and historical and current CO_2 emissions are considered. The section finishes with a look at the challenges and generic approaches to reducing CO_2 emissions.

For the purpose of the report, the sectors include the groups of consumers shown in table 4.1.1, as detailed in DUKES Table 1.3.

4.2 Energy use

Figure 4.2.1 shows the changing pattern of energy use by the industry, transport, domestic and commercial sectors. Figure 4.2.2 gives the breakdown of primary energy use between the sectors in 2006.

These figures show that the largest single demand for primary energy is 85 million tonnes oil equivalent per year (MTOE/yr) from the electricity sector, with the transport sector rising towards 60 MTOE/yr. Together these sectors represent over 60% of the UK's annual fuel consumption. The domestic, industry and commercial sectors are now consuming a declining share, each between 10 and 35 MTOE/yr.

Figure 4.2.3 indicates the mix of UK economy primary energy sources. It shows that, in 2006, oil and natural gas each represented about 35% of the total, with coal about 19%. The balance included a declining element of about 7% from nuclear electricity, and a growing contribution of around 2% from renewable sources. These energy inputs were not all used directly: a significant part of the energy supply is converted to electricity. The forms of energy consumed by end users in the economy, excluding the electricity generation sector, are summarised in figure 4.2.4.

Table 4.1.1 Powering the Future sector definition

Powering the Future sectors	DUKES Table 1.3 sectors
Transport	Transport
Domestic	Domestic
Industry	Iron and steel, other industries, energy industry use, petroleum refineries, coke manufacture, blast furnaces
Commercial	Commercial, public administration, agricultural
Electricity	Electricity generation

Figure 4.2.1 Primary energy use by sector[3]

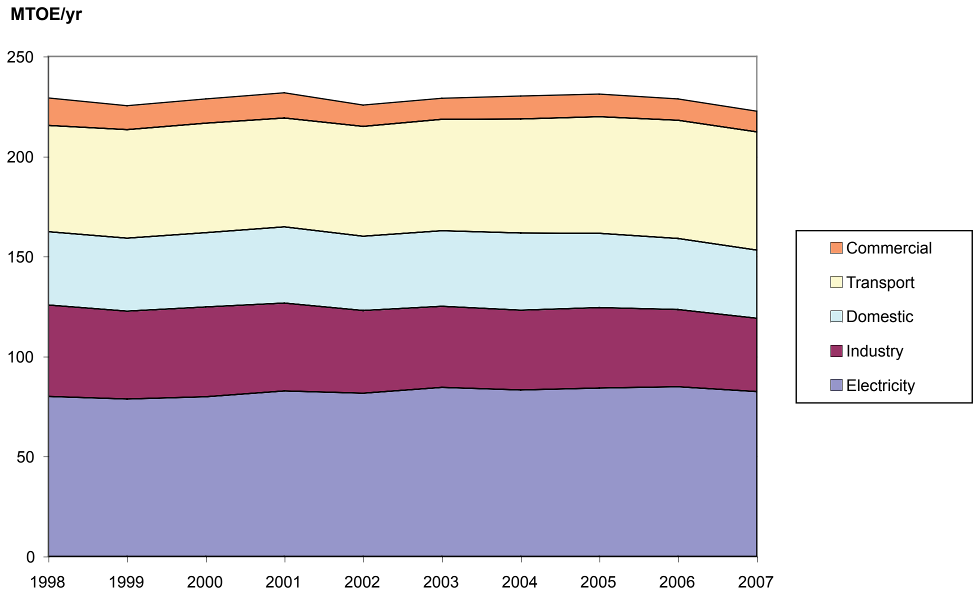
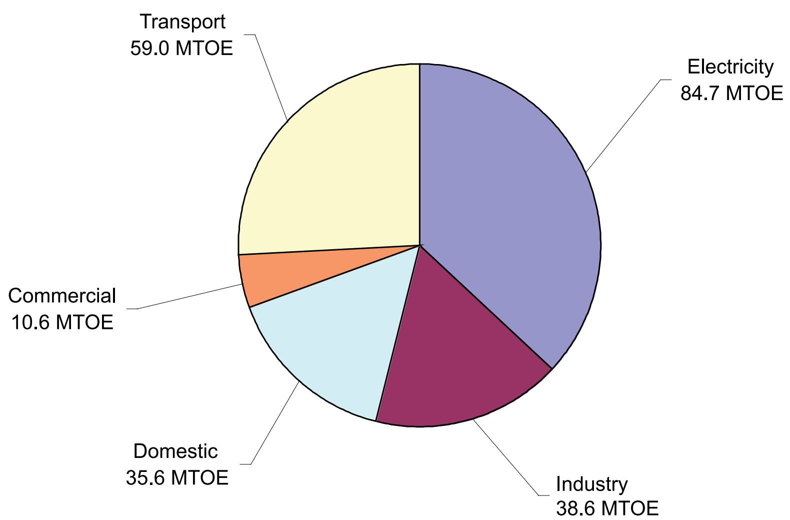


Figure 4.2.2 Primary energy consumption by sector in 2006[4]



Total consumption = 228.6 MTOE

Rounding introduces an error of 0.1 to the total

[3],[4] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

Figure 4.2.3 UK economy primary energy sources in 2006[5]

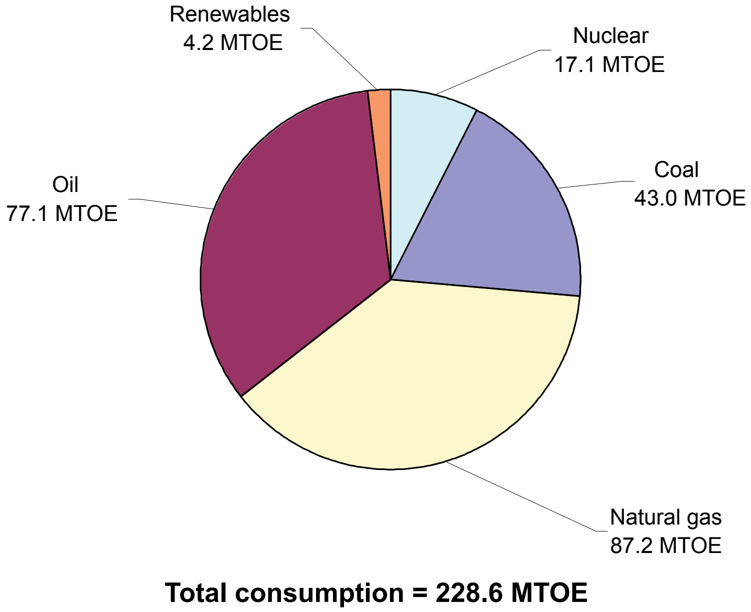
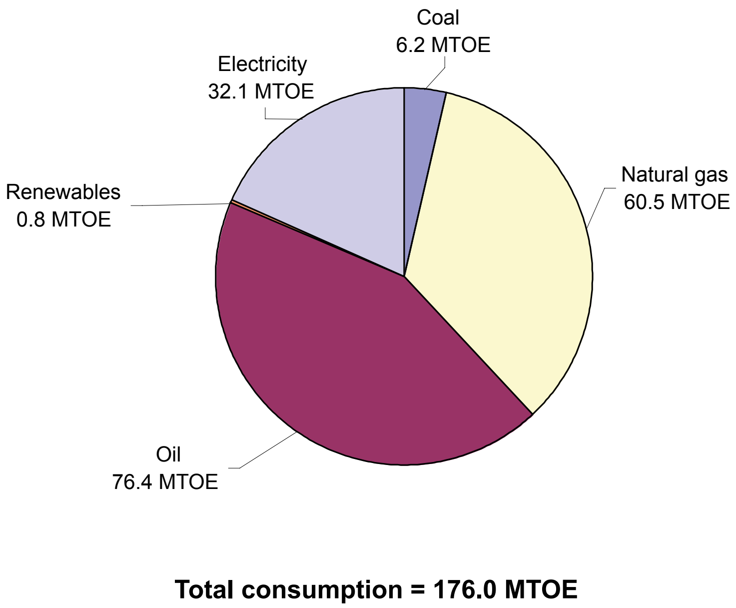


Figure 4.2.4 Energy supplied to end users 2006[6]



[5],[6] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

Comparing figure 4.2.4 with figure 4.2.3 shows that a significant proportion of energy supplied to the economy as coal or natural gas is transformed into electricity, whereas oil is used more directly by end users.

4.3 Future availability of energy resources

Future use of fossil fuels will be significantly affected by limitations in resources available internationally. Historically the prices of these resources have varied significantly as demand and production have changed with economic growth and the exploitation of new reserves. In future the prospect of higher prices for the more limited availability of resources is certain, but the security and longevity of supply is much less predictable.

The level of reserves is an important measure of the future available mineral resource, but it is notoriously difficult to estimate with any degree of confidence. The difficulties are many and include the commercial and political sensitivity of resource data, the diversity of technical appraisal techniques, and the sensitivity of the size of the economically recoverable reserves to future commodity price assumptions. A popular measure of the longevity of oil reserves is the reserve/production (R/P) ratio. Dividing the end-of-year estimated oil reserves by the oil production in that year provides an indication of how many years of reserve are left at the current production rate.

While the actual amount of oil reserves is the ultimate limiting factor, the rate of extraction and production is also of importance. 'Peak oil' describes the point at which maximum extraction of oil has been reached and after which production must decline. The predicted world peak oil date is contentious; while some deny that oil resources are finite, most reputable bodies such as the International Energy Agency consider that peak oil is likely by 2020. The consequences of peak oil are uncertain, but it is likely that oil prices will rise and become increasingly volatile as supplies become less reliable.

A respected source of data concerning reserves of oil, gas and coal is the BP Statistical Review of World Energy[7]. In its 2009 report, BP indicates that the Middle East has another 80 years of production while Europe has just 20 years. The worldwide total R/P ratio is 40 years. BP reports that the R/P ratio for worldwide natural gas is 63 years; for Europe it is also 63 years.

Coal has a worldwide R/P ratio of 122 years, with Europe having 51 years. The UK is shown to have 155 million tonnes of coal reserve. At the current rate of production, this would last just nine years (from the end of 2008), giving the UK an R/P ratio of nine.

Perhaps because of security reasons, R/P ratio information is not available for uranium. Uranium is used as the fuel for nuclear reactors and it faces similar limitations to fossil fuels. In 2006, the Organisation for Economic Co-operation and Development (OECD) published information concerning uranium reserves[8], stating that known resources would last 85 years at the current rate of use. However, the World Nuclear Association estimates that the figure is over 200 years[9], based on the OECD figure and an expected increase in uranium prices (making more uranium resources viable). Other sources of nuclear fuel include thorium, which occurs naturally at three times the level of uranium. Technology to use thorium in existing nuclear reactors is not mature but there is potential for at least their partial conversion to use this fuel.

The R/P ratio is at best only an indication. We know that production rates change with changes in demand, and that the declared reserves will also change.

Critically, the ratio calculation uses reserves that are proven both economically and technically. It takes no account of resources that may become viable reserves in the future, through changes in fuel prices or improved technology. However, as few regions of the world remain unexplored, large finds of valuable fossil fuel or mineral resources will be increasingly unusual. These figures indicate that the availability and price of fossil fuels in 2050 will be radically different to those applying today.

While mineral energy resources represent finite geological resources, energy resources exploiting biomass represent a share of the world's finite biosystem. These biomass resources are even less well understood than mineral resources.

Biomass – non-fossil fuels derived from plant materials and animal waste – is a key resource but it is inconsistently defined, creating inevitable discrepancies between available data. In 2005, the Carbon Trust produced a review[10] that shows that UK-

[7] BP, 'Statistical Review of World Energy 2009' 2009.

[8] Organisation for Economic Co-operation and Development, 'Uranium 2005: Resources, Production and Demand' 2005.

[9] World Nuclear Association, 'Supply of Uranium' 2009.

[10] Paul Arwas Associates, 'Biomass Sector Review for the Carbon Trust' 2005.

sourced biomass has energy equal to 3.5 MTOE at current levels of production, with a potential to supply twice this value. By contrast, Defra[11] suggests that the current level of UK-sourced biomass energy is 5.6 to 6.7 MTOE. Various biomass-fuelled projects are proposed that would import large amounts of biofuel such as wood. However, the international market is not mature and the sustainable level of biomass import remains uncertain. Given the adverse impact on international food prices that resulted from early efforts in the USA to increase the production of biofuels for transport, it is clear that it will not be sustainable to increase UK biomass supplies by a large factor through further imports. The maximum available biomass in the UK is thus likely to be limited to a value of around 20 MTOE.

Biogas is produced from the biological decay of organic matter, typically waste or agricultural products, and can generally be used as an alternative means of delivery of biomass energy. However, biogas is foreseen to be produced only from UK-sourced waste and is unlikely to radically increase the available biomass energy resource.

Fuel availability is limited by the amount of naturally occurring resource that is both economic and technically feasible to extract and exploit. Fuel availability can also be restricted by commercial and political pressures so it is important to maintain a diverse fuels policy that avoids overdependency on single-fuel sources.

4.4 Current CO_2 emissions by sector

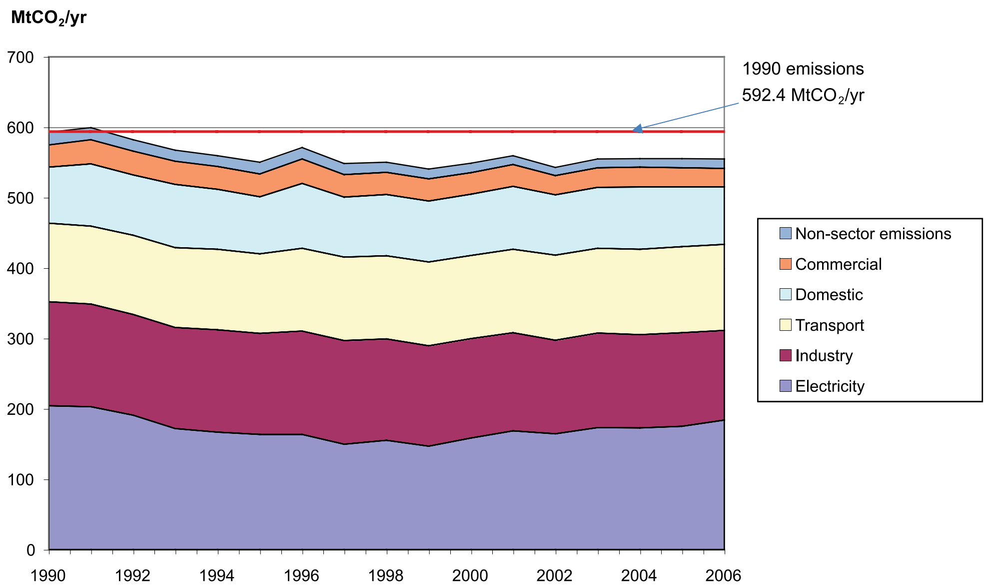
Figure 4.4.1 shows the contribution to CO_2 emissions by each sector.

Emissions by power stations in the electricity sector show a falling trend from 1990 to 2000 as gas burned in new, more efficient combined cycle gas turbine (CCGT) power stations with lower emissions displaced coal burned in older power plant. Since 2000, CO_2 emissions have increased somewhat as the rising price of gas relative to coal has reversed this trend, increasing the proportion of coal in the current fuel mix.

Despite its lower proportion of primary fuel input, industry emits a higher proportion of the total CO_2. This is due to emissions from coal burning for steel production, the use of high-carbon residuals from crude oil as fuel for oil refining, and the inherent emissions of various chemical processes such as cement making.

Transport is a major emitter because of the diesel and petrol burn, with a rising trend reflecting increased traffic growth.

Figure 4.4.1 CO_2 emissions from primary energy sources by sector[12]



[11] Department for Environment, Food and Rural Affairs, 'UK Biomass Strategy' 2007.

[12] Department for Environment, Food and Rural Affairs, 'Table 5b: Estimated emissions of carbon dioxide (CO_2) by National Communication source category, type of fuel and end user: 1970-2007' 2008.

The relatively constant and modest emissions from the domestic sector reflect the dominant use of natural gas, which is a relatively low emitter of CO_2 per unit energy released compared with other fuels. The emissions of the commercial sector can be seen to be only 5% of the total and to be declining slowly. The CO_2 sector emissions for 2006 are shown in figure 4.4.2.

4.5 The challenge of reducing CO_2 emissions

The Stern Review[13] identified the severe economic impact that climate change would have on the UK economy without concerted preventative action. The Review recommended that policy should aim to limit atmospheric CO_2 to below 450 ppm. This required that atmospheric CO_2 emissions should peak no later than 2016 and then decline at 5% per year to reach 70% below 2006 levels by 2050.

The rapid growth of global CO_2 emissions in recent years has resulted in concerns that irreversible climate change may result from runaway warming if CO_2 levels in the atmosphere exceed a tipping point in the range of 450-500 ppm.

Government policy on CO_2 emissions was set out in the Energy White Paper 2007[14]. It was subsequently incorporated in the Climate Change Act 2008, committing to reducing CO_2 emissions by 80% of 1990 values by 2050, with intermediate CO_2 budgets delivering real progress by 2020.

The EU Renewables Directive (15% of UK energy requirements in 2020 to be met from renewable sources) is driving the government's renewables strategy for 2020. The Renewable Energy Strategy 2009 calls for a large part of electricity supply to be from renewable sources by 2020, supported by strong growth in renewable energy use for heat.

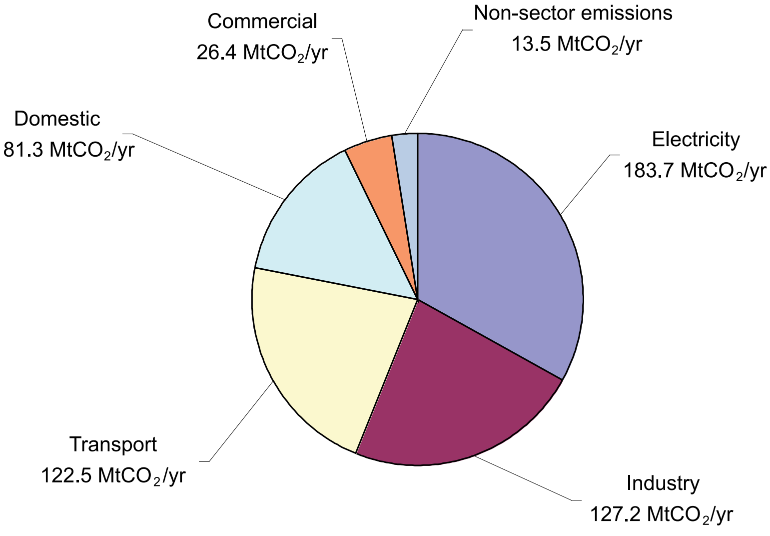
4.6 Options for the reduction of CO_2 emissions

There are four general groups of methods for reducing CO_2 emissions:

- demand reduction
- efficiency improvement
- substitution of alternative fuels or energy source
- capture and storage of CO_2 emissions

Each type of solution can contribute to a reduction in CO_2 emissions. The first three types can be applied to every sector, while CCS is more appropriate for large fixed-point sources of CO_2 emissions such as a steel works or power plant.

Figure 4.4.2 CO_2 emissions by sector for 2006[15]



Total emissions = 554.6 $MtCO_2$/yr

[13] Stern N, 'The Economics of Climate Change' 2006.

[14] Department of Trade and Industry, 'Meeting the Energy Challenge. A White Paper on Energy' 2007.

[15] Department for Environment, Food and Rural Affairs, 'Table 5b: Estimated emissions of carbon dioxide (CO_2) by National Communication source category, type of fuel and end user: 1970-2007' 2008.

4.6.1 Demand reduction

This range of measures includes reducing demand by changing the needs of the sector, for example by reducing the need or by substituting an alternative provision.

4.6.2 Efficiency improvement

Improvements in efficiency of energy use are feasible in all sectors. Continuous small-scale improvements to process or service are common, but more radical measures are often needed to deliver large improvements.

4.6.3 Substitution of alternative fuels or energy source

Available fuels have different CO_2 emission footprints for the energy they release, as shown in table 4.6.3.1.

Conversion from one fuel to another has the potential to reduce CO_2 emissions. In the 1990s, natural gas-fired combined cycle power plants replaced many of the less efficient coal-fired power stations. The lower carbon content of the fuel and the more efficient thermal cycle played a significant role in reducing electricity sector emissions.

Replacing power plants that burn fossil fuels with energy from renewable sources, such as hydroelectricity, also reduces CO_2 emissions. Even so, the lifetime impact of the CO_2 released for plant manufacture and construction means that even renewable energy has a CO_2 emissions footprint, as shown in table 4.6.3.1.

The combustion of biomass, such as wood or straw, to produce heat and/or electricity is considered to be neutral in CO_2 emission terms as the carbon was recently removed from the atmosphere by the living plant.

Secondary fuels as listed in table 4.6.3.1, such as the coal or natural gas used to stabilise biomass combustion, and emissions associated with the construction of the facility, remain as fossil carbon emissions.

The replacement of current power plant over the next 20 years provides the opportunity to reduce the carbon intensity of electricity by the development of renewable sources, nuclear power and CCS, so that electricity could be expected to have only 10-20% of its current CO_2 emissions by 2050. For this reason, substituting electricity for other fuels may, apparently paradoxically, offer reduced overall CO_2 emissions after about 2030.

Table 4.6.3.1 CO_2 emissions for various fuels for heating and power generation[16]

Fuel	Fossil CO_2 emissions for heating (kg/MWh)	Fossil CO_2 emissions for electricity production (kg/MWh)
Coal	300	800-900
Diesel oil	250	500-750
Petrol	240	600-920
Liquid petroleum gas (LPG)	210	525-800
Liquid natural gas (LNG)*	203	340-410
Natural gas	190	320-380
Nuclear		17[17]
Wind		16[18]
Biomass fuels	5-100	15-300

*including LNG production emissions

[16] Derived from: Department for Environment, Food and Rural Affairs, 'Guidelines for the Measurement and Reporting of Emissions by Direct Participants in the UK Emissions Trading Scheme' 2003.

[17],[18] Derived from: World Nuclear Association, 'Comparative Carbon Dioxide Emissions from Power Generation' 2009.

4.6.4 Carbon capture and storage

Carbon capture, either by pre-treatment of fuels or post-treatment of exhaust gases, is being developed but has not yet been demonstrated on the scale of modern power plant.

Significant chemical processing is involved in the necessary separation, and all current technologies require substantial energy input. These features mean that carbon capture is likely to be costly in both capital investment and in the degraded performance of the power generating plant.

Long-term carbon storage in geological formations is being demonstrated and evaluated at the scale typical of a 150 MW coal-fired power plant. Although progress is being made for different types of geological storage, significant uncertainties remain about the costs and effectiveness of large-scale and long-term geological storage of CO_2.

The complexity of carbon capture technology means that it is only suitable for fixed installations, and is unlikely to be applied economically to small installations.

4.7 CO_2 emission reduction measures applied to the different sectors

The potential of the generic types of CO_2 emission reduction measures is reviewed in the subsequent sections of this report for the various sectors. Not all measures are readily applied to all sectors so, for example, while CCS may be feasible for large power stations and for some industrial processes, it is unlikely to be viable for individual road vehicles or for domestic heating systems.

The sectors are considered in order of their fossil energy use, with the electricity sector being addressed after the others to take account of forecast changes in the patterns of demand for electricity:

Transport	section 5
Domestic	section 6
Industry	section 7
Commercial	section 8
Electricity	section 9

5. Transport

5.1 Sector introduction

The transport sector consumes around 26% (59 MTOE) of the fossil fuel supply to the UK economy and emits 22% of UK CO_2 (2006 figures).

Road transport dominates UK transport energy consumption. Any transfers of traffic from road to rail, which carries around 10% of the total, will strongly affect the rail sector. Because of the modest scale of rail energy consumption and its sensitivity to road transport strategy, detailed consideration of this part of the transport sector is not attempted in this report pending clearer definition of overall transport strategy.

To reduce CO_2 emissions from road transport, the energy currently delivered from fossil petroleum fuels will have to be substantially replaced by alternatives. The scale of the sector and its energy consumption indicates that a successful change strategy will inevitably represent a major change for the UK economy and for road users.

5.2 Current position

In 2004, fuel consumed by the UK fleet of road vehicles was split as shown in figure 5.2.1.

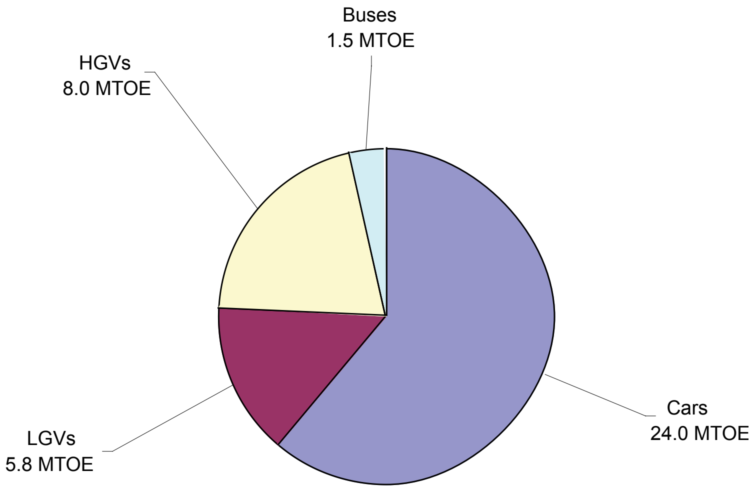
5.3 Forecast changes in fuel consumption

The Department for Transport (DfT) forecasts a sustained growth in road traffic and consequently in fuel consumption. The major consumers of fuel are cars, LGVs and heavy goods vehicles (HGVs).

The DfT uses a model, the National Transport Model (NTM), to forecast transport data including fuel consumption by various classes of goods vehicle. Vehicle fuel consumption to 2030 is shown in figure 5.3.1. These forecasts have been extrapolated to predict that HGV fuel usage will grow steadily by 25% from 8 million tonnes in 2004 to about 10 million tonnes in 2050. Fuel usage by LGVs, on the other hand, is projected to increase much more rapidly from 5.8 million tonnes in 2004 to 14.5 million tonnes in 2050, an increase of 150%. This leads to a 60% increase in the total fuel consumed by goods vehicles.

The forecast overall growth in consumption by fuel category is shown in figure 5.3.2.

Figure 5.2.1 Annual fuel consumption by road vehicle type in 2004 (DfT)[19]



Total consumption = 39.3 MTOE

[19] Department for Transport, 'National Transport Model (NTM)' 2003.

Figure 5.3.1 NTM-predicted growth of fuel consumption by goods vehicle[20]

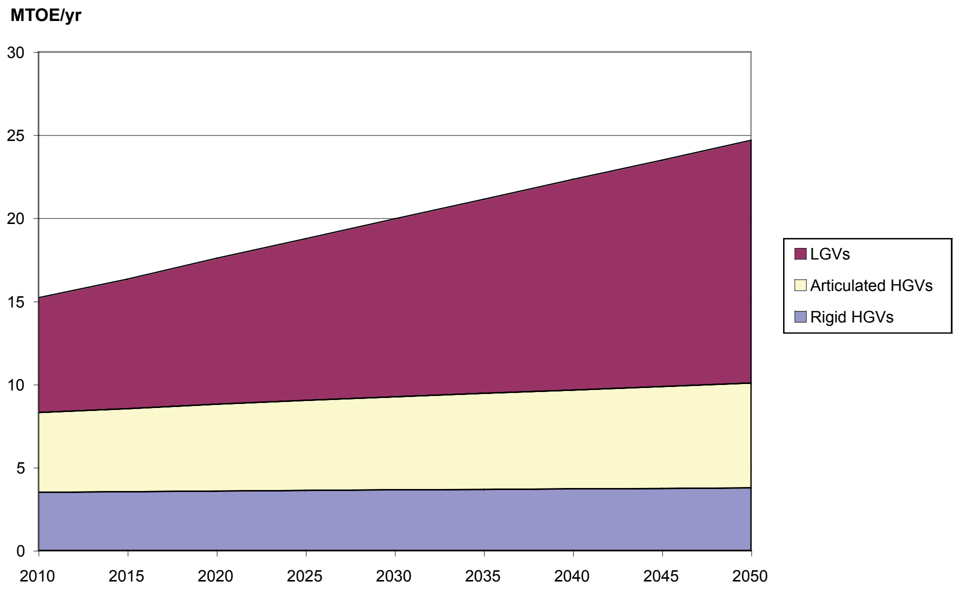
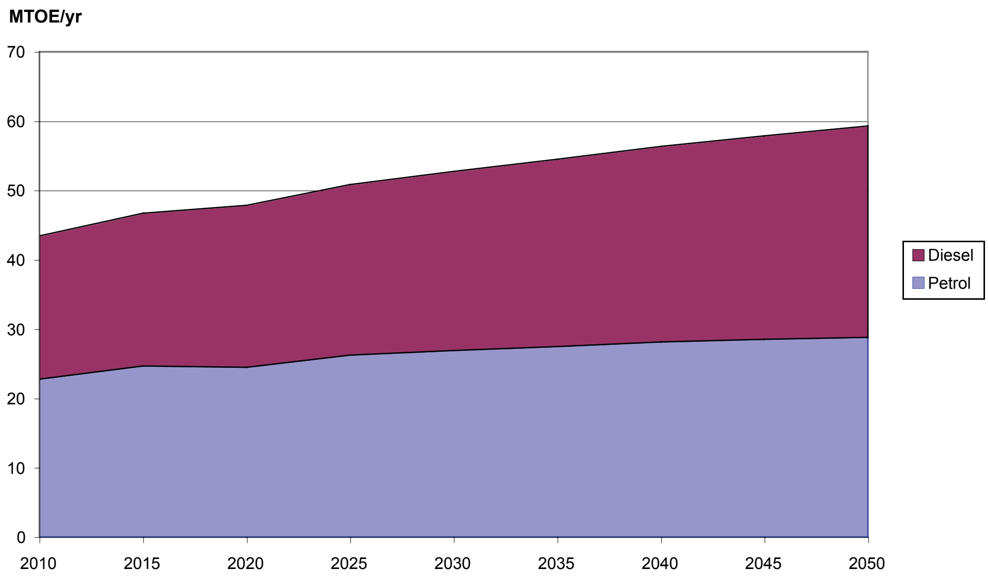


Figure 5.3.2 Projected fuel demand growth by road vehicles[21]



[20],[21] Based on NTM traffic forecasts and extrapolated to 2050.

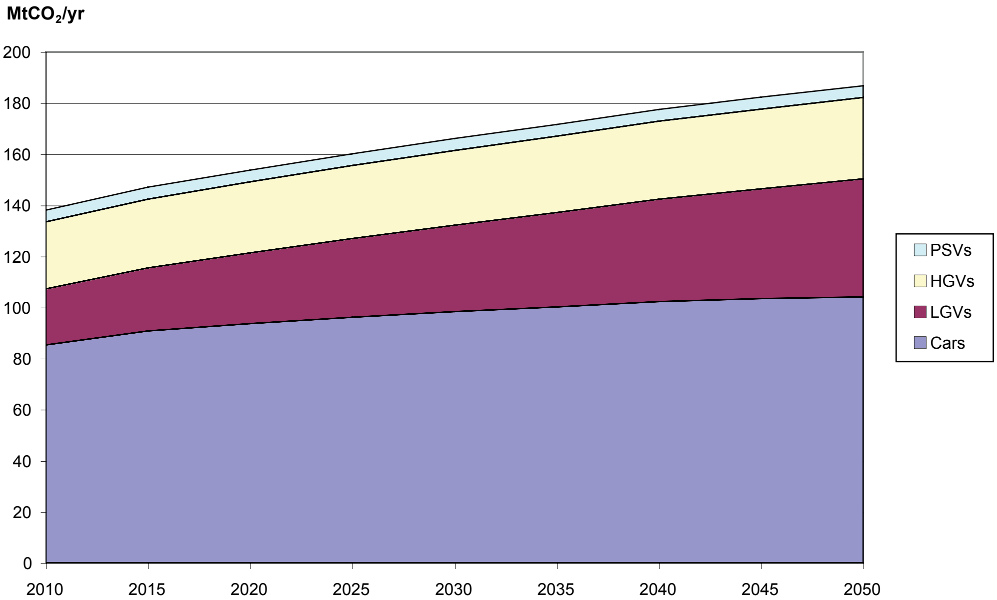
The corresponding CO_2 emissions have been calculated from the DfT and the Department for Business, Enterprise and Regulatory Reform (BERR) reports for each class of vehicle using the same growth assumptions as for the NTM. A significant increase is forecast from 2004 levels of 124 million tonnes per year to a predicted 187 million tonnes per year in 2050 as shown in figure 5.3.3. The scale of this increase is a good indication of how challenging it will be to reduce the UK economy's CO_2 emissions by 80% by 2050, as required by the Climate Change Act 2008.

The fuel consumption and CO_2 emissions growth projections shown in figures 5.3.2 and 5.3.3 are used as the baseline for the improvement measures discussed below.

As well as predicting future road traffic demands, the DfT also has projections based on current transport policy. The first of these policies is that vehicle efficiency will improve in future years. The EU is in the process of setting CO_2 emission targets for new vehicles. The short-term targets are still under negotiation but it seems certain that they will be in the region of 120 gCO_2/km. In the absence of a significant technological advancement such as the catalytic converters that helped reduce particulate pollutants in the late 1980s, the only feasible way to reduce CO_2 emissions (without reducing vehicle miles) is to increase fuel efficiency. In light of this, the DfT predicts, through its NTM, a continuation of current trends of efficiency improvement of 1.15% per year in petrol cars and 1.35% in diesel cars. Fuel efficiency of HGVs is predicted to increase by 0.8% per year. As the internal combustion engine is already well developed, such trends of improvement in efficiency cannot be sustained in the long term. However, improvements in efficiency are likely to occur through incremental improvements in engine performance and the progressive adoption of energy efficiency measures such as regenerative braking.

The second policy-based element is that a proportion of the petrol-driven car fleet will switch to diesel cars in future years. This is based on a policy that attempts to maintain diesel prices at the pump at a comparable level to petrol. The improved efficiency of diesel engines over petrol engines should then make diesel cars financially attractive. The likely long-term increase in oil prices in future years will make this switch increasingly attractive to the average car owner. In the 2004 base year, petrol-fuelled cars represented 79% of the overall fleet, with diesel making up most of the remaining 21%. Other fuel types such as LPG and

Figure 5.3.3 Projected growth in road vehicle CO_2 emissions[22]



[22] Based on NTM traffic forecasts and extrapolated to 2050.

electricity make up less than 1% of the fleet. The DfT predicts that by 2025 petrol cars will make up 57% of the fleet with diesel representing the remaining 43%.

A third policy aimed at reducing the rise of CO_2 emissions from vehicles is the obligation to include 5% renewable biofuel in all vehicle fuel from 2015.

These policy elements have been combined with the forecast traffic growth from the NTM to predict the overall effect on CO_2 emissions, as shown in figure 5.3.4.

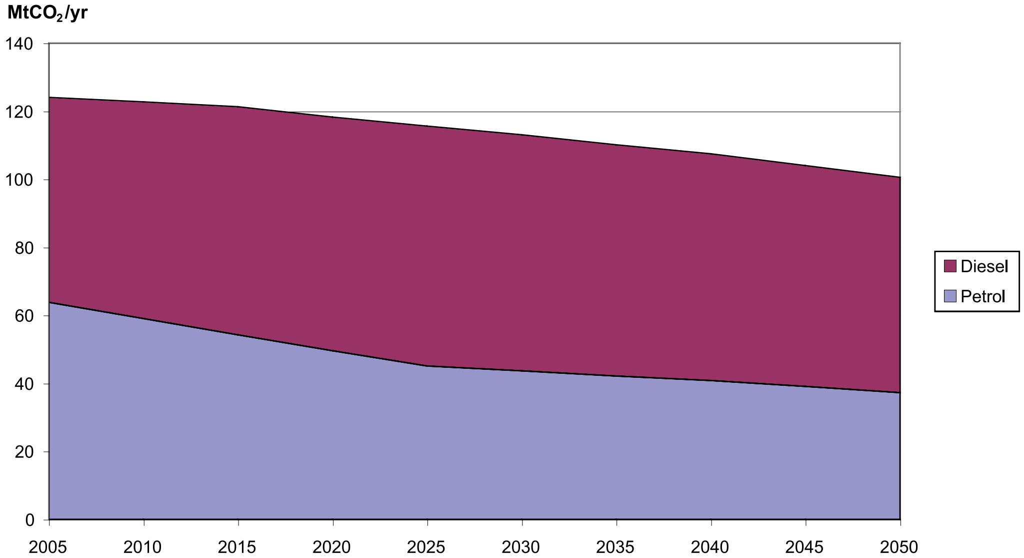
5.4 Review of potential options

In modelling road transport energy use, Parsons Brinckerhoff has recognised the effects of potentially different levels of adoption of electric vehicles in urban and rural areas. The detailed breakdown of fuel consumption into NUTS4 areas[23], published by BERR, has been used to categorise consumption as 'rural' or 'urban' in our model.

We initially considered a wide range of potential improvements, but several categories were set aside after preliminary investigation:

- The possibility of achieving a reduction in overall transport emissions by discouraging travel (for example through increased fuel, vehicle or road-use duties) or reducing the need for travel (for example through increased home working or telecommuting) are not considered here. These would be economic or social solutions which are outside the remit of this study.
- The potential for improvements in efficiency of vehicles using conventional internal combustion is significant in the short term. However it appears that even the aggregate benefit of such improvements will not approach the required reduction in CO_2 emissions. This is best illustrated by considering a vehicle with a 15% efficient use of energy in its fuel, which is not atypical for a modern car. If the CO_2 emissions are to be reduced to 20% of current levels, but the same energy has to be delivered to move the car over the required journey, the fuel has to be used 0.15/0.2 = 75% efficiently to achieve the desired reduction in emissions. It is unlikely that this would ever be feasible. Any improvement above 50% efficiency of use of fuel in an internal combustion engine vehicle seems unlikely from a practical thermodynamic perspective. Since the short-term improvements in vehicle performance are not sufficient to allow internal combustion engines to remain the primary energy source in vehicles in 2050, this report does not consider such improvement options further.

Figure 5.3.4 NTM-predicted CO_2 growth with DfT emission reduction policies[24]



[23] Department for Business, Enterprise and Regulatory Reform, 'Experimental Regional and Local Authority Road Transport Consumption Statistics 2002-2004' 2005.

[24] Based on NTM traffic forecasts and extrapolated to 2050.

- A wide range of options is afforded by switching vehicle fuels to fuels offering lower CO_2 emissions. Some possibilities are already commercially available, for example conversion to LPG, but the reductions in CO_2 emissions are limited to 10-15%. Others, such as conversion to compressed natural gas, are being tried experimentally, but again the ultimate reduction is limited to about 20%. Since these possibilities are relatively well understood but offer limited reductions in CO_2 emissions, they have not been examined further in this report. Less conventional fuel conversions, including substitutions of biofuels or hydrogen, or switching to electricity, are evaluated in detail as they offer the potential for large reductions in CO_2 emissions.

Table 5.4.1 describes the potential measures that have been evaluated fully. Further details of this analysis can be found in appendix A1. Appendix A1 considers a range of penetration assumptions, but only the largest was found to be effective in delivering sufficient CO_2 reductions. The measures and these higher penetration figures are detailed in table 5.4.1. The large-scale conversion of vehicles to battery electric power by 2030 appears to be feasible given recent major progress in such vehicle technology compared with other energy intermediates such as hydrogen. The analysis has not drawn a distinction between battery electric vehicles and battery/internal combustion engine hybrids where the vehicle is charged primarily from external supplies.

Table 5.4.1 Description of the selected measures for transport sector response to CO_2 emissions

Measure	Description	Assumptions
Reduced road travel	Reduced car journeys by promotion of transfer to public transport.	15% reduction in fuel consumption
Biofuels	Biofuels are derived from agricultural crops, forest material or agricultural wastes. Fuels derived from these sources can be used as a substitute for at least part of the diesel or gasoline content of transport fuels.	15% of consumption
Cars, LGVs and buses to battery power	Battery electric power becomes the primary fuel for cars, LGVs and buses, and electricity is largely decarbonised. It may be supplemented by the burning of hydrocarbon-based fuels for the small proportion of journeys that exceed the battery range. Cars would be charged where they park, to distribute the charging demand over the 24-hour period. Buses and LGVs would exchange discharged batteries at charging stations.	95% of consumption in urban areas and 70% in rural areas
HGVs to electricity	No current alternative for HGVs using diesel engines is considered adequate. A conceptual conversion to directly delivered electricity, for example via overhead lines, is used to test potential benefits.	50% reduction of HGV consumption in rural areas
Cars to hydrogen	Cars would be fuelled with hydrogen at high pressure, with fuel cells providing electricity to a drive train similar to other electric vehicles.	95% in urban areas and 70% in rural areas

Battery-powered electric vehicles have long been used for purposes where their key advantage of zero emissions at point of use is valued. These electric vehicles have the reputation of being cumbersome, as exemplified by the milk float with its large and heavy lead-acid battery. More recently, research driven by the demands of portable electronic equipment such as mobile phones and laptop computers has allowed battery-powered cars with much more attractive features to be produced. These now include high-performance sports cars that may be the harbinger of battery electric cars for the mass market.

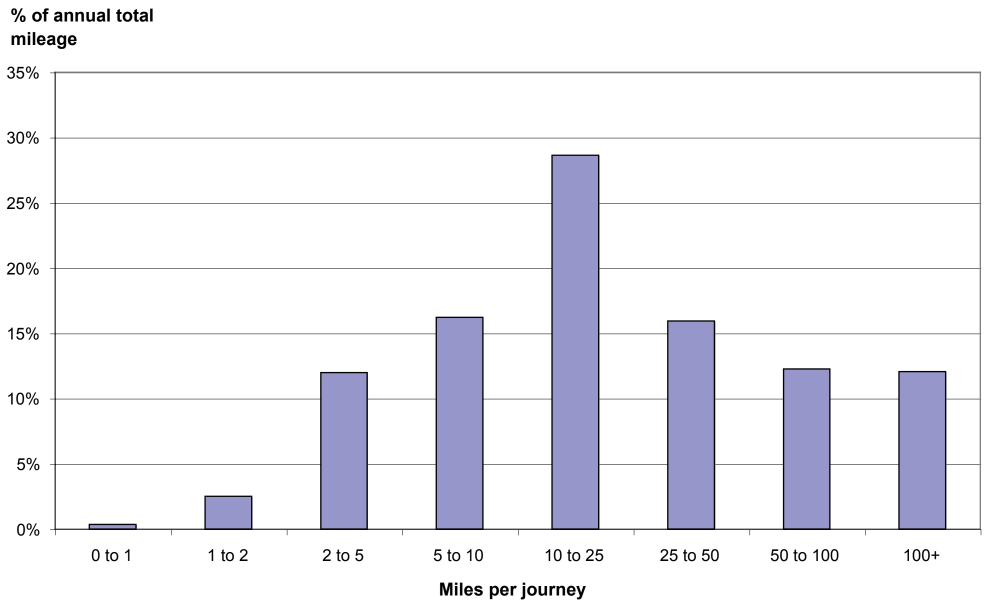
This study has considered battery electric technology as being suitable for many cars, LGVs and for buses. For these vehicle types, the range limitations imposed by limited battery energy capacity can be managed by providing charging points where cars are parked and battery exchange stations. Such exchange stations would enable longer-distance journeys by LGVs or buses to be supported by swapping a discharged standard battery pack for a fully charged one. It is unlikely that the limitations imposed by a standard battery design would be acceptable in the highly competitive car market, or that an intensive network of continuously manned battery exchange stations would be viable.

The current generation of hybrid vehicles, typified by the Toyota Prius, uses batteries and an electric drive train to improve the efficiency of use of the internal combustion engine, achieving slightly better fuel economy from a petrol engine than would be achieved using a diesel engine. The next generation of hybrid vehicles – the so-called plug-in hybrids – will use batteries charged from public supply as the main energy source and will include an engine to increase the range beyond the battery capacity of typically 50-100 miles. Studies[25] show that only about 25% of journeys exceed 50 miles and only 12% exceed 100 miles, as shown in figure 5.4.1. The adoption of plug-in hybrid vehicles with these 50-100-mile battery capacities could therefore be considered to be a conversion of 75-90% of journeys to electric power. Hybrid vehicles can therefore be seen to be part of the process of switching energy source rather than a separate solution.

5.4.1 CO_2 reductions

Switching to battery- or hydrogen-powered road vehicles has a major impact on CO2 emissions. Figure 5.4.1.1 shows the overall CO_2 reduction effects of the options including changes of emissions in the electricity sector, where appropriate, compared with the 'business as usual' case. Electricity sector emissions

Figure 5.4.1 Distribution of car journey length



[25] Department for Transport, 'National Transport Model (NTM)' 2003.

are based on indicative levels of 0.4 tCO_2/MWh in 2020 and 0.1 tCO_2/MWh in 2050.

In figure 5.4.1.1, both the *cars to battery* and *cars to hydrogen* measures would have a significant contribution to reducing CO_2 emissions. However the adverse impact of the additional electricity consumption of *cars to hydrogen* can be seen in the reduced net CO_2 reduction compared with the *cars to battery* measure.

LGVs to battery offers a valuable reduction in CO_2 emissions. These emissions increase strongly from 2020 to 2050 because of the forecast growth in LGV traffic.

Reduced road travel and *HGVs to electricity* offer valuable reductions in the transport sector's CO_2 emissions. Both measures offer greater reductions in 2050 than in 2020 but for different reasons: *HGVs to electricity* takes advantage of the lower carbon content of electricity as it becomes available, whereas the reduction in road travel is seen as a year-on-year trend.

Buses to battery offers only modest contributions to CO_2 reductions.

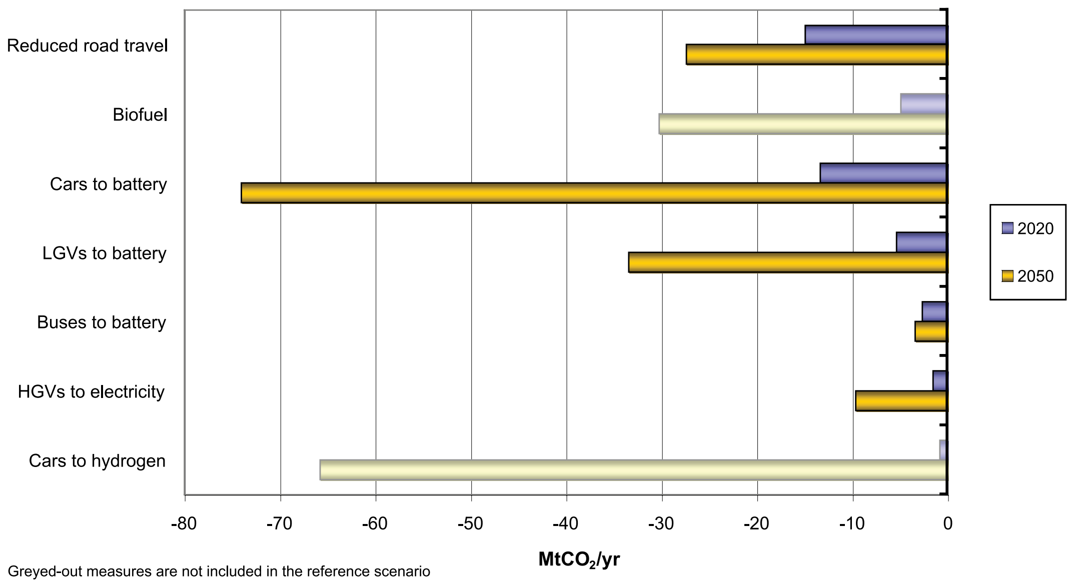
Large-scale conversion of road transport to biofuels is limited by the available biomass that can be employed without affecting food production or causing environmental damage. A limit of 5% biofuel content of transport fuels is considered to be the highest sustainable level.

5.4.2 Electricity demand

Figure 5.4.2.1 shows the increase in electricity production required to switch road transport to electricity compared with the 'business as usual' case.

Figure 5.4.2.1 shows that the alternative measure of converting vehicles to hydrogen would require nearly twice as much electricity as the battery vehicle measure. Not only would the large increase result in more serious problems with the scheduling of hydrogen production, but the projects required to construct the additional generating capacity and infrastructure for hydrogen would be comparable in scale to building a duplicate set of UK power stations and electricity and gas networks. Such projects would incur massive costs and yet produce a smaller CO_2 reduction benefit than conversion to batteries. In view of these findings, conversion of vehicles to hydrogen produced from electricity is not considered viable.

Figure 5.4.1.1 Transport measures – net change in sector CO_2 emissions



Greyed-out measures are not included in the reference scenario

The alternative route to produce hydrogen is through the treatment of hydrocarbons such as coal and natural gas. The coal or hydrocarbon is reacted with steam and oxygen in a gasifier followed by a water shift reaction to convert the resulting carbon monoxide to hydrogen and CO_2. Following clean-up processes, the CO_2 is separated for geological disposal and the hydrogen compressed for delivery in a gas distribution network. This complex process would be needed on an unprecedented scale to produce sufficient hydrogen for road vehicles, committing the UK to large-scale coal importation and CO_2 storage for the foreseeable future. The complexity, inflexibility and uncertainty of this method of supplying energy to road vehicles means it is unlikely to be adopted; it has therefore not been considered further in this report.

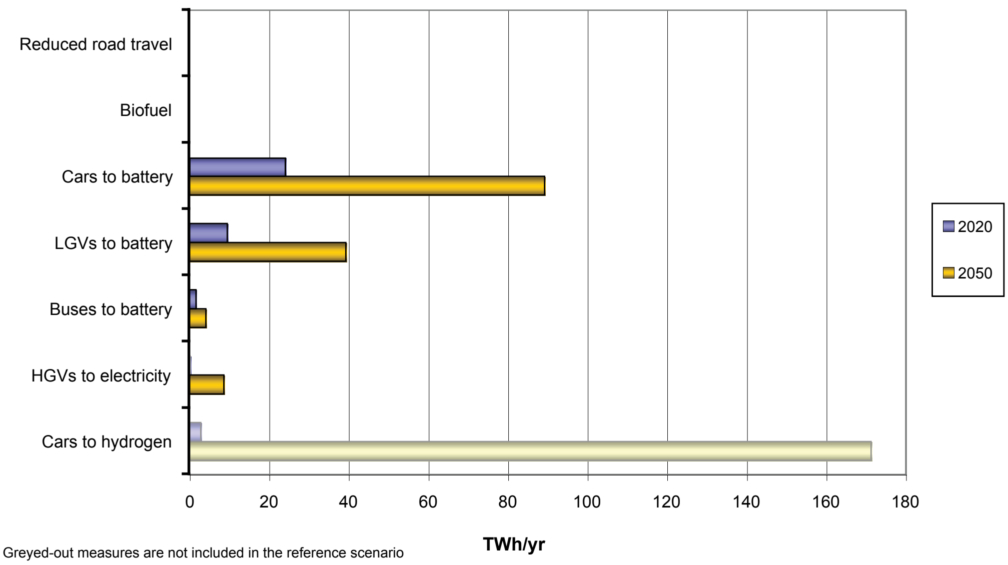
The average charging power for all battery vehicles is forecast to reach 15 GW by 2050. If this energy were to be delivered during the 9-hour low-demand period each night, the night-time demand would rise by over 40 GW in 2050.

The large increase in night-time demand would be likely to exceed day-time peaks from about 2025 and would challenge distribution network capacity. The best way of meeting these demands is likely to involve 'smart grid' technologies to control the charging of vehicles connected to the network via distributed charging facilities, wherever and whenever they were parked.

The scale of charging demand within the distribution network increases with the number of battery electric vehicles. At higher levels of penetration, even with charging available wherever there was parking, battery electric vehicles would require a significant proportion of network capacity. To avoid network overload caused by the coincidental charging of vehicles (for example at the end of the day), the active coordination of charging with network operation would be essential. Such functions can also be provided by 'smart grid' technology, to make maximum use of the capabilities of the transmission and distribution networks without necessitating large-scale and costly asset reinforcement or replacement.

The coordination of vehicle charging by the 'smart grid' could be extended to provide balancing of the variable generation of intermittent renewables. The benefit of this in improved reliability and economy of electricity supply could be shared with drivers via an attractive 'smart' tariff for vehicle charging.

Figure 5.4.2.1 Transport measures – change in electricity demand



Greyed-out measures are not included in the reference scenario

5.5 Transport sector scenario options

Table 5.5.1 shows which of the transport sector measures are included in the scenario analysis. An entry of 1 indicates that the measure is included in the scenario, with a 0 indicating that a measure is not included. A number between 0 and 1 indicates that the measure is only partially adopted by a particular scenario since it cannot be applied at the level of penetration initially assumed.

5.6 Sector-specific issues

1. Changes in travel habits to cut car use, combined with a large-scale and rapid switch to electric vehicles, will be necessary for the transport sector to make adequate contributions to the required reduction in CO_2 emissions.

2. The use of electricity via battery or plug-in hybrid cars and LGVs is found to offer the largest potential CO_2 reductions.

3. Neither hydrogen energy storage nor batteries are likely to be able to store sufficient energy to provide HGVs with an acceptable journey range. However, the benefits of mitigating emissions from HGVs are found to be considerable and urgent work is required to develop alternative means of delivering low-carbon energy to them.

4. Overnight off-peak electricity can only meet demand for charging vehicle batteries until about 2025. After this date, battery charging will need to be distributed across the 24 hours to avoid new demand peaks overloading generation, transmission and distribution systems.

5. Substituting carbon-neutral biofuels for petrol and diesel can achieve substantial reductions of CO_2 emissions. Although the quantities of biofuels available are limited, a 5% reduction in CO_2 emissions by substitution of biofuels is likely to be sustainable.

6. Irrespective of the method of production, hydrogen used to power vehicles is found to require a costly network of large-scale production facilities. Hydrogen production from electricity would require at least twice the electricity generation capacity needed for battery electric vehicles. Production from coal or hydrocarbons is complex and would require large-scale CO_2 separation and geological storage. In addition, a new large-scale network for hydrogen distribution and vehicle filling would be necessary. This large additional infrastructure is unlikely to be viable given the inferior saving in CO_2 emissions compared with electric battery vehicles.

Table 5.5.1 Transport sector scenario options selections

Option	Scenarios											
	1 Reference	2 Reduced renewable heat	3 Application of large-scale industrial CHP	4 No new nuclear programme	5 No CCS	6 Aggressive wind adoption	7 Economic growth rate	8 Building insulation	9 Battery power adoption by cars and vans	10 Wind generation reduced by 5 GW	11 PV electricity	12 Unspecified industrial efficiency improvements
Reduced road travel	1	1	1	1	1	1	1	1	1	1	1	1
Biofuel	0	0	0	0	0	0	0	0	0	0	0	0
Cars to battery	1	1	1	1	1	1	1	1	0.72	1	1	1
LGVs to battery	1	1	1	1	1	1	1	1	1	1	1	1
Buses to battery	1	1	1	1	1	1	1	1	1	1	1	1
HGVs to electricity	1	1	1	1	1	1	1	1	1	1	1	1
Cars to hydrogen	0	0	0	0	0	0	0	0	0	0	0	0

6. Domestic

6.1 Sector introduction

The domestic sector consumes about 16% (36 MTOE) of the fossil fuel supply to the UK economy and emits 15% of UK CO_2 (2006 figures).

The domestic sector is the third-largest consumer of energy in the British economy. It is a highly diverse sector with different types and ages of housing in urban and rural contexts with varying degrees of access to energy sources.

The ownership of housing is predominantly private, although significant numbers of houses are owned by housing associations and private landlords. Policies to reduce energy consumption, and hence CO_2 emissions, have been developed and applied progressively for new-build housing through the revision of the Building Regulations. Pressure for improved energy efficiency in existing homes has increased with rising energy prices. To sell a house, a vendor must provide a Home Information Pack containing an energy performance certificate. Further changes in regulations to enforce improvements in the existing housing stock can be foreseen.

The 2006 Code for Sustainable Homes (CfSH) has the long-term target of reducing CO_2 emissions from homes by 2050, with an interim target of all new homes built after 2016 being carbon neutral.

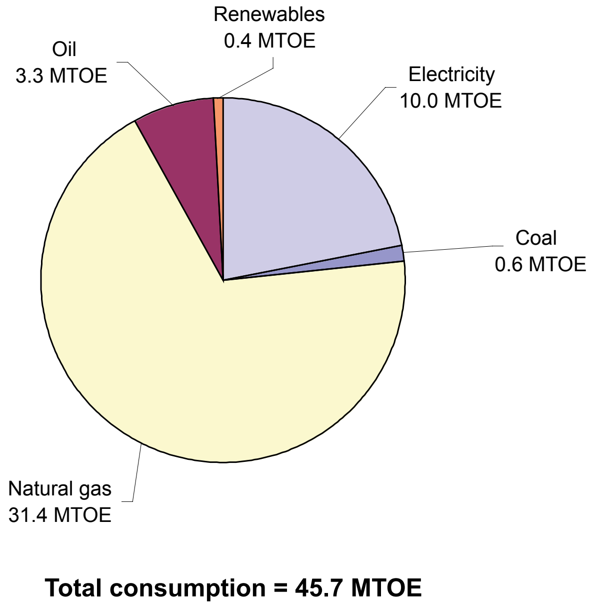
40% House[26] has been used as one of the sources of data for this report. It is acknowledged that this report is five years old and was produced against a 60% CO_2 reduction target. Its use is still valid, particularly for the 'local stewardship' model which has many similar assumptions to this report.

6.2 Current position

Energy consumption in the domestic residential sector is dominated by the use of gas, which represents over 70% of energy delivered, as shown in figure 6.2.1.

The second most significant domestic sector energy source is electricity at 22%. Oil and coal together represent about 9% of the total, and are concentrated in rural areas away from the gas distribution network.

Figure 6.2.1 Domestic sector energy consumption in 2006[27]



[26] Boardman B *et al*, '40% House' 2005.
[27] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

The trend of fuel consumption, illustrated in figure 6.2.2, shows a declining share for coal and an overall reduction of consumption over the ten years, despite a rising population. This is probably due to the increasing adoption of more efficient condensing gas central heating boilers and the improved insulation of existing housing.

6.3 Forecast changes in energy demand

The population of the UK is predicted to increase from 58.8 million in 2006 to 73.8 million by 2050[28].

The number of houses in the UK in 2006 was approximately 25.4 million[29]. If the number of people per household remains constant at 2.32 through to 2050, the number of houses required will increase by 6.4 million to 31.8 million, an increase of 25%[30]. New build also occurs through the routine demolition and rebuilding of existing housing stock and is estimated to total 3.2 million by 2050[31]. Overall, 9.6 million new homes will be required for these households by 2050, representing 30% of the total.

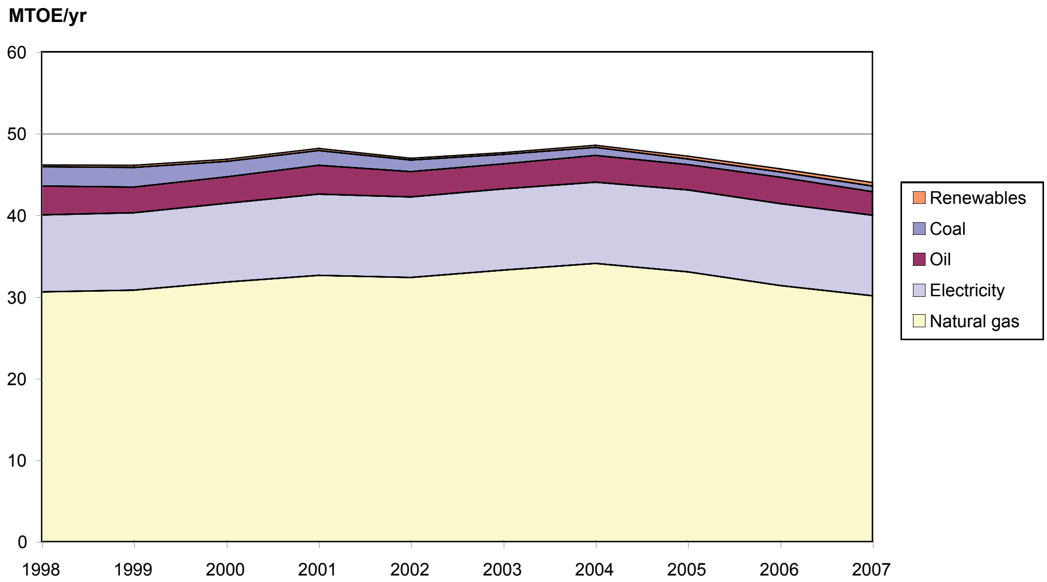
Based on these assumptions, and assuming that there were no further improvements in home construction, insulation or domestic appliances, the future heating and electricity demands would increase to reflect the growth in the number of homes as shown in figure 6.3.1. New homes are assumed to be built in accordance with the CfSH, ie all new homes will have zero carbon emissions by 2016.

If current trends continue, these consumptions of energy would result in a CO_2 emission from heating fuels, and from the relevant share of the electricity sector emissions, rising from 145 to 153 million tonnes of CO_2 per year, an increase of 5%.

6.4 Review of potential options

Table 6.4.1 describes the technology measures to reduce CO_2 emissions from energy consumption in the domestic sector that have been analysed in this report. Full details of this analysis can be found in appendix A2. A figure is given for the level of penetration assumed for each technology measure.

Figure 6.2.2 Trend in domestic sector energy consumption[32]



[28] Office for National Statistics, '2006-based National Population Projections' 2007.

[29] Estimated from: DCLG, 'National Population Projections and Housing Statistics' 2006.

[30] This differs from the DCLG housing survey on two counts: PB's figures are based on the ONS 2006 population forecast and assume that there will be no reduction in housing occupancy.

[31] This approximates to 32,000 homes per year for the UK, slightly higher than the 22,000 per year for England reported in Barker K, 'Review of Housing Supply. Delivering Stability: Securing our Future Housing Needs' 2004.

The assumptions made for this sector are generally in line with those presented in 40% House[33], which targets a 60% reduction in domestic CO_2 emissions by 2050. Where necessary, these assumptions have been adjusted to better target the current 80% commitment, and such revised assumptions are noted as they arise.

Other measures could be used to reduce CO_2 emissions from this sector, however only the measures identified in table 6.4.1 were taken forward. The other measures were either technically immature, or their net effect was considered too small to make a noticeable contribution.

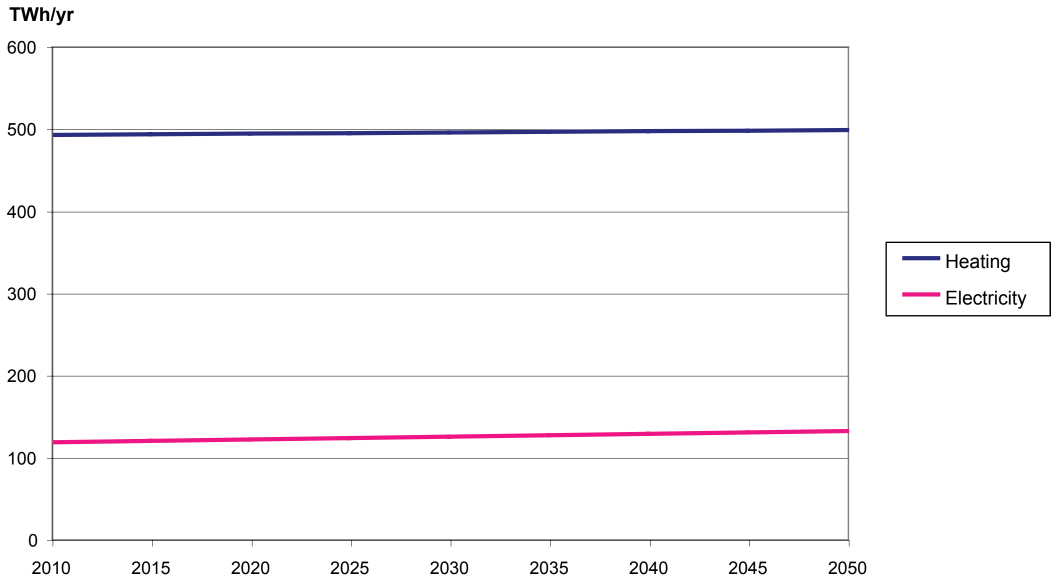
6.4.1 CO_2 reductions

Figure 6.4.1.1 shows the overall CO_2 reduction effects of the options, including changes of emissions in the electricity sector, where appropriate, compared with the 'business as usual' case. Electricity sector emissions are based on indicative levels of 0.4 tCO_2/MWh in 2020 and 0.1 tCO_2/MWh in 2050.

From figure 6.4.1.1 it is clear that *insulation* provides a significant improvement on CO_2 emissions from this sector. Displacing coal and oil consumption for space heating through *domestic biomass* and *community biomass* technologies would reduce contributions to CO_2 emissions. While these technologies would be an effective use of biomass and are included in the scenario analysis, up to 12 MTOE of suitable biomass would be required.

Figure 6.4.1.1 shows that the adoption of *domestic CHP* would result in a small reduction in net CO_2 by 2020 (and only while the carbon density of electricity generated in the electricity sector is relatively high); after 2030 it actually increases CO_2 emissions. This measure is not considered further because of its adverse effect on long-term CO_2 emissions, although its adoption as a short-term measure could offer a small benefit in the period before 2030.

Figure 6.3.1 Projected domestic sector 'business as usual' energy demands[34]



[32] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.
[33] Boardman B *et al*, '40% House' 2005.
[34] Derived from: Boardman B *et al*, '40% House' 2005.

Table 6.4.1 Summary of the selected measures for domestic sector response to CO_2 emissions

Measure	Description	Assumptions
Insulation	There are a number of measures that can improve the energy performance of existing homes: • increased insulation of roof, walls and floors • improvement to window glazing • improvement to door insulation • improved draught-proofing and ventilation control • heat recovery from ventilation	Penetration reaching 80% by 2025 and 100% of remaining existing homes by 2050
Domestic biomass	Biomass can be used to displace coal and oil burning where there is a ready supply of fuel in a suitable form, such as wood pellets, wood chip or logs. A biomass boiler can provide both space and water heating on a controlled basis.	Penetration reaching 80% by 2030 and 90% of oil- and coal-burning homes by 2050
Community biomass	The application of community heating is likely in new urban residential developments and refurbishments where housing density is sufficient to make heat distribution economical. Generation of electricity as a CHP scheme is likely for larger installations. Such systems could use a wider range of biomass than would be feasible on a domestic scale, including agricultural wastes such as straw and appropriate refuse-derived fuels. Gas could be used as a fuel for such schemes but would not be acceptable under the CfSH.	19% of existing homes and 22% of new homes by 2050 (as per 40% House)
Domestic CHP	Domestic CHP uses more advanced technology to replace the domestic heating boiler with a dual-purpose unit that generates electricity and rejects heat from the power generation process to the heating system. The advantage of domestic CHP is that it produces electricity within the home, offsetting imported power while converting a high proportion of the energy to useful forms.	38% penetration of existing homes by 2050 (as per 40% House)
Ground source heat pumps	Ground source heat pumps collect heat from a network of buried pipes and, using technology similar to an air conditioning unit, reject heat at a higher temperature for domestic heating. Ground source heat pumps currently achieve approximately a five-to-one coefficient of performance, ie one unit of electricity delivers five units of heat energy.	8% penetration of new homes
Air source heat pumps	Air source heat pumps are similar to ground source heat pumps but collect heat from the air and reject heat at a higher temperature for domestic heating. The greater difference in temperature between heat source and heating system than for a ground source heat pump means that only 2.4 units of heat are delivered per unit of electricity.	8% penetration of existing homes (as per 40% House)
Solar water heating	Solar heating typically uses absorber tubes within an evacuated glass envelope with a circulation of water to the hot water storage tank. Carbon emission reduction derives from lower heating fuel and electricity use for water heating.	Penetration rises to 60% of all homes by 2035 (as per 40% House)
Appliance efficiency	Progressive improvement in appliances and lighting brought about by ever-tighter efficiency targets.	44% reduction in electrical consumption per house by 2050 (as per 40% House)

Measure	Description	Assumptions
Domestic wind	Domestic wind turbines have a typical rating in the range of 1-2 kW and are mounted on high sections of a building. In built-up areas their effectiveness is reduced by turbulence and the lower wind speeds accessible at low elevations. They generate at all times of day and night and may produce more power than the immediate domestic load.	Penetration rises to 10% of all homes by 2050
Domestic solar PV	Solar PV systems install an array of solar panels on the south-facing roofs of houses. A typical installation is assumed to include 9 m^2 of panel. Efficiency is expected to rise as technology becomes more advanced, from the current 10% to around 25% by 2050. This will give a peak output of 1 kW in 2009 with new units delivering 2.5 kW by 2050.	Penetration reaching 20% by 2035 and 30% of all homes by 2050

Figure 6.4.1.1 Domestic measures – net change in sector CO_2 emissions

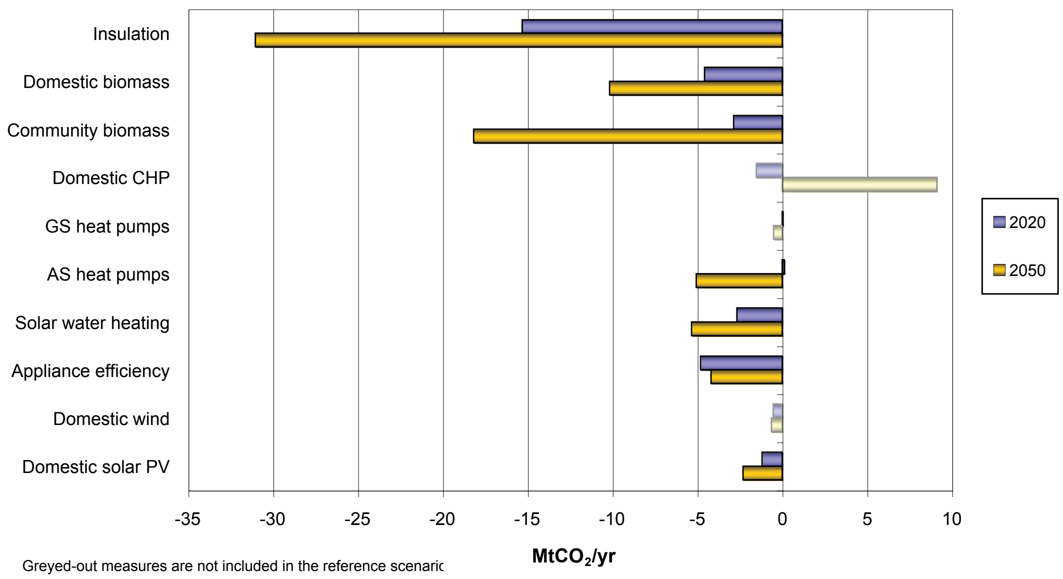


Figure 6.4.1.1 also shows that *ground source heat pumps* have a small negative effect on overall emissions in 2020 because of the increased use of electricity. Ground source heat pumps could make a minor contribution to emissions reduction by 2050 when electricity has a lower carbon content. They are not considered further as the benefit is not likely to be significant.

Air source heat pumps have a greater impact than *ground source heat pumps*, offering a useful net reduction in CO_2 by 2050.

Solar water heating and *appliance efficiency* offer useful reductions.

Other measures do not have a significant impact on the CO_2 emissions of this sector.

6.4.2 Electricity demand

Each measure has an effect upon the domestic sector's demand for electricity. The actual changes in demands from the 'business as usual' case are shown in figure 6.4.2.1.

As discussed earlier, despite its potential reduction in demand for electricity, *domestic CHP* does not offer net CO_2 reduction benefits after 2020 and is not considered further.

Air source heat pumps increase electricity demand but have an overall benefit in reducing CO_2 emissions.

Adopting the remaining technologies, with the exception of *domestic wind*, would reduce the demand for electricity from this sector. *Domestic wind* does not offer a worthwhile benefit and is not considered further.

6.5 Domestic sector scenario options

Table 6.5.1 shows how the domestic sector measures are included in the scenario analysis. An entry of 1 indicates that the measure is included in the scenario, with a 0 indicating that a measure is not included. A number between 0 and 1 indicates that the measure is only partially adopted by a particular scenario since it cannot be applied at the level of penetration initially assumed.

6.6 Sector-specific issues

1. Significant reduction in the energy consumption and CO_2 emissions from existing residential buildings demands radical reduction in heat losses through greatly improved insulation and better control of ventilation with heat recovery.

2. Substantial reduction in CO_2 emissions is possible through renewable heat applications using biomass and solar energy.

3. Providing biomass-fuelled community heating and CHP schemes for existing and new higher-density housing offers significant reductions in CO_2 emissions.

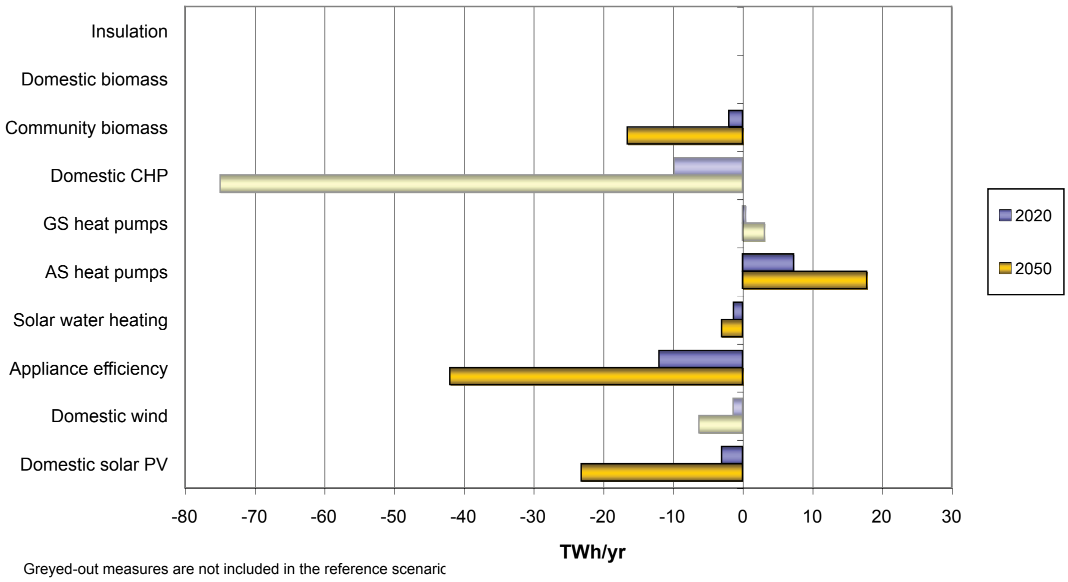
4. Adopting more efficient lighting and appliances provides a significant reduction in consumption of electricity in the domestic sector.

5. Community biomass-fuelled CHP plant and domestic PV electricity production offer a substantial reduction in net electricity demand.

6. Applying air source heat pumps to existing homes offers worthwhile CO_2 emission reductions, particularly after 2025. Ground source heat pumps are largely limited to new homes and therefore offer much smaller benefits.

7. Domestic-scale CHP does not offer a significant or sustained contribution to carbon emission reduction, particularly as the carbon content of electricity falls after 2025.

Figure 6.4.2.1 Domestic measures – change in electricity demand



Greyed-out measures are not included in the reference scenaric

Table 6.5.1 Domestic sector scenario options selections

Measure	Scenarios											
	1 Reference	2 Reduced renewable heat	3 Application of large-scale industrial CHP	4 No new nuclear programme	5 No CCS	6 Aggressive wind adoption	7 Economic growth rate	8 Building insulation	9 Battery power adoption by cars and vans	10 Wind generation reduced by 5 GW	11 PV electricity	12 Unspecified industrial efficiency improvements
Insulation	1	1	1	1	1	1	1	0.5	1	1	1	1
Domestic biomass	1	0.5	1	1	1	1	1	1	1	1	1	1
Community biomass	1	0.5	1	1	1	1	1	1	1	1	1	1
Domestic CHP	0	0	0	0	0	0	0	0	0	0	0	0
Ground source heat pumps	0	0	0	0	0	0	0	0	0	0	0	0
Air source heat pumps	1	1	1	1	1	1	1	1	1	1	1	1
Solar water heating	1	0.5	1	1	1	1	1	1	1	1	1	1
Appliance efficiency	1	1	1	1	1	1	1	1	1	1	1	1
Domestic wind	0	0	0	0	0	0	0	0	0	0	0	0
Domestic solar PV	1	1	1	1	1	1	1	1	1	1	0.5	1

7. Industry

7.1 Sector introduction

The industry sector includes the diverse range of manufacturing and processing industries within the UK economy.

The industry sector consumes about 17% (39 MTOE) of the fossil fuel supply to the UK economy and emits 23% of UK CO_2 (2006 figures). This disproportionately high emissions figure is due to the CO_2 released from the processing of materials, for example in cement making.

The diversity of the industry sector is fundamental to its character, making it more difficult to produce broad assessments of potential improvements in CO_2 emissions. Parsons Brinckerhoff's experience of energy efficiency evaluation and CHP projects for a range of industrial clients has informed the analyses.

7.2 Current position

Figure 7.2.1 shows the trend in energy demand in the industry sector. For simplicity, it excludes the oil refining and coke production subsectors which have similar trends.

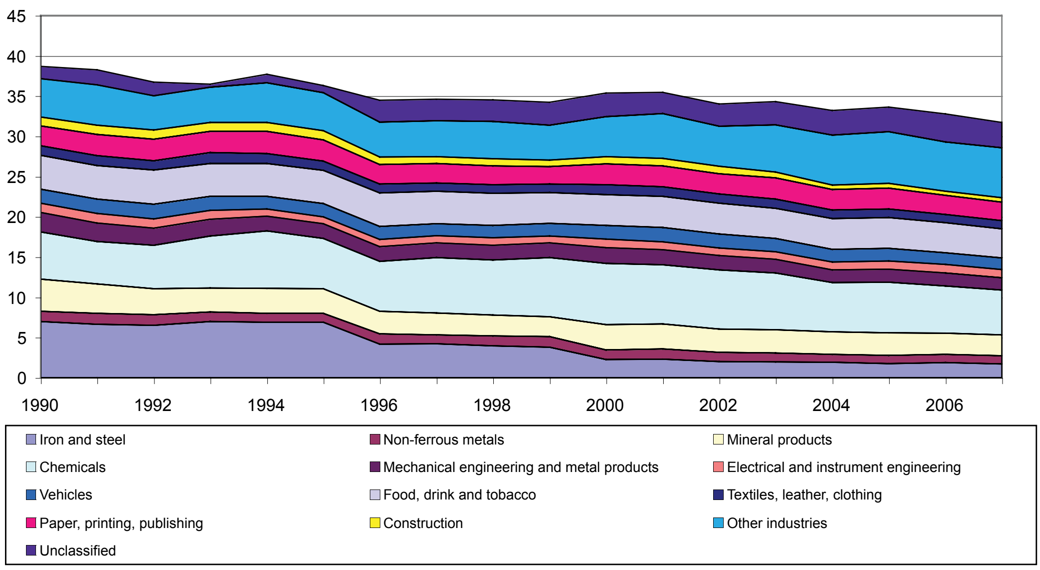
There has been an overall decline in energy consumption, primarily as a result of a significant fall in iron and steel production. Many subsectors show steady energy consumption; a few, such as chemicals, have a more variable consumption resulting from factors specific to that subsector.

The breakdown of energy consumption for all the subsectors for 2006 (the base year for the purposes of analysis) is shown in figure 7.2.2.

The subsectors have very different energy demands with the four major subsectors (chemicals; iron and steel; refined petroleum products; food, drink and tobacco) representing nearly half of the total consumption in the industry sector.

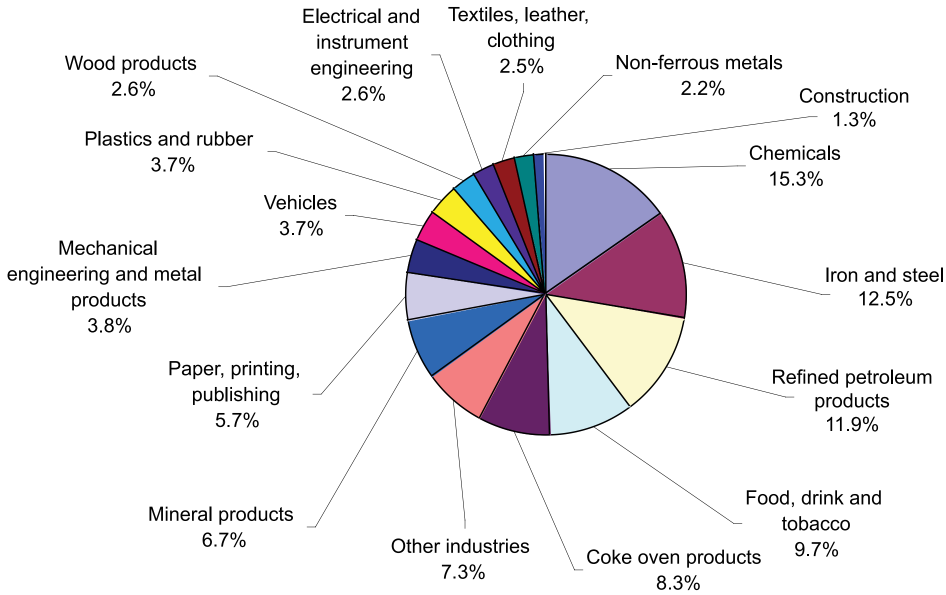
The energy demand is met by the consumption of various fuels, and figure 7.2.3 illustrates the breakdown of fuels used in 2006. These figures show that natural gas is the major energy source, with a 40% contribution. Oil and electricity make similar contributions at 24% while coal represents 11% of the total. Renewable energy contributes a negligible amount in this sector, about 0.5% of the total.

Figure 7.2.1 Industry sector energy consumption by subsector[35]



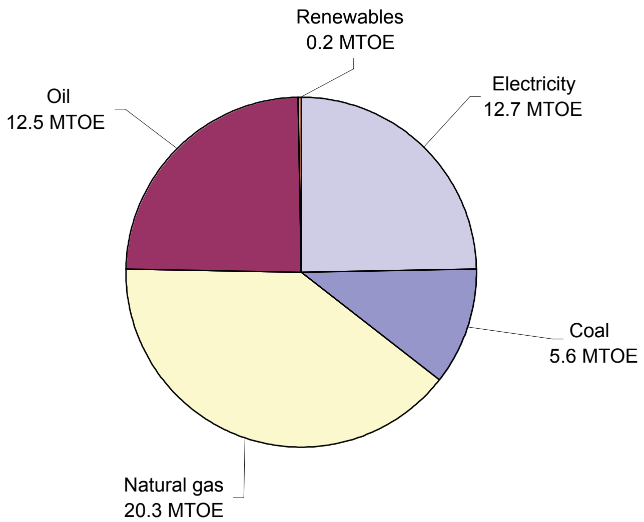
[35] Derived from: Department for Business, Enterprise and Regulatory Reform, 'Energy Consumption in the United Kingdom: Industrial Data Tables 2008 Update' 2008.

Figure 7.2.2 Energy consumption by industry subsector for 2006[36]



Percentage calculation introduces a total rounding error of 0.2%

Figure 7.2.3 Industry sector energy use by fuel for 2006[37]



Total consumption = 51.3 MTOE

[36] Derived from: Department for Business, Enterprise and Regulatory Reform, 'Energy Consumption in the United Kingdom: Industrial Data Tables 2008 Update' 2008.

[37] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

Although data on significant industries is available from Defra, there is no information on how CO_2 emissions break down into subsectors. The trend of CO_2 emissions from 1990 to 2006 is shown in figure 7.2.4.

CO_2 emissions follow a downward trend similar to energy consumption. Emissions are predominantly from fuel use, but some industrial processes, such as cement or lime manufacture, release CO_2 from the raw materials being processed.

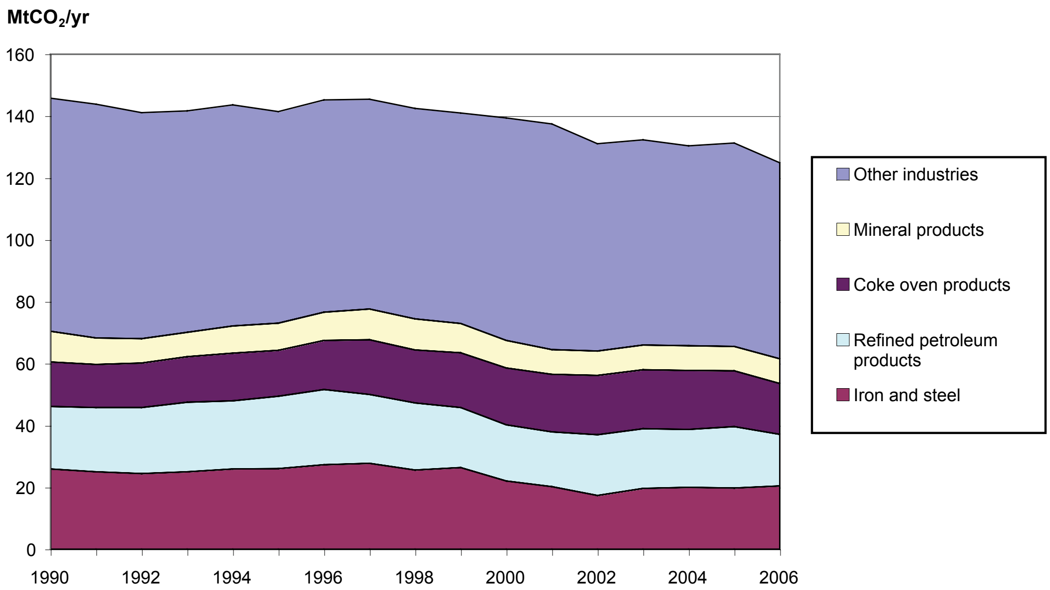
7.3 Forecast changes in energy demand

Because of the diverse nature of this sector and its sensitivity to economic conditions, forecasting future energy use and CO_2 emissions is subject to greater levels of uncertainty. The longer-term energy performance of industry can be estimated on the basis of assumptions about the rate of economic growth and increasing efficiency of energy use in industry.

The long-term rate of economic growth has a significant impact on fuel use and emissions, and the impact of different assumptions is considered in the 'business as usual' case. Figure 7.3.1 shows the forecast CO_2 trend for the industry sector for three different rates of average economic growth over the period: a low case of 0.75%, a central case of 1.5%, and a high case of 2.25%. This comparison shows that at the central rate of growth of 1.5%, CO_2 emissions will rise by about 40% in the period to 2050, although the growth in emissions is tempered by improvements in energy efficiency. For the higher growth rate assumption of 2.25%, industrial CO_2 emissions will grow strongly, rising by over 80% to around 220 million tonnes per year. The low-case increase assumption is forecast to result in a growth of less than 10% in industrial CO_2 emissions over the period. These trend curves indicate that achieving large reductions in CO_2 emissions from industry will be increasingly difficult to achieve in the face of higher rates of economic growth.

Analysis presented in the Digest of UK Energy Statistics allows long-term energy performance to be estimated. The 17-year trend of major industries, as shown in figure 7.3.2, suggests a range of annual improvement in energy use per unit output from 0.62% per year to 1.65% per year. Although the 'all industry' decline is 1.65% per year, Powering the Future uses a more pessimistic figure of 0.62% per year as being representative of the rate of improvement over the

Figure 7.2.4 Industry sector CO_2 emissions[38]



[38] Department for Environment, Food and Rural Affairs, 'Table 5b: Estimated emissions of carbon dioxide (CO_2) by National Communication source category, type of fuel and end user: 1970-2007' 2008.

Figure 7.3.1 Industry sector CO_2 emissions

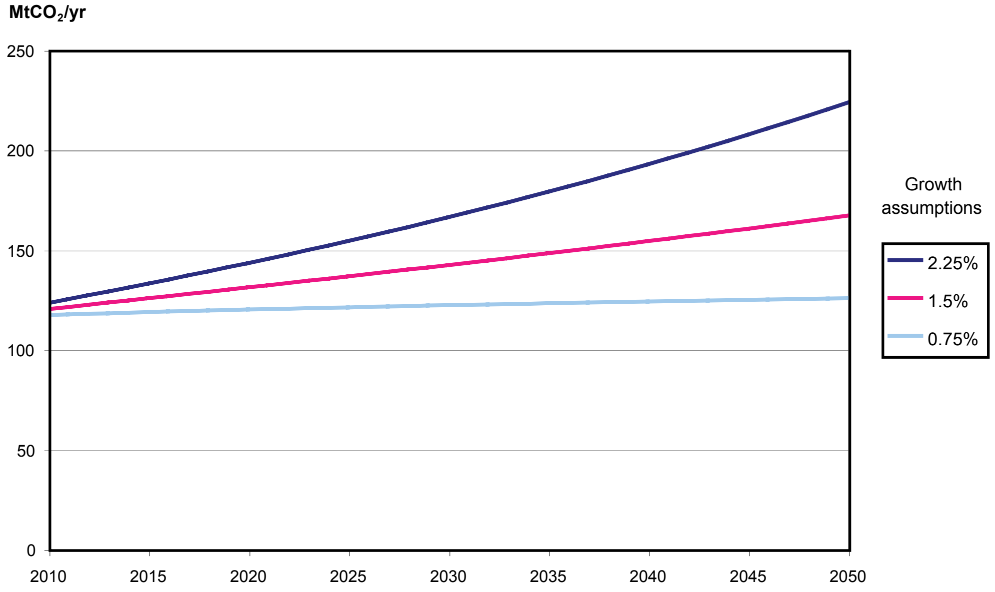
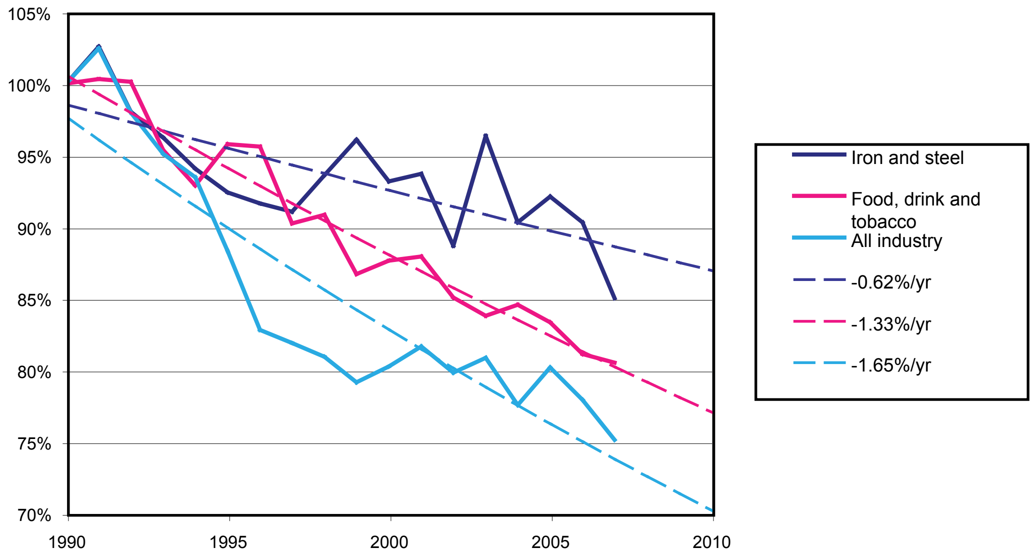


Figure 7.3.2 Improving industry sector energy consumption per unit output (1990 base)[39]



[39] Derived from: Department for Business, Enterprise and Regulatory Reform, 'Energy Consumption in the United Kingdom: Industrial Data Tables 2008 Update' 2008.

past ten years. This will also avoid an unrealistic assumption being made about the sustainable trend of energy efficiency improvements.

We have produced an energy and emission model of the major industry subsectors. The model uses a matrix of fuel consumptions for the subsectors, adjusted for specific cases, with forecasts of economic growth, population growth, and industry energy efficiency used to predict consumption of the major classes of fuels and electricity. Using these annual estimates, the CO_2 emissions resulting from fuel combustion are calculated by applying the standard conversion factors from Defra environmental reporting guidelines. The model has been calibrated for fuel and emission data for 2006 as the reference year.

7.4 Review of potential options

Table 7.4.1 summarises the potential measures that have been analysed for this sector. Full details of this analysis can be found in appendix A3. For each measure, a figure for penetration has been assumed based upon our experience in the sector. In preparing and evaluating measures for reduced energy use and reduced CO_2 emissions, extensive use was made of the BERR industry data tables. The limited available data on energy use and the inherent diversity of processes and technology employed has, however, restricted the range of potential measures which could be properly evaluated. As a result, several categories of potential improvement measures could not be assessed; they include the following industry-specific measures:

- development of processes that use less energy or produce less carbon
- improved integration of processes to enhance energy efficiency
- collective export of low-grade heat for use on and off site via a district heating system
- changes to products to reduce the use of energy-intensive manufacturing processes
- changes to products to minimise lifecycle carbon emissions
- changes to the product lifecycle to maximise reuse
- recycling to minimise the energy-intensive manufacture of new products

The contribution of these additional measures needs to be evaluated more fully for each industry subsector, but for the purposes of this report they have been included in the non-specific *efficiency improvements* measure.

While we were preparing Powering the Future, major UK businesses voiced their concern to us that the inadvertent costs of carbon trading and improvement programmes could force producers offshore. This would damage the UK economy directly by the loss of employment and indirectly by increasing imports. The latter would increase global CO_2 emissions through the use of less-advanced processes and increase fuel consumption from international travel – the exact reverse of the intent of such measures.

7.4.1 CO_2 reductions

Figure 7.4.1.1 shows the net CO_2 reduction for the measures analysed, including the CO_2 reduction resulting from changes in the sector's demand for electricity from the 'business as usual' case. Electricity sector emissions are based on indicative levels of 0.4 tCO_2/MWh in 2020 and 0.1 tCO_2/MWh in 2050.

The challenge of identifying a comprehensive set of improvement measures for industry is highlighted by the relative scale of *efficiency improvements* which is at least five times the magnitude of most of the other measures.

Industrial CCS is a significant technology with the potential to make a major contribution to CO_2 reduction in industry. Its full benefit will not be realised until the technology achieves sufficient maturity to be used in a widespread manner.

Industrial CHP and *biomass CHP* have CO_2 emissions related to the carbon content of electricity produced in the electricity sector, as shown in figure 7.4.1.1. *Industrial CHP* provides a useful measure in the early part of the period, but would not offer worthwhile CO_2 reduction benefits in new applications after 2030 when the carbon intensity of electricity will have declined significantly. The absence of a sustainable large-scale source of biomass prevents *biomass CHP* from being included as a feasible measure. Other measures have only small impacts on the CO_2 emissions of the sector, but are included. The savings arising from *electrical efficiency* are considered to be part of the ongoing improvements in industrial energy efficiency and are not taken forward as a separate measure.

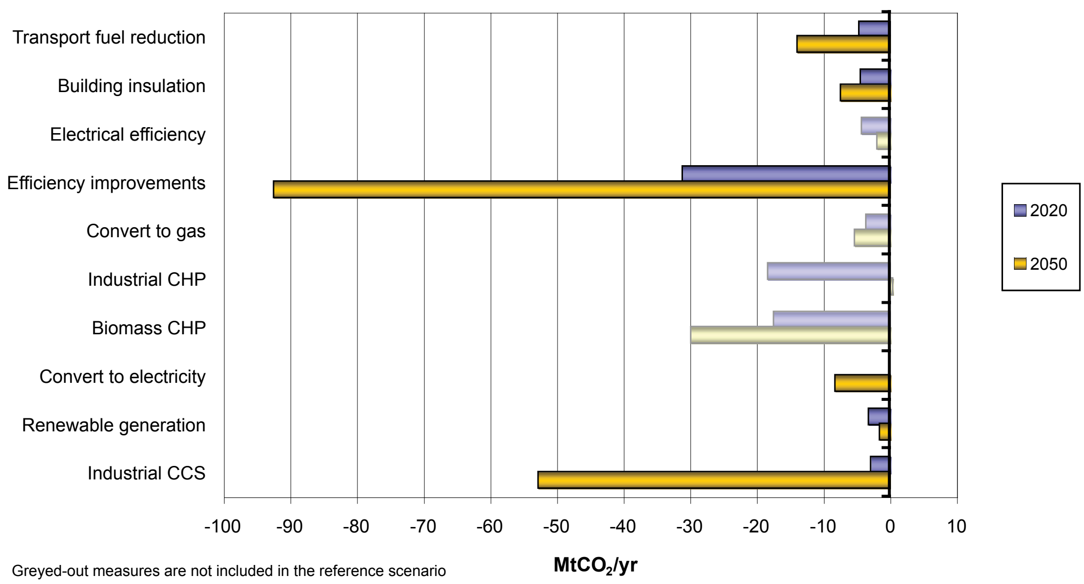
Convert to gas would require a shift to a more expensive fuel and offers only a small benefit; it is not taken forward in the reference scenario.

Table 7.4.1 Description of the selected measures for industry sector response to CO_2 emissions

Measure	Description	Assumptions
Transport fuel reduction	Reduction in the demand for products involving energy-intensive production methods may not arise from actions within the industry sector but may result from changes elsewhere. This measure results from the potential reduction in demand for petrol and diesel fuels if electric vehicles displace significant numbers of internal combustion engine vehicles in the transport sector. Reduced demand in the transport sector cuts consumption in oil refining within the industry sector.	Reduction of 74% of petroleum fuel consumption
Building insulation	The industry sector includes many heated buildings and warehouses. Improving the insulation of these buildings would significantly reduce the need for space heating, with an associated reduction in fuel consumption.	50% average reduction across industry
Electrical efficiency	Electricity demand in industry includes a major component from motors, lighting and air compressors. These demands can be reduced by ensuring that motors are progressively replaced by higher-efficiency units, and that lighting is upgraded to the most efficient fittings. Compressed air systems are frequently found to be wasteful in delivering energy, with leakage levels often exceeding 30% of demand. In many processes, fixed-speed motors are used with pumps and control valves or hydraulic couplings to machinery which result in a continuous waste of energy compared with the use of variable-speed drives.	Reductions of: process heat = 5%, drying and separation = 10%, motors = 10%, compressed air = 30%, lighting = 50%, refrigeration and space heating = 35%, other = 10%. Implemented progressively between 2010 and 2025
Efficiency improvements	Industry-specific reductions in product and process carbon intensity, and improvements in energy recovery and reuse.	50% reduction in energy use by 2040
Convert to gas	For a given heat requirement, the combustion of natural gas results in a much lower carbon emission than combustion of oil or – more significantly – coal. Many industrial energy uses require heat, and conversion to natural gas offers a feasible, if not necessarily economic, means of reducing CO_2 emissions.	100% coal and oil except in iron and steel, coke ovens and oil refining
Industrial CHP	CHP offers a means of generating power from a fuel, commonly natural gas, while making use of the heat rejected by the power cycle for process or space-heating duties.	70% low-temperature processes, 50% drying, 70% space heating. Heat to power ratio = 1
Biomass CHP	Using biomass fuels instead of natural gas in CHP plants has a different impact on power requirements and CO_2 emissions from industry. Biomass fuels cannot be used to fire gas turbines directly and biomass gasification is not yet proven. Such CHP plant must therefore use biomass-fired boilers to raise high-pressure steam. The steam drives a turbine to generate power, with the exhaust steam delivered at about 10 bar, suitable for lower-temperature process heating. This configuration means that the power generated per unit heat delivered is much less than for a combined cycle CHP plant fuelled on natural gas.	70% low-temperature processes, 50% drying, 70% space heating. Heat to power ratio = 5.6

Measure	Description	Assumptions
Convert to electricity	As the fossil carbon use in each sector decreases over the period to 2050 and the cost of CO_2 emissions rises inexorably, unconventional processes will become increasingly attractive to industry. Developments in new processes are being continually explored within industry to identify opportunities to reduce costs or increase the quality of products.	90% of high-temperature process energy use
Renewable generation	Industrial sites offer significant potential for the installation of renewable energy plant, primarily exploiting wind and solar energy.	Wind: 10 MW/km^2, 20% of floorspace, 25% capacity factor Solar: 300 MW/km^2, 10% of floorspace, 10% capacity factor
Industrial CCS	The technology and infrastructure necessary to capture CO_2 emissions and collect them for long-term storage is likely to incur the lowest cost when applied to small numbers of larger CO_2 emitters. Several industry segments include large installations with nationally significant scales of CO_2 emissions. These include steel works, oil refineries, petrochemical sites, cement works and coke oven complexes.	Typically 70-80% of major point-source emitters, with 90% capture

Figure 7.4.1.1 Industry measures – net change in sector CO_2 emissions



Greyed-out measures are not included in the reference scenario

7.4.2 Electricity demand

Figure 7.4.2.1 shows the potential electricity demand changes offered by the industry sector measures compared to the 'business as usual' case.

As discussed above, *industrial CHP* will be beneficial from a CO_2 emission perspective until around 2030, after which it has a negative impact. After 2030, it continues to have a positive effect on this sector's demand for electricity. The scale of generation from CHP rises from 6.6 GW in 2020 to 13 GW in 2050 at the level of penetration assumed. This may not be feasible because of process, practical and financial constraints affecting industry.

As can be expected, *convert to electricity* would increase the sector demand for centrally produced electricity as high-temperature processes use electricity instead of a primary fuel.

Renewable generation embedded within the sector has the potential to reduce net electricity demand by about 10% of current consumption by 2050.

7.5 Industry sector scenario options

Table 7.5.1 shows which of the industry sector measures are included in the scenario analysis. An entry of 1 indicates that the measure is included in the scenario, with a 0 indicating that a measure is not included. A number between 0 and 1 indicates that the measure is only partially adopted by a particular scenario since it cannot be applied at the level of penetration initially assumed.

7.6 Sector-specific issues

1. The diversity of the sector means that generic measures offer inadequate CO_2 reductions. Radical process energy efficiency improvements will be required to cut consumption by over 50%.

2. The application of gas-fuelled CHP has the potential to offer a large reduction of up to 20% in sector CO_2 emissions and industrial electricity demand by 2025. However, the subsequent decline in carbon intensity of power production in the electricity sector would progressively reduce the value of this improvement after 2025, so that later implementations would not deliver useful emission reductions.

3. The application of CCS to large industrial emitters offers a reduction in sector CO_2 emissions of up to 30% in 2050.

4. The conversion of many high-temperature processes to electricity after 2025, when the carbon intensity of electricity from the electricity sector is reduced, would offer a reduction in CO_2 emissions of around 8% in 2050.

5. The substitution of biomass fuels for fossil fuels is not feasible on the required scale because of the limited available resources.

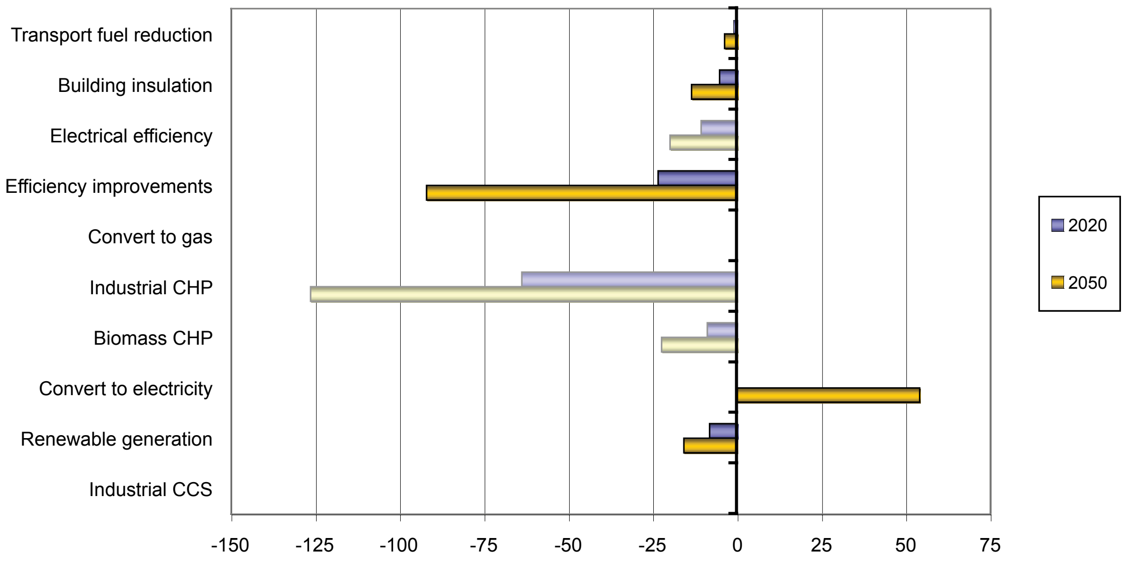
6. Embedded renewable energy systems such as wind and solar could supply around 10% of current industrial electricity consumption by 2050.

7. Industry sector emissions are closely related to the UK's economic growth. A 1% increase in the assumed long-term growth rate of 1.5% results in a significant increase in sector CO_2 emissions.

8. Funding the requirements for substantial reductions in CO_2 emissions and improvements in energy efficiency necessary from UK industry – without undermining its competitiveness – is a fundamental challenge.

9. There is widespread concern that the inadvertent costs to industry of carbon trading and improvement programmes may force industries offshore to areas with lower or no emission targets. This would damage the UK economy directly by the loss of employment and indirectly by increasing imports. The latter would increase global CO_2 emissions – the exact reverse of the intent of such measures.

Figure 7.4.2.1 Industry measures – change in electricity demand



Greyed-out measures are not included in the reference scenario

Table 7.5.1 Industry sector scenario options selections

Option	Scenarios											
	1 Reference	2 Reduced renewable heat	3 Application of large-scale industrial CHP	4 No new nuclear programme	5 No CCS	6 Aggressive wind adoption	7 Economic growth rate	8 Building insulation	9 Battery power adoption by cars and vans	10 Wind generation reduced by 5 GW	11 PV electricity	12 Unspecified industrial efficiency improvements
Transport fuel reduction	1	1	1	1	1	1	1	1	1	1	1	1
Building insulation	1	1	1	1	1	1	1	1	1	1	1	1
Electrical efficiency	0	0	0	0	0	0	0	0	0	0	0	0
Efficiency improvements	1	1	1	1	1	1	1	1	1	1	1	1
Convert to gas	0	0	0	0	0	0	0	0	0	0	0	0
Industrial CHP	0	0	1	0	0	0	0	0	0	0	0	0
Biomass CHP	0	0	0	0	0	0	0	0	0	0	0	0
Convert to electricity	1	1	1	1	1	1	1	1	1	1	1	1
Renewable generation	1	1	1	1	1	1	1	1	1	1	0.75	1
Industrial CCS	1	1	1	1	0	1	1	1	1	1	1	1

8. Commercial

8.1 Sector introduction

For the purposes of this report, references to the commercial sector comprise the following groups of energy consumers as defined for DUKES Table 1.3: Supply and use of fuels:

- commercial
- public administration
- agricultural
- miscellaneous

The diversity of the sector means that only a partial assessment of emission reduction measures can be quantified. We have focused primarily on the commercial and public administration elements, which represent over 80% of the energy consumption (and hence CO_2 emissions) of the sector.

The commercial sector only consumes about 5% (11 MTOE) of the fossil fuel supply to the UK economy and emits about 5% of UK CO_2 (2006 figures).

8.2 Current position

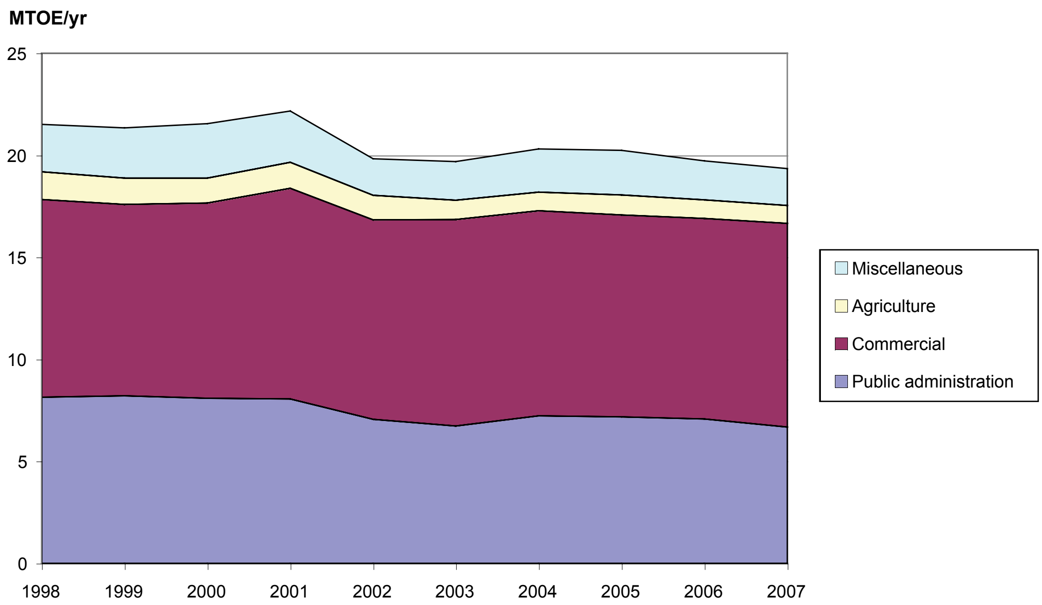
Figure 8.2.1 shows the trend in commercial sector energy demand.

The energy demands are met by various fuels. The trend of consumption of each fuel is shown in figure 8.2.2 while the breakdown of fuel use in 2006 is shown in figure 8.2.3.

These figures show that natural gas and electricity are the predominant energy sources at around 45% of total consumption each.

From 1990 to 2007 there was a slight downward trend in natural gas, while electricity demand grew consistently over the same period. Oil consumption now represents about 8% of energy consumption, having declined somewhat erratically from over 15% in 1990. Coal consumption has remained at minimal levels while renewable energy increased to almost 1% of the total by 2006.

Figure 8.2.1 Energy consumption in the commercial subsectors[40]



[40] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

Figure 8.2.2 Fuel consumption in commercial sector[41]

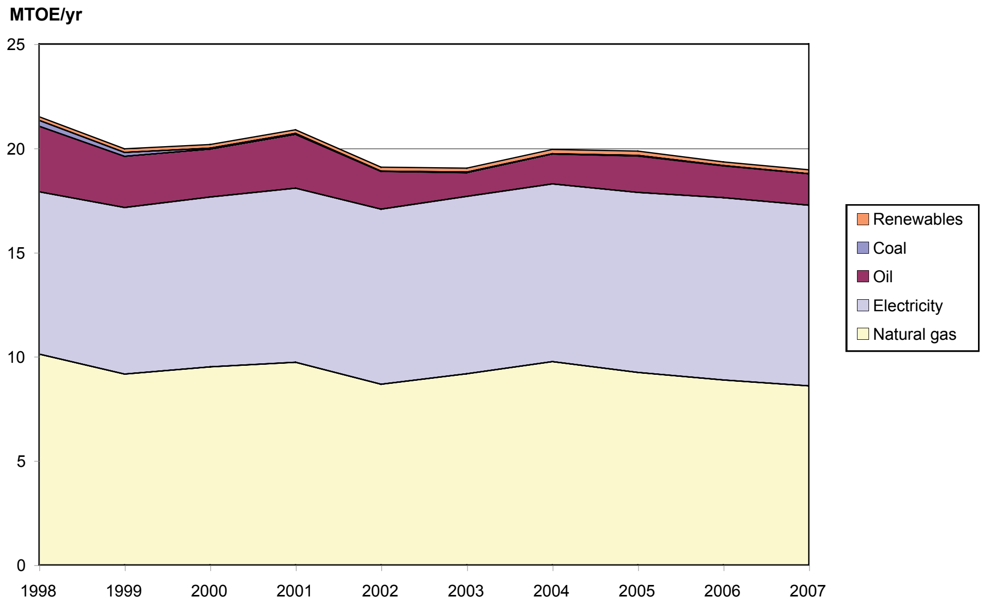
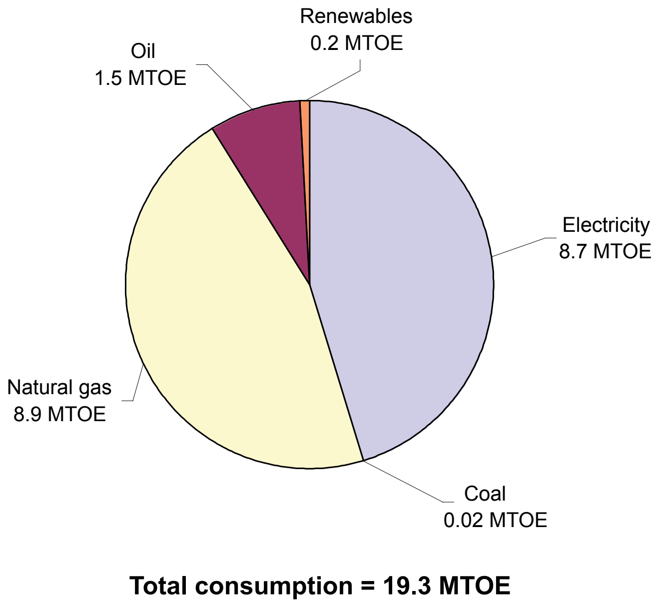


Figure 8.2.3 Commercial energy use by fuel for 2006[42]



[41],[42] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

Defra statistics for CO_2 emissions for the sector are shown in figure 8.2.4. These generally follow the trend of the corresponding fuel consumptions in figure 8.2.1 and show that agricultural emissions are substantially constant while the emissions of the commercial sector have declined by over 15% since 1998. The step change between 2001 and 2002 appears to be due to recession conditions.

8.3 Forecast changes in energy consumption

The commercial sector is modelled on the basis of the floorspace occupied and representative assumptions about the energy consumptions of existing and new construction. The current floorspace in the sector is estimated at 450 million m^2 based on the commercial and industrial floorspace and rateable value statistics[43] produced by the Department of Communities and Local Government (DCLG). It is expected that a replacement rate of at least 1% per year will apply in the period to 2050. In addition, the growing working population will require additional space, estimated at 73 million m^2 on the basis of constant area per employee and a sustained share of the working population being employed in this sector. The replacement of old buildings and creation of additional space for increased staff numbers will require the construction of 258 million m^2 of new floorspace by 2050.

8.4 Review of potential options

The potential measures for this sector evaluated in this report are summarised in table 8.4.1.

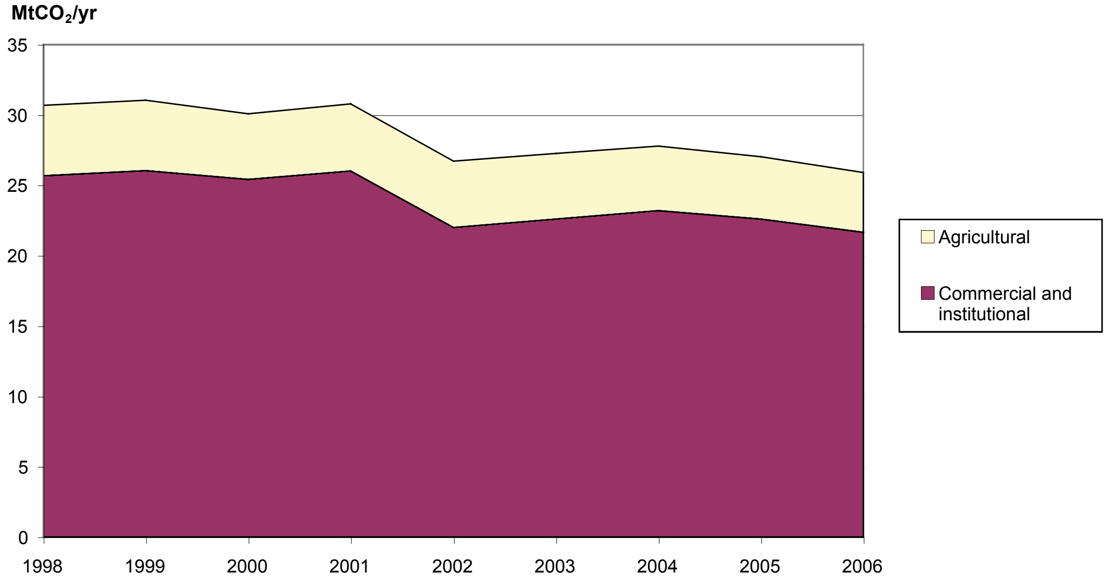
Other measures could be used to reduce CO_2 emissions from this sector, however only the measures identified in table 8.4.1 were taken forward. The other measures were either technically immature or had a net effect too small to make a noticeable contribution.

Appendix A4 contains details of these measures together with a more detailed analysis of their impacts.

8.4.1 CO_2 reductions

Figure 8.4.1.1 shows the net CO_2 reduction for the measures analysed, including the CO_2 reduction resulting from changes in the sector's demand for electricity from the 'business as usual' case. Electricity sector emissions are based on indicative levels of 0.4 tCO_2/MWh in 2020 and 0.1 tCO_2/MWh in 2050.

Figure 8.2.4 Defra CO_2 emission data for the commercial sector[44]



[43] Department of Communities and Local Government, 'P412 Commercial and Industrial Property: Bulk Class Hereditaments by Floorspace Sizeband: England and Wales, 1st April, 1998-2008' 2009.

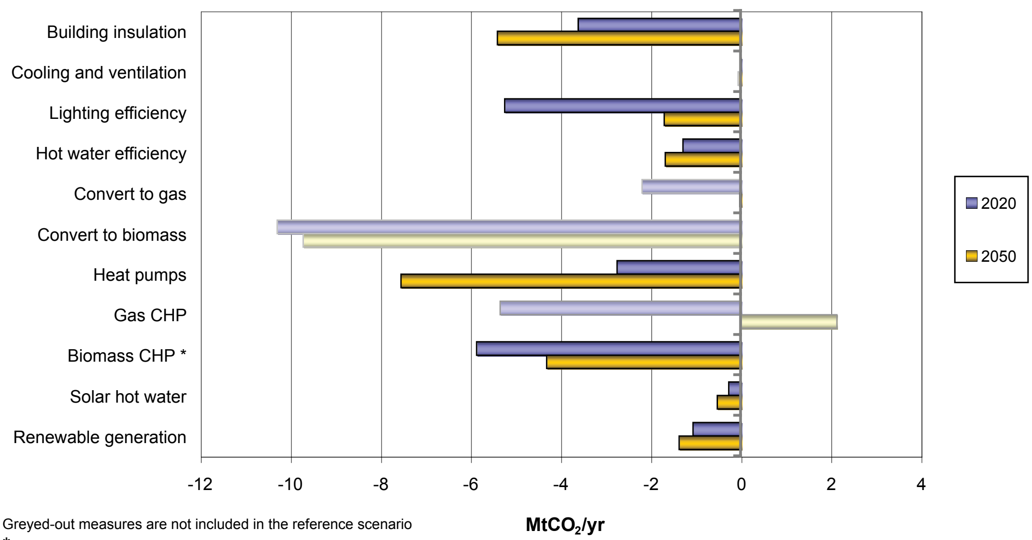
[44] Department for Environment, Food and Rural Affairs, 'Table 5b: Estimated emissions of carbon dioxide (CO_2) by National Communication source category, type of fuel and end user: 1970-2007' 2008.

Table 8.4.1 Description of the selected measures for commercial sector response to CO_2 emissions

Measure	Description	Assumptions
Building insulation	The buildings in this sector range from newly constructed to those over 100 years old. The standards to which the older building stock was constructed differ substantially from those applicable today and those expected in future. New construction is expected to follow the domestic residential sector in becoming carbon neutral by 2017, meaning that the energy consumption of new buildings will fall to low levels. Meanwhile existing stock must be upgraded to achieve at least a 1% per year reduction in energy consumption to meet the CO_2 reduction commitment.	Energy consumption per unit floor area for heating reduced to 25% of current levels by 2050
Cooling and ventilation	Cooling and ventilation represent significant electricity consumption in existing and new commercial building stock. There is a significant opportunity to increase the rate at which best-practice standards are applied to existing stock.	Reduction to 30% below current best-practice energy consumption for existing stock, new to be reduced at 1% per year
Lighting efficiency	Lighting is a major energy consumer in buildings and lighting technology has advanced radically over the past 50 years with the expectation of further significant improvements in energy efficiency by 2050.	80% reduction for existing and 65% reduction for new by 2050
Hot water efficiency	The poor design of existing hot water systems and compliance with legionella regulations produce significant energy wastage. This measure considers that, by 2050, hot water systems in existing buildings can be brought up to the best-practice levels defined in CIBSE Guide F, and that standards for new buildings will demand a best-practice energy consumption that is 30% below current best practice.	Reduction of hot water energy consumption of existing buildings to current best-practice standards and new buildings to 70% of this level
Convert to gas	Significant CO_2 emissions result from the use of coal and oil for building heating. Electricity is also used for space or water heating to a significant degree resulting in excess emissions due to the current CO_2 emissions of electricity generation.	Reductions: coal 100%, oil 100%, electricity 50%
Convert to biomass	Conversion of heating systems to use carbon-neutral biomass-derived fuels could offer a significant reduction in CO_2 emissions. Such conversion is not feasible for all types and scales of buildings and it has been assumed that lower levels of penetration are achieved for gas and electric heating.	Reductions: coal 100%, oil 100%, gas 80%, electricity 30%
Heat pumps	Heat pumps can be used for space heating, extracting heat from the surrounding environment to supply the building. For the larger installations typically required in the commercial sector, the ambient or ventilation exhaust air is used as the source of heat. Although this arrangement requires higher electricity consumption per unit heating supplied than alternatives, it offers reduced consumption compared with electric heating. It can be cost effective in comparison with other fuels, particularly when the heat pump is configured to provide seasonal cooling when required.	Reductions: coal 100%, oil 100%, gas 90%, electricity 50%

Measure	Description	Assumptions
Gas CHP	CHP units are becoming widely available for smaller applications typical of commercial buildings. These offer high efficiency of use of gas and valuable electricity production, with an overall energy efficiency of over 85%.	Reductions: coal 100%, oil 100%, gas 60%, electricity 35%. Power-to-heat ratio = 0.6
Biomass CHP	The potential benefits of the use of carbon-neutral biomass fuels in CHP systems would be expected to be larger than for gas-fired systems. However, while gas can be burned in the internal combustion engines or gas turbines widely used in CHP systems, most biomass fuels can only be burned to raise steam to drive a steam turbine. This is only effective at a larger scale and offers a lower power-to-heat ratio.	Reductions: coal 100%, oil 50%, gas 30%, electricity 20%. Power-to-heat ratio = 0.2
Solar hot water	Solar heating for hot water systems is an established technology for domestic use and has the potential for use in the commercial sector. There are clearly differences between the domestic and commercial sectors that may require refinement of the technology and its application; nevertheless it has the potential to make a useful contribution to the reduction of fossil fuel consumption.	20% reduction of hot water energy use
Renewable generation	Commercial buildings offer some possibilities for on-site renewable power generation. Solar PV arrays can be installed on roof areas and on some favourable sections of facades. Wind turbines can be installed where there is sufficient open space, for example around larger retail warehousing. Wind turbine performance is assumed to be reduced by adjacent buildings.	Wind: 10 MW/km^2, 30% of floorspace, 25% capacity factor Solar: 300 MW/km^2, 10% of floorspace, 10% capacity factor

Figure 8.4.1.1 Commercial measures – net change in sector CO_2 emissions



Greyed-out measures are not included in the reference scenario
* partially included in the reference scenario

Building insulation offers a significant improvement in CO_2 emissions, but the benefits of other measures are not as clearcut. *Biomass CHP* and *convert to biomass* require up to 60 million tonnes per year of biomass that Defra[45] indicates is unlikely to be available in the UK. *Heat pumps* offer a significant reduction in CO_2 emissions. *Convert to gas* has a small benefit but is likely to result in increased costs and is not considered in the scenario analysis. Other measures have minor impacts on sector CO_2 emissions.

The CO_2 emissions of power generated in the electricity sector will change with time, as generating technologies with lower emissions are adopted. Some measures, such as *gas CHP*, are only beneficial while the carbon intensity of production in the electricity sector is high. Conversely, *heat pumps* only contribute to CO_2 emissions reduction when the carbon content diminishes. Both of these are included in the scenario analysis for the periods when they offer significant CO_2 reductions.

8.4.2 Electricity demand

Each measure has an effect on electricity consumption in the commercial sector. The changes in demand for supply from the electricity sector, compared with the 'business as usual' case, are shown in figure 8.4.2.1.

Gas CHP, *renewable generation* and *lighting efficiency* measures all show major reductions to the net commercial sector demand. *Heat pumps* increase electricity demand for heating, although they offer overall benefits in CO_2 reduction.

8.5 Commercial sector scenario options

Table 8.5.1 shows which of the commercial sector measures are included in the scenario analysis. An entry of 1 indicates that the measure is included in the scenario, with a 0 indicating that a measure is not included. A number between 0 and 1 indicates that the measure is only partially adopted by a particular scenario since it cannot be applied at the level of penetration initially assumed.

8.6 Sector-specific issues

1. Improved insulation of commercial buildings offers a 20% reduction in CO_2 emissions and reduces costs of fuel use.

2. The application of gas-fuelled CHP would offer a reduction of up to 20% in CO_2 emissions by 2025. However the subsequent decline in carbon intensity of power generation in the electricity sector would eliminate the value of this measure after 2035.

3. The extensive substitution of biomass fuels for fossil fuels, either directly or through biomass CHP, is not feasible on the required scale because of the limited available resources, although smaller-scale substitutions are both feasible and desirable.

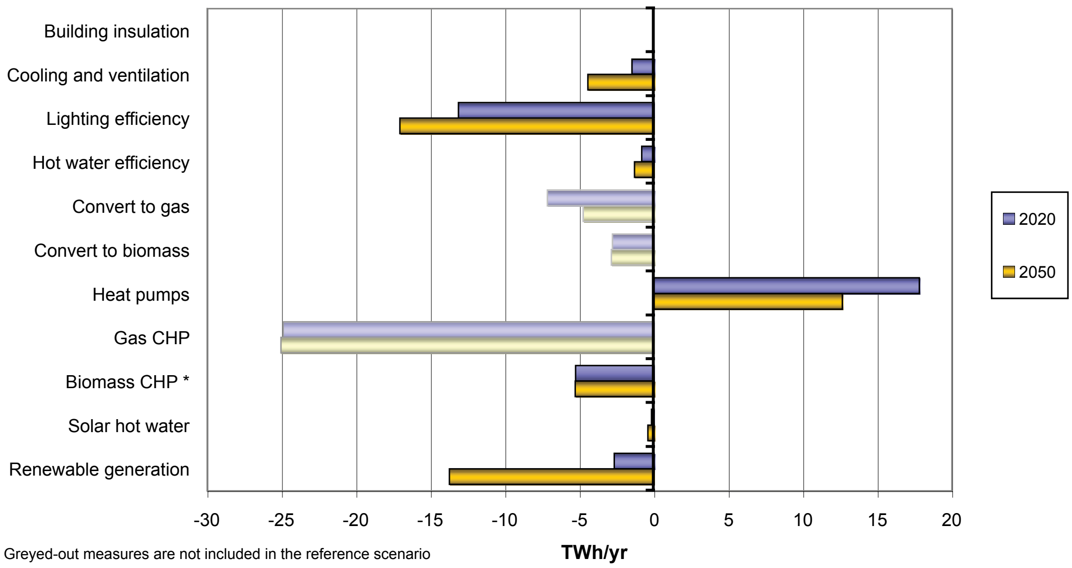
4. Wider adoption of heat pumps to meet the heating demand of buildings offers a significant reduction in CO_2 emissions after 2020.

5. Improvements in lighting and hot water systems offer useful reductions of about 10% each in sector emissions.

6. Embedded renewable energy systems such as wind and solar could supply up to 5% of the sector's electricity demand by 2020 and up to 20% of demand by 2050.

[45] Department for Environment, Food and Rural Affairs, 'UK Biomass Strategy' 2007.

Figure 8.4.2.1 Commercial measures – change in electricity demand



Greyed-out measures are not included in the reference scenario

*partially included in the reference scenario

Table 8.5.1 Commercial sector scenario options selections

Measure	Scenarios											
	1 Reference	2 Reduced renewable heat	3 Application of large-scale industrial CHP	4 No new nuclear programme	5 No CCS	6 Aggressive wind adoption	7 Economic growth rate	8 Building insulation	9 Battery power adoption by cars and vans	10 Wind generation reduced by 5 GW	11 PV electricity	12 Unspecified industrial efficiency improvements
Building insulation	1	1	1	1	1	1	1	0.5	1	1	1	1
Cooling and ventilation	1	1	1	1	1	1	1	1	1	1	1	1
Lighting efficiency	1	1	1	1	1	1	1	1	1	1	1	1
Hot water efficiency	1	1	1	1	1	1	1	1	1	1	1	1
Convert to gas	0	0	0	0	0	0	0	0	0	0	0	0
Convert to biomass	0	0	0	0	0	0	0	0	0	0	0	0
Heat pumps	1	1	1	1	1	1	1	1	1	1	1	1
Gas CHP	0	0	1	0	0	0	0	0	0	0	0	0
Biomass CHP	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Solar hot water	1	0.5	1	1	1	1	1	1	1	1	1	1
Renewable generation	1	1	1	1	1	1	1	1	1	1	0.6	1

9. Electricity

9.1 Sector introduction

The UK electricity sector comprises three levels:

- large generating stations that provide a high proportion of the power
- the transmission network that links together the generating stations and major substations at high voltage (to minimise energy losses)
- the distribution network, supplied from the high-voltage substations and ultimately connected to every home and business in the country

Electricity is not only produced in the electricity sector: a small but significant part is made by so-called auto-producers – generation embedded in consumers' facilities. The prospective growth of this type of power production has been addressed in each of the sectors and recognised as a reduction in demand for power supplied from the electricity sector rather than being considered in detail here.

The electricity industry is regulated to address actual and potential monopoly issues. The industry has a complex structure commercially, designed to maintain competition and reasonably minimise costs. The industry as a whole is not regulated to minimise CO_2 emissions, but there are some mechanisms in place, for example the Renewables Obligation which acts to increase renewable generation.

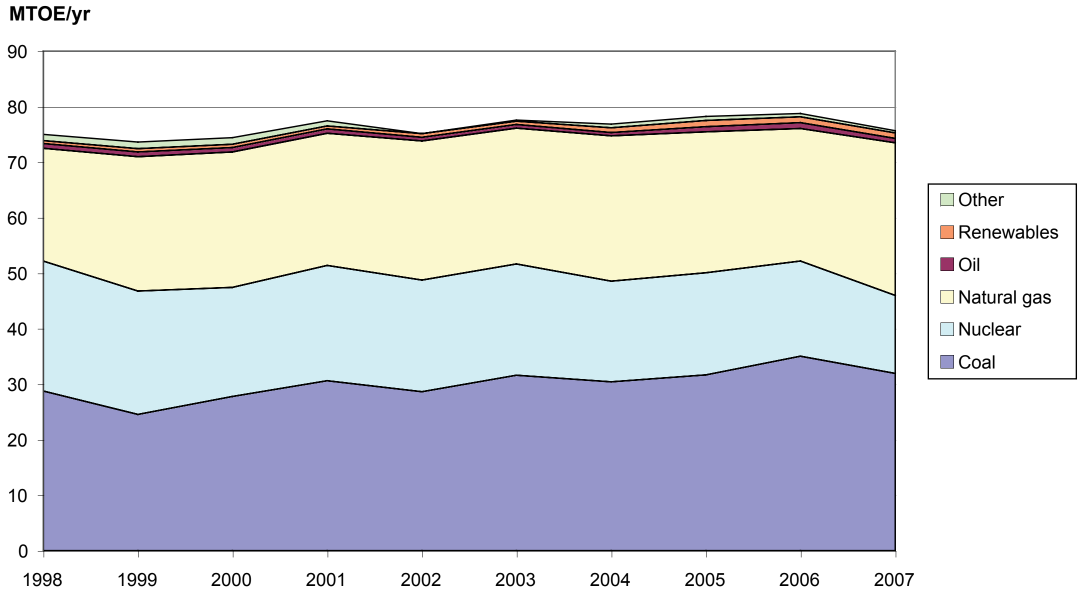
As mentioned in section 4 of this report, the electricity sector consumes 85 MTOE/yr (37%) of primary energy and in 2006 discharged 33% of CO_2 emissions in the UK. Unlike other sectors, the scale and character of its operation are determined by the demand for electricity from the other sectors. The opportunity to reduce CO_2 emissions is therefore limited to the selection of a generating plant mix and operating regime rather than measures to reduce demand.

9.2 Current position

Electricity production has experienced sustained but low growth, reflecting growing demands from most sectors. Figure 9.2.1 shows the contributions to electricity production by fuel, and figure 9.2.2 shows the breakdown of power plant energy consumption by fuel in 2006.

Over the period, coal consumption has decreased while gas consumption has increased, reflecting the changing costs of both fuels. In recent years the relative cost of the fuels has resulted in some increase in the use of coal, as utilities attempt to minimise their expenditure on fuel.

Figure 9.2.1 Electricity sector fuel consumption[46]



[46] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 1.3: Supply and use of fuels' 2008.

Consumption of gas generally has risen over the period, reflecting the growth of capacity of newer, more efficient CCGT plant.

The energy contribution of nuclear power plant has declined with the progressive closure of the first-generation gas-cooled Magnox series of reactors and the declining availability of the remaining AGR reactors. The contribution of renewable energy sources, primarily wind and hydroelectric power, can be seen to have nearly tripled from a low base during the period, rising to represent over 5% of energy input. Meanwhile, consumption of oil and other fuels has remained small at a total of less than 2% of fuels throughout the period.

The detailed breakdown of fuel use by electricity production for 2006 is shown in figure 9.2.2. It illustrates the minor role of oil, primarily as a fuel for plant that only operates to meet peak demands, compared with coal and gas which supply the bulk of demand.

The electricity sector has different characteristics from other industries, particularly in respect of its need to instantaneously balance production with demand.

The limited energy storage that the electricity system currently has is mainly in the form of rotational energy of the generating plant and as energy stored as water pumped to high-level reservoirs in pumped-storage schemes in Wales and Scotland. This water can be released to generate power at very short notice to manage the transients that result from other generating units breaking down or from sudden demand surges.

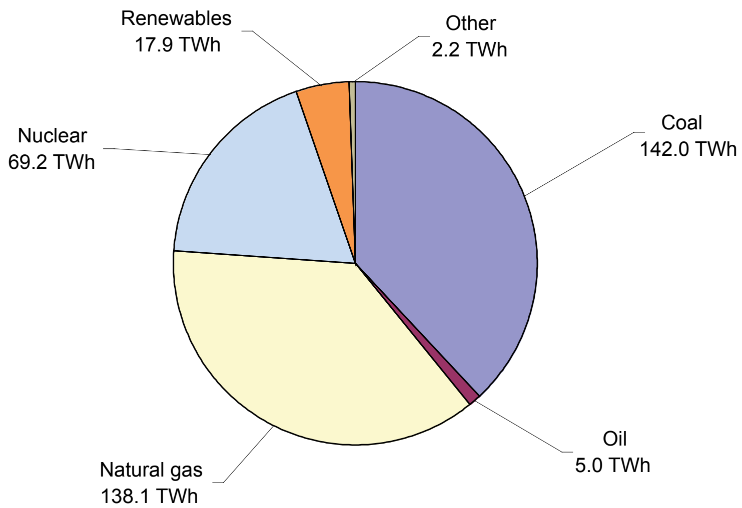
In order to assist the balancing of supply and demand, some large consumers accept the risk of limited interruption to their supplies in return for discounted tariffs.

The production of electricity continuously follows the demand, which varies according to the season and the time of day. Typical daily demand curves are shown in figure 9.2.3.

Despite the structure of the UK electricity industry, the commercial arrangements do not affect the fundamental operation of the system.

Generating plant is operated to minimise the overall costs of producers in supplying power to their

Figure 9.2.2 Electricity energy use by fuel for 2006[47]



Total production = 374.4 TWh

[47] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 5.6: Electricity fuel use, generation and supply' 2008.

consumers. This means that the lowest-cost plant is scheduled to meet the continuous baseload demand, while progressively more expensive plant is scheduled to supply shorter-duration slices of capacity up to the peak demand period for each day. National Grid Company (NGC), the transmission system operator, contracts a small amount of capacity to meet unforeseen mismatched peaks and troughs in demand and to manage upsets resulting from breakdowns.

This range of duties means that different types of plant, with different fuels, must be procured to fulfil duties from baseload to peaking, to ensure that suppliers can meet their demands at minimum cost.

The trend of the mix of power plant capacity by fuel is shown in figure 9.2.4.

The changing profile of power generating plant capacity shows that coal and nuclear are gradually declining as plant is retired, while new gas capacity continues to be built. The capacity of auto-generation or CHP within industry has risen significantly. While renewable generation has grown with the addition of new wind generation, wind capacity remains modest compared with the existing hydroelectric capacity. The future trend of capacity is considered in section 9.4.

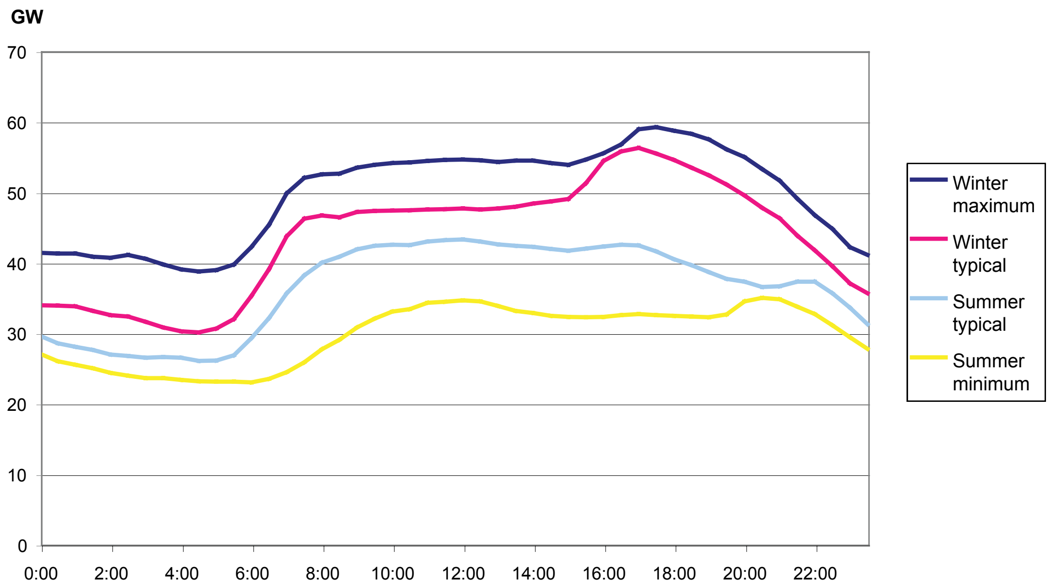
The percentage of the potential electricity production actually delivered by the different plant types (their utilisation) varies as their availability and relative fuel costs change with time. This is illustrated in figure 9.2.5.

The rising utilisation of coal and declining utilisation of gas- and oil-burning plant over the period reflects the shifting relative prices of the fuels.

Nuclear plant utilisation has fallen from above 70% in 1999 to below 60% in 2007. The significant technical problems that have affected the AGRs as they approach the end of their lives have resulted in extended shutdown periods. Modern PWR nuclear stations, typified by Sizewell B, achieve utilisations in the 85-90% range, but currently represent only a small part of the nuclear capacity.

The utilisation of renewable capacity is not shown in figure 9.2.5 as the statistics for capacity and production are not based on consistently defined categories of renewable generation.

Figure 9.2.3 Typical daily electricity demand curves for 2006[48]



[48] Produced from: National Grid Company, 'Demand Data Jan-Jun 2006' and 'Demand Data Jul-Dec 2006' 2007.

Figure 9.2.4 Generating plant capacity by fuel[49]

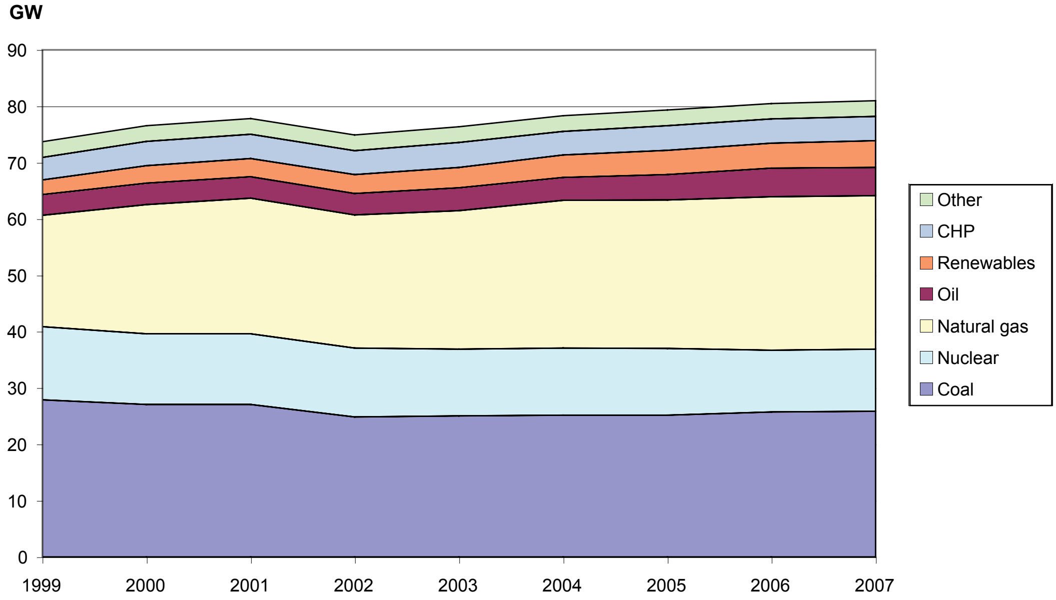
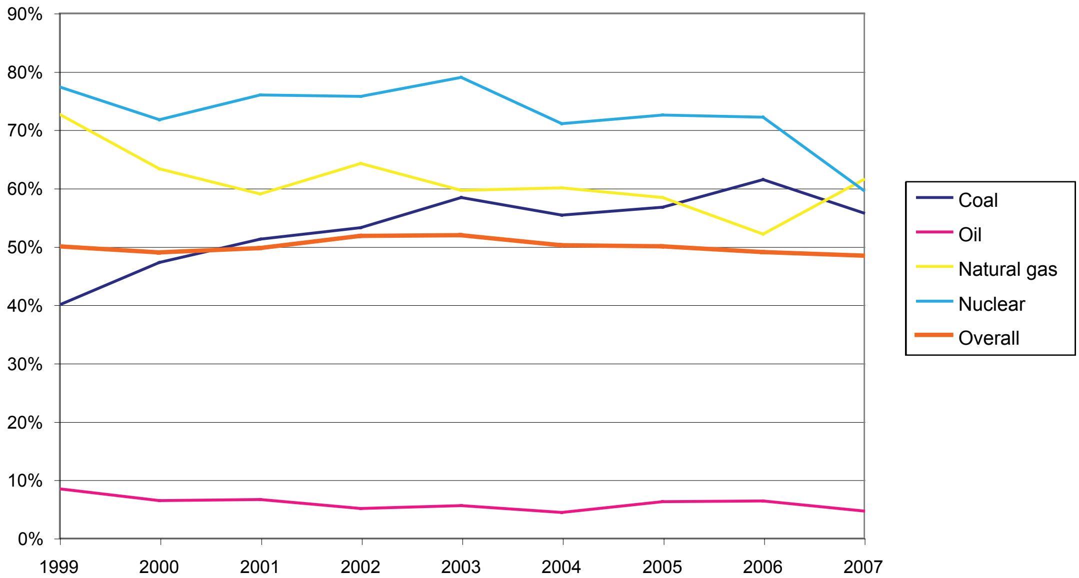


Figure 9.2.5 Power plant utilisation[50]



[49] Department for Business, Enterprise and Regulatory Reform, 'DUKES Tables 5.8-5.9: Plant capacity: England and Wales, Scotland and Northern Ireland' 2008.

[50] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 5.6: Electricity fuel use, generation and supply' 2008.

The average utilisation of generating plant overall during the period can be seen to remain in the 49-53% range. This consistency implies that, despite major changes in the operation of the plant driven by fuel prices, the relationship between installed capacity and average consumption has not changed significantly.

CO_2 emissions from the electricity sector since 1999 are shown in figure 9.2.6.

The 20% rise in CO_2 emissions over the period can be contrasted with the increase in electricity production of about 6%. There was an increase in coal-fired generation caused by the decline in utilisation of gas-fired plant due to the rising gas price, and falling production by nuclear plant. Since a coal-fired power plant emits approximately twice the CO_2 of a gas-fired plant of the same electrical capacity, this shift towards coal-fired generation caused a significant increase in emissions.

Throughout the period, oil-fired plant made a very small contribution to CO_2 emissions.

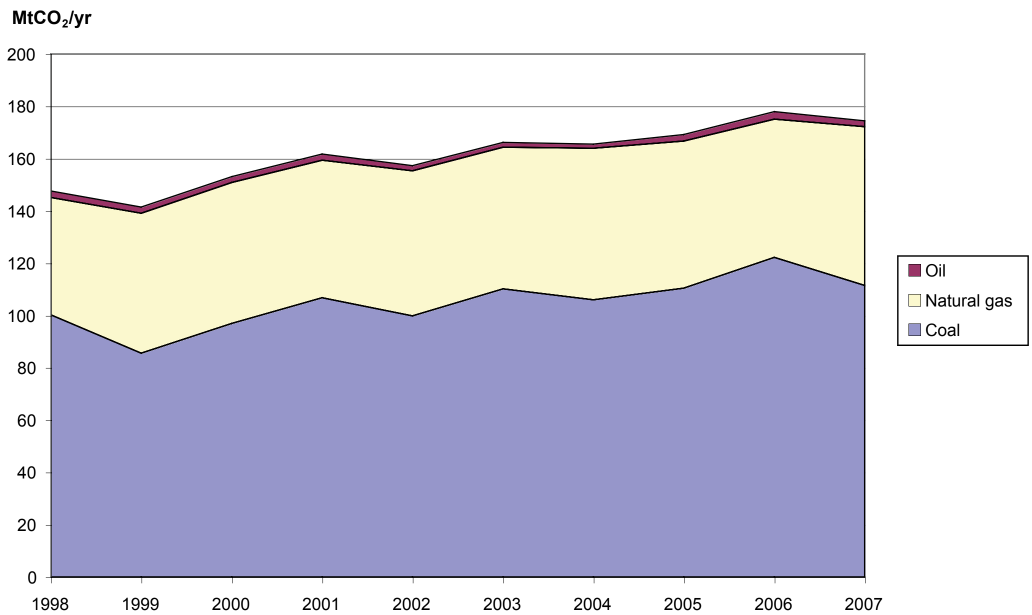
9.3 Transmission and distribution issues

Connecting new generating stations to the grid network and to consumers is a key element of adding new capacity to the UK electrical system. Most of the existing transmission networks were constructed more than 40 years ago and have been progressively uprated and reinforced since that time. This means that spare capacity is limited and that connections for new generating capacity in many areas of the country cannot be provided in less than five years, as new transmission lines and substations must first be designed, permitted, purchased and installed. This issue is accentuated by the growth of coastal and offshore intermittent renewable generating capacity which is often remote from the main transmission network.

The scale of change to the established patterns of supply and consumption identified in this report is very significant. It is not possible to analyse all of the impacts of these changes on the electricity transmission and distribution systems at this time.

It is clear, however, that major changes in network operation will be required. New technologies such as ‘smart grid’ controls will be essential alongside major investments in transmission and distribution networks to complement and facilitate the changes required

Figure 9.2.6 Electricity sector CO_2 emissions by fuel[51]



[51] Derived from: Department for Business, Enterprise and Regulatory Reform, ‘DUKES Table 5.4: Fuel used in generation’ 2008.

throughout the UK energy infrastructure. As the future path of development of the electricity system becomes clearer, the development of holistic strategies linking energy users, generators and the energy delivery networks will be a vital part of the work to successfully address the forthcoming challenges.

9.4 Forward capacity

The electricity generation industry comprises five main groups of plant constructed at different dates and using different technologies. As the plants successively reach the end of their lives, their declining output will dominate the trend of forward capacity:

- first-generation nuclear plant – the Magnox reactors (built 1960-1970)
- 500 MW and 660 MW units burning coal, oil or gas (built by the Central Electricity Generating Board, 1965-1980)
- second-generation nuclear plants – the AGR units (built 1975-1985)
- early CCGT units (built 1990-2000)
- later CCGT units (built 2000 to present)

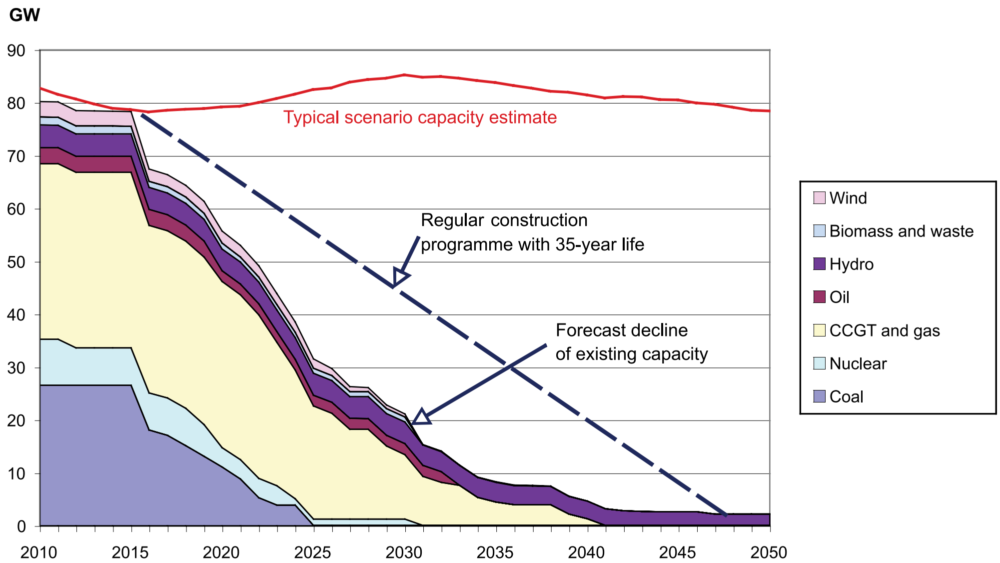
The first group of nuclear reactors will be shut down by around 2010. Some of the 500 MW and 660 MW coal-fired steam turbine units will be shut down by 2015 to comply with the EU Large Combustion Plant Directive unless they are equipped with flue-gas desulphurisation facilities. In any case, these large and relatively inefficient units are already 30-55 years old and none is likely to remain in service after 2030. The remaining nuclear plant will be shut down when their operating licences expire which, apart from Sizewell B, will be in the period to 2025. The gas turbine plant will have lives determined by economic considerations, but they are unlikely to remain viable for much longer than 30 years.

The retirement forecasts for the different types of existing plant and for plant already under construction have been combined to predict the likely forward capacity profile of known plant. This provides a basis for assessing the new construction necessary to maintain operation to 2050 (see appendix A5 for detail).

Figure 9.4.1 shows the forward capacity of existing and committed generation plant derived from this analysis.

The forward capacity forecast shows that nuclear generation will be minimal after 2025, and that existing coal-burning units are all likely to be shut down by the same date. Few existing CCGT units will still be in operation by 2035. The only existing plant that will remain in service beyond 2050 will be the hydroelectric units that represent about 2.5% of total current capacity.

Figure 9.4.1 Forward capacity of existing and committed plant[52]



[52] Derived from: Department for Business, Enterprise and Regulatory Reform, 'DUKES Table 5.11: Power stations in the United Kingdom (operational at the end of May 2008)' and National Grid Company, 'Transmission Entry Capacity (TEC) Data' 2008.

The steep decline of forward capacity is a worrying and unprecedented situation. The dashed line in figure 9.4.1 shows what an idealised forward capacity profile might look like, assuming capacity had been added consistently prior to 2010 with a 35-year plant life. Reducing CO_2 emissions over the period is made much more difficult by the enlarged gap between forward demand and remaining existing capacity, as additional generation plant with reduced CO_2 emissions will need to be constructed in the interim. However, the rapid retirement of so much generating plant with high carbon emissions presents a good opportunity to establish a new low-carbon electricity sector.

The total forward capacity that will be necessary for the reliable operation of electricity supply in future needs to be sufficient to meet peak demands with an additional plant margin for security of supply. Peak demand depends on the pattern of consumption by users. The demand can then be met from generating plant and any controllable energy storage within the system. Over the period to 2050, it is certain that the patterns of demand, and hence the relationship of peak demand to installed capacity, will change because of the application of intermittent renewable generation and adoption of more energy-efficient technologies by consumers. The transfer of energy supply from fossil fuels to electricity in some sectors, for example for road transport, will also affect demand patterns. However, these large additional groups of consumers may also offer opportunities to control demand through the use of 'smart grid' technologies.

'Smart grid' technologies involve managing the use of the available power and capacity of an electrical generation, transmission and distribution network by using digital technologies to provide coordinated scheduling of parts of the demand for the electrical energy by the consumers. 'Smart grids' promise to make better use of energy, reduce cost and increase delivery flexibility.

9.5 Options for future capacity additions

The major plant types that are candidates for new power generation to be constructed in the UK prior to 2050 are outlined in table 9.5.1.

Large-scale biomass electrical power generation is not considered to have a major role to play in future capacity mixes. Using biomass for electricity generation is not the most effective use in terms of overall CO_2 reduction or the best way to use a limited resource. As discussed in section 2.3, the amount of biomass available to the UK now and in coming years is likely to be limited. The maximum sustainable biomass-fired generation is estimated to be in the order of 5 GW if all available indigenous and imported biomass resources were to be used directly for power generation.

The candidate types of plant each have different characteristics for construction, with different lead times for major equipment and duration of construction work on site. In addition, the capability of industry to design, supply, construct and commission such plant is limited by technical resources such as large forging facilities and the availability of skilled and experienced staff. Such limitations on the rate of construction are profound and difficult to change quickly.

Table 9.5.2 summarises the practical lead times and historical build rates for these types of plant. The figures are necessarily indicative as they depend upon planning and regulatory delays and international competition for key human and technical resources. The indicative rates of construction figures are an estimate of the maximum rates likely to be feasible, as indicated in the comments.

9.6 Intermittent renewable generation

The integration of large amounts of intermittent renewable generation with other generation types is a contentious issue. The scale of intermittent renewables which can be connected to an electricity system has been subject to considerable debate, with wide-ranging estimates of the maximum feasible input from intermittent energy. Denmark's 20% of wind energy input is often quoted but, because of the strong link between Denmark and Germany, only 7% of energy supplied to the combined German and Danish systems is from intermittent renewable sources[53].

A large contribution of wind generation is foreseen to meet the EU Renewables Directive which requires that 15% of all energy use will be from renewable sources by 2020. The stated ambition of the government's consultation on the UK Renewable Energy Strategy[54] is to increase the level of renewable generation to 30-35% of electricity by 2020. At least 70% of this renewable energy is foreseen to be generated from wind.

[53] Bach P-F, 'Wind Power and Spot Prices: German and Danish Experience 2006-2008' 2009.
[54] Department of Energy and Climate Change, 'The UK Renewable Energy Strategy' 2009.

Table 9.5.1 Major power plant types likely to be installed in the UK to 2050

Type	Fuel	Typical efficiency (%)	Exhaust gas clean-up required	Despatch role	Typical unit capacity (MW)
Coal	Coal	35-45%	Dust/NOx/SOx	Mid merit – baseload	800
Coal with CCS	Coal	25-35%	Dust/NOx/SOx CO_2	Mid merit – baseload	800
Nuclear	Uranium	35%	Not applicable	Baseload	1,200-1,600
CCGT	Gas	58%	Not currently necessary	Mid merit – baseload	850
CCGT with CCS	Gas	48%	CO_2	Mid merit – baseload	800
Wind	Renewable	-	Not applicable	Not despatchable	2.5-7.5
Tidal	Renewable	-	Not applicable	Not despatchable	1,000-8,000 as 40 MW turbines
Biomass	Renewable	30-40%	Dust/NOx/SOx may be necessary	Mid merit – baseload	30-200

Table 9.5.2 Potential lead times and maximum build rates for different plant types

Type	Typical unit capacity (MW)	Lead time: decision to operation (years)	Indicative maximum build rate (MW/year)	Comment
Coal	800	6	1,500	Half of the peak build rate of the late 1960s, when the UK had four power plant suppliers
Coal with CCS	800	13	1,000	Build rate reflects combination of power and process plant and lead time for technology proving
Nuclear	1,200-1,600	11	1,500	Industry-estimated lead times have been extended by one year for legal challenges and two years for construction delays/shortages of key forgings. Build rate is the estimated capacity of the two major international suppliers to complete plant
CCGT	850	4	2,000	Build rate reflects the ‘dash for gas’ (1990-1997)
CCGT with CCS	800	12	1,000	Build rate reflects combination of power and process plant and lead time for technology proving
Open cycle gas turbine	25-60	3	600	Build rate estimated from PB’s international experience
Wind	2.5-7.5	3	800	Build rate based on completion of new UK wind plant during 2008
Tidal	1,000-8,000 as 40 MW turbines	10	2,000	Estimate based on data from current Severn Tidal Power Study

The UK electricity system must achieve high levels of reliability. For this reason, any variability from wind generation needs to be countered by a despatched response from the balance of generating plant, international interconnections, and any controllable demand or energy storage. The balance of generating plant currently includes approximately 3 GW of pumped-storage generation which can be brought into service within a few minutes, and around 1 GW of fast-starting simple-cycle gas turbine power plant.

The ability of the other generation connected to the system to compensate for wind variability is determined by the plant mix. Nuclear power plant is largely inflexible and unable to contribute; CCGT and thermal plant are moderately flexible; and simple-cycle gas turbine plant offers rapid start-up and flexible despatch.

With small-scale wind generation, the compensating changes required from the other generating plant to counter wind variability are small. As the wind contribution increases, the scale of responses required becomes greater and more difficult to deliver from other generating plant. With large-scale wind generation, the capability of conventional generating plant to increase output rapidly becomes a limitation.

Large penetrations of wind generation present another difficulty to the balancing of the electricity network. The frequency of the generated and distributed electricity in the UK is controlled to 50 Hz, within a small tolerance. Wind generating plant not only displaces plant that can be used to control network frequency, but it also contributes to frequency instabilities by having erratically variable output.

Parsons Brinckerhoff has analysed the effect of adding a large group of wind farms to the UK power system. Building on work by Oswald *et al*[55], we studied the impact of up to 30 GW of wind capacity distributed across the UK from north to south and from east to west, based on the data for real wind farms and historical meteorological data. The meteorological data was used to predict the hour-by-hour wind production for the wind estate. The model and the full analysis are detailed in appendix A5.

Combining the actual hourly consumer electricity demands with the predicted wind generation for the same period gives a net demand to be met by load-following generation. A sample of this pattern of demand, net of the output from 25 GW of wind capacity for January 2005, is shown in figure 9.6.1.

There are serious consequences of this highly variable demand, which has to be met by other generation. The impact of demand net of wind generation on a model of the current generation mix was evaluated for different scales of wind capacity.

With 30 GW of distributed wind capacity, the net demand was found to include some periods with sustained high rates of demand increase which exceeded the capability of the generating plant mix. Avoiding consumer disconnection under these conditions would require large transient imports or additional fast-response generating plant. It was estimated that 10 GW of additional fast-response generation would be needed to connect 30 GW of wind capacity without affecting reliability of supply.

It is unlikely that the 10 GW needed to accommodate the high wind penetrations would be met by building new pumped-storage facilities, given the high capital costs and limited candidate sites. The alternative of large transient import of power via international interconnections is challenging because of the scale of the transfer needed and the difficulty of scheduling back-up capacity at short notice.

The cost-effective fast-response power plant is likely to be open cycle gas turbines (OCGT)s. These have high carbon emissions but would need to operate for only a limited period each year.

The second consequence of high wind penetration relates to the utilisation factor of load-following plant. The analysis found that this utilisation factor falls almost linearly with installed wind capacity from over 50% with zero wind capacity to as low as 20% at 30 GW wind capacity. This reduced utilisation would apply even during peak demand months during the winter. The despatch strategy required to provide sufficient integrity of supply in the presence of large amounts of wind generation means that the utilisation of load-following conventional generating plant is much lower than current levels (see appendix A5).

Low utilisation has a significant impact on the choice of the lowest-cost power plant technology for the load-

[55] Oswald J *et al*, ‘Will British Weather Provide Reliable Electricity?’ 2008.

following role. At high utilisation, high-efficiency plant with lower CO_2 emissions but higher capital cost (such as coal with CCS) would offer the minimum life cost. At lower utilisation it is likely that lower-cost plant such as gas-fired CCGTs would be the preferred solution. At very low utilisation (around 20% or below) only simple-cycle gas turbines would be cost effective, and carbon capture would be unlikely to be feasible.

These adverse consequences of high wind generation have been recognised in the scenario analysis.

9.7 Forward demand

The forward demand for electricity from the UK economy is the sum of the demands of the sectors. This has been modelled for each different scenario. Scenario analysis allows carbon reduction strategies to be compared, and highlights the most effective reduction measures (see section 10).

The overall annual demand for electricity for each scenario must be matched by sufficient generating plant capacity to maintain the expected levels of security of supply. The mix of generating plant types is selected to achieve a balance of baseload, mid-merit and peaking capacity while reasonably minimising CO_2 emissions.

The electrical energy consumption of each scenario is matched by adjusting the despatch of the selected plant mix. The operation of the different plant types allows the CO_2 emissions of the electricity sector to be calculated. The process of matching the plant mix and its despatch to the overall electricity demand is described for the reference scenario as an illustration of the process applied to each scenario.

9.7.1 Reference scenario electricity consumption

The demand for electricity in each sector will be met partly by generation distributed within the sector and partly from electricity generated in the electricity sector. The electricity generated within the sectors for the reference scenario is shown in figure 9.7.1.1. The respective electricity demand for grid-supplied electricity from each sector is shown in figure 9.7.1.2. The total demand to be met by the electricity sector also includes an allowance for network losses, assumed conservatively to be 7% of consumption.

The aggregated demand for the reference scenario shows that demand from the domestic, industry and commercial sectors declines by about 50% by 2030. The demand from the transport sector however rises rapidly from 2015 to 2030 and then more slowly to 2050 when it represents 50% of demand due to the

Figure 9.6.1 Electricity demand net of 25 GW wind estate – January 2005

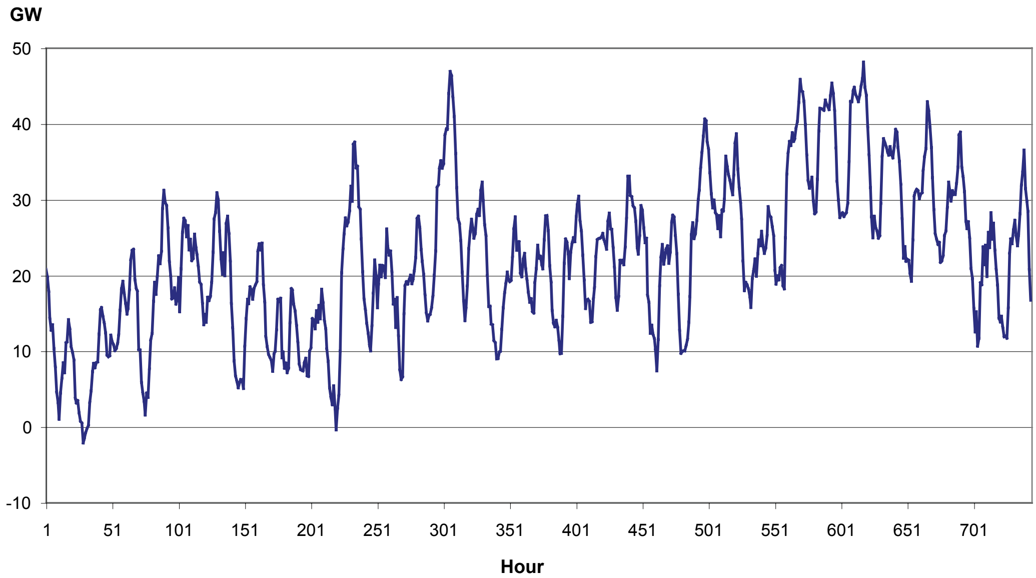


Figure 9.7.1.1 Electricity production from other sectors for the reference scenario

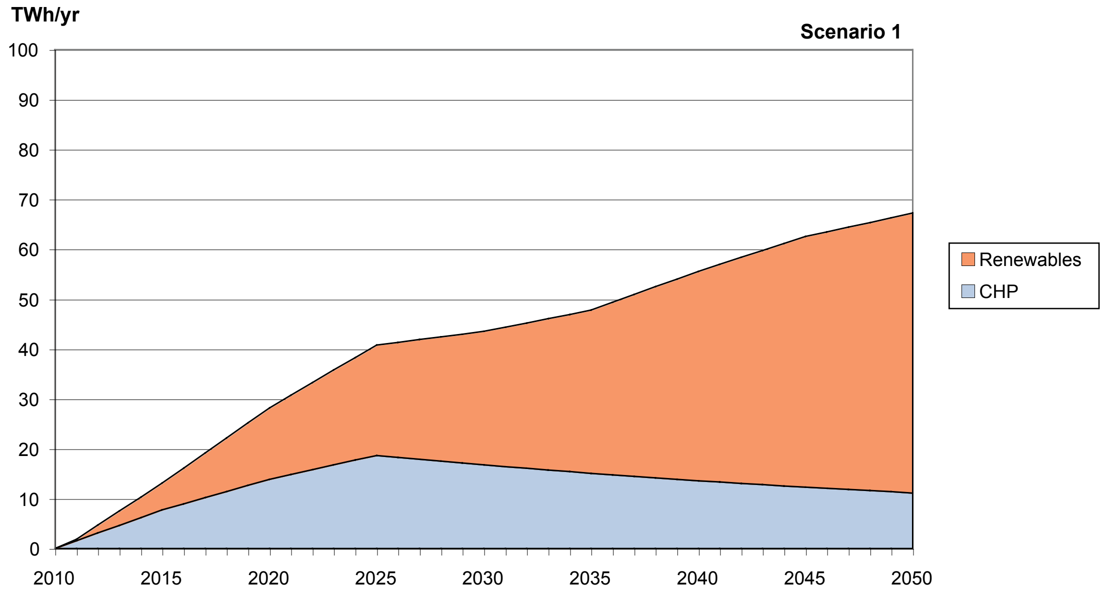
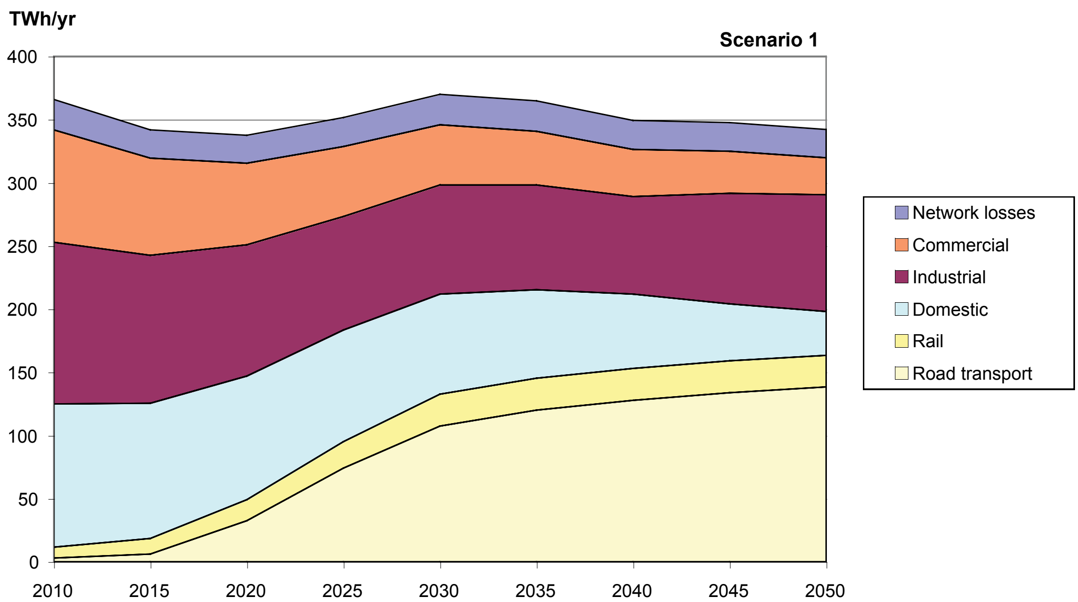


Figure 9.7.1.2 Electricity sector demand for the reference scenario



growth in use of electric vehicles. The total electricity consumption varies within a small range of +3% to -7% of current values during the period.

9.7.2 Reference scenario required capacity

Reference scenario required capacity is estimated from the annual total electricity consumption.

The magnitude of annual consumption and the pattern of demand determine the installed capacity required for a secure electricity supply. Current patterns of demand on the UK electricity system mean that the installed capacity has an utilisation of 49% (see figure 9.2.5). Future changes in demand patterns due to the flattening of daily peaks by 2050 are estimated to increase the utilisation to 62.5%.

This estimate is based on the pessimistic assumptions that the seasonal and weekly variability of transport energy demand will be similar to the current demands and that the measures applied in other sectors will not reduce the seasonal variability in demand pattern.

The trend of estimated annual average energy demand which will supply the annual consumption in one year, and the required installed capacity for the reference scenario, are shown in figure 9.7.2.1.

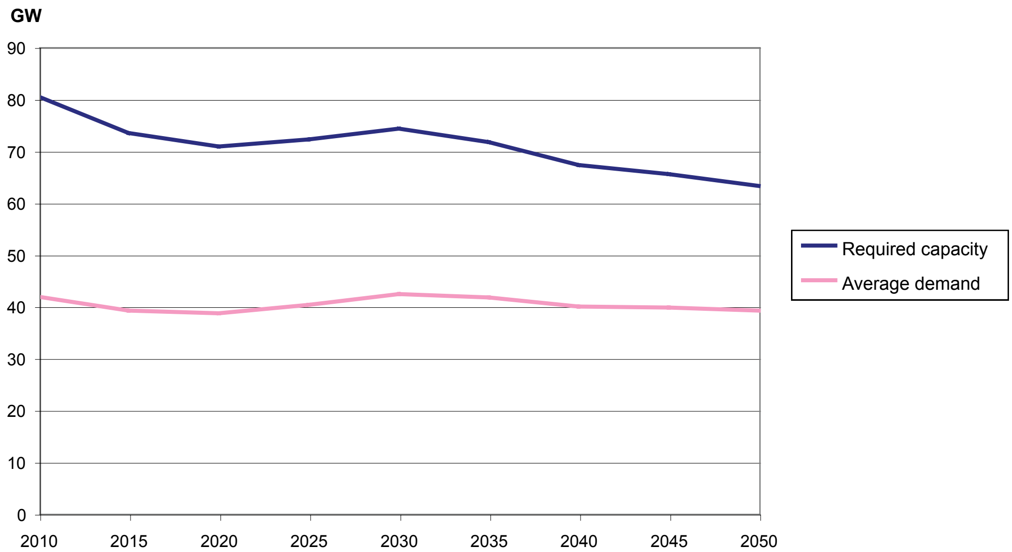
The analysis illustrated by figure 9.7.2.1 illustrates that while the average demand supplied by the electricity sector does not fall substantially by 2050, the required installed capacity declines by 20% because of changes in patterns of demand. This is technically attractive in allowing the more intensive use of equipment and results in substantial economies in plant and network investment. This will minimise the likely upward pressure on tariffs from increasing fuel costs and higher plant capital costs for carbon abatement.

9.7.3 Reference scenario new capacity

The capacity development assumptions of the reference scenario have been produced to provide adequate power capacity throughout the period while achieving a reasonable diversity of fuels and technologies. The resulting new capacity programme has been defined simply as a constant build rate to a maximum installed capacity for each type of plant. The date for the first generation of each type of new plant has been defined as the earliest date at which such plant could reasonably be expected to be in operation following a decision to procure by mid 2010.

The capacity development programme for the reference scenario comprises the types and scales of new plant construction detailed in table 9.7.3.1.

Figure 9.7.2.1 Annual average demand and required installed capacity for the reference scenario



The construction of new capacity for the reference scenario requires a high overall construction rate with a sustained completion rate of about 4.4 GW per year. This programme would present serious challenges to the UK construction industry in terms of the skills and resources needed to manage and implement the number of large projects, particularly in the context of a major international programme of carbon abatement. The scale of such construction work would be comparable to the annual construction industry capability for infrastructure for all sectors and would represent about 15% of the annual turnover of the construction industry[56]. Currently, power plant projects represent about 5% of the industry turnover.

9.7.4 Reference scenario total power generation capacity

The required new-build construction programme described above can be added to the forward capacity of the existing power plant, illustrated in figure 9.7.4.1, to give a future power capacity profile.

The new plant capacity profile has been chosen to ensure that the required capacity is met by 'firm' capacity, ie not subject to intermittency of renewables. This approach provides a margin of capacity for intermittency of embedded renewable generation within the sectors.

9.7.5 Reference scenario despatch of electricity generation

The power plant available in future will need to continue to be operated to satisfy the instantaneous system power demands. The plant will be scheduled to run on the conventional minimum marginal cost basis so that nuclear and renewable generation will operate throughout the year. Coal plant with carbon capture would be expected to be scheduled next and

Table 9.7.3.1 Capacity development programme for the reference scenario

Plant type	Target capacity (GW)	Construction rate (MW/yr)	Comment
Coal	0	-	Not included because of its significant adverse effect on sector CO_2 emissions.
Coal with CCS	12	1,000	Capacity included as application of CCS allows greater fuel diversity in the system. Construction rate is 30% of the rate of coal plant construction in the 1960s, when there was a large UK power plant industry.
Nuclear	20	1,200	Included because of its very low CO_2 emissions. Capacity selected to reflect a sufficient reactor fleet to create a viable industry without requiring the creation of new nuclear sites. Construction rate limited to approximately 80% of maximum potential, although this is 70% above the highest historical rate achieved for UK nuclear plant.
CCGT	28	1,800	Included as it offers a good balance of economy and CO_2 emissions and has the flexibility to be used efficiently as mid-merit or peaking plant. The target capacity avoids increasing the current peak gas demand for power over the period. Construction rate approximately 90% of the maximum rate during the 'dash for gas'.
CCGT with CCS	0	-	Not included in this scenario as further CO_2 emissions reduction is not required.
Wind	15	800	Wind capacity is allowed to grow to 15 GW to maximise use of resource without creating significant problems from wind intermittency. Construction rate reflects the rate of consumption of wind plant in 2007-2008.
Tidal	8	2,000	Included as representative of prospective tidal projects.

[56] Office for National Statistics, 'New Orders in the Construction Industry, February and April 2009' 2009.

then, filling the remaining demand, gas turbine-based plant would meet the peak demands. After about 2030, peaks within the day will be managed by the control of vehicle battery charging. In this way, 'peak' demand periods will be spread over at least 24 hours and probably correspond to the working days each week, with maximum demands occurring during the winter.

The total energy demand of the sectors and the losses in the electricity transmission and distribution system will be matched to the production of the electricity sector. The electricity sector model was run with utilisations of the various plant types adjusted to deliver an excess of production of about 3% above the consumption level forecast in the sectors. This does not correspond to 'spare electricity' but instead represents excess CO_2 emissions caused by non-ideal plant despatch.

Figure 9.7.5.1 shows the electricity sector plant despatch which matches the sector demand forecast net of the energy contributions of embedded CHP and renewable generation within the consuming sectors. The latter contributions are shown in figure 9.7.1.1, indicating that approximately half of the renewable generation is embedded in other sectors in the reference scenario.

The contributions to the generation of electricity in all sectors in this scenario in 2050 are coal = 16%, gas =14%, nuclear = 30%, and renewables = 31%.

9.7.6 Reference scenario electricity sector CO_2 emissions

The CO_2 emission profile corresponding to the assumed despatch of plant in the electricity sector is shown in figure 9.7.6.1.

The consequence of the despatch strategy adopted is that by 2050 the electricity sector achieves a reduction of approaching 85% of 1990 CO_2 emissions of the sector and is below 80% from about 2035. Significantly, in this scenario CO_2 emissions fall to below 50% of the 1990 level in about 2021.

Figure 9.7.4.1 Future capacity profile for the reference scenario

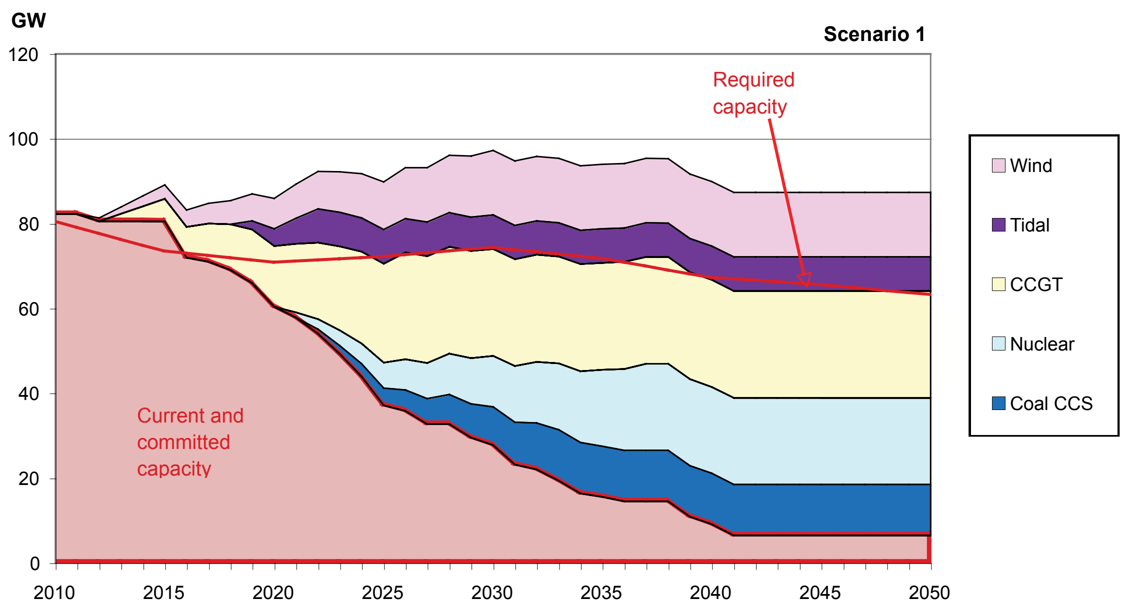


Figure 9.7.5.1 Generation contributions matched to consumption for the reference scenario

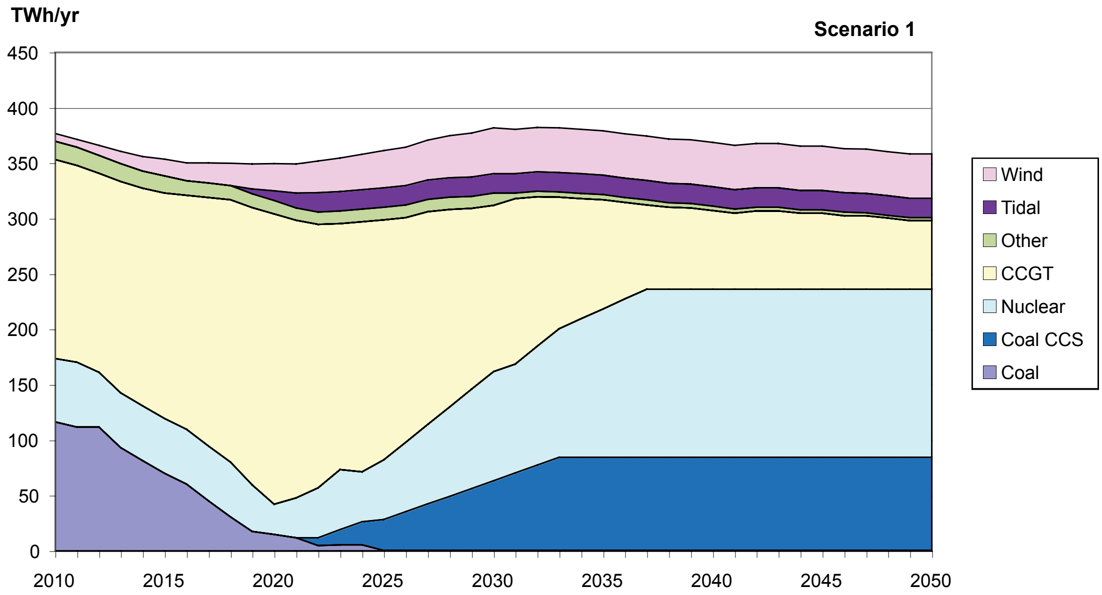
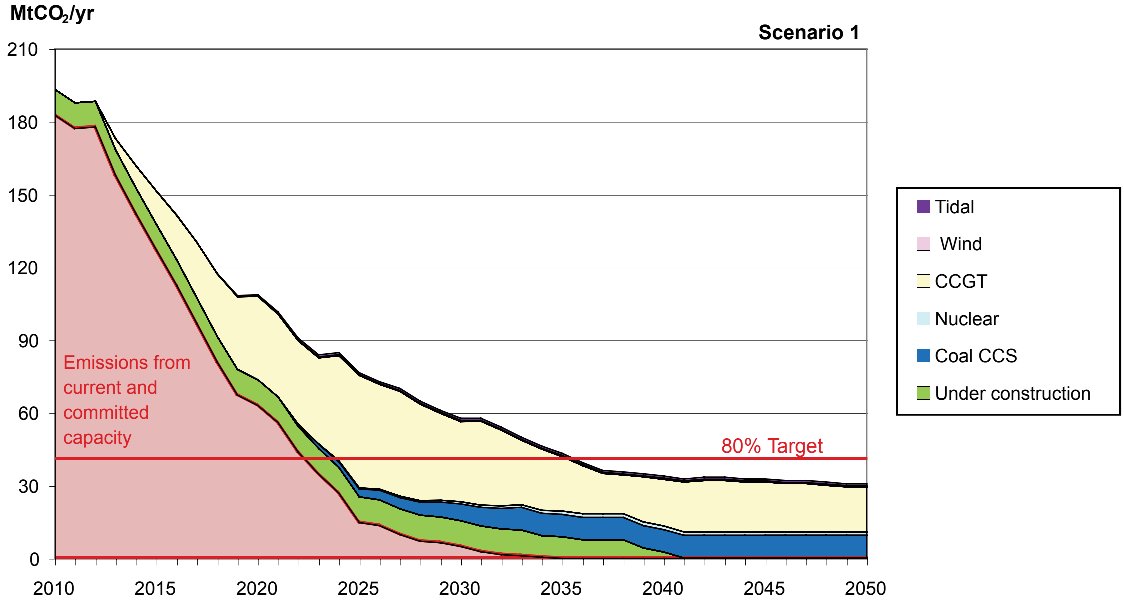


Figure 9.7.6.1 Electricity sector CO_2 emissions for the reference scenario



9.8 Sector-specific issues

1. UK generating capacity is forecast to fall to half of the current value by 2023. The rate of new plant construction necessary to maintain adequate capacity for reliable electricity supply from about 2020 is at least equal to the highest historical rate achieved by the industry. This new-build programme will not only have to meet capacity requirements but must do so while achieving CO_2 emissions commitments.

2. Transmission and distribution network system development will make a critical contribution to the implementation of the changes identified in this report. A holistic approach to the production, transmission, distribution and control of electricity production and demand will be essential if the transition away from intensive fossil fuel use is to be made successfully.

3. Renewable power generation will make a large contribution to future electricity production and is likely to include a significant component embedded within each sector, reducing production required in the electricity sector.

4. Intermittency in renewable power generation will be a major challenge and will require management through coordinated planning of generating plant types and capacities along with measures to control demand.

10. Scenario analysis

10.1 Introduction

There is a wide range of potential outcomes to the efforts to reduce CO_2 emissions in the different sectors. To provide a coherent assessment of some of the major directions that might be followed, Powering the Future adopts a scenario approach. The overall assumptions made for each scenario are applied consistently across all sectors. The scenario analysis evaluates the criticality of the various measures to the objective of the UK meeting its climate change commitments. The consequences of adopting alternative scenarios in terms of the overall level of CO_2 emissions and the extent to which the UK would then depend on critical technologies or fuels, are evaluated and compared.

The impacts of the following measures are evaluated in the scenario analysis:

- renewable heat
- large-scale application of CHP in industry
- radical energy efficiency improvement in industry
- improvement in building insulation
- adoption of electric vehicles for road transport
- nuclear power programme
- CCS in industry and power generation
- large-scale wind generation by 2020 or 2050
- extensive solar PV generation

The sensitivity of the level of CO_2 emissions to different rates of economic growth is tested in a further scenario to provide a yardstick for the scale of improvement offered by the measures.

10.2 Analysis methodology

The scenario analysis uses a reference scenario and 11 variations which test the sensitivity of outcomes to changes in selected measures or groups of measures. A reference scenario was defined as the basis for the scenario analysis, designed to achieve the climate change CO_2 emission reduction commitment by the application of selected measures consistently across all sectors. This approach was adopted to minimise the risk of failure through overdependence on the contribution of specific measures or sectors.

The reference scenario includes the following main measures:

- transfer of significant car travel to rail or bus services
- conversion of cars and LGVs to battery electric power
- intensive improvement in the insulation of existing homes, and commercial and industrial buildings
- application of biomass fuels for community heating and to replace domestic coal and oil heating
- solar hot water heating
- application of heat pumps in domestic and commercial buildings
- adoption of radically improved appliances and lighting technology
- improvements in industrial processes which will reduce absolute industrial energy use to 50% of 2006 levels by 2040
- embedded renewable power generation in industry, domestic and commercial sectors, rising to 46 GW PV and 6 GW from larger-scale wind by 2050
- new central power generation to include 15 GW wind, 8 GW tidal, 12 GW coal with CCS, 20 GW nuclear and 28 GW gas CCGT

The scenario analysis applies groups of CO_2 abatement measures defined for each scenario to the sector models. The sector behaviour in terms of fuel and electricity consumption and CO_2 emissions is then calculated according to measures applicable in each scenario, taking account of the interaction between measures and sectors. In this way, the effect that one measure has in reducing part of the sector energy consumption is properly reflected in the savings calculated for further measures affecting the same energy consumption. For example, improved thermal insulation in a commercial building will reduce the benefit of also applying a more efficient heating system.

For each scenario, the electricity consumptions of the sectors are aggregated. The types of generating plant in the electricity sector and their utilisation are selected to meet this aggregated demand while both reasonably minimising CO_2 emissions of the electricity sector and meeting criteria for diversity of energy source and reliability. The electricity sector CO_2 emissions are calculated from the utilisation of the various power plant types and aggregated with the emissions of the other sectors to derive the scenario overall CO_2 emission for the UK economy.

The fuel consumptions of each sector are finally aggregated in each scenario to allow the scale and distribution of primary energy use to be assessed.

The steps taken to model each scenario are summarised below:

1. Apply scenario measures as defined for each sector.
2. Combine the effects of measures on fuel demand, CO_2 emission and electricity consumption in each sector, accounting for interactions between measures.
3. Aggregate electricity consumption of sectors.
4. Match electricity sector plant mix and capacity to meet required reliability criteria.
5. Match electricity production with aggregated demand from other sectors.
6. Aggregate the fuel and CO_2 emissions from all sectors.
7. Calculate the sensitivity of CO_2 emissions to a 100% change in the measure tested by the scenario.
8. Present results in charts and/or tables.

10.3 Summary of scenarios

Each scenario is compared with the reference scenario and is summarised below.

Scenario 1 – reference scenario

A scenario that successfully meets the emissions requirements and is used as a baseline for comparison.

Scenario 2 – reduced renewable heat

The level of renewable heat (biomass heating and solar water heating) is reduced in all sectors by 50% compared with the reference scenario.

Scenario 3 – application of large-scale industrial CHP

The industry sector has the potential to host a substantial base of gas-fuelled CHP plant to provide the large amounts of heat used in the sector at lower temperatures for space heating, process heating, drying and similar. Extending the use of CHP to the feasible maximum has not occurred in many industries because of the limited return on the necessary investment. This scenario tests the impact on CO_2 emissions of adding 11 GW of such CHP capacity.

Scenario 4 – no new nuclear programme

The value to carbon emissions of the 20 GW nuclear programme included in the reference scenario is tested in this scenario, which excludes new nuclear power.

Scenario 5 – no CCS

At the scale of the large coal power plant assumed for the reference case, CCS is unproven technology. This scenario tests whether UK commitments can be met without this technology in either the industry or electricity sectors.

Scenario 6 – extends wind to 30 GW by 2020; scenario 10 – reduces wind generation by 5 GW

The targets set by the EU Renewables Directive call for 15% of UK energy demand to be met by renewable sources by 2020. The UK Renewable Energy Strategy responds to this by calling for 30% of electricity to be supplied from renewables by 2020. Scenario 6 applies this strategy as an acceleration of wind construction to supplement the existing wind and tidal capacity included in the reference scenario. Scenario 10 tests the value of the slower wind-build programme of the reference scenario by reducing wind capacity by 5 GW.

Scenario 7 – economic growth rate

The economic growth rate has been shown to have a significant effect on UK CO_2 emissions. The sensitivity of CO_2 emissions to GDP is tested by this scenario which uses a GDP of 2.5% average to 2050 compared with 1.5% assumed for the reference scenario.

Scenario 8 – building insulation

The reference scenario includes an aggressive reduction in the energy used to heat buildings, by applying improved insulation. This scenario examines the effect of only achieving 50% of the improvement of the reference scenario.

Scenario 9 – battery power adoption by cars and vans

The reference scenario demands that a high proportion of vehicle fuel use is converted to electricity by adopting battery and plug-in hybrid vehicles. This scenario tests the impact of reducing the level of adoption so that the reduction of fossil fuel consumption by cars and vans falls from 78% to 50% of the ‘business as usual’ case.

Scenario 11 – PV electricity

PV electricity production in the domestic, commercial and industry sectors is assumed to grow to 46 GW by 2050 in the reference scenario. The sensitivity of CO_2 emissions to the level of PV generation is tested

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in this scenario, which assumes a 50% reduction in PV generation compared with the reference scenario.

Scenario 12 – unspecified industrial efficiency improvements

Because of the diverse nature of industrial processes, the reference scenario has assumed that unspecified improvements in efficiency from new industrial processes will reduce energy use, and hence CO_2 emissions, by 50% by 2040. This scenario tests the effect of omitting these unidentified improvements.

10.4 Results

The results of each scenario in terms of 2050 CO_2 emissions and power production required in the electricity sector are shown in table 10.4.1.

The reference scenario has the following characteristics:

- achieves the 80% CO_2 reduction by 2050, with reductions of 34% by 2020 and 65% by 2030
- applies lower confidence and potentially more costly carbon abatement technologies, such as CCS, at the lowest feasible level
- requires historically high rates of new generating plant construction to maintain reliable electricity supplies
- requires the largest credible implementation of all selected measures across the different sectors
- reduces consumption of all fossil fuels and depends on none for more than 25% or less than 12% of total primary energy consumption

The review of the results of the scenario analysis can be considered from two perspectives: as a test of the acceptability of each as an alternative to the reference scenario, and as a means of evaluating each measure for its effectiveness. Both of these alternative methods will be used to highlight significant results of the scenario analysis.

Table 10.4.1 Scenario CO_2 emissions and electricity production in 2050

Scenario number	Description	CO_2 emissions ($MtCO_2$/yr)	CO_2 emissions (% target)	Electricity sector production (TWh/yr)
1	Reference	111	99%	369
2	50% reduction in renewable heat	127	114%	380
3	Addition of 11 GW industrial CHP	111	99%	290
4	Omits 20 GW nuclear power programme	123	110%	370
5	Omits CCS in electricity and industry sectors	138	123%	369
6	Extends wind to 30 GW and brings forward to 2020 as per the UK Renewable Energy Strategy	109	97%	369
7	Increases economic growth rate by 1% to 2.5%	131	117%	431
8	Omits 50% of building insulation energy reductions	125	111%	378
9	Reduces transfer of vehicle energy to electricity by 28%	151	134%	308
10	Reduces wind generation by 5 GW	113	101%	371
11	Reduces solar PV generation by 50%	111	99%	393
12	Omits industrial 50% efficiency improvement by 2040	161	143%	485

10.5 Review of scenario results

Figure 10.5.1 shows the carbon emissions in 2050 for each scenario, while figure 10.5.2 shows the total 2050 fuel consumption for each scenario.

Comparing the scenarios with the reference scenario, the following observations can be made:

Scenario 2 – reduced renewable heat

This scenario assumes a reduced application of renewable heat technologies (biomass and solar heating). This results in an increase in CO_2 emissions of 16 $MtCO_2$/yr, caused by the increased combustion of fossil fuels and a small increase in electricity demand as a result of the reduction of biomass-fuelled CHP electricity generation.

Scenario 3 – application of large-scale industrial CHP

This scenario explores the impact of extensive application of CHP in industry. The result is a small overall increase in CO_2 emissions due to the significant extra electricity that has to be generated by fossil fuels, but an overall reduction in fuel consumption as CHP power generation is more efficient than the coal CCS or CCGT plant otherwise required.

A key issue for this scenario is the substantial cost to industry of applying CHP. Since European competition regulation prohibits direct government support for industry, funding would need to be generated by industry or sourced though more complex and uncertain mechanisms such as carbon trading. The creation of a simple and effective mechanism to assist industry in investing in this technology will be essential if it is to be adopted more widely.

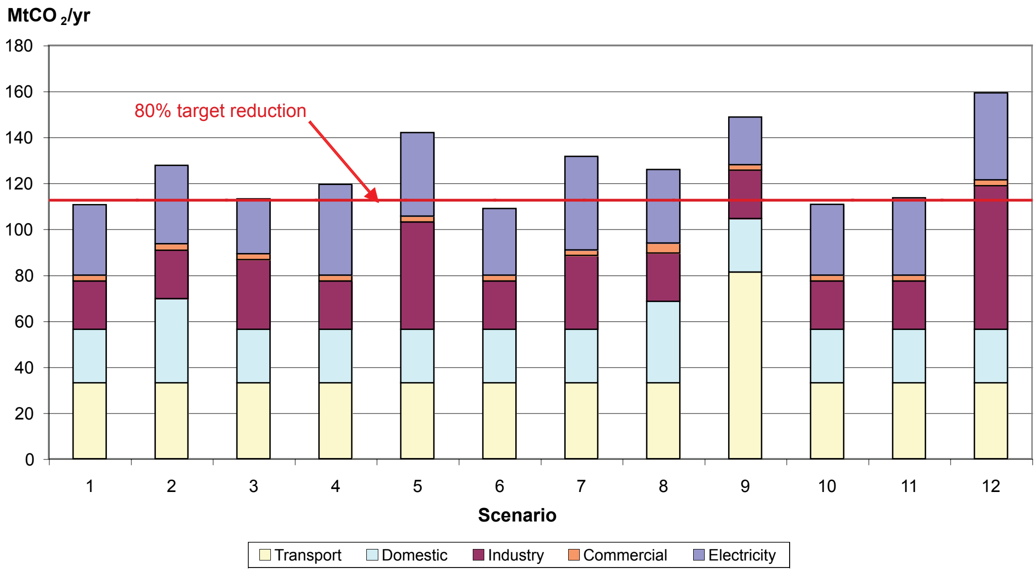
Scenario 4 – no new nuclear programme

If no new nuclear power plant were to be constructed, the electricity sector would substitute additional coal CCS and gas-fuelled CCGT plant to replace the nuclear capacity.

CO_2 emissions within the electricity sector are managed by increased application of carbon capture, both to the increased coal-fired capacity and to around half of the gas-fired CCGT capacity. This increased application of CCS may not be economic given the relatively low load factor of the load-following plant. Indeed, even the feasibility of using CCS with plant with load factors as low as 25% is not known at the current stage of development of the technology.

Despite the increased use of carbon capture, the scenario exceeds the 80% CO_2 emissions reduction commitment by a modest 12 $MtCO_2$/yr. Since the nuclear energy is replaced by coal and gas,

Figure 10.5.1 CO_2 emissions of each scenario in 2050



dependence on these fuels would be increased by 60% and 30% respectively.

One adverse consequence of omitting a nuclear programme is a dependence on CCS technology to manage over 50% of carbon emissions. Given the current stage of development of CCS technology, such dependence could represent an unacceptable level of risk of failure to achieving the CO_2 emission commitments.

Scenario 5 – no CCS

CCS technology is not yet a proven technology on the scale of a typical power plant, but is seen to be an important part of the solution to CO_2 emissions. This scenario examines the impact of this technology not proving viable, by assuming that no carbon capture will be used as a carbon abatement measure in either the electricity or industry sector.

The scenario assumes that the electricity that is no longer available from carbon capture coal plant is met by increasing nuclear and gas-fired CCGT capacity, these being the options best able to minimise CO_2 emissions from the electricity sector.

The scenario analysis shows that, without CCS, CO_2 emissions from the industry sector alone in 2050 bring non-electricity CO_2 emissions close to the 80% reduction target. With the unavoidably increased emissions from the electricity sector, the overall CO_2 emissions exceed the target by 27 $MtCO_2$/yr, more than 24% above the commitment level.

The balance of fuel consumed by the UK economy is somewhat altered in this scenario, with coal consumption declining by 75% and nuclear increasing by 30%; gas, however, only increases by 3% over the reference case.

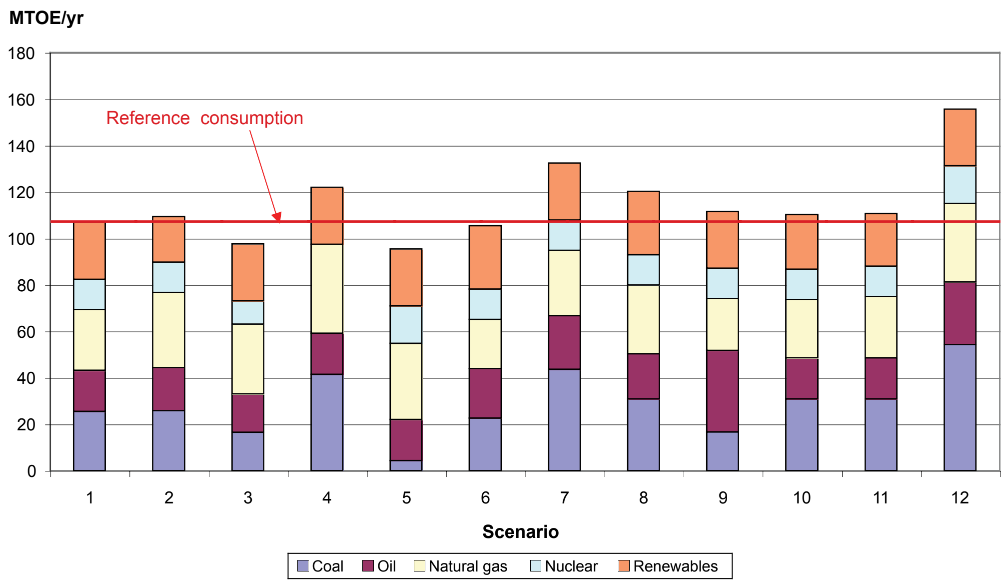
The outcome of this scenario emphasises the need for the development of CCS technology and illustrates its critical role in delivering the CO_2 reduction commitment.

Scenario 6 – extends wind to 30 GW by 2020

In this scenario, the rate of construction of wind generation in the electricity sector is increased to at least four times the historical maximum levels to achieve a capacity of 30 GW by 2020.

The first consequence of the large increase in wind capacity is the need to install 9 GW of oil-fuelled OCGT plant by 2020. This will provide rapid-response generation to manage the large dynamic mismatches that can arise between generation and demand.

Figure 10.5.2 Fuel consumptions of each scenario in 2050



The second consequence is that the much-reduced baseload demand can only support the strategically necessary nuclear plant and 10 GW of coal CCS. All other generation will be load-following at a low load factor. Part of this duty is met by 10 GW of CCGT plant, but the rest is oil-fired OCGT plant. The capacity of OCGT plant increases to 18 GW by 2050.

The results of this scenario are that carbon emissions are reduced to 2.5% below the commitment level by 2050 and are only 97% of the reference scenario in 2020. Electricity from renewable sources reaches 29% of total consumption in 2020.

The balance of fuel consumption in the UK economy is significantly different in this scenario: it has only 90% of the coal consumption and 80% of the gas consumption but 120% of the oil consumption of the reference scenario.

The increased level of oil dependence in this scenario is a consequence of applying a high level of renewable generation early in the period. The increased generation by renewables at this early stage undermines the viability of alternative lower-carbon generation technologies, blocking future options for further carbon reductions. These adverse effects suggest that strong emphasis on early renewable electricity production can restrict future options, while offering no significant longer-term advantages in terms of CO_2 emission reduction.

Scenario 7 – economic growth rate

The increased economic growth rate in this scenario produces significantly increased emissions, particularly in the industry and electricity sectors, as increased economic activity results in higher energy consumption.

The additional electricity demand is met by more rapid construction of a larger programme of 20 GW of coal CCS plant, while gas-fired CCGT is reduced to 19 GW to minimise emissions. The load factor of the CCGT plant is increased by adding 10 GW of oil-fired OCGT to provide the economic peaking capacity necessary for reliable system operation.

The increased economic activity pushes the CO_2 emissions above the 2050 commitment level, increasing them by nearly 20% above those of the reference scenario.

The fuel consumption profile is substantially altered in this scenario: coal consumption is increased by 70%, oil by 30% and gas by 8%, compared with the reference scenario.

Scenario 8 – building insulation

The omission of 50% of the improvement in building insulation included in the reference scenario results in significantly increased fuel and electricity consumption and therefore CO_2 emissions.

The scenario attempts to minimise the increase in carbon emissions in other sectors by adjusting the electricity sector generation mix. The capacity of coal CCS plant is increased to 15 GW while the CCGT plant is reduced to 20 GW. The smaller capacity of medium-duty CCGT plant is supplemented by 8 GW of OCGT capacity to provide the economic peaking capacity.

Despite the measures adopted, the scenario exceeds the CO_2 emission reduction commitment level by 12%.

The fuel consumption pattern for the scenario is increased above the reference scenario, with coal consumption increased by 20%, oil by 10% and gas by 13%.

The results show that this measure is critical to achieving the CO_2 reduction commitment. Because of the diverse ownership of buildings and the wide range of building types, stronger leadership and better-targeted strategies will be required in order to make this measure effective.

Scenario 9 – battery power adoption by cars and vans

This scenario assumes reduced adoption of electric vehicles from high to medium penetration, representing a drop from 78% to 50% of road transport fossil fuel being displaced by electricity. This change increases fossil fuel consumption and emissions from the transport sector while reducing demand on the electricity sector.

The reduced electricity demand is met by reducing the coal CCS capacity to 7 GW and CCGT plant capacity to 16 GW while adding 4 GW of OCGT to provide peaking capacity.

Despite the small reduction in CO_2 emissions from the power sector, the increase in transport emissions causes the overall CO_2 emissions in 2050 to exceed the commitment level by 39 $MtCO_2$/yr, or by over 35%.

The additional fossil fuel consumption in the transport sector radically alters the profile of fuel consumption for this scenario in 2050, so that while coal consumption is reduced by 35%, oil increases by 100% and gas is reduced by 15% compared with the reference scenario. Fuel dependence is increased, with oil representing 30% of primary energy consumption.

The switch of road transport to electricity can be seen to deliver a large reduction in CO_2 emissions but will require radical changes to be made. A comprehensive and coordinated strategy for implementation will be essential if the necessary carbon reductions are to be delivered to meet the overall 2050 commitment.

Scenario 10 – reduces wind by 5 GW
The reduction of wind generation in the electricity sector is compensated by increasing the coal CCS capacity from 12 GW in the reference scenario to 13 GW.

The shift of electricity production from wind results in only a marginal change in CO_2 emissions compared with the reference scenario.

The fuel consumption profile of this scenario is only significantly changed from the reference scenario by an increase in coal consumption of 10%.

Scenario 11 – solar PV
The solar PV generation of the reference scenario is halved in this scenario. The reduction of electricity production is balanced by increasing the coal CCS capacity to 15 GW.

The reduction in electricity generated by solar PV causes a small increase in CO_2 emissions in 2050 compared with the reference scenario, exceeding the commitment level by 2%.

Fuel consumption is increased: coal consumption by 20% and gas by 1%.

Scenario 12 - unspecified industrial efficiency improvements
In this scenario, the 50% improvement of industrial process energy efficiency by 2050 assumed in the reference case is excluded. There is a substantial increase in fuel consumption and carbon emission in the industry sector and increased electricity demand on the electricity sector.

The increased electricity demand is met by increasing the coal CCS capacity to 24 GW, nuclear capacity to 25 GW, and OCGT capacity to 10 GW. The contribution of the OCGT enables the gas CCGT capacity to be reduced to 22 GW.

CO_2 emissions are increased by 50 $MtCO_2$/yr compared with the reference scenario, exceeding the commitment level by 42%. The CO_2 emission increase is dominated by the 42 $MtCO_2$/yr additional emissions by the industry sector.

The fuel consumption profile is significantly affected in this scenario, with coal consumption increased by 105%, oil by 50% and gas by 30%. Fuel dependence rises, with coal increasing to over one third of primary energy supply.

The significant adverse effects of omitting these improvements in industry indicate that the challenging issue of delivering radical and sustained improvements needs to be addressed. The improvements will incur considerable capital expenditure. In the competitive international marketplace, significant contribution by government will be required to avoid the damaging economic and environmental impacts of industry being compelled to migrate production overseas. Such expenditure may require changes to European law to permit the necessary interventions without breaching EU competition regulations.

10.6 Review of effectiveness of measures
The scenarios test the effect of selected changes in penetration of particular measures on CO_2 emissions and fuel consumption patterns. Since the changes in penetration of the measures are not the same, a further stage of analysis is applied to normalise the results. This allows a proper comparison of the value of the measures tested in the scenario analysis in reducing CO_2 emissions. The results of this analysis are shown graphically in figure 10.6.1.

This analysis highlights those individual measures which are critical to delivering the desired emission reductions. Since the reference case applies CO_2 emission reduction measures at the maximum credible level in each sector, the omission of one large-value measure cannot be compensated in any other sector, causing a major breach of the 2050 CO_2 emission commitment. One feature of this analysis is that alternative low-carbon measures in the electricity sector appear to have low value, which belies their collective importance (100 $MtCO_2$/yr emissions).

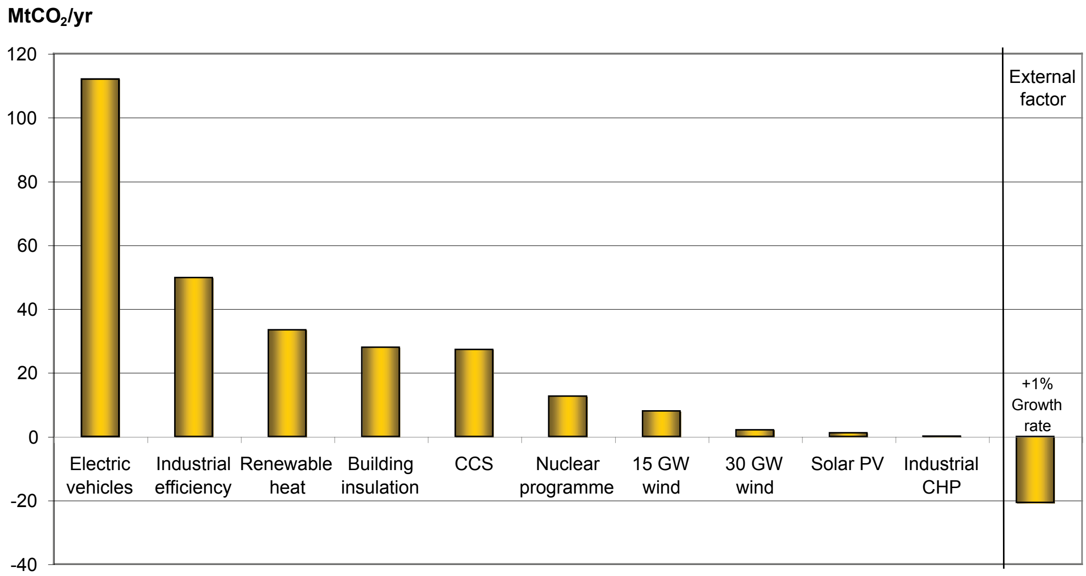
The chart shows beyond doubt that the impact of conversion to electric vehicles is such that high priority should be given to converting the maximum number of vehicles by 2050, despite the increase in electricity consumption.

The significant impact of industrial energy efficiency improvement is also highlighted. The task of halving energy consumption while maintaining economic growth, combined with the diverse nature of industry, means that substantial change in industry is likely to require more than complex market incentives. Since the reference scenario assumes that the maximum improvements are achieved in every sector, there are no effective alternatives in any sector to compensate for failure to achieve the necessary improvement in industry. Such a failure would result in the 2050 commitment level being radically exceeded.

The analysis demonstrates the significance of a group of measures of similar importance: renewable heat, building insulation and CCS. Together these measures represent close to 100% of the carbon emissions reduction commitment and are therefore critical to achieving it. Renewable heat, ie the use of biomass and solar energy for heating, is a recently identified element of government strategy. The importance of this measure is demonstrated here and is found to be strongly dependent on the effective use of our limited biomass fuel resources. These resources should be directed towards heating and CHP applications which make maximum use of the available renewable energy.

Radical improvement in the level of insulation of existing homes and business premises can be seen to be very important. The necessary level of improvement

Figure 10.6.1 Value of CO_2 reduction measures in 2050



is demanding and will require technical, economic and social support to ensure that effective measures are applied progressively to a very high proportion of existing buildings in the period to 2050.

CCS technology has the potential to cut CO_2 emissions in both the industry and electricity sectors. It is important that the current programme to apply the technology to power generation is extended to industrial processes. Appropriate support should be given to ensure that the capture of unavoidable carbon emissions from key industrial processes does not make it uneconomic for them to operate in the UK. The alternative – effectively forcing these processes offshore to locations which allow a more limited abatement of CO_2 emissions – will be entirely counterproductive from the perspective of climate change.

Taken separately, the nuclear programme, PV generation and wind have a relatively low value as CO_2 emission reduction measures. This counterintuitive result is a consequence of the similarity in CO_2 emissions of this group of power generation technologies. Thus, for example, a reduced wind contribution can be compensated by an increased application of nuclear generation, or vice versa, with little change in CO_2 emissions. This result means that, from a CO_2 emission perspective, these measures are valid alternatives and that the choice or balance between them needs to be made on other grounds such as cost, fuel availability, and reliability and security of electricity supply. In fact, the collective contribution of these measures is essential, offering over 100 $MtCO_2$/yr reduction in electricity sector emissions.

The small value for large-scale CHP is somewhat unexpected. It reflects the declining value of gas-fuelled CHP as a CO_2 reduction measure when the carbon intensity of electricity produced in the electricity sector is radically reduced by 2050. The review of the results for 2020 in figure 10.6.2 enables CHP to be placed in a proper perspective.

Figure 10.6.1 also provides a yardstick for the various measures in the form of a sensitivity comparison for a 1% increase in average economic growth rate.

The sensitivity of outcome to economic growth rate suggests that the level of application of measures is likely to require adjustment during the period to correct for changes in actual economic growth rate.

The scenario analysis enables the value of measures to be assessed at different dates during the period to 2050. Figure 10.6.2 shows the calculated value of the measures in 2020. Clearly their overall impact is lower, because of the practical rates of implementation of the measures assumed in our model.

A surprising result is that the value of building insulation in 2020 is comparable to its value in 2050 showing that this measure should be applied vigorously from the outset. The value of efficiency improvements in industry and the introduction of electricity to road transport are also seen to be high, deserving early and intensive work in their respective sectors.

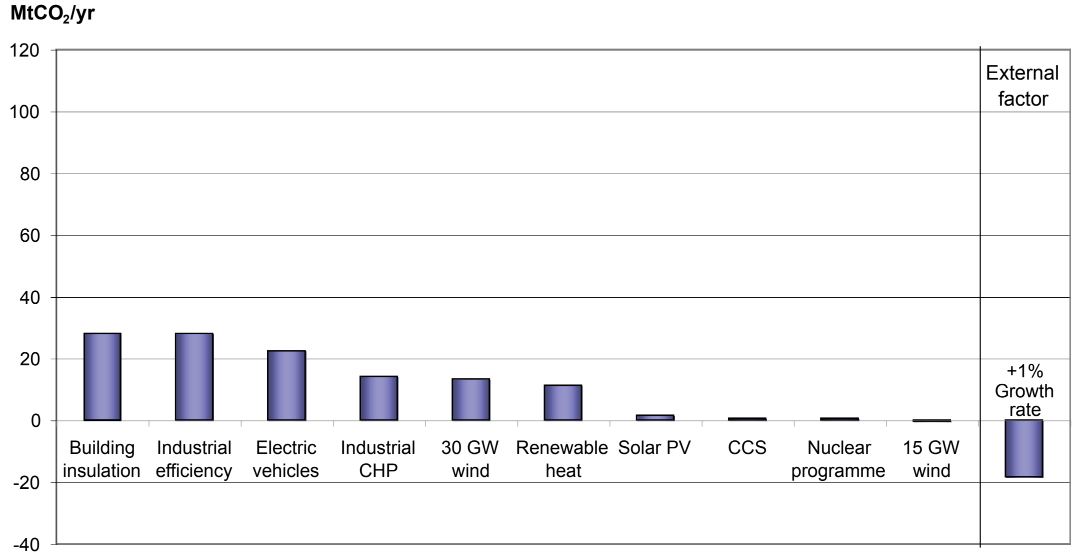
Industrial CHP has a significant and positive value in 2020 which actually continues to increase until about 2030. At this point the declining carbon intensity of production in the electricity sector generally starts to reduce the value of the measure to overall carbon emissions. This indicates that the application of CHP in industry before 2025 is likely to be a valuable measure, whereas its later application is unlikely to contribute useful CO_2 reductions.

In 2020, large-scale wind generation can be seen to have CO_2 benefits comparable to those for renewable heat. However, the large scale of implementation of wind is accompanied by the intermittency issues discussed earlier, requiring substantial additional fast-response balancing facilities to ensure the stable operation of the grid. Greater long-term benefits in terms of CO_2 emissions are seen to derive from renewable heat rather than early application of large-scale wind generation.

Other measures including CCS, solar PV and new nuclear generation all offer limited benefits in 2020 as their scale of penetration is too limited to contribute significantly to CO_2 reduction.

The contrast between the results for 2020 and 2050 highlights the serious risk that early short-term technology policy decisions may have unintended and negative effects on the UK's total CO_2 emissions in the longer term. It is essential that policies promoting particular measures are prepared in the light of longer-term strategy. In this way, opportunities for carbon reduction are exploited without blocking the future application of technologies which offer greater long-term reductions. Failure to coordinate strategy within and across the different sectors risks creating stranded assets and wasted resources. This reduces the likelihood of the UK achieving its challenging commitments, relinquishing the potential for international leadership, and weakening the international drive to limit the risk of catastrophic climate change.

Figure 10.6.2 Value of CO_2 reduction measures in 2020



Appendix A1.
Transport sector

The following measures are assessed for the transport sector:

- reduced road travel
- switch to biofuel
- switch cars, LGVs and buses to battery
- switch HGVs to electricity
- switch cars to hydrogen

A1.1 Reduced road travel

Many car journeys could be avoided by switching to public transport. We considered the impact of policies that encourage the use of buses or trains instead of cars.

We evaluated a range of cases, from a modest switch of 15% to a high figure of 40% by 2050, assuming a linear decline in car use between 2015 and 2030. The reduction in car use was balanced by the increased fuel consumption by public transport as a result of extending routes and providing a sufficient service to justify the reduced car usage. We assumed that in urban areas the energy saving in cars would be balanced by an increase in bus or rail energy use equivalent to one eighth of the car fuel saving; in rural areas, where routes are more widespread, we assumed one quarter of the car fuel saving.

The result of the analysis is shown in figure A1.1.1.

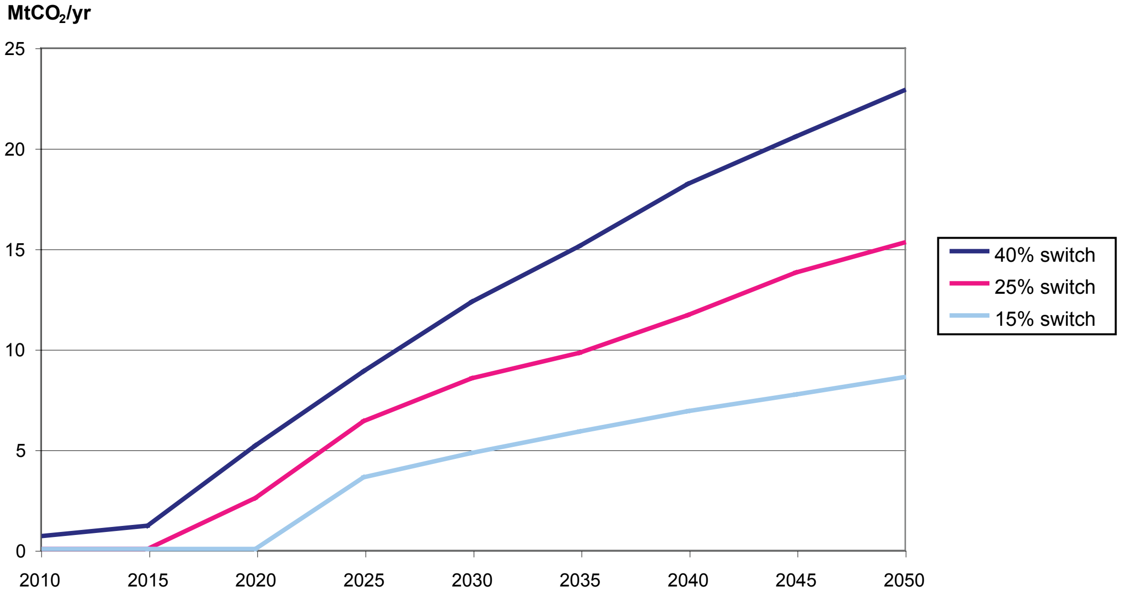
The reduction in CO_2 emissions from this option is substantial. But a switch of even 15% will be difficult to achieve because of the likely resistance from car drivers and the need to at least double the scale of public transport services and route coverage.

A1.2 Switch to biofuel

Biofuels are derived from agricultural crops, forest material or agricultural waste, which are used to produce bioethanol and biodiesel. The fuels derived from these sources can be used as a substitute for at least part of the diesel or gasoline content of transport fuels. Since the carbon in biofuels is derived from recently living material, it is considered to have a neutral effect on atmospheric CO_2 levels when burned.

There are serious concerns that processing the raw materials to produce biofuels involves the intensive use of energy and petroleum products, increasing the fossil CO_2 emissions attributable to the resulting fuel. In addition to these reservations, it has become apparent that, even with the scale of production achieved in 2007, biofuels derived from agricultural products such as maize or palm oil competed with food production.

Figure A1.1.1 CO_2 emissions reduction from switching to public transport



This competition causes the prices of staple commodities to rise significantly and increases the pressure for damaging deforestation so that agriculture can be extended into new areas. Such considerations have rendered the expansion of biofuel production – and its value as a low-carbon fuel – highly contentious.

These concerns mean that a wholesale switch to biofuels is no longer considered feasible. For the purposes of this study, we have therefore evaluated a limited switch of up to 15% biofuel for cars. The switch of fuel has been assumed to reach 5% by 2025, 10% by 2035 and 15% by 2045, corresponding to the low, medium and high cases respectively.

The impact of this switch is shown in figure A1.2.1.

The result of the switch to biofuels is substantial but the scale of the switch is restricted by what would be considered an acceptable impact of biofuel production on other land uses.

A1.3 Switch cars, LGVs and buses to battery

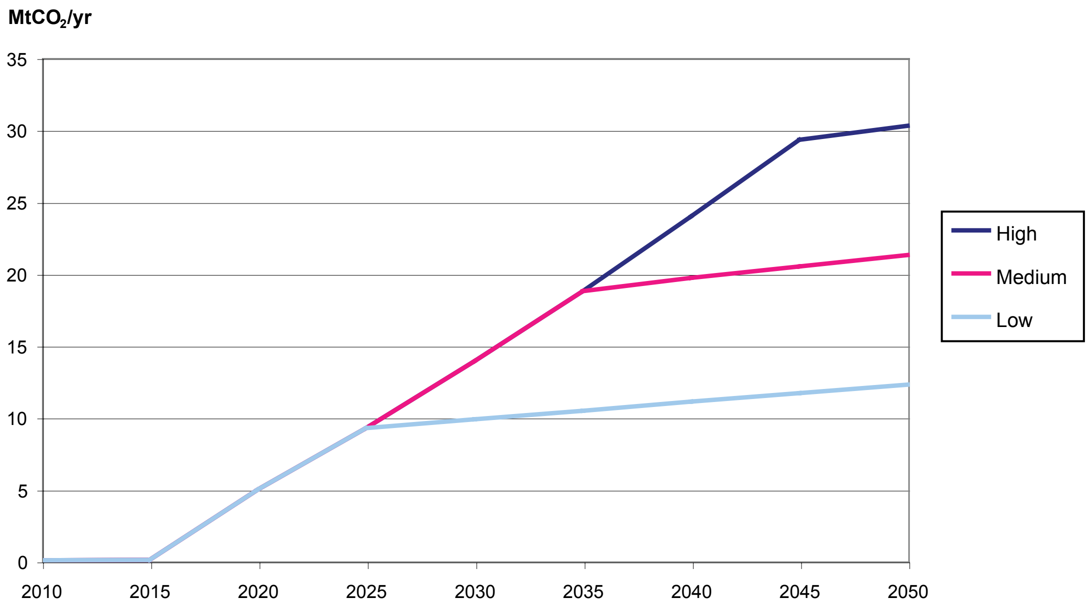
Substituting electricity as the energy source for vehicles is attractive as it enables a wider range of sources of energy to be used for transport, instead of just petroleum-derived fuels. This flexibility is helpful in reducing overall CO_2 emissions provided that sources of electricity with small CO_2 emission footprints can be used, such as renewable or nuclear power.

It is not feasible to directly replace oil-based fuels with electricity, as it would require every vehicle to have access to electricity at every point in its journey. Indirect replacement requires electrical energy to be converted to an intermediate form that can be converted to electricity when required. There are two intermediates which appear to be feasible within the period of interest to this study: chemical energy within a battery, as reviewed here, or chemical energy in the form of hydrogen, considered in A1.5.

This study has assumed three levels of penetration of battery electric vehicles. For battery-powered cars, LGVs and buses, the cases are detailed in table A1.3.1. These alternative levels of fuel substitution reflect different assumptions about the take-up of electric or plug-in hybrids.

We have assumed that commercial vehicles will adopt the battery electric power option before privately owned cars, as faster vehicle turnover and sensitivity to

Figure A1.2.1 CO_2 emissions reduction from switching cars to biofuel



economy of operation among competing commercial operators can be expected to drive change more quickly.

The reduction in emissions for switching cars to battery is shown in figure A1.3.1.

The corresponding impact on electrical energy required for battery charging is shown in figure A1.3.2. A similar analysis for the switch of LGVs to battery shows that CO_2 emissions would reduce rapidly until 2025 and then follow the increasing demand from the growth of such vehicles. In 2050, reductions in CO_2 emissions would reach 37, 23 and 9 $MtCO_2$/yr for the high, medium and low cases respectively. The corresponding rise in electricity consumption would be 39, 24 and 9 TWh/yr by 2050.

The adoption of battery power by buses is found to offer a relatively small reduction in CO_2 emissions, but one which can be quickly achieved by 2020, rising to 3.8 $MtCO_2$/yr for the high case by 2050. The corresponding additional electricity demand increases to just over 4 TWh/yr by the same date.

Aggregating the reductions in emissions for cars, LGVs and buses gives a total reduction in CO_2 emissions for switching to battery electric power as shown in figure A1.3.3.

The corresponding increase in electricity consumption is shown in figure A1.3.4.

A1.4 Switch HGVs to electricity

HGVs represent about 20% of road transport fuel use but are unlikely to be suitable for conversion to battery electric power since their power and range requirements are significantly beyond current and foreseeable battery technology. Other than conversion to biofuel – which is restricted by limited biomass availability – there appears to be no readily available technology to radically reduce carbon emissions from HGVs. In order to assess the value of a future technology shift, the potential magnitude of benefit from such an advance must be evaluated.

We have used a conceptual option to evaluate the magnitude of savings potentially available from converting the energy source for HGVs. This concept would deliver electricity to hybrid HGVs via overhead lines (OHL) on motorways and primary routes.

Table A1.3.1 Fuel substitution assumptions for battery electric vehicles

Vehicle type	Case	Rural	Urban	Timing
Cars	High Medium Low	70% 40% 10%	95% 60% 30%	10% by 2015 90% by 2030
LGVs	High Medium Low	70% 40% 10%	95% 60% 30%	10% by 2015 90% by 2025
Buses	High Medium Low	70% 40% 10%	95% 60% 30%	10% by 2015 90% by 2025

Figure A1.3.1 CO_2 emissions reduction from switching cars to battery

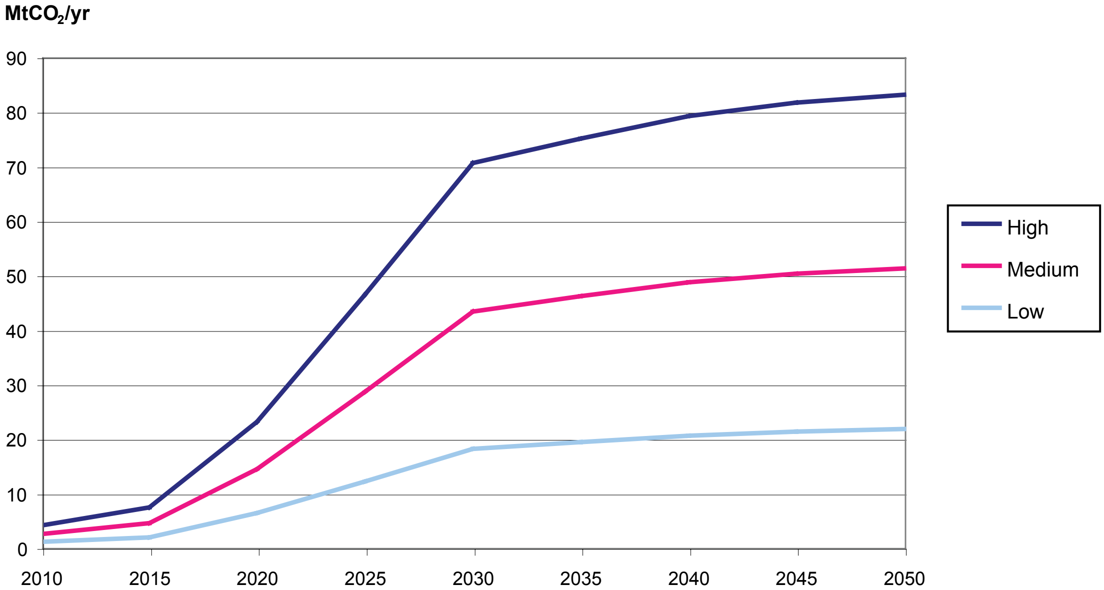


Figure A1.3.2 Increase in electricity consumption from switching cars to battery

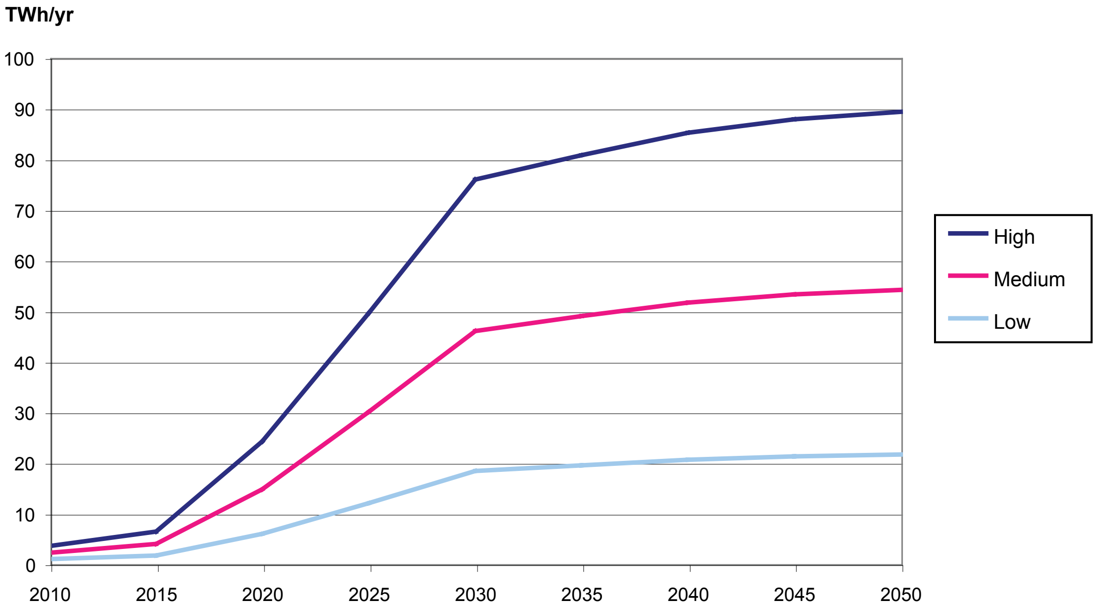


Figure A1.3.3 CO_2 emissions reduction from switching cars, LGVs and buses to battery

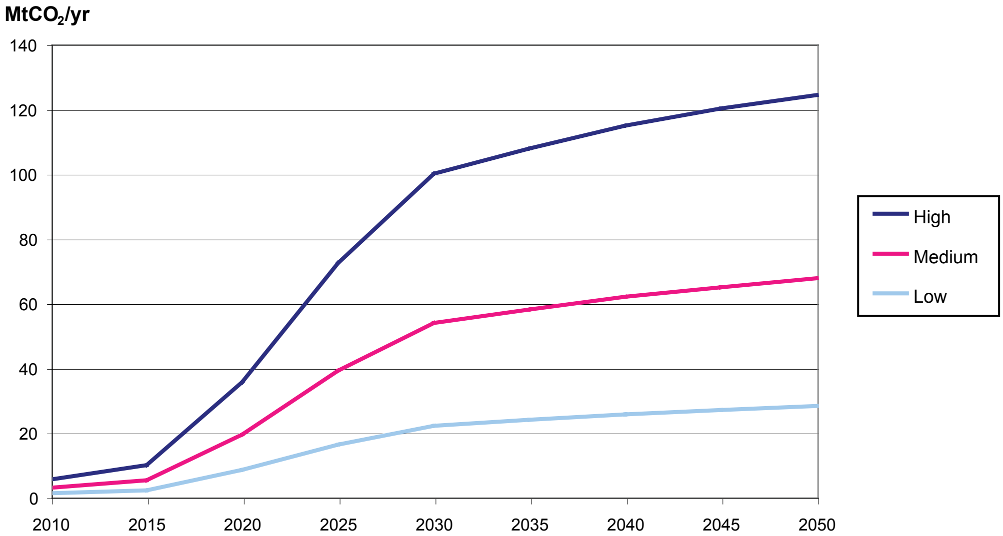
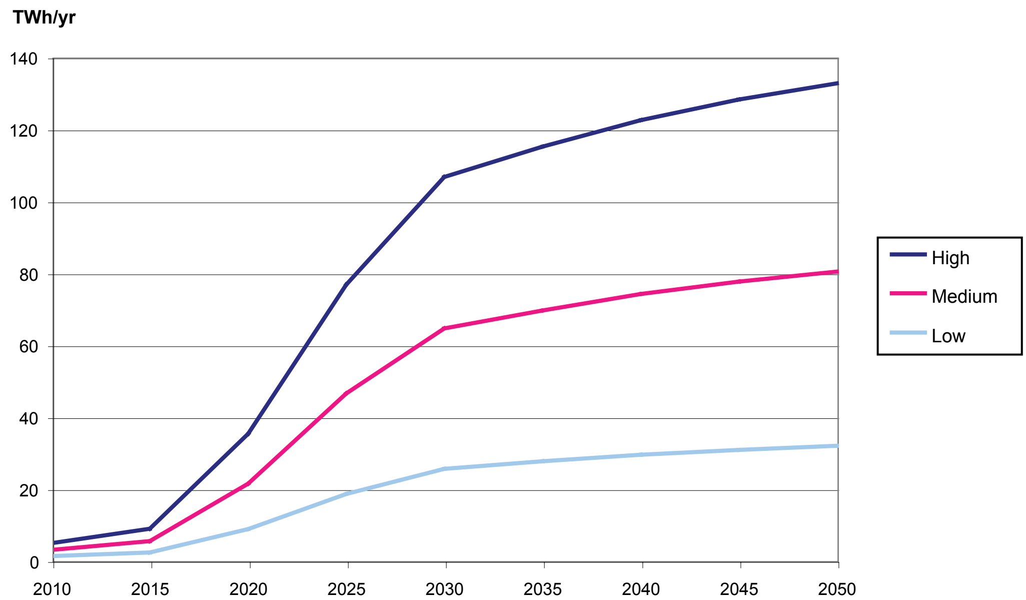


Figure A1.3.4 Increase in electricity consumption from switching cars, LGVs and buses to battery



For HGVs, the penetration of OHL power is assumed to be primarily in the rural areas through which the motorway network runs, while much lower levels are assumed for the urban areas where only limited electrification of routes would be expected.
After a period of preparation of the key routes, the adoption time for switchover of HGVs to overhead electric power has been assumed to be more rapid than for adoption of battery-powered private vehicles. Faster vehicle turnover and sensitivity to economy of operation among competing operators can be expected to drive higher rates of early adoption. The assumptions used in modelling are detailed in table A1.4.1.

Figure A1.4.1 shows the results of the analysis of the CO_2 emission reductions achieved by switching HGVs to electric power delivered by overhead lines.

The scale of CO_2 reduction for switching HGVs to electricity is modest, but the assumptions have been conservative. Further evaluation is needed of potential measures to deliver low-carbon energy to HGVs. The corresponding impact on electrical energy requirements for switching HGVs to electric power is shown in figure A1.4.2.

The efficiency of delivery of electrical energy to HGVs using OHL connections is higher than for battery-powered vehicles, meaning that the CO_2 emission reductions resulting from each TWh are about 25% greater. This significantly reduces the cost of additional generation per tonne/yr of CO_2 avoided.

A1.5 Switch cars to hydrogen

The idea of converting vehicles from oil-based fuels to hydrogen with zero CO_2 emissions at the point of use is very appealing. The technologies needed to establish a ‘hydrogen economy’ have been subject to research since at least the 1970s, when the Battelle Institute conducted research into hydrogen storage in heavy metal powders.

The basic elements of a system using hydrogen as the energy carrier for vehicles consists of the conversion of water to hydrogen (normally involving electrolysis), compression of the gas for transport through a distribution network and further storage in suitable pressure tanks on the vehicle, and then conversion to electricity to drive propulsion motors using a fuel cell. These components have all been demonstrated, although hydrogen storage has proven challenging: the gas must be held at extreme pressure to reduce

Table A1.4.1 Assumptions for HGVs switching to electricity

Vehicle type	Case	Rural	Urban	Timing
HGVs	High	50%	10%	20% by 2025 80% by 2035
	Medium	25%	5%	
	Low	10%	2%	

Figure A1.4.1 CO_2 emissions reduction from switching HGVs to electricity

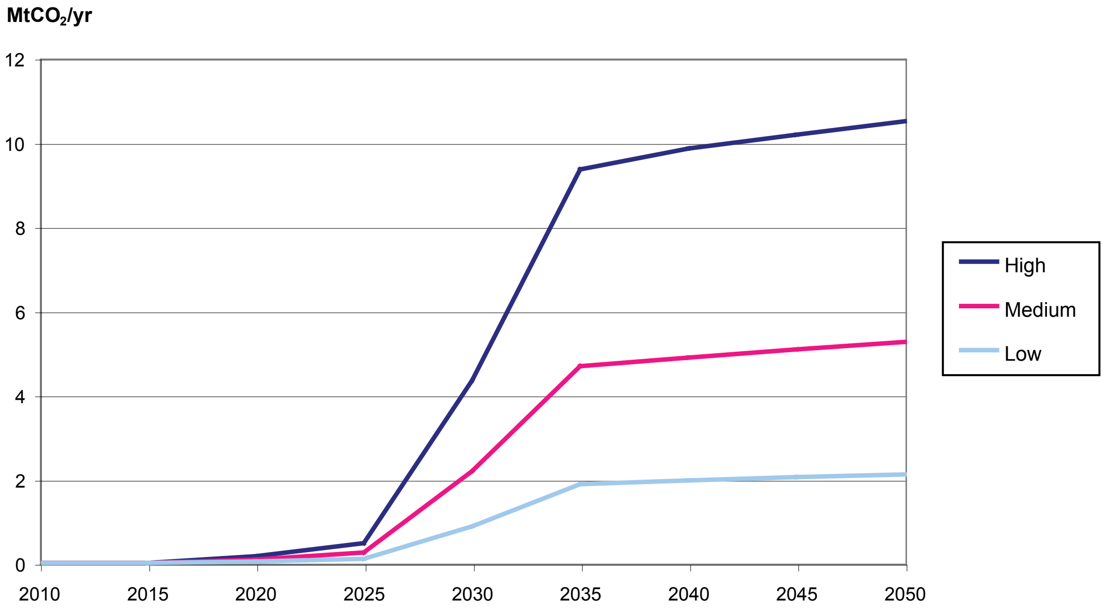
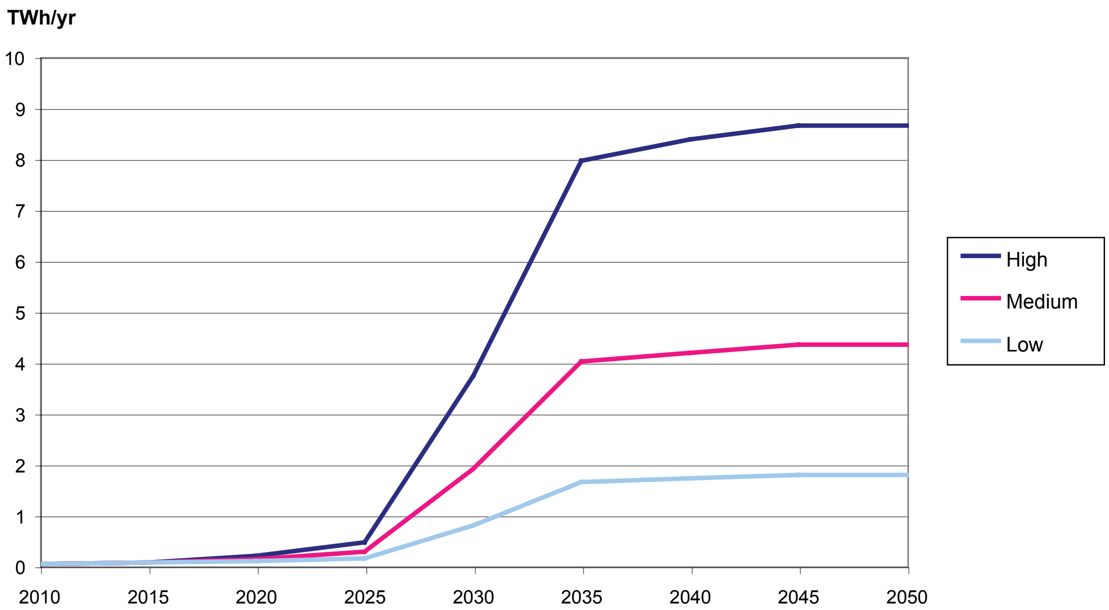


Figure A1.4.2 Increase in electricity consumption from switching HGVs to electricity



the size of storage tank required to hold sufficient gas for a useful vehicle range. The high-pressure storage tank weight, typically 20-30 times the weight of gas it can hold, becomes a major load for the vehicle to carry.

Extensive research has been conducted into the potential absorption of hydrogen into other materials to enable large quantities to be held at lower pressures, but a cost-effective solution has yet to be found. Storing hydrogen in a car in liquid form is impractical because of its extremely low boiling point (-253°C). Even with sophisticated insulation, the fuel will continually boil in the storage tank, wasting energy and creating a potential fire hazard around the vehicle's gas vent.

Fuel cells that convert hydrogen directly to electricity are being demonstrated successfully and are progressing towards commercial viability. Reliability remains an issue, however, and designs are costly as they often depend upon the use of components manufactured from precious metals.

Powering the Future has considered the switching of cars to hydrogen supplied from filling stations, with hydrogen produced by electrolysis of water using electricity from the local distribution network.

The levels of penetration for a switch to hydrogen cars were assumed to be the same as for battery-powered electric cars (see table A1.3.1). However, we assumed that the switching transition would occur ten years later than for battery-powered cars, and that take-up would be slower, given the need to further develop the technology and to establish the necessary network of hydrogen filling stations.

The impact on CO_2 emissions of converting cars to hydrogen is shown in figure A1.5.1.

The corresponding energy required from electricity for this conversion to hydrogen is shown in figure A1.5.2.

By the end of the study period, the benefits of switching cars to hydrogen are similar to those of switching cars to electricity, ie a reduction in CO_2 emissions of around 73 $MtCO_2$/yr. However, the later transition away from oil fuels means that the cumulative emissions of CO_2 by 2050 are 800 million tonnes higher than for the electric vehicle case.

Figure A1.5.1 CO_2 emissions reduction from switching cars to hydrogen

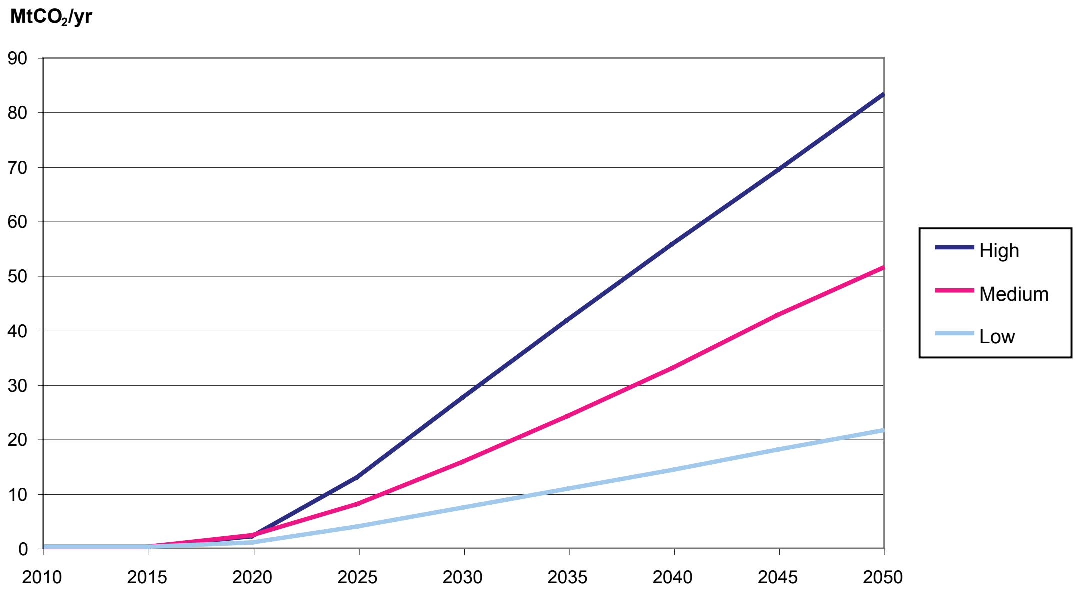
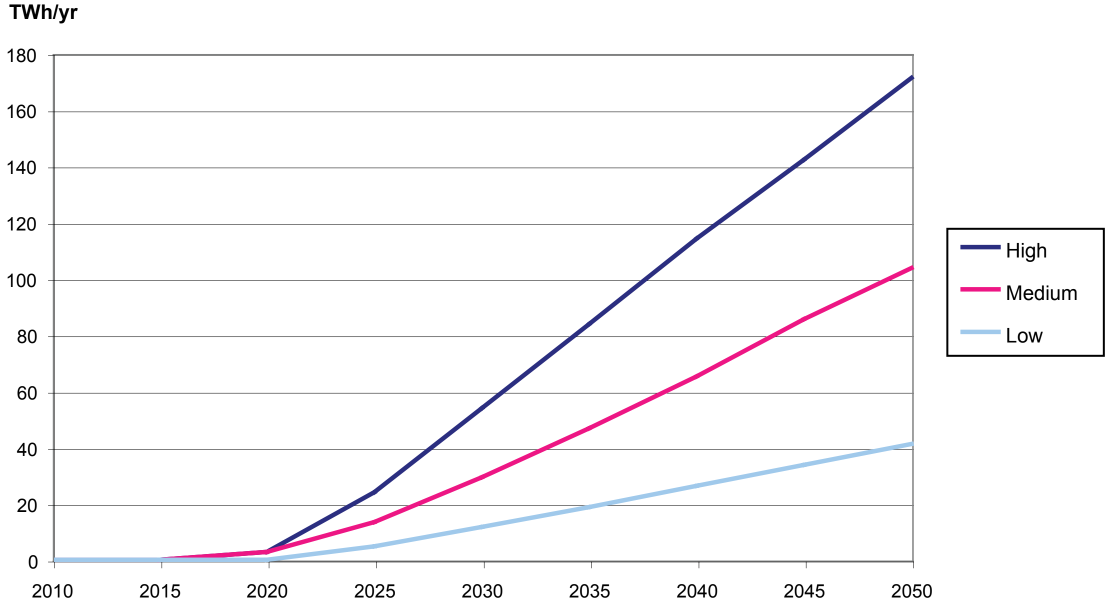


Figure A1.5.2 Increase in electricity consumption from switching cars to hydrogen



Appendix A2. Domestic sector

The following measures are assessed for the domestic sector:
- insulation improvement
- domestic biomass
- community biomass
- domestic CHP
- domestic heat pumps
- domestic solar heating
- appliance efficiency
- domestic solar PV
- domestic wind

A2.1 Insulation improvement

Most of the energy consumed in a domestic setting is used for space heating and this demand can be reduced by a variety of technical means. The application of such measures will need to be encouraged and enforced, for example through the progressive tightening of the Building Regulations, and their application to existing as well as new construction or modifications. The extent to which tighter regulations are applied to existing homes, and the linkage between compliance and events affecting the home (such as its extension or sale), is an important debate.

It is important to recognise that the existing housing stock (less those demolished) will still represent over 60% of the stock in use in 2050. To achieve significant improvements in energy use, and significant CO_2 emission reductions from this sector, the energy efficiency of the existing stock must be substantially improved by 2050.

Measures to improve the energy performance of existing houses include:
- increased insulation of roof, walls and floors
- improvement to window glazing
- improvement to door insulation
- improved draught-proofing and ventilation control
- energy recovery from ventilation exhaust to inlet air

While increased roof insulation is readily fitted in most existing properties, installing enhanced floor insulation can be very disruptive and costly. Improving the insulation of walls that already have cavity insulation or have no cavity would involve intrusive internal or external cladding.

The assumptions and measures from the 40% House report[57] have been extrapolated within feasible limits to meet the 80% target for carbon reductions. In addition to the measures identified in 40% House, we introduced other measures such as heat recovery from ventilation exhaust airflows.

We evaluated the impact of these measures on the assumption that the measure resulted in a reduction in the fuels that are currently consumed. Figure A2.1.1 shows how CO_2 emissions would be reduced for:
- a base case applying the improvements uniformly over the period to 2050
- an accelerated case where 80% of the improvements are implemented by 2025
- a low case where only 70% of the target improvements are achieved

Improving the standard of insulation has the potential to offer significant reductions. An accelerated refurbishment programme of existing stock provides a cumulative saving of around 250 $MtCO_2$ by 2050, equivalent to around ten times the potential annual saving. The low case still offers a substantial reduction in CO_2 emissions, but over the period results in excess emissions of almost 200 $MtCO_2$ compared with the base case.

A2.2 Domestic biomass

Biomass can be used where there is a ready supply of fuel in a suitable form, such as wood pellets, wood chip or logs. Other forms of biomass are not readily used in a domestic system due to problems with storage and handling. A modern biomass boiler can provide both space and water heating on a controlled basis.

The substitution of biomass for existing fuels is most likely in rural areas that are off the natural gas network, where coal, oil and LPG are currently used. This represents approximately 10% of current domestic heating demand. A larger penetration of biomass would be feasible – subject to fuel availability – and would deliver a proportionate reduction in CO_2 emissions. Figure A2.2.1 illustrates the potential reduction in CO_2 emissions. The low case represents 50% of current oil and coal burn being replaced with biomass by 2050, the high case 90%, and the accelerated case represents a more rapid replacement, with 80% of existing coal and oil heating replaced by 2030.

The reduction curves suggest that biomass substitution is a valuable option. Promoting a more rapid biomass

[57] Boardman B *et al*, '40% House' 2005.

Figure A2.1.1 CO_2 emissions reduction from improved insulation of existing homes

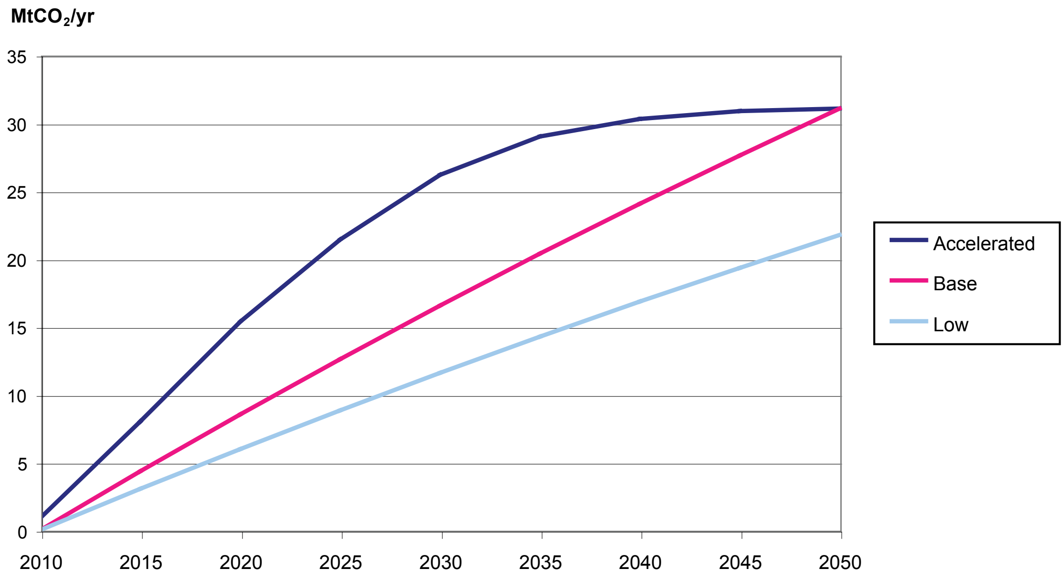
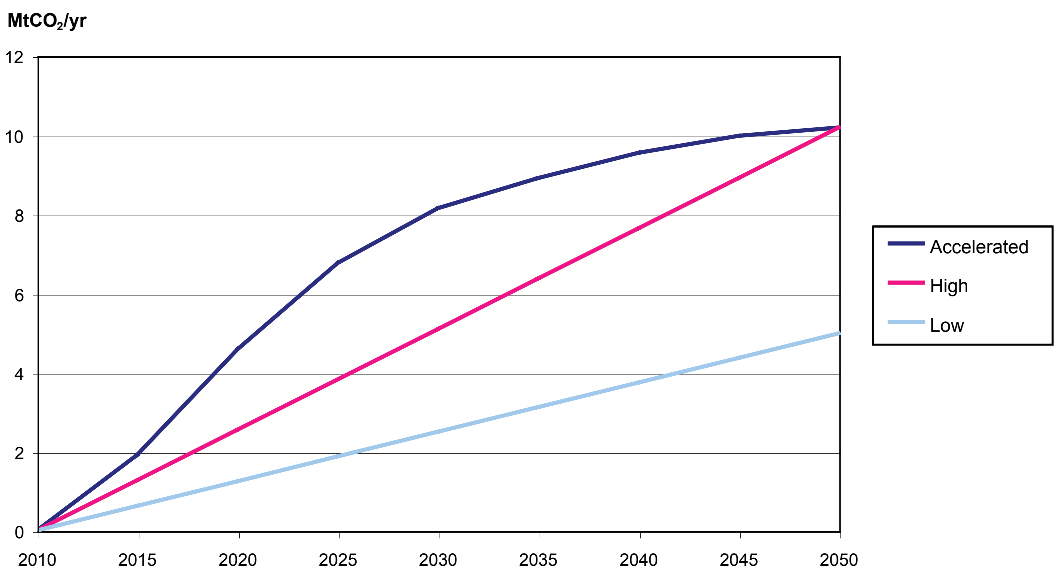


Figure A2.2.1 CO_2 emissions reduction from domestic biomass



substitution would avoid at least 60 million tonnes of CO_2 emission by 2050.

A2.3 Community biomass

More extensive penetration of biomass can be expected from community heating systems delivering heat to larger groups of homes. Such systems could use a wider range of biomass than would be feasible on a domestic scale, including agricultural wastes such as straw or appropriate refuse-derived fuels. Community biomass boilers would be more efficient than domestic units and have lower operating costs. They would also be better suited to tighter environmental controls on emissions.

Community heating could also exploit the low-temperature residential heat load as the heat rejection system for a combined heat and power plant. Such plants would consume more fuel than for heating duty alone, but would generate electricity with minimal CO_2 emissions for typically 5,000-7,000 hours per year.

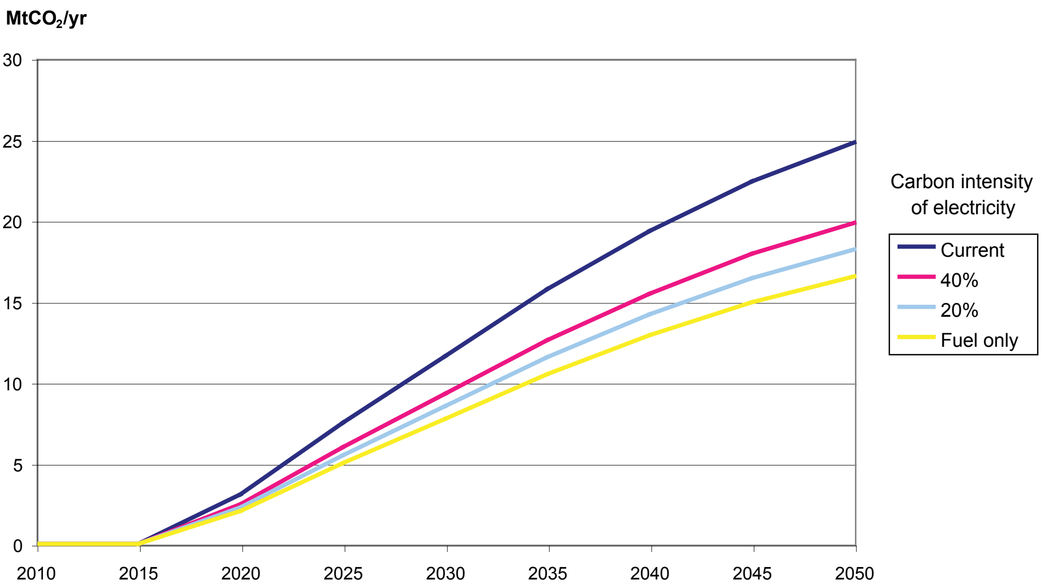
The application of community heating is likely in urban residential developments and in refurbishments where housing density is sufficient to make heat distribution economical. Following other studies[58], we have assumed that 4.1 million refurbished homes and 2.2 million new homes will incorporate community heating by 2050. Figure A2.3.1 shows the reduction in CO_2 emissions from such a programme, illustrating the effect of the carbon intensity of electricity, and the impact of incorporating CHP or providing heating only.

This analysis demonstrates the value of community heating, and the significant benefit in including CHP in these schemes to avoid a cumulative total of between 20 and 100 million tonnes of CO_2 that would otherwise be emitted by power generation between 2015 and 2050.

The CHP cases reach an electricity production of over 16 TWh/yr by 2050, corresponding to about 2,400 MW of low-CO_2 generation capacity integrated into the domestic sector. This represents a valuable contribution to the reduction of demand on generating plant in the electricity sector and makes use of about 85% of the energy from the available biomass fuels. The growth of this power generation is shown in figure A2.3.2.

The electricity generated by these CHP plants represents over 10% of the electricity demand of the sector.

Figure A2.3.1 CO_2 emissions reduction from the application of community biomass



[58] Boardman B *et al*, '40% House' 2005.

A2.4 Domestic CHP

Domestic CHP uses more advanced technology to replace the domestic heating boiler with a dual-purpose unit that generates electricity and rejects heat from the power generation process to the heating system. Alternative technologies are being explored to perform this dual function including Stirling engines and fuel cells. Such systems are currently at the experimental demonstrator stage and are not expected to be available for wider installation before 2015.

The advantage of domestic CHP is that it produces electricity within the home, offsetting imported power and converting a high proportion of the fuel energy to useful forms. The implications of embedded power generation within the local electricity distribution network are significant: equipment would need to be upgraded and metering enhanced so that exported power could be properly recognised though a feed-in tariff or similar mechanism.

The impact of domestic-scale CHP on CO_2 emissions is less clearcut. CHP currently offers the potential to substitute a proportion of power and heat produced independently of each other with the more efficient combined production of power and heat. Conventional power generation currently produces electricity with an associated CO_2 emission of around 500 kg/MWh. Based on current emissions for gas and electricity, an average house which uses mains-supplied electricity together with a high-efficiency condensing boiler, has the overall CO_2 emissions shown in table A2.4.1.

For comparison, in a well-optimised situation, where a domestic CHP unit with 15% power generation efficiency and 95% overall efficiency is used to provide all of the electricity demand of the home (with the excess output exported to meet the heating demand), the total CO_2 emissions are as shown in table A2.4.2.

At around 17%, the reduction in CO_2 emissions is modest, but this will increase as CHP power generation efficiency improves. However, it must also be assumed that the carbon intensity of generation in the electricity sector will fall, and this will substantially reduce the benefit of domestic CHP. In addition, the heating and electricity demand of the average house will fall simultaneously as a result of improved insulation and appliance efficiency, reducing benefits further.

Figure A2.4.1 illustrates the maximum potential CO_2 reduction for a CHP take-up rising to 38% of existing houses. Where applicable, we have used assumptions for electricity and heat consumption from 40% House. Electrical output is allowed to exceed domestic consumption so that all of the heat required for the

Figure A2.3.2 Electricity production by community biomass

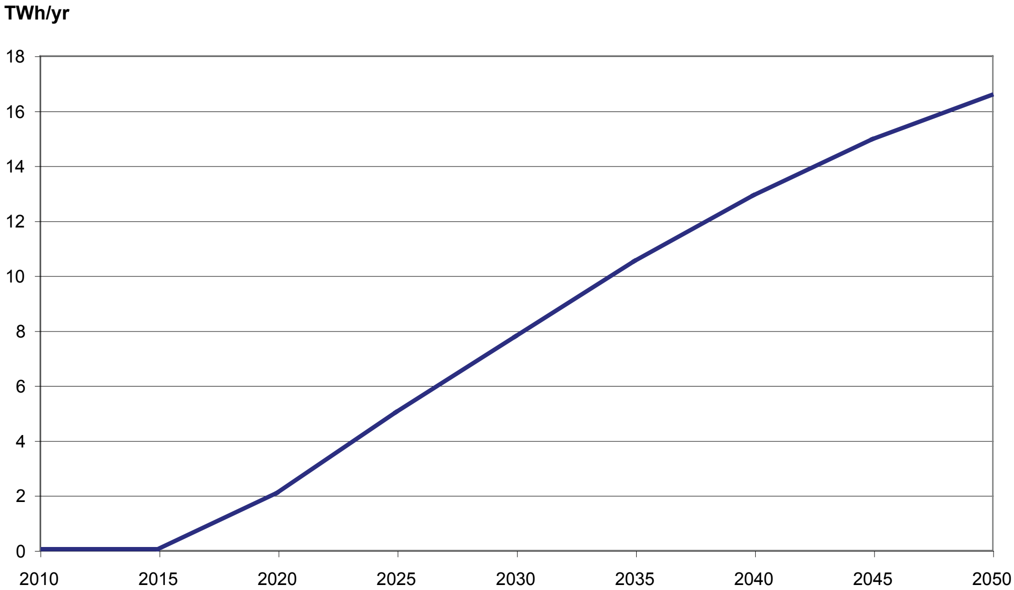


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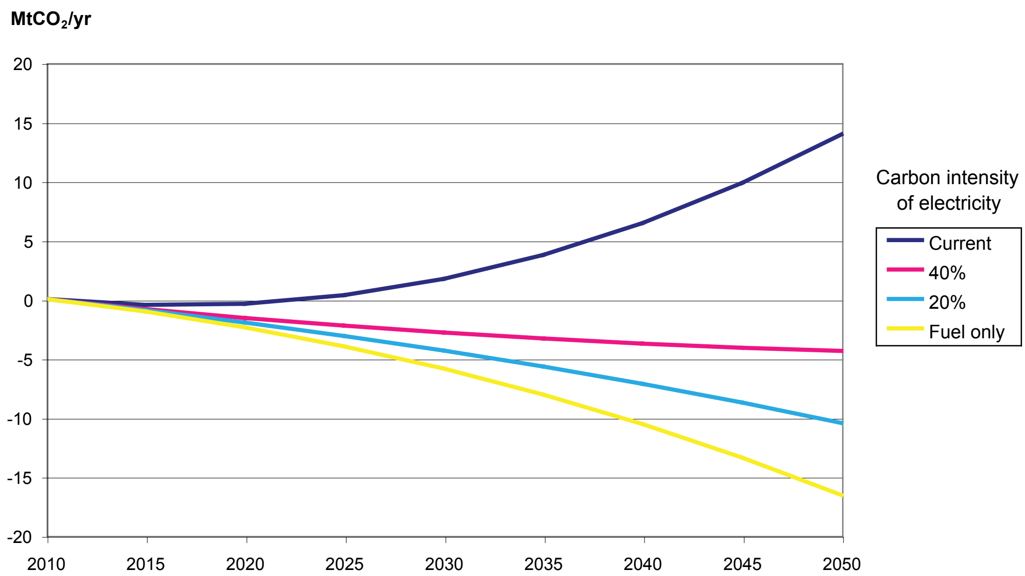
Table A2.4.1 Domestic consumption – heating and hot water

Use	Annual consumption (kWh)	Specific emission (kg/MWh)	CO_2 emission (t/yr)
Electricity	3,000	500	1.48
Heating and hot water	19,600	190	3.72
Total	22,600	-	5.2

Table A2.4.2 Domestic consumption – CHP

Use	Annual consumption (kWh)	Annual input energy (kWh)	Specific emission (kg/MWh)	CO_2 emission (t/yr)
Electricity CHP	3,000	In heating and hot water CHP	-	-
Heating and hot water CHP	19,600	24,500	190	4.66
Net electricity export	675	In heating and hot water	500	-0.34
Total	23,275	24,500	-	4.32

Figure A2.4.1 CO_2 emissions reduction from domestic CHP



home, both for space and water heating, is supplied from the CHP unit.

The power generated by the CHP unit is credited with the saving of CO_2 emissions from displaced gas-fuelled power. The electrical efficiency of the CHP stock is assumed to rise from 15% to 35% by 2050 and the overall energy efficiency of the units is assumed to be 95%.

The potential benefit of domestic CHP can be seen for the 'current' curve of carbon intensity of electricity. However, as the carbon intensity of electricity must be reduced to 20% or less of current levels by 2050, domestic CHP will offer no reduction in CO_2 emissions and may increase emissions, although it may offer other economic or technical advantages.

The corresponding forecast of electricity generated by domestic CHP systems is illustrated in figure A2.4.2, which shows the level of generation rising to over 50% of the electricity demand of the sector by 2050.

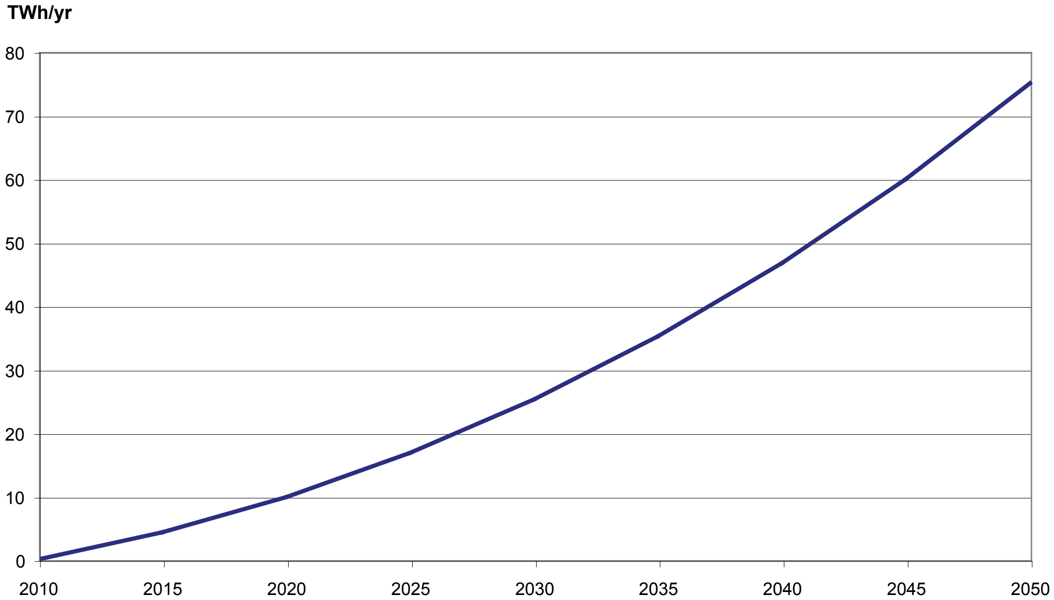
A2.5 Domestic heat pumps

There are two types of heat pump that can be applied for domestic heating. Both of these devices 'pump' heat from lower-temperature sources to a higher temperature suitable for heating. Ground source heat pumps extract heat directly or indirectly from the ground, while air source heat pumps extract heat from the outside air.

A ground source heat pump collects heat from a network of buried pipes and, using technology similar to an air conditioning unit, delivers heat at a higher temperature for domestic heating. For optimum efficiency the heat collection network must be extensive, and the heating is best delivered at a low temperature, typically through an underfloor water circulation system. Given the disruption involved in installing this type of system in an existing house, it is best applied to new-build properties. Nevertheless, some estimates of their application suggest that about 2.7 million installations will be operating by 2050[59]. We have assumed an 8% penetration of new properties by ground source heat pumps.

Ground source heat pumps currently achieve a coefficient of performance of approximately five-to-one, ie one unit of electricity delivers five units of heat energy. Figure A2.5.1 shows the potential CO_2 emission reductions achieved by the application of

Figure A2.4.2 Electricity production from domestic CHP



[59] Hitchin R, 'The UK Heat Pump Market' 2004.

ground source heat pumps, assuming a growing application from 2010. The reference home is assumed to use a gas heating boiler while the heat pump user is assumed to have an all-electric home.

Figure A2.5.1 indicates that ground source heat pumps would make a small contribution, as the carbon intensity of electricity falls from 2025 onwards. This small scale is a result of the limited extent of application of the technology.

The corresponding forecast of electricity consumption by domestic ground source heat pumps is shown in figure A2.5.2. The maximum level of generation by ground source heat pumps, reached in 2050, is not significant, being less than 3% of the sector's electricity demands.

Air source heat pumps use heat exchangers in the ventilation exhaust and/or the outside air to collect heat which is then delivered to the home at a higher temperature. As the temperature of the air in winter is often significantly lower than the soil 1 m below the surface, the electricity consumption of air source heat pumps is approximately 70% higher than ground source heat pumps delivering the same heat output.

Figure A2.5.3 shows the potential CO_2 reduction from applying air source heat pumps to 1.7 million existing homes, following the assessment in 40% House.

Applying air source heat pumps gives a significantly higher reduction in CO_2 emissions than ground source heat pumps, and the reduction builds up more quickly because of the large base of existing housing. Once again we see that the emission reduction is only positive once the carbon intensity of electricity has been significantly reduced. This means that, from a CO_2 perspective, this measure is only worthwhile after about 2020.

The corresponding forecast of electricity consumed by domestic air source heat pumps is illustrated in figure A2.5.4, which shows the level of generation rising to over 13% of the sector's electricity demand by 2050.

A2.6 Domestic solar heating

Solar heating for domestic hot water has been developed to a high level and the scale of early application means that wider application can be reasonably assessed. The technology typically uses absorber tubes within an evacuated glass envelope with a circulation of water to the hot water storage tank.

Figure A2.5.1 CO_2 emissions reduction from domestic ground source heat pumps

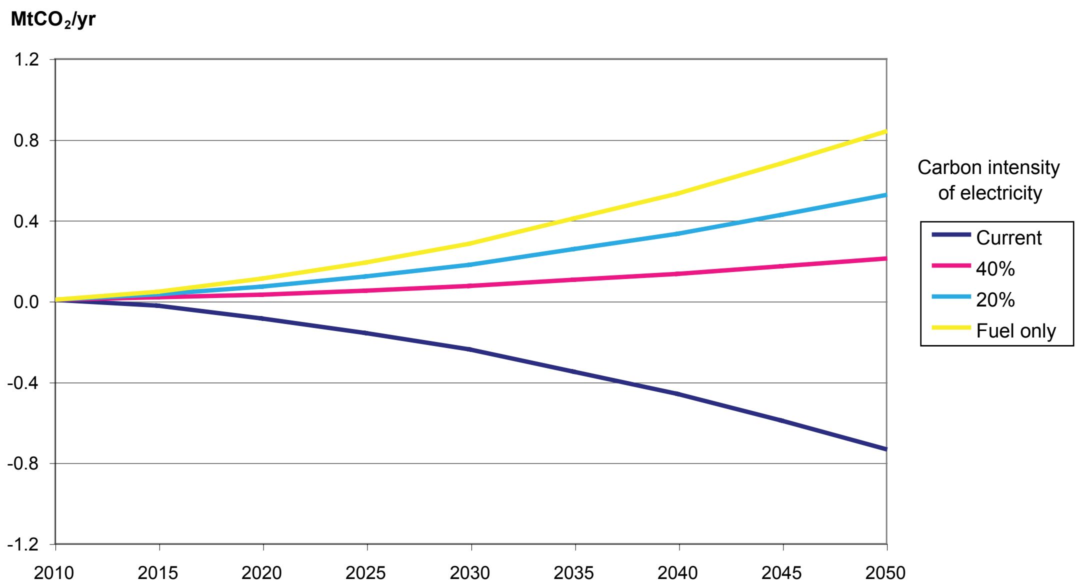


Figure A2.5.2 Increase in electricity consumption from domestic ground source heat pumps

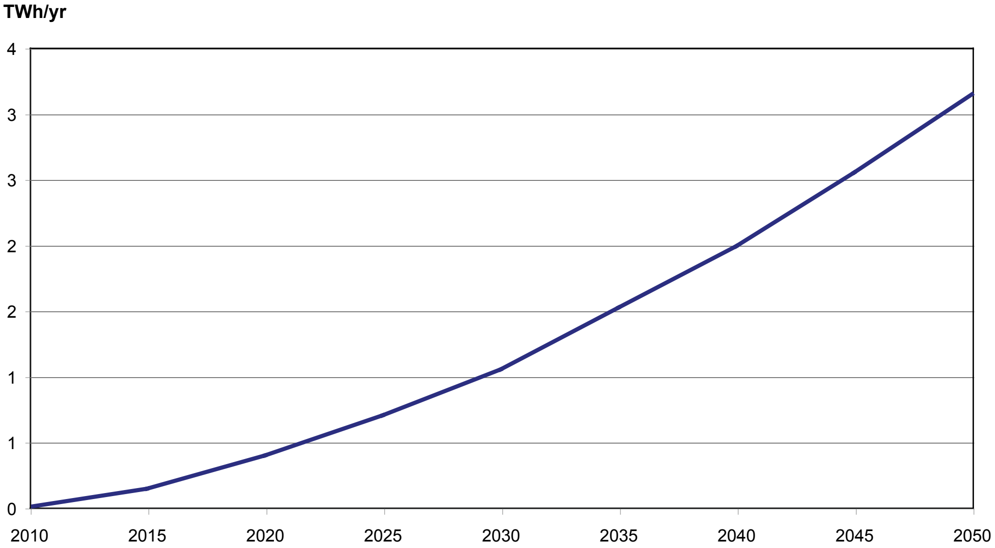
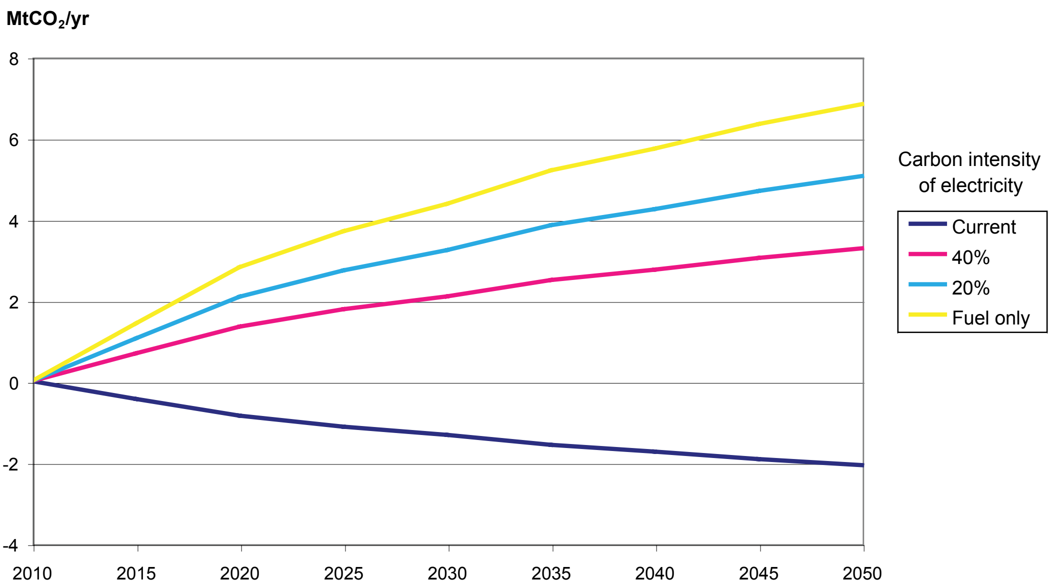


Figure A2.5.3 CO_2 emissions reduction from domestic air source heat pumps



Other studies[60] suggest that solar heating can, on average, meet over 30% of water heating energy requirements. Following the assessment made in 40% House, we have assumed that solar water heating will be applied in 60% of the domestic housing stock by 2050. The technology is currently available and could be promoted to achieve this level of penetration over a 20-year period (the accelerated case). With smaller incentives it could be implemented as linear application by 2050 from 2010 (the low scenario). Figure A2.6.1 shows CO_2 emission reductions compared to a reference case where water heating is by gas.

The more aggressive high case avoids the emission of approximately 50 million tonnes of CO_2 compared with the slower low case. To obtain this benefit, the wide and early application of this technology would need to be encouraged.

A2.7 Appliance efficiency

Reducing net electrical consumption can take three broad forms:

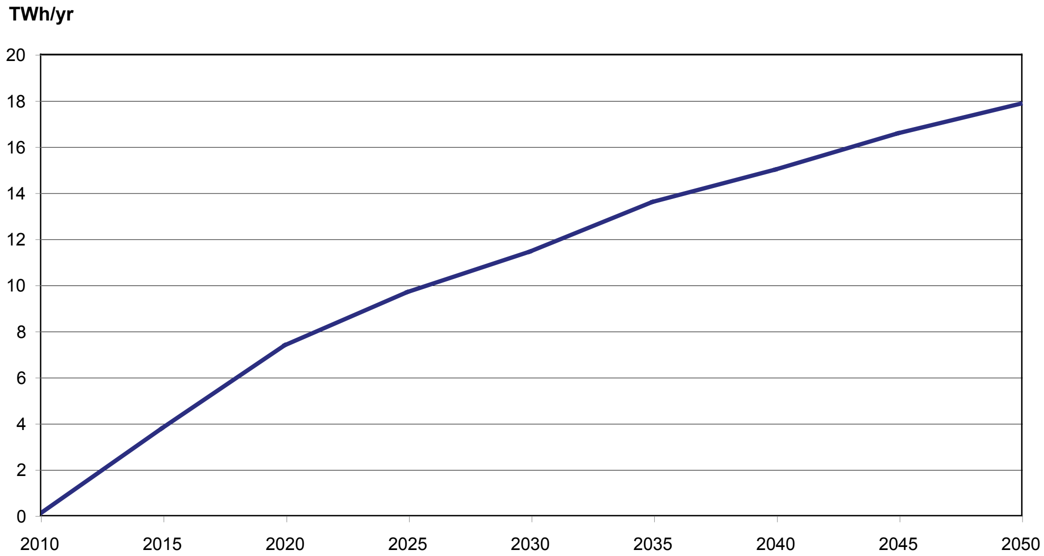
- improvements in the efficiency of household electrical equipment
- significant improvements in the design of new houses, and associated improvements in efficiency
- incorporation of power generation within the house through domestic CHP or renewable generation

This section only considers the impact of improvements in the efficiency of lighting and appliances within the house.

Residential electrical consumption in 2006 totalled 115 TWh. It is predicted to fall to 106 TWh by 2050, based on projections of the number of households and new construction. The reduction in electrical demand is primarily achieved by the increased efficiency of electrical devices. The saving is estimated at 1,320 kWh over the period 1998 to 2050[61]. Powering the Future annualises this figure to a continuous saving of 25 kWh per year.

As the Code for Sustainable Homes takes an increasing effect, new houses will use energy in a way that is significantly more efficient. However, these houses represent new consumers, and their demand for electrical energy will offset most of the energy saved through efficiencies in existing houses. Replacement build for demolished houses makes a small contribution to reducing overall demand, but at current demolition rates it represents a saving of just a few percent of residential demand in 2050.

Figure A2.5.4 Increase in electricity consumption from domestic air source heat pumps



[60] Department of Energy and Climate Change, 'The UK Renewable Energy Strategy' 2009.

[61] Boardman B *et al*, '40% House' 2005.

A2.8 Domestic solar PV

The domestic application of solar PV power generation has received considerable publicity. It remains, however, a very costly option at present, with domestic installation costs of about £6,000/kW peak. With the UK's practical daylight levels, this capital cost gives an effective unit cost of electricity of about 40p/kWh, even with a 5% discount rate. Substantial increases in production and improvements in the performance of solar PV panels are expected to reduce these costs significantly over the next 20 to 30 years. For the purpose of this analysis, we assume that, from 2035 onwards, PV panels will become cost effective without subsidy, and that subsidies and promotion will result in an earlier large-scale adoption of the technology.

We assume that the average latitude for homes in the UK is 53° north, with an equinoctial solar energy input of 820 W/m^2, an array size of 9m^2 on a south-facing roof, with a 30% output factor to allow for cloud and fouling of the panels. We also assume that by 2050 the efficiency of the solar panels will rise to 25% from current levels of around 10%. Two cases have been considered: the later case in which wide adoption of solar PV is deferred until after 2030 (when it is expected to become economically viable), and an early case where incentives are provided and adoption takes place more quickly. In both cases it is assumed that the final market penetration is 30% of houses as in 40% House.

Figure A2.8.1 shows the growth of electricity production from solar PV for the two cases.

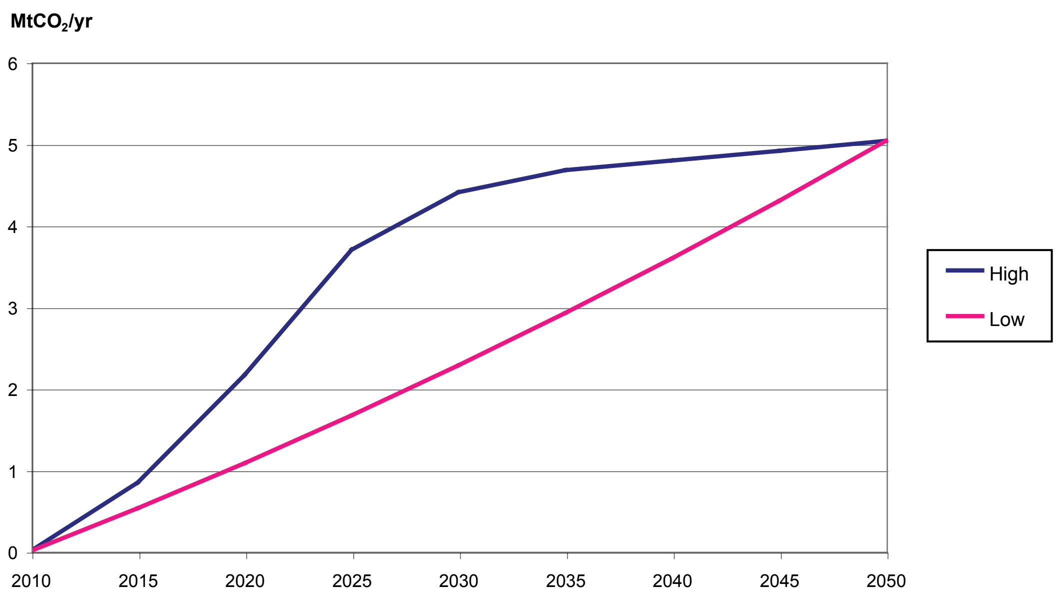
The more conservative later case has been assumed for subsequent analysis.

A2.9 Domestic wind

Several suppliers now offer small wind turbines for domestic installation. These units are typically in the range of 1-2 kW and are mounted on suitable chimneys or other high sections of buildings. In built-up areas their effectiveness is reduced by turbulence and the lower wind speeds accessible at low elevations. This gives a reduced capacity factor of 10-15% compared with 25-30% for larger-scale units.

Domestic wind turbines generate at all times of day and night, subject to wind conditions, and may produce more power than the immediate domestic

Figure A2.6.1 CO_2 emissions reduction from solar water heating



load. Without suitable connection and tariff provisions, such power has no value to the homeowner, adversely affecting the economic case for their installation.

Various studies of the potential scale of installation of domestic wind turbines have estimated that between 5% and 10% of homes would install them by 2050. There are however widespread doubts regarding the viability of such large-scale application.

Figure A2.9.1 shows the scale of electricity production possible from domestic wind generators, assuming 5% and 10% penetration of 1.5 kW units with a capacity factor of 15%.

Figure A2.9.1 illustrates the relatively small energy contribution likely from domestic wind generation. Apart from favoured locations in rural areas and in more exposed positions, it appears unlikely that domestic wind will be cost effective or make a significant impact on the overall electricity demand in the domestic sector.

Figure A2.8.1 Electricity production from domestic solar PV

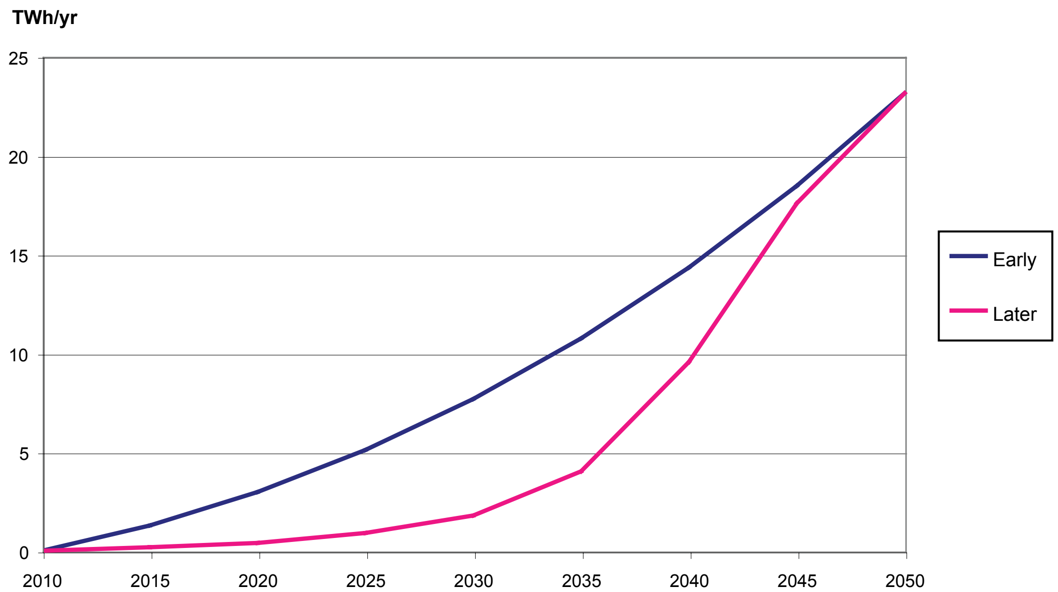
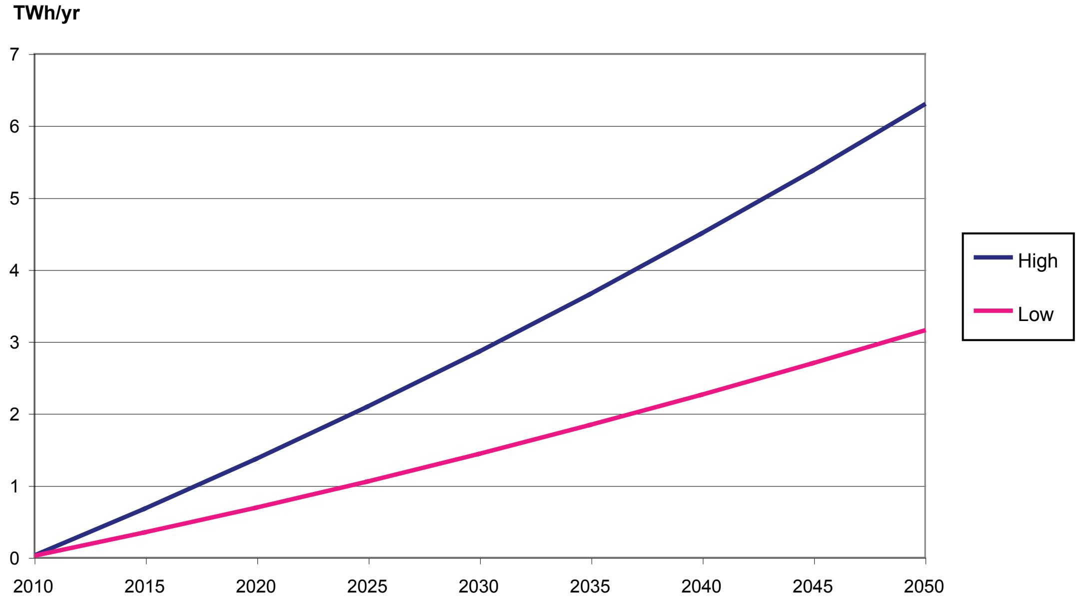


Figure A2.9.1 Electricity production from domestic wind generation



Appendix A3. Industry sector

The following measures are assessed for the industry sector:

- transport fuel reduction
- building insulation
- electrical efficiency
- efficiency improvements
- convert to gas
- convert to biomass
- industrial CHP
- convert to electricity
- renewable generation
- carbon capture and storage

A3.1 Transport fuel reduction

The transport sector analysis (appendix A1) identified the potential for electric vehicles to progressively displace internal combustion engine vehicles burning petroleum fuels. The resulting reduction in demand for diesel and petrol will bring a corresponding reduction in CO_2 emissions and electricity consumption in oil refineries which are included in the industry sector.

Figure A3.1.1 shows the CO_2 reductions that result from replacing fossil fuels with electricity as described in the high case, detailed in the transport section (appendix A1).

The reduction of CO_2 emissions from oil refining resulting from the declining use of petroleum products for transport is significant: about 8.5% of the 'business as usual' value in 2050. The corresponding reduction in electricity consumption is 3.75 TWh, or about 3% of the 2050 level.

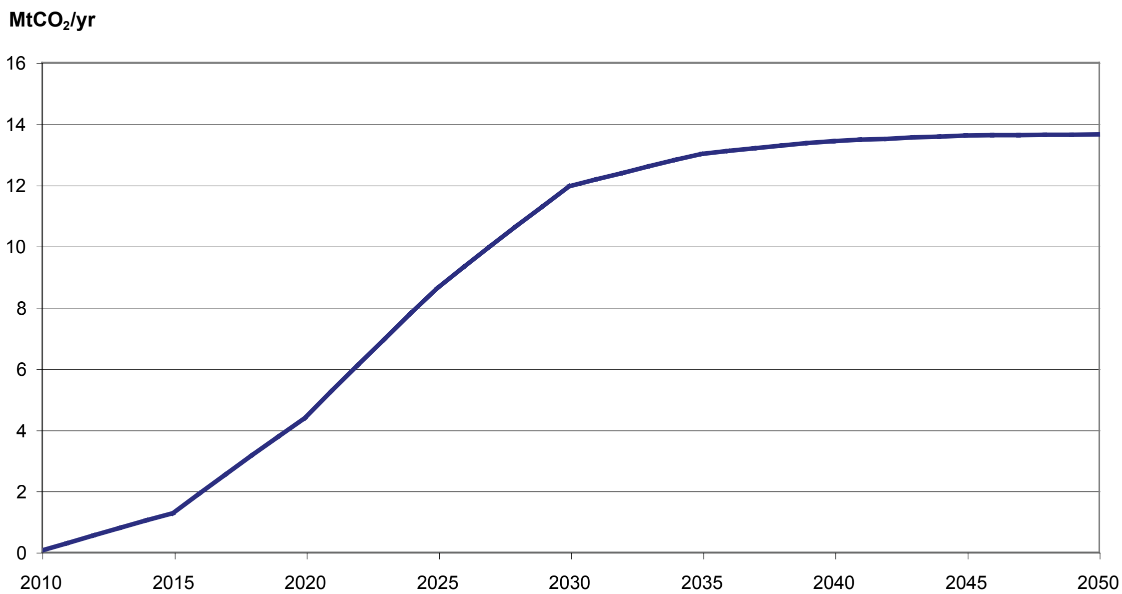
A3.2 Building insulation

The industry sector includes many heated buildings and warehouses. Improving the insulation of these buildings would significantly reduce the need for space heating, with an associated reduction in fuel consumption. It has been assumed that insulation will provide an average reduction in space-heating demand of 50%. The progressive application of new standards to achieve this improvement is assumed to be completed by 2030.

Figure A3.2.1 shows the impact on CO_2 emissions of this change to space-heating requirements.

The analysis indicates that a reduction of 5 $MtCO_2$/yr could be achieved by 2030 and 6 $MtCO_2$/yr by 2050. This is a modest reduction of about 3.5% of industrial emissions, but one readily delivered by changes to the appropriate industrial construction standards.

Figure A3.1.1 CO_2 emissions reduction from reduced road transport fuel consumption



A3.3 Electrical efficiency

Electricity demand in industry includes a major component from motors, lighting and air compressors. These demands can be reduced by ensuring that motors are progressively replaced by higher-efficiency units, and that lighting is upgraded to the most efficient fittings. Compressed air systems are frequently found to be wasteful in delivering energy, with leakage levels often exceeding 30% of demand. In many processes, fixed-speed motors are used with pumps and control valves or hydraulic couplings to machinery which result in a continuous waste of energy compared with the use of variable-speed drives.

The potential reduction in electricity consumption was evaluated to assess the significance of improved motors, lighting and related equipment. Data in the BERR industrial data tables 2008 update[62] was used to calculate the applicable reductions for most industrial sectors. This data does not include breakdowns of energy use for several significant sectors, such as refined petroleum products, so not all industrial energy consumption is included in this analysis. Nevertheless, the results give a useful indication of the possible scale of savings. Table A3.3.1 shows the assumed reductions in consumption as a result of the measures outlined above.

The reductions have been assumed to be greater than currently achievable to take some account of future improvements in technology. The resulting savings were assumed to be implemented progressively from 2010 to 2025.

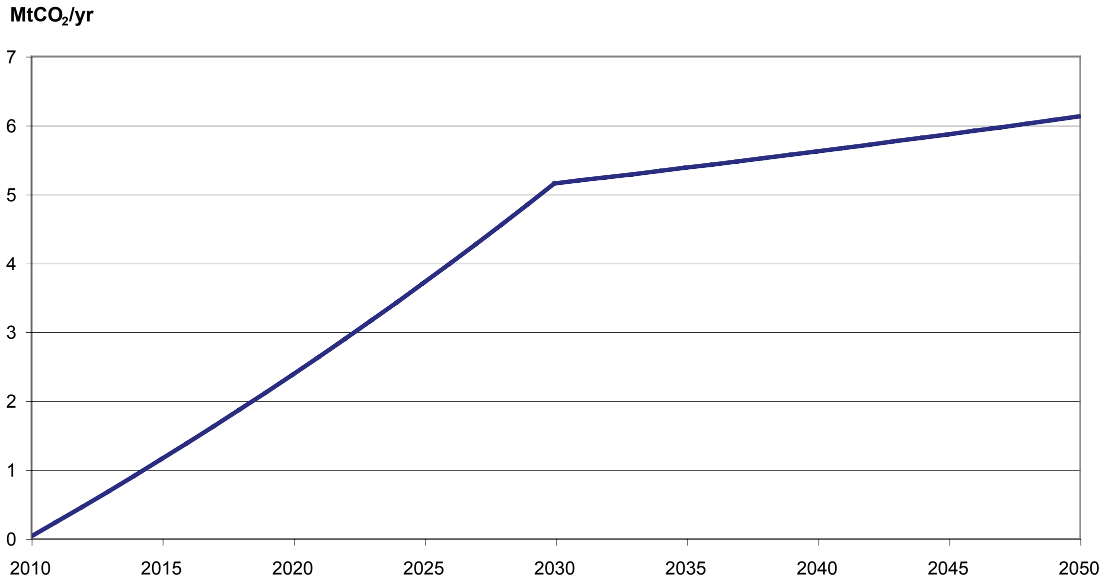
Figure A3.3.1 shows the result of the evaluation.

The reduction in electricity consumption is about 12% of the 'business as usual' value from 2025. Although this is a significant improvement, it represents only a 0.85% reduction per year from 2010 to 2025. Set alongside the rate of reduction in energy intensity for different industry sectors of between 0.6% and 1.6% per year, it appears that this class of improvement should be considered to be part of the progressive reduction in energy intensity being implemented by industry, rather than being considered as a separate measure.

A3.4 Efficiency improvements

Given the diversity of industrial processes, it is not possible to produce a comprehensive set of improvement measures to estimate all of the potential improvements in energy efficiency and reductions in CO_2 emissions. The potential measures fall into several categories, considering changes to industrial

Figure A3.2.1 CO_2 emissions reduction from improved building insulation



[62] Derived from: Department for Business, Enterprise and Regulatory Reform, 'Energy Consumption in the United Kingdom: Industrial Data Tables 2008 Update' 2008.

processes and to the relationship between industry and its markets and neighbouring communities. The classes of measure include:

- lower energy-intensive or carbon-intensive processes
- improved integration of processes to enhance energy efficiency
- collective export of low-grade heat for use on and off site via a district heating system
- changes to products to reduce the use of energy-intensive manufacturing processes
- changes to products to minimise lifecycle carbon emissions

Since the detailed evaluation of such measures would be a large study in its own right, we have estimated the scale of improvement needed to achieve a reasonable contribution to CO_2 reductions by industry. Figure A3.4.1 shows the large CO_2 reduction impact of this non-specific measure applied as continuous improvement from 2010 to 2040. Figure A3.4.2 shows the reduction in electricity consumption for the non-specific measure.

A3.5 Convert to gas

For a given heat requirement, the combustion of natural gas results in much lower CO_2 emissions than the combustion of oil or, more significantly, coal. Many industrial energy uses require heat, and conversion to natural gas offers a feasible, if not necessarily economic, means of reducing CO_2 emissions. This option has been evaluated assuming that oil

Table A3.3.1 Assumed reductions in energy demand

Process						
Thermal processes	Drying and separation	Motors	Compressed air	Lighting	Refrigeration and space heating	Other
5%	10%	10%	30%	50%	20%	10%

Figure A3.3.1 Reduction in electricity consumption from improved electrical efficiency

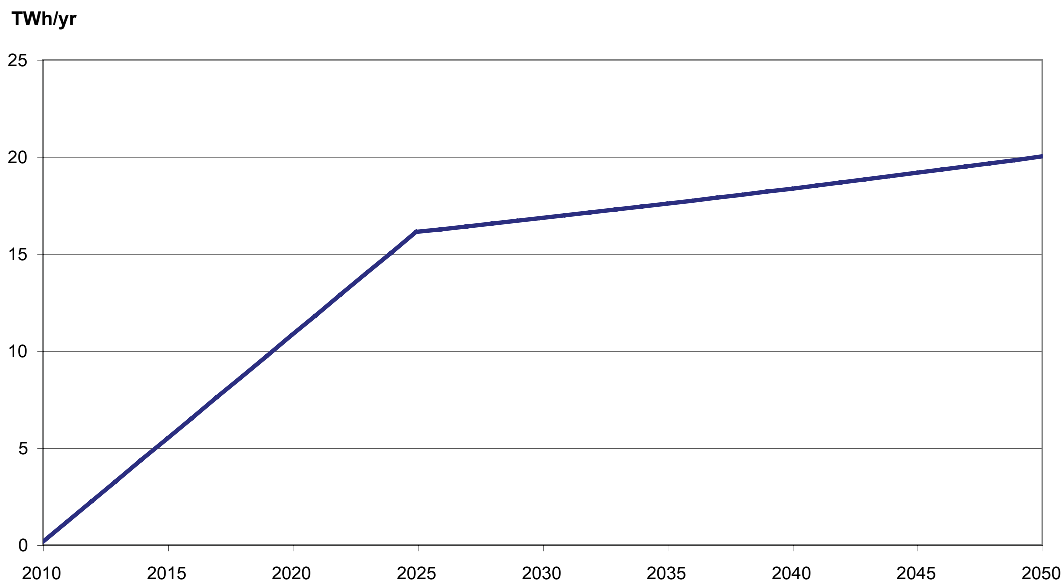


Figure A3.4.1 CO_2 emissions reduction for non-specific efficiency improvements

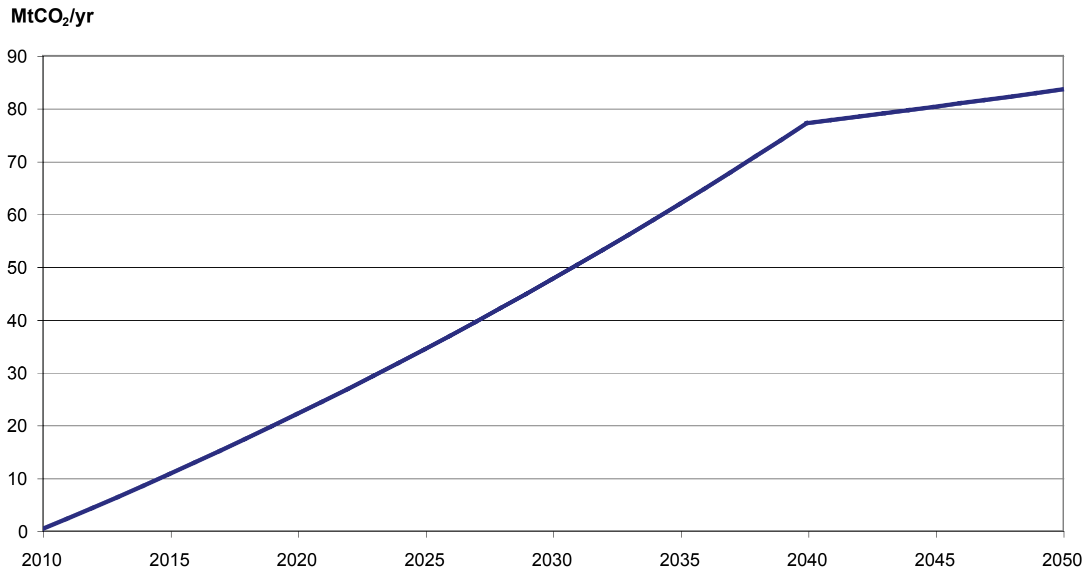
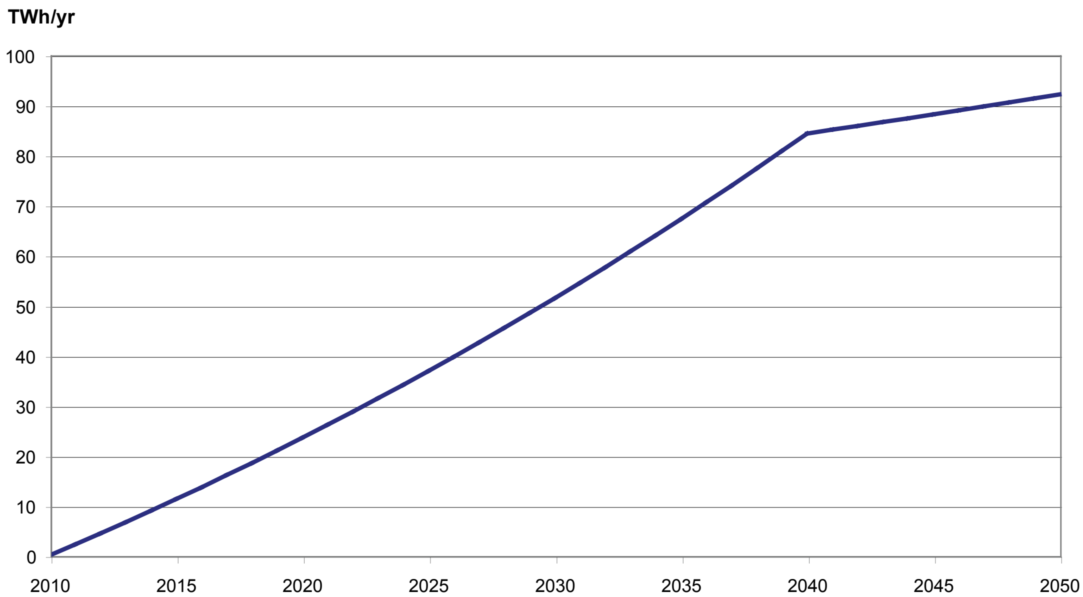


Figure A3.4.2 Reduction in electricity consumption from non-specific efficiency measures



refining and coke manufacture continue to use their existing fuels and that only 20% of the fuel burned in the iron and steel industry is converted to natural gas. Since conversion between fuels is already feasible, it is assumed that conversion begins in 2010 and is completed by 2025.

Figure A3.5.1 shows the results of the evaluation.

Given the modest scale of CO_2 emission reduction – about 4.5 MT/yr or 4% of industrial emissions – and the significant additional cost of using natural gas compared with coal, this option is unlikely to be viable.

A3.6 Convert to biomass

An alternative to conversion to natural gas would appear to be conversion to renewable biomass fuels. Such conversion would offer a CO_2 reduction of about three times that of converting coal to natural gas, making it a more attractive option than other fuel conversions. However, the limited supply of biomass-derived fuels means that only a small part of industrial fuel use could be converted in this way.

A3.7 Industrial CHP

CHP offers a means of generating power while making use of the heat rejected by the power cycle for process or space-heating duties.

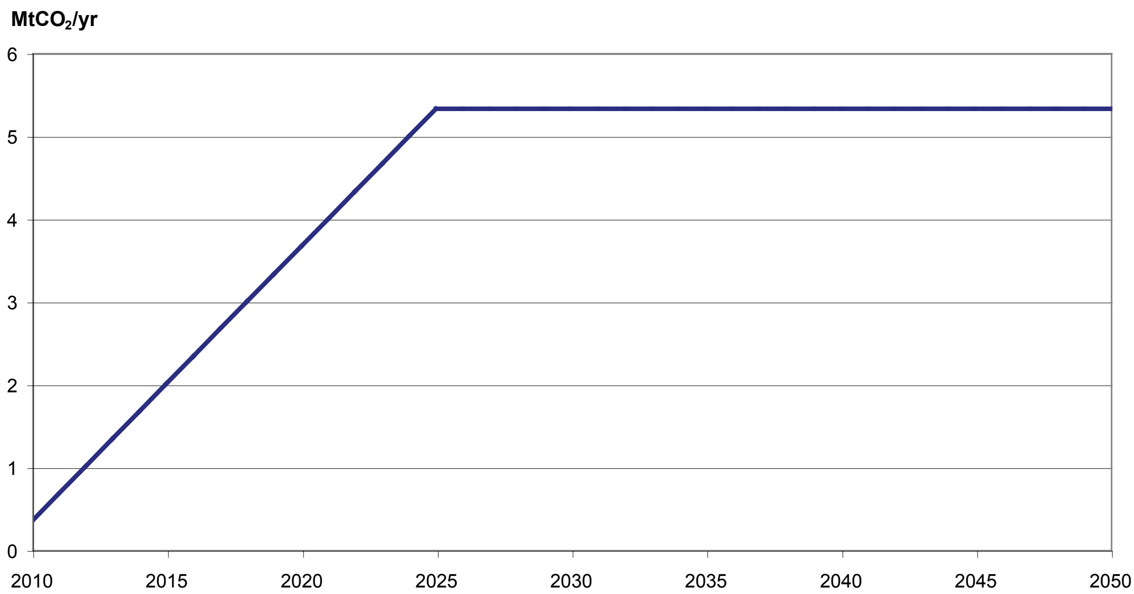
The wider use of CHP has been evaluated for the UK industrial base, excluding the oil refining and iron and steel segments where more complex issues require specific solutions. Assumptions relating to the proportions of existing energy use replaced by heat from alternative CHP applications are shown in table A3.7.1.

Heat losses are assumed to be identical to existing losses.

The electricity generated by CHP is subtracted from industrial consumption.

The CHP enhancements are assumed to be implemented linearly from 2012 to 2025.

Figure A3.5.1 CO_2 emissions reduction from conversion of other fuels to gas



A3.7.1 Gas CHP

Natural gas-fired CHP systems usually include combined cycle designs with a gas turbine burning gas with heat recovered from the GT exhaust gases to raise steam. The steam is expanded though a steam turbine to appropriate process conditions (typically 10-20 bar, 200°C) suitable for distribution to heat-consuming processes on site.

Gas-fuelled CHP is assumed to have a power-to-heat ratio of 1 and is applied from 2015 to 2025.

The results of the analysis are shown in figure A3.7.1.1.

The rapid reduction in CO_2 emissions to 2025 can be seen for electricity at the current level of carbon intensity. The intermediate curves for transitions of the carbon content of electricity to 40% and 20% of current values reach a peak in 2025 and then decline more slowly to 2050. This shows that natural gas-fuelled CHP has significant value while the carbon content of electricity remains high. When CO_2 emissions fall in the electricity sector, natural gas-fuelled CHP becomes less attractive as an emissions reduction measure.

The implication of these curves is that industrial CHP fuelled on natural gas is only a useful measure for installation in the interim period from 2015 to 2030.

The corresponding forecast of electricity generated by industrial CHP systems is shown in figure A3.7.1.2.

The electricity generated by the CHP systems represents a significant proportion of power consumption in the industry sector, rising to 65% of the 'business as usual' consumption.

A3.7.2 Biomass CHP

Using biomass fuels in CHP plants instead of natural gas has a different impact on industry sector power requirements and CO_2 emissions. Biomass fuels cannot be used to fire gas turbines directly and biomass gasification is not yet proven. As liquid biofuels suitable for diesel engines (such as palm oil) are only available in limited quantities, biomass-fuelled CHP plant will generally need to burn solid biomass in boilers. These boilers will raise high-pressure steam to drive a steam turbine generating power, with its exhaust steam delivered at about 10 bar, suitable for lower-temperature process heating. This configuration means that the power generated per unit heat delivered is much less than for a combined cycle CHP plant fuelled on natural gas.

Table A3.7.1 Heat replacement by CHP application

Heat use	Proportion from CHP
Low-temperature processes	70%
Drying	50%
Space heating	70%

Figure A3.7.1.1 CO_2 emissions reduction from gas CHP

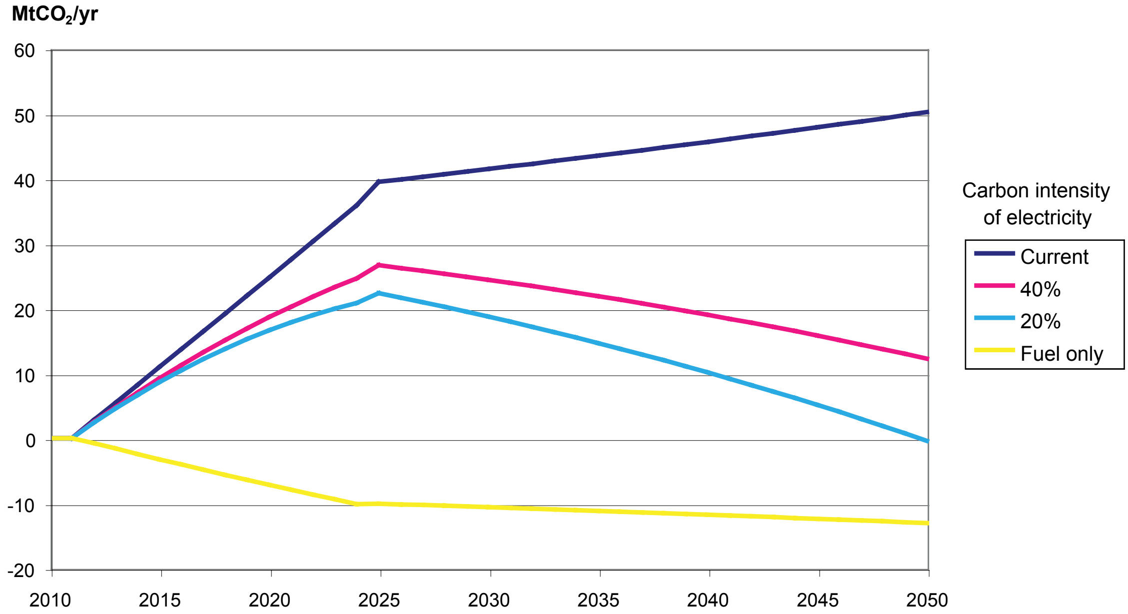
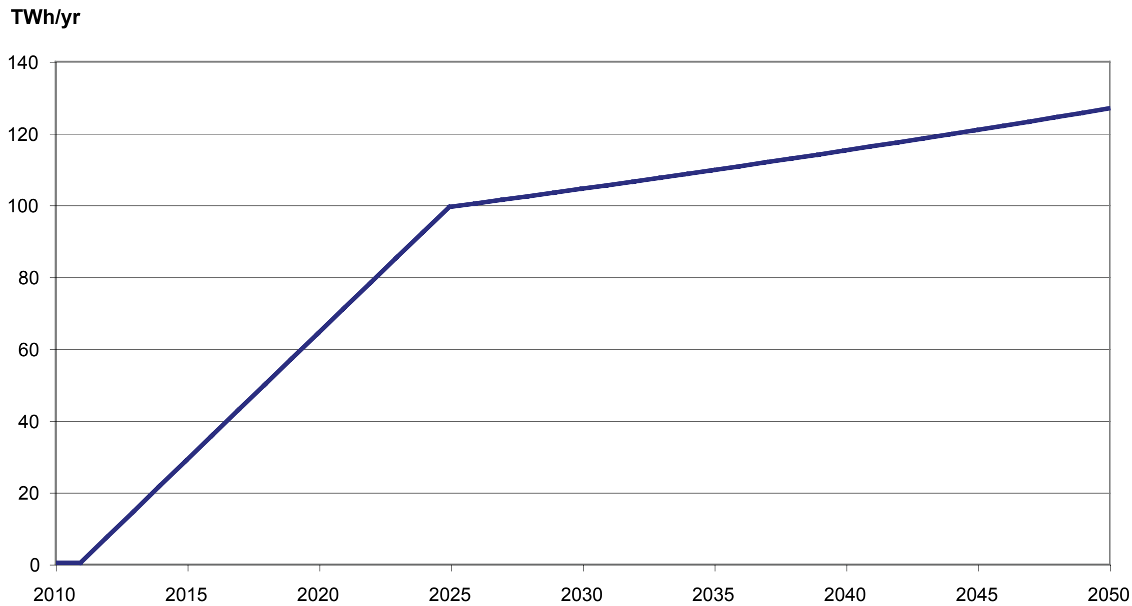


Figure A3.7.1.2 Electricity production from gas CHP



Using identical assumptions about the take-up of biomass CHP in industry as for the natural gas CHP option, the CO_2 emission reduction and electricity generation were calculated and presented in figures A3.7.2.1 and A3.7.2.2.

Figure A3.7.2.1 shows that biomass CHP offers a significant and sustained CO_2 emission reduction. Even allowing for the carbon intensity of electricity falling to 20% of its current value, the reduction in CO_2 emissions from this option continues to rise, reaching almost 30 million tonnes per year by 2050.

The figure for electricity generation shown in figure A3.7.2.2 is less than 20% of the figure for the application of natural gas-fuelled CHP because of the lower thermal cycle performance of biomass-fuelled plant.

The biomass consumption needed to deliver the heat and electricity displaced from other fuels rises to 8.3 MOTE in 2050. The actual quantity of biomass will be three to four times this amount because of the relatively low heating value of biomass fuels. It is unlikely that approximately 40 million tonnes/yr of suitable biomass material would be available in the UK to meet this requirement.

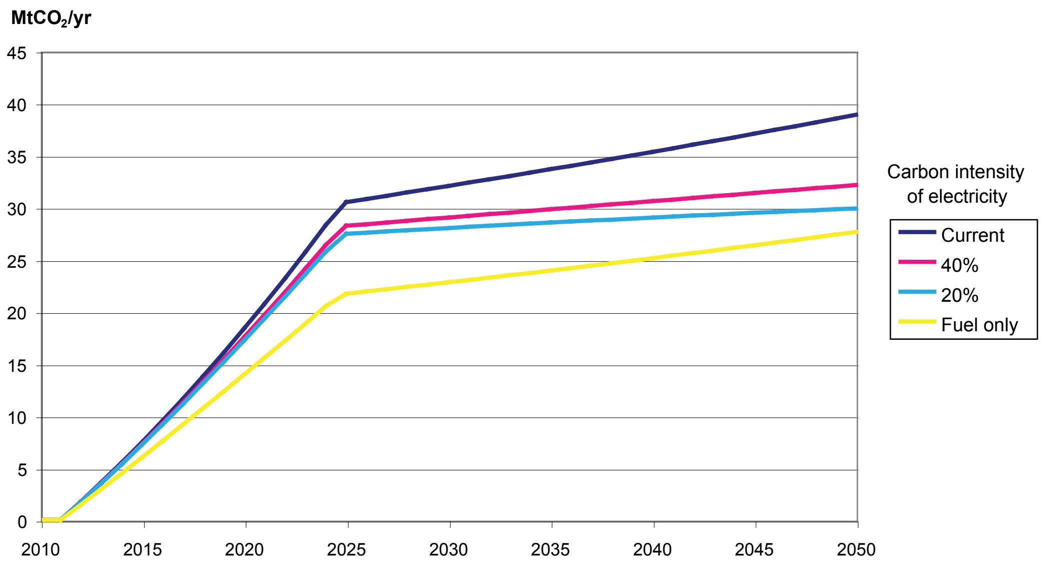
A3.8 Convert to electricity

As the fossil carbon use in each sector decreases over the period to 2050, pressure to reduce CO_2 emissions is expected to rise inexorably and unconventional low-carbon processes will become increasingly attractive to industry. One such possibility considered here is the development of processes that avoid the use of fossil fuels by using electricity as the energy source.

The development of new processes is being explored continually within industry to identify opportunities to reduce costs or increase the quality of products. In future, far more processes will change to reduce CO_2 emissions and cut costs. Since these developments apply to diverse processes currently using high temperatures, the actual relationship between the current use of fuel and the future use of electricity (for example by electrolytic processes) is unknown. We have therefore pessimistically assumed that the same energy input will be required from electricity as from the current fossil fuel.

The data on high-temperature process fuel use available from the BERR industrial data tables is limited to the chemical, mineral processing, iron and steel, mechanical engineering, electrical engineering and vehicles subsectors. This restricted set of data has

Figure A3.7.2.1 CO_2 emissions reduction from biomass CHP



been used as a sample to test the impact of switching 90% of high-temperature process energy use to electricity. A timescale for transition from 2025 to 2045 has been used, as it appears likely that the reduced carbon intensity of electricity at that time will make such conversions attractive.

The impact on industrial CO_2 emissions of this option is shown in figure A3.8.1 and the additional electricity consumption data is shown in figure A3.8.2.

The CO_2 emission reduction rises to a modest 14 million tonnes per year with an increase of electricity consumption of 54 TWh/yr by 2050. These figures correspond to a CO_2 emission reduction of 0.25 kg/kWh, approximately half the level of current electricity generation. This means that the option will only be effective in reducing CO_2 emissions when electricity has a carbon intensity below this level. Since the target value for electricity is around 0.1 kg/kWh, the replacement of fossil fuels by electricity after 2025 would appear appropriate.

The assumptions made in the analysis are inevitably approximate, but it is significant that no improvement in process energy use has been assumed. Any improvement in energy efficiency achieved in converting processes to electricity would increase the benefit seen from this measure. Developments in technology are therefore likely to mean that this option will become progressively more attractive and important as a future CO_2 emission reduction measure.

A3.9 Renewable generation

Industrial sites offer significant potential for the installation of renewable energy plant, primarily exploiting wind and solar energy. Data published by the Department of Communities and Local Government enables an estimate of industrial floorspace to be made. Table A3.9.1 shows the distribution of industrial and commercial floorspace in England and Wales in 2006.

Assuming that the industrial sites were the predominately larger sites gives an estimate of 225 million m^2 for industrial floorspace.

Since there are no national statistics for industrial land area, it is only possible to estimate the area of industrial land on which wind turbines might be erected. We have estimated that only 450 million m^2 or 450 km^2 would be suitable for wind generation.

Figure A3.7.2.2 Electricity production from biomass CHP

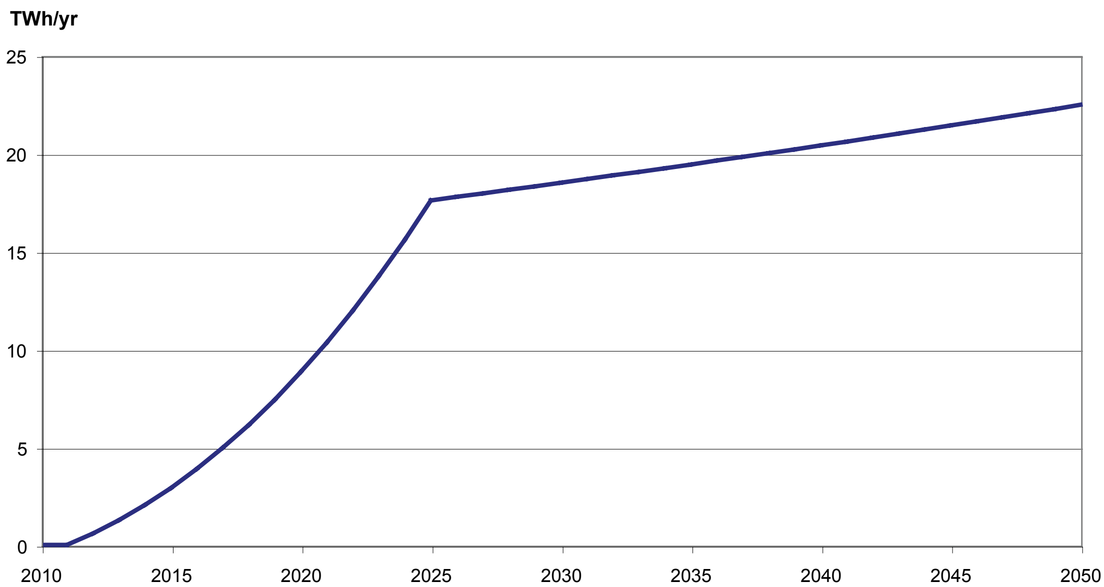


Figure A3.8.1 CO_2 emissions reduction from converting high-temperature process to electricity

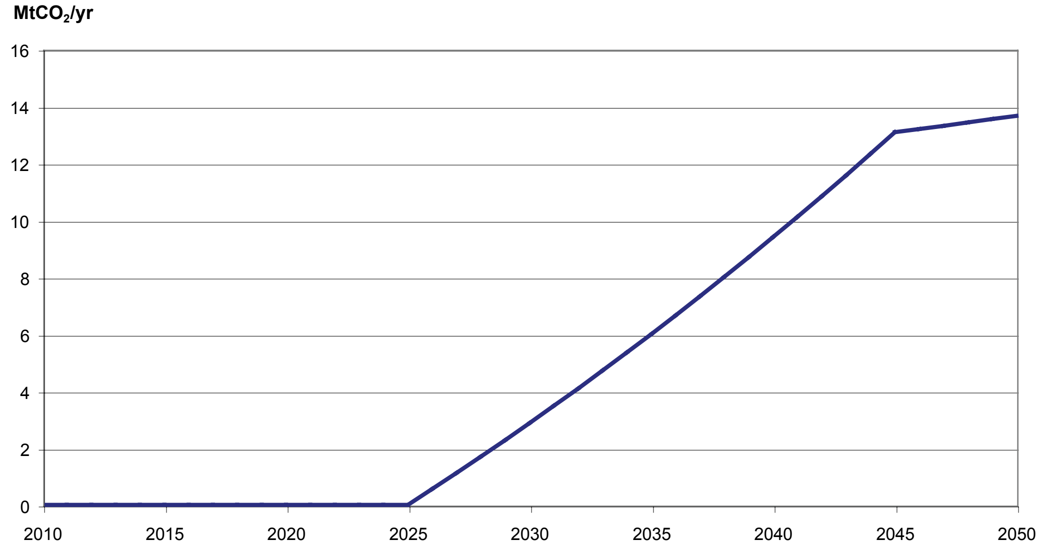
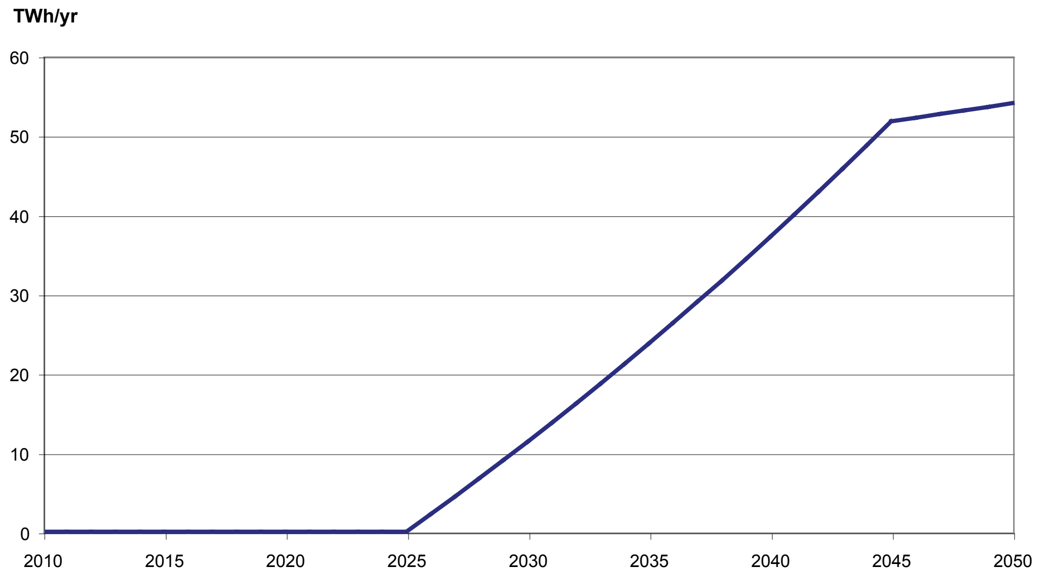


Figure A3.8.2 Increase in electricity consumption from converting high-temperature processes to electricity



Using a guideline figure of 10 MW/km² for density of onshore wind capacity indicates that a potential capacity of 4.5 GW of wind capacity could be installed. The capacity factor of these wind turbines would be lower than for wind farms sited for maximum performance, so an estimate of 25% was used rather than the 30% typical for onshore wind farms. The potential contribution of wind from industrial sites is therefore 9.9 TWh/yr.

Solar PV power generation could be installed on the roofs of many industrial buildings in a similar way to that described for the domestic residential sector.

Assuming that a solar panel area equivalent to 10% of floorspace could be installed, and using the same performance assumed for domestic solar PV systems, industrial solar PV systems could deliver a peak output of 6.75 GW and energy of 6 TWh/yr in 2050.

Figure A3.9.1 shows the estimated growth of this on-site renewable energy capacity from the industrial sector, with the pessimistic assumption that there is no increase in industrial buildings or land to 2050.

A3.10 Carbon capture and storage

The technology and infrastructure needed to capture CO_2 emissions and collect them for long-term storage is most likely to be viable when applied to small numbers of large CO_2 emitters. Several industry segments have large installations with nationally significant scales of CO_2 emission. These include steel works, aluminium smelters, major oil refineries and petrochemical sites, cement works and coke oven complexes.

Table A3.10.1 lists the key industrial emitters and their 2006 CO_2 emissions.

The analysis assumes that the energy used in the capture process results in no further emissions. Since the technology for the large-scale capture and storage of CO_2 is currently being developed, it has been assumed that the first installation would be in 2020, with all of the target emissions being captured by 2035.

Figure A3.10.1 shows the reduction in CO_2 emissions achieved by applying CCS in accordance with these assumptions.

The reduction achieved represents an overall cut in industrial emissions of about 30% of the 'business as usual' value in 2050, indicating the significance of these key emitters and the importance of CCS as an option.

Table A3.9.1 Floorspace distribution[63]

Floorspace total in 000m²								All bulk premises
Year	Floorspace size bands in m²							
	Up to 30.00	30.01-100	100.01-300	300.01-1,000	1,000.01-3,000	3,000.01-10,000	More than 10,000	Total
2006	2,856	32,103	75,063	113,394	110,586	119,048	142,511	595,561

[63] Department for Communities and Local Government, 'P412 Commercial and Industrial Property: Bulk Class Hereditaments by Floorspace Sizeband: England and Wales, 1st April, 1998-2008' 2009.

Figure A3.9.1 Electricity production from on-site renewable generation

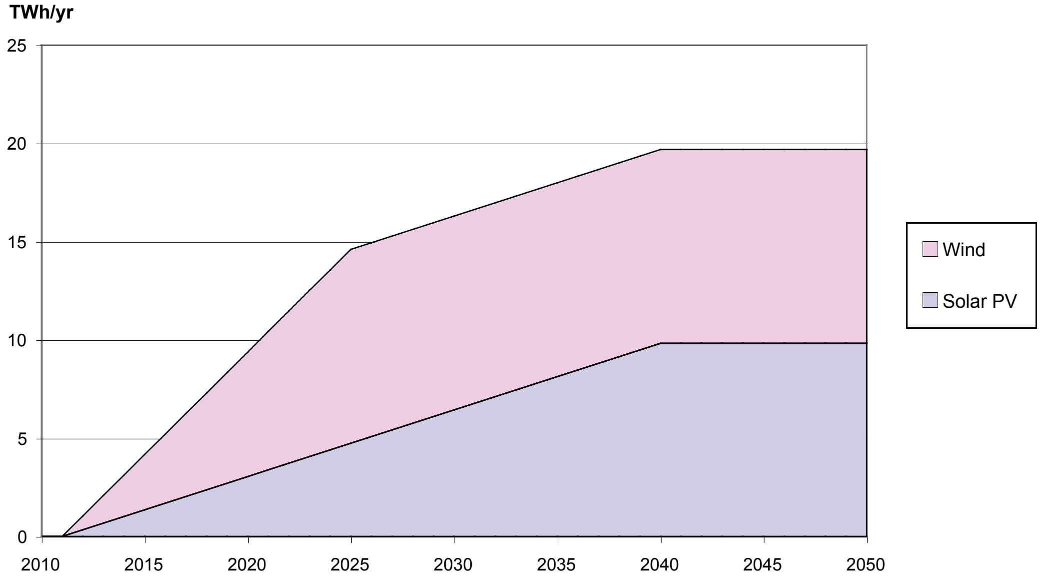


Figure A3.10.1 CO_2 emissions reduction from applying CCS to major industrial emitters

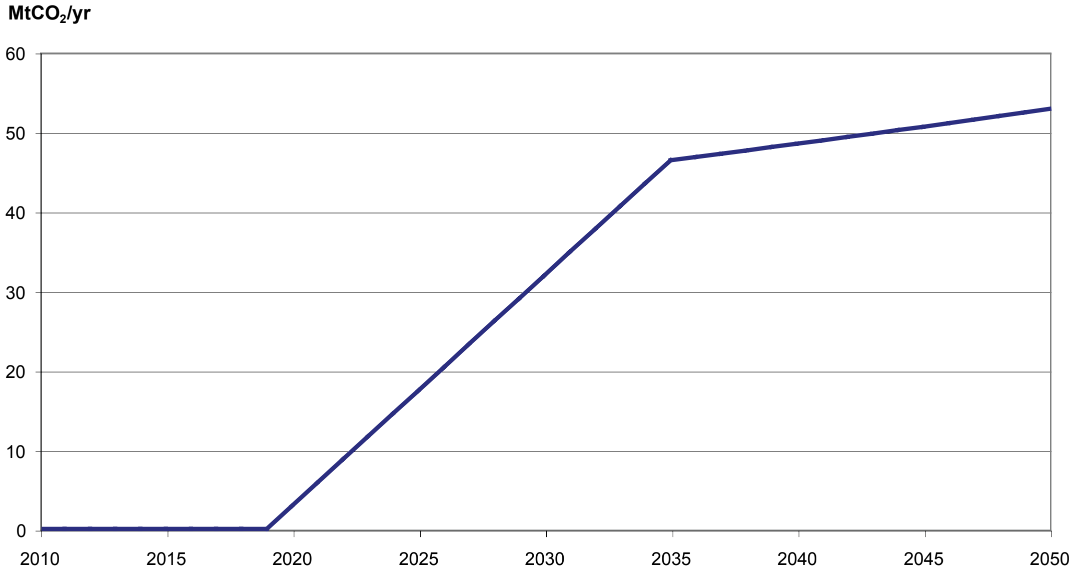


Table A3.10.1 Potential reductions in CO_2 emissions by CCS

Key emitters	2006 CO_2 emission ($MtCO_2$/yr)	Subject to capture (%)	Capture efficiency (%)	Target process
Chemicals	1.56	90	90	Ammonia production
Refined petroleum products	15.68	80	90	All
Coke oven products	8.14	70	90	All
Mineral products	5.89	95	90	Cement manufacture
Iron and steel	20.46	70	90	All
Non-ferrous metals	0.57	90	90	Aluminium smelting

Appendix A4.
Commercial sector

The following measures are assessed for the commercial sector:

- building insulation
- cooling and ventilation
- lighting efficiency
- hot water efficiency
- convert to gas
- convert to biomass
- heat pumps
- gas CHP
- biomass CHP
- solar hot water
- renewable generation

A4.1 Building insulation

The buildings used in this sector range from newly constructed to those over 100 years old. The older building stock was constructed to very different standards to those which apply today and those expected in future.

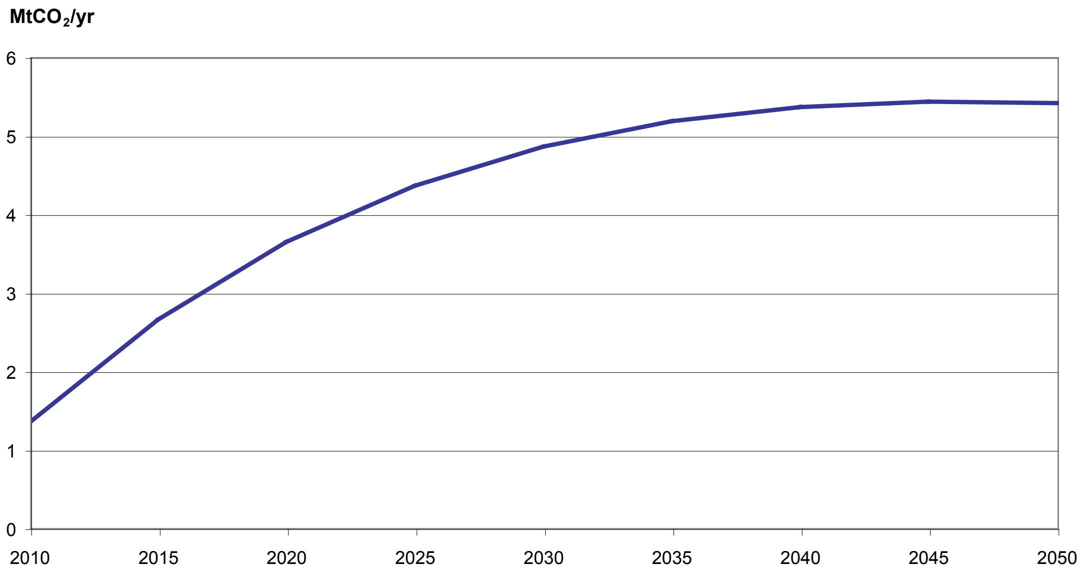
New construction is expected to follow the domestic residential sector in complying with requirements to become carbon neutral by 2018 for public buildings and 2016 for privately owned buildings. This shift will mean that the energy consumption of new buildings will fall to low levels. Meanwhile, in order to satisfy the requirements of the carbon reduction commitment, existing stock must be upgraded to achieve a reduction in energy consumption of at least 1%.

This measure evaluates the impact of upgrading the building stock to reduce energy consumption by enhancing insulation and introducing other measures such as reduced air leakage. The potential for a greater and faster reduction in building heat demands has been based on the significant difference between the average existing energy consumption revealed by BERR data and 'best practice' identified in CIBSE Guide F[64]. It has been assumed that the remaining existing buildings will comply with current best-practice energy consumptions, reduced by a further 30% by 2050.

Figure A4.1.1 shows the reduction in CO_2 emissions from heating fuels while figure A4.1.2 shows the reduction in electricity consumption.

These reductions are significant, exceeding 25% of the sector's heating requirements in 2025, rising to nearly 50% by 2050. Electricity consumption is cut by 4% by 2020 and 6% by 2050.

Figure A4.1.1 CO_2 emissions reduction for improved building insulation



[64] Chartered Institution of Building Services Engineers, 'CIBSE Guide F, Energy Efficiency in Buildings' 2004.

A4.2 Cooling and ventilation

Cooling and ventilation represents considerable electricity consumption in existing and new commercial building stock. There is a significant opportunity to increase the rate at which best-practice standards are applied to existing stock.

Energy consumption for cooling and ventilation in the base case is assumed to fall by 1% per year. In the improved case, it is assumed to fall by 3% per year, bringing the average performance of existing buildings to 30% better than current best practice by 2050. Meanwhile, new buildings are assumed to comply with improved standards which would drive energy consumption downwards at 2% per year. These levels of reduction imply significant improvements in cooling systems, reflecting the increasing use of passive design techniques in new buildings.

Figure A4.2.1 shows the reduced electricity demand within the sector as a result of these improvements.

This is a useful improvement of about 7% in the sector's electricity consumption by 2050, compared with the base case.

A4.3 Lighting efficiency

Lighting is a major consumer of energy in buildings. Lighting technology has advanced radically over the past 50 years, and further significant improvements in energy efficiency are expected by 2050.

The base case assumes a reduction in electricity consumption per unit floor area for lighting in existing buildings by 14% over the period to 2050, a conservative figure given the much larger reduction in the previous 40 years. In the improved case we assumed that the trend of lighting efficiency improvement will result in a reduction in lighting electricity consumption per unit floor area of existing space by 80%, to 70% of current best-practice levels.

For new buildings, the base case assumes a reduction of electricity consumption per unit floor area for lighting of 35% by 2050. The improved case assumes that new building lighting electricity consumption per unit floor area will fall by 65% over the same period.

The resulting electricity consumption reduction is shown in figure A4.3.1.

Figure A4.1.2 Reduction in electricity consumption from improved building insulation

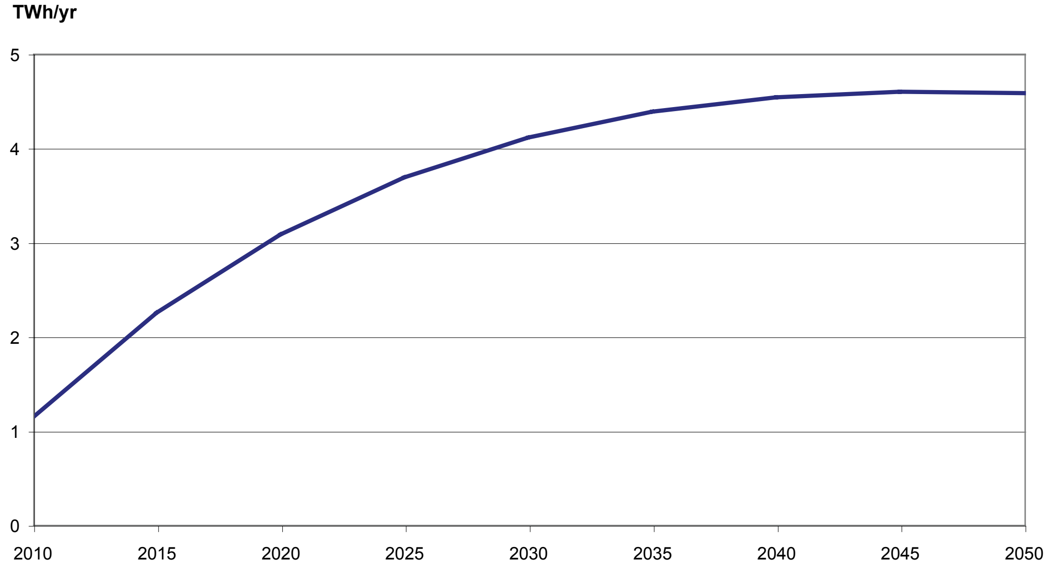


Figure A4.2.1 Reduction in electricity consumption from improved efficiency in cooling and ventilation

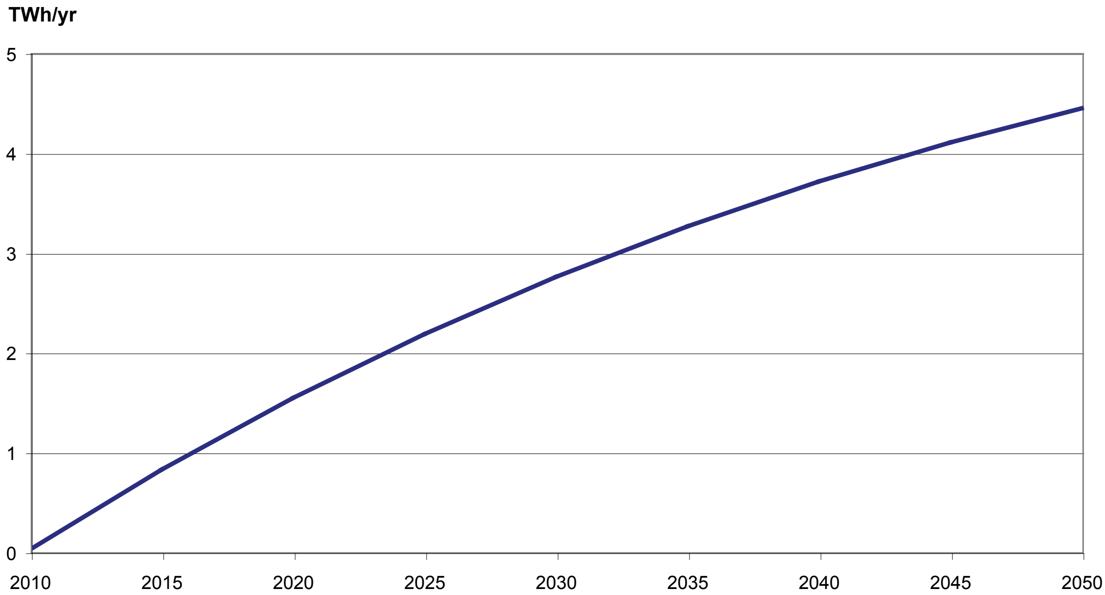
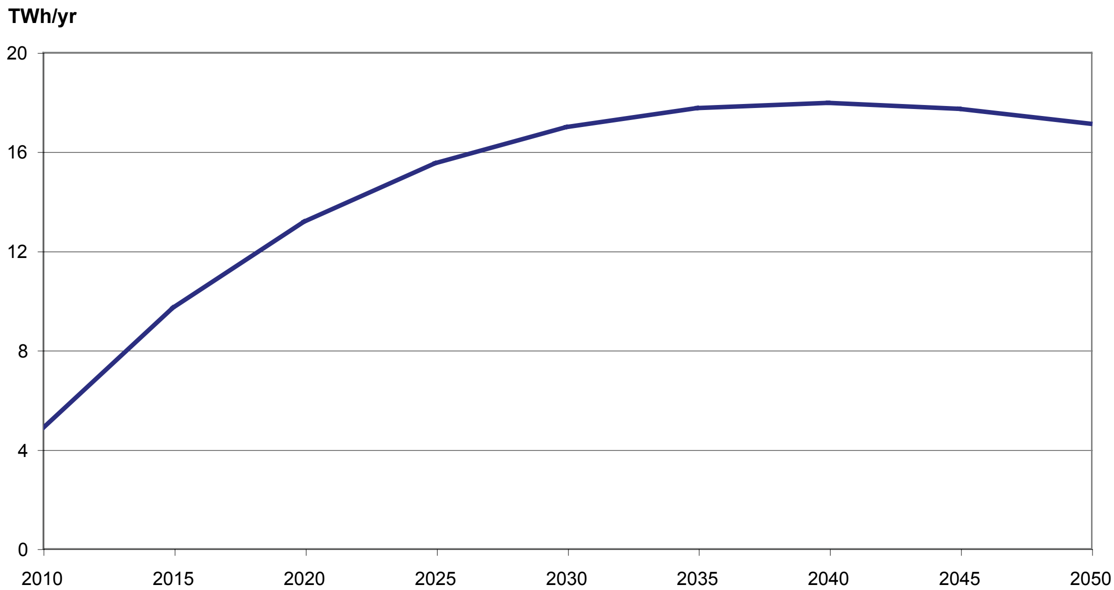


Figure A4.3.1 Reduction in electricity consumption from improved lighting efficiency



The reduction in electricity consumption reaches its peak value in 2040 due to the reductions in existing buildings. As those buildings are progressively replaced during the period, the absolute saving falls to 17 TWh or 23% of the 'business as usual' case electricity demand in 2050.

A4.4 Hot water efficiency

Analysis of the BERR statistical data shows that the energy attributed to hot water supply in this sector is significantly worse than the CIBSE Guide F values. The poor design of existing hot water systems and compliance with legionella regulations produces significant energy wastage.

This measure considers that, by 2050, hot water systems in existing buildings can be brought up to the best-practice levels defined in CIBSE Guide F, and that standards for new buildings will demand a best-practice energy consumption that is 30% below current best practice.

The results of the analysis are shown in figures A4.4.1 and A4.4.2 for reduction of CO_2 emissions and reduction in electricity consumption respectively.

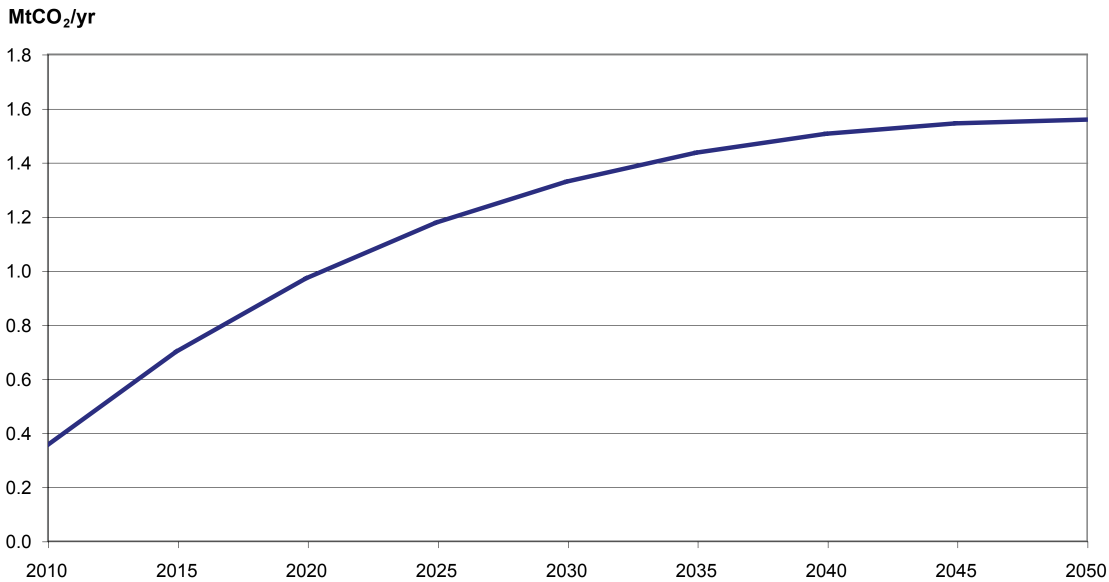
The reduction in CO_2 emissions is a significant addition to the underlying base improvement assumption, reducing sector CO_2 emissions by about 14% of 2050 values.

The reduced electricity demand improvement is less significant, rising to about 2% of the 2050 'business as usual' electricity demand.

A4.5 Convert to gas

Significant CO_2 emissions result from the use of coal and oil for building heating. Electricity is also used for space or water heating to a significant degree, resulting in excess emissions because of the current carbon efficiency of electricity. This option considers the conversion of all coal and oil heating to gas – a relatively straightforward conversion. Only 50% of

Figure A4.4.1 CO_2 emissions reduction from improved hot water system efficiency



electrical heating is assumed to be converted to gas, given the difficulties of converting some types of electrical heating. Since these conversions can be applied in conjunction with a building upgrade, we assumed that the switch could be completed by 2020.

Figure A4.5.1 shows the impact of this switch on CO_2 emissions. Figure A4.5.2 shows the associated reduction in electricity consumption in the sector.

These findings show that converting other fuels to gas would achieve a sector reduction in CO_2 emissions of up to 17% by 2020. This would decline to near zero as electricity sector production becomes less carbon intensive by 2050. Electricity consumption is reduced by 8% in 2020, falling to 6.6% of its 'business as usual' case value by 2050. The profile of benefits of this option suggests that promoting an early implementation of this measure to existing buildings in the sector would deliver a useful contribution to early emission reduction, but that further adoption on new construction after 2030 would not offer additional benefits.

A4.6 Convert to biomass

Conversion of heating systems to use carbon-neutral biomass-derived fuels could offer a significant reduction in CO_2. Such conversion is not feasible for all types and scales of buildings and it has been assumed that 100% of coal and oil heating, 80% of gas heating and 30% of electrical heating can be converted to biomass fuel. Since the conversions are potentially more complex, and new supply chains need to be established, it has been assumed that the conversion would start in 2010 but would not be completed until 2025.

Figure A4.6.1 shows the predicted reduction in CO_2 emissions resulting from this switch. Figure A4.6.2 shows the reduction in electricity consumption.

Figure A4.4.2 Reduction in electricity consumption from improved hot water system efficiency

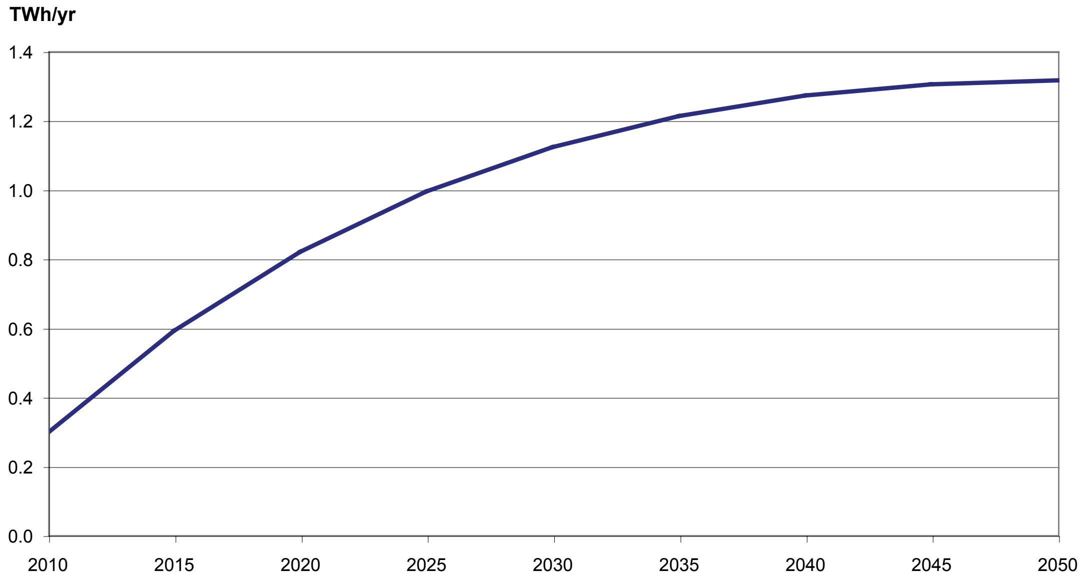


Figure A4.5.1 CO_2 emissions reduction from converting other fuels to gas

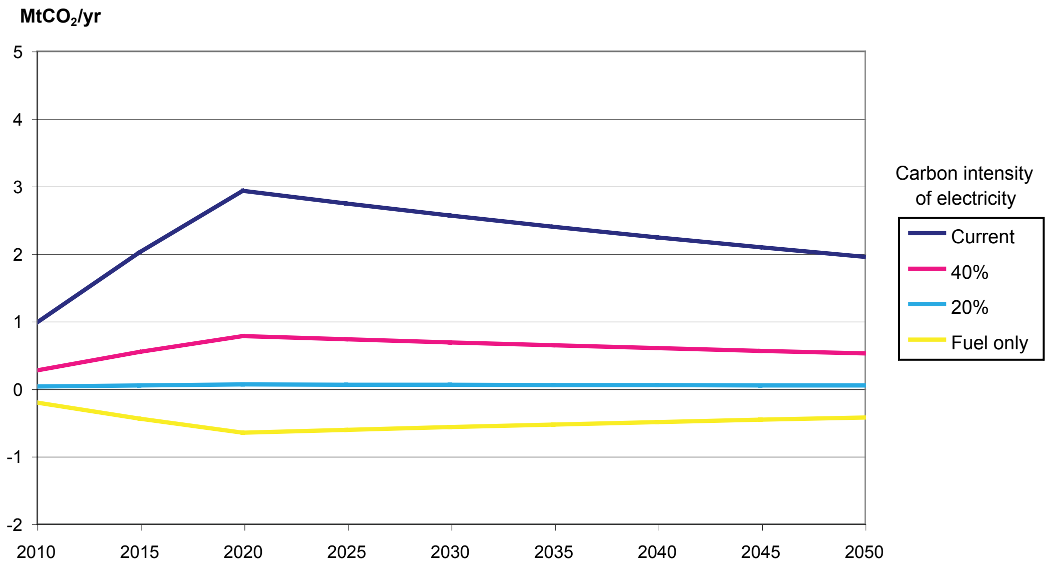


Figure A4.5.2 Reduction in electricity consumption from converting other fuels to gas

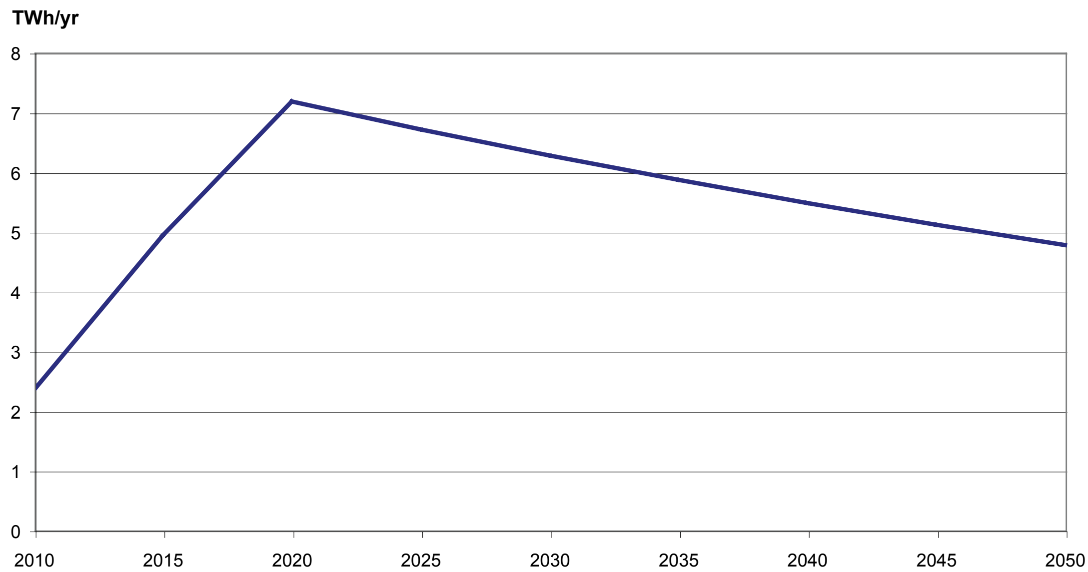


Figure A4.6.1 CO_2 emissions reduction from converting other fuels to biomass

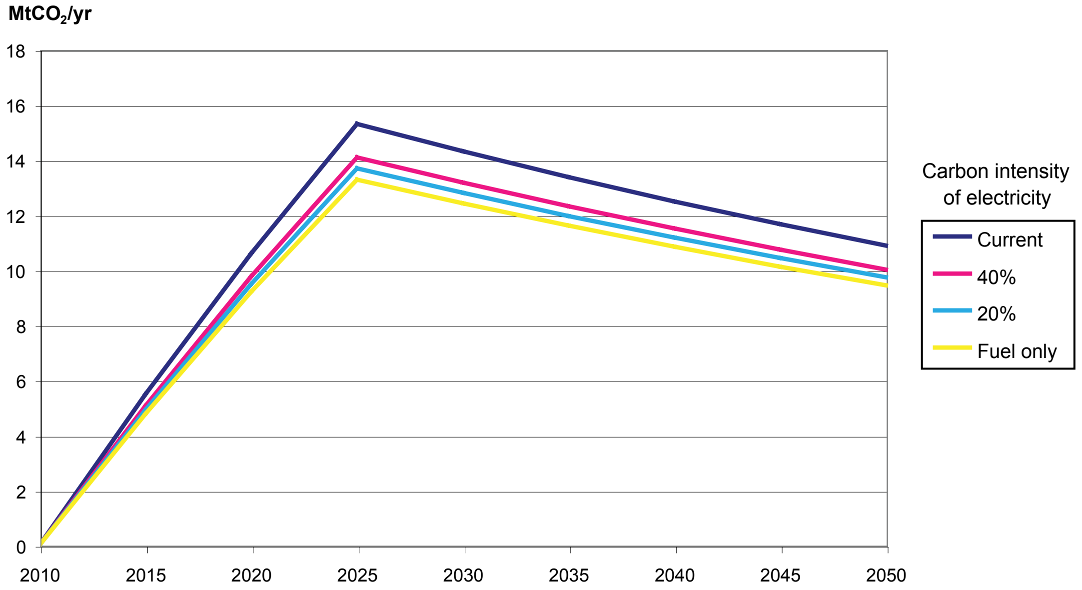
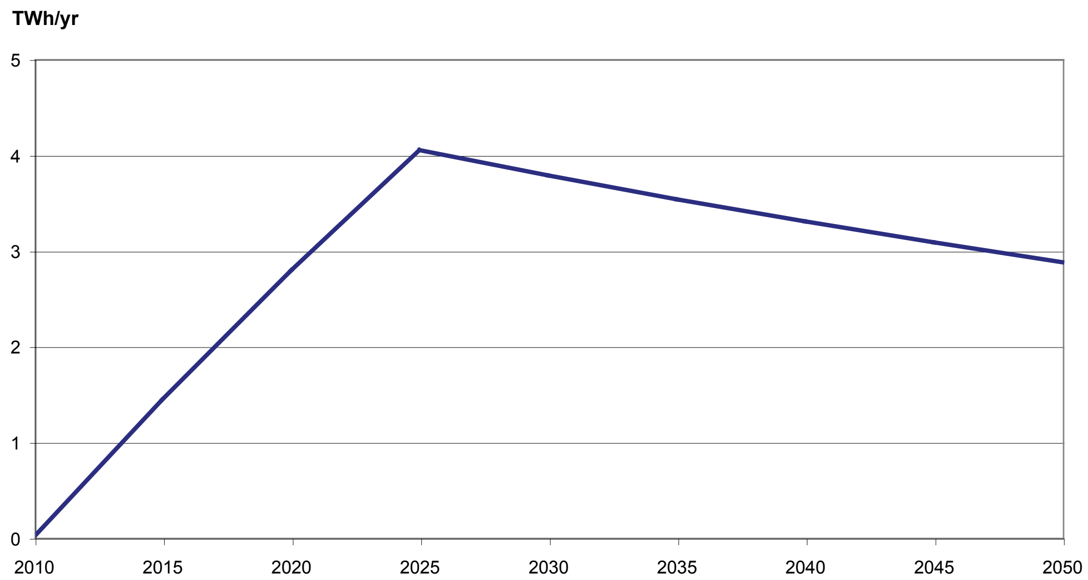


Figure A4.6.2 Reduction in electricity consumption from converting other fuels to biomass



This analysis shows that the reduction in CO_2 emissions from a switch to biomass would be a minimum of 13 million tonnes per year in 2025 and 9 million tonnes per year in 2050, a reduction of 82% in each case. Further CO_2 emission reductions result from the elimination of some electricity demand. In 2025 these could be as high as an additional two million tonnes per year. By 2050 the figure is likely to have declined to about 0.3 MT/yr as a result of the significant decline in the carbon content of electricity by that date.

The corresponding reduction in electricity demand for this measure is 4 TWh/yr in 2025, falling to 2.8 TWh/yr by 2050. This is a reduction in sector electricity demand of almost 4%.

The scale of reduction in CO_2 emission from this switch would make it an attractive option. However, the energy required as biomass comes to 8.7 MTOE in 2050, approximately 40 million tonnes of biomass fuel per year. Only a fraction of this quantity of biomass is likely to be available, limiting the potential switch of fuel.

A4.7 Heat pumps

Heat pumps can be used for space heating, extracting heat from the surrounding environment to supply the building. For smaller-scale installations, heat can be extracted from the ground or adjacent bodies of water. For the larger installations typically required in the commercial sector, the ambient or ventilation exhaust air is used as the source of heat. Although this arrangement requires higher electricity consumption per unit heating supplied than alternatives, it offers reduced consumption compared with electric heat. It can be cost effective in comparison with other fuels, particularly when the heat pump is configured to provide seasonal cooling when required.

The performance of the heat pumps assumed for this switch is based on a coefficient of performance of 2.6, the corresponding minimum value defined in CIBSE Guide F. We assumed that heat pumps replace 100% of coal and oil heating, 90% of gas heating and 50% of electric heating. Energy consumption for hot water is assumed to be unaffected, and the switch completed for existing buildings by 2025.

Figure A4.7.1 shows the CO_2 reduction and figure A4.7.2 shows the increase in electricity consumption for this fuel switch.

The CO_2 emission reduction achieved by the assumed application of heat pumps is substantial. Considering the direct CO_2 emissions in the sector, a 78% reduction from the 'business as usual' case is achieved from 2025 to 2050. If allowance is made for the increased CO_2 emissions in supplying electricity, the benefit in 2025 is likely to be cut to about 25%, rising to 66% if the carbon content of electricity is reduced to 20% of its current value by 2050, as is expected.

This option clearly offers significant benefits in the longer term, but it is best promoted after 2015 when the carbon intensity of electricity is falling rapidly.

The increase in electricity demand caused by the widespread adoption of heat pumps in this sector is important, representing an increase of 20% in 2025 and 18% in 2050. The benefits of the significant emissions reductions may nevertheless make this an attractive option overall.

A4.8 Gas CHP

Combined heat and power units are becoming widely available for the smaller applications typical of commercial buildings. These offer high efficiency of use of gas and valuable electricity production, with effective electricity generation efficiency generally in excess of 90%.

This option considers the application of high-performance CHP systems to displace a large part of the heating and hot water energy demands of the sector while contributing electricity into the distribution system. The electrical output of CHP units is typically 40-100% of their heat output. A figure of 60% has been used as an indicative ratio for the mix of likely system types needed to match the larger heating loads in the sector.

It has been assumed that coal and oil burn will be completely replaced, and gas-fired heating reduced by 60%, as CHP will only provide the baseload heat demands. 35% of electricity used for heating is assumed to be replaced by CHP heat. It is also assumed that any excess electricity can be exported.

Figure A4.8.1 shows the impact of the application of gas-fuelled CHP on CO_2 emissions. Figure A4.8.2 shows the reduction in electricity consumption.

Figure A4.7.1 CO_2 emissions reduction from heat pumps

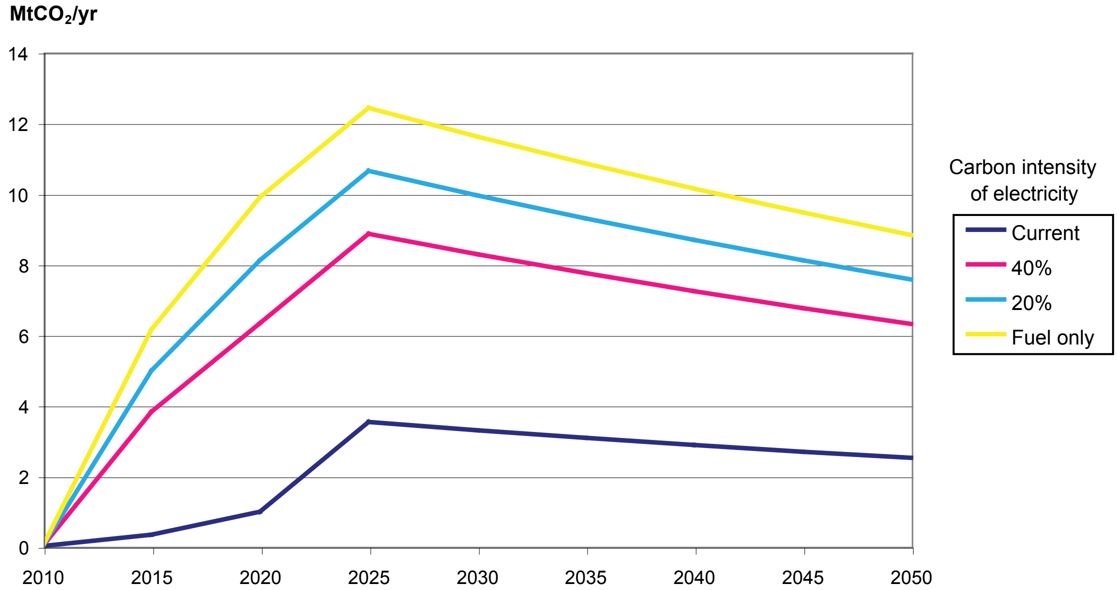
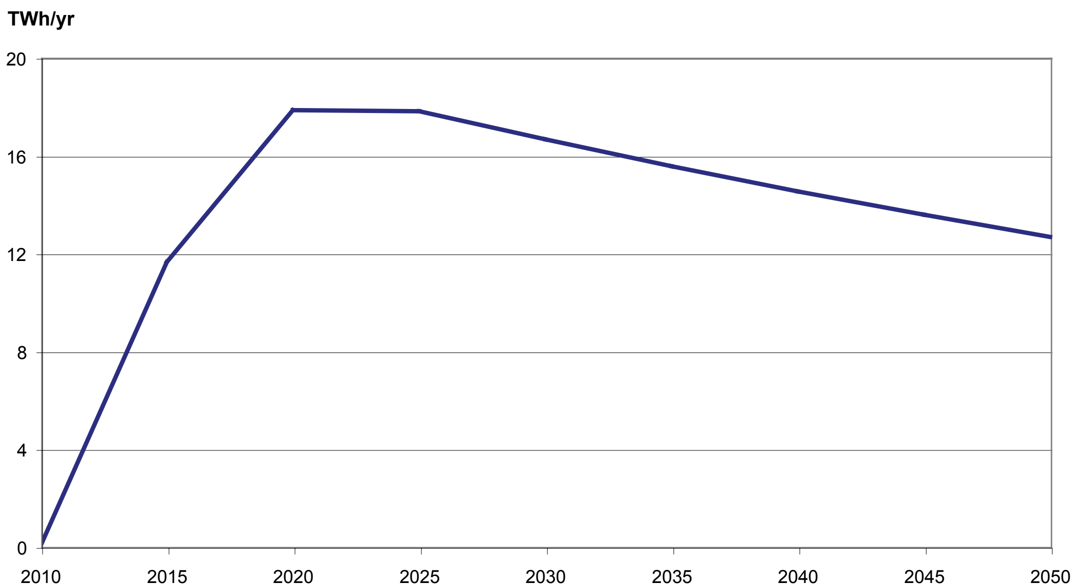


Figure A4.7.2 Increase in electricity consumption from heat pumps



Applying gas CHP has a substantial impact on sector CO_2 emissions and electricity consumption. Overall CO_2 emissions are reduced by up to 11 million tonnes per year in 2025 if electricity retains its current carbon intensity. However, in the same year, strictly fuel-related CO_2 emissions in the sector are increased by almost 7 million tonnes per year. The change to overall fuel-related and electricity-related emissions of the sector in 2025 is a reduction of around 19% of 'business as usual' values.

By 2050 the overall impact on CO_2 emissions is likely to be close to neutral, as the carbon intensity of electricity will have fallen to around 20% of current levels. This suggests that the application of gas CHP is an appropriate option early in the period to 2050, but that application after 2030 is unlikely to deliver large benefits in overall carbon reductions attributable to the sector.

Gas CHP plays a significant role in reducing electricity consumption in the sector, offering a 40% reduction in demand from 2025.

A4.9 Biomass CHP

The benefits of gas CHP have been shown to be significant, and the potential of using a carbon-neutral biomass fuel in CHP systems is expected to be greater. The type of CHP system is likely to be different, as most biomass fuels cannot be burned in the diesel engines or gas turbines at the heart of smaller gas-fired CHP systems. The alternative CHP design burns the biomass in a boiler to generate steam which drives a steam turbine. This concept is likely to be viable only for larger-scale application and also has a much lower power-to-heat ratio than the gas CHP designs, with values typically in the range of 10-25%. We have assumed a figure of 20% for this study.

The penetration of the large biomass-fired CHP systems will be lower than for gas-fired CHP because of the restriction imposed by the larger minimum scale of application. Replacement levels of 50% of coal and oil, 30% of gas, and 20% of electric heating and water energy use have been assumed. We assumed that the conversion of sites to biomass CHP would be completed by 2025. Other assumptions for fuel use efficiency are the same as for gas CHP.

Figure A4.8.1 CO_2 emissions reduction from gas CHP

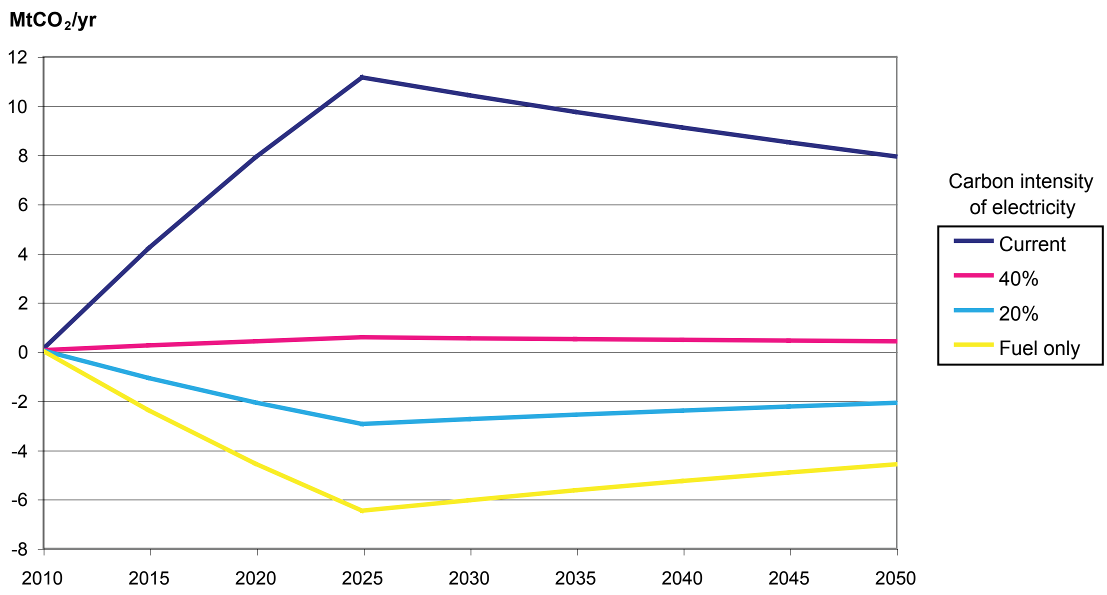


Figure A4.9.1 shows the result of the analysis of reduction in CO_2 emissions. Figure A4.9.2 shows the reduction in sector electricity consumption.

The CO_2 emission reduction from the application of biomass CHP is significant, with sector fuel-related CO_2 emissions reduced by 34% of the declining profile of 'business as usual' emissions from 2025. Overall emissions, including those associated with the production of electricity for the sector, are reduced by 15% in 2050.

The electricity consumption of the sector is reduced by 7.4 TWh/yr in 2025, representing a cut of 8.5%.

The biomass fuel energy consumption of the CHP systems assumed for the sector is calculated as 4.0 MTOE. At a typical biomass calorific value of 8,000 kJ/kg, this is equivalent to about 20 million tonnes of biomass per year. Given that this equates to the UK's total available biomass, the application of biomass CHP is likely to be feasible only at a reduced level of penetration to that assumed here.

A4.10 Solar hot water

Solar heating for hot water systems is an established technology for domestic use and has the potential for use in the commercial sector. There are clearly differences between the domestic and commercial sector which may require refinement of the technology and its application; nevertheless it has the potential to make a useful contribution to reducing fossil-fuel consumption.

Experience in the domestic sector indicates that 30-50% of hot water energy requirements can be supplied from solar water heating. A conservative figure of 20% has been selected for the assessment of its impact here.

Figure A4.10.1 shows the result of the analysis of reduction in CO_2 emissions.

Figure A4.10.2 shows the impact on electricity consumption of applying solar water heating.

Solar water heating offers modest reductions in CO_2 emissions: around 5% of emissions by the sector

Figure A4.8.2 Electricity production from gas CHP

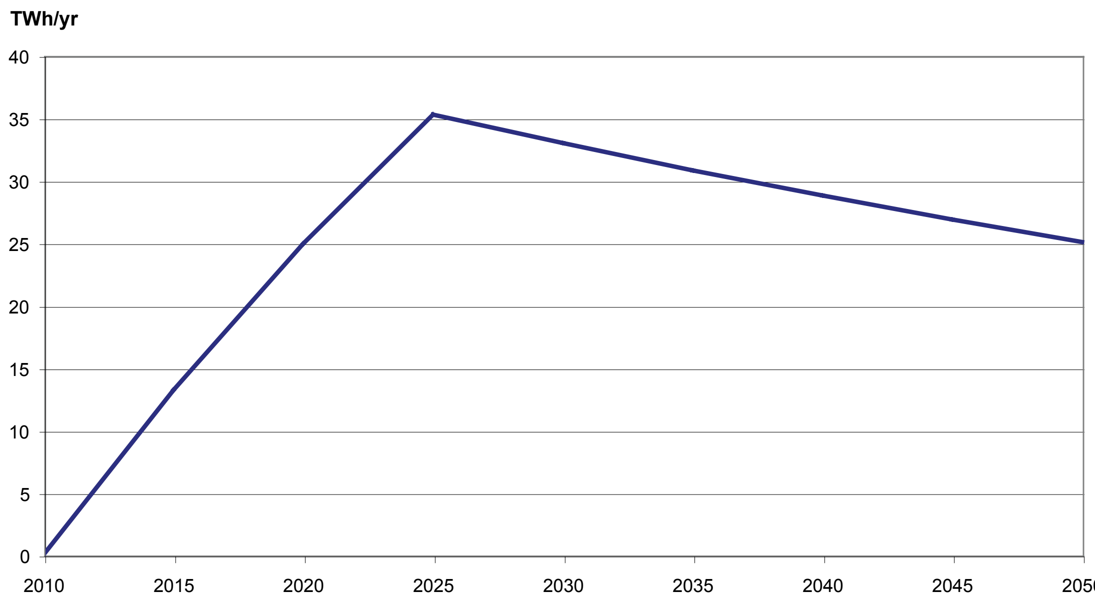


Figure A4.9.1 CO_2 emissions reduction from the application of biomass CHP

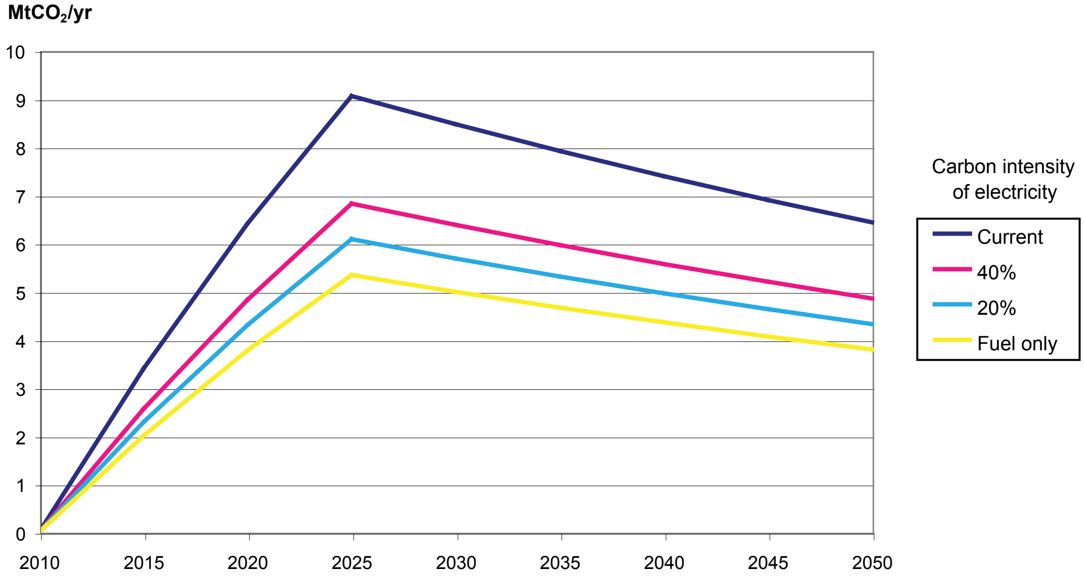
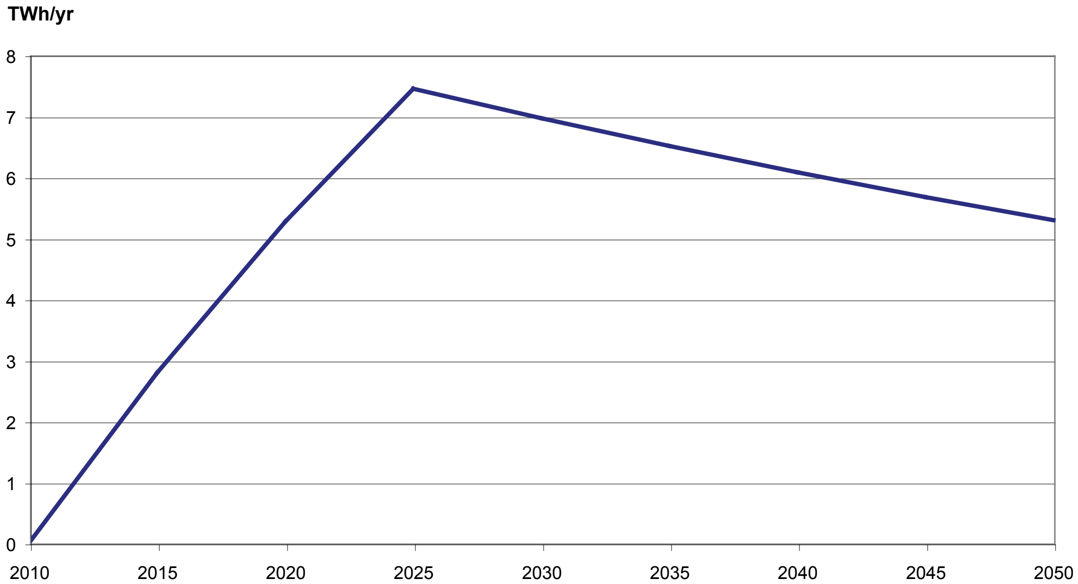


Figure A4.9.2 Electricity production from biomass CHP



in 2050. The reduction in electricity is even smaller, approximately 0.6%.

The temperature of solar hot water can reach high enough levels in summer for it to be used as the heat source for absorption chiller systems. The use of solar energy for building cooling could offer a reduction in energy consumption, but its impact cannot be modelled in detail because of insufficient data. It is likely however that the benefit would be at least as great as for the application of solar water heating.

A4.11 Renewable generation

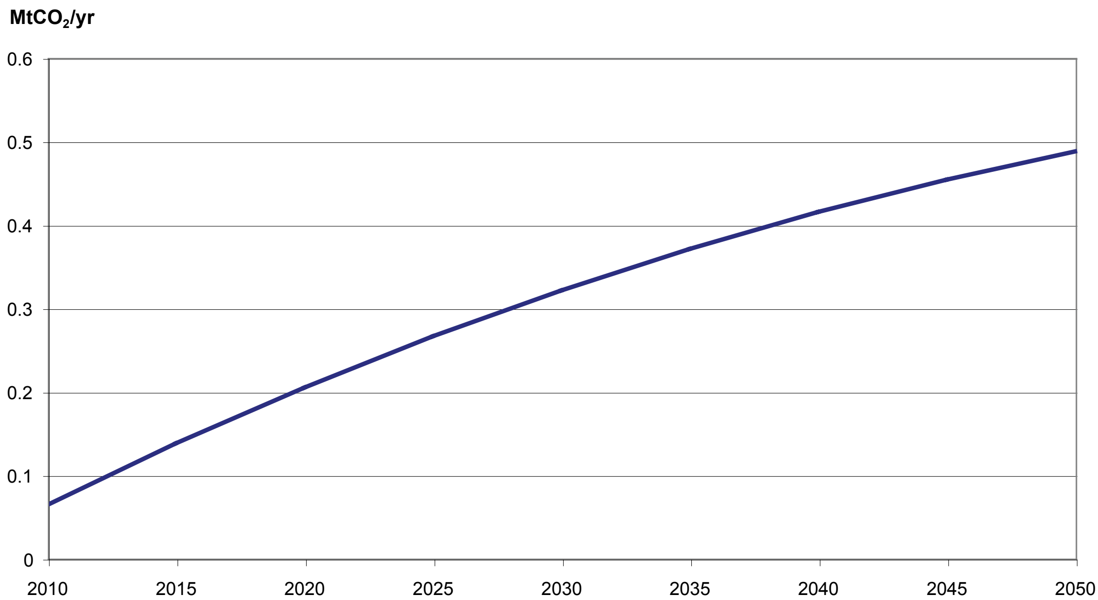
Commercial buildings offer some possibilities for on-site renewable power generation. Solar PV arrays can be installed on roof areas and on some favourable sections of facades. Wind turbines can be installed where there is sufficient open space, for example around larger retail warehousing. Wind turbine performance is likely to be reduced because of the positioning, but a useful contribution to electricity demand could still be made.

Assumptions for PV and wind generation technology have been made as for their application on industrial sites (see A3.9). For commercial premises, we assumed that land available on the site adjacent to the premises equal to 30% of floorspace was suitable for wind generation. We also assumed that solar PV panels could be installed on roof or wall space equivalent to up to 10% of the floorspace area. Estimates of commercial floorspace derived from DCLG[65] data indicate that 450,000 m^2 were in use in 2006.

Figure A4.11.1 shows the estimated electricity production from these renewable sources.

The analysis indicates that by 2040 up to 20% of the sector electricity consumption could be met by on-site renewable generation.

Figure A4.10.1 CO_2 emissions reduction from solar hot water



[65] Department for Communities and Local Government, 'P412 Commercial and Industrial Property: Bulk Class Hereditaments by Floorspace Sizeband: England and Wales, 1st April, 1998-2008' 2009.

Figure A4.10.2 Reduction in electricity consumption from solar hot water

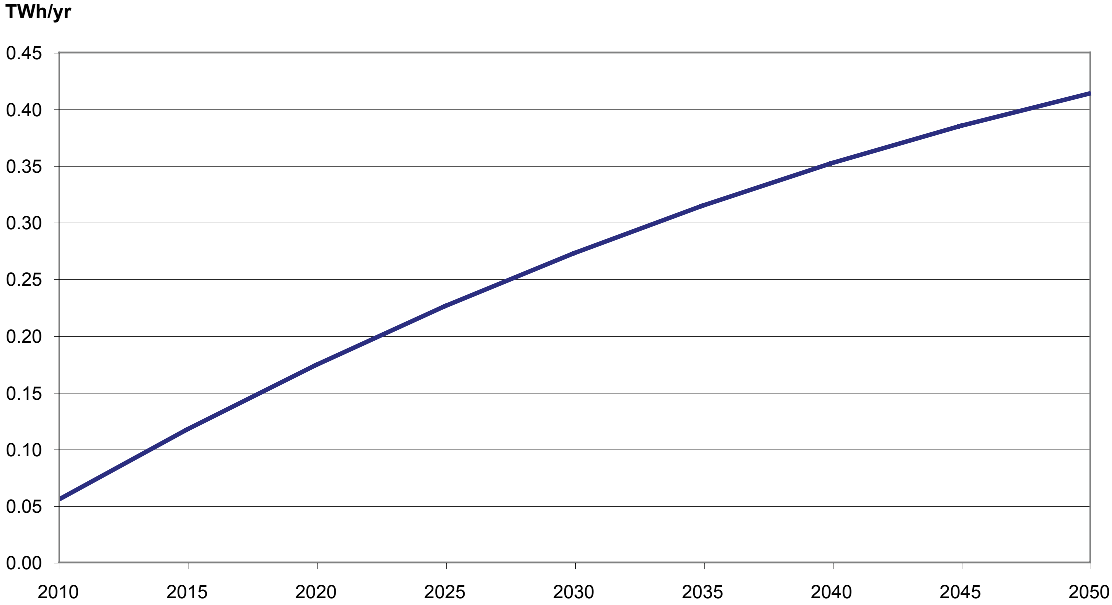
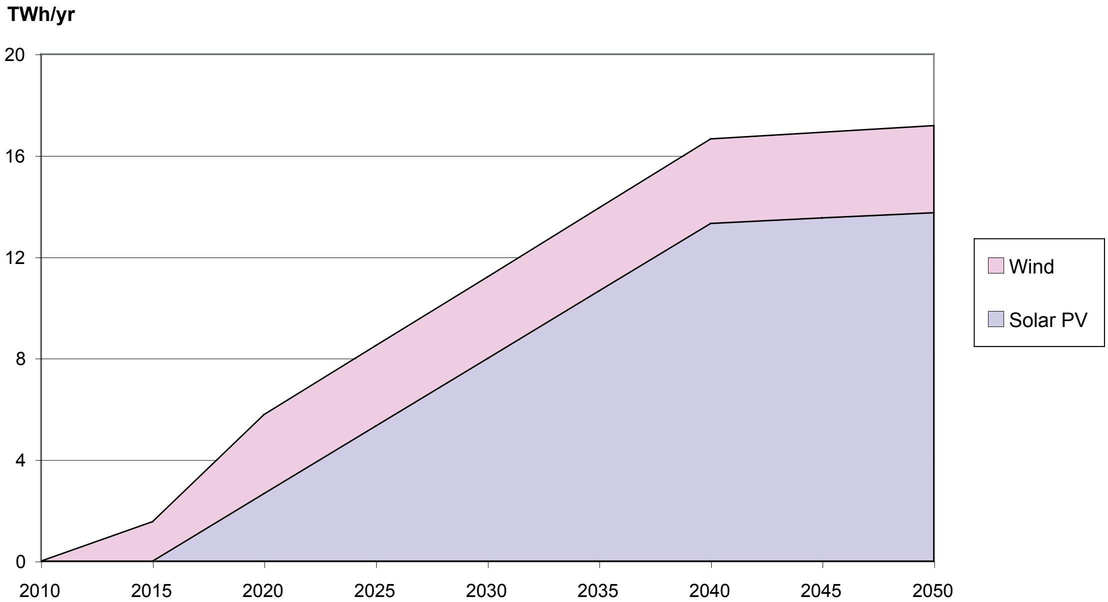


Figure A4.11.1 Electricity production from on-site renewable generation



Appendix A5. Electricity sector

Additional information is presented on the following aspects of the electricity sector:

- existing generating plant
- options for new generating capacity to meet future electricity demand
- interactions between intermittent renewables and other generation

A5.1 Existing generating plant

Table A5.1.1 shows the capacity of plant already existing or under construction, by type, to 2050.

The remaining life of existing and new plant has been calculated on the basis of the lives detailed in table A5.1.2. These plant lives do not account for generation plant affected by the EU Large Combustion Plant Directive. The Directive requires that plant which emits significant levels of exhaust-gas emissions must be fitted with appropriate abatement technology by 2015 or be closed down. Where additional emissions abatement facilities are not installed, plant is assumed to close down in 2015.

A5.2 Options for new generating capacity to meet future electricity demand

The major plant types that are foreseen to contribute to power generation in the UK by 2050 are outlined below.

A5.2.1 Coal-fired plant

Future coal-fired plant is expected to be based either on supercritical-fired boiler or integrated gasification combined cycle (IGCC) technology.

Supercritical-fired boiler plant burns coal in a furnace raising steam at very high pressure and temperature conditions, typically 600°C and 300 bar; the steam is then expanded in a large steam turbine to generate power. This steam cycle can deliver energy efficiencies of up to 45%, with further challenging developments at high temperatures still offering up to 50% in the longer term. Supercritical technology is only advantageous in large units, typically over 700 MW.

IGCC power plant is a new technology that has only recently become commercially available. As its name suggests, the plant first gasifies the coal by partial combustion before burning the gaseous products, after

Table A5.1.1 Forward capacity of plant already existing or under construction, by type

Plant type	Plant capacity (MW)								
	2010	2015	2020	2025	2030	2035	2040	2045	2050
Nuclear	8,683	7,043	3,653	1,188	1,188	-	-	-	-
Coal	26,574	26,574	11,135	-	-	-	-	-	-
CCGT and gas	33,220	33,220	31,382	21,418	12,230	4,459	1,295	-	-
Oil	3,116	3,116	2,080	2,070	2,070	15	15	-	-
Hydro	4,301	4,222	4,115	4,115	4,115	3,724	3,323	2,616	2,171
Biomass and waste	1,526	1,468	1,135	983	945	44	-	-	-
Wind	2,897	2,783	2,240	1,762	569	50	-	-	-

cleaning, in a gas turbine which is part of a combined cycle power plant. The process offers an efficiency of around 50%, but there are significant challenges in achieving reliable gasification process operation and gas clean-up. The range of scale of plant is typically from a minimum of 600 MW.

A5.2.2 Coal with CCS

There are three alternative technologies for carbon capture applied to coal-fired plant: post-combustion capture, pre-combustion capture and oxyfuel combustion.

In post-combustion capture, the flue gas from a coal plant is blown through an absorber tower where it is brought into contact with a liquid chemical called a solvent. Typical solvents for this process are amines and chilled ammonia. The solvent absorbs CO_2 from the flue gas, and the cleaned flue gas exits at the top of the absorber. The CO_2-rich solvent exits as a liquid at the base of the absorber. The solvent is heated and then enters another column, where the CO_2 is stripped from the solvent and exits the process slightly above atmospheric pressure. The CO_2 is then compressed or liquefied for transport.

The driving force behind the process is that the solvent absorbs more CO_2 at lower temperatures. For this reason the flue gas is cooled before entering the absorber, and the solvent is heated in the stripper.

For an amine process, the flue gas must be cooled to about 50°C. Steam, usually taken from the turbine, is required to heat the solvent in the stripper. In addition to this steam, electrical energy is required for the fan to overcome the absorber pressure drop, for the pumps for the solvent, and for CO_2 compression.

For chilled ammonia, the operating temperature in the absorber is much colder – about 5°C. The flue gas must therefore be electrically chilled. This energy requirement is balanced by the reduction in steam required in the ammonia stripper. The flue gas is also physically much smaller after chilling, and so the fan requires much less power. Finally, the CO_2 exits the chilled ammonia process at a higher pressure, so less compression is required. Overall, the chilled ammonia capture process is likely to have lower auxiliary power losses than the amine capture process. However, the chilled ammonia process is not currently as well developed as the amine process.

Table A5.1.2 Life assumptions for existing power plant, by type

Plant type	Life (years)
Gas	25
Nuclear	Nuclear plant retirements have taken account of the retirement dates defined in the licence conditions
Wind	20
Hydro	80
Pumped storage	80
Coal	50
Oil	50
CCGT	30
Diesel	50
Biomass	30
Waste	20

Pre-combustion carbon removal is achieved by means of gasification of the coal in an IGCC. In an IGCC plant, coal is converted to a gaseous fuel using a chemical process called gasification, which consists of a number of stages:

- preheating and drying of the feedstock
- devolatisation, where volatiles are driven off through heating to leave a char consisting primarily of carbon; the volatile content is often recycled to the gasification process to provide heat
- partial oxidation of the char to produce carbon monoxide and hydrogen
- shift reaction of the carbon monoxide with steam to produce CO_2 and hydrogen

Although gasification and IGCC have been well understood for a number of years, IGCC plants are uncommon. This is because IGCC has a similar efficiency to supercritical coal, but higher initial and operating costs. Interest has however been renewed recently, as IGCC with pre-combustion capture may have similar costs to standard coal plant with post-combustion capture.

For IGCC with pre-combustion capture, as much as possible of the carbon monoxide is converted to CO_2 in the shift reactor, and the resulting mixture of CO_2 and hydrogen (with some steam and carbon monoxide) enters the CO_2 absorber. The gas exits the absorber with a much lower CO_2 content and is then used as a high hydrogen content fuel in a CCGT cycle. The flue gas from this cycle contains very little CO_2 and can be exhausted to atmosphere.

The physical absorption process used for pre-combustion capture from IGCC is very similar to the chemical absorption process described above for post-combustion capture. In the absorber, the gas mixture comes into contact with the solvent, which absorbs the CO_2. The rich solvent is diverted to a stripper, where the CO_2 is removed using steam taken from the steam turbine; the CO_2 is then compressed for transport.

An oxyfuel process is one in which the fuel is burned in oxygen in the absence of nitrogen, so that the flue gas contains no nitrogen, and is almost entirely composed of CO_2 and steam, making the CO_2 much easier to capture. As burning with pure oxygen would result in excessively high temperatures in combustion, CO_2, steam, or a mixture of both must be recirculated through the system to dilute the oxygen supplied to the burners, thereby reducing the temperature of combustion to conventional levels. A number of possible oxyfuel cycles are under development. Depending on the cycle, the combustion flue gas may enter a turbine and/or an HRSG, and the CO_2 may be separated before or after part of the flue gas is recycled to the combustion chamber.

The main energy requirement is the production of the oxygen for the process. The two technologies currently used are cryogenic oxygen production and oxygen transport membrane technology.

An oxycoal process is typically similar to a supercritical coal plant, with pulverised coal burned in a mixture of oxygen, CO_2 and steam, which heats the steam in the boiler/HRSG. A large proportion of the flue gas is then mixed with oxygen and returned to the combustion chamber, with the rest of the flue gas being cooled to separate the CO_2 and steam.

The technology for an oxycoal plant is largely established, but no large plant using the technology has yet been constructed.

A5.2.3 Nuclear

Current nuclear power plant is based on nuclear reactors which transfer heat either by heating water or boiling water. The boiling water reactors raise steam within the reactor from heat release from nuclear fission; the steam is then expanded in a steam turbine to raise power. Pressurised water reactors function by heating water at high pressure in the reactor, and the heated water is used to boil water in a secondary cycle. The steam in the secondary cycle is expanded through a steam turbine to raise power. Boiling water reactors are not currently being considered for approval in the UK, while a PWR is currently operational at Sizewell B. Pressurised water reactors are currently available as standard designs of 1,200 MW and 1,600 MW by Westinghouse and Areva respectively. Future designs may offer greater capacity combined with increased use of passive safety features to further reduce the already low risks of large-scale accidents.

Nuclear technology is advancing, with so-called Generation IV reactors in development. These use different technologies, such as the helium-cooled pebble bed modular reactor being developed in South Africa, which may offer some economic or technical advantages. Some new technologies are exploring the possibility of alternative nuclear fuels, such as thorium, to address the potential shortages in uranium supply in case of a large international programme of reactor construction. None of these new technologies is yet commercially available, and they have not been considered in this report.

In view of the extended period of approval of proposed plant by the Nuclear Installations Inspectorate, and the necessary planning approvals (including any planning enquiry and potential legal challenges from anti-nuclear interests), the actual lead time for a first new nuclear power plant to become operational is at least ten years.

A5.2.4 Combined cycle gas turbine

This technology burns gas in a large industrial gas turbine to generate power. The hot exhaust gases of the gas turbine are used to raise steam in a boiler and further power is generated by expanding the steam in a turbine in the secondary steam cycle. This well-established technology offers a high efficiency of fuel conversion, now approaching 60%, combined with low atmospheric emissions. As a result of the low carbon content of the fuel and high cycle efficiency, the CO_2 emissions per unit of electricity of CCGT plant are typically about 40% of those of a conventional coal plant.

Combined cycle power plant has been subject to continuous development since it was introduced, and plant capacity has increased from a typical 350 MW in 1990 to 850 MW today. Efficiency has improved from around 50% to nearly 60% over the same period. This trend of improvement is expected to slow, although the technology can be expected to achieve an efficiency of about 65% by 2030, with a corresponding reduction in CO_2 emissions.

A5.2.5 Combined cycle gas turbine with CCS

There are two methods of implementing carbon capture from a gas turbine:

- Scrub the CO_2 from the GT exhaust in the same way as for post-combustion carbon capture with coal. The process performance is limited by the high levels of excess air inherent in gas turbine operation resulting in a CO_2 concentration in exhaust gases of about 3-4% rather than the 16% typical of coal.

- Remove the carbon from the natural gas before combustion. This process has been proposed by BP, but as the resulting fuel gas has a high hydrogen content, the use of the more efficient F-class gas turbines is not currently feasible. The resulting serious loss of overall plant efficiency and the high cost of the chemical process plant mean that this is not the preferred method of carbon capture for a CCGT.

A5.2.6 Marine

The potential for a variety of marine power generation technologies is significant, with large wave and tidal resources accessible to the UK.

Currently there is no commercially proven wave power generation technology applied in the UK. While there is considerable development work in progress, it is difficult to be confident that a significant contribution to electrical energy needs will be delivered from this resource by 2050.

Tidal power has been considered on several occasions in the UK and a current study for the government is considering various alternative projects to exploit the tidal power opportunities presented by the Severn estuary. The potential schemes range from a large barrage from Cardiff to Weston-super-Mare to a smaller barrage at the M4 Severn Bridge (the Shoots barrage), along with a variety of designs using lagoons impounded within the estuary. All of these projects would employ hydroelectric turbine technology to generate power from flows between higher and lower reservoirs. There is a range of other tidal power technologies in development that do not depend on reservoirs being constructed. These technologies exploit tidal currents such as those of the Pentland Firth, which can reach up to 10 knots in places. The currents drive rotating or flapping devices to convert the movement of water into mechanical power and hence to electricity. Several of these technologies are being tested but none is yet available for commercial application.

A5.2.7 Wind power

Power generation from wind has developed radically in the past 20 years. The capacity of the individual turbine has increased by an order of magnitude to typically 3 MW, with an increase in scale of wind farms from tens to hundreds of megawatts. A notable development in the last ten years has been the introduction of large-scale offshore wind generation. Offshore wind generation benefits from stronger and more consistent winds and fewer siting problems than onshore, but the technology involves much more costly foundation design and higher installation and maintenance costs. The largest wind turbines are very large in size, typically up to 200 m high, and are therefore most easily sited offshore. Units of up to 10 MW in capacity are foreseen, which should reduce both costs and the number of undersea connection power export cables required. The connection of wind generators to the electrical transmission system presents a number of challenges. These include the remote locations and the intermittency of generation which can restrict the effective utilisation of transmission network capacity.

A5.3 Interactions between intermittent renewables and other generation

Integrating large amounts of intermittent renewable generation, such as wind, with other generation types is a contentious issue. The scale of intermittent renewables which can be connected to an electricity system has been subject to considerable debate, with wide-ranging estimates of the maximum feasible input from intermittent energy. Denmark's 20% of wind energy input is often quoted but, because of the strong link between Denmark and Germany, only 7% of energy supplied to the combined German and Danish systems is from intermittent renewable sources[66].

A large contribution of wind generation is foreseen to meet the government's commitment to the EU that 15% of all energy use will be from renewable sources by 2020. The stated ambition of the government's consultation on the renewable energy strategy for the UK[67] is to increase the level of renewable contribution to 30-35% of electricity by 2020. At least 70% of this renewable energy is foreseen to be generated from wind.

This section of Powering the Future assesses the interaction between large-scale wind generation and the balance of generating plant, to identify the necessary measures to maintain a reliable electricity supply while achieving a substantial reduction in CO_2 emissions.

A5.3.1 Characteristics of wind generation

The key characteristic of wind generation in the UK is its variability, reflecting the British weather systems that it exploits. This variability affects individual turbines, complete wind farms and multiple wind farms as weather systems move across the country. Since this study is concerned with large-scale wind energy contributions, it is necessary to assess the effect of linking large numbers of widely distributed wind farms to the electricity system. Setting aside the significant but resolvable engineering issues associated with electrical connections for these installations, the scale and distribution of wind energy generation is expected to somewhat reduce the variations in output with time. However, Oswald[68] has shown that 25 GW of wind generation widely distributed across the country still has substantial variability. Figure A5.3.1.1 shows a sample of the modelled output of this wind estate, taking account of the actual weather data for the different areas of the country for January 2005.

The level of variability of wind production differs between years. This is shown in figure A5.3.1.2, which illustrates the capacity/duration curve for January 2005 and 2006 for the modelled 25 GW wind estate.

The energy delivered during January 2005 is substantially greater than in January 2006 and the variations in production are considerable, despite the smoothing effects of the geographical distribution and scale of wind capacity compared with a single wind generator at about 2 MW.

Oswald also shows that there is significant seasonal variation in wind output. This conclusion is supported by other studies[69], which show that the summer load factor is typically less than two thirds of the mid-winter value.

A5.3.2 Variability of intermittent renewable generation

The UK electricity system must achieve high levels of reliability. For this reason, any variability from wind generation needs to be countered by a despatched response from the balance of generating plant, international interconnections, and any controllable demand or energy storage. The balance of generating plant currently includes approximately 3 GW of pumped-storage generation which can be brought into service within a few minutes, and around 1 GW of fast-starting simple-cycle gas turbine power plant.

It has been argued that large-scale interconnection of the UK to neighbouring electricity networks will give sufficient diversity of intermittent renewable generation to provide reliable and continuous renewable power. However, various studies[70] suggest that the capacity and physical scale of the interconnected networks would have to be very large to exceed the size of

[66] Bach P-F, 'Wind Power and Spot Prices: German and Danish Experience 2006-2008' 2009.
[67] Department of Energy and Climate Change, 'The UK Renewable Energy Strategy' 2009.
[68] Oswald J *et al*, 'Will British Weather Provide Reliable Electricity?' 2008.
[69] National Grid, 'Operating the Electricity Transmission Networks in 2020', 2009.
[70] Oswald J *et al*, 'Will British Weather Provide Reliable Electricity?' 2008 and Bach P-F, 'Wind Power and Spot Prices: German and Danish Experience 2006-2008' 2009.

Figure A5.3.1.1 Modelled UK wind output – January 2005[71]

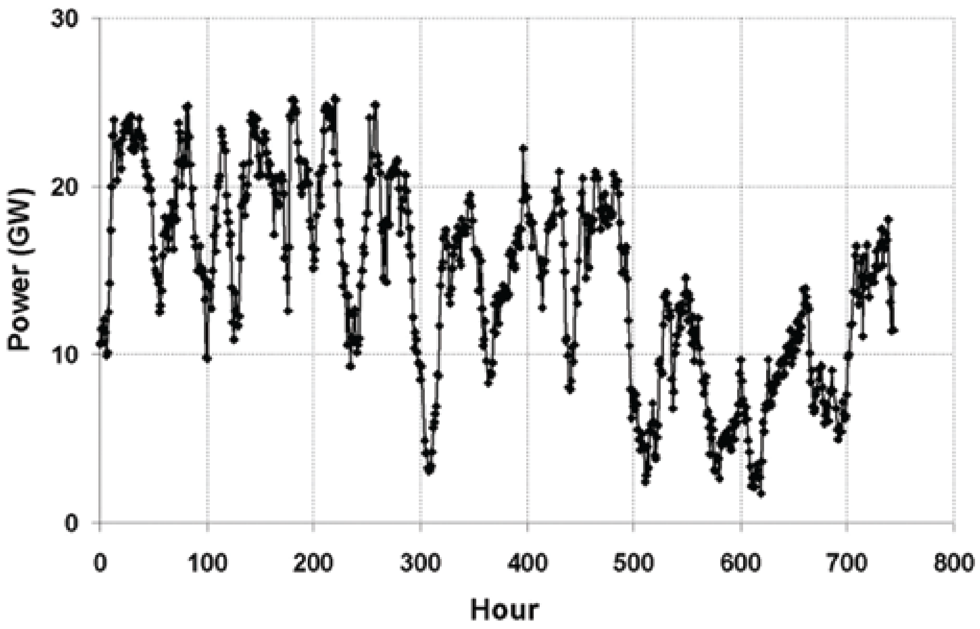
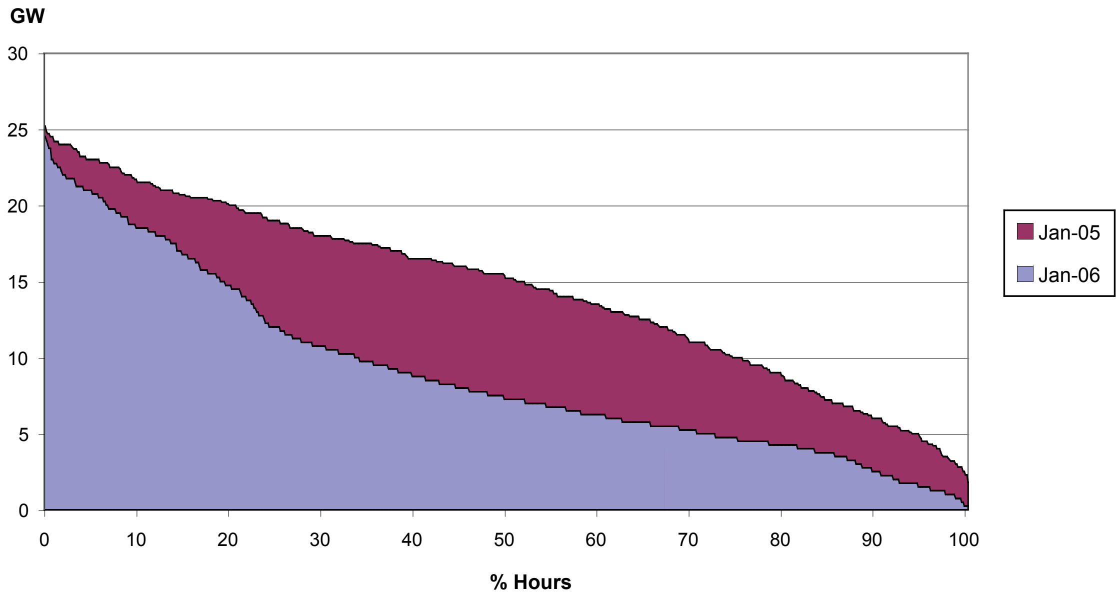


Figure A5.3.1.2 25 GW modelled wind estate – output duration curves[72]



[71] Oswald J *et al*, 'Will British Weather Provide Reliable Electricity?' 2008.
[72] Derived from: Oswald J *et al*, 'Will British Weather Provide Reliable Electricity?' 2008.

the weather systems that affect Northern Europe. Changes in weather and hence wind generation typically travel west to east, with a few hours' difference between events in Ireland, the UK and Germany. There is extensive evidence of large-scale mid-winter weather in which very little wind generation was available across Northern Europe[73]. Under these conditions, electrical system interconnections would contribute little to the continuity of intermittent renewable generation or security of supply.

The risk of minimal wind generation coinciding with peak demand means that although wind will contribute a significant proportion of the energy to the electricity system, it will be necessary to maintain conventional capacity sufficient to meet peak demand without wind. The ability of the other generation connected to the system to compensate for wind variability is determined by the plant mix. Nuclear power plant is largely inflexible and unable to contribute; CCGT and thermal plant are moderately flexible; and simple-cycle gas turbine plant offers rapid start-up and flexible despatch. Typical start-up, loading and de-loading rates for different plant types are shown in table A5.3.2.1.

Judging from the rate of increase of generation output on the peak winter day, the current plant mix has a sustained capability for about 7.5 GW/hour load increase for the highly predictable daily demand cycle. This capability represents about 25% per hour loading rate for the 30 GW of plant involved in daily load cycling.

The challenges for response of plant are its limited rates of ramping up and down to follow demand, and the time it takes to bring into service plant that has been shut down. The former can be changed by adjusting the plant mix; the latter cannot be radically changed but could be managed better with improved weather forecasting to provide advance notice of significant wind changes.

With small contributions by wind generation, the compensating changes required from the other generating plant to counter wind variability are also small. As the contribution increases, the responses required become larger and more difficult to deliver from other generating plant. The difficulty of bringing large plant into service sufficiently quickly becomes the limiting feature in managing rapid decreases in wind production.

We analysed the two sample January cases modelled by Oswald to identify the scale of hour-to-hour production changes for the 25 GW wind estate. The results are shown in figure A5.3.2.1.

Table A5.3.2.1 Typical dynamic characteristics for different plant types

Plant type	Condition	Start to full load (hours)	Sustained loading ramp rate	Sustained de-loading ramp rate
Nuclear	Cold	48	8%/hour	8%/hour
Coal	Cold	12	20%/hour	20%/hour
Coal	Hot	3	100%/hour	100%/hour
CCGT	Cold	12	20%/hour	20%/hour
CCGT	Hot	2	100%/hour	100%/hour
Simple-cycle GT	Cold	0.3	300%/hour	300%/hour
Hydroelectric	Water available	0.1	1,000%/hour	1,000%/hour
Pumped storage	Reservoir full	0.03	3,000%/hour	3,000%/hour

[73] Oswald J *et al*, 'Will British Weather Provide Reliable Electricity?' 2008 and Bach P-F, 'Wind Power and Spot Prices: German and Danish Experience 2006-2008' 2009.

Figure A5.3.2.1 shows that wind variability changes from year to year, but that the overall distribution of rates of change is predominantly below ± 2 GW/hour with about 20% of hours exceeding this rate for 2005 and 12% for 2006. The extremes of the distribution are found to be +7.7 GW/hour and -4.8 GW/hour.

This analysis has been based upon data for January 2005 and January 2006, because January is representative of the most arduous conditions resulting from a large-scale application of wind generation. However, the full distribution of potential extreme changes can only be adequately assessed by modelling the performance of the 25 GW wind estate using many years of historical wind data. For the purposes of this study, the modelled wind data for January 2005 and 2006 was scaled to identify the likely implications of wind variability at different magnitudes of wind generating capacity. Further work is clearly needed to address all months of the year in a more comprehensive analysis of historical weather data, so that reliable statistical information can be extracted. The relationship between capacity of wind generation and the level of contribution to electricity supply depends on the assumed load factor. This varies between years as shown in figure A5.3.2.2 and also between seasons. The lines can be seen to be slightly curved downwards at larger scales of wind due to increasing levels of spilling when the total wind production cannot be utilised.

A5.3.3 Interaction of wind with system demand

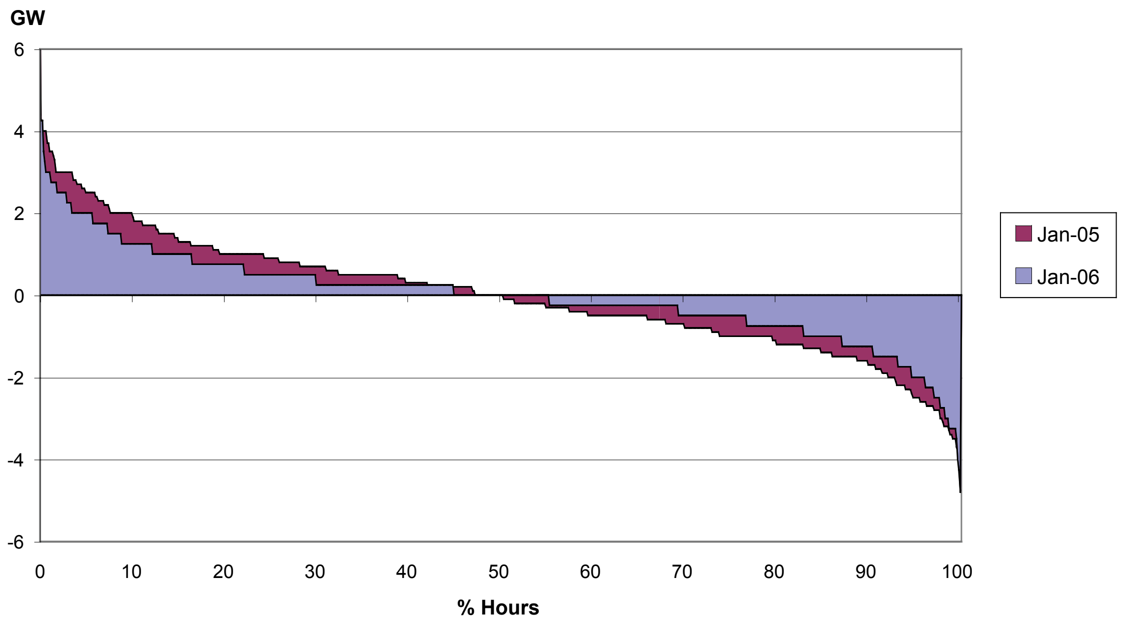
The electricity system meets demands from consumers that vary with seasonal, weekly and daily cycles. The demand data for January 2005 is shown in figure A5.3.3.1.

The pattern of demand shown in figure 5.3.3.1 includes the end of the Christmas holiday period and the smaller demands for weekend days. The daily demand cycle shows a sharp rise from about 06:00 to 09:00 followed by a relatively steady demand period rising to a late afternoon peak at about 18:00 before declining to a night-time level between 0:30 and 05:30.

The distribution of rates of change of demand is shown in figure A5.3.3.2.

Combining the demands shown in figure A5.3.3.1 with the modelled wind data for the 25 GW wind estate for the same period gives a demand to be met from other generation as shown in figure A5.3.3.3.

Figure A5.3.2.1 25 GW modelled wind estate – ordered changes in wind output[74]



[74] Derived from: Oswald J *et al*, 'Will British Weather Provide Reliable Electricity?' 2008.

Figure A5.3.2.2 Wind contribution to electrical energy supply

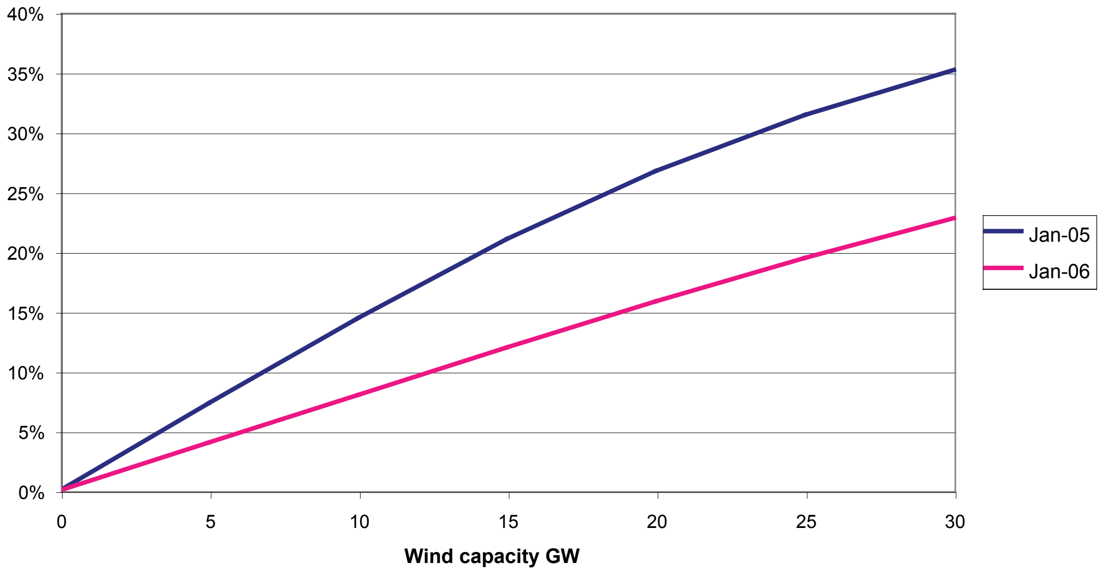
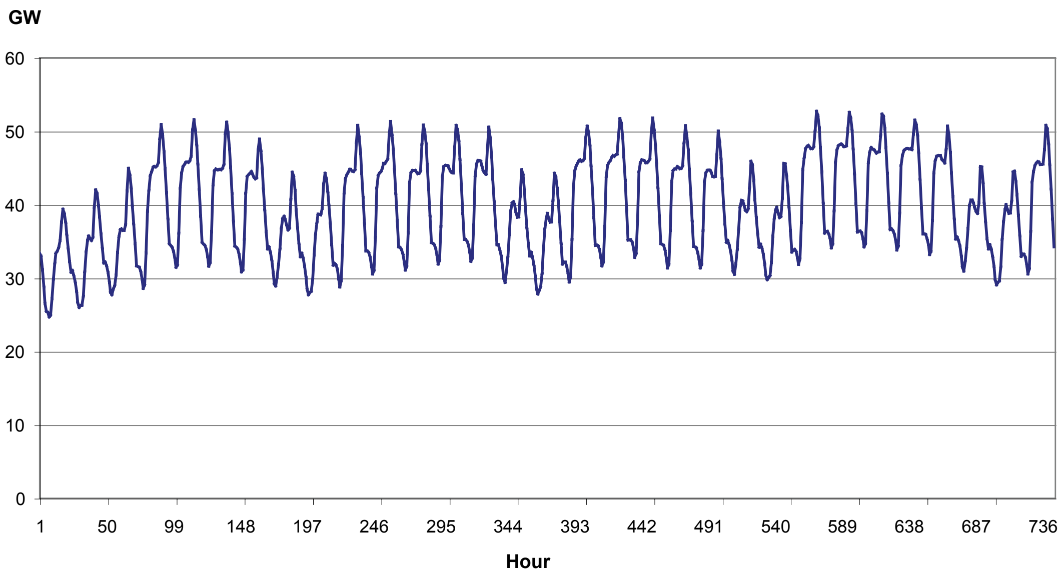


Figure A5.3.3.1 Electricity system demand data for January 2005[75]



[75] Produced from: National Grid Company, 'Demand Data Jan-Jun 2005' 2005.

The net demand shown in figure A5.3.3.3 has a lower average than the raw demand, as would be expected, but an increased variability due to the coincidence of some periods of high wind with low demand and vice versa.

We created a despatch model to assess how the overall generating system would handle demand modified by significant wind generation. It included the following generation components:

- an inflexible nuclear baseload component
- a scaled contribution from wind generation using January 2005 and January 2006 modelled data from the Oswald study
- a load-following generation component
- pumped-storage generation
- fast-response peaking generation plant
- contracted disconnectable demand

Each component was allocated a capacity according to the run. The pumped-storage, fast-response peaking generation and contracted disconnectable load were given the current available capacities of 2.8 GW, 1 GW and 1 GW respectively.

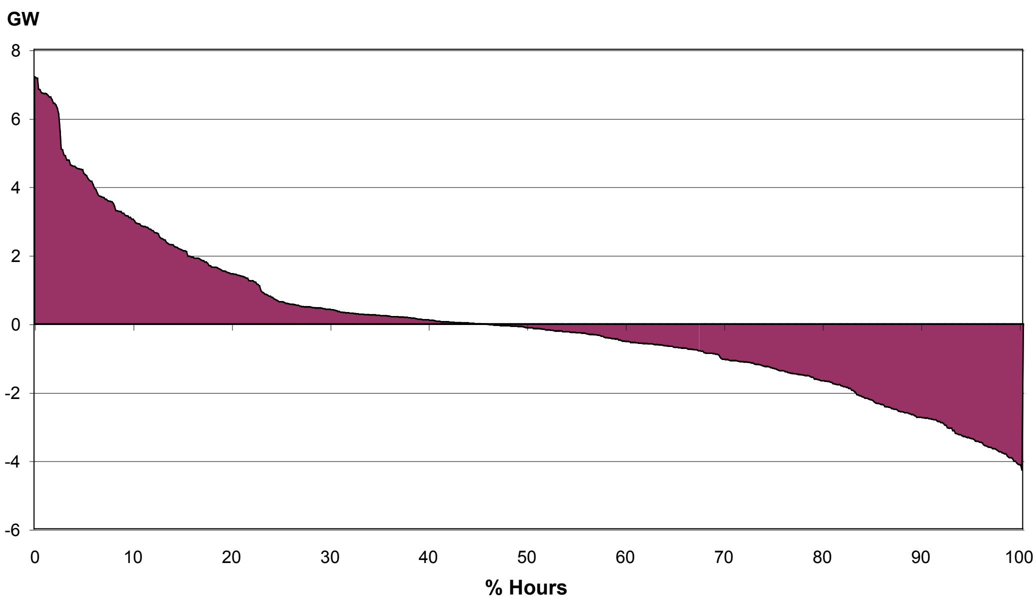
The load-following plant was assumed to run at between 50% and 100% of its capacity and be able to increase or decrease output at up to 50% of capacity per hour. It was assumed that the capacity of the load-following plant could be increased or decreased at 5 GW/hour one hour after its utilisation reached 100% or 50% respectively. These parameters reflect the capabilities of conventional coal or CCGT plant when operating with reasonably well forecast demand patterns but with some uncertainty in timing of load changes.

The limitations of power plant response to the rapid changes in wind production are handled in case of declining wind by progressively using the pumped-storage, peaking plant or contracted disconnectable load and, in the case of rapidly rising wind production, by spilling excess wind energy.

This despatch model was used to assess the impact of varying amounts of wind capacity on the reliability of electricity supply and on the level of wind energy that had to be spilled.

Figure A 5.3.3.4 shows how the number of interruptions (caused by the need to balance supply with demand) varies as the installed wind capacity increases under a fixed 20 GW of nuclear capacity.

Figure A5.3.3.2 Ordered change in electricity demand for January 2005[76]



[76] Produced from: National Grid Company, ‘Demand Data Jan-Jun 2005’ 2005.

Figure A5.3.3.4 shows that above approximately 10 GW of wind capacity, at least one interruption was observed during the modelled months. This corresponds to a loss-of-load probability of over 0.15% at 10 GW of wind, rising to 1.5% at 30 GW of wind capacity. These excessive levels of unreliability would have to be reduced to a level considered acceptable in the industry, ie about 0.1%.

The reliability of electricity supply can be improved at high wind penetrations by increasing the system fast-response capability. Typical measures include increased capacity of balancing peaking plant and increased contracted disconnectable load. The consequences of these alternatives on the number of interruptions would be similar, but their costs and other effects would be different. Figure A5.3.3.5 shows how increasing the balancing capability of the system would reduce the number of interruptions at 30 GW of wind capacity.

The additional balancing capability of the system required to eliminate interruptions depends on the level of wind capacity and inflexible nuclear capacity, as shown in figures A5.3.3.6 and A5.3.3.7.

The interaction between wind generation and other generators means that there are times when excess wind needs to be spilled. The scale of spilling of excess wind energy was evaluated for different magnitudes of wind capacity installed. Figure A5.3.3.8 shows the relationship for 15 GW of nuclear capacity.

Figure A5.3.3.8 shows that spilling of excess wind energy remains at a low level below 15 GW of wind capacity but that it rises significantly to represent between 3% and 12% of wind energy at 30 GW of wind capacity. Nevertheless, even at the 2005 spill level, when wind energy was at a higher value, the cost of electricity from wind would not be substantially increased by the lost revenue from the spilled power. The corresponding case where nuclear capacity was increased to 20 GW is shown in figure A5.3.3.9.

The results for the larger inflexible nuclear capacity show a substantial increase in spilling compared with the 15 GW nuclear capacity case. With spilling exceeding 20% of wind generation above 25 GW of wind capacity, the viability of wind capacity above this level would be reduced.

Figure A5.3.3.3 Electricity demand net of 25 GW wind generation – January 2005

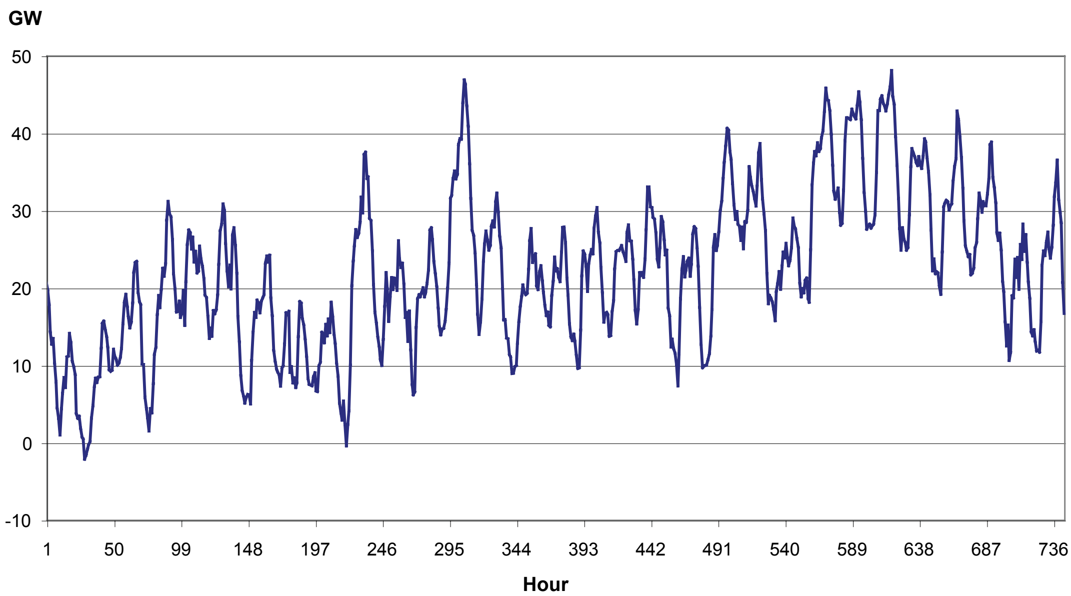


Figure A5.3.3.4 Number of interruptions with wind capacity – 20 GW nuclear

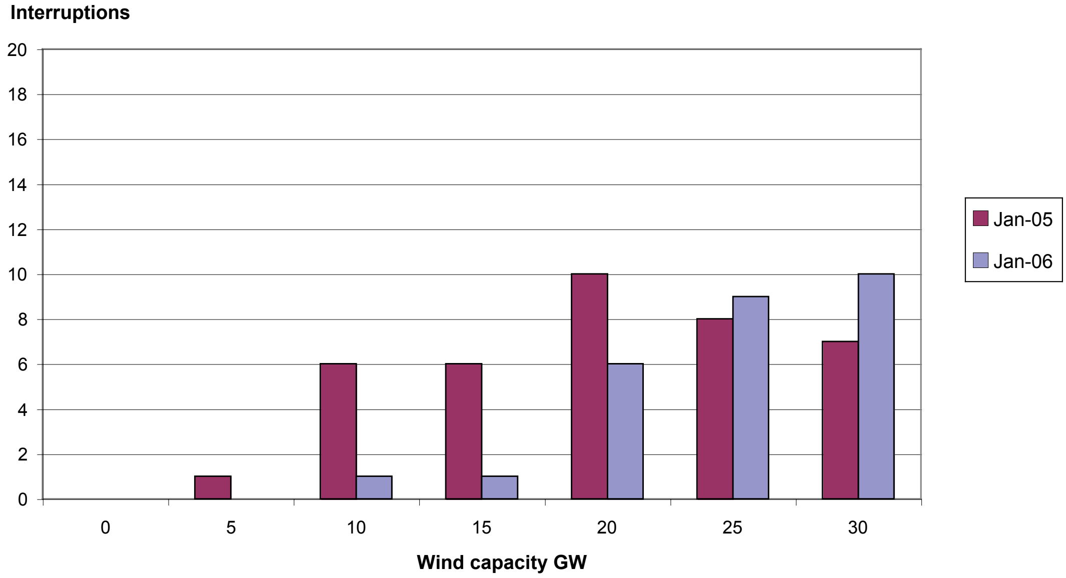


Figure A5.3.3.5 Number of interruptions with increased system-balancing capability – 20 GW nuclear

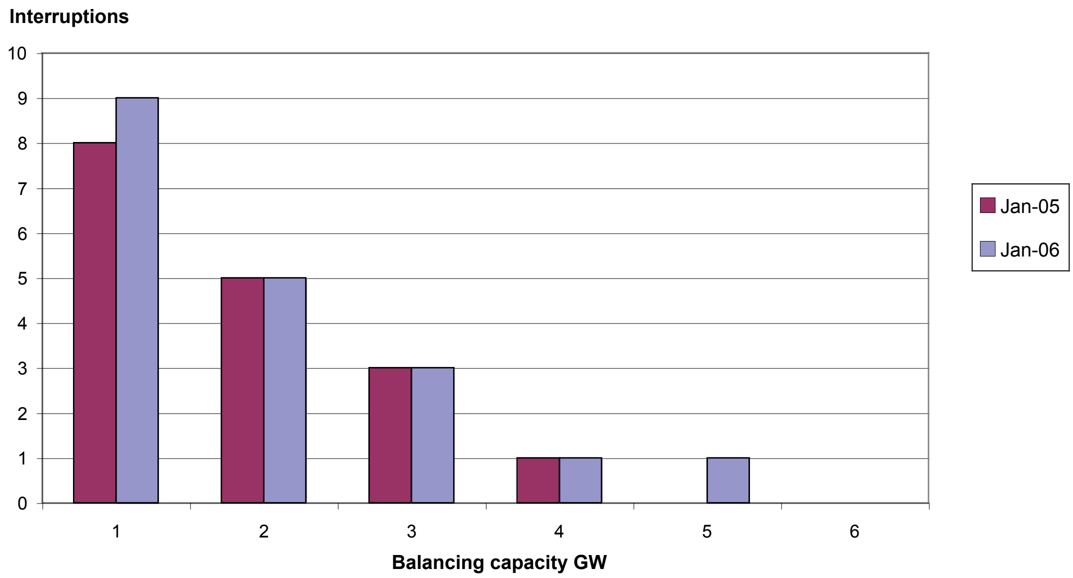


Figure A5.3.3.6 Additional fast-response generation to achieve zero unplanned outages – 15 GW nuclear

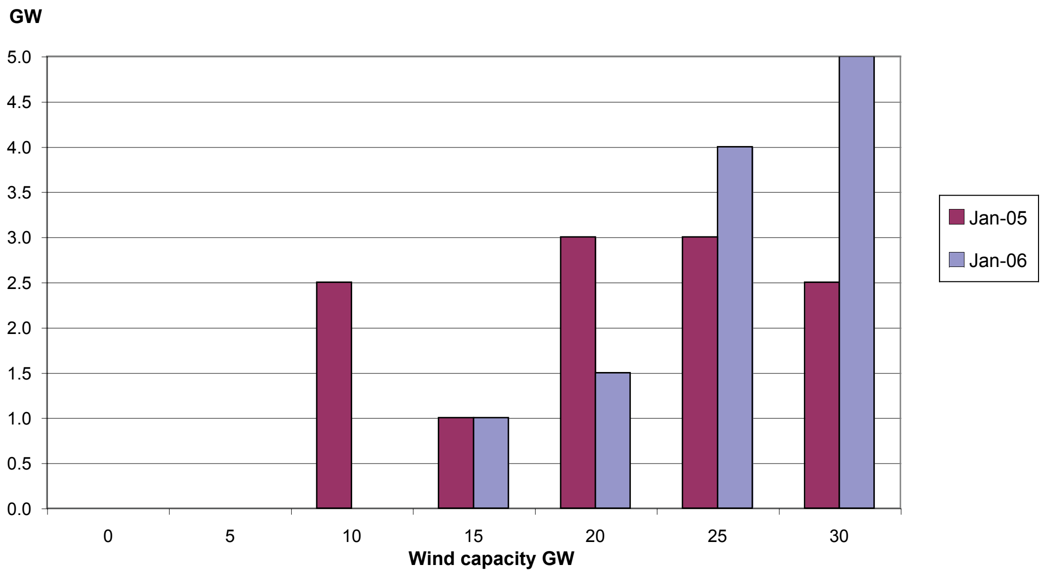


Figure A5.3.3.7 Additional system-balancing capability to achieve zero disconnections – 20 GW nuclear

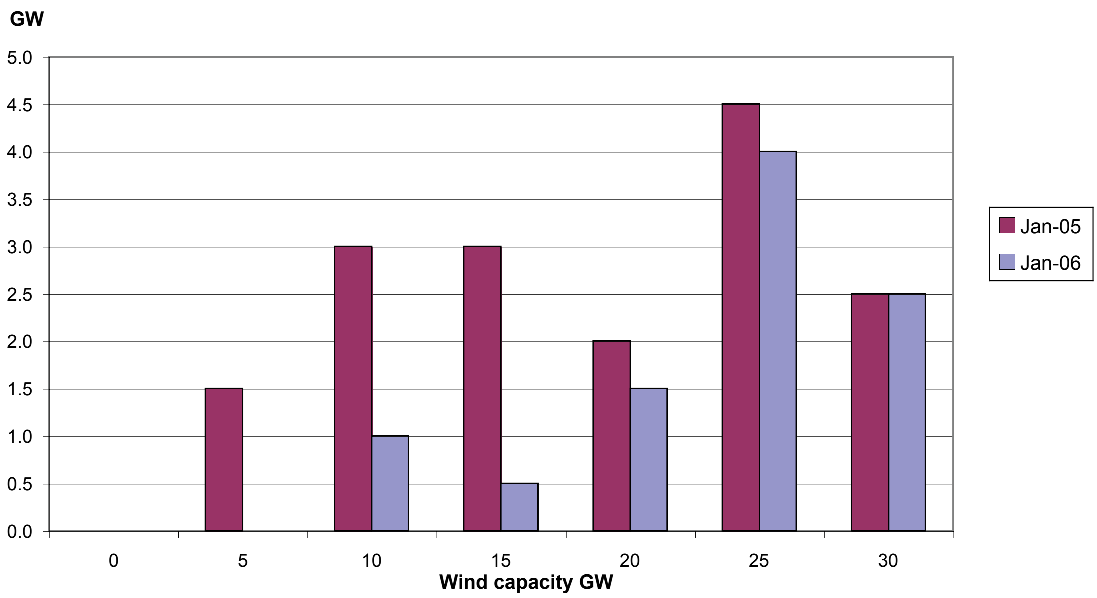


Figure A5.3.3.8 Variation of wind spill with wind capacity – 15 GW nuclear

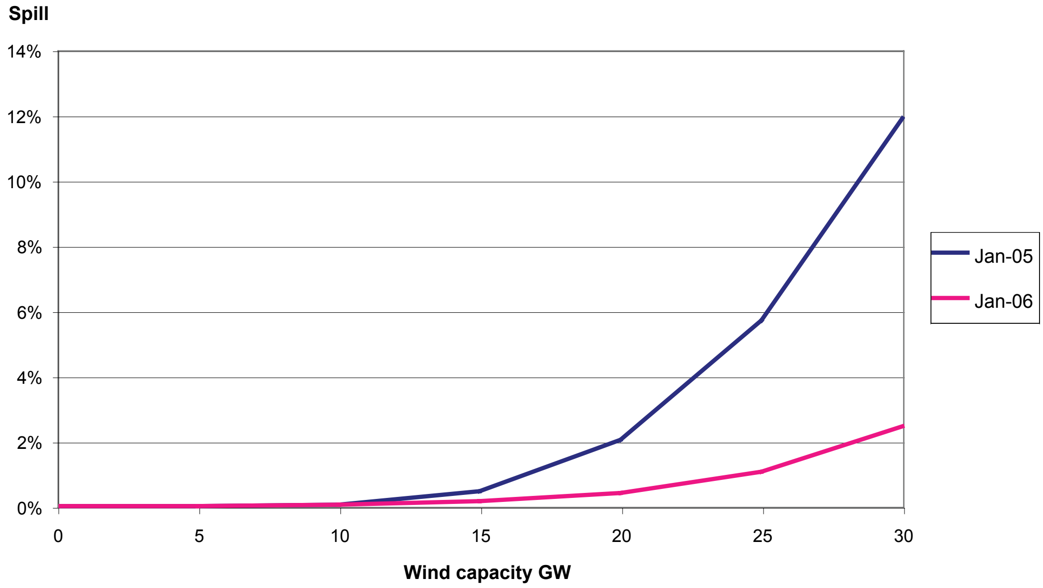
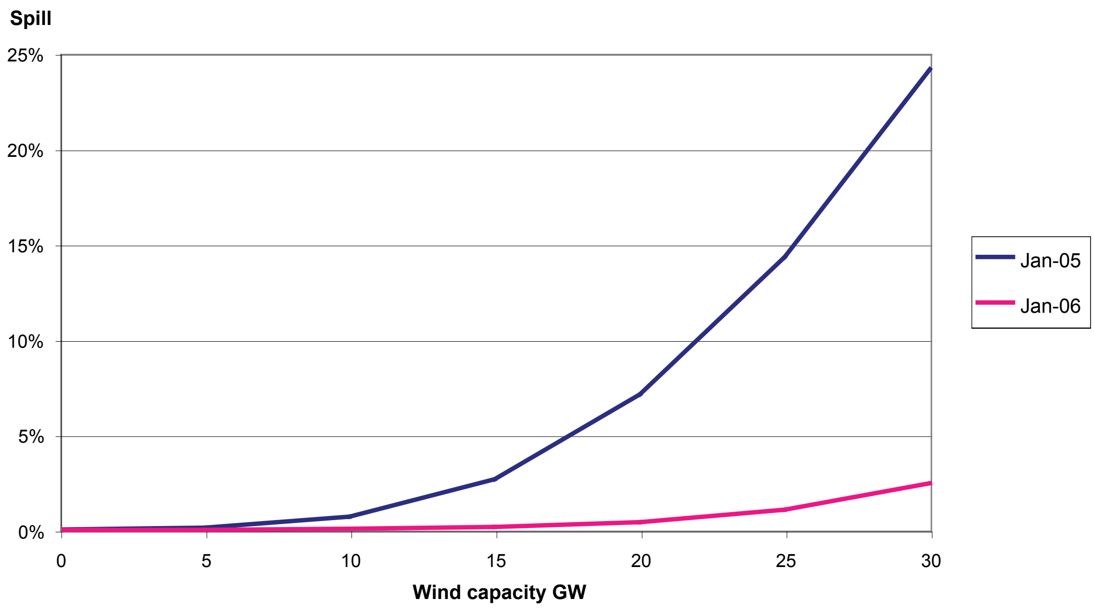


Figure A5.3.3.9 Variation of wind spill with wind capacity – 20 GW nuclear

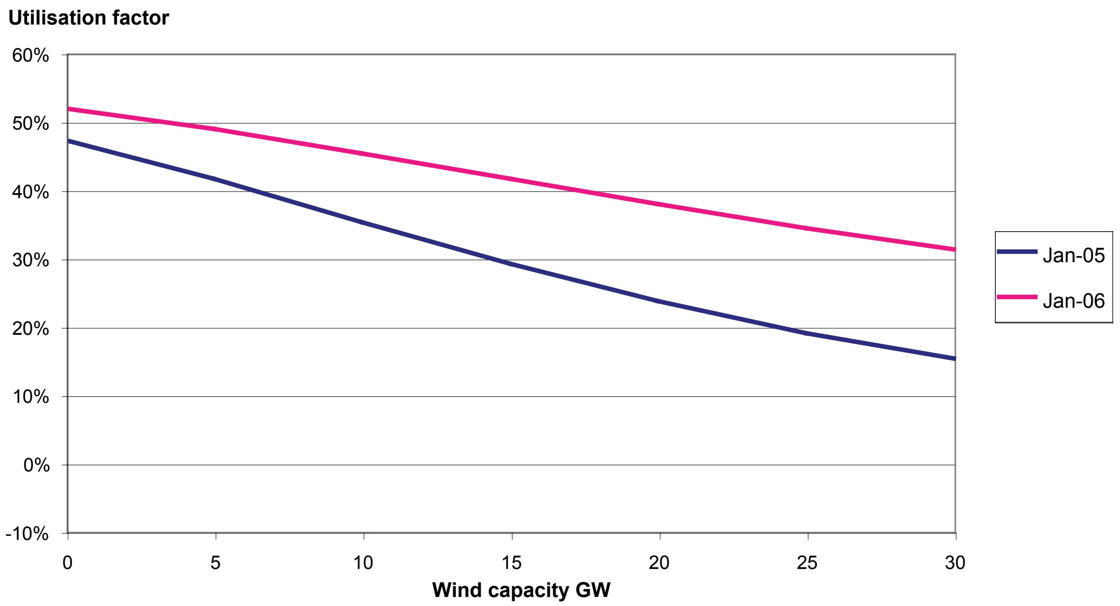


The utilisation of the load-following power plant determines some elements of the cost of power generated and the level of CO_2 emissions. Figure A5.3.3.10 shows how the utilisation of the load-following capacity declines with increasing wind capacity.

The utilisation factor of load-following plant can be seen to fall almost linearly with installed wind capacity, from over 50% with zero wind capacity to 20% and 37% respectively for 2005 and 2006. While this figure again illustrates the variability in wind contribution between years, it also shows that utilisation of the large capacity of the required load-following plant can fall to very low levels.

Low load factors have a significant impact on the choice of the lowest-cost power plant technology for this role. At high load factors, higher capital cost plant type with high efficiency and lower CO_2 emissions would offer the minimum life cost. At lower load factors it is likely that lower-cost plant such as CCGTs burning gas would be preferred over coal plant with carbon capture. At very low load factors of around 20% or below, only simple-cycle gas turbines would be cost effective and carbon capture would be unlikely to be feasible.

Figure A5.3.3.10 Utilisation factor of load-following plant – 20 GW nuclear



Appendix A6.
Scenario data tables

This appendix presents the data tables for key results and assumptions.

The data is presented for each stage of the derivation of the overall CO_2 emissions of the UK economy, set out to aid comparison of the different scenarios.

A6.1 Scenario electricity demands

The sector electricity consumptions, net of embedded generation, are aggregated with transmission and distribution losses to derive the demand to be met from the electricity sector. Table A6.1.1 details the sector net consumptions for each scenario.

Table A6.1.1 Sector net annual electricity consumptions for each scenario (TWh)

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 1	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	319.5	315.2	328.6	345.8	340.7	326.4	324.7	319.7
	Network losses	23.9	22.4	22.1	23.0	24.2	23.9	22.8	22.7	22.4
	Total	**365.7**	**341.8**	**337.3**	**351.6**	**370.0**	**364.6**	**349.2**	**347.4**	**342.0**
Scenario 2	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	107.2	99.5	91.6	84.1	76.3	66.0	53.5	43.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.5	65.1	56.3	48.6	43.3	38.1	33.8	30.1
	Total consumption	341.8	320.1	317.4	332.8	351.4	347.6	334.4	333.6	329.3
	Network losses	23.9	22.4	22.2	23.3	24.6	24.3	23.4	23.4	23.1
	Total	**365.8**	**342.5**	**339.7**	**356.1**	**376.0**	**372.0**	**357.8**	**357.0**	**352.4**
Scenario 3	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	91.5	53.0	20.9	18.7	16.6	13.9	16.8	18.1
	Commercial	89.0	70.5	52.6	42.1	38.4	38.1	37.3	33.0	29.4
	Total consumption	341.8	287.4	252.6	246.2	268.9	270.0	262.9	254.0	245.4
	Network losses	23.9	20.1	17.7	17.2	18.8	18.9	18.4	17.8	17.2
	Total	**365.7**	**307.5**	**270.3**	**263.4**	**287.7**	**288.9**	**281.3**	**271.8**	**262.6**
Scenario 4	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	319.5	315.2	328.6	345.8	340.7	326.4	324.7	319.7
	Network losses	23.9	22.4	22.1	23.0	24.2	23.9	22.8	22.7	22.4
	Total	**365.7**	**341.8**	**337.3**	**351.6**	**370.0**	**364.6**	**349.2**	**347.4**	**342.0**
Scenario 5	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	319.5	315.2	328.6	345.8	340.7	326.4	324.7	319.7
	Network losses	23.9	22.4	22.1	23.0	24.2	23.9	22.8	22.7	22.4
	Total	**365.7**	**341.8**	**337.3**	**351.6**	**370.0**	**364.6**	**349.2**	**347.4**	**342.0**

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 6	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	319.5	315.2	328.6	345.8	340.7	326.4	324.7	319.7
	Network losses	23.9	22.4	22.1	23.0	24.2	23.9	22.8	22.7	22.4
	Total	**365.7**	**341.8**	**337.3**	**351.6**	**370.0**	**364.6**	**349.2**	**347.4**	**342.0**
Scenario 7	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	133.0	127.7	119.8	110.5	112.4	114.7	114.0	135.5	150.4
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	346.7	330.2	331.2	349.2	372.0	372.6	363.0	372.6	377.8
	Network losses	24.3	23.1	23.2	24.4	26.0	26.1	25.4	26.1	26.4
	Total	**371.0**	**353.3**	**354.4**	**373.6**	**398.0**	**398.7**	**388.4**	**398.7**	**404.2**
Scenario 8	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	108.7	101.3	92.9	85.0	76.3	64.8	51.2	40.3
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.6	78.2	66.0	57.2	49.8	44.7	39.6	35.3	31.6
	Total consumption	342.4	322.3	320.2	335.1	353.4	348.9	334.7	332.9	327.6
	Network losses	24.0	22.6	22.4	23.5	24.7	24.4	23.4	23.3	22.9
	Total	**366.4**	**344.9**	**342.6**	**358.6**	**378.2**	**373.3**	**358.1**	**356.2**	**350.5**
Scenario 9	Road transport	3.0	2.4	18.5	43.7	63.4	70.5	75.3	78.8	81.6
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	316.0	301.3	298.2	301.9	291.2	273.9	269.8	263.0
	Network losses	23.9	22.1	21.1	20.9	21.1	20.4	19.2	18.9	18.4
	Total	**365.7**	**338.2**	**322.4**	**319.0**	**323.0**	**311.6**	**293.0**	**288.7**	**281.5**
Scenario 10	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	117.0	103.8	89.9	86.2	82.9	77.4	87.5	92.3
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	319.5	315.2	328.6	345.8	340.7	326.4	324.7	319.7
	Network losses	23.9	22.4	22.1	23.0	24.2	23.9	22.8	22.7	22.4
	Total	**365.7**	**341.8**	**337.3**	**351.6**	**370.0**	**364.6**	**349.2**	**347.4**	**342.0**

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 11	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	107.0	98.1	88.6	80.2	72.2	63.5	54.1	46.2
	Industry	128.1	117.9	105.8	93.1	89.7	86.6	81.3	91.5	96.2
	Commercial	89.0	77.8	66.8	58.8	52.3	48.1	44.0	39.8	36.3
	Total consumption	341.8	321.1	319.8	335.6	354.6	352.0	341.8	344.2	342.0
	Network losses	23.9	22.5	22.4	23.5	24.8	24.6	23.9	24.1	23.9
	Total	**365.7**	**343.6**	**342.2**	**359.1**	**379.4**	**376.6**	**365.7**	**368.3**	**366.0**
Scenario 12	Road transport	3.0	5.9	32.4	74.1	107.3	120.0	127.8	133.7	138.2
	Rail	8.4	12.6	16.7	20.9	25.1	25.1	25.1	25.1	25.1
	Domestic	113.4	106.9	97.9	88.2	79.3	70.2	58.8	45.3	34.6
	Industry	128.1	127.9	126.2	124.1	136.2	152.6	170.5	190.8	200.4
	Commercial	89.0	77.1	64.5	55.4	47.8	42.5	37.3	33.0	29.4
	Total consumption	341.8	330.4	337.6	362.8	395.8	410.5	419.5	428.0	427.7
	Network losses	23.9	23.1	23.6	25.4	27.7	28.7	29.4	30.0	29.9
	Total	**365.7**	**353.6**	**361.3**	**388.2**	**423.5**	**439.2**	**448.9**	**458.0**	**457.7**

A6.2 Scenario new generating capacity programme

The plant types, capacities and build rates selected for each scenario are listed in table A6.2.1.

Table A6.2.1 Plant capacities and build rate assumptions for each scenario (MW and MW/yr)

Plant type		Scenario 1	2	3	4	5	6	7	8	9	10	11	12
Coal	Build rate	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Coal	Max capacity	0	0	0	0	0	0	0	0	0	0	0	0
Coal CCS	Build rate	1,000	1,000	1,000	1,500	0	800	1,500	1,000	1,000	1,000	1,000	2,000
Coal CCS	Max capacity	12,000	12,000	7,000	20,000	0	10,000	20,000	15,000	10,000	13,000	15,000	24,000
Nuclear	Build rate	1,200	1,200	1,200	0	1,500	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Nuclear	Max capacity	20,000	20,000	16,000	0	26,000	20,000	20,000	20,000	16,000	20,000	21,000	25,000
CCGT	Build rate	1,800	2,000	900	1,800	2,500	1,000	1,800	1,500	1,440	1,900	2,100	1,400
CCGT	Max capacity	28,000	30,000	23,000	16,000	35,000	12,000	19,000	20,000	23,000	28,000	28,000	22,000
CCGT CCS	Build rate	0	0	0	1,800	0	0	0	0	0	0	0	0
CCGT CCS	Max capacity	0	0	0	18,000	0	0	0	0	0	0	0	0
Wind	Build rate	800	800	800	800	800	3,000	800	800	800	800	800	800
Wind	Max capacity	15,000	15,000	15,000	15,000	15,000	30,000	15,000	15,000	15,000	10,000	15,000	15,000
Tidal	Build rate	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Tidal	Max capacity	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
OCGT	Build rate	0	0	0	400	0	1,000	600	600	0	0	0	800
OCGT	Max capacity	0	0	0	6,000	0	18,000	10,000	8,000	0	0	0	10,000

A6.3 Scenario CO_2 emission

The sector CO_2 emission profiles for each scenario are shown in table A6.3.1.

Table A6.3.1 CO_2 emission profiles for the electricity sector for each scenario ($MtCO_2$/yr)

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 1	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	193.3	152.3	110.9	79.9	60.2	45.0	35.9	35.0	34.2
	Total	**530.9**	**468.1**	**373.1**	**272.5**	**197.8**	**148.7**	**122.8**	**113.6**	**110.8**
Scenario 2	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	86.1	74.4	62.1	51.9	44.3	39.1	36.3	34.4	33.1
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.6	12.0	9.5	7.7	5.5	3.9	3.3	2.8
	Electricity	193.3	153.0	110.9	80.5	62.4	47.6	38.3	38.3	37.5
	Total	**531.6**	**471.7**	**378.8**	**281.4**	**210.0**	**162.6**	**137.4**	**129.7**	**127.5**
Scenario 3	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	105.8	98.3	81.5	60.6	43.0	32.4	28.9	30.3
	Commercial	17.7	15.4	13.4	10.8	8.4	5.5	3.5	3.0	2.5
	Electricity	192.5	140.9	88.4	52.4	37.9	31.5	29.0	26.6	24.7
	Total	**530.1**	**461.0**	**358.9**	**256.2**	**186.2**	**145.1**	**124.4**	**114.1**	**110.7**
Scenario 4	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	191.8	153.2	111.4	81.1	58.4	51.8	48.8	47.6	46.8
	Total	**529.4**	**469.0**	**373.7**	**273.6**	**196.1**	**155.6**	**135.7**	**126.2**	**123.3**
Scenario 5	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	94.2	84.9	71.8	60.0	47.5	44.7	46.7
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	191.8	152.3	109.1	81.3	66.2	52.3	37.2	36.6	35.7
	Total	**529.4**	**468.1**	**373.8**	**286.7**	**224.6**	**182.4**	**147.8**	**139.9**	**138.0**
Scenario 6	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	191.8	145.7	97.5	72.9	59.0	43.8	33.7	32.8	32.2
	Total	**529.4**	**461.5**	**359.8**	**265.5**	**196.7**	**147.6**	**120.6**	**111.4**	**108.7**

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 7	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	112.2	110.8	103.3	83.8	62.3	43.9	32.9	29.1	32.1
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	194.8	156.7	117.7	87.8	66.5	46.6	37.9	41.7	43.8
	Total	**536.1**	**480.6**	**391.4**	**292.1**	**215.3**	**160.7**	**133.9**	**129.5**	**131.5**
Scenario 8	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	87.1	77.4	65.9	55.2	46.9	40.1	36.3	33.2	30.7
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	18.4	15.7	13.4	11.0	9.4	7.1	5.4	4.9	4.5
	Electricity	192.5	154.4	114.3	85.5	65.9	47.6	36.8	36.5	35.4
	Total	**532.5**	**477.1**	**387.2**	**291.1**	**217.8**	**165.3**	**137.3**	**128.4**	**124.8**
Scenario 9	Transport	126.0	130.8	114.6	92.7	81.1	78.9	79.6	80.3	81.3
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	193.3	151.0	106.3	69.3	46.4	35.5	29.2	28.0	26.2
	Total	**530.9**	**470.6**	**381.2**	**287.3**	**220.7**	**181.2**	**160.8**	**153.3**	**151.0**
Scenario 10	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	191.8	152.3	110.7	80.9	64.9	48.4	37.8	37.6	36.9
	Total	**529.4**	**468.1**	**373.0**	**273.5**	**202.6**	**152.1**	**124.8**	**116.2**	**113.4**
Scenario 11	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	102.6	91.8	72.1	51.1	33.6	23.9	20.0	21.0
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	193.3	153.0	111.7	82.4	63.2	47.0	34.1	34.7	34.7
	Total	**530.9**	**468.9**	**373.9**	**275.0**	**200.9**	**150.8**	**121.0**	**113.4**	**111.3**
Scenario 12	Transport	126.0	127.0	101.9	67.3	44.5	36.9	34.9	33.6	33.1
	Domestic	85.4	71.8	56.9	44.1	34.9	28.1	24.6	22.0	20.0
	Industry	108.5	112.0	110.2	96.1	78.8	64.2	62.0	59.8	62.5
	Commercial	17.7	14.4	11.6	9.0	7.2	5.1	3.5	3.0	2.5
	Electricity	193.3	156.0	120.6	87.6	65.0	52.4	41.9	42.5	42.5
	Total	**530.9**	**481.2**	**401.2**	**304.2**	**230.4**	**186.7**	**167.0**	**160.8**	**160.5**

A6.4 Consumption of fuels by UK economy

Table A6.4.1 shows the consumption of the main fuel classes by the UK economy in the period to 2050 for each scenario.

Table A6.4.1 Profile of annual consumption of fuels in UK economy (MTOE)

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 1	Coal	43.5	29.1	12.2	14.5	22.2	26.5	25.5	25.3	25.5
	Oil	65.5	63.5	51.8	37.1	26.3	21.3	18.6	17.7	17.7
	Gas	85.3	82.0	82.0	66.5	50.1	37.5	29.5	27.4	26.2
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.1	13.1	13.1
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**201.0**	**185.5**	**161.4**	**139.8**	**126.7**	**118.1**	**109.5**	**107.4**	**107.5**
Scenario 2	Coal	43.5	29.2	12.4	14.7	22.5	26.8	25.8	25.6	25.8
	Oil	65.5	63.8	52.4	37.8	27.1	22.3	19.6	18.6	18.6
	Gas	85.6	83.1	83.6	69.2	54.1	42.0	34.4	33.0	32.1
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.1	13.1	13.1
	Renewable	1.8	5.9	11.3	14.1	16.0	17.1	18.3	19.3	20.1
	Total	**201.3**	**186.3**	**161.9**	**140.5**	**128.2**	**119.7**	**111.1**	**109.6**	**109.7**
Scenario 3	Coal	43.5	29.0	12.0	14.2	18.4	17.5	16.5	16.3	16.5
	Oil	65.5	62.8	50.6	35.4	24.9	20.1	17.6	16.6	16.6
	Gas	84.9	79.8	77.5	61.3	47.1	38.6	33.0	30.3	28.9
	Nuclear	4.9	4.2	2.3	4.6	8.5	10.8	10.8	10.8	10.8
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**200.7**	**182.5**	**155.5**	**132.7**	**118.5**	**108.2**	**100.5**	**98.0**	**97.7**
Scenario 4	Coal	43.5	29.1	12.2	18.1	30.2	42.4	41.4	41.2	41.4
	Oil	65.5	63.8	52.5	38.2	27.5	22.5	19.8	18.8	18.9
	Gas	84.6	82.0	81.3	70.1	57.5	46.8	41.0	38.8	37.6
	Nuclear	4.9	4.2	2.3	0.8	0.8	0.0	0.0	0.0	0.0
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**200.3**	**185.8**	**161.5**	**144.3**	**135.6**	**132.9**	**125.0**	**122.9**	**122.9**
Scenario 5	Coal	43.5	29.1	12.2	7.3	6.3	5.3	4.3	4.1	4.3
	Oil	65.5	63.5	51.8	37.1	26.3	21.3	18.6	17.7	17.7
	Gas	84.6	82.0	81.2	68.5	55.8	44.8	34.1	32.1	30.8
	Nuclear	4.9	4.2	2.3	5.6	10.4	14.4	17.3	17.3	17.3
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**200.3**	**185.5**	**160.6**	**135.5**	**118.5**	**107.1**	**97.1**	**95.2**	**95.2**
Scenario 6	Coal	43.5	29.1	12.2	13.1	19.0	23.7	22.7	22.5	22.7
	Oil	65.5	64.3	53.6	39.9	29.9	24.9	22.2	21.2	21.3
	Gas	84.6	77.9	73.4	59.8	45.3	32.7	24.2	22.1	21.0
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.1	13.1	13.1
	Renewable	1.8	8.6	17.2	20.8	22.5	24.1	25.6	26.9	27.9
	Total	**200.3**	**184.2**	**158.8**	**138.2**	**125.2**	**116.9**	**107.8**	**105.8**	**105.9**

		2010	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 7	Coal	43.8	29.9	13.3	19.5	31.8	44.1	43.1	43.1	43.7
	Oil	66.0	65.0	54.5	40.8	30.7	25.8	23.0	22.4	23.0
	Gas	86.5	84.5	85.4	69.4	51.2	35.0	27.1	27.4	28.1
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.1	13.1	13.1
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**203.0**	**190.3**	**168.6**	**151.5**	**141.8**	**137.7**	**129.1**	**130.0**	**132.9**
Scenario 8	Coal	43.5	29.2	12.3	14.6	22.3	30.1	30.8	30.7	30.9
	Oil	65.6	64.2	53.2	39.1	28.3	23.2	20.5	19.5	19.6
	Gas	85.9	85.1	86.4	72.2	56.4	41.8	32.5	30.5	29.0
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.1	13.1	13.1
	Renewable	1.8	6.7	13.4	17.8	21.0	23.1	25.0	26.5	27.7
	Total	**201.7**	**189.4**	**167.6**	**148.3**	**136.4**	**129.7**	**121.9**	**120.3**	**120.2**
Scenario 9	Coal	43.5	29.1	12.2	14.5	22.2	23.0	22.0	21.8	22.0
	Oil	65.5	64.8	56.2	45.8	38.9	35.7	34.0	33.7	34.3
	Gas	85.3	81.5	79.9	61.7	43.8	33.9	27.3	25.0	23.4
	Nuclear	4.9	4.2	2.3	4.6	8.5	10.8	10.8	10.8	10.8
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**201.0**	**186.2**	**163.7**	**143.8**	**133.1**	**124.7**	**116.8**	**115.3**	**115.4**
Scenario 10	Coal	43.5	29.1	12.2	14.5	22.2	28.3	27.3	27.1	27.3
	Oil	65.5	63.5	51.8	37.1	26.3	21.3	18.6	17.7	17.7
	Gas	84.6	82.0	81.9	67.0	52.3	38.7	30.1	28.3	27.1
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.1	13.1	13.1
	Renewable	1.8	6.6	13.0	16.9	18.6	20.2	21.7	22.9	23.9
	Total	**200.3**	**185.5**	**161.4**	**140.1**	**127.8**	**120.0**	**110.7**	**109.0**	**109.1**
Scenario 11	Coal	43.5	29.1	12.2	14.5	22.2	30.0	30.8	30.6	30.8
	Oil	65.5	63.5	51.8	37.1	26.3	21.3	18.6	17.7	17.7
	Gas	85.3	82.4	82.4	67.7	51.5	37.7	27.6	26.2	25.4
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	13.8	13.8	13.8
	Renewable	1.8	6.4	12.7	16.5	18.9	20.3	21.4	22.3	23.1
	Total	**201.0**	**185.7**	**161.4**	**140.3**	**127.3**	**120.9**	**112.3**	**110.6**	**110.8**
Scenario 12	Coal	43.5	29.8	13.7	24.0	41.3	51.9	52.0	52.0	52.5
	Oil	65.5	65.0	54.7	41.2	31.7	28.2	27.2	26.5	26.9
	Gas	85.3	84.9	88.8	72.3	54.2	43.3	36.3	35.2	34.8
	Nuclear	4.9	4.2	2.3	4.6	8.5	11.5	15.4	16.1	16.1
	Renewable	1.8	6.6	13.0	17.1	19.6	21.3	22.8	24.0	25.0
	Total	**201.0**	**190.5**	**172.6**	**159.2**	**155.3**	**156.2**	**153.6**	**153.9**	**155.4**

Appendix A7.
Areas for further work

This appendix contains suggested areas for further in-depth research.

A7.1 Policy issues

- Assess the likely future behaviour of carbon markets as planned policies are applied. Estimate the likely changes in carbon price to identify any potential adverse risks or perverse consequences. The latter will need to be avoided by amending the market scope, rules or scale of free carbon credits.
- Establish mechanisms to track policy proposals for carbon reduction measures and ensure that their impacts on all sectors of the economy are fully evaluated and managed before the policies are implemented.

A7.2 Capability development

- Assess the capability and capacity of the engineering, manufacturing and construction sectors to implement the scale and programme of improvement projects identified in Powering the Future.
- Identify shortfalls in capability and capacity for each sector.
- Define strategies that support the development of capability and capacity in those sectors. Foster the disciplines and skills needed to deliver the improvement projects on schedule.
- Develop a strategy to identify where UK capability in ‘green technologies’ related to carbon emission reduction is sufficient to establish a UK leadership role internationally. Define the steps to support, strengthen and make this capability effective.

A7.3 Evaluation of options

- Identify issues and impacts of proposed measures including practical, economic, social and environmental consequences.
- Review cost data from various sources, and relate data to the likely scale of application and CO_2 reduction to establish a cost hierarchy for reduction for measures across the economy.
- Relate the alternative power generation options to costs from Parsons Brinckerhoff’s Powering the Nation report (2010 reissue).

A7.4 Transport

- Identify issues and opportunities for transition of road transport from petroleum fuel to electricity. Prepare a strategy and timeline for the changes required, including economic, social, environmental and infrastructure issues.
- Prepare a strategy to increase the capacity and use of public transport networks in order to reduce road transport use for passengers and freight.
- Evaluate the potential application of CO_2 emission reduction measures to aviation and marine transport to enable an appropriate strategy for emission reduction to be developed consistent with international best practice.
- Evaluate the impact of electric vehicle adoption on UK road transport infrastructure and facilities. Define a strategy to promote the implementation of the necessary changes at each level of the system.
- Investigate further potential options to radically reduce CO_2 emission by the HGV fleet, including assessment of alternative fuels, hybrid vehicle concepts and direct electricity supply.

A7.5 Domestic

- Establish a programme to qualify best-practice external or internal wall insulation and ventilation heat recovery technologies, and the appropriate methods of applying them to the diversity of existing housing stock.
- Prepare a strategy to promote the wide application of radical energy reduction improvements. These could include providing financial incentives to owners (eg stamp duty adjustment according to property energy performance) and placing additional obligations on mortgage lenders.
- Prepare a strategy to promote the application of domestic renewable heat aimed particularly at displacing coal and oil by biomass and the wider adoption of solar water heating technology.
- Work with other EU countries to define an escalator of appliance energy efficiency requirements to progressively drive down the energy consumption of domestic appliances.

A7.6 Industry

- Review the status of industry sector CO_2 emission reduction efforts. Prepare a strategy to strengthen actions and delivery of efficiency improvements in products and processes.
- Review the mechanisms available to fund process improvements in industry to reduce CO_2 emissions. Develop strategies to support industry in achieving reductions in emissions without breaching EU regulations.
- Identify those EU regulations which limit the funding of CO_2 emission reduction measures in industry. Propose and negotiate changes to ensure support is permitted to prevent industry leaving the EU and increasing its emissions by transferring production elsewhere.
- Assess the application to major industrial emitters of CCS technology currently being supported through the UK CCS pilot project competition, identifying changes required in scale, process and operation. Establish a programme to support the development needed to make this technology appropriate to industrial applications.

A7.7 Commercial

- Review the incentives and obligations applicable to owners of commercial property and governmental bodies to ensure that existing property is progressively upgraded to defined standards comparable with the current requirements of Part L of the Building Regulations for insulation, ventilation and energy use.
- Review the current strategy for the application of the Building Regulations to existing property. Ensure that the regulations become progressively more demanding of existing property, and that owners are obliged to upgrade to the appropriate standard within a defined time or to demolish the building as unfit for further use.
- Establish a programme of technology development and promotion for the application of renewable electricity generation technologies, including best-practice demonstration installations.

A7.8 Electricity

- Review the current strategy for renewable development to identify aspects which require changes to the electricity system to handle larger scales of intermittent renewable generation. Assess the role of generators, supply companies, distribution companies and the transmission system operator in mitigating the risks to supply reliability.
- Review the impact on the electricity system generation mix of a large penetration of renewable generation by 2020. Assess the economic viability of different types of fossil generation at reduced load factors and the likely consequences on overall carbon emissions by the sector to 2050.
- Assess the implications of the battery-charging demands of a large-scale rollout of electric vehicles on distribution system capacity and on transmission and generating system operation.
- Prepare a strategy for infrastructure development to support roadside charging for off-peak and future despatched continuous charging.
- Assess the impact on charging mechanisms, tariffs and competitive electricity supply of large numbers of electric vehicles becoming new mobile consumers.
- Prepare a strategy for ‘smart grid’ definition, development, standardisation and implementation to support economic and reliable network operation and electricity supply through the radical changes foreseen in the next 30 years.

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Appendix A9. Glossary

AGR	Advanced gas-cooled reactor
AS	Air source (heat pump)
BERR	Department for Business, Enterprise and Regulatory Reform
BP	British Petroleum
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CfSH	Code for Sustainable Homes
CHP	Combined heat and power
CIBSE	Chartered Institution of Building Services Engineers
CO_2	Carbon dioxide
DCLG	Department of Communities and Local Government
Defra	Department for Environment, Food and Rural Affairs
DfT	Department for Transport.
DUKES	Digest of UK Energy Statistics
ETS	Emissions Trading Scheme
EU	European Union
GS	Ground source (heat pump)
GW	Gigawatt
HGV	Heavy goods vehicle
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
kW	Kilowatts
LGV	Light goods vehicle
Magnox	First-generation UK gas-cooled reactor using magnesium alloy clad uranium fuel
$MtCO_2$/yr	Million tonnes of carbon dioxide per year
MTOE/yr	Million tonnes oil equivalent per year
MW	Megawatt
MWh	Megawatt hours
NGC	National Grid Company
NOx	Nitrogen oxide emissions
NTM	National Transport Model
NUTS4	Standard division of the UK into areas and regions
OCGT	Open cycle gas turbine
OECD	Office for Economic Co-operation and Development
Ofgem	Office of the Gas and Electricity Markets – the market regulator
OHL	Overhead lines
PB	Parsons Brinckerhoff
ppm	Parts per million
PSV	Public service vehicle (bus)
PV	Photovoltaic
PWR	Pressurised water reactor – most widely used type of nuclear reactor
R/P	Reserve/production ratio
Smart grid	Use of communications and control technologies to coordinate operation of electricity generation and consumption with the transmission and distribution networks to minimise costs and enhance reliability
SOx	Sulphur dioxide emissions
TEC	Transmission entry capacity
TWh	Terawatt hour
TWh/yr	Terawatt hour per year
URN	Unique reference number
Utilisation	Percentage actual energy production of potential energy production in a given period
W	Watt









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