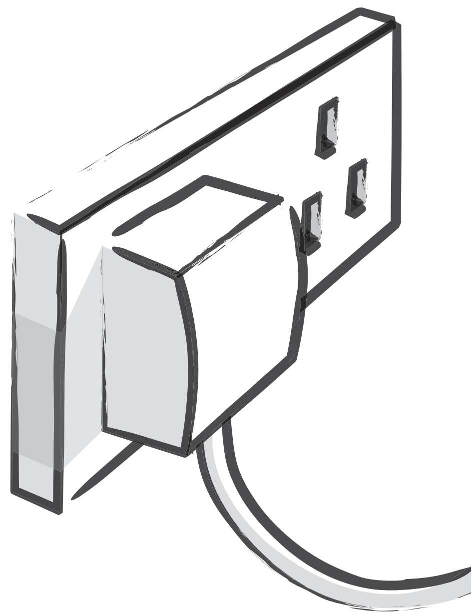
WWF

The balance of power

Reducing CO_2 emissions from the UK power sector

A report for WWF-UK by ILEX Energy Consulting, May 2006



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The views of the authors expressed in this publication do not necessarily reflect those of WWF.

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ACKNOWLEDGEMENTS

The responsibility for results obtained, views expressed and wording in this report is solely that of ILEX.

LIST OF ABBREVIATIONS

BAU	Business as Usual scenario
BETTA	British Electricity Trading and Transmission Arrangements
CCGT	Combined Cycle Gas Turbine
CCA	Climate Change Agreements
CCP	Climate Change Programme
CHP	Combined Heat and Power
CC&S	Carbon Capture and Storage
CO_2	Carbon Dioxide
DEFRA	Department of Environment, Food, and Rural Affairs
DTI	Department of Trade and Industry
ELV	Emissions Limit Value
EEC	Energy Efficiency Commitments
EPC	Engineer, Procure and Commission
EU	European Union
E&W	England and Wales
ETS	Emissions Trading Scheme
EWP	Energy White Paper
FGD	Flue Gas Desulphurisation
GHGs	Greenhouse Gases
IPCC	Intergovernmental Panel on Climate Change
LCPD	Large Combustion Plants Directive
OCGT	Open Cycle Gas Turbine
NAP	National Allocation Plan
NETA	New Electricity Trading Arrangments
NG	National Grid

NI	Northern Ireland
NO_X	Nitrous Oxide
PIU	Performance Innovation Unit
PS1	PowerSwitch 'Policy Extension' scenario
PS2	PowerSwitch 'Policy Evolution' scenario
RO	Renewables Obligation
SCR	Selective Catalytic Reduction
SO_2	Sulphur Dioxide
TWA	Time weighted average
UEP	Updated Energy Projections
UK	United Kingdom
UMIST	University of Manchester Institute of Science and Technology
WWF	A leading global environmental organisation

Conventions

- All prices are in July 2006 money unless otherwise stated.
- All years are calendar years ending 31st December unless otherwise stated.

EXECUTIVE SUMMARY

Climate change is the most serious environmental threat facing the world today. In order to avoid the worst effects of climate change, future global greenhouse gas emissions will need to be reduced substantially from current levels. The UK Government has already made an international commitment to deliver a 12.5% reduction from 1990 emissions by 2008-2012. It has also adopted its own national goals to reduce CO_2 emissions by 20% by 2010 and by some 60% by 2050.

Electricity generation is currently the biggest single source of CO_2 emissions in the UK, responsible for approximately a third of total emissions. To deliver cuts consistent with achievement of the Government's long-term national targets, it is likely that electricity generation would be expected to emit virtually no CO_2 at all by 2050. The need to reduce CO_2 emissions arising from power generation is therefore a very important consideration in the current energy review, if the ambitious goals adopted by government are to be achieved.

WWF has commissioned ILEX to provide a realistic assessment of the potential to achieve significant CO_2 emissions reductions in the UK power sector by 2010, 2016, 2020 and 2025 without new nuclear build.

We have developed and modelled three main scenarios. Firstly a 'Business as Usual' scenario (BAU) that incorporates the impact of government policies adopted to date, and presents our central view of the future in the absence of further government policy changes in this area. This is then compared against two alternative 'PowerSwitch' scenarios (PS1 and PS2) that incorporate additional government aspirations from the Energy White Paper, as well as extending and evolving existing government policies in this area.

These PowerSwitch scenarios do not rely on the emergence of significant technological advances or radical policy shifts. Instead they focus on achieving emissions reductions through conventional means – through energy efficiency measures, additional encouragement of renewable and CHP generation, and through a rising price of carbon in the EU Emissions Trading Scheme (ETS).

The results are very promising. Our analysis shows that the power sector has already managed to reduce its emissions significantly since 1990 and further reductions are expected under BAU by 2010, driven by recently adopted policies in this area. However these reductions are offset by rising electricity demand and falling nuclear generation, causing BAU emissions to start rising again over time. By 2025, BAU emissions are projected to be 18% below 1990 emissions levels.

The analysis shows that relatively minor extensions to current policies and targets could enable the UK power sector to cut its CO_2 emissions by approximately 40% from 1990 levels by 2010 and maintain them at this level until 2025 despite the closure of almost all nuclear power plants during this period. The modelling also shows that further incorporation of government aspirations and evolution of existing policies could potentially reap reductions of around 55% from 1990 levels through to 2025.

A key issue is the extent to which existing coal fired plant remains in operation. We have assumed that all such plant that has been fitted with FGD will be in service until just beyond the scope of the study. The presence of existing coal fleet could well delay the build of new CCGT and still maintain sufficient capacity margin. Should there be more new build of CCGT than detailed in this study, then the level of CO_2, and SO_2, emissions will be less than that forecast. This issue will need to be addressed shortly following the end of the study period, as we anticipate that there will be a reduction of 14 GW of capacity due to the closure of old coal fired plant in 2026.

This analysis assumes that generation from renewable sources increases to 20% and 25% using the Renewables Obligation arrangements. It may be appropriate to supplement this scheme to ensure a more diverse mix of renewable generation sources.

A key issue is the role that gas will play in the fuel mix. The results suggest that by 2025 between 62% and 65% of electricity generated will be done using gas. We have provided an illustrative example of the impact of carbon capture and storage (CC&S), which suggests that it could be used to achieve significant reductions in CO_2 emissions and enable the UK to maintain a more diverse fuel mix. However, the analysis does not involve an analysis of all of the costs and constraints associated with CC&S.

We have also looked at various cost implications of achieving these reductions, though we have not attempted to provide a full cost-benefit analysis, since this will be dependent on the specific design of the policies used. Our analysis shows the net costs incurred under the PowerSwitch scenarios are lower than the costs incurred under BAU. Further, that total electricity bills could actually be lower as a result of the increased energy efficiency in the PowerSwitch scenarios, even though wholesale prices would generally be expected to rise.

One of the key drivers behind these results is the Government's aspirations for reducing electricity demand. While measures to reduce electricity demand are potentially extremely cost effective, it should be noted that they could be difficult to accomplish unless the Government ensures that current obstacles to energy efficiency are effectively addressed in the near future.

Another key driver in all three scenarios is the impact of the EU ETS. Even at relatively low carbon price levels the EU ETS can have a significant impact on fuel mix and emissions.

1. INTRODUCTION

1.1 Climate change is the most serious environmental threat facing the world today. Levels of carbon dioxide (CO_2) in the global atmosphere have risen by more than a third since the industrial revolution and are now rising faster than ever before. This has already led to rising global temperatures and significant changes in the world around us. Without major action to reduce emissions of CO_2 and other greenhouse gas, the future consequences could be serious.

1.2 In order to avoid the worst effects of climate change, greenhouse gas concentrations in the atmosphere will need to be stabilised rather than being allowed to continually increase. However, the climate system is subject to such great inertia that stabilisation of CO_2 concentrations at any level will require reduction of global CO_2 emissions to substantially below current emission levels. According to the Intergovernmental Panel on Climate Change (IPCC), the world's most authoritative body on climate change, stabilising concentrations at even double pre-industrial levels will eventually require cuts of more than 60% in annual global emissions[1].

1.3 As a result of the Kyoto Protocol, most developed nations have agreed to take a first step along this route and commit to binding cuts in emissions of CO_2 and other greenhouse gases. As part of this, the UK is required to deliver a 12.5% reduction in greenhouse gas emissions from 1990 emission levels by 2008-2012. In addition, the UK Government has also adopted its own national goals – to reduce CO_2 emissions by 20% from 1990 levels by 2010 and also by some 60% by 2050, with evidence of real progress towards this long-term goal by 2020. However, the review of the Government's Climate Change Programme concluded in March 2006 that CO_2 emissions will only fall by 15% to 18% by 2010.

1.4 Electricity generation is currently the biggest single source of CO_2 emissions worldwide. It is also the major source of emissions in the UK, responsible for about a third of total CO_2 emissions. In order to deliver cuts consistent with achievement of the Government's long-term national targets, it is likely that electricity generation will be expected to emit virtually no CO_2 at all by 2050[2]. However, emissions from the power sector have been increasing in recent years, and are now 15% about the level in 1997. The need to reduce CO_2 emissions arising from power generation is therefore a very important consideration for future climate change and energy policy, if the goals adopted by government are to be achieved.

1.5 In February 2003 the UK Government released its Energy White Paper (EWP), titled 'Our Energy Future'[3], which set out four goals for energy policy:

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1 'Climate Change 2001: Synthesis Report', Figure 25c, IPCC, 2001.

2 'Options for a Low Carbon Future: a report produced for DTI, DEFRA and the PIU', AEA Technology, February 2002.

3 See http://www.dti.gov.uk/energy/whitepaper/ourenergyfuture.pdf

- to put ourselves on a path to cut the UK's CO_2 emissions by some 60% by about 2050 with real progress by 2020;
- to maintain the reliability of energy supplies;
- to promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity; and
- to ensure that every home is adequately and affordably heated.

1.6 In January 2006 the UK Government commenced an Energy Review, which involved issuing a consultation paper, titled 'Our Energy Challenge'[4]. This consultation seeks comment on progress towards achieving the goals listed in the EWP, and focuses on the following questions:

- What more could the government do on the demand or supply side for energy to ensure that the UK's long-term goal of reducing carbon emissions is met?
- With the UK becoming a net energy importer and with big investments to be made over the next twenty years in generating capacity and networks, what further steps, if any, should the government take to develop our market framework for delivering reliable energy supplies? In particular, we invite views on the implications of increased dependence on gas imports.
- The Energy White Paper left open the option of nuclear new build. Are there particular considerations that should apply to nuclear as the government re-examines the issues bearing on new build, including long-term liabilities and waste management? If so, what are these, and how should the government address them?
- Are there particular considerations that should apply to carbon abatement and other low-carbon technologies?
- What further steps should be taken towards meeting the government's goals for ensuring that every home is adequately and affordably heated?

1.7 In preparation to responding to the 2006 Energy Review consultation, WWF commissioned Ilex to undertake an analysis of three scenarios for the UK power market. The key focus of this analysis are:

- the potential to achieve significant reductions in CO_2 emissions; and
- the implications for the fuel mix, in particular the extent to which gas is used in the context of no further nuclear build.

1.8 This analysis is an update and extension of a 2004 report to WWF in support of PowerSwitch, which is a major international campaign aimed at transforming power generation into a virtually carbon-free industry in developed countries.

1.9 Ilex has been asked to develop and model the following three scenarios for 2010, 2016, 2020 and 2025:

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4 See http://www.dti.gov.uk/energy/review/energy_review_consultation.pdf

- a **Business as Usual scenario (BAU)** – which assumes the continuation of existing policy measures with the current likelihood of success;
- a **PowerSwitch 'Policy Delivered' scenario (PS1)** – which assumes the continuation and success of existing policy measures and targets; and
- a **PowerSwitch 'Policy Evolution' scenario (PS2)** – which assumes the implementation and success of new ambitious but realistic policy measures.

1.10 Key differences between the 2006 and 2004 study include

- up to date assumptions regarding fuel prices and the price of CO_2 allowances for the EU ETS;
- modelling scenarios in 2010, 2016 (the year by which coal fired plant that opted out under the LCPD will have closed), 2020 and 2025;
- the growth in electricity demand for each scenario assumes the same level of economic growth;
- the decommissioning of nuclear plant takes place as currently scheduled;
- a sensitivity analysis to show the potential impact of some coal fired capacity fitted with carbon capture and storage (CC&S) facilities;
- microgeneration plays a growing role in 2020 and 2025 in the PS2 scenario; and
- the PS2 scenario assumes that regulations will require CCGT plant to run ahead of coal fired plant in 2020 and 2025.

1.11 This report summarises the findings of our analysis:

- section 2 provides an overview of the scenarios and input assumptions used;
- section 3 presents the projected power sector emissions levels and generation fuel mix for each scenario in 2010, 2016, 2020 and 2025;
- section 4 provides estimates of the cost implications for the different scenarios;
- section 5 provides illustrative examples of likely impacts on different plant types;
- section 6 draws out the key messages and conclusions arising from the study;
- Annex A summarises the key input assumptions and results; and
- Annex B provides details of ILEX's modelling approach.

2. SCENARIOS AND INPUT ASSUMPTIONS

2.1 We have developed and modelled three main scenarios for this study. These are:

- a **Business as Usual scenario (BAU)** – which assumes the continuation of existing policy measures with the current likelihood of success;
- a **PowerSwitch 'Policy Delivered' scenario (PS1)** – which assumes the continuation and success of existing policy measures and targets; and
- a **PowerSwitch 'Policy Evolution' scenario (PS2)** – which assumes the implementation and success of new ambitious but realistic policy measures.

The input assumptions used for modelling each scenario are discussed below.

Fuel prices

2.2 Future fuel prices, particularly the relative prices of gas and coal, are likely to be a key influence on future emissions. Table 1, below, sets out the annual average fuel prices that were used for modelling all three scenarios. These prices are based on ILEX's standard central fuel price projections and reflect what we consider to be a reasonable balance between gas and coal price differentials. However, we should emphasise that different fuel price relativities would be likely to affect the results obtained. All prices refer to the gross calorific value of fuel delivered to a power station on a variable cost basis.

Table 1 – Fuel prices in 2006 £/GJ

2006 £/GJ	Coal	Medium Distillate Oil (MDO)	Very Low Sulphur Fuel Oil (VLSFO)	Spot gas
2010	1.54	5.76	3.38	3.25
2016	1.52	5.22	3.15	3.07
2020	1.42	5.40	3.23	3.05
2025	1.36	5.73	3.40	3.05

Source: ILEX Analysis

2.3 Table 2 provides a comparison between the prices we have used in this analysis and those the DTI used in the February 2006 version of the UK Energy and CO2 Emissions Projections[5], which are referred to as the Updated Energy Projections (UEP). The UEPs include four scenarios for fuel prices, and Table 2 uses the central prices that favour gas.

Table 2 – Comparison of Ilex and DTI's assumed fuel prices

	Ilex	DT's central (1) favouring gas

[5] See http://www.dti.gov.uk/energy/sepn/uep_feb2006.pdf

£/GJ	Gas	Coal	G/C ratio	Gas	Coal	G/C ratio
2010	3.25	1.54	2.11	2.26	0.89	2.55
2020	3.05	1.42	2.15	2.26	0.80	2.83

Source: ILEX Analysis and DTI

2.4 Table 2 indicates that the fuel prices we used are far higher than those that the DTI assumed. This is due to fuel prices increasing between when the DTI set its prices and when we selected ours. However, the key difference is in the ratio of gas to coal prices, which is far lower for our prices than for DTI's. A high gas to coal ratio means that the price of gas is high relative to coal, suggesting generators will prefer to use of coal. This indicates that the prices we used will tend to favour the use of gas more than the prices in the DTI's model.

The EU Emissions Trading Scheme (EU ETS)

2.5 The EU ETS in 2005 requires generators to have sufficient allowances to cover their CO_2 emissions. Table 3, below, sets out the carbon price assumptions that have been used for each scenario. For BAU, we have assumed a relatively low carbon price, while in the PowerSwitch scenarios, we have assumed that the scheme as a whole becomes more stringent, due to Member States setting stricter allocation levels, resulting in higher carbon prices. The carbon prices used provide a range of possible prices, which is appropriate given the uncertainty for carbon prices beyond 2010. For all scenarios we assume that the full opportunity cost of carbon is passed through into wholesale electricity prices in the years in question. For comparison, carbon priced have been between €20/tCO_2 and €30/tCO_2 since the middle of 2005.

Table 3 – Carbon prices in 2006 €/tCO_2

2002 €/tCO_2	BAU	PS1	PS2
2010	20	30	30
2016	20	30	35
2020	20	30	35
2025	20	30	40

Source: ILEX Analysis

The revised Large Combustion Plants Directive (LCPD)

2.6 From 1 January 2008, the UK will need to comply with the revised LCPD. This places limitations on the emissions of sulphur dioxide (SO_2), nitrogen oxides (NOx) and dust (particulate matter) into the air from all combustion plant with a thermal input of greater than 50MW. Operators in the UK were able to choose whether their plant would:

- Be subject to specific emission limit values (ELVs), which set concentration limits on the emissions from a particular site, where concentration limits are measured in mg per cubic metre of waste gas flow.
- Be subject to a national emission reduction plan (NERP), which involves a cap and trade arrangement for national mass limits on emissions, where mass limits are measured in tonnes per year. It is proposed that plants will receive allowances based on applying the ELV to historic volumes of waste gas flow.
- Opt out of the scheme, in which case they will only be allowed to run for a maximum of 20,000 hours between 2008 and 2015, and the plant must close by the end of 2015.

2.7 Table 4 below, details the choice operators have made regarding their plant.

Table 4 – Status of UK electricity generating plant for the LCPD

Emission Limit Values	National Emissions Reduction Plan	Opted out
Aberthaw;	Drax;	Cockenzie;
Cottam;	Eggborough;	Didcot A;
Ferrybridge plants 3&4;	Longannet; and	Fawley;
Fiddlers Ferry;		Ferrybridge plants 1 & 2;
Fifoots (Uskmouth);		Grain;
Kilroot;		Ironbridge;
Ratcliffe;		Kingsnorth;
Rugeley; and		Littlebrook D; and
West Burton		Tilbury

Source: DEFRA notification to the European Commission, 28th February 2006

2.8 Our modelling assumes that all coal plant that has chosen to be subject to ELVs or a NERP will be fitted with Flue Gas Desulphurisation (FGD) and continue to be available throughout the period of the study. Beyond 2016 further investment in NOx abatement technology will be required to allow plant that has opted in to continue operating.

2.9 More coal fired plant decided to opt in and fit FGD than initially anticipated, which is primarily driven by expectations about the future price relativity between gas and coal. The implication of a higher level of coal fired capacity through the study period is that there will be less build of CCGT plant, which has the potential to lead to higher CO_2 emissions than previously anticipated. It should be noted that this may fall as much of the coal fire plant will be coming to an end of its life toward the end of the study period, with approximately 14 GW of coal fired plant due to retire in 2026.

Electricity demand

2.10 Table 5 sets out the growth rates and electricity demand figures used for modelling each scenario. These figures are for total system demand, including demand met by autogeneration (on-site generation), CHP and renewable plant.

Table 5 – Electricity demand

	BAU	PS1	PS2
Growth rate (% p.a.)	1.15	0.44	0.11
Electricity demand in 2010 (TWh)	405	388	380
Electricity demand in 2016 (TWh)	435	399	383
Electricity demand in 2020 (TWh)	456	406	386
Electricity demand in 2025 (TWh)	482	416	388

Source: DTI UK Energy andCO_2 Emissions Projections Feb 2006 and ILEX Analysis

2.11 The growth rates in demand for electricity used reflect those that the DTI used in its February 2006 UEP. This publication provides the following forecasts for electricity demand in the UK:

- ***without measures***, which does not include the impact of the Climate Change Programme. This forecasts electricity demand to increase at 1.49% p.a. until 2010, after which demand grows at 0.74% p.a. This equates to a growth rate of 1.15% p.a. between 2004 and 2015.
- ***with measures***, which includes the impact of the Climate Change Programme. This forecasts electricity demand to increase at 0.11% p.a. until 2010, after which demand grows at 0.83% p.a. This equates to a growth rate of 0.44% p.a. between 2004 and 2015.
- ***call on grid***, which does not include embedded generation and will not be considered in this report.

2.12 The BAU and PS1 scenarios use the DTI's average forecast growth in electricity demand for the 'without measures' and 'with measures' cases of 1.15% and 0.44% respectively to project electricity demand until 2025. The PS2 scenario applies the initial 'with measures' growth rate of 0.11% from 2004 to 2025.

2.13 The use of the DTI's forecast growth in electricity demand differs from other Ilex analysis, which has relied on the National Grid's (NG's) projections, published in its Seven Year Statements. The key reason for this is that the NG's forecasts assume different levels of GDP growth while the DTI assumes the same GDP growth for each of its cases. As the focus of this analysis is on the impact of policy measures rather than economic conditions on CO_2 emissions, it is preferable to used forecasts that assume the same level of economic growth.

2.14 For purposes of comparison, Table 6 details the per annum growth rates for GDP and electricity demand in the NG's Central and Low cases and the averages of the DTI's 'without measures' and 'with measures' scenarios.

Table 6 – Comparison of National Grid and DTI forecasts

	National Grid (2004/5 to 2011/12)		DTI's (2004 to 2015)	
Growth	Central case	Low case	'without measures'	'with measures'
GDP	2.6%	2.3%	2.55%	2.55%
Overall electricity demand	1.3%	0.2%	1.15%	0.44%

Source: ILEX Analysis and NG Seven Year Statement May 2005

2.15 The demand growth rate assumed for PS2 of 0.11% p.a. contrasts with the assumption used in previous Ilex analysis of –0.2% p.a., which was based on the mid point of electricity demand projections underlying the Energy White Paper (EWP). The EWP relied on the projections from the Energy Paper 68 (EP68), which assumed in its central case that GDP would grow by 2.25%.

2.16 The starting point used in this analysis is 382TWh in 2004, which is the total volume of electricity that DUKES cites as being available. This is more than the starting point that the DTI used, which was 359 TWh in 2005, which is the gross supply to the grid plus imports. The key difference is that this analysis includes autogeneration, CHP and renewables, and hence will yield higher estimates of CO_2 emissions.

Renewable capacity

2.17 The Renewables Obligation (RO) requires suppliers to purchase a proportion of their supplies from eligible renewable generation. These target proportions will increase through 10.4% in 2010/11 to 15.4% in 2015/16 and are scheduled to remain in place until March 2027.

2.18 In all three scenarios, we have assumed that the RO policy mechanism remains the chief driver of increased generation from renewable sources. One of the most important aspects of the way that the RO works is the concept of the buy-out option. If suppliers cannot meet their obligation by demonstrating that they have made the necessary purchases of renewable power, they have to meet any shortfall by paying a buy-out price. The money accrued from this is redistributed to all suppliers in proportion to the amount of renewable power they actually buy, as defined by the number of certificates they hold. This combination of the buy-out price and redistribution of the buy-out fund effectively means that the support level for electricity generated from renewables is high when the level of renewables is well below the target level, but decreases as the target is neared.

2.19 Given the way in which the RO works, the target levels that have been set are unlikely to be met in current circumstances. This has led to the following assumptions:

- in the BAU scenario, it is assumed that the actual generation from renewables falls short of the 2010/11 and 2015/16 obligations by 15%, and remains at that level;
- in the PS1 scenarios, it is assumed that the actual generation from renewables hovers close to the 2010/11 and 2015/16 obligation, after which the obligation is increased to 20% by 2020 and the level of generation moves toward and remains at that level; and
- in the PS2 scenarios, it is assumed that the actual generation from renewables hovers close to the 2010/11 and 2015/16 obligation, moves towards the revised obligation of 20% by 2020 after which the obligation is increased to 25% by 2025 and the level of generation moves toward this level.

2.20 The PS1 and PS2 scenarios will require additional measures and/or changes to the RO to ensure that the stated generation from renewables is achieved.

2.21 Table 7 sets out the obligation-related renewable capacity assumptions that we have used for modelling each scenario.

Table 7 – Renewable capacity (GW)

TWh	BAU	PS1	PS2
2010	8.0	9.9	9.5
2016	14.2	17.2	16.3
2020	15.6	20.2	19.6
2025	17.2	21.9	26.8

Source: ILEX Analysis

2.22 It should be noted that the renewable electricity generated for the PS2 scenarios is lower than that for the PS1 scenario until 2025, despite the PS1 scenario having the same target until 2020. This is because the Renewable Obligation (RO) is based on a certain percentage of total supply – so the higher the total demand for electricity, the higher the requirement and incentive under the RO to deliver more renewable capacity. If demand is reduced, the equivalent RO target levels can therefore be achieved more easily and at lower cost (although additional costs may well be incurred in making the demand reduction itself).

Combined Heat and Power (CHP)

2.23 The UK Government has set a target of 10 GW of CHP capacity being installed by 2010. In the BAU scenario, it is assumed that actual installed CHP capacity falls short of this target by 20%, and thereafter grows at the same rate as the demand for electricity. This is consistent with the assumptions that the National Grid makes in its projections.

2.24 In PS1 it is assumed that the 10 GW target is achieved, and thereafter CHP capacity increases at the same rate as the demand for electricity. PS2 assumes that the 10 GW target is achieved, and thereafter a new target of 15 GW of CHP capacity by 2025 is set and achieved. Table 8 sets out the CHP capacity assumptions used for modelling each scenario.

Table 8 – CHP capacity (GW)

GW	BAU	PS1	PS2
2010	8.0	10.5	10.5
2016	8.5	10.7	12.5
2020	8.9	10.9	13.8
2025	9.2	11.0	15.3

Source: ILEX Analysis

Microgeneration

2.25 The uptake of microgeneration has potential to make a significant impact on the demand on the overall electricity system and on CO_2 emissions. This has been addressed through assuming that in PS2 microgeneration provides 0% of electricity supply in 2010 and 2016, 3% in 2020 and 5% in 2025. This generation will be split between carbon neutral technology, such as PV and wind, and carbon producing technology such as micro CHP and solid oxide fuel cells. It is assumed that that 25% of microgeneration is carbon neutral and 75% is carbon producing, which is based on the results of the Potential for Microgeneration study that the Energy Savings Trust (EST) published. The assumptions for PS2 are summarised in Table 9 below.

Table 9 – PS2 assumptions on microgeneration capacity (MW)

MW	Carbon neutral	Carbon producing	Total
2010	0	0	0
2016	0	0	0
2020	79	472	550
2025	131	786	917

Source: The Energy Savings Trust, Potential for Microgeneration, November 2005 and Ilex analysis

Other capacity assumptions

2.26 Our models take the status of current plants and future projects from the Seven-Year Statements for NG and from Ofreg (NI). Adjustment to the data is made, where necessary, to reflect industry knowledge.

2.27 Where specific decommissioning dates are not known, plant retirements are based on nominal station lives of around 40-years for coal plant and 30-years for

Combined Cycle Gas Turbines (CCGTs). In each scenario, we have assumed that all coal fired plant without FGD is retired by the end of 2015 due to the LCPD constraints.

2.28 Each scenario assumes that nuclear power stations will retire on currently announced closure dates and that there will not be any new nuclear power stations commissioned in the UK. Table 10 details the scheduled closure dates for the nuclear plant within the UK.

Table 10 – Scheduled dates for closure of nuclear plant

Plant	Type	Capacity (MW)	Closure date
Dungeness A	Magnox	444	2006
Dungeness B	AGR	1,070	2018
Hartlepool	AGR	1,207	2014
Heysham 1	AGR	1,165	2014
Heysham 2	AGR	1,322	2023
Hinkley Point B	AGR	1,297	2011
Hunterston B	AGR	1,238	2011
Oldsbury	Magnox	475	2008
Sizewell A	Magnox	470	2006
Sizewell B	PWR	1,220	2035
Torness	AGR	1,270	2023
Wylfa	Magnox	1,082	2010

Source: ILEX Analysis

2.29 For each scenario, new entry (beyond that supplied by specific plant currently under construction) is delayed until either required by a combination of demand growth and plant retirements, or incentivised by rising price levels under the EU ETS. The generic capacity installed in the longer term is assumed to be of baseload CCGT technology.

2.30 Scenario PS2 assumes that from 2020 regulatory measures will be imposed to ensure that gas fired plant will always operate ahead of coal fired plant. At this time, most of the coal fired plant will be in the order of 50 years old and the need to fit FGD and NOx abatement facilities will reduce their already low levels of thermal efficiency. In this context, the PS2 scenario assumes that the use of coal fired plant will be restricted to supplying peak demand. This may require a capacity charge to ensure to ongoing availability of such plant. Consequently this scenario will indicate the lower bound of CO_2 emissions from the UK power sector for the given demand for electricity and configuration of generators.

Impact of changes in prices

2.31 As mentioned earlier, WWF commissioned Ilex to undertake an analysis of the impact of three scenarios for the UK power sector in 2004. Since then there have been some significant developments that will have a material impact on this analysis. The first is the increase in fuel prices, particularly those for gas. Table 11 details the coal and gas prices used in each study, along with the ratio of gas to coal prices.

Table 11 – Differences in coal and gas prices for 2004 and 2006 PowerSwitch studies

	2004 study			2006 study		
£/GJ	Coal	Gas	G/C ratio	Coal	Gas	G/C ratio
2010	1.2	1.7	1.42	1.54	3.25	2.11
2020	1.1	1.9	1.73	1.42	3.05	2.15

Source: Ilex analysis

2.32 Table 11 illustrates that gas has become significantly more expensive relative to coal, suggesting that coal will be preferred as a base load fuel while gas will be preferred as a marginal fuel. While this often occurs during winter periods, when higher demand for gas pushes up the price, the changes in price relativities mean that coal will be preferred to gas for much longer periods during the year, leading to higher CO_2 emissions.

2.33 Another difference between the studies is the CO_2 prices are assumed to be much higher in the 2006 study. Table 12 indicates the impact of CO_2 prices on the gas to coal ratio for each scenario. It suggests that although CO_2 prices are higher in the current study, they do not alter the gas to coal price ratio sufficiently to make gas equally preferred to coal. In fact, the BAU scenario of €20/tCO_2 effectively returns the ratio to the level that existed prior to the recent changes in fuel prices.

Table 12 – Impact of CO_2 price on gas to coal ratio

	2004 study G/C ratio			2006 study G/C ratio		
£/GJ	BAU	PS1	PS2	BAU	PS1	PS2
2010	1.27	1.16	1.09	1.48	1.33	1.33
2020	1.35	1.17	1.06	1.47	1.32	1.26

Source: Ilex analysis

2.34 The implications of these changes is two fold:

- electricity prices will be higher in the 2006 study than in the 2004, stemming from the higher fuel prices, and the higher price for CO_2 allowances; and
- it will require more effort to achieve reductions in CO_2 emissions, given the price advantage that coal has to gas.

Summary

2.35 Table 13 summarises the key differences in the assumptions used for each scenario.

Table 13 – Summary of scenario assumptions used for BAU, PS1 and PS2 scenarios

	BAU	PS1	PS2
EU ETS carbon price	€20/tCO_2	€30/tCO_2	€30/tCO_2 in 2010 €35/tCO_2 in 2016 and 2020 €40/tCO_2 in 2025
Electricity demand	Grows by 1.15% (DTI)	Grows by 0.44% (DTI)	Grows by 0.11% (DTI)
Renewable capacity	Falls short by 15% of RO target of 15.4% by 2015/16	Hovers close to RO target of 15.4% by 2015/16 and to a new RO target of 20% by 2020.	Hovers close to RO target of 15.4% by 2015/16 and to new RO target of 20% by 2020 and 25% by 2025.
CHP capacity	Achieves 8 GW by 2010 and grows with energy demand	Achieves 10 GW by 2010 and grows with energy demand	Achieves 10 GW by 2010 and 15 GW by 2025
Capacity	Nuclear to retire as scheduled with no new build. Coal and oil fired plant that has opted out under LCPD retire end of 2015. New build consists of renewables, CHP, CCGT and interconnectors	As in BAU	As in BAU and regulations are imposed to ensure that CCGT plant always run ahead of coal fired plant in 2020 and 2025. Microgeneration provides 3% of electricity supply in 2002 and 5% in 2025.

Source: ILEX Analysis

3. PROJECTED EMISSIONS AND GENERATION MIX

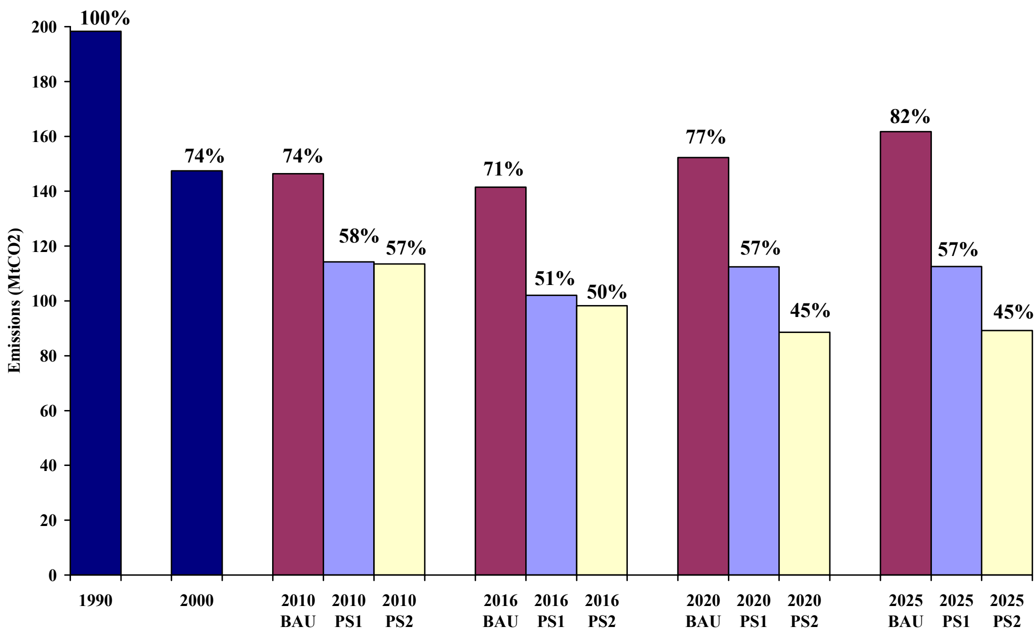
3.1 This section presents the key results from our analysis, including projected power sector CO_2 emissions levels and the expected generation fuel mix under each scenario for 2010, 2016, 2020 and 2025.

3.2 The results are very promising. They show that, by incorporating government aspirations and evolving current policies in this area, the UK power sector could be able to cut its CO_2 emissions by 40-55% (from 1990 levels) for each of the years considered. These reductions are driven by a combination of lower electricity demand, and increased fuel switching to low carbon technologies, under the PowerSwitch scenarios.

3.3 These same drivers are also likely to have beneficial implications for other power sector emissions, such as SO_2 levels. However, this increased fuel switching might also exacerbate future security of supply concerns, related to overdependence on gas and the intermittency of wind. These findings are discussed further below.

3.4 Figure 1 shows projected UK power sector CO_2 emissions levels for each scenario in 2010, 2016, 2020 and 2025 compared to historic 1990 and 2000 emissions levels. The percentages given in the chart show what the emissions levels are as a percentage of 1990 emissions levels.

Figure 1 – CO_2 emissions projections compared to historic levels ($MtCO_2$)



Source: Ilex analysis

3.5 Figure 1 shows that large reductions have already been achieved since 1990, due mainly to the market-led dash for gas that took place in the 1990s. However, under the BAU scenario, it is unlikely that there will be continued significant further reduction in CO_2 emissions, and that they could potentially start rising. By 2025 BAU emissions are projected to be 162 $MtCO_2$ (a reduction of 18% from 1990 emissions levels of 198 $MtCO_2$).

3.6 The increase in CO_2 emissions under the BAU scenario are primarily driven through:

- the higher gas to coal price relativity, leading to a preference for the use of coal;
- there will be more coal fired plant operating beyond 2015 than earlier anticipated, due for fewer such plant opting out under the LCPD; and
- there is a significant increase in CCGT capacity, which replaces nuclear plants that are being decommissioned and meets the growth in demand.

3.7 Table 14 compares the level of emissions from DTIs central case in the UEP and the results from this analysis. While the results appear similar, there are some underlying differences. This study assumes fuel prices that favour gas and include a price for CO_2 allowances, suggesting that it should indicate higher gas burn than in the DTI study. A possible explanation as to why the Ilex results do not show lower CO_2 emissions may be due to different assumptions regarding the type of available generation capacity, such that we have assumed that there is more coal fired capacity due to a higher level of such capacity opting in under the LCPD than originally expected.

Table 14 – Comparison in emissions from DTI and Ilex study (MtC)

Study	2010	2010
DTI - Central case favourable to gas	41	38
DTI - Central case favourable to coal	41	42
Ilex – BAU	40	41

Source: Ilex analysis and DTI UEP February 2006

3.8 When the existing policy approach is extended slightly, in the PS1 scenario, Figure 1 shows that emissions levels drop to just below 60% of 1990 levels, with emissions of 114 $MtCO_2$, 102 $MtCO_2$, 112 $MtCO_2$ and 113 $MtCO_2$ in 2010, 2016, 2020 and 2025 respectively. In PS2, where policy evolves a little more, emission levels drop to 113 $MtCO_2$, 98 $MtCO_2$, 89 $MtCO_2$ and 89 $MtCO_2$ (a reduction in the order of 55% from 1990 levels).

3.9 All three scenarios show overall emissions levels staying relatively constant beyond 2010, despite underlying factors changing significantly over this period. This is because the factors driving a natural increase in emissions over time (e.g. reducing nuclear generation and rising electricity demand) tend to be mitigated by other factors that reduce emissions (e.g. reducing coal generation and increasing contribution of renewables). Under the PowerSwich scenarios, the downward influences just outweigh the upward influences on emissions, while the opposite is true in the BAU scenario.

3.10 These projected emissions levels are based on the definition of power sector emissions employed by the Government, for consistency of comparison between historic and future levels and targets. This excludes emissions from imports and some emissions from autogeneration whose emissions are instead categorised within the relevant industry sector. Table 15 details the additional CO_2 emissions that should be included if autogeneration emissions were to be included within the power sector, This variation in impact is mainly due to the different CHP levels anticipated in each scenario over time.

Table 15 - Additional CO_2 emissions arising from autogeneration

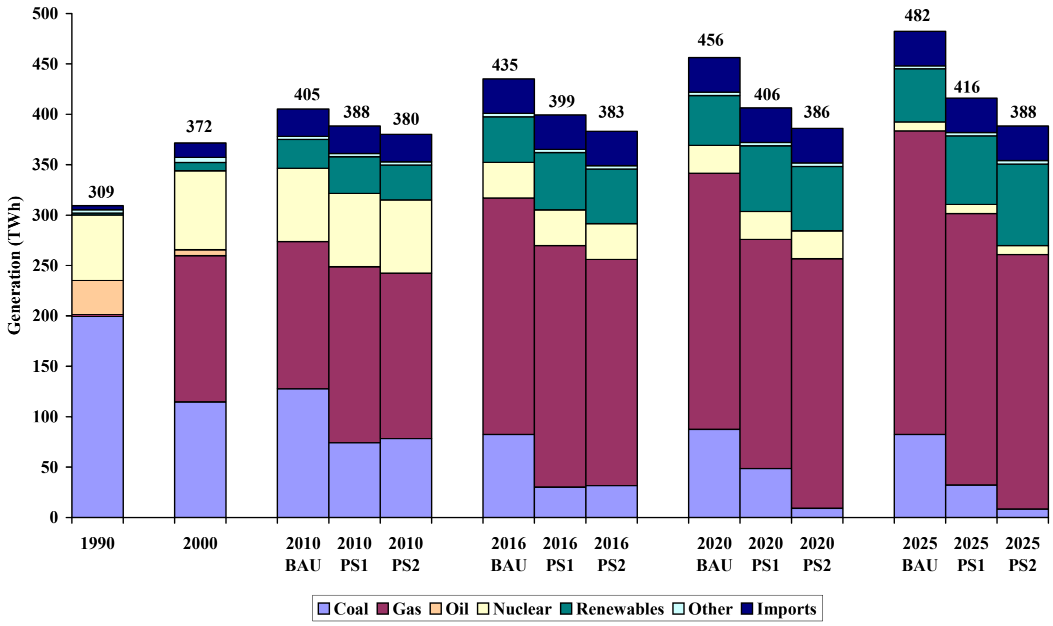
	BAU	PS1	PS2
2010	14	11	12
2016	10	7	9
2020	9	8	8
2025	8	4	8

Source: Ilex analysis

3.11 The drivers behind these results can be illustrated more clearly by looking at the breakdown of generation by fuel type, in Figure 2, overleaf. This shows that generation from coal, oil and nuclear plant is expected to decline over time, as existing plant come to retirement age, with coal burn also declining due to the LCPD. This is offset by increasing levels of both gas-fired and renewable generation. Microgeneration facilities are split between renewables and gas depending on the type of facilities used.

3.12 The policy extensions and evolutions assumed in PS1 and PS2 then encourage further fuel switching to take place, while simultaneously dampening demand. Overall, this results in similar levels of gas-fired, renewable and imported electricity generation occurring in each scenario, but with the reduced demand in the PowerSwitch scenarios more than offsetting the generation lost from coal.

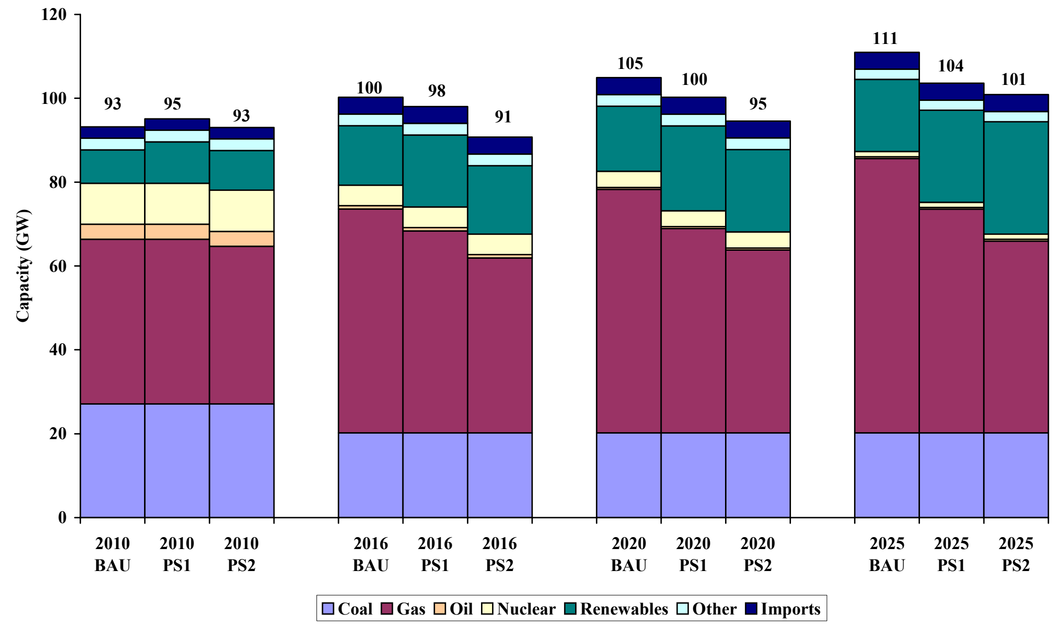
Figure 2 – Generation by fuel type (TWhs)



Source: Ilex analysis

3.13 In addition to the generation by fuel, it is important to consider the changes in the electrical generating capacity over time for each scenario, which is detailed in Figure 3 below.

Figure 3 – Capacity by fuel type (GW)

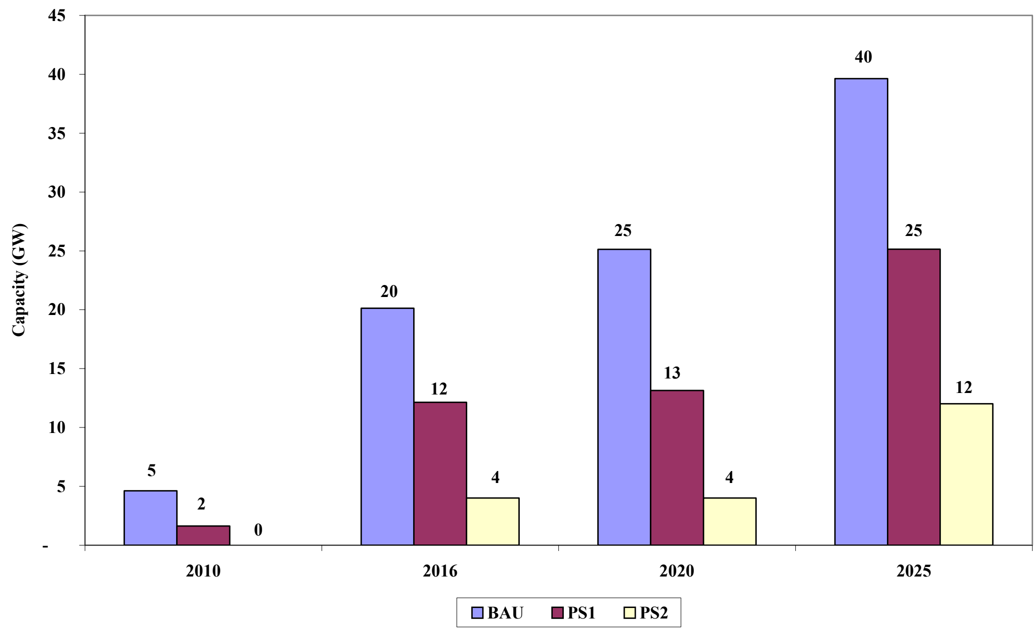


Source: Ilex analysis

3.14 Figure 3 illustrates that the level of coal capacity is the same in all scenarios, based on whether coal fired plant opts in or out under the LCPD. The NG Seven Year Plan for 2005 indicates that ACS peak demand in 2004/05 was 61.5GW. If the growth rate for each scenario is applied to this rate, it is assumed that renewables are only available 35% of the time and all CHP is removed, then the capacity margin remains between 13% and 19% for BAU and PS1. For PS2 it remains between 8% and 19%, which is reasonable given the high level of embedded generation under this scenario.

3.15 This analysis assumes that apart from renewables, CHP, interconnectors and microgeneration, the only form of new electricity generating build will be from CCGT. Figure 4 indicates the cumulative additional capacity of CCGT from 2006.

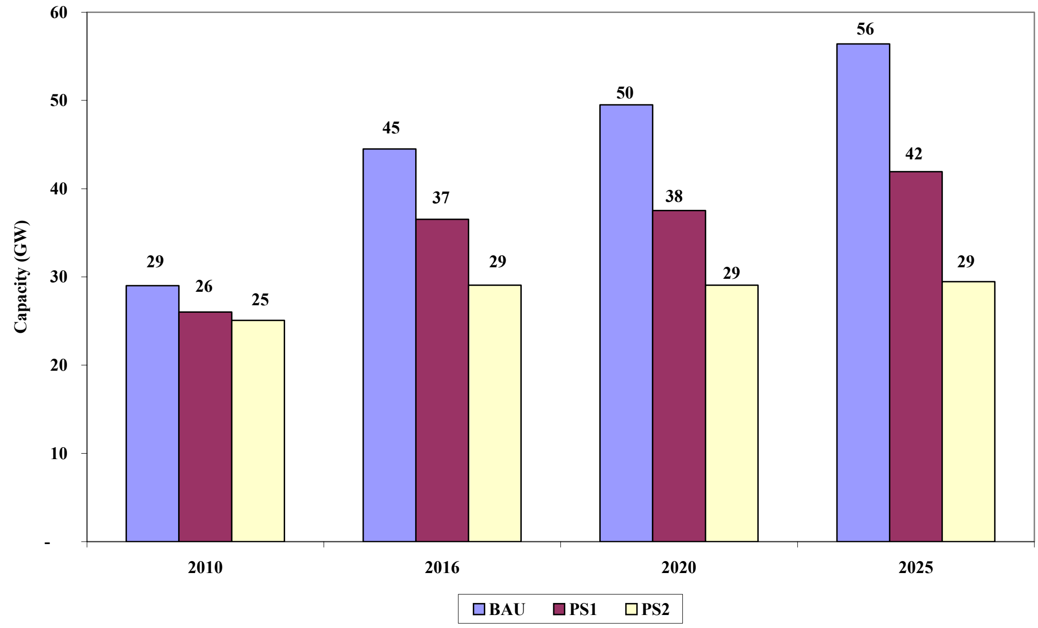
Figure 4 – Cumulative additional CCGT capacity from 2006 (GW)



Source: Ilex analysis

3.16 During the study period the only retrial of CCGT is between 2020 and 2026, when approximately 7.6GW of capacity is taken out of the system. The installed capacity for CCGT for each scenario over the study period is shown in Figure 5.

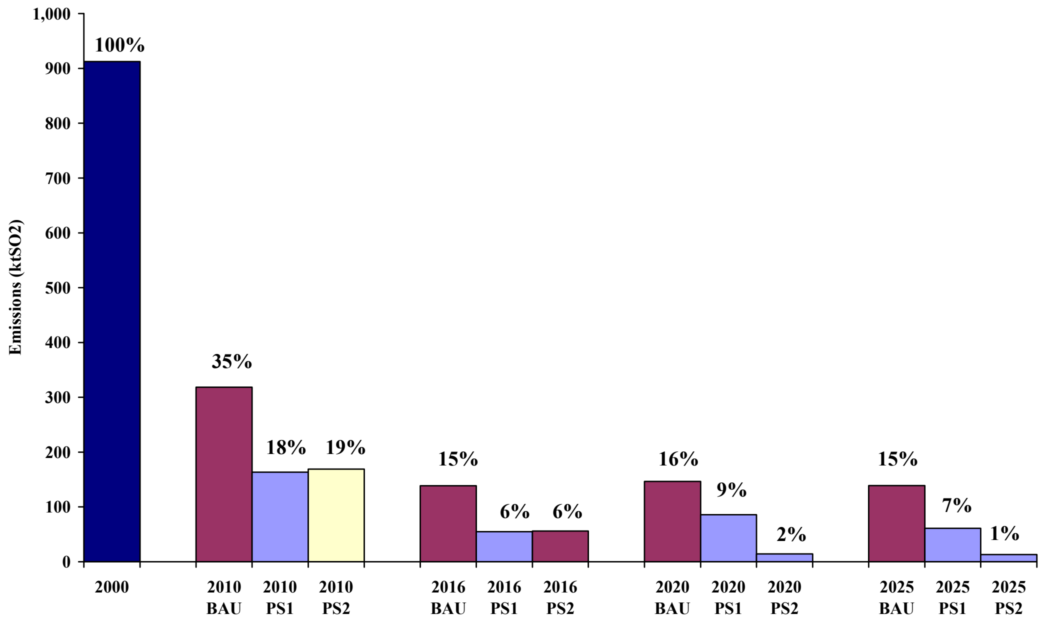
Figure 5 – Installed CCGT capacity (GW)



Source: Ilex analysis

3.17 Although this study focuses on CO_2 emission reductions, these changes in underlying generation and demand are also likely to have beneficial implications for other power sector emissions. For example, Figure 6, below, shows projected power sector SO_2 emissions levels for each scenario in 2010, 2016, 2020 and 2025, compared to historic 2000 levels. The percentages given in the chart show what the emissions levels are as a percentage of 2000 emissions levels.

Figure 6 – SO_2 emissions projections compared to historic levels (ktSO_2)



Source: Ilex analysis

3.18 Figure 6 shows that substantial reductions from historic levels are expected under all three scenarios. Under BAU, this is mainly driven by the LCPD. For the PowerSwitch scenarios, further reductions are due mainly to the rising carbon price in the EU ETS, lower demand levels and additional generation from renewables and CHP. The negligible level of SO_2 emissions in PS2 in 2020 and 2025 reflects the regulatory obligation that gas is to run ahead of coal.

3.19 However, this shift in fuel use from coal and nuclear to gas and renewables over time could also have negative implications, such as raising diversity of supply concerns related to over dependence on gas-fired generation and gas imports. This is a potential concern under all three scenarios. In the BAU scenario, gas-fired generation contributes 301 TWh in 2025, making up 62% of total generation. In PS1 this drops to 269 TWh (65% of total generation). In PS2 the absolute level drops slightly further to 252 TWh, but lower overall generation levels mean that the proportion is also 65%.

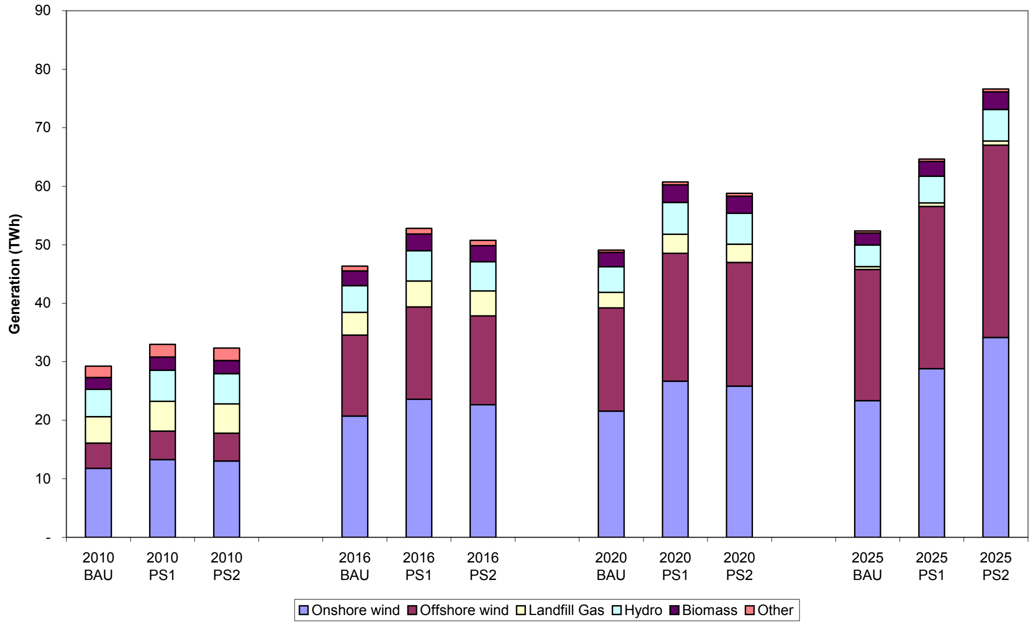
3.20 These proportions are actually lower in magnitude than the contribution made by coal-fired generation in the past (e.g. over 80% of total generation in the 1970s). However it is not over dependence on one particular fuel type, per se, that is necessarily the main issue, it is where the fuel comes from. Since gas production from UK fields is expected to decline over time, this is likely to lead to greater dependence on imported gas, and hence potential vulnerability to others' actions.

3.21 This is not a new issue – many other countries are not fortunate enough to have their own supplies of fuel and so are already dependent on imports. The UK is therefore in a relatively privileged position at present of being able to source much of its fuel needs from domestic supply. However, this is an issue that is likely to apply increasingly to the UK in future as domestic gas supplies dwindle. Ensuring that gas is purchased from a wide variety of different sources on the global market, and increasing gas interconnection and storage facilities, could potentially ease concerns in this area, though may not address them completely.

3.22 Figure 7 shows the further breakdown of renewable generation by technology type. In all three scenarios the RO is assumed to be the chief policy instrument driving an increasing contribution by renewable generation. The RO is a market mechanism that is designed to encourage the development of near-to-market technologies. As such, it will result in the development of technologies in order of cost-effectiveness. The most cost-effective technologies are currently onshore and offshore wind[6].

[6] Although onshore wind is considered to be more cost effective than offshore wind, it also currently faces additional planning barriers. Our analysis therefore shows the majority of additional renewable generation under the PowerSwitch scenarios coming from offshore wind, despite it being more costly.

Figure 7 – Breakdown of renewable generation (TWhs)



Source: Ilex analysis

Note: This chart only shows the breakdown of renewable generation defined as being eligible for certificates under the Renewables Obligation. It excludes generation from other renewables, such as large-scale hydro.

3.23 Since wind is the most unpredictable of renewable technologies, this dominance of wind in all three scenarios is likely to require a larger plant margin than needed at present, in order to help guarantee supplies. With much of the wind resource being located in the north and offshore of UK, distribution and transmission networks are also likely to require strengthening in future, in order to transport the power to the load.

3.24 In order to mitigate these impacts, and to enable more significant reductions of CO_2 in the longer term, it is likely that other policies, in addition to the RO, would need to be put in place to encourage a more diverse range of carbon-neutral technologies to come forward under these reduced demand scenarios.

3.25 Recently there has been a considerable degree of interest in the possibility of capturing CO_2 emissions from major sources, particularly from power stations, and storing them in underground deposits, such as depleted oil and gas fields and saline aquifers. This approach is often referred to as Carbon Capture and Storage (CC&S). Currently there are considerable uncertainties regarding the costs and technical arrangements associated with CC&S, however, it is worth considering the impact such technology could have on CO_2 emissions and fuel diversity if CC&S is applied to coal fired plant.

3.26 Below are two illustrative examples of the impact of replacing CCGT plant with coal fired plant using CC&S. Table 16 details the assumptions used in this comparison. Details for coal fired plant without CC&S have been included to illustrate how is it assumed that coal fired plant with CC&S is assumed to run with a much higher load factor, have a lower efficiency, and have a dramatically lower emission factor.

Table 16 – Assumptions used to compare CCGT with coal fired using CC&S

Assumptions	CCGT	Coal without CC&S	Coal with CC&S
Carbon capture			96%
Load factor	68%	50%	70%
Emission factor (tCO2/MWh)	0.19	0.30	0.012
Efficiency (HHV)	58%	36%	28%

Source: IPCC and Ilex analysis

3.27 Table 17 details the outcomes assuming that 2GW of coal fired plant with CC&S replaces 2 GW and CCGT. The key result is the dramatic reduction in CO_2 emissions, which have fallen by 87%. The other notable result is the higher fuel use, which is more than double that required in the CCGT. The financial impact on the running costs will depend on the relative prices between gas and coal the savings that could be achieved through having to submit fewer CO_2 allowances.

Table 17 – Illustration of impacts of replacing 2GW of CCGT capacity with coal fired and CC&S

	CCGT	Coal with CC&S	Difference CCGT & CC&S
Capacity (GW)	2	2	-
Generation (TWh)	11.9	12.3	0.4
CO2 emissions (mtCO2)	3.9	0.5	-3.4
Fuel use (input value in TWh)	20.5	43.8	23.3

Source: Ilex analysis

3.28 Table 18 details the outcome assuming that 4GW of capacity is replaced, which shows similar proportions in the increase in fuel use and decline in CO_2 emissions as was the case when 2GW were replaced.

Table 18 - Illustration of impacts of replacing 4GW of CCGT capacity with coal fired and CC&S

	CCGT	Coal with CC&S	Difference CCGT & CC&S
Capacity (GW)	4	4	-
Generation (TWh)	23.8	24.5	0.7
CO2 emissions (mtCO2)	7.8	1.1	-6.8
Fuel use (input value in TWh)	41.1	87.6	46.5

Source: Ilex analysis

3.29 In terms of the impact of the use of CC&S on CO_2 emissions and diversity of fuel use, if f it is assumed that in 2020 there are 2GW of coal fired plant with CC&S and in 2025 there are 4 GW of coal fired plant with CC&S; then the impact under PS1 is:

- in 2020 CO_2 emissions fall from 57% of 1990 levels to 55%, while coal fired generation increases from 12% to 15% and gas fired generation decreases from 56% to 53%; and
- in 2025 CO_2 emissions fall from 57% of 1990 levels to 53%, while coal fired generation increases from 8% to 14% and gas fired generation decreases from 65% to 59%.

3.30 In the case of PS2, the impact of the above illustration of the use of CC&S is:

- in 2020 CO_2 emissions fall from 45% of 1990 levels to 43%, while coal fired generation increases from 2% to 5% and gas fired generation decreases from 61% to 58%; and
- in 2025 CO_2 emissions fall from 45% of 1990 levels to 42%, while coal fired generation increases from 2% to 8% and gas fired generation decreases from 61% to 55%.

3.31 There is a considerable degree of uncertainty about the costs associated with CC&S. The costs associated with CC&S include the:

- loss of available capacity at the power plant, which can be in the order of 40% for coal fired plant;
- capture of CO_2 at source, which differs according to type of plant being fitted and whether the CC&S is being fitted during the construction of a new plant or an existing plant is being retrofitted with CC&S;
- transport of the CO_2 to appropriate sites; and
- storage of CO_2.

3.32 It is possible that the CO_2 could be used to enhance oil recovery, and in essence provide a revenue stream for such techniques. This is likely to off set some of the costs, although there will only be a finite number of sites where this is possible.

3.33 Given the various possibilities of implementing CC&S, it is very difficult to arrive at accurate cost estimates. The IPCC report titled 'Carbon Dioxide Capture and Storage'[7] provide some capital cost estimates of the cost of MEA facilities to capture CO_2 at source, are

- between £450 and £700 per kw for new super critical plant; and
- in the order of £1000 kw for retrofitting sub critical plant.

3.34 In conclusion, subject to the security of supply concerns discussed above, the results look promising. The sector has already managed to reduce its emissions

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7 See http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_WholeReport.pdf

significantly to date and further reductions are expected under BAU, driven by recently adopted policies in this area. Relatively minor extensions to current policies and targets could enable the UK power sector to cuts its CO_2 emissions close to 40% from 1990 levels by 2010 and maintain them at this level until 2025. Further incorporation of government aspirations and evolution of existing policies could potentially reap CO_2 emissions reductions of around 55% from 1990 levels by 2025.

3.35 The following section builds on this analysis and provides some high-level estimates of the likely cost implications of achieving such emissions reductions.

4. COST IMPLICATIONS

4.1 The cost implications of achieving the CO_2 emissions reductions in the ways suggested by the PowerSwitch scenarios comprise a number of different elements, including the costs of generation, the costs of investment in new plant, the costs of reducing demand and the system costs of additional renewables. In this section we examine various additional costs associated with each of the PowerSwitch scenarios over and above those associated with the BAU scenario. Some of these costs would be passed on, through electricity prices, to customers, so we also consider the potential impact on electricity bills.

4.2 We should emphasise that these cost estimates are not intended to provide a comprehensive cost-benefit analysis of achieving the emissions reductions identified. They do not include all aspects of likely costs - for example, the programme costs of the policies required to drive the changes. They also do not attempt to take into account many of the environmental benefits associated with reduced CO_2 emissions and other air pollution reductions. These estimates should therefore not be taken as an overall cost of achieving the reductions. However, they do at least help to give an idea of the general magnitude of economic impact that could be expected in the UK.

4.3 Table 19 summarises the various cost implications estimated in the study. This shows that the variable costs of generation actually result in sizeable savings compared to BAU in each year. This stems predominately from the lower growth in demand and the higher use of CHP and renewables.

4.4 The study also shows that the cost of capital investment in new plant could result in either savings or additional expenditure compared to BAU. The key capital cost in BAU is the investment in new CCGT plant, and while there is some increases in CCGT capacity in PS1 and PS2, it is less than that in BAU, particularly for PS2. However, this is offset with increases in capital expenditure for CHP, renewables, and in the case of PS2, microgeneration.

4.5 The net cost of energy efficiency measures ranges from delivering large savings to moderate increases in costs, depending on the unit estimates used. The system costs of additional renewables would be expected to increase costs by 2020 and again by 2025 for PS2, though this impact looks to be small compared to the other impacts considered.

Table 19 – Summary of cost implications considered (£m)

	2010		2016		2020		2025	
£m	PS1	PS2	PS1	PS2	PS1	PS2	PS1	PS2
Variable cost of generation	-329	-404	-911	-984	-1,237	-1,770	-1,635	-2,291
Cost of investment in new plant	2,516	1,817	-1,882	-4,182	-471	-340	-868	1,610
Net cost of energy efficiency measures	-2,623 < 439	-2,693 < 449	-3,224 < 537	-3,533 < 589	-3,257 < 543	-5,211 < 868	-4,022 <670	-5,935 <989
System cost of additional renewables	-	-	-	-	285	285	285	470

Source: Ilex analysis

4.6 It should be noted that these costs/savings are not additive. That is, each of the estimates presented above cannot be added together in order to reach an overall net cost/saving. This is because they are not all on a consistent basis. For example, the net costs of energy efficiency measures are based on the range of unit cost estimates used in the supporting analysis for the Energy White Paper. These are overall resource cost estimates that include the benefits gained by energy savings, as well as the capital investment required to undertake the measures. There is therefore some degree of overlap between the variable costs of generation and the costs of energy efficiency measures, both of which take the reduction of demand into account, resulting in some double-counting.

4.7 The cost estimates also relate to different time periods, depending on what they are measuring. In most cases, the costs are a per annum estimate, relating purely to the costs incurred for the emissions reduction achieved in the years considered. For example, the savings arising from the lower cost of generation are based on the estimated variable costs of providing the generation levels required in 2010, 2016, 2020 and 2025, but not taking into account the impact on the cost of generation, or on emissions, in intervening years.

4.8 However, the cost of investment in new plant is slightly different since plant tends to be developed on an incremental basis over time rather than all coming onto the system in the same year. Consequently, the estimates for each year indicate the investment required from the preceding reported year to provide the capacity needed for each year.

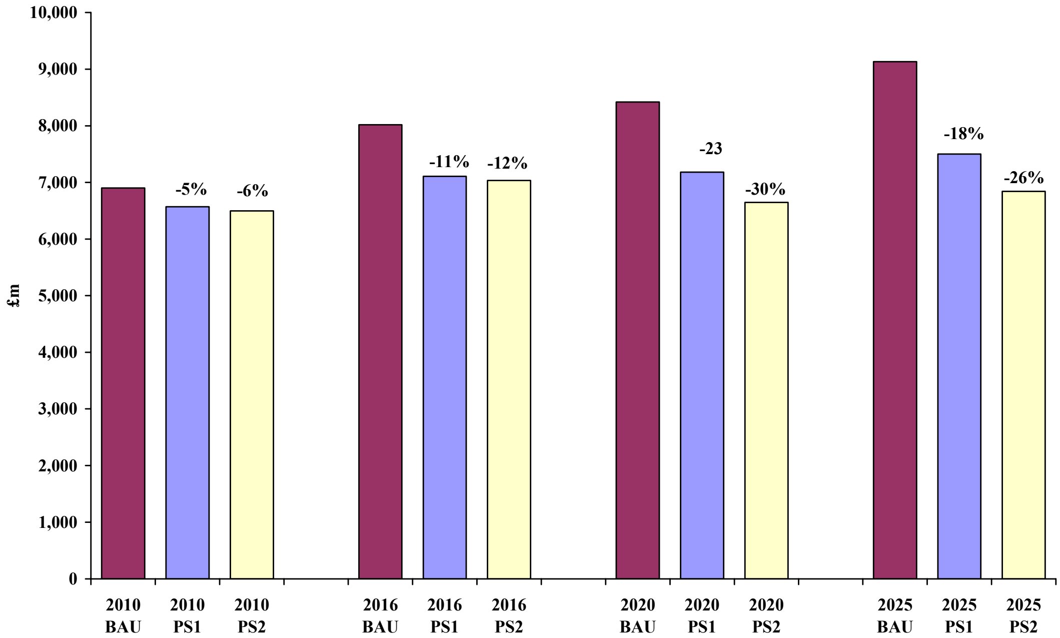
4.9 These cost estimates are explained in more detail below.

Variable cost of generation

4.10 Figure 8, overleaf, shows the projected variable cost of generation for each year under each scenario. This is an output of the model and includes the cost of fuel, variable other works costs and the opportunity cost of carbon incurred in generation[8], but excludes the fixed year on year costs of keeping plant on the system. On this basis, the variable costs of nuclear and renewable generation are assumed to be negligible. The figures given in the chart next to the PowerSwitch results show the percentage change in generation costs compared to those incurred under BAU.

4.11 Figure 8 shows that the costs of generation in 2010 are roughly similar in all three scenarios, though slightly lower in the PowerSwitch scenarios than under BAU. The difference increases in 2020, after which they move slightly closer together in 2025.

Figure 8 – Variable cost of generation (£m)



Source: Ilex analysis

4.12 There are opposing forces at work driving these results. Several aspects of the PowerSwitch scenarios act to increase the costs of generation, including rising carbon prices and the use of a more expensive fuel mix than under BAU. However, these upward influences on generating cost are outweighed by the reduction in generation required as a result of lower demand.

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8 In reality, the introduction of a cost of carbon does not necessarily result in an increase in the actual cost of generation unless generators have to purchase their allowances. However, even if generators are given all of the allowances they need for free, they should still face an additional opportunity cost from generating, since they could otherwise sell these allowances to others. This opportunity cost should, in principle, affect their operating and pricing decisions in the same way as any other resource cost. And it is likely that this will increasingly become an actual cost over time if the EU ETS moves towards an auctioned approach to distributing allowances. We have therefore factored it into the costs of generation.

4.13 This reduction in generation costs is not necessarily a benefit to generators. The numbers cited are the costs associated with the electricity generated, which is lower in PS1 and PS2 than in BAU. Such a reduction in output could lead to lower revenue and potentially profits. The impact on wholesale prices and electricity bills is discussed in more detail in paragraphs 4.41 – 4.45.

4.14 The impact of energy efficiency, while likely to be beneficial for society as a whole, would therefore be likely to have adverse impacts for some generators, unless they were able to claw back some of the benefit in some way, such as through effective energy services agreements with their customers or by a shift in market conditions to enable provision of energy services to become a viable core business.

Cost of investment in new plant

4.15 Table 20, below, sets out the assumptions used to estimate the cost implications of capital investment in new plant under the different scenarios. Since actual costs will vary from plant to plant, these are generic estimates based on ILEX market knowledge. The costs associated with microgeneration were taken from the report the EST published called Potential for Microgeneration.

Table 20 – Capital costs of investment in different plant type £/kW

Capital costs £/kW	2010	2016	2020	2025
Generic GT	215	215	215	215
Generic CCGT	450	450	440	440
Generic CHP	590	590	590	590
Onshore Wind	671	628	599	566
Offshore Wind	988	921	878	828
Other Renewables (based on biomass)	1,275	1,050	900	756
Microgeneration - carbon producing (1.2 kWe CHP)	1,950	1,820	1,790	1,750
Microgeneration - carbon neutral (small wind turbine)	1,500	1,000	800	750

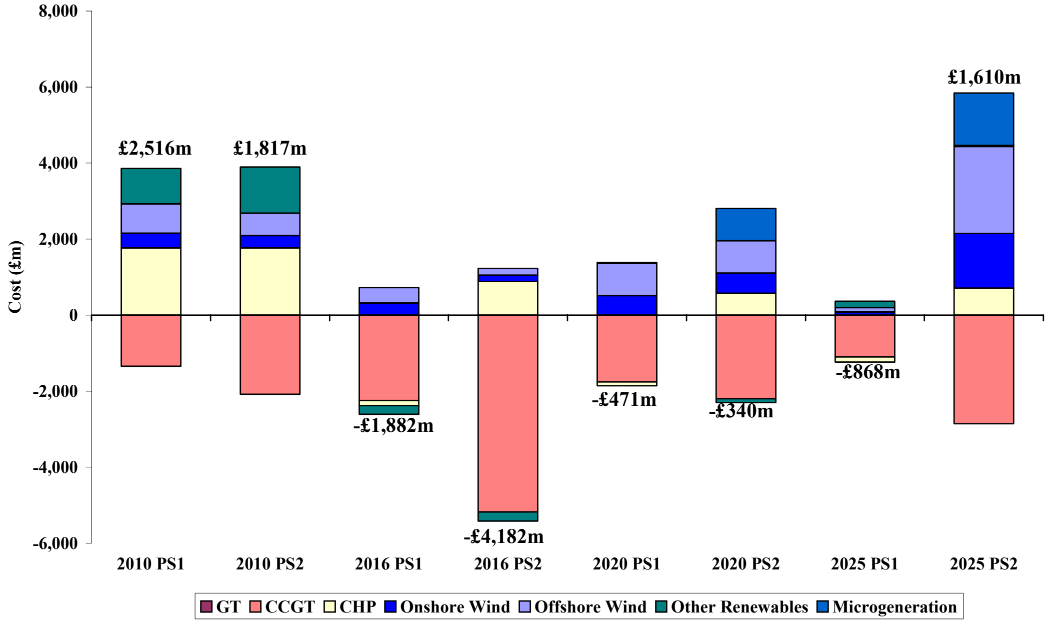
Source: Ilex analysis and EST Potential for Microgeneration

4.16 Based on the above cost estimates, Figure 9 summarises the estimated cost of capital investment in new plant required in the PowerSwitch scenarios, over and above that required to achieve the BAU scenario[9]. The estimated costs are shown by technology type, with the figures given in the chart showing the total capital cost compared to BAU. Since plant tend to be developed on an incremental basis

9 This excludes the cost of capital investment arising from the need for higher plant margins to support a higher proportion of renewables, since this cost is included in the system costs for additional renewables, discussed later.

over time, the numbers indicate the investment costs incurred between the reported years.

Figure 9 – Estimated cost of capital investment in new plant compared to BAU (£m)



Source: Ilex analysis

4.17 Figure 9 shows that the total investment required is greater in PS1 and PS2 than in BAU in 2010, due to the cost of the renewables being significantly higher than the CCGT that they replace. While additional investment is required by 2016, especially to replace the coal fired plant that has opted out under the LCPD and the decommissioned nuclear plant, the lower growth in electricity demand in PS1 and PS2 means that the lower capacity requirement lead to overall lower capital costs despite higher unit costs of the renewable capacity.

4.18 It should be emphasised that the costs shown above are the differences between the BAU and PowerSwitch scenarios, meaning that the absolute investment required will be these values added to the investment needed in the BAU scenario.

Cost of energy efficiency

4.19 Table 21 details the savings[10] in emissions for each of the PowerSwitch scenarios from the BAU scenario in terms of MtC.

10 For the purposes of this analysis we have assumed that the reduced demand directly displaces generation from new combined cycle gas turbines. This has become a standard practice and provides a conservative estimate of the emissions effect of a reduction in electricity consumption. If it were to be assumed that the displaced plant were coal-fired then the net costs per tCO_2 saved would be lower still.

Table 21 – Emissions savings from BAU - MtC

	2010	2016	2020	2025
PS1	8.0	10.7	10.9	13.4
PS2	9.0	11.8	17.4	19.8

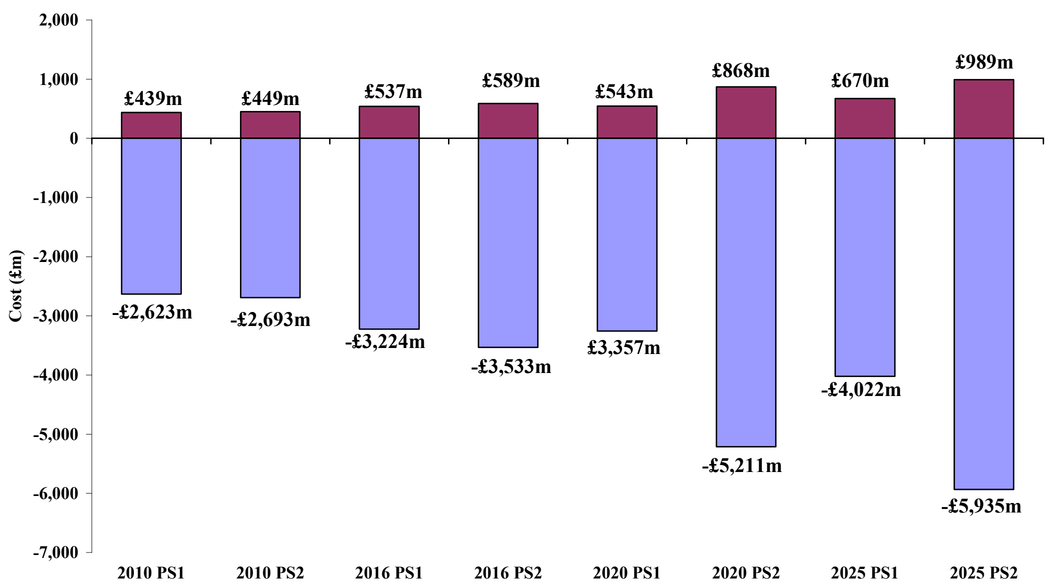
Source: Ilex analysis

4.20 Figure 10 shows the estimated range of net costs incurred in order to reduce demand by the extent supposed in the PowerSwitch scenarios. These figures are based on the energy efficiency cost estimates used in the supporting analysis for the PIU Energy Review[11] and the Energy White Paper[12]. Annex 5 to the PIU Energy Review distinguishes between whether the barriers to energy efficiency are:

- hidden costs, where costs are between 30-£50/tC; or
- market failures, where energy efficiency investment is considered to be extremely cost effective and costs range from -£300/tC to -£100/tC.

4.21 The net costs of energy efficiency were derived through applying both the lowest and the highest cost estimates identified in the Energy White Paper to each tonne of carbon saved. These estimates are detailed in Figure 10, which shows that the net cost of energy efficiency measures varies widely, from delivery of large savings of £5,935m to an increase of £989m in 2025 for PS2 alone.

Figure 10 – Estimated range of net costs of energy efficiency (£m)



11 PIU Energy Review http://www.number-10.gov.uk/su/energy/19.html

12 'Our Energy Future – creating a low carbon economy – supplementary annex for the White Paper', DEFRA and Department for Transport, 2002.

Source: Ilex analysis

4.22 Although it is not clear in the underlying documentation, the cost estimates identified in the Energy White Paper look to be overall resource cost estimates that include the benefits gained by energy savings as well as the capital investment required to undertake the measures. This means that there is some degree of overlap between the variable costs of generation, discussed above, and the net cost of energy efficiency measures, both of which take the reduction of demand into account.

4.23 The breakdown of the figures underpinning the EWP analysis is not publicly available, so it is not possible to provide consistent figures for the capital cost of investment in energy efficiency measures alone. However, the UK government has already introduced a range of programmes targeted at different end-user groups with the aim of improving energy efficiency and some estimated capital costs for these programmes have been included in the recent energy efficiency strategy[13].

4.24 The Energy Efficiency Commitments (EEC) require suppliers to achieve energy savings in the domestic sector, with a particular focus on the fuel-poor. For the current EEC scheme, which runs from 2002-2005, capital investment costs in energy efficiency are estimated to be £160m p.a. for each of the three years of the scheme. This is estimated to result in energy savings of £150m p.a. that continue for the lifetime of the measures installed (10-40 years) and to reduce carbon emissions by 0.4MtC p.a. by 2010.

4.25 The Climate Change Agreements (CCAs) are voluntary energy saving targets agreed by energy intensive sectors in exchange for a reduction in the Climate Change Levy. For the CCAs, the projected reduction of 2.4MtC p.a. by 2010 is estimated to incur capital costs of £240m p.a. for the duration of the agreements, and to result in energy savings of £390m p.a. for the lifetime of the measures installed.

4.26 These figures are illustrative only, since the capital costs incurred will be specific to each policy, but they should at least help to illustrate the relative magnitude of capital costs incurred compared to energy savings in current programmes. An overall resource cost has not been provided for the CCAs, but has been estimated at -£150/tC for the current EEC. This is close to the mid-point of the EWP range of -£300 to +£50/tC used for the estimates in Figure 10.

4.27 These results are consistent with many recent studies on the costs of energy efficiency, which have concluded that there is a large potential for savings in energy use that more than payback the original investment in terms of reduced energy bills. However, under these circumstances, economic theory suggests that this investment in energy efficiency should already have taken place. The fact that it has not suggests that there are currently substantial barriers to the uptake of energy efficiency.

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13 'Energy Efficiency: The Government's Plan for Action', DEFRA, April 2004.

4.28 Research conducted by the Carbon Trust highlights that the barriers to energy efficiency are different in every organisation, but are often related to organisational commitment, capital constraints and technical know-how. In the household sector, there are likely to be different barriers to improving energy efficiency, including lack of information, high up-front costs, and the disruption of undertaking measures. A more detailed discussion of the barriers to energy efficiency, and suggestions for how these might be addressed, is included in Annex 4 of the Government's action plan for energy efficiency[14].

4.29 Removing these barriers, which has proved so intractable to date, would be likely to require the implementation of an extensive programme of policies for energy efficiency, to address the wide range of different barriers experienced.

System costs of additional renewables

4.30 Costs to the grid system of increasing the proportion of renewable generation comprise:

- strengthening of distribution and transmission networks to accommodate larger numbers of renewable installations; and
- the need to provide a larger plant margin to account for lower load factors and unpredictability of some renewable technologies.

4.31 We estimate that the additional system cost of increasing the proportion of renewables from 15.4% under BAU to 20% under the PowerSwitch scenarios is likely to be roughly £285m pa, which will increase to £470m pa as the proportion of electricity which renewables generates rises to 25%.

4.32 These estimates are based on a study of the system cost of additional renewables undertaken for the DTI by ILEX and Professor Goran Strbac of the University of Manchester Institute of Science and Technology (UMIST)[15]. The cost of increasing the proportion of renewables in GB from 10% in 2010 to 20% by 2020 was estimated at between £150m and £418m p.a. This cost rose to between £341m and £968m pa when renewables generated 30% of electricity requirements. The estimates from this report were averaged to yield the estimates used in this PowerSwitch study.

4.33 The report concluded that the system costs would be greatest in circumstances where wind located in the north of GB formed the majority of the additional renewable capacity. Costs were reduced in circumstances where the renewable technology mix was more diverse, including a significant proportion of biomass, and geographically more dispersed.

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14 'Energy Efficiency: The Government's Plan for Action', DEFRA, April 2004.

15 'Quantifying the system costs of additional renewables in 2020' ILEX and UMIST, October 2002. Located at: http://www.dti.gov.uk/energy/developep/080scar report v2 0.pdf

4.34 In the PowerSwitch scenarios it is assumed that the Renewables Obligation continues to be the main support mechanism. Because the Obligation is a market mechanism, it provides incentives to develop the cheapest technologies first. This, in combination with the lower level of obligation arising from lower demand, means that generation from onshore and offshore wind dominates in both scenarios. Hence system costs are likely to be towards the higher end of the range presented above (i.e. around £400m).

4.35 However, it should be noted that some of these system costs are likely to be incurred under BAU, which is assumed to increase the proportion of renewables to 15.4% by 2020. The additional system cost to increase the proportion of renewables from 15.4% to 20%, is therefore likely to be roughly half of this (i.e. £200m)[16].

4.36 A more diverse mix of technologies would be likely to lower the system costs, from the figure mentioned above, as well as facilitating longer term reductions in emissions. However, the development of a more diverse range of renewable technologies might require the implementation of other policy instruments, in addition to the Obligation, which would, in themselves be expected to incur costs.

Programme costs

4.37 Programme costs relate to the costs of administering the policy programmes that are put in place. Examples include the time and expense incurred by government to design, implement and monitor the policies, as well as the administrative costs and time spent by others as part of their compliance with the requirements of the policies (e.g. through additional monitoring and reporting requirements). Tax-flows and subsidies are not programme costs since these are inter-society transfers rather than actual resource costs.

4.38 The additional programme costs incurred by the PowerSwitch scenarios will vary depending on the specific policies used to drive the changes, and hence cannot be quantitatively estimated here. However, programme costs have already been estimated for some existing policies in the Climate Change Programme, and these can be used to illustrate the potential magnitude of these costs compared to the other costs incurred.

4.39 Annex 6 of the Government's action plan on energy efficiency[17] estimates that the programme costs for the Climate Change Agreements are £1m p.a. for the

16 It could be argued that the costs of moving from BAU would be less than half the costs of moving from 10% to 20%, since the majority of the infrastructure costs would already have been incurred in order to reach the 15.4% target. On the other hand, one could equally argue that the costs would be more than half the total costs, since the provision of back-up capacity would need to increase more than proportionately as the proportion of wind increases. Overall, assuming that about half of the costs incurred are additional to the BAU scenario would appear to be roughly reasonable.

17 'Energy Efficiency: The Government's Plan for Action', DEFRA, April 2004.

duration of the agreements, while the programme costs for the current phase of the Energy Efficiency Commitments are £30m p.a. for each of the three years of the scheme. A progress report for the UK Emissions Trading Scheme[18], states that implementation costs have included staff resources of £560k and consultancy costs of £1.3m to design, set-up and maintain this innovative new scheme to date.

4.40 As stated above, these costs are illustrative only, since they will depend on the specifics of the policies used to drive the changes. However, it should be noted that, while large in absolute terms, these programme costs generally tend to be small in comparison to the other costs and savings arising from the policies implemented.

Impact on electricity bills

4.41 Some of the costs discussed above would be likely to be passed on to customers in electricity prices. In this section, we therefore also examine the potential implications for electricity bills resulting from the combined impact of wholesale prices and reduced electricity demand. Further implications for retail electricity prices, arising from the specific policies used, are also discussed.

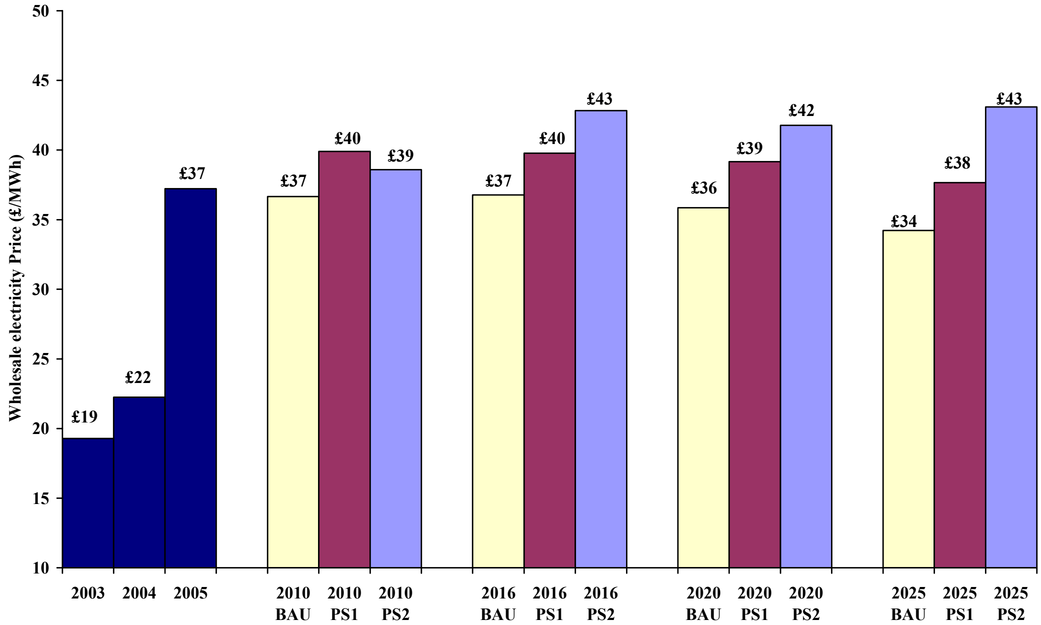
4.42 Figure 11, below, shows projected annual average wholesale electricity prices in each year for each scenario, compared against historic levels. This is an output of the model and assumes that the full opportunity cost of carbon is passed through into wholesale prices.

4.43 The wholesale prices are significantly different for each scenario. The wholesale prices for BAU and PS1 appear to migrate downward over the period, which is due to declining fuel prices. On the other hand, the wholesale price for PS2 remains high, and even increases slightly. This is due to the:

- price of CO_2 allowances being higher in the PS2 scenario than in the other scenarios and rising over the period offsetting any reduction in the price of fuel; and
- regulatory obligation in PS2 which requires gas to run ahead of coal means that the price always reflects the cost of using a higher percentage of the more expensive gas.

18 'The UK Emissions Trading Scheme: Auction Analysis and Progress Report', DEFRA, October 2002.

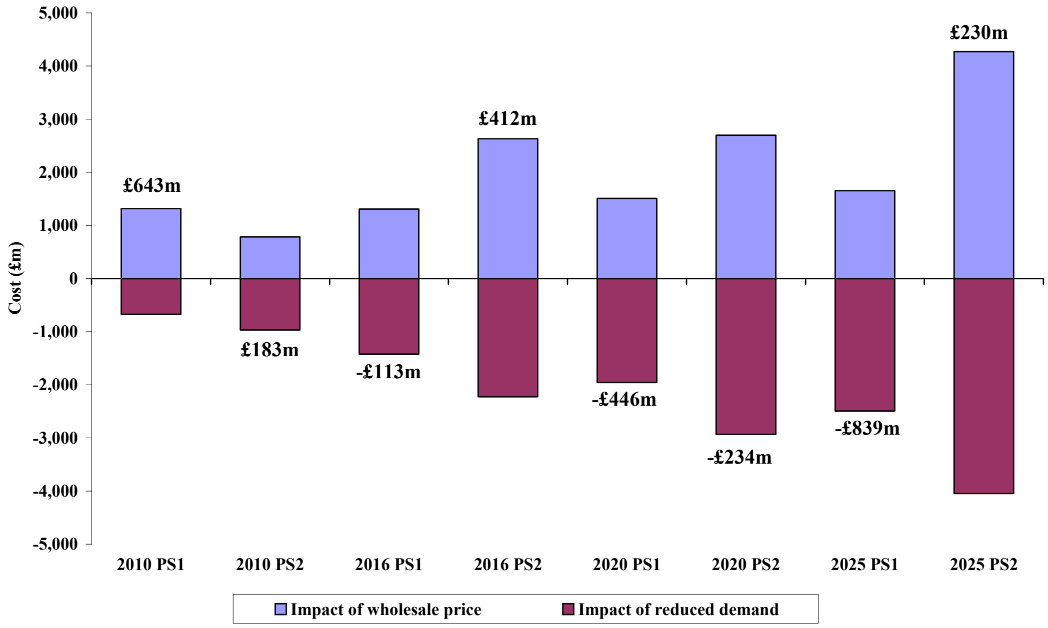
Figure 11 – Historic and projected wholesale electricity prices (£/MWh)



Source: NETA data, Ilex analysis

4.44 The impact of these increases in wholesale price on the amount consumers pay for their electricity will depend on the extent to which the price increase is passed through into retail prices and the extent to which customers can reduce their energy use through implementation of the energy efficiency measures. This will vary between different customer types. Figure 12, below, shows the estimated impact on total electricity bills, resulting from the combined impact of increased wholesale prices and reduced electricity demand, based on the assumption that the total increase in wholesale price is fully passed through into retail prices.

Figure 12 – Estimated impact on electricity bills (£m)



Source: Ilex analysis

4.45 Overall, Figure 12 shows that the impact of lower demand is more significant than the impact of the higher prices. There are three exceptions

- PS1 in 2010 there was a notable increase in the wholesale price, due to there being higher gas burn;
- the price for CO_2 allowances increased from €30tCO_2 to €35tCO_2 in 2016, resulting in jump wholesale electricity prices; and
- the price for CO_2 allowances increased from €35tCO_2 to €40tCO_2 in 2025, resulting in another jump in wholesale electricity prices.

4.46 In theory, therefore, energy efficiency measures should make it possible for all consumers to reduce electricity bills under the PowerSwitch scenarios compared to BAU, even if the increase in wholesale price is fully passed through into retail prices. It may be important, however, to consider the distribution of efficiency gains across all users to ensure that poorer and more vulnerable sections of the community are not exposed to increased prices.

4.47 The aspects considered above are not intended to provide an all-inclusive estimate of the final impact on electricity bills. Depending on the specific policies used to drive the different scenarios, it is possible that other costs may also be passed through into electricity bills through increases in retail electricity prices.

4.48 For example, we have assumed in the study that future renewable generation in the PowerSwitch scenarios will continue to be driven by a Renewables Obligation, similar in design to the current Obligation. This would therefore be expected to have an impact on retail prices and electricity bills in the same way that the current Obligation does.

4.49 A similar situation exists with other policy areas. For example, the use of an Energy Efficiency Commitment type programme to drive the future reductions in electricity demand might be expected to increase retail prices due to suppliers passing through the costs incurred by them to undertake measures. On the other hand, most other methods of driving energy efficiency improvements, such as voluntary agreements (similar to the current Climate Change Agreements), subsidies, tax breaks, information campaigns, buildings regulations, appliance labelling or improved appliance standards, would not be expected to have an adverse impact on retail electricity prices.

4.50 In conclusion, reductions in electricity demand can result in lower electricity bills under the PowerSwitch scenarios than under BAU, even though wholesale prices in the PowerSwitch scenarios are significantly higher than BAU levels. However, it should be noted that this is not intended to be an all-inclusive estimate of the impact on electricity bills. Depending on the specific policies used to drive the different scenarios, it is possible that other costs may also be passed through into electricity bills through increases in retail electricity prices. This is illustrated by examples of current policies that might be expected to have an impact on electricity bills, including the Renewables Obligation and the Energy Efficiency Commitments.

5. ILLUSTRATIVE EXAMPLES OF IMPLICATIONS FOR DIFFERENT PLANT TYPES

5.1 This section provides some examples of the likely impacts of the BAU and PowerSwitch scenarios on different plant types. It should be emphasised that these are illustrative examples, designed to convey the general implications only – in reality, the specific implications will vary from plant to plant.

Coal-fired plant

5.2 Electricity generation from coal-fired plant is likely to decline, even in a business as usual scenario, due to the combined introduction of the LCPD and the EU ETS. Any plant choosing not to fit Flue Gas Desulphurisation (FGD), and choosing instead to opt out of the LCPD, will be likely to have to close by 2015, and only be able to generate at relatively low load factors from 2008 onwards, in any case. However, in order to recoup the investment cost of fitting FGD, any plant fitting FGD will generally need to run at relatively high load factors in future – something made more difficult by the introduction of a carbon price from 2005 onwards. Future load factors are therefore generally projected to fall, despite the assumption that coal prices fall relative to gas prices over time.

5.3 Costs associated with installing FGD facilities are dependent on the installation in which they are installed. As an illustration of the costs, British Energy reported that installing FGD to two of the four 500MW units at Eggborough would cost between £60 and £70 million[19].

5.4 The PowerSwitch scenarios exacerbate these impacts. Higher carbon prices and lower electricity demand are likely to reduce load factors still further, as coal-fired plant are pushed down the merit order. Indeed, in the PS2 scenario, regulations are imposed requiring gas to run ahead of coal, resulting in virtually no coal being used in this scenario beyond 2020.

Gas-fired plant

5.5 Electricity generation from gas-fired plant is likely to increase in future under all three scenarios. Load factors of existing plant are likely to increase, even under BAU, due to the fuel-switching driven by the LCPD and EU ETS. This is despite high gas prices relative to coal prices in all scenarios. The BAU scenario also results in significant levels of new CCGT plant being built over time in order to meet increasing demand and the generation relinquished by the expected retirement of many coal and nuclear plant over this period.

5.6 Under the PowerSwitch scenarios, further switching from coal to gas-fired plant takes place as a result of the increasing carbon price, benefiting existing CCGTs

[19] See http://www.british-energy.com/documents/CSR_full_doc_2003-04.pdf

and CHP. However, the lower demand levels, together with increasing proportions of renewable and CHP capacity, mean that less new CCGT plant needs to be built, resulting in slightly lower levels of gas-fired generation overall compared to BAU.

Renewable plant

5.7 Conditions for wind-powered generation are likely to improve over time under BAU, driven by increasing Obligation levels, falling capital costs, and slowly rising electricity prices due to the LCPD and EU ETS.

5.8 Under the PowerSwitch scenarios, the Obligation is extended from 15.4% to 20% by 2020, while in PS2 the Obligation increases to 25% by 2025. In addition, higher electricity prices, due to elevated carbon prices, would be expected to provide further incentive to the deployment of renewables sources of generation. However, since this is accompanied by reductions in demand for electricity, the targets becomes easier to meet, since the renewable generation levels required under the Obligation become correspondingly lower.

5.9 The RO is assumed to be the chief policy instrument driving an increasing contribution by renewable generation for all scenarios, resulting in wind generation being by far the most dominant technology to emerge. Unless the RO target is increased still further, and/or additional policies besides the RO are put in place, there is likely to be insufficient support to encourage a more diverse range of emerging renewable technologies to come forward.

Overall

5.10 In general, coal-fired plant are likely to be hardest hit compared to present circumstances under all three scenarios, due to increasing amounts of environmental regulation. The PowerSwitch scenarios exacerbate this, leading to very low or even zero levels of coal-fired generation by 2016. Gas- and wind-powered plant, on the other hand, generally do better over time, and existing plant, in particular, benefit as a result of the additional fuel-switching and higher electricity prices that result under the PowerSwitch scenarios.

5.11 The impact of lower electricity demand levels from increased energy efficiency in the PowerSwitch scenarios, while likely to be beneficial for society as a whole, would be likely to curb the need for additional new generation capacity, and could also have adverse impacts for some existing generation plant. Finding ways to be able to share in the benefits from reduced electricity demand (e.g. through development of energy services) is therefore likely to become increasingly important to generators in future, if a high priority is given to energy efficiency as a means of reducing emissions.

within the UK and trying to influence other countries to do likewise. Such an approach appears to have been relatively unsuccessful to date, though is potentially likely to be much more effective in the second phase, as international targets start to bite in other countries.

6.7 The additional fuel switching experienced under the PowerSwitch scenarios could exacerbate future security of supply concerns related to over-dependence on imported gas. Although the absolute level of gas-fired generation is lower in both the PowerSwitch scenarios than under BAU, gas-fired generation contributes a slightly higher proportion of total generation in 2025 under the PS2 scenario than under BAU (65% rather than 62%). Increasing gas interconnection and storage facilities, as well as ensuring that gas is purchased from a wide variety of different sources, should help to ease concerns in this area, though is unlikely to address them completely.

6.8 Illustrative analysis indicates that CC&S from coal fired stations has the ability to significantly reduce CO_2 emissions, suggesting that it could be used to ensure a satisfactory level of fuel diversity. However, there are many uncertainties regarding these technologies and the costs are considered to be high.

6.9 If higher targets for renewable generation of 20% and 25% are established and these levels are driven solely through an extended RO, the resulting generation is likely to be dominated by wind, with very few other renewable technologies coming forward, making additional longer term reductions in emissions more difficult.

6.10 Since wind is the most unpredictable of renewable technologies, the dominance of wind in all three scenarios is likely to require a larger plant margin than needed at present, in order to help guarantee supplies. With much of the wind resource being located in the north and offshore of the UK, distribution and transmission networks are also likely to require strengthening in future, in order to transport the power to the load.

6.11 In order to mitigate these impacts, and to enable more significant reductions of CO_2 in the longer term, it is likely that other policies, in addition to the RO, would need to be put in place to encourage a more diverse mix of carbon-neutral technologies to come forward.

6.12 Consideration needs to be given to the various issues raised, including security of supply implications, longer-term emissions reductions and being able to mobilise the significant potential of electricity demand reductions and the EU ETS. However, none of these issues is likely to be insurmountable and overall, the results look promising. The analysis shows that incorporating government aspirations and evolving current policies could enable the UK power sector to cut its emissions by 45-55% from 1990 levels through until 2025.

ANNEX A – ASSUMPTIONS AND RESULTS SUMMARY TABLE

	BAU	PS1	PS2
Input assumptions			
EU ETS carbon price	€20/tCO_2	€30/tCO_2	€30/tCO_2 in 2010 €35/tCO_2 in 2016 and 2020 €40/tCO_2 in 2025
Electricity demand growth per annum	Grows by 1.15% (DTI)	Grows by 0.44% (DTI)	Grows by 0.11% (DTI)
Renewables	Falls short by 15% of RO target of 15.4% by 2015/16	Hovers close to RO target of 15.4% by 2015/16 and to a new RO target of 20% by 2020.	Hovers close to RO target of 15.4% by 2015/16 and to new RO target of 20% by 2020 and 25% by 2025.
CHP capacity	Achieves 8 GW by 2010 and grows with energy demand	Achieves 10 GW by 2010 and grows with energy demand	Achieves 10 GW by 2010 and 15 GW by 2025
Plant retirements	Nuclear to retire as scheduled with no new build. Coal and oil fired plant that has opted out under LCPD retire end of 2015. New build consists of renewables, CHP, CCGT and interconnectors	As in BAU	As in BAU and regulations are imposed to ensure that CCGT plant always run ahead of coal fired plant in 2020 and 2025. Microgeneration provides 3% of electricity supply in 2002 and 5% in 2025.

	BAU	PS1	PS2
Emissions projections			
CO2 in 2010 (MtCO2)	146	114	113
CO2 in 2016 (MtCO2)	141	102	98
CO2 in 2020 (MtCO2)	152	112	89
CO2 in 2025 (MtCO2)	162	113	89
SO2 in 2010 (KtSO2)	318	164	169
SO2 in 2016 (KtSO2)	139	55	56
SO2 in 2020 (KtSO2)	147	86	14
SO2 in 2025 (KtSO2)	139	61	13
Cost implications*			
Change to variable cost of generation in 2010 (£m)		-329	-404
Change to variable cost of generation in 2016 (£m)		-911	-984
Change to variable cost of generation in 2020 (£m)		-1,237	-1,770
Change to variable cost of generation in 2025 (£m)		-1,635	-2,291
Change to cost of investment in new plant in 2010 (£m)		2,516	1,817
Change to cost of investment in new plant in 2016 (£m)		-1,882	-4,182
Change to cost of investment in new plant in 2020 (£m)		-543	868
Change to cost of investment in new plant in 2025 (£m)		-670	1,610

ANNEX B – DETAILS OF ILEX MODELS

B.1 ILEX's *XGen* models are simulation models of various European power markets, which use Excel (with Visual Basic) for transparency and ease of use. Our models cover the determinants and influences on the electricity markets:

- power station costs and operation which are simulated in a physical model;
- current and future gaseous emissions limits that constrain power station operation;
- the influence of the Regulator in encouraging generators to operate in what he believes is a competitive manner;
- the influence of new entrants who may decide to enter the market if they perceive that the price is right; and,
- the ability and/or willingness of participants to exit the market.

B.2 At present, there is a single power market in England & Wales (E&W), with separate markets operating in Scotland and Northern Ireland. However, Ofgem proposed in 2000 that the current E&W New Electricity Trading Arrangements (NETA) be implemented in Scotland in the form of the British Electricity Trading and Transmission Arrangements (BETTA). When implemented, BETTA is expected to introduce a single trading market across England, Wales and Scotland, made possible through the upgraded capacity of the Scotland-England interconnector. In our modelling of the WWF scenarios, we have therefore run all scenarios as a Great Britain (GB) market, with separate modelling for the Northern Ireland (NI) market.

B.3 The details of our GB model, known as *GBGen*, are set out in more detail below, to illustrate the general approach used. The same basic approach was used for the separate NI modelling, though since the NI power sector is very small (with electricity demand only around 2% of the size of that in the GB power sector), the NI model is much less detailed than the GB model structure discussed below.

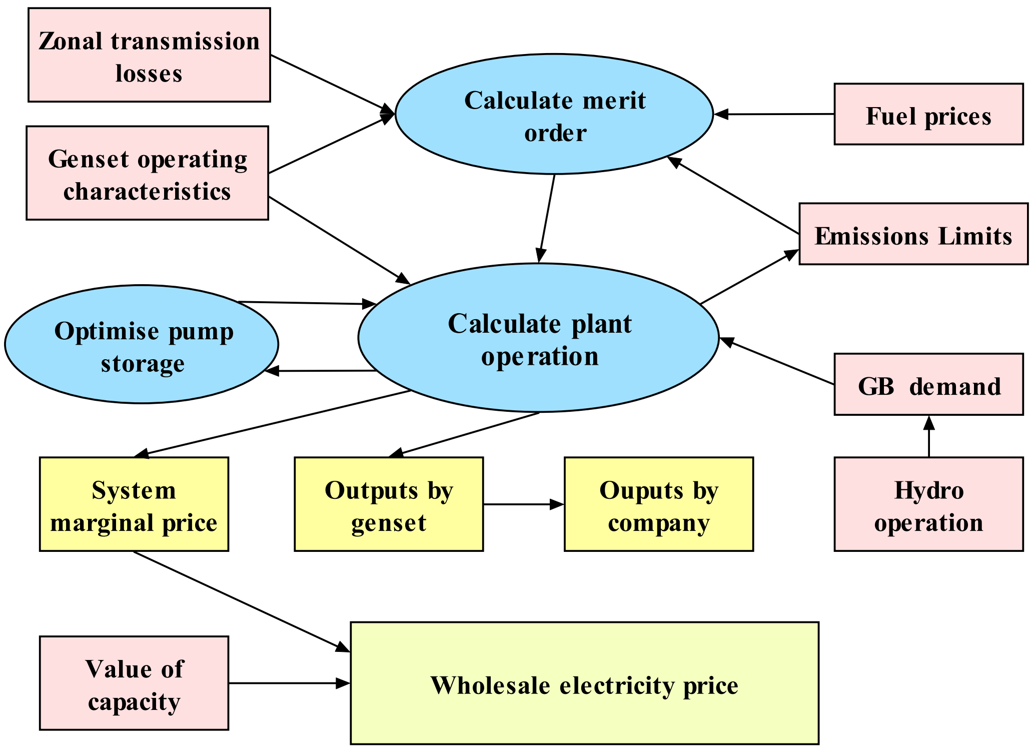
GBGen

B.4 *GBGen* is configured to model the day-ahead market in Great Britain. We assume that market operation will be driven by the underlying economics, and as such the model calculates the equivalent of system marginal prices based on the short-run marginal cost of production.

B.5 *GBGen* has been designed to project electricity prices, fuel used and emissions from a range of future scenarios, defined in terms of such factors as developments in the market, and movements in fuel price, generating capacity and demand on the system.

B.6 To derive these prices and the associated plant operating regimes, the model simulates the operation of plant on a half-hour-by-half-hour basis for 25 sample days (a business day and non-business day for each month of the year, plus a 'peak' day representing the ten days of the year with exceptionally high demand). Figure 13 illustrates the high-level operation of the model.

Figure 13 – Schematic operation of *GBGen*



B.7 Thus, for each half-hour of the 25 sample days the model calculates the cost of operation of each of the gensets and optimises to arrive at the least cost solution.

B.8 In calculating which of the plant should operate, and the price they would require to do so, the model uses the following methodology. A daily merit order is calculated based on the operating costs of the plant running at full output. This is used to identify the marginal plant in any half-hour. The start-up and no-load costs of the marginal plant are then added to the marginal plant's full-load efficiency cost to arrive at an energy price for that half-hour.

B.9 GBGen treats interconnectors as floating capacity. We assume that coal plant will be on the margin and have incremental pricing of tranches of capacity to represent the varying prices of import electricity. A value of carbon is incorporated into the import price to reflect the impact of the EU ETS on prices in other countries.

B.10 For each half-hour for each sample day the outputs from the model include:

- the energy price in p/kWh;
- the generation for each genset in TWh;
- the fuel used for each genset in TWh;
- the income of each genset in £k; and

- the operating costs for each genset in £k.

B.11 The capacity element in price is calculated separately at a level which, when combined with the energy price, results in a wholesale price that is consistent with underlying scenario assumptions. The variation in price over the year is projected, and price duration curves are produced for both energy and capacity, and the two combined.

B.12 Hence, the model can be used to simulate the operation of the day-ahead market against a range of different future scenarios including fuel prices, demand growth, emissions limits, new-builds and retirals.

Emissions modelling

B.13 The generation and fuel burn figures are used to forecast emissions of CO_2, SO_x and NO_x and ensure emissions limits are met. Adjustments can then be made to fuel specification and price, plant availabilities and capacity scenarios to reduce emissions, if necessary to meet the limits.

B.14 *GBGen* includes an emissions module, which allows us to model the current Environment Agency plant and company SO_x emission limits (the Table A and Table B limits) for generators. We extend these bubble limits forward from 2005 to 2007. From 2008 we assume that under the LCPD the UK will choose the ELV route and those plant that have opted out of the LCPD do not operate for more than 20,000 hours between 2008 and 2016. This module effectively iterates, constraining generation down by plant or owner, until the emission limits are met. Under the 20,000 hour rule we assume a maximum annual load factor of 40% until the 20,000 hours are used up.

B.15 We assume that emissions limits under LCPD will be met through the use of low-NO_x burners or over-fired air and improved combustion techniques, but that any capital expenditure will not necessarily be recovered through higher market prices.

Pumped storage

B.16 Our market model, *GBGen*, includes a module for modelling the operation of the pumped storage plant. *GBGen* balances the operation of pumped storage within a sample day – that is, the energy pumped must equal that generated within each day (taking into account the assumed efficiency of the pumped storage operation).

B.17 The pumped storage plant is scheduled to pump when prices are low and to generate when prices are high. The maximum level of generation or pumping in any period is restricted to ensure both that physical limits on the plant are met and that the price differential between the pumping and generating periods is sufficient to justify the operation.

B.18 Once we have defined the periods in which the pumped storage plant could operate, and the maximum operation in each period, *GBGen* profiles the pumping and generation in such a way to reduce the level of price spikes on the system – either by generating in periods of high demand or pumping overnight . The total generation in a day is also restricted by the maximum allowed by the storage reservoirs.

B.19 The final stage of the process is to define how the pumped storage plant would bid when it operates. When the plant is pumping there will be a more expensive plant operating than would have been the case otherwise. We assume that this more expensive plant would set the energy component of the marginal price at that time – but we restrict the start-up/no-load component to the lesser of that before or after pumped storage operation . When the plant is generating, we assume that it would be possible for the pumped storage to shadow bid at just below the cost of the thermal plant that would need to run in its place. We have restricted the level of shadow bidding so that the resulting marginal price is halfway between what it would have been with the pumped storage operation (but without shadow bidding) and without pumped storage operation.

New entry financial model

B.20 In addition to all of the above, a financial model of new plant is used to calculate the TWA (time-weighted average) price that a new entrant would require in order to satisfy reasonable financial criteria under a range of scenarios. The major inputs to this model are projections of future gas prices and of new plant efficiencies and costs. The projections from *GBGen* are compared with the new entrant requirements to ensure system equilibrium in the longer term. The assumed costs and efficiency of generic new entry CCGT and OCGT are set out in more detail below.

CCGT

B.21 ILEX continually reviews UK CCGT projects to validate assumptions for current and advanced new entrant prices. ILEX is in a strong position to do this since it has been engaged by the lending banks or the developers on nearly all of the UK CCGT projects.

B.22 Our approach involves:

- tracking the capital and operating cost trends;
- tracking the CCGT cycle efficiency trends;
- establishing the real pre-tax, pre-finance returns on each project necessary for financeability;
- calculating capacity and energy prices for current and future CCGTs; and
- evaluating the key risks on each project and how these are mitigated, or not, in the commercial arrangements and how these might influence new entrant pricing.

B.23 The average pre-finance, pre-tax real return for projects commissioned between 1999 and 2001 is 13% over a fifteen-year life. This average has remained relatively constant over the past few years and ensures adequate debt service cover ratios. There are no indications of a change that would mean that this would not apply to current and future transactions.

B.24 Although few projects have been financed recently, since the wave of new entry over earlier years, we have consulted with project developers and engineering firms about the current costs of CCGT new entrants. EPC (Engineer, Procure and Commission) contract costs appear to have increased since the projects developed around 1997-1999, from around £275/kW to £330/kW (2002 money). To this we add £125/kW for other project costs, such as development costs, site costs and connections. This gives a total specific capital cost (excluding interest during construction) of £455/kW (2002 money).

B.25 Operating costs are estimated at around £25/kW/yr for fixed costs, £0.3/MWh for non-fuel variable costs and CCGT cycle efficiencies currently average around 50% (HHV).

B.26 ILEX plots the past and current trends in these key parameters to derive values for future CCGT projects. Reference has also been made to expert sources of information to check our projections.

B.27 For a future new entrant, we expect efficiency to improve, with a projection for increased efficiency of 55% by about the year 2010. We do not expect the recent trend of capital cost increase to continue, but project a reduction of approximately 10% in all costs (i.e. £405/kW capital cost, £22.5/kW fixed annual costs and £0.27/MWh for non-fuel variable costs).

B.28 Current and future new entrant prices are calculated using a 13% pre-tax and real rate of return. Combining capital, fixed, fuel and other variable costs, we produce the following formulae for the calculation of the costs of baseload (assuming a 90% load factor) new entry CCGTs in the medium (up to about 2010) and long term (beyond about 2010):

Medium term CCGT: **13.05 + 0.68g (2002 £/MWh)**

Long term (post-2010) CCGT: **11.60 + 0.62g (2002 £/MWh)**

where g is the price of gas in p/therm.

B.29 Further adjustments are made to reflect the impact of the EU ETS on new entry costs. In scenarios where new entrants are awarded all their allowances for free, the new entry cost is unchanged from that set out above. However, in scenarios where new entrants do not receive a free allocation and have to purchase all their EU ETS allowances in the market-place, the gas price is adjusted upwards to reflect the full opportunity cost of carbon that it embodies, leading to higher new entry costs.

OCGT

B.30 Open-cycle gas turbines (OCGTs) are less efficient, but cheaper than CCGTs. As such they can be useful as peaking or mid-merit plants. Present figures for the latest technology are an efficiency of 34.5% combined with a capital cost of

£269/kW (excluding funds used during construction), fixed other works costs of £12/kW p.a. and variable non-fuel costs of £0.53/MWh (all 2002 money).

B.31 If, in the limit, such a plant were not to operate at all, it would set a value for capacity of £57 per kW p.a. (2002 money). If that were the case, the value of capacity on the system would be expected to average out at that level.

B.32 We consider, however, that the value of peaking capacity will be somewhat less than this, because:

- plant in a purely peaking role will tend to be of relatively low capital cost, even at the expense of reduced efficiency;
- peaking plant can be conveniently located within distribution networks, where they can gain economic benefit by being sited close to electricity demand which reduces their effective cost to the larger system; and
- there may be a growth in demand-side management as a means of coping with periods of peak demand on the system. This will tend to weaken the value of peaking generation capacity towards the cost of the cheapest projects.

B.33 Therefore, we consider that a lower figure of £47 per kW p.a. would be appropriate for the value of peaking capacity in the longer term (in 2002 money values). This £47 per kW p.a. 'cap', which is equivalent to £5.3/MWh on a time-weighted average (TWA) basis, is one input into the determination of the value of capacity in our projections.

ILEX

Quality Control Check Sheet

POWERSWITCH! - SCENARIOS OF CO_2 EMISSIONS FROM THE UK POWER SECTOR

Report Unique Serial No: 2006/052

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6. CONCLUSIONS

6.1 Electricity generation is the biggest single source of CO_2 emissions in the UK, responsible for approximately a third of total emissions. After falling steeply in the early 1990's, emissions from the sector have increased in recent years driven by increasing demand and higher gas prices relative to coal prices. The need to reduce CO_2 emissions arising from UK power generation is a very important consideration for future climate change and energy policy, if the ambitious goals adopted by government are to be achieved.

6.2 Our analysis shows that the UK power sector has already managed to achieve significant reductions in its CO_2 emissions since 1990, and further reductions are expected under BAU. By incorporating government aspirations and evolving current policies in this area, the UK power sector may be expected to cut its CO_2 emissions by approximately 50% (from 1990 levels) through until 2025 without additional nuclear build.

6.3 A key issue is the extent to which existing coal fired plant remains in operation. We have assumed that all such plant that has been fitted with FGD will be in service until just beyond the scope of the study. This could delay new CCGT build while maintaining sufficient capacity margin. Should there be more new build of CCGT than this study assumes, the level of CO_2, and SO_2, emissions will be less than that forecast. This issue will need to be addressed shortly following the end of the study period, as we anticipate that there will be a reduction of 14 GW of capacity due to the closure of old coal fired plant in 2026.

6.4 Our analysis also shows that many of the costs incurred under the PowerSwitch scenarios are lower than those incurred under the BAU scenario. In particular the variable costs of generation are lower as are the aggregate investment costs. However, the higher price for CO_2 allowances and obligations to run gas ahead of coal can be expected to result in higher electricity prices, and the final outcome for consumers will depend on whether they use electricity more efficiently.

6.5 However, this should not be taken to mean that such reductions would be easy to obtain. One of the key drivers behind these results is the Government's aspiration for reducing electricity demand. While measures to reduce electricity demand are potentially extremely cost effective, they could be difficult to accomplish unless current obstacles to energy efficiency are effectively addressed in the near future. If these electricity demand reductions were not achieved, then more measures would need to be introduced elsewhere (e.g. to bring forward new generation technologies), in order for similar levels of emissions reductions to be maintained.

6.6 Similarly, the EU ETS has the potential to be a key driver of emissions reductions in the power sector, since the carbon price is able to incentivise significant fuel switching away from coal to less carbon intensive forms of generation. However, the price of carbon in the EU ETS is something that is determined at a European level, driven by the overall stringency of the National Allocation Plans submitted by each member state. It is therefore not something that the UK Government can determine on its own, though it can lead by example by setting stringent targets

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To download the ILEX report "The balance of power - reducing CO2 emissions from the UK power sector" visit: wwf.org.uk/climatechangecampaign/thebalanceofpower.pdf

To download WWF's full submission to the government's Energy Review visit: www.wwf.org.uk/filelibrary/pdf/cc_rspnsenrgyrvw.pdf

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