OXFORD ECONOMIC RESEARCH ASSOCIATES

CENTRICA

SECURITY OF SUPPLY, ENERGY INVESTMENT REQUIREMENTS AND COST IMPLICATIONS

AUGUST 2004

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

Executive Summary

New challenges

The last 15 years have seen UK energy markets develop and adapt to privatisation and competition against a background of energy self-sufficiency, falling environmental emissions and lower consumer prices. Now the UK energy system is facing a set of radically different challenges—in particular, gas import dependency is rapidly emerging as the UK Continental Shelf (UKCS) declines, coupled with the need to respond to climate change.

While demand for gas continues to grow, industry figures suggest that import dependence will emerge as early as 2005, with imports representing between 46% and 72% of total demand by 2009/10.

To enable this transition, the underlying infrastructure of the gas delivery system will need to be overhauled to ensure that the volume and diversity of import sources can be realised. This report analyses existing data on gas and electricity supply–demand projections and assesses the scale of required investment to ensure secure, reliable supplies to UK customers over the next five years.

New investment requirements

The analysis suggests that infrastructure investment in gas pipelines, storage facilities and offshore fields, combined with new electricity generation projects, will be in the order of £10 billion to £18.1 billion over the period 2005 to 2010.

What is different about the investment in the gas sector is that it shows a trend away from UKCS investment towards transit infrastructure—such as new interconnectors and liquefied natural gas (LNG) terminals—in order to supply sufficient import capacity, and further gas storage facilities to provide additional short-term supply flexibility. Although this report constructs both high- and low-import-dependency models, the required investment figures are similar. This is because additional UKCS investment is a substitute for import requirements in the low-import scenario. However, UKCS investment incorporates delivery capacity and development of actual gas fields, whereas the import infrastructure projects only provide for delivery capacity.

Electricity investment will also be required in order to maintain a sufficient capacity margin within the system. The new investment in the generation sector will lead to a shift in the generation mix, with additional renewable and gas-fired generation replacing the nuclear fleet and ageing coal stations over the medium term. The capital investment required up to 2009/10 reflects the initial phase of this adjustment and there is a large range in the expected cost, depending on whether the majority of capacity requirements are met by new combined-cycle gas turbines (CCGTs), or whether the government's renewables target of 10% of electricity supply coming from renewable sources is met by 2010.

Although it is anticipated that investment in the electricity sector will be lower than that required in gas over the next five years, further significant investment will be required thereafter as the nuclear fleet retires.

Delivery of new investment

Several of the gas projects—eg, the Interconnector UK (IUK) upgrade and the Isle of Grain terminal—are progressing at, or ahead of, assumed schedules, whereas other projects are still at pre-planning or pre-construction phase, and there may still be tightness in the market over the next few years. Indeed, in its most recent planning scenarios, National Grid Transco (NGT) has expressed the view that it is unrealistic to assume that all of the proposed import projects will proceed to their proposed development timescale and delivery volumes.[1]

In electricity, the potential lag in responding to market signals for new investment due to construction times of at least 18 months to two years may also serve to tighten margins in the short term. However, the analysis assumes a required 20% capacity margin, whereas it is entirely possible that the market and NGT could operate securely at lower levels, either in the short or long term.

In the UK gas market, high wholesale commodity prices, expected to persist in the current forward curve, have incentivised some of the large infrastructure projects to proceed, on the expectation of significant volumes of gas flowing into the UK market. This suggests that prices close to current levels will adequately cover the production and transportation costs of the new sources of imported gas.

However, given that several of the necessary importation projects are still not at the construction phase, the implication is that wholesale prices may need to remain at relatively high levels to ensure that the investment is undertaken. In the longer-term, as these projects enter the market, the volumes they deliver can be expected to exert a dampening effect on market prices as the immediate supply–demand constraint is relaxed.

[1] Transco (2004), 'Transporting Britain's Energy: Development of NTS Investment Scenarios', July.

Contents

1. Introduction

The energy sector in Great Britain is entering a period of change. While demand for both gas and electricity is expected to continue growing, the supply side's ability to respond to this growth and maintain security of supply will depend on a programme of major investments in both markets.

In the gas sector, physical import dependence is emerging, requiring additional investment in transit infrastructure to ensure diversity and reliability of supplies. In electricity, the retirement of the nuclear fleet, restrictions on coal-fired generation through environmental policies, and commitment to a more renewable generation mix will lead to 15% of current capacity closing by 2009/10, rising to around one-third by 2015/16, and necessitating significant network investment to facilitate the integration of the new generation mix.

Using publicly available projections of demand- and supply-side changes, this briefing paper investigates the volume of investment that may be required over the period up to 2010 in order to ensure that energy supplies are reliably provided to all end-users, and also the associated investment cost. The position in both electricity and gas is presented, together with a consideration of the implications of relying on market-based provision of such investment.

The structure of the report is as follows:

- section 2 analyses the investment requirements in the gas sector, looking at the implications of the anticipated decline in production from the UK Continental Shelf (UKCS) and emerging import dependence against a background of growing demand;
- section 3 undertakes the same analysis for the electricity market; and
- section 4 summarises the main anticipated investment costs and discusses the conditions under which the required investment may be expected to emerge and the uncertainties over the timing of new investment.

2. Gas Market Investment Requirements

Two broad trends in the underlying market conditions are signalling that the British gas industry is entering a period of transition:

- demand is continuing to grow, with power generation being the main driver—although growth is unlikely to match the 4.9% per annum growth rates observed since 1990, anticipated growth is still around 1.2% per annum;[2]
- UKCS supply is forecast to diminish as existing fields go into decline and new fields become less economic to develop, resulting in both greater import dependence and lower swing (or flexibility) in beach supplies.

Taken together, these points suggest a simple implication. Additional investment is required to ensure that the demand for gas can be met, both at peak times and across the year. In particular, the capacity of the system to support more imports of gas, and from more diverse sources, including liquefied natural gas (LNG), must increase. Diversity of supply sources and of entry points for imports can both serve to improve security of supply. The trends themselves, and the implications for investment, are expanded upon below.

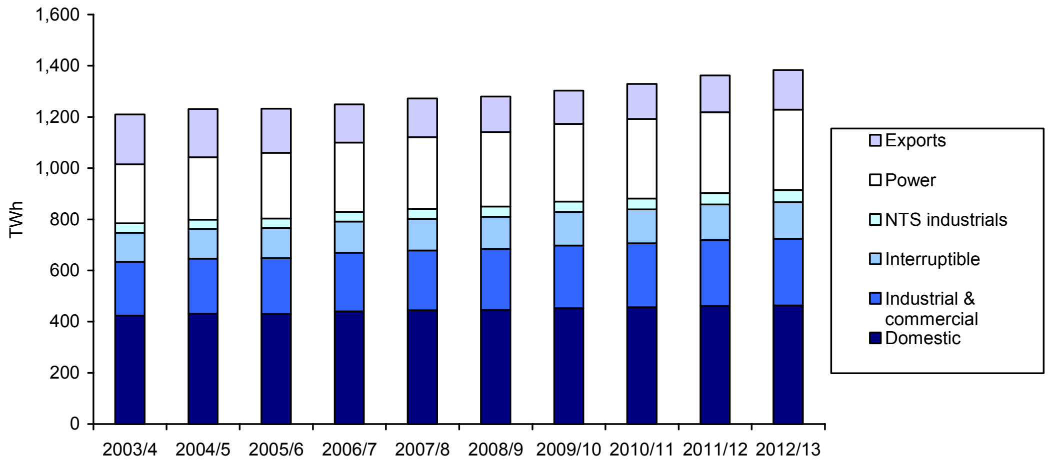
2.1 Demand

Figure 2.1 presents the forecast of annual demand from the high-demand scenario in NGT's 2003 'Ten Year Statement'.[3] This shows an expectation of a relatively stable pattern of growth over the period from 2004/05 to 2010/11, with the exception of the power generation sector, where the importance of gas-fired generation is expected to increase (total demand in this sector increasing by around 40% over the period in question).

[2] This is the growth rate predicted in the central Transco demand forecast over the period 2004/05 to 2009/10. The high-demand scenario has annual growth of around 2.6% per annum and the low-demand scenario at 0.4% per annum.

[3] National Grid Transco (2003), 'Transportation Ten Year Statement 2003', December, has been used rather than the more recent projections in NGT's 'Transporting Britain's Energy 2004' publication, since the latter figures are still preliminary and subject to change as a result of the Transporting Britain's Energy consultation. However, it should be noted that the more recent analysis suggests that demand levels will be lower than indicated in the Ten Year Statement, but also that UKCS decline (and in particular, peak availability) will be steeper than previously anticipated.

Figure 2.1: Gas demand forecasts by sector, 2003/04 to 2012/13



Source: NGT (2003), 'Transportation Ten Year Statement 2003', December.

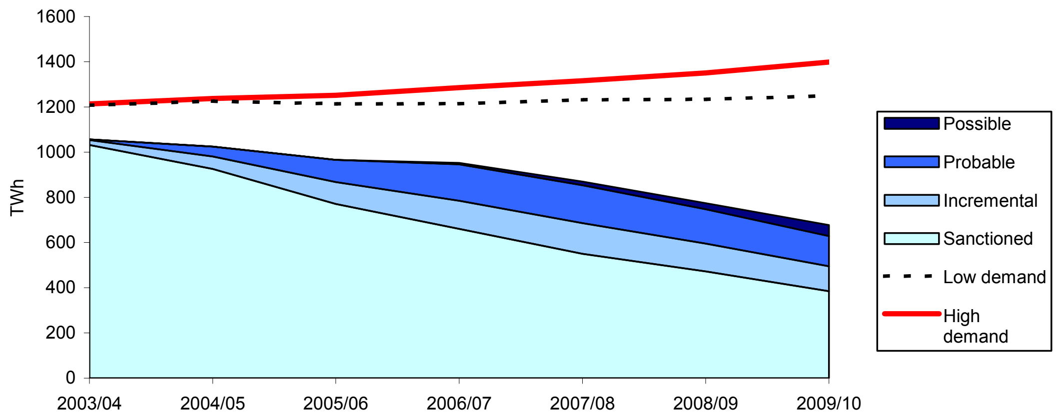
2.2 Domestic supply

As Figure 2.2 shows, using current projections of UK gas resources, that there is already a reliance on imported gas. This is consistent with the pattern shown in projections in Transco's recent consultation document, 'Transporting Britain's Energy: Development of NTS Investment Scenarios', published in July 2004.

The combination of small discovery and development volumes and the operating environment in the North Sea contribute to high development and operating costs/barrel of oil equivalent (boe).[4] These factors undermine the economic case for further exploration effort, although it may be possible to exploit the benefits of emerging pipeline ullage and existing infrastructure capability in the future, thereby lowering these costs.

[4] Analysis by Wood Mackenzie shows that, taking account of all developments between 1996 and 1999, the UKCS had average development costs of around $4/boe, compared with Norway at $3.4/boe and the Netherlands at $2.2/boe. The UKCS ongoing operating costs were similarly higher.

Figure 2.2: UKCS supply and UK demand, 2003/04 to 2009/10



Source: NGT (2003), 'Transportation Ten Year Statement 2003', December; UKOOA.

Nevertheless, even assuming relatively benign conditions for the UKCS, imports can be expected to account for around 42% of total supply by 2010 and 66% by 2020. The sources of this gas will be Norway, the Netherlands, Russia and various LNG producers active in the global market, particularly Algeria and Qatar.[5]

The switch in sources carries with it further implications for the ability of supply to adjust quickly to changing levels of demand—ie, the swing capability in the system. Whereas the majority of the UKCS fields were designed to provide large swing capacity (as set out in their initial contracts), the main transnational pipes that will deliver imported gas are anticipated to have a much lower swing capability. (Evidence from long-term contracts and pipe design in Continental Europe suggests a typical pipeline swing of around 30% at maximum.)

The low swing from European imports will be further exacerbated by the characteristics of the remaining UKCS fields, which will be:

- *smaller*—reducing the likelihood of major swing flexibility; and
- *older*—increasing the likelihood of production disruptions at any point in time, thereby increasing likely supply shortages.

In the European markets, lack of swing in contracts and delivery is countered by higher levels of gas storage availability than in the UK.[6] Thus, progress on expected new infrastructure projects—in particular, the new onshore storage facilities proposed or being developed at, for example, Aldbrough, Byley, Humbly Grove and Welton, and the proposed LNG import facilities at Isle of Grain and Milford Haven—will greatly influence the degree to which supply flexibility will be able to dampen any expected

[5] There is no UK LNG terminal at present, but, as discussed later in the report, it is anticipated in both the Joint Energy Security of Supply (JESS) Working Group reports and Transco's 2003 'Ten Year Statement' that terminal developments will emerge over the period 2005/06 to 2009/10 at Isle of Grain and Milford Haven.

[6] The UK currently has storage capacity equivalent to around 3% of annual demand, compared with figures in excess of 20% in most European countries.

increase in daily volatility. In terms of salt cavity storage, new additions, if they all emerged, would represent a substantive increase in short-term supply flexibility.[7]

2.3 Future investment scenarios

The trends in demand and supply sources described above imply that new investment is necessary to:

- enable new imports to access the market (eg, interconnectors or LNG terminals), responding to higher expected prices and growing gas demand; and
- exploit the higher volatility in gas prices as a result of reductions in short-term supply flexibility (eg, through additional salt cavity storage facilities).

The JESS Working Group reports[8] provide several scenarios of mixes of such projects, differentiated by their probability of occurring:

- *minimum investment*—no new major infrastructure investment offshore or onshore;
- *proven investment*—minimum investment plus projects which, on available evidence, have a better than 90% chance of being developed;
- *probable investment*—proven investment plus projects which have a 50–90% chance of being developed; and
- *possible investment*—probable investment plus projects with a less than 50% chance of being developed.

Applying a similar approach, details of proposed investments that would be included in each of the three new investment categories are shown in Tables 2.1 and 2.2, which focus on import and storage investments respectively.

[7] However, in terms of overall capacity, this would be expected to have limited influence on seasonal variations due to the size differential with Rough. Additional seasonal flexibility is likely to be introduced through utilisation patterns of new interconnectors.

[8] Joint Energy Security of Supply (JESS) Working Group (2003), 'Third Report', November; and Joint Energy Security of Supply (JESS) Working Group (2004), 'Fourth Report', May.

Table 2.1: Potential import investments

Scenario	Investments included	Operational date	Operational volumes (bcm/yr)	Peak capacity (GWh/d)	Reported development cost (£m)
Proven	Zeebrugge interconector upgrade (Phase I)	2005/06	8	249	75
Probable (proven plus)	LNG at Isle of Grain	2005/06[1]	5	108+	130
	Ormen Lange to Easington	2006/07	20	758+	Transport infrastructure: 1,560 Field development: 3,720
	Zeebrugge interconector upgrade (Phase II)	2006/07	7.5	249	75
	Dragon LNG	2007/08	10	162+	259
	South Hook LNG	2007/08	15	325+	518
	Dutch interconnector	2006/07	10	433+	330
Possible (probable plus)	Other LNG	tbc	–	81+	129
	Other Norwegian gas	2007/08	–	325+	–

Note: [1]The Isle of Grain terminal is expected to be operational from Q1 2005.
Source: Joint Energy Security of Supply (JESS) Working Group (2003), 'Third Report', November; Joint Energy Security of Supply (JESS) Working Group (2004), 'Fourth Report', May; UKOOA; company statements; International Energy Agency (IEA).

Table 2.2: Potential storage projects

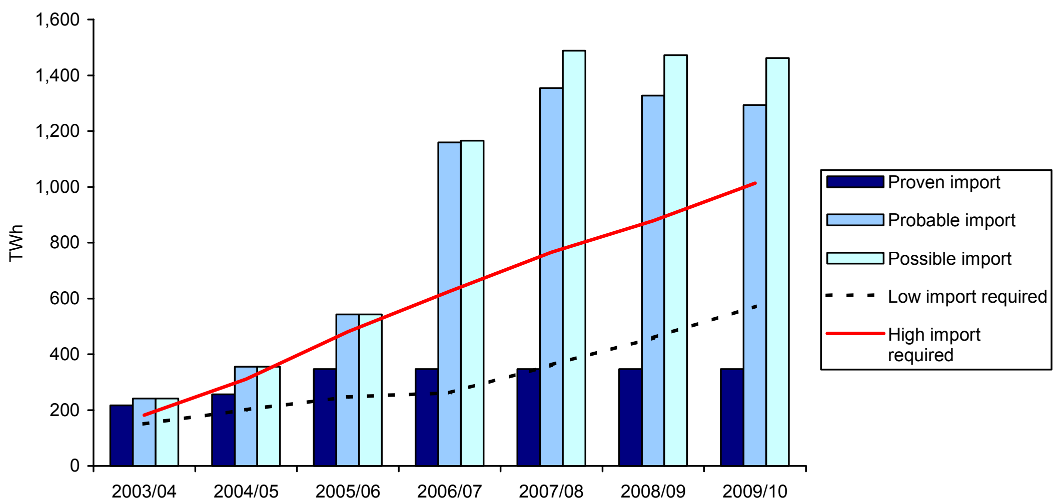
Scenario		Date	Deliverability (GWh/d)	Space (GWh)	Cost (£m)[1]
Probable	Aldbrough	2007/08	421	4,427	225
	Cheshire—Byley	2007/08	210	3,162	100
	Humbly Grove	2005/06	79	2,951	32–96
Possible (probable plus)	Welton	2007/08	89	3,056	50
	Bletchingley	2009/10	~273	~9,750	32–96
	Albury	2010/11	~273	~9,750	99–297
	Fleetwood	2008/09	~421	~6,008	55–165

Note: [1] Where ranges are given, the low estimate is calculated under the assumption of a cost per cubic meter storage identical to Welton for which official figures exist. The high estimate assumes a cost per cubic meter in the high end of the range of generic cost estimates presented in IEA (2004), 'World Energy Investment Outlook 2003'.
Source: Joint Energy Security of Supply (JESS) Working Group (2003), 'Third Report', November; Joint Energy Security of Supply (JESS) Working Group (2004), 'Fourth Report', May; company statements; IEA.

The implications of the realisation of the different investment scenarios are shown in Figures 2.3 and 2.4 below. Figure 2.3 shows the annual import requirement increasing over time. The speed with which import dependence increases is a function of both the growth in demand and the decline in the UKCS production. The low-import scenario reflects both a low level of demand growth and maximum exploitation of UKCS field potential (including sanctioned, proven, probable and possible production from the most recent UKOOA analysis). In contrast, the high-import scenario combines high demand growth with UKCS production limited to sanctioned fields.

In both scenarios there are sufficient import projects reported in Table 2.1 as either proven or probable such that, assuming they are all operational at the proposed date, expected annual demand requirements can be met. However, in the high-import scenario, all identified import projects will need to be operational, or additional UKCS volumes will be required.

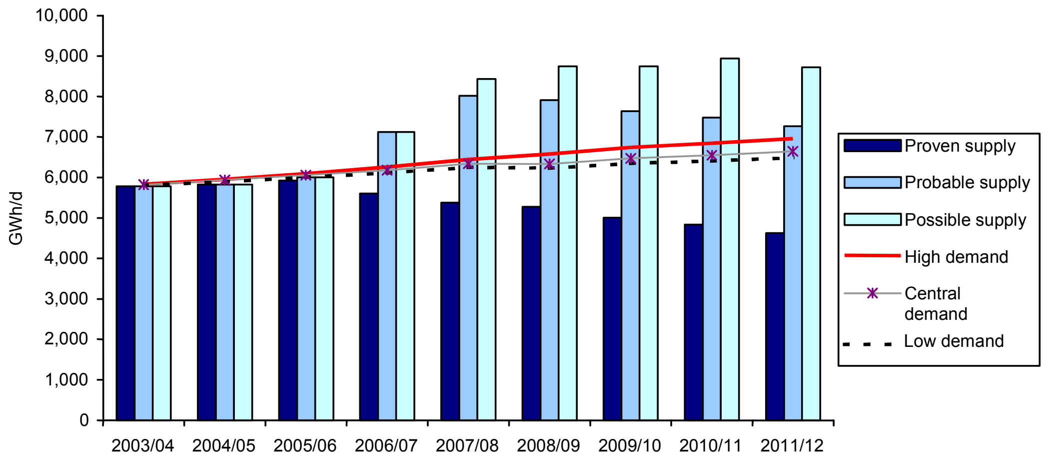
Figure 2.3: Import requirement and ability to meet demand



Source: NGT (2003), 'Transportation Ten Year Statement 2003', December; OXERA calculations.

Although annual supply may be met by the timely arrival of new projects, Figure 2.4 shows a different picture for peak supply availability. Applying Transco's own scenarios of peak demand to the import and storage investment scenarios implies that, despite the longer-term peak supply–demand balance being achievable through the realisation of the probable gas storage projects, problems may emerge in the short term, over the next few winters, because there is no scope for an investment response.

Figure 2.4: Peak supply–demand balance



Source: NGT (2003), 'Transportation Ten Year Statement 2003', December; OXERA calculations.

2.4 Cost of investment

In the low-import scenario, the annual supply shortfall from the UKCS is up to 573 TWh by 2009/10, and the peak supply shortfall would be up to 1,900 GWh/day. These shortfalls must be met from import sources and additional storage facilities if there is no offsetting demand reduction. In the high-import scenario, these figures increase to 1,014 TWh and 2,300 GWh/day respectively.

Several projects, which could potentially meet these shortfalls, are already under construction or are in pre-construction phases of development. Using publicly available information for these projects, as presented in Tables 2.1 and 2.2 above, the total market investment cost of ensuring that the infrastructure is in place to meet the supply–demand balance is in the region of £7 billion to £8.3 billion, as shown in Table 2.3.[9]

Table 2.3:Gas investment cost projections (£ billion)

Project	Low-import scenario	High-import scenario
Additional UKCS investment	5.1	1.2
Import infrastructure	1.4	6.7
Storage investment	0.36 to 0.42	0.36 to 0.42
Total	**6.86 to 6.92**	**8.26 to 8.32**

Note: UKCS gas investment is assumed to be 45% of total UKCS capital expenditure (CAPEX).

The low-import scenario has a lower investment requirement due to a combination of lower total demand and less accurate information on the total UKCS investment cost. Publicly available industry information, produced by UKOOA, does not differentiate between oil- and gas-related investment, and therefore the value of UKCS gas investments may be inaccurate.

[9] The cost of additional LNG tankers has not been included as this is thought to be a global market cost.

In addition to the market-based investments in new fields, transit, and storage infrastructure, there will also be a need to upgrade the National Transmission System (NTS) by Transco. The latest investment forecast, provided in ‘Transporting Britain’s Energy 2004’, predicts a spend in the order of £1 billion in the period 2004/05 to 2012/13. Thus, in total, infrastructure investment in the region of £8–£9 billion can be expected over the next five years or so.

3. Electricity Market Investment Requirements

Like the gas market, the electricity market is also entering a period where additional investment requirements are beginning to emerge, although this is not as pronounced as it is for the gas.

- The closure and decommissioning of the nuclear fleet, which currently provides around 20% of Great Britain's total electricity demand, has begun, and around 2.5 GW of capacity (4% of peak demand) will be closed by 2010.
- Coal-fired generation will face increasingly tougher environmental restrictions on its emissions as a result of the Large Combustion Plants Directive, requiring either investment in emission-abatement equipment or restricted operation and, ultimately, closure.
- Government targets for renewable generation, incentivised through the Renewables Obligation, are for 10% of electricity to be sourced from renewable generation by 2010. With renewables currently providing 2.3% of supply, this entails more than a fourfold increase in renewable generation capacity. Furthermore, additional network infrastructure enhancements will be required to ensure the reliable delivery of these new, smaller-scale, generation technologies.

As with the gas analysis, the demand and supply conditions, together with future investment scenarios, are presented below.

3.1 Demand

Electricity demand in Great Britain in 2003/04 stood at 347 TWh, with average cold spell (ACS) peak demand of 61.2 GW. Figures 3.1 and 3.2 present projections of annual and peak electricity demand growth to 2010/11, and are derived from the seven-year statements of the three transmission licence holders in Great Britain:[10]

- the National Grid Company (NGC);
- ScottishPower Transmission Ltd (SPTL);
- Scottish Hydro-Electric Transmission Limited (SHETL).

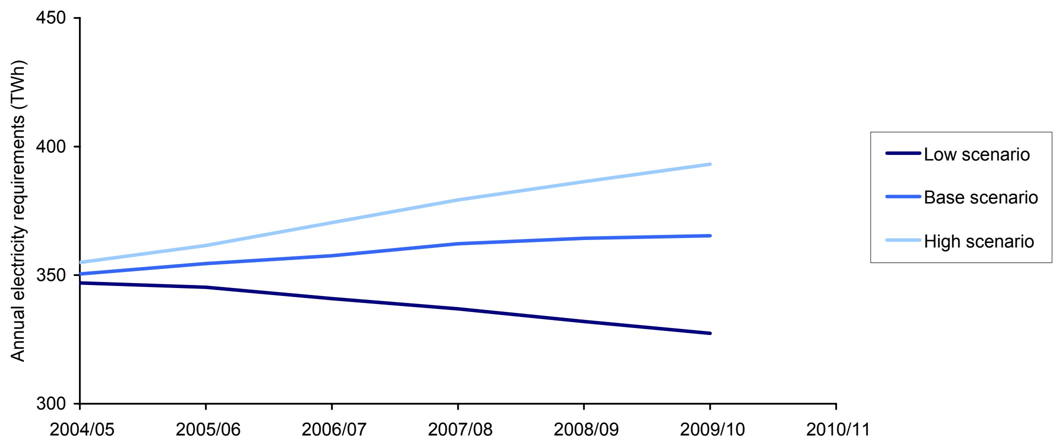
The figures show three broad scenarios of future peak and annual demand growth—low, base and high—corresponding with those provided in the NGC seven-year statement, where the key differences arise in the underlying assumptions on factors such as income growth, levels of distributed generation, energy prices and energy efficiency developments.

The base scenario forecasts growth of around 0.7% per annum—lower than has been observed over the period since privatisation, but comparable with rates of growth observed since 2000. The high scenario sees a continuation of the post-privatisation trend growth of around 1.8% per annum, whereas the low scenario represents a situation where

[10] ScottishPower (2003), 'Transmission Seven Year Statement for the Years 2003/04 to 2009/10', April; SHETL (2003), 'Seven Year Transmission Statement 2003 for the Years 2003/04 to 2009/10', June; and NGC (2004), 'Seven Year Statement', March.

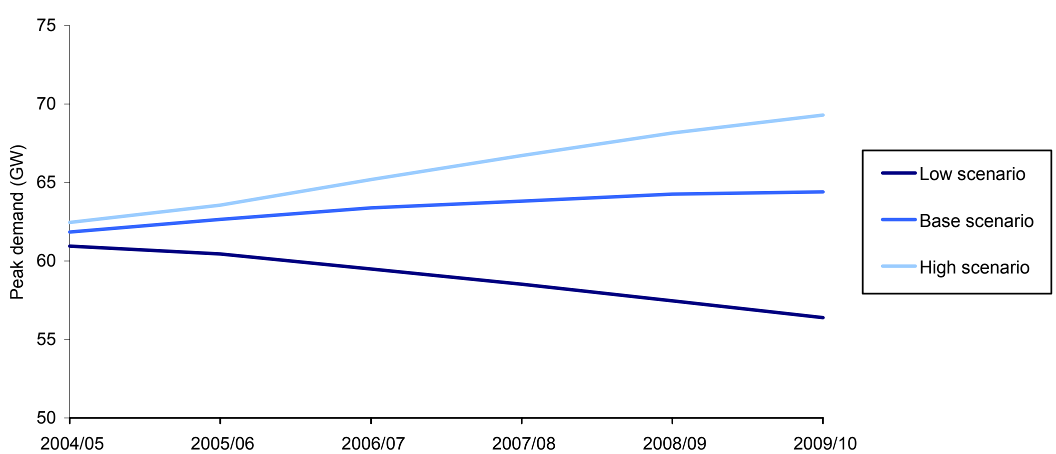
demand growth actually falls.[11] However, in all cases, the rates of change in annual and peak demands are similar, suggesting that there will be no additional stress on the system at peak times (a situation which might have arisen if the majority of growth had been from peak users).

Figure 3.1: Annual electricity requirements for Great Britain



Source: NGC, SHETL and SPTL seven-year statements.

Figure 3.2: Peak demand for Great Britain



Source: NGC, SHETL and SPTL seven-year statements.

Since the analysis here is intended to consider the level of investment required to maintain security of supply, the peak demand forecasts are augmented by the inclusion of

[11] The reduction in demand in the low scenario is a function of high levels of assumed energy efficiency improvements and distributed generation. However, since the assumptions underlying this scenario could not be obtained from NGC's seven-year statement, the report focuses on the base and high scenarios.

a peak capacity margin, which is assumed to be 20%.[12] Thus, sufficient capacity will be required to meet the hypothetical peak demand levels shown in Table 3.1.

Table 3.1: Peak demand with 20% margin

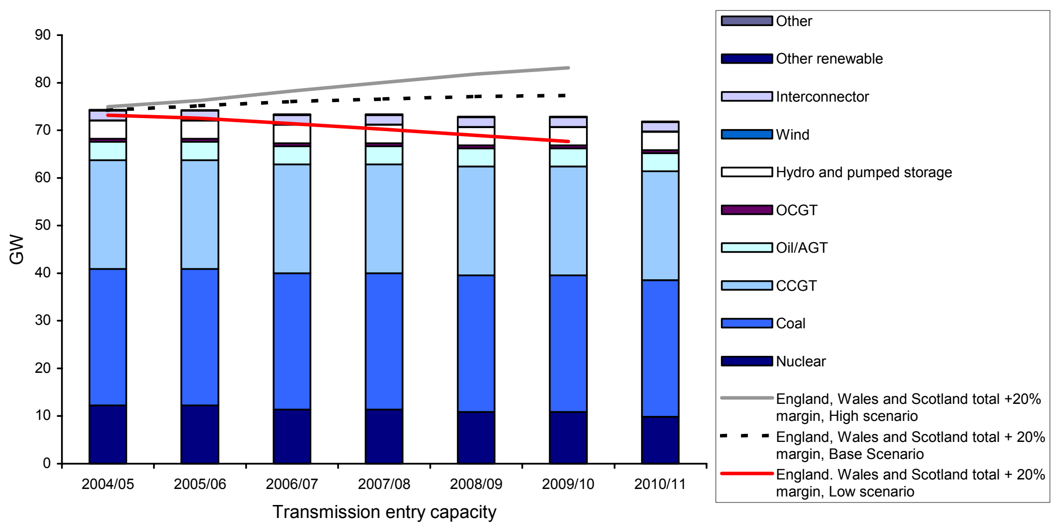
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Low scenario	73.1	72.5	71.4	70.2	69.0	67.7
Base scenario	74.2	75.2	76.1	76.6	77.1	77.3
High scenario	74.9	76.3	78.2	80.1	81.8	83.2

Source: OXERA calculations.

3.2 Supply

Figure 3.3 shows how the peak demand projections from Table 3.1 compare with the available generation capacity in Great Britain. As can be seen, in both the base and high-demand scenarios, the existing capacity, of around 73.6 GW, is insufficient to meet the margin-adjusted peak demand from as early as 2006/07. This is a function not only of demand growth, but also of the agreed programme of nuclear plant closures, which will result in the loss of around 2.5 GW of capacity, as outlined in Table 3.2 below. New investment will therefore be needed to meet the shortfall.

Figure 3.3: Peak demand (including capacity margin) and generation



Notes: OCGT, open-cycle gas turbine; AGT, auxiliary gas turbine; CCGT, closed-cycle gas turbine.
Source: NGC, SHETL and SPTL seven-year statements and OXERA calculations.

[12] A peak capacity margin is not necessarily an appropriate measure of supply security for the electricity sector; however, past NGC planning margins have utilised a figure of around 20% and this corresponds with recent historical capacity margins.

Table 3.2: Nuclear plant closures to 2010

Station	Date of Closure	Capacity (MW)
Dungeness A	2006/07	440
Sizewell A	2006/07	458
Oldbury	2008/09	470
Wylfa	2010/11	1,006

Source: NGC (2004), 'Seven Year Statement', March.

3.3 Future investment scenarios

Taking the current mix of plant on the system, making appropriate adjustments to the effective capacity availability of wind,[13] and allowing for the nuclear closure programme, Table 3.3 shows the effective peak capacity availability of the currently installed capacity.

Table 3.3: Existing capacity by plant type (MW)

Plant type	2004/5 TEC	2005/6 TEC	2006/7 TEC	2007/8 TEC	2008/9 TEC	2009/10 TEC	2010/11 TEC
Nuclear	12,229	12,229	11,331	11,331	10,861	10,861	9,855
Coal	28,679	28,679	28,679	28,679	28,679	28,679	28,679
CCGT	22,849	22,849	22,849	22,849	22,849	22,849	22,849
Oil/AGT	3,821	3,821	3,821	3,821	3,821	3,821	3,821
OCGT	642	642	642	642	642	642	642
Hydro and pumped storage	3,836	3,836	3,836	3,836	3,836	3,836	3,836
Offshore wind farm	407	204	204	204	204	204	204
Interconnector	1,988	1,988	1,988	1,988	1,988	1,988	1,988
Other renewable	95	54	54	54	54	54	54
Other	100	100	100	100	100	100	100
Total	**74,646**	**74,402**	**73,504**	**73,504**	**73,034**	**73,034**	**72,028**
Total available to meet peak demand[1]	**74,381**	**74,269**	**73,371**	**73,371**	**72,901**	**72,901**	**71,895**

Note: TEC, transmission entry capacity. Assumes the capacity value of wind is 35%.

As Figure 3.3 shows, no new investment is required in the low scenario. However, in both the base and high scenarios, a shortfall in capacity can be identified, as Tables 3.4 and 3.5 show.[14] In the base scenario, the incremental investment identified is of the order of 4,000 MW; in the high scenario, up to 10,000 MW may be required.

[13] Wind generation is de-rated to 35% to reflect the average load factor, as has been applied in previous studies. See, for example, Dale et al. (2004), 'Total Cost Estimates for Large-scale Wind Scenarios in UK', *Energy Policy*, **32**:17, November, 1,049–56.

[14] No adjustment has been made for an assumed increase in demand-side response within the market. If such a response were to occur, peak requirements would be reduced. However, there has been no evidence of increased demand-side participation since the introduction of the New Electricity Trading Arrangements (NETA) in March 2001.

Table 3.4: Capacity shortfall, base scenario (MW)

	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Total capacity available to meet peak demand	74,381	74,269	73,371	73,371	72,901	72,901
GB peak demand +20% margin, base scenario	74,223.6	75,183.6	76,064.4	76,588.8	77,113.2	77,274
Shortfall	**–**	**914**	**2,693**	**3,217**	**4,212**	**4,373**

Source: NGC, SHETL and SPTL seven-year statements and OXERA calculations.

Table 3.5: Capacity shortfall, high scenario (MW)

	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Total capacity available to meet peak demand	74,381	74,269	73,371	73,371	72,901	72,901
GB peak demand +20% margin, high scenario	74,943.6	76,263.6	78,224.4	80,068.8	81,793.2	83,154
Shortfall	**563**	**1,994**	**4,853**	**6,697**	**8,892**	**10,253**

Source: NGC, SHETL and SPTL seven-year statements and OXERA calculations.

The new investment scenarios to meet these shortfalls are constructed from two sources.

- The seven-year statements indicate that some response to this shortfall is already planned and that there are a number of projects scheduled to come online over the period up to 2010. These are shown in Table 3.6 and account for 2,750 MW of the anticipated shortfall.

- The remainder of any shortfall is assumed to be met by new CCGT plant. Not only is this broadly consistent with the gas demand scenarios as described in section 2, but it also represents the least expensive capital investment and thus minimises the expected investment cost. However, this will not be compatible with achievement of the government's renewables target and, therefore, actual investment costs may be higher.

Table 3.6: Cumulative scheduled new capacity (MW)

Plant type	2004/05 TEC	2005/06 TEC	2006/07 TEC	2007/08 TEC	2008/09 TEC	2009/10 TEC	2010/11 TEC
Wind	832.35	1134.35	1134.35	1134.35	1134.35	1134.35	1134.35
CCGT	800	800	800	800	800	800	800
CHP	760	760	760	760	760	760	760
Waste to energy and biomass	56	56	56	56	56	56	56
Hydro	2	2	2	2	2	2	2
Total	**2,450**	**2,752**	**2,752**	**2,752**	**2,752**	**2,752**	**2,752**

Source: NGC, SHETL and SPTL seven-year statements.

It can be seen that the incremental investment required over and above the scheduled new capacity in Table 3.6 (ie, the maximum shortfall in Table 3.5 less the scheduled capacity in Table 3.6) is never more than around 2 GW per annum, which is consistent with past build rates and, therefore, is likely to be achievable. However, in the high-demand scenario, that first incremental investment will need to be operational by 2006/07 if the peak position is to be met. Given the lead time of at least two years for the construction of a new station, it is possible that a peak shortfall may occur under this scenario because the market has no time to respond.

3.4 Cost of investment

The investment identified in section 3.3 represents the physical construction of new plant. The capital cost associated with different generation technologies are shown in Table 3.7. It is clear that there is a wide variation in the cost estimates, but the established gas-fired technologies (CCGT and OCGT) represent the cheapest alternatives.

Table 3.7: Capital cost estimates for different plant types (£/KW)

Plant type	IEA capital cost, lower estimate[1]	IEA capital cost, upper estimate[1]	RAE capital cost estimate
Coal-fired PF	435	707	820
Coal-fired CFB	598	707	730
Biomass-fired BFB	815	1,359	1,840
Coal-fired IGCC	707	870	1,000
Gas-fired OCGT	190	245	330
Gas-fired CCGT	219	326	300
Nuclear fission	924	1,169	1,150
Wind turbine, onshore	489	598	740
Wind turbine, offshore	815	870	920
Wave and marine technologies	–	–	1,400

Notes: [1] These figures were converted from $/kW with the exchange rate £0.54357:$1, as of July 22nd 2004. PF, pulverised fuel; CFB, circulating fluidised bed; BFB, bubbling fluidised bed; IGCC, integrated gasification combined cycle.
Source: IEA (2004), 'World Energy Investment Outlook: 2003 Insights'; and Royal Academy of Engineering (RAE)(2004), 'The Cost of Generating Electricity', study undertaken by PB Power, March.

Assuming that the scheduled plant in Table 3.6, together with the appropriate incremental CCGT investment—2,358 MW and 8,328 MW in the base and high scenarios respectively[15]—is realised,[16] the cost associated with new generation investment is expected to be £2.1–£2.5 billion in the base scenario, and £3.3–£4.3 billion in the high scenario.

This also includes around 500 MW of additional combined heat and power (CHP) plant, which is forecast in the seven-year statements to be built, but which is netted off the demand position for the purposes of the transmission forecasts.

No additional network investment has been assumed in this analysis. Nevertheless, if the mix of plant that emerges has a stronger bias towards renewable generation, it is

[15] The scheduled wind capacity is de-rated as for existing wind generation in Table 3.3.
[16] The fourth JESS report (May 2004) indicates that there is an additional 7,270 MW of CCGT capacity already consented. Therefore, the assumption that all additional capacity could be sourced as CCGT is not unrealistic in the timeframe.

anticipated that there will be a substantive transmission reinforcement investment requirement in the order of £1 billion.

Assuming that the government will reach its target of 10.4% of electricity demand to be sourced from renewable generation by 2010, the shortfall in capacity would be met with a more expensive mix of generation and would require the additional infrastructure investment. Table 3.8 shows the mix and level of capacity required to meet simultaneously the Renewables Obligation target and the assumed peak capacity margin under the base and high-demand scenarios. The total volume of investment is higher, and the associated capital cost is double that of a gas-generation bias in meeting the shortfall.

In the base-demand scenario, the renewable investment cost is £5.1–£7.3 billion and in the high-demand case, the cost is £6.1–£8.8 billion.

Table 3.8: Additional capacity requirements (Renewables Obligation target met in 2010, MW)

	Total capacity: base scenario	Total capacity: high scenario
Biomass	1,618	1,742
Wind: offshore	4,490	4,834
Wind: onshore	3,929	4,230
CCGT	0	3,324

4. Conclusions

Overall, the analysis of publicly available data suggests that the UK electricity and gas industry will need to undertake between £10–£18.1 billion of investment over the next five years. This level of investment does not differ significantly from recent trends, but the focus of investment activity is changing.

In the scenarios developed above, and reproduced in Table 4.1 below, over half of the investment is anticipated to be undertaken in the gas industry, and up to 85% of that may be non-UKCS investment. This fundamental shift reflects the importance of the changing gas supply position for the UK. In addition, this level of investment is underpinning much lower demand growth rates than similar levels of investment over the course of the 1990s.

Table 4.1: Investment cost summary (£ billion)

	Low investment	High investment
Gas	7.9	9.3
Electricity	2.1 to 7.3	3.3 to 8.8
Total	**10.0 to 15.2**	**12.6 to 18.1**

While investigating the cost of the required investment, this analysis was not intended to investigate whether the identified investments will be operational by the assumed dates.

Although several of the gas projects—eg, the IUK upgrade and the Isle of Grain terminal—are progressing at, or ahead of, the assumed schedules, other projects are still at pre-planning or pre-construction phase, and there may still be tightness in the market over the next few years. Indeed, in its most recent planning scenarios, NGT has expressed the view that it is unrealistic to assume that all of the proposed import projects will proceed to their proposed development timescale and delivery volumes.[17]

In electricity, the potential lag in responding to market signals for new investment due to construction times of at least 18 months to two years may also serve to tighten margins in the short term. However, this analysis assumes a required 20% capacity margin, whereas it is entirely possible that the market and NGT could operate securely at lower levels, either in the short or long term.

The final decision on whether and when to invest will be linked to expectations of the return that the investor will be able to achieve in the market. Recently, the electricity and gas sectors have seen opposing trends in investment activity that can potentially be linked to differences in future price expectations.

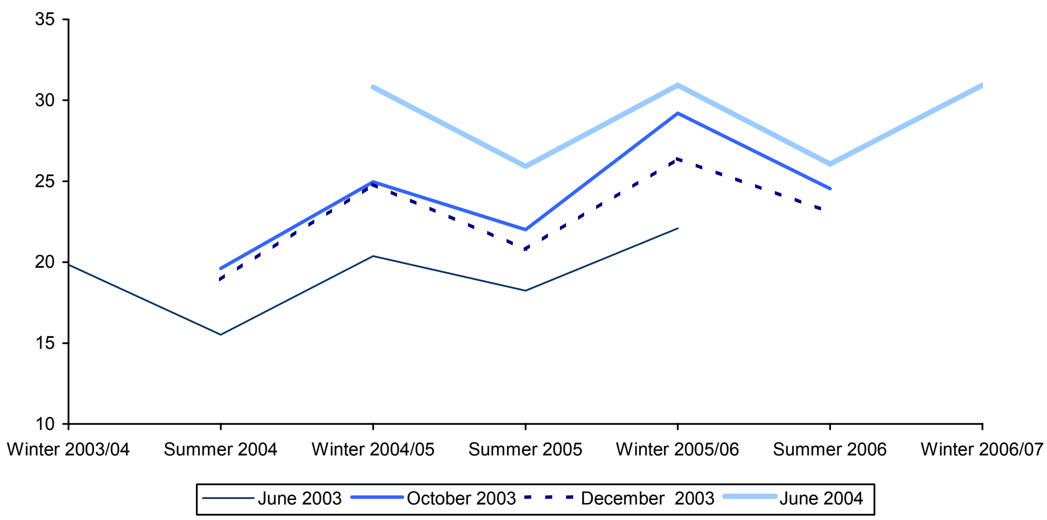
In electricity, despite there being 8 GW of CCGT plant with consent, only 800 MW is currently under construction. This reflects market expectations of future wholesale electricity prices relative to new entry costs. Figure 4.1 shows that, in the past year, there has been a significant increase in the forward curve for electricity, with the largest rises occurring in the contracts for delivery of electricity over the 2004/05 winter. In June 2003, it was possible to trade winter 2004/05 contracts for just over £20/MWh (well below new entry cost); by June 2004, however, these contracts were trading at over

[17] Transco (2004), 'Transporting Britain's Energy: Development of NTS Investment Scenarios', July.

£30/MWh. Similar but slightly less severe rises can be seen in the prices for the other forward contracts.

Based on these higher expectations of future electricity prices, it may seem reasonable to assume that electricity generation is expected to become more profitable, and hence the value of power stations should increase. However, one of the reasons for the recent increases in electricity prices has been rising fuel prices. Therefore, electricity generators may not have seen a significant increase in their profit margins, or in the spark spread in the market.[18]

Figure 4.1: Electricity forward season prices (£/MWh)



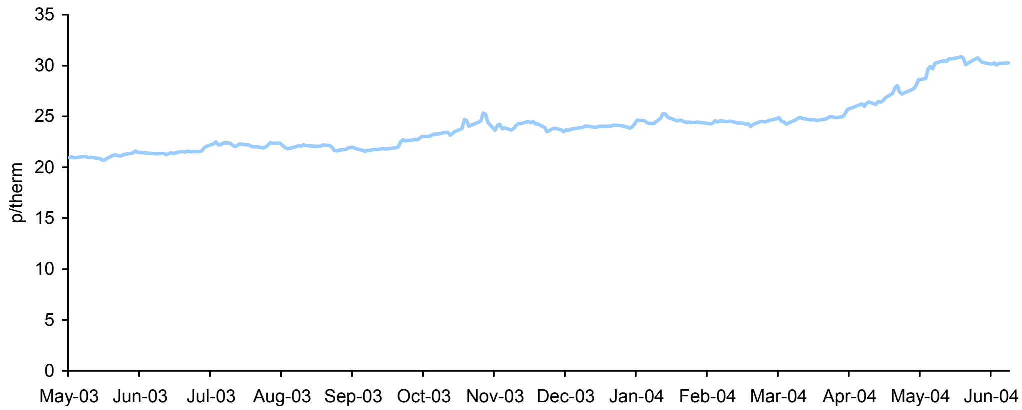
Source: Argus.

In the UK gas market, wholesale commodity prices have been much stronger and annual forward prices have exhibited a strong upward trend, as shown in Figure 4.2. These price levels are expected to persist if the current forward curve is a true reflection of market expectations, where prices are reported as trading above 30p/therm for both 2005 and 2006. Such high prices may have incentivised several of the large infrastructure projects to proceed, on the expectation of significant volumes of gas flowing into the UK market. This suggests that prices close to current levels are sufficient to cover the production and transportation costs of the new sources of imported gas that will use this infrastructure.

However, given that several of the necessary importation projects are still not at the construction phase, the implication is that wholesale prices may need to remain at relatively high levels to ensure that the investment is undertaken and the new volumes of gas are committed to the UK market. In the longer term, as these projects enter the market, the volumes they deliver can be expected to exert a dampening effect on market prices as the immediate supply–demand constraint is relaxed.

[18] For a more detailed discussion of spark-spread developments, see OXERA (2004), 'Sparking Interest in Power Stations', *The Utilities Journal*, July, 32–33,.

Figure 4.2: Year-ahead NBP gas prices



Source: European Spot Gas Markets.

Data Appendices

Appendix 1: Gas Demand

Transco's annual and peak gas demand forecasts are presented in Tables A1.1 and A1.2. Once more, a wide range of assumptions underlie the different scenarios. For example, in the central scenario, annual economic growth of 2.6% is assumed, consistent with that in the NGC base forecast for electricity, an oil price of around $24/barrel is predicted, together with stable, then rising, wholesale gas prices. Installed CHP plant increase from 4.8GW to 7 GW, below the current Defra projections of 8.1 GW by 2010.[19] The high and low scenarios reflect variations on these assumptions.

Table A1.1: Annual forecast gas demand (TWh)

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
High	1,213	1,237	1,252	1,286	1,316	1,351	1,399	1,434
Central	1,210	1,231	1,232	1,249	1,272	1,280	1,303	1,329
Low	1,207	1,225	1,213	1,214	1,231	1,234	1,250	1,271

Source: NGT (2003), 'Ten Year Statement'.

Table A1.2: 1-in-20 peak-day firm demand (undiversified, GWh)

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
High	5,833	5,957	6,093	6,261	6,443	6,578	6,745	6,851
Central	5,822	5,934	6,058	6,182	6,341	6,335	6,470	6,545
Low	5,812	5,888	6,001	6,110	6,252	6,229	6,347	6,406

Source: NGT (2003), 'Ten Year Statement'.

Appendix 2: Electricity Demand

The combined Great Britain electricity demand forecasts are shown in Table A2.1. The three scenarios for demand growth are drawn from NGC's 'Seven Year Statement' (March 2004). The high and low scenarios in NGC's forecasts reflect favourable and adverse situations for peak and annual electricity requirements on the NGC transmission system, covering not only differences in income growth and prices, but also assumptions about the penetration of distributed generation (ie, non-transmission-connected generation which thereby reduces the expected demand from transmission-connected generation) and the success of energy efficiency programmes.

[19] Defra (2004l), 'The Government's Strategy for Combined Heat and Power to 2010', April.

Table A2.1: Peak and annual demand forecasts, Great Britain

Base year for scenario	Peak demand (GW)			Annual demand (TWh)		
	Low scenario	Base scenario	High scenario	Low scenario	Base scenario	High scenario
2004/05	61.0	61.9	62.5	346.99	350.43	354.93
2005/06	60.5	62.7	63.6	345.30	354.48	361.57
2006/07	59.5	63.4	65.2	340.91	357.57	370.42
2007/08	58.5	63.8	66.7	336.88	362.18	379.24
2008/09	57.5	64.3	68.2	332.02	364.37	386.36
2009/10	56.4	64.4	69.3	327.38	365.38	393.07

Source: NGC, SHETL and SPTL seven-year statements.

The low scenario assumes GDP growth of 1.9% per annum, compared with 2.6% in the base scenario. Furthermore, a particularly high profile is assumed for environmental issues in this scenario, with energy conservation encouraged by way of investment and subsidies on both the demand and generation sides. Energy efficiency schemes for domestic and business customers are promoted and investment in more efficient generation sees the environmental targets set for 2010 for CHP and renewable energy being achieved.

In contrast, the high scenario assumes higher GDP growth of 3% per annum, coupled with a slow rate of take-up for both CHP and renewable generation embedded within distribution networks.

Appendix 3: UKCS Production Forecasts

Table A3.1 presents the underlying UKCS production forecasts from UKOOA's 2004 Economic Report.[20] 'Sanctioned' production includes fields that are already in production or under development; 'incremental' includes new projects within sanctioned fields; 'probable' includes projects with an estimated chance of more than 50% of proceeding within five years; and 'possible' includes projects with an estimated chance of succeeding within five years of less than 50%. Whether the incremental, probable and possible projects will materialise will depend on a range of factors determining their economic viability, including the expected price of gas and the regulatory framework.

Table A3.1: UKCS projected gas production (TWh)

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Sanctioned	1,032	926	771	660	551	472	385
Incremental	22	55	98	125	136	123	109
Probable	3	44	98	161	167	153	133
Possible	0	0	0	6	16	27	49
Total	**1,057**	**1,025**	**966**	**952**	**870**	**775**	**677**

Source: UKOOA (2004).

[20] UKOOA (2004), *Maximising Britain's Oil and Gas Resource*, Economic Report 2004.

Appendix 4: Forecast UKCS Investment Costs

Identified costs for all non-exploration oil and gas investment in the different field categories is presented in Table A4.1. It is assumed in the analysis that 45% of this is attributed to gas production.

Table A4.1: Forecast UKCS investment by field type (oil and gas, £m)

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Sanctioned	1,799	1,092	674	401	271	201	142
Incremental	868	832	890	522	390	251	160
Probable	938	1,185	1,080	581	243	285	270
Possible	0	16	116	325	626	480	452
Total	**3,605**	**3,124**	**2,760**	**1,829**	**1,530**	**1,217**	**1,024**

Source: UKOOA (2004).