



## THE FUTURE OF UK GAS: A PHASE DIAGRAM

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A report to Oil & Gas UK  
(formerly UKOOA)

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THE FUTURE OF UK GAS: A PHASE DIAGRAM



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## EXECUTIVE SUMMARY

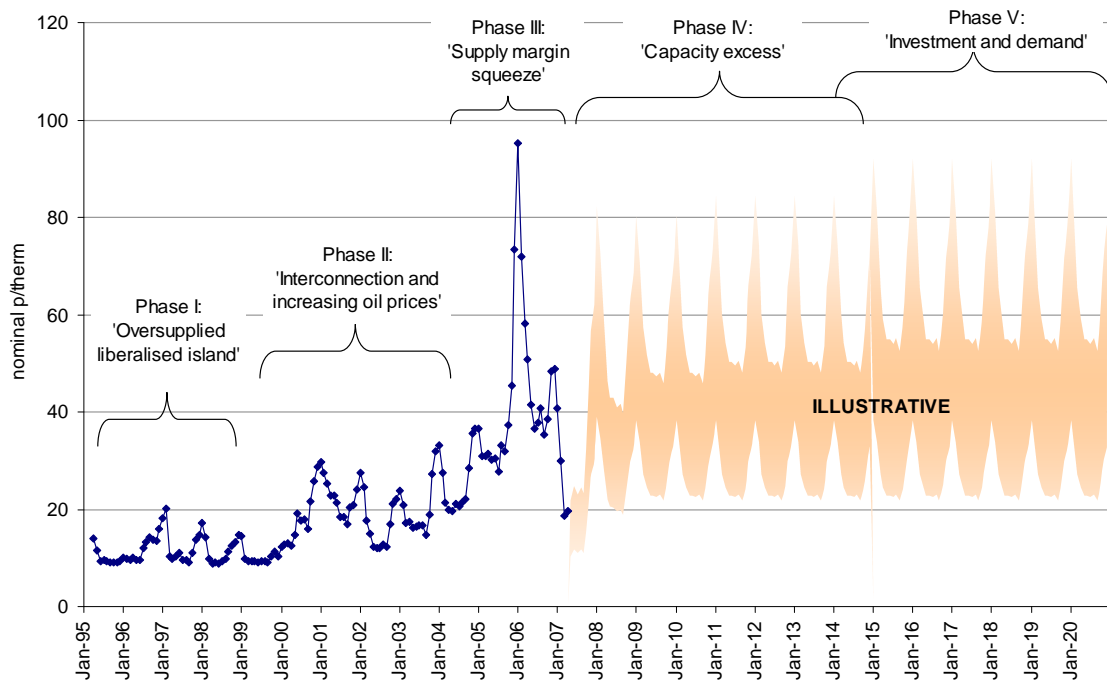
UKOOA has asked Pöyry to look at how the UK gas market might evolve out to 2020 with particular reference to the recent movement in gas prices and the impact the current investment programme could have into the future.

In our study we have looked back at the evolution of the UK gas industry since the introduction of competition and the formation of the wholesale market in the mid-1990s. We have categorised both the history and the future into different phases.

### Historical phases of the UK gas market

Since the UK gas market was liberalised in the 1990s, the market has evolved in a series of phases, each marked by shifts in both the underlying fundamentals and in price. There have been three distinct historical phases, as shown in Figure 1.

Figure 1 – Historical and future evolution of the UK gas market



Source: Pöyry Energy Consulting

**Phase I ('oversupplied liberalised island')** occurred during the 1990s, with the start of the liberalised UK market, with gas supplies coming mainly from the UK Continental Shelf. The UK gas market was isolated from other countries and as a result was in a situation of oversupply, with easy access to gas in the North Sea keeping prices low.

**Phase II ('interconnection and increasing oil price')** occurred during 1998-2003 and was marked by the commissioning of the UK-Belgium interconnector in Q4 1998. For the first time in the history of the gas industry, gas could flow directly from the UK into the Continent, and vice-versa. As a result of this physical linkage, UK prices became linked to

Continental prices, and thus linked to the oil price. This in turn led to increasing gas prices as the price of oil rose during this phase.

**Phase III ('supply margin squeeze')** from 2004 to 2006, was distinguished from Phase II by concerns about the availability of supply. This led to monthly prices approaching £1 per therm.

Pöyry believes we are on the cusp of a change from Phase III to **Phase IV ('capacity excess')**, with a total of around 60bcm of new gas importation capacity already completed or due in the next few years (approximately 60% of UK gas demand). The new capacity available over this recent winter plus the very warm weather has led to a collapse in prices during 2007.

How the future will look post-2010 is unclear, but the combination of growing gas demand from power generation, and further investment in the UKCS, LNG and new pipelines, will determine what gas is still being produced from the UKCS, what gas is being imported from Norway and the Continent and via LNG. This future, called **Phase V 'investment and demand'** is defined to reflect the possible outcomes arising from the growth of gas demand and from different investment approaches.

### *Phase III – what happened and could it have been foreseen?*

We believe that there was a change in the UK gas market from Phase II to Phase III over the winter of 2004/05, as shown on Figure 1. The early winter was uneventful despite some concerns about insufficient supply, largely because of relatively warm weather. However, in late February and early March 2005 there was a cold spell in the UK and across North-West Europe, which caused a sharp spike in gas prices in the UK.

The awareness of a possible problem increased in the period up to the start of the new gas year from October 2005. Various meetings between industry, regulator and government were organised to see if any plans could be put in place to improve security of supply before the winter started. However, the 2005/06 winter turned out to be particularly difficult for some industrial consumers, especially energy intensive industries such as fertilizer manufacture, steel, chemicals and glass. Gas prices experienced a shock in November 2005 as an unusually cold spell, combined with warnings about a potential further cold winter, pushed prices past 150p/therm. After a period of lower prices, a fire at the Rough storage facilities in February 2006 caused National Grid to issue the first ever 'gas balancing alert'. Shortly after this prices rose to nearly 200p/therm, only to crash back down a week later as the market was sufficiently reassured that there would be enough supply to meet demand. These higher wholesale gas prices fed through for higher prices to all gas consumers including domestic users.

Although periods of high prices are to be expected with all commodities, it is worth understanding what contributed to the tight supply-demand balance.

Firstly, demand was in line with, if not lower than, expectations, as forecast 5 years earlier by National Grid. There were also a number of years of warnings about the imminent drop in production from the UKCS. National Grid's forecasts were predicting this back as far as 2002.

There appear to have been problems with long-term forecasting for the expected rate of reduction of the UKCS, with revisions of the likely deliverability from 100% in 2000 down to 90% by 2006.

However, although wholesale prices did not react to the likelihood of a supply-demand shortfall, it appears that individual players were reacting to the perceived shortfall, with planning starting on Langeled in 2000, BBL in 2002 and Interconnector reinforcement in 2003. However, a key investment project, the Langeled pipeline, was delayed by a year due to delays in signing the inter-government treaty.

Smaller investment, such as the expansion of the Interconnector from Belgium, was brought on ahead of time for the winter. However, to the surprise of some, gas from the Continent did not immediately flow through the interconnector in sufficient quantities to fill up all the expanded capacity.

Overall, it can be considered that the market (as expressed through the market price) reacted somewhat slowly to the new world, continuing to project a continuance of business as usual scenario such that sufficient gas would be available on the day even when facts were pointing otherwise. The market also underestimated how high prices would have to go to balance supply and demand, partly because of a lack of historical references in a market that is a little over 10 years old. However, when the market eventually reacted to the possibility of a shortfall of supply, as it did in November 2005, prices reacted very strongly.

There can be no doubt that the volatility of UK gas prices has increased, and is much higher overall than most other commodities, whether metals, oil or agricultural produce. However, the factors that make gas prices so volatile could be changing as we enter Phase IV. In particular, the greater interconnection to the Continent will increase the geographic size of a market, currently limited to just the UK, to include North-West Continental Europe. This, in conjunction with the large volume of new LNG import capacity means that the UK will become part of a more global LNG market in the future.

We could also see a gas market that is more heavily traded, as a result of a large number of new players recently entering the market. This could also expand further as a result of increased trading opportunities within Continental Europe and through the LNG market. Ultimately, the more trading that occurs, the more competitive a market will become and the more likely prices will delink from oil. Nevertheless, it appears unlikely that the forward curve will be particularly liquid in the medium-term, as even the market for Brent crude oil (the largest commodity market) remains dominated by short-term trading.

### ***Future phase IV: 'capacity excess' – what could the world look like?***

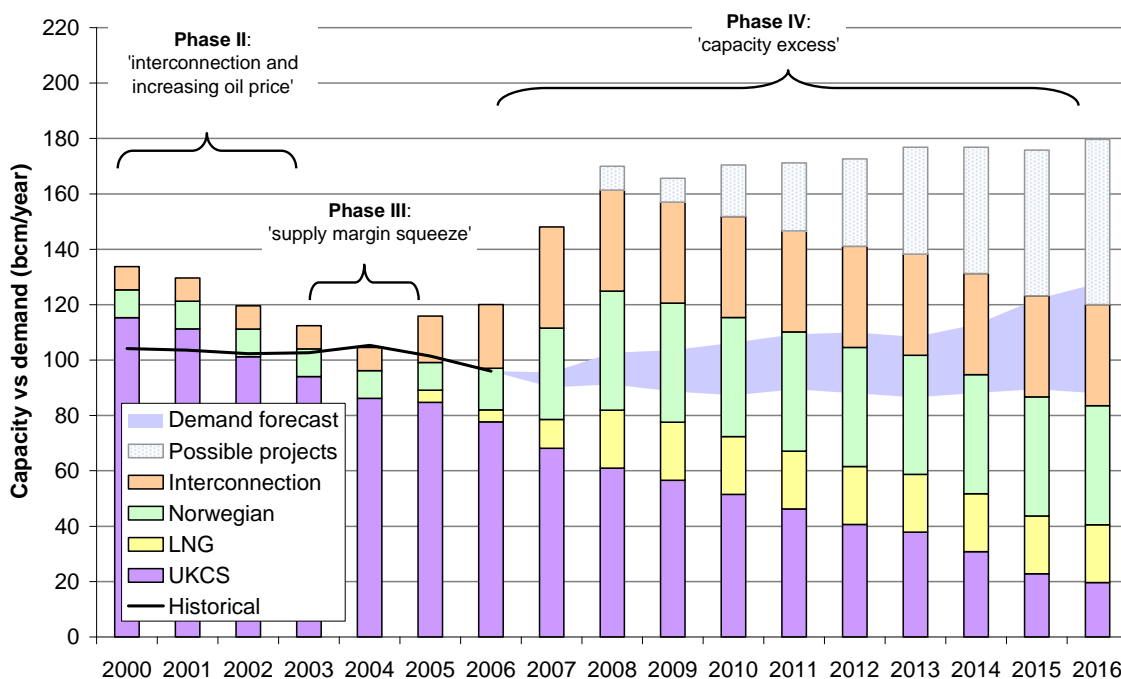
#### *What suggests we are entering a new Phase IV?*

There are a number of key facts that suggest we are entering a new phase for the UK market and that we are moving, or have already moved, from **Phase III 'supply margin squeeze'** to a new **Phase IV of 'capacity excess'**.

Firstly, there is the sheer amount of new capacity that is already online or due to come on in the forthcoming years, as shown in Figure 2. The LNG import facility at the Isle of Grain, owned by National Grid, became operational during summer 2005 with 4.4bcm/yr of capacity. October 2006 saw the opening of the Langeled pipeline, bringing in gas from Norway, through a pipeline that eventually will see up to 23 bcm/yr of gas from the giant Ormen Lange field. In addition to this, the BBL interconnector, linking the UK to the Netherlands, started delivering gas to the UK in December, with a capacity of 14 bcm. These were in addition to the expansion of the UK-Belgium interconnector in November 2005 from 8bcm/yr to 16bcm/yr and again in October 2006, raising its import capacity to 23bcm/yr.

Added to these pipeline projects, at Milford Haven in Wales, there are two well-advanced LNG projects due to come on-line in the next year – Dragon and South Hook, for 6bcm/yr and 10.5bcm/yr respectively, with a second phase of Isle of Grain for 8.6bcm/yr in late 2008. There are a number of other LNG projects currently being considered for the UK, including a third phase of the Isle of Grain for 7bcm/yr, a second phase of the South Hook project which would add an extra 10.5bcm/yr in 2010 and a further expansion to the Dragon terminal, to take the capacity to 12bcm/yr. Also there are proposals for further projects such as those at Canvey Island, Amlwch, Coryton and offshore in Morecambe Bay.

**Figure 2 – Demand compared to available capacity**



Source: Pöyry Energy Consulting

Added to this plethora of new capacity has been the reaction of market prices over the last 6 months. The view of the market (as expressed through the forward curve) has shifted enormously in a year, from predicting prices for Q1 08 at over 80p/therm to around 40p/therm by March 2007, due to an exceptionally mild winter<sup>1</sup> but also due to new importation capacity being commissioned, and a sense of the security of supply problem now being solved for the foreseeable future.

*What could Phase IV look like?*

It is difficult to assess how Phase IV ‘capacity excess’ could evolve or indeed the likelihood of any specific scenario coming about. However, we have illustrated a series of possible ‘worlds’ that could evolve, as shown in Figure 3. The scenario approach takes

<sup>1</sup> Second mildest since records began in 1914

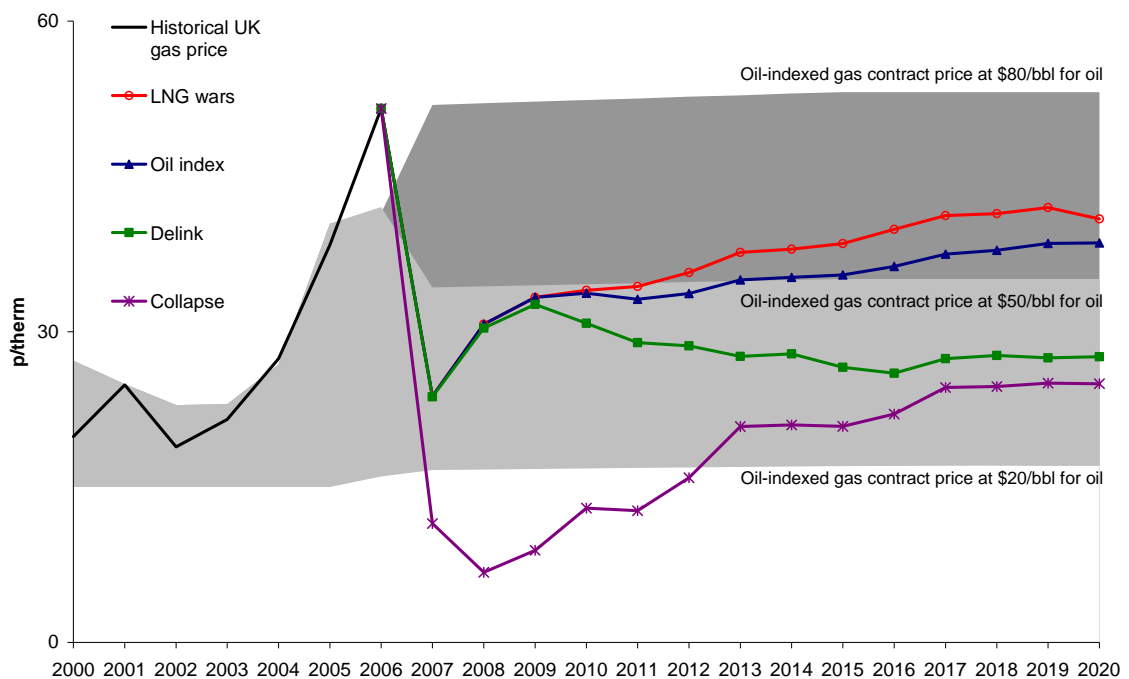
account of different possible futures, incorporating different market structures, and the tracks of each scenario are designed to account for the variety of possible price drivers that could dominate in that scenario. It should be noted that prices in the future can move from one price track to another, as the underlying fundamentals change. All these worlds assume \$50/bbl oil price (2007 real).

Our future worlds are called:

- Oil-indexed
- Pipeline delink
- Collapse
- LNG wars

The ‘oil-indexed’ scenario is in many ways a return to Phase III. In this scenario gas prices on the Continent stay closely linked to oil prices and the impact of these oil linked gas contracts continue to influence UK gas market prices. However, if we are entering a new phase, history would indicate that there is a potential for a sudden shift in gas pricing. With the significant amount of investment that is occurring, the excess capacity in the UK, competition introduced by LNG, and the potential for the UK to become a gas hub, there could be an excess of supply over demand. This could result in the ‘de-link’ scenario, where gas prices fall towards their Long Run Marginal Costs (LRMC) and are no longer linked with the oil price. The over-supply in the UK could lead to the excess UK gas being exported to Europe so providing a market impetus which, when combined with a continued drive from Brussels to liberalise markets and increase competition, could extend the ‘delinked’ future on to the Continent.

**Figure 3 – Possible worlds in Phase IV**



Source: Pöyry Energy Consulting. All scenario tracks assume \$50/bbl (2007 real).

Our collapse scenario is an extension to the pipeline delink scenario but in this world gas prices collapse quickly to the LRMC and in some cases down further to the Short Run Marginal Costs (SRMC). In this future, gas is in plentiful supply, perhaps caused by a continuation of warm winters, and this could create the situation for a price collapse back to prices seen in Phase I. The role of weather is key and something not modelled here is the impact of a series of cold winters. Cold weather would test the ability of the new UK infrastructure and the existing offshore and onshore infrastructure to deliver and would also show how LNG would flow in such a scenario. However, given the large over-capacity situation that is developing in the UK market, it is unlikely that a cold winter would see prices returning to those seen during Phase III.

Of course, the UK market is now beginning to become part of a global LNG market, with the ability to divert cargoes originally destined for the UK to the US or Asia, and vice versa. Our modelling suggests that the effect of these cargo diversions is unlikely to have a significant impact on UK gas prices in the medium-term, due both to the size of the combined UK/European market and due to the overall excess capacity. However, the combination of high global demand for LNG and individual markets (such as the US) dragging gas into them could impact the UK price post 2020. Other markets that are more dependent on LNG, for example Spain, are much more heavily affected by a global LNG market.

In all these future Phase IV worlds we have assumed an oil price forecast of \$50/bbl (2007 money). With Brent having peaked at \$78 in August 2006, it remains possible that a much higher Brent price could drag up Continental gas prices. This would create an intriguing prospect – the high returns possible from supplying gas to Europe ought to create a climate that encourages significant investment, leading to an oversupply situation made worse by suppressed demand from those self-same high oil prices. This situation would have all the characteristics for a ‘de-link’ of gas prices from oil prices and a collapse in gas price. Whether it could occur would depend both on whether investment is permitted to happen, or whether some European markets remain closed to competition.

### ***Future phase V – how is investment and demand going to change the longer-term picture?***

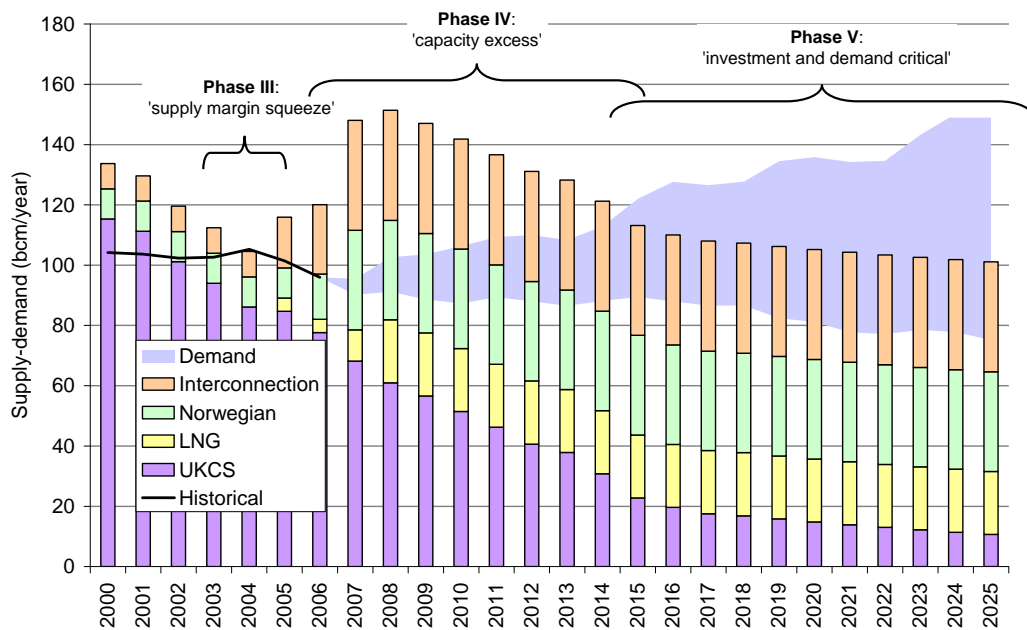
#### *Gas demand growth in the UK*

The growth of gas demand is highly uncertain when looking 10 to 15 years into the future, as the main area of growth (power generation) is facing a significant number of challenges – renewing and replacing existing generation with gas-fired, coal-fired or (in the longer-term) nuclear plant. This is combined with the fuel price relativity of gas and coal, the extent to which a price for carbon influences the running of plant (and the generation mix) along with the impact of ‘eco-friendly’ measures such as renewables and demand reduction. We believe that the electricity generating sector is facing a challenge that is greater now than ever before in deciding what type of new generation capacity to build. This higher uncertainty and risk in electricity generation feeds through to the gas industry in its evaluation of how to invest to meet the highly uncertain future gas demand.

As regards gas demand for the UK as a whole, there are also uncertainties for the Industrial & Commercial (I&C) and domestic/residential sectors, such as the effects of prices, building regulations and insulation, warmer winters and improvements in boiler efficiency, to name a few. We estimate that this will give a range of gas demand growth of +/-1% each year.

If we combine the power sector demand forecasts for the High and Low scenarios with forecasts of the I&C and residential sectors, as shown in Figure 38, we end up with a wide range of demand that varies between 75bcm and 150bcm by 2025.

**Figure 4 – The transition to Phase V**



Source: Pöyry Energy Consulting

There is a case to be made that a Phase V, dependent on both gas demand and investment, could begin around 2015, as the combination of depletion in the UKCS and rising demand forces decisions to be made on future investments. Of course, if the bottom of our range of gas demand forecasts comes about, it is possible that no new infrastructure could be required in the UK, and the current 'building binge' will be the last one for the foreseeable future in the UK gas market.

*Investment decisions*

From speaking to industry participants, it was clear that internal gas price forecasts are the key determinant of most investment decisions in the UKCS, with other investments such as LNG terminals being determined on a combination of internal price forecasts and larger 'strategic' analysis. However, current prices could affect decision making by altering the perception of risk and reward – this could potentially be more of a factor for larger investments with a longer pay back.

High oil prices have significantly increased investment in oil, which in turn has led to much higher costs for participants, as the cost of wages, rigs, shipping etc have been driven up. It was considered that in gas investments, 60% of the costs were directly linked to oil investment (such as salaries or availability of steel) and 40% were unrelated (such as specialised gas drilling rigs). As a result, high oil prices on their own have significantly increased the cost of searching for and producing gas in the UKCS. The biggest threat to UKCS investment would be a slump in gas price unaccompanied by a drop in oil prices (delinking of gas and oil prices). This would mean high E&P costs as a result of oil prices, without high gas prices to offset them.

Investing in the UKCS largely remains one of small incremental investments, typically around locations where companies already own infrastructure. There are concerns that gas could become 'stranded' for good in the UKCS as a result of the cost of extraction being higher than returns generated. This would be the case where new small gas fields near to existing infrastructure will not be able to be brought into production in future if that existing infrastructure is not maintained and is eventually abandoned.

Some potential gas fields, eg West of Shetlands, are remote from any existing infrastructure and need to be of a certain size to be financially viable. The combination of low gas prices and expensive investment in infrastructure will make such projects very unlikely to progress.

#### *Dynamic modelling of investment*

Pöyry has also examined the effect that investment decisions and types of investment could have on the gas market, using our gas model Pegasus<sup>2</sup>. From this modelling, we reach a number of conclusions with importance for the future Phase V.

Firstly, investments in the UKCS are impacted by the market, but have no impact on the market. This is primarily due to the size of any future gas finds, which tend to be small and incremental (particularly when compared to large new import pipelines or LNG terminals), and as a result have little impact on the market price. This is also due to the interconnection of the UK market both to the Continent and the international LNG market, which is a much larger overall area to affect.

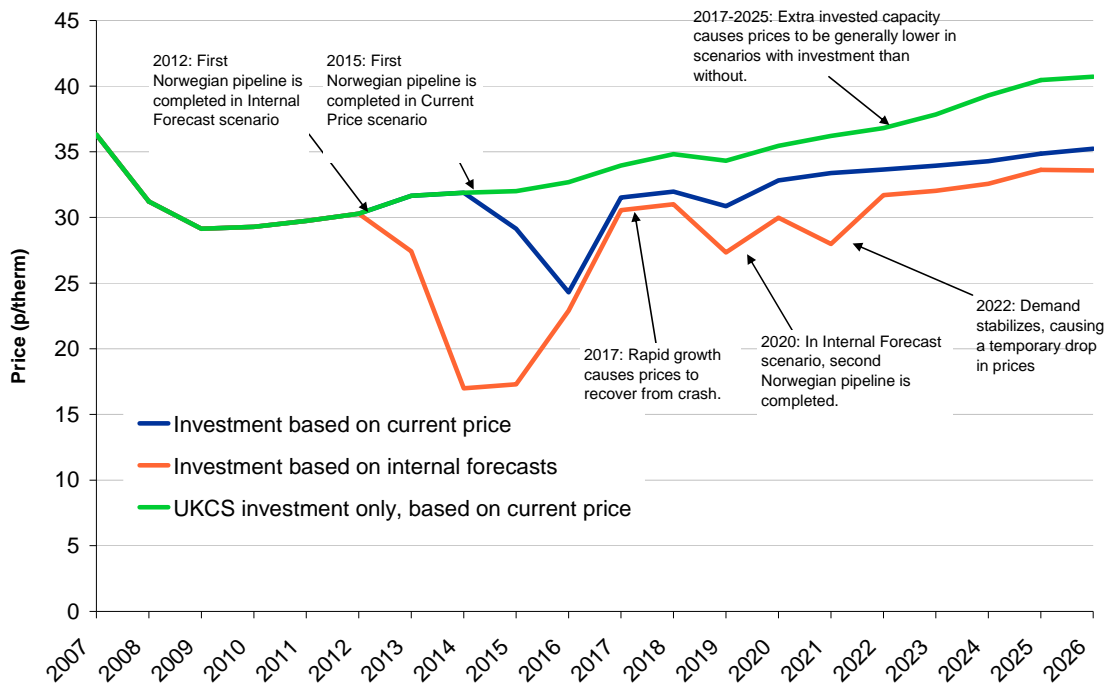
Large new pipeline investments, due to their inherent destination inflexibility, and reliance on running near full capacity to recoup investments, have the potential to upset the market for a period of time, as shown in Figure 5.

Given the nature of its inherent flexibility, LNG regasification terminals (when not accompanied by dedicated liquefaction plants) also have relatively little impact on the market. This is because the LNG does not have to flow into the UK market and can be diverted elsewhere – which as a result is unlikely to depress prices. Where LNG is accompanied by a dedicated liquefaction plant and a long-term contract, the likelihood of price effects are much greater, as it will behave in much the same way as a pipeline.

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<sup>2</sup> Pan-European GAS model + US

**Figure 5 – Effect of new import pipeline on UKCS price**



Source: Pöyry Energy Consulting

Since companies are not overly sensitive to current prices and tend to rely on internal price projections, this appears to increase the likelihood of a price drop caused by over investment, rather than reduce it. This seems to be the result of the propensity of projections (whether the forward curve or internal projections) to project the current world into the future. Consequently, periods where a number of companies invest together are likely to recur.

However, given the increasing interconnection of the UK market to both NW Europe and the global LNG market, the impact of any future cycles of over- or under- investment may be as a result of European or global periods of investment, rather than a merely UK-centric one.

### Conclusions

This report has highlighted the shifting phases that the UK gas market has undergone in the last 10 or so years, and we believe that the market is on the cusp of a further shift.

- Gas prices increased through Phase I to Phase III. The tightening supply demand margin led to some very high prices towards the end of Phase III but the gas industry invested in new gas importation capacity and this has helped gas prices to fall. We believe that the industry reacted reasonably promptly given the size of the new projects. The recent sharp decline in prices is also due in part to the very warm winter. The comfortable gas supply margin in the UK (and on the Continent) has weakened the relationship of UK gas prices with oil-linked Continental gas prices.
- Gas traded in the UK wholesale markets as a commodity is very volatile and has become more volatile over recent years. However, liquidity is increasing and new financial traders have entered the market. The increasing ‘geographic spread’ of the

UK market due to interconnection and LNG, suggests that volatility should reduce, but it is unlikely to increase the volume traded on the forward curve which will remain short-termist.

- Phase IV – which is just starting – is a period when the UK will have a significant excess of gas importation capacity. We model a range of possible worlds: gas prices stay linked to oil/oil products; gas prices delink from oil; a gas price collapse; a squeeze on UKCS production and LNG wars. The analysis suggests some of the key drivers for the future Phase IV, such as the ongoing impact of oil-indexation and how this could evolve in a buyer's market. A collapse scenario, driven in part by ongoing warm weather, could see UKCS production suppressed. The impact of the LNG wars world seems to suggest that any future LNG market will only have a relatively mild impact on UK gas prices, although it could have an impact driving more competition and increased liberalisation.
- Of the Phase IV worlds investigated, Pöyry is of the opinion that oil-indexation remains the most likely outcome, although the likelihood of prices being lower than this is much greater than in the past. Despite the large capacity excess in Phase IV, the combination of significant interconnection to the Continent (where oil-indexation is dominant), worldwide LNG trade (where most contracts remain oil-indexed) and the strong market instinct to look to the oil markets for guidance suggests that a return to 'normal' weather would be accompanied by a return to a 'normal' oil-indexed world. Another factor in preventing a move to full gas-on-gas competition is the lack of liquid wholesale markets capable of trading out years into the future. Our observations of how other commodity markets also lack forward liquidity is important since, if gas continues to behave as other commodities, the long term ambitions of the Commission may need revising. The Commission place great faith on liquid wholesale markets as a requirement of both liberalised energy markets and of investment decisions.
- Phase V – we conclude that forecasting gas demand is becoming ever more difficult. We believe that the electricity generating sector is facing a challenge that is greater now than ever before in deciding what type of new generation capacity to build. This higher uncertainty and risk in electricity generation feeds through to the gas industry in its evaluation of how to invest to meet the highly uncertain future gas demand. Our annual gas demand range varies between 75bcm and 150bcm by 2025. If gas demand falls to 75 bcm the UK will not need any further investment in additional gas importation infrastructure since the existing pipes and LNG terminals will suffice. Conversely, growth in gas demand will need to trigger new investment.
- We found that major oil/gas companies use similar methodologies in taking investment decisions. The companies use projections of gas prices combined with Net Present Value (NPV) calculations to see if a project is NPV positive. The projects with the highest NPV get the go-ahead. Interestingly most companies are not capital constrained but internal resources are a problem: management time and obtaining the right expert resources (ie drilling crews/rigs etc) do impose limitations. The current gas price is not a major factor other than in small projects (eg tie backs) where small gas fields need to be brought to market in the next 12 months or so, although in large complex projects such as LNG terminals, the current price could impact the perception of risk and have more influence as investment decisions are much more complex and less clear-cut.
- UKCS development is mainly based around bringing small finds to market using existing infrastructure of offshore gas pipelines. Several companies argued that there was a danger that if these small fields are not developed soon there was a

danger that the offshore infrastructure would be abandoned and that this would mean the gas would be lost for good (the concept of 'stranded gas').

- There is the possibility of more significant new gas finds west of Shetland, to add to those already made, but there is no existing infrastructure to bring the gas to shore. Some companies argued that investment in such major infrastructure is unattractive in the current business environment and requires a better tax regime. The Government would be repaid in the form of the tax revenues on the gas when produced.
- Our dynamic modelling revealed that UKCS gas production will be increasingly impacted by the market but has limited ability to impact the UK market in terms of price. This is due to the small size of likely new gas fields.
- LNG regasification terminals (when not accompanied by dedicated liquefaction plants) also have relatively little impact on the UK market. This is because the LNG does not have to flow into the UK market and can be diverted elsewhere – as a result it is unlikely to depress prices.
- The most significant impact arises from new pipelines. We found that a new Norwegian pipeline of around 30 bcm/annum capacity could cause UK gas prices to fall sharply in the immediate period after the pipeline comes on-line. Without the new pipelines UK gas prices rise steadily from 2010 out to 2030.
- Into Phase IV and beyond, the UK gas consumer will become subject to investment decisions made outside the UK market, both in Europe, and increasingly by decisions made across the world.

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# 1. INTRODUCTION

## 1.1 Introduction

Pöyry Energy Consulting (formerly ILEX Energy Consulting) has been asked by UKOOA, now Oil & Gas UK, to investigate how the UK gas market may evolve into the future.

This report follows on from a series of previous independent reports carried out for UKOOA:

- 'What influences gas prices in the UK and why have they increased through 2000?', ILEX, January 2001.
- 'UK gas prices: past and future', ILEX, March 2002.
- 'Gas prices in the UK' – ILEX, October 2004.
- 'Storage, gas prices and security of supply', ILEX, October 2005.

## 1.2 Pöyry Energy Consulting

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Pöyry is a global consulting and engineering firm focusing on the energy, forest industry, infrastructure and environment sectors.

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## 2. THE PHASE EVOLUTION OF THE UK MARKET

### 2.1 Introduction

The UK gas market has been marked by a series of phases, where the underlying fundamentals of the market have shifted significantly. These events have been caused by a range of factors, including interconnection to the Continent, changes in oil prices, shifts in supply and demand fundamentals and concerns over security of supply.

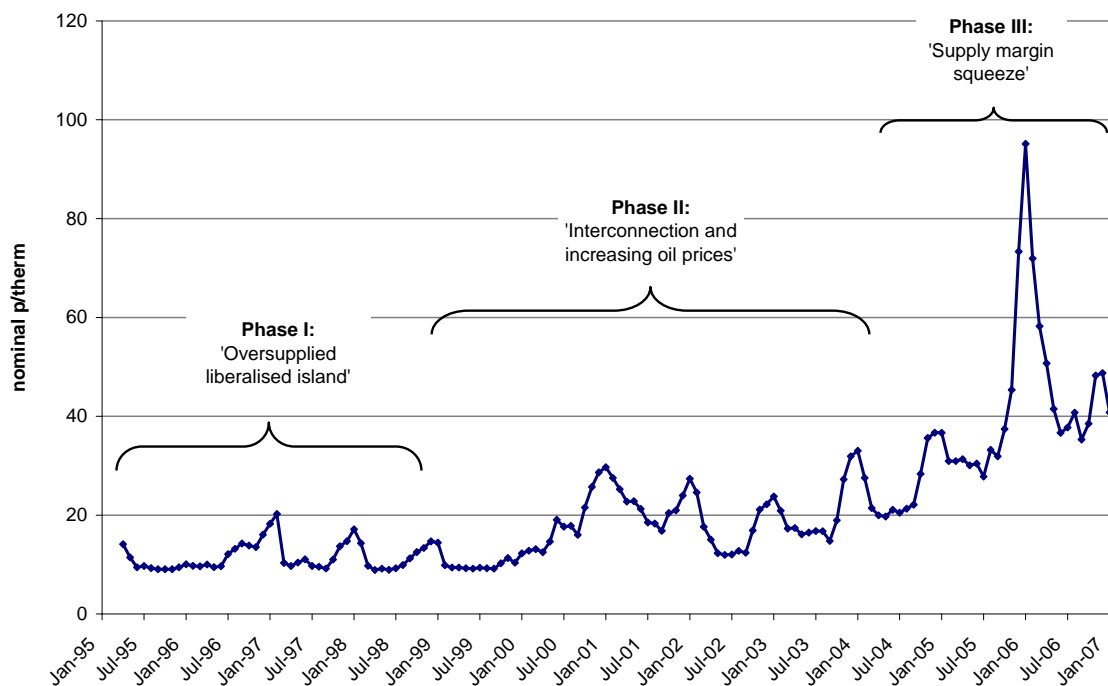
As can be seen from Figure 6, there have been three distinct historical phases in the movement of wholesale gas prices: Phase I during the 1990s, characterised by low prices; Phase II during 1998-2003, when prices became oil-indexed; and Phase III from 2004 to 2006, during which worries over supply saw monthly prices approaching £1 per therm (which it actually surpassed for a few days in the winter of 2005-6).

Pöyry believes we are on the cusp of Phase IV, with a significant shift in the dynamics of the market occurring at the moment.

This section gives an overview of the main phases experienced so far in the liberalised UK gas market, and introduces the phases that we may experience in the future.

### 2.2 Looking back

**Figure 6 – Historical evolution of the UK gas market**



Source: Pöyry Energy Consulting.

### 2.2.1 Phase I – ‘oversupplied liberalised island’

During the first period of the liberalised UK market, gas supplies came wholly from the UK Continental Shelf, with almost no imports from abroad<sup>3</sup>. The UK gas market was isolated from other countries and as a result was in a situation of oversupply, with easy access to gas in the North Sea keeping prices low.

Demand during this period was largely from residential and industrial & commercial (I&C) customers, with power generation only accounting for 15% of demand in 1994. However, by 1998 power generation accounted for almost 30% of demand, growing at 30% annually, as a result of low prices which stimulated demand.

### 2.2.2 Phase II – ‘interconnection and increasing oil’

The second phase of the UK market came with the construction of the UK-Belgium interconnector in Q4 1998. For the first time in the history of the gas industry, gas could flow from the UK into the Continent, and vice-versa. The pipe was built with the intention of exporting the excess production from the UKCS (UK Continental Shelf) into Europe, whilst allowing some reverse gas flows into the UK when needed in the future after the UKCS supplies were exhausted.

The potentially significant impact of the Interconnector passed largely unnoticed to begin with, since Continental prices during this time were similar to UK prices as a result of very low oil prices at \$13/bbl. Initial flows through the Interconnector (in import mode) were in the opposite direction to those foreseen.

However, the effect of Continental oil-indexed gas prices became much more apparent over the following 6 years with both oil and oil-product prices doubling between 1998 and 2000 to an average of \$28/bbl and subsequently rising to \$40/bbl through 2004<sup>4</sup>. This had a consequent effect on the Continental gas price, which was indexed to oil and oil-products on long-term contracts. As a result, significant volumes of gas began to flow out of the UK system onto the Continent, where buyers took advantage of the cheaper prices and UK shippers took advantage of higher margins. Thus, UK gas prices became linked to Continental gas prices and hence to international oil and oil-product prices.

From 1998 to 2004, demand from electricity generation grew at a much more modest rate, at only 5% per year, as a result of a slowing of CCGT new build, and increasing coal generation as a result of higher gas prices. Domestic demand grew at 2% per year while I&C dropped slightly by 0.5% per year over the period.

### 2.2.3 Phase III – ‘supply margin squeeze’

During Phase III, the oil-indexation of gas prices continued, with international oil prices continuing to rise to over an average of \$60/bbl during 2006. This led to much higher Continental gas prices and hence higher ‘underlying’ UK gas prices.

However the factor that distinguishes Phase III from Phase II was concern about the tightening supply margin.

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<sup>3</sup> In 1995 only 2.3% of gas supplies came from sources other than the UKCS

<sup>4</sup> IEA Brent FOB

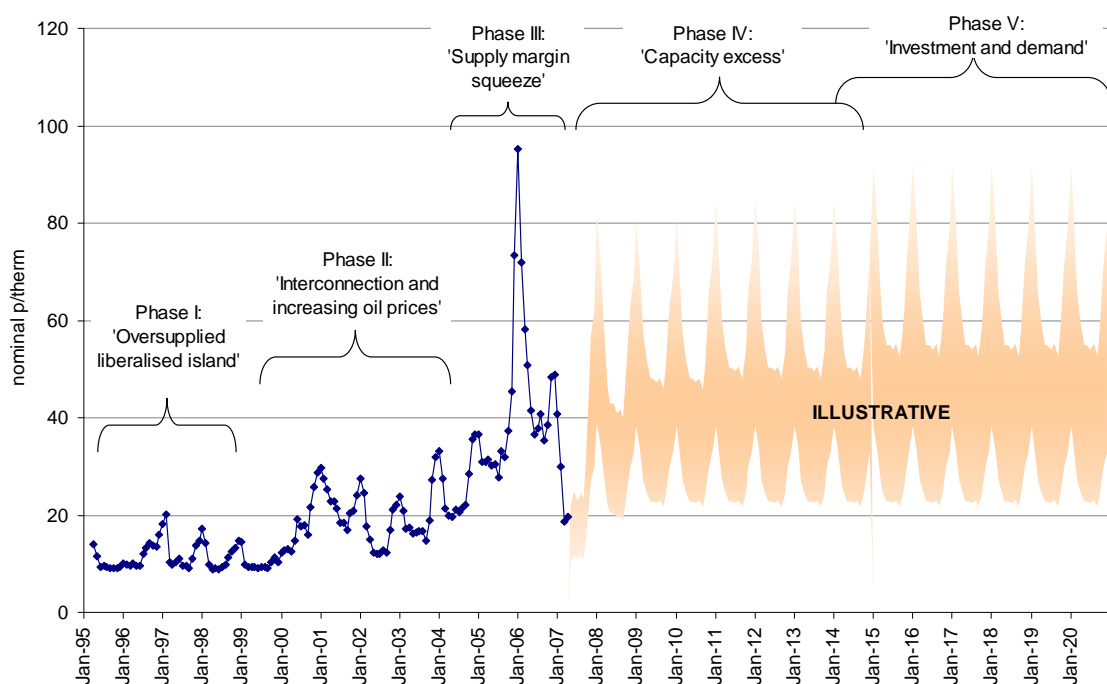
During the 1980s and 1990s, and during Phase I and Phase II, the UKCS was being developed at a fast rate, with significant production of gas reserves. The decline in production of gas had been forecast for some time, but the rate increased during 2004-06 more than forecast.

As a result, gas prices rose very sharply during the winter 2005/06, as the market matched supply to demand. The following summer, UK prices did not delink and fall below the Continental price, but instead remained linked to high oil prices.

Phase III is discussed in detail in section 3, along with the major drivers behind it.

### 2.3 Looking forward

**Figure 7 – Historical and future evolution of the UK gas market**



Source: Pöyry Energy Consulting. Prices are nominal.

#### 2.3.1 Future phase IV – ‘capacity excess’

As discussed in detail in section 4, the UK market now appears to be entering a period of capacity excess. The LNG import facility at the Isle of Grain, owned by National Grid, became operational during summer 2005 with 4.4bcm of capacity. October 2006 saw the opening of the Langeled pipeline, bringing in gas from Norway, through a pipeline that eventually will see up to 23 bcm/year of gas from the giant Ormen Lange field. In addition to this, the BBL interconnector, linking the UK to the Netherlands, started delivering gas to the UK in December, with a capacity of 14 bcm. These were in addition to the expansion of the UK-Belgium interconnector in November 2005 from 8bcm to 16bcm and again in October 2006, raising its import capacity to 23bcm. As a result, there is a total of around 60bcm new capacity available or due in the next few years (approximately 60% of UK gas demand). Also the very warm period through winter 2006/07 has led to a collapse in the

forward curve arising from the 'bubble or overhang' of gas which should have been consumed over the winter.

Note that this period is not necessarily marked by an excess of gas (although that is one possibility), but an excess of capacity available to bring gas into the UK.

### **2.3.2 Future phase V – 'investment vs demand'**

As discussed in section 5, it seems likely that a future phase will evolve after the current 'capacity excess' phase has run its course. How this might evolve is unclear, but the combination of growing gas demand from power generation, and further investment in the UKCS, LNG and new pipelines, will determine to what extent there is a sudden shift in market or a gentle trend.

## **2.4 Summary**

In the next section, we discuss in some detail what happened in Phase III, along with how the market reacted and what we can learn from past events that could suggest how the market will react in the future. In section 4, we discuss what suggests that we are entering a new phase, and how Phase IV might evolve. In section 5, we discuss what might happen post-Phase IV, as the uncertainty around demand growth and investment increases.

### 3. PHASE III – ‘SUPPLY MARGIN SQUEEZE’. WHAT HAPPENED AND COULD IT HAVE BEEN FORESEEN?

#### 3.1 Introduction

During the period 2004 – 2006 the UK market appeared to enter a new phase, the ‘supply-demand squeeze’. Reducing production from the UKCS combined with a lag for new supplies to the market meant that prices during the winter months reached all time highs.

This section examines how the situation arose, how the market reacted and what we can learn from past events that could suggest how the market will react in the future.

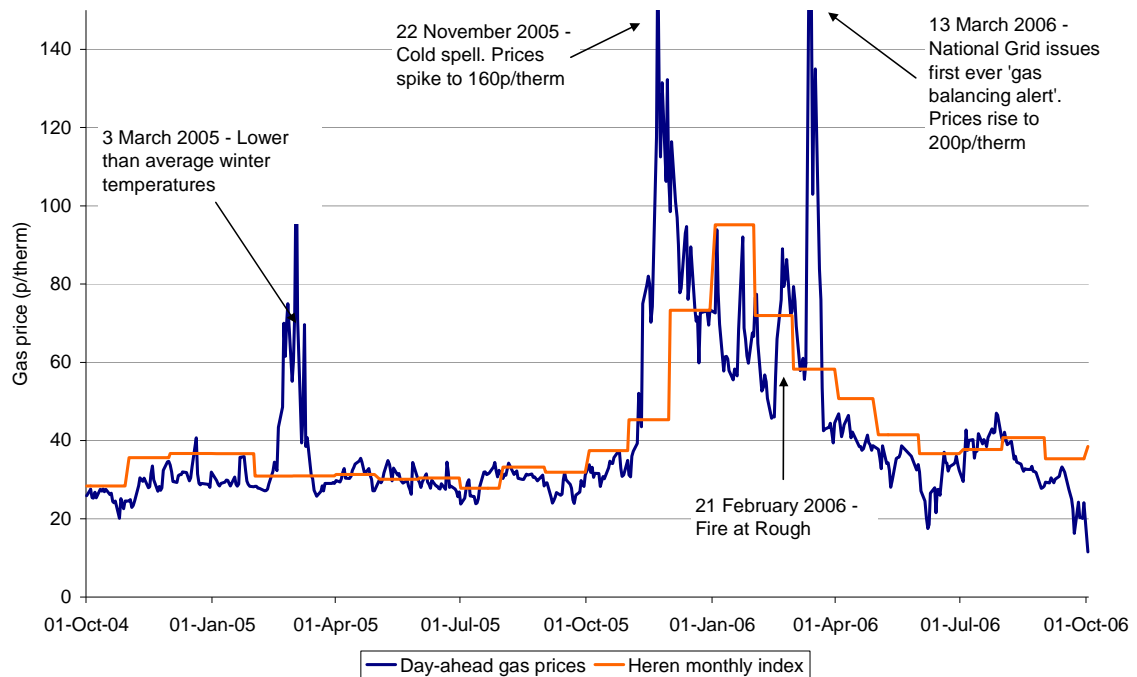
#### 3.2 Market reaction

As can be seen from Figure 8, the change from Phase II to Phase III during the early winter of 2004/05 was uneventful despite some concerns about insufficient supply, largely as the early part of the winter was relatively warm. However, in late February and early March 2005 there was a cold spell in the UK and across North-West Europe, which caused a sharp spike in gas prices in the UK. By mid-March 2005 prices had returned to European oil-indexed prices, which continued through summer 2005.

The 2005/06 winter turned out to be extremely difficult for some industrial consumers, particularly energy intensive industries such as fertilizer manufacture, steel, chemicals and glass. Gas prices experienced a shock in November 2005 as an unusually cold spell, combined with warnings about a potential further cold winter, pushed prices past 150 p/therm. Prices stayed high for several months fluctuating between 60 and 90 p/therm before weakening in mid February 2006 to 46 p/therm.

Things came to a head at the end of February 2006, when a fire at the Rough storage facilities caused the National Grid to issue the first ever ‘gas balancing alert’. Shortly after this, prices rose to nearly 200p/therm, only to crash back down a week later as the market was sufficiently reassured that there would be enough supply to meet demand.

**Figure 8 – Day-ahead gas prices during Phase III**



Source: Pöyry Energy Consulting. Day-ahead and month-ahead gas price as reported by Heren.

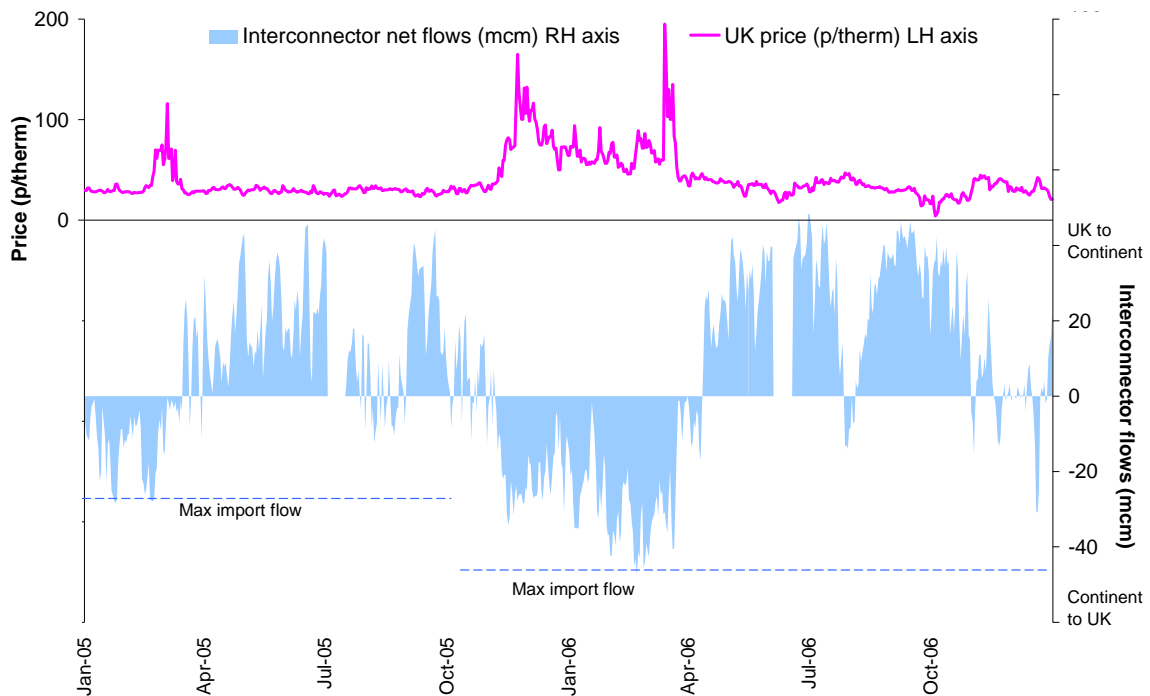
During winter 2005-6, the DTI commissioned Pöyry to carry out a study looking at the potential damage to UK industry which might result from interruption of gas supplies to the energy intensive industry sectors. Our report to the DTI is available on our website<sup>5</sup>. We found that the potential economic damage was equivalent to a value of £11/therm, that is, for each therm of gas interrupted the result is around £11 of economic damage.

A gas supply emergency<sup>6</sup> was not declared in the winter of 2005/06 but some industrial consumers 'self-interrupted': that is they decided that it was not worth manufacturing their products given their exposure to the very high wholesale prices. In some cases the industrial user was able to share some of the rewards gained by selling back their gas to their gas supplier/shipper but most could not. Demand fell and the UK saw 'demand destruction' – defined as where demand fell off the system and was not expected to return.

<sup>5</sup> Economic implications of a gas supply interruption to UK industry, ILEX, January 2006

<sup>6</sup> Where normal market rules are suspended to be replaced by a 'command and control' system to ensure that the system remains safe until the emergency is over

**Figure 9 – Interconnector flows vs. UK day ahead prices**



Source: IUK flows – Interconnector (UK) Ltd; UK gas price (day-ahead) – Heren.

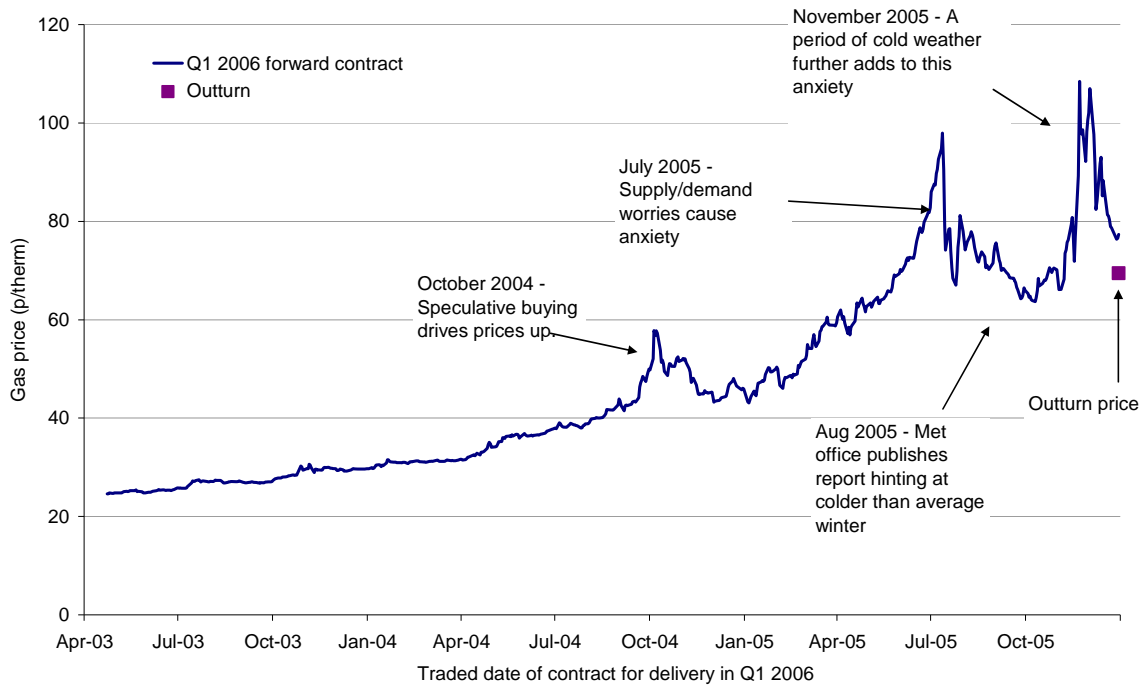
Figure 9 shows how the UK-Belgium Interconnector reacted to the spike in prices in 2005 and 2006. During the gas price spike of March 2005 the Interconnector reached full import flows. However, on 22 November 2005, although prices reached a then-record value of 165p/therm, this was not matched by the Interconnector flows which only operated at approximately 32 mcm/day rather than the new maximum of 48mcm/day. This caused significant concern for the market as it was worried that the Interconnector might not flow at maximum during the winter as Continental suppliers held onto their gas. Later in the winter the Interconnector flowed at full import rate in response to the outage at Rough in February 2006, as Continental storage gas was released to supply the UK market.

Figure 10 shows how the market has reacted over time to price of gas for Q1 2006. The winter contract was traded at 20p/therm in early 2003, and rose slowly during 2003 and 2004 almost entirely as a result of rising Brent prices (and forecasts of Brent). Worries about the impending supply-demand tightness were not reflected in market prices until well into 2005, despite a brief speculative spike in October 2004. Prices rose during 2005 faster than Brent prices were rising, suggesting that the market was beginning to react to concerns about the forthcoming winter. In August 2005 the Met Office published a report wrongly suggesting that the winter could be “among the coldest third of winters over the last fifty years”.<sup>7</sup> However, it was the knowledge of a potential gas shortfall, caused largely by a period of cold weather in November 2005, along with the potential shortfall in

<sup>7</sup> North Atlantic Oscillation Report, Met Office, August 2005

gas from the Continent via the Interconnector that caused the market to react to the potential shortfall.

**Figure 10 – The evolution of the Q1 2006 gas contract**



Source: Pöyry Energy Consulting.

### 3.3 To what extent was Phase III foreseen?

#### *Demand*

It can be seen from Figure 11, demand forecasts from 2000 until 2005 were consistently above 100bcm but the out-turn demand for the period was less than 100bcm. As a result, unexpected growth in demand was not a cause of the supply-demand tightness.

#### *Supply*

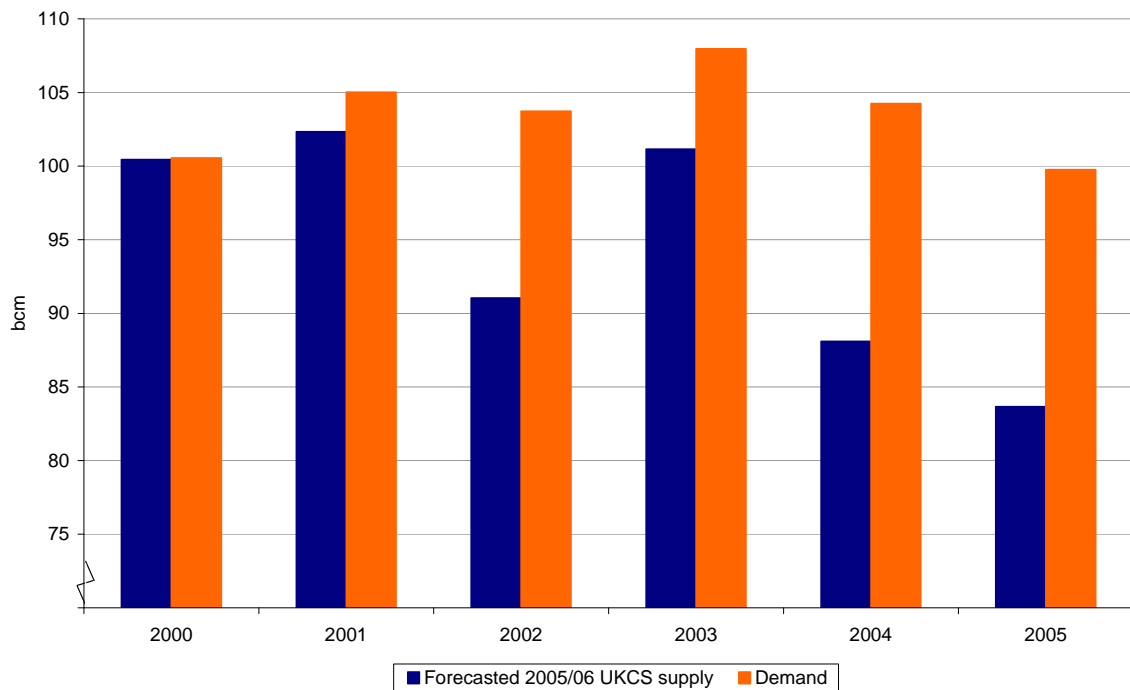
From as early as 2000<sup>8</sup> and earlier, there have been forecasts of the decline in supply from the UKCS, as shown in Figure 11. Using historical supply forecasts from the National Grid, it can be seen that whereas the first two years' forecasts for 2005/06 (2000 and 2001 respectively) were relatively optimistic, a reduction in UKCS forecasts occurred in 2002. In 2003 supply forecasts rose, only to fall even further in 2004 and 2005 than was originally predicted.

In the JESS (Joint Energy Security of Supply) reports published by the DTI, unrealistically high assumptions were used in their forecasts for UKCS outages, which had to be revised

<sup>8</sup> Gas Transportation Ten Year Statement 2000

downward as more information about the UKCS became available. In 2003, the UKCS was assumed to have an availability of 100% at times of peak, implying that all UK fields would be able to produce at full capacity at the same time and there would be no outages. In 2004 they predicted a production rate of 95% (5<sup>th</sup> JESS report, November 2004). In 2006 however this was revised even further downwards to 90% to better reflect reality (7<sup>th</sup> JESS report, December 2006).

**Figure 11 – The shifting change in UKCS supply forecast and UK demand**

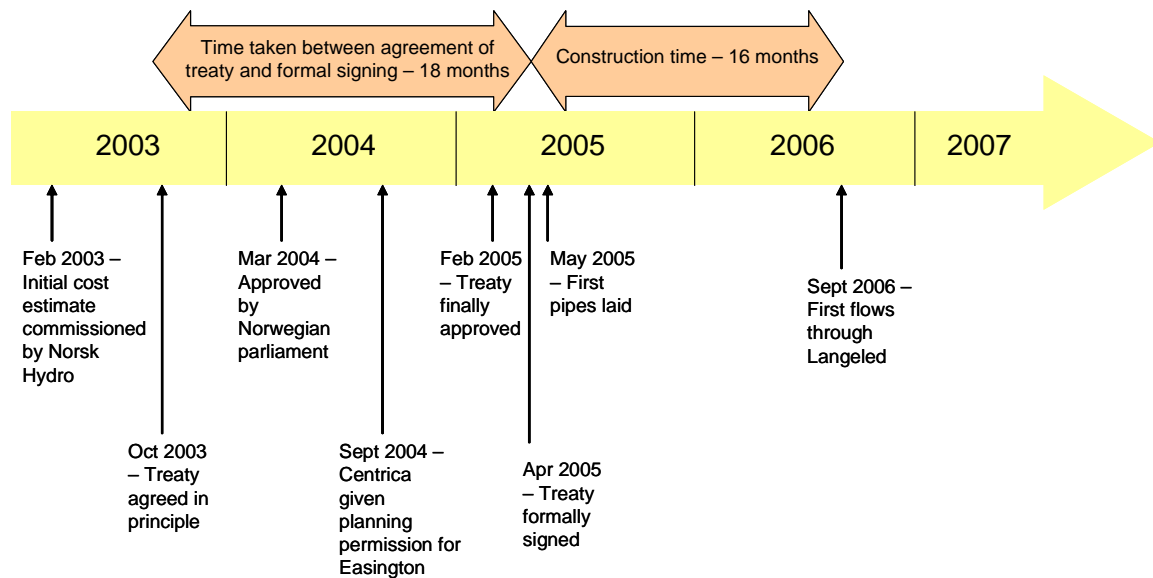


Source: Gas Transportation Ten Year Statements , National Grid.

The delay of the Langeled pipeline was also important in driving the tight supply-demand position during Phase III. With a capacity of 23bcm, the Langeled pipeline is of key importance to a market where historical supplies were declining. However, as shown in Figure 12, there were significant delays introduced by the UK government over signing of the treaty, including a setback of one year between it being signed by the Norwegians and the UK signing. This resulted in the delay of the construction of the pipeline by over a year, whereas the construction and development of the field and pipeline have proceeded to schedule.

Other investment was made as a result of this forecast depletion of the UKCS, including the BBL pipeline from the Netherlands to the UK, which began getting bids for capacity in 2002, and the Welsh LNG terminals, which applied for planning permission in 2003.

**Figure 12 – Timeline for development of Langeled**



Source: Pöyry Energy Consulting.

### 3.4 Have prices really been that volatile?

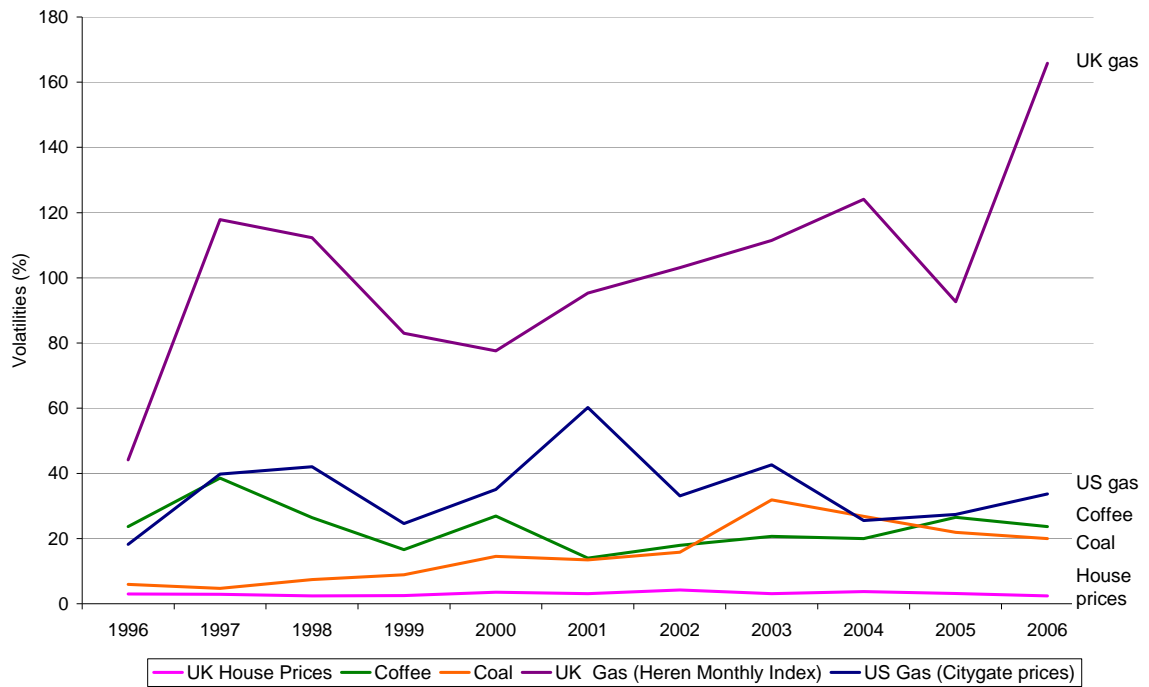
During Phase III, the volatility of gas prices increased significantly, with spikes in prices above £2/therm. This increased risk for all market participants, and many industries complained of reduced competitiveness internationally. At the same time, residential customers saw bills rise by 40%, increasing the number of those in fuel poverty by 200,000 during 2004 and 2005 alone<sup>9</sup>.

However, the price for any commodity, be it coffee or electricity, is likely to ‘go down as well as up’. So have the price spikes in the gas market been typical of commodities, or do gas prices show much higher volatility than other prices?

Figure 13 compares the volatility of a number of commodities that have monthly indices. It is clear that the volatility of gas prices (UK and US) is much greater than other commodities, such as coffee or coal or house prices, and of all the commodities listed, the UK gas is the most volatile.

<sup>9</sup> Source: energywatch quoting Dti figures. Fuel poverty defined by the Dti as a household that spends more than 10% of its income on fuel to maintain a satisfactory heating regime.

Figure 13 – Volatility of monthly traded products

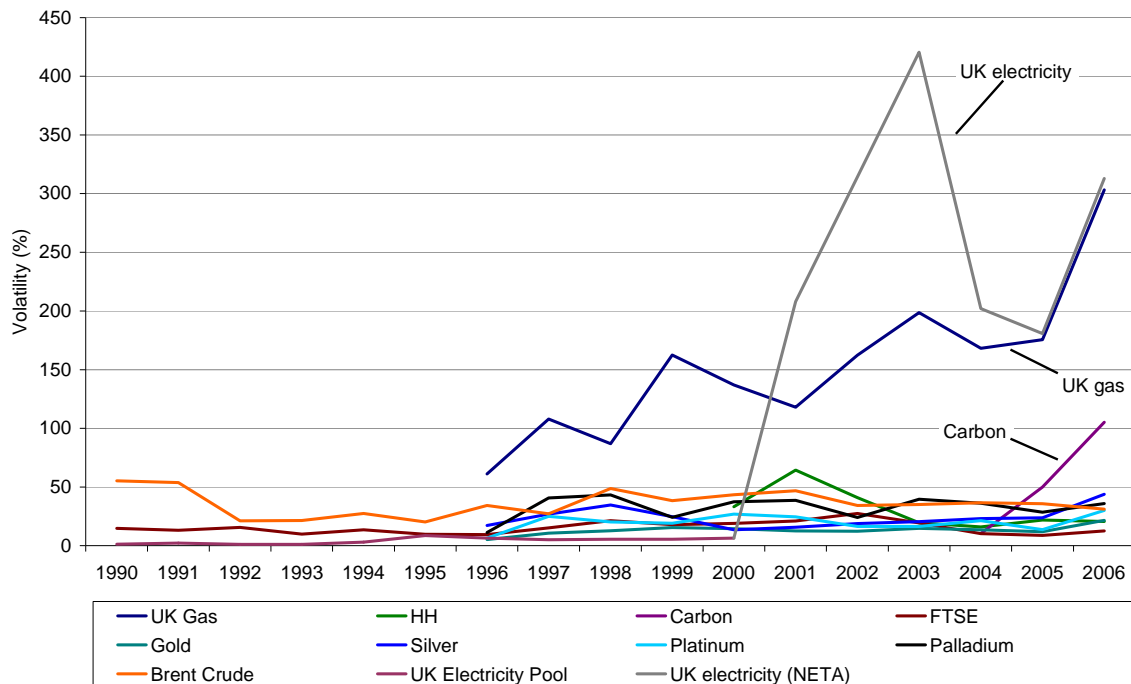


Source: ICE; Pöyry Energy Consulting.

For products that are traded daily or have daily indices, there is a similar pattern, as shown in Figure 14. Here both UK gas and electricity prices<sup>10</sup> are the most volatile, and are about 5 times more volatile than other commodities such as metals (gold, silver, platinum, palladium) or Brent crude. Theoretically, electricity should be the most volatile, partly because supply and demand have to be balanced on a second-by-second basis, resulting in occasional price spikes to bring capacity into the market, and partly because the major driver in the UK of electricity prices is the gas price due to CCGTs. The carbon market also shows high volatility during 2006 due to the drop in prices from €30/tCO<sub>2</sub> to about zero – much of this is due to the uncertainty of a very new market that is highly sensitive to uncertain political and regulatory decisions.

<sup>10</sup> As shown through NETA (New Electricity Trading Arrangements) prices

Figure 14 – Daily volatilities



Source: Pöyry Energy Consulting; various.

From this analysis there appear to be four main reasons for the volatility in UK gas prices. The first reason is the inherent annual price swing caused by demand seasonality – high demand for gas in winter and low demand in summer. This is not true for other commodities which either have flat annual demand due to industrial processes (such as metals) or flat annual consumption (coffee, for example, is consumed both in summer and in winter).

Secondly, the other commodity prices do not react so swiftly to changes in weather. Although supply for many commodities (such as coffee, wheat or corn) can be weather dependent, the sources of supply for these products are spread globally, thus reduced supply from one zone as a result of bad weather can be matched by an increase elsewhere.

Third is the geographically localised nature of the UK gas market. Most commodities are traded globally ensuring mismatches between supply and demand are smoothed. The UK gas market remains relatively local, despite some element of interconnection to the Continent. This is different from the US market where the geographic size of the market is much bigger.

Finally, is the balanced nature of supply and demand. In the US market there are much greater volumes of storage. In other commodities (apart from electricity) it is relatively cheap to store products, allowing supply and demand to be balanced. In the Brent crude market, a number of suppliers (above all Saudi Arabia) hold large volumes of excess capacity to be able to dampen down price changes if required.

As a result, it is the unique combination of factors that make UK gas prices so volatile – a seasonal demand for gas in a small geographic market, combined with a high variability in demand due to the weather and low quantities of storage.

The changing nature of the UK market as we move into Phase IV suggests that future volatility should be much lower. This is primarily due to there being much greater interconnection to the Continent, which will increase the geographic size of the 'UK' gas market. Also important is the large volume of new LNG import capacity. This means that the UK market will become part of a more global LNG market in the future – allowing supply to be diverted from the UK in summer to meet air conditioning demand in more southern countries, and back to the UK again during cold periods in winter.

### 3.5 To what extent is the forward curve helping?

The forward curve is key to the successful functioning of a commodity market as it allows players to hedge their positions and allows those with a lesser appetite for risk and reward to offload it onto those with a greater appetite.

However, there have been many concerns about the UK gas forward curve, with worries about its liquidity and reliability for trading. Therefore, given the high volatility of UK gas prices, it would be expected that the forward curve for gas would be more liquid than other commodities.

Figure 15 compares the proportion of trades for each forward month on the forward curve of Brent crude (as traded on the ICE), Henry Hub (as traded on Nymex), UK electricity (as traded on the ICE) and UK gas (traded both OTC<sup>11</sup> and on the ICE). It is clear that UK gas has the highest proportion of the curve traded forward, particularly in the OTC market.

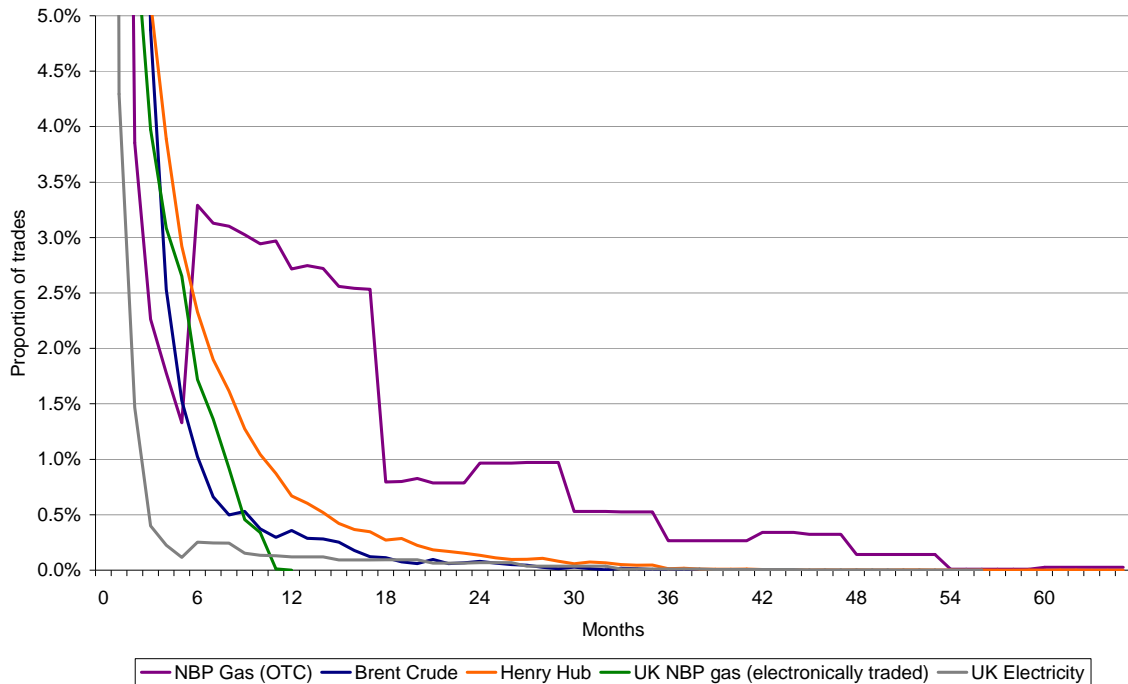
The effect of the seasonality in gas prices implies that there is a high proportion of trades still being traded six months ahead, or a season. This proportion is, however, relative – it may seem from the graph that there is a significant amount of trading going on for winter/summer ahead contracts, particularly for 6 months ahead, but in reality it is only 3.5% of trades, or 7 in 200 trades being carried out for a month ahead. The majority of trades are taking place for within-month or month-ahead contracts.

The demise of Enron has a major impact on the gas traded markets. Enron was a significant trader in its own right but there was also an impact on many other company's perception of risk. This led to increased credit control of traders with greater back office control and a decline in overall liquidity. In addition, higher prices reduce the volume which can be traded within a given credit limit.

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<sup>11</sup> Over-the-Counter

Figure 15 – Proportion of trades at each month on the forward curve in 2006



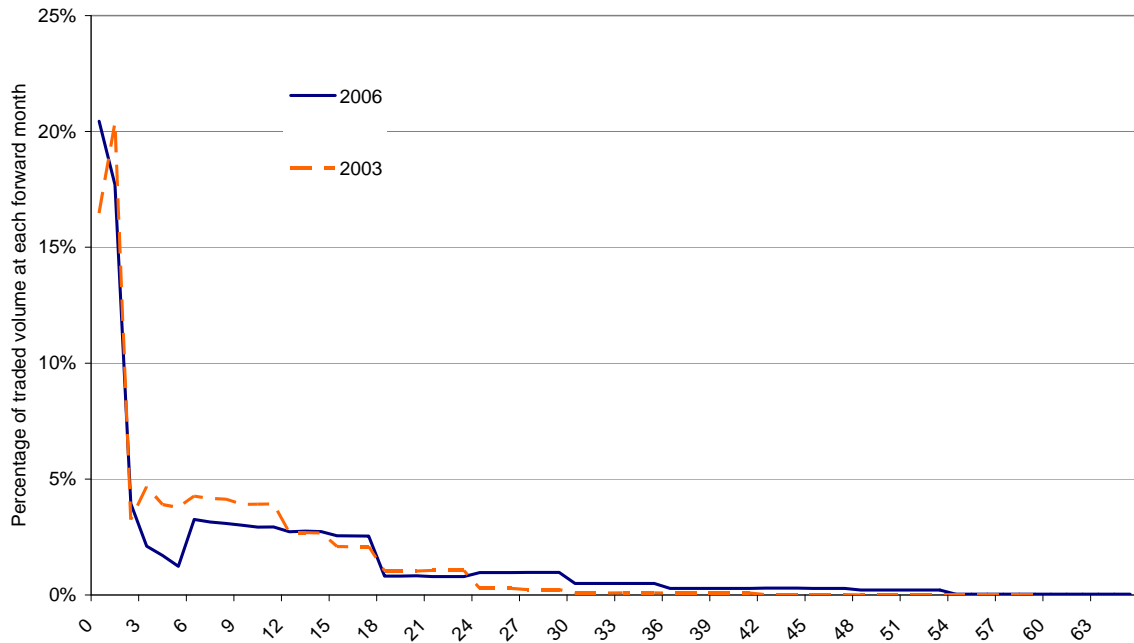
Source: Pöyry Energy Consulting, ICE and Heren. Data for all 2006.

According to our interviews (see section 5.3) the commodity market in general has recently seen the entry of large numbers of new traders, in particular banks, which are now doing much greater volumes of trades. Other anecdotal evidence suggests that the commodity market is liquid up to three years out. These interviews suggest that the increase in gas being traded for 40, 50 and in some cases 60 months in advance may be due to the large number of financial traders entering the market. The effect on the forward curve comparing 2003 and 2006, has been limited to date, as shown in Figure 16. The curve is showing a slightly lower proportion traded forward in 2006 compared to 2003, with a higher volume of within-month trades.

Markets present new risks as well as rewards. The collapse last year of Amaranth Advisors, a US hedge fund that lost \$6bn as a result of being wrong-footed by natural gas prices, is a recent reminder of the risks face companies participating in commodities markets. A recently published report by the FSA<sup>12</sup> warns banks and funds over what has been described as a ‘commodities gold rush’ – an enormous influx of capital into the commodities markets, including gas.

<sup>12</sup> ‘Growth in commodity investment: risks and challenges for commodity market participants’, FSA Markets Infrastructure Department, March 2007

**Figure 16 – Proportion of trades on the UK gas OTC forward curve (2003 vs 2006)**



Source: Pöyry analysis of Heren data.

### 3.6 Conclusion

Phase III ‘supply margin squeeze’ has seen a sudden transformation of the UK market. The concerns about sufficient supply to meet winter demand had a dramatic effect on prices, sending them almost as high as 200p/therm. Much of the information to suggest impending tightness, including forecasts of the decline of the UKCS, was available in the public domain four or five years before the tightness was experienced. This caused new pipelines (notably Langeled) to enter the planning process, but this process took longer than expected, with delays introduced by the UK government over signing a key treaty. Also the decline in the UKCS was somewhat faster than forecasts had indicated, compounded by problems with long-term forecasting of deliverability, bringing the date forward when new capacity was required.

The evolution of Phase III suggest that the forward curve reacted late to the prospect of a tight supply-demand balance, whereas market participants began planning new capacity much earlier. In many ways this reflects the short-term nature of the forward markets, which tend to project the current world forwards, with most trading in the short-term rather than further out. The market also underestimated how high prices would have to go to balance supply and demand, partly because of a lack of historical references in a market that is a little over 10 years old.

There can be no doubt that the volatility of UK gas prices has increased, and so is much higher overall than most other commodities, whether metals, oil or agricultural produce. However, the factors that make gas prices so volatile could be changing as we enter Phase IV. In particular the greater interconnection to the Continent, which will increase the geographic size of the ‘UK’ gas market, and the large volume of new LNG import capacity which means that the UK market will become part of a more global LNG market in the future.

We could also see a product that is more heavily traded, as a result of a large number of new players entering the market. This could also occur as a result of increased trading opportunities within Europe and through the LNG market. Ultimately, the more trading that occurs, the more competitive a market will become and the more likely prices will delink from oil, a subject discussed in detail in the next section. Nevertheless, it appears unlikely that the forward curve will ever be particularly liquid in the medium-term, as even the market for Brent crude (the largest commodity market) remains dominated by short-term trading.

## 4. FUTURE PHASE IV: 'CAPACITY EXCESS' – WHAT COULD THE WORLD LOOK LIKE?

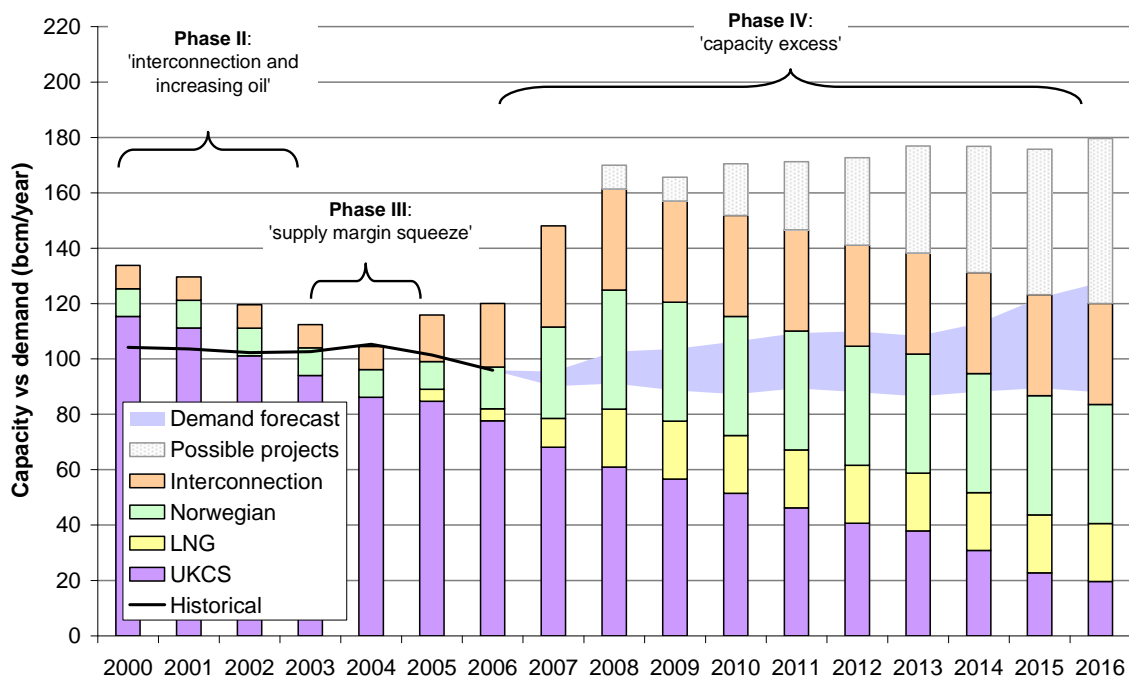
### 4.1 What suggests we are entering a new Phase IV?

#### *The cornucopia of capacity*

There are a number of key facts that suggest we are entering a new phase for the UK market and that we are moving, or have already moved, from Phase III 'supply margin squeeze' to a new Phase IV of 'capacity excess'.

Firstly, there is the sheer amount of new capacity that is already online or due to come on in the forthcoming years, as shown in Figure 17. The LNG import facility at the Isle of Grain, owned by National Grid, became operational during summer 2005 with 4.4bcm of capacity. October 2006 saw the opening of the Langeled pipeline, bringing in gas from Norway, through a pipeline that eventually will see up to 23 bcm/year of gas from the giant Ormen Lange field. In addition to this, the BBL interconnector, linking the UK to the Netherlands, started delivering gas to the UK in December, with a capacity of 14 bcm. These were in addition to the expansion of the UK-Belgium interconnector in November 2005 from 8bcm to 16bcm and again in October 2006, raising its import capacity to 23bcm.

**Figure 17 – Demand compared to available capacity**



Source: Pöry Energy Consulting

Added to these projects, a number are due to come on-line in the next year. At Milford Haven in Wales there are two LNG projects underway – Dragon and South Hook. Dragon will supply 6 bcm/yr of Egyptian LNG to the UK by Q3 2007 and is being financed

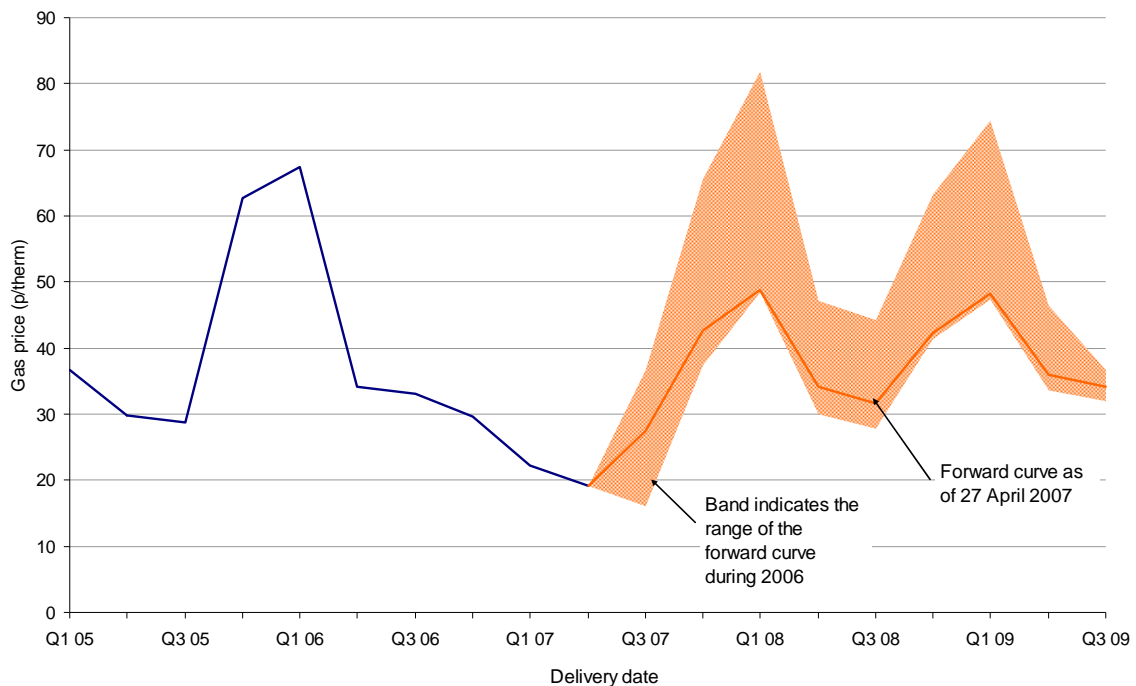
by BG, Petronas and 4Gas. South Hook is the largest of the current LNG projects and will have a capacity of 10.5bcm/yr in Q1 2008. The project is part of the Qatargas II LNG in which ExxonMobil and Qatar Petroleum are the major shareholders. There is also a second phase of Isle of Grain for 8.6bcm/yr in late 2008.

There are a number of other LNG projects currently being considered for the UK, including a third phase of the Isle of Grain for 7bcm, a second phase of the South Hook project which would add a further 10.5bcm/yr in 2010 and a second phase to the Dragon LNG terminal, taking its capacity to 12bcm. Also there are proposals for further projects such as those at Canvey Island, Amlwch, Coryton and offshore in Morecambe Bay.

**The reaction of market prices**

A further reason to expect a shift in the market has been the reaction of market prices over the last 6 months, as shown in Figure 18. The view of the market (as expressed through the forward curve) has shifted enormously in a year, from predicting prices for Q1 08 at over 80p/therm to around 40p/therm by March 2006.

**Figure 18 – Forward curve volatility**

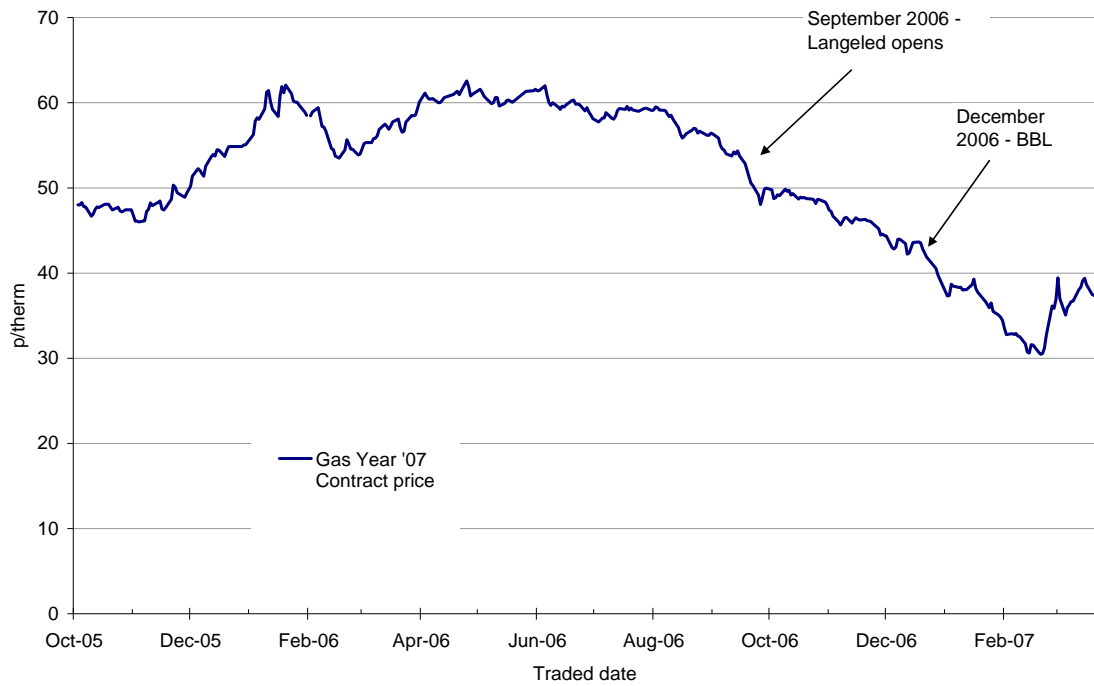


Source: Pöry Energy Consulting. Historical prices are quarterly average of UK NBP day-ahead prices from Heren.

There have been two main drivers of this shift in prices.

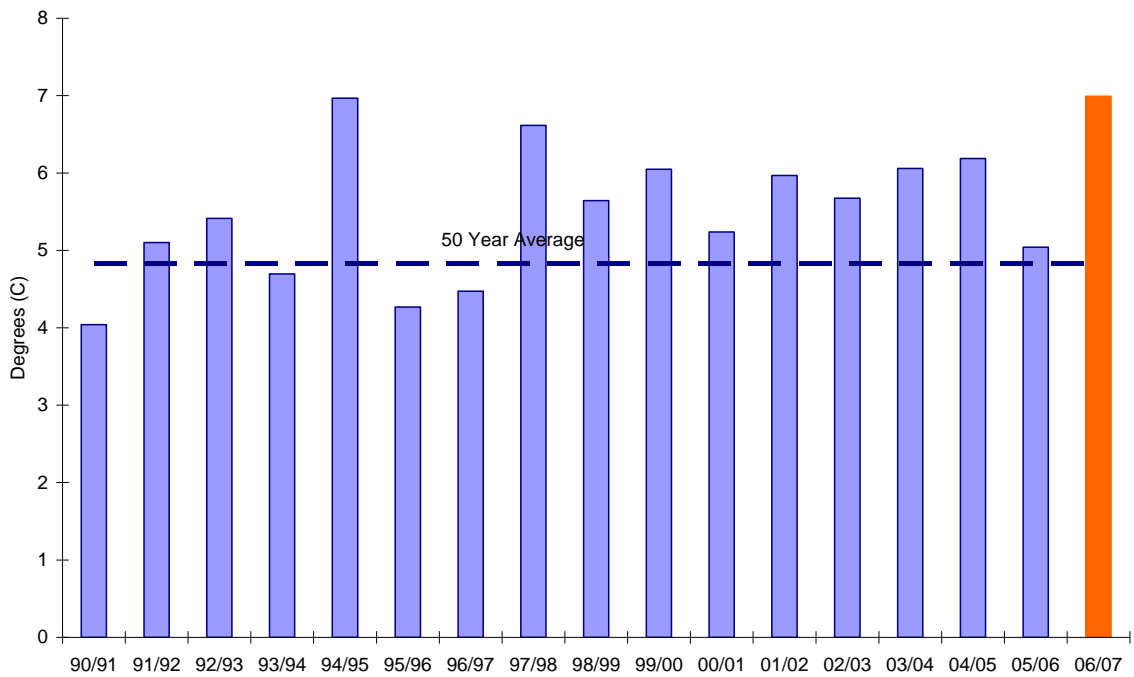
The first has been the commissioning and successful testing of the BBL and Langeled pipelines. Although both projects have been on schedule, it was not until both began flowing gas that the market was sufficiently reassured to begin to reduce the winter risk premium.

**Figure 19 – The effect of commissioning BBL and Langeded on Gas Year '07 price**



Source: Pöyry Energy Consulting.

**Figure 20 – UK average winter temperatures**

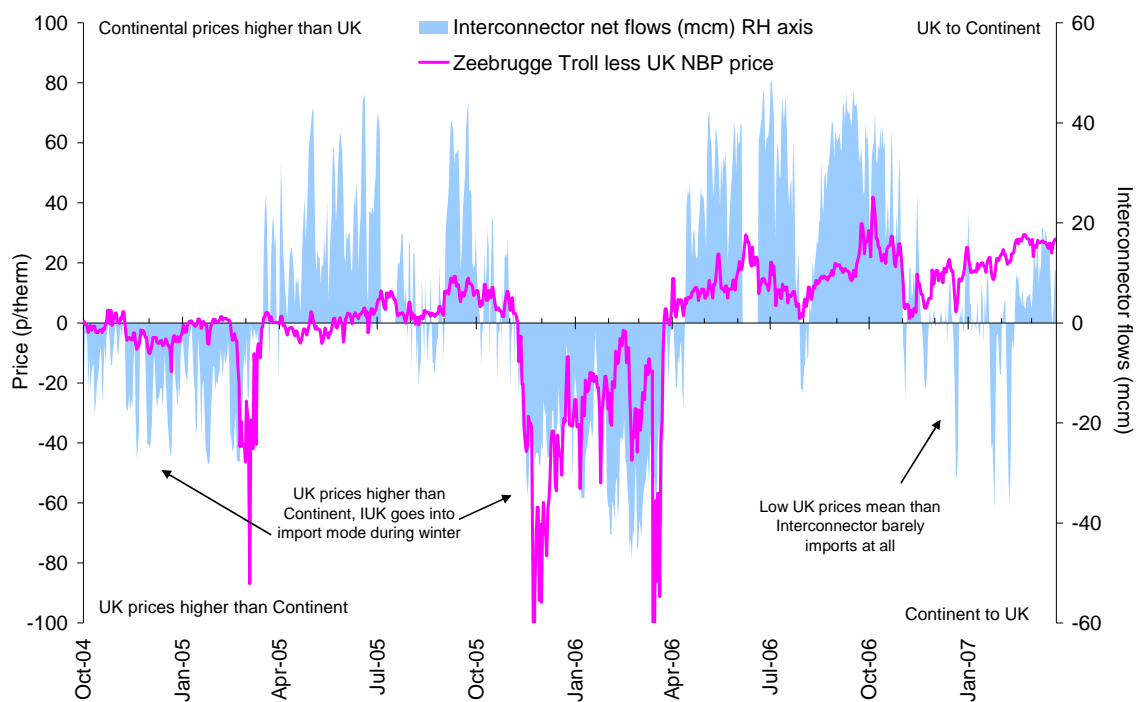


Source: The Met Office; average winter temperature for year defined as average daily temperature in Central England (CET) for November, December, January and February. Analysis: Pöyry Energy Consulting.

The second driver has been the second mildest winter on record. Figure 20 shows winter temperatures over the last 17 years (November, December January and February) with temperatures during 2006 on average 45% warmer than the 50 year historical average. However, temperatures across Europe have also been at record highs during the winter, leading to significantly suppressed demand both in the UK and on the Continent.

The net effect has been that long-term contracts, which are typically oil-indexed but with minimum take-or-pay restrictions, have been reduced so that they supply the minimum possible. Even at these lower volumes, there has been an excess of gas, meaning that despite very low UK prices, which are significantly less than oil-indexed contract prices, the Interconnector has not been exporting gas to the Continent, but rather flipping between import and export modes. In addition, the BBL pipeline has been transporting gas to the UK, against the natural price ‘pressure’, due to a long-term contract.

**Figure 21 – Interconnector flows and price differential between UK and Continent**



Source: IUK; Zeebrugge troll price from Heren EGM, UK NBP price Heren day-ahead.

## 4.2 What could Phase IV look like?

Pöyry has modelled four future scenarios in an attempt to capture a range of possible outcomes during a future Phase IV. These include the continued indexation of gas to oil prices and the impact of ending this link; as well as the potential for oversupply to cause the gas price to collapse and suppress production from the UKCS; and, finally the potential for worldwide competition for LNG to push up UK prices.

These scenarios expose some interesting potential features of Phase IV.

- Could the UK become a European LNG hub?
- Could gas prices remain sub-10p/therm for over a year?
- Will UK prices become linked to the US?

## 4.3 Capacity excess: oil-indexed versus de-linked gas prices

### 4.3.1 Oil-gas linkage

The linkage between gas prices and oil prices ('oil-gas indexation') has its roots back in the 1960s in the Netherlands, when the principle behind valuing and pricing gas in Europe was established as gas was first introduced as a substitute fuel, mainly for oil products such as HSFO, LSFO and gasoil<sup>13</sup>. Clearly, with no traded market in gas at that stage, valuing a product for both buyers and sellers was difficult. Comparing the price of gas with competing fuels offered both buyers and sellers a gas price that followed other markets (especially oil) that they were comfortable with, and gave a clear and simple price with hedging opportunities available through the liquid oil markets. Above all, it meant that buyers would have reduced risk switching fuels as the price of gas would reflect the fuel they were previously using. Subsequently as gas from various sources – Norway, Russia and Algeria – was introduced more widely into Europe the same principle was generally followed.

As a result, most of the long-term contracts that supply gas to European (although not UK) markets price the gas in a way that links it to competing fuels – above all oil and oil-products, as oil-products tend to be the main alternative fuel to gas for heating<sup>14</sup>.

In economic theory, there is a band of prices within which actual prices should fall. The bottom of the band is the long-run marginal cost (LRMC) – this is the cost which reflects the entire costs of getting gas to market, including construction, financing, operation and a reasonable return. A price below this would see supply companies making lower than expected returns, and therefore would be unlikely to be sustained in the long-term. The top of the band is set by the opportunity cost<sup>15</sup> – in this case the cost of competing fuels. A price above this would cause a consumer to switch fuels, therefore lowering demand and reducing prices back into the band again. In a perfectly competitive market with plenty of gas supply, prices should tend towards the long-run marginal cost, as consumers are able to switch between competing gas price offers and hence drive down prices. In a less competitive market or one where limited supplies are available, the only option for consumers is to switch supply from gas to other fuels, and as a result gas suppliers can price toward the opportunity cost.

This is shown in Figure 22, where the opportunity cost has been based on switching to oil products as represented by Continental long-term contracts, and the long-run marginal cost rises from 10-20p/therm from 1996 to 2015 with more expensive gas coming into the UK (an illustrative assumption). Historically, UK prices have been at the bottom of this band, but rose to the top during 2003 and 2004, with prices during 2006 being above the band a result of the tight supply-demand balance.

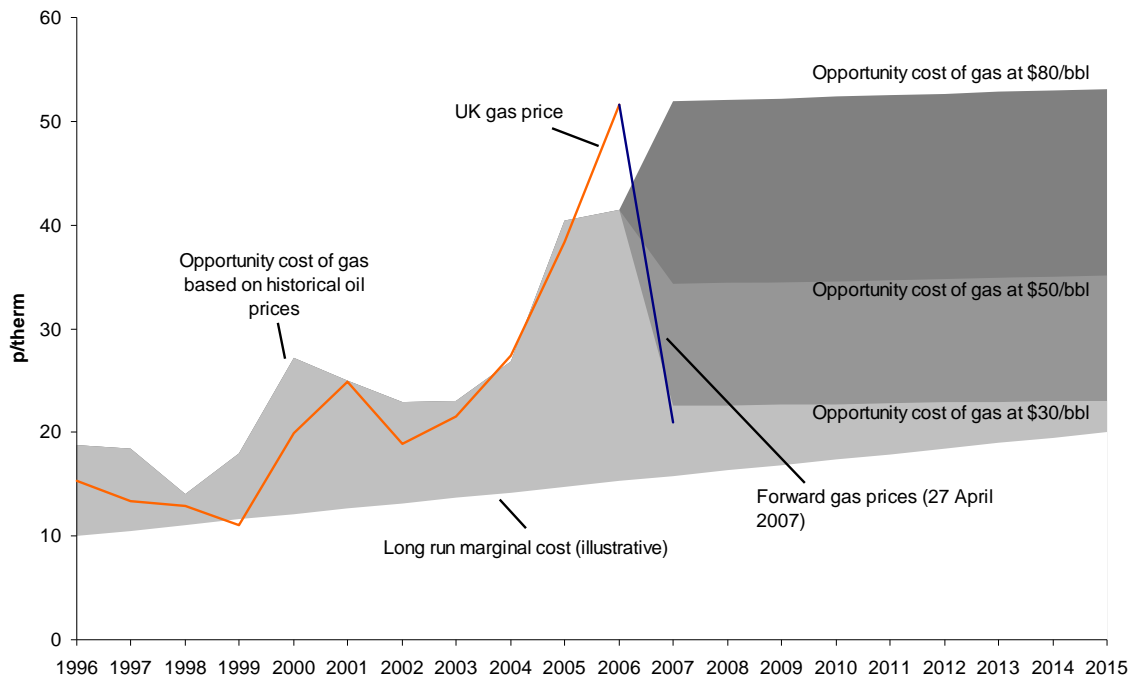
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<sup>13</sup> HSFO and LSFO are High Sulphur Fuel Oil and Low Sulphur Fuel Oil – both types of heavy fuel oil. Gas oil is much lighter and similar to diesel

<sup>14</sup> Of the 500 long-term contracts examined by the European Commission representing 400bcm of gas, over two-thirds had indexation to oil or oil-products (DG Competition report on energy sector inquiry, 10 January 2007)

<sup>15</sup> Opportunity cost is defined as the cost of something in terms of an opportunity foregone, or the most valuable forgone alternative.

Figure 22 – Illustration of long-run marginal cost and opportunity cost of gas



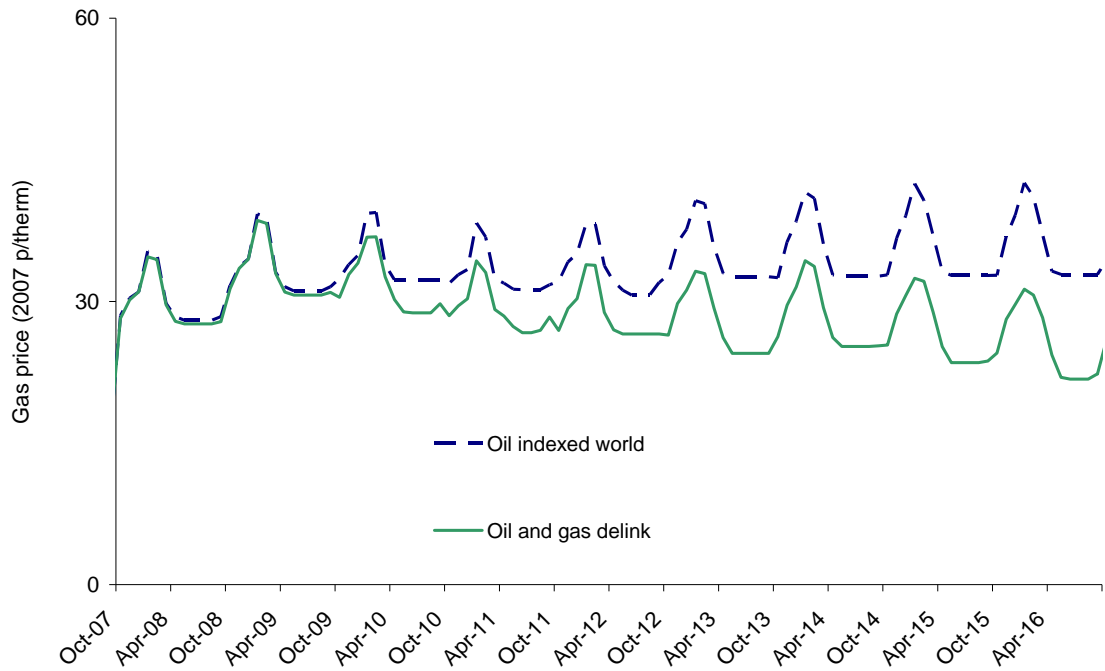
Source: Pöyry Energy Consulting. Historical gas prices are nominal.

### 4.3.2 Oil-indexed and de-linked scenarios

The two scenarios in Figure 23 explore how the effect of a delink between oil and gas prices could influence gas prices for Phase IV. In the ‘oil-indexed’ scenario, we assume that oil prices remain at \$50/bbl (2007 real) and pipeline gas prices in Europe remain indexed to oil price (a ‘business as usual’ assumption). As a result, prices in the UK drop slightly in 2007 and 2008 as a result of high capacity, but return in the medium-term to oil-indexation in a similar manner to Phase II.

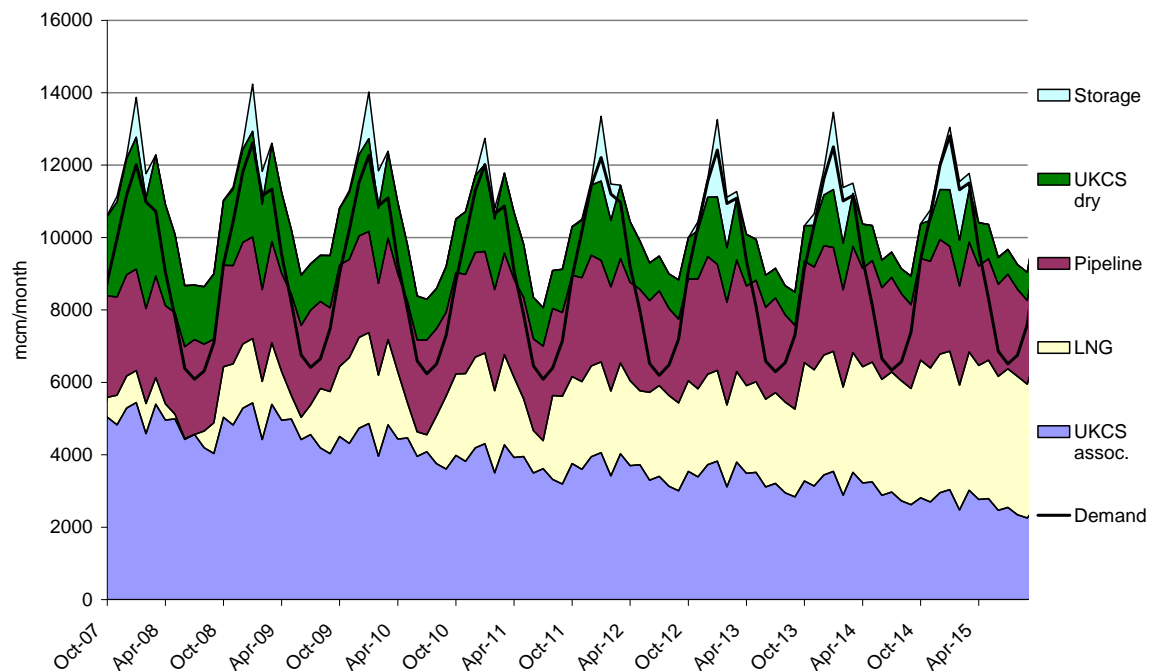
In the ‘delinked’ scenario we assume that European gas prices gradually de-link from oil price over the next three years. This could occur for a number of reasons. Firstly, long-term contracts could be rebased (‘reopened’), potentially to a non-oil-indexed measure. This could also begin to occur as a result of liberalisation pressure from the European Commission. It could be possible that high prices throughout Europe lead to more capacity and lower demand, shifting the balance of power from suppliers to consumers. A final possibility is that the UK oversupply leads to large exports of gas from the UK into Europe, and that leads to downwards pressure on prices. Figure 23 shows the corresponding price projections. A de-linking from oil price (which is maintained at \$50/barrel real throughout all scenarios) reduces gas prices by about 25% as prices move from opportunity cost towards long-run marginal cost.

**Figure 23 – ‘Oil-indexed’ versus ‘de-linked’ gas price scenario**



Source: Pöyry Energy Consulting. Assumes oil at \$50/bbl (real 2007).

**Figure 24 – ‘Oil-indexed’, LNG base-load scenario, UK gas supply-demand**

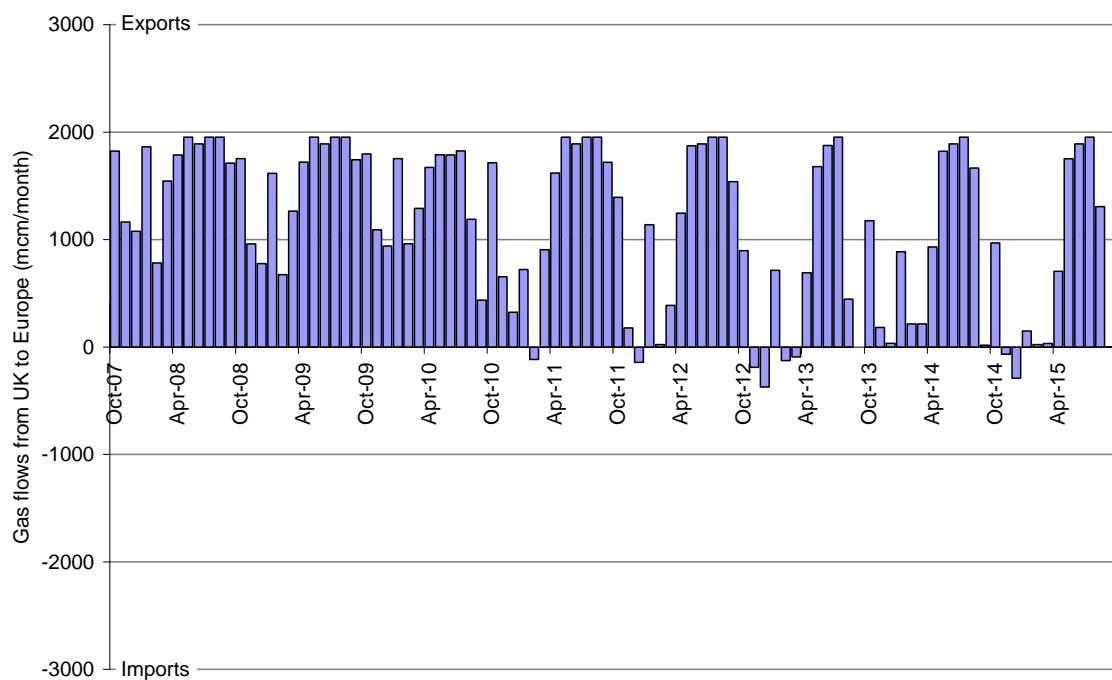


Source: Pöyry Energy Consulting . UKCS has been split into associated (gas production with oil) and dry gas (gas only).

For the ‘oil-indexed’ scenario, LNG remains competitive with pipeline gas from Europe and is able to undercut it, causing it to base-load throughout the year (see Figure 24). Under these conditions the UK transforms into an ‘LNG hub’ and the Interconnector operates in export mode at most times of the year (see Figure 25).

This picture of the UK becoming a hub for the whole of Europe is an interesting development. Pöry’s analysis of the UK market incorporates developments on the Continent, which have an increasing influence during the period of Phase IV and further in to the future. The capacity of interconnection between the UK and the Continent has reached levels which have linked the markets to such an extent that the size of the Continental market can now dampen effects in the UK – like the export of excess LNG - or alternatively magnify them – like the recent mild weather and ‘gas bubble’.

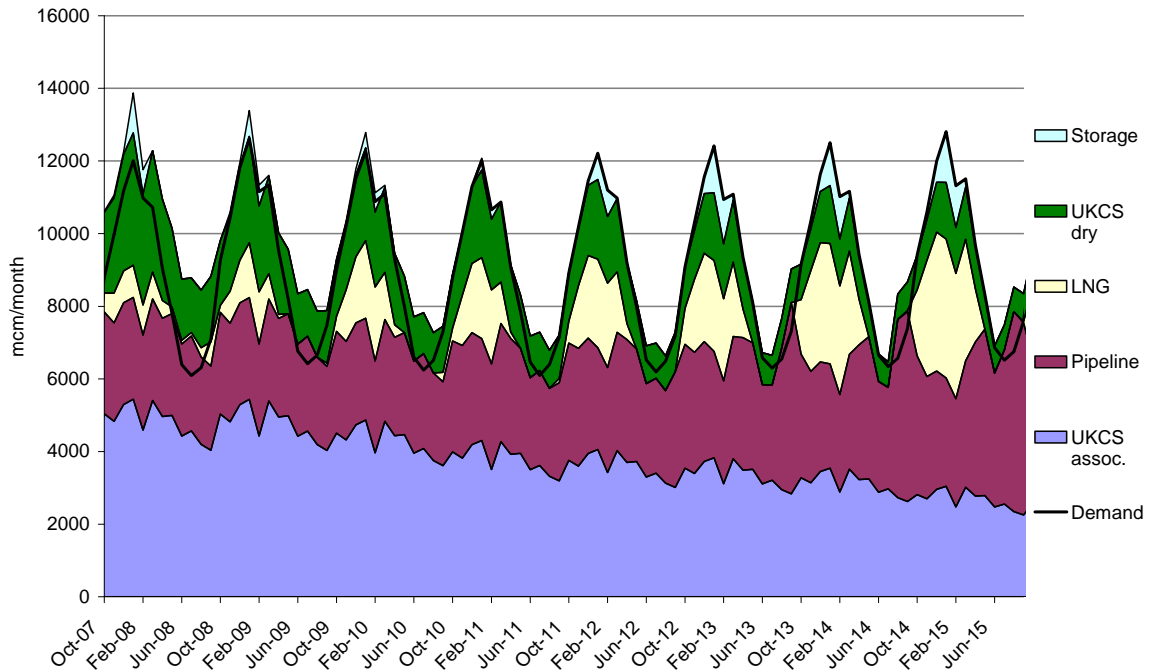
**Figure 25 – Interconnector + BBL flows in ‘oil-indexed’ (LNG baseload) scenario**



Source: Pöry Energy Consulting.

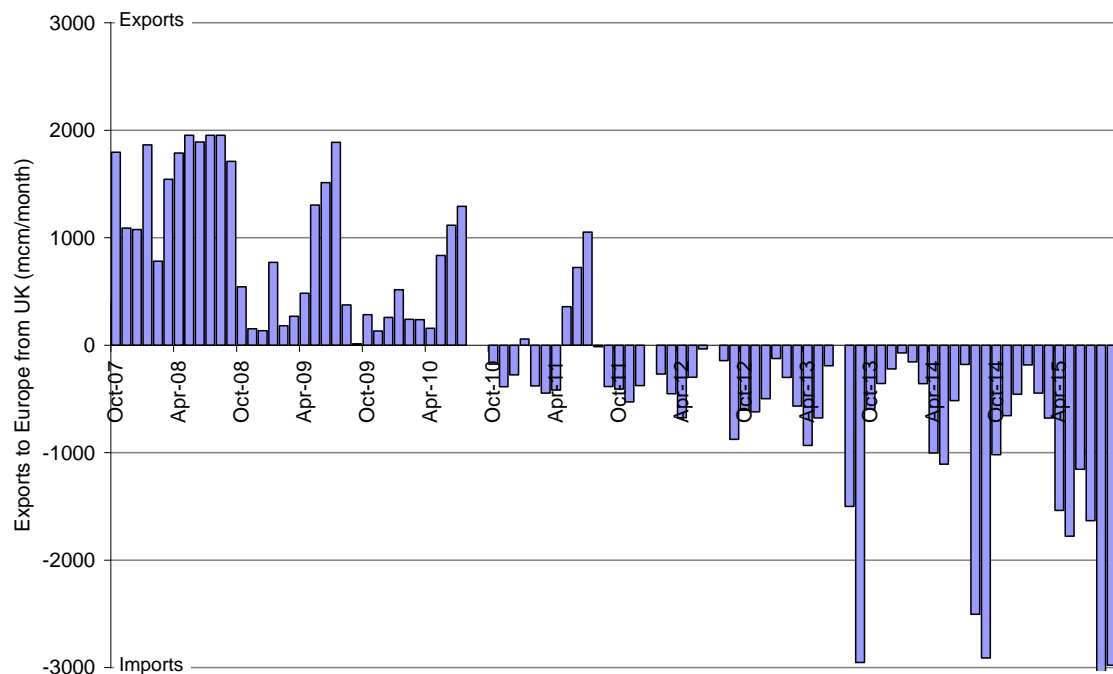
In contrast to the ‘oil-indexed’ scenario, under the ‘de-link’ scenario pipeline gas undercuts LNG and LNG ceases to baseload, and operates at a load factor of about 50%. Figure 26 and Figure 27 show the UK supply-demand picture under these conditions, and the greatly reduced exports to the Continent, which are restricted to the summer months until 2012 when the Interconnector remains in import mode.

Figure 26 – ‘De-linked’ scenario, LNG peaking scenario, UK gas supply-demand



Source: Pöyry Energy Consulting. UKCS has been split into associated (gas production with oil) and dry gas (gas only).

Figure 27 – Interconnector + BBL flows in the ‘delink’ (LNG peaking) scenario



Source: Pöyry Energy Consulting.

### 4.4 Capacity excess: price collapse

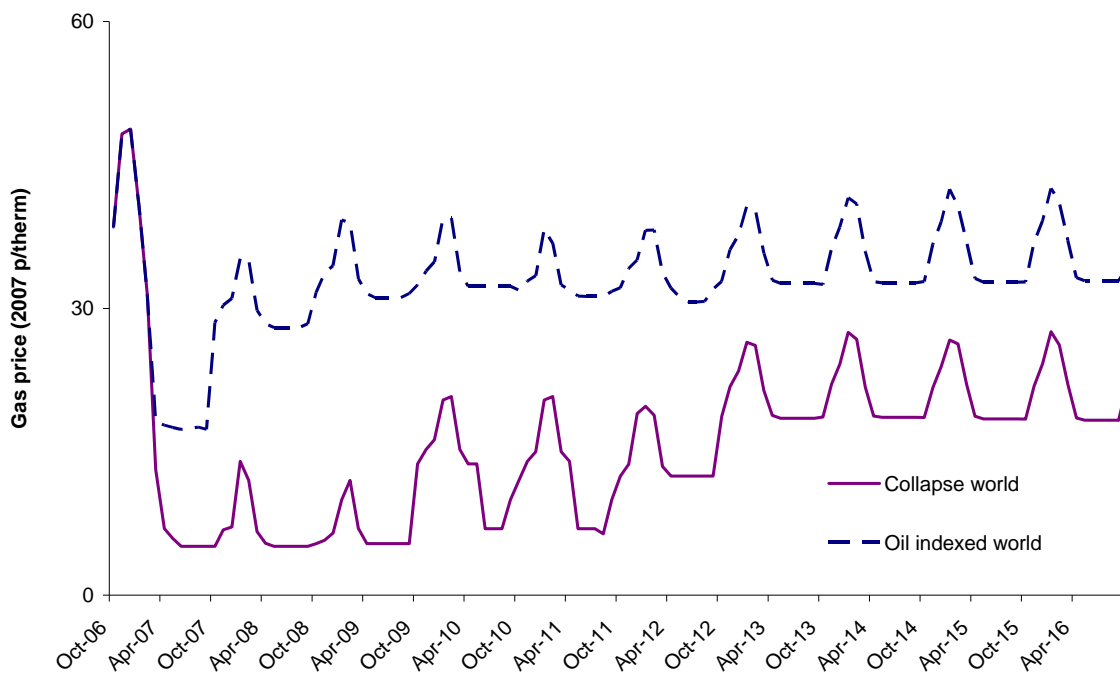
With Continental gas prices significantly above the long-run marginal cost for a period of time due to high oil prices, companies are making high profits. In a typical market, a period of high prices and high profits will be followed by one of much lower prices, as significant investment brings on new capacity and causes prices to drop.

In the UK market we have seen some of this pattern occur already, as the very high prices during Phase III have caused the movement toward the Phase IV ‘capacity excess’ scenario. The question is how low could prices go?

Our ‘price collapse’ scenario includes a reduction in UK demand lasting a couple of years, caused by a further two warm winters, which combined with an oversupply situation in the UK drives an immediate de-linking of gas prices from oil. Figure 28 shows the recent history of the gas price falls and the price collapse scenario, alongside the projected oil-indexed gas prices. The impact is dramatic, causing prices to remain sub-10p/therm nearly continuously for 2 years, before a gradual recovery as demand picks up.

In reality, we might not expect to see gas demand drop as far as indicated, as CCGTs would run baseload, significantly increasing gas demand. Furthermore, the influence of long-term oil-indexed contracts in market pricing is likely to persist more than this scenario suggests. Alternatively, a period of cold weather could quickly reset the market back towards the ‘oil-indexed’ scenario as demand rises and the gas excess caused by take-or-pay contracts reduces.

**Figure 28 – Price collapse scenario versus oil-indexed price projection**

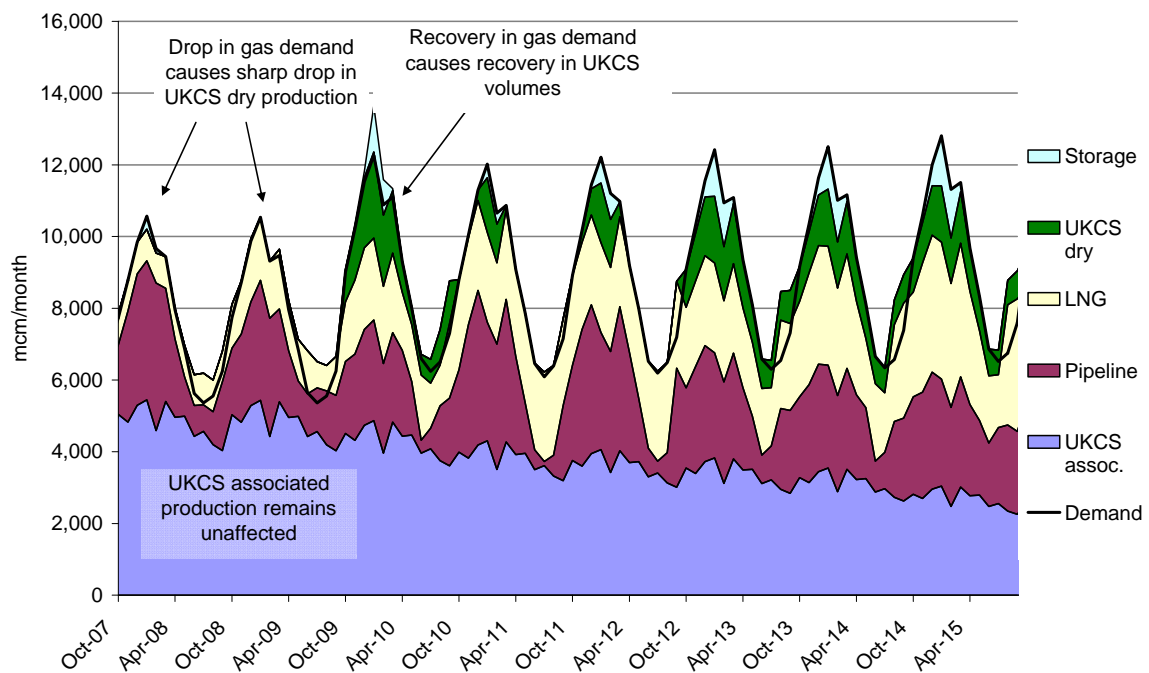


Source: Pöyry Energy Consulting. Assumes oil at \$50/bbl (real 2007).

### 4.5 Capacity excess: UKCS squeeze

Our analysis showed that increased imports do little to suppress production from the UKCS, as the excess is simply exported through the Interconnector. However, the low demand and low prices seen in the collapse scenario do have an impact on UKCS production. Figure 29 shows how UKCS production is suppressed under the collapse scenario until October 2012, when prices start to recover. This is because of the combination of take-or-pay on long-term contracts (which prevent reductions in flow rates), along with associated gas (which flows based on the oil price rather than the gas price), forces the dry UKCS gas to be turned down.

**Figure 29 – Collapse scenario, UK gas supply-demand**



Source: Pöyry Energy Consulting. UKCS has been split into associated (gas production with oil) and dry gas (gas only).

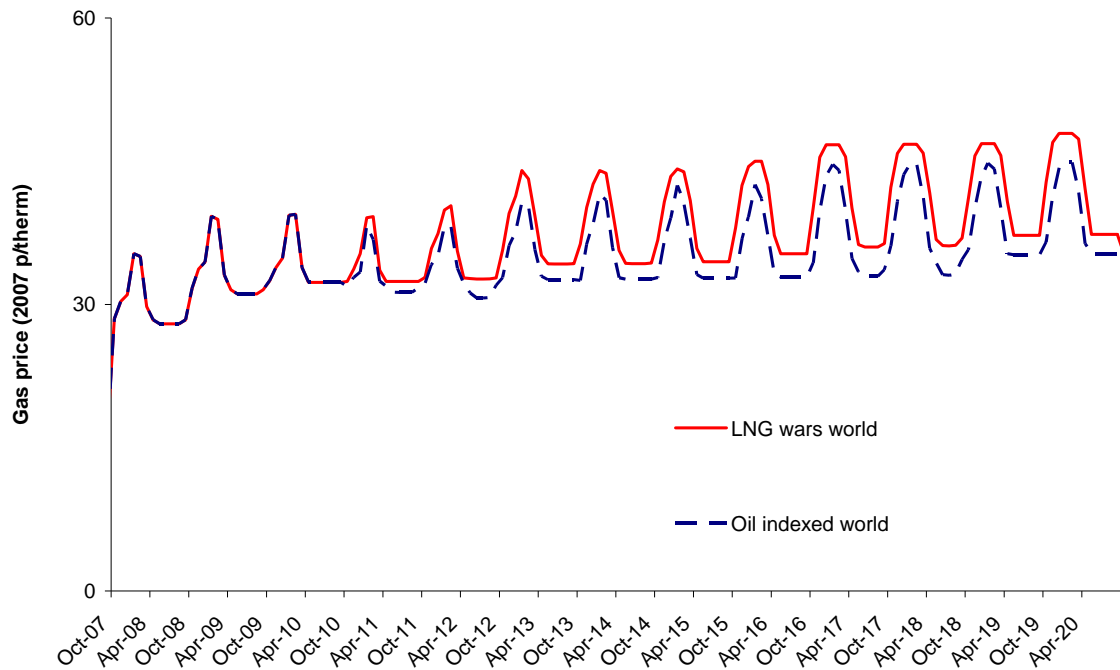
### 4.6 Capacity excess: LNG wars

During Phase IV, the UK is due to have at least 20bcm (about 20% of UK annual demand) of new LNG terminal capacity built, probably somewhat more. The Atlantic basin LNG market could begin to exert influence on prices in other markets, as cargoes are diverted between the UK, the US, North-West Europe, Spain and Italy. Furthermore, the global LNG market could also begin to have an effect, as cargoes from the Middle East are diverted to the Pacific basin to supply Japan, India or Chinese demand for gas.

In our ‘LNG wars’ scenario, we assume that 25% of available liquefaction capacity for the Atlantic basin is diverted to Asia, reducing the volume of cargoes available for the Atlantic basin market. However, this has a minimal impact on the UK market, as there are sufficient supplies from other sources to supply gas demand in the UK without affecting price.

If we assume a doubling of the US gas price in the LNG wars scenario, reflecting the possibility of serious disruption to the US market, caused by hurricanes and further competition for gas, this leads to UK prices rising by about 8%, as shown in Figure 30. Firstly, the competition for LNG links the UK and US markets, and then the UK feels the effect of high US prices. The effect remains muted due to the capacity available in the UK – when LNG becomes too expensive, other sources of gas are used instead.

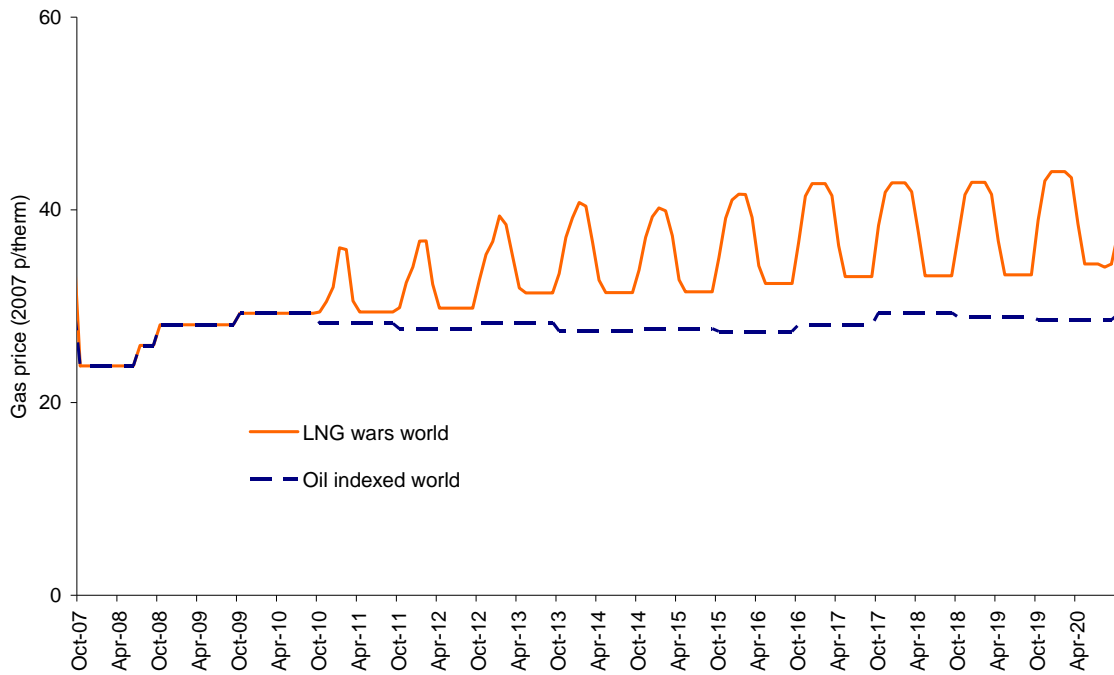
**Figure 30 – LNG wars scenario versus oil-indexed price projection**



Source: Pöyry Energy Consulting. Assumes oil at \$50/bbl (real 2007).

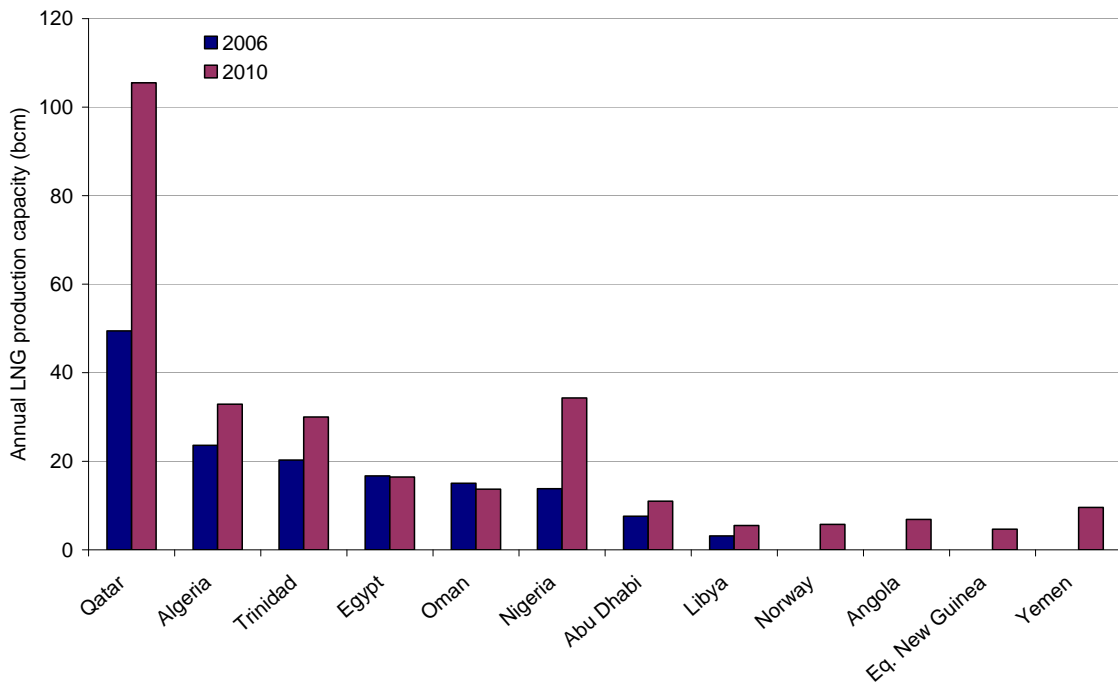
The effect on other countries is much more dramatic. The Spanish gas market in particular is heavily affected by the worldwide LNG market as over 60% of supply can come from LNG. Figure 31 shows Spanish prices as a result of the ‘LNG wars’ scenario. A market that was previously dominated by long-term contracts with minimal seasonality as a result of strong counter-seasonal CCGT load is made highly seasonal as a result of having to compete for LNG with the US and Asia.

**Figure 31 – Spanish gas prices in the ‘oil-indexed’ and ‘LNG wars’ worlds**



Source: Pöyry Energy Consulting. Assumes oil at \$50/bbl (real 2007).

**Figure 32 – LNG production in 2006 and 2010**



Source: Pöyry Energy Consulting.

Due to its global nature, LNG could be sourced from around the world, although most of the LNG supply for Europe is likely to come from Atlantic basin countries and the Middle East, rather than the Pacific. This is due to the high cost of shipping liquefied gas across the globe.

Figure 32 shows current and forecast LNG liquefaction capacities for Middle East and Atlantic basin countries. Qatar currently produces the most LNG, and it is set to double this in the next four years. Other countries are set to increase production, with Norway, Equatorial New Guinea and Yemen joining the list of LNG producing nations in the next few years.

Of the new LNG terminals in the UK, Isle of Grain, with 4.4bcm of capacity, will probably deliver mostly Algerian LNG due to its co-ownership by Sonatrach, although BP (who own the other half of Phase I) may source gas from various locations. Dragon LNG, with a capacity of 6bcm, has a long-term supply contract between Petronas and Centrica, delivering Egyptian LNG. The South Hook project (10bcm) has been designed to receive gas from Qatar, with Qatar Petroleum owning 70% of the project.

## 4.7 High oil

The price of Brent has been a significant factor in the UK market since the beginning of Phase II with the connection of the UK to the Continent. Brent prices have been volatile in the recent past, with Brent prices peaking in August 2006 at \$78/bbl, having been as low as \$10/bbl in 1999.

Long-term gas contracts, as mentioned above, tend to be indexed to oil (Brent) and oil-products (gasoil, LSFO and HSFO), and the underlying formulas in many of the North-West European long-term contracts tend to be similar. Also, oil products have historically shown a strong link with Brent crude. As a result, a Brent crude forecast can be translated into an approximate gas price in these long-term contracts.

There is a complicating factor, however, due to the influence of exchange rates. Most long-term contracts take the price of oil in euros to obtain a gas price in euros. Since oil is priced in US dollars, the exchange rate influences the gas price. This is important since the Euro-US dollar exchange rate has swung from 0.85 US dollars per Euro in 2000 to about 1.30 currently, an increase of 50%.

Assuming that exchange rates between the dollar and the Euro remained at 1.33 dollars per Euro and the dollar and the pound remain at around 2 dollars per pound, an oil price of \$80/bbl would mean a gas price of about €27/MWh or 50p/therm. With an oil price of \$100/bbl, gas prices would be €33/MWh or 61p/therm. This can be compared to the average price in 2004 of 33p/therm, and 2006 of 45p/therm.

On a typical investment, with a LRMC of about 20-25p/therm, an oil price at \$100/bbl would imply an extra 35-40p/therm in profit. However, it is important to note that periods of high returns counterbalance periods when prices are low.

The outcome depends fundamentally on the nature of the market. In a fully liberalised market where new entrants are free to enter, we might expect substantial amounts of new capacity to be built. However, the barriers to entry in this market are large. Any new capacity could be pipelines, marginal fields and above all LNG liquefaction plants and new regasification terminals. As a result there could be a flood of new gas into the market, which would undercut the old oil-indexed contracts. This ought to lead to a drop in prices as more new supply is available, and there could be a shift in power from a seller's

to a buyer's market. This outcome is in many ways what we have seen in the UK market in the last few years, leading to the transition to Phase IV.

This in turn could lead to price-reopener clauses being triggered in the older contracts, leading them to be re-priced downwards.

However, throughout Europe in general, market entry is more difficult than in the UK, with incumbents able to prevent access to new markets. Also it is possible that owing to global demand for gas that it proves difficult to bring extra gas into the European market – supply is not free to expand as it would be in the 'liberalised' economic model. As a result, an alternative outcome would be a continuation of the oil-indexation scenario (ie 'business as usual'), but more extreme. Gas would be imported into the UK, especially LNG which would be able to make very high returns at those prices, and then flow out. In the UK market prices would remain high as they would remain indexed to oil, although summer prices would drop well below the oil-indexed price as the Interconnector was full.

A further effect would be in demand destruction. Just as we have seen in the UK the permanent loss of demand as a result of high gas prices due to tight supply-demand, a similar effect would be seen on the Continent. Electricity prices would rise in many countries due to the high cost of gas for generation. Coal plant (despite the cost of carbon permits under the EU ETS) might become the favoured source of generation, along with nuclear, which at those gas prices would be competitive. Gas would not penetrate further into the domestic market, which would remain dominated by electrical heating, and higher energy prices might drive continued improvements in insulation. There would be further impetus to develop renewables, which although remaining expensive, would become increasingly comparable – particularly onshore wind.

## 4.8 Conclusions

It is difficult to assess how Phase IV could evolve or indeed the likelihood of any specific scenario coming about. However, we have illustrated a series of possible 'worlds' that could evolve, as shown in Figure 33 on an annual basis.

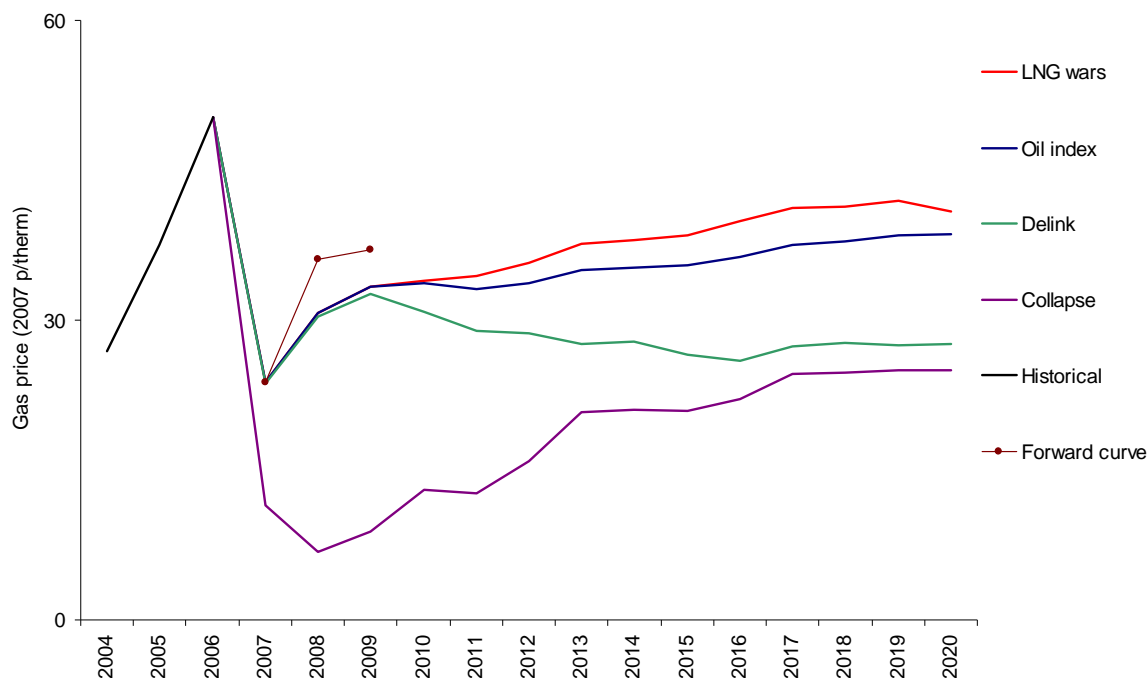
The 'oil-indexed' scenario, which in many ways is a return to Phase III, is the closest to the current forward curve. Nevertheless, if we are entering a new Phase, history would indicate that there is a potential for a sudden shift in gas pricing. Given the significant amount of investment that is occurring, the excess capacity in the UK, competition introduced by LNG, and the potential for the UK to become a gas hub, a plausible outcome could be the 'delink' scenario, with the excess UK gas exported to Europe providing a market impetus, combined with a continued drive from Brussels that provides a regulatory framework to liberalise markets and increase competition.

However, given the current low prices that the market is experiencing, a continuation of warm winters combined with a gas glut could create the situation for a price collapse back to prices seen in Phase I. Something that we have not modelled here, but equally probable, would be a series of cold winters. This could test the new UK infrastructure and would show how LNG would flow in such a scenario. However, a return to the high prices of Phase III is unlikely due to the significant excess of capacity that exists.

Of course, the UK market is now beginning to become part of a global LNG market, with the ability to divert cargoes originally destined for the UK to the US or Asia, and vice versa. Our modelling suggests that the effect of these cargo diversions is unlikely to have a significant impact in the medium-term, both due to the size of the combined UK/European market and due to the excess capacity. However, the combination of high

global demand for LNG and individual markets (such as the US) dragging gas into them could impact the UK price.

**Figure 33 – Annual prices for Phase IV**



Source: Pöyry Energy Consulting. Assumes oil at \$50/bbl (real 2007). Forward curve on 27 April 2007.

Of the Phase IV worlds investigated, Pöyry is of the opinion that oil-indexation remains the most likely outcome, although the likelihood of prices being lower than this is much greater than in the past. Despite the large capacity excess in Phase IV, the combination of significant interconnection to the Continent (where oil-indexation is dominant), worldwide LNG trade (where most contracts remain oil-indexed) and the strong market instinct to look to the oil markets for guidance suggests that a return to ‘normal’ weather would be accompanied by a return to a ‘normal’ oil-indexed world. Another factor in preventing a move to full gas-on-gas competition is the lack of liquid wholesale markets capable of trading out years into the future. Our observations of how other commodity markets also lack forward liquidity is important since, if gas continues to behave as other commodities, the long term ambitions of the Commission may need revising. The Commission place great faith on liquid wholesale markets as a driver of both liberalised energy markets and of investment decisions.

These future Phase IV worlds have all assumed an oil price forecast of \$50/bbl (2007 money). With Brent having peaked at \$78 in August 2006, it remains possible that a much higher Brent price could drag up Continental gas prices. This would create an intriguing prospect – the high returns possible from supplying gas to Europe ought to create a climate that encourages significant investment, leading to an oversupply situation made worse by suppressed demand from those self-same high oil price. This situation would have all the characteristics for a delink of gas prices from oil prices and a collapse in gas price. Whether it could occur would depend on whether investment is permitted to happen, and whether European markets remain closed to competition.

## 5. FUTURE PHASE V – ‘INVESTMENT VS DEMAND’

### 5.1 Introduction

The gas world that emerges for phase IV could be any one of those discussed in the previous section. However, how the market evolves after the ‘capacity excess’ of Phase IV will be determined by one of two major influences: the extent to which gas demand grows, and the amount of investment in new gas infrastructure.

Gas demand growth is highly uncertain looking 10 to 15 years into the future, as the main area of growth, power generation, is facing a significant number of challenges – renewing and replacing existing generation with gas-fired, coal-fired or (in the longer-term) nuclear plant. This is combined with the fuel price relativity of gas and coal plant, the extent to which a price for carbon influences the running of plant (and the generation mix) along with the impact of ‘eco-friendly’ measures such as renewables and demand reduction. We believe that the electricity generating sector is facing a challenge that is greater now than ever before in deciding what type of new generation capacity to build. This higher uncertainty and risk in electricity generation feeds through to the gas industry in its evaluation of how to invest to meet the highly uncertain future gas demand.

Investment is key to contributing to the supply-demand balance, with an excess potentially leading to oversupply, and underinvestment leading to a tighter supply-demand position. The mix of investment is also important, as the underlying market that emerges as a result of significant new pipeline infrastructure will be very different from one where large quantities of LNG regasification come on stream.

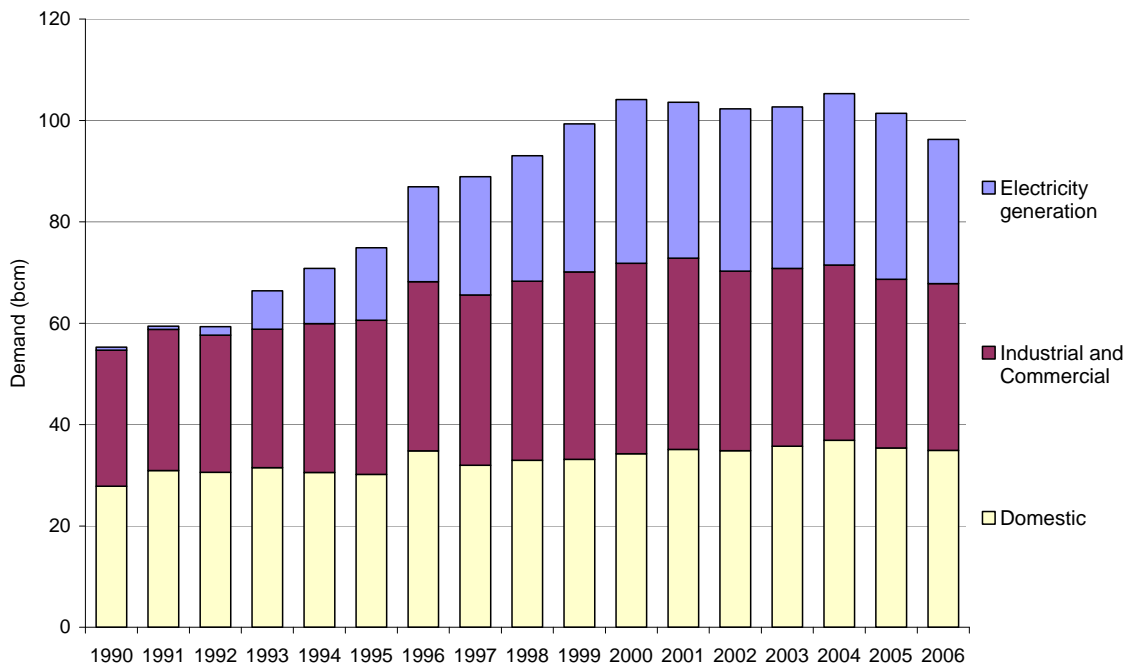
This section investigates both the future long-term potential for demand growth, and how the supply of gas to the UK will be influenced by the investment decisions made by participants, many of which will be influenced by events happening in the next few years.

### 5.2 How could demand growth impact future Phase V?

As shown in Figure 34, gas demand growth in the UK has been driven primarily by the electricity generation sector, with annual growth of 4.3% from 1996 to 2006, compared to no growth in the domestic sector and slightly falling industrial and commercial (I&C) demand growth. Electricity generation has risen from 1% of the gas demand in 1990 to 30% by 2006 as a result of 20GW of CCGT capacity installed (about 25% of the UK total).

In the residential sector where demand is primarily for space heating (ie central heating), the stable gas demand has been the result of increasing house build offset by improving efficiency and a series of warm winters. In the I&C sector, gas demand has been falling slightly owing to reduction in energy intensive industries combined with a smaller manufacturing sector and outsourcing.

**Figure 34 – Historical growth of gas demand in the UK**



Source: DTI. 2006 data estimate based on first 3 quarters.

In the future, the main driver of demand growth will be the electricity generation sector. This is firstly because the electricity sector is the one most sensitive to gas prices and the price of gas compared to other fuels. Whilst homeowners or businesses are typically unable to switch between fuels to meet their energy needs, companies can switch generation from coal to gas plant within their portfolio to meet electricity demand, or the market as a whole can switch. As a result, future gas demand will be sensitive to the price relationship between coal and gas.

Furthermore, much coal-fired plant is likely to have to be retired in the near future, which will lead to new-build of CCGTs, again pushing up gas demand.

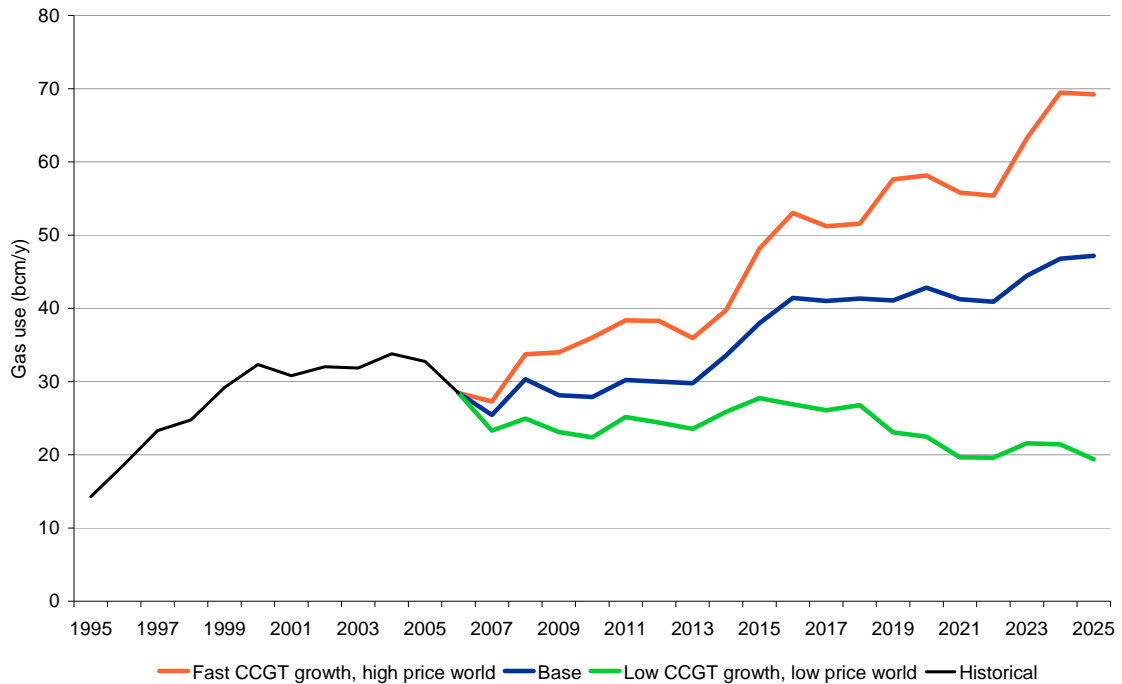
Finally, environmental constraints or legislation, such as restrictions on emissions of sulphur and the effect of the EU ETS (EU Emissions Trading Scheme) to reduce emissions of CO<sub>2</sub>, will also influence the generation mix.

This section explores the range within which gas demand could grow in the future, focusing particularly on the effects of the electricity generation sector.

**5.2.1 CCGT new build**

The range of gas demand as a result of CCGT new build is quite considerable, as shown in Figure 35. This shows three scenarios, internally consistent, that describe the evolution of the UK electricity market.

Figure 35 – Gas demand from power generation in high and low worlds



Source: Pöyry Energy Consulting. Note high price, low price refer to electricity prices, not gas prices. Note that the base case does not represent a 'Central' view.

There are certain features that are common to all scenarios – in particular the effect of the LCPD (Large Combustion Plant Directive) which causes a number of coal-fired plant to be retired in 2015 (including Cockerhale, Tilbury, Kingsnorth and Ferrybridge) and be replaced by gas. This causes a sharp rise in gas consumption at this time.

The base case view assumes \$50/bbl oil, €20/tCO<sub>2</sub><sup>16</sup> and CCGTs as the new build of choice. This leads to gas demand for power generation growing by 35% to 37bcm by 2015 and 66% to 47bcm by 2025.

The fast CCGT growth, high electricity price world assumes that significant build of new CCGTs is required. This is due to higher electricity prices and faster electricity demand growth. The combination of more CCGTs and a high carbon price of €30/tCO<sub>2</sub> mean that gas demand for electricity generation grows to 48bcm by 2015 and 69bcm by 2025.

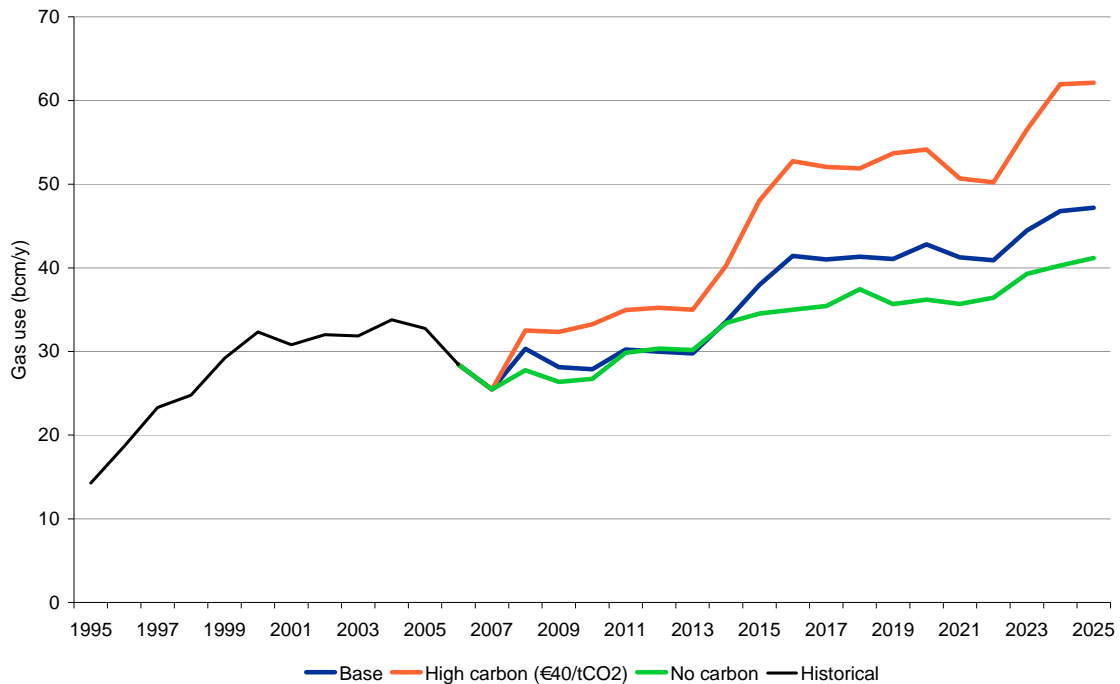
The low CCGT growth, low electricity price world assumes that electricity prices, and electricity demand growth are both low (and hence the amount of new build of CCGTs). This is combined with a low carbon price which leads to increased running of coal plant. Thus, gas demand for electricity generation drops by 2% by 2015 and by 30% by 2025, on 2006.

<sup>16</sup> All 2007 real

### 5.2.2 Carbon and the EU ETS

The EU ETS is another major potential driver of gas demand. Assuming that all other factors remain unchanged in the UK market from our Base case, Figure 36 shows how the carbon price that emerges from the ETS can affect the gas demand.

**Figure 36 – Gas demand from power generation and the EU ETS**



Source: Pöyry Energy Consulting. Note that the base case does not represent a 'Central' view.

In the base case, with carbon at €20/tCO<sub>2</sub>, coal is cheaper than gas during the winter and shoulder months, but this is reversed during the summer period due to the seasonality of gas prices. As a result, coal plant runs at baseload for much of the year, with gas running preferentially during the summer

With a high carbon price of €40/tCO<sub>2</sub>, coal plant is heavily disadvantaged compared to gas CCGTs, as their emissions are around 2.5 times greater for each unit of electricity produced. As a result, it becomes much cheaper to run gas plant rather than coal, and gas displaces coal in the merit order for much of the year. This leads to a further 10 bcm of gas burn in 2015 and 15bcm by 2025 compared to the base case.

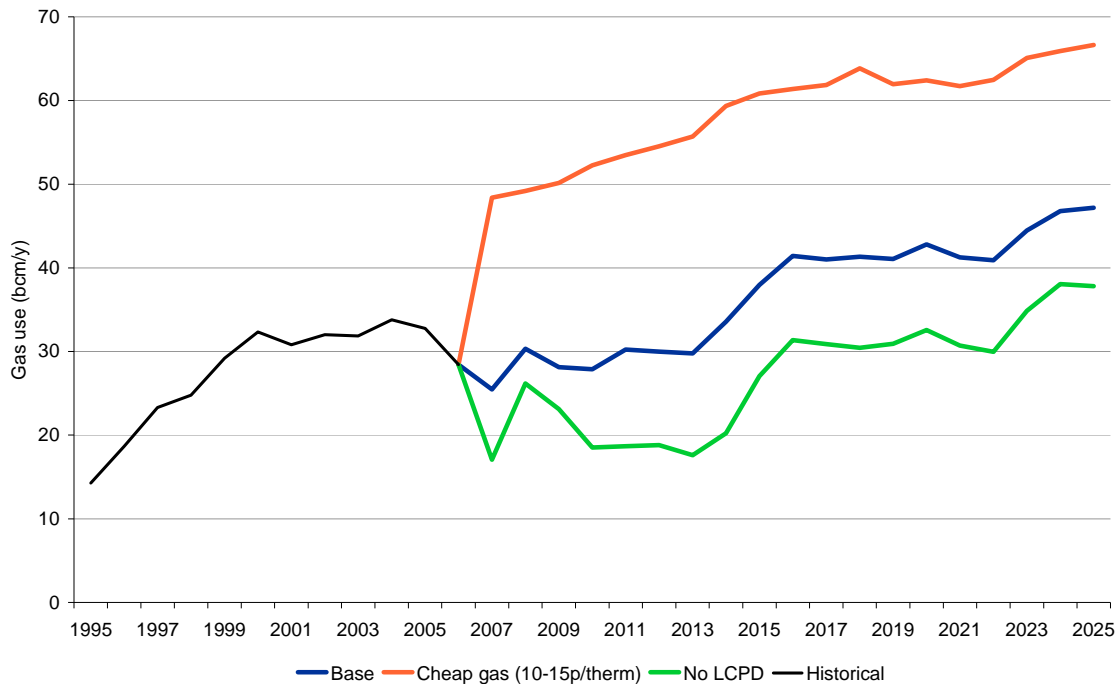
With no carbon price, coal becomes much cheaper than gas to run. However, the effect is muted as coal is already running at baseload for much of the year, and hence does not displace gas plant much more than already. Gas demand is reduced by only 3bcm in 2015 and by 6bcm in 2025 compared to the base case.

It should be noted that the effect of carbon is highly dependent on the relativity between coal and gas. Depending on the relativity in the base case, the effect of a changing carbon price can be quite significant, or almost non-existent.

### 5.2.3 Other factors

There are a number of other factors that contribute to gas demand in the power sector. Figure 37 shows two additional scenarios, chosen to highlight the extremes that may occur in gas prices and the effect of environmental legislation (the LCPD).

**Figure 37 – Gas demand forecasts from a ‘Cheap Gas’ and ‘No LCPD’ scenarios**



Source: Pöyry Energy Consulting. Note that the base case does not represent a ‘Central’ view.

In the ‘Cheap Gas’ scenario, we have assumed a world where the price of gas has fallen to 10-15 p/therm, effectively a return to the Phase I ‘oversupplied liberalised island’ world. This causes it to undercut coal plant, allowing it to become a base-loading rather than a mid-merit fuel. Thus gas would run ahead of coal for all of the year, as was the case during the 1990s. This leads to a very significant jump in gas demand for power generation, from 28bcm to 48bcm in 2007. By 2015, gas demand is 32bcm higher than in 2006.

In the ‘No LCPD’ scenario, we have modelled the impact of removing the LCPD (Large Combustion Plant Directive) on gas demand. The LCPD limits generation from plant with high sulphur dioxide emissions, in particular coal plant that does not have FGD (flue gas desulphurisation). As a result, it restricts the use of coal plant and forces much of it to be retired by 2015. The base case scenario included the LCPD which constrained the building and generation of coal plants. If the LCPD were to be removed, coal plants are no longer limited in their output, and are therefore able to operate at a higher load factor, displacing CCGTs. This causes a decrease in gas demand (as can be seen in 2007, where demand slumps by 30%).

In both scenarios we have assumed that low gas prices and high gas demand can co-exist.

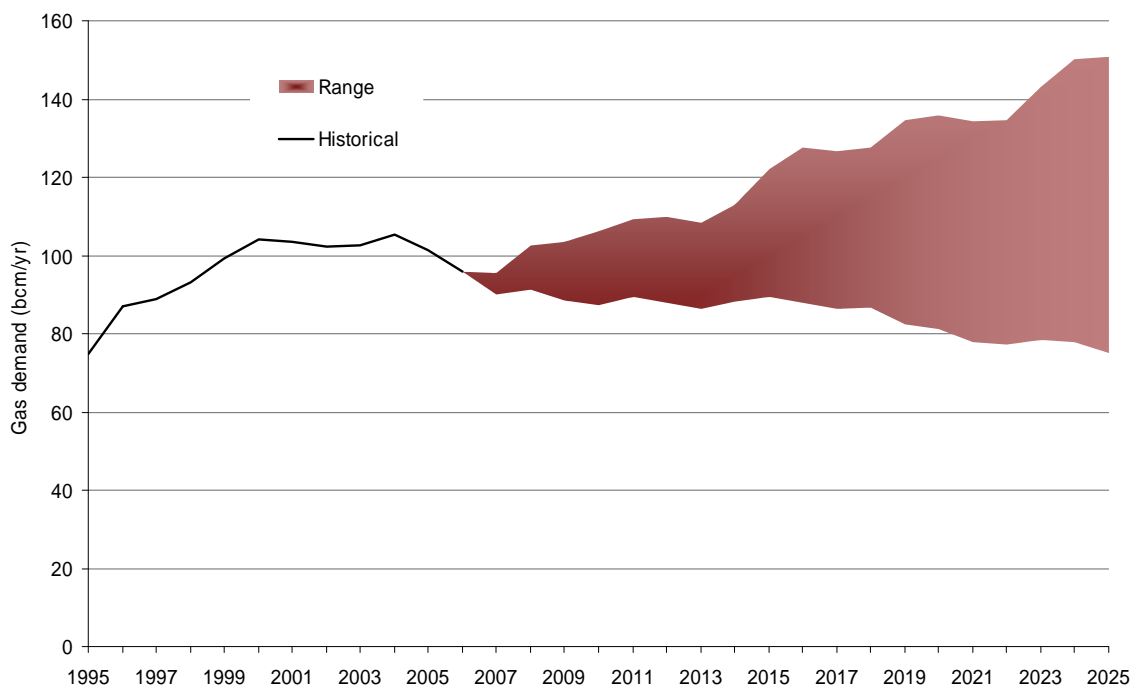
### 5.2.4 Conclusion

It is clear from the previous analysis that there is considerable uncertainty surrounding the electricity sector as regards gas demand, resulting from the myriad of variables and uncertainties involved.

With respect to gas demand for the UK as a whole, there are also uncertainties for the I&C and residential sectors: the effects of prices, building regulations and insulation, warmer winters and improvements in boiler efficiency, to name a few. We estimate that this will give a range of gas demand growth at between +/-1% each year.

If we combine the power sector demand forecasts for the High and Low scenarios with forecasts of the I&C and residential sectors, as shown in Figure 38, we end up with a band that varies between 75bcm and 150bcm by 2025.

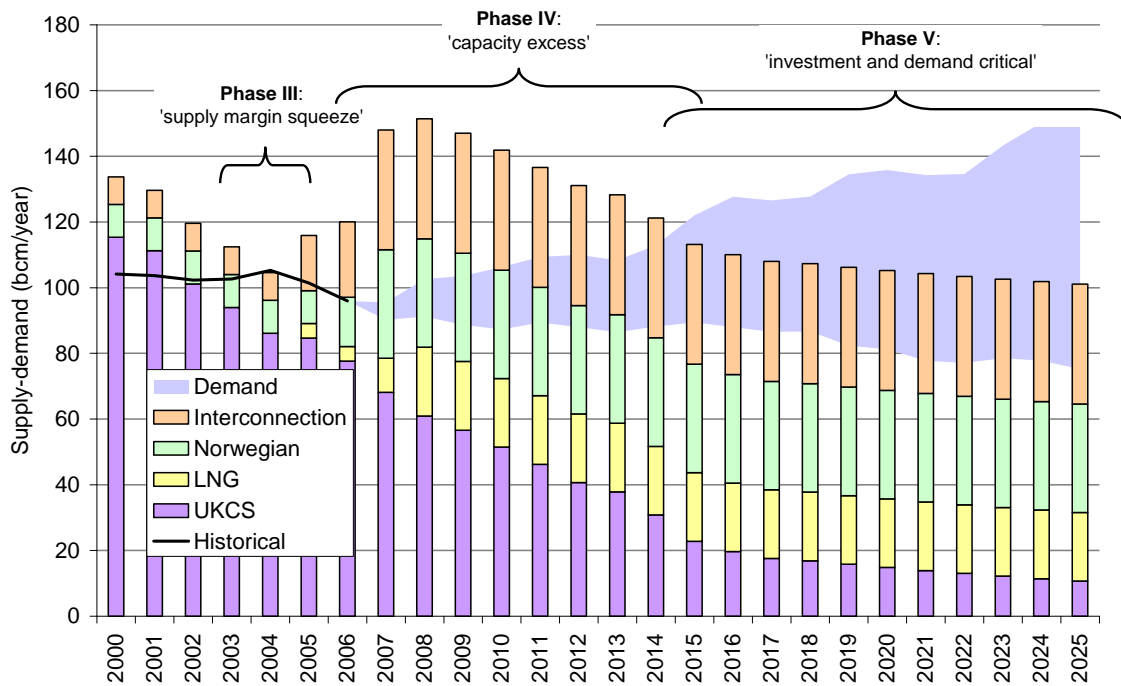
**Figure 38 – The range of forecasts for UK gas demand**



Source: Pöyry Energy Consulting. Analysis assumes Seasonal Normal Temperature (SNT).

Figure 39 shows the range of UK gas demand compared to the annual capacity, assuming that only definite projects come on-line. This graph suggests that a transition to Phase V could begin to occur around 2015, as the combination of depletion in the UKCS and rising demand forces decisions to be made on future investments. However, if the bottom of our range of gas demand forecasts comes about, it is possible that no new infrastructure could be required in the UK, and the current 'building binge' will be the last one for the foreseeable future in the UK gas market.

Figure 39 – The transition to Phase V



Source: Pöyry Energy Consulting.

### 5.3 How do major players take investment decisions?

To understand how investment decisions could impact the UK market in the medium-term, Pöyry interviewed a number of major gas participants. These were chosen to be representative of the major players in the UK market – some with interest only in dry gas, others with mixed oil and gas interests and others with current or future LNG regasification investments.

From the interviews we aimed to gain a view of what methodologies market players use to invest, and what drives the decision to make very large capital investments in projects that have long lives and how that would differ from investments for shorter-life projects.

#### 5.3.1 Decision methodology

As regards the investment criteria, all participants used hurdle rates of either IRR or NPV<sup>17</sup> for projects. Typically projects would be valued with an internal model to assess NPV, based on expected revenue from gas (and oil) sales, along with expected costs (both upfront capital costs and ongoing costs). Those projects that had the highest NPV would get the go-ahead. However, scenario planning was also important, with most companies using a P50/P10 (50% Probability, and 10% Probability) approach, with the projects with the highest NPV under a P50 scenario getting the go-ahead. Projects that

<sup>17</sup> Internal Rate of Return or Net Present Value

were NPV negative under the P10 scenario would not get the go-ahead, irrespective of the value creation under a P50 view.

However, very few companies considered themselves capital constrained and hence needing to choose between projects to allocate capital effectively. Rather, resource constraints (above all management and personnel time) were regarded as key. The view was expressed that this could change within 18 months if low prices continued for much longer, with internal price forecasts dropping and capital availability being more constrained as a result.

### **5.3.2 Forecasts, forward curve or current prices?**

Almost all participants used an internal price 'deck' (or internal long-term forecasts) to value projects based on forecasts produced by an internal economics analysis department or similar. Typically this price deck was used for all projects (both up- and downstream) that a company invested in. The forward curve might be used for some investments, but typically only as a sensitivity to confirm that the project was viable at rates currently available in the market.

For short-term investments, such as fields in the Southern Basin and close to existing infrastructure, with a short commissioning of one month or an expected life of 1-2 years, the forward curve was used by participants to decide whether the project should go-ahead. This could be related to trading positions – 'locking in' the value of the project when it came on-line.

There was a general view that current prices did not directly impact investments, as investments were made on the basis of internal price projections. However, it was felt that current prices did impact the perception of risk – and that marginal projects could be refused go-ahead if current prices were low.

For larger investments, such as new regasification terminals or large new offshore investments, the decision process is more complex, accounting for strategic plans as much as financial modelling. Again, the internal price projections were more important than either forward or current price considerations. However, the perception of risk due to current prices could have more influence as investment decisions were based on more 'fuzzy' criteria rather than a simple hurdle rate.

### **5.3.3 Infrastructure and location**

Another factor influencing investments is the existence of infrastructure. Clearly investments are much more economic if investment in infrastructure such as large pipelines has already been made – as a result, exploration for new gas fields is much more likely to happen near existing pipelines. Furthermore, investing to discover gas in areas where players did not own or have a share in a pipeline was expensive as it could leave one player open to losing value to other players through high charges for infrastructure usage ('value capture').

Different areas of the UKCS were regarded as presenting their own unique difficulties. The Southern Gas Basin is now only yielding small scale low pressure finds, which means most are only viable near to existing infrastructure. West of Shetland is an area that has some available gas (with finds of 1.5Tcf) but requires significant investment in new pipelines to bring the gas to the mainland. Some companies argued that investment in such major infrastructure is unattractive in the current business environment and requires a better tax regime. The Government would be repaid in the form of the tax revenues on the gas when produced

Entry capacity was also mentioned as a factor in decisions, as the cost of landing gas on the UK mainland could be influenced by either the cost of obtaining capacity or an inability to get it. The capacity auction process was also described by one participant as a disincentive to invest, with the recent significant changes in baseline capacity leading to uncertainty.

#### **5.3.4 Effect of oil price**

All participants were very clear on the impact of high oil prices on investment. High oil prices had significantly increased investment in oil, which in turn had led to much higher costs for participants, as the cost of wages, rigs, shipping etc had been driven up. It was considered that in gas investments, 60% of the costs were directly linked to oil investment (such as salaries or availability of steel) and 40% were unrelated (such as specialised gas drilling rigs). As a result, high oil prices on their own had significantly increased the cost of searching and producing gas in the UKCS. The biggest threat to UKCS investment would be a slump in gas price unaccompanied by a drop in oil prices (delinking of gas and oil prices). This would mean high E&P costs as a result of oil prices, without high gas prices to offset them.

In fact, some participants stated that they had already seen a drying-up of investment, particularly in short-term production projects (such as tie-backs). However, others said that their corporate price decks had not been adjusted in light of what was considered a short-term slump in prices, and hence investment was still continuing.

The high costs and high investment in the North Sea had created a further problem – a lack of experienced staff. A number of companies stated that production and exploration were being limited by an absence of experienced staff, and the use of ‘greenhorns’, or inexperienced personnel, had led to inefficiencies and more outages.

Generally speaking, it was regarded as extremely unlikely that companies would keep profitable gas in the ground on the hope that they might make more money in the future – if prices were above the NPV hurdle rate, the gas would flow irrespective of future beliefs of prices.

#### **5.3.5 Stranded gas**

A final common theme was that of stranded gas. Stranded gas comes about when reserves of gas are no longer economic to produce. As a result, the infrastructure is decommissioned. However, if the remaining gas does become more valuable in the future, due to rising gas prices or improved technology, it is too costly to extract as the infrastructure is no longer in existence – hence the gas becomes stranded.

Gas can also become stranded due to falling pressures of reservoirs. As the reservoir pressure falls the gas requires more compression to lift the pressure so that the gas can enter the NTS at 70bar. Since gas is required to power the compressors, this can significantly increase the cost of getting the gas onshore, and past a certain pressure drop, the gas becomes stranded.

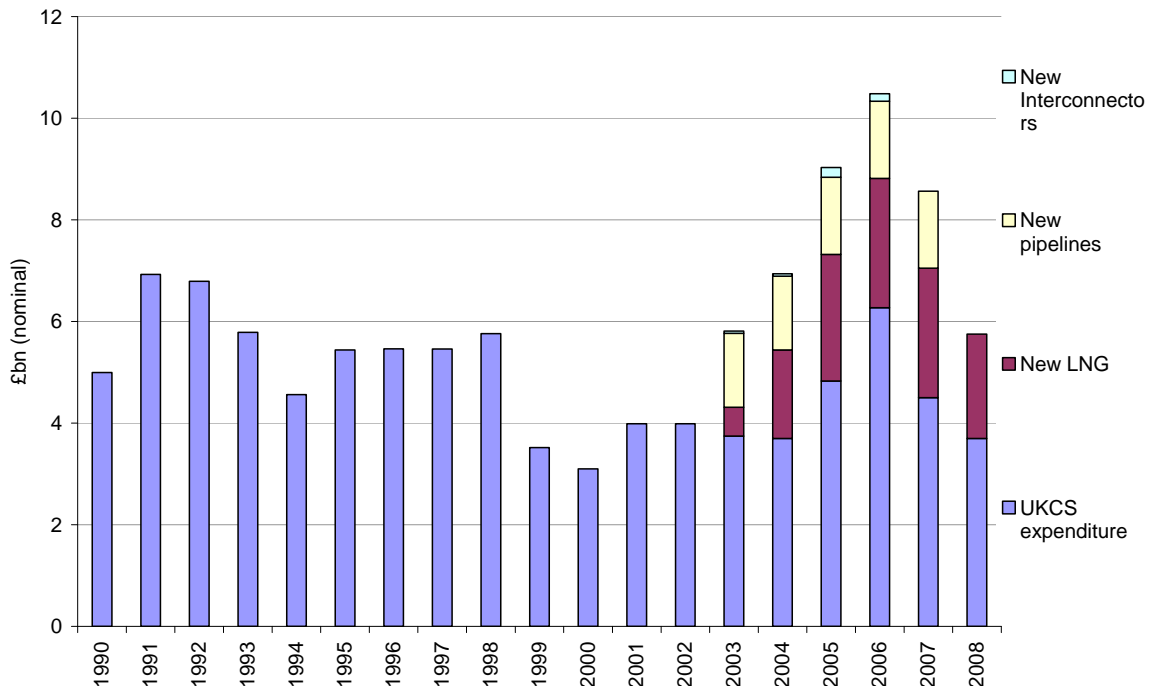
### **5.4 Historical investment in the UK gas market**

The manner in which companies have been investing in the UK gas infrastructure in the last few years has led to significant spending, as shown in Figure 41. Investment in the UKCS reached £6bn in 2006, significantly more than during the period 1999-2004 when investment dropped to below £4bn annually. However, the investment in new import pipelines, above all the Langeled pipeline and Ormen Lange field, and new LNG

terminals along with their associated shipping and liquefaction plants, has raised investment to over £10bn during 2006.

As a result, it is clear that the UK remains a market where companies are keen to invest, and probably one where companies are likely to invest in the future.

**Figure 40 – Historical and projected investment in the UK gas market**



Source: Pöyry analysis. UKCS investment data from UKOOA, includes exploration and development only. New pipelines includes field development cost. LNG investment based on all elements of LNG chain (liquefaction, transport and regasification) in proportion to the regasification terminal size assuming baseload operation.

### 5.5 Modelling the effect of future investment decisions

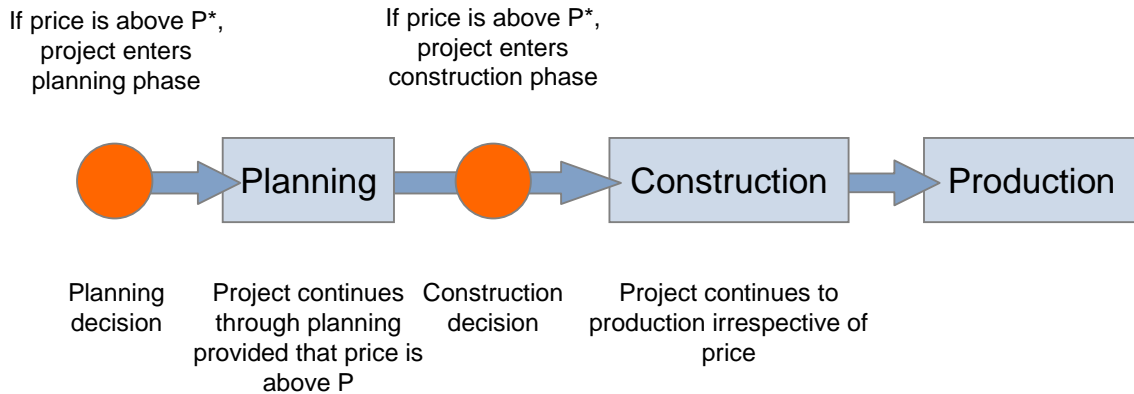
In the worlds illustrated in the previous section we have made exogenous assumptions about new capacity that comes on-stream, depending on how we believe players will react to changes in prices, and also on the underlying aim of the scenario – an Abundant scenario will (by definition) have much more capacity coming on-line than a Constrained scenario. However this exogenous approach does not account for how the actions of large numbers of players with a portfolio of investment opportunities can influence a market – either through large numbers of projects appearing simultaneously leading to a price collapse, or players not investing in the market due to concerns about the risk reward balance.

However, it is possible to model the underlying drivers of investment decisions as part of price modelling (“dynamic investment modelling”), to understand how the actions of players might impact the UK market. This section first explores some of the drivers of investment decisions by major players, and then looks at how these decisions have impacted the market and could impact it in the future.

To understand how future decisions could impact the market, we have examined a series of scenarios using dynamic investment modelling. This uses the Pöyry gas model,

Pegasus, to model how much new capacity comes on-stream, given inputs about the current or future price, the period of planning and construction and the expected price that new entrants would require to get the go-ahead on projects.

**Figure 41 – Dynamic investment modelling through Pegasus**



$P^*$  is the required price a new entrant needs to invest in new infrastructure

Source: Pöyry Energy Consulting.

An overview of the dynamic investment process is shown in Figure 41. In each year there is a certain capacity that is available to enter the planning stage – this could be new LNG terminals, new UKCS production or new import pipelines. Depending on the hurdle price this new capacity requires ( $P^*$ ), the model decides whether the capacity enters the planning phase or is rejected that year. The hurdle price,  $P^*$ , can be compared each year to either the model price in that year, or an internal price forecast.

Once in the planning process, prices (or the expectation of them) have to remain above the hurdle price  $P^*$  otherwise the investment will be rejected. If prices are high enough for two consecutive years, the project moves into the construction phase. From this point onwards, the project will move towards completion irrespective of the market price.

## 5.6 What effect could future investment decisions have on the market?

For the purposes of modelling, we have considered three scenarios:

- **‘UKCS only’**. For this scenario, we have assumed that the only new capacity available to come on-stream is from the UKCS.
- **‘Norwegian pipelines rule the day’**. In addition to new UKCS investment, a further 30bcm/year pipeline from Norway becomes available for planning in 2009, and a further 20bcm/year pipeline in 2016. Both these pipelines, owing to the cost of the investment, are assumed to flow at a minimum of 90% of maximum flow rates.
- **‘LNG future’**. In addition to new UKCS investment, we assume that further LNG Terminal 1, 2 and 3 are available to enter the planning stage from 2007 onwards. In addition we assume that further generic capacity is available in 2015, 2020 and 2025. Note that we have not assumed that any further LNG liquefaction upstream comes online as well – these LNG terminals are assumed to be built solely to take

advantage of price arbitrages between markets. Although the LNG regasification terminals themselves do not have a take-or-pay constraint, the upstream liquefaction plants do, and hence must run at high load factors.

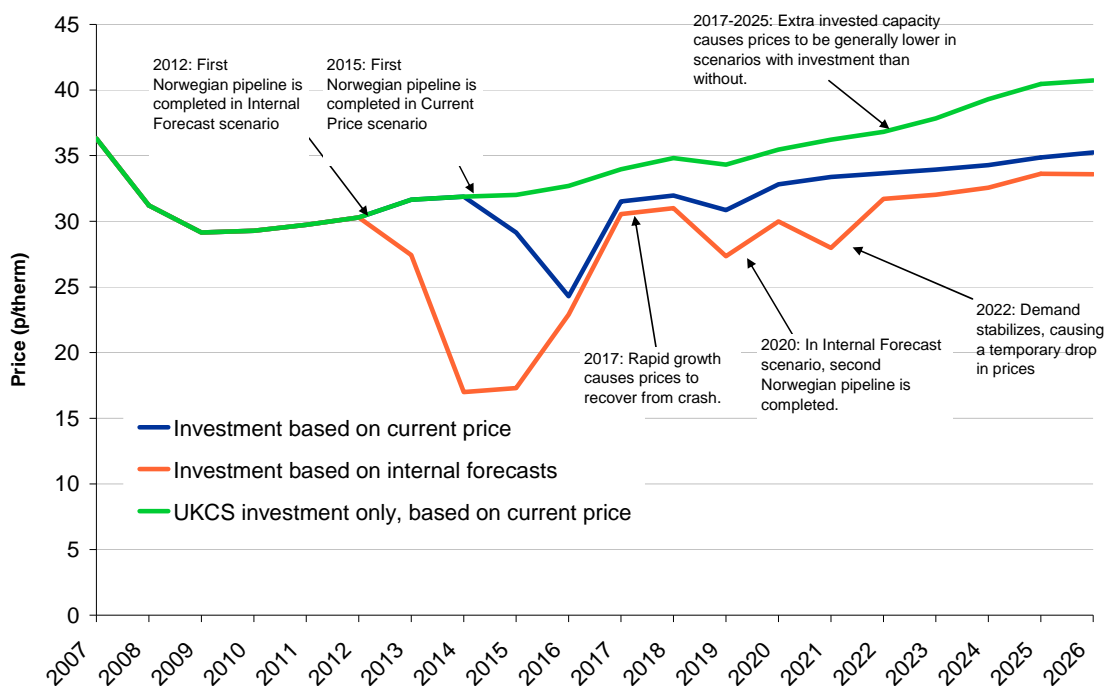
To understand how the nature of investment decisions can impact the market, we analyse two investment methodologies.

- **Current price methodology:** this is where the decision to invest is based solely on the current market price. This could be the case for small projects with short lifetimes, or where the risk perception of future projects is driven by current events in the market, as suggested by our interviews.
- **Internal price forecasts:** this assumes that companies are investing based on internal price ‘decks’ or forecasts. For the purposes of modelling, we assume that these internal forecasts are based around a world of continuing long-term oil indexation. This assumption best reflects the results of our interviews, which suggested that internal projections have a strong influence on investment decisions.

### 5.6.1 ‘Norwegian pipelines rule the day’

In this scenario, we assume that in addition to new UKCS investment, a further 30bcm/year pipeline from Norway becomes available for planning in 2009, and a further 20bcm/year pipeline in 2015. As shown in Figure 42, the effect on prices of the proposed pipelines could be quite dramatic.

**Figure 42 – Effect of new import pipeline on UKCS price**

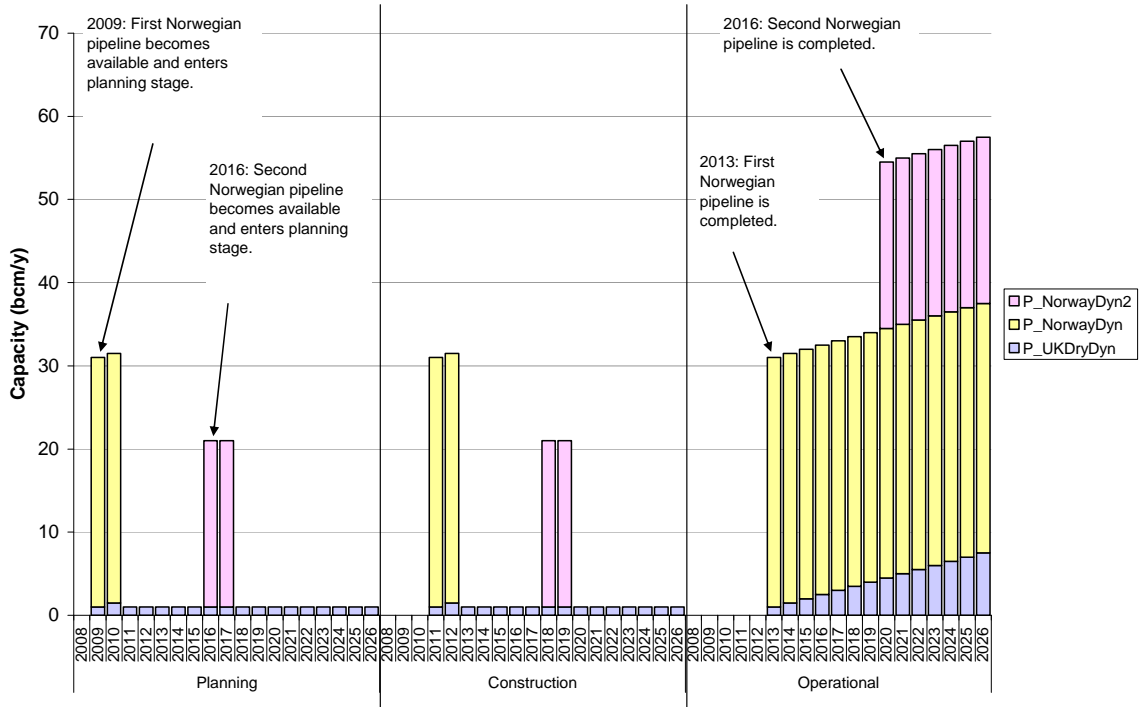


Source: Pöyry Energy Consulting.

Assuming that companies are using internal price forecasts for financing investments, this leads to a collapse in prices in 2014 as a new import pipeline comes on-line after two years of planning and two years of construction. The price drop remains until demand

picks up in 2016. As shown in Figure 43, a second pipeline then enters the planning phase in 2016 and is completed in 2020, leading to a further drop in prices.

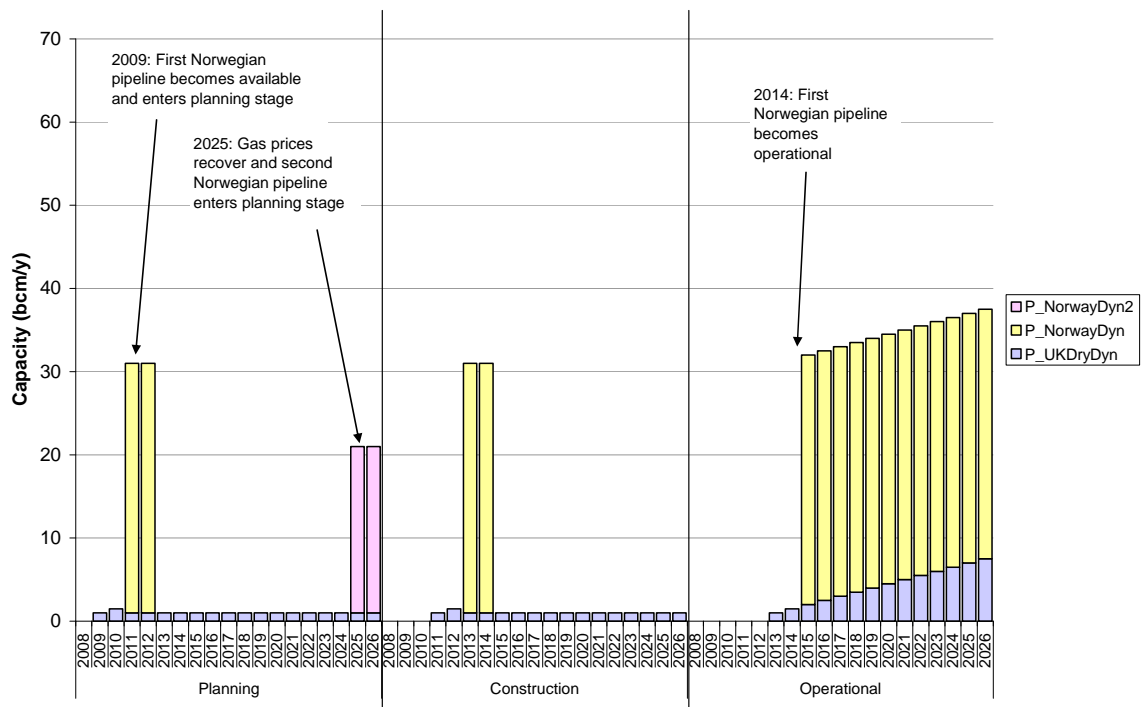
**Figure 43 – New capacity – import pipeline scenario (internal price forecast)**



Source: Pöyry Energy Consulting.

Assuming that companies are driven by the current price, as shown in Figure 44, means that the 2009 pipeline is delayed and does not enter the planning process until 2011 when prices are high enough. This leads to construction during 2012 and 2013 and the pipeline entering service in 2014. Again this leads to a price collapse in 2015 and 2016, but it is short-lived as gas demand picks up soon afterwards due to commissioning of CCGTs as a result of the LCPD.

**Figure 44 – New capacity – import pipeline scenario (current price methodology)**



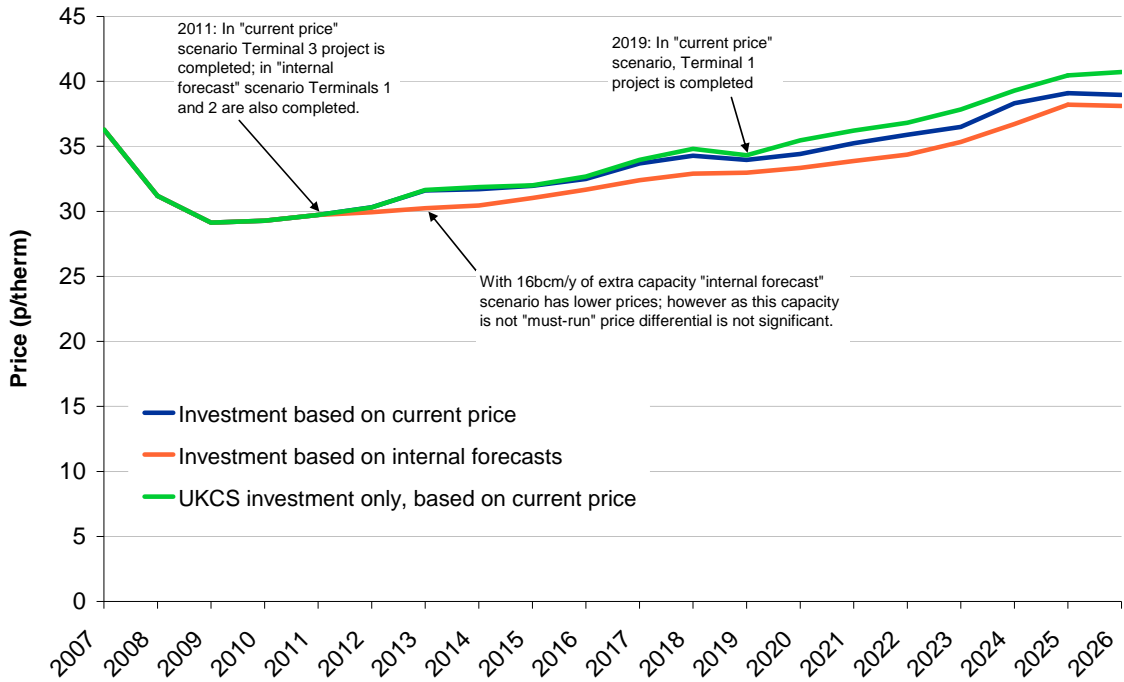
Source: Pöyry Energy Consulting.

### 5.6.2 LNG and UKCS only

The effect of new LNG import terminals on the UK price is much more limited, as shown in Figure 45.

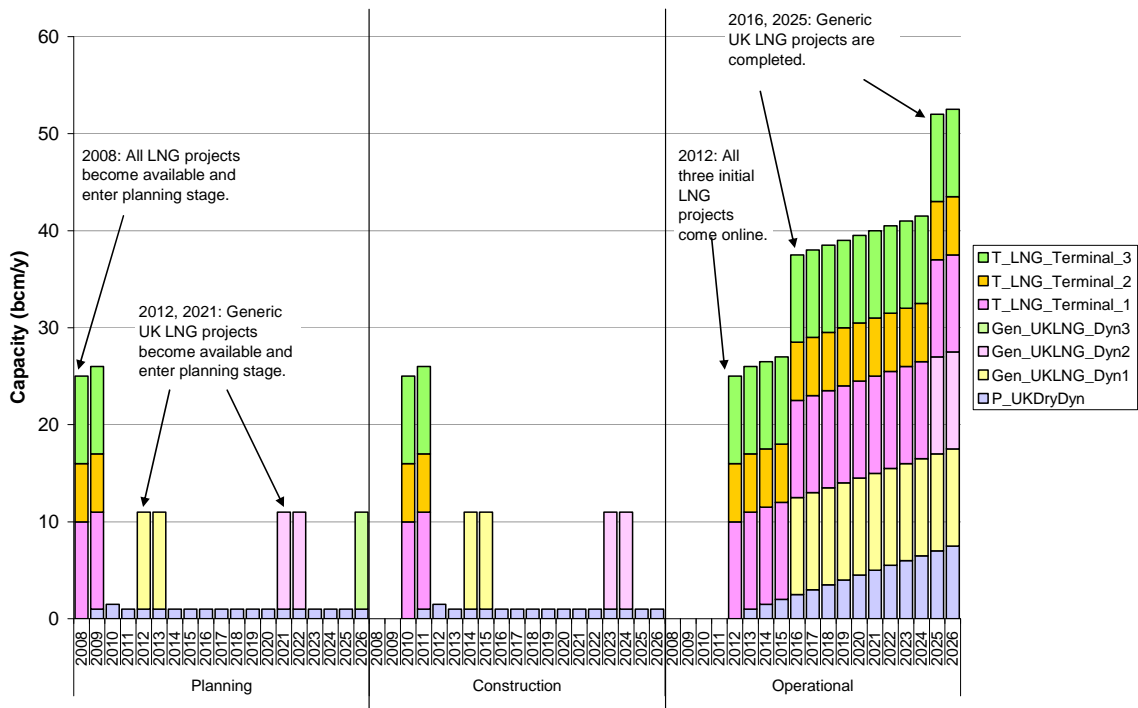
In the internal price forecast methodology, due to the assumption of high future prices based on ongoing high oil prices, all three new LNG projects enter planning during 2008 and 2009 and are constructed during 2010 and 2011, as shown in Figure 46. However, the effect of a further 30bcm of LNG regasification capacity on the market is relatively limited, with prices dropping only 2 or 3 p/therm. This is because despite the extra LNG capacity, there is no compulsion for the new terminals to supply gas and the interconnection to Europe allows any excess gas to flow out of the UK through the interconnectors. As further LNG terminals are built on the expectation of continued high prices in 2012 and 2021 the effect on prices remains limited and utilisation of terminals continues to fall.

**Figure 45 – Effect of new LNG import terminals on UK gas price**



Source: Pöyry Energy Consulting.

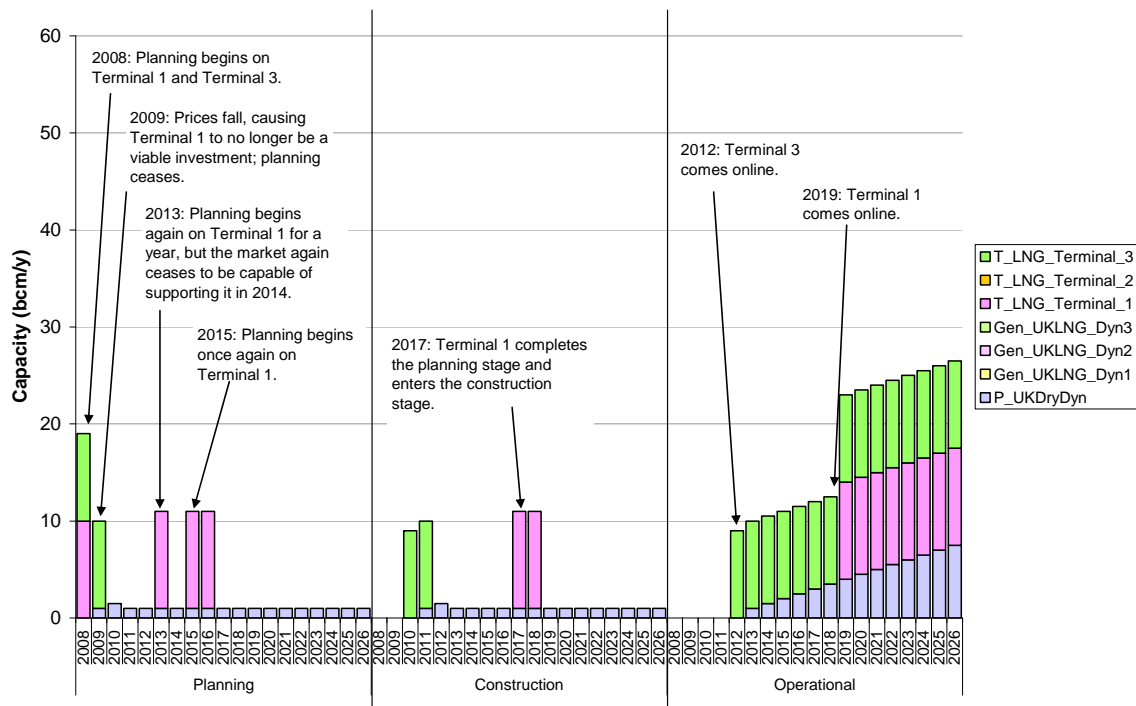
**Figure 46 – New capacity – import pipeline scenario (internal price forecast)**



Source: Pöyry Energy Consulting.

If investments are made on the basis of current prices only, we have a different pattern of investment. In 2008, Terminal 1 (T1) and Terminal 3 (T3) both enter the planning phase, but a drop in prices in 2009 causes the T1 project to be delayed. T3 is constructed during 2010 and 2011, entering service the following year. However, prices are not high enough for the T1 project until 2013, but again it is delayed due to a drop in prices, so does not get constructed until 2017. Once this extra capacity comes on-line, the effect on price is minimal, with a change of less than 1p/therm from the UKCS only case.

**Figure 47 – New capacity – import pipeline scenario (current price methodology)**



Source: Pöyry Energy Consulting.

## 5.7 Conclusion

As shown in this section, the uncertainty for future UK gas demand is quite considerable – a reasonable band would be between 75bcm and 150bcm by 2025. However, there is a case to be made that a Phase V, dependent on both gas demand and investment, could begin around 2015, as the combination of depletion in the UKCS and rising demand forces decisions to be made on future investments. Of course, if the bottom of our range of gas demand forecasts comes about, it is possible that no new infrastructure could be required in the UK, and the current ‘building binge’ will be the last one for the foreseeable future in the UK gas market.

From speaking to industry participants, it was clear that internal price forecasts were the key determinant of most investment decisions in the UKCS, with other investments such as LNG terminals being determined on a combination of internal price forecasts and larger ‘strategic’ analysis. Despite this, current prices could affect decision making by altering the perception of risk – this could potentially be more of a factor for larger investments that used less clear-cut criteria.

Investing in the UKCS largely remains one of small incremental investments, typically around locations where companies already own infrastructure. However the cost of exploring for gas has had a detrimental effect on gas investments due to high North Sea costs. There also exist concerns that gas could become 'stranded' in the UKCS as a result of the cost of extraction.

Larger possible fields, for example West of Shetland, are not the same since they need significant new infrastructure and this makes the investment more risky. Some companies argued for a better tax regime, stimulating this type of project which would in the long run be advantageous to the UK gas consumer, via more secure gas production close to the UK, and the Treasury when tax revenues are collected as production starts.

From the modelling of investment decisions, there are a number of conclusions with importance for the future Phase V.

Firstly, investments in the UKCS are impacted by the market, but have no impact on the market. This is primarily due to the relatively small size of any future gas finds, which tend to be small and incremental, and as a result have little impact on the market price. This is also due to the interconnection of the UK market both to the Continent and the international LNG market, which is a much larger overall area to affect.

Large new pipeline investments, due to their inherent destination inflexibility, and reliance on running near full capacity to recoup investments, have the potential to upset the market for a period of time. Part of this is due to the inherent 'lumpiness' of gas investments – often the economic size for pipelines and offshore fields can be sufficiently large to reduce market prices.

Given the nature of the inherent flexibility, LNG regasification terminals (when not accompanied by dedicated liquefaction plants) also have relatively little impact on the market. This is because the LNG does not have to flow into the UK market and can be diverted elsewhere – as a result it is unlikely to depress prices. Where LNG is accompanied by a dedicated liquefaction plant and a long-term contract, the likelihood of price effects are much greater as it will behave in much the same way as a pipeline.

Since companies are not overly sensitive to current prices and tend to rely on internal price projections, this appears to increase the likelihood of a price drop caused by over investment, rather than reduce it. This seems to be the result of the propensity of forecasts (whether the forward curve or internal projections) to project the current world into the future. Consequently, periods where a number of companies invest together are likely to recur.

Nonetheless, given the increasing interconnection of the UK market to both NW Europe and the global LNG market, the impact of any future cycles of over- or under- investment may be as a result of European or global periods of investment, rather than merely in the UK.

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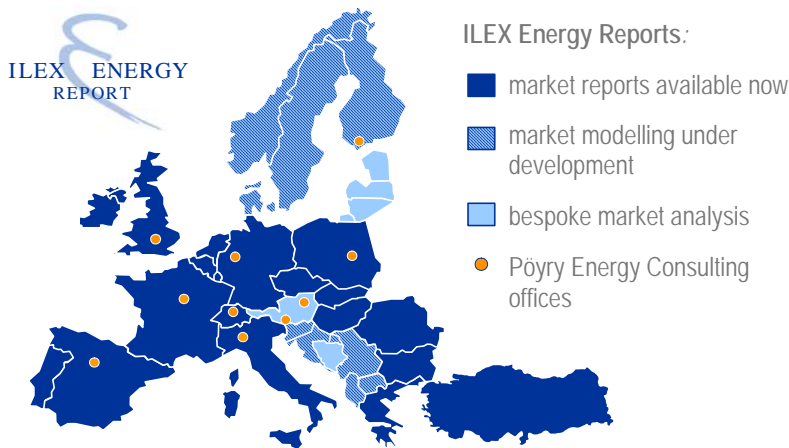
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