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**Prospects for UK Oil and Gas Import Dependence**

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Linda Stephen

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**DEPARTMENT OF ECONOMICS**

## **NORTH SEA ECONOMICS**

Research in North Sea Economics has been conducted in the Economics Department since 1973. The present and likely future effects of oil and gas developments on the Scottish economy formed the subject of a long term study undertaken for the Scottish Office. The final report of this study, The Economic Impact of North Sea Oil on Scotland, was published by HMSO in 1978. In more recent years further work has been done on the impact of oil on local economies and on the barriers to entry and characteristics of the supply companies in the offshore oil industry.

The second and longer lasting theme of research has been an analysis of licensing and fiscal regimes applied to petroleum exploitation. Work in this field was initially financed by a major firm of accountants, by British Petroleum, and subsequently by the Shell Grants Committee. Much of this work has involved analysis of fiscal systems in other oil producing countries including Australia, Canada, the United States, Indonesia, Egypt, Nigeria and Malaysia. Because of the continuing interest in the UK fiscal system many papers have been produced on the effects of this regime.

From 1985 to 1987 the Economic and Social Science Research Council financed research on the relationship between oil companies and Governments in the UK, Norway, Denmark and The Netherlands. A main part of this work involved the construction of Monte Carlo simulation models which have been employed to measure the extents to which fiscal systems share in exploration and development risks.

Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy

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# Prospects for UK Oil and Gas Import Dependence

Professor Alexander G. Kemp and  
Linda Stephen

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# Prospects for UK Oil and Gas Import Dependence

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## 1. Introduction

It is well known that the UK reverted to becoming a net gas importer in 2004 following a period from 1997 to 2003 of being a net exporter. Ongoing net oil imports are frequently stated to be imminent. There are implications for the UK balance of trade and security of energy supply. The prospective size of net imports over the longer term has often been discussed in rather alarmist terms generally without adequate supporting information on supply and demand. The gas supply problems of the 2005-2006 winter have added to concerns about the future market situation.

The present study sets out to produce up-to-date estimates of prospective UK oil and gas supply and demand. There is much emphasis on gas supply and demand because of the extra complexities of peak demand and supply and uncertainties surrounding the phasing and scale of import and storage schemes. The estimates reflect the uncertainties surrounding international oil and gas prices. Substantial attention is given to the peak winter demand issue and the summer situation of relatively low demand.

## **2. Methodology and Assumptions**

The projections of production have been made through the use of financial simulation modelling, including the use of the Monte Carlo technique, informed by a large, recently-updated, field database validated by the relevant operators. The field database incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to 316 sanctioned fields, 112 incremental projects (76 probable and 23 possible) relating to these fields, 19 probable fields, and 23 possible fields. These are unsanctioned but are currently being examined for development. An additional database contains 215 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block location are available for these. They are not currently being examined for development by licensees.

Monte Carlo modelling was employed to estimate the possible numbers of new discoveries in the period to 2030. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types (oil, gas, condensate) of discovery. A moving average of the behaviour of these variables over the past 10 years was calculated separately for 6 areas of the UKCS (Southern North Sea, (SNS), Central North Sea (CNS), Moray Firth (MF), Northern North Sea (NNS), West of Scotland (WOS), and Irish Sea (IS)), and the results employed for use in the Monte Carlo analysis. Because of the very limited data for WOS and IS over the period judgemental assumptions on success rates and average sizes of discoveries were made for the modelling.

It is postulated that the exploration effort depends substantially on a combination of (a) the expected success rate, (b) the likely size of discovery, and (c) oil/gas prices. In the present study 3 future oil/gas price scenarios were employed as follows:

<b>Table 1 Future Oil and Gas Price Scenarios</b>		
	Oil Price (real) \$/bbl	Gas Price (real) Pence/therm
High	40	36
Medium	30	28
Low	25	24

These values are below current market levels but are used to reflect values generally used by investors when assessing long-term investments.

The postulated numbers of annual exploration wells for the whole of the UKCS are as follows:

<b>Table 2 Exploration Wells</b>		
	2006	2030
High	50	38
Medium	38	27
Low	31	20

The annual numbers are modelled to decline in a linear fashion over the period.

It is postulated that success rates depend substantially on a combination of (a) recent experience, and (b) size of the effort. It is further suggested that higher effort is associated with more discoveries but with lower success rates compared to reduced levels of effort. This reflects the view that low levels of effort will be concentrated on the lowest risk prospects, and thus that higher effort involves the acceptance of higher risk. For the UKCS as a whole 3 success rates were postulated as follows:

<b>Table 3 Success Rates</b>
Medium effort/Medium success rate = 23%
High effort/Low success rate = 19%
Low effort/High success rate = 24%

It is assumed that technological progress will maintain these success rates over the time period.

The mean sizes of discoveries made in the period for each of the 6 regions were calculated. It was then assumed that the mean size of discovery would decrease in line with this historic experience. Such decline rates are quite modest. For 2004 the average size of discovery for the whole of the UKCS was 34 million barrels of oil equivalent (mmboe). For purposes of the Monte Carlo modelling of new discoveries the SD was set at 50% of the mean value. In line with historic experience the size distribution of discoveries was taken to be lognormal.

Using the above information the Monte Carlo technique was employed to project discoveries in the 6 regions to 2030. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

<b>Table 4 Total Number of Discoveries to 2030</b>	
High Effort/Low Success Rate	221
Medium Effort/Medium Success Rate	179
Low Effort/High Success Rate	146

For each region the average development costs (per boe) of fields in the probable and possible categories were calculated (See Section 3). These reflect substantial cost inflation over the last 2 years. Using these as the mean values the Monte Carlo technique was employed to calculate the development costs of



new discoveries. A normal distribution with a  $SD = 20\%$  of the mean value was employed. For the whole of the UKCS the average development costs on this basis were \$9.45/boe. Annual operating costs were modelled as a percentage of accumulated development costs. This percentage varied according to field size. It was taken to increase as the size of the field was reduced reflecting the presence of economies of scale in the exploitation costs of fields.

With respect to fields in the category of technical reserves it was recognised that many have remained undeveloped for a long time, but it was assumed that, reflecting the high current costs and prospective technological progress, their development costs would be aligned with those for new discoveries for each of the regions. For purposes of Monte Carlo modelling a normal distribution of the recoverable reserves for each field with a  $SD = 50\%$  of the mean was assumed. With respect to development costs the distribution was assumed to be normal with a  $SD = 20\%$  of the mean value.

The annual numbers of new field developments were assumed to be constrained by the physical and financial capacity of the industry. This subject is currently very pertinent in the UKCS. The ceilings were assumed to be linked to the oil/gas scenarios with maxima of 22, 20 and 17 respectively under the High, Medium, and Low Price Cases. These constraints do not apply to incremental projects which are additional to new field developments. To put these assumptions in perspective 13 new fields received development approval in 2005 but in the 1990's significantly higher numbers (around 20 per year) were achieved.

A noteworthy feature of the 112 incremental projects in the database validated by operators is the expectation that the great majority will be executed over the 3 years from 2006. It is virtually certain that in the medium and longer-term

many further incremental projects will be designed and executed. They are just not yet at the serious planning stage. Such projects can be expected not only on currently sanctioned fields but also on those presently classified as in the categories of probable, possible, technical reserves and future discoveries.

Accordingly, estimates were made of the potential extra incremental projects from all these sources. Examination of the numbers of such projects and their key characteristics (reserves and costs) being examined by operators over the past 5 years indicated a decline rate in the volumes. On the basis of this, and from a base of the information of the key characteristics of the 112 projects in the database, it was felt that, with a decline rate reflecting historic experience, further portfolios of incremental projects could reasonably be expected. As noted above such future projects would be spread over all categories of host fields. Their sizes and costs reflect recent trends.

The financial modelling incorporated a discount rate, field economic cut-off, and the full details of the current petroleum tax system including the changes in the 2006 Budget. The base case emphasised has a post-tax discount rate of 10% in real terms. An important assumption is that adequate infrastructure will be available to facilitate the development of the future projects. It is also important to note that it is assumed that investment decisions are made on the basis of the oil/gas prices indicated. When the prospective investments in probable and possible fields and incremental projects were subjected to economic analysis it was found that most were quite small and the returns in terms of NPVs were correspondingly often small on the assumptions described above. It was felt that, to reflect the relationship between the risks and rewards involved, a minimum expected NPV at the discount rates employed would be necessary before the project/field was sanctioned. For purposes of this study minimum NPVs of £10 million were employed as thresholds.

Estimates of UK gas demand were obtained from a variety of reputable sources including National Grid, Energy Contract Company (ECC), JESS Reports and DTI<sup>1</sup>. A full list is given in the references at the end of the paper. Similarly, estimates regarding the phasing and scale of gas import schemes was derived from a variety of sources. Often they gave rather different estimates and the figures shown here reflect the judgement of the authors. Estimates of the phasing and size of gas storage schemes were also derived from a variety of sources and those presented again reflect the judgement of the authors. The results presented make a clear distinction between new storage which is confirmed (and thus very likely to be available) and possible new storage (which is much more uncertain).

It is important to note that the data on import projects relate to the capacity of the scheme in question. This is clearly not the same as the likely size of the gas flows. Experience in the winter of 2005-2006 showed that the capacity might not be used on the scale available, both with gas from pipelines and in LNG form. In the presentation of the results different assumptions are made about gas flows through the Interconnector and the LNG schemes.

### **3. Results**

#### a) Annual Supply and Demand - Oil

Potential oil production (excluding NGLs) under the \$30, 28 pence scenario is shown in Chart 1. After an increase in 2007-2008 a key feature is the fairly fast decline from sanctioned fields. In the later part of the period the pace of decline moderates such that in 2020 production from this category of field is around 200,000 b/d. Incremental projects

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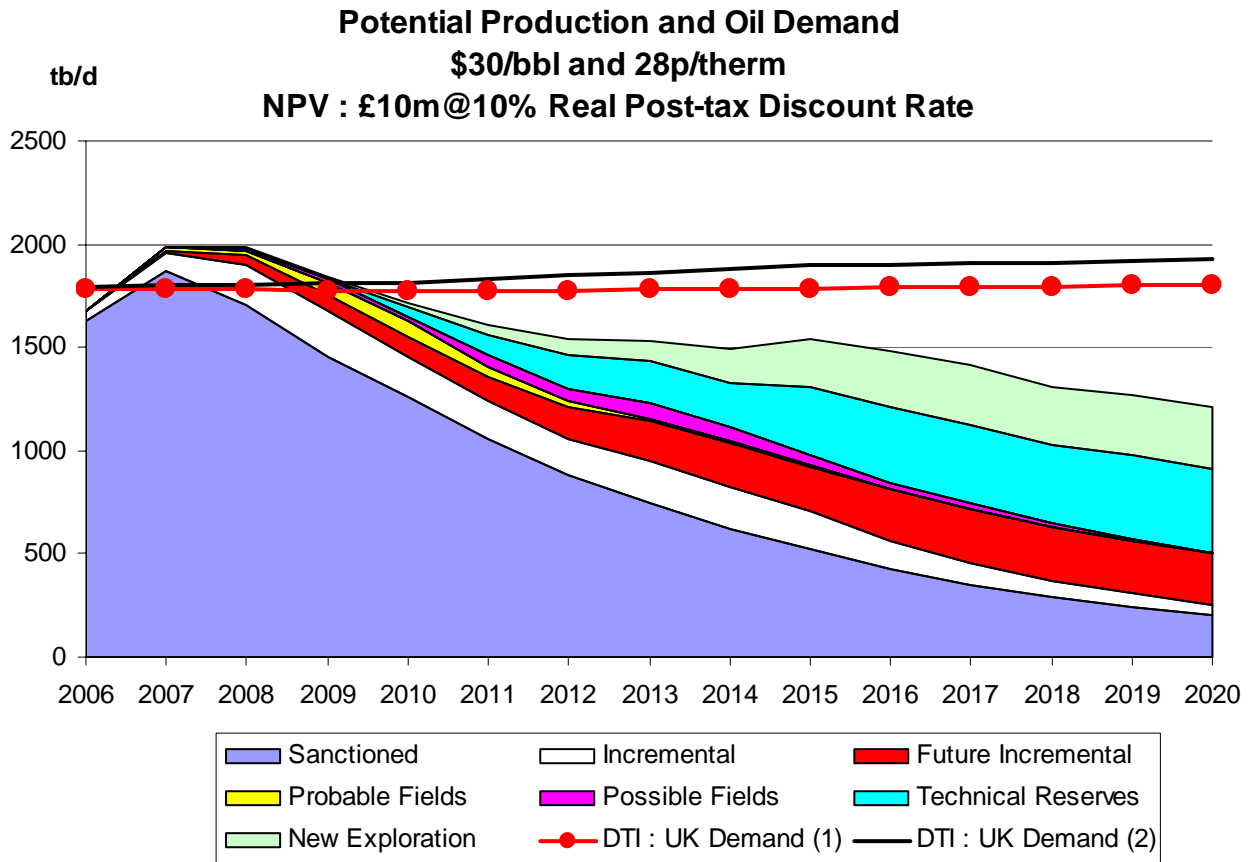
<sup>1</sup> For both oil and gas the DTI UK demand projections are based on the High and Low cases in UK Energy and CO<sub>2</sub> Emissions Projections (UEP26), DTI, July, 2006 – [www.dti.gov.uk/files/file31861.pdf](http://www.dti.gov.uk/files/file31861.pdf)

make a major contribution to the moderation of the decline rate over the next few years.

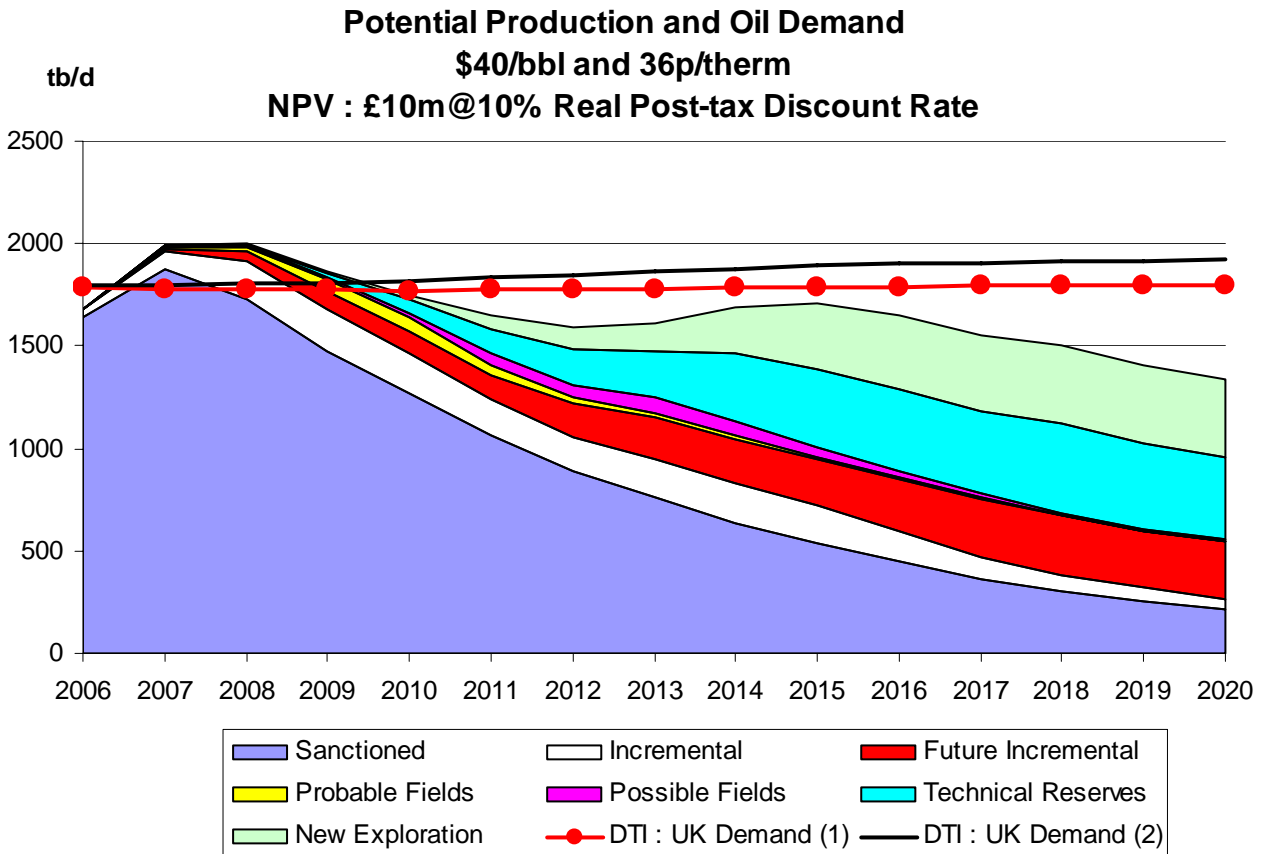
Other features of the results are the major long-term contributions made by fields in the technical reserves category and new discoveries from 2015 onwards. In 2020 total production is around 1.2 mmb/d and the future incremental projects, technical reserves, and new discoveries contribute the great majority of the output. To give a plausible range two demand estimates based on DTI projections are shown. Oil production may exceed demand until 2010 after which the shortfall in supply grows to 600 to 700 tb/d by 2020.

In Chart 2 oil production prospects under the \$40, 36 pence case are shown. Exploration activity and the pace and volume of new field developments are significantly higher under this scenario. Aggregate production holds up very well in the short-term, but falls to 1.7 mmb/d in 2010. There is only a gentle fall after that due to the development of large numbers of fields in the categories of new discoveries and technical reserves. By 2020 output is 1.34 mmb/d with the great majority coming from technical reserves, new discoveries and future incremental projects. Again oil production may exceed demand until 2010 after which the shortfall in supply grows to 462 to 584 tb/d by 2020.

### Chart 1



### Chart 2



In Chart 3 under the \$25, 24 pence price scenario oil production falls quickly after 2008 to a level of just over 1.6 mmb/d in 2010. By 2020 it is around 0.88 mmb/d. The longer term contributions from technical reserves and new discoveries are very much less under this scenario. Again oil production may exceed demand until 2010 after which the shortfall in supply grows to 923 to 1046 tb/d by 2020.

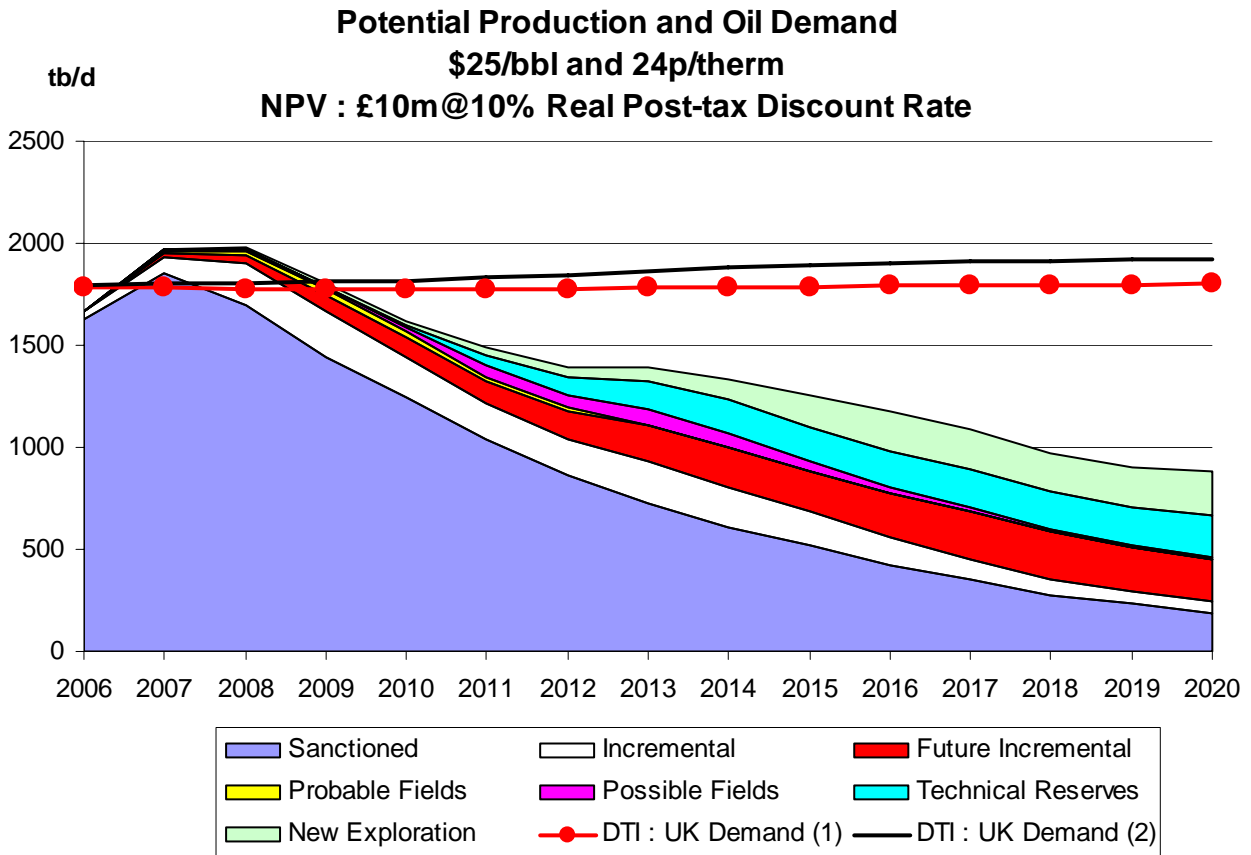
b) Annual UK Production and Demand-Gas

In Chart 4 prospective UK production of natural gas (excluding NGLs) under the \$30, 28 pence case and potential UK demand are shown. In 2010 6.9 bcf/d is produced and 4 bcf/d in 2020. Production from the sanctioned fields falls at a fairly fast pace after 2007, but by 2013 this category of field still accounts for over 50% of total output. By 2020 technical reserves and new discoveries account for around 60% of total production. Chart 4 also shows estimates of gas demand based on those produced by National Grid's 10-Year-Statement (2005), the Energy Contract Company (2006) and the DTI. For all demand estimates, production from the UKCS is insufficient to meet gas demand throughout the entire period. The National Grid demand estimates are the highest. Using the National Grid or Energy Contract Company estimates of demand, the demand shortfall may be 3917 mmcf/d to 3997 mmcf/d by 2010. Using the DTI estimates of gas demand the shortfall is between 1981 mmcf/d and 3141 mmcf/d in 2010, between 5120 mmcf/d and 6656 mmcf/d in 2015 and between 5633 mmcf/d and 7974 mmcf/d in 2020.

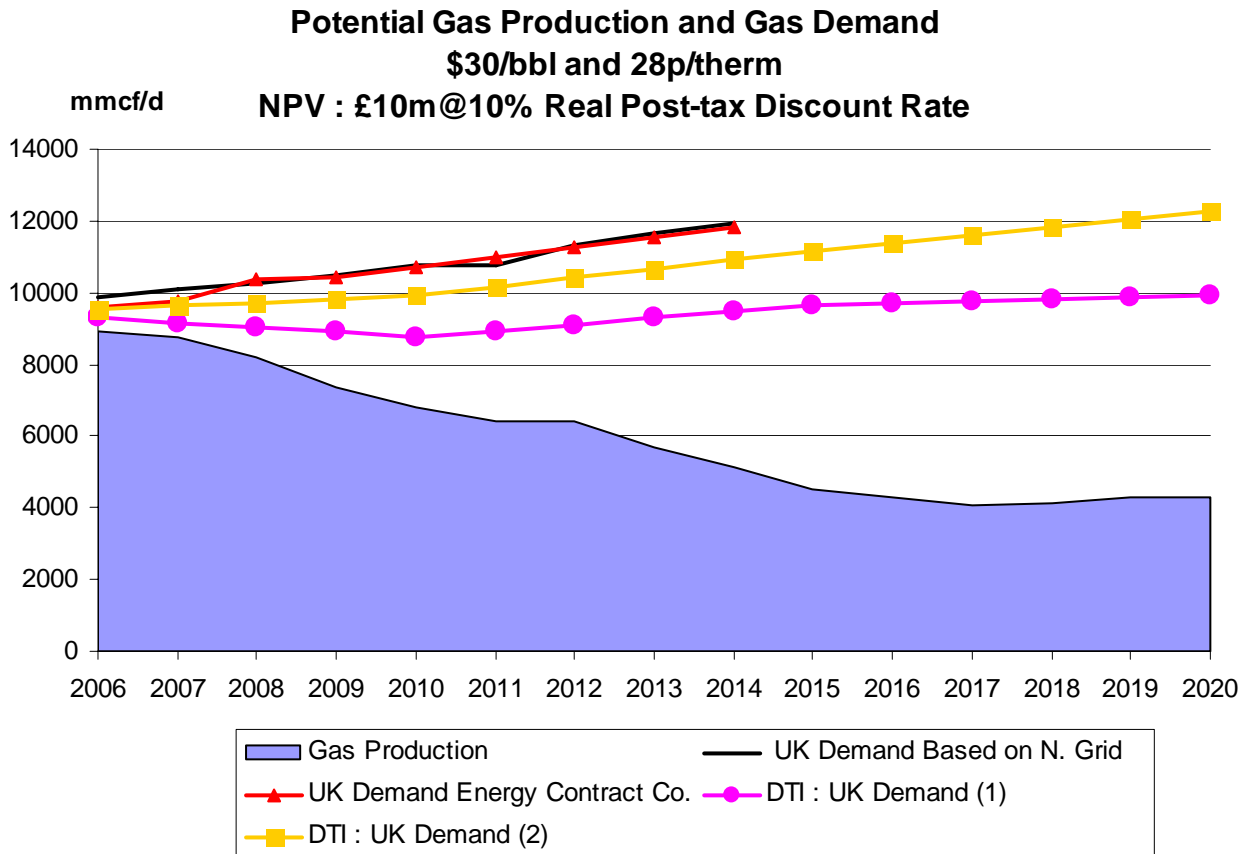
By 2010 UKCS indigenous gas production may fulfil 63% of UK demand according to the demand estimates of National Grid and the Energy Contract Company, or 68% to 77% of UK demand as seen by the DTI.

By 2015 UKCS gas production may fulfil only 40% to 47% of UK demand as seen by the DTI. By 2020 35% to 43% of UK demand may be met by UKCS production.

### Chart 3



### Chart 4





In Chart 5 gas production under the \$40, 36 pence scenario is shown. Output falls to around 7 bcf/d in 2010. Thereafter the development of large numbers of field in the categories of technical reserves and new discoveries moderates the decline rate. By 2020 output is 5.6 bcf/d. Using the National Grid or Energy Contract Company estimates of demand, the demand shortfall may be 3696 mmcf/d to 3776 mmcf/d by 2010. Using the DTI estimates of gas demand the shortfall may be between 1760 mmcf/d and 2920 mmcf/d in 2010, between 4254 mmcf/d and 5790 mmcf/d in 2015, and between 4281 mmcf/d and 6623 mmcf/d by 2020.

By 2010 UKCS gas production may fulfil 65% of UK demand according to the demand estimates of National Grid and the Energy Contract Company, or 71% to 80% of UK demand as seen by the DTI. By 2015 UKCS gas production may fulfil only 48% to 56% of UK demand as seen by the DTI. By 2020 46% to 57% of UK demand may be met by UKCS production.

In Chart 6 gas production under the \$25, 24 pence scenario is shown. It falls sharply from 8.8 bc/f in 2007 to 6.6 mcf/d in 2010. In 2020 it is around 3 bcf/d. Using the National Grid or Energy Contract Company estimates of demand, the demand shortfall may be 4118 mmcf/d to 4198 mmcf/d by 2010. Using the DTI estimates of gas demand the shortfall may be between 2181 mmcf/d and 3341 mmcf/d in 2010, between 5732 mmcf/d and 7268 mmcf/d in 2015 and between 7049 mmcf/d and 9390 mmcf/d by 2020.

By 2010 UKCS indigenous gas production may fulfil 61% to 62% of UK demand according to the demand estimates of National Grid and the Energy Contract Company, or 66% to 75% of UK demand as seen by the

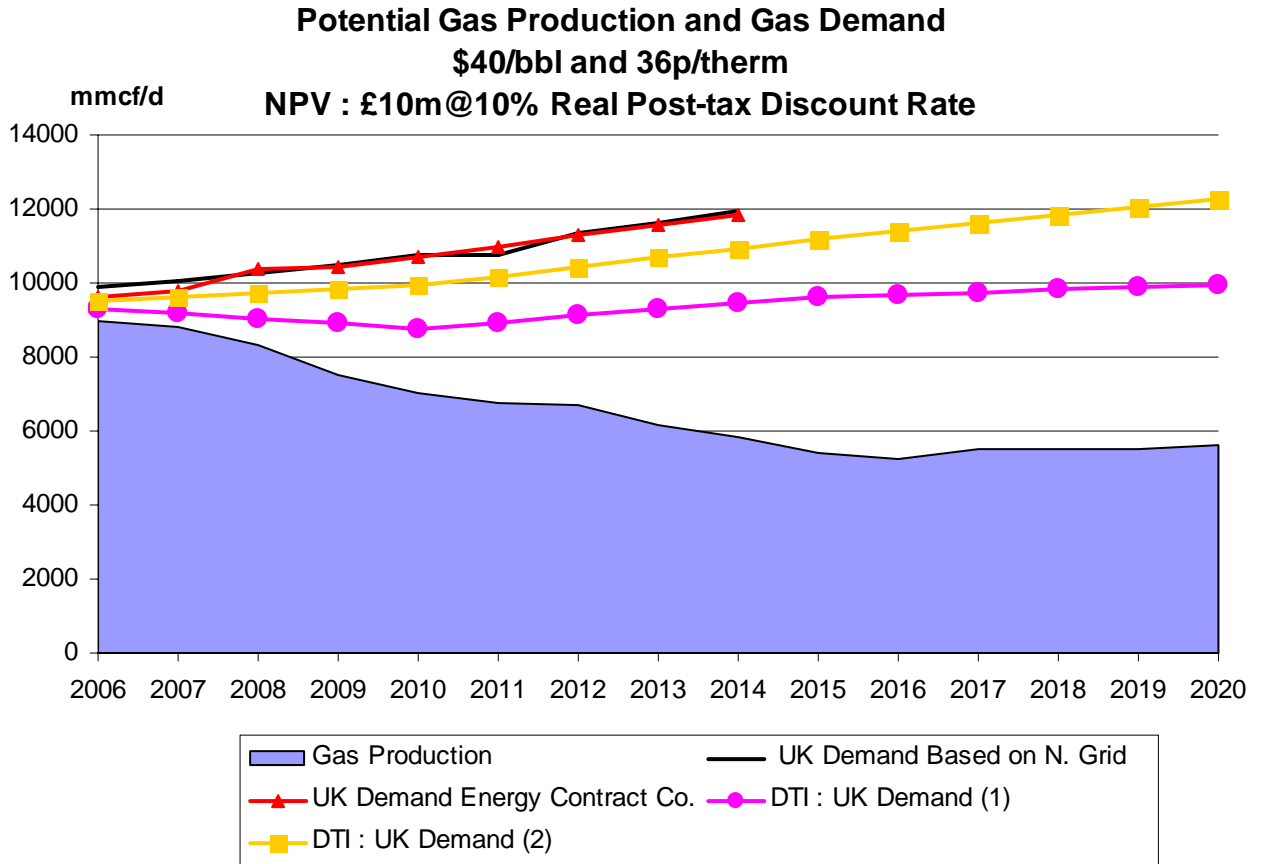
DTI. By 2015 UKCS production may fulfil only 35% to 41% of UK demand as seen by the DTI. By 2020 23% to 29% of UK demand may be met by UKCS production.

A considerable number of import schemes, both by pipeline and LNG, have either been sanctioned or are currently being seriously examined. In addition several storage schemes have also been implemented or are being planned. IUK capacity is set to increase in 2007 to 2275 mmcf/d, Langeled capacity in 2007 should be 2470 mmcf/d, Vesterled capacity should be 1275 mmcf/d in 2007, BBL capacity should be 1550 mmcf/d in 2008 and there may be “other” imports from Norway in 2008 via existing pipelines such as FLAGS of about 900 mmcf/d. The Isle of Grain capacity is set to increase in 2009 to 1225 mmcf/d. There could be approximately 590 mmcf/d of capacity from Milford Haven’s Dragon facility in 2009 increasing to almost 800 mmcf/d in 2012 and the Milford Haven’s South Hook facility could provide capacity of more than 2000 mmcf/d by 2012 in two stages. The two schemes at Teesside (Excelerate and ConocoPhillips) are aggregated in the charts<sup>2</sup>

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<sup>2</sup> In Charts 7-24 information on all the known schemes is shown. Other schemes such as Irish Sea Offshore LNG are not shown because of lack of information on the likely capacities.

### Chart 5



### Chart 6

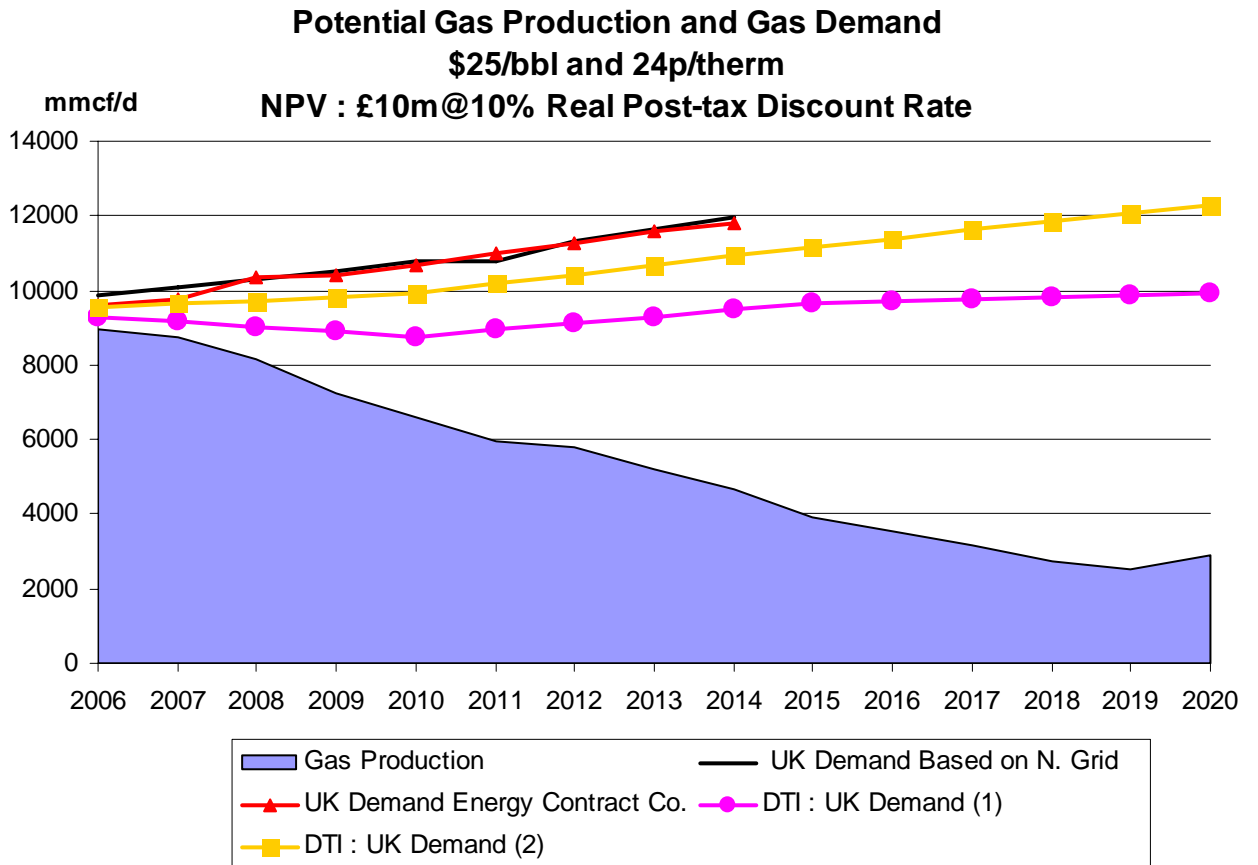


Chart 7 shows expected annual average UK demand plus exports to Ireland and the Netherlands<sup>3</sup> alongside potential production and estimates of net imports at the \$30/bbl and 28p/therm price. Net IUK is the Bacton to Zeebrugge Interconnector at capacity minus known contracted exports. The other import schemes show their estimated capacity.

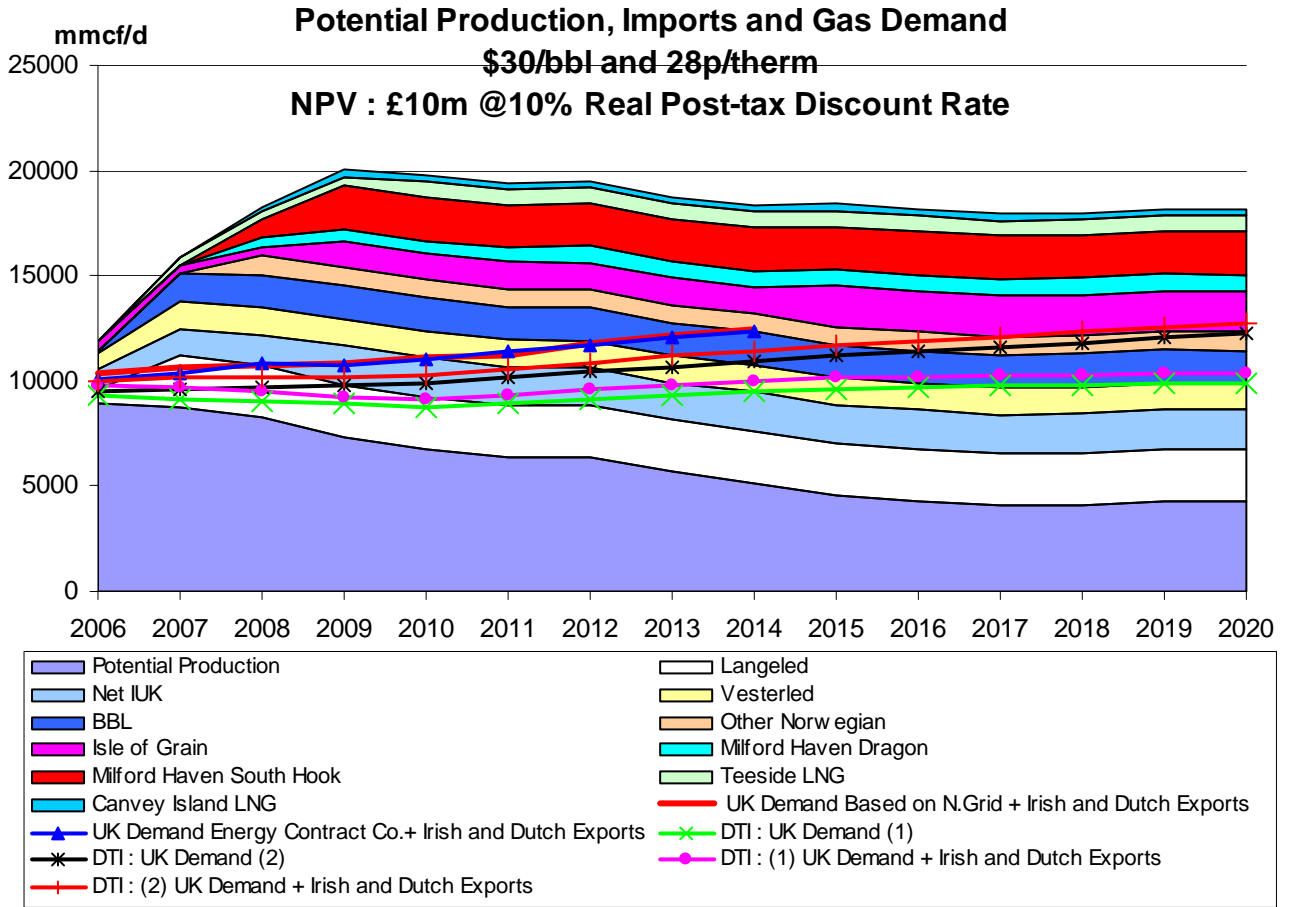
UK potential production plus Langeled and Vesterled imports seem to be just sufficient to satisfy UK annual average demand in 2006 according to all demand estimates shown, although the position is very tight with the National Grid estimate. After this a very substantial capacity supply surplus is in prospect. The Langeled pipeline officially opened on 16<sup>th</sup> October 2006 and could initially supply 1447 mmcf/d increasing to 2470 mmcf/d in October next year. However, initially at least, because of capacity constraints the total volume of gas which will flow from Norway in the Langeled and Vesterled pipelines will be less than the total capacities. Once facilities have been upgraded to bring Norwegian gas from the Ormen Lange field into line with the gas specification required in the UK the full joint capacity may be utilised.

Under all scenarios the growing import capacity plus indigenous production amply satisfies UK demand. At the medium price, by 2010 61% to 77% of UK demand is met by indigenous production, by 2015 this may fall to 39% to 47% and by 2020 it may only satisfy 35% to 43% of gas demand. Chart 8 shows annual expected demand plus exports to Ireland and the Netherlands alongside potential production and low-level net imports at the \$25, 24 pence price.

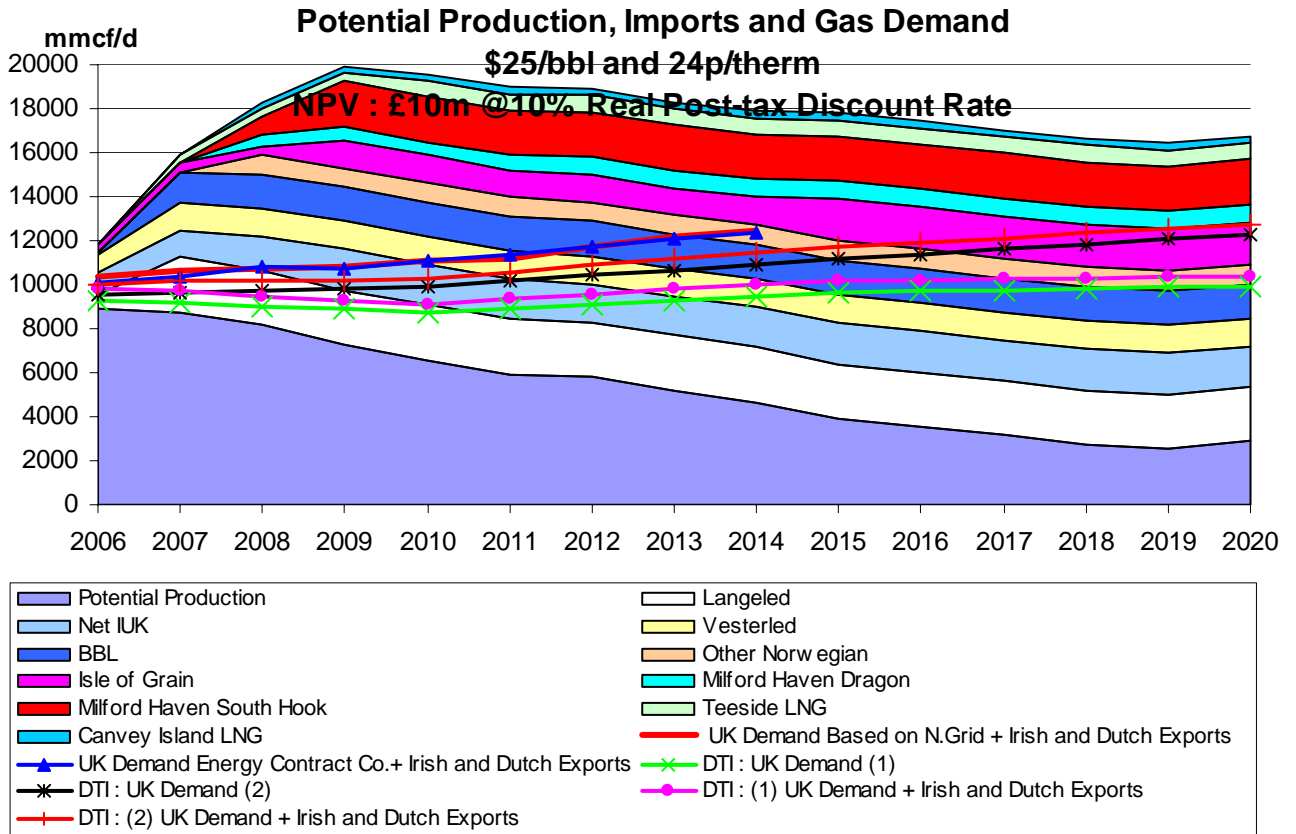
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<sup>3</sup> Exports to the Netherlands exclude any through the BBL line.

### Chart 7



### Chart 8

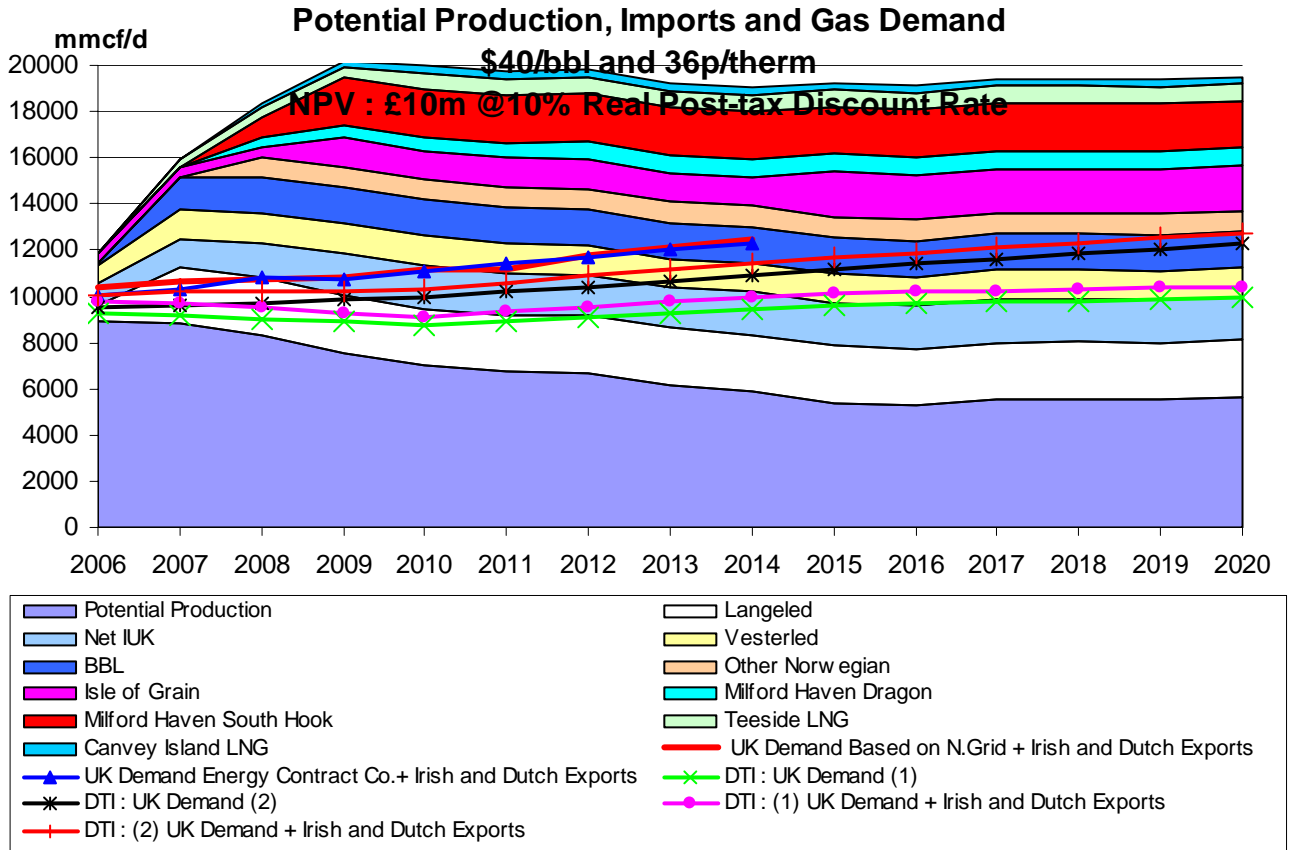


With the \$25 price the supply/demand position is tight in 2006 under the National Grid demand estimate. While there is enough capacity to meet demand up to 2020, between 86% and 96% of UK demand in 2006 is met by indigenous production, by 2010 this falls to 59% to 75%, by 2015 to 33% to 41%, and by 2020 indigenous production may only satisfy 23% to 29% of gas demand. Chart 9 shows annual expected demand plus exports to Ireland and The Netherlands alongside potential production and net imports at the \$40, 35 pence price.

UK potential production plus imports via Langeled and Vesterled should be sufficient to satisfy demand in 2006. By 2010 63% to 80% of UK demand is met by indigenous production by 2015 this falls to 46% to 56%, and by 2020 indigenous production may only satisfy 46% to 57% of gas demand.

In Charts 10, 11 and 12 the results are shown under changed assumptions whereby the Interconnector's import capacity is shown (rather than Net IUK). Chart 10 shows annual expected demand plus exports to Ireland and The Netherlands alongside potential production and capacity imports at the \$30/bbl and 28p/therm price. This indicates a very comfortable position for UK supplies if the import capacity were fully employed.

### Chart 9



### Chart 10

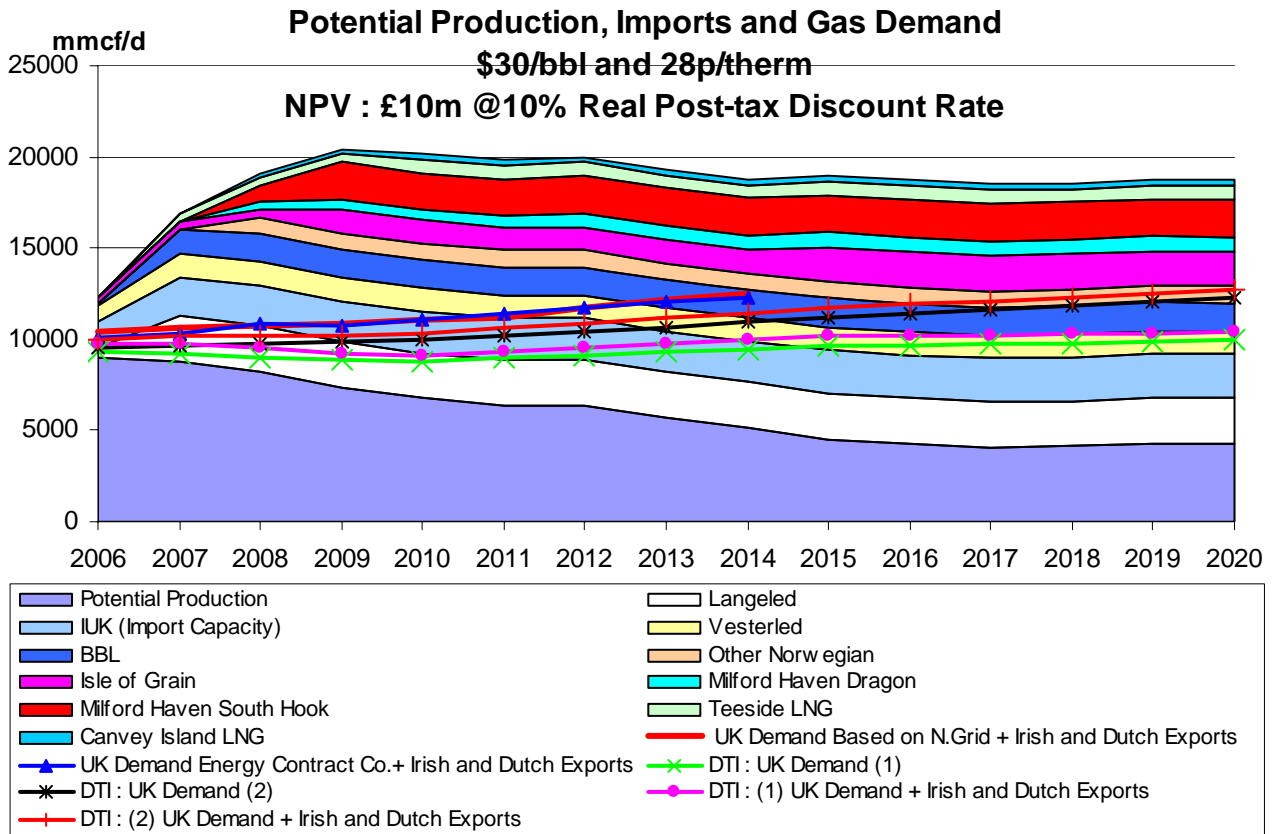


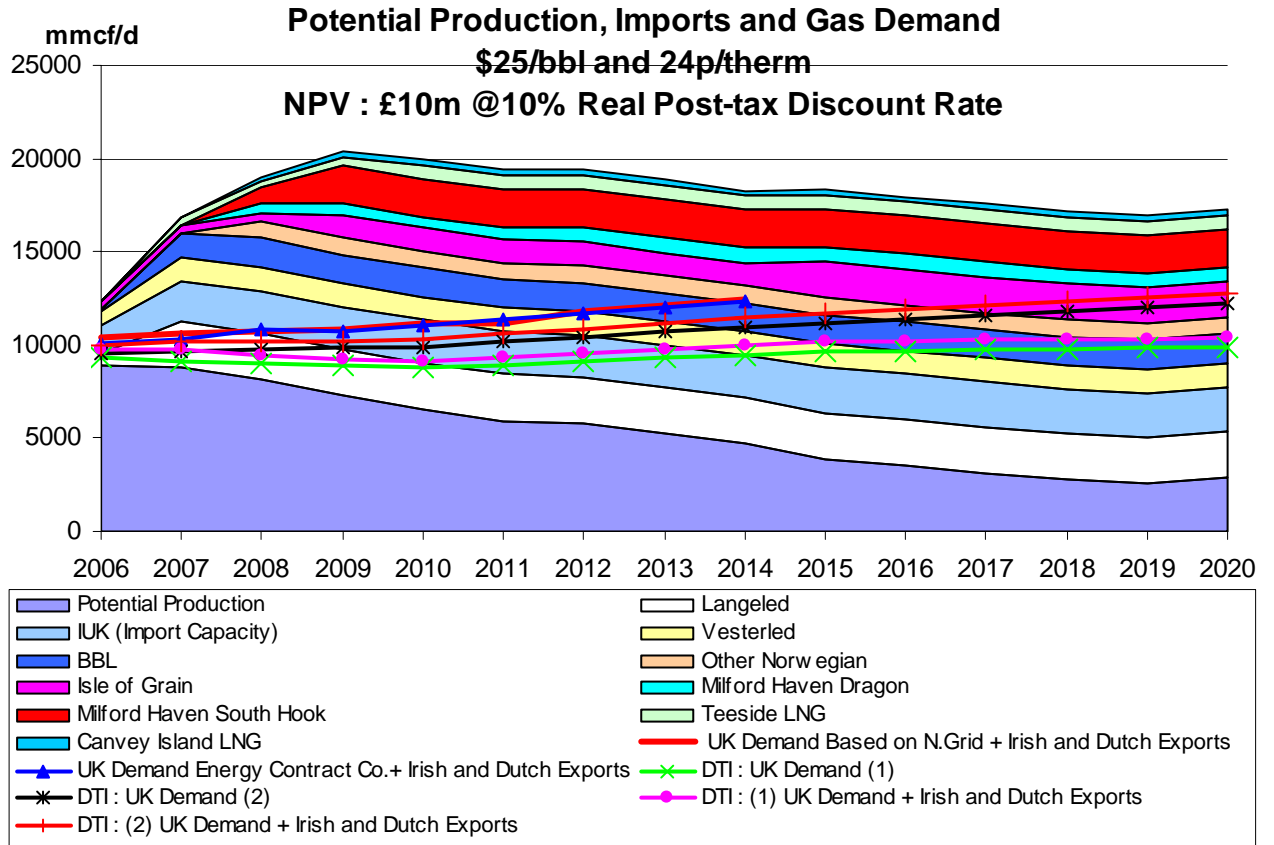
Chart 11 shows annual expected demand plus exports to Ireland and The Netherlands alongside potential production and capacity imports at the \$25/bbl and 24p/therm price. Even with the lower level of UK production the capacity is adequate to meet demand to 2020.

Chart 12 shows annual expected demand plus exports to Ireland and The Netherlands alongside potential production and capacity imports at the \$40/bbl and 36p/therm price. The total capacity comfortably exceeds UK demand.

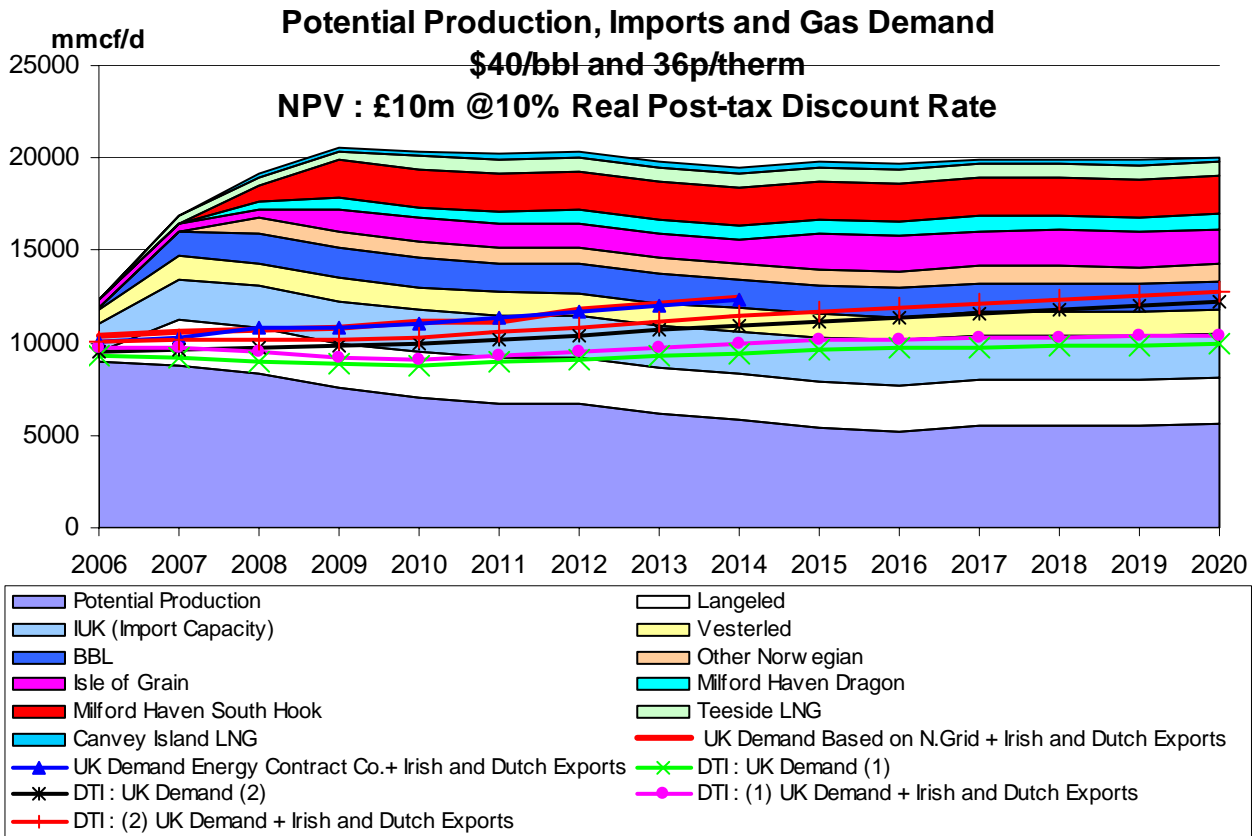
It is important to emphasise that the import capacity figures should not be equated with gas flows. The capacity could be underutilised. The LNG market is increasingly international in character and at least some gas is being sold on a spot or short-term basis according to the attractiveness of different markets. Further, even with pipeline gas the flows may also not correspond to the capacity and short-term price differentials. This has already happened with the Interconnector and could happen with the BBL line. Thus caution is required in interpreting the charts.



### Chart 11



### Chart 12



c) Peak Gas Demand and Supply

A potentially more pressing problem is whether or not gas supply, storage and demand management (through the use of interruptible contracts) will be adequate to meet peak demand. Much of UK peak demand was historically provided for through the swing factor from SNS fields. However, because of the changing nature of contracts and the depletion of the older fields, much of this swing has gone. Newer contracts tend not to have the same requirements for swing gas, and a large proportion of UKCS gas is now extracted as associated gas where the pace of oil extraction determines the rate of gas supplied. Given that the gas price is much higher in periods of peak demand there is still some incentive for producers to attempt to increase their swing potential.

The National Grid view of peak demand shown is undiversified demand for 1 in 20 winter conditions. This means that the 1 in 20 peak demand occurs simultaneously in all parts of the UK. This could exceed expected or diversified demand by around 10%. National Grid is obliged to use undiversified demand in the planning of its network since any element of the system has to accommodate 1 in 20 conditions. Gas customers with the ability to switch to alternative fuel sources may do so when the gas price rises. National Grid estimates that this potential to switch may reduce demand by 10%. In the JESS reports (see References) the concept of severe winter demand is employed. This relates to 1 in 50 winters.

Two cases of peak gas production have been employed in this study. The first case, High Swing, is based on recent historic performance (modest compared to earlier dates) where a field's swing factor is known or, for future fields, is based on the average swing factor for the area and field

type. The second case, Low Swing, is based on a much lower swing factor to take account of the change in contract styles and the current typical nature of new gas production.

Table 5 shows the estimated prospective deliverability, capacity, and number of days over which the deliverability is sustainable from storage in the year 2015. The estimates are those of the authors based on information from a variety of sources (see References). Those projects in the new confirmed category are very likely to become available. Those in the new possible category are subject to much more uncertainty. The storage in the possible category becomes significant only in 2009, building up to a plateau in 2012. (See following charts).

<b>Table 5</b>			
<b>Potential Storage Capacity and Deliverability in 2015</b>			
<b>Current Storage/ LNG</b>	<b>Deliverability (mmcf/d)</b>	<b>Number of Days</b>	<b>Capacity (mmcf)</b>
<b>Rough</b>	1483	67	113560
<b>Hornsea</b>	635	18	11155
<b>LNG</b>	1694	5	9178
<b>Hole House</b>	106	10	988
<b>Hatfield Moor</b>	71	23	4095
<b>Humbly Grove</b>	254	37	10255
<b>Confirmed New Storage</b>			
<b>Aldbrough</b>	1412	11	14826
<b>Byley</b>	565	10	5825
<b>Hole House</b>	212	5	1003
<b>Caythorpe</b>	388	18	7060
<b>Saltfleetby</b>	1906	11	21180
<b>Welton</b>	318	48	15356
<b>Possible New Storage</b>			
<b>Holford</b>	251	24	6001
<b>Albury 1</b>	388	15	5648
<b>Fleetwood</b>	4024	15	60010
<b>Bletchingley</b>	2753	11	30888
<b>Portland (1)</b>	953	11	10590
<b>Albury 2</b>	388	65	25240
<b>Gateway</b>	1094	31	34241
<b>Portland (2)</b>	635	28	17474
<b>Portland (3)</b>	635	28	17474
<b>Gainsborough</b>	124	65	7992

Chart 13 shows potential peak supply with a High Swing factor and demand at the medium price with current and potential storage and imports. The figures for imports reflect the capacity of the schemes. The figures for storage reflect the deliverability rates (Shown in Table 5 for 2015).

When storage and imports are added to the High Swing factor peak demand should be met, although the market is very tight in 2006 with the National Grid peak estimate. Subsequently there should be adequate capacity, though there may be a problem with peak demand in 2021 onwards if the confirmed new storage does not materialise.

Chart 14 shows potential peak supply with a Low Swing factor and demand at the medium price with current and potential storage and imports.

With the Low Swing factor is reduced peak demand in 2006 is not met under the National Grid demand estimate and the JESS severe winter outlook projection. The shortfall in 2006 may be 1158 mmcf/d to 1622 mmcf/d. There may be problems satisfying JESS severe winter peak demand from 2017 onwards if the “Possible New Storage” and “Confirmed New Storage” do not materialise. The high price scenarios are now examined.

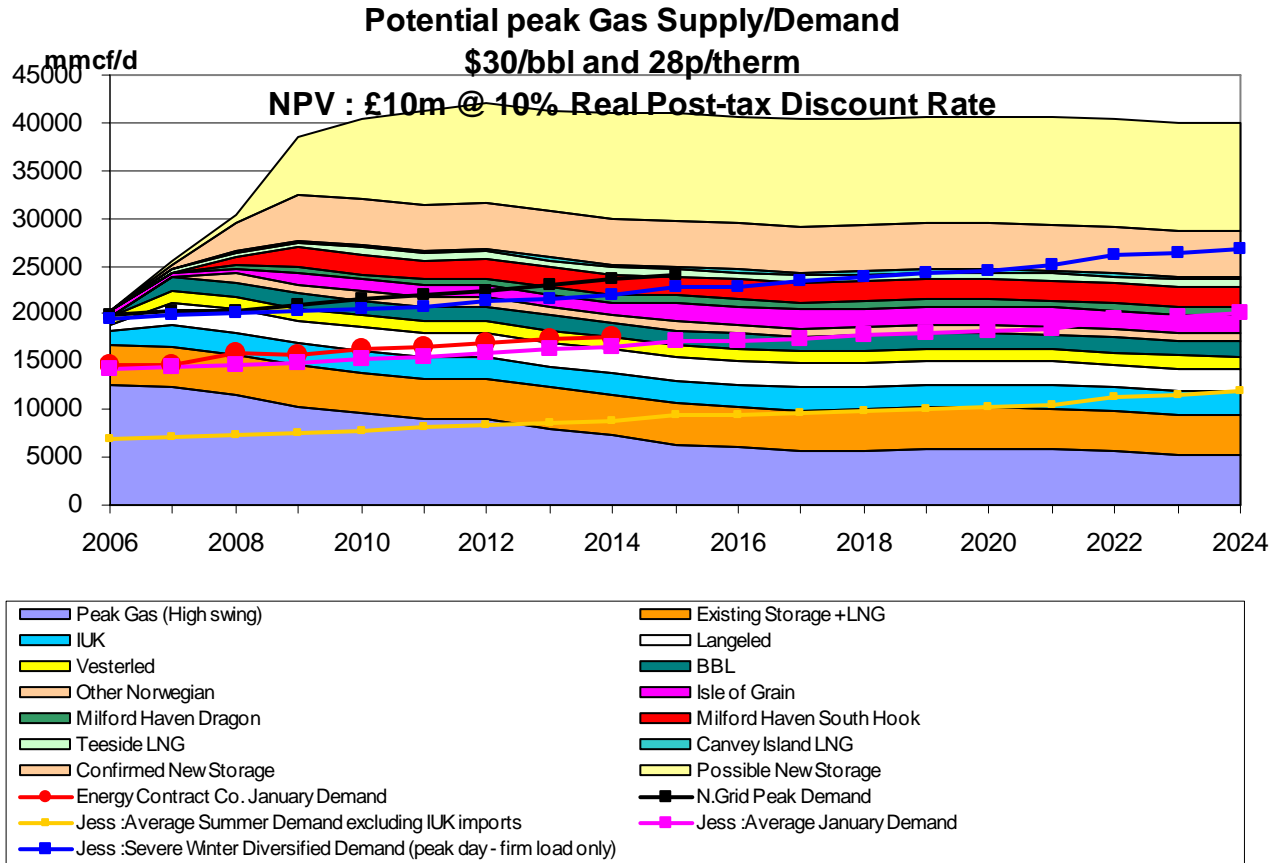
Chart 15 shows the potential peak supply/demand position to 2024 with a High Swing factor. There is no supply shortfall in 2006. There may be problems satisfying JESS severe winter demand from 2022 if “Possible New Storage” and “Confirmed New Storage” do not materialise.

Chart 16 shows the potential peak supply/demand position to 2024 with a Low Swing factor. There is a supply shortfall in 2006 under the National Grid demand projection and the JESS severe winter outlook projection. The shortfalls are 1619 mmcf/d and 1155 mmcf/d. There may be problems satisfying Jess severe winter and National Grid peak demands from 2021 onwards if the “Possible New Storage” and “Confirmed New Storage” do not materialise.

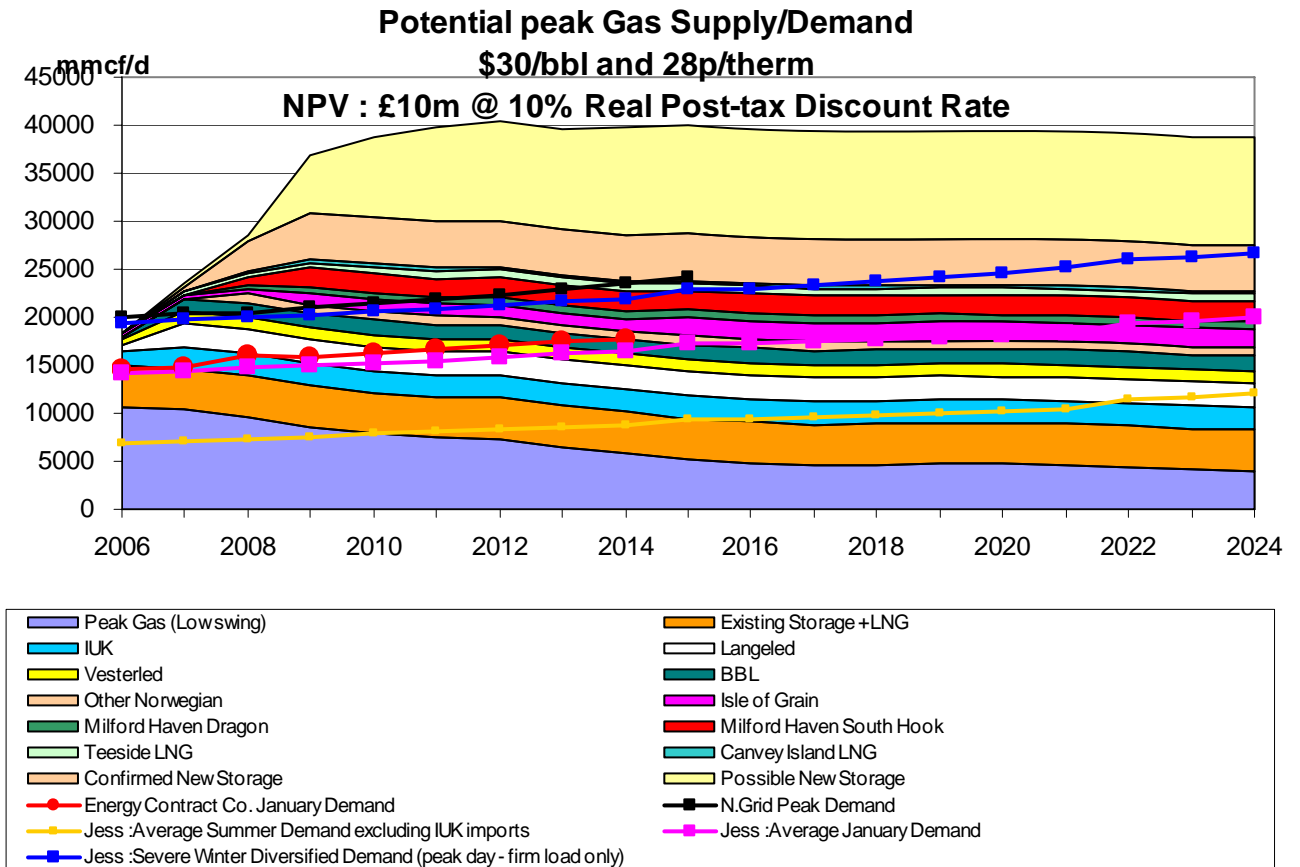
Chart 17 shows the potential peak supply/demand position to 2024 with the High Swing factor. Supply should generally be adequate to meet the demand projections but new storage is required from around 2017.

Chart 18 shows the potential peak supply/demand position to 2024 with a Low Swing. There is a demand shortfall in 2006 with the National Grid and JESS severe winter outlook demand projections. The shortfalls are 1630 mmcf/d and 1165 mmcf/d. There may also be problems in satisfying National Grid peak demand from 2016 the “Possible New Storage” and “Confirmed New Storage” do not materialise. If “Possible New Storage” does not materialise there may be a shortfall of 402 mmcf/d in 2024.

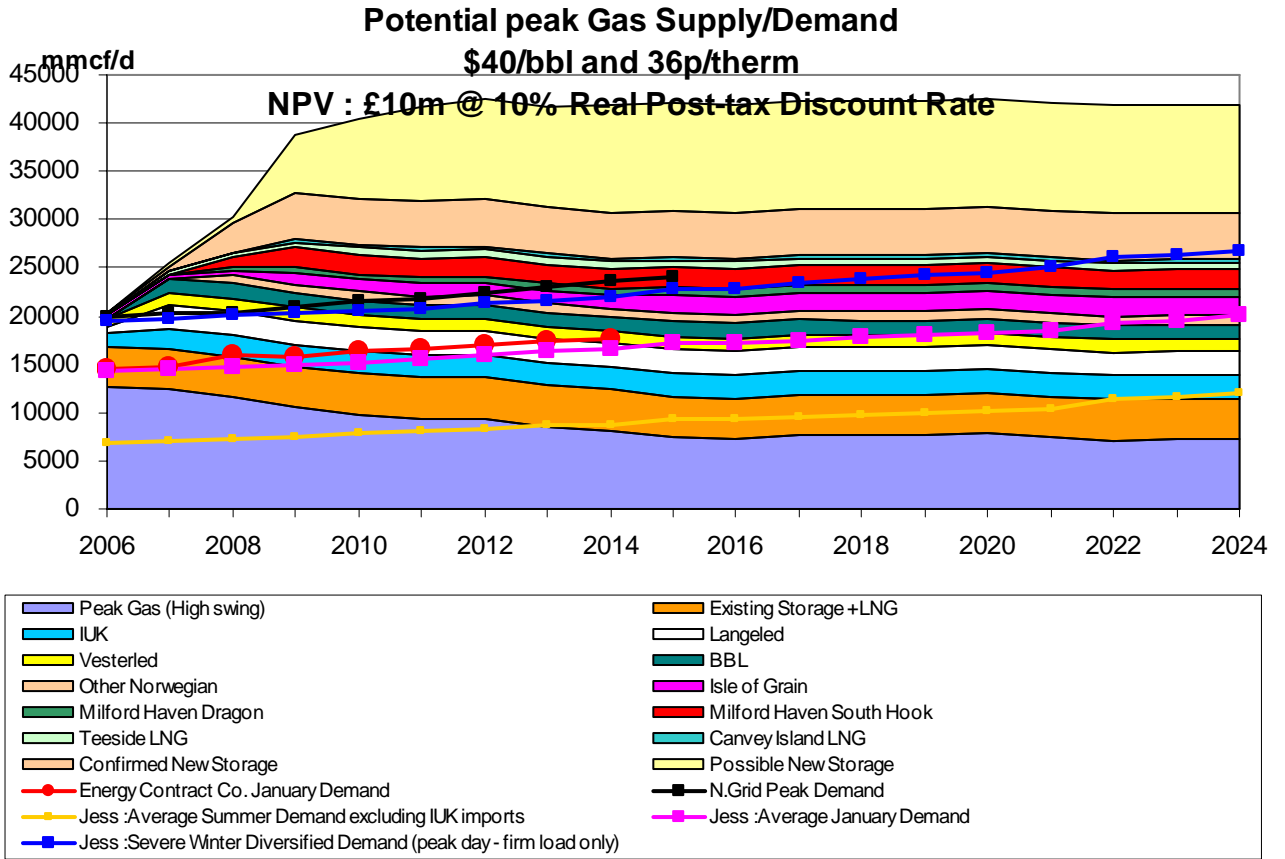
### Chart 13



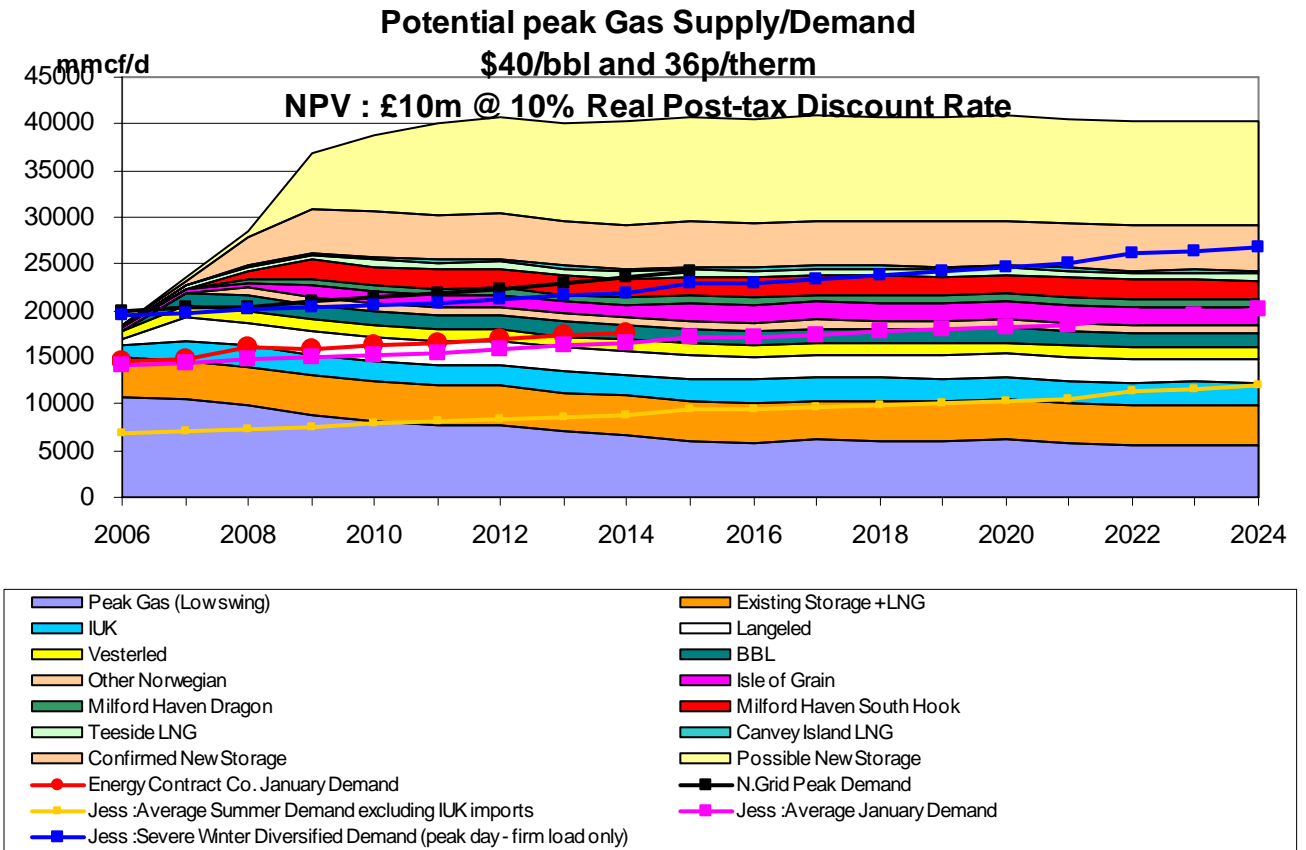
### Chart 14



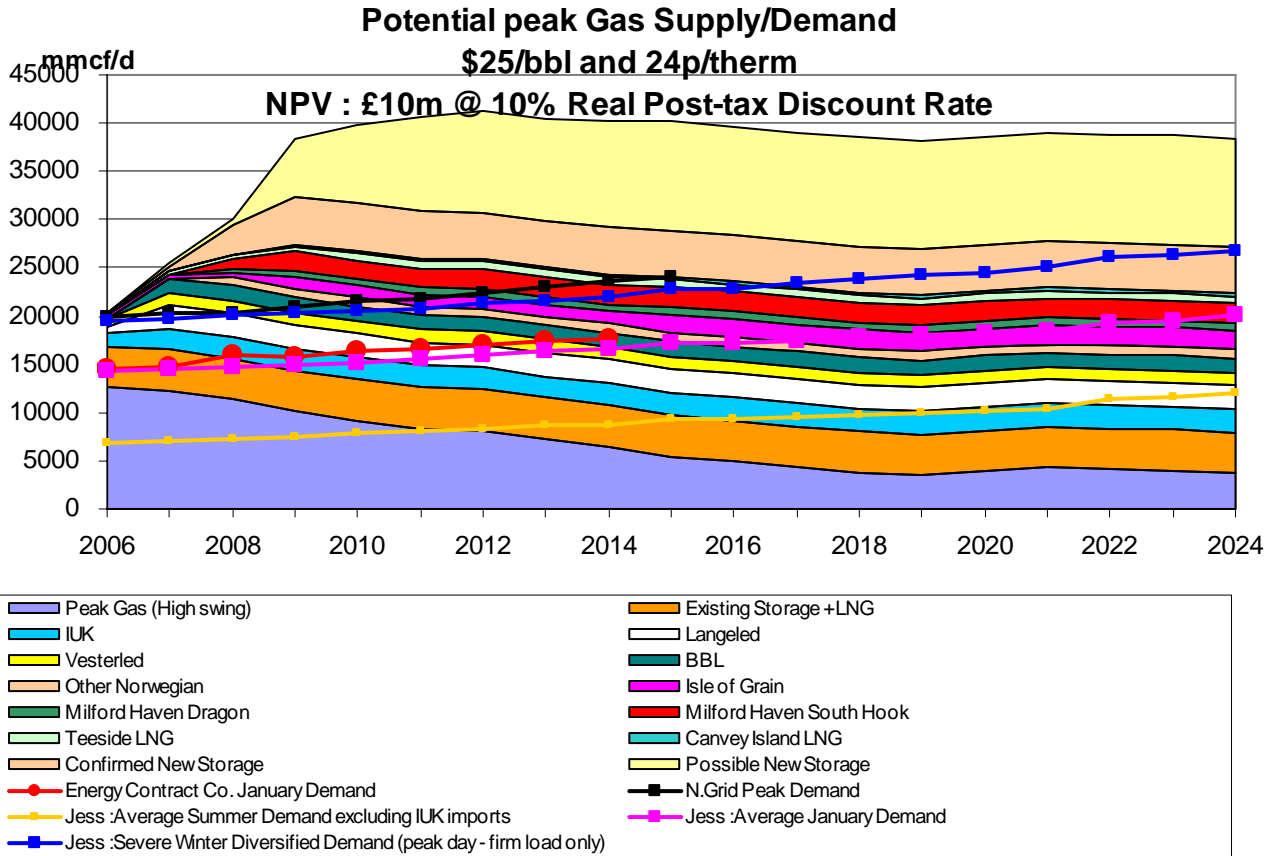
### Chart 15



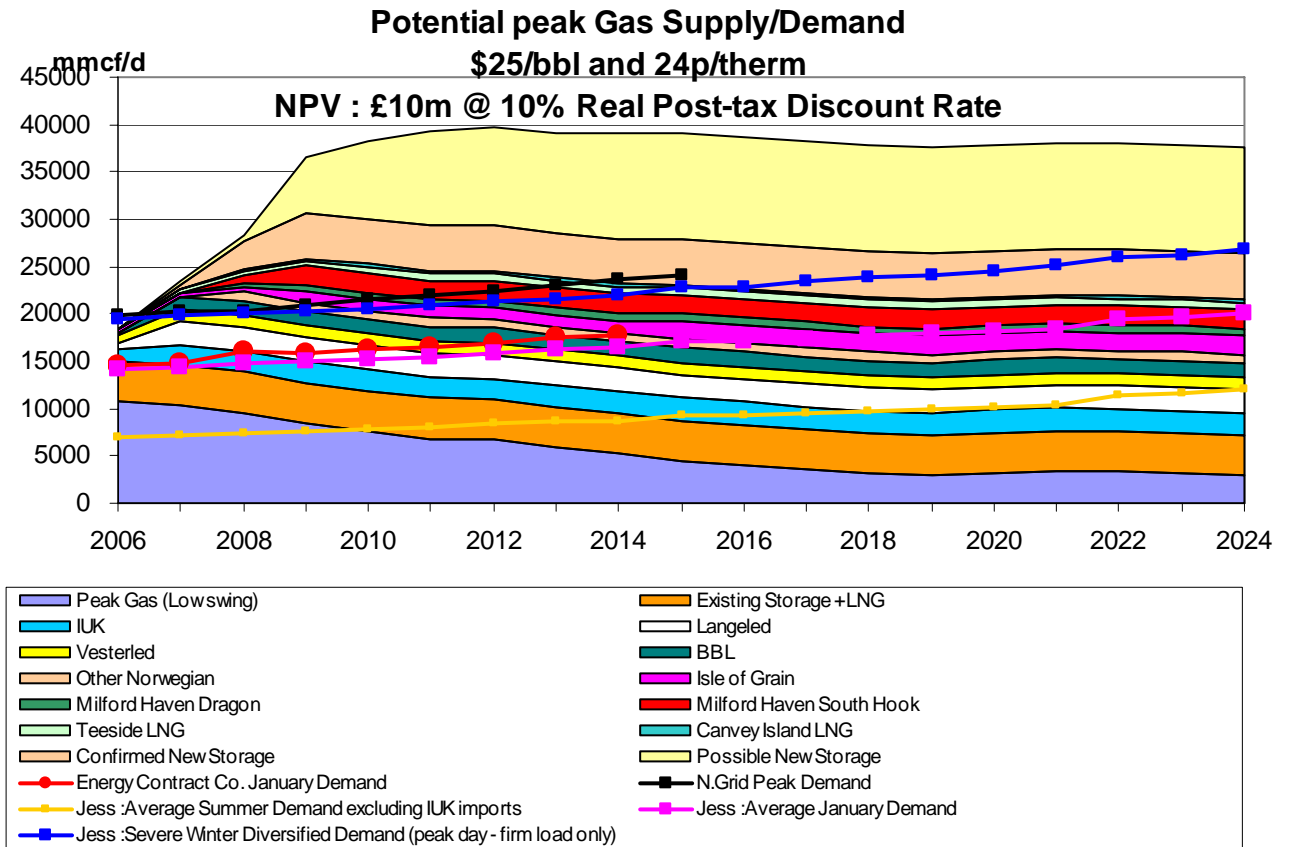
### Chart 16



### Chart 17



### Chart 18





d) Summer Supply and Demand with Restrained Imports

There is understandably much concern regarding supply security in peak demand winter periods, but there is very little public attention paid to the supply/demand position in the summer months. Supply is normally reduced in the summer months by scheduled maintenance programs and demand is lower as less gas is required for power generation and for the domestic market. Two cases are examined with respect to utilisation of the import capacity. In the first the gas flows are well below capacity, especially with respect to the LNG schemes. In the second the capacity is heavily used. Specifically, in the first case it is assumed that Langeled and BBL will operate at around capacity in the summer months, but Vesterled and Other Norway will operate at only 55% of capacity. It is also assumed that Isle of Grain, Milford Haven South Hook, Milford Haven Dragon, Teeside LNG and Canvey Island LNG schemes operate at 30% of capacity in most summer months<sup>4</sup>. The summer production was calculated from annual production and peak swing. The production shown below assumes an average swing factor (between High and Low).

Chart 19 shows the summer position on the above assumptions at the \$30 and 28p price. The “negative” portion of the production in the chart shows the gas being put into existing storage in the summer months<sup>5</sup>. After 2006 the excess supply potential rises from 2526mmcf/d to a peak of 2750mmcf/d in 2008. This is consistent with a fall in the summer spot price. Some gas might then be diverted to the European market. LNG can also be diverted to other markets. In the longer term (post 2015) it is

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<sup>4</sup> The assumptions for summer capacity utilisation of the Vesterled and Other Norway pipelines and the Milford Haven South Hook and Dragon, Teeside and Canvey Island LNG schemes follow those made by The Energy Contract Company (2006). (See References).

<sup>5</sup> Looking ahead gas will also be put into the new storage schemes but the uncertainties on the volumes concerned are so great that this is not presented here.

clear that domestic production plus the restrained imports are insufficient to meet UK demand. The scenario is not a viable one in the longer term.

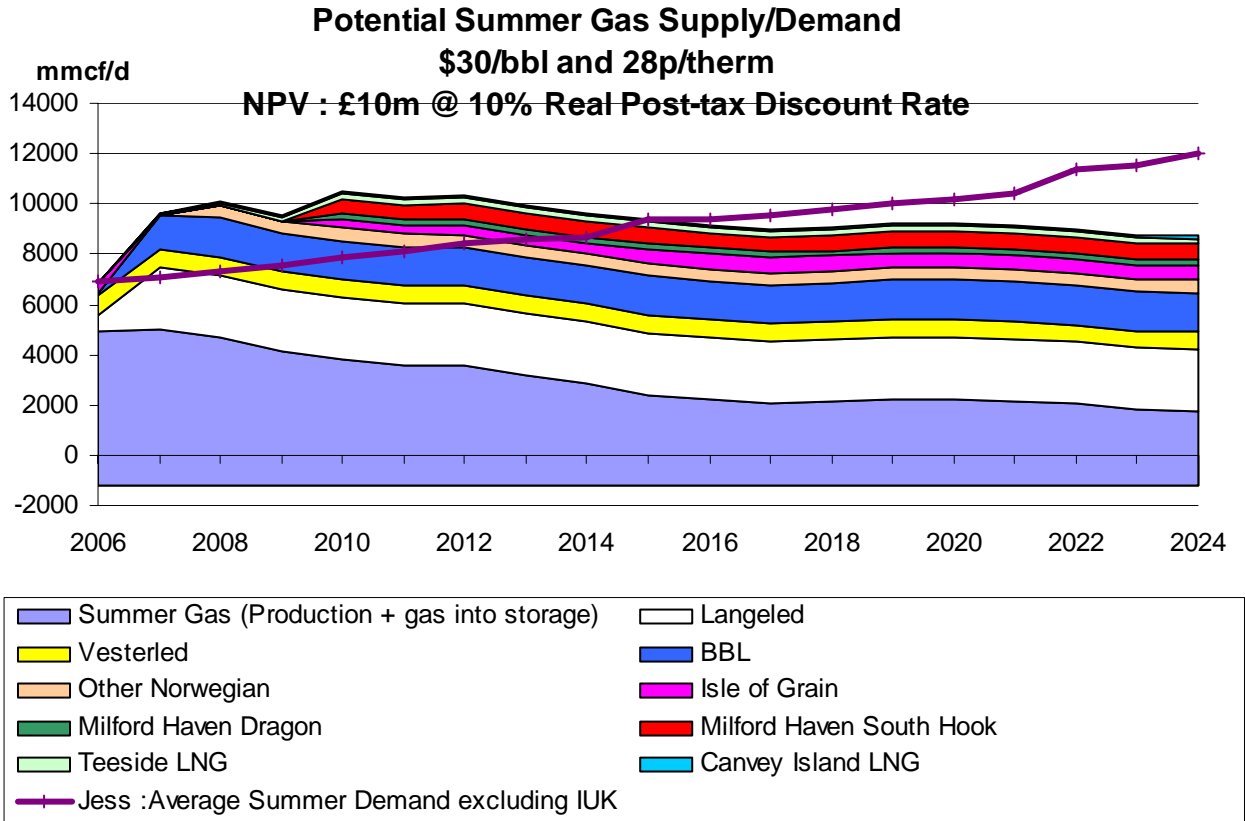
Chart 20 shows the summer position at the low price. After 2006 the potential supply excess rises from 2498mmcf/d to a peak of 2696mmcf/d in 2008 which is again consistent with a fall in summer prices. There could again be diversion of gas to other markets. After 2014 domestic production plus the restrained imports fall well short of UK demand, suggesting that the scenario is not viable in the long run.

Chart 21 shows the summer position at the high price. After 2006 the potential supply excess rises from 2525mmcf/d to a peak of 2795mmcf/d in 2008. This again could lead to falls in the spot summer price and a diversion of supplies to other markets. From around 2020 further imports will be required.

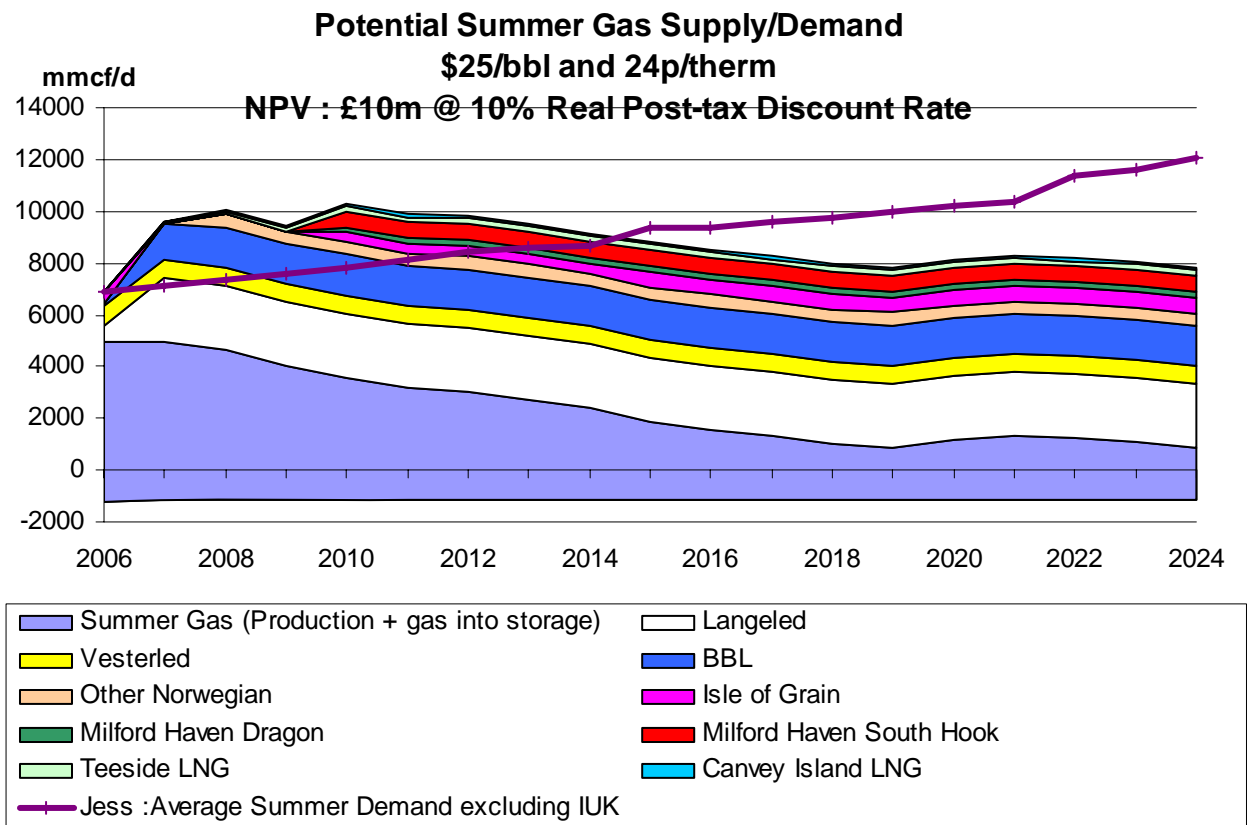
e) Summer Supply and Demand with Imports at Capacity

Charts 22, 23 and 24 show prospective summer supply with the import projects at around their capacities. It is seen that there is then a substantial potential surplus of gas, consistent with a fall in spot wholesale price. This is the case under all the price scenarios, though by 2024 the capacity would be fully utilised.

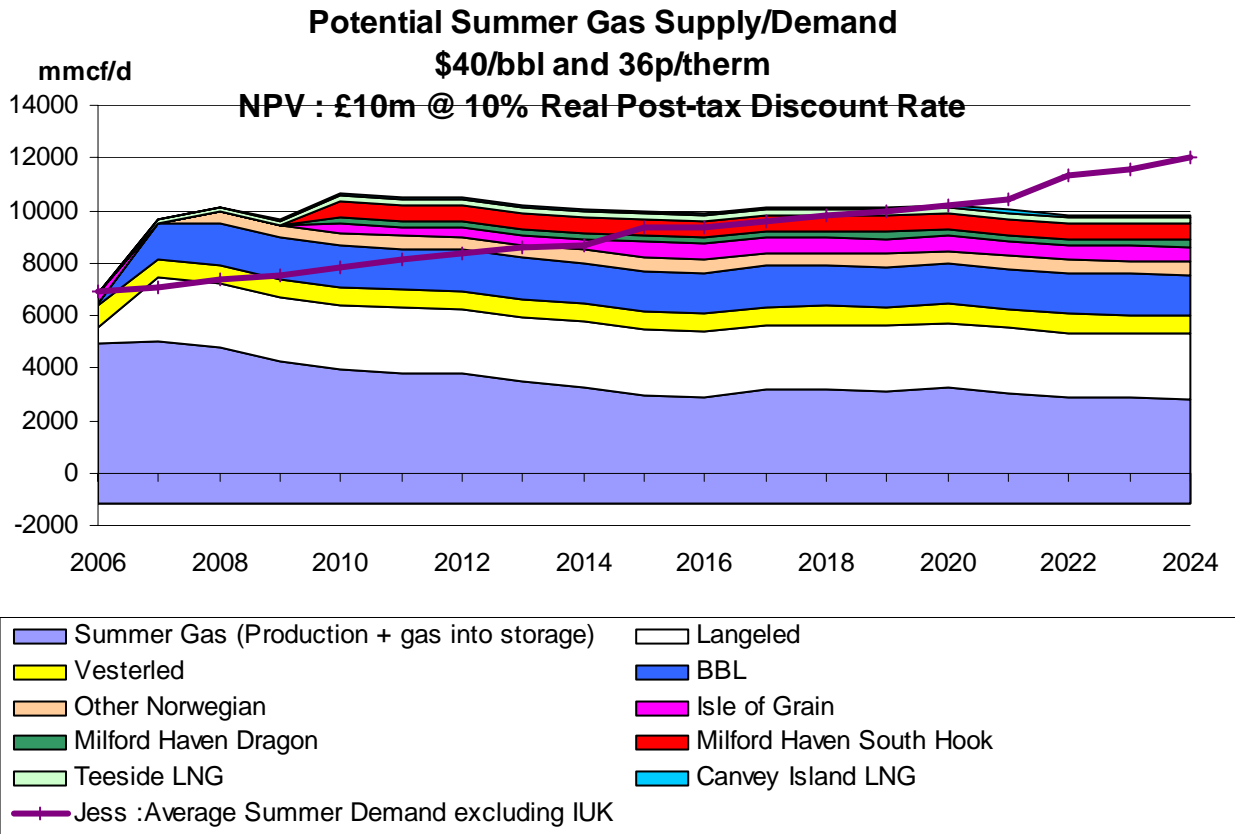
### Chart 19



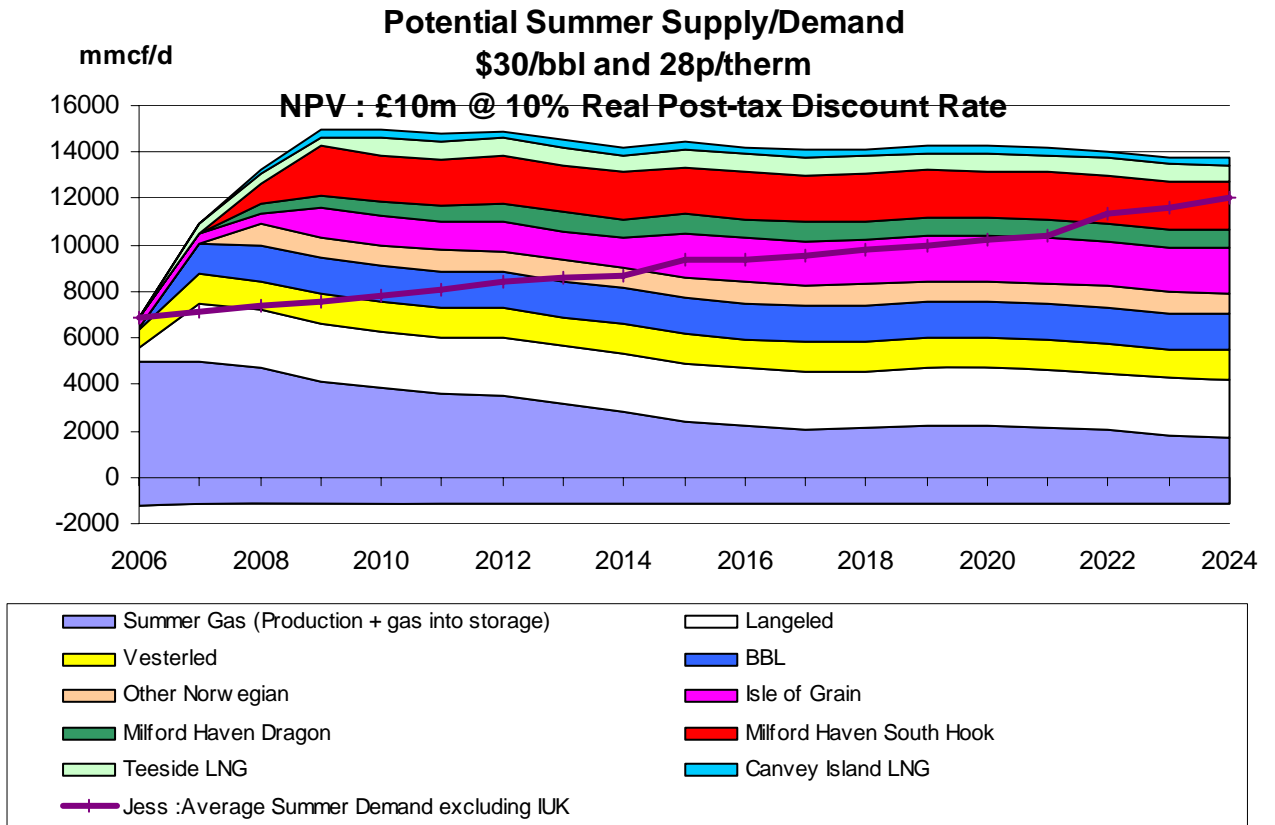
### Chart 20



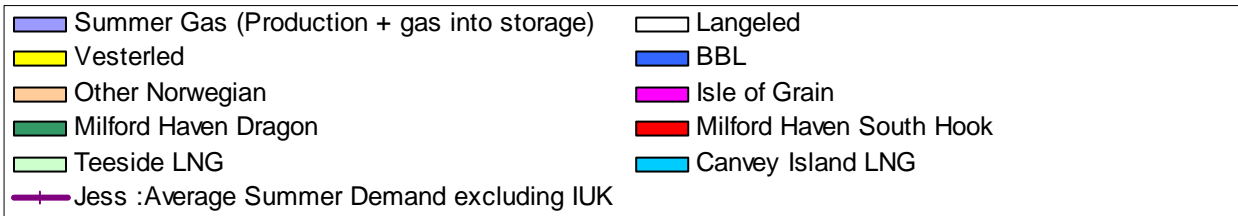
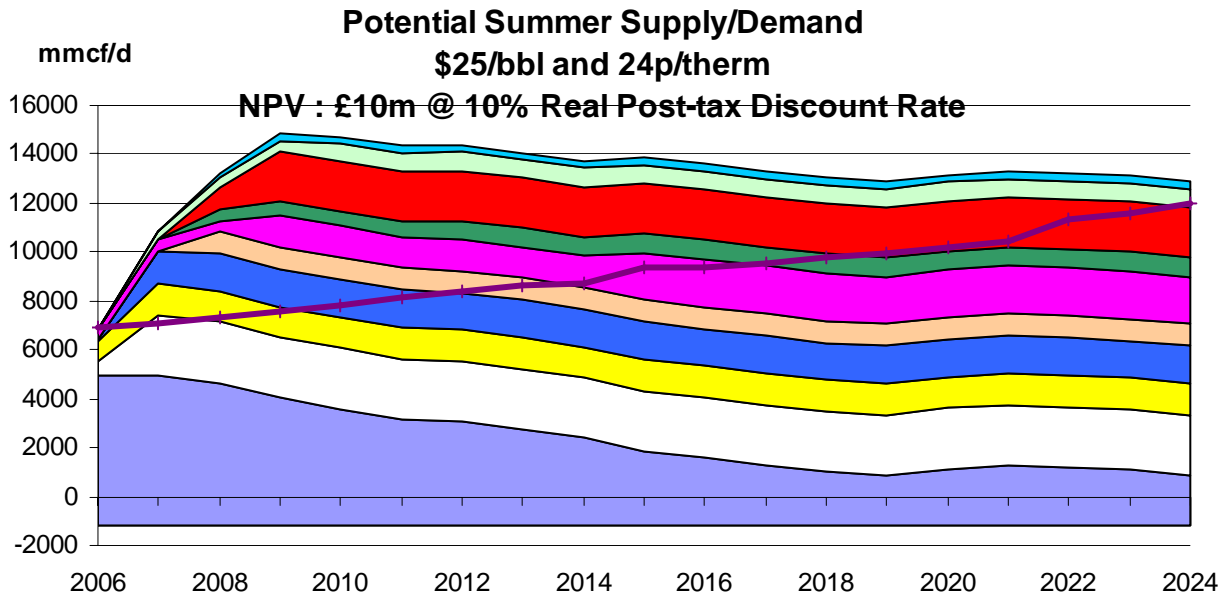
### Chart 21



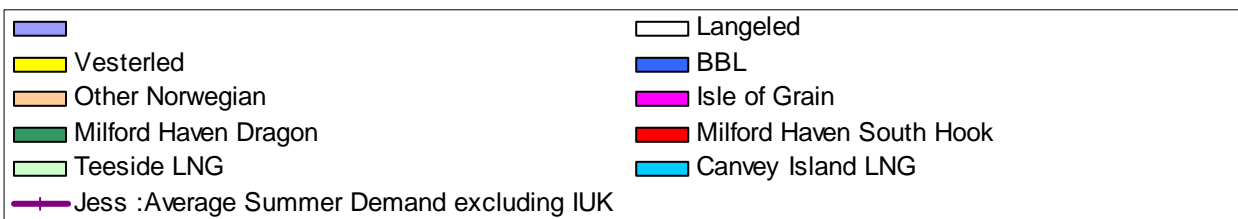
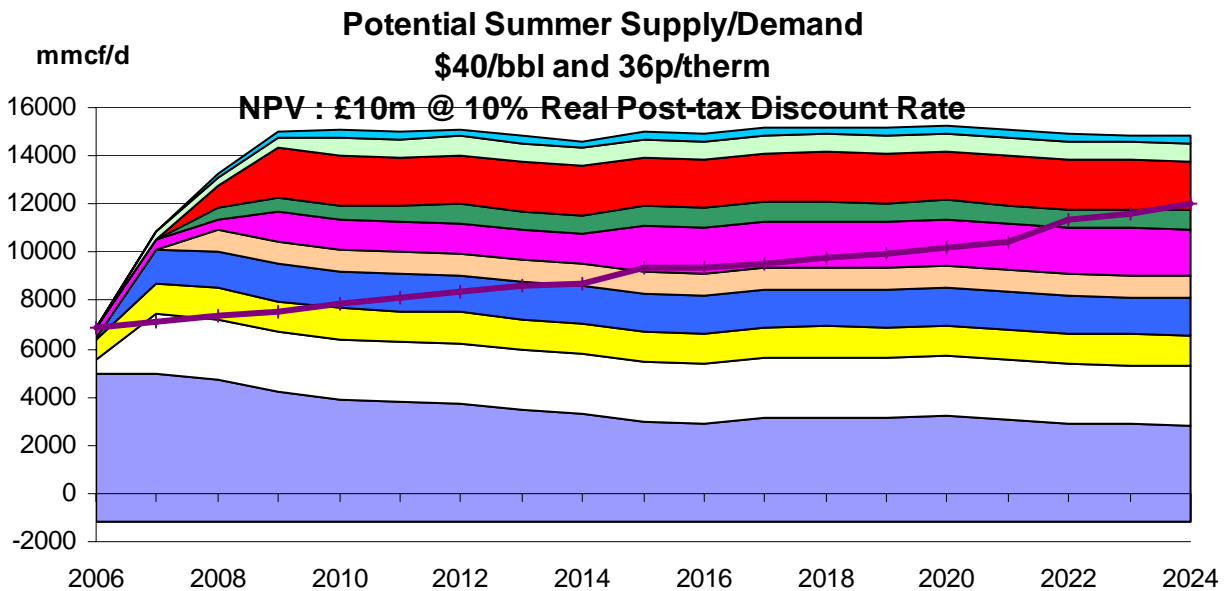
### Chart 22



### Chart 23



### Chart 24



#### **4. Conclusions**

In this study projections of potential gas production from the UKCS under different assumptions have been made with the employment of financial simulation modelling and a high quality field database. The modelling suggests that under the \$30, 28 pence price scenario production could fall from 8.9bcf/d in 2006 to 6.8 bcf/d in 2010 and 4.3 bcf/d in 2020. Under the \$40, 36pence scenario it could fall to 7 bcf/d in 2010 and 5.6 bcf/d in 2020, and under the \$25, 24pence scenario it could fall to 6.6 bcf/d in 2010 and 2.9 bcf/d in 2020.

These production prospects were compared with a number of reputable projections of potential UK gas demand. Net gas imports will be required on a growing scale. Under the \$30, 28 pence scenario imports could comprise 23% to 37% of total requirements in 2010 and 57% to 65% of total demand in 2020. Under the \$25, 24 pence scenario the corresponding reliance on gas imports becomes 25%-39% in 2010 and 71%-77% in 2020. Under the \$40, 36 pence scenario the corresponding reliance on gas imports becomes 20%-35% in 2010 and 43%-54% in 2020.

The various projected import projects were then examined. On an annual average basis it was found that potential capacity plus UK production could significantly exceed annual UK demand throughout the period. This is consistent with gas prices falling from their present levels. But there are other possibilities and in particular some of the gas relating to the import projects may be diverted to other markets. This could happen with LNG which is increasingly becoming an international market. At least marginal supplies can be diverted to the most attractive short-term markets depending on the contractual arrangements. Also, as the experience of the winter of 2005-2006 highlighted, gas flows through the Interconnector may not follow the short-term

price differentials. Much depends on the contractual arrangements in the European continent.

The key general point with respect to future gas prices is that they will depend on the supply/demand situation not only in the UK but in other markets. For LNG this means both the USA and the European continent, and for pipeline gas the European continent in particular.

From the projections it is noteworthy that the UK's direct dependence on Russian gas is likely to be very small in the period examined, though some Russian gas may flow through the Interconnector and the BBL pipelines. The main effect is indirect emanating from the increasing importance of Russia as a gas supplier to the European continent, with the consequences for the UK resulting from its growing interdependence with Europe.

With respect to UK security of gas supply the prospective growth in capacity is comforting not only because of its scale but also because of its diversity. The import projects are well-diversified both with respect to sources of gas and infrastructure.

The study also examined the peak demand situation. In the near term (winter 2006-2007) the supply/demand balance will be tight. This is especially the case if the swing factor from UK production is lower than historically achieved and 1 in 20 winter demand conditions are experienced. This would mean substantially higher demand than experienced in the last few winters. Using the National Grid definition it involves 1 in 20 winter demand conditions occurring simultaneously in all regions of the UK. From the evidence it may be concluded that the risks of a serious problem emerging in the winter of 2006-2007 are not as high as was the case in 2005-2006, but they cannot be

dismissed. In the medium-term the development of new storage projects and import schemes should ensure that peak demand can be comfortably met on the basis of capacity available from import projects and storage. It will, of course, be necessary that the new import capacity is reflected in corresponding gas volumes, and there can be no guarantee that this will be the case. In the winter spot prices may go very high in one market and lead to the diversion of marginal supplies either in LNG or pipeline form to where the most attractive returns can be obtained.

The prospective summer supply/demand balance, given the import capacity that is being created to ensure security of supply in peak winter conditions, is consistent with a fall in spot prices. Much will then depend on how much of the import capacity is utilised which in turn will depend on market opportunities elsewhere.

A further final conclusion is that while the study gives substantial comfort regarding prospective security of gas supply the uncertainties surrounding the market are very large. This follows from the increasingly interrelated nature of the international market and the uncertain supply/demand outlook in the USA and Continental Europe which will both be requiring increasing quantities of imported gas. Wholesale prices are likely to be volatile.

The prospect for continuing oil import dependence in some respects involves complexities as the necessary infrastructure is largely in place and there is not a peak demand problem comparable to that in the gas market. Oil import dependence still involves uncertainties relating to the supply prospects in several of the main producing countries. These will be reflected in price volatility which is likely to remain substantial.



It is emphasised that the oil and gas production projections depend on the continued success of the various PILOT/DTI initiatives relating to (a) the activation of fallow fields and blocks, (b) the Infrastructure Code of Practice, and (c) the stewardship of mature fields. The facilitation of asset transactions, including the solution to the problem of financial security for decommissioning liability should enhance activity in mature fields. The prolongation of the life of the infrastructure will also enhance development activity in the long-term. If the various initiatives do not bear fruit on a substantial scale the low production case could be the result.

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