STRATEGIC STORAGE AND OTHER OPTIONS TO ENSURE LONG-TERM GAS SECURITY

A report to DTI

April 2006
STRATEGIC STORAGE AND OTHER OPTIONS TO ENSURE LONG-TERM GAS SECURITY

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STRATEGIC STORAGE AND OTHER OPTIONS TO ENSURE LONG-TERM GAS SECURITY

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EXECUTIVE SUMMARY

The delivery of significant quantities of reliable, new gas supplies is required to meet future demand for gas, and there are a number of large infrastructure projects currently under development that will bring new commercial supplies of gas to the UK. There is some debate, however, as to whether the level of security of supply that will be delivered by the market, under its current regulatory structure, is as high as may be economically, socially or politically desirable.

In addition there are a number of factors that have led to calls to examine the question of the long-term security of supply:

- increased use of gas in electricity generation;
- UKCS production has a declining ‘swing’ capability;
- reliability of existing gas industry infrastructure; and
- UK will be increasingly reliant on imports increasingly remote from the UK. Imports will arrive by pipeline through Europe and as LNG in tankers delivering gas production from countries outside Europe.

There is the possibility of a ‘gap’ between supply and demand. By definition the gap opens when the commercial supply cannot meet commercial demand. The only option left for supply to balance demand is for involuntary firm demand load shedding with the consequent interruption to industry and industrial production. Forced interruption of firm gas demand would cause industry to incur unexpected costs through loss of production. There may be a basis for government intervention if the costs of the market failure are sufficiently high.

Calculating the potential gap

We calculate the ‘gap’ between demand and supply by assuming that the government takes no action to develop solutions to address the gap. In this ‘do nothing’ world, the commercial market is left to operate without any interference. The expected gap between supply and demand is our estimate of the extent to which the market, left to its own devices, will not meet firm customer demand in the future, resulting in involuntary firm load shedding. We calculate a probability distribution for the gap between supply and demand; the ‘expected gap’ is the mean of this probability distribution.

We attempt to quantify the gap in gas supply in Great Britain, for each year in the timeframe 2006 to 2020. We attempt to assess both the annual volume shortfall (in billion cubic metres, or bcm) and the number of days in the year during which the shortfall pertains.
Supply-demand

We have developed three scenarios – Constrained, Balanced and Abundant – for supply/demand conditions over the next 15 years. The scenarios include projections for demand, UKCS production, import capacity and storage capacity. These projections include known projects as well as generic new build. In these scenarios, our demand and capacity projections are combined in ‘opposition’ (e.g. high demand growth with low capacity) in order to create high, central and low gas price scenarios.

The Constrained, Balanced and Abundant scenarios correspond to P10, P50 and P90 cases, respectively, in the probability modelling. This means that, in any given year, we estimate there is a 10% chance of the supply/demand balance being tighter than in the Constrained world; and a 90% chance of it being tighter than in the Abundant world.

Table 1 – Supply-demand scenarios

<table>
<thead>
<tr>
<th></th>
<th>Demand</th>
<th>Domestic UK supply</th>
<th>Available import capacity</th>
<th>Storage capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constrained (high price)</td>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Balanced (central price)</td>
<td>Central</td>
<td>Central</td>
<td>Central</td>
<td>Central</td>
</tr>
<tr>
<td>Abundant (low price)</td>
<td>Low</td>
<td>High</td>
<td>High</td>
<td>High</td>
</tr>
</tbody>
</table>

Source: ILEX

The three scenarios – Constrained, Balanced and Abundant – represent the range of possible future scenarios for the UK gas industry plus a central scenario. Together the three scenarios represent an envelope of outcomes and we would expect that the future UK supply/demand balance is likely (with 80% likelihood) to be contained within this envelope. The position in any year will depend on future demand and supply, and we would expect the path taken to go through periods of constraint and periods of abundance as part of the normal commercial investment cycle. The winter of 2005/06 is an example of a period of constraint.

Furthermore, these scenarios are based on ‘normal’ conditions (for example, normal weather patterns and long term supply reliability) and do not take account of random or unpredictable effects. These are simulated separately, as discussed in the following section.
Simulation approach

In order to estimate interruption likelihood, we need a probabilistic framework for our supply demand scenarios\(^1\). We also need to quantify atypical effects – comprising short-term losses in supply, and variations in demand due to weather – both of which are outside the scope of our initial scenarios. In order to combine our scenarios and capture these various short-term effects, ILEX has developed a simulation model of future gas supply and demand, using our GB Gas Model as a basis.

It has proved to be very difficult to reach consensus on the probabilities of supply interruption, and on the proportions of supply that might be interrupted. ILEX’s approach has been empirical: we have based our probability estimates on observed historical events that have affected Britain’s gas supply. We have based our outage proportions on the relative sizes of individual fields in the UKCS, while we have assumed that any individual LNG source or pipeline could be completely curtailed. We have run the analysis with an alternative set of probabilities (and interruption proportions) based on greater supply reliability, determined by the DTI.

We model the risk of losses of supply and variation in demand in the three scenarios. The likelihood of a given shortfall is then determined from the number of iterations which give at least that level of shortfall, out of a total number of 1000 iterations.

The supply/demand gap

The following key messages emerge from the analysis of the potential gap between supply and demand:

- regardless of one’s views on the probabilities that outages will occur at individual sources, there is always a minimum level of supply gap risk, which is associated with demand variation and the underlying balance of demand and supply;
- at the 1 in 20 chance level, the gap is close to zero, but there is a 1 in 50 chance that the gap could be comparable with 1 Rough Equivalent\(^2\);
- aside from the next two winters – which are too imminent for the advent of a major new storage facility – this gap only becomes manifest in the years from 2014 onwards in the commercial market;

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\(^1\) The probabilities here are not for the scenarios themselves (whose probability is zero as they are point estimates) but for the world being ‘better’ or ‘worse’ than any particular scenario.

\(^2\) A Rough Equivalent is a measure of storage capacity based on the largest storage facility in the UK. Rough can supply around 44mcm/day for a period of 75 days i.e. a total volume of 3.3bcm.
• the profile of modelled outages tends to suggest that a solution which covers 60-90 days of shortfall is more suitable than one which covers a few days or weeks;

• even a strategic storage facility equivalent to Rough would not completely eliminate the risk of a shortfall, and the cost-benefit analysis needs to consider the magnitude of the residual risk; and

• 1-day supply interruptions cannot be ignored, though other factors in aggregate make a greater contribution to the risk of a supply shortfall.

Alternative Options

We look at alternative options that could close a shortfall between gas supply and gas demand in the UK (the gap) equivalent to one Rough storage facility (one RE), or 44 mcm/day for 75 days. We do not imply that 75 days is necessarily optimal (though the simulation results suggest it may be a reasonable duration) but by specifying the storage requirements in detail, we can compare alternatives numerically.

To be considered, any option must deliver incremental physical gas to the UK, or bring about an actual reduction in the UK gas demand. The options must be separate from, and additional to, the commercial arrangements that are called upon for balancing supply and demand under normal conditions.

We group the options that could fill a shortfall between supply and demand under a) increase in the supply of gas, and b) reduction in gas demand; and describe each of the options in turn. DTI requested that the three most promising alternative options should be developed in more detail. After some discussion about the feasibility of each option to fill the gap it was decided that the short listed options were:

• storage in the UK using any of depleted field storage, salt cavern storage and LNG storage tanks. The higher deliverability of salt cavern and LNG storage would mean that only part of the deliverability would be used to provide a 75-day service;

• supply from Europe, probably sourced from new-build storage, could be used and would require additional transit and interconnector capacity to transport the gas to the UK; and

• oil storage at CCGT sites.

Economic impact of interruption

By examining the cost of a gas supply interruption in a ‘do nothing’ scenario we can estimate the avoided cost, or benefit, of developing different amounts of strategic storage. This builds on work previously undertaken by ILEX and Global Insight (GI) on the effects of a UK gas shortage.
Data published by the Office of National Statistics, in particular the Annual Business Inquiry, has been used to measure the impact on the UK economy. Gross value added (GVA) at basic prices has been used in order to quantify these economic impacts where GVA is defined as the value of goods and services less the value of the products used to make them\(^3\).

The approach to modelling the costs of interruption has been based on the following:

- the costs of interruption are based on the industrial sector of the economy only (the commercial sector is not included). The analysis is based on the energy intensive sectors of industry, because these are the sectors most likely to be cut off involuntarily in the event of a physical gas shortage;

- we have assumed the impact of switching-off demand for one day will result in costs from one day’s lost production from the sector impacted and from the sectors directly upstream and directly downstream of the gas interruption. We do not include costs of restarting, cost of damage to stock and/or plant and loss of market share to offshore companies;

- we take account of the reduction in electricity demand associated with lost production, and assume that the electricity demand reduction leads to lower gas consumption at gas-fired CCGT power stations;

- in total we have identified up to 90mcm/day of gas interruption from the industrial sector which is greater than the potential gap in the simulation; and

- the order of interruption is important. We assume that the order is optimised taking account of the total GVA cost (direct+upstream+downstream) with the lowest cost sectors (GVA per mcm) interrupted first. This is the constrained optimum (blue) line shown in Figure 1. Without this optimisation the GVA costs could be significantly higher, as shown by the brown line. The purple line shows the direct costs only and is the impact that would occur if there were no upstream or downstream effects.

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\(^3\) ONS definition: GVA + taxes on products – subsidies on products = GDP
Figure 1 – GVA loss per day (£m) compared to Gas saved per day (mcm) – Ranked by energy-intensive sector taking account of both direct and indirect costs

The slope of the curve represents the GVA impact on a per unit basis. It is consistently £11-12/therm, over the range of involuntary gas interruption modelled.

Source: DUKES, ONS and ILEX analysis

Whenever, in the simulation, there is a gap between demand and supply (after the demand response to price has been netted off), then the model looks up the level of the gap (in mcm) to determine the resulting economic cost (in £m). The losses are summed for each year to give a total annual economic loss from gas supply interruptions. The model reports these annual losses for each year in each iteration of the simulation.

Costs

Storage in the UK

The costs of storage in the UK are based on the costs of new storage recently developed or presently under development in the UK. The projects represent a range of different size facilities and have different characteristics in terms of the amount of cushion gas required and the capital expenditure. The shorter duration salt cavern and LNG storage facilities generally have higher capex costs per volume of storage.

The average figures quoted give an indication of cost. In the implementation section of this report we allow the cost to be set by the market, and cheaper alternatives where they exist would be expected to come through.
Supply from Europe

Since there is no evidence of spare storage capacity in NW Europe, the costs of supply from Europe would be the cost of new build storage plus the cost of transportation to transit Europe and through the gas interconnector. If it were possible to access gas production from Groningen in the Netherlands, we would expect the service to be priced competitively against the other alternatives in NW Europe.

The costs of transit capacity from Europe are likely to add between £0.5 and £1.0 billion pounds in addition to the cost of new build storage, making a supply from Europe uneconomic compared with storage in the UK.

Reduced gas demand at CCGTs

The costs of providing 75 days of backup fuel capability for 400MW are scaled up to cover 10 GW of generation capacity (a Rough equivalent) and would require 26 tanks at twenty-five 400MW CCGTs, giving a total of 650 tanks.

With oil storage there is a risk that, in a high gas price and constrained world in which strategic reserve is required, the amount of gas used and therefore the amount that can be interrupted at CCGTs would be limited, providing at maximum 1 to 1.5 RE (the total installed CCGT capacity is around 2.5 RE).

We looked at the option of holding reserve capability at mothballed coal plant and found that the option may be able to offer a limited amount of capacity.

Benefits

By combining our analysis of GVA loss per day within the simulation, we have obtained a probability distribution for the economic impact due to a gas shortfall. Using the ILEX probabilities (and outage proportions), the impact is significant at the 95th percentile, from 2014 onwards; and it rises to around £20bn per annum at the 99th percentile. In other words, there is a 5% chance of a significant impact from 2014 onwards; and a 1% chance that the impact could be at least £20bn per annum.

If instead of the ILEX probabilities (and outage proportions) we use the alternative set supplied by the DTI, the impact is no longer significant at the 95th percentile, although it is substantial (£5bn-£10bn per annum) at the 99th percentile, from 2015 onwards.

The expected impact is simply the average of all 1000 iterations. This is the green line in Figure 2. The expected impact over the timeframe is simply the sum of the expected impact in each year. Note that this statement does not depend on an assumption that the Constrained scenario, or the Abundant scenario, is sustainable for the entire timeframe. Even if the supply/demand balances for consecutive
years are deemed to be independent of each other, the mean of the sum is equal to the sum of the means.

We can now obtain the benefit of a Rough equivalent by inserting an extra RE into the simulation model and re-running the simulation. The result is the yellow line in Figure 2 and is the residual GVA impact per annum, even if an extra Rough is developed. The difference between the green and yellow lines is the black line, which is therefore the (mean) economic benefit of the extra RE.

**Figure 2 – Benefit of Rough equivalent, using ILEX probabilities (mean outcome)**

Using the ILEX probability assumptions, the benefit is expected to be around £0.5 billion per annum after 2020, based on the average benefit over the timeframe 2015 to 2020. Using the alternative probability assumptions, the mean benefit is around £0.2 billion per annum after 2020.

We estimate that a solution which addresses a shortfall is likely to be needed by 2014. In addition, we make the following assumptions in relation to a storage facility (oil or gas):

- the storage facility will take 3 years to develop, and the costs of it will be incurred 2 years prior to operation;
- the storage facility has a 30 year asset life; and
- the relevant public sector discount rate is 3.5% real.
With these assumptions, the NPV at the end of 2012\textsuperscript{4} (the year in which the costs are incurred) is £8.6 billion using the ILEX probabilities, and £3.4 billion using the alternative probabilities.

**Summary of costs and benefits**

Table 2 summarises the net present value based on an investment in one Rough equivalent operational in the year 2014 and available for a period of 30 years (the assumed asset life).

Table 2 shows the range of costs and covers the full range of fuel price assumptions for depleted field storage (£1.2 to £2.4 billion) and for distillate storage at CCGTs (£0.9 to £1.4 billion).

The benefits are based on the two cases we have used for source outage events and probabilities: the ILEX case and the alternative case. Note that the ILEX figure of £8.6 billion is our best estimate, not the top of a range.

**Table 2 – Summary of costs and benefits**

| Investment in one Rough equivalent (3.3 bcm) operational in 2014 | Benefit | £8.6 billion (ILEX case)  
| | | £3.4 billion (alternative case) 
| Cost | £0.9 to £2.4 billion  
| Net benefit | £6.2 to £7.7 billion (ILEX case)  
| | £1.0 to £2.5 billion (alternative case) 

Benefits are discounted at 3.5%

We conclude that under the range of assumptions analysed the net benefit of providing one Rough equivalent of strategic reserve is positive and at least of the order of £1-2 billion. Our best estimate of the net benefit is £6-8 billion. If we discount this back to 1\textsuperscript{st} January 2006, then our best estimate of the net benefit is £5-6 billion.

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\textsuperscript{4} We assume the benefits are realised at the end of each year from 2014 onwards, and the cost is incurred at the end of 2012.
Comments on the results

The results of our analysis shown above suggest that the NPV of building a Rough equivalent is likely to be substantially in excess of its cost. At first sight, this seems odd given that the probability of a gas supply shortfall is small, even post 2015. However, our research indicates that the economic impact, if a shortfall does occur, could be many times as great as the cost of the RE. The economic costs to the economy of running short of gas are not commensurate with the narrow commercial costs to the gas industry itself.

In calculating the economic impact, we have assumed loss of output in not only the directly affected sectors, but also the sectors immediately upstream and downstream (“with second-order effects”). Although we have not analysed the economic impact “without second-order effects” in detail, it is apparent from Figure 1 above that the results would fall by approximately one-third. Even with this assumption, the net benefit of an RE appears to be positive.

Of course, the choice of discount rate is important and using a higher discount rate would make the investment less attractive. However, sensitivity analysis shows that even doubling the rate (to 7% real) gives a benefit of £5.5 billion (ILEX) and £2.2 billion (alternative); and hence the net benefit, after subtracting the cost, is still likely to be positive.

It is noteworthy that our analysis assumes the government is risk neutral. We have assumed in our work that an uncertain financial impact of £X occurring with probability Y is equivalent to a certain financial impact of £XY. This is risk neutral by definition, because mathematically it focuses on the expectation or mean outcome. In practice, government might consider that the former is more undesirable than the latter, i.e. government might be risk averse in the same way that most people are risk averse with their finances. Any attempt to introduce a measure of risk averseness would make the conclusions that we have reached even more stark.

Implementation

We envisage a three part process:

- Determine quantity of strategic storage required and the timetable;
- Determine the process by which the required quantity is provided; and
- Determine the trigger or mechanism for the use of the strategic storage.

We recommend that the DTI, in conjunction with Ofgem, conduct a similar evaluation to determine the quantity of strategic storage required using analytical techniques similar to those used above and based on transparent modelling of the gas/supply outlook. We recommend a detailed evaluation every three years with annual updates of a less rigorous nature in between.
We suggest two possible options which could be examined in more detail if a decision is made to implement a form of strategic storage. In the first option National Grid (NG) would take on a new licence obligation to run a process, details to be agreed with Ofgem, requiring NG to pay for the options bid into a form of a competitive process. In the second option gas suppliers take on a new enhanced form of licence obligation for security of supply. This could be called a Security of Supply Obligation (SOSO) similar in nature to the Renewable Obligation. We also evaluated a third option, setting a very high emergency cash out price (£12/therm to reflect the estimated damage to the economy) and compensating consumers who have been interrupted at this price.

In our view, any form of strategic gas option must be clearly ring fenced from the commercial market and not to be used in other than clearly defined circumstances. This would allow normal winter/summer gas price differentials to continue to drive commercial investment in both storage and other gas importation infrastructure and other forms of gas flexibility, such as alternative fuels at CCGTs and industrial sites.

The existence of a strategic reserve will have a psychological impact on the market and this is likely to reduce the volatility of prices on the forward curve. We cannot see that this impact can be avoided. However, in our view having a clear set of rules for the triggering the use of strategic reserve will largely mitigate the impact on the spot price.

In our view the trigger for the use of strategic reserve should be a significant loss of supply for a long duration (weeks rather than days). In our view a tightening of the supply-demand balance should not in itself trigger the strategic reserve. If demand is higher than normal due for example to severe weather, and the supply-demand balance is tight, then this would not in our view trigger the strategic reserve as to do so would require anticipation of the situation later in the winter. Instead the normal commercial market should be allowed to continue to operate. If the tightness persists through the winter and storage stocks fall to the level at which a Gas Supply Emergency is triggered, then at this point the strategic reserve would be triggered.

**Risks and unintended consequences**

The main risk we identify is that an intervention to provide a strategic reserve has an adverse impact on commercial storage projects and the provision of other alternatives to storage in the UK. As a consequence the amount of new storage developed by the market is less than it would otherwise have been without the intervention increasing the amount of strategic reserve required. Unless this risk can be mitigated, the cost of providing strategic storage could be considerably increased. In addition, the risks associated with option 3, the high emergency cash out price, are potentially very high and could lead to market failure.
To mitigate the risks the following steps would need to be considered:

- To signal to the market well in advance the requirement to have a strategic reserve and to have a capacity requirement that is delivered over a number of years, and to allow the strategic requirement to be met from a number of different facilities, including standby fuel at CCGTs.

- The strategic reserve would be used to replace a known loss of supply. However, this would not be triggered immediately; instead the commercial market would be left to operate for a period (e.g. a week) before any action is taken. During this week the prices in the commercial market would be expected to rise. Once the strategic reserve is triggered, the ‘gas’ released would be sold by NG to shippers through the cash-out mechanism at the prevailing cash-out price.

- Have a predefined set of rules for triggering the release of strategic reserve. The triggers would not include the price of gas. The sharp rise in gas price seen in November 2005 (when the spot price rose sharply to around 120p/th) would not trigger the use of strategic reserve.

- The strategic booking would be ring fenced and the quantities of reserve reported.

- Another mitigation could be to make Ofgem, the agency closest to the UK gas market, the agent that makes the decision and pushes the button, in order to diminish the potential for the strategic reserve to be used as a political tool.

**Summary and recommendations**

Security of supply in gas has become a topic of concern amongst consumers, gas industry players and government. There are a number of factors that have led us to examine the question of the long-term security of supply:

- increased use of gas in electricity generation;
- UKCS production has a declining ‘swing’ capability;
- reliability of existing gas industry infrastructure; and
- UK will be increasingly reliant on imports increasingly remote from the UK. Imports will arrive by pipeline through Europe and as LNG in tankers delivering gas production from countries outside Europe.

ILEX concluded in its report for UKOOA in October 2005 that the UK market, as currently structured, could deliver “bite sized” gas storage projects but could not provide “strategic storage” to insure against high risk but low probability events.

Our conclusions based on more detailed analysis remain the same. In our view, the UK gas market will bring forward some new gas storage facilities if planning procedures are eased to allow the commercial storage market to work efficiently; but the total quantity of gas storage may still fall short of providing the level of security against high impact-low probability event which the Government may
prefer, without some form of intervention. We do not consider planning difficulties as the primary reason for the UK having less gas storage than Germany or France but we believe that easing planning procedures is necessary to allow the commercial storage market to work efficiently.

Our analysis, using probabilities of supply problems, indicates that the UK has a potential problem in the next two years followed by a period when the size of the problem is much reduced. This is due to the number of gas importation projects planned to be commissioned over the next few years. The problem reappears from 2014 when the UKCS production has declined further and demand has increased. However, we must caution that:

- the size of the gap is based on views of the supply/demand position 20 years into the future;
- the size of the gap is based on views of probabilities which cannot be considered precise; and
- the new importation projects may be delayed or, even if built, may import less gas than is assumed in our scenario modelling to date.

We suggest that there is a risk that the UK gap could be better or worse than forecast. However, the risk may not be symmetrical in that the potential damage to the UK of a worse outcome than the one we have predicted is very costly to the economy.

We suggest that two approaches be considered by the DTI as possible alternative courses of action. These are set out below and both assume that after full consideration of this study, and all the other Energy Review related analysis and further consultation, that the Government decides that a form of strategic reserve should be provided.

**Fast Track timetable**

If the outcome of the Energy Review is a move to a more risk averse future, the DTI would fast track further studies and consultation to develop strategic reserve. The aim would be to complete the development and full consultation by mid 2007. Licence changes may take a bit longer but the objective would be to launch the strategic reserve initiative by the end of 2007 to stimulate provision of reserve by 2011.

**Post 2013 timetable**

There may not be much that can be done on the supply side to help with the potential problem in the next two years. The apparent breathing space until 2014 should be used to develop the detailed implementation arrangements.

We recommend that the DTI, following the Energy Review, publish a timetable leading to putting strategic reserve in place by 2014. This would include a detailed evaluation study in 2008 of the supply/demand position having
experience of the outturn of the gas importation projects and the quantities of gas delivered.

We recommend that the DTI with Ofgem instigate an industry group tasked with developing detailed implementation rules and licence modifications with a delivery date of the end of 2007.

Following on from the 2008 evaluation study, the DTI would instigate the start of the strategic reserve scheme by the end of 2009. This will allow sufficient time to bring forward some reserve by 2014.
1. INTRODUCTION

1.1 The DTI has asked ILEX to undertake a study on the long-term security of gas supply to the UK.

1.2 The balancing of supply and demand in the gas market takes place through commercial arrangements whereby market participants (shippers) are responsible for balancing their supply with the demand of their portfolio. This is achieved through a mix of commercial arrangements including: gas storage, ‘swing’ from gas supplies and a limited amount of voluntary interruption of end users demand.

1.3 The delivery of significant quantities of reliable, new gas supplies is required to meet future demand for gas, and there are a number of large infrastructure projects currently under development that will bring new commercial supplies of gas to the UK. There is some debate, however, as to whether the level of security of supply that will be delivered by the market, under its current regulatory structure, is as high as may be economically, socially or politically desirable.

1.4 In addition there are a number of factors that have led to calls to examine the question of the long-term security of supply:

- increased use of gas in electricity generation;
- UKCS production has a declining ‘swing’ capability;
- reliability of existing gas industry infrastructure;
- UK will be increasingly reliant on imports increasingly remote from the UK. Imports will arrive by pipeline through Europe and as LNG in tankers delivering gas production from countries outside Europe; and
- ILEX concluded in its report for UKOOA in October 2005\(^5\) that the UK market, as currently structured, could deliver “bite sized” gas storage projects but would not provide “strategic storage” to insure against high risk but low probability events.

1.5 There is the possibility of a ‘gap’ between supply and demand. By definition the gap opens when the commercial supply cannot meet commercial demand. Since supply and demand must always balance the only option left for supply to balance demand is for involuntary demand load shedding with the consequent interruption to industry and hence industrial production. In the event of a Gas Supply Emergency priority is given to maintaining supply to domestic consumers. This can result in firm industrial end users being interrupted. The impact of interruption on costs were estimated by ILEX in a separate study for the DTI in

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December 2005 and a similar methodology has been used in this study to estimate the costs of interruption of industry. The estimated impact of interruption is significant.

1.6 An alternative to interruption of the industrial and commercial sectors would be to invest in some kind of strategic reserve that could be used to fill the gap at the time of need. The benefit of the investment is that one would avoid the cost that would have been incurred under the ‘do nothing’ case. The benefit is uncertain as it depends on the frequency and extent of the gap. The expected benefit has to be weighed against the certain cost of investing in a strategic reserve.

1.7 There may be a basis for government intervention if the costs to the economy are sufficiently high. However, the decision to intervene in the market has to also take account of the potential unintended consequences caused by the intervention itself.

1.8 The government could also modify the existing regulatory framework. The change could be to extend the licence obligations to require a higher level of security of supply for other classes of consumers eg the industrial and commercial sectors, or a modification to the emergency cash out prices.

1.9 In 2006 the UK has no strategic reserve to insure against a long-term loss of gas supply to the UK. This report looks at the case for government intervention – within the framework of the existing market structure – to develop or stimulate some form of strategic reserve.

1.10 Section 2 looks at the potential ‘gap’ based on the tightness of future supply and demand, and the reliability of future gas supplies.

1.11 Section 3 describes the alternative options to fill a ‘gap’ and develops a short list of three options.

1.12 Next in Section 4 we look at the costs incurred if there is interruption to firm gas demand.

1.13 In Section 5 we present the numerical results of the costs and benefits.

1.14 Section 6 describes the options for implementation. Section 7 describes the risks and unintended consequences that may result from government intervention in the market.

1.15 Section 8 gives the conclusions of the study.

“Economic Implications of a Gas Supply Interruption to UK Industry”, ILEX, December 2005
2. CALCULATING THE POTENTIAL GAP

Introduction

2.1 In this section, we attempt to quantify the likely shortfall in gas supply in Great Britain, for each year in the timeframe 2006 to 2020. We attempt to assess both the annual volume shortfall (in billion cubic metres, or bcm) and the number of days in the year during which the shortfall pertains. This section is largely concerned with likelihood: for each level of shortfall we attempt to assign a probability (more strictly, a probability density) of its occurrence.

2.2 We need first to define what we mean by ‘shortfall’, or – another word that we use synonymously – ‘gap’. This is the extent to which firm gas supply is interrupted in any given year. Its most likely value is zero. The shortfall or gap does not include interruptible gas (whether Transco or shipper interruptible), nor does it include self-curtailment by gas customers in response to price. We do not, in this study, project gas prices, but we do assume that gas demand will fall whenever prices rise sharply during a shortage. For the extent of this ‘demand response’ we rely, as requested by the DTI, on work done by GI in 2005\(^7\). This demand response is subtracted from demand first, in our modelling, whenever there is a supply shortage. If there is still not enough gas to meet demand, it would then be necessary to interrupt customers involuntarily: the extent to which this would be required is what we mean by ‘gap’.

2.3 Our electricity market modelling shows that coal plant operate at high load factors during winter months as higher winter gas and electricity prices make this period the most profitable for coal fired plant. The power sector demand response, whereby coal fired power station are scheduled ahead of gas fired so releasing gas back to the system, is therefore already incorporated into our analysis in the initial calculation of the ‘gap’.

\(^7\) Specifically, we assume a demand response level of 11.4 mcm/day from energy intensive industry, based on GI estimates. We do not consider an additional response from the power sector. In our scenarios, coal stations operate at baseload (typically 85% load factor) during winter months (without the potential to increase output further) – which means that the power sector demand response witnessed in 2005/06 is already included in our analysis. There is a secondary issue about CCGTs with back-up capability. Only a minority (around one quarter of the overall capacity) of CCGTs have back-up capability; these are predominantly older than average CCGTs, and some of this capacity is likely to have closed, or been mothballed, by 2015 when the gap becomes significant in our analysis. Furthermore, the GI estimate assumes a significant increase in refinery output and road tanker utilisation, and it is not clear that there would be much further scope to re-stock CCGT distillate storage tanks. If there were to be significant investment in back-up capability, the situation would be different, but our ‘gap’ calculation is premised on no such action being taken.
2.4 We calculate the ‘gap’ by assuming that the government takes no action to develop strategic storage. In this ‘do nothing’ world, the commercial market is left to operate without any interference beyond the existing regulatory regime. The gap is our estimate of the extent to which the market, left to its own devices, will not meet firm customer demand in the future.

2.5 This ‘gap’ is not synonymous with a requirement for provision of strategic storage (although it does show the potential requirement). The economics of strategic storage depend on several factors that we address in later sections, including the costs of its provision, the economic damage caused by a gas supply shortfall, and unintended consequences of its provision. The economics also depend on the extent to which the gap may be reduced – because the success or otherwise of a storage facility in covering a loss in supply depends on the characteristics (capacity and rate of supply in particular) of the facility, and whether it can cover the magnitude and duration of the interruption. In Section 5, we consider the impact on the gap of the introduction of different types of storage, in order to assess their benefits in averting economic loss.

The supply-demand balance in the UK 2006 to 2020

Summary of UK gas demand forecasts to 2020

2.6 Our view of possible total UK annual gas demand is summarised in Figure 3. For the purposes of our modelling we have also profiled the demand so that it reflects average monthly demand for March to November, but for the December, January and February we have created a sample business day, non-business day and peak day, so that the winter peaks can be modelled more accurately. The monthly profile is shown in Figure 4.
Figure 3 – Forecasts of UK demand

Source: ILEX and National Grid’s Ten Year Statement (throughput excluding exports and sites not supplied via transmission system)

Figure 4 – Monthly forecast of UK demand for the Central scenario

Source: ILEX
**Exports**

2.7 Exports to the Continent have not been included in the ILEX demand projections because of the flexibility of the UK-Continent interconnector to act as a balancing tool in the UK supply-demand picture. These flows of gas are modelled explicitly in our GB Gas Model.

2.8 The ILEX supply-demand analysis incorporates three projections for exports to the Republic of Ireland based on Irish demand and indigenous production.

**Gas supplies from the UKCS**

2.9 ILEX bases its UKCS supply projections on field reserves and historical and peak production rate information from the DTI. The information on reserves and peak production is on a field-by-field basis.

2.10 Future levels of annual production are estimated using projected depletion rates, based on the relationship between the original recoverable reserves, recoverable reserves at 31 December 2004, the peak flow rate and whether the fields are associated with oil production (generally a longer depletion period) or not.

2.11 In addition to ILEX’s projection of production from existing UKCS fields, new UK gas is added to UKCS production based on DTI reserve data. Figure 5 shows the three ILEX scenarios for UKCS production.

**Figure 5 – ILEX projections of UKCS production**

![Image](image.png)

Source: ILEX

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8 Information contained on the DTI Oil and Gas website at [http://www.dti.gov.uk/](http://www.dti.gov.uk/)
Import capacity

2.12 ILEX projects three scenarios for new import capacity to the UK. The scenarios capture the ILEX view of the likely range of project timings, based on industry knowledge and our experience with project developers over the last 15 years.

2.13 For the Interconnector, owing to the limited flows seen during the winter 2005/06, we have reduced its effective capacity to simulate the contractual and physical difficulties of bringing gas to the UK via this route.

2.14 In the case of BBL, we have also reduced the initial flows, for similar reasons to the Interconnector.

2.15 For Langeled we have estimated that about 5bcm of gas will flow following completion of the southern leg in Q4 2006, with Norwegian companies diverting gas from Zeepipe/Europipe. Following the link to the Ormen Lange field, the pipeline will be able to flow the full 23bcm. Details of the new import capacity projections are contained in Annex A.

Storage capacities

2.16 We model three storage scenarios: low, central and high. The low case has the new storage projects that are either under construction or at the planning stage, but excludes the largest depleted field project and the largest salt cavern project; and has no new storage facilities after 2012. The Central scenario is the same as the Low as far as 2012, thereafter it has the addition of a new depleted field every third year starting in 2015. The High scenario includes the largest depleted field project and the largest salt cavern project an additional 1.5 bcm. The total storage volume increases from 4.2 bcm in 2006, to between 7.8 bcm (low) and 11.0 bcm (high) by 2020. Details of storage projections are contained in Annex A.

Supply-demand

2.17 The three ILEX demand scenarios can be combined with the UKCS production projections, the import capacity scenarios and the storage scenarios to produce three supply-demand balances. In each case the demand projection is combined with the opposing capacity scenario to create high, central and low gas price scenarios.

2.18 The Constrained, Balanced and Abundant scenarios, shown in Table 3, correspond to P10, P50 and P90 cases in the probability modelling.
The three scenarios represent a range of possible future scenarios for the UK gas industry. Together the three scenarios represent an envelope of outcomes and we would expect that the future UK supply/demand to be contained within this envelope. The position in any year will depend on future demand and supply, and we would expect the path taken to go through periods of constraint and periods of abundance as part of the normal commercial investment cycle. However, the envelope represents the spread of possible outcomes ranging between P10 and P90. There is a 10% chance that the outcome will be more extreme than the Constrained scenario. The winter of 2005/06 is an example of a period of constraint.

Figure 8 shows the supply-demand balance (UK demand including exports to Ireland, and gas supply capacity) on a January business day, under the Abundant, Balanced and Constrained scenarios, respectively.

Under the Abundant scenario about half the import capacity via pipeline and LNG is utilised on an average January business day over the period. Under the Balanced scenario nearly all the import capacity is utilised by 2015, and under the Constrained scenario, storage would be required on a January business day over most of the period. The demand shown in the figures represents that seen during an average winter, obviously during periods of colder weather and on peak demand days more of the available capacity would be utilised.
Figure 6 – Abundant supply-demand on January business day

Source: ILEX
Figure 7 – Balanced supply-demand on a January business day

Source: ILEX

Figure 8 – Constrained supply-demand on a January business day

Source: ILEX
1-in-50 cold, 1-in-50 warm

2.22 In a 1-in-50 cold year we assume demand increases by 4% between April and September and by 11% between October and March. This is based on analysis of the National Grid 10-Year Statement, and the difference between average and 1:50 demand over highest 180 days of year.

2.23 The demand curve published by National Grid, showing gas demand on a ‘normal’, ‘cold’ and ‘warm’ day, shows the decrease in demand (relative to ‘normal’) on a ‘warm’ day is about 63% of the increase in demand (relative to ‘normal’) on a ‘cold’ day. 9

2.24 Applying this asymmetrical shift in demand to the annual figures it follows that in a 1-in-50 warm year demand between April and September decreases by 2.5% and between October and March decreases by 7%.

Period 2020 to 2050

2.25 Assuming production from the UKCS declines steadily over the period from 2020 to 2050, and demand remains level, only about 5-10% of demand will be met from UK reserves from 2030 onwards. Norwegian production is likely to decline over this period as well, leading to a gradual fall in available pipeline imports. Under the Balanced scenario, the supply gap will not be significant until around 2040 and additional LNG supplies are likely to make up the shortfall alongside further investments in storage.

Simulation approach

2.26 The DTI is keen to understand the likelihood of future supply interruptions, in the context of the prospective future operation of the commercial market. We have described our three main scenarios for demand and supply in the market, from now until 2020, and how long or short the market is, assuming typical conditions and reliable supply, in each scenario. In order to estimate interruption likelihood, we need to assign probabilities to these scenarios. We also need to quantify atypical effects – comprising short-term losses in supply and demand variation – which are outside the scope of our scenarios.

2.27 There are a large number of uncertainties that need to be addressed in estimating the likelihood of a supply gap. Individual sources of supply may experience technical problems. The timing of entry of new sources (pipeline imports and LNG) to replace the depleting UKCS is uncertain. Political events and priorities may lead to supply reductions from certain regions overseas. Random weather effects can lead to unforeseen peaks in demand. The level of demand response to price is not certain.

9  www.nationalgrid.com
2.28 In order to bring together all of these uncertainties within a single framework, ILEX has developed a simulation model of future gas supply. This is a cut-down version of our GB Gas Model, with the supply/demand and storage sections retained, but some of the pricing detail removed in order to simplify the simulation process.

2.29 The model assigns specific probability distributions to interruptions in individual supply sources; it also assigns probability distributions to the variation in demand in each season. The model utilises Latin Hypercube sampling within @RISK software in order to simulate, via repeated iterations, the magnitude, frequency and economic impact of a gas supply shortfall. The likelihood of a shortfall greater than a certain level is then determined from the number of iterations which give at least that level of shortfall, out of a total of 1000 iterations\(^\text{10}\). For example, if there are 5 iterations that give a shortfall of at least 1 bcm in the year 2010, then the probability of the shortfall being at least 1 bcm in 2010 is \(\frac{5}{1000} = 0.5\%\).

2.30 In order to interpret the results from the simulation, we have compared the gap with a Rough equivalent\(^\text{11}\). To set them in context, the additional storage requirement to provide security for a 1 in 50 cold winter in 2005/06 would have been approximately one Rough equivalent. In other words, had demand out-turned at Transco’s 1 in 50 forecast level, it would have exceeded available supply by around 3 bcm over the winter.

2.31 Details on the main assumptions in the simulation model are presented below.

**Supply outages and demand variation**

2.32 Within our simulation model, we have separated all of the sources of gas supply into a number of tranches, comprising 3 UKCS, 5 LNG, 3 pipeline and 2 storage tranches, 13 in total. We have also undertaken analysis using a different set of tranches supplied by the DTI, comprising 2 UKCS, 1 LNG, 3 pipeline and 1 storage, 7 tranches in total. We assume that these tranches are independent of one another.

2.33 For each tranche, we have estimated a probability of interruption and a proportion of supply affected. To simplify the analysis, and on the basis of the strong

\(^{10}\) The choice of 1,000 for the number of iterations was pragmatic. A largely number (e.g. 10,000) would give fractionally better results but take proportionately longer to run. In our view, the difference in accuracy between 1,000 and 10,000 iterations is a minor issue. Furthermore, given the large uncertainties surrounding probabilities, interruption levels, costs and benefits, unintended consequences, etc., a high degree of precision is probably spurious.

\(^{11}\) A Rough Equivalent is a measure of storage capacity based on the largest storage facility in the UK. Rough can supply around 44mcm/day for a period of 75 days i.e. a total volume of 3.3bcm.
seasonality in gas demand, we have assumed that interruptions only occur in winter months, **defined as October to March inclusive**. For each winter, we have considered four generic supply outages covering different time periods:

- 1-day outage: supply loss for 24 hours;
- 2-week outage;
- balance-of-winter outage: if an outage occurs, then it lasts until the end of March; and
- 2-winter outage: this is an extension of the balance-of-winter outage – the source of supply is affected for the whole of the following winter as well.

2.34 It has proved to be very difficult to reach consensus on the probabilities of supply interruption. ILEX’s approach has been empirical: we have based our probability estimates on observed historical events that have affected Britain’s gas supply. We have based our outage proportions on the relative sizes of individual fields in the UKCS, while we have assumed that any individual LNG source or pipeline could be completely curtailed. Table 4 shows the specific assumptions made by ILEX for outage proportions and probabilities (blank entries indicate zero probability).

**Table 4 – Source outage events and probabilities (source: ILEX)**

<table>
<thead>
<tr>
<th>Proportion affected</th>
<th>1-day event</th>
<th>2-week event</th>
<th>1 winter event</th>
<th>2 winter event</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Technical</td>
<td>Political</td>
<td>Technical</td>
<td>Political</td>
</tr>
<tr>
<td>UKCS 1</td>
<td>10%</td>
<td>0%</td>
<td>3</td>
<td>2.0%</td>
</tr>
<tr>
<td>UKCS 2</td>
<td>10%</td>
<td>0%</td>
<td>3</td>
<td>5.0%</td>
</tr>
<tr>
<td>UKCS 3</td>
<td>10%</td>
<td>0%</td>
<td>3</td>
<td>5.0%</td>
</tr>
<tr>
<td>LNG 1</td>
<td>100%</td>
<td>50%</td>
<td>6</td>
<td>20.0%</td>
</tr>
<tr>
<td>LNG 2</td>
<td>100%</td>
<td>50%</td>
<td>6</td>
<td>20.0%</td>
</tr>
<tr>
<td>LNG 3</td>
<td>100%</td>
<td>50%</td>
<td>6</td>
<td>20.0%</td>
</tr>
<tr>
<td>LNG 4</td>
<td>100%</td>
<td>50%</td>
<td>6</td>
<td>20.0%</td>
</tr>
<tr>
<td>LNG 5</td>
<td>100%</td>
<td>50%</td>
<td>6</td>
<td>20.0%</td>
</tr>
<tr>
<td>Pipe 1</td>
<td>100%</td>
<td>50%</td>
<td>3</td>
<td>10.0%</td>
</tr>
<tr>
<td>Pipe 2</td>
<td>100%</td>
<td>50%</td>
<td>3</td>
<td>10.0%</td>
</tr>
<tr>
<td>Pipe 3</td>
<td>100%</td>
<td>0%</td>
<td>3</td>
<td>5.0%</td>
</tr>
<tr>
<td>Storage 1</td>
<td>100%</td>
<td>0%</td>
<td>1</td>
<td>2.0%</td>
</tr>
<tr>
<td>Storage 2</td>
<td>50%</td>
<td>0%</td>
<td>1</td>
<td>2.0%</td>
</tr>
</tbody>
</table>

Terminal outages: 1 in 500 years per terminal (one winter event)

2.35 Table 5 shows an analogous table supplied by the DTI. There are two views (Low and High) for ‘proportion affected’ and two views (Low and High) for probabilities, giving four combinations in total. While this gives a range, it is clear that even the top of the range (High/High) is more optimistic than the ILEX figures in Table 4. For example, ILEX considers 1-day events as much more likely\(^\text{12}\); some 2-week events have a 1 every 5 years probability in our view; our

\(^{12}\) In fact, these events are less important, given their short duration, than the combined impact of events that are 2 weeks or longer. In the results, we consider a sensitivity in
balance of winter events can occur for political as well as technical reasons; and we explicitly consider 2-winter events and terminal outages (albeit with very low probabilities). Given this divergence of views, we present the results from both sets of assumptions in this report. As we shall see, it is possible to draw a number of key conclusions in spite of the differences.

Table 5 – Source outage events and probabilities (source: DTI)

<table>
<thead>
<tr>
<th>Source</th>
<th>Proportion affected</th>
<th>Probability (1 in X years)</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>1-day</td>
<td>2-week</td>
<td>1 winter</td>
</tr>
<tr>
<td>UKCS 1</td>
<td>9%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
<tr>
<td>UKCS 2</td>
<td>4%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
<tr>
<td>LNG</td>
<td>13%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
<tr>
<td>Pipe 1</td>
<td>8%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
<tr>
<td>Pipe 2</td>
<td>8%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
<tr>
<td>Pipe 3</td>
<td>10%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
<tr>
<td>Storage</td>
<td>10%</td>
<td>1 in 500</td>
<td>1 in 1000</td>
<td>1 in 10000</td>
</tr>
</tbody>
</table>

Terminal outages: no separate probabilities

2.36 We have kept the probability distributions themselves as simple as possible. The 1-day events we have modelled using a Poisson distribution: this assumes that the events occur discretely and independently, with the average frequency as specified in the above tables. Other events we model as separate Bernoulli trials on a monthly basis: for example, a 2-week event which could affect 10% of UKCS1 supply (see Table 4) is a trial with a 2%/6 = 0.33% chance of ‘success’ in any given winter month.13 Political ‘events’ are treated as separate from, and independent of, technical events.

2.37 We consider the outages of different duration in turn, from 1D events up to 2-winter events. Each outage event reduces the proportion of available supply from the affected source; and subsequent events are applied pro rata to the residual proportion. In this way, double counting of events is avoided. (Suppose two separate events occur, which separately reduce source availability by X% and Y%. The remaining availability after both events have occurred is the original availability multiplied by (1-X%)*(1-Y%).)

2.38 Turning to demand variation, we have made the following assumptions, based on historical analysis of Transco data. Compared with average conditions, and over the season as a whole:

- in a 1 in 50 warm winter, demand is 7% lower
- in a 1 in 50 cold winter, demand is 11% higher

which we set all the 1-day events to zero likelihood: the results of this sensitivity are broadly comparable with our main case.

Since there are 6 months in the winter, and a 2% risk for the winter as a whole.
• in a 1 in 50 warm summer, demand is 2.5% lower
• in a 1 in 50 cold summer, demand is 4% higher

2.39 With these assumptions, we have created a triangular distribution of demand multipliers for each season (the average multiplier being 1), from which we sample repeatedly to determine whether each season in turn has above or below average demand. The distribution is constructed in such a way that the 1 in 50 multiplier is the average (i.e. mean) value of the top 2%, or bottom 2% as appropriate, of the probability distribution.

2.40 Finally, we assign weights to our underlying supply/demand scenarios on the basis that the Constrained scenario is a P10 world and the Abundant scenario is a P90 world. Here P10 and P90 mean that the probability that the underlying conditions are tighter (the surplus of available gas over demand is smaller) than in the scenario is, respectively, 10% and 90%. This assignment of weights to the scenarios is necessary in order to estimate the likelihood of future supply interruptions; we do also show the results for scenarios separately.

2.41 In our view, the Constrained and Abundant scenarios are sustainable for several years at a stretch, though possibly not for the entire timeframe. However, the model treats years one at a time, and it is not necessary to take a view on whether these scenarios are or are not sustainable across years. We focus on the mean (i.e. expected) outcomes in deriving our estimate for the benefits of storage. Whereas extreme events depend on one’s view of sustainability (for example, a 1 in 100 chance repeated in two consecutive years only has a likelihood of 1 in 10,000 if one believes the years are independent), the mean outcomes do not. The expected shortfall over a 15 year timeframe is the sum of the expected shortfall in each of the 15 years.

2.42 It is important to consider these different scenarios, rather than ‘making do’ with the Balanced scenario. If we simply used the Balanced scenario, we would understate the expected risk of shortfall. This is because the probability and severity of shortfall rise rapidly as the world becomes more constrained. If the shortfall in the Constrained scenario was X% greater than, and the shortfall in the Abundant scenario was X% less than, the shortfall in the Balanced scenario, then the expected outcome of the ‘blended’ scenario would be the same as in the Balanced scenario. But this is not the case. The shortfall in the Constrained scenario is much more than X% greater than that in the Balanced scenario. This seems to suggest that the Constrained scenario ‘biases’ the results of the blended scenario. The bias is real and reasonable; it would be unreasonable to think that

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14 This is the simplest continuous probability distribution that allows for skew.

15 We estimate that our P10 scenario is representative of the bottom 20% (for the supply surplus), since 10% is halfway between 0% and 20%. Similarly, we estimate that our P90 scenario is representative of the top 20% of outcomes for the supply surplus.
the shortfall risk simply grows at a steady (linear) rate as the supply/demand balance narrows.

**Results of the simulation**

*Strategic world (demand equals available supply)*

2.43 To set the scene for our more complex analysis, we first undertook a simplified simulation in which we assumed that demand and available supply always balance exactly in the commercial world. In this analysis, we simply focused on the outage probabilities in Table 4 above and the proportion of total demand accounted for by each tranche of supply in each year. We assumed in this simulation that the commercial world can react to demand variations, so weather is not a factor.

2.44 The point of this simulation is to understand how supply ‘shocks’ on their own might contribute to a strategic requirement. Furthermore, it might be argued that this requirement should be calculated without reference to the commercial surplus or deficit, on the grounds that a strategic resource should not interfere with the operation of the market. Providers of commercial storage earn revenues during years which are ‘tight’, to compensate them for years which are ‘slack’. If these commercial providers perceive that government will build strategic storage whenever there is a risk of the market being ‘tight’, then their own incentives to invest in storage are reduced. This is a possible unintended consequence of strategic storage provision, which we discuss in more detail in Section 7.

2.45 Figure 9 below shows the gap at two different confidence levels, 95% and 99%, in this ‘strategic world’. For example, in 2008 there is a 95% likelihood that the gap will be less than 1.5 bcm, and a 99% chance that it will be less than 2.5 bcm. The gap gradually rises over time as Britain becomes increasingly reliant on imported gas (which we assume in Table 4 has a greater risk of curtailment than UKCS gas), but shows some signs of levelling off by 2020. By that time, the gap is approximately 3.5 bcm per annum, at the 99% level, which is around one Rough equivalent (This means that there is a 1% chance that the gap could exceed 3.5 bcm per annum in 2020.)

2.46 Hence we estimate that supply shocks, viewed in isolation, will contribute around one Rough equivalent to the annual supply gap by 2020, at the 99% level of confidence.
2.47 Notwithstanding the argument of paragraph 2.44 above, we appreciate that the DTI is concerned to understand the likelihood of interruption within the context of commercial market operation. Therefore, the bulk of our analysis has taken account of ILEX market scenarios and demand variation, in addition to supply reliability.

2.48 Figure 10 shows percentiles from 95% to 100% for the annual supply gap in our ‘do nothing’ scenario. This figure is based on the ILEX probabilities and outage proportions shown in Table 4 above. The supply gap is only significant for these high percentiles – and there is a big difference between the 99th percentile and the 100th percentile (maximum loss, i.e. 1 in 1000 since there are 1000 iterations in the simulation), indicating that the probability distribution has a long ‘tail’. An analogy may be drawn with heights of people in a population: 99% of people in Britain are shorter than a height of not much above six feet, but the tallest person is over seven feet.

2.49 On the basis of our Rough equivalent measure, the gap is about one Rough equivalent at the 98% level in the years after 2015. Before 2015, the gap is insignificant even at the 99% level. The results for the early years are of academic interest only, given that any storage development will take a few years to implement. The result for 2006, which suggests one Rough equivalent
somewhere between the 98th and 99th percentile, is consistent with Transco’s 1 in 50 level for 2005/06 referred to in paragraph 2.30. Note that the years in the figure are calendar years.

2.50 The dip in 2018 is not considered significant. It is important to bear in mind that these very high percentiles are based on relatively few iterations, and chance fluctuations are magnified. In our scenarios, there is a slight fall in the supply gap compared with 2017. However, we cannot honestly differentiate between these two years with any degree of confidence. Rather, the results in the figure should be interpreted with a “broad brush”, which is that prior to 2015 there is only a very small risk of supply shortages, but post 2015 the risk is significant at the 5% level. In other words, there is a 5% or 1 in 20 chance that the gap between demand and supply could be substantial.

2.51 In Annex C, we include an example of a probability distribution for the gap in a single year (2019), which shows the cluster of outcomes close to zero, and the ‘long tail’ with a small probability of a gap as high as 12-13 bcm as seen in Figure 10.

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16 The “1 in 50” winter is technically between the 98th and 99th percentiles. It is higher than the 98th percentile, because this percentile marks the level that is exceeded 2% of the time, whereas Transco’s 1 in 50 is, given the way it is calculated, the expected value of the top 2% of outcomes. It is lower than the 99th percentile, because the probability density function is not flat between the 98th and 100th percentiles but slopes downwards, which implies the mean of the top 2% is to the left of the 99th percentile.

17 A comparison may be made with heights in a population. The average heights of successive generations are likely to be very close, but the heights of the tallest people in successive generations will show significant variation. Such variation may be partially explicable (diet, lifestyle, etc.), but will to some extent simply be due to chance.
Figure 10 – Annual supply gap, based on ILEX probabilities of source outages

Source: ILEX

2.52 In addition to our blended scenario, in which we sample within the simulation between our Abundant, Balanced and Constrained scenarios on a probabilistic basis, we have run the analysis for each of these scenarios separately. The results, for the supply gap at the 99th percentile, are shown in Figure 11. The Constrained scenario gives significantly higher outage levels than the other scenarios – and drags up the blended results for this percentile (“lengthens the tail”)[18]. Henceforth in this report we concentrate on the blended scenario: this is necessary in order to assign a likelihood to interruptions, and hence to derive a value for strategic storage.

[18] Because we are focussing on the tail of the distribution, it is inevitable that the Constrained scenario will have a greater impact than the other scenarios (even though, a priori, we think the Balanced scenario is more likely to occur). The subset of iterations which show a significant level of shortfall is biased towards the Constrained scenario. Another way to express this is in Bayesian terms: the probability of the world being in the Constrained scenario, given that there is a significant supply shortfall, is higher than the probability that the world is in the Balanced or Abundant scenarios.
In addition to annual supply gap, we show results for the number of days of interruption in each year (Figure 12). There is substantial variation in these results, but broadly we conclude that in years when interruptions occur, it is likely the interruptions will affect many days in the winter and not just a few. Reasons to expect this include: a) weather is correlated from one day to the next, and a ‘cold snap’ lasting several days or weeks is more likely than the occurrence of one or two isolated days of very high demand in the year; b) many of our outage events last for 2-weeks or longer; and c) a general tightness in the underlying demand/supply balance is likely to persist over months and not a few days. However, our analysis has been primarily focused on annual volumes and more work needs to be done to develop a better understanding of the within-year distribution of supply shortfall.

It is not appropriate to consider the average number of days’ interruption, because the average is comprised of many iterations when the number of days equals zero, and a small number of days when the outage is typically 60-90 days as shown in the graph. In other words, if outages occur, they tend to last for 60-90 days in our modelling.
In the footnote to paragraph 2.35, we indicated that results are broadly comparable if we discount 1-day interruptions. This is shown in Figure 13, which shows the expected (mean) gap with and without the 1-day events. The mean value is calculated by adding the gaps from each of the 1000 iterations and dividing the sum by 1000\(^2\). Although there is a 30% difference between the two sets of results in the later years, it is apparent that most of the supply gap arises from the combination of other factors (e.g. weather, two week events, and uncertainty in the underlying supply/demand balance).

We believe it is methodical to include 1-day events. The argument that “the market can cope with 1-day events” fails to take account of the fact that while this might be true if nothing else happens simultaneously, a 1-day outage which occurs at the same time as (say) a spike in demand and/or a 2-week event affecting another source of supply could result in customer interruptions.

In most of the iterations, the annual gap is zero in every year. In a minority of iterations, the gap is positive, and in a very small number of iterations the gap is substantial. This ‘long tail’ explains why the ‘Main’ results are occasionally below the ‘Main without 1D events’ results. This outcome is simply due to chance, rather than anything fundamental, and would disappear if a sufficiently large number of iterations were to be considered.
2.56 We have also considered the impact of a ‘political’ event that reduces the availability of the interconnectors or the gas flowing through them. Specifically, we altered the probability of a political 1-winter outage event for Pipe 1 and Pipe 2 (see Table 4 above) from 2% to 100%, thus capping the availability of these pipes at 50% of their capacity for the entire timeframe. (In this way, we obtain results for each year of the timeframe: we are not implying that a reduction in interconnector availability would last for 15 years.) All other assumptions are as in the main blended scenario.

2.57 The results of this sensitivity are shown in Figure 14. The expected shortfall in later years is roughly twice as great as in our main results. This factor of two translates to the impact on GVA described in Section 5 below.
2.58 The above analysis was predicated on Table 4. We now consider how the results change if we use the probabilities and outage volumes in Table 5. In that table, supplied by the DTI, there are really four alternative scenarios: a High and Low case for the outage proportion; and a High and Low case for the probabilities. As mentioned already, the “High High” case is in fact more optimistic than the ILEX view.

2.59 In Figure 15 we show a comparison of all four of these alternative scenarios. The figure shows the mean supply gap (i.e. the average of all 1000 iterations) for each scenario separately. It is immediately striking that there is virtually no difference between them. This is because the probabilities of outages are sufficiently low in all of these scenarios that they have little discernible effect. Essentially, there is a minimum level of ‘gap’ which arises because of weather effects and uncertainty in the underlying supply/demand balance, and pertains even if the supply sources are 100% reliable. To illustrate this further, we have run an extra “zero zero” case, in which the supply sources are indeed assumed to be 100% reliable, and the results are similar.

2.60 With the probabilities in Table 5, even the 1-day events are only occurring (on average) once every 5 years in the High case. The 2-week outages only occur once every 10 years; the balance of winter once every 100 years. At these
probability levels, source outages are in effect irrelevant to the outcome, given that our timeframe is only 15 years. (The odd 1-day event and 2-week event occurs, but is highly unlikely to be simultaneous with other factors that put a strain on the market’s ability to cope.)

**Figure 15 – Annual supply gap, based on alternative probabilities of source outages (mean outcomes)**

![Graph showing annual supply gap based on alternative probabilities of source outages.](image)

Source: ILEX

2.61 In Figure 16, we show percentiles (95%, 99% and 100%) for the supply gap. We have chosen the “Low High” case at random – all cases give effectively the same results. The results may be compared with those in Figure 10; it is apparent that the risk of curtailment is significantly lower when we use the alternative assumptions.

2.62 In these alternative scenarios, it appears that one Rough equivalent would comfortably meet the volume requirements at the 99th percentile in the years post 2015. There is, however, a very small chance that the Rough equivalent might not cover the gap fully.

2.63 It is important to note that although these results suggest the gap is unlikely to be significant (it is close to zero at the 95% level), we cannot yet conclude that strategic storage would be uneconomic. That depends on the costs of storage and the costs of economic disruption if interruptions occur. In Section 4 below, we translate the results of Figure 16 (and Figure 10 above) into the expected level of benefits of strategic storage provision, having first costed the options in Section 3.
2.64 Figure 17 below shows the number of days’ interruption using the alternative probabilities. Again, the pattern is for interruptions of 60-90 days, or none.
Figure 17 – Number of days of interruption (alternative probabilities)

Summary

2.65 The following key messages emerge from the analysis in this section:

- regardless of one's views on the probabilities that outages will occur at individual sources, there is a minimum level of supply gap risk, which is associated with demand variation and the underlying balance of demand and supply;
- the probability distribution for the supply gap has a long tail – at the 95th percentile, the gap is close to zero, but at the 98th or 99th percentile (depending on one’s probability estimates) the gap is 1 Rough equivalent or higher;
- however, this gap only becomes manifest in the years after 2015 in the commercial market; prior to that the gap is close to zero even at the 99th percentile;
- the profile of outages tends to suggest that a facility which covers 60-90 days of shortfall is more suitable than one which covers a few days or weeks;
- a strategic storage facility equivalent to Rough would not eliminate the risk of a shortfall, and the cost-benefit analysis needs to consider the magnitude of the residual risk; and
- 1-day supply interruptions cannot be ignored, though other factors in aggregate make a greater contribution to the risk of a supply shortfall.
3. ALTERNATIVE OPTIONS

3.1 In this section we look at alternative options that could close a shortfall between gas supply and gas demand in the UK; we call this a ‘gap’. To be considered any option must deliver incremental physical gas to the UK, or bring about an actual reduction in the UK gas demand. The options must be separate from, and additional to the commercial arrangements that are called upon for balancing supply and demand under normal conditions.

3.2 The requirement is for physical gas. We considered the use of a financial insurance product but dismissed this option since the intention is to fill the ‘gap’ to avoid the physical damage of an interruption, rather than pay compensation after the damage has been incurred.

Filling the gap

3.3 We group the options that could fill a shortfall between supply and demand under two headings:
- increase in the supply of gas; and
- reduction in gas demand.

3.4 We develop the possibilities by considering the different sources of supply and the different sectors of demand. Table 6 lists the possible ways to fill the gap and for each option quantifies the requirement to fill a gap equivalent to one Rough storage facility, a Rough equivalent (or RE). One RE is our measure of storage capacity that we use when talking about security of supply. Rough can supply around 44 mcm/day for a period of 75 days, that is a total volume of 3.3 bcm. Of the existing storage facilities in the UK, only Rough has sufficient size and duration to provide security over the full winter period. Other UK storage facilities (such as salt caverns and onshore depleted field storage) could only cover the required period of time at a much lower daily rate; or alternatively provide the required daily rate for a much shorter period (the facility would empty part way through the winter).

3.5 The list in Table 6 suggests a range of alternative options that could potentially fill the gap.
Table 6 – Summary of alternative options to fill a gap equivalent to one Rough storage facility

<table>
<thead>
<tr>
<th>Supply source</th>
<th>Incremental supply</th>
<th>Quantity to provide one Rough Equivalent (RE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK gas production</td>
<td>Hold back production in reserve. The Sean field in the North Sea is a commercial way of doing this; usage is triggered by the price of gas.</td>
<td>3 facilities equivalent to the Sean field would be required to provide 1 RE.</td>
</tr>
<tr>
<td>Interconnectors</td>
<td>Capacity booked in the interconnector and in upstream, transit pipelines and linked to a source of supply in Europe (e.g. storage facility).</td>
<td>Transit and interconnector capacity equivalent to the total capacity of the IUK in 2005/6.</td>
</tr>
<tr>
<td>Imports from Norway</td>
<td>Additional imports and production capacity in Norwegian sector.</td>
<td>80% of Langeled capacity</td>
</tr>
<tr>
<td>LNG stocks</td>
<td>Additional onshore tanks of LNG to store gas.</td>
<td>28 onshore tanks (based on the tank capacity for the expansion of Isle of Grain).</td>
</tr>
<tr>
<td>Storage</td>
<td>Single offshore field possible</td>
<td>Total capacity equivalent to 44mcm/day for 75 days</td>
</tr>
<tr>
<td></td>
<td>A number of onshore fields</td>
<td></td>
</tr>
</tbody>
</table>

**Demand**

| Power generation       | CCGTs run on distillate. Requires increased onsite storage and distribution facilities. | Around 10 GW of CCGTs (40% of current CCGT capacity) required to stop burning gas for 75 days. Infrastructure to store and deliver 3 million tonnes of distillate. |
| Industrial             | Major industry run on alternative fuel. Requires onsite storage, conversion of plant to dual-fuel and enhanced fuel distribution capability. | Interruption of all of the direct gas demand from the energy intensive sector to provide 1 RE              |
| Commercial/Residential | Smart metering to levy a surcharge at time of strategic requirement                  | One RE would be achieved from reducing the temperature of all space heating (commercial and domestic) by around 2 degrees Celsius |

Source: ILEX

**Evaluation of the Options**

**UK gas production holding back reserve**

3.6 The economics of gas production brings forward production wherever and whenever possible so long as prices are above marginal costs. Holding back gas
production is costly because of the high opportunity cost (in a commercial market the gas would be produced).

3.7 If producing field were used to provide the cover, then there is the risk that the facility is a one-shot-only: once it has produced the gas the maximum production rate falls, and the field cannot be recharged without the addition of compressors. A field with the capability to refill is a depleted field storage facility such as Rough.

3.8 Holding back production from existing gas fields will reduce the available supply and in the short-term tighten supply/demand. This is not an option under the current supply/demand balance, but might be considered more attractive at a time when the UK supply/demand balance is in surplus.

**Interconnectors**

3.9 Under this option capacity in an interconnector pipeline would be reserved to supply the gap. The transportation capacity required for one RE would be equivalent to the whole of the existing capacity of the IUK plus an equivalent amount of capacity to transit NW Europe to the source of supply, probably a storage facility in NW Europe.

3.10 The transportation capacity would need to be incremental and additional to the commercial capacity used for existing supplies otherwise it will reduce the capacity available and would reduce existing supplies to the UK. If there were a new interconnector or an enhancement to the capacity, then a tranche of capacity could be booked and reserved specifically to provide strategic reserve.

**Imports from Norway**

3.11 Additional production from the Norwegian sector could be used to supply the UK. As with holding back UK gas production there is a high opportunity cost of holding back production. In addition, as with interconnectors this option would require additional capacity over and above the existing commercial capacity equivalent to 80% of the Langeled pipeline capacity.

3.12 The combination of high opportunity cost and high transportation costs are likely to make imports from Norway uneconomic compared with other alternatives.

**LNG stocks**

3.13 Stocks of LNG could be held in highly insulated tanks located onshore at or near the existing UK terminals (including the new LNG terminals) and take delivery from LNG tankers by sea. The gas would enter the NTS through the existing entry terminals.

3.14 The LNG tanks planned for the expansion of the Isle of Grain LNG facility in the UK have a capacity of 190,000 mcm of liquids each, equivalent to 120 mcm of
28 LNG tanks of this capacity could supply the volume equivalent to one Rough facility.

3.15 Onshore liquefaction could be considered instead of tanker delivery, but this is likely to be uneconomic as it would require liquefaction facilities to be built, and the liquefaction facilities would be unused for most years (except for replacing boil-off). It would be more cost-effective for the liquefaction to take place in the country of production at the liquefaction plant built for filling the tankers. The tanks would need to be topped up with LNG periodically to replace boil-off.

Storage

3.16 This option is to construct new storage capacity offshore and/or onshore in the UK. Storage facilities could be a mixture of the existing types of storage: salt cavern and depleted field. To provide storage capability with a volume equivalent to one Rough would probably involve the combination of several new projects. It would be possible to spread the storage reserve around new and existing facilities.

Power generation

3.17 It is assumed that price responsive switching to coal/oil-fired plant would take place under the commercial market. A demand side response from the power generation sector would require the CCGTs to stop burning gas and either the CCGTs to be run on distillate fuel, or the CCGT plant interrupted to be replaced by an equivalent amount of generation plant running on coal or oil.

3.18 There is about 25 GW of CCGT capacity in Great Britain of which around 5.8 GW have some form of fuel switching capability at present.

3.19 The current maximum distillate stock capacities (160,000 tonnes) only allow the plant to operate for a few days before the fuel runs out and the plant needs to replenish stocks or return to gas. In order for the 10 GW of CCGT plant (one Rough equivalent) to run on distillate fuel for a 75-day winter period, distillate availability would need to be around 3 million tonnes either through stockpiling or constant replenishing of supply. The current stock capacities are less than 5% of this requirement.

Industrial demand

3.20 Currently about 10%-15% of UK energy intensive industry using natural gas can switch to alternative fuel. However the level of stocks of standby fuel held on site are insufficient to enable the industrial process to switch for a prolonged period without regular deliveries of fuel by road tanker. In some cases where stocks are held on site the stocks are as little as a few days of standby fuel.

21 DTI, JESS report Nov 2004
3.21 The cost of equipping the remaining 85-90% of the energy intensive sector with the capability to run on dual-fuel (boiler conversion, onsite tanks to store fuel and operating costs) and to provide the road tanker capability to refuel is likely to be prohibitively expensive.

**Commercial and residential demand**

3.22 We consider the potential for a demand side response from the commercial and residential sectors. Maintaining the gas supply to these sectors of the market has the highest priority. However, it may be possible to encourage demand side reduction to fill a gap. Using ‘smart’ metering it might be possible in the future to levy a surcharge when strategic reserve is required. A higher price and/or rewarding demand reduction could be used to provide a demand side response from customers, for example by switching down the thermostat.

3.23 We can estimate the potential size of a demand side response in terms of what a reduction would come from switching down the thermostat in all commercial and residential properties by 1 degree Celsius. We estimate that turning down the thermostat by 1 degree Celsius would reduce daily demand by around 250 GWh/day. One RE is 455 GWh/day and would require all commercial and domestic loads to turn-down by almost 2 degree Celsius during the winter period. This is unlikely to be achieved in reality, but it does give a measure of the potential for demand-side response from the commercial and residential sectors.

3.24 Under the existing arrangements commercial and residential customers are not exposed directly to a sudden rise in wholesale gas prices and there is not a significant demand side response from these sectors.

**Short-list of alternative options**

3.25 DTI requested that the three most promising alternative options should be developed in more detail. After some discussion about the feasibility of each option to fill the gap it was decided that the short listed options were: storage in the UK, supply from Europe and reduced gas demand at CCGTs. Each of the three alternative options is described below and costed in Section 5.

**Storage in the UK**

3.26 There are three different types of storage facility in the UK: depleted gas field and depleted oil field (which can be either on-shore or off-shore), salt caverns and liquefied natural gas (LNG). Figure 18 illustrates schematically the different types of underground storage facility. LNG is a cryogenic liquid and is stored...
above ground in highly insulated tanks. Examples of each type of storage facility are described in turn.

Figure 18 – Schematic of different types of underground storage facility

![Schematic of different types of underground storage facility]

Source: Ontario Ministry of Natural Resources, ILEX

3.27 Table 7 lists the UK storage facilities that were operating in 2004/05 by storage type.

Table 7 – Storage facilities operating in the UK in winter of 2005/06

<table>
<thead>
<tr>
<th>Storage Type</th>
<th>Facilities operating in 2005/06</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depleted field</td>
<td>Rough, Hatfield Moor, Humbly Grove</td>
</tr>
<tr>
<td>Salt Cavern</td>
<td>Hornsea, Hole House</td>
</tr>
<tr>
<td>Liquified Natural Gas (LNG)</td>
<td>Glenmavis, Partington, Avonmouth, Dynevior Arms.</td>
</tr>
<tr>
<td>LNG terminal</td>
<td>Isle of Grain</td>
</tr>
</tbody>
</table>

Isle of Grain LNG was a storage facility that has now been converted to an LNG importation terminal.

**Depleted field**

3.28 Rough is by far the largest gas storage facility in the UK and is a partially depleted, offshore gas field. Compression is required for injection and for transporting the production into the National Transmission System (NTS) the onshore gas grid. Humbly Grove, an onshore depleted field, came on stream in the November 2005.
3.29 There are a number of new depleted field storage projects in the UK that are awaiting planning permission. These are onshore rather than offshore and the projects are a mixture of depleted gas fields, and depleted oil fields.

**Salt cavern**

3.30 Hornsea is a set of nine man-made salt caverns at a depth of 1.8 km below the surface. Compression is required to inject gas into the salt cavern. Gas flows under its own pressure on withdrawal.

3.31 Salt caverns are man made. The process involves pumping water down into the cavern to dissolve the salt and to produce a cavern of the necessary size. The brine which is produced by this process is either disposed of by pumping it into the sea, or used as a raw material feedstock. It takes several years to leach a new salt cavern.

3.32 There are at present a number of new salt cavern storage projects in the UK either under development or at the planning stage.

**LNG**

3.33 The four LNG storage sites liquefy natural gas by cooling it to -160 degrees Celsius and store the liquid above the ground in a highly insulated container. Their key feature is their ability to rapidly re-vaporise the natural gas and deliver it to the NTS. The LNG storage sites pre-date the recent developments in LNG importation.

3.34 With LNG importation the LNG is delivered to receiving terminals by tanker as a liquid where it is offloaded and stored onshore in highly insulated tanks at each of the terminals. The liquid LNG is regasified and exported into the national transmission system. The UK currently has one LNG terminal in operation (with plans for expansion) as well as two new LNG terminals under construction and a number of other projects on the planning board.

3.35 Additional LNG tanks would be constructed at the LNG terminals, and at the other gas entry terminals to provide LNG storage. Tanks at the gas terminals could be filled from LNG tankers using floating bridge technology with tankers making deliveries at times of low demand. The LNG stored in the tanks would slowly boil-off and the tanks would need to be topped up periodically.

**Filling the gap from storage**

3.36 A Rough equivalent could be provided from a number of separate storage facilities, and from a mixture of different types of storage.

3.37 The physical characteristics of depleted field storage are that it takes a long time to fill (60 to 180 days) and a long time to empty (45 to 75 days). The numbers vary according to the type of facility, the number of wells and the above ground
engineering. It would be possible to provide a Rough equivalent from a number of separate facilities. In section 5 we develop the costs based on a combination of offshore and onshore depleted field storage.

3.38 The physical characteristics of salt cavern storage are that it takes a range of times to fill (10 to 160 days) and a short time to empty (10 to 17 days). The numbers vary according to the depth of facility (shorter fill times in lower pressure of shallow facilities) and the above ground engineering (compressors, driers). It would be possible to provide a Rough equivalent by using only part of the deliverability thereby extending the time to empty and this is what we do in Section 5 when we develop the costs of providing a RE from salt cavern storage.

3.39 The physical characteristics of LNG storage are that it fills when tankers make deliveries, and can be emptied in a short time period (5 to 15 days). The time to empty is limited by the re-gasification kit and the capacity of the NTS. It would be possible to provide a Rough equivalent by using only a fraction of the re-gasification capacity thereby extending the time to empty and this is what we do in Section 5 when we develop the costs of providing a RE from LNG storage.

Supply from Europe

3.40 We envisage that a supply from Europe that is capable of supplying the UK with incremental supply during the winter (a time when demand is greatest) will involve deliveries from storage\(^\text{23}\). The alternative sources of supply in Europe, such as pipeline imports from Norway or Russia, do not sufficient capability to swing. It is uneconomic to supply swing directly from remote gas production as it would require investing in additional capacity over the full length of the pipeline.

3.41 Figure 19 shows the types of gas storage available around Europe. The large volumes of storage in Germany, France and Italy are used to provide a swing supply to the domestic markets and to provide strategic storage cover. The storage volume in the UK is much smaller as historically the UK has had the benefit of swing supplies from the North Sea. Our research suggests that the storage position in NW Europe is perceived to be tight and that there is no perceived surplus of storage capacity by the companies operating in the countries. There are plans to develop new storage capacity in Germany and Italy. Thus a strategic reserve would require new storage facilities to be built in NW Europe to supply the UK.

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\(^{23}\) Groningen a producing field in the Netherlands is providing swing supply to the domestic market in the Netherlands and assisting the Dutch gas-depletion policy. Groningen is providing security of supply to the Dutch market, and has its annual output capped at 42.5 bcm. If Groningen could be used to supply one RE or 3.3 bcm for security of supply to the UK market then there would need to be a concession on its output. We would expect the service from Groningen to be priced against the alternatives in NW Europe. In addition, Groningen supplies low cal gas which is outside the UK gas specification.
Figure 19 – Type of gas storage (mcm)

Source: IEA Natural Gas Information 2004

3.42 If the UK were to contract for a strategic supply from NW Europe then new storage facilities would need to be developed. Figure 20 shows the location of the existing storage facilities in Europe. The storage facilities are geographically spread around Europe, with a concentration of facilities in NW Europe in Germany and the Benelux countries.
3.43 Strategic storage provided from facilities in NW Europe would require transportation capacity to transit the countries and interconnector capacity to reach the UK.

3.44 Our analysis indicates that using supplies from Europe to fill a gap would be uneconomic as it would involve the cost of building new storage facilities, the investment in new transportation capacity to transit Europe and interconnector capacity to reach the UK. Storage in Europe would entail additional risk compared with storage held locally in the UK: there would be the risk of political interference and the risk of failure of the transportation capacity to transit Europe and flow through the interconnector to the UK. We conclude that the construction of new storage in the UK is going to be cheaper and more reliable than supply from Europe.

**Reduced gas demand at CCGTs**

3.45 The issue is the options available for the UK electricity generating sector to continue to provide power in the event of a major curtailment in the gas supply system. At first sight, there are three possible options available:

- Mothballed coal plant which can be returned to service at short notice;
- Mothballed oil plant which can also be returned to service at short notice; and
- Oil storage, or oil available at short notice, at CCGT sites.

Source: ILEX
3.46 In our solutions we would let the market settle the mix based on least cost and it may be that a combination of the above options could provide part of the required capacity. The options are examined in more detail below.

*Mothballed Coal Plant*

3.47 Coal plant has the advantage that large amounts of reserve fuel can be stocked at relatively low cost, and with little stocking maintenance requirements. Indeed, coal stocking has been the main way in which the UK has maintained a reserve power generation fuel stock since the 1984 miners strike, and this has been facilitated by the fuel security code.

3.48 However, the reserve capability only has value on plant which is not already running, and which can replace gas fired CCGT capacity at short notice. In the medium term, some of this might be achieved from coal plant which is opted out of LCPD, and which is therefore available but limited on operating hours. After the lifetime of LCPD, in the longer term the capacity must have been mothballed, but is maintained such that it is capable of being returned to service at short notice such that it can operate reliably for a period of weeks. It may be that this could be provided by plant which is partly mothballed, such that for example, a 2000MW station operates only two out of four 500MW units, but maintains the remaining two units such that they are capable of being returned to service at short notice.

3.49 However, if a coal plant is completely shut down and mothballed, it is quite difficult to see how this type of plant can be maintained such that it is available to replace gas CCGT plant at short notice for a number of reasons:

- Coal plant is inherently a mechanically complex, and maintenance intensive generation technology. Hence if the plant has been mothballed, a considerable amount of maintenance work will be required to keep the coal handling plant (including the conveyors, mills etc), the boilers and the generators capable of operation at short notice, which will be costly.

- Coal plants are also labour intensive, and although it might be credible to contract out the maintenance of the plant, it is not clear where the staff would come from to operate it at short notice. It is also worth noting that it would probably not be possible to move staff from another station due to that fact that in general, coal plants are quite different from one another, and therefore operating skills are not easily transferable at short notice, and there may be serious health and safety issues in trying to do this.

- Most of the remaining coal plants that would be in this mothballed category were built in the 1960s, and are already at their designed life of 40 years, and hence maintenance will become increasing difficult and expensive in the medium term.
3.50 We conclude that the amount of reserve capacity that could be provided by coal plant is limited. A significant proportion of the existing coal plant will be decommissioned, and those stations that remain open may be uneconomic to hold back capacity in reserve. Thus the quantity of capacity reserve that could potentially be provided is limited and would not provide 10GW of capacity. However, we do not rule out the possibility that some of the coal stations may be able to provide reserve.

*Mothballed Oil Plant*

3.51 Although oil plants are mechanically simpler than coal plants since they do not have coal and ash handling systems, there would still be concerns about how reliably they could be started at short notice, and where the staff to operate them would be sourced.

3.52 Older oil plants would have significant tankage already installed, and would probably have plenty of space for additional HFO storage. We conclude that providing additional storage at oil plant may be an option, and will assume that the costs of providing 75 days storage will be similar to the costs at CCGT plant.

*Oil Storage at CCGT Sites*

3.53 The JESS and NGC Winter Outlook reports make clear that around 5.7GW of existing 25 GW total CCGT capacity has oil backup and storage capability, and provides indicative information as to how long this plant can continue generating on distillate at maximum and average storage levels.

3.54 The amount of CCGT generating capacity that can be run on back up fuel supplies is limited: starting with average back-up fuel availability levels the amount of capacity drops off sharply from 5.7GW and falls to half that level within five days24 (starting at maximum availability the capability halves in a week.)

3.55 We conclude that the existing back-up capability is extremely limited. To provide 75 days cover would require greatly increased storage capability. For the purpose of costing we ignore the existing storage capability that amounts to around 5% of the total required.

3.56 There are a large number of issues related to storage capacity and safety on site, physical delivery, technological and regulatory issues which are described below.

*Fuel storage*

3.57 75 days of fuel for a 400MW station will require 112,000 tonnes of storage (equivalent to 26 tanks of 5,000 m3 capacity). We assume there is insufficient delivery capacity to restock significant volumes during the winter (see Section

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24 Taken from Figure 10 in the 2005 NGC Winter Outlook Report
3.63) Refuelling by sea tanker may be available in some cases located near the coast. However, we assume that the requirement is to store the full 75 days stock on site.

3.58 The total storage requirement to supply 10GW of capacity for 75 days would be 2.8 million tonnes, and require a total of 650 tanks of 5,000 m³ capacity.

**Tanks**

3.59 We have carried out investigation and analysis of the approximate costs of distillate tanks. This indicates that the cost of 10,000 m³ of storage in the form of two 5,000 m³ steel tanks would be in the order of £1 million, or £0.5 million per tank. This would be for steel tanks with no wall coating, but a roof coating for corrosion protection, and with no bunding or fire protection.

**Bund**

3.60 The Environment Agency (EA) requires that oil and chemical storage tanks are bunded to contain any leaks or spillages. The requirement is for the bund to be able to hold 110% of the volume of the largest tank.

3.61 It is our view that it is unlikely that the EA would give consent for a lined earth bund, and hence a concrete bund would be required. We estimate that for the above 5500 m³ storage volume required for each tank, the bunding would cost in the region of £250k.

**Fire protection**

3.62 Distillate tanks require two forms of fire protection, firstly foam injection into the top of the tanks, and secondly water sprays on the outside of the tank. The water system would be relatively straightforward to tie in to the existing power station fire supply, but stations without distillate will not have a foam system. This would need to be installed, and the cost of this would be in the order of £100k for a central foam generator, and for the installation of nozzles in each tank.

**Delivery systems**

3.63 The means of delivery of the distillate to the power station is important both for the initial fill of the tanks, and also for any replenishment during a prolonged gas supply interruption. Distillate can be delivered by pipeline, road, rail or barge. Taking these in turn.

- Pipeline: this would be the preferred means of delivery, as it is independent of third parties and a very reliable means of delivery at short notice. However, the viability of pipeline delivery depends on the volume being delivered, and pipelines are really only suitable for high volumes due to their high capital cost, and the high cost of the fuel which would be actually stored in the pipes. Here we are looking at a backup supply for an unlikely and infrequent event, and therefore the capital cost is unlikely to be justified unless the station were adjacent to an existing pipeline or refinery.
・ Road delivery: road delivery is unlikely to be practical for power station deliveries due to the high volumes required. In addition most stations have planning constraints which preclude delivery by road. In practice the capacity for road delivery does not exist as the current infrastructure is designed for the capacity required for the domestic, industrial and commercial market.

・ Rail Delivery: this is the mechanism most often used by power plants in the UK, and requires proximity to an existing rail connection. Many of the UK CCGT power stations are either built on the site of existing coal fired stations, or old industrial brown field sites, which would usually have had a rail connection at some time in the past. A rail siding is required to unload the rail cars, and pump the distillate to the storage tanks. Assuming a 22 car train were used, a 200m siding would usually be required. The cost of a 200m twin siding is estimated to be in the region of £300,000. In addition to this is the cost of a connection to the Network Rail system if one does not already exist, and the pipeline from the siding to the oil storage tanks which will obviously depend on the distance between the two. A 22 car train has a capacity of about 1,400 tonnes; without onsite storage one delivery per day would be required for a 400 MW station. This rules out significant restocking over the winter due to the insufficient capacity of the rail network.

・ Barge delivery: this is only practical where the power station is adjacent to a navigable waterway. However, a number of stations use this means of distillate delivery. It has the advantage of being able to deliver large volumes very quickly, and also to access directly the Rotterdam market rather than relying on UK refineries. There are a number of power stations on or relatively near navigable waterways which in theory ought to be able to use this delivery system. It is very difficult to estimate the cost of the capital works required as the cost will vary significantly from station to station depending on whether wharfs exist near the stations, and how far they are away, and hence the practicality of a pipeline link. In this case it may be possible to reduce the tank storage on site and to restock during winter. We do not include this capability in our estimate and assume that the 75 days storage is provided on site.

Technology issues

3.64 Technology issues of running CCGTs on distillate include:

・ Lower efficiency: all CCGTs in the UK are designed to fire on natural gas as the primary fuel. When firing on distillate, there is a risk that the flue products will condense in the stack leading to corrosion. The plant therefore increases the exhaust temperature from the Heat Recovery Steam Generator (HRSG) to minimise condensation risk, but at the penalty of reduced HRSG efficiency. This reduction is in the order of 2% of overall cycle efficiency.

・ Firing technology: broadly speaking, large industrial gas turbines used in power generation, can be classified into three technology groups, ‘E’, ‘F’ and ‘H’ determined by the firing temperatures employed in the combustion chamber, and hence the maximum thermodynamic efficiency achievable. The
mix of existing generating capacity is split reasonably evenly between type ‘E’ and ‘F’, and only one type ‘H’. It is our understanding that the older and lower firing temperature ‘E’ class gas turbines will operate satisfactorily on distillate for extended periods of time. There is a question however as to what experience there is in firing the ‘F’ class gas turbines on distillate. It is our understanding that although these machines have the capability of operating on distillate with some modifications to the combustion systems, there is very little experience of operating them for extended periods on this fuel. We are not aware that the one ‘H’ class machine has any distillate capability.

Regulatory Issues – COMAH

3.65 The Control of Major Accident Hazards Regulations 1999 (as amended by the Control of Major Accident Hazards (Amendment) Regulations 2005) lay out the safety systems required for large hazardous industrial sites. Although it applies mainly to the chemical industry, it also applies to other industries where certain threshold quantities of dangerous substances are stored. It therefore applies to power station sites which store distillate in quantities in excess of 2,500 tonnes, which therefore includes virtually all oil backup facilities at CCGTs. COMAH lays out two levels of hazard management systems required, depending on the amount of the hazardous substance stored: ‘lower tier (LT) for storage capacity of between 2,500 and 25,000 tonnes capacity; and ‘top tier (TT)’ for storage capacity in excess of 25,000 tonnes.

3.66 Existing CCGT sites with oil backup that are caught by the regulations will be in lower tier. If there is to be a significant expansion of storage capacity, then the site will become top tier, with a significantly increased regulatory and hence cost burden on the site.

Filling the gap: risk of insufficient CCGT gas burn

3.67 There is a risk that CCGT plant in future holds a position at the top of the merit order for electricity generation. The consequence of this would be that the CCGT plant only runs at a low load factor. This would limit the amount of CCGT gas demand that could be interrupted.

3.68 ILEX’s analysis of the UK electricity market envisages that in a future of high gas prices when CCGT plant is providing only 15% of winter electricity demand. This would limit the capability of CCGT interruption to around 15%*70GW = 15GW CCGT capacity. To provide the cover of one RE it would be necessary to have a total of 10GW of CCGT capacity installed with standby fuel capability (this capability could be at any of the CCGTs, not just the CCGTs that are being interrupted). We conclude that the there is a risk in a high gas price, constrained world – the world where strategic reserve is required – that the amount of gas that can be interrupted at CCGTs would be limited, providing at maximum 1 to 1.5 RE. However, this is still a credible policy option for provision up to the 10GW or 1RE level.
Summary

3.69 We listed a whole range of alternatives to deliver incremental supply or incremental demand reduction equivalent to one Rough storage facility. We short-listed three alternatives and described them in more detail.

3.70 The following alternative options were short-listed and could each potentially provide one Rough equivalent (RE):

- storage in the UK using any of depleted field storage, salt cavern storage and LNG storage tanks. The higher deliverability of salt cavern and LNG storage would mean that only part of the deliverability would be used to provide a 75-day service;

- supply from Europe, probably sourced from new-build storage, could be used and would require additional transit and interconnector capacity to transport the gas to the UK; and

- oil storage at CCGT sites could provide 75 days of storage requiring 2.8 million tonnes of distillate in a total of 660 tanks (26 tanks per 400 MW unit). With oil storage there is a risk that in a high gas price, constrained world – the world where strategic reserve is required – that the amount of gas that can be interrupted at CCGTs would be limited, providing at maximum 1 to 1.5 RE.
4. BENEFITS (AVOIED COSTS)

4.1 This section aims to provide a quantification of the benefits of different levels of strategic storage to the UK economy. By examining the cost of a gas supply interruption in a ‘do nothing’ scenario we can estimate the avoided cost, or benefit, of developing different amounts of strategic storage. This section builds on work previously undertaken by ILEX and Global Insight (GI) on the effects of a UK gas shortage.

4.2 The purpose of this section is to:
- to describe the information available;
- to set out our assumptions as to the sectors:
  - directly affected by interruption;
  - directly upstream of those sectors that will be affected; and
  - directly downstream of those sectors that will be affected;
- to provide a quantification of potential losses to the economy of different levels of interruption to these sectors.

4.3 The text below is structured along these lines.

Information available

4.4 We have reviewed the sources of information listed below. We have concentrated on using published information that is readily available for all sectors, supplemented with information provided at interviews with industry representatives where available.
- Digest of UK Energy Statistics (DUKES) 2005;
- Office of National Statistics (ONS) publications, including the Annual Business Inquiry (ABI); and
- information provided at sector interviews.

4.5 Much of the published information classifies industries according to the Standard Industrial Classification (SIC) codes. During this analysis we have classified industries down to the most detailed level possible. These codes enable classification down to the installation specific level although we have been restricted by an absence of available detailed data on gas use.
Energy Usage

4.6 The principle source of data on energy usage was DUKES 2005\textsuperscript{26}. Dukes publishes these statistics by sector, defined by SIC codes. The SIC codes used to classify sectors are shown in Table 8.

\textsuperscript{26} www.dti.gov.uk/energy/inform/dukes
### Table 8 – DUKES sectors classified by SIC codes

<table>
<thead>
<tr>
<th>Sector</th>
<th>SIC codes included</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel producers</td>
<td>10-12 23 40</td>
</tr>
<tr>
<td><strong>Final consumers (industrial):</strong></td>
<td></td>
</tr>
<tr>
<td>Iron and steel</td>
<td>27 (excluding 27.4, 27.53, 27.54)</td>
</tr>
<tr>
<td>Non-ferrous metals</td>
<td>27.4 27.53 27.54</td>
</tr>
<tr>
<td>Mineral products</td>
<td>14 26</td>
</tr>
<tr>
<td>Chemicals</td>
<td>24</td>
</tr>
<tr>
<td>Mechanical engineering and metal products</td>
<td>28 29</td>
</tr>
<tr>
<td>Electrical and instrument engineering</td>
<td>30-33</td>
</tr>
<tr>
<td>Vehicles</td>
<td>34 35</td>
</tr>
<tr>
<td>Food beverages and tobacco</td>
<td>15 16</td>
</tr>
<tr>
<td>Textiles, clothing, leather and footwear</td>
<td>17-19</td>
</tr>
<tr>
<td>Paper printing and publishing</td>
<td>21 22</td>
</tr>
<tr>
<td>Other industries</td>
<td>13 20 25 36 37 41</td>
</tr>
<tr>
<td>Construction</td>
<td>45</td>
</tr>
<tr>
<td>Transport</td>
<td>60-63</td>
</tr>
<tr>
<td><strong>Other final users:</strong></td>
<td></td>
</tr>
<tr>
<td>Domestic</td>
<td>Not covered by SIC 2003</td>
</tr>
<tr>
<td>Public administration</td>
<td>75 80 85</td>
</tr>
<tr>
<td>Commercial</td>
<td>50-52 55 64-67 70-74</td>
</tr>
<tr>
<td>Agriculture</td>
<td>1 2 5</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>90-93 99</td>
</tr>
</tbody>
</table>

Source: DUKES

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27 SIC code 2 covers Forestry, logging and related services. We have excluded this sector from the analysis due to its low gas use and separation from other agricultural areas.
4.7 DUKES only provides data down to the sector specific level shown above. Although we have been able to match the above data on energy usage using SIC codes any attempt to disaggregate the data further has not been possible.

*Economic impact*

4.8 Data published by the ONS, in particular the ABI have been used to measure the impact on the UK economy. Gross value added (GVA) at basic prices has been used in order to quantify these economic impacts where GVA is defined as the value of goods and services less the value of the products used to make them. GVA is measured before the costs of wages and capital investment are taken into account. These data are all published according to SIC codes.

*Simplifying assumptions*

4.9 In order to allow quantification of the impacts in the time available and with the necessary transparency, we have made the following simplifying assumptions:

- a sector’s output and gas use is spread evenly across the year (so a day’s output constitutes 1/365 of total annual output). This assumption is least appropriate for those industries that are seasonal in nature:
  - it will overstate the GVA impact where output tends to be lower than average in winter or gas use tends to be higher than average in winter;
  - it will understate the impact where output is usually higher than average in winter or gas use tends to be lower than average in winter; and
- the GVA generated by a sector is spread evenly across all its output. This is least appropriate where we have used aggregate sector classes and that aggregate sector includes a range of diverse products the GVA of which varies significantly.

*Costs of a supply interruption*

*Sectors directly affected by gas interruption*

4.10 We first look at the sectors directly affected by a gas interruption in the UK. In order to build up of picture of those sectors that would be affected in a gas interruption situation we have drawn on previous studies undertaken for the DTI by both ILEX and GI.

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28 ONS definition: GVA + taxes on products – subsidies on products = GDP
29 ILEX: Economic Implications of a Gas Supply Interruption to UK Industry
30 GI: Estimation of Industrial Buyers’ Potential Response to Short Periods of High Gas and Electricity Prices
GI sector mapping

4.11 The GI study examined around 200 large industrial consumers who consume around 270 GWh of gas per day. This represents approximately 5-6% of national gas demand. The ILEX study built on this work to provide a view of the potential impact to the UK economy of a gas supply interruption to UK industry. Although the GI study was examining the ‘voluntary’ demand reduction of these large industrial consumers, it was concluded by both the DTI and ILEX that these industries were a good representation of the sectors that could theoretically be ‘cut off’ by Transco during a gas interruption (see paragraph 4.15).

4.12 In order to enable comparison between the Global Insight report and other data it was necessary to map the GI “energy-intensive industry sectors” into SIC codes and then into their respective DUKES sectors. This mapping is shown in Table 9 below.

Table 9 – Energy intensive industry sectors mapped onto SIC codes and DUKES sectors

<table>
<thead>
<tr>
<th>Energy intensive industry sector</th>
<th>SIC sub section</th>
<th>SIC class</th>
<th>Relevant DUKES sector</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aluminium</td>
<td>DJ</td>
<td>27.42</td>
<td>Non-ferrous metals</td>
</tr>
<tr>
<td>Ammonia/Fertilisers</td>
<td>DG</td>
<td>24.15</td>
<td>Chemicals</td>
</tr>
<tr>
<td>Bricks</td>
<td>DI</td>
<td>26.40</td>
<td>Mineral Products</td>
</tr>
<tr>
<td>Cement</td>
<td>DI</td>
<td>26.51</td>
<td>Mineral Products</td>
</tr>
<tr>
<td>Chlor-alkali</td>
<td>DG</td>
<td>24.13</td>
<td>Chemicals</td>
</tr>
<tr>
<td>Gases</td>
<td>DG</td>
<td>24.11</td>
<td>Chemicals</td>
</tr>
<tr>
<td>Glass</td>
<td>DI</td>
<td>26.1</td>
<td>Mineral Products</td>
</tr>
<tr>
<td>Food and Beverages</td>
<td>DA</td>
<td>15</td>
<td>Food, beverages, etc</td>
</tr>
<tr>
<td>Newsprint</td>
<td>DE</td>
<td>22.21</td>
<td>Paper, Printing, etc</td>
</tr>
<tr>
<td>Paper</td>
<td>DE</td>
<td>21.12</td>
<td>Paper, Printing, etc</td>
</tr>
<tr>
<td>Paperboard</td>
<td>DE</td>
<td>21.12</td>
<td>Paper, Printing, etc</td>
</tr>
<tr>
<td>Petroleum refining</td>
<td>DF</td>
<td>23.20</td>
<td>Petroleum refineries</td>
</tr>
<tr>
<td>Plastics</td>
<td>DG</td>
<td>24.16</td>
<td>Chemicals</td>
</tr>
<tr>
<td>Refining</td>
<td>DF</td>
<td>23.20</td>
<td>Petroleum refineries</td>
</tr>
<tr>
<td>Steel</td>
<td>DJ</td>
<td>27.1</td>
<td>Iron and Steel</td>
</tr>
</tbody>
</table>

Source: GI, DUKES and ILEX analysis

4.13 For the remainder of this report we have taken the broader DUKES sectors as our basis for analysis due, in part, to the improved availability of data at this level. This is equivalent to an assumption of highly connected, within industry processes combined with widespread ‘just-in-time’ production which is representative of what we have found in our industry interviews. This increases significantly the
total level of gas use covered in this analysis when compared with the GI study but also the associated overall financial costs of a supply interruption.

**Potential gas reduction**

4.14 In order to identify the economic impact of a large scale interruption we have identified the gas usage of each sector of the economy using the DUKES classifications identified in Table 8 above. The gas use by sector is shown in Figure 21 below.

**Figure 21 – Gas use by DUKES sector in 2004**

Source: DUKES and ILEX analysis

4.15 The combination of high gas and electricity usage, both in total as well as on a ‘per site’ basis, and a relatively low GVA of the industrial sector, mean that the energy intensive industrial sectors are likely to meet the bulk of a reduction in gas usage during a supply interruption.

4.16 However, in order to ‘save’ a large volume of gas it may be necessary to also interrupt users in other areas of the economy besides industry. Using the DUKES classification the ‘alternative’ sectors that use large volumes of gas broadly fall under the headings of:

- electricity and heat production;
- energy industry;
- domestic usage;
- public administration usage; and
- commercial usage.
4.17 Due to the political and critical national infrastructure ramifications we have excluded both the domestic and the public administration sectors from this study. We have also concluded that the energy industry would remain largely unaffected due to the importance of maximising gas production during a gas shortage.

4.18 However, we could see a reduction in gas usage by other sectors:

- The electricity and heat production sectors as:
  - the Refineries sector is a major consumer of both gas and electricity and as such it is included both in the GI sector analysis and in our analysis below; and
  - production reductions by large industrial users due to gas interruptions are likely to lead to significant reductions in electricity demand.
- The commercial sector although the extremely high GVA of this sector, particularly in relation to its gas use, would suggest that commercial sites are less likely to be interrupted than industrial ones.
- The Agricultural sector as it has a relatively high gas use, relatively low GVA and is heavily reliant on the industrial sector (see paragraph 4.29 below).

Electricity usage

4.19 The potential for a significant reduction in gas usage by the Energy transformation sector would be restricted by the necessity of a continued electricity supply (‘the lights stay on’ assumption). However, the UK industrial sector not only uses a large volume of gas in its processes but also of large volumes of electricity. As such any interruption of gas supplies leading to industrial sector shut-downs would also lead to a lowering of electricity demand.

4.20 Making the assumption that any reduction in electricity demand leads to a corresponding reduction in production by CCGTs we can convert electricity demand reduction into a figure for gas saved. This will allow a comparison across industries. This conversion is shown in Table 10 below.

---

31 We assume a CCGT HHV efficiency of 50%. The full electricity demand reduction would lead to a total fall in CCGT production equivalent to approximately 13GWs. As we experience a level of ‘involuntary’ electricity demand reduction significantly below this total reduction in our models and is therefore compatible with our earlier assumptions on winter CCGT generation in the modelled period.
Table 10 – DUKES sector electricity use (GWh) in 2004 converted to gas use (mcm)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Electricity use (GWh)</th>
<th>Converted to gas use (mcm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petroleum refineries</td>
<td>6,177</td>
<td>1,144</td>
</tr>
<tr>
<td>Iron and steel</td>
<td>5,412</td>
<td>1002</td>
</tr>
<tr>
<td>Non-ferrous metals</td>
<td>7,277</td>
<td>1347</td>
</tr>
<tr>
<td>Mineral products</td>
<td>7,849</td>
<td>1453</td>
</tr>
<tr>
<td>Chemicals</td>
<td>23,170</td>
<td>4290</td>
</tr>
<tr>
<td>Mechanical engineering, etc</td>
<td>8,513</td>
<td>1576</td>
</tr>
<tr>
<td>Electrical engineering, etc</td>
<td>6,818</td>
<td>1262</td>
</tr>
<tr>
<td>Vehicles</td>
<td>5,686</td>
<td>1053</td>
</tr>
<tr>
<td>Food, beverages, etc</td>
<td>12,324</td>
<td>2282</td>
</tr>
<tr>
<td>Textiles, leather, etc</td>
<td>3,396</td>
<td>629</td>
</tr>
<tr>
<td>Paper, printing, etc</td>
<td>13,253</td>
<td>2454</td>
</tr>
<tr>
<td>Other industries</td>
<td>21,653</td>
<td>4009</td>
</tr>
<tr>
<td>Construction</td>
<td>1,799</td>
<td>333</td>
</tr>
<tr>
<td>Agriculture</td>
<td>4,194</td>
<td>776</td>
</tr>
</tbody>
</table>

Source: DUKES, ONS and ILEX analysis

Financial impacts

4.21 We have compared the 2004 GVA of each DUKES sector using data from the Annual Business Inquiry conducted by the ONS. The industrial sector\(^{32}\) had a combined GVA of approximately £210bn in 2004 and the contribution by each DUKES sector is shown is summarised in Figure 22.

\(^{32}\) Including the Agricultural and Petroleum refineries sectors
Figure 22 – GVA by DUKES sector as a percentage of industry total in 2004

Source: DUKES, ONS and ILEX analysis

**Ranking of directly affected sectors**

4.22 When looking at an emergency gas supply interruption scenario, in particular at who would be subject to an interruption of supply, it is necessary to consider not only the gas ‘saved’ by turning off a sector but also the subsequent cost to the economy (in this case measured in GVA).

4.23 In order to ‘rank’ these industrial industries and obtain a theoretical interruption order, we can consider the gas use by each sector per unit of GVA contributed. An industry with a higher figure will use a larger volume of gas compared to its GVA than an industry with a lower figure. This calculation is displayed below in Table 11 and illustrated in Figure 23. It includes gas saved by the reduction in electricity demand (see paragraph 4.19).
Table 11 – DUKES sectors ranked by Gas Use (mcm) per GVA (£m)

<table>
<thead>
<tr>
<th>Sector</th>
<th>GVA (£)</th>
<th>Gas Use (mcm)</th>
<th>Gas use / GVA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-ferrous metals</td>
<td>1312</td>
<td>1636.47</td>
<td>1.25</td>
</tr>
<tr>
<td>Iron and steel</td>
<td>2055</td>
<td>1820.04</td>
<td>0.89</td>
</tr>
<tr>
<td>Chemicals</td>
<td>15888</td>
<td>7979.71</td>
<td>0.50</td>
</tr>
<tr>
<td>Petroleum refineries</td>
<td>2740</td>
<td>1347.65</td>
<td>0.49</td>
</tr>
<tr>
<td>Agriculture</td>
<td>2032</td>
<td>994.49</td>
<td>0.49</td>
</tr>
<tr>
<td>Mineral products</td>
<td>7657</td>
<td>2599.12</td>
<td>0.34</td>
</tr>
<tr>
<td>Textiles, leather, etc</td>
<td>3739</td>
<td>1243.14</td>
<td>0.33</td>
</tr>
<tr>
<td>Other industries</td>
<td>20371</td>
<td>4759.91</td>
<td>0.23</td>
</tr>
<tr>
<td>Food, beverages, etc</td>
<td>22427</td>
<td>4775.65</td>
<td>0.21</td>
</tr>
<tr>
<td>Paper, printing, etc</td>
<td>19874</td>
<td>3828.37</td>
<td>0.19</td>
</tr>
<tr>
<td>Vehicles</td>
<td>17717</td>
<td>1962.23</td>
<td>0.11</td>
</tr>
<tr>
<td>Electrical engineering, etc</td>
<td>16345</td>
<td>1614.99</td>
<td>0.10</td>
</tr>
<tr>
<td>Mechanical engineering, etc</td>
<td>24492</td>
<td>2323.07</td>
<td>0.09</td>
</tr>
<tr>
<td>Construction</td>
<td>54738</td>
<td>584.86</td>
<td>0.01</td>
</tr>
</tbody>
</table>

Source: DUKES, ONS and ILEX analysis
4.24 We see a wide range of values of gas usage per unit GVA across different industries with construction standing out as having an extremely low absolute value corresponding to a very high marginal interruption cost. In other words there would be very little gain, in terms of a gas saving, but a very high cost, in terms of GVA loss, of turning off the construction sector compared to other industrial sectors.

4.25 This analysis gives us a basis for our avoided cost estimate (that is the benefit of strategic storage). In order to ‘save’ a given level of gas during an emergency shortage situation where the market will not provide that gas, we should theoretically turn off those users who are using the most gas but providing the least benefit to the economy. Given that the industrial sector will be interrupted first and considering only the direct GVA costs, the above ranking is the theoretically optimum order in which to switch off industries. Figure 24 shows the cumulative GVA loss to the economy compared to the cumulative gas ‘reclaimed’ of turning off industry in the order shown in Table 11 above.  

The graph has a marginally different path to that obtained from simply plotting the figures in Table 11 as we have incorporated the industrial demand response as described by GI before calculation.
4.26 This gives us a curve that increases steeply as we experience much higher marginal GVA loss as a larger volume of gas is needed. The slope of the graph corresponds to the gas use per GVA of each sector or in other words, the GVA cost of saving an extra unit of gas. If we also look at gas use in the commercial sector it is possible to extend the graph to cases where a larger volume of gas is required. This is shown in Figure 25.

Source: DUKES, ONS and ILEX analysis

In this case the slope corresponds to the unit cost in £m/mcm although exactly the same shape would be observed if the units were pence/therm. The conversion factor for this is 271 – i.e. (cost in £m/mcm)*271 = (cost in Pence/therm)
Figure 25 – GVA loss per day (£m) compared to Gas saved per day (mcm) – Ranked according to direct costs and including commercial

This kink demonstrates the very high marginal cost of ‘saving’ gas by interrupting the construction sector.

Source: DUKES, ONS and ILEX analysis. Notes: As gas use in the commercial sector is approximately doubled in winter we use a value of $2/365$ of yearly gas use per day. The GVA for the commercial sector is underestimated in this figure due to a lack of available data on financial intermediation.

4.27 Due to its importance to the UK economy and un-concentrated gas use we have assumed that commercial would be interrupted after industry and therefore excluded it from the remainder of our analysis. However it is important to note that as the amount of gas that is needed goes beyond that that can be provided by industry the GVA costs to the economy increase rapidly.

Robustness of this ranking

4.28 Unfortunately, this theoretical ‘optimum’ ranking is unlikely to be attainable due to:

- indirect effects of turning off the industrial sectors on other sectors of industry and the rest of the economy;
- difficulties in physically switching off sectors where gas use is not concentrated in a small number of locations; and
- additional costs to the industries themselves above and beyond those associated with production loss.

We take these factors into account in the sections below.
Sectors upstream of gas interruption

4.29 As well as suspending production in sectors directly affected, we would expect a gas supply interruption to have indirect, ‘knock-on’ effects to other areas of the economy. This section deals with industries directly upstream of those directly affected by a gas interruption.35

4.30 We have used the Leontief multiplier36 to identify upstream sectors that are likely to be affected by an interruption to the energy intensive industry sectors. The table below shows (in the left hand column) which sectors would be affected by a change in demand from the sectors directly affected by gas interruption (listed across the top row).

Table 12 – Upstream sectors affected by small changes in energy intensive industry sector demand

<table>
<thead>
<tr>
<th>Upstream sectors</th>
<th>Aluminium</th>
<th>Ammonia/ fertilizers</th>
<th>Bricks</th>
<th>Cement</th>
<th>Chlor-alkali</th>
<th>Glass</th>
<th>Heavy food</th>
<th>Heavy fuel</th>
<th>Newsprint</th>
<th>Paper and paperboard</th>
<th>Refining and petro-chemicals</th>
<th>Plastics</th>
<th>Steel</th>
<th>Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Banking &amp; finance</td>
<td></td>
<td></td>
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<tr>
<td>Wholesale distributio</td>
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<tr>
<td>Other land transport</td>
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<tr>
<td>Electricity production &amp; distribution</td>
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<tr>
<td>Ancillary Transport services</td>
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<tr>
<td>Oil &amp; gas extraction</td>
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<tr>
<td>Construction</td>
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<td>Estate agent activities</td>
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<tr>
<td>Miscellaneous manufacturing nec &amp; recycling</td>
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<tr>
<td>Gas distribution</td>
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<tr>
<td>Agriculture</td>
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<tr>
<td>Wood &amp; wood products</td>
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<tr>
<td>Coal extraction</td>
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<tr>
<td>Coke ovens, refined petroleum &amp; nuclear fuel</td>
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<td>Inorganic chemicals</td>
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<tr>
<td>Accountancy services</td>
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<tr>
<td>Paper &amp; paperboard products</td>
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<tr>
<td>Animal feed</td>
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<tr>
<td>Membership organisations nec (pt)</td>
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<tr>
<td>Industrial gases &amp; dyes</td>
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<tr>
<td>Insurance &amp; pension funds (pt)</td>
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</tr>
</tbody>
</table>

Source: ONS and ILEX analysis Source: ONS and ILEX Notes: excludes impact on demand within the directly affected sector. For each sector we have chosen the top five sectors that would be affected.

35 There will be effects all along the supply chain but we have only examined those industries one step away or adjacent in supply terms to the directly affected industries.

36 The Leontief multiplier shows how a marginal increase in demand would impact on the demand of other sectors.
4.31 As can be seen in Table 12, the Banking & Finance, Wholesale distribution and Other Land Transport are all upstream of the majority of the directly affected sectors.

4.32 We have not attempted to calculate the extent of the losses to these sectors in this report not because they are unlikely to be affected, but due to the significant difficulties with quantification from:

- the diverse customer base of these industries making it difficult to put a figure on the GVA losses we could expect from an interruption in gas supply specific to the energy intensive industry sectors;
- problems with looking at the direct chain of supply from the upstream sectors to the energy intensive industry sectors; and
- indirect effects to the banking sector as its performance will be strongly linked to the economy’s performance as a whole.

4.33 However, we have included the upstream sectors of Electricity production and distribution, by converting electricity to gas use (see paragraph 4.19), and of Agriculture specifically due to its direct linkage to the Heavy Foods sector and the likely unrecoverable nature of its sales losses. For this reason it is included in Table 11 above.

Sectors downstream of gas interruption

4.34 We have also looked at the possible impacts downstream of the directly affected sectors37. To do this we have taken information provided during interviews with stakeholders to form a view of the key customers of the energy intensive industry sectors.

37 There will be effects all along the supply chain but we have only examined those industries one step away or adjacent in supply terms to the directly affected industries.
Table 13 – Downstream sectors mapped onto SIC codes and DUKES sectors

<table>
<thead>
<tr>
<th>GI sectors</th>
<th>Downstream sectors</th>
<th>SIC class</th>
<th>Relevant DUKES sector</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steel</td>
<td>Vehicles</td>
<td>34.10</td>
<td>Vehicles</td>
</tr>
<tr>
<td>Steel</td>
<td>Metal products</td>
<td>28</td>
<td>Mechanical Engineering</td>
</tr>
<tr>
<td>Steel</td>
<td>Wires</td>
<td>31.3</td>
<td>Electrical Engineering</td>
</tr>
<tr>
<td>Steel, Aluminium, Cement, Glass &amp; Bricks</td>
<td>Construction</td>
<td>45.2</td>
<td>Construction</td>
</tr>
<tr>
<td>Aluminium</td>
<td>Aviation</td>
<td>35.30</td>
<td>Vehicles</td>
</tr>
<tr>
<td>Paper, Paperboard</td>
<td>Packaging</td>
<td>74.82</td>
<td>Paper, printing, etc.</td>
</tr>
<tr>
<td>Cement</td>
<td>Concrete</td>
<td>26.63</td>
<td>Mineral Products</td>
</tr>
<tr>
<td>Glass</td>
<td>Glass Containers</td>
<td>26.13</td>
<td>Non-ferrous metals</td>
</tr>
<tr>
<td>Chemicals</td>
<td>Packaging (Plastics)</td>
<td>25.22</td>
<td>Other Industries</td>
</tr>
<tr>
<td>Chemicals</td>
<td>Silicon chips</td>
<td>30.02</td>
<td>Electrical Engineering</td>
</tr>
<tr>
<td>Chemicals</td>
<td>Shoes</td>
<td>19.3</td>
<td>Textiles, Leather etc.</td>
</tr>
<tr>
<td>Chemicals</td>
<td>Water</td>
<td>41.00</td>
<td>Other industries</td>
</tr>
</tbody>
</table>

Source: DUKES, industry and ILEX analysis

Including both direct and indirect effects

4.35 Using the relationships from Table 13 we can build up a picture of how industry is interconnected. From these connections it is possible to incorporate indirect effects by assuming that when an industry is switched off any industry either directly upstream or directly downstream of the interrupted industry will also shut down. This assumption characterises a high level of inter-industry connection combined with ‘just-in-time’ production leading to a low level of stocks of essential inputs. It is largely representative of what we have found in industry interviews.

4.36 The use of imports to mitigate these effects has been excluded as we believe they would be severely restricted in the event of the kind of interruptions we are analysing. It is doubtful that in the event of a large scale gas interruption to UK industry, firms could arrange alternative supplies of a number of key inputs to a level that would enable production to resume as:

- the interruptions are by their nature unplanned so there would be little opportunity for firms to make arrangements with alternate foreign suppliers before the event;
4.37 Taking these upstream and downstream effects into account and using the same ranking as before gives us Figure 26.

Figure 26 – GVA loss per day (£m) compared to Gas saved per day (mcm) – Ranked according to direct costs only but including indirect costs

Source: DUKES, ONS and ILEX analysis

4.38 While both the graphs end at the same point where all industry is interrupted, incorporating indirect costs while keeping the same ranking leads to a significantly higher cost at every level of gas interruption.

Alternative Rankings

4.39 Whereas the ranking shown above is the theoretically optimum path based on direct costs, it does not consider the physical constraint of interrupting industries where gas use in not constrained to a small number of locations. In reality we
would observe some industries with significantly more concentrated energy use than others and as such it would be easier to interrupt these industries in an emergency gas interruption scenario. The GI study specifically examined these energy intensive sectors and it is from these sectors we will draw our alternative ranking.

4.40 Even though we could only directly switch off approximately half the industrial sectors if we restrict ourselves to the energy intensive industry sectors, we would still expect the GVA loss to tend towards the same total as before as we move towards the maximum industrial gas saving. Due to the interconnectedness of industry, industries we do not interrupt directly will cease production and therefore gas use as sectors they are adjacent to in the supply chain are interrupted. As more and more users are directly interrupted these indirect effects increase until all industry is shutdown and we arrive at the same end point as before.

4.41 Taking account of both the physical restrictions to interrupting industry and the indirect costs to other sectors we can develop an alternative ranking that minimises the GVA loss for a given level of gas use. This will give us an alternative path that is as close to the theoretically optimum path as possible taking into account both indirect costs and physical interruption constraints. This alternative ranking or constrained optimum path is shown below in Figure 27.

**Figure 27 – GVA loss per day (£m) compared to Gas saved per day (mcm) – Ranked by GI sector taking account of both direct and indirect costs**

![Graph showing GVA loss per day (£m) compared to Gas saved per day (mcm) – Ranked by GI sector taking account of both direct and indirect costs](image)

The slope of the curve represents the GVA impact on a per unit basis. It is consistently £11-12/therm, over the range of involuntary gas interruption modelled.

Source: DUKES, ONS and ILEX analysis
4.42 When ordering the sectors we have assumed that the directly affected GI sector comes off first before the associated indirectly affected sectors. In effect we assume a small time-lag between the direct and indirect effects.

4.43 This constrained optimum path is significantly lower than the ‘original ranking including indirect costs’ case even though we are further restricting ourselves to just switching off energy intensive users. This shows the value of considering indirect costs to industry when designing an emergency gas supply interruption schedule.

Additional costs

4.44 We take ‘additional’ effects or costs to be costs to the economy or industries above and beyond those associated with a simple loss in production. There is the potential for very large additional costs to some industries including:

- upstream and downstream effects that were unquantified, including effects further up and down the supply chain;
- the costs and extra time needed to restart the process of production once gas supplies return (in some cases restarting the process would be impossible once stopped);
- costs of replacing equipment or stock damaged by the loss of gas supply (in some cases this is much more significant than the loss of production itself);
- loss of both short and long term market share of domestic producers to overseas companies in industries where produce can be imported/exported; and
- long term loss of investment in the UK due to a downgrading of perceived security of supply.

4.45 Due to their far reaching nature we have not attempted to include these additional costs in our analysis. We recognise that there are some potentially mitigating effects of stocks and imports that we have excluded from the analysis. However, our interviews with industry in an earlier study indicated that stock levels are generally low (a matter of days) and that the scope to be able to import substitute products at short notice from offshore would be extremely limited.

4.46 We see our constrained optimum path as a low side case of the cost to the economy of an interruption to gas supplies. It assumes the full GI demand side reduction at no economic cost; that all industries are switched-off in the optimal order given our constraints; and does not include any of the potentially significant additional losses to the economy.

4.47 If we were to include only the direct GVA impact then the costs would be lower at around two-thirds of the direct and indirect costs used in the modelling (see Figure 27).
**Incorporation of costs into quantity modelling**

4.48 We have incorporated the constrained optimum path shown in Figure 27 into the simulation modelling described in Section 2. Whenever, in the simulation, there is a gap between demand and supply (after the demand response to price has been netted off), then the model looks up the level of the gap (in mcm) to determine the resulting economic cost (in £m). The losses are summed for each year to give a total annual economic loss from gas supply interruptions. The model reports these annual losses for each year in each iteration of the simulation.

4.49 This modelling approach makes a number of simplifying assumptions:

- economic damage is limited to the days of interruption; once gas supply is resumed, industry is immediately able to resume operations, with no long-term costs or loss of market share (there may, of course, be significant long-term costs and market share losses, but we are not quantifying them);
- this damage consists in complete and irrecoverable loss of GVA pro-rata to the number of days’ interruption;
- the sectors which experience this GVA loss are those directly interrupted and the sectors immediately upstream and immediately downstream; and
- economic damage is limited to industry; there are no knock-on effects on other sectors of the economy.

**Interaction of strategic reserve and gas prices**

4.50 We assume that the provision of strategic reserve does not have an impact on the commercial gas price. Thus there is no additional benefit beyond the cost savings identified above.

4.51 We assume that the strategic reserve will be ring fenced from the commercial market and there will be a strict set of rules for to trigger the use of the strategic reserve (see implementation in Section 6). It is designed that the strategic reserve is used to replace a loss of supply to the UK. It would be used to mitigate the physical consequences of a loss of supply. Once the strategic reserve has been triggered it will restore the supply demand balance prior to the supply problem. We assume that the volatility of gas prices is unaffected by the strategic reserve; the usage is triggered by a physical loss of supply, and price spikes (on their own) are not sufficient to trigger the use of the reserve.

4.52 The aim will be to minimise the impact on UK summer-winter price differentials. However the psychological impact of having a strategic reserve and greater security of supply is likely, if anything to reduce extremes in prices. The filling of strategic reserve will create extra demand. Demand will be off-peak but it is to have a slight temporary impact on the summer gas price. Impact and price mitigation steps are discussed in Section 7.
Summary

4.53 The approach to modelling the costs of interruption has been based on the following:

- the costs of interruption are based on the industrial sector of the economy only (the commercial sector is not included). The analysis is based on the GI study;
- we have assumed the impact of switching-off demand for one day will result in costs from one day’s lost production in the sector impacted and in the sectors directly upstream and directly downstream of the gas interruption. We do not include costs of restarting, cost of damage to stock and/or plant and loss of market share to continental companies;
- we assume the gas and electricity demand to be interrupted and assume that the electricity demand interrupted results in a direct reduction in gas usage at gas-fired CCGT power stations. In total we have identified up to 90mcm/day of gas interruption; and
- the order of interruption is important. We assume that the order is optimised taking account of the total GVA cost (direct+upstream+downstream) with the lowest cost sectors (GVA per mcm) interrupted first. Without this optimisation the GVA costs would be significantly higher.
5. ESTIMATED COSTS AND BENEFITS

5.1 In this section we look at the costs of the alternative options short listed in section 3. We look at the benefits in terms of the costs that would be incurred if nothing were done (the ‘do nothing’ case).

COSTS

5.2 In this section we develop a range of costings for the alternative options that were shortlisted in Section 3. The options are as follows:

- Storage in the UK: provided from depleted field storage, salt cavern storage or from LNG storage;
- Supply from Europe: provided from new build storage in Europe with transportation to the UK; and
- Reduced gas demand at CCGTs: achieved by holding 75 days stocks of alternative fuel on site.

Storage in the UK

5.3 The costs of storage in the UK are based on the costs of new storage recently developed or presently under development in the UK. The projects represent a range of different size facilities and have different characteristics in terms of the amount of cushion gas required and the capex. The shorter duration salt cavern and LNG storage facilities generally have higher capex costs per volume of storage.

5.4 For each type of storage our research has produced a range of costs; we present the average cost in the tables below. In each case we present the average cost giving the sensitivity to the fuel price assumption which affects the cost of the working gas and the cost of the cushion gas (cushion gas is required to provide the working pressure in depleted field and salt cavern storage, and is required to maintain the low temperature in an LNG tank). The average figures quoted may hide a range; however for the purpose of this study the costings are intended to give an indication of cost. In the implementation section of this report we expect the cost to be set by the market, and cheaper alternatives where they exist would be expected to come through.
### Table 14 – Depleted field storage: costs of providing 3.3bcm of storage, giving
sensitivity to DTI fuel price assumption

<table>
<thead>
<tr>
<th>Price assumption:</th>
<th>Central case, 36p/th (£million)</th>
<th>Low, 21p/th (£million)</th>
<th>High, 50p/th (£million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working gas</td>
<td>391</td>
<td>230</td>
<td>549</td>
</tr>
<tr>
<td>Cushion gas</td>
<td>977</td>
<td>576</td>
<td>1,373</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>475</td>
<td>475</td>
<td>475</td>
</tr>
<tr>
<td>Total cost</td>
<td>1,843</td>
<td>1,281</td>
<td>2,397</td>
</tr>
</tbody>
</table>

Source: ILEX. Fuel prices based on 5-year average 2008 to 2012 of DTI crude price converted to gas oil equivalent. Costs based on an average of onshore and offshore facilities.

### Table 15 – Salt cavern storage: costs of providing 3.3bcm of storage, giving
sensitivity to DTI fuel price assumption

<table>
<thead>
<tr>
<th>Price assumption:</th>
<th>Central case, 36p/th (£million)</th>
<th>Low, 21p/th (£million)</th>
<th>High, 50p/th (£million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working gas</td>
<td>391</td>
<td>230</td>
<td>549</td>
</tr>
<tr>
<td>Cushion gas</td>
<td>293</td>
<td>173</td>
<td>412</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>1,742</td>
<td>1,742</td>
<td>1,742</td>
</tr>
<tr>
<td>Total cost</td>
<td>2,425</td>
<td>2,145</td>
<td>2,703</td>
</tr>
</tbody>
</table>

Source: ILEX. Fuel prices based on 5-year average 2008 to 2012 of DTI crude price converted to gas oil equivalent. Costs based on an average of deep and shallow salt caverns.
STRATEGIC STORAGE AND OTHER OPTIONS TO ENSURE LONG-TERM GAS SECURITY

Table 16 – LNG storage: costs of providing 3.3bcm of storage, giving sensitivity to DTI fuel price assumption

<table>
<thead>
<tr>
<th>Price assumption:</th>
<th>Central case, 36p/th (£million)</th>
<th>Low, 21p/th (£million)</th>
<th>High, 50p/th (£million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working gas</td>
<td>391</td>
<td>230</td>
<td>549</td>
</tr>
<tr>
<td>Cushion gas</td>
<td>39</td>
<td>23</td>
<td>55</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>2,048</td>
<td>2,048</td>
<td>2,048</td>
</tr>
<tr>
<td>Total cost</td>
<td>2,478</td>
<td>2,301</td>
<td>2,652</td>
</tr>
</tbody>
</table>

Source: ILEX. Fuel prices based on 5-year average 2008 to 2012 of DTI crude price converted to gas oil equivalent. Costs based on a combination of the cost of 8 tanks at two new LNG terminals and 20 additional LNG tanks.

Supply from Europe

5.5 As mentioned in Section 3.41, the costs of supply from Europe would be the cost of new build storage plus the cost of transportation to transit Europe and through the gas interconnector.

5.6 The costs of new build storage would be similar to the figures given in Table 14 of around £1,800 million in the central case. The costs of transportation would be extra. The IUK interconnector currently has capacity to flow from Zeebrugge to Bacton at a capacity of 48 mcm/day (slightly more than 1 RE). The costs of the IUK are estimated to be around £600 million (£350 million original project and £150 for extra compression to enhance the flow capability).

5.7 The likely costs of transit capacity from Europe is likely to be an additional cost of between £500 and £1,000 million pounds in addition to the cost of new build storage making a supply from Europe uneconomic compared with storage in the UK.

Reduced gas demand at CCGTs

5.8 A 400MW ‘E’ class CCGT module (i.e. a single gas turbine and single steam turbine/heat recovery steam generator combination) which is often used in the UK will burn approximately 1,500 tonnes of distillate per day at 50% efficiency. We base the costings on providing 75 days (112,000 tonnes) of backup fuel capability on site in 26 tanks (each tank 5,000 m3 capacity). The costs include an estimate of the safety and delivery costs.
5.9 The table below shows the costing for providing 75 days storage for a 400MW CCGT.

**Table 17 – Costs of providing 75 days distillate storage for a 400MW CCGT, DTI central fuel price 215£/tonne**

<table>
<thead>
<tr>
<th>Estimated cost (£million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel cost</td>
</tr>
<tr>
<td>Fixed cost</td>
</tr>
<tr>
<td><strong>Total cost</strong></td>
</tr>
</tbody>
</table>

Source: ILEX. Assumed fuel price 215£/tonne based on 5-year average 2008 to 2012 crude price converted to gas oil equivalent.

5.10 The fuel costs of distillate storage include the cost of purchasing carbon credits to cover the higher emissions when running on distillate storage. This cost would be payable at the time the strategic reserve was called upon. At a price for carbon of €30/tonneCO2 the cost of additional carbon would be around £2.6 million. The plant would also require a concession for sulphur emissions produced when burning distillate.

5.11 The costs of providing 75 days of backup fuel capability for 400MW are scaled up to cover 10 GW of generation capacity (a Rough equivalent) and would require twenty-five 400MW CCGTs, a total of 650 tanks of distillate storage.

5.12 The table below shows the estimated cost of providing 75 days storage for 10GW of generation capacity. It shows the sensitivity of the cost to the DTI fuel price assumptions.

**Table 18 – Costs of providing 75 days distillate storage for a 10GW CCGT, giving sensitivity to DTI fuel price assumption**

<table>
<thead>
<tr>
<th>Price assumption:</th>
<th>Central case, 215£/tonne (£million)</th>
<th>Low, 129£/tonne (£million)</th>
<th>High, 327£/tonne (£million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel cost</td>
<td>670</td>
<td>428</td>
<td>987</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>432</td>
<td>432</td>
<td>432</td>
</tr>
<tr>
<td><strong>Total cost</strong></td>
<td><strong>1,102</strong></td>
<td><strong>860</strong></td>
<td><strong>1,419</strong></td>
</tr>
</tbody>
</table>

Source: ILEX. Assumed fuel prices based on 5-year average 2008 to 2012 of DTI crude price converted to gas oil equivalent.
Summary of costs

Table 19 – Costs of providing a Rough equivalent (RE), range of DTI fuel price assumptions

<table>
<thead>
<tr>
<th></th>
<th>Depleted field storage</th>
<th>Salt cavern storage</th>
<th>LNG storage</th>
<th>Distillate storage at CCGTs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low fuel price</td>
<td>1,281</td>
<td>2,145</td>
<td>2,301</td>
<td>860</td>
</tr>
<tr>
<td>Central fuel price</td>
<td>1,843</td>
<td>2,425</td>
<td>2,478</td>
<td>1,102</td>
</tr>
<tr>
<td>High fuel price</td>
<td>2,397</td>
<td>2,703</td>
<td>2,652</td>
<td>1,419</td>
</tr>
</tbody>
</table>

Source: ILEX. Assumed fuel prices based on 5-year average 2008 to 2012 of DTI crude price converted to gas oil equivalent.

5.13 The cost of supply from Europe would be the cost of new build storage (as in the table above) plus the cost of transportation to transit Europe and through the gas interconnector, an additional cost estimated at between £500 and £1,000 million for transportation capacity.
BENEFITS (AVOIDED COSTS)

5.14 In Figure 28, we show the percentiles of GVA impact from the gas supply shortfall in each year, using the ILEX probabilities shown in Table 4 above, together with the relationship between GVA and gas loss in Figure 27. The impact is significant from 2015 onwards. On a unit basis, the GVA impact is consistently around 11-12 £/therm. For comparison, the highest gas prices witnessed during the winter 2005/06 were under 2 £/therm.

Figure 28 – Percentiles of GVA impact, using ILEX probabilities

Source: ILEX

5.15 If instead of the ILEX probabilities (and outage proportions) we use the alternative probabilities (and outage proportions) given in Table 5, we obtain the results shown in Figure 29 below. The impact is no longer significant at the 95\textsuperscript{th} percentile, although it is substantial (£5bn-£10bn per annum) at the 99\textsuperscript{th} percentile, from 2015 onwards. In other words, there is a 1\% chance that from 2015 onwards the annual costs of gas supply interruption to the economy could be in the range of £5bn-£10bn. Again, on a unit basis, the average impact is 11-12 £/therm, based on the slope of the graph in Figure 1.
5.16 In Section 2, we obtained the result that one Rough equivalent would broadly cover the supply gap at the 98th or 99th percentile, depending on which set of probabilities one uses. We can now obtain the benefit of a Rough equivalent, in two ways, as follows. The first way is to integrate the residual GVA cost, by calculating the residual amount multiplied by the probability density, over and above the percentile covered by the RE, and summing. The second way (which serves as a check on the algebra) is to insert an extra RE into the simulation model and re-running the simulation.

5.17 ILEX has calculated the benefit of an RE using both the above methods, which give similar results. These are shown in Figure 30 and Figure 31, for the ILEX and alternative probabilities respectively. These figures show the mean expected benefit (the average of 1000 iterations), and how it changes with the addition of a RE.
5.18 The green line shows the results of the simulation, and is the economic corollary of the main (blended scenario) results described in Section 2. The yellow line is the residual expected GVA impact per annum, even if an extra RE is developed. The difference between the green and yellow lines is the black line, which is therefore the (mean) economic benefit of the extra RE.

5.19 Using the ILEX probability assumptions, the benefit is expected to be around £0.5 billion per annum after 2015, simply based on the average benefit for the period 2015 to 2020. Using the alternative probability assumptions, the mean benefit is around £0.2 billion per annum after 2015. As explained in Section 2, even if the supply sources are perfectly reliable, there is a risk of supply shortages due to unexpectedly cold weather, and the possibility that the underlying supply/demand gap in the commercial market will be tight. The case for an extra RE is therefore not wholly contingent on the perceived reliability of sources of supply.
5.20 It is straightforward to translate the annual benefits of an extra RE shown in the above two diagrams into net present value estimates – although the answer is sensitive to the annual benefit assumed post 2020. In our view, as discussed in Chapter 2 the risk of supply shortfall post 2020 is unlikely to fall, and may rise. Adopting a conservative approach to the value of an RE, we have kept the benefit flat – assuming for the ILEX case an annual benefit of £0.5 billion, and for the alternative case an annual benefit of £0.2 billion.

5.21 As stated above, the benefit is around 4£/cubic meter (11-12£/therm), whether we use ILEX or alternative probabilities, because the slope of the graph in Figure 1 is broadly constant across the likely range of daily gas interruption. Our analysis of the volume requirement (presented in Figure 13 and Figure 15) suggests that by 2020, the expected (mean) saving from 1 RE is 110-140 mcm per annum using the ILEX probabilities and 40-55 mcm per annum using the alternative probabilities. The expected values are the averages of all 1000 iterations in the simulation.

5.22 We are not saying that we would see an interruption of 110-140 mcm each year. Rather, we are saying that there is (typically) a 95% chance of no interruption at all, a small chance (say 4%) of a significant level of interruption (0-5 bcm) and a very small chance (say 1%) of a very significant level of interruption (5-10 bcm). The weighted average of these interruption levels gives the mean or expected outcome of 110-140 mcm. This behaviour was illustrated in Figure 10 above.
5.23 On the basis of Figure 30 and Figure 31, we estimate that strategic storage is likely to be needed by 2014. In addition, we make the following assumptions:

- the storage facility will take 3 years to develop, and the costs of it will be incurred 2 years prior to operation;
- the storage facility has a 30 year asset life, which means its final year of operation is 2043; and
- the relevant public sector discount rate is 3.5% real.

With these assumptions, the NPV at the end of 2012\(^{38}\) (the year in which the costs are incurred) is £8.6 billion using the ILEX probabilities, and £3.4 billion using the alternative probabilities. These NPVs are the sums of the discounted savings shown in Figure 32. A table of costs and benefits in each year is included in Annex B.

**Figure 32 – Discounted savings from 1 Rough equivalent**

We assume the benefits are realised at the end of each year from 2014 onwards, and the cost is incurred at the end of 2012.

\(^{38}\) Source: ILEX
SUMMARY OF COSTS AND BENEFITS

5.24 Table 20 summarises the net present value based on an investment in one Rough equivalent operational in the year 2014 and available for a period of 30 years (the assumed asset life).

5.25 Table 20 shows the full range of costs covered in the above section and covers the full range of fuel price assumptions for depleted field storage (£1.2 to £2.4 billion) and for distillate storage at CCGTs (£0.9 to £1.4 billion).

5.26 The benefits are based on the two cases we have used for source outage events and probabilities: the ILEX case and the alternative case. Note that the ILEX figure of £8.6 billion is our best estimate, not the top of a range.

Table 20 – Summary of costs and benefits

<table>
<thead>
<tr>
<th></th>
<th>Investment in one Rough equivalent (3.3bcm) operational in 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benefit</strong></td>
<td>£8.6 billion (ILEX case)</td>
</tr>
<tr>
<td></td>
<td>£3.4 billion (alternative case)</td>
</tr>
<tr>
<td><strong>Cost</strong></td>
<td>£0.9 to £2.4 billion</td>
</tr>
<tr>
<td><strong>Net benefit</strong></td>
<td>£6.2 to £7.7 billion (ILEX case)</td>
</tr>
<tr>
<td></td>
<td>£1.0 to £2.5 billion (alternative case)</td>
</tr>
</tbody>
</table>

Benefits are discounted at 3.5%

5.27 We conclude that under the range of assumptions analysed the net benefit of providing one Rough equivalent of strategic reserve is positive and at least of the order of £1-2 billion. Our best estimate of the net benefit is £6-8 billion.

Comments on the results

5.28 The results of our analysis shown above suggest that the NPV of a Rough equivalent is likely to be substantially in excess of its cost. At first sight, this seems odd given that the probability of a gas supply shortfall is small, even post 2015. However, our research indicates that the economic impact, if a shortfall does occur, could be many times as great as the cost of the RE. The economic costs to the economy of running short of gas are not commensurate with the narrow commercial costs to the gas industry itself.

5.29 In calculating the economic impact, we have assumed loss of output in not only the directly affected sectors, but also the sectors immediately upstream and
downstream (“with second-order effects”). Although we have not analysed the economic impact “without second-order effects” in detail, it is apparent from Figure 27 above that the results would fall by approximately one-third. Even with this assumption, the net benefit of an RE appears to be positive.

5.30 Of course, the choice of discount rate is important and using a higher discount rate would make the investment less attractive. However, sensitivity analysis shows that even doubling the rate (to 7% real) gives a total benefit of £5.5 billion (ILEX) and £2.2 billion (alternative); and hence the net benefit, after subtracting the cost, is still likely to be positive.

5.31 It is noteworthy that our analysis assumes the government, acting on behalf of society, is risk neutral. We have assumed in our work that an uncertain financial impact of £X occurring with probability Y is equivalent to a certain financial impact of £XY. This is risk neutral by definition, because mathematically it focuses on the expectation or mean outcome. In practice, government might consider that the former is more undesirable than the latter, i.e. government might be risk averse in the same way that most people are risk averse with their finances. Any attempt to introduce a measure of risk averseness would, of course, make the conclusions that we are reaching even more stark.

5.32 Essentially, government is faced with the choice between a relatively small certain cost and a potentially very large impact occurring with a very small probability. The best course of action is not apparent \textit{a priori}, but our analysis is giving a strong indication that development of a strategic storage gas supply facility the size of a Rough equivalent is merited.

5.33 In terms of timing, however, it appears that from 2008 there are likely to be several years of security in the market. On the basis of Figure 30 and Figure 31 above, a strategic storage facility should be developed in time for 2014. To leave it later would be to risk considerable damage to the British economy.
6. IMPLEMENTATION

6.1 We are required to examine what mechanisms could be used irrespective of whether a decision is made to stimulate the provision of a form of strategic storage. In sections 3 and 5 above various options, capable of providing a form of additional gas flexibility, have been evaluated. In this section we look at what form of implementation mechanism could be used to deliver a mixture of the various options.

6.2 Our underlying considerations in deriving the implementation plan are set out below:

- market based where possible eg auction to allow discovery of best options;
- lowest cost ie economically efficient;
- we assume that consumers of gas will ultimately pay for any strategic option in the form of higher gas prices;
- open to a variety of providers using different options;
- lowest possible impact on commercial market and existing market players;
- transparent rules of delivery such that all market players understand how and when option will be used\(^\text{39}\);  
- centrally administered by one body ie National Grid;
- minimise political interference; and
- minimise all other risks and unintended consequences.

6.3 One of the biggest potential risks of a market intervention by Government in this area is the damage to the value of existing gas storage facilities and other supply infrastructure. This risk arises from the building of additional storage over and above that which the market would build. If a large amount of strategic storage is built and its operation is not adequately separated from the commercial market the value of commercial storage could crash. Risks are discussed in more detail in section 7. With this risk in mind we have attempted to construct an implementation mechanism which attempts to “ring fence” strategic storage from the operation of the commercial market.

6.4 We envisage a three part process:

- determine quantity of strategic storage required and the timetable;
- determine the process by which the required quantity is provided; and

\(^{39}\) We have also considered whether the rules should be kept secret in order to prevent players second guessing the market.
• determine the trigger or mechanism for the use of the strategic storage.

6.5 Firstly, we look at how the required amount of strategic storage is determined. Secondly, we examine the mechanism of how the various options ie gas storage of different types, demand reduction measures etc, might compete in order that an economically efficient outcome results namely the lowest cost options are built. Finally, we look at the operation of the strategic options and how its use is triggered.

Determination of the amount

6.6 In Section 2 above we have attempted to determine what amount of strategic gas storage is required and by when using the ILEX models of gas supply and demand. Our analysis is based on our best view given current information. Going forward, we recommend that the DTI, in conjunction with Ofgem, conduct a similar evaluation to determine the quantity of strategic storage required using analytical techniques similar to those used above and based on transparent modelling of the gas/supply outlook. We would expect a detailed evaluation every three years with annual updates of a less rigorous nature in between. It can be seen from analysis in section 2 that the gap only becomes manifest in 2015. The period from now up to 2008 will be crucial in allowing the DTI to update our analysis using more up to date information as more information becomes available on what gas importation or storage projects are progressing.

6.7 We would envisage a set of rules that specify the equivalence of the different alternatives for supplying “gas”. For example the storage of distillate at CCGTs would be given a conversion factor to calculate an equivalent amount of gas from demand side reduction.

Provision – the contractual framework

6.8 We suggest two possible options which could be examined in more detail if a decision is made to implement a form of strategic storage.

Option 1

6.9 In this option National Grid (NG) would take on a new licence obligation to run a process, details to be agreed with Ofgem, requiring NG to pay for the options bid into a form of a competitive process. We would expect that NG run an auction with competing bids from energy companies willing to provide a quantity of “gas”. Companies could qualify to take part based on certain criteria including credit provisions and creditability. NG would select the lowest price bids up to the strategic “gas” quantity as defined by the DTI and Ofgem (see 6.6 above). Ofgem would allow NG to recover the full costs of both running the process and accepting the bids via NG’s Price Control.
6.10 The details of payment by NG to the “gas” bidders would need to be carefully looked at but we recommend an annual fee to the form of essentially a “capacity” payment. The “capacity” payment will be for the “gas” as a commodity however.

6.11 NG recovers the costs of the capacity payments to the “gas” providers via the Price Control which is effectively passed through to consumers via higher gas transportation charges. We do not consider here as to whether the additional costs are recovered from all gas consumers equally or whether there should be some form of mechanism to distribute the costs differently between classes of gas consumers eg between domestic and I&C gas consumers.

6.12 NG would also take on some form of obligation to audit the service accepted via the auction process. It is essential that both the gas and capacity is available when strategic options are triggered.

6.13 When the use of strategic storage is triggered NG would make available the gas at the NBP to shippers via the normal balancing process.

6.14 In this option revenue flows are:

- from NG to strategic storage providers via monthly/annual capacity payments;
- from shippers to NG in the form of higher gas transportation charges;
- from consumers to suppliers/shippers in the form of higher gas prices;
- when use is triggered shippers will pay NG for the strategic gas released from store; and
- NG will recycle the revenue from the sale of the gas in the normal way.

Option 2

6.15 In this option gas suppliers take on a new enhanced form of licence obligation for security of supply. This could be called a Security of Supply Obligation (SOSO) similar in nature to the Renewable Obligation. Ofgem would probably need to take on a monitoring/auditing role to make sure suppliers met their obligations.

6.16 Each supplier is required by its licence to make provision for an additional quantity of “gas” to be made available when the need for strategic gas is triggered.

6.17 The quantity of strategic gas to be acquired by each supplier is derived from the total quantity as determined by the DTI and Ofgem as above. The total required is sub-divided on an annual basis based on each supplier’s portfolio of customers projected for that year. We believe that the SOSO should be provided for both domestic and I&C customers in each suppliers’ portfolio.

6.18 Since each supplier is obliged to acquire the additional “gas” the supplier will then go out and book the additional gas storage or supply flexibility or arrange demand side reduction. This additional demand, over and above, that required under the existing licence provision will stimulate additional investment.
6.19 Payment in this option is between the gas supplier and the “gas” provider be it storage or demand reduction. NG is not involved and no central market mechanism is needed. Gas transportation tariffs stay unaffected but the additional costs incurred by the supplier is passed on to consumers via higher gas prices.

6.20 In this option the revenue flows are:

- gas suppliers pay storage or other flexibility providers for capacity/space and fill it with gas;
- gas suppliers pass on the cost of the capacity and the gas to consumers via higher gas prices; and
- when strategic gas is triggered the gas supplier can access the additional strategic gas to use for its customers or sell in the market as it wishes.

**Operation and trigger**

6.21 In our view, any form of strategic gas option must be strongly ring fenced from the commercial market and not to be used in other than clearly defined circumstances. This would allow normal winter/summer gas price differentials to continue to drive commercial investment in both storage and other gas importation infrastructure.

6.22 In our view the trigger for the use of strategic reserve should be a significant loss of supply for a long duration (weeks rather than days). In our view a tightening of the supply-demand balance should not in itself trigger the strategic reserve. If demand is higher than normal due for example to severe weather, and the supply-demand balance is tight, then this would not in our view trigger the strategic reserve as to do so would require anticipation of the situation later in the winter. Instead the normal commercial market should be allowed to continue to operate. If the tightness persists through the winter and storage stocks fall to the level at which a Gas Supply Emergency is triggered, then at this point the strategic reserve would be triggered.

6.23 Strategic storage would not be used simply because gas prices rise – this means that it would not have been used in November 2005 when gas prices rose to over £1.25 /therm.

6.24 We have considered who should control the use of strategic storage. The options include:

- The direct authority of the Secretary of State (SOS);
- Ofgem; or
- The Network Emergency Co-ordinator (NEC).

6.25 The risks of exposure to short-term political pressure, existing statutory obligations and proximity to the UK gas sector suggests to us that, on balance, Ofgem is best placed to perform this role. However careful consideration is
needed before a final decision is taken over who takes control of any strategic storage.

6.26 We envisage a Gas Supply Emergency would trigger the use of the strategic reserve. The NEC will work on alleviating any gas supply emergency and should not be placed at the centre of deciding when to use the strategic storage. The rules in the safety case should make it clear when the trigger operates.

**Transparency or secrecy?**

6.27 We have also considered the pros and cons of making the trigger and operational rules transparent or secret. The options could be:

- public (open & transparent) rules for intervention/non-intervention; or
- intervention to require the personal approval of SOS.

6.28 There may be a case for keeping the rules private. This takes us into games theory which points to the advantages in certain circumstances of keeping rules secret. This would deny the companies the benefit of knowing exactly when the strategic gas storage might be used.

6.29 In our view Ofgem (or the SOS) should make the decision based on clear transparent rules. However, the SOS and/or Ofgem would need to maintain some form of flexibility to allow unforeseen events to be dealt with, as no Government would fetter its discretion in dealing with what could be a national emergency.

6.30 For example, we would expect a test involving a loss of gas supply of a certain size and of a certain duration ie both quantity and temporal. The quantity could be a loss of a gas supply of at least 20% of normal UK supply and for a duration of greater than one week.

6.31 A recent test, relating to when strategic storage should be activated, would have been the fire at Rough which is around 10% of winter supply at 44 mcm/day when daily demand is around 400 mcm. In this case, loss of Rough fails the 20% quantity percentage but passes the temporal test in that its loss until May/June was a balance of winter event of much greater than one week.

6.32 Another choice that must be made relates to the quantity of strategic gas released. It is our view the quantity released should be the same as the loss of supply triggering its use. The impact on gas prices would be to stabilise prices near to what the price would have been without the supply problem.

6.33 The use of strategic storage must also be integrated to Gas Supply Emergency provisions. This would require careful consideration and study in relation to NG’s Safety Case which is beyond the scope of this study.
Distributional effects

6.34 A decision to build strategic storage would be justified on the basis that a low probability, high impact (cost to UK industry) event is replaced with the known spend on providing the strategic reserve.

6.35 Under the ‘do nothing’ scenario nothing is spent and the risk of supply interruption is faced by UK industry since domestic customers will continue, in most circumstances, to get gas. If strategic reserve is provided then the potential cost faced by UK industry is reduced significantly. However, the cost of providing the strategic reserve must be funded and this is done through a charge on end users. We envisage the charge being levied on all gas users on the basis that the security requirement is both for weather (most of the weather sensitive load is in the domestic and commercial sectors) and to protect against loss of supply.

6.36 If the charge were levied on all gas demand, the ‘strategic levy’ would amount to around 0.3p/th\(^{40}\) in addition to the wholesale price of gas currently around 65p/th and 58p/th for the years 2007 and 2008 respectively.

6.37 In the event that the strategic reserve were used there would be additional costs of withdrawing stock, and replenishing stock:

- under option 1 the costs would be recovered from the sale of the gas to shippers at the cash out price at the time of strategic reserve. It is likely that the cash out price at the time the stock is withdrawn will be higher than the price at the time the stock is replenished. The strategic reserve would recover only its costs, and any profit or loss from releasing and replenishing stock would be re-circulated via the strategic levy on end consumers;
- under option 2 the costs are faced by the supplier at the time of accessing the strategic “gas”.

A third option: modification of the existing framework

Gas Supplier Licence obligation

6.38 It is important to note that domestic gas suppliers already have a licence requirement to provide sufficient gas to meet their customers demand in a 1:50 winter\(^{41}\) (Condition 32A of the supplier licence). It is not clear to us that suppliers are fulfilling this requirement or that Ofgem monitor how provision is made. We suggest that further examination is made of how domestic suppliers meet this requirement. This is important in two ways, firstly if it is found that currently that

\(^{40}\) Based on a capital cost of £1,800 annualised over 30 years at a discount rate of 3.5% and levied on all gas demand

\(^{41}\) Set out 32a licence provision
insufficient provision has been made enforcement may lead to higher demand for storage so reducing any strategic requirement. Secondly, in the SOSO option above some form of auditing would be required and any lessons that could be learnt from the existing licence enforcement would be useful.

**Set emergency cash out prices**

6.39 Gas shippers have an incentive to balance since they face cash out of any imbalance at the prevailing cash out price on the day. Some parties believe that this is sufficient to ensure that gas shippers (and/or the related gas suppliers) will book adequate storage or interruption flexibility. However, at stage two of an emergency the normal commercial arrangements are suspended and cash-out price is fixed at the SMP buy price on that day. All shippers are then in the same position. We would have more confidence in the assertion that adequate incentives exist if the cash out price during an emergency was set at a very high value. It should also be noted that in an emergency some firm load shedding may be called for and that this would normally result in the larger consumers coming off the system. We suspect that the current arrangements mean an emergency is a form of low cost option for gas shippers/suppliers since the costs that they face are lower than booking adequate storage – in order to avoid an emergency.

6.40 An alternative to investing in some kind of strategic reserve could be to revise the cash-out arrangements in a Gas Supply Emergency. Under the existing arrangements at stage 2 of a Gas Supply Emergency the commercial market is suspended and the shippers’ exposure is capped at the emergency cash-out price. This means that suppliers are not fully exposed to the very high gas prices that end users would be willing to pay to avoid the full impact of damage to their industrial sector. An alternative would be to set an emergency cash-out price based on the wider cost to the economy of involuntary demand load shedding. Our study indicates an emergency cash-out price that achieved this would be around 12 £/th.

6.41 In the event of involuntary demand load shedding the end user that is interrupted would be paid compensation based at the emergency cash out price on the quantity of gas interrupted (the largest users are daily metered so it is possible to estimate the gas demand they would have taken had they been able to use gas on the day).

6.42 Faced with the potential of extremely high and unavoidable prices, the suppliers would take measures to mitigate their exposure through additional commercial arrangements that could include additional storage. In this way the market would be responsible to provide greater security of supply than it does at present and any requirement for strategic reserve may be very small.

**Distributional effects**

6.43 Under the ‘set emergency cash out prices’ option, the shippers total demand portfolio would include an estimate for the gas the firm customers interrupted would have consumed. The shipper’s balance on the day would include all firm
load including those customers that had been interrupted as part of emergency load shedding. If the shipper had insufficient gas to supply this ‘firm portfolio’ then the shipper would be cashed out at 12£/th on the imbalance.

6.44 Money would flow from the shipper to NationalGrid. The moneys could flow from NationalGrid to the end users who had suffered involuntary demand load shedding as compensation.

**Market Failure and Existing Market Rules**

6.45 The possible economic costs of interruption of the industrial and commercial sectors are significant and not well understood either by the affected sectors, the gas industry or by government. The ILEX study (see footnote 6) attempted to quantify the damage to the economy for the first time. We suspect that one reason for the apparent market failure in providing sufficient security is that the market has not been fully aware of the potential damage.

6.46 Another possible reason for the apparent market failure is the interaction of the Safety regime and the commercial regime via the suspension of the commercial market during a Gas Supply Emergency as discussed above.

6.47 Alternatively, the government could modify the existing regulatory framework to extend the licence obligations to require a higher level of security of supply for other classes of consumers eg the industrial and commercial sectors.

6.48 The DTI has recently published a consultation document 42 in response to Directive 2004/67/EC concerning measures to safeguard security of natural gas supply. Article 4 of the Directive requires Member States to protect supplies to household customers in particular circumstances and permits the extension of such protection to certain other customers. It also allows Member States to set indicative minimum targets for storage facilities.

6.49 The DTI stated (in para 2.4.3) regarding implementation of Article 4:

“The rest of the Article allows Member States to extend similar protection to that given to household customers to small and medium-sized enterprises and others who cannot switch fuels; to use storage facilities on Member States’ own territory or, with agreement, those on the territory of another Member State, to contribute to security of supply (although without impeding the proper functioning of the internal market); and to set indicative targets for storage. These provisions are optional and in line with better regulation principles, ie to minimise regulatory burdens, we do not intend to take steps to implement them.”

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7. RISKS AND UNINTENDED CONSEQUENCES

7.1 The main risk we identify is that an intervention to provide a strategic reserve has an adverse impact on commercial storage projects and the provision of other alternatives to storage in the UK. As a consequence the amount of new storage developed by the market is less than it would otherwise have been without the intervention increasing the amount of strategic reserve required. In the following paragraphs we look at the risks that exist.

Risk 1: The new storage projects that are currently at planning stage get built for strategic reserve rather than for commercial storage service

7.2 The risk is that the new storage projects get diverted to strategic reserve rather than contributing to the commercial market.

7.3 The mitigation would be to signal to the market well in advance the requirement to have a strategic reserve and to have a capacity requirement that is delivered built-up over a number of years, and to allow the strategic requirement to be met not from a number of different facilities, including standby fuel at CCGTs.

7.4 The payment mechanism for strategic reserve would be structured to provide a definite revenue stream making it more attractive to strategic storage operators. For this reason the rate of return earned by strategic storage would be lower than the rate of return earned by commercial storage which faces an uncertain revenue stream.

7.5 If the amount of new commercial storage were reduced, the consequence would be to make the commercial market tighter and this would increase the value of commercial storage stimulating more development of the commercial alternatives. The strategic reserve will be held quite separate from commercial storage.

Risk 2: the strategic reserve provides a safety cushion for the commercial market

7.6 The risk is that shippers know that there is a strategic reserve to fall back on and do not make adequate provision of cover for themselves. Another possible risk is that the providers of gas supply infrastructure are not adequately incentivised to build in reliability.

7.7 The mitigation would come from the lead up to the use of the strategic reserve. We would propose that the strategic reserve would be used to replace a known loss of supply. However, this would not be triggered immediately; instead the commercial market would be left to operate for a period (e.g. a week) before any action is taken. During this week the prices in the commercial market would be expected to rise. Once the strategic reserve is triggered, the ‘gas’ released would
be sold by NG to shippers through the cash-out mechanism at the prevailing cash-out price.

7.8 There is a risk that during the period leading up to the release of strategic ‘gas’ that the commercial stocks of storage get withdrawn and are lower than they would have been if the strategic reserve were triggered earlier. However, we consider the uncertain price risk faced by shippers is crucial to preserving value in the commercial market. We note that low storage stocks are a trigger for a Gas Supply Emergency, and a Gas Supply Emergency itself would trigger the use of the strategic reserve. The use of strategic storage should also be integrated to Gas Supply Emergency provisions. This would require careful consideration and study in relation to NG’s Safety Case.

**Risk 3: the strategic reserve is used as a political tool at times of high prices**

7.9 The risk is that the reserve is used when prices get ‘uncomfortably high’ and the government is under pressure to release ‘gas’ into the market. The release of strategic reserve would impact the commercial price of gas and reduce price spikes. This would effectively cap prices and thereby cap the value of commercial storage.

7.10 The mitigation would be to have a predefined set of rules for triggering the release of strategic reserve. The triggers would not include the price of gas. The sharp rises in gas price seen in November 2005 or March 06 (when the spot price rose sharply to around 120p/th, and 195 p/th respectively) would not trigger the use of strategic reserve.

7.11 A further mitigation could be to take the decision to ‘push the button’ away from the Government minister. Instead Ofgem the agency closest to the UK gas market could be the agent that makes the decision and pushes the button.

**Risk 4: the key assumptions behind the decision turn out to be incorrect**

7.12 This study identifies a potential need to invest in strategic reserve in time for 2014. Due to the lead times involved in the construction of new storage, a decision would need to be taken around the year 2009.

7.13 We recommend that the DTI, in conjunction with Ofgem, conduct an evaluation to determine the quantity of strategic storage required using analytical techniques similar to those used above and based on transparent modelling of the gas/supply outlook. We would expect a detailed evaluation every three years with annual updates of a less rigorous nature in between. This would mean that there would be re-evaluation of the assumptions and of the requirement closer to the time before any decision was taken.

7.14 We recommend that the strategic requirement is introduced in a number of phases, rather than all at once. This would give the opportunity to test out the rules and operation of the strategic reserve prior to committing to the full requirement. A
phased approach would give flexibility to re-examine the alternative options and to allow new alternatives (such as might arise from new technologies) to be included.

7.15 If the strategic reserve is built and the assumptions underlying it are correct, then it should not be expected that the reserve will be used very often. There is a risk that the strategic reserve would be viewed as a failure, however, this would be mistaken as the purpose of the strategic reserve is to provide insurance against low probability, high impact events which will happen infrequently. It will be necessary to carefully manage the expectation of how often the strategic reserve will ‘save the day’ but when it does the benefit will be significant.

**Risk 5: separation of the strategic reserve from the commercial access**

7.16 The risk is that the strategic reserve is not effectively separated from the commercial market.

7.17 To mitigate the risk the strategic booking would be ring fenced and the quantities of stocks in the reserve reported to an independent body.

**Risk 6: The strategic storage has an impact on the gas price**

7.18 The existence of a strategic reserve will have a psychological impact on the market and this is likely to reduce the volatility of prices on the forward curve. We cannot see that this impact can be avoided. However, the impact is mitigated through the rules for triggering the use of the strategic reserve.

7.19 In our view having a clear set of rules for the triggering the use of strategic reserve will largely mitigate the impact of the strategic reserve on the spot price. Shippers face the commercial cashout price and this would be expected to be extremely high before strategic reserve is used. It should be noted that we explicitly rule out price as a trigger for the use of the strategic reserve. If the impact on the spot price is mitigated then it follows that the impact on the forward curve and the winter-summer differentials (one of the factors that drives investment in commercial storage) will be reduced.

7.20 Mitigating the impact that the strategic reserve has on the gas price requires the market to understand the rules for triggering its use and for the market to believe that the rules will not be changed when it comes to actual practice.

**Discussion of risk under the options**

7.21 In section 6 we identified two options for implementing a strategic reserve. Both options rely on market mechanisms to procure the “gas”. Risks 1 to 4 apply to both the options.

7.22 Risk 5, the separation of strategic reserve from commercial gas, is different under the two options.
7.23 Option 1 is centrally administered by NG. Under this option fixing the quantity and the purchasing of this quantity and the release of “gas” is centrally administered.

7.24 Under option 2 the total quantity is calculated centrally and allocated to suppliers based on their supply portfolios. Suppliers make arrangements to procure “gas” and in the event of the trigger being activated, the suppliers can access their reserve and/or sell the reserve in the market. Under this option there are additional requirements to ensure that:

- suppliers cannot access the reserve before the trigger is activated; and
- when the trigger is activated, there would need to be a separate mechanism to ensure that the total quantity of “gas” released is the same as the loss of supply triggering its use (see Section 6.32).

**Risks under revising the emergency cash out.**

7.25 The emergency cash out option has the advantage that all the storage is commercial storage booked by the shippers. Consequently adopting this option would have a positive impact on the quantity of commercial storage.

7.26 However, faced with exposure to extreme cash-out prices set at £12/therm, suppliers may withdraw from the UK market, preferring instead to operate in markets where their exposure is less. New market entrants would be deterred by the potential exposure. We would expect the competitiveness of gas supply in the UK to be damaged in a market with fewer players. Such a fundamental change to the regime could lead to a form of re-nationalisation where only a state monopoly would be the only company capable of survival. This would be the ultimate market failure.
8. CONCLUSIONS

8.1 Security of supply in gas has become a topic of concern amongst consumers, gas industry players and government. There are a number of factors that have led us to examine the question of the long-term security of supply:

- Increased use of gas in electricity generation;
- UKCS production has a declining ‘swing’ capability;
- Reliability of existing gas industry infrastructure eg the fire at Rough; and
- UK will be increasingly reliant on imports increasingly remote from the UK. Imports will arrive by pipeline through Europe and as LNG in tankers delivering gas production from countries outside Europe.

8.2 ILEX concluded in its report for UKOOA in October 2005 that the UK market, as currently structured, could deliver “bite sized” gas storage projects but could not provide “strategic storage” to insure against high risk but low probability events.

8.3 Our conclusions based on more detailed analysis remain the same. In our view, the UK gas market will bring forward some new gas storage facilities but the total quantity of gas storage will not approach that seen in Germany or France without some form of intervention. We do not consider planning difficulties as the primary reason for the UK having less gas storage than Germany or France but we believe that easing planning procedures in necessary to allow the commercial storage market to work efficiently.

8.4 From this study we conclude:

The supply/demand “gap”

i) There is a potential “gap” between supply and demand, this gap is significant over the next 2 years but then disappears as the new gas importation projects are commissioned but reappears from 2014 onwards as we become increasingly dependent on remote gas sources and demand increases.

ii) The risk of a “gap” exists whatever view one takes of a risk of an outage to a source or facility due to demand variation and the underlying demand and supply.

iii) The size of the “gap” varies according to scenario assumptions, weather and supply reliability but there is a 1:50 chance that the gap could be around 3.5 to 4 bcm/annum.

Filling the “gap”

iv) The “gap” can be filled in a number of ways. We conclude that the best options are:
• gas storage using any of depleted filed, salt cavern and LNG storage tanks; and/or
• supply from Europe, with additional transit and interconnector capacity; and/or
• oil storage at gas-fired electricity generation sites.

Cost/benefits
v) The potential impact of the “gap” on the UK economy is significant. We estimate that the NPV of a Rough Equivalent, developed for operation from 2014, would be £8.6 billion as of 2012, in terms of the avoided economic costs.
vi) The cost of putting in place gas storage, supply from Europe or oil storage to fill a gap the size of 3.3bcm (one RE) ranges between £0.9 billion to £2.4 billion.

vii) The net benefit to UK plc is therefore between £6.2 billion to £7.7 billion. In the alternative case, with lower probabilities of supply problems, the net benefit is reduced to £1.0 billion to £2.5 billion.

Cost/benefits
viii) The cost of providing UK strategic reserve appears justified.

Implementation
ix) A three part process is recommended:
• determine quantity of strategic storage required and the timetable;
• determine the process by which the required quantity is provided; and
• determine the trigger or mechanism for the use of the strategic storage.

x) We recommend that DTI with Ofgem determine the quanity of strategic storage requirement every three years.

xi) We examined two options for provision, one where NG run a centrally run process where it buys strategic storage via an auction and pays capacity payements to the successful providers. The second option relies on a new gas supplier licence obligation called a Security of Supply Obligation. Both seem worthy of further study.

xii) We also evaluated a third option where emergency cash out prices are set at a very high value of £12/therm. We felt the risks associated with this option were very high due to shipper/suppliers withdrawing from the market.

xiii) We recommend that the trigger for use of the strategic storage is under the control of Ofgem. The rules for its operation should be independent on gas prices but involve a test of a loss of a gas supply of a certain size at least 20% of normal UK supply and for a duration of greater than one week.

xiv) We recommend that the rules are transparent and public.
Risks and unintended consequences

xv) We conclude that the main risk of building strategic reserve is an adverse impact on commercial storage projects and the provision of alternatives.

xvi) We conclude that this risk and others can be avoided by careful design of the rules.

xvii) For option 3 the risks could be very high.

Summary and recommendations

8.5 Our analysis, using probabilities of supply problems, indicate that the UK has a potential problem in the next two years followed by a period when the size of the problem is much reduced. This is due to the number of gas importation projects planned to be commissioned over the next few years. The problem reappears from 2014 when the UKCS production has declined further and demand has increased. However, we must caution that:

- the size of the gap is based on views of the supply/demand position 20 years into the future;
- the size of the gap is based on views of probabilities which cannot be considered precise; and
- the new importation projects may be delayed or built but less gas is made available for importation than assumed in our scenario modelling to date.

8.6 We suggest that there is a risk that the UK gap could be better or worse than forecast. However, the risk may not be symmetrical in that the potential damage to the UK of a worse outturn than the one we have predicted is very costly to the economy.

8.7 We suggest that two approaches be considered by the DTI as possible alternative courses of action. These are set out below and both assume that after full consideration of this study, all the other Energy Review related analysis and further consultation that the Government decides that a form of strategic reserve should be built.

Fast Track timetable

8.8 If the outcome of the Energy Review is a move to a more risk averse future, the DTI would fast track further studies and consultation to develop strategic reserve. The aim would be to complete the development and full consultation by mid 2007. Licence changes may take a bit longer but the objective would be to launch the strategic reserve initiative by the end of 2007 to stimulate provision of reserve by 2011.
Post 2013 timetable

8.9 There is nothing that can be done to help with the potential problem in the next two years. The apparent breathing space until 2014 should be used to develop the detailed implementation arrangements.

8.10 We recommend that the DTI, following the Energy Review, publish a timetable leading to strategic reserve in place by 2014. This would include a detailed evaluation study in 2008 of the supply/demand position having experience of the outturn of the gas importation projects and the quantities of gas delivered.

8.11 We recommend that the DTI with Ofgem instigate an industry group tasked with developing detailed implementation rules and licence modifications with a delivery date of the end of 2007.

8.12 Following on from the 2008 evaluation study, the DTI would instigate the start of the strategic reserve scheme by the end of 2009. This will allow sufficient time to bring forward some reserve by 2014.
# ANNEX A– ILEX FORECASTS OF NEW CAPACITY AND STORAGE

Table 21 – ILEX forecasts of new capacity

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High, Central and Low refer to price scenario

Table 22 – ILEX forecasts of UK storage capacity, space in bcm

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ANNEX B – FORECAST BENEFITS OF A ROUGH EQUIVALENT

Table 23 – ILEX forecasts of the expected benefits of a rough equivalent (avoided costs of supply interruption)

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Figure 33 – Benefit of Rough equivalent, using alternative probabilities (mean outcome) – analogous to Figure 2 in the report

[Graph showing the benefit of Rough equivalent over years 2006 to 2020, with lines representing different scenarios: Main results, Main with extra RE, Benefit of RE.]
ANNEX C – PROBABILITY DISTRIBUTION FOR THE GAP IN A SAMPLE YEAR

Figure 34 - Example of a probability distribution for the gap between supply and demand (2019, ILEX probabilities)

C.1 The horizontal axis shows the annual shortfall in bcm. The vertical axis is 'probability density', such that the total shaded area equals one. The mean shortfall in this example is 0.24 bcm. There is a 95% chance that the shortfall would be less than 1.7 bcm. The highest level of shortfall is close to 14 bcm.
STRATEGIC STORAGE AND OTHER OPTIONS TO ENSURE LONG-TERM GAS SECURITY

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**质量控制检查表**

**STRATEGIC STORAGE AND OTHER OPTIONS TO ENSURE LONG-TERM GAS SECURITY**

报告唯一序列号：2006/059

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