THE
ENERGY CONTRACT
COMPANY

The gas storage market in the UK and review of revenue assumptions in economic model for the Islandmagee gas storage project

A REPORT FOR	**InfraStrata**
SUBMITTED BY	**THE ENERGY CONTRACT COMPANY**
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Contents

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1. Introduction

1.1. InfraStrata is the promoter of a new gas storage project at Islandmagee in Northern Ireland. It has prepared an economic model showing the project returns. The assumptions on revenue are based on data from a gas storage valuation model provided by Baringa Partners ("the Baringa Model").

1.2. The Energy Contract Company ("ECC") has been asked by InfraStrata to carry out a brief high level study on the gas storage market in the UK. This will cover Government energy policy and its impact on gas demand volatility, the availability of peak gas and the implications for gas price volatility.

1.3. This market background part of the study will be used to evaluate the assumptions on gas prices and gas price volatility used in the Islandmagee project economic model. Daily variations in gas demand, which have always existed in the UK, should become greater in future, due to the increasing dominance of renewable generation in the power market. The viability of alternative sources of peak gas to meet these needs are looking rather uncertain, which should materially increase the daily price volatility in the British gas market.

1.4. There are two basic types of gas storage facilities. The most common type are depleted fields, such as the Rough facility in the UK. These are existing fields which have produced most of their gas and have been redeveloped to allow for injection of gas, predominantly during summer periods, which can then be re-delivered during periods of high demand in the winter. Such facilities have high storage capacity but relatively low injection and production rates. They tend to focus on meeting seasonal demand for gas in the winter. The other main type of storage is salt cavern storage facilities. This is developed by drilling down into a salt layer and leaching out the salt to create a cavern. Gas can then be injected into the cavern and produced later. Salt Caverns have limited storage capacity, but can achieve high rates of injection and production. They are therefore best utilised to exploit the short term variations in gas price, or volatility, throughout the year.

1.5. Volatility is highly significant for salt caverns such as Islandmagee, which can produce and inject gas at a high short term rate. This enables the facility users to take advantage of short term price volatility; injecting gas on days when prices are low and producing when prices rise. The greater the price volatility, the more opportunities there are for the facility users to make money. So, the higher the volatility, the greater the value of a facility such as Islandmagee.

2. Executive Summary

2.1. Most gas sold in the UK is used for space heating, so demand has always varied significantly from day to day, due to temperature variations. In future these short term variations in demand should become significantly greater. UK Government energy policy now emphasises the need to replace power generation from fossil fuels with electricity generated from renewable sources, such as wind. As wind does not blow every day, gas fired generation will have to make up the deficit. Short term gas demand levels will therefore vary increasingly, depending on whether the wind is blowing or not.

2.2. Many of the traditional means of meeting peak gas demand such as swing from offshore fields and interruptible gas sales contracts have almost disappeared now, but have been replaced by other sources of peak supply, such as pipeline gas imports from the rest of Europe and LNG imports. However, there are some drawbacks to reliance on these sources in future. Historic data shows gas suppliers in the rest of Europe are reluctant to supply the UK in cold winter conditions, if it means that they might be short of gas themselves. There are also problems with LNG as a source of peak gas, as the long-time lags for the delivery of LNG cargoes mean that it is difficult for LNG producers and traders to react to high prices in the UK market, which might have collapsed by the time a cargo arrives in the UK.

2.3. In the rest of Europe the traditional means of supplying supplementary gas to meet peak demand was to use gas storage, although this was always less common in the UK. Gas storage levels in the UK are very low compared to the rest of Europe. Average storage capacity is only equivalent to 6.4% of annual demand in the UK, compared to 25-35% in the other major markets in Europe.

2.4. The problem in the UK has been exacerbated by recent technical problems on the Rough storage facility, which has severely restricted injection this summer. There have also been problems on the Hornsea storage facility. Both of these facilities, which account for almost 75% of UK gas storage capacity, are now over 30 years old and their continuing availability in the longer term must be subject to some doubt.

2.5. The cessation of injection at Rough this summer seems to have led to a surge in price volatility from late August onwards. From October 2013 to July 2016 the Short term Gas Volatility Index averaged 34%. However in the last month or so this has more than trebled to 126%. This surge in volatility has potentially great significance for the Islandmagee project. Salt cavern storage projects such as Islandmagee depend on short term volatility to enable the users to gain from injecting gas on low price days and producing later on when prices have risen. The greater the volatility the more profitable the project.

2.6. Overall the conclusion of the first part of the study is that due to the increased use of renewable generation, gas demand will become even more variable on a short term basis in future. The existing means of meeting this variation in demand may well be inadequate in future, so price volatility is likely to increase in future and could increase significantly.

2.7. The paper sets out the key assumptions in the Baringa model, which is used to provide the revenues levels in the Islandmagee financial model. The Baringa model relies on the use of historic pricing data to calculate future gas price volatility. The historic volatility and seasonality levels were much higher than they have been in the period 2012 to mid-2016. However the expectation is that gas price volatility will be significantly higher in future. So whilst future volatility may not follow historic patterns, the underlying assumptions in the Baringa model are reasonable, in the opinion of the Energy Contract Company, for the reasons set out below.

3. Changes in gas market volatility

3.1. Conventional Gas demand variation

Gas is used primarily as a fuel for heating in the UK and so short term demand levels will vary substantially with temperature levels. Set out below in figure 1 is a generic illustration from National Grid Gas showing the short term demand levels in the British Market on a cold day and a warm day[1]. Demand figures are in million cubic metres per day (mcm/d). This illustration represents the "historic" temperature related variations in demand, which have always existed in the British market. It does not include the additional short term variations due to government energy policy which are dealt with below in section 3.2.

Figure 1 Gas Demand on cold and warm days (mcm/d)

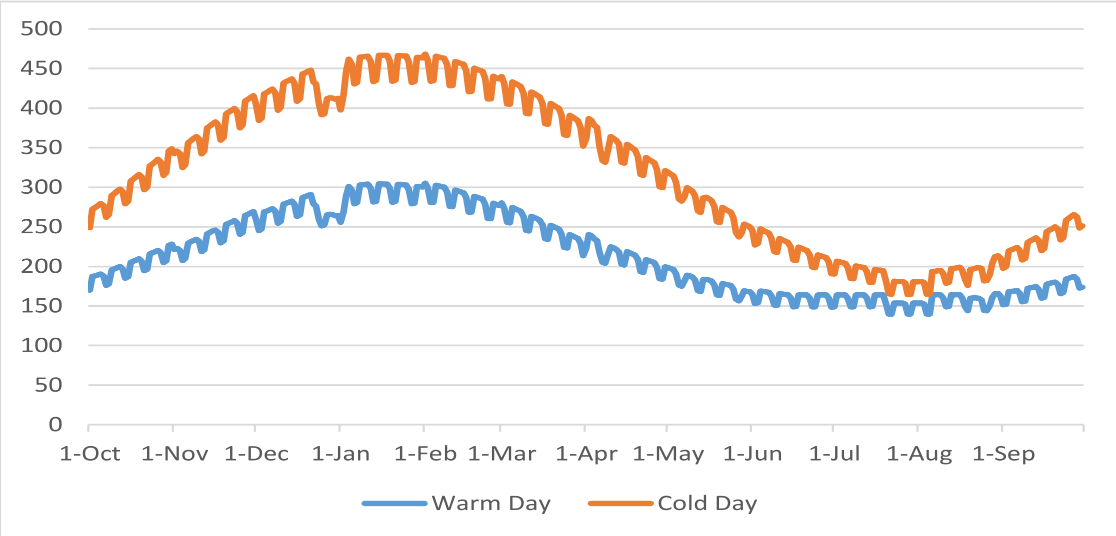


Figure 1 shows that in the winter short term gas demand in Britain could vary significantly due to variations in temperature alone. However, in summer the degree of variation is noticeably less.

3.2. Impact of Government Energy Policy.

The extent of short term variation in gas demand has already changed somewhat due to Government Energy Policy and this is likely to have an even greater impact on demand in future. In recent years the key element in UK Energy Policy has been concern over global warming and the need to reduce CO_2 emissions. This has led to an emphasis on the phasing out of generation by fossil fuels such as

[1] A cold day is defined as a temperature 5ºC below seasonal normal temperatures (SNT), and a warm day is 5ºC above SNT.

coal, oil and to some extent natural gas and its replacement by renewable generation and nuclear power.

However, in trying to replace fossil fuels with renewable sources, the government is faced with a major problem. Although there are a number of potential means of renewable generation, most of it (71.5 % of the total[2]) is onshore or offshore wind. Wind does not blow all the time and it cannot match the hourly pattern of electricity demand. Wind turbines are only expected to operate around 27% of the time onshore and between 33% and 38% of the time offshore[3] . The government has therefore had to devise a number of incentives for other developers to provide back-up generation capacity to "keep the lights on". Such back up generation has initially been around 60% gas, but this percentage is expected to increase significantly in future, as existing coal and nuclear stations are closed.

With the move to renewable generation, the peak short term demand for gas will still remain very high. According to National Grid Gas, despite the annual decline in sales, the peak short term demand may remain constant or even increase.[4] For many days each year renewable plant, especially wind, will be unable to generate and the gas fired plant will have to fill the gap. This means that in future short term gas demand will become increasingly volatile, fluctuating dramatically, depending on whether the wind is blowing or not. National Grid suggest that in the next decade the increase in short term gas demand due to lack of wind alone could be around 90 mcm/day. At that time, average annual gas demand is expected to be around 190 to 210 mcm/d. This process can also be observed to an even greater extent in Ireland where the levels of wind in the generation mix are amongst the highest in Europe.

[2] Electricity Market Reform Delivery Plan – DECC December 2013 Table 4

[3] UK Future Energy Scenarios. National Grid July 2013 , Table 3

[4] National Grid UK Future Energy Scenarios July 2013 Section 4.3.6

4. Sources of additional Peak Gas

4.1. Introduction

Most gas supply contracts do not contain much additional capacity to supply the higher short term variation in gas demand. This section of the paper now moves on to various other means of meeting peaks in gas demand and their viability going forward.

4.2. Decline in traditional means of meeting peak demand

The problem of significant variation in short term gas demand has always existed, although it will become more of a problem in future. Unfortunately the traditional means of dealing with this issue seem to have essentially disappeared now.

4.2.1 Historically, British Gas could cover a large measure of peak demand through the use of the flexibility in its supply contracts with UK gas producers, known as "Swing". The older gas contracts allowed British Gas to nominate between 130% and 170% of the average short term quantity on any day. However, these fields have now declined significantly and today most UKCS gas is sold under spot related contracts with no swing. This historic element of volume flexibility in supply has virtually vanished now.

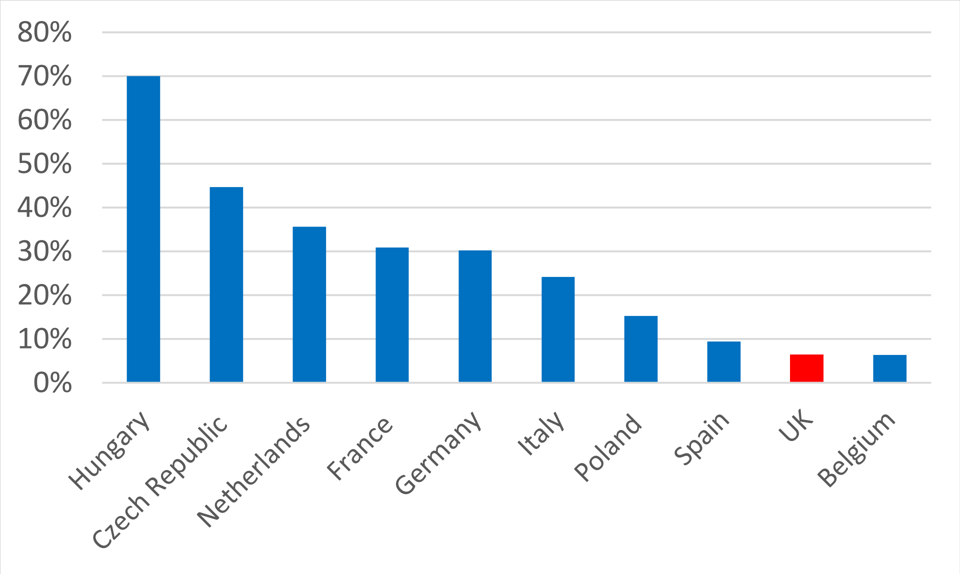
4.2.2 The other method adopted in the past by British Gas to meet peaks in demand was the Interruptible contract. This allowed British Gas to sell gas to power stations or large industrial customers, with the right to withhold supply on a defined number of days per year. Gas could then be diverted to premium markets such as household sales. These contracts still existed until as recently as 2010, but now seem to have disappeared from the market

4.3. Low levels of gas storage in UK

4.3.1 Comparison with the rest of Europe

The traditional means of meeting peak demand in most gas markets in the rest of Europe was to rely on gas storage. However, for the reasons set out above this was never the case in the UK. As a result the levels of gas storage in the UK are very low compared to other comparable markets in Europe and the United States. Figure 2 shows the gas storage capacity in the ten biggest gas markets in Europe expressed as a % of the annual gas demand.

Figure 2. Gas storage Capacity as a % of Annual Gas Demand in 2015[5]



The level of gas storage capacity in the UK (equivalent to 6.4% of annual demand) is very low compared with the European average. For the other four major gas markets in Europe[6], gas storage capacity is typically equivalent to around 25 to 35 % of annual demand. The UK storage level is also low compared with the other major traded gas markets in the world, the United States and Canada. Here gas storage capacity is equivalent to 17.4% and 19.6% respectively, of annual gas demand.

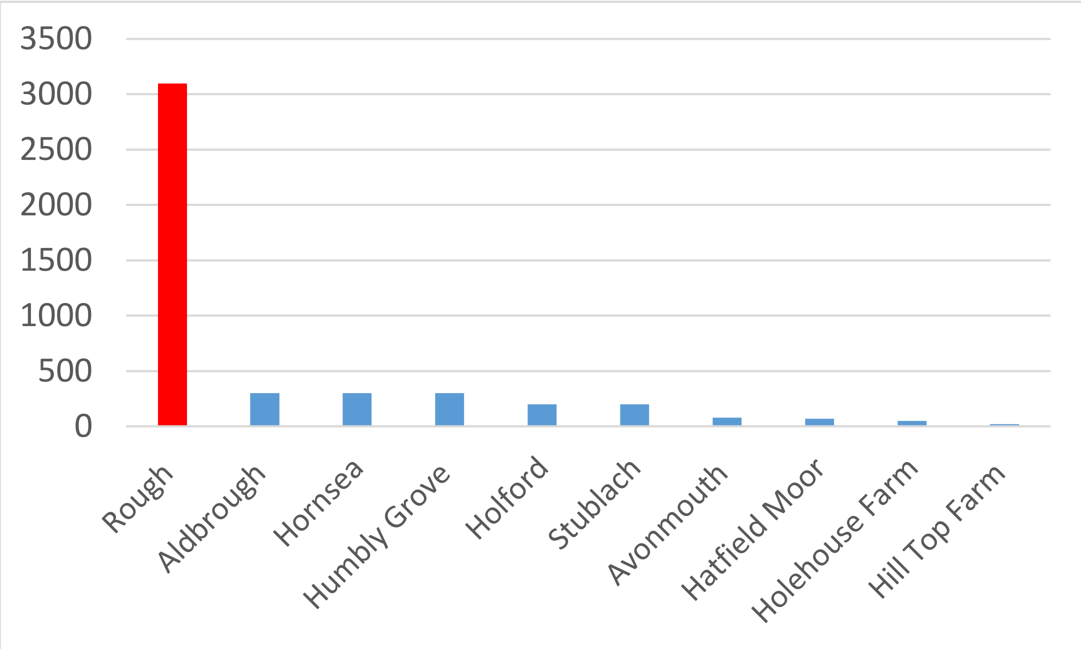
4.3.2 Dependency on Rough

The problem on storage is actually even worse than suggested above. The UK has ten different storage facilities but capacity is heavily concentrated in just one site, the Rough Field. Figure three below shows that this contains no less than 67% of all UK gas storage capacity.

[5] Source. IEA Natural Gas Information 2015. Tables 5 and 28

[6] Germany, Italy, France and the Netherlands

Figure 3 Capacity in UK Gas storage facilities (million cubic metres)



4.3.3 Recent problems with Rough

The problems with dependency on Rough have been thrown into sharp relief recently by a series of serious technical problems on the facility. In June 2016 Centrica Storage announced that as a result of testing work on the wells, they had identified a problem with the maximum pressure allowed. They carried out further tests and then announced in Mid-July that the problem was more serious than previously thought and that injection of gas would have to be suspended until March/April 2017. Over the coming winter, gas production could continue, but at a reduced level, from 20 wells, equivalent to around 75% of nominal maximum capacity. However deliverability will be limited due to the lack of injection into Rough this summer. Currently Rough is believed to be only around 30-40 % full at the time of writing, compared to around 100% normally at this time of year. In the meantime all sales of storage capacity for 2017/18 have been suspended.

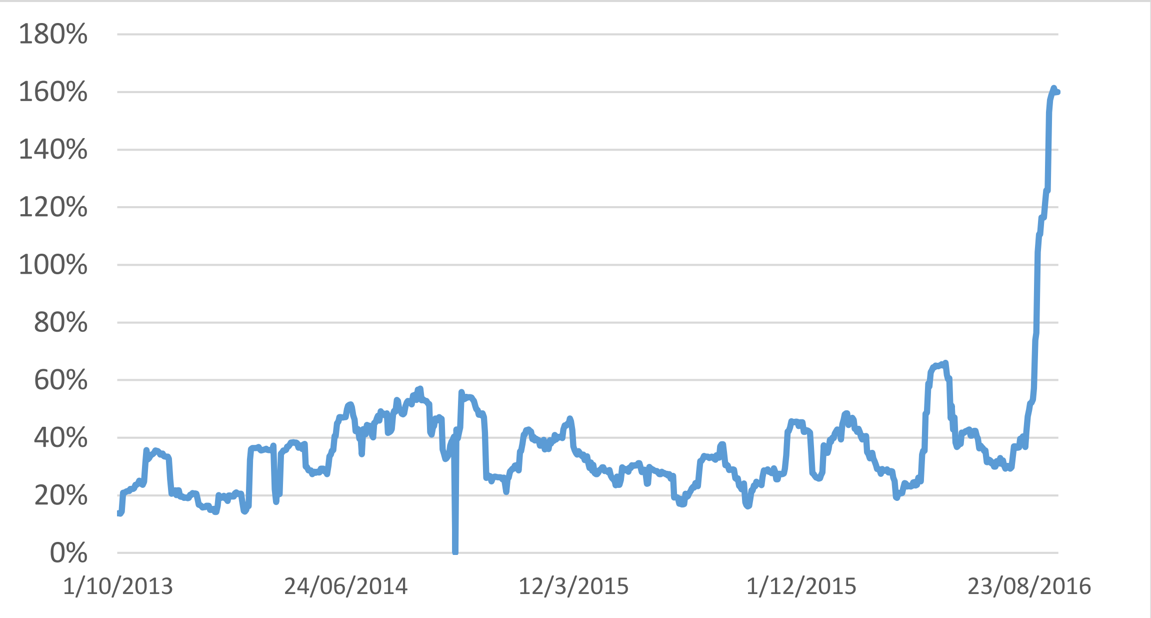
It is unclear what the long term future will be for Rough. It may well be able to resume normal operations in the spring of 2017. However, the facility will by then have been in operation for 32 years. It is quite possible that it may require major capital expenditure to keep it in operation in the longer term. Given that Rough relies on seasonal gas price differentials, which are currently very low on the forward curve, there must be some doubt whether Centrica would be willing to make such expenditure without some form of government intervention or support. There may also be some doubt about the future of the other older storage facility, Hornsea.

This is operated by Scottish and Southern Energy (SSE) and has also been in operation for over thirty years. It is smaller than Rough but still accounts for 6.5% of all UK Storage capacity. In 2015 SSE closed down two out of the six storage caverns, citing concerns about financial viability in current market conditions, but it is unclear if these caverns will re-open in future.

4.3.4 Impact on Price volatility

One of the key features of the gas market in Great Britain in the last few years has been the low volatility in gas prices. The volatility refers to the extent to which price vary from day today. When prices go up and down a lot volatility is high and vice versa. Figure 4 below shows the volatility for the last three gas years from October 2013 to September 2016.[7]

Figure 4 - Day ahead Volatility Index for gas years 2013/14 to 2015/16



[7] Source Heren European Spot Gas Markets. The Volatility Index is defined as the standard deviation of the percentage change in the daily prices for the last 20 trading days multiplied by the square root of 252. There are on average 252 trading days in the year.

Figure 4 shows a dramatic increase in volatility in the last two months and particularly in the last month. The volatility index figures are:

1st October 2013 to 15th July 2016 - 34%

16th July 2016 to 26th September 2016 - 73%

27th August to 26th September - 126%

The dramatic increase in volatility recently does not reflect extreme weather conditions or exceptional levels of gas demand. It widely believed in the gas industry to reflect the effective closure of Rough to new injection of gas this summer. Although it was limited in scale compared to storage in other European markets, Rough had always acted as a safety valve to dispose of surplus gas in summer and this support for the price was removed from mid-July onwards. If Rough was to be curtailed in future, due to lack of new investment, it could have an even greater effect on winter price volatility. As figure 1 showed, short term gas demand and the short term variations in that demand are much greater in winter than summer. This could potentially lead to much greater price volatility in winter than has been observed so far this summer.

4.4. Access to gas from the rest of Europe

4.4.1 Historic pattern of supply

Some elements of peak gas supply in the British market have deteriorated in recent year but others have improved. In particular Great Britain is now connected to the Continent by two pipelines, the BBL line from the Netherlands to Bacton and the Interconnector from Belgium to Bacton. Total Import capacity in these lines is around 115 mcm/day, equivalent to 24% of peak day demand. The Dept. of Energy, and it successors have always laid great store on the contribution made at peak demand time by gas imported from the rest of Europe. In particular they used the high level of imports during the very cold weather in March 2013 to justify their lack of intervention in the gas storage market. In its' announcement at the time [8] DECC said "*the UK gas market is continuing to function well in attracting gas from a range of sources to meet current and future demand and has coped well with extreme winter conditions, such as the extended cold snap this March*". In fact in March 2013 the UK gas market was heavily dependent on the Interconnector, which on some days was importing at over 100% of nominal capacity. Do these substantial flows indicate that gas volumes will flow freely to the highest price markets in future? There is no doubt that the market in the rest of Europe has changed significantly in recent years, but it may be premature to conclude that this will always permit

[8] DECC Press release 4th September 2013

substantial imports to the UK from the rest of Europe at times of high demand. There are a number of special circumstances which may suggest these high level imports in early 2013 were a one-off and may not be achievable in the future.

- In 2013, the gas markets in most of Europe were very depressed through a combination of the global recession, increased coal burn in generation and increased renewables, especially wind, reducing gas's share of the power generation market. In 2011 gas demand in Europe declined by 10%[9]. In 2012 and 2013 it declined by a further 2% and 1.4% respectively.[10] As a result many major gas utilities may have been unable in 2012/13 to reach the take or pay levels under their long-term gas contracts. As they had surplus gas, they welcomed the opportunity to dispose of it in the spot market.
- Finally the date of the increased demand for gas is highly significant. The real upsurge in gas imports took place in March 2013, right at the end of the winter. By March most holders of storage capacity in the rest of Europe could see the end of winter in sight and were relatively relaxed about supplying gas for export.
- This pattern could also be seen quite clearly in the winter of 2005/06. There was a price surge in Day-Ahead prices in November 2005 which the government was disappointed and frustrated did not attract significant volumes of spot imports from the rest of Europe. In contrast, later in the same winter when the Rough field suffered a mechanical failure in mid-February 2006, the midpoint of the winter was past and gas suppliers in Europe were willing to export spot gas to the UK. Volumes going through the Interconnector from mid-February to late March 2006 were very substantial.

Overall our view is that there will be many occasions when gas will continue to flow freely from the rest of Europe. However, the level of gas imports may decline when the need is greatest. North West Europe is a relatively small area and on many occasions when temperatures are low, and gas demand high in the UK, it will also be cold in the rest of North West Europe. In these circumstances, when they may also be short of gas, the major utilities on the Continent may be reluctant to export gas to the UK, if it means their own customers going short.

4.4.2 Impact of Brexit

Following the referendum in June 2016 the government has decided to implement a process of withdrawal from the EU. It is hard to judge what impact this would have on availability of gas from the

9 Eurogas Statistical Report 2012

10 Eurogas Report 18 March 2014

rest of Europe, not least because the nature of our withdrawal from the EU will not become clear for some time. At present, free movement of goods and services between EU countries means that there are currently no legal barriers to importing gas from Europe at times of high demand. The freedom of movement of gas into the UK will not be improved by Brexit and it is quite possible it may become restricted. Under some forms of Brexit gas may not be able to move as freely from the rest of Europe to the UK as it does currently. This would mean our security of supply for gas could be compromised to some degree in future.

4.5. Can LNG fill the gap

The other major change in gas supply security over the last decade has been the construction of three major LNG import terminals in Britain. This opens the UK up to supply from LNG sources worldwide, in addition to pipeline gas imports. LNG import capacity in the UK is very significant, at 132 mcm/d, equivalent to 27% of peak day demand in Great Britain. However, is it feasible for LNG to provide meaningful amounts of gas at peak times, in response to price signals from the day ahead gas market in Britain? On balance this seems unlikely.

4.5.1 The biggest problem is the time lag between the price signal emerging that the British market was short of gas and the earliest date that a cargo could reach the UK market. The closest source of LNG to the UK are Nigeria and the new LNG export terminals in the United States, which are mainly in the Gulf of Mexico. The time taken for a cargo to arrive from these terminals in the UK would be a minimum of 14 to 15 days, including the bare minimum of time to negotiate a cargo purchase and to re-gasify the LNG on arrival. In the time it takes for the cargo to arrive, the need for the gas could have passed and the price in the UK could have fallen.[11]

4.5.2 It is possible, although unusual, to buy LNG cargoes from another buyer that are already "on the water" and heading for another destination. However given the wide geographical spread of LNG importing counties it would really only be possible to purchase another cargo that was already heading for Western Europe. Cargoes destined for the other major LNG markets of Asia and Latin America would probably be even further away from the UK, than from the original loading terminal. The problem then arises that the weather in much of Europe is often similar to that of the UK. If demand is exceptionally high in the UK it would probably also be high in much of the

[11] This is the bare minimum period to secure a cargo and assumes that LNG Master Trade Agreements are already in place with potential LNG suppliers. In reality a 3-4 week timelag might be more realistic.

rest of Europe. In these circumstances major European utilities that import LNG such as Eon, RWE, Eni and Engie might also be short of gas and hence reluctant to sell cargoes at short notice.[12]

4.5.3 Finally there may be an institutional barrier to the import of spot LNG cargoes to meet peak gas requirements. As far as ECC is aware, no supervisory body in the gas market; such as National Grid Gas, Ofgem or DBEIS, has the remit, or indeed the expertise, to purchase spot LNG cargoes to supply the British market at peak times. It also seems unlikely that the numerous private sector gas suppliers to the UK market such as British Gas, Eon, RWE and Engie would be willing to purchase spot cargoes to support the British market. The timelags involved make it very risky for an individual company to try and support the market in general because of the time lags outlined above. For example if the UK spot prices price were high enough to justify buying an LNG cargo at $15/mmbtu, there is no guarantee that prices will still be at that level when the cargo finally arrives. In this case, if UK prices were to drop to $10/mmbtu, then the company concerned would lose $15 million per cargo (= £12 Million). It seems unlikely they would be willing to take this risk.

4.5.4 Historically there is little evidence that LNG imports would rise if price increased sharply in the UK market. During the very cold weather in March 2013, when the UK market came quite close to running out, Day Ahead prices increased sharply and exceeded £1.00 /therm for several days. Despite this clear "price signal", LNG imports were negligible, averaging only 9 mcm/d throughout March 2013. This is equivalent to only 6.8% of UK LNG Import capacity.

[12] The Spanish LNG importers might be an exception to this general rule

5. Conclusions on the gas storage Market

5.1. Historically there has always been a high level of short term variability in gas demand due to temperature variations. However, in future this short term variation in demand seems likely to increase still further. The increased use of renewables in power generation means that any short term shortfall in generation on days when the wind is not blowing, will have to be made up predominantly by gas fired plants.

5.2. The current set of mechanisms to cope with these demand fluctuations is imperfect. LNG cannot really provide cargoes to meet short term peaks in the market and the availability of gas from Europe may be restricted. In these circumstances it appears likely that gas price volatility will be higher in future than it has been in the last few years, perhaps much higher.

6. Evaluation on model assumptions on volatility

6.1. Introduction

InfraStrata have prepared a financial model to show the returns on the Islandmagee gas storage project. This in turn draws on annual project revenue estimates produced by a gas storage model produced for InfraStrata by Baringa Partners. The Baringa model generates revenue estimates for three cases; Low Case, Reference Case and High Case, although only the Reference Case revenue assumptions are used in the InfraStrata model itself. These revenues formed the basis for InfraStrata determining the cash flow for the project over a 20 year period. The InfraStrata economic model assumes a capex and pre operations opex of £308 million and 65% debt. The Net Present Value at an 8% discount rate is calculated as £67 million and with a 10% discount rate as £38 million.

ECC has not reviewed the mechanics of these two models but has examined the key gas market assumptions that underlie the Baringa model.

6.2. The key assumptions

The Baringa model depends on a number of key assumptions about the gas market and draws both on historic market data for the periods 2000 to 2010 and 2012 to 2015 and on the government gas price forecasts for the future. These key assumptions/prices are as follows:

6.2.1 The assumption on basic gas prices from 2014 to 2018[13] is taken from the ICE forward curves up to 2018, as at early January 2016. From 2025 to 2035 it uses the annual gas price forecast prepared by the Department of Energy and Climate Change (DECC) - Reference Scenario basis.[14] Between 2018 and 2025 the prices are interpolated between the two forecasts. Beyond 2035 the prices are extrapolated from the DECC forecasts. These prices are used in all three Baringa scenarios.

6.2.2 The monthly variation in gas prices in future are based on the historic relationship between the price in each month of the year and the average price for that year, using the historic monthly spot market gas prices published by the ICE. The monthly price ratios values for the period 2000 to 2010, which was a period of relatively high volatility, were used by Baringa to calculate their High Case scenario. The monthly price ratios values for the period 2012 to 2015, which was a period of relatively low volatility, were

[13] The Infrastrata financial model only uses the Baringa revenue forecasts from 2021 onwards.

[14] Updated energy and emissions projections 2015 - DECC November 2015

used by Baringa to calculate their Low Case scenario. The Reference Case figures used are an average of the Low Case and High Case values.

6.2.3 The short term volatility assumptions used by Baringa to calculate future short term gas price volatility are again based on historic values for volatility. The short term volatility for the period 2000 to 2010, which was a period of relatively high volatility, were used by Baringa to calculate their High Case scenario. The short term volatility for the period 2012 to 2015, which was a period of relatively low volatility, was used by Baringa to calculate their Low Case scenario. The Reference Case figures used are an average of the Low Case and High Case values.

6.2.4 All of these assumptions were used as input to the Kystore gas storage valuation tool,[15] to produce annual revenue figures for the Islandmagee project. I can confirm that the Reference Case annual revenue figures produced by the Baringa Model Reference Case have been correctly transcribed into the InfraStrata economic model.

6.3. Conclusions

One of the difficulties faced in trying to value a storage project in the UK gas market is that the world oil and gas markets have been turned upside down in the last three years, partially by the emergence of lower cost shale gas and oil in North America. It may therefore be difficult to rely on historic market data to assess the future.

The economics of Salt Cavern storage projects, such as Islandmagee, will be driven to a large extent by short term price variations in the gas market, or price volatility. However, as the earlier part of this paper has shown, there are good reasons to suppose that gas price volatility will rise significantly in future. It will increase as the proportion of renewables in the generation mix rises and the market's ability to respond to variations in demand deteriorates. The short term supply difficulties are compounded by the uncertainties over the future of the Rough and Hornsea storage facilities, which together constitute almost 75% of UK gas storage capacity.

The Islandmagee financial model relies on levels of price volatility which are above those observed in the market place between 2012 and mid-2016. Whilst future volatility may not follow historic patterns, it is still expected to be high. Therefore, for all the reasons set out above those assumptions can fairly be described as reasonable ones to make.

[15] Kystore is produced by Kyos Ltd