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Gas security of supply report: Further measures modelling

A report for Ofgem from Redpoint Energy

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Contents

List of figures

List of tables

1 Executive summary

Background

In November 2011, the Secretary of State for Energy and Climate Change asked Ofgem to assess the potential risk to medium and long term gas security of supply in Great Britain and appraise potential further measures to enhance security of supply in the GB gas market. Ofgem has undertaken a process of identifying potential further measures and developing an indicative design to illustrate how these options could work. To support its assessment, Ofgem appointed Redpoint Energy to conduct economic modelling of the gas market and the potential further measures.

This document sets out the assumptions that have been made for the modelling of the measures, the modelling framework and corresponding results. It should be read in conjunction with Appendix 4 to Ofgem's Gas Security of Supply report, which sets out the indicative designs of the further measures. For the most part, the modelling assumptions are consistent with the indicative options set out in Ofgem's report. However, in some instances, additional assumptions have been made or alternative options have been modelled (eg where the indicative design options set out in Appendix 4 are set to meet a protected customer standard and where this does not provide any additional security of supply under our modelling assumptions).

Modelling approach

We have deployed the same modelling framework as has been used to analyse the cash-out reforms proposed under Ofgem's Gas security of supply Significant Code Review, which we describe below.

Given the inherent trade-off between model complexity and tractability, building a model with a realistic representation of the GB gas system that is able to generate unanticipated shocks to that system and capture the market response to those shocks is clearly a very challenging task. Our aim was to build a model that is fit for purpose given the need to assess the risk to GB gas security of supply under the Gas SCR reforms and with the inclusion of the further measures options being considered.

The model is built on the basis of daily granularity whilst fully reflecting the interdependency between consecutive days in terms of demand, storage and other factors. Simplifications to the way that the GB gas system is represented in the model were made where it was felt that such simplification would have a minimal impact on the modelling results. Model behaviour was sense-checked against historically observed data where possible. However, we note that a Gas Deficit Emergency has never occurred and relevant historic evidence, particularly with respect to supply outages, is often limited.

The methodology centres on stochastic modelling of the gas market using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. The model contains a full representation of the gas supply infrastructure and demand segments, together with a representation of the electricity sector. The model constructs an annual supply profile for a given demand curve at monthly granularity, and then generates day-by-day simulations incorporating stochastic variations in demand (gas and electricity), gas supply availability and wind output. Flow responses to these daily variations are modelled without foresight of future variations.

Modelling assumptions are based on National Grid's Gone Green scenario and Ofgem's internal analysis. Assumptions on infrastructure availability take into account historical data where possible but also intend to reflect other risks, eg geopolitical events.

As explained further in Section 4, the average Long-range Storage (LRS)[1] outage frequency modelled for the options and the Counterfactual, to which the options are compared, was identified during a Quality Assurance (QA) review as being high. We note that this QA review also identified that the same error was present in the modelling for the Gas SCR Impact Assessment.

In order to assess the impact of a change in the LRS outage frequency assumption to a lower level, the Counterfactual is also modelled using a lower LRS outage frequency. In this document, we refer to this revised Counterfactual scenario as the Revised Base Case. On the basis of the modelling results, our considered opinion is that this difference in assumptions does not alter the conclusions drawn from the results and the modelling results for the options are compared against the Counterfactual on the basis of the same storage outage frequency assumptions.

Potential measures

The further measures described below are modelled under the assumption that cash-out reform under Gas SCR is in place. We note however, that at the time of writing, this reform has not yet been introduced[2].

Demand side response (DSR) tender

This is assumed to take the form of an annual auction, where demand that becomes interruptible receives an upfront payment at the start of the year and an option exercise payment if it is interrupted.

The DSR tender is intended as a measure which can provide additional certainty that the expected potential for DSR that has been identified will emerge (although at additional cost). We would expect that this measure should only be considered further if there is evidence that additional barriers to interruptible contracts mean that the incentives provided by the SCR reforms will not be sufficient to encourage the emergence of the potential for DSR that is believed to exist. Therefore, the total volume of DSR modelled under this option is consistent with the total volume of DSR under cash-out reform in the modelling done for the Gas SCR Draft Impact Assessment. This means that that the two lowest VoLL tranches of DM gas demand in the model become interruptible under the DSR tender option.

For these tranches, the option exercise price is assumed to be 75% of the average VoLL for that tranche. If a given tranche is the highest VoLL tranche to be interrupted in the model, the system gas price at this point is determined by the option exercise price for that tranche.

Financial reliability option

Reliability options are assumed to be implemented as purely financial contracts. The option seller is free to hedge the financial exposure under the option through investment in physical assets or by entering into other contracts. Total exposure under the option is determined by the total number of options sold and the difference between the option strike price and the actual spot price of gas in the market if the latter is higher.

Total volume of options is determined exogenously on the basis of forecast 1-in-20 peak demand by all firm gas customers excluding CCGTs in National Grid's Gone Green scenario. We have calculated a rational

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[1] LRS is defined as a storage facility with a relatively low ratio of daily deliverability to total capacity.

[2] See http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx for details of Ofgem's proposed decision and supporting analysis.

physical hedge for the sellers of these options in the form of new Short-range Storage (SRS)[3] investment (although in practice, participants are not restricted in their choice of hedge).

Service obligation on the System Operator

Response to implementation of the SO service obligation is modelled as the provision of responsive physical supply with a high ratio of deliverability to total volume. While the option design does not prescribe that the System Operator's response to the obligation must be through storage, for the purposes of our modelling, we make the assumption that the System Operator's response to the obligation is to commission an additional storage facility. This facility operates outside of the market and does not affect the market price of gas. It is only activated in order to prevent firm demand interruption.

Storage obligation

In our modelling of this option, an obligation is placed on suppliers to book and fill a certain amount of storage capacity over the winter period when the risk to security of supply is at its greatest. Storage can only be released for the purposes of preventing network isolation (with NDM interruptions used as a proxy in the model). The amount of storage under the obligation is determined administratively.

Our modelling assumes that the restrictions placed on existing storage capacity as a result of the obligation lead to some storage new build, although the amount of new capacity being created is estimated to be limited.

Semi-regulated storage

Under this option, it is assumed that sufficient support is provided in order to deliver an additional LRS facility and hence we model the impact of adding such a facility to the infrastructure mix.

The semi-regulated storage facility operates under an illustrative cap and floor regime by which the capex cost of the facility and the cost of cushion gas are paid by the owners of the facility and its subsequent revenues are guaranteed to lie between the cap and the floor on an annual basis. Consumers (or taxpayers) will pay the difference between the floor level and actual revenues if revenues fall below the level of the floor within a given review period.

Strategic stocks

Under this option, it is assumed that an additional LRS facility is commissioned, which would operate outside of the market. It is modelled to have the same associated daily deliverability as the additional supply source in the SO service obligation option, but with sufficient capacity to deal with lengthy outage events, potentially lasting for a whole winter.

Our modelling results for the SO service obligation are the same as for the Strategic stocks option. Both are modelled to have the same associated daily deliverability. While the Strategic stocks option is assumed to provide sufficient capacity to deal with lengthy outage events, our modelling results do not contain any interruptions that are long enough to justify this extra capacity.

[3] SRS is defined as a storage facility with a relatively high ratio of daily deliverability to total capacity.

Impact on security of supply

Table 1 shows the expected annual quantity of unserved demand for firm DM, NDM and firm electricity demand tranches under the Counterfactual and modelled further measures. Note that the results represent an average of modelled 2020 and 2030 spot years.

Table 1 Unserved demand (Million therms per year)[4]

Options	Firm DM gas	NDM gas	Firm electricity[5]
Counterfactual (cash-out reform)	0.029	0.656	0.018
Demand side response tender	0.028	0.711	0.018
Financial reliability option	0.016	0.469	0.013
Service obligation on the System Operator	0.008	0.242	0.007
Storage obligation	0.024	0.312	0.017
Semi-regulated storage	0.007	0.288	0.007
Strategic stocks	0.008	0.242	0.007

The results for the DSR tender option are similar to the Counterfactual results since they make similar assumptions about interruptible contracts. The expected impact of NDM interruptions for the DSR tender option is higher than the equivalent figure for the Counterfactual. Since the interruption prices for interruptible DM gas demand tranches and thus the system prices when those tranches are interrupted are 25% lower in this option than in the Counterfactual, on average, more gas would be expected to be attracted into GB under the Counterfactual than under the DSR tender option.

For the Financial reliability option, the estimated SRS investment is 121 mcm of capacity with associated deliverability of 10 mcm/day. The estimated reduction in unserved demand on all tranches of firm gas and electricity demand relative to the Counterfactual is significant. The greatest effect is on unserved firm DM gas demand. This is due to the fact that 10 mcm/day deliverability is not sufficient to deal with some of the larger interruptions, but can be expected to prevent more of the smaller interruptions.

Under the Service obligation option, a supply source is made available with a daily deliverability limit of 22 mcm/day. The estimated reduction in unserved demand on all tranches of firm gas and electricity demand in this option is very significant. Unserved demand for all tranches is more than halved under this option relative to the Counterfactual.

[4] Total amount of energy unserved shows the total impact of interruptions on customers. It incorporates information on both the probability of interruptions and the average impact of interruptions when they occur and is hence a useful measure of security of supply.

[5] Firm electricity demand includes demand from I&C, SME and domestic electricity customers. Electricity demand converted into gas terms using theoretical CCGT efficiency of 51%.

The Storage obligation, as modelled, significantly reduces the impact of interruptions on all tranches of firm demand. The greatest impact is on NDM outages since the storage obligation can only be breached to prevent an NDM interruption. The Storage obligation also reduces the probability and impact of other types of firm gas demand interruptions. Since, under the obligation, gas is withheld from the market at the start of winter but more gas is released into the market at the end of winter, in our modelling, the latter effect prevents certain firm DM gas interruptions where otherwise, storage may have been depleted. However, in theory it is also possible that a storage obligation could result in an increase in DM gas demand interruptions as the obligation is designed to hold back gas for the purposes of preventing NDM interruptions and may stop gas from being released when this could otherwise prevent large DM gas customers from being firm load shed.

In the Semi-regulated storage option, unserved demand is reduced considerably relative to the Counterfactual. Firm gas demand unserved is more than halved for all tranches. The storage facility is also estimated to have an effect on GB wholesale gas prices, with the summer-winter spread being reduced.

Under the Strategic stocks option, the modelling results are the same as for the Service obligation on the System Operator as our modelling sees no interruptions that are longer than the period which can be covered by the Service obligation under our assumptions. However, since the total gas capacity in the Strategic stocks option is much greater than the total capacity under the Service obligation, the total cost associated with this option is significantly greater.

Conclusions

Results presented in this document do not represent a full cost benefit analysis of the options but only initial analysis based on indicative designs. In particular, costs and benefits are considered in a simplified form and impact of potential unintended consequences is not considered. A full CBA would need to be performed on any options considered in order for those options to be taken forward.

Although DSR tender option results do not show a significant difference in security of supply compared to the Counterfactual results, the DSR tender is intended as a measure which can provide additional certainty that the expected potential for DSR that has been identified will emerge (although at additional cost).

Reliability options are designed to create strong private financial incentives to maintain security of supply. A lower strike price increases the security of supply effect of the option but also increases the cost and the risk to the sellers of the options. Results for reliability options are wholly dependent on assumptions on the physical hedging response, which is highly uncertain because financial exposure under reliability options is very difficult to predict, as is the extent of risk aversion and the implied risk premium that may be demanded by the sellers of the options. Hence the benefits in terms of improved security of supply, and the associated cost, are highly uncertain.

The SO service obligation significantly reduces unserved demand in our model and operates outside of the market. It is designed to address the risk of relatively short supply interruptions by requiring the SO to identify potential security of supply shortfalls and take actions to mitigate the likelihood of these shortfalls leading to a GDE . The implied security standard can be varied with option design, where a higher security standard would imply higher cost. The response of the System Operator to a Service obligation may not take the form of physical storage and would depend on the details of the design of the obligation.

Strategic storage also operates outside of the market and is designed to address the risk of prolonged supply shortfalls by requiring a central body to procure additional gas storage. This option does not show any additional security of supply benefit in the modelled results relative to the service obligation, but could, in theory, play an important role in the context of very broad-ranging or longer term events that are not seen in our model. The cost of this option would be significant given that it implies a high ratio of capacity to deliverability.

The storage obligation is designed to address over-reliance on spot markets as a source of gas in periods of high demand. As modelled, it brings significant security of supply benefits, particularly with respect to NDM demand at which it is targeted. The impact of the obligation on other demand tranches is less certain, although the obligation modelled in this study shows a benefit in terms of reduction in unserved demand for all firm demand tranches. The market response to the obligation in terms of new capacity investment, and hence also the cost of this option, are likewise uncertain. This is because the economic cost of storage obligation is difficult to evaluate as the value of the reduction of flexibility of storage implied by the obligation is highly uncertain.

The semi-regulated storage option is designed to address a potential market failure in the provision of seasonal storage capacity. It provides significant security of supply benefits under the modelling, but these could only be expected to materialise towards the end of this decade. It is uneconomic under our assumptions on the basis of private returns and would be likely to require significant support under any regulatory regime. Estimated reduction in cost of gas to consumers due to regulated storage is generally less than the estimated level of support required, but there is significant uncertainty around the costs and benefits of the option that have been identified.

2 Background

The competitive gas market in Great Britain (GB) has so far delivered secure supplies and witnessed high levels of investment in gas infrastructure. Although GB has been a net importer of gas since 2004due to declining production from the UK Continental Shelf (UKCS), international markets have so far been effective in supplying gas to GB. However, Ofgem has observed that there is some uncertainty over future developments in global gas markets.

In its Gas SCR draft decision document, Ofgem stated its intention to reform the gas cash-out arrangements in GB, with the preferred option for reform being capped emergency cash-out[6]. However, it observed that capping the cash-out price may leave some of the costs of a demand interruption with consumers, who may not be well placed to either handle those costs or to make provisions in order to mitigate them. Ofgem noted further that the Government may decide that this merits further measures to enhance security of supply in the gas market.

In November 2011, the Secretary of State asked Ofgem to assess the potential risk to medium and long term gas security of supply in Great Britain and appraise potential further measures to enhance security of supply in the GB gas market. Ofgem has undertaken a process of identifying potential further measures and developing their design. To support its assessment, Ofgem appointed Redpoint Energy to conduct economic modelling of the gas market and the potential further measures.

This document sets out the assumptions that have been made for the modelling of the options, the modelling framework and corresponding results. It should be read in conjunction with Appendix 4 to Ofgem's Gas Security of Supply report, which sets out the indicative designs of the further measures. For the most part, the modelling assumptions are consistent with the indicative options set out in Ofgem's report. However, in some instances, additional assumptions have been made or alternative options have been modelled (eg where the indicative design options set out in Appendix 4 are set to meet a protected customer standard and where this does not provide any additional security of supply under our modelling assumptions).

[6] Ofgem's proposed final decision was published in July 2012.

3 Modelling approach

We have used the same modelling approach for analysing potential Further measures to enhance security of supply as was used to analyse the options for cash-out reform under the Gas significant code review. This approach is described below.

Given the inherent trade-off between model complexity and tractability, building a model with a realistic representation of the GB gas system that is able to generate unanticipated shocks to that system and capture the market response to those shocks is clearly a very challenging task. Our aim was to build a model that is fit for purpose given the need to assess the risk to GB gas security of supply under SCR reforms and the effect of the further measures considered in the report. Our model is built on the basis of daily granularity whilst fully reflecting the interdependency between consecutive days in terms of demand, storage and other factors. Simplifications to the way that the GB gas system is represented in the model were made where it was felt that such simplification would have a minimal impact on the modelling results. Model behaviour was sense-checked against historically observed data where possible.

The methodology centres on stochastic modelling of the gas market using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. The model contains a full representation of the gas supply infrastructure and demand segments, together with a representation of the electricity sector. The model constructs an annual supply profile for a given demand curve at monthly granularity and generates day-by-day simulations incorporating stochastic variations in demand (gas and electricity), gas supply availability and wind output.

'Decision rules' are used to determine the associated supply flows on the day, rather than finding an optimal solution across a period, to reflect lack of perfect foresight. These are captured through the construction of 'tranches' of each supply source, which are defined as an available volume either at absolute price levels or at differentials to a given benchmark. Logic for liquefied natural gas (LNG) reflects the 'lag effect' associated with lead-times for delivery of shipments by driving supply off a rolling average price over a set number of historic days, rather than the market price on the day.

Storage is handled by using a set of calibrated withdrawal/injection rules as functions of relative spot/forward price differentials, inventory levels, and time of year. Because prices have a well-defined seasonal profile, long-run storage generally tends to be built up in advance of winter and drawn down during the winter period. The mean behaviour of long-run and short-run storage is sense-checked in relation to actual historic storage profiles. Clearly this approach greatly simplifies real decisions made by market participants. However, we believe that on an average basis over a large number of simulations, it provides a fair way to reflect typical market behaviour to a level that enables conclusions to be drawn with regard to the potential impact of further measures options.

On each day, an optimisation routine is used to determine a combined gas/electricity supply match and to derive a short-run marginal price. The stochastic components in the model are driven by appropriate distribution functions. Commodity prices (feeding into the benchmark prices for continental gas and LNG, coal generation costs, and the carbon costs for CCGTs) use a correlated mean-reverting process.

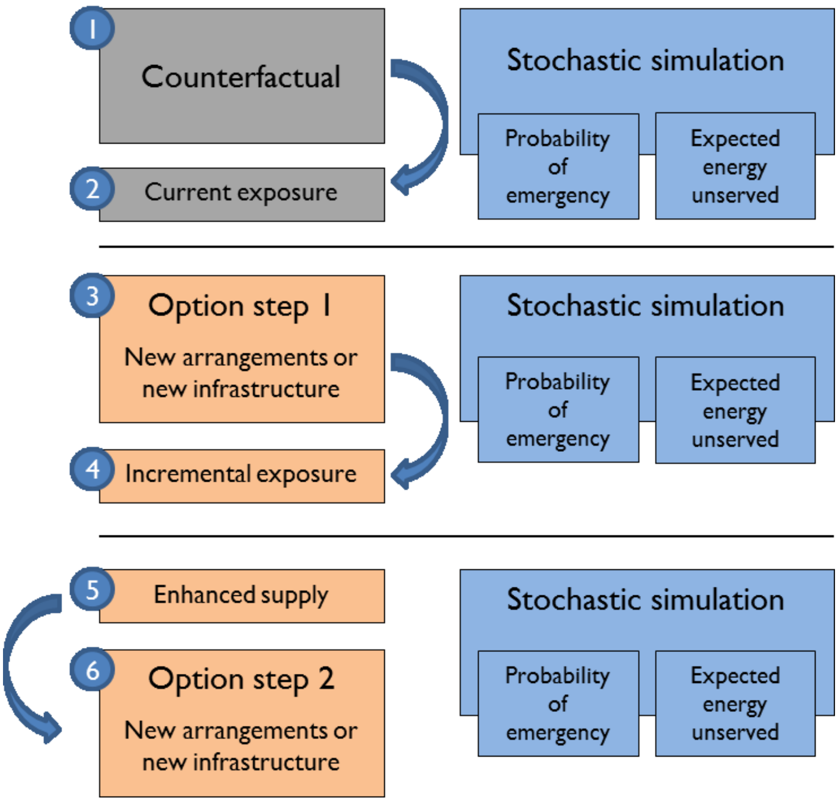
The seasonal pattern of UK Continental Shelf (UKCS) gas flows is estimated from historic data provided by National Grid using monthly dummy variables in a linear regression. Stochastic deviations from the expected seasonal mean production level are drawn from a distribution fitted to the residuals of an Autoregressive Moving Average (ARMA) model and persistence of shocks estimated by that model is applied to the simulated residuals in order to model UKCS output shocks with a realistic duration. This captures variability in both upstream and terminal output.

Norwegian Continental Shelf (NCS) output is modelled as separate strategic and non-strategic components. Output from the non-strategic component is assumed to be based on long-term contractual arrangements and hence it does not vary with changes in the spot market price of gas in the GB market. Output from the strategic component is assumed to go to the market where the price of gas is highest and hence behaves in the same manner as Interconnector UK (IUK) imports. The modelling methodology for the non-strategic part of NCS supply is exactly as for UKCS above.

Infrastructure outage probabilities are modelled using the Poisson distribution. Outage magnitude and duration are modelled using the lognormal distribution. Assumptions for distribution parameters were agreed jointly by Redpoint and Ofgem after accounting for stakeholder responses to the Gas Security of Supply Significant Code Review Draft Impact Assessment. In many cases, given the associated low probabilities, there is no historic dataset that can be used to derive the parameters[7].

Stochastic daily variation in demand is modelled in a similar way to stochastic UKCS output. The seasonal pattern of demand is estimated from historic data provided by National Grid using monthly and weekly dummy variables in a linear regression. Stochastic deviations from the expected seasonal mean demand level are drawn from a distribution fitted to the residuals of an Autoregressive Moving Average (ARMA) model and persistence of shocks estimated by that model is applied to the simulated residuals in order to model demand shocks with a realistic duration. Gas demand from power generation is determined endogenously in the model.

The steps involved in modelling the Counterfactual and a given proposed option are described below. Modelling is conducted using representative years to 2030.



[7] The impact of different assumptions is tested in the sensitivity analysis.

1. Estimate the probability and expected level of unserved demand under the Counterfactual by running multiple simulations.

2. Determine the expected 'industry exposure' associated with emergencies. Our assumption here is that shippers in aggregate are contracted to match the volume supplied prior to demand interruption, and hence that they are exposed to the volume of demand interruption at the associated cash-out price.

3. Re-run GB model under proposed option, determining a revised probability and impact of emergencies.

4. Determine the revised expected 'industry exposure' associated with demand interruptions under the option. Depending on the option modelled, this may not be priced at cash-out (eg reliability options).

5. Determine the additional storage capacity that the industry would obtain to reduce its exposure to the level estimated in the Counterfactual (if this is higher under the option modelled). This is estimated on the basis of the profit-maximising additional storage level where the marginal cost in terms of extra storage capacity obtained is equal to the marginal benefit in terms of reduced exposure.[8]

6. Re-run the model with this additional storage capacity and again determine the probability of emergencies and the expected unserved demand.

7. Compute the change in the wholesale cost of gas, the additional cost of the incremental storage capacity and the benefit of any reduction in firm interruption.

The stochastic model is run for spot years 2012, 2016, 2020 and 2030 for the Counterfactual. In each case, 1,500 simulations are run, with each simulation consisting of a continuous 365 day period. Each simulation begins on 1 April. The starting level of gas storage is assumed to be 20% for LRS and 50% for SRS in every simulation.

The effects of each further measure option relative to the Counterfactual are estimated by subjecting the model to the same set of underlying events (i.e. using the same random number seed) for the Counterfactual and each of the options. Hence all options are compared on a like-for-like basis.

The model is based on a daily optimisation routine. In order to keep the model computational time to a realistic level, for each simulated day, the optimisation routine does not iterate to an absolute optimum but settles for a solution that is close to the optimum. Because of the large number of simulations carried out, in a few instances, this can introduce arbitrary differences between like-for-like simulations under different options that impact the results. On the whole, such differences are small and average out when simulation results are summarised.

Given the complexity of the modelling, it is not possible to formally derive confidence intervals around the modelling results. However, on a qualitative basis, large differences in results must be seen as more statistically significant than small differences. Likewise, differences that relate to more frequent events must be seen as being more statistically significant than differences that relate to rare events.

[8] We note that this is a simplified assumption which has its own limitations. First, the model assumes that companies are neutral to risk. The existence of insurance markets indicates that some companies might be risk averse (wanting to avoid the biggest risks). Building risk aversion into companies' assessment could lead to additional investments in security of supply. Second, the model assumes that the only investment response available to companies is investing in storage capacity. In reality, companies might have more cost-effective instruments available to enhance security of supply, such as long-term supply contracts and diversification of imports. Therefore, companies' responses to the incentives created may be greater than suggested by the modelling.

The issue of statistical significance must also be considered with respect to which aspects of the modelling results are given the greatest weighting in any assessment. In particular, the change in the probability of different types of demand interruption contains less information than the total volume of interruptions by type. This is due to the fact that interruptions are a threshold event. If a modelled option succeeds in reducing the size of certain interruptions without preventing any of them, this effect will not be visible in the probability of interruptions estimated from the modelling results. This consideration is especially important with regard to rare events like NDM customer interruptions.

We provide a case study below which demonstrates the model dynamics in the run-up and the course of an NDM outage in one of the Counterfactual simulations. The point of this example is not to suggest that this exact sequence of events is how the market would react in practice, but to demonstrate an example of the model dynamics, which, when aggregated across many simulations, allow quantitative conclusions to be drawn to support a qualitative case. The following case study refers to a simulation for spot year 2030.

In Figure 1, we see the model gas market dynamics and in Figure 2 we see the modelled power generation for the corresponding period. Where the red line showing Non Power Generation (NPG) demand rises above the stack of supply sources, firm gas demand is interrupted. NPG demand reaches a peak of 317 mcm/day on 19 Dec[9]. This, combined with a severe reduction in the ability of LRS to deliver gas, no LNG shipments being delivered into GB and lack of gas in SRS, results in DM gas being interrupted on 18 Dec and NDM gas demand being interrupted on 19 Dec[10]. No CCGTs are subject to involuntary interruption throughout this episode since other electricity supply sources, including wind, coal, interconnectors and CCGTs running on distillate, are sufficient to meet electricity demand. Although the cash-out price rises in the run-up to 19 Dec and reaches £20/th on that date, total gas supply is not sufficient to prevent an NDM interruption.

Demand falls rapidly in the next few days and the supply shortage is resolved. Shortly after LRS is restored to its full withdrawal capacity, a negative shock to interconnector capacity occurs. From 3 Jan, demand starts rising rapidly. However, the spike in prices that occurs during the NDM interruption increases LNG shipments into GB since availability of LNG to flow into GB is determined by a 2 week moving average of the GB price lagged by 7 days. This is the proxy used in the model to reflect the lag involved in LNG responses to market events given shipping schedules, implying in this case an increased expectation of prices following the event that leads to decisions by market participants to send cargoes to GB. The increase in available LNG allows for an increase in the volume of gas injected into SRS in the days after the price spike. When the subsequent demand spike and interconnector outage come around, there is ample supply to meet demand and no demand interruptions occur.

[9] 317 mcm/day represents approximately a 98.6th percentile of annual maximum demand figures in all the simulations for 2030 carried out in our study. In other words, out of the 1,500 simulations carried out for 2030, less than 21 will see an absolute annual peak demand of above 317 mcm/day.

[10] Since an NDM interruption lasts for a minimum of 14 days under our modelling assumptions, the NDM customers interrupted on 19 Dec are off for the subsequent 13 days, which can be seen in the persistent gap between total demand and total supply during that period.

Figure 1 Example of modelled gas market dynamics

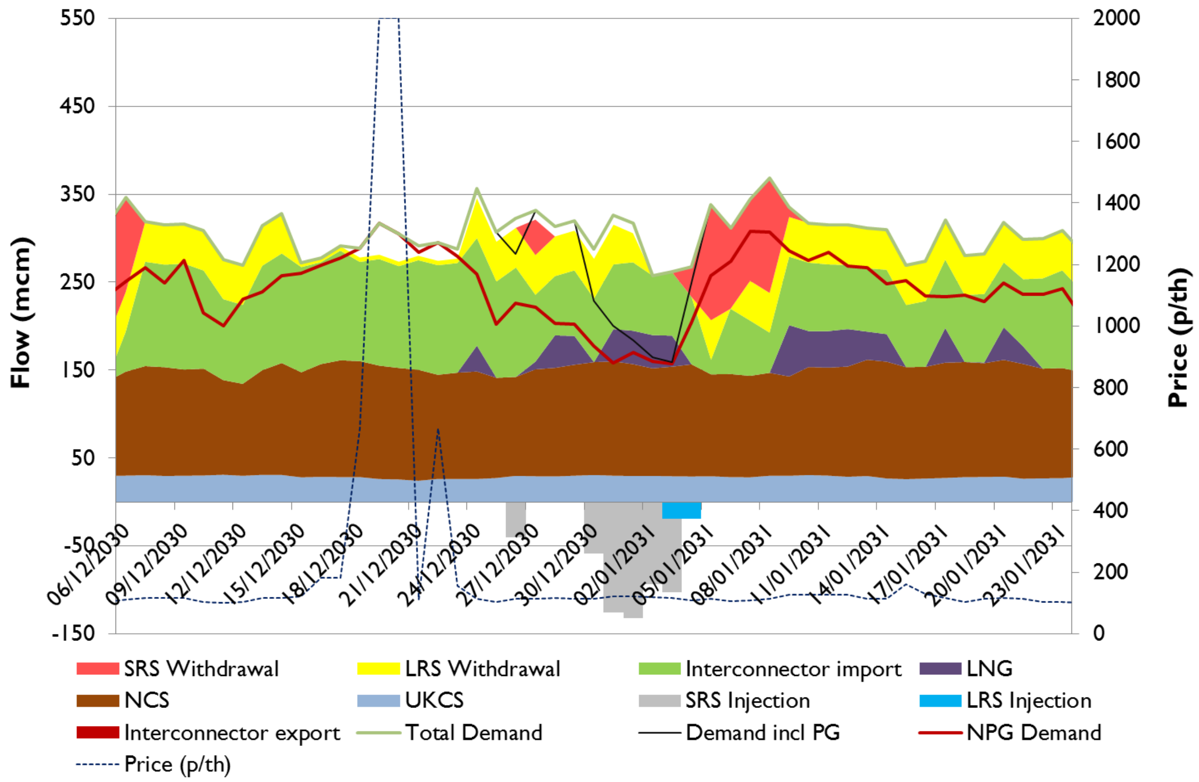
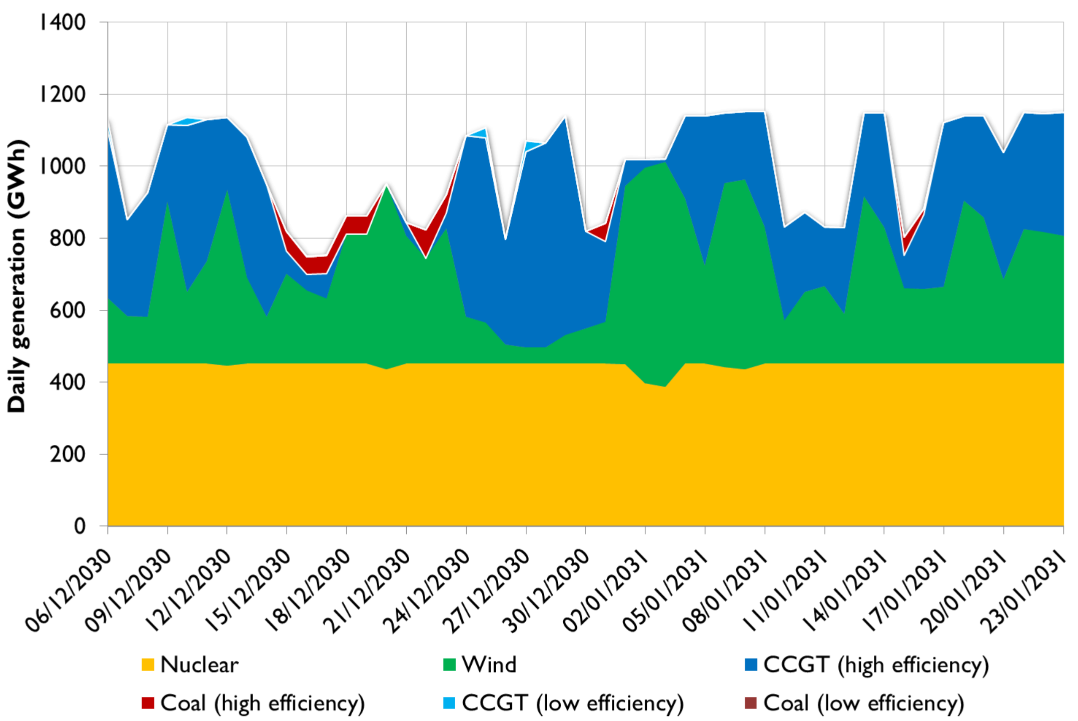


Figure 2 Example of modelled power generation



4 Modelling assumptions

Overview

This section sets out a summary of our modelling assumptions. These assumptions include changes as a result of stakeholder feedback on the modelling done for the Gas Security of Supply Significant Code Review Draft Impact Assessment. They also include other revisions with the latest available information, including changes to fuel price assumptions, exchange rates, NPG demand, annual supply from different sources, electricity demand and the electricity generation.

Modelling low probability events for which there are no direct historic precedents requires assumptions that frequently cannot be verified using historic data. In the course of this modelling exercise, assumptions were calibrated to historically observed data where possible. Where such calibration was not possible, we have made clear and transparent assumptions which are set out in this section. Broadly, the set of assumptions adopted in our modelling are designed to be consistent with Ofgem's internal analysis and NG's Gone Green scenario under which the UK meets its decarbonisation and renewable energy targets.

Commodity prices

Our commodity price assumptions rely on prices quoted in forward markets dating from April 2012 for the period up to 2015. For the period after 2015, our assumptions are based on the International Energy Agency's 2011 World Energy Outlook published in Nov 2011. For Henry Hub prices, our assumptions are based on prices quoted in forward markets dating from 25 April 2012 for the period up to 2020. After 2020, we assume that the Henry Hub price rises at the same rate as the crude oil price.

The market price of gas in GB is determined endogenously within the model given the total demand for gas, the supply curve of domestic and imported gas supply, the available DSR and the margin of available capacity over total demand. This price is calculated on a daily level.

Assumptions on the average annual level of the carbon price are taken from forward markets in 2012 (as of 20/06/11), then utilise DECC's short term traded carbon values for UK public policy appraisal values to 2030[11].

Daily volatility in coal, carbon and Henry Hub prices is simulated using a correlated, mean-reverting Brownian motion process. The input scenario commodity price is used as the mean in the calculation.

Exchange rates

Exchange rate assumptions are derived from the mid-market rate as of 26 April 2012 and are assumed to remain constant in real terms thereafter. The assumed £/$ exchange rate is 1.62 and the assumed £/€ exchange rate is 1.22.

Gas supply

Average daily flow in UKCS gas on an annual basis is based on data for Figure 3.3A in the National Grid Ten Year Statement (TYS2011)[12] in the Gone Green scenario[13].

[11] http://www.decc.gov.uk/assets/decc/11/cutting-emissions/carbon-valuation/3137-update-short-term-traded-carbon-values-uk.pdf

[12] http://www.nationalgrid.com/NR/rdonlyres/E60C7955-5495-4A8A-8E80-8BB4002F602F/50703/GasTenYearStatement2011.pdf

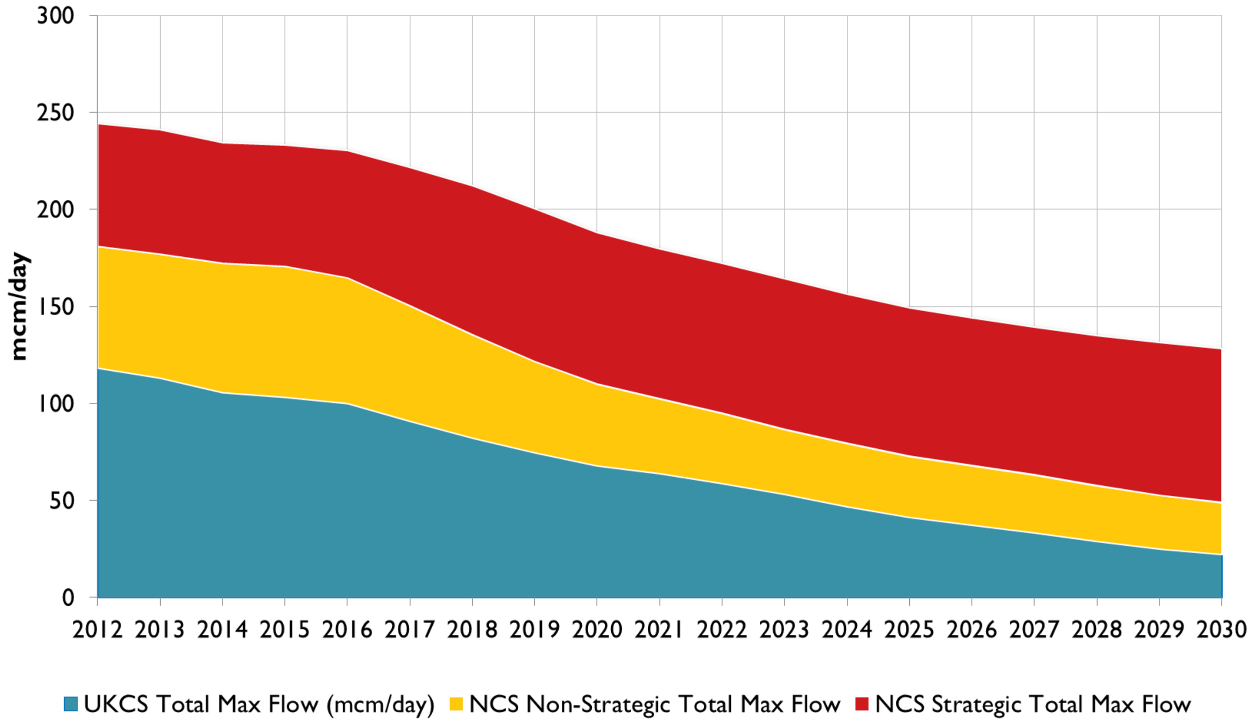
[13] Note that this does not include any projections on shale gas development in the UK, which would represent an upside risk to the projections of UKCS output.

NCS output is modelled as separate strategic and non-strategic components. Output from the non-strategic component is assumed to be based on long-term contractual arrangements and hence it does not vary with changes in the spot market price of gas in the GB market. Output from the strategic component is assumed to go to the market where the price of gas is highest and hence behaves in the same manner as IUK imports.

The modelling methodology for the non-strategic part of NCS supply is exactly as for UKCS above. Predicted annual capacity and flow data is taken from TYS2011 on the basis of the Gone Green scenario. The proportion of non-strategic NCS supply is set at the ratio of forecast NCS imports into GB (Figure 3.3A of TYS 2011) and total NCS peak capacity (Figure 3.3C of TYS 2011).

The maximum daily flow from UKCS and the strategic and non-strategic parts of NCS is shown in Figure 3.

Figure 3 Maximum daily flow from UKCS and NCS



Variability in gas supply and outages

Variability in UKCS and NCS supply is calibrated to historic data spanning ten years, as described in Section 3. Seasonal variation in UKCS and non-strategic NCS is modelled as a proportion of total output. Hence seasonal variation in the output of these supply sources declined in proportion with the decline in annual production.

Supply outages on all gas supply sources are also modelled as a sudden component. The parameters for sudden supply shocks consist of:

- Expected frequency of occurrence in a given year - modelled using a Poisson distribution;
- Mean and standard deviation of outage duration based on a lognormal distribution; and

- Mean and standard deviation of the magnitude of the shock, as a multiplicative factor applied to full capacity and based on a lognormal distribution[14].

It is assumed that outages are twice as likely to happen in the coldest 6 months of the year than in the warmest 6 months. This assumption applies to all sudden shocks in our modelling. Outages on different supply sources are assumed to be independent of each other. Detailed assumptions on supply outages are given in Table 2 below.

Table 2 Infrastructure outage parameters[15]

Stochastic Supply Outages								
Supply source	Average frequency (in a 6 month period)		Duration		Magnitude (proportion of capacity available after shock)			
	Summer	Winter (effective annual frequency)	Mean (days)	Standard Deviation	Mean	Standard Deviation	Min	Max
UKCS	0.03	0.07	10	2	0.80	0.20	0	1
NCS	0.03	0.07	10	2	0.60	0.20	0	1
BBL Prior to 2016	0.12	0.25	6	20	0.55	0.30	0	1
LNG	0.12	0.25	6	20	0.70	0.30	0	1
IUK Prior to 2016	0.12	0.25	6	20	0.55	0.30	0	1
BBL & IUK From 2016	0.25	0.49	6	20	0.78	0.30	0	1
LRS (Counterfactual)	0.30	0.60	10	2	0.50	0.30	0	1
SRS (Counterfactual)	0.30	0.60	10	2	0.80	0.20	0	1
LRS (Revised Base Case)	0.15	0.30	10	2	0.50	0.30	0	1
SRS (Revised Base Case)	0.30	0.60	10	2	0.80	0.20	0	1

Storage outages are modelled as a multiplicative shock[16] to the maximum rate of injection and withdrawal for long and short range storage separately. Since several SRS facilities are modelled as a single block, the average impact of an outage reflects the proportion of overall SRS capacity that the average SRS facility represents. This is also the case for parameters that relate to LNG supply outages. The average impact of an outage reflects the proportion of overall LNG import capacity that the average LNG terminal represents.

The average LRS outage frequency modelled for the options and the Counterfactual, to which the options are compared, was 0.3 and 0.6 for summer and winter respectively, as shown in the table above. This was identified during a QA review as being high. We note that this QA review also identified that the same error was present in the modelling for the Gas SCR Impact Assessment and that the Redpoint Gas SCR Modelling report incorrectly reported the actual assumptions on LRS and SRS outage frequency as 0.15 and 0.3 for summer and winter respectively, although we consider the actual SRS outage frequency parameters used in the modelling, 0.3 and 0.6 for summer and winter respectively, to be within reasonable bounds.

[14] Multiplicative shock representation implies that a shock of 0.3 makes 70% of capacity unavailable (ie 30% would be available).

[15] Note that for the average frequency in 6 winter months, 0.5 indicates 1 outage expected in every 2 winter 6 month periods.

[16] The impact of the shock takes the form of multiplying the maximum rate of injection and withdrawal by a number between zero and one, thus reducing the ability of the storage facility to refill or sell gas into the system for the duration of the shock.

In order to assess the impact of a change in the LRS outage frequency assumption to a more realistic level, the Counterfactual is also modelled using a lower LRS outage frequency. In this document, we refer to this revised Counterfactual scenario as the Revised Base Case. A comparison of the results can be seen in Section 6.2. On the basis of these results, our considered opinion is that this difference in assumptions does not alter the conclusions drawn from the results and the modelling results for the options are compared against the Counterfactual on the basis of the same storage outage frequency assumptions.

For LRS in particular, we note that the Rough storage facility was completely unavailable for several months[17] in 2006 as a result of a fire, but this is the only major outage incident on that facility that we are aware of. We also note that one data point is not sufficient to define a probability distribution. Although the average outage probability for LRS in our revised assumptions is higher than what has been observed historically, the corresponding mean magnitude and duration are significantly lower. This is because our assumptions represent all potential events that can affect the ability of LRS to inject gas into storage or deliver gas into the GB gas network, including problems with the gas field, rig, pipeline infrastructure (on-shore and off-shore) and problems at the Easington terminal, including all associated equipment.

For UKCS and NCS, the average frequency of sudden shocks is less than one in ten years since the continuous variation in output from these supply sources, before sudden shocks are applied, is calibrated to a ten year historic data set. For these supply sources, sudden outages represent rare events that are not present in the historic data set used for the calibration.

From 2016, BBL is assumed to acquire reverse flow capability and is assumed to trade in the same way as IUK. We merge BBL capacity into IUK capacity in our model from this date and adjust IUK interruption parameters accordingly, with higher probability of outages and lower average impact of outages to reflect the fact that the combined entity represents two separate interconnectors.

Continental price shocks

To reflect the possibility of supply and/or demand shocks in the Continental European gas market, a stochastic price shock is introduced to imports and exports over IUK as well as the ‘strategic’ part of NCS supply which is not covered by contractual arrangements.

Frequency of such shocks is modelled as a Poisson distribution with average frequency of shocks (in a year) set at 0.08 in the warmest six months of a given year and 0.16 in the coldest six months. Shock duration is modelled as a lognormal distribution with mean of 10 and standard deviation of 2. Shock magnitude is modelled as a multiplicative factor to the pre-shock price level with a lognormal distribution truncated at 1 and 10. The mean shock magnitude is 2 and its standard deviation is 1.

Gas quality issues

Gas quality issues are assumed to impact flows over IUK only. The gas flowing to GB is made up to the GB quality standard in Belgium by mixing gas sourced from Russia with gas from other sources (e.g. Norway) and there is no specific treatment facility in place at the moment. Although Fluxys[18] have put forward a proposal for such a treatment facility, it is not certain at this stage that construction of this facility will go ahead.

[17] Declaration of Force Majeure was published on 16 Feb 2006 and withdrawn on 20 Nov 2006. The facility was completely unavailable for over three months during this time. Source: Howard Rogers, “The impact of import dependency and wind generation on UK gas demand and security of supply.” August 2011.

[18] Independent operator of the natural gas transmission system in Belgium.

Without a treatment facility in place, any supply shock to Russian gas increases the probability that flows over IUK do not meet the GB gas quality standards. This risk is likely to increase over time as the average specification of gas coming from Norway is set to increase.

Since supply shocks relating to Russian gas are built into the continental price shocks functionality, capacity reductions relating to gas quality issues are assumed to be correlated with positive price shocks to the continental gas price. The relevant linear correlation coefficient is assumed to be 0.5.

Frequency of such shocks is modelled as a Poisson distribution with average frequency of shocks in a given year set at 0.07 in the coldest six months of the year and 0.03 in the warmest six months of the year. Shock duration is modelled as a lognormal distribution with mean of 10 and standard deviation of 2. Shock magnitude is modelled as a multiplicative factor to the pre-shock IUK maximum import capacity with a lognormal distribution truncated at 0 and 1. The mean shock magnitude is 0.3 and its standard deviation is 0.2.

Storage

Gas storage parameters are derived from information provided to Redpoint by Ofgem and National Grid. For modelling purposes, storage facilities are amalgamated into two tranches, long range and short range. We classify Rough as long range and all remaining storage facilities that are currently in operation as short range. We do not distinguish between short and medium range storage for the purposes of our modelling.

Detailed storage parameters used to inform our modelling are given in Table 3. These were taken from Ofgem's Pivotality model[19].

Table 3 Model storage parameters

Storage Type	Start Year	Capacity (GWh)	Max Injection Rate (GWh/day)	Max Withdrawal Rate (GWh/day)
Long Range	2012	36,800	238	455
Short Range		16,528	1307	1346
Long Range	After 2012	36,800	238	455
Short Range		18,028	1482	1521

Interconnectors

The IUK annual maximum import and export flows are assumed to be 25.5bcm and 20.0bcm respectively. The continental price in the model is represented as the German Average Import Price (GAIP). This is deterministic and based on a calibrated relationship with the crude oil price[20].

[19] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=181&refer=Markets/WhlMkts/CompandEff

[20] Note that we model a disconnection in the relationship between the continental gas price and the oil price in periods of low LNG prices. This is as a result of calibrating model price outputs to historic data.

Generally, when the spot price in GB is greater than the Continental gas price, gas will flow into GB. As that price difference increases, imports into GB increase until either maximum import capacity is reached or the price difference has been eliminated.

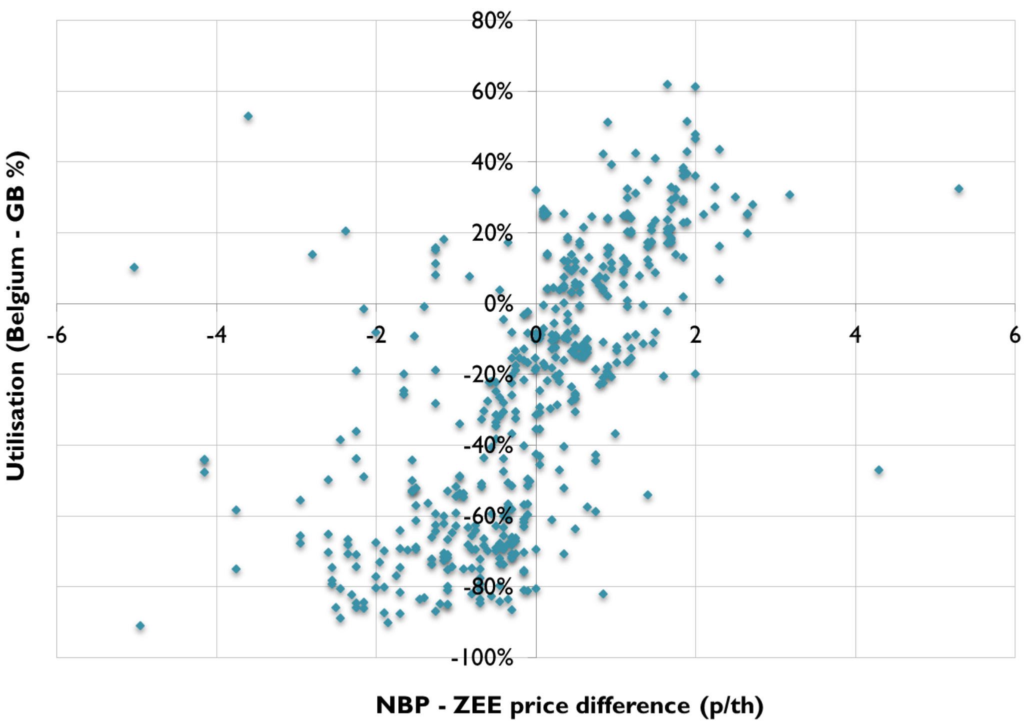
The annual maximum flow on the Balgzand Bacton Line (BBL) is 20bcm on a capacity basis. No reverse flow is assumed to be possible on BBL until 2016, from which point the export capacity of BBL is set equal to its import capacity. From that point we assume that BBL will behave in the same way as IUK[21].

No new interconnection capacity is assumed to be built within the model horizon.

We model the supply elasticity of both IUK and BBL on the basis of historic data on price differences and flows. The supply curve line of best fit parameters are derived from the properties of the data. The data set covered the period from 1 Oct 2009 to 31 Jan 2012. Note that since we do not model the TTF and ZEE market prices explicitly but rather have a single continental price, interconnector supply curves are formulated with respect to the difference between the model GB price and the model Continental price.

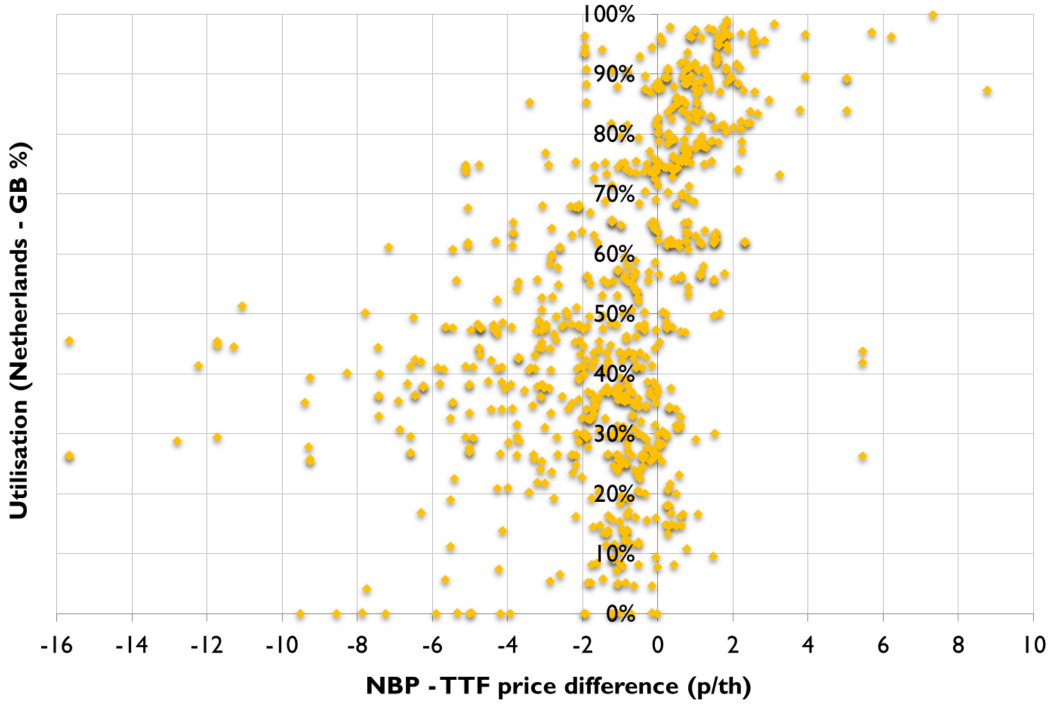
The scatter plots for the historic relationship between price differentials and utilisation for IUK and BBL respectively are given below.

Figure 4 IUK utilisation



[21] Note that BBL currently has a 'virtual' reverse flow capability, meaning that it can vary its import utilisation into GB between 0% and 100%.

Figure 5 BBL utilisation



IUK: Proposed line of best fit is $y = 0.375x - 0.25$, where y is % utilisation with respect to imports into GB and x is the GB-Continent price difference.

BBL: Proposed line of best fit is $y = 0.2x + 0.6$, where y is % utilisation with respect to imports into GB and x is the GB-Continent price difference.

To reflect the apparent differences in the relationship between interconnector flows and price differentials between different periods, the slope of the supply curve varies stochastically around the line of best fit. In both cases, the supply curve pivots around the y intercept, -0.25 for IUK and 0.60 for BBL. The pivoting motion is driven by the outcome of a single random variable in each case. In our supply curve representation, it feeds into the price difference required to achieve a given level of utilisation of the interconnector. The effect of the random variable on a given price difference on the supply curve increases in proportion to its distance from the origin.

We use the lognormal distribution for the random variable and apply the variable multiplicatively to the price differences in the supply curve. This ensures proportionality of the effect of the variable to the distance from the origin. The choice of distribution naturally constrains that variable to values that are consistent with the model's optimisation routine.

Let the lognormally distributed random variable be denoted by L. The formula for the supply curve is then given by $y = a + bx/L$. The mean of the distribution of L is set at 1. The standard deviation of the distribution is set at 0.3 for IUK and 1 for BBL, producing the following two distributions for the random variables applied to IUK and BBL supply curves respectively.

Figure 6 IUK supply curve variability

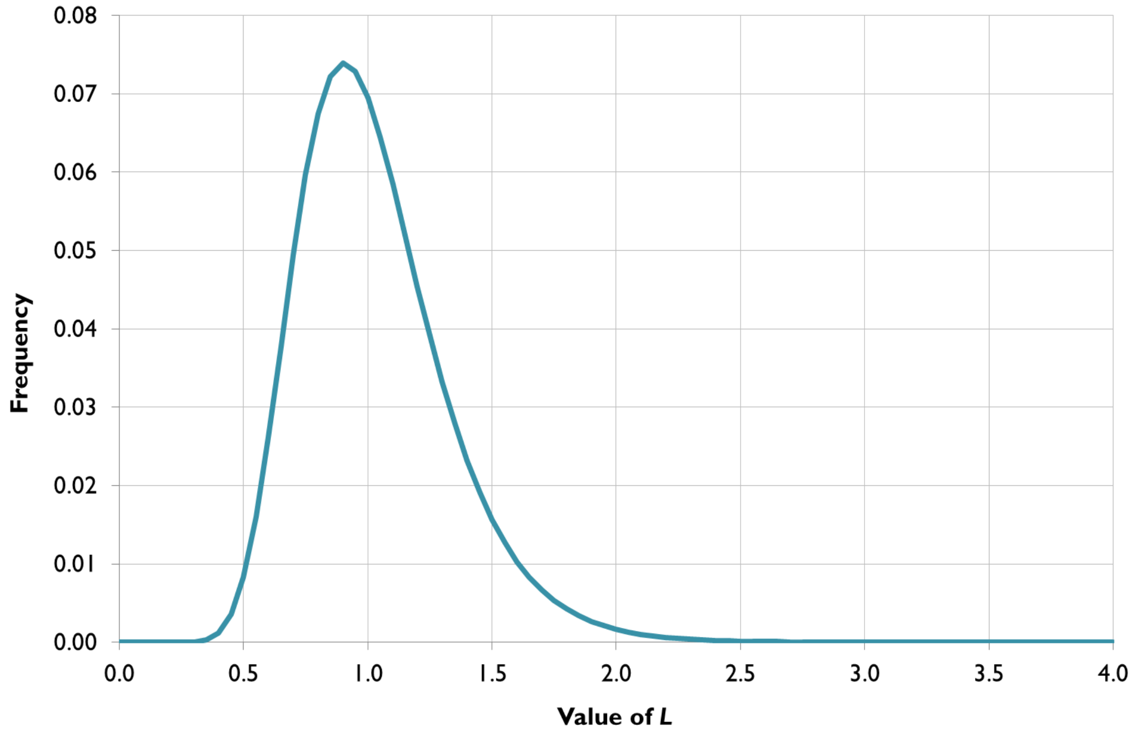
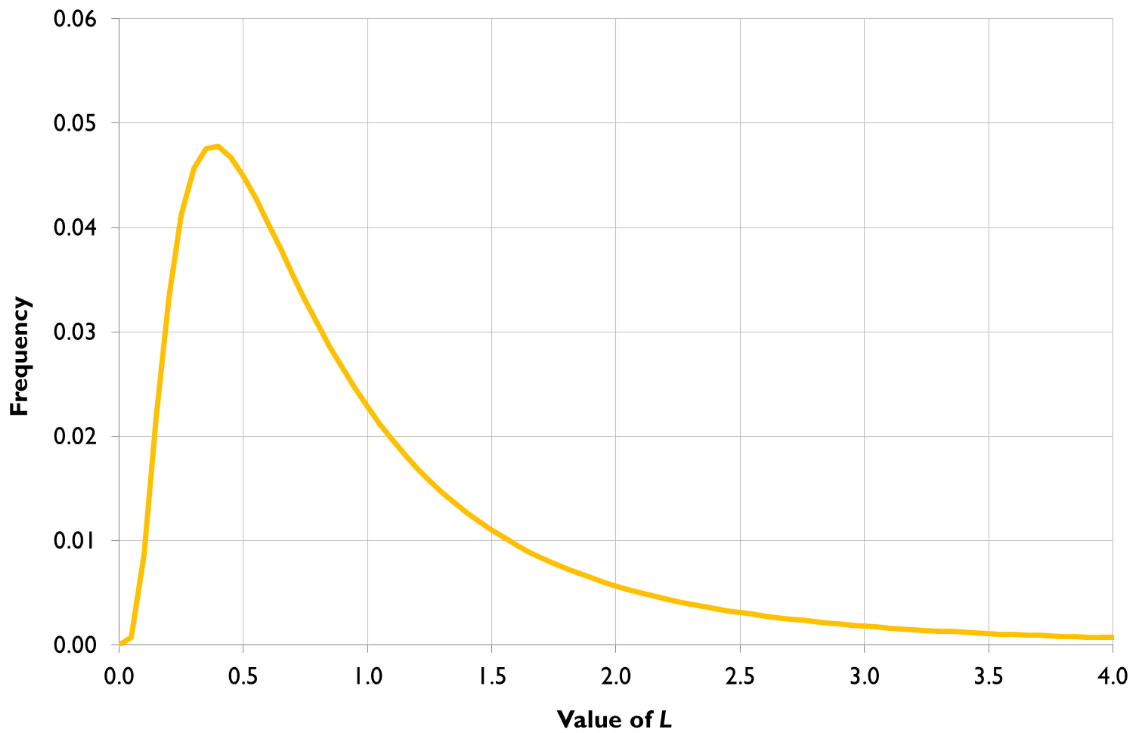


Figure 7 BBL supply curve variability



LNG

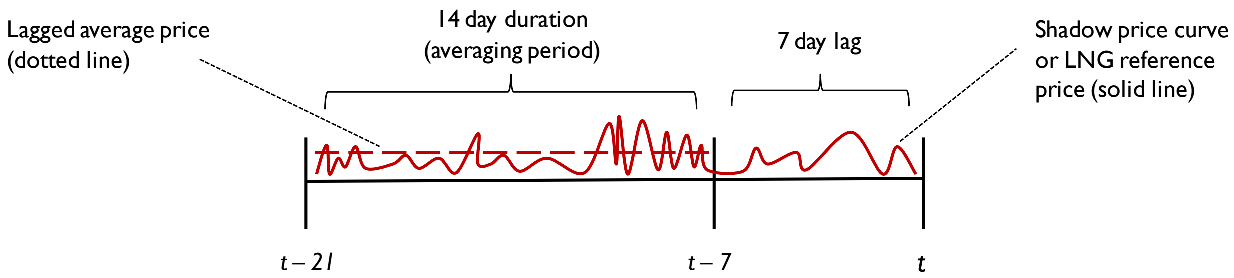
LNG maximum annual flow, i.e. the maximum amount of gas that can be sent out from all LNG terminals in a year, is assumed to be 51.5 bcm between 2011 and 2017 and 57.5bcm thereafter. The base 2011 assumption is taken from National Grid's Ten Year Statement, with an additional 6 bcm facility assumed to come online in 2017. This equates to the construction of either a Dragon 2 or Port Meridian sized terminal. Both of these projects have planning granted but no FID has been taken.

Historically, European LNG prices have been driven by the crude oil price much of the time, reflecting the prices paid for LNG by East Asian countries who lack indigenous gas resources. More recently, a rapid increase in shale gas production in the USA has changed the supply-demand balance by reducing US net gas imports and pushed LNG prices into relatively closer alignment with the Henry Hub price at some periods.

In our modelling, the LNG price can vary between the Henry Hub price and an oil-linked Japanese Crude Cocktail (JCC) price between different simulations to reflect the uncertainty about future drivers of the LNG price. The mix between the two price indices in each simulation is determined by a uniformly distributed random variable.

The LNG lag component of the model reflects the fact that LNG shippers are normally not able to make a decision to bring spot cargoes to the UK market 'on the day', given the time required to re-route ships and coordinate terminal logistics. Rather, they will make a decision in advance based on prices observed in the GB market over a prior period of days or weeks.

To reflect this in the model, we calculate a lagged average of the LNG price for the purposes of determining LNG supply. This is shown in the diagram below.



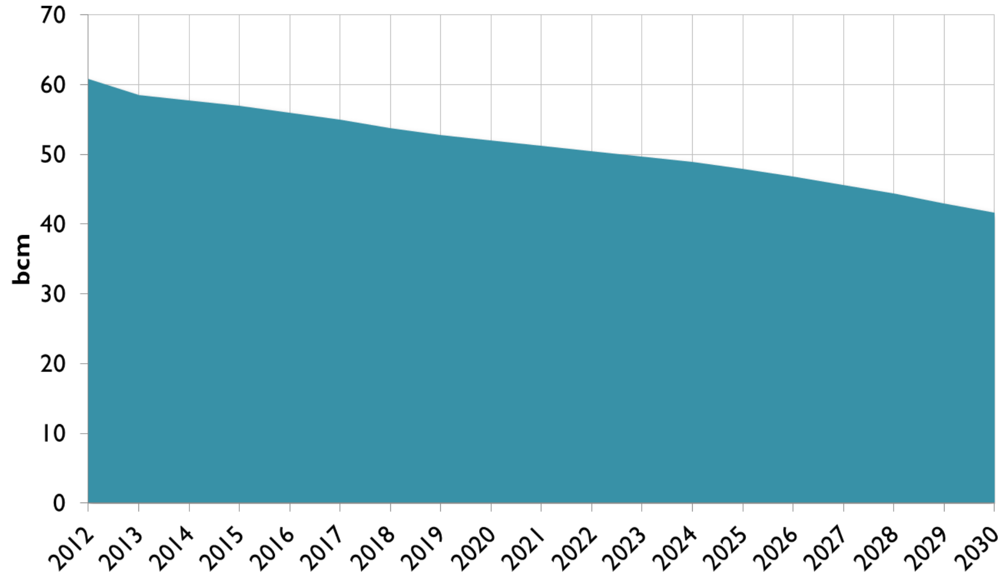
The amount of LNG gas available to flow into GB at time *t* is determined by the difference between the 14 day average system gas price, lagged by 7 days, and the LNG reference price, determined by a mixture of the Henry Hub price and the JCC price depending on the scenario and year modelled. The greater the difference, the greater is the available LNG supply subject to the overall capacity limit. This means that there is a minimum lag of 7 days between a spike in the GB gas price and additional LNG supply becoming available to flow into GB.

Once a decision is made to bring cargoes to the UK, the amount of LNG that is available to flow is determined. The actual flow of LNG is determined by the spot price after arrival at time *t*. This means that if a short but large price spike results in an unusually high LNG availability later, this cannot result in a surplus of supply over demand.

Gas demand

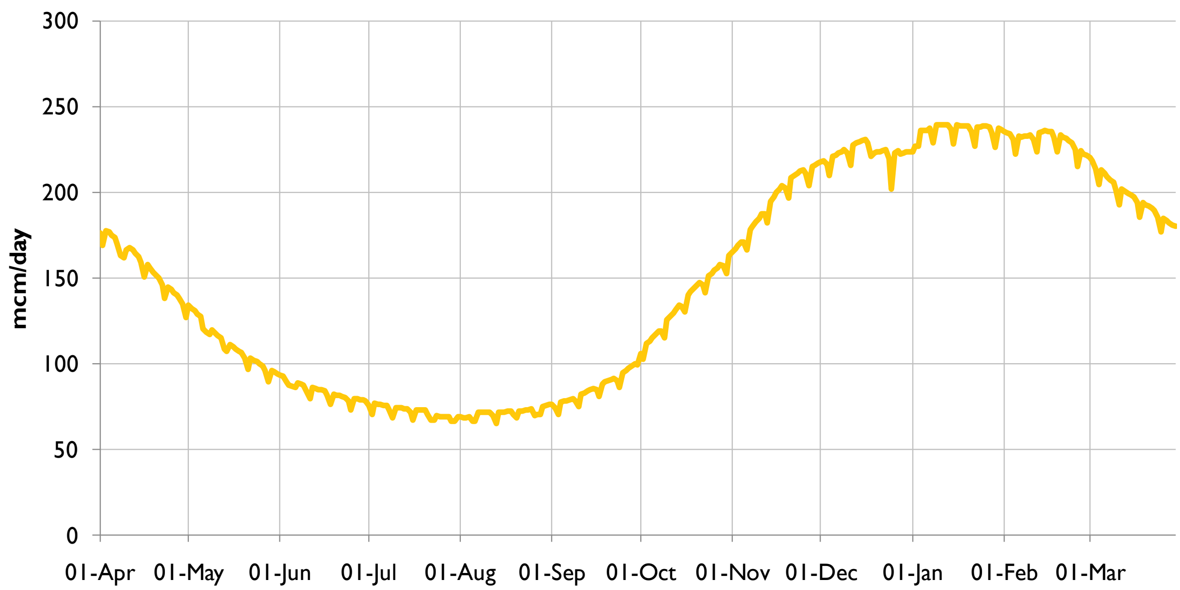
Total National Transmission System (NTS) non-power generation (NPG) gas demand is taken from the 2011 Gone Green scenario provided to us by National Grid. This includes net exports to Ireland. Total annual NTS NPG gas demand by year is given in Figure 8.

Figure 8 Total annual NTS NPG gas demand



The seasonal normal shape of demand based on 2011 annual demand is shown in Figure 9.

Figure 9 Expected demand shape

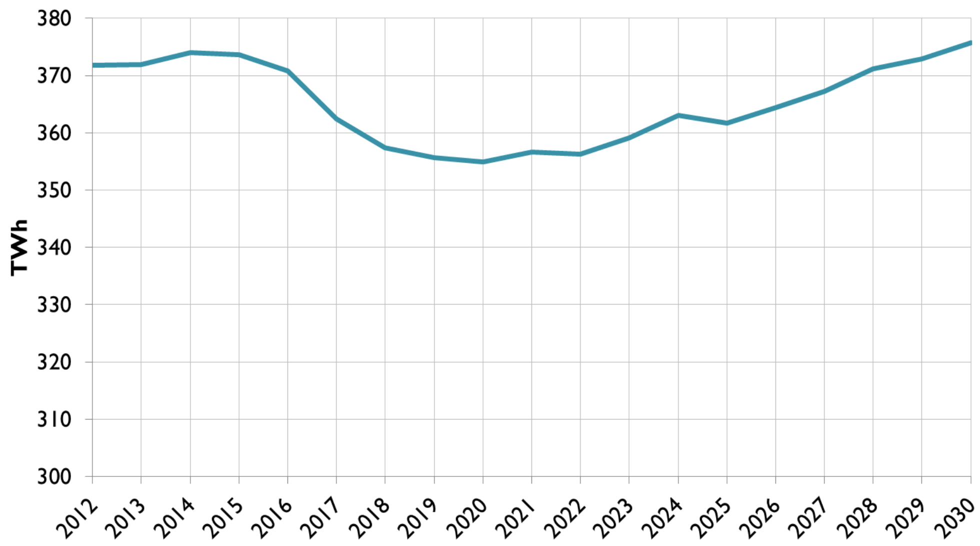


Electricity demand

Total annual demand for electricity is taken from Ofgem's November 2011 internal analysis. It is plotted in Figure 4 below. Overall demand for 2010 is taken from National Grid's 2010 Ten Year Statement. Demand is then assumed to grow in line with economic output as well as increasing electrification of heat and transport. Energy efficiency polices are also taken into account.

Short term economic output forecasts are based on HM Treasury's comparisons of independent forecast document[22], with trend growth taken from the March 2011 OBR Economic and Fiscal Outlook[23] (energy intensity of growth is taken from Ofgem's Project Discovery). Assumptions on electrification of heat and transport are taken from Redpoint analysis based on pathway 3 of DECC's pathways analysis[24]. Energy efficiency forecasts are taken from Ofgem analysis of pathway 3 of DECC's pathways analysis.

Figure 10 Total annual electricity demand



Daily electricity demand in the model is subject to stochastic variation. This is modelled on the same basis as commodity price volatility using a mean reverting random process. The mean reversion rate is 50 and volatility is 0.01 for both peak and off-peak demand. The minimum distance from mean is 0 for peak demand and 0.9 for off-peak demand. The maximum distance from mean is 10 for peak demand and 1.1 for off-peak demand.

Electricity generation

The model has a simplified representation of the GB electricity system and the amount of gas required for electricity generation is determined endogenously in the model. The generation mix in the model consists of nuclear, wind, CCGT and coal. The latter two technologies are split into two tranches by efficiency.

Assumptions for the generation capacity mix are taken from Ofgem's internal analysis, based on Project Discovery and updated with information from National Grid and industry. Because Ofgem analysis contains

[22] Available online: http://hm-treasury.gov.uk/d/201111forcomp.pdf

[23] Available online: http://budgetresponsibility.independent.gov.uk/economic-and-fiscal-outlook-march-2011/

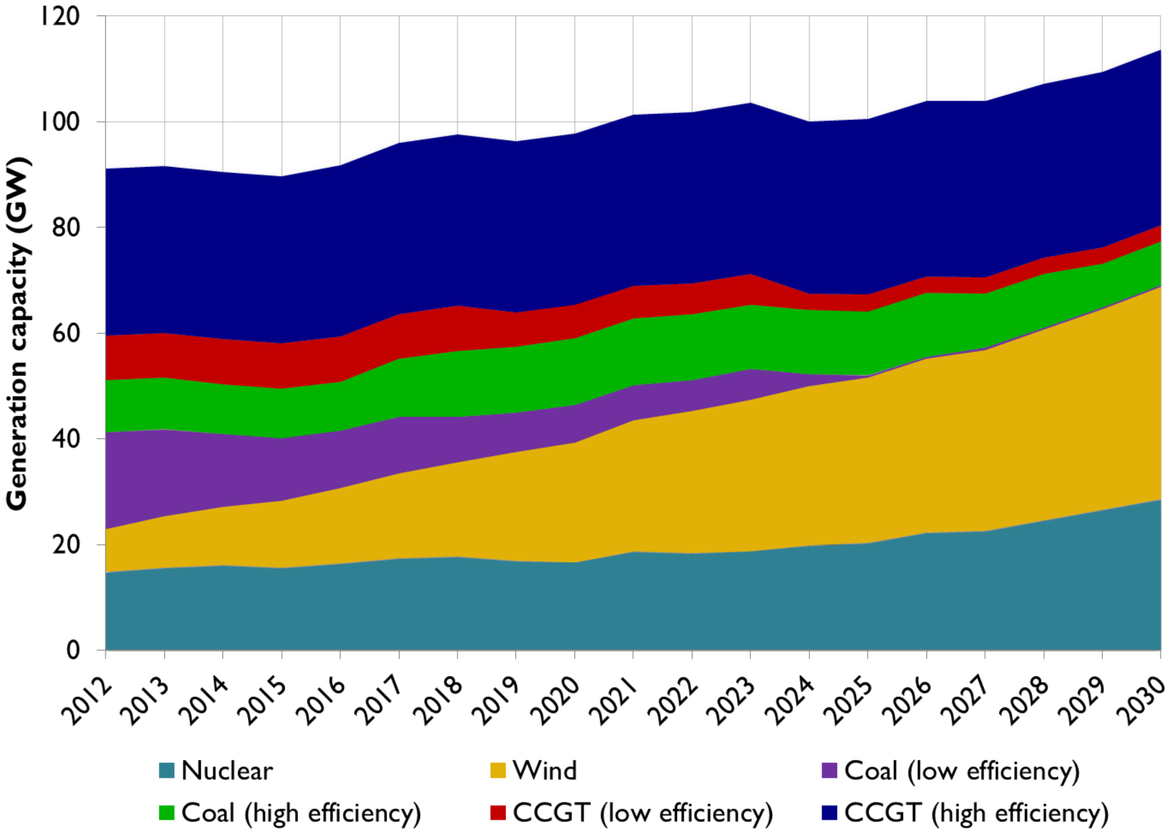
[24] Available online: http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

a fuller representation of the generation stack, a number of assumptions are made in order to translate that representation into our model. These are as follows:

- Carbon Capture and Storage (CCS) coal is incorporated into high efficiency coal;
- Combined Heat and Power (CHP) is incorporated into low efficiency CCGT;
- Oil, Advanced Gas Turbine (AGT), pumped storage and Open Cycle Gas Turbine (OCGT) modelled as a single category of peaking plant;
- Non-intermittent renewables are incorporated into nuclear.

Table 4 shows the generation capacity mix as represented in our model.

Table 4 Model generation capacity mix



LCPD/IED[25] plant in the model are assumed to be constrained with respect to their total annual output. The instantaneous flexibility of these plant is modelled as a tranche of DSR priced above the peaking plant tranche. Hence in the course of unusually high electricity demand or, more likely, shortage of generation from CCGTs, LCPD/IED plant are allowed to operate up to their expected technical availability. Under these circumstances, interconnectors are also assumed to be importing power into GB up to their full capacity.

[25]The Large Combustion Plant Directive (LCPD) is currently applied to the power sector to limit SOx, NOx and particulate emissions. This affects the coal and oil fleet in GB. The Industrial Emissions Directive (IED) recasts seven existing Directives, including the Large Combustion Plant Directive and the Integrated Pollution Prevention and Control (IPPC) Directive, with tighter limits in particular for NOx emissions, coming into force in 2016.

Stochastic wind output is generated by simulating a daily average load factor. Wind speeds are modelled using a Weibull distribution. To convert this into a load factor, the distribution is transformed using a turbine 'power curve'. This produces a 'U-shaped' distribution.

Given the daily granularity of our model, it is solved with respect to peak and off-peak periods for each day separately to reflect the difference between the levels of peak and off-peak electricity demand.

Demand side response and firm demand interruption

DSR and interruption are represented jointly in the model through the definition of supply sources priced at the VoLL of each corresponding tranche of demand. Whether the interruption of each tranche is commercial demand-side response or involuntary interruption varies with the Option being modelled. The tranches for gas demand used in the model, in increasing order of VoLL, are as follows:

1. Firm DM tranche 1 (318 p/th VoLL – 12.1 mcm/day in 2012)
2. Firm DM tranche 2 (668 p/th VoLL – 14.9 mcm/day in 2012)
3. Firm DM tranche 3 (1661 p/th VoLL – 9.6 mcm/day in 2012)
4. Non-Daily Metered (NDM) customers (2000 p/th VoLL – 113.3 mcm/day in 2012)

The three tranches of Firm DM demand are derived by amalgamating several categories from the London Economics (LE) VoLL study[26] according to similar VoLLs for those categories. The VoLL for each corresponding tranche is derived by taking an average VoLL of their constituent categories weighted by their respective gas demand in 2007 as given in the LE study.

NDM demand is combination of domestic and Small and Medium-sized Enterprise (SME) demand. These categories are amalgamated as it is likely to be impossible to distinguish between them for the purposes of cutting off tranches of demand. This tranche is priced at the domestic gas customer VoLL as estimated by Ofgem based on figures provided by LE.

Note that the three firm DM tranches do not include CCGTs. Since our model solves the electricity and gas markets simultaneously, we represent CCGT interruptions through interruptions of electricity customers supplied by CCGTs. These are set out below.

For electricity demand, the tranches are taken from Project Discovery. They are as follows, listed in increasing order of VoLL:

1. Interruptible I&Cs (£150/MWh VoLL – 53 GWh/week day)
2. Firm I&Cs (£4,000/MWh VoLL – 240 GWh/week day)
3. Domestic& SME (£5,000/MWh VoLL – 1,235 GWh/week day)

The corresponding VoLLs for each of these tranches are likewise taken from the Project Discovery[27][28].

[26] London Economics was commissioned by Ofgem to conduct a study of Values of Lost Load for different types of GB gas consumer in support of Ofgem's Gas Significant Code Review consultation.

[27] Note that Project Discovery treats domestic and SME electricity demand tranches separately. However, for the purposes of our modelling, we merged SME demand into domestic demand as it would be difficult to load shed domestic and SME electricity customers separately.

[28] See http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Discovery/Documents1/Discovery_Scenarios_ConDoc_FINAL.pdf

When gas supply is scarce, the model will seek out all opportunities for commercial self-interruption and fuel switching away from gas generation before interrupting firm gas demand. As a general rule, firm electricity demand supplied by CCGT generation is interrupted before any firm gas demand regardless of the relative VoLLs of electricity and gas customers. This is in line with NGG's likely emergency procedures. Apart from this rule, different tranches of demand are interrupted in the order of increasing VoLL. Any NDM demand that is interrupted remains off for the subsequent 14 days.

One possibility for commercial self-interruption is switching to distillate. Data compiled by Ofgem (by means of updating the Project Discovery analysis) suggests that total CCGT capacity with distillate backup in GB falls from around 5.5 GW to around 4.7 GW between 2011 and 2025. Further, the NG Winter Outlook report 2011/2012 states that the total amount of distillate available in GB is around 100 mcm in gas equivalent terms. Using assumptions on CCGT efficiency and the split between peak and off-peak hours from our model, 100 mcm of distillate translates into 8.8 days of peak output in 2011.

Given that CCGTs are interrupted before firm DM gas demand and 8.8 days is longer than any firm DM gas demand interruption observed under the Counterfactual assumptions, distillate backup forms a tranche of demand side response for peak electricity demand in the model, priced above the level of peaking plant. The instantaneous quantity of demand side response available changes in line with total capacity of plant with distillate backup.

Order of interruption

Under the Counterfactual in which the SCR reforms are assumed to be in place, tranches 1 and 2 of DM gas demand are assumed to be interruptible. It is assumed that, under the terms of the interruptible contracts, interruption takes place when the market price of gas exceeds the interruption price.

Although the gap between the VoLLs of the newly interruptible gas demand tranches and £20/th is relatively large, the interruption price is assumed to be competed down to the VoLLs of the two tranches of demand. This is due to the fact that at an interruption price higher than VoLL, customers would benefit from being interrupted first and would thus have a strong financial incentive to offer a lower interruption price.

Firm load shedding is deemed to set in when firm interruptions occur. At this point, the cash-out price rises to £20/th. In case of a deficit of gas to supply total demand, the general order of events is as follows.

Voluntary interruption and fuel switching

1. Electricity fuel switching from gas to coal and oil
2. LCPD/IED plant run to full technical availability
3. Fuel switching to distillate
4. DSR for Interruptible I&C electricity exercised (if supplied by CCGT generation)
5. DSR for Interruptible DM tranche 1 gas exercised
6. DSR for Interruptible DM tranche 2 gas exercised

Involuntary interruption

7. Interruption of CCGTs supplying Firm I&C electricity customers
8. Interruption of CCGTs supplying Domestic & SME electricity

9. Interruption of firm DM tranche 3 gas
10. Interruption of Non-Daily Metered (NDM) gas

5 Further measures options modelling assumptions

5.1 Introduction

For each intervention option, there are clearly a wide range of variants with respect to the exact design and means of implementation. Appendix 4 to the Gas Security of Supply Report 'Descriptions of Further Measures' sets out indicative designs for each of the options being considered. For the purposes of modelling, we have developed specific designs for each of the options. The majority of these designs are consistent with the designs set out in the appendix. However, in a number of cases, further assumptions have been made in order to model the option. We describe below the specific assumptions made for this purpose. These designs and the analysis of each option are intended to be indicative at this stage.

5.2 DSR tender

This is assumed to take the form of an annual auction, where demand that becomes interruptible receives an upfront payment at the start of the year and an option exercise payment if it is interrupted.

The total volume of DSR under this option is consistent with the total volume of DSR under cash-out reform in the modelling done for the Gas SCR Draft Impact Assessment. A DSR tender could support the incentives introduced under the SCR reforms by helping to ensure that the potential for interruptible demand envisaged under the SCR is delivered.

In terms of modelling assumptions, this means that that the two lowest VoLL tranches of DM gas demand in the model are interruptible under the DSR tender. This assumption is an approximate representation of a situation where every customer in all three tranches of DM gas demand would consider becoming interruptible for a certain proportion of its total gas demand[29].

For each of the two tranches of DM gas demand that become interruptible, the option exercise price is assumed to be 75% of the average VoLL for that tranche[30]. If a given tranche is interrupted in the model, the system gas price at this point is determined by the corresponding option exercise price, this being the marginal system cost of gas at that point.

Modelling runs under the above pricing assumptions are used to derive the option payment for each interruptible tranche of DM demand. This is done under the principle that a given customer within each tranche is indifferent between signing the interruptible contract and remaining firm, assuming that this customer is risk neutral, is a price taker, and the other customers in the two interruptible tranches of demand have signed up to be interruptible.

The welfare of that customer in the case where it becomes interruptible is determined by the upfront payment (a variable determined by the indifference condition set out above) and the difference between its VoLL and the exercise price times the probability of being interrupted as calculated from the model under

[29] It is likely that a DSR tender would encourage self-selection for lowest VoLL among DM gas customers.

[30] The actual discount of the exercise price to VoLL is uncertain, with 75% being an assumption made for modelling purposes. The reduction in customer welfare due to the discount to VoLL would be offset by the upfront payments to customers. The upfront payments would enable customers to cover the costs of participation in the DSR tender.

the pricing assumptions described above. As we are assuming an annual auction, time value of money plays no part in this calculation.

The welfare of that customer in the case where it remains firm is determined by the probability of it being interrupted and the difference between its VoLL and the demand side response payment that it would receive upon being interrupted.

5.3 Financial reliability option

Reliability options are assumed to be implemented as purely financial contracts. The option seller is free to hedge the financial exposure under the option through investment in physical assets or by entering into other contracts. Total exposure under the option is determined by the total number of options sold and the difference between the option strike price and the actual spot price of gas in the market if the latter is higher.

Total volume of the options is determined exogenously on the basis of forecast 1-in-20 peak demand by all firm gas customers excluding CCGTs in National Grid's Gone Green scenario. The option strike price is likewise determined exogenously at 75% of VoLL of firm DM gas demand under cash-out reform[31]. The total exposure across all sellers of reliability options is calculated as

EXP = Max(0, (MP-EP)*PD);

where MP is market price, EP is option exercise price and PD is diversified 1-in-20 peak day demand. The response of sellers of the options to this new exposure is estimated on the basis that the only hedge available to them is physical storage. The hedge value of the additional physical storage is calculated given the probability weighted overall benefit in terms of payments under the options saved as a result of having that storage in place. This is given by

H = Max(0, (MP-IP)*W);

evaluated only for the periods in which the market price exceeds the option exercise price, where IP is the weighted average injection price and W is the daily withdrawal limit for the additional storage built as a hedge. (This reflects an assumption that the storage would be "reserved", and used only to cover the exposure associated with the reliability contract when prices rose above the strike price.)

5.4 Service obligation on the System Operator

This option is modelled as the provision of responsive physical supply with a high ratio of deliverability to total volume. While the option design does not prescribe that the System Operator's response to the obligation must be through storage, for the purposes of our modelling, we make the assumption that the System Operator's response to the exposure created by the obligation is to commission an additional storage facility. This facility operates outside of the market and does not affect the market price of gas. It is designed to cover all firm demand and is only activated in order to prevent firm demand interruption. If this supply source is on the margin, the system gas price is set to £20/th.

[31] While the exact option strike price can vary depending on a number of factors, in our modelling, it is set at a lower level than the VoLL of the first tranche of what is deemed to be protected demand under this option, in this case it is firm DM demand, in order to incentivise provisions that would reduce the likelihood of protected customers being interrupted.

In deriving the physical characteristics of this supply source, we used the same values as those calculated for strategic stocks (see Section 5.7 for details), but assumed that the volume of supply would only be sufficient to meet 7 continuous days of use. This suggests 0.15 bcm of volume for 22 mcm/day deliverability. In storage terms, this would imply a very high deliverability to space ratio, but the actual service obligation would allow for this to be met through other types of measures(eg additional LNG terminal tank space/send-out or through diversifying storage sites so that access to pockets of storage at a number of different sites may lead to higher deliverability and hence lower volume being required).

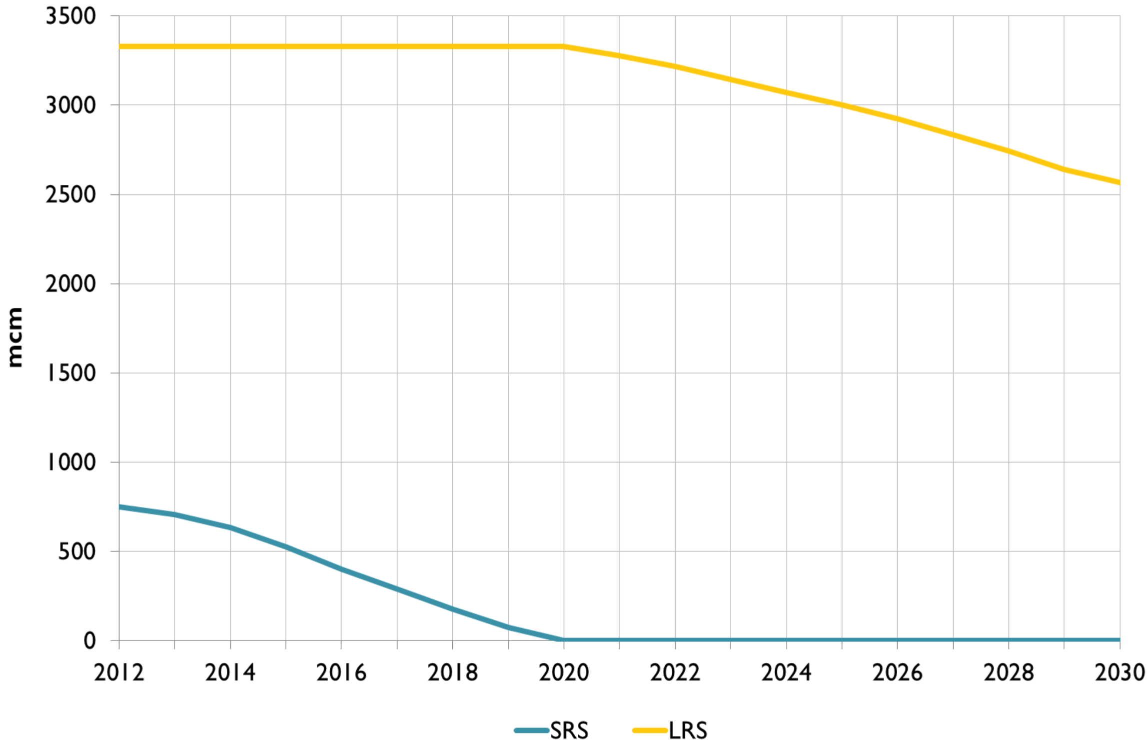
5.5 Storage obligation

In our modelling of this option, an obligation is placed on suppliers to book and fill a certain amount of storage capacity over the winter period when the risk to security of supply is at its greatest. Storage can only be released for the purposes of preventing network isolation (with NDM interruptions used as a proxy in the model). The amount of storage under the obligation is determined administratively.

In our modelling, the maximum level of the obligation for a given year, which is reached on 1 Dec, is derived by calculating the cumulative difference from 1 Dec to 1 Mar between the average expected demand and the 1-in-50 cold winter demand in Ofgem's internal analysis. This is to reflect a potential objective with this option of avoiding a systemic over-reliance by market participants at an aggregated level on using the short term markets to meet demand increases above seasonal normal levels if it is believed that such over-reliance may exist. The profile of the obligation through the winter from 1 Dec to 1 Mar is determined by the change in the cumulative difference as it reduces to zero by 1 Mar. Time scales for the start and end of the obligation are kept the same across all years modelled, with the only change being the size of the obligation in each year.

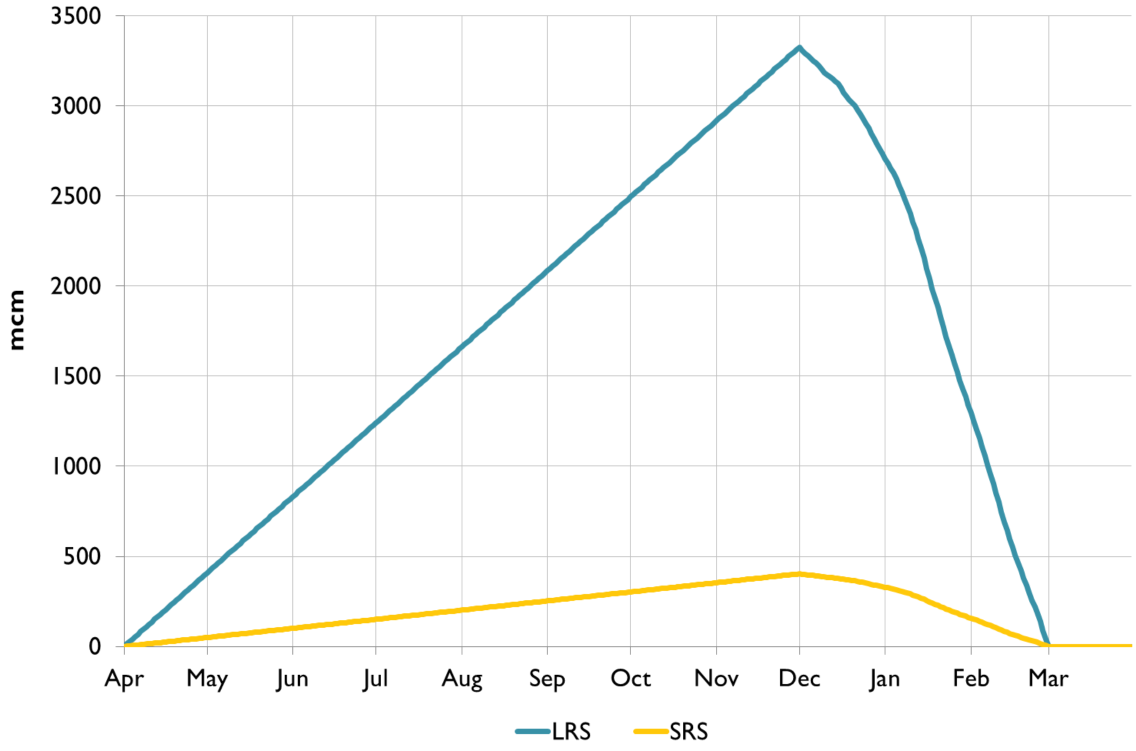
The maximum storage obligation level modelled for years between 2012 and 2030 is shown in Figure 11. The total level of the obligation falls between 2012 and 2030 as gas demand falls in this period.

Figure 11 Maximum storage obligation level in years 2012 to 2030



The profile of the storage obligation through the year is shown in Figure 12. Although the obligation only formally starts on 1 Dec of each year, we have determined a long ramp-up in the obligation in the run-up to 1 Dec to ensure that the model meets the obligation on that date.

Figure 12 2011 Storage obligation profile



Although the obligation is not specific to any particular type of storage, we assume that the cheapest way for it to be implemented is through existing LRS since the profile of the obligation is similar to the normal utilisation profile of LRS. However, in 2012, the capacity of existing LRS is not sufficient to meet the obligation in full and we assume that the rest of the obligation is met through SRS capacity. As the maximum level of the obligation falls over the years with falling demand, we assume that this is translated into a fall in SRS capacity covered by the obligation first. Subsequently, when SRS is no longer required to meet the obligation, further reductions in the level of the obligation lead to reductions in the volume of LRS covered by the obligation.

Since the normal pattern of SRS usage is relatively volatile, we assume that the storage obligation represents a significant restriction on the operation of SRS and thus reduces its economic value. We therefore conduct an illustrative calculation of how much new SRS capacity may be built to replace the value lost through having the storage obligation imposed on a proportion of SRS capacity. Firstly we assume that having SRS capacity covered by the obligation reduces its value by 50%[32]. We assume further that new SRS capacity can only come online from 2016 and that the economic life of new SRS capacity is 30 years. Given the remaining expected utilisation of SRS for the purposes of the obligation from 2016 onwards, and the assumptions stated above, we work out the amount of new SRS capacity that would be equivalent to the economic value of the restrictions on existing SRS capacity implied by the obligation. We take into account the fact that a future restriction has a lower value than a current restriction using a theoretical discount rate of 10%. The results of this calculation, which give the quantity of new SRS capacity built in response to the obligation, are given in Section 6.3.4.

[32] We base this assumption on the observation that the observed historic profile of SRS use has a strong seasonal component, as does the obligation, but that it is relatively volatile and hence an obligation would significantly restrict the operation of SRS on a day-to-day level.

The storage obligation is treated as a hard constraint in our model and can only be suspended to prevent, or reduce the severity of, NDM interruptions. Once suspended, all storage is available to flow freely on that day subject only to technical constraints on the rate of withdrawal and quantity of gas in storage. In subsequent days, the constraint of the amount of gas in storage is reset to the minimum of the baseline obligation level and the level of storage at the end of the last day in which the obligation was suspended.

Any residual storage capacity that remains after accounting for the capacity required to meet the obligation can be used for normal commercial purposes. Because gas stored under the obligation can only be used to prevent NDM interruptions, the model treats this gas as being effectively ring-fenced from normal trading operations.

5.6 Semi-regulated storage

Under this option, it is assumed that sufficient support is provided in order to deliver an additional LRS facility and hence we only model the impact of adding such a facility to the infrastructure mix. The modelled additional GB storage facility has capacity of 2 bcm, daily injection limit of 13 mcm and daily withdrawal limit of 25 mcm. It is assumed to be operational ahead of the 2020 spot year modelled and operates in the same way as the existing LRS capacity on the system.

The costs of the option in terms of the payments made under the theoretical cap and floor regime are calculated outside of the model. Details of the illustrative calculation used to calculate payments under the theoretical cap and floor regime are given in Section 6.3.5.

5.7 Strategic stocks

This option is modelled as the provision of an additional physical supply source that operates outside of the market and does not affect the market price of gas. It is designed to cover all firm gas demand and is only activated in order to prevent firm demand interruption. If this supply source is on the margin, the system gas price is set to £20/th.

In deriving the physical characteristics of this supply source, we considered the potential supply shortfall, relative to all firm demand, in an 'extreme' (1-in-50) winter with the terminal at Bacton[33] assumed to be out for the whole period. We took 2020 as the year of the assessment. The winter period is defined to be 1 Dec to 28 Feb for the purposes of the calculation.

Under certain scenarios taken from Ofgem's internal analysis, we see a supply shortfall of 1.6 bcm cumulatively across the winter, which occurs when gas-in-store runs out[34].There is no specific deliverability shortfall in this scenario, as if there is gas in store, there is sufficient deliverability to meet maximum demand. In light of this, we set the ratio of volume to deliverability to match the Rough ratio, which implies22 mcm/day.

In practice, our modelling produces no instances where the strategic stocks would be required for more than 7 days continuously, and hence the results are the same as for the SO Service obligation (described in Section 5.4), other than the cost of the facility.

[33] Note that this is consistent with DECC's N-1 security standard.

[34] In this analysis, we assume that all existing LRS and SRS capacity is full at the start of winter and no re-injection takes place in the course of winter.

6 Results

6.1 Introduction

The following sections set out the modelling results under the further measures options and the Counterfactual against which the options are compared. The results presented from this point onwards are averages over all the simulations and spot years for a given policy configuration. Since not all of the options were modelled for the same set of spot years, the basis for the averages will sometimes differ between different options. To ensure an appropriate basis for comparison, the Counterfactual results that are shown alongside the results for further measures modelled are based on an average for the same spot years.

6.2 Revised Base Case

This section describes the modelling results for the Counterfactual against which the results for further measures are compared. It assumes that cash-out reform under Gas SCR is in place. We note however, that at the time of writing, these reforms have not yet been introduced[35].

As noted in Section 4, the average LRS outage frequency modelled for the options and the Counterfactual was 0.3 and 0.6 for summer and winter respectively, which was identified during a QA review as being high. In the best view of Redpoint, a more realistic assumption would have been frequencies of 0.15 and 0.3 for summer and winter respectively. We note that this QA review also identified that the same error was present in the modelling for the Gas SCR Impact Assessment.

In order to assess the impact of the LRS outage frequency assumptions on the modelling results, the Counterfactual was re-modelled using LRS outage frequencies of 0.15 and 0.3 and a comparison of the results can be seen below (where Counterfactual is the original and the Revised Base Case is modelled using lower LRS outage assumptions). Our considered opinion is that this difference in assumptions does not significantly alter the modelling results or the conclusions drawn from the results. Hence the modelling results under the options are still compared against the original Counterfactual.

Table 5 gives the estimated average probabilities of at least one outage in a simulated year for four selected tranches of demand under the Counterfactual and the Revised Base Case.

[35] See http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx for details of Ofgem's proposed decision and supporting analysis.

Table 5 Average annual probability of at least one outage

	Counterfactual	Revised Base Case
Firm DM gas	1 in 128	1 in 140
NDM gas	1 in 167	1 in 162
Firm I&C electricity	1 in 75	1 in 74
Domestic & SME electricity	1 in 333	1 in 316

Table 6 shows the expected annual quantity of unserved demand for the same demand tranches. This gives a more accurate picture of the change in estimated security of supply as a result of the change in LRS outage assumptions since it captures all changes in unserved demand. This is not the case for probabilities of interruptions since only changes that are large enough to prevent all interruptions of a given type in at least one simulated year are captured.

Table 6 Unserved demand

Million therms/year	Counterfactual	Revised Base Case
Firm DM gas	0.026	0.024
NDM gas	0.618	0.623
Firm I&C electricity	0.027	0.024
Domestic & SME electricity	0.003	0.003

6.3 Further measures options

6.3.1 Demand side response tender

This option was modelled for spot years 2016, 2020 and 2030. In this option, the price at which tranches 1 and 2 of firm DM gas demand are interrupted is set at 75% of the VoLL of the corresponding tranche[36]. These tranches are interrupted when the market price of gas is higher than the interruption price.

Table 7 shows the probability of interruption for different demand tranches for the option and the Counterfactual and Table 8 shows the corresponding expected annual unserved demand. The averages are calculated for the DSR auction and Counterfactual result on the basis of the same spot years.

[36] This is 238 p/th and 501 p/th for tranches 1 and 2 respectively.

Table 7 Average annual probability of at least one outage

	DSR auction	Counterfactual
Firm DM gas	1 in 129	1 in 125
NDM gas	1 in 167	1 in 167
Firm I&C electricity	1 in 75	1 in 75
Domestic & SME electricity	1 in 400	1 in 300

Table 8 Unserved demand

Million therms/year	DSR auction	Counterfactual
Firm DM gas	0.025	0.026
NDM gas	0.619	0.582
Firm I&C electricity	0.027	0.026
Domestic & SME electricity	0.004	0.004

As expected, the results for this option are similar to the Counterfactual results since they make similar assumptions about interruptible contracts. The expected impact of NDM interruptions under the DSR tender option is higher than the equivalent figure for the Counterfactual. Since the interruption prices for interruptible DM gas demand tranches and thus the system prices when those tranches are interrupted are 25% lower in the DSR tender option than in the Counterfactual, on average, more gas would be expected to be attracted into GB under the Counterfactual with cash-out reform.

There is a difference in the probability of domestic and SME electricity outages between the Counterfactual and the DSR tender option. However, given the extremely low probability of such interruptions and the fact that no equivalent effect is seen in the impact of interruptions, we do not consider this difference to be statistically significant.

Table 6 shows the estimated DSR costs under the option. A detailed explanation of the methodology used to calculate these costs is given in Section 5.2.

Table 9 Estimated DSR costs (DSR auction)

Year	Demand tranche	Option fee (p/th)	Total annual option fees (£m)	Total annual interruption fees (£m)	Total annual DSR fees (£m)
2016	DM gas tranche 1	0.14	2.19	3.22	5.41
	DM gas tranche 2	0.06	1.27	1.29	2.56
	Total DM gas		3.46	4.51	7.97
2020	DM gas tranche 1	0.22	3.29	4.55	7.86
	DM gas tranche 2	0.06	1.15	0.94	2.09
	Total DM gas		4.44	5.49	9.95
2030	DM gas tranche 1	0.26	4.22	6.12	10.34
	DM gas tranche 2	0.09	1.82	1.76	3.58
	Total DM gas		6.04	7.88	13.92

6.3.2 Financial reliability option

Under this option, the sellers of the Reliability options are collectively liable for the difference between the option strike price, set at 1246 p/th[37], and the price of gas in the market on any given day. The number of options issued (in mcm terms) is 258 mcm in 2020 and 199 mcm in 2030[38]. This option is designed to protect all firm demand from interruptions, which guides the choice of the option strike price and the quantity of gas covered by the options.

We estimated a response in terms of volume of physical hedge in the form of new SRS capacity using the methodology described in Section 5.3. The estimated SRS investment in our sensitivity modelling is 121 mcm of capacity with associated deliverability of 10 mcm/day[39]. We have assumed that the gas in the new SRS facilities is only called upon when the system gas price rises above the option strike price.

Table 10 shows the probability of interruption for different demand tranches Table 11 shows the corresponding expected annual unserved demand. The averages are calculated for the Reliability options and Counterfactual result on the basis of the 2020 and 2030 spot years modelled.

[37] This represents 75% of the VoLL of the firm DM gas demand tranche.

[38] Total volume of gas under the options is determined exogenously on the basis of forecast 1-in-20 peak demand by all firm gas customers excluding CCGTs in National Grid's Gone Green scenario and firm DM gas demand tranches 1 and 2.

[39] The ratio of capacity to deliverability is based on average of corresponding ratios for all SRS facilities operational in the Counterfactual model by 2020.

Table 10 Average annual probability of at least one outage

	Reliability options	Counterfactual
Firm DM gas	1 in 188	1 in 103
NDM gas	1 in 273	1 in 150
Firm I&C electricity	1 in 125	1 in 88
Domestic & SME electricity	1 in 750	1 in 600

Table 11 Unserved demand

	Reliability options	Counterfactual
Firm DM gas	0.016	0.029
NDM gas	0.469	0.656
Firm I&C electricity	0.012	0.017
Domestic & SME electricity	0.000	0.001

Overall, the estimated reduction in the probability of interruption on all tranches of firm gas and electricity demand achieved under this option relative to the Counterfactual is significant but considerably smaller than in the Reliability options sensitivity. The greatest effect is on unserved firm DM gas demand. This is due to the fact that 10 mcm/day deliverability is not sufficient to deal with some of the larger interruptions, but can be expected to prevent more of the smaller interruptions.

The total annual expected pay-out[40] under the options, after taking into account the effect of the physical storage hedge on wholesale gas prices, is £8.6m in 2020 and 2030. The estimated cost of the hedge, including the investment cost of the SRS facilities and the associated cushion gas, is £115m[41]. The pay-out from the hedge is £1.3m in 2020 and £1.4m in 2030[42]. Note that the estimate of the optimal hedge is approximate and hence the cost of the hedge can be expected to differ from the pay-out from the hedge when estimated from our modelling results.

[40] This refers to payments from the sellers of these options to the buyers, triggered by instances when the gas price moves above the option exercise price.

[41] See Appendix A.1 for details of how this figure is calculated.

[42] Pay-out under the hedge is the arbitrage profit on the SRS capacity estimated to be built in response to the exposure created by the Reliability options. We assume that withdrawal from this storage takes place only when the options are exercised.

6.3.3 Service obligation on the system operator

The Service obligation option is modelled for the 2016, 2020 and 2030 spot years. Under this option, a supply source is made available outside of the market that only operates in order to prevent or mitigate firm demand interruption. It has a daily deliverability limit of 22 mcm/day. This reflects National Grid's actions as system operator to cover estimated gaps in provision. When it is called upon, the cash-out price is set at £20/th.

Table 12 shows the probability of interruption for different demand tranches and Table 13 shows the corresponding expected annual unserved demand.

Table 12 Average annual probability of at least one outage

	Service obligation	Counterfactual
Firm DM gas	1 in 409	1 in 125
NDM gas	1 in 409	1 in 167
Firm I&C electricity	1 in 180	1 in 75
Domestic & SME electricity	1 in 900	1 in 300

Table 13 Unserved demand

	Service obligation	Counterfactual
Firm DM gas	0.009	0.026
NDM gas	0.191	0.582
Firm I&C electricity	0.010	0.026
Domestic & SME electricity	0.001	0.004

The estimated reduction in the probability of interruption on all tranches of firm gas and electricity demand achieved as a result of the service obligation option is very significant. The estimated capex cost associated with the Service obligation is £200m[43].

6.3.4 Storage obligation

The Storage obligation option is modelled for the 2016, 2020 and 2030 spot years. The profile and rules of operation for the storage obligation are set out in Section 5.5. The volume of new SRS capacity that is estimated to be built in response to the storage obligation is 42 mcm. The associated deliverability of this

[43] See Appendix A.1 for details of how this is calculated.

new capacity is 3.5 mcm/day. The estimated total capex cost for the 3.5 mcm/day facility is £41m[44].Given the small estimated amount of extra SRS capacity to be developed, we assume that this would most likely take place through an extension to an existing facility or facilities.

Table 14 shows the probability of interruption for different demand tranches and Table 15 shows the corresponding expected annual unserved demand.

Table 14 Average annual probability of at least one outage

	Storage obligation	Counterfactual
Firm DM gas	1 in 167	1 in 125
NDM gas	1 in 281	1 in 167
Firm I&C electricity	1 in 92	1 in 75
Domestic & SME electricity	1 in 450	1 in 300

Table 15 Unserved demand

	Storage obligation	Counterfactual
Firm DM gas	0.017	0.026
NDM gas	0.208	0.582
Firm I&C electricity	0.017	0.026
Domestic & SME electricity	0.002	0.004

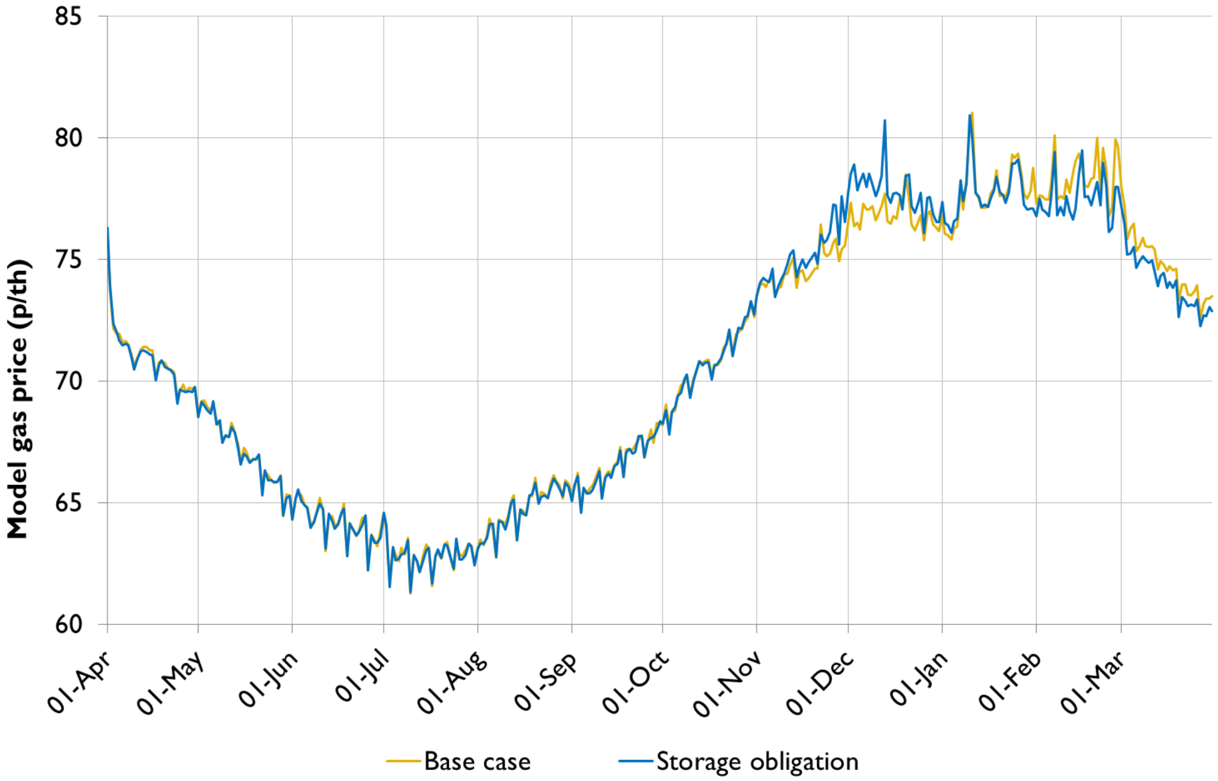
The effect of the Storage obligation option is to reduce significantly both the probability and impact of interruptions on all tranches of firm demand. The estimated average impact of NDM outages is more than halved under the storage obligation and reduced by less than one half for the other tranches of firm gas demand. The effect on the corresponding probabilities of interruptions is less dramatic but is the same directionally.

Since the storage obligation can only be violated to prevent an NDM interruption, the fact that it has the greatest effect on the impact and probability of NDM interruptions is to be expected. It also reduces the probability and impact of other types of firm gas demand interruptions. Figure 13 reveals the likely reason for the positive effect of the Storage obligation on firm DM interruptions seen in our modelling. Under the obligation, the average model gas price is higher at the start of winter and lower at the end of winter and beginning of spring than under the Counterfactual. This suggests that, under the obligation, gas is withheld from the market at the start of winter but more gas is released into the market at the end of winter. The

[44]See Appendix A.1 for details of how this is calculated.

latter effect prevents certain firm DM gas interruptions where otherwise, storage may have been depleted. However, in theory it is also possible that a storage obligation results in an increase in DM gas demand interruptions as the obligation is designed to hold back gas for the purposes of preventing NDM interruptions.

Figure 13 Average annual price profiles (2020)



6.3.5 Semi-regulated storage

This option was modelled for spot years 2020 and 2030. Under this option, an additional long-range gas storage facility is assumed to be operational in the spot years modelled, with total capacity of 2 bcm and withdrawal limit of 25 mcm/day. It is assumed to operate on exactly the same basis as the existing Rough long-range storage facility[45].

Table 16 shows the probability of interruption for different demand tranches and Table 17 shows the corresponding expected annual unserved demand. The averages are calculated for the Semi-regulated storage and Counterfactual result on the basis of the same spot years.

[45] See Section 3 for an explanation of how the behaviour of storage is represented in the model.

Table 16 Average annual probability of at least one outage

	Semi-regulated storage	Counterfactual
Firm DM gas	1 in 500	1 in 103
NDM gas	1 in 500	1 in 150
Firm I&C electricity	1 in 188	1 in 88
Domestic & SME electricity	1 in 3000	1 in 600

Table 17 Unserved demand

Million therms/year	Semi-regulated storage	Counterfactual
Firm DM gas	0.007	0.029
NDM gas	0.288	0.656
Firm I&C electricity	0.007	0.017
Domestic & SME electricity	0.000	0.001

In the Semi-regulated storage option, security of supply is improved considerably relative to the Counterfactual. Both the probability of interruptions and the impact of interruptions as measured by demand unserved are more than halved with the 2 bcm semi-regulated storage facility in place. Since the semi-regulated storage facility is assumed to operate within the market on the same basis as the existing Rough long-range storage facility, it is possible for it to be depleted at a time when an interruption occurs.

Since an LRS facility generally injects gas during the warmer months and releases gas during the colder months, a 2 bcm facility can be expected to affect the market price of gas in the periods in which it is active in the market. Figure 14 shows the average annual model price profiles for the Counterfactual and the Semi-regulated storage option for the 2020 spot year[46]. There is a reduction in the spread of winter to summer gas prices as a result of the additional 2 bcm long-range storage facility. The reduction in the summer to winter spread[47] is 1.4 p/th in 2020 and 1.6 p/th in 2030.

[46] The profile is calculated by taking an average of all 1,500 simulations for each day in the spot year shown.

[47] Summer is defined as the period from 1 Apr to 30 Sep and winter is defined as the remaining 6 month period.

Figure 14 Average annual price profiles (2020)

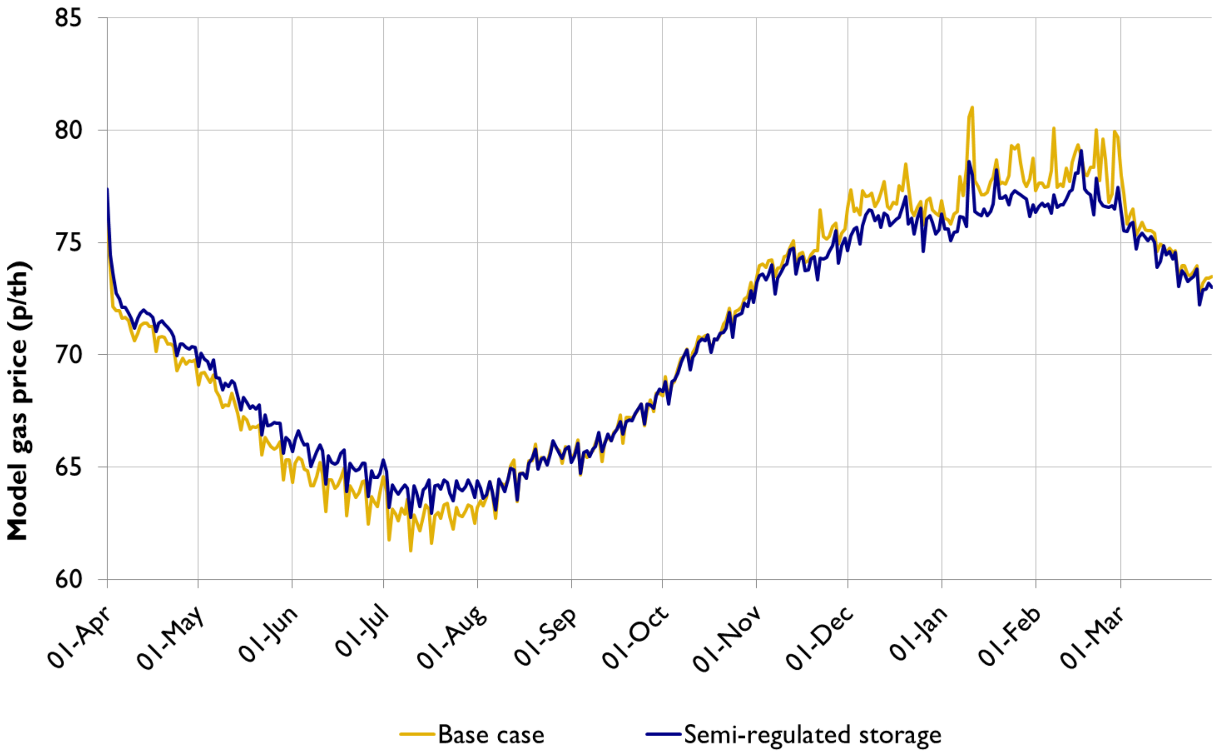


Table 18 shows the change in the total wholesale cost of gas[48] as a result of the additional 2 bcm storage facility evaluated over all simulations and for the simulations in which there are no interruptions. The reason for excluding simulations that contain interruptions is that under cash-out reform, when the cash-out price rises to £20/th, it is highly unlikely that all demand is paying this price since most supply will be contracted ahead of time. Hence, if an additional storage facility prevents a firm demand interruption and lowers the cash-out price from £20/th to a much lower level, it would likely not be the case that all demand is experiencing this reduction in the price that it is paying for gas.

Evaluation of the change in the total cost of gas as a result of the semi-regulated storage facility for simulations without interruptions may therefore yield a more realistic result than doing so for all simulations. However, there is a significant likelihood that a bias is introduced when certain simulations are excluded. Specifically, it is likely that simulated years that contain interruptions are also ones with more extreme demand and price dynamics and thus potentially more scope for price arbitrage for the semi-regulated storage facility. Hence evaluation on the basis of selected simulations may underestimate the effect of the additional storage facility of the total cost of gas.

[48] Total cost of gas for a given scenario is calculated as the product of the model daily gas price and the daily served demand for gas.

Table 18 Change in total cost of gas

£ million	2020	2030
All simulations	-77	-43
Simulations without interruptions	-21	5

In order to assess the cash flows under a cap and floor regime, we have estimated the arbitrage profits[49] for the 2 bcm semi-regulated long-range storage facility in our model. We note that as the model is designed at a market level, the operation of individual assets within the model are not optimised. This means that arbitrage profits are likely to be conservative[50]. The results are as follows.

Table 19 Annual arbitrage profit of semi-regulated storage facility

£ million	2020	2030
Annual profit	38	36

The semi-regulated storage facility operates under an illustrative cap and floor regime by which the capex cost of the facility and the cost of cushion gas are paid by the owners of the facility and its subsequent revenues are guaranteed to lie between the cap and the floor on an annual basis. If the market revenues of the facility fall below the cap, there is assumed to be a mechanism to "top up" to the floor, and, vice versa, if market revenues exceeded the cap, these would be recovered. The cap and floor regime is defined in terms of the annual revenues that are required to make a certain rate of return given a 4 year construction period, capex costs and an economic life of 25 years.

Given estimated total capex cost of £1,442[51], the estimated private real rate of return on the investment is -3.0%. In order for the investment to have an expected real rate of return of 8%, it would have to make an annual profit of approximately £152m flat over the economic life of the facility.

For a theoretical cap and floor regime, we have conducted an illustrative calculation on the basis of a 4% symmetrical band around 8% (a theoretical target rate of return) in real terms. In this arrangement, the floor would be set at 6% and the cap would be set at 10%. Assuming that returns are assessed on an annual basis and translating this into the annual profit that would be required to make those rates of return, 6% and 10% correspond to £123m and £184m respectively. Given the results for individual simulations in our model, revenues fall below the floor level in 1394 of 1500 years simulated and rise above the cap in 50 of 1500 years simulated. The average annual support payments to the semi-regulated storage facility under this illustrative regime would be £90m.

We note that under this option, the possibility of unintended consequences with respect to the effect on other storage facilities is significant. While we consider it is unlikely that any existing storage facilities

[49] Defined as revenues minus variable injection and withdrawal costs. The sum of injection and withdrawal costs is assumed to be 2 p/th.

[50] Storage behaviour in the model is driven by behavioural rules which are calibrated to mimic observed behaviour of storage in the market. However, this means that storage behaviour is not optimised against prices in every simulation, and is hence likely to be less profitable than a storage unit that adapts its behaviour to prices optimally in real time.

[51] See Appendix A.1 for details of how this is calculated.

would close as a result of a new semi-regulated storage facility being put in place since their investment costs are sunk, there is a strong possibility that a large semi-regulated storage facility would crowd out new market-based storage investment.

6.3.6 Strategic stocks

For strategic storage, the security of supply metrics in terms of probability of demand interruption and unserved demand can be expected to be the same as for the Service obligation option as the daily deliverability of gas is the same in both cases in our modelling. However, strategic storage would entail a much higher cost since the total capacity of the storage facility under this option is much greater.

Under this option, the additional supply source modelled has a daily deliverability limit of 22 mcm/day. When it is called upon, the cash-out price is set at £20/th.

Table 12 shows the probability of interruption for different demand tranches and Table 13 shows the corresponding expected annual unserved demand.

Table 20 Average annual probability of at least one outage

	Service obligation	Counterfactual
Firm DM gas	1 in 409	1 in 125
NDM gas	1 in 409	1 in 167
Firm I&C electricity	1 in 180	1 in 75
Domestic & SME electricity	1 in 900	1 in 300

Table 21 Unserved demand

	Service obligation	Counterfactual
Firm DM gas	0.009	0.026
NDM gas	0.191	0.582
Firm I&C electricity	0.010	0.026
Domestic & SME electricity	0.001	0.004

The estimated reduction in the probability of interruption on all tranches of firm gas and electricity demand achieved as a result of the Strategic stocks option is very significant. The estimated capex cost associated with the Service obligation is £1,276m[52].

[52] See Appendix A.1 for details of how this is calculated.

6.4 Sensitivities

6.4.1 Infrastructure outages

This sensitivity on the Counterfactual represents a test of the way that changes in the probability, magnitude and duration of some of the underlying shocks that can cause a GDE feed through into the actual probability of a GDE occurring. It concentrates on supply shocks, doubling the mean duration, magnitude and probability of outages on all supply infrastructure in the model relative to the corresponding Counterfactual parameters.

Table 22 shows the average probability of outages on different tranches of demand. The probability of instances of unserved demand is generally higher than in the Counterfactual and is more than doubled when the probability, magnitude and duration of infrastructure outages are doubled.

Table 22 Probability of at least one outage in a given year (2020)

	Counterfactual	Infrastructure outages sensitivity
Firm DM gas	1 in 125	1 in 48
NDM gas	1 in 167	1 in 60
Firm I&C electricity	1 in 71	1 in 28
Domestic& SME electricity	1 in 300	1 in 125

Table 23 shows the corresponding expected unserved demand figures. The impact of interruptions is more than doubled in the sensitivity relative to the Counterfactual.

Table 23 Unserved demand (2020)

Million therms/year	Counterfactual	Infrastructure outages sensitivity
Firm DM gas	0.025	0.107
NDM gas	0.395	1.438
Firm I&C electricity	0.025	0.084
Domestic & SME electricity	0.001	0.005

6.4.2 LNG price

As described in Section 4, the Counterfactual assumption for the LNG price in our model is that it is driven by a mixture of the Henry Hub price and the oil linked JCC price to reflect the uncertainty about future drivers of the LNG price. The mix between the two price indices in each simulation is determined by a uniformly distributed random variable. The LNG price tends to be much higher when it is linked to the JCC price.

Figure 15 shows a plot of the total number of interruption days in each simulation against the value of the LNG price variable in each corresponding simulation. Interruption days are summed across all tranches of electricity and gas demand, hence interruption of two tranches of demand in a single day would represent two interruption days. When the LNG price variable is equal to 0, the LNG price is driven entirely by the Henry Hub price. When it is equal to 1, the LNG price is driven entirely by the JCC price.

Figure 15 LNG price and outage days

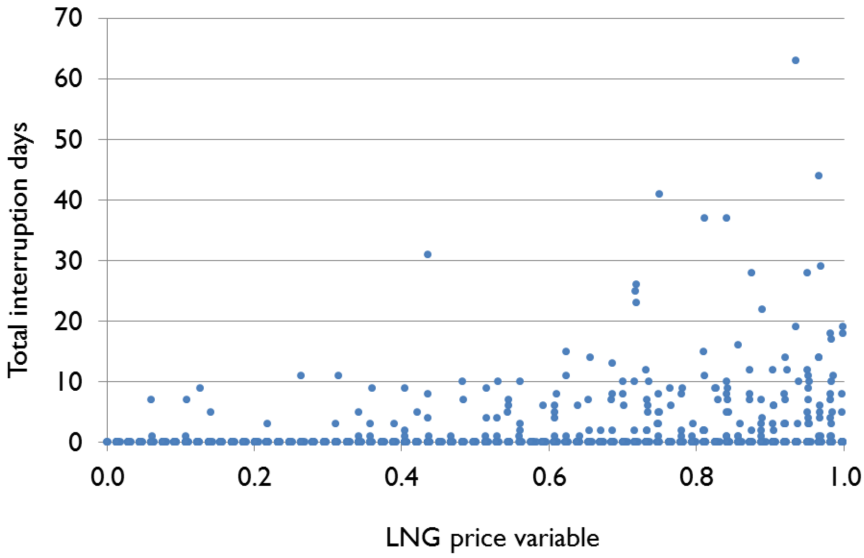


Figure 15[53] demonstrates that the risk to GB security of gas supply is generally higher when LNG price is high and driven by the JCC price[54]. The reason for this is that a low LNG price and thus high LNG imports into GB leave IUK and BBL to respond to shocks by bringing extra supplies into GB when necessary. When the LNG price is very low, GB tends to act as an LNG import hub, exporting surplus gas into the continent via the interconnectors, increasing the potential contribution of the interconnectors in averting demand interruptions. However, when the LNG price is high and LNG imports into GB are low, the GB system is more vulnerable to negative shocks since BBL and IUK are generally already bringing gas into GB at near full capacity and LNG supplies are not able to respond to a sudden shock quickly enough because of the time it takes to re-route LNG cargoes.

Under this sensitivity, the LNG price is permanently driven by the JCC price. Table 24 shows interruption probabilities. In the sensitivity, the probability of interruptions on all tranches of gas and electricity demand is higher than under Counterfactual assumptions.

[53] Data is based on simulations under Counterfactual assumptions for 2016.

[54] The linear correlation coefficient between the two variables plotted in Figure 15 is 0.23.

Table 24 Probability of at least one outage in a given year

	Counterfactual (2016)	LNG price sensitivity (2016)	Counterfactual (2020)	LNG price sensitivity (2020)
Firm DM gas	1 in 214	1 in 79	1 in 125	1 in 83
NDM gas	1 in 214	1 in 94	1 in 167	1 in 107
Firm I&C electricity	1 in 58	1 in 17	1 in 71	1 in 36
Domestic & SME electricity	1 in 150	1 in 48	1 in 300	1 in 188

Table 25 shows the expected unserved demand figures under the sensitivity. The impact of all types of interruptions is significantly higher in this sensitivity than in the Counterfactual for both of the spot years shown.

Table 25 Unserved demand

Million therms/year	Counterfactual (2016)	LNG price sensitivity (2016)	Counterfactual (2020)	LNG price sensitivity (2020)
Firm DM gas	0.020	0.056	0.025	0.046
NDM gas	0.436	1.172	0.395	0.792
Firm I&C electricity	0.044	0.123	0.025	0.047
Domestic & SME electricity	0.010	0.030	0.001	0.004

6.4.1 Reliability option sensitivity

Under this sensitivity, the sellers of the Reliability options are collectively liable for the difference between the option strike price, set at 238 p/th[55], and the price of gas in the market on any given day. The volume of options issued is 320 mcm in 2020 and 246 mcm in 2030[56]. This sensitivity represents a much higher security standard than the core Reliability option. Here, reliability options are set to cover all customers, including those DM gas customers that are assumed to be interruptible. We have estimated how such options might be hedged in the form of new SRS capacity using the methodology described in Section 5.3.

[55] This represents 75% of the VoLL of tranche 1 of interruptible DM gas demand.

[56] Total volume of gas under the options is determined exogenously on the basis of forecast 1-in-20 peak demand by all firm gas customers excluding CCGTs in National Grid's Gone Green scenario plus interruptible DM gas demand tranches 1 and 2.

The estimated SRS investment in our modelling is 531 mcm of capacity with associated deliverability of 44 mcm/day[57][58]. The estimated total capex cost for the 44 mcm/day facility is £509m[59]. We have assumed that the gas in the new SRS facilities is only called upon when the system gas price rises above the option strike price.

Table 26 shows the probability of interruption for different demand tranches and Table 27 shows the corresponding expected annual unserved demand. The averages are calculated for the Reliability option sensitivity and Counterfactual results on the basis of the 2020 and 2030 spot years modelled.

Table 26 Average annual probability of at least one outage

	Reliability options	Counterfactual
Firm DM gas	1 in 750	1 in 103
NDM gas	1 in 1500	1 in 150
Firm I&C electricity	1 in 429	1 in 88
Domestic & SME electricity	1 in 3000	1 in 600

Table 27 Unserved demand

	Reliability options	Counterfactual
Firm DM gas	0.003	0.029
NDM gas	0.010	0.656
Firm I&C electricity	0.002	0.017
Domestic & SME electricity	0.000	0.001

Overall, the estimated reduction in the probability of interruption on all tranches of firm gas and electricity demand achieved as a result of reliability options is large. This is due to the fact that the deliverability implied by the estimated optimal hedging response is relatively large at 44 mcm/day.

The total annual expected pay-out[60] under the options, after taking into account the effect of the physical storage hedge on wholesale gas prices, is £20m in 2020 and £49m in 2030. The cost of the hedge, including

[57] The ratio of capacity to deliverability is based on average of corresponding ratios for all SRS facilities operational in the Counterfactual model by 2020.

[58]Note that we estimate the hedge for the 2020 and 2030 spot years separately. We then put the greater of the two resulting amounts, which in this case corresponds to the 2020 estimate, into our model on the basis of the assumption that an investment in a physical hedge, once made, cannot be reduced in a future year.

[59] See Appendix A.1 for details of how this figure is calculated.

[60] This refers to payments from the sellers of these options to the buyers, triggered by instances when the gas price moves above the option exercise price.

the investment cost of the SRS facilities and the associated cushion gas, is £509m[61]. The pay-out from the hedge is £20m in 2020 and £38m in 2030[62].

6.4.2 Semi-regulated storage without demand side response

Like the Semi-regulated storage option with the assumption that DSR has emerged, this option was modelled for spot years 2020 and 2030 but only under cash-out reform. Under this sensitivity, tranches 1 and 2 of DM gas demand are assumed to remain firm under cash-out reform. The cash-out price rises to £20/th when tranche 1 of firm DM gas demand is interrupted. The order of interruption in a GDE is such that CCGTs are interrupted before tranche 1 of firm DM gas demand.

Table 28 shows the probability of interruption for different demand and Table 29 shows the corresponding expected annual unserved demand. The averages are calculated for the Semi-regulated storage options and Counterfactual result on the basis of the same spot years.

Table 28 Average annual probability of at least one outage

	Semi-regulated storage (No DSR sensitivity)	Semi-regulated storage	Counterfactual
Firm DM gas	1 in 120	1 in 500	1 in 103
NDM gas	1 in 500	1 in 500	1 in 150
Firm I&C electricity	1 in 94	1 in 188	1 in 88
Domestic & SME electricity	1 in 600	1 in 3000	1 in 600

Table 29 Unserved demand

Million therms/year	Semi-regulated storage (No DSR sensitivity)	Semi-regulated storage	Counterfactual
Firm DM gas	0.071	0.007	0.029
NDM gas	0.228	0.288	0.656
Firm I&C electricity	0.018	0.007	0.017
Domestic & SME electricity	0.001	0.000	0.001

[61] See Appendix A.1 for details of how this figure is calculated.

[62] Pay-out under the hedge is the arbitrage profit on the SRS capacity estimated to be built in response to the exposure created by the Reliability options. We assume that withdrawal from this storage takes place only when the options are exercised.

In the Semi-regulated storage option without DSR, security of supply is improved considerably relative to the Counterfactual for NDM gas customers only. Both the probability of interruptions and the impact of interruptions for that tranche as measured by demand unserved are more than halved with the 2 bcm semi-regulated storage facility in place. NDM gas unserved demand is reduced in the sensitivity relative to the core Semi-regulated storage option. This is as expected since, without DSR, the cash-out price under the sensitivity would rise to £20/th more often than under the core option, bringing more gas into GB on average.

Security of supply for firm DM gas and firm electricity customers is significantly worse under the sensitivity that under the core Semi-regulated storage option. This is because, under the sensitivity, the buffer of interruptible demand tranches is removed and hence firm DM gas demand and firm electricity demand supplied by CCGT are interrupted more often.

Overall, this sensitivity shows that the beneficial effects of modelled semi-regulated storage on security of gas supply are only preserved for NDM gas demand when the assumption on increase in interruptible contracts due to cash-out reform is removed. Hence it also shows the importance of DSR for security of supply of firm DM and firm electricity customers. Interruptible DM demand can provide a very significant buffer to protect firm DM gas and firm electricity customers from interruption.

6.4.3 Semi-regulated storage delivering 4 bcm storage facility

This sensitivity was modelled for spot years 2020 and 2030 under cash-out reform only. Here, an additional long-range gas storage facility is assumed to be operational in the spot years modelled, with total capacity of 4 bcm and withdrawal limit of 50 mcm/day. It is assumed to operate on exactly the same basis as the existing Rough long-range storage facility[63].

Table 30 shows the probability of interruption for different demand tranches under the 4 bcm semi-regulated storage sensitivity, the 2 bcm semi-regulated storage option and the Counterfactual. Table 31 shows the corresponding expected annual unserved demand. The averages are calculated on the basis of the same spot years.

Table 30 Average annual probability of at least one outage

	Semi-regulated storage sensitivity	Semi-regulated storage	Counterfactual
Firm DM gas	1 in 750	1 in 500	1 in 103
NDM gas	1 in 1000	1 in 500	1 in 150
Firm I&C electricity	1 in 600	1 in 188	1 in 88
Domestic & SME electricity	1 in 1500	1 in 3000	1 in 600

[63] See Section 3 for an explanation of how the behaviour of storage is represented in the model.

Table 31 Unserved demand

Million therms/year	Semi-regulated storage sensitivity	Semi-regulated storage	Counterfactual
Firm DM gas	0.003	0.007	0.029
NDM gas	0.029	0.288	0.656
Firm I&C electricity	0.003	0.007	0.017
Domestic & SME electricity	0.000	0.000	0.001

In the 4 bcm sensitivity, security of supply is improved considerably relative to the 2 bcm storage scenario. This applies to both the probability of interruptions and the impact of interruptions as measured by demand unserved. The expected levels of unserved demand for all firm demand tranches are reduced to relatively very small levels. Moreover, in terms of volume of interruption, the effect of the additional 2 bcm of storage capacity is only moderately weaker than the effect of the first 2 bcm of capacity.

Since a long-range storage facility generally injects gas during the warmer months and releases gas during the colder months, a 4 bcm facility can be expected to significantly affect the market price of gas in the periods in which it is active in the market. Figure 16shows the average annual model price profiles for the Counterfactual, the Semi-regulated storage option and the 4 bcm storage sensitivity for the 2020 spot year[64]. There is a visible reduction in the spread of winter to summer gas prices as a result of the additional 2 bcm long-range storage facility on top of the first 2 bcm semi-regulated storage facility. The reduction in the summer to winter spread[65]is 2.5p/th in 2020 and 2.9p/th in 2030.

Around the beginning of August, there is a visible artefact in prices caused by modelled semi-regulated storage finishing its seasonal injection cycle. This is a result of storage injection and withdrawal being driven by behavioural rules, described in Section 3, which are not based on an optimisation exercise and not re-calibrated in light of the extra storage capacity modelled in the sensitivity. Hence the revenues for the 4 bcm facility may be underestimated in our modelling.

[64] The profile is calculated by taking an average of all 1,500 simulations for each day in the spot year shown.

[65] Summer is defined as the period from 1 Apr to 30 Sep and winter is defined as the remaining 6 month period.

Figure 16 Average annual price profiles (2020)

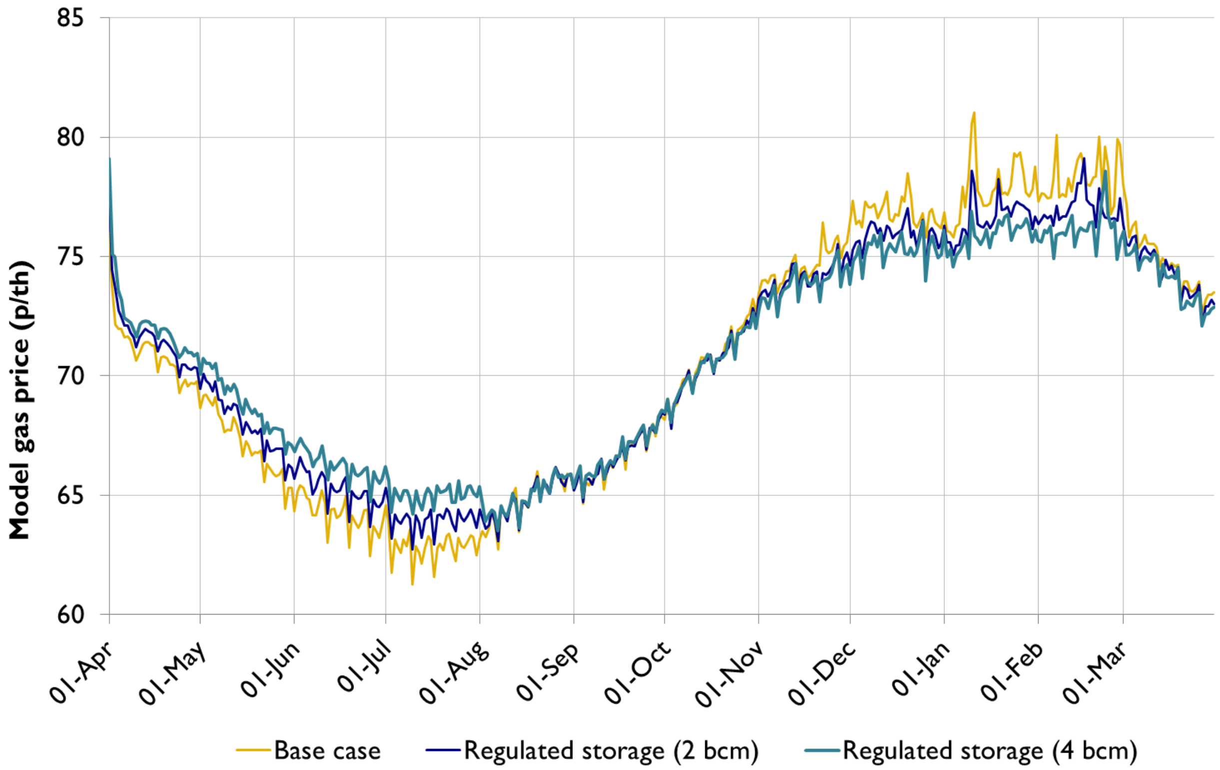


Table 32 shows the change in the total cost of gas[66] as a result of the additional 4 bcm storage facility evaluated over all simulations as well as simulations in which there are no interruptions.

Table 32 Change in total cost of gas

£ million	2020	2030
All simulations	-96	-46
Simulations without interruptions	-16	31

The estimated arbitrage profits for the4 bcm semi-regulated long-range storage facility in our model are as shown in Table 33. We again note that, as specific facilities are not optimised in the model these are likely to be conservative. These are only slightly higher than the estimated profits for a 2 bcm facility. The reason for this is that the larger storage facility has a greater effect on the seasonal price spread and this cannibalises its own revenues when it trades in the market. This effect is amplified by the variable costs of injection and withdrawal.

[66] Total cost of gas for a given scenario is calculated as the product of the model daily gas price and the daily served demand for gas.

Table 33 Annual arbitrage profit of semi-regulated storage facility

£ million	2020	2030
Cash-out reform	43	39

Given estimated total capex cost of £2,884m, a 4 year construction period and an economic life of 25 years, the estimated private real rate of return on the investment is -6.4% under cash-out reform. In order for the investment to have an expected real rate of return of 8% (a theoretical target rate of return) it would have to make an annual profit of approximately £304m on average over the economic life of the facility.

For a theoretical cap and floor regime, we have conducted an illustrative calculation on the basis of a 4% symmetrical band around 8% in real terms. In this arrangement, the floor would be set at 6% and the cap would be set at 10%. Assuming that returns are assessed on an annual basis and translating this into the annual profit that would be required to make those rates of return, 6% and 10% correspond to £246m and £369m respectively. Given the results for individual simulations in our model, under cash-out reform with 4 bcm semi-regulated storage, revenues fall below the floor level in 1428 of 1500 years simulated and rise above the cap in 31 of 1500 years simulated. The average annual support payments to the semi-regulated storage facility under this illustrative regime would be £210m under cash-out reform.

7 Conclusion

Results presented in this document do not represent a full cost benefit analysis of the options but only initial analysis based on indicative designs. In particular, costs and benefits are considered in a simplified form and impact of potential unintended consequences is not considered. A full CBA would need to be performed on any options considered in order for those options to be taken forward.

Although DSR tender option results do not show a significant difference in security of supply compared to the Counterfactual results, the DSR tender is intended as a measure which can provide additional certainty that the expected potential for DSR that has been identified will emerge (although at additional cost).

Reliability options are designed to create strong private financial incentives to maintain security of supply. A lower strike price increases the security of supply effect of the option but also increases the cost and the risk to the sellers of the options. Results for reliability options are wholly dependent on assumptions on the physical hedging response, which is highly uncertain because financial exposure under reliability options is very difficult to predict, as is the extent of risk aversion and the implied risk premium that may be demanded by the sellers of the options. Hence the benefits in terms of improved security of supply, and the associated cost, are highly uncertain.

The SO service obligation significantly reduces unserved demand in our model and operates outside of the market. It is designed to address the risk of relatively short supply shortfalls interruptions by requiring the SO to identify potential security of supply shortfalls and take actions to mitigate the likelihood of these shortfalls leading to a GDE . The implied security standard can be varied with option design, where a higher security standard would imply higher cost. The response of the System Operator to a Service obligation may not take the form of physical storage and would depend on the details of the design of the obligation.

Strategic storage also operates outside of the market and is designed to address the risk of prolonged supply shortfalls by requiring a central body to procure additional gas storage. This option does not show any additional security of supply benefit in the modelled results relative to the service obligation, but could, in theory, play an important role in the context of very broad-ranging or longer term events that are not seen in our model. The cost of this option would be significant given that it implies a high ratio of capacity to deliverability.

The storage obligation is designed to address over-reliance on spot markets as a source of gas in periods of high demand. As modelled, it brings significant security of supply benefits, particularly with respect to NDM demand at which it is targeted. The impact of the obligation on other demand tranches is less certain, although the obligation modelled in this study shows a benefit in terms of reduction in unserved demand for all firm demand tranches. The market response to the obligation in terms of new capacity investment, and hence also the cost of this option, are likewise uncertain. This is because the economic cost of storage obligation is difficult to evaluate as the value of the reduction of flexibility of storage implied by the obligation is highly uncertain.

The semi-regulated storage option is designed to address a potential market failure in the provision of seasonal storage capacity. It provides significant security of supply benefits under the modelling, but these could only be expected to materialise towards the end of this decade. It is uneconomic under our assumptions on the basis of private returns and would be likely to require significant support under any regulatory regime. Estimated reduction in cost of gas to consumers due to regulated storage is generally less than the estimated level of support required, but there is significant uncertainty around the costs and benefits of the option that have been identified.

A Modelling results

A.1 Gas storage costs - methodology

The principal costs associated with gas storage are the project cost and the cushion gas cost. The costs can vary significantly not only with regard to individual projects but also depending on whether the storage is LRS or SRS.

Project Cost of LRS and SRS

In order to calculate the cost of LRS and SRS, various new projects under construction in Europe were considered. The data on working gas volume, maximum withdrawal capacity and capital cost of these under construction projects was collected from various company websites and their annual reports, gas storage project websites, gas storage reports and other sources of secondary research. The ratio of deliverability to working gas volume as well as project cost per mcm was calculated for all the projects. Based on the calculation, a relationship between deliverability to working gas volume and capital cost was established separately for LRS and SRS. The relationship derived is as follows:

Table 34 Capital cost equations

Type of gas storage	Equation
SRS	$y = 6.1288x + 0.3365$
LRS	$y = 28.495x + 0.1587$

where,

y= capital cost of the gas storage in £m/mcm

x = deliverability (mcm/day) / working gas volume (mcm)

While analysing the project cost of various SRS projects under construction, it was observed that in a few projects, the project cost was higher or lower by up to 15-20% than that derived from the above mentioned equation. The similar variation in LRS projects was observed up to 10-12%. Unique factors such as the pre-existing geological conditions, differing technical standards, cycle time and compression of gas can lead to variation in project cost for individual LRS and SRS projects. Additional factors like salt depth, leaching and disposal of brine can further impact the project cost for SRS projects. This can ultimately impact the overall capital expenditure of the gas storage projects. Therefore, it is advisable to run a sensitivity analysis on the project cost while taking an investment decision for gas storage projects.

Cushion Gas Cost

The volume of cushion gas varies significantly for Depleted Gas Field and Salt Cavern Gas Storage, depending on the reservoir characteristics and the desired maximum and minimum pressures of the facility. Cushion gas forms a significant proportion of the upfront capital cost of LRS and SRS projects. Cushion gas cost as a proportion of upfront capital cost is higher for LRS than that of SRS projects. The typical ratio of cushion gas volume to working gas volume is 1:167 for LRS and 0.45:168 for SRS. For LRS, since a depleted gas field is used, typically 20% of the cushion gas is initially in place whereas it is zero for SRS.

[67]Source: Study on Natural Gas Storage in UK, October 2008 by Ramboll Oil and Gas

Total Capital expenditure of Gas Storage for Further measures options

The total capital expenditure of gas storage which includes the project cost and cushion gas cost for various further measures options has been derived using the equation mentioned above for project cost for both LRS and SRS and the cushion gas cost. The total capital expenditure for various further measures options is given in Table 35. Please note that the costs shown in this table are not directly comparable across different options since each option is designed to meet a different security standard.

Table 35 Storage capex costs

Further measures option	Type of Storage	Working Gas Volume (mcm)	Deliverability (mcm/day)	Gas Storage Capital Expenditure (£m/mcm)			Total Gas Storage Capex (£m)
				Project	Cushion Gas	Total	
Financial reliability options	SRS	121	10	0.84	0.11	0.95	115
Storage obligation	SRS	42	3.47	0.84	0.10	0.94	40
SO Service obligation	SRS	150	22	1.24	0.10	1.33	200
Semi-regulated storage	LRS	2,000	25	0.51	0.21	0.72	1,442
Strategic stocks	LRS	1,780	22	0.51	0.21	0.72	1,276
Financial reliability options sensitivity	SRS	531	44	0.84	0.11	0.96	509
Semi-regulated storage sensitivity	LRS	4,000	50	0.51	0.21	0.72	2,884

The cushion gas initially in place has been assumed 20% for LRS and none for SRS. The gas cost to be injected for cushion gas has been assumed based on commissioning year of the further measures option.

[68]Source: Study on Natural Gas Storage in UK, October 2008 by Ramboll Oil and Gas

Table 36 Cushion gas costs

Further measures option	Spot year by which storage would be commissioned	Cost of Cushion Gas (p/therm)
Financial reliability options	2020	68.2
Storage Obligation	2016	58.6
SO Service obligation	2016	58.6
Semi-regulated storage	2020	69.3
Strategic stocks	2020	69.3

Gas Storage Operating Cost

The operating cost of a storage facility varies significantly depending on the volume of the storage and depth of the storage. SRS have a wider variation in operating cost to that of LRS projects due to the increased technical requirements to operate such facilities at higher pressures, increased level of monitoring due to fragile geological conditions, high deliverability required and higher maintenance rates due to environmental concerns and corrosive quality of salt. The gas storage operating costs are assumed as follows69:

Table 37 Gas storage operating costs

Type of Gas Storage	Operating Cost (£ m/mcm)	Average Operating Cost (£ m/mcm)
LRS	0.01 – 0.02	0.015
SRS	0.01 – 0.06	0.035

[69] Source: Study on Natural Gas Storage in UK, October 2008 by Ramboll Oil and Gas

A.2 Revised Base Case

This section shows the annual modelling results for the two Counterfactual cases.

Table 38 Probability of at least one outage in a given year (Counterfactual)

	2012	2016	2020	2030
Firm DM gas	1 in 136	1 in 214	1 in 125	1 in 88
NDM gas	1 in 167	1 in 214	1 in 167	1 in 136
Firm I&C electricity	1 in 75	1 in 58	1 in 71	1 in 115
Domestic & SME electricity	1 in 500	1 in 150	1 in 300	Less than 1 in 1500

Table 39 Unserved demand(Counterfactual)

Million therms/year	2012	2016	2020	2030
Firm DM gas	0.026	0.020	0.025	0.033
NDM gas	0.723	0.436	0.395	0.916
Firm I&C electricity	0.028	0.044	0.025	0.010
Domestic & SME electricity	0.000	0.010	0.001	0.000

Table 40 Probability of at least one outage in a given year (Revised Base Case)

	2012	2016	2020	2030
Firm DM gas	1 in 136	1 in 214	1 in 150	1 in 100
NDM gas	1 in 150	1 in 214	1 in 188	1 in 125
Firm I&C electricity	1 in 71	1 in 52	1 in 88	1 in 107
Domestic & SME electricity	1 in 500	1 in 136	1 in 375	1 in 1500

Table 41 Unserved demand (Revised Base Case)

Million therms/year	2012	2016	2020	2030
Firm DM gas	0.024	0.019	0.024	0.028
NDM gas	0.751	0.352	0.471	0.919
Firm I&C electricity	0.024	0.044	0.021	0.009
Domestic & SME electricity	0.000	0.010	0.001	0.000