Winter Consultation Report 2007/8

Executive Summary

Introduction

1. This report represents the third stage of National Grid's consultation process on the outlook for the gas and electricity demand-supply balance for winter 2007/8. Recognising that our sources of data are necessarily incomplete, over recent years we, in conjunction with Ofgem, have conducted a consultation exercise designed both to help inform the industry and also to provide us with feedback to support the production of the Winter Consultation Report.
2. In March 2007 we published our Preliminary Report, which reviewed developments during winter 2006/7, and provided an initial view of winter 2007/8. Following feedback and gas supply developments, we revised our view in our Consultation Update Document published in June 2007.
3. We received 7 responses to the June document, which are summarised in Appendix I. There was general support for our assumptions, and there were no areas of major disagreement. Our Final View, detailed in this report, reflects specific points raised and further analysis since the publication of the June Update.
4. As we seek to further improve on our analysis and the consultation process, we would welcome feedback on our analysis and the proposed process for the consultation on the outlook for winter 2008/9.

Gas

5. For winter 2007/8, we expect the commencement of flows from LNG at Milford Haven and the Aldbrough storage facility. Storage space at Hole House Farm is also expected to increase. These increases in capacity more than offset the continued decline in supplies from the UK Continental Shelf (UKCS).
6. Whilst developments in importation infrastructure have led to a view of a less tight winter for 2007/8, the supply-demand outlook remains uncertain, especially in terms of how such capacity will be utilised. The range of potential supply availability is wide, reflecting not only the normal risks associated with major infrastructure projects, but also commercial uncertainties associated with competing markets on the Continent and globally in terms of LNG.
7. Our Final View reflects a higher view of imported gas supply, partially offset by lower supplies from storage. The forecast of gas supply, including storage, represented by our Final View is around 73 mcm/d higher than the September 2006 Base Case assumptions for 2006/7. This means that although the demand forecast is higher, the supply-demand balance has improved.

8. We have incorporated the Final View supply assumptions into our safety monitor calculations. The total non-storage supply assumption of 395 mcm/d used for calculating the safety monitors is 60 mcm/d higher than the equivalent figure used in setting the 2006/7 safety monitors and 20 mcm/d below the Final View supply assumption for this coming winter[1]. This results in lower monitor levels of just 1.2% of all storage, compared with the equivalent 16% level used in setting the 2006/7 monitors. There is no longer a Safety Monitor requirement for Medium or Short duration storage.

Gas Demand Side Response

9. With an improved gas demand-supply balance, the requirement for gas demand response is lower than the 2006/7 Base Case. Under the Final View assumptions, there is only a requirement for demand-side response, from both CCGT and non-CCGTs, in cold winters under low supply conditions.

Electricity

10. The outlook for the electricity market in 2007/8 appears less uncertain than that for the gas market, with the notified generation background broadly similar to that observed prior to the 2006/7 winter. Whilst January 2008 sees the implementation of the Large Combustion Plant Directive and the second phase of the Emissions Trading Scheme (ETS II), we do not believe these factors will significantly influence security of supply during winter 2007/8. Provided the electricity market continues to make plant available in response to the appropriate price signals, demand should be able to be met in full even under severe conditions.

11. Last winter the operation of the electricity market was characterised by gas-fired generation displacing coal-fired generation, and coal increasingly providing the marginal capacity. Consequently, gas demand from Combined Cycle Gas Turbine (CCGT) plant was well above the level implicit in our unrestricted demand forecasts. At current fuel and carbon prices for winter 2007/8, we expect coal-fired generation to be preferred to gas-fired generation, and this is reflected in our forecast of the CCGT gas burn, which is forecast to be around 54 mcm/d. This forecast is considerably lower than the outturn CCGT demand during Q1 2007, but is similar to our winter 2006/7 Base Case. While the gas market remains dependent upon imported supplies, the swing in gas consumption by CCGT stations continues to be key in achieving a balance between gas supply and demand.

Consultation Process

12. Given National Grid’s role in the market, our intelligence on the gas and electricity supply-demand outlooks is reliant on the data and insights that we receive from others. As the winter consultation process has evolved over recent years, we have received several comments on the timing of the reports, and how the process interacts with Transporting Britain’s Energy, (TBE).TBE is our longer term

[1] A supply risk of 20 mcm/d has been included for the Safety Monitor calculations to reflect uncertainty in the supply assumptions; notably the assumption regarding the availability of LNG from Dragon for most of the winter period

consultation process with the gas and power community, and provides an insight into how energy markets may evolve and is a key/important component in our plans for network development.

13. Following publication of this paper, our proposed process for feedback for this winter and next year's winter consultation is:

    - Within winter updates will be posted regularly on National Grid's website. These updates will then form the basis of a summary document at the end of the winter;
    - Preliminary Winter 2008/9 Consultation in mid/late May 2008. Responses sought by early July 2008;
    - Ofgem/National Grid event in summer 2008 to discuss key issues, particularly those raised in responses;
    - Full Winter 2008/9 Consultation Report in late September 2008.

14. To help us improve the process for the Winter 2008/9 Consultation, we would appreciate any comments on the proposed process, and indeed any of our analysis within this report. We would appreciate receiving feedback as soon as possible but not later than Friday 9 November 2007.

15. National Grid is also considering the publication of a Summer Outlook, covering potential electricity issues, such as demand-supply balance, how demand responds to high temperatures, and transmission issues. We are considering a less formal process than that undertaken for the winter outlook, with the report being published April-May 2008. We would like suggestions as to the contents and timing of the proposed Summer Outlook Report.

16. Responses should be e-mailed to: andrew.ryan@uk.ngrid.com. Where requested, we will treat information provided to us on a confidential basis. However, respondents may send confidential information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.

17. Unless specifically asked not to by respondents, we will share all responses received with Ofgem. Unless marked confidential, responses will be published on Ofgem's website. Respondents shall request that their information is marked confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

Roles and Responsibilities

18. The competitive gas and electricity markets in the UK have developed substantially in recent years and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas and electricity to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem, whilst the Department

for Business Enterprise & Regulatory Reform (BERR) has a role in setting the regulatory framework for the market.

Legal Notice

19. National Grid operates the electricity transmission network through its subsidiary National Grid Electricity Transmission plc and the gas transmission network through its subsidiary National Grid Gas plc. For the purpose of this report “National Grid” is used to cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licences.

20. National Grid has prepared this consultation document in good faith, and has endeavoured to prepare this consultation document in a manner which is, as far as reasonably possible, objective, using information collected and compiled by National Grid from users of the gas transportation and electricity transmission systems together with its own forecasts of the future development of those systems. While National Grid has not sought to mislead any person as to the contents of this consultation document, readers of this document should rely on their own information (and not on the information contained in this document) when determining their respective commercial positions. National Grid accepts no liability for any loss or damage incurred as a result of relying upon or using the information contained in this document.

Copyright

21. Any and all copyright and all other intellectual property rights contained in this consultation document belong to National Grid. To the extent that you re-use the consultation document, in its original form and without making any modifications or adaptations thereto, you must reproduce, clearly and prominently, the following copyright statement in your own documentation:

Chapter 1: Gas

22. This Chapter focuses on the gas supply-demand outlook for the forthcoming winter. A significant amount of importation infrastructure has now been completed or is under construction, which will allow new sources of gas to be brought into the UK. This has been a positive response to the decline of supplies from the UKCS. However, a high level of uncertainty remains on the supply side for winter 2007/8 as to how such infrastructure will be utilised.

23. In this Chapter we examine issues associated with gas demand, each of the various sources of supply, and the interactions between those sources. In our March document we illustrated the implications of these issues with analysis that focused on an 'Initial View' of supplies. This view was subsequently updated in June and presented as our 'Revised View' of supplies.

24. Following further feedback and market intelligence, we have again updated our forecasts, to present a Final View of supplies. For most supply components, this is not materially different to our previously presented Revised View.

25. In terms of analysis we have provided additional assessment of potential Norwegian flows to the UK and an insight into European storage levels and LNG shipments.

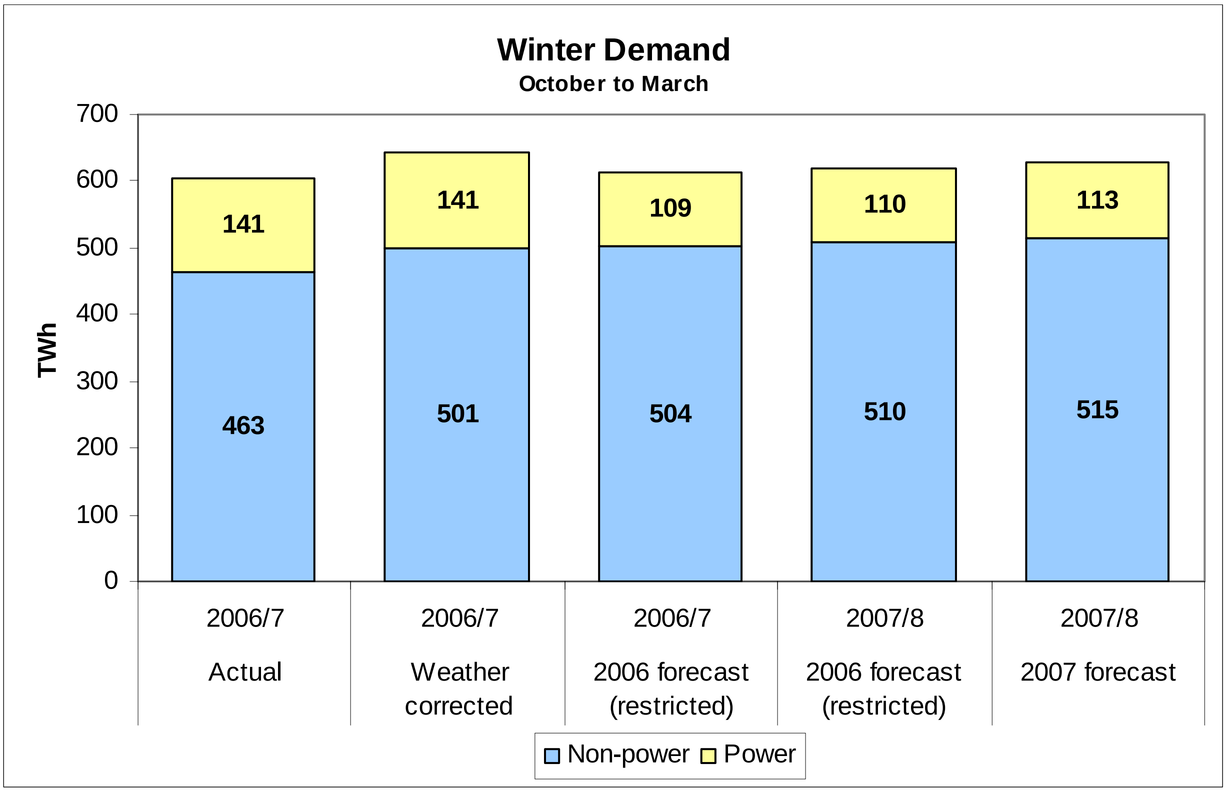
26. Again we welcome views on all aspects of our analysis, and in particular on our assumptions concerning imported gas supplies and demand growth.

Gas demand

27. The demand background used for the analysis in this section is the updated set of demand forecasts for 2007/8 that we have recently produced as part of the 2007 TBE process. These demand forecasts are fundamentally very similar to the forecasts for 2007/8 produced in 2006, which underpinned the analysis in our March document. Given the relatively high price of gas, especially when compared with coal in the electricity generation market, we assume a "restricted" view of gas demand, which reflects a degree of demand-response to prices.

28. The latest forecast suggests that demand will be slightly higher, as illustrated in Figure 1, and this change is primarily the result of a reassessment of fuel prices and the impact this has had upon consumption.

Figure 1 – Winter Demand[2]



29. The validation that we have undertaken on the revised forecasts gives us a high level of confidence that they properly reflect the historical data available to us and therefore represent our Final View of demand.

30. The 2006 demand forecast provided views of both restricted and unrestricted levels of demand, which gave a good fit to actual demand at different times during winter 2006/7. The variation between forecast and actual demand in 2006/7 was largely explained by variations in the level of power generation.

31. Consequently, the final 2007 forecast contains a single revised view with the level of gas demand for power generation based on a quarterly analysis of the generation ranking order. For the peak months of the 2007/8 winter the ranking order assumes that coal will be preferred to gas with the result that forecast power generation gas demand is close to the minimum needed by the electricity sector on a high demand day. This reduces the scope for further reductions in gas powered generation on high demand winter days.

32. Our power generation assumptions are supported by forward prices for the winter which indicate that coal fired plants will be more economic to operate than their gas fired counterparts, as detailed in Appendix II. Though 1 January 2008 sees the introduction of the Large Combustion Plant Directive (LCPD) and a significant increase in the price of carbon, due to the commencement of phase 2 of the EU emissions trading scheme, the market prices imply that coal-fired generation will be more economic than gas-fired. However, in the event of a mild winter or high gas

[2] Weather corrected demand is actual demand adjusted to seasonal normal weather conditions using the weather sensitivity parameter from the demand model.

supplies it is possible that gas prices may fall, due to the depression of weather sensitive demand, and this combined with higher carbon prices could prompt switching from coal-fired to gas-fired generation, as was witnessed during December 2006 to March 2007.

Demand-side response

33. In Chapter 3, we examine the potential for demand-side response from CCGTs, in the context of a relatively low forecast gas demand from power stations.

34. Our final view of CCGT gas demand in 2007/8 is around 54 mcm/d on peak winter weekdays, which is comparable to our 2006 forecast for 2006/7 of 53 mcm/d. As winter 2006/7 progressed, outturn CCGT demand increased from a range of 55-70 mcm/d to a higher range of 60-90 mcm/d, reflecting the fall in gas prices. While the gas market remains dependent upon imported supplies, the swing in gas consumption by CCGT stations continues to be key in achieving a balance between gas supply and demand.

35. Whilst there is little or no need for other large users to provide a demand-response in most conditions, there will potentially be a need for large users to deliver a significant reduction in demand in the event of cold weather and low gas supply.

Transportation capacity

36. Transporters may curtail the demand of interruptible customers for the purposes of capacity management. However, we have also observed market driven demand reduction at times of high demand, thereby removing the need to curtail such interruptible demand. Therefore, in the absence of plant failure or unexpected peak demand-supply patterns, we do not anticipate a material level of demand interruption for transmission capacity management in 2007/8.

37. The rapidly changing profile of gas supplies will naturally lead to new patterns of gas flow on our transmission system. For example, we reported increased flows around Easington last winter and these are anticipated to continue this winter due to the commencement of supplies from the Ormen Lange field through Langeled, and the Aldbrough storage facility. Additional network investment is being undertaken to ensure baseline capacity obligations can be honoured for this winter.

38. National Grid has obligations to release capacity ahead of the day and also within-day, on an interruptible and firm basis. National Grid has also recently put forward a UNC Modification Proposal (Mod 0159) and received approval to release additional discretionary interruptible capacity. The combined effect of the obligations and the buyback incentive seek to maximise the capacity offered at a given Aggregated Supply Entry Point (ASEP) and also the volume of gas transported away from that ASEP. If any constraint arises, National Grid endeavours to minimise costs to manage the constraint through a range of tools, such as options and prompt buybacks.

39. The recent price control settlement has sought to change the capacity regime by including a trade and transfer obligation on National Grid, under which capacity rights/obligations could increase at one ASEP and be reduced at another. On 6 September Ofgem approved a Trade and Transfer UNC Modification Proposal (Mod 0169) and an associated Methodology Statement. A two round auction will now be held ahead of this winter, which will allow Users to bid for capacity above an ASEP's obligated level. Therefore, depending on the results of the auction, this could lead to

increased firm capacity being available at ASEPs such as Teesside and Easington. However, it should be noted that there would be corresponding, but not necessarily equivalent, reductions at other ASEPs. National Grid, in support of the now approved Transfer and Trade Methodology Statement[3], issued some indicative information on exchange rates, which showed that a moderate increase in capacity at Easington could be achieved through reducing all of the available capacity at the Isle of Grain.

Gas supply

40. The following sections examine each of the potential (non-storage) gas supply sources in turn: UKCS, Assessment of European markets, European imports from Belgium, Holland and Norway respectively; and LNG.

UKCS gas supplies

41. In recent years, we have used the term ‘beach’ gas to denote UKCS gas supplies plus Norwegian imports through the Vesterled line into St Fergus. With the increasing number of imported gas sources, and the potential for substitution between Vesterled and other routes, the concept of ‘beach’ gas has become less useful. We are therefore again focusing on UKCS supplies specifically, as distinct from the various import sources.

42. The analysis in our March document to provide an Initial View was based on our 2006 forecasts, combined with our experience last winter and our most up-to-date intelligence regarding new UKCS developments.

43. Following feedback and receipt of 2007 TBE information, we revised our UKCS maximum forecast in June, resulting in a marginal increase in supplies.

44. Following further feedback and intelligence, we have re-assessed our UKCS forecast to form a Final View of the maximum forecast by terminal as shown in Table 1. This is broadly the same as previously reported though Bacton and Theddlethorpe are slightly higher and Teesside and St. Fergus are slightly lower. Most of these minor changes are brought about by our latest view of new developments expected this winter.

Table 1 – 2007/8 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2006/7		2007/8		
	Forecast	Highest	Initial View (March)	Revised View (June)	Final View
Bacton	75	55	67	74	76
Barrow	24	25	23	22	22
Easington	16	15	15	13	13
Burton Point	2	4	2	2	2
St Fergus[4]	94	95	89	89	88
Teesside	30	35	28	26	24
Theddlethorpe	26	28	26	26	27
Total[5]	**267**	**257**	**249**	**252**	**252**

[3] http://www.nationalgrid.com/NR/rdonlyres/B17AFDCB-1DF4-43DD-A62B-DEBDB63C7A6F/19723/TransferandTradeMethodologyStatementv10310807.pdf
[4] Excludes Vesterled

45. Our final view of UKCS supplies includes a year-on-year decline of 24 mcm/d from existing fields, which is offset by incremental developments totalling around 9 mcm/d. It should be noted that uncertainty continues over the volumes that will be available from incremental developments due to timing and commissioning issues.

46. For the purposes of supply-demand analysis and safety monitor assessments, it is appropriate to assume a level of UKCS supply below the maximum forecast when calculating the supply outlook. The chosen level should reflect the level of delivered (non-storage) UKCS gas that we might expect on average in a prolonged cold spell. Last winter (excluding specific high swing supplies into Bacton and Barrow), we observed a near consistent availability of approximately 90%. Whilst we acknowledge that this could possibly be lower under more severe conditions, we propose to retain an assumed availability rate of 90% and capture a lower level as a supply sensitivity.

47. We acknowledge that we may see a within winter decline of supplies from the UKCS, however as our starting position represents typical rather than maximum winter availability and we have adopted a prudent approach for new supplies expected to come on-stream during the winter we are not factoring in a within winter profile.

48. As highlighted above, there remains scope for upside and downside against our Final UKCS supply forecast, for example:

- There would be some upside against this Final view if producers were able to achieve a higher level of average availability than 90%. Equally, downside risk results from the potential for outturn availability to be lower than 90%;
- Supply availability early in the winter could be lower in the event of late commissioning of new fields or delays in the resumption of production following maintenance outages;
- Supply availability later in the winter could be lower given a greater than projected level of within-winter decline of existing fields;
- As observed last winter, supply availability could be much lower if high swing supplies are not fully utilised.

Assessment of European Gas Market

49. Whilst data on Continental gas markets across Europe continues to improve, the availability of data remains fragmented with some countries and transmission operators providing extensive data with others less or very little. Consequently it remains difficult to provide a comprehensive overview of either experiences of Continental operators in the past or a view on Continental markets for the future, notably for the winter of 2007/8.

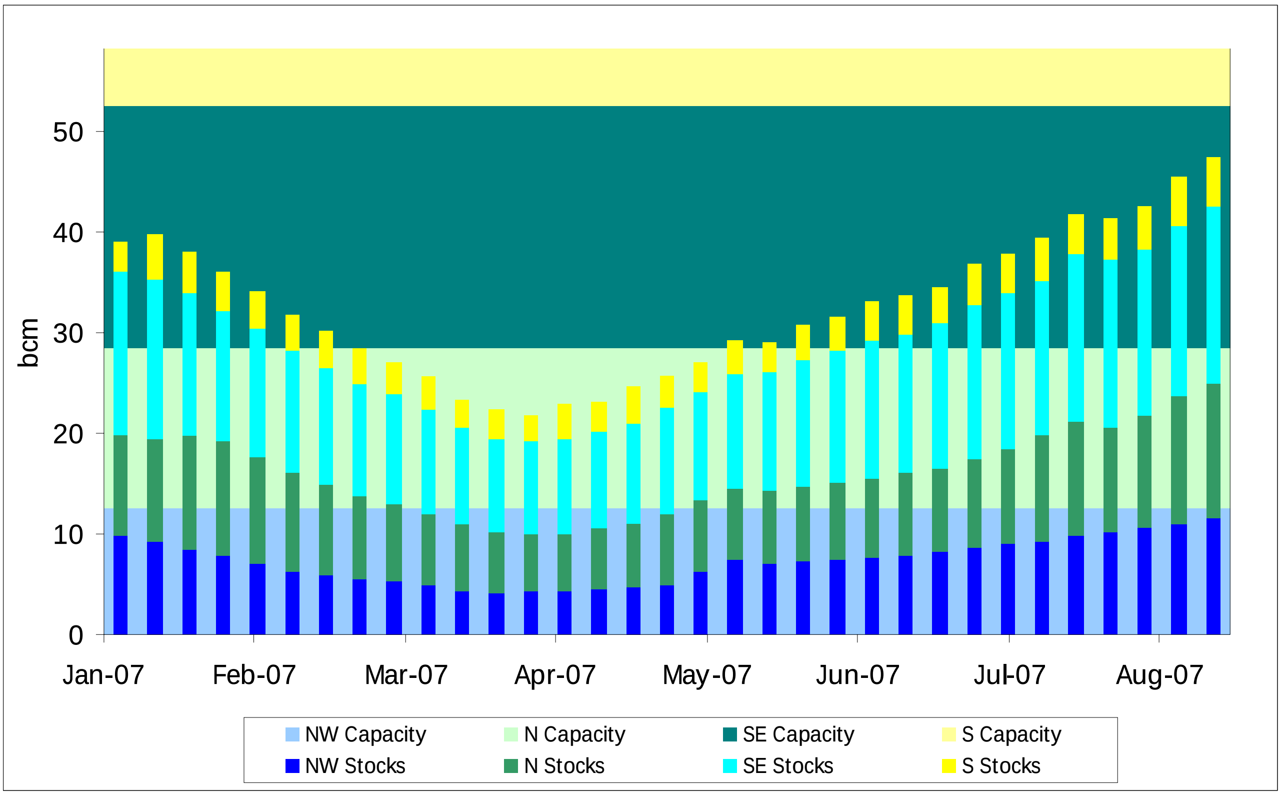
50. The areas where we have extracted near complete data, or where we can assess incomplete data by difference include levels of gas held in Continental storage sites, LNG deliveries to Europe and Norwegian exports to the UK and Continent. These

[5] For operational and security planning, a 90% supply availability factor was used, hence 267 mcm/d equated to an overall supply of 240 mcm/d

are reviewed / analysed in the following charts ahead of our assessment of imported gas sources to the UK.

51. Figure 2 shows storage capacities and storage stock levels across Europe with data extracted from the Gas Storage Europe website[6].

Figure 2 – European Storage Capacity and Storage Levels



52. The chart shows European storage capacity and storage stock levels by 4 geographic areas as shown in Table 2. Total capacity reported is nearly 60 bcm and as of the end of August, storage stocks were in excess of 80%, with all areas on course to have near full storage stocks for winter 2007/8. The chart also shows the relatively high storage levels at the end of last winter with stocks only falling to about 40% of capacity due primarily to the mild weather.

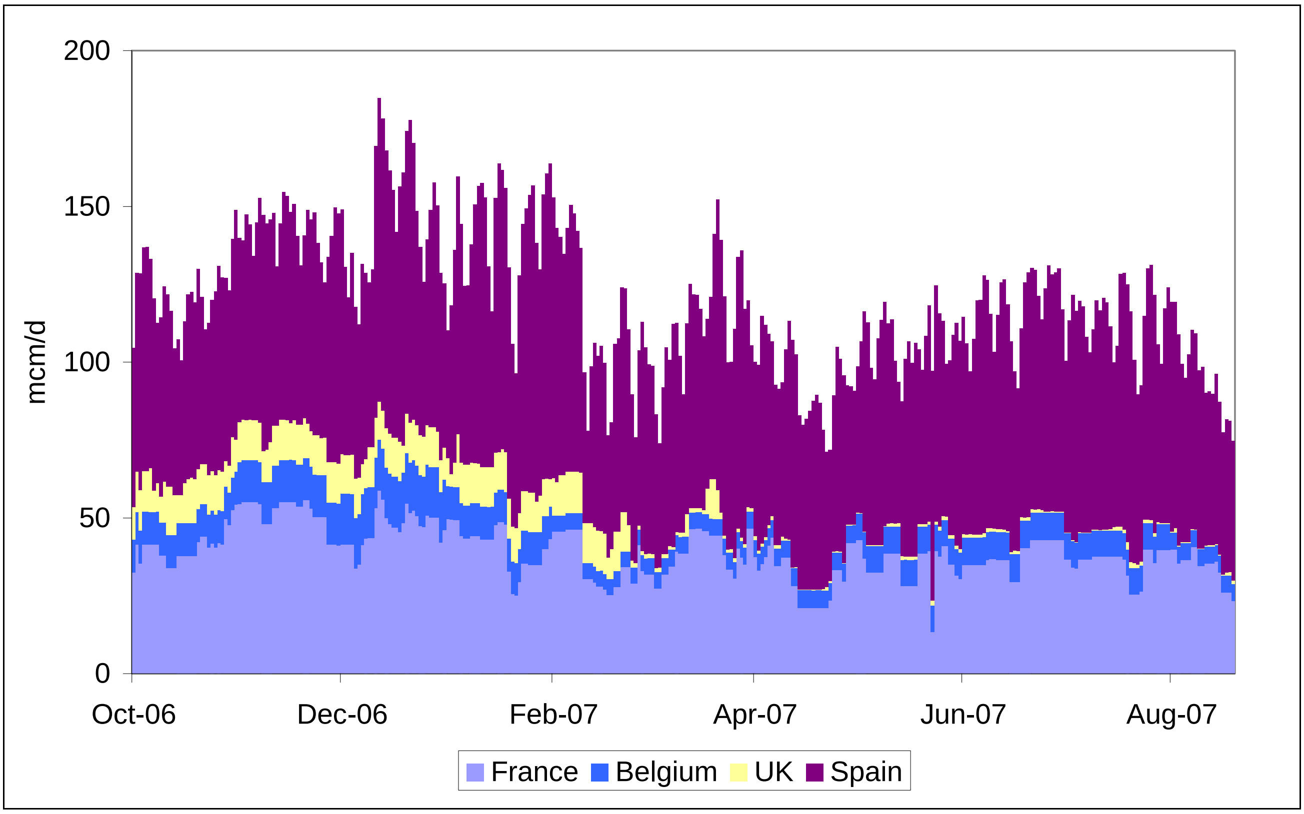
Table 2 – Geographic Areas for Reporting of European Storage

North West	**North**	**South East**	**South**
UK	Demark	Italy	Spain
France (except South)	Germany	Czech Republic	France (South)
Belgium	Netherlands	Austria	
		Slovakia	
		Hungary	

[6] http://transparency.gie.eu.com/

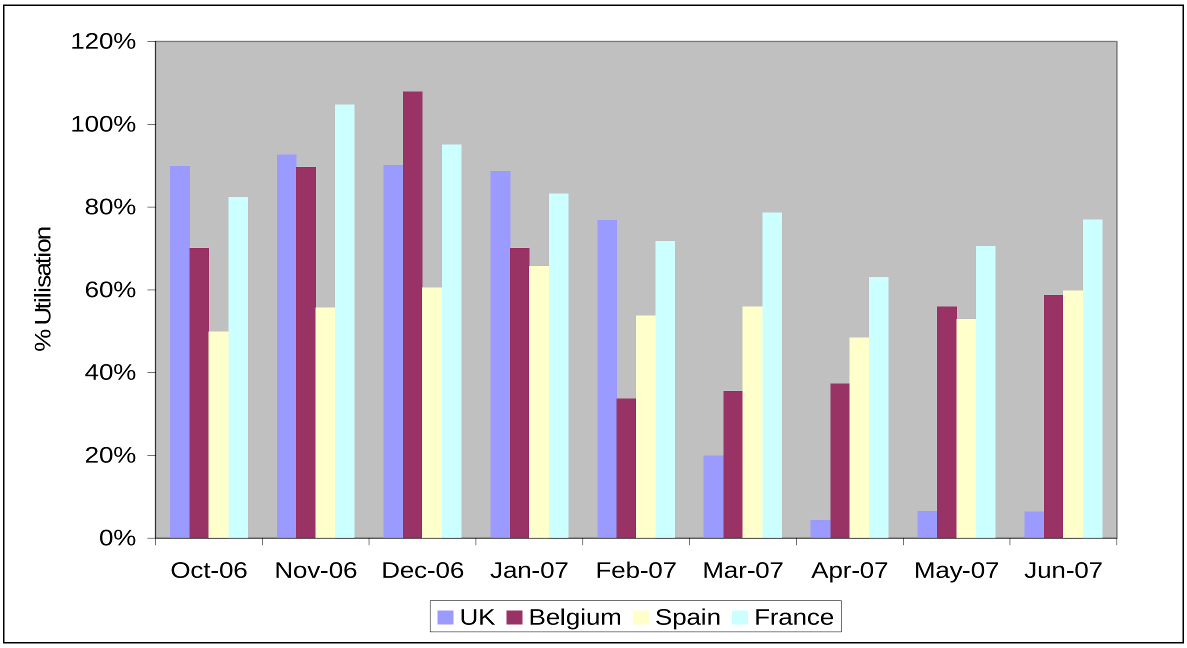
53. Figure 3 shows gas flows from LNG in France, Belgium, UK and Spanish markets between October 2006 and August 2007. The data was derived from GdF, National Grid, Enagas and various shipping websites.

Figure 3 – Gas flows of LNG to European Markets



54. The chart shows relatively high levels of LNG delivered to French and Spanish markets with lower levels to Belgium and UK. The UK deliveries peter out in spring 2007, showing the seasonality of LNG supply to the UK market. This is highlighted in Figure 4 that shows the utilisation of import capacity based on monthly flows and import capacity as of the end of 2006.

Figure 4 – Utilisation of European LNG

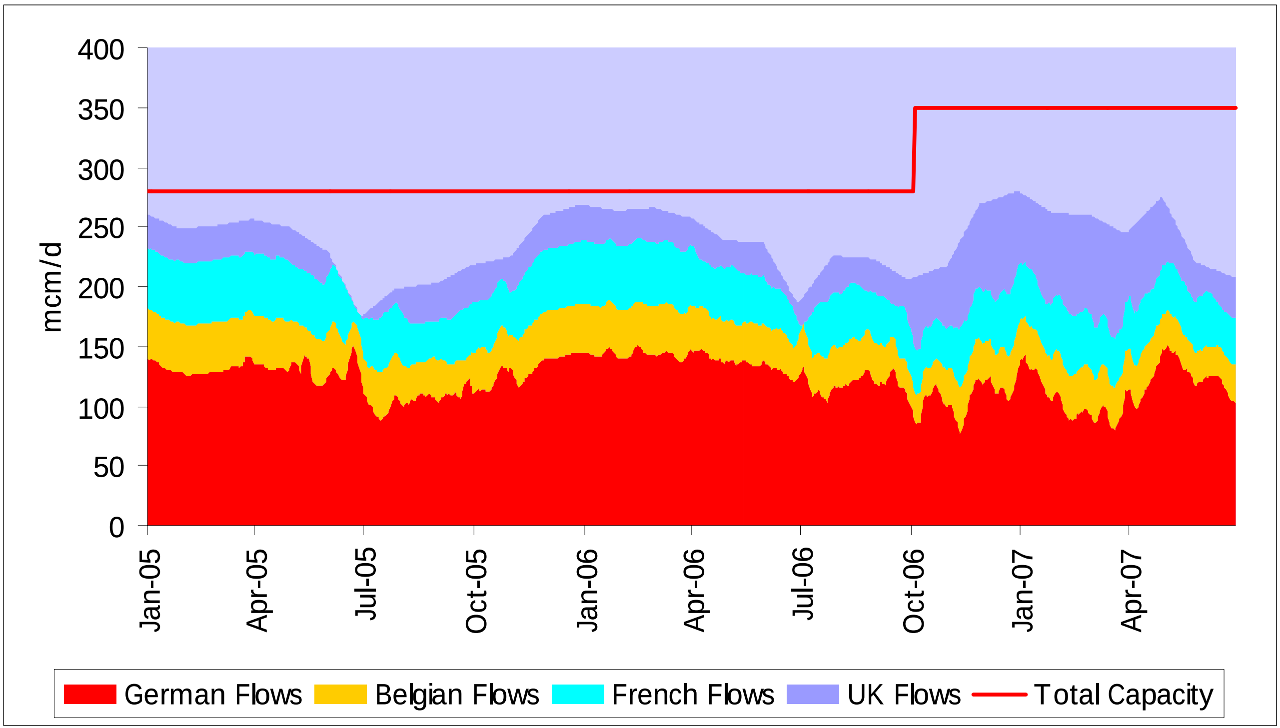


55. The figure shows very high winter utilisation of UK and Belgium LNG import facilities, with much lower seasonality in terms of deliveries to France and Spain. This reinforces the view that much of the LNG to these markets is contracted on a long term basis rather than delivered through shorter term market mechanisms. Spain, and to a lesser extent France, relies on LNG to meet about 70% of its winter demand, i.e. it must have LNG to meet demand and it may not have the opportunity to release LNG to other markets.

56. Figure 5 shows an estimate of Norwegian exports to Europe between January 2005 and July 2007. The data is based on daily flow information that has been smoothed over a 7 day period[7].With limited availability of data for the three Norwegian pipelines that flow gas to Germany, the German flows have been estimated by the difference between total Norwegian production as reported by the Norwegian Petroleum Directorate (NPD) website and the flows to Belgium, France and the UK. Also shown on the chart are aggregated export capacities as reported by Gassco, the Norwegian offshore operator.

[7] The data for Belgium is from Fluxys' website for entry flows from Zeepipe, the data for France is from GdF's website for entry flows from Franpipe and the data for the UK is the aggregation of Langeled data from National Grid's website and an estimate of Vesterled flows

Figure 5 – Norwegian exports to Europe



57. The figure shows similar aggregated exports from Norway to Europe for the period January 2005 to August 2007; however the make-up of the flows shows a noticeable change from October 2006 with higher flows to the UK as a result of the start-up of the Langeled pipeline. These are highlighted in the following table that shows exports by destination for the winter period October to March inclusive for 2005/6 and 2006/7.

Table 3 – Norwegian Winter Exports 2005/6 & 2006/7

Country	Winter 05/06 Bcm	Winter 06/07 Bcm	Winter 05/06 % utilisation	Winter 06/07 % utilisation
Belgium	7.1	6.0	94%	81%
France	9.1	7.9	95%	83%
Germany	24.9	19.2	90%	69%
UK	5.2	12.8	78%	66%
Total	**46.2**	**45.9**	**90%**	**72%**

58. The 12.8 bcm of exports to the UK for last winter resulted in an estimated peak flow of 98 mcm/d and an average flow of 70 mcm/d. This was higher than our 2006 Winter Consultation forecast of 48 mcm/d but this needs to be set in the context of a very mild winter on the Continent. Hence this level of flow to the UK might have been lower if demand on the Continent had been higher.

59. For winter 2007/8 we expect deliveries from the Ormen Lange field to supplement existing Norwegian production. Volumes from Ormen Lange are expected to

commence at about 30 mcm/d in winter 2007/8 and subsequently increase over the next two years.

60. We have developed a high level model of the Norwegian offshore network and have estimated Norwegian production for next winter using trend data of existing fields, from the NPD website, with the addition of Ormen Lange. With existing production anticipated to be similar or marginally higher, the increase in Norwegian production is essentially that from Ormen Lange i.e. an extra 30 mcm/d.

61. To estimate Norwegian exports to Europe for winter 2007/8 we have used our Norwegian offshore network model to ensure daily flows can be achieved but biased the flows based on previous winter experiences. Namely a high Continental bias based on the winter of 2005/6, a UK bias based on the winter of 2006/7 and a central view based on combining both winters. These are highlighted in the following table.

Table 4 – Possible Norwegian Winter Exports 2007/8

Country	Central View bcm	Pro-UK View bcm	Pro-Continent bcm
Belgium	6.8	6.4	7.2
France	8.7	8.2	9.0
Germany	21.8	20.6	23.9
UK	14.6	16.8	12.0
Total	**52.0**	**52.0**	**52.0**
Average UK flow (mcm/d)	**80**	**92**	**66**

Imported gas sources

62. As the UKCS continues to decline, the UK is becoming increasingly reliant on gas delivered via new and existing importation routes to ensure security of supply. Risks associated with the delivery of these projects, and the extent to which existing infrastructure will be used, add to the overall level of uncertainty surrounding the supply outlook.

63. With the commissioning last winter of Langeled, BBL, and Teesside GasPort in addition to the capacity upgrade of IUK there is undoubtedly less uncertainty over the availability of import capacity for winter 2007/8. In addition to these projects, for this winter there are two major import projects under construction at Milford Haven and further capacity expansion being made available at IUK and BBL, through further compression and enhancements to the Dutch gas network. Whilst there is therefore less uncertainty over the availability of import capacity, the uncertainty shifts as to how such capacity will be utilised and how the UK will compete for gas on a European and in the case of LNG a global basis. The following sub-sections outline each of the supply sources in turn and the assumptions behind our Final View of supplies for next winter.

Norwegian imports

64. The Langeled pipeline from the Sleipner platform in the Norwegian North Sea to Easington became operational last October with a capacity of 25 bcm per year (68 mcm/d). The second leg of the Langeled pipeline, connecting the Ormen Lange field to the Sleipner platform, is now completed with commercial deliveries from Ormen Lange expected to commence in October.

65. Though Langeled is now the primary source of Norwegian supplies to UK, we still anticipate significant imports through the 36 mcm/d capacity Vesterled pipeline.

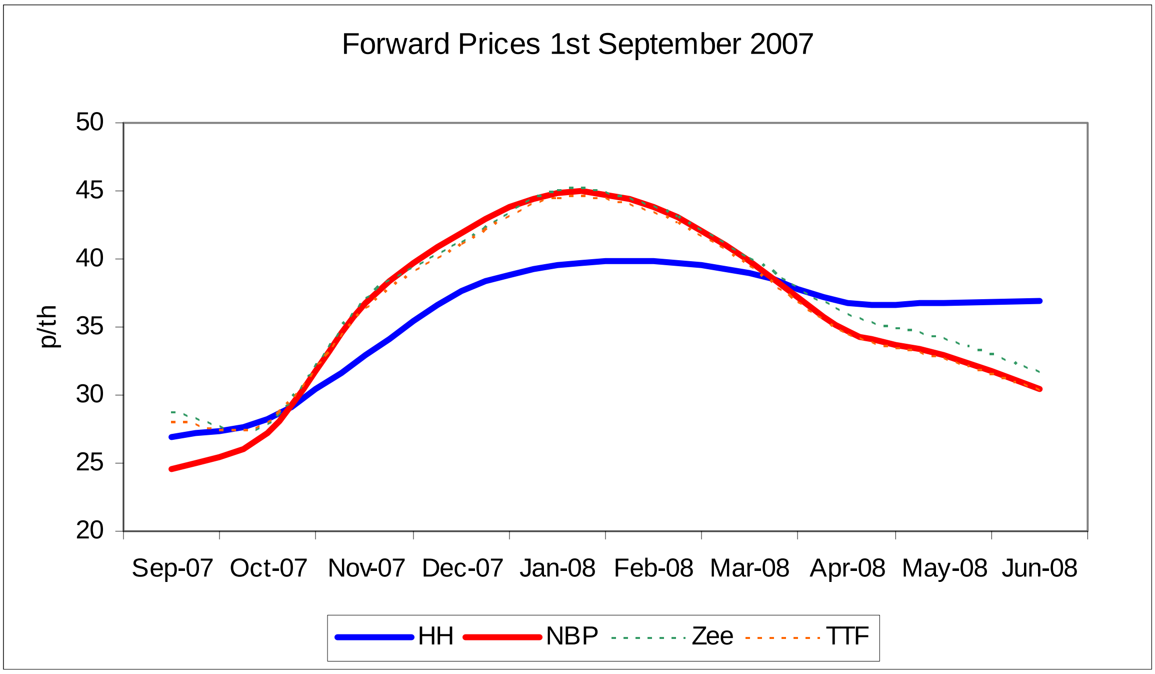
66. In addition to Langeled and Vesterled, a third pipeline between Norway and the UK is now in place. This is the Tampen Link from the Norwegian Statfjord field through the FLAGS pipeline to St Fergus. Initial volumes through this link are anticipated to be modest though there is scope to deliver appreciable volumes through this link at a later date.

67. Our previously reported analysis for Norwegian exports to Europe for winter 2007/8 suggests higher exports due primarily to Ormen Lange. Consequently we have increased our view of flows from Norway for next winter to the central view detailed in Table 4, namely total winter imports of 14.6 bcm equivalent to average daily flows of approximately 80 mcm/d, 10 mcm/d higher than previously forecast. For this forecast, the following assumptions are made:

    - Flows of 80 mcm/d, split approximately 30 mcm/d through Vesterled and 50 mcm/d through Langeled;
    - We acknowledge that flows through these pipelines could be materially higher, potentially 35 mcm/d through Vesterled and 70 mcm/d through Langeled. The Tampen Link could also provide additional volumes;
    - There is also some downside risk to Norwegian flows associated with delays to the commissioning of Ormen Lange and the possibility that the Continent may take higher levels of Norwegian supplies than delivered last winter;
    - In assuming approximately 50 mcm/d through Langeled, there is potentially insufficient head room in the Easington baseline (~98 mcm/d) to accommodate both UKCS supplies to Easington and full deliveries from Rough. If the capacity rights held by shippers are used to support higher Langeled supplies then other supplies to Easington may have to be restricted unless capacity above baseline can be provided. The Pannal to Nether Kellet pipeline is planned to be operational from October 2007. This pipeline should enable the expected new gas flows at Aldbrough to be accommodated in addition to the baseline quantities at Easington and Hornsea. The increased transmission capability from the NTS arising from the Pannal to Nether Kellet pipeline can be directed to a certain extent to flows in Easington area (includes Aldbrough and Hornsea), though specific network capacity limitations remain, notably from Easington to Paull. On this basis, as in winter 2006/7, National Grid may release additional discretionary interruptible capacity to accommodate flows above Easington terminal baseline when Aldbrough and Hornsea flows are reduced;
    - As detailed previously, the implementation of Trades and Transfers may also result in additional capacity release at Easington terminal; however such arrangements will result in lower capacity at other ASEPs.

68. Figure 6 provides an updated view as of 1 September 2007, of forward prices for winter 2007/8 in the UK, Continental Europe and in the US at the Henry Hub (HH). After a period when European prices were below the equivalent HH price for most of the winter, European prices are now higher for most of the winter following falls in US prices due to a combination of high storage levels and a US hurricane season to date with limited effects on gas production. Whilst the current forward prices suggest that the risk of LNG cargo diversion to the United States is relatively low[8], the history of markets suggests these conditions can readily change. Besides the competition for LNG spot cargoes with the US market, the Asian market may also compete with the Atlantic Basin. Indeed, during the summer the Japanese market has imported additional LNG following the earth quake that impacted power output from Japan's largest nuclear power station.

Figure 6 – Monthly Forward gas price comparison



Belgian Interconnector (IUK)

69. The capacity of IUK was increased last winter from 48 to 68 mcm/d. Plans remain in place to further expand this to 74 mcm/d in October 2007, through an increase in operating pressure.

70. With regard to next winter, there are two developments in Belgian infrastructure that could potentially influence the flows towards UK. These are:

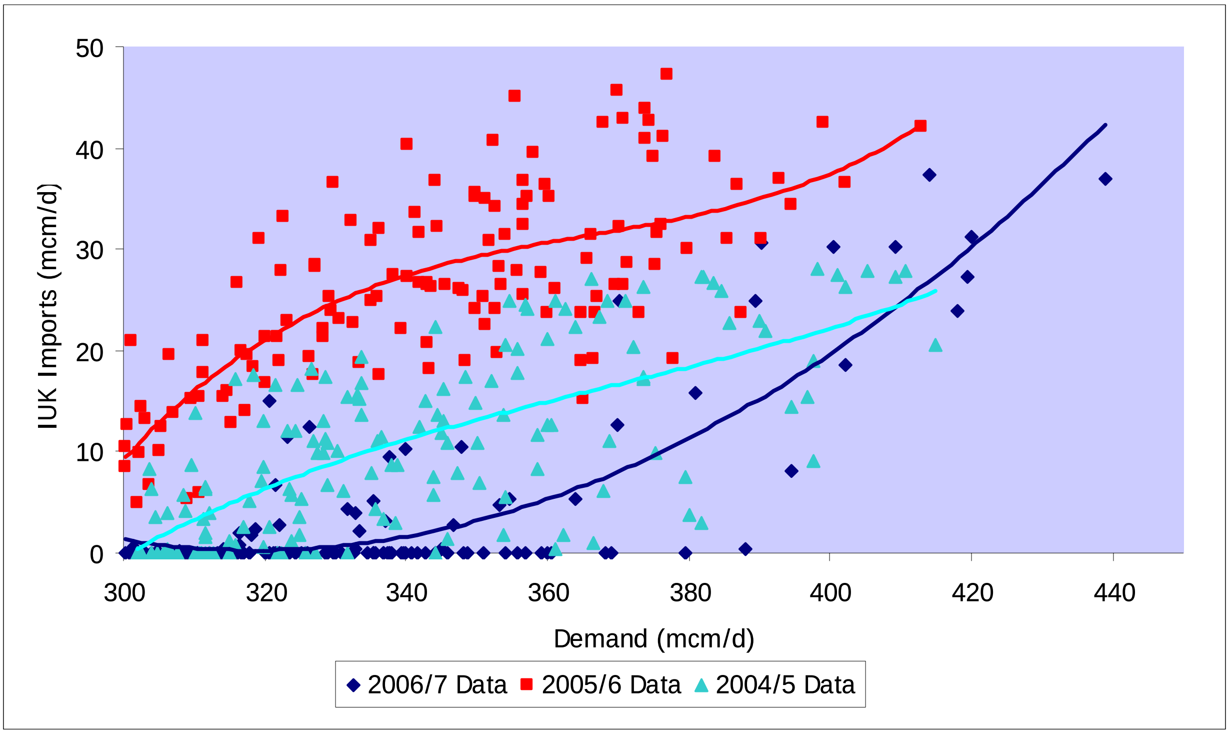
- The Zeebrugge Platform: the completion of some investments and trading arrangements in the Zeebrugge area that should enable easier interconnections between the Zeepipe terminal, which receives gas from Norway, the LNG terminal and IUK. The target date for this is reported as the end of 2007;
- Gas from the Zeebrugge Zeepipe terminal may flow to the UK, if compliant with the UK gas quality. An increase of send-out capacity as part of the

8 This graph excludes any transport costs. The typical transport cost for LNG across the Atlantic is estimated at about 4 p/therm

extension of the LNG terminal is also planned, with completion before end 2007.

71. In our March and June documents we reported our view of imports through IUK as up to 30 mcm/d through to December and up to 40 mcm/d post December, but only when certain market conditions prevailed. Whilst this view remains generally valid we have decided to modify our final view for IUK imports and subsequent analyses to reflect the operational experience that IUK imports have tended to respond to market conditions, and in particular demand, as highlighted in the following chart for the last 3 winters.

Figure 7 – IUK import analysis



72. The chart shows that IUK imports generally increase with UK demand but are also dependent on the supply / demand fundamentals for the winter. Hence in the above chart, winter 2005/6 was 'tight' with winters 2004/5 and 2006/7 less so.

73. Though we anticipate an improving supply position for winter 2007/8, a prudent approach is required for a security planning level. Hence our final view of IUK imports next winter is based on the experience of winter 2006/7. Under these conditions we would expect IUK to commence importation at demands around 320 mcm/d (range 300 – 390), reach 20 mcm/d at about 400 mcm/d (range 340 – 445) and reach 40 mcm/d at about 435 mcm/d (range 415 – 445). However as shown in the shaded area in Figure 7, such levels of imports could materialise over a wide range of demands.

74. To reflect the highest level of IUK imports experienced to date we also make the assumption that IUK imports do not exceed 50 mcm/d.

75. Other assumptions for IUK operation remain valid as previously reported namely

- Operating as a marginal source of supply with IUK responding to market differentials between the UK and Belgium. Whilst the forward prices are currently essentially the same across Belgium and GB (see Figure 6), suggesting little or no flow, developments during the winter could create market opportunities for IUK to flow in either direction;
- For imports to the UK, we believe the supply availability will be lower through to December due to uncertainties over the release of Continental storage that may be held back for Continental markets.

<u>BBL</u>

76. The Netherlands-UK pipeline, (BBL, short for ‘Balgzand Bacton Line’), was commissioned in the early part of last winter with an initial capacity of around 30 mcm/d. This has now been increased to around 40 mcm/d after the installation of a third compressor in March 2007, and enhancements to the Dutch network. It is anticipated that a new 48 inch pipeline from Grijpskerk to Wieringermeer will be completed by November 2007 which will provide additional transmission capacity between Oude Statenzijl and Julianadorp (BBL starting point), enabling additional volumes to be transported to Julianadorp and potentially through BBL.
77. Unlike IUK, BBL currently can only flow gas towards the UK. The primary driver for its construction was a contract between Gasunie and Centrica, through which GasTerra, now a separate company following the re-structuring of Gasunie, will deliver 8 bcm/annum to Centrica for ten years, with a winter: summer split of 5:3. This equates to roughly 27 mcm/d over the winter period.
78. Our Final View for flows through BBL for next winter remain the same as we reported in the March and June documents, namely:
    - A near uniform supply of 25 mcm/d;
    - But the capacity upgrade means that there is the possibility of higher levels of supply;
    - Or if BBL’s operation became more sensitive to the UK’s market prices, there is the possibility of lower and more variable levels of supply.

<u>Total European imports</u>

79. The previous sub-sections have outlined the developments and issues associated with each of the gas importation routes from Europe. In aggregate, the total physical import pipeline capacity from Europe is now approximately 250 mcm/d, broadly commensurate with peak capacity from the UKCS. Whilst it is possible that any one source may supply at levels near its maximum at times during the 2007/8 winter, we have highlighted a number of issues that together are likely to prevent gas flows close to this combined maximum level.

<u>LNG</u>

80. Last winter we observed regular deliveries of LNG into Grain and the unloading of part of a cargo at Teesside GasPort for commissioning purposes. For next winter we have the possibility of additional LNG through two new terminals at Milford Haven: South Hook and Dragon.
81. Dragon is still reported to commission during Q4 2007, the capacity for Phase 1 is 6 bcm/year, equivalent to a base load rate of 16 mcm/d. There is expected to be

some swing in the supplies from Dragon and a level of 25% has been assumed to result in a Final View peak supply of 20 mcm/d.

82. Press reports have indicated that the LNG supply contract through Dragon between Petronas and Centrica has been terminated. Whilst this may impact some deliveries through Dragon, we are not proposing to change our view of supplies for Dragon as other shippers may take the gas and as indicated in Figure 6, the UK is currently an attractive destination for winter LNG spot cargoes when compared to the US.

83. South Hook is still expected to be commissioning during H1 2008. The Phase 1 capacity of 10.5 bcm/year is equivalent to a base load rate of 29 mcm/d. However as the commissioning date for South Hook is possibly later than our October – March winter period, we are excluding deliveries from South Hook from our Final View.

84. With South Hook excluded from our forecast for next winter, our aggregated Final View for LNG next winter remains 33 mcm/d, made up of 13 mcm/d from Grain, the average flow during winter 2006/7, and 20 mcm/d from Dragon. This forecast is subject to considerable uncertainty as the following list highlights:

- Market uncertainty – currently US gas prices for next winter, as shown in Figure 6, are below those in the UK for most of the winter. Under these conditions, the UK could be expected to attract some of the cargoes that could have been expected for the US. Due to the volatility of short term markets this position could readily change;
- Whilst it remains a possibility, for security analysis purposes we continue to assume no LNG flows through Teesside GasPort. We acknowledge this could provide an upside of typically 11 mcm/d ;
- Delays to either commissioning Dragon or in the construction of the NTS expansion to connect Milford Haven could result in deferred deliveries. The current position on the NTS expansion remains to target completion of both the Milford Haven to Aberdulais pipeline and the Felindre to Tirley pipeline in time for Milford Haven LNG deliveries this winter (2007/8);
- If South Hook is completed earlier than now expected, this will provide a material upside to our LNG forecast.

Storage

85. As reported in March and June we expect the Aldbrough storage facility to become operational during winter 2007/8, though we are not expecting design flow rates until after 2007/8. Storage space at Hole House Farm is also expected to increase.

86. Table 5 shows our assumed levels of storage space and maximum deliverability for next winter. These include estimated levels of space and deliverability for Aldbrough.

Table 5 – Assumed 2006/7 storage capacities and maximum deliverability levels[9]

	Space (GWh)	Maximum Deliverability (GWh/d)	Maximum Deliverability (mcm/d)	Days at full rate
Short (LNG)	1939	526	49	3.7
Medium (MRS)	9703	485[10]	45	20
Long (Rough)	35295	455	42[11]	77.6

Final View

87. In the previous sections we have outlined the main points arising from our consultation on the appropriate supply assumptions for winter 2007/8 analysis, and we have indicated how we believe that the Final View of supplies should be developed to properly reflect these points. We have also highlighted the residual uncertainties for each of the supply sources.

88. Table 6 summarises the Final View emerging from this consultation process, and compares these with the assumptions made in our March and June documents and those made in respect of last winter in our Winter Consultation Report 2006/7. Whilst we acknowledge that the second half of the winter may provide a higher level of supply than in the first half due to the possibility of higher IUK flows and increased supplies from Milford Haven, we are for ease of analysis and understanding now just reporting a single weighted level of supply.

[9] Excludes Operating Margins gas + Scottish Independent Undertakings
[10] Assumes average deliverability for Humbly Grove and includes estimates for Aldbrough
[11] Subject to the availability of Easington entry capacity

Table 6 – Supply assumptions incorporated into Final View (mcm/d)

	2006/7 Base Case	2007/8 Max Capacity	2007/8 Initial View	2007/8 Revised View	2007/8 Final View
UKCS	240	252	224	227	227
Norway	48	116[12]	70	70	80
IUK	36	74	37	37	50[13]
BBL	14	41	25	25	25
LNG	13	80	46	33	33
Total Non-Storage	**350**	**563**	**402**	**392**	**415**
LNG	49	49	49	49	49
MRS	32	45	45	45	45
Rough	42	42	42	42	37[14]
Total	**473**	**699**	**538**	**528**	**546**

89. Despite a decline in our UKCS forecast of 5%, when compared to last winter our Final View of non-storage supplies for next winter is now 19% higher than 2006/7. This increase in non-storage supply has been driven by increases across the range of import sources, though as we have detailed previously, supply will only ever equal demand and at certain times supplies, notably IUK, will be driven by market conditions.

90. As detailed in the previous supply sections, considerable uncertainty remains over all of the supply sources, as captured in Table 7 below.

[12] Assumes nominal 10 mcm/d capacity through Tampen Link
[13] Based on demands of 450 mcm/d or higher
[14] Assumes Easington capacity at 98 mcm/d, made up of 50 Langeled, 11 UKCS and 37 Rough. Lower Langeled, UKCS or higher capacity will increase Rough assumption

Table 7 – Non-storage supply uncertainties (mcm/d)

	2007/8 Final View	Sensitivity	Supply Change
UKCS	227	85% rather than 90% supply availability	-13
		+/- 5% forecast error	+/- 11
		Zero flow from high swing UKCS supplies[15]	-23
Norway	80	Higher Norwegian deliveries to UK	+20[16]
		Increased Norwegian deliveries to Continent	-20[17]
IUK	50[18]	Maximum flows to UK experienced so far	+0
		Zero UK imports to reflect well supplied UK	-50
BBL	25	Higher flows to reflect increased capacity[19]	+10
		Lower flows to reflect shift to market conditions	-10
LNG	33	Deliveries made at Teesport	+11
		Deliveries made at South Hook	+36[20]
		Dragon – commissioning delay or NTS delays	-20
		Cargoes diverted from Grain to US or other markets	-13
Total	**415**	**Aggregated Non-Storage Supply Range**	**+88** **-160**

91. Table 7 highlights the considerable uncertainty associated with the non-storage supply forecast. Whilst it is extremely unlikely that the potential range would ever manifest, it is prudent to consider both an upside and downside to the Final View. To capture this we have assumed a supply range around the Final View of +/- 30 mcm/d. This reflects the loss or gain of key infrastructure equivalent to an annual demand of about 10 bcm. Whilst this level may appear a little arbitrary, it is of a similar magnitude to the Safety Monitor assumptions of a 20 mcm/d reduction for import uncertainty.

92. Examples of an increase of supplies of approximately 30 mcm/d could be full volumes through both Langeled and Vesterled, or earlier than expected deliveries from South Hook. An example of a decrease of supplies of approximately 30 mcm/d could be no material LNG deliveries to the UK next winter arising through more

[15] Assumes 10% of UKCS, to reflect no flow from high swing UKCS supplies into Bacton and / or possibly Barrow
[16] Assumes pro-UK deliveries and 10 mcm/d through Tampen
[17] Assume pro-Continental deliveries
[18] Assumes UK demand at 450 mcm/d
[19] Assumed level, reflect lower uncertainty when compared to IUK
[20] Assumes a 25% swing above annual supply

attractive market opportunities elsewhere or low IUK imports at relatively high demands.

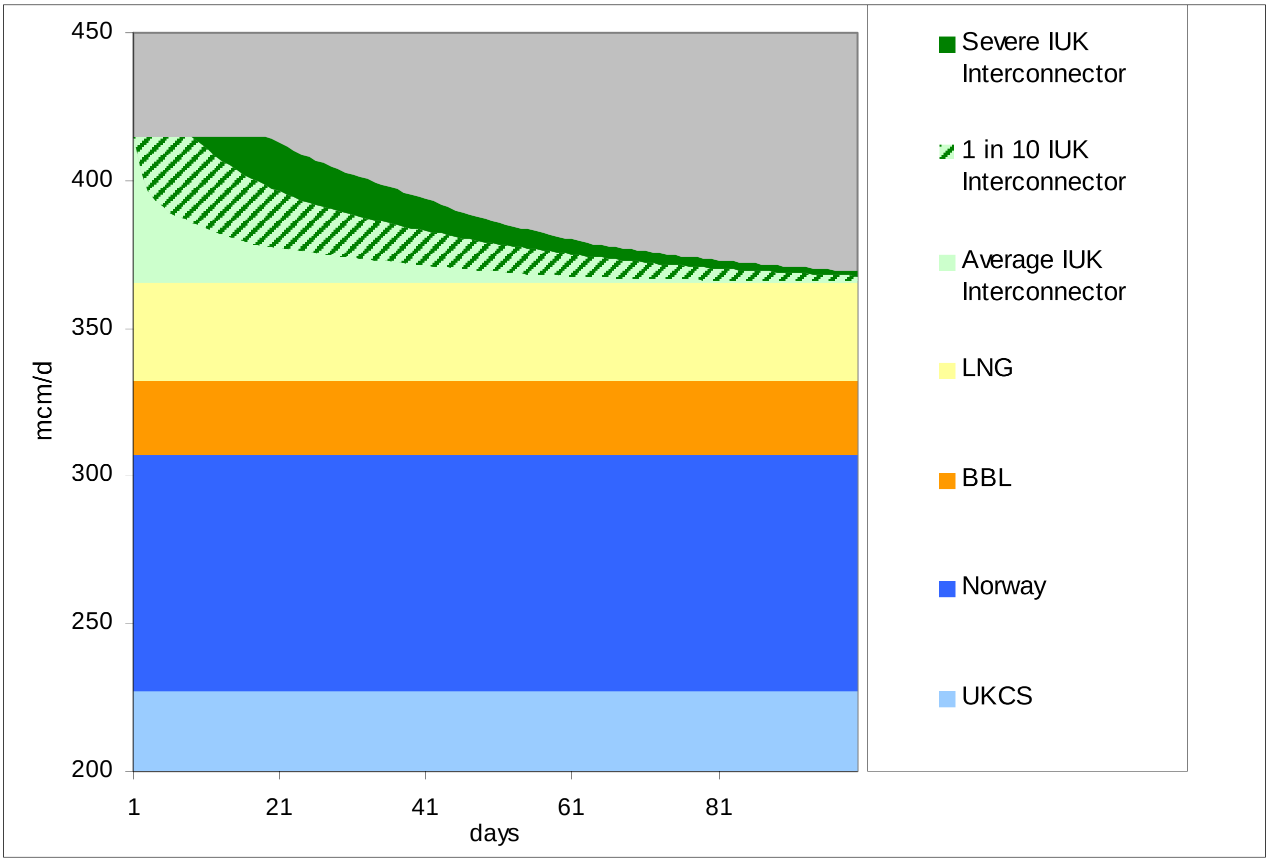
93. The following sections provide analysis of the supply-demand position in 2007/8 assuming the Final View incorporating our supply range of +/- 30 mcm/d and utilising our latest demand forecasts. This analysis is in two forms:

- an assessment of supply availability for average, 1 in 10 and 1 in 50 weather conditions;
- an analysis of projected supply availability against demand conditions corresponding to a very cold day, a very cold week and a very cold month.

Analysis of Final View

94. Figure 8 highlights the supply availability of non-storage supplies that make-up our Final View.

Figure 8 – Final View - non-storage supply availability



95. The figure shows that the level of supply availability for IUK is dependent on the demand, hence higher for more severe[21] conditions. Though not illustrated, to some extent this holds true for all types of supply. For example high swing UKCS supplies flowed very little last winter and this supply pattern may repeat itself if gas prices are subdued or alternative supplies are sourced in preference. Gas from Norway also

[21] Severe conditions are UK demands associated with a 1 in 50 winter

has supply options namely UK or the Continent and LNG has supply options on a global level.

96. Figures 9. 10 and 11 show the Final View of supplies with a supply range of +/- 30 mcm/d overlaid on a load duration curve of average, 1 in 10 and 1 in 50 demand respectively, with demand broken down into the Domestic, Other Non Daily Metered (NDM) and Daily Metered (DM) sectors. The forecast DM demand includes CCGT demand that could provide a demand-side response if high prices were to materialise. As detailed in Chapter 3, this level of demand-side response could potentially equate to approximately 10 mcm/d. However it may be materially lower on the days of highest demand as under these conditions we have already factored in lower use of CCGTs due to the anticipation of a higher gas price and thus preferential use of alternative fuels.

97. For clarity of presentation, the supply scenario lines are smoothed representations of the total availability of supply (UKCS, imports and storage excluding operating margins and Scottish Independent Undertakings bookings) implied by the respective scenarios. The irregular shape of the smoothed supply curve reflects limits on storage space and our assumptions for IUK imports. No allowance has been added for storage cycling or the possibility that certain supplies, notably IUK, will be driven by market conditions and therefore could be argued to be overstated when supply far exceeds demand.

98. Where the assumed level of supply exceeds the level of assumed demand a reduction in the level of supply will occur in order for demand and supply to balance. Where the level of demand exceeds the level of supply a demand response is required. Table 8 summarises the implied level of demand response required over the highest 100 days of demand, for the Final View of supplies and for the extremes of the supply range.

Figure 9 – Supply availability vs average load duration curve for 2007/8

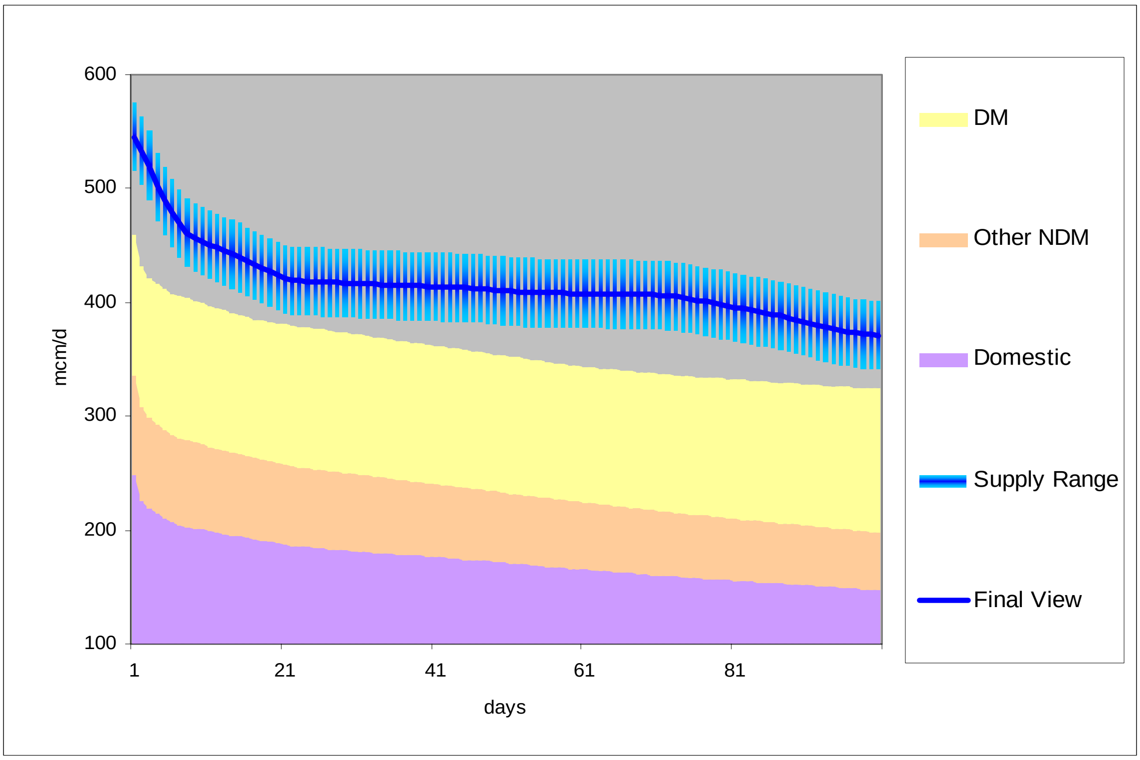


Figure 10 – Supply availability vs 1 in 10 load duration curve for 2007/8

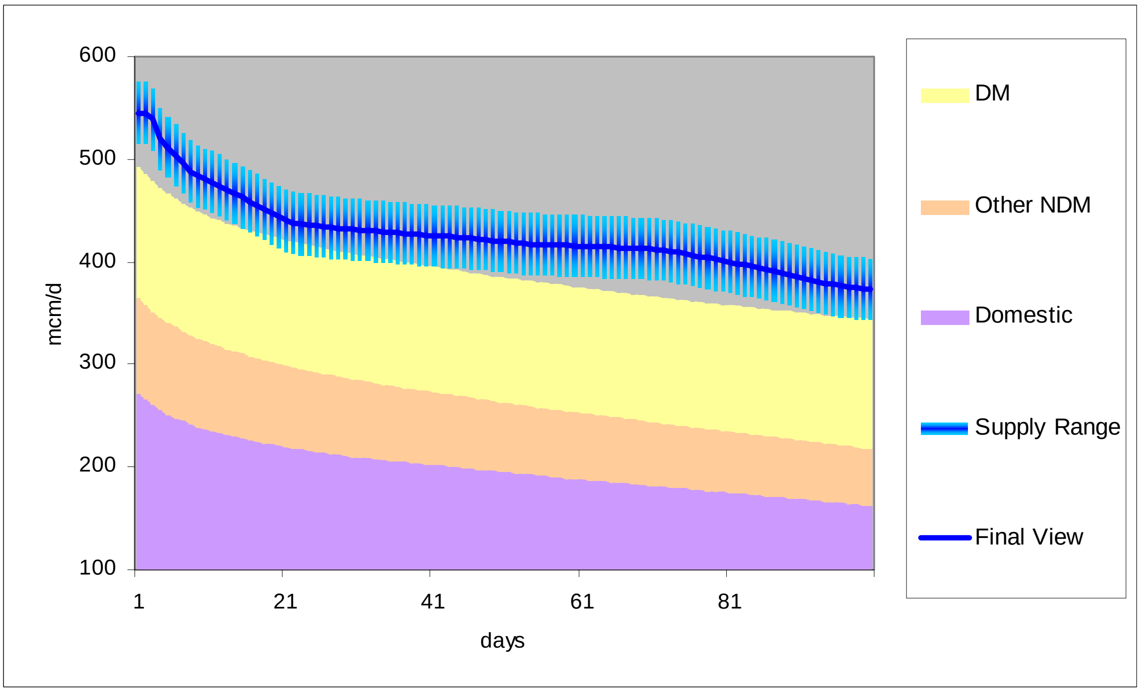


Figure 11 – Supply availability vs 1 in 50 load duration curve for 2007/8

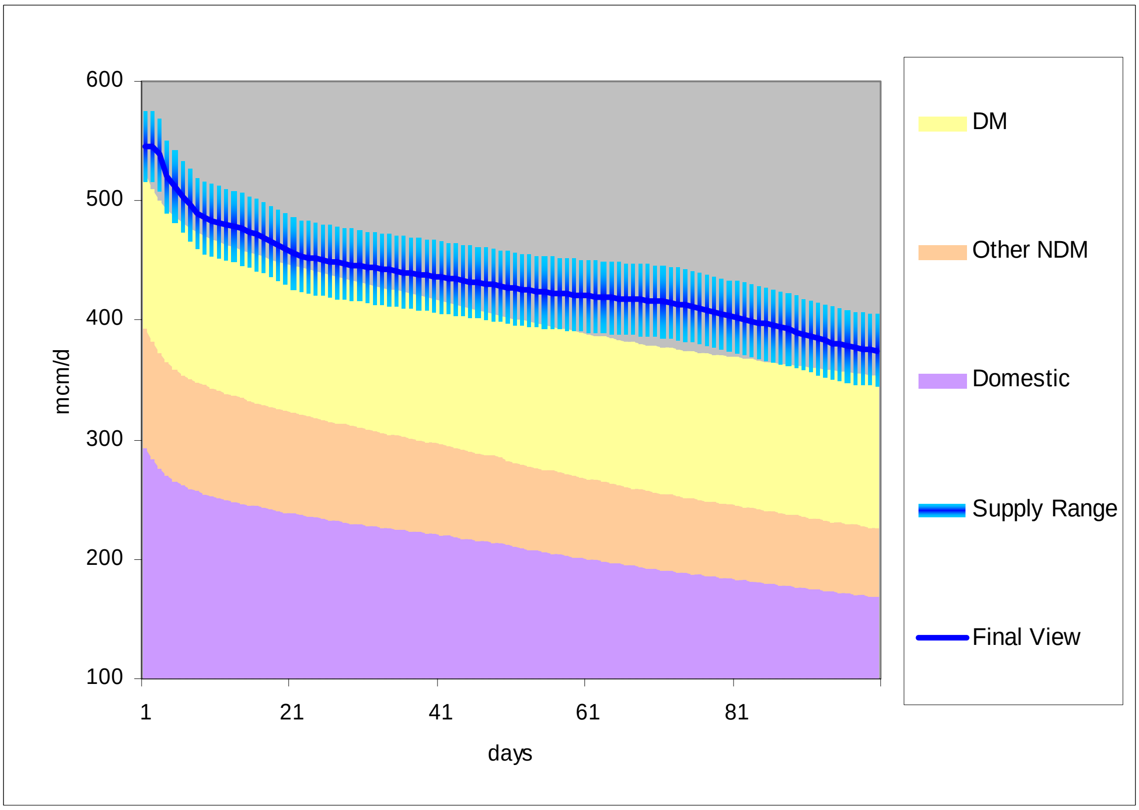


Table 8 – Demand response requirements under Final View assumptions (bcm)

	Average	1 in 10	1 in 50
Final View	0	0	0
Final View +30 mcm/d	0	0	0
Final View -30 mcm/d	0	0.15	0.65

Cold spell analysis

99. The analysis presented in the previous section focused on potential weather conditions across the entire winter. It is of course possible for the winter as a whole to be average (or otherwise unremarkable) but for it still to contain a short spell of very cold weather. This section therefore considers isolated cold spells.

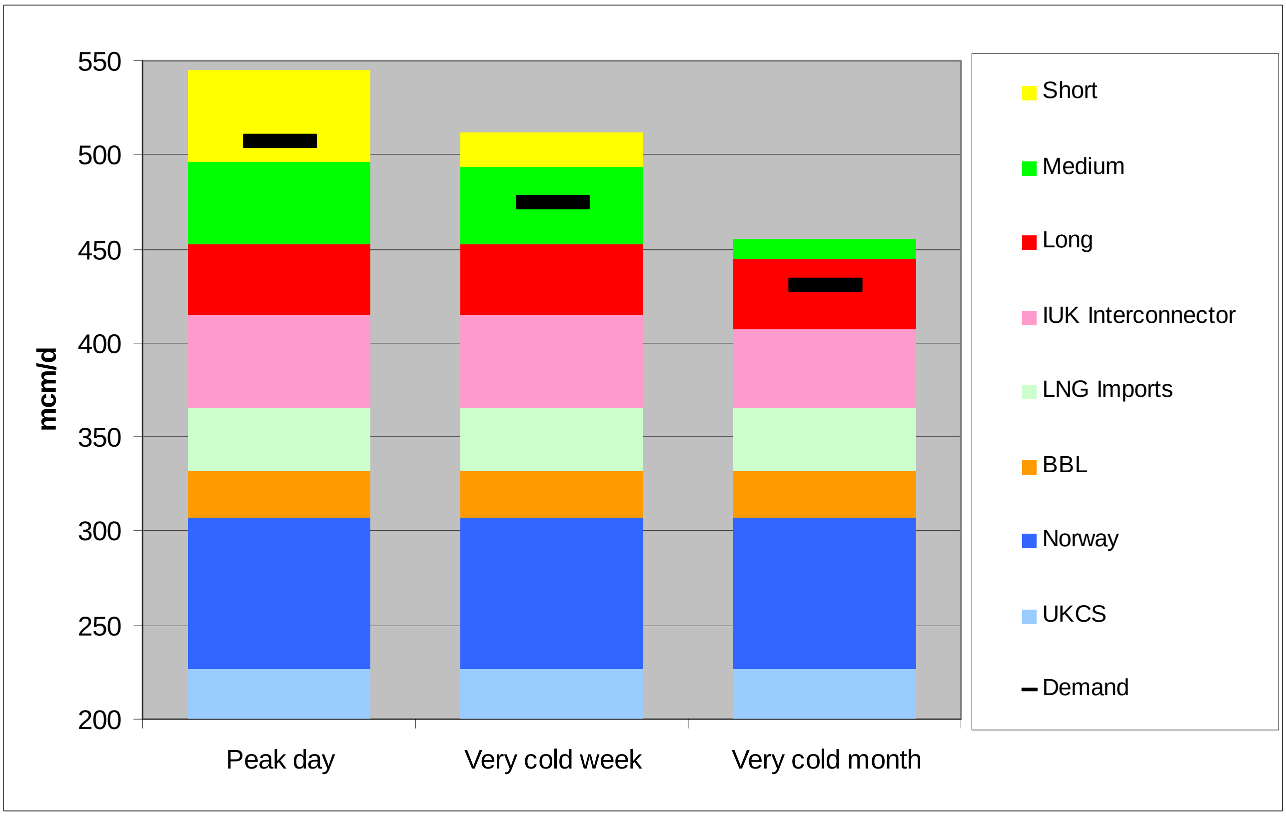
100. Figures 12 and 13 show bar charts consisting of three levels of demand, namely those commensurate with a peak day[22], a very cold week[23] and a very cold month[24]. Against these levels of demand is shown the supply availability[25] under the Final View, and the associated level of demand response required for supply and demand to balance.

101. To give a sense of the weather conditions that these cases represent, the average national temperatures across the country associated with these cold spells would typically be around:

- a 1 in 20 peak day temperature of -4.7 ºC
- a very cold week temperature of -3.5 ºC
- a very cold month temperature of -0.7 ºC

[22] Diversified demand for a 1 in 20 Peak day
[23] Diversified demand for a 1 in 50 (severe) cold week
[24] Diversified demand for a 1 in 50 (severe) cold month
[25] Storage deliverability reflects storage duration

Figure 12 – Cold spell analysis for 2007/8, with Final View supply assumption

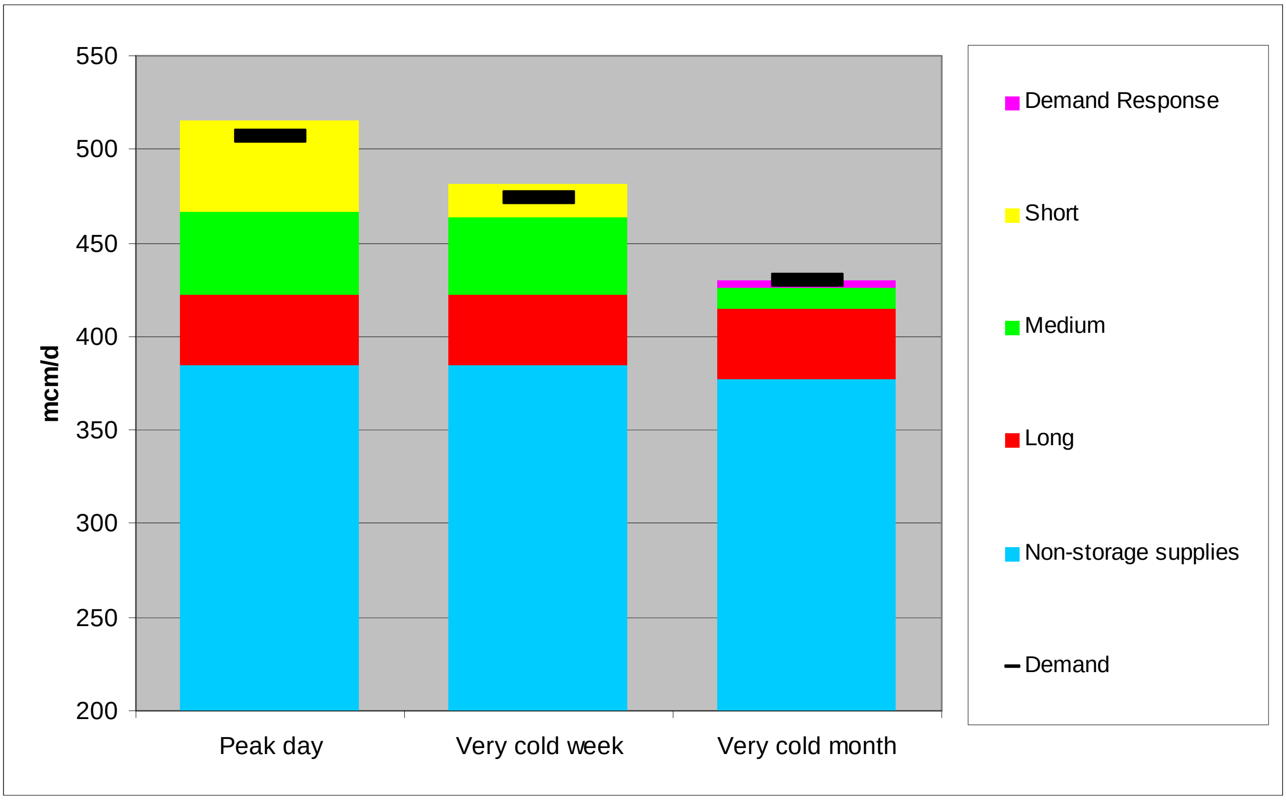


102. The analysis illustrates that for a 1 in 20 peak day with average temperatures across the country around -5 ºC, supplies are sufficient to meet demand and hence there is no demand response required.

103. Similarly for the very cold week and very cold month, there is no requirement for a demand response.

104. If the above analysis is repeated for the Final View with a 30 mcm/d reduction of non storage supplies, the results are as follows:

Figure 13 - Cold spell analysis for 2007/8, at 30 mcm/d below Final View



105. With non-storage supplies reduced by 30 mcm/d, for the 1 in 20 peak day and very cold week no demand response is required.

106. For the very cold month conditions, a daily demand response of 4 mcm/d is required, reflecting the lower availability of storage stocks through depletion during the extended cold period.

Safety Monitors

107. On 31 May 2007, we published our preliminary view of initial safety monitor levels for 2007/8 as required under the Uniform Network Code (Q5.2.1).

108. It is our responsibility to keep the monitors under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do so on the basis of the information available to us. In doing so, we must recognise that the purpose of the safety monitors is to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. It is therefore appropriate that we adopt a prudent approach to setting the initial monitor levels.

109. Our latest safety monitor calculations incorporate our Final View supply assumptions. Of particular note are the higher IUK flows assumed for severe demands and Norwegian flows at 80 mcm/d. We have continued to include a supply risk allowance of 20 mcm/d to mitigate the ongoing potential import supply uncertainty, notably the assumption regarding the availability of LNG from Dragon for most of the winter period.

110. The total non-storage supply assumption of 395 mcm/d used for calculating the safety monitors is 60 mcm/d higher than the equivalent figure used in setting the

2006/7 safety monitors and 20 mcm/d below the Final View supply assumption for next winter. A comparison of the non-storage supply levels used for calculating the 2007/8 safety monitors and for the 2006/7 safety monitors is shown in Table 9.

Table 9 – Comparison of 2006/7 and 2007/8 Safety Monitor non-storage supply assumptions (mcm/d)

Non-storage supply type	2006/7 Safety Monitor	2007/8 Safety Monitor
UKCS	240	227
Norway	48	80
IUK	35	50[26]
BBL	14	25
LNG	13	33
Supply risk allowance	-15	-20
Total	**335**	**395**

111. The resulting monitor levels shown in Table 10 are significantly below the 2006/7 monitors. These are primarily due to the higher non-storage supply assumptions.

Table 10 – 2007/8 Safety monitor space requirement

Storage type	2006/7 Safety Monitor (%)	Assumed storage space (GWh)[27]	2007/8 Safety Monitor space (GWh)	**2007/8 Safety Monitor (%)**
Long duration storage (Rough)	16.8%	35295	530	**1.5%**
Medium duration storage (MRS)	11.9%	8233[28]	0	**0.0%**
Short duration storage (LNG)	21.8%	1939	0	**0.0%**
Total	16.1%	45467	530	**1.2%**

112. We will confirm the initial safety monitor levels and publish the winter profiles (i.e. how the monitors reduce later in the winter) by 1 October.

113. During winter 2007/8, we intend to enhance within winter feedback to the industry regarding supply assumptions and resulting changes to Safety Monitors by means of monthly updates via our Gas Operational Forum and our website.

[26] Based on demands of 450 mcm/d or higher
[27] Excludes Operating Margins Gas and Scottish Independent Undertakings
[28] Excludes Aldbrough space

Chapter 2: Electricity

Electricity Demand Levels for 2007/8

114. Our latest Average Cold Spell (ACS) peak demand forecast for winter 2007/8 remains at 60.8 GW, which includes a 0.3 GW flow to Northern Ireland, as forecast in the March and June documents. This is based on our experience last winter, and represents a drop of 0.5 GW from last year's forecast for 2006/07. There has been no disagreement with this forecast in the responses to our March or June documents.

115. Around 0.8-1.3 GW of demand management was observed at times of peak demand in the winter of 2006/07, as consumers responded to periods of potential triad demands or high electricity prices. When forecasting demand, we assume this level of demand response will continue and we have recognised this in our peak demand forecasts. For winter 2007/8, as reported in our earlier documents, we have assumed 1 GW of demand-side response at the peak periods of the day in our demand forecasts for normal, ACS and severe conditions.

Notified Generation Availability

116. The quoted plant margin for winter 2007/8 currently reported in the August update to the 2007 Seven Year Statement (SYS) is 26.5%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 77.8 GW.

117. As reported in earlier reports, British Energy has announced reduced nuclear output at Hinkley Point and Hunterston during 2007/8, which represents a loss of 0.8 GW. All other capacity available during Q1 2007 is expected to be available during 2007/8.

118. However though Langage (0.85 GW) have contracted for TEC for 2007/8, they are not due to commission in 2007/8. Also, while the SYS figure includes 0.7 GW of renewable generation in Scotland with a commissioning date during 2007/8, only 0.3 GW of this is expected to be fully operational by the start of the winter.

119. The latest view of TEC capacity available for winter 2007/8 is therefore 75.8 GW, 0.2 GW higher than reported in June 2007, due to small increases in TEC held by several existing stations.

120. The GB Demand at ACS Peak reported in the SYS is 61.5 GW, excluding station load. The latest view of plant margin continues to be around 23%.

121. Wind is increasing its share of the GB generation market, and there will be about 1.2 GW of fully operational capacity visible to National Grid by winter 2007/8. As detailed in the Preliminary Consultation Report, our experience of wind generation is that over the winter it tends to generate on average around 35% of its maximum output. The capacity figure assuming a wind output loadfactor of 35% is 74.8 GW, which gives a plant margin of 22%.

122. This headline plant margin as quoted in the SYS is a useful, broad indicator of the amount of generating plant on the system for the winter. At an operational level, generators provide us with more detailed information about their expected availability. We use this to derive an operational view of generation availability,

which can differ from the SYS view for a variety of reasons including planned outages and operational restrictions on output.

123. Our current operational view of generation capacity anticipated to be available for winter 2007/8 continues to be 75.5 GW, unchanged from the Revised View presented in June 2007. A broad breakdown of this capacity is shown in Figure 14.

124. The generating companies provided us in 2006 with a list of mothballed plant, together with an estimate of the time that the plant would take to return to service from a decision being made to return. Reflecting this information and the continued availability of previously short-term mothballed plant, there is no plant that could return within 3-6 months. However, as summarised in Table 7, 1 GW remains long-term mothballed, and continues not to have TEC. It is considered unlikely that this 1 GW of long-term mothballed plant would make itself available for winter 2007/8.

125. As part of their ongoing Grid Code obligations, generators will notify us by mid June of any changes in their ability to return mothballed plant to service. As no changes have been notified to us, we have assumed the status to plant is unaltered from 2006.

Figure 14 – Generation Capacity, winter 2007/8

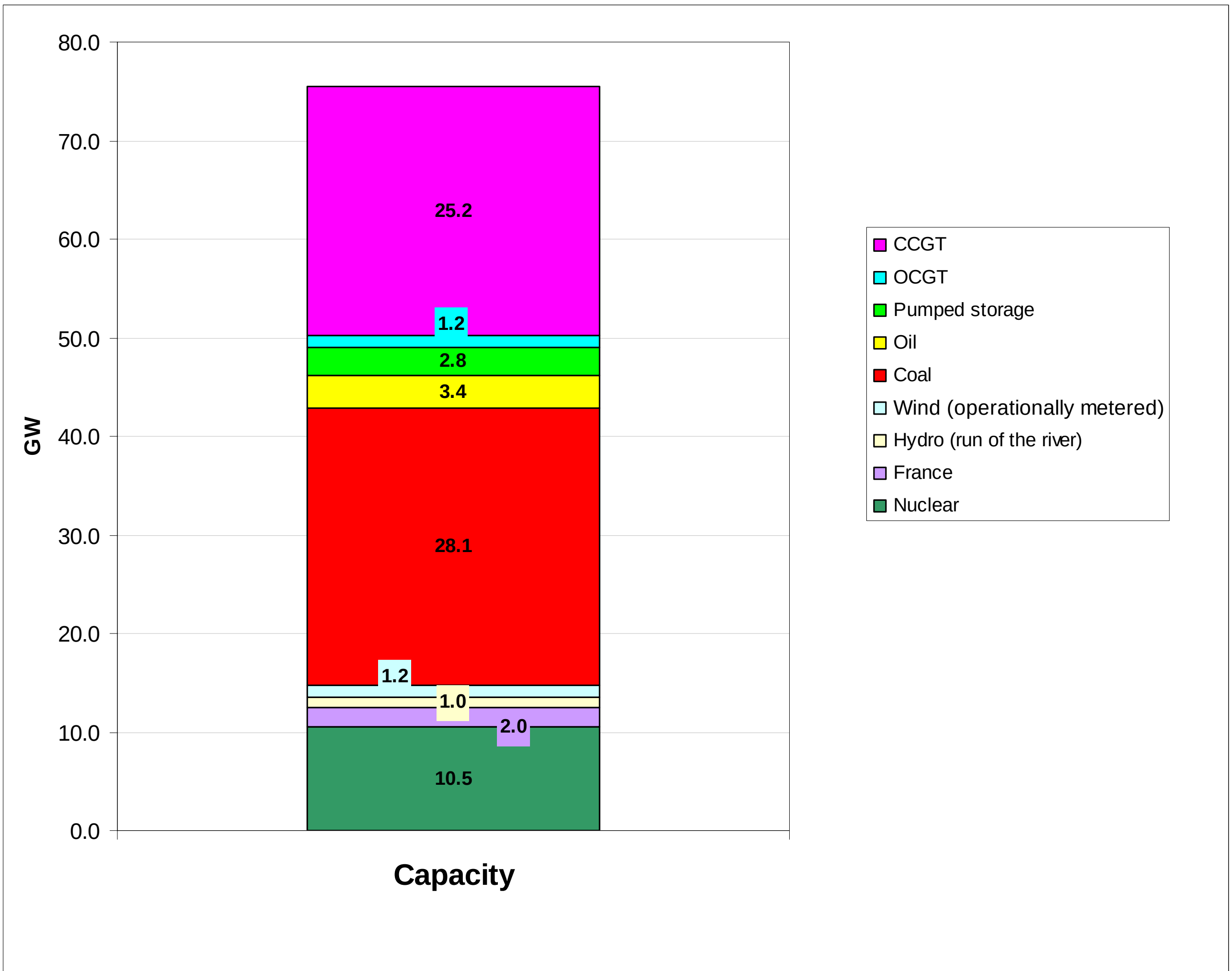


Table 11 - Mothballed Capacity, winter 2007/8

	Could Return within 3-6 months	Long Term Unavailable Plant
Generation capable of being returned within period (GW)	0	1

Contracted Reserve

126. In order to achieve a demand-supply balance, National Grid procures services from either generation or demand side providers to be able to deal with actual demand being greater than forecast demand and plant breakdowns. This requirement is met from both synchronised and non-synchronised sources. We procure the non-synchronised requirement from a range of service providers including Balancing Mechanism (BM) participants, non-BM generating plant and demand reduction.

127. Following extensive consultation with the industry, we have recently completed a review of the way in which this requirement for reserve is procured. Two key changes have resulted from this review:

    - a revised BM Start-Up service to ensure that, if necessary, we are able to access all generation regardless of its fuel within the required timescale in the Balancing Mechanism;
    - the introduction of a revised product for Short Term Operating Reserve (STOR). STOR is procured by a tender process which is run three times per year.

128. STOR has enabled greater participation in the provision of reserve, particularly from the demand-side. Through consultation with the demand-side working group and engagement with potential providers to tailor the service to meet their specific technical requirements, STOR has facilitated market access for more participants. For winter 2007/08, we have already procured an additional 130 MW of reserve from new demand-side service providers.

129. Since the June report, National Grid has contracted for additional reserve via the June 2007 Tender round. For winter 2007/8, the current total level of contracted STOR reserve is 2.2 GW, 1.6 GW from generation in the BM and 0.6 GW from demand-side providers.

130. National Grid is currently assessing 0.5 GW of services through the August 2007 STOR Tender Round. Though the assessment has not yet concluded, it is likely that National Grid will procure additional reserve through this tender round. The results of this tender round will become available via the National Grid website on 12 October.

131. There is a continual requirement to provide frequency response on the system. This can either be contracted ahead of time or created on synchronised sources within the BM. There is around 1.4 GW of reserve which is typically required to

create response over the winter demand peak. 0.85 GW has been contracted already, 0.3 GW within the BM and 0.55 GW with demand-side providers.

132. National Grid continues to have Maximum Generation contracts in place for winter 2007/8, which provide potential access to 1 GW of extra generation in emergency situations. However, this is a non-firm emergency service and would only be used to avoid demand control. Given that it is non-firm and that generation operating under these conditions normally has a significantly reduced reactive power capability (which in turn can have a significant impact on transmission system security), it is not included in any of our margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

Forecast Position for winter 2007/8

133. Figure 15 shows the normal demand forecasts, and the generator availability declared to National Grid by generators under Grid Code Operating Code 2 (OC2), both including and excluding 2 GW of delivery from the UK-France Interconnector[29]. Though a few power stations are indicating that they will be on outage during the peak months of this coming winter, this is no different to previous years' experience. Overall the current levels of notified unavailability are similar to historic levels.

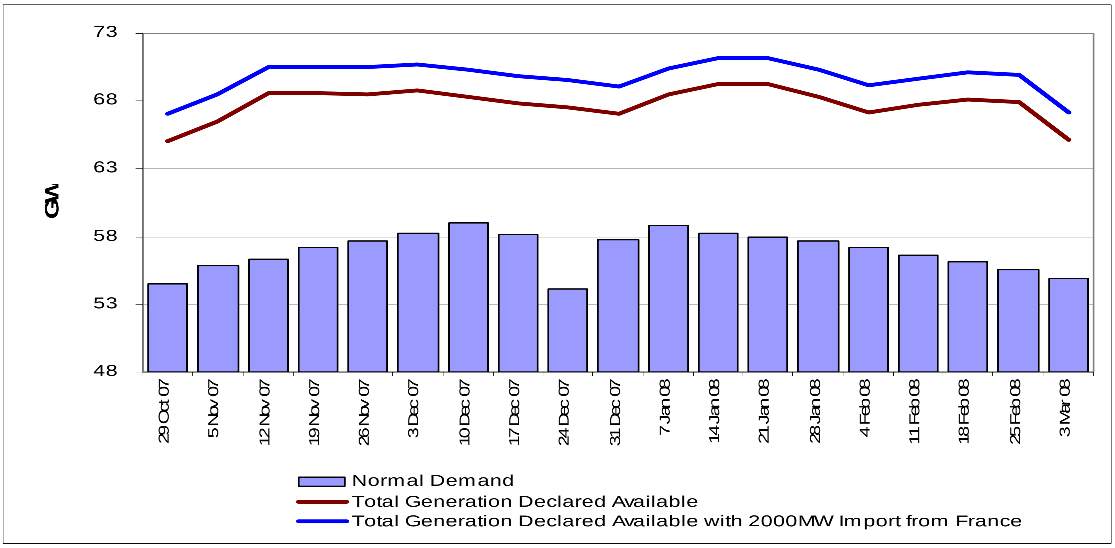
134. Figure 15 illustrates a winter in which average weather conditions are experienced each week, resulting in average temperatures across the winter of 7 °C. It shows weekly forecast generation availability as declared by the generators under the Grid Code. This reflects planned unavailability, but does not include an allowance for unplanned generator availability.

135. As can be seen in Figure 15, with full exports from France the excess generation over average weekly peak demand would be around 12-15 GW. However, Figure 15 does not reflect the fact that even in an average winter there will be times when demand is above normal and approaches or exceeds ACS levels.

136. It is necessary to hold varying levels of reserve services such that within-day we have adequate reserve to cover for short-term generator breakdown and demand forecast errors. On average, this amounts to a requirement of around 6 GW at the day-ahead stage from the generation shown available below. The margin shown in Figure 15 does not reflect this requirement.

[29] The French Interconnector comprises two pairs of 500MW circuits and has annual availability around 95-97%. Full availability is assumed at peak times although if an unplanned outage were to occur then availability could be reduced in increments of 500MW.

Figure 15 – Demand and Notified Generator Availability, Winter 2007/8



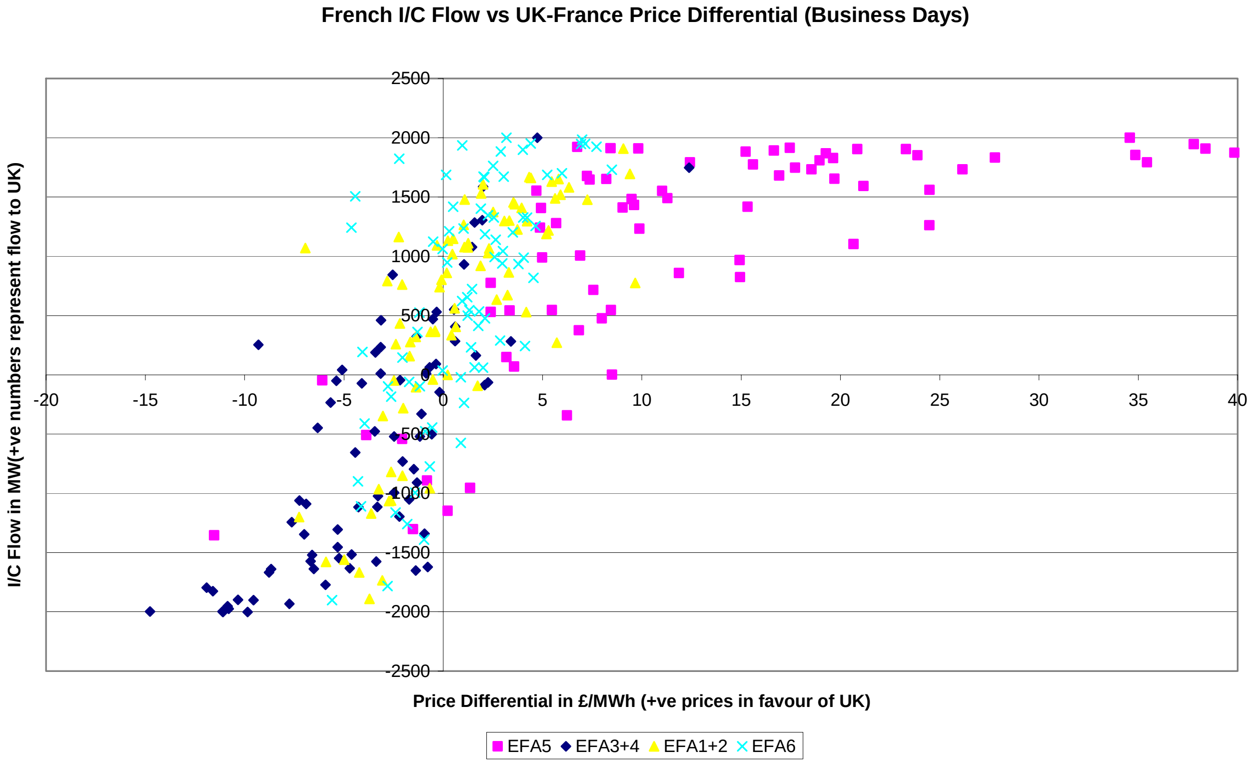
Scenario for Modelling Purposes

137. Based upon historic availability patterns, we have assumed generator availability rates as detailed in Table 12. Actual availability patterns will reflect a multitude of factors, including unplanned events, fuel prices, demand levels, outage plans, the impact of LCPD, and European price differentials. Whilst it is impossible to predict precisely how the electricity and gas markets will respond to the demand-supply balance, the availability rates assumed reflect conditions we could reasonably expect on cold winter weekdays.

138. As expected, flows across the French Interconnector tend to respond to dayahead price differentials between UK and France, as illustrated by Figure 16, which details the outturn flows and dayahead price differentials over winter 2006/7. Power flows to the UK when the UK price is higher than France, and flows to France when the French market is at a premium to the UK.

139. The current forward prices are higher in Britain than in France, as detailed in Appendix III, but the differential is lower than at this stage in September 2006. Our assumption is that at times of a tight gas demand –supply balance in the UK, GB electricity prices will be higher than France, and power will continue to flow to the UK at the full 2 GW rate at the peak periods of the day.

Figure 16 – Winter 2006/7 - French Interconnector Flows and Dayahead Prices[30][31]



140. We have assumed that no plant is short-term mothballed for this forthcoming winter. This seems reasonable as the same behaviour exhibited itself in winter 2006/7. No return of long-term mothballed plant has been assumed. Overall, we assume an 86% availability rate across the winter, as detailed in Table 12.

[30] The actual flows have been adjusted to remove the effect of interconnector trades and SO-SO actions undertaken by National Grid.
[31] The 24 hour day has been split into 6 4-hour blocks, with EFA1 covering 2300 to 0300, EFA2 03:00 to 07:00, EFA 3 07:00 to 11:00; EFA4 11:00 to 15:00, EFA 5 15:00 to 19:00 and EFA 6 19:00 to 23:00.

Table 12 - Assumed Plant Availability, winter weekdays

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.5	80%	8.4
French Interconnector	2.0	100%	2.0
Hydro generation	1.0	60%	0.6
Wind generation	1.2	35%	0.4
Coal	28.1	85%	23.9
Oil	3.4	95%	3.3
Pumped storage	2.8	100%	2.8
OCGT	1.2	95%	1.1
CCGT	25.2	90%	22.7
Total	**75.5**		**65.3**
Average availability		**86%**	

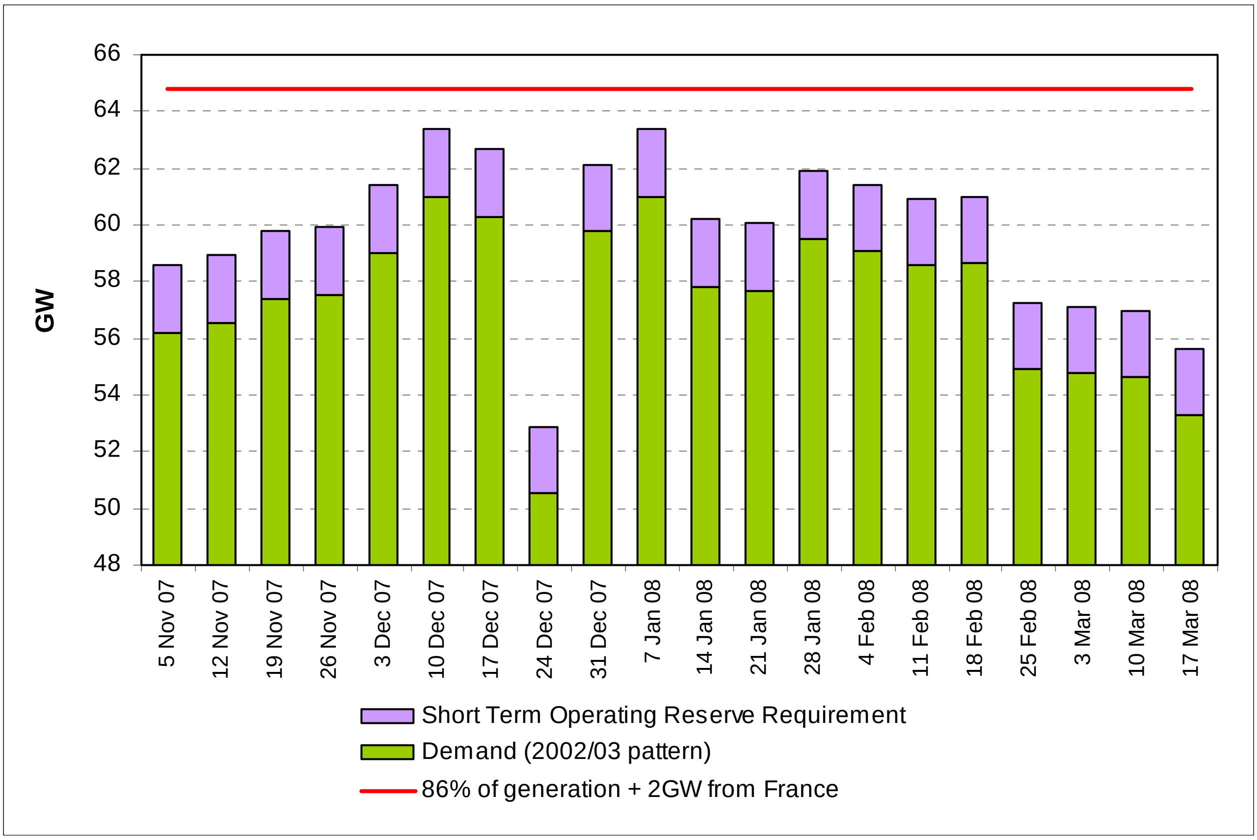
141. This scenario is used to illustrate the ability of the electricity sector to meet demand under average (typical) and 1 in 50 weather conditions, and to provide gas demand side response as detailed further in Chapter 3. The week-by-week profile of unavailability has been smoothed across the winter as a whole.

Average Winter Conditions

142. To illustrate a typical winter, demand has been forecast by assuming the weather pattern of 2002/3. This is a good representation of a typical winter, with a forecast peak winter demand of around 60.8 GW and a normal pattern of high demand spells occurring in December and January.

143. As illustrated in Figure 17, under average winter conditions, there should be more than sufficient plant to meet demand. Under these average weather conditions, there would be scope for the electricity sector to reduce gas demand and provide a material level of demand-side response for the gas sector.

Figure 17 – Forecast Demand under Average Weather Conditions (2002/3 Weather Pattern) and Generator Availability, Winter 2007/8

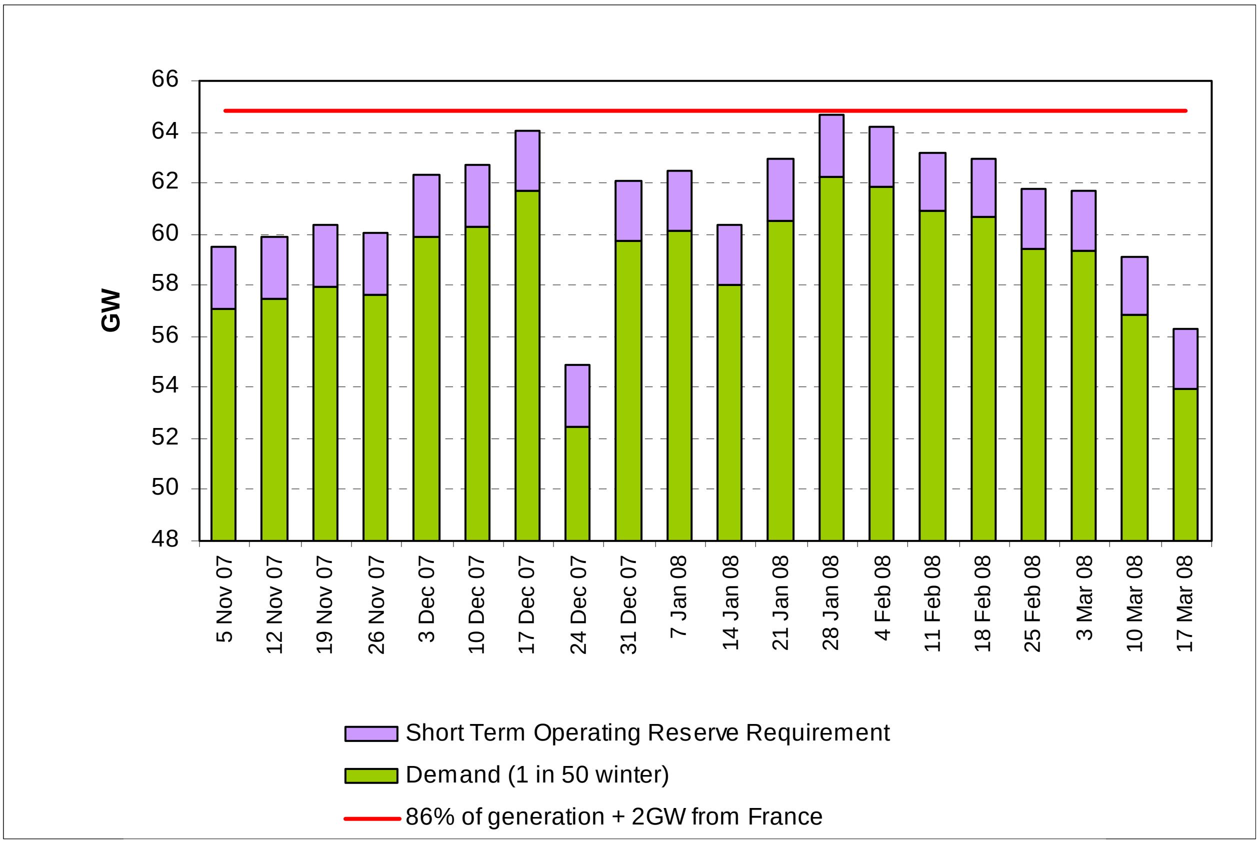


1 in 50 Cold Winter Conditions

144. In 1 in 50 cold winter conditions, where average temperatures across the country would be around -1°C for 1 month and around 1°C for another month, peak demand may increase in the order of 2 GW above ACS demand. The weather pattern experienced in 1946/47 is representative of such a 1 in 50 winter, although we have no recent experience of how demand would respond to these extreme temperatures.

145. If these weather patterns were to occur this winter, as illustrated in Figure 18, the anticipated electricity margin would be sufficient provided we do not experience high levels of plant breakdowns or CCGT unavailability in response to high gas prices.

Figure 18 – Forecast Demand under 1 in 50 Weather Conditions (1946/47 Weather Pattern) and Generator Availability, Winter 2007/8



Chapter 3: Gas / electricity interactions

146. This Chapter describes our analysis of the potential gas demand response available from the power sector. Though the assumptions remain unchanged from the June document, as there is a requirement for gas demand-side response on fewer days, as detailed in Chapter 2, the overall response able to be provided by CCGTs has marginally declined.

147. Gas-fired power stations can be expected to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. This ability to arbitrage between gas and power is not restricted to those power stations that have interruptible gas transportation arrangements. For example, in the 2005/6 winter, there were occasions when firm CCGTs commercially self-interrupted whilst interruptible power stations continued to generate.

148. The willingness of the CCGTs to commercially interrupt themselves will be determined by a number of factors, including:

- the spark spread, which is itself influenced by the ability of the power generation sector to meet demand through switching to other fuels;
- the Large Combustion Plant Directive (LCPD);
- the price of CO_2 emission allowances;
- the price of alternative fuels;
- any environmental constraints (e.g. SO_2) that limit the extent of running on other fossil fuels.

149. Our analysis has sought to determine the potential reduction in gas demand that could be achieved through a response from CCGTs under the gas supply scenarios and consistent with the preservation of sufficient generation capacity to meet electricity demand. We have done this using detailed simulation analysis in which both gas and electricity demand and supply conditions are modeled.

150. The analysis is underpinned by a set of modelling assumptions, which together define the potential for other forms of generation to replace gas when required.

Power generation gas demand and distillate back-up

151. CCGTs are expected to provide a maximum of 25.2 GW of generating capacity in GB for the coming winter, as shown in Table 13. Of this, 3.3 GW have access to gas through non-NTS pipelines and 4.2 GW have the capability to run on distillate. Based upon information provided to us by generators, we assume there is enough distillate to run for 200 hours across the winter.

152. The maximum theoretical power generation gas demand in GB for winter 2007/8 as shown in Table 13 is based upon an assumed average efficiency of 50%. Typically CCGT gas demand is between 50 and 70 mcm/d and only a few occasions does demand rise above 90 mcm/d.

Table 13 – Maximum 2007/8 GB power generation demand[32]

	Maximum gas demand (mcm/d)	CCGT capacity (GW)
NTS-connected	107	24.1
LDZ-connected	5	1.1
Total	**112**	**25.2**

153. Reflecting current fuel prices, as discussed in Chapter 1, our Revised View assumes that coal will be preferred to gas with the result that our power generation gas demand forecast of around 54 mcm/d is already close to the minimum needed by the electricity sector on a high demand day. This reduces the scope for further reductions in gas powered generation at the top end of the load duration curve.

Analysis of potential CCGT demand response – modelling assumptions

154. A number of respondents have previously identified practical issues that could limit the extent of any CCGT response. Issues raised included:

- Technical risks associated with frequent switching to/from and prolonged use of distillate;
- Limitations on the levels of switching to coal and oil as a result of environmental constraints and LCPD considerations;
- Ability to replenish stock may be difficult, especially in prolonged severe weather conditions and if stocks are delivered by road tankers;
- Behaviour might be affected by potential exposure to high imbalance costs if plant fails to generate;
- The ability to rely upon flows from France, especially outside of the peak half-hours.

155. The Large Combustion Plant Directive (LCPD) limits the running hours of 11 GW of stations without Flue Gas Desulphurisation (FGD) to 20,000 hours from 1 January 2008 to 31 December 2015. There is a number of power stations currently installing FGD equipment, in preparation for the commencement of the LCPD Directive on 1 January 2008.

156. However current market prices for coal, carbon and gas imply that coal-fired generation will be preferred to gas-fired generation for winter 2007/8 on strictly marginal cost terms, as detailed in Appendix II. At this stage we do not see any significant security of supply issues over this coming winter with the early stages of LCPD. We assume that at times of high demand or system stress during winter 2007/8 coal and oil stations will continue to make themselves available, albeit at a commercially higher price.

[32] Figures exclude smaller embedded power generators, typically Combined Heat and Power stations, which do not participate in the Balancing Mechanism.

157. The following is a summary of our latest modelling assumptions for winter 2007/8:

- Nuclear runs as base load – 24 hours a day, 7 days a week, with availability of 80%.
- No explicit constraints relating to fuel stocks, LCPD, CO_2 or SO_2 emission limits are applied to coal generation, but overall coal plant is assumed to operate at a maximum load-factor of 85%;
- Imports into GB through the French Interconnector are available off-peak (7pm-7am) at 100% of capability, the peak 4 hours (3pm-7pm) at 100% of capability and the link is at float at other times. This is based on analysis of historical flows and a review of forward spreads between UK and European markets. It should be noted that there is uncertainty over what the actual flows will be on the day as prompt electricity prices in individual markets will influence direction and magnitude of flow on the Interconnector. If the UK did export to France during the afternoon and late evening periods, the daily demand-side response able to be provided by CCGTs would fall by around 5 mcm/day.
- 3.3 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as base load[33];
- 3.9 GW of NTS-supplied CCGTs run as base load, reflecting technical and contractual constraints such as the requirement to provide heat and power to industrial consumers;
- 4.2 GW of CCGTs run 12 hours per day on distillate for a total of 200 hours;
- Pumped storage stations generate only during the peak 6 hours of each day;
- Oil stations generate only during the peak 12 hours of weekdays;
- Non-baseload CCGTs are the marginal generators during winter peak periods;
- As several OCGT units have reserve obligations to National Grid, they are assumed to be low merit and run only very occasionally;
- Plant availability factors as shown in Table 14, consistent with an average availability rate of 86%.

[33] We recognise that non-NTS CCGTs may not always operate as baseload. However this assumption is not material from the perspective of the model results since if these CCGTs were not generating we would assume additional gas flows onto NTS and additional CCGT NTS generation elsewhere.

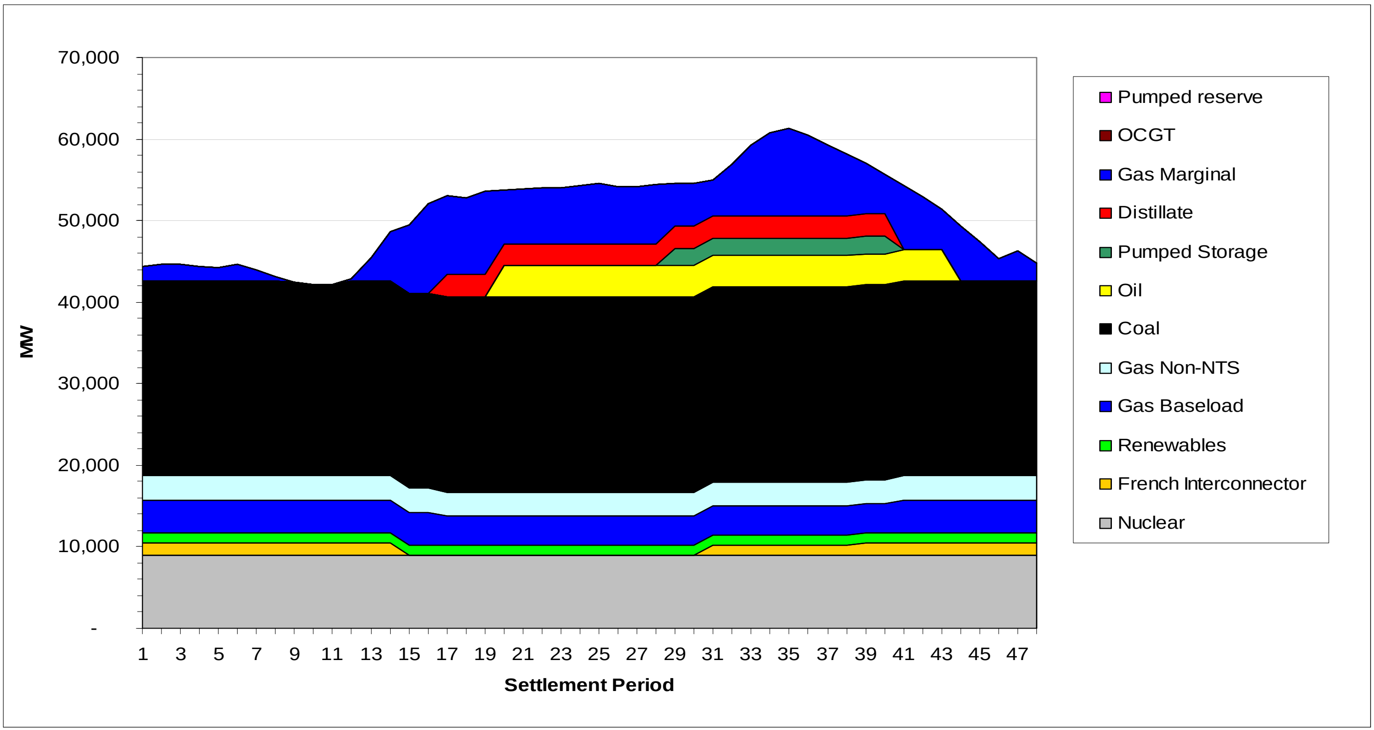
Table 14 – Assumed plant availability factors for demand-side response analysis

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)	Model Assumptions Summary
Nuclear	10.5	80%	8.4	Baseload
French Interconnector	2.0	100%	2.0	Baseload, except 7 am to 3pm weekdays
Hydro generation	1.0	60%	0.6	Baseload
Wind generation	1.2	35%	0.4	Baseload
Coal	28.1	85%	23.9	Baseload
Oil	3.4	95%	3.3	12 hours over peak
Pumped storage	2.8	100%	2.8	6 hours over peak
OCGT	1.2	95%	1.1	Low merit, run occasionally
Non-NTS CCGT	3.3	90%	3.0	Baseload
Baseload CCGT	3.9	90%	3.5	Baseload
Distillate CCGT	4.2	90%	3.8	200 hours
CCGT	13.8	90%	12.4	Marginal plant
Total	**75.5**		**65.3**	
Average availability		**86%**		

Analysis of potential CCGT demand response – simulation results

158. Figure 19 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modelling assumptions described above. It shows approximately 24 GW of coal-fired generation throughout the day, gas as the marginal fuel across the day and distillate used for 12 hours around the peak. demand period

Figure 19 – Potential generation profile - cold winter weekday



159. The simulation has been run for a range of supply levels and the required response calculated for average, 1 in 10 and 1 in 50 weather conditions.

160. Tables 15, 16 and 17 summarise the results from the simulation – projections of the relief that the electricity sector could provide to the gas market under the assumptions described in this Chapter. It also summarises the remaining demand response required from other gas consumers.

Table 15 – Potential CCGT demand response (bcm), Revised View assumptions

	Average	1 in 10	Severe
Required	0.0	0.0	0.0
Potential CCGT	0.0	0.0	0.0
Deficit	0.0	0.0	0.0

Table 16 – Potential CCGT demand response (bcm), Revised View plus 30 mcm gas supply

	Average	1 in 10	Severe
Required	0.0	0.0	0.0
Potential CCGT	0.0	0.0	0.0
Deficit	0.0	0.0	0.0

Table 17 – Potential CCGT demand response (bcm), Final View minus 30 mcm gas supply

	Average	1 in 10	Severe
Required	0.0	0.15	0.65
Potential CCGT[34]	0.0	0.15	0.30
Deficit	0.0	0.00	0.35

161. As Table 15 and 16 illustrate, our modeling suggests that no demand response would be required, even in a severe winter, under the Revised View and +30 mcm supply scenario. Under the scenario where gas supply is 30 mcm lower than the Revised View, as detailed in Table 17, a demand side response of 0.65 bcm would be required of which only 0.31 bcm could be supplied by the power generation sector.

[34] These values represent the relief CCGTs could provide for all the days when the Revised View supplies do not meet the demand. The available relief from the CCGTs may be less than anticipated as on the days of highest demand we have already factored in lower use of CCGTs due to the anticipation of a higher gas price and thus preferential use of alternative fuels

Appendix I - Summary of Responses to June 2007 Update

162. Following its Preliminary report published in March 2007, National Grid received feedback on a range of specific questions. We reflected such feedback and further analysis in our June Update, where our Revised View reflected marginal changes to our Initial View.

163. Reflecting the earlier comprehensive feedback and relatively minor changes in our Revised View, in the June update we asked for feedback on a limited range of issues.

164. National Grid received 7 responses to our Winter 2007/8 Consultation Update, published in June 2007. The responses provided us with valuable additional information relating to the forthcoming winter, which has helped us to confirm the analysis contained within the June consultation update document.

165. This note by National Grid provides a summary and overview of the issues raised and views expressed without attributing comments to individual organisations.

166. We would like to thank the following for responding to the 2007/8 Consultation Update Document published in June.

- Centrica Energy
- EDF Energy
- Energy Watch
- Oil and Gas UK
- Scottish and Southern Energy

167. The views contained in the 2 confidential responses have not been reflected in this summary report.

168. We invited comments on all aspects of our Revised View, but in particular we welcomed views on:

    - the extent to which European gas would flow to GB from Norway, Belgium and Netherlands at an average rate of 132 mcm/d, especially at times of high European demand;
    - the degree to which gas demand over winter 2007/8 will increase, in response to the relatively lower gas prices;
    - whether electricity demand will bounce back, or be stagnant, as we assume;
    - the extent to which the flows on the France-GB electricity interconnector will be towards GB, at times of high demand across Europe.

169. Respondents were in general agreement with the analysis set out in the report. In addition to commenting on the specific questions raised, respondents also took the opportunity to comment on wider issues.

Gas Flows

170. 2 respondents explicitly agreed with our Revised View that European gas supplies would be around 132 mcm/d.

171. However another respondent felt there was room for the gas supply to increase above our Revised View:

- we had not factored in a within winter profile for new supplies that are expected to come on-line;
- we had ignored the potential capacity upgrade scheduled for the BBL pipeline;
- we assumed just 70 mcm/day flows from Norway and ignored the Tampen Link;
- we assumed no LNG flows through Teesport;
- we have excluded deliveries from South Hook.

172. 1 respondent was concerned that gas quality remained an issue, which may discourage flows of additional European gas.

173. 1 respondent expressed potential concerns as to the timing of planned maintenance, and whether this could reduce security of supply during adverse weather conditions.

174. 1 respondent expressed concern about the lateness of investment in the Easington area.

Gas Demand

175. 1 respondent considered our forecast of non-daily metered gas demand to be too high, as it did not think demand would bounce back with the fall in the retail price.

176. Several other respondents considered there to be a high chance that spot gas prices would fall and that CCGT gas demand would consequently rise.

Electricity Flows

177. 1 respondent expressed concerns that the emissions limits bubbles (B limits) would influence the running of coal-fired generation in Q4 2007, and that LCPD would influence running behaviour from 1 January 2008.

Appendix II - GB Fuel and Electricity Prices

Tables 7 and 8 show that at current market prices (as of Monday 24 September 2007) for winter 2007/08, the profit (spread) over fuel and carbon costs is greater for coal-fired generation than for gas-fired generation.

When considering the relative attractiveness of different fuels, the transport and O&M (operation and maintenance) costs have been ignored. At current market prices for winter 2007/08, they are not considered to significantly influence the relative attractiveness of the different fuels.

1) Assumed efficiencies

gas	coal	oil
49%	36%	35%

2) GB Power Prices £/MWh

	Q4 07	Q1 08	summer 08	winter 08/09
Base Load (24 hours * 7 days per week)	37.30	47.70	40.90	45.60
Peak (12 * 5)	48.85	60.00	49.70	57.75
offpeak	30.88	40.87	36.01	38.85

3) Gas Prices

	Q4 07	Q1 08	summer 08	winter 08/09
p/th	41.1	50.0	38.2	49.7
£/MWhe	28.6	34.8	26.6	34.6

£/MWhe is derived by the following calculation for gas-fired generation
Cost of gas-fired generation (£/MWhe)= gas price (p/therm) / *[29.3071 (kWh per therm)*efficiency]* * *[1000 (kWh per MWh)/100 (p per £)]*

4) Exchange Rates

€ to £	$ to £
0.6975	0.49491

5) Coal Prices

	Q4 07	Q1 08	summer 08
$/tonne	98.75	97.5	98.13
£/tonne	48.9	48.3	48.6
£/MWhe	19.47	19.22	19.35

£/MWhe is derived by the following calculation for coal-fired generation
Cost of coal fired generation (£/MWhe)= [coal price (£/tonne)/25.1 (GJ per tonne)] * *[3.6 (GJ per MWh)/efficiency]*

6) Carbon Price

	€ per tonne	£ per tonne	Gas £/MWh	Coal £/MWh	Oil £/MWh
carbon intensity (tonne of CO2 per MWhe)			41%	94%	86%
Carbon 2007 (ETS I)	0.07	0.05	0.02	0.05	0.04
Carbon 2008 (ETS II)	21.9	15.3	6.26	14.36	13.14

Due to the higher carbon content of coal compared with gas, and the lower efficiency, coal-fired generation produces over twice as much CO2 per MWhe as does gas-fired generation.
Cost of carbon (£/MWhe)= carbon price (£/tonne) * carbon intensity (tonne of CO2 per MWhe)

7) Clean Spark Spread for Gas-Fired Generation £/MWh

	Q4 07	Q1 08	summer 08	winter 08/09
Base Load (24 hours * 7 days per week)	8.69	6.62	8.04	4.73
Peak (12 * 5)	20.24	18.92	16.84	16.88
offpeak	2.28	-0.21	3.15	-2.02

Clean spark spread (£/MWh)= wholesale electricity price (£/MWh) – marginal fuel cost of gas-fired generation (£/MWhe) – cost of carbon (£/MWhe)
For Q1 2008 baseload electricity this is 47.7-34.8-6.3=6.6 £/MWh

8) Clean Dark Spread £/MWh

	Q4 07	Q1 08	summer 08
Base Load (24 hours * 7 days per week)	17.8	14.1	7.2
Peak (12 * 5)	29.3	26.4	16.0
offpeak	11.4	7.3	2.3

Clean dark spread (£/MWh)= wholesale electricity price (£/MWh) – marginal fuel cost of coal-fired generation (£/MWhe) – cost of carbon (£/MWhe)
For Q1 2008 baseload electricity this is 47.7-19.2-14.4=14.1 £/MWh

Definition of terms used in the tables
Baseload denotes "flat operation" - same level 24 hours per day, 7 days per week
Peak denotes operation during the peak 12 hours of the day (07-19:00), 5 days per week
Off-Peak denotes operation during the off-peak periods (00 -07:00, 19-24:00 weekdays, and 00-24:00 weekends)

Q4 2007 is Oct-Dec 07 in the gas market, weeks 40-52 electricity
Q1 2008 is Jan-Mar 08 gas, weeks 01-13 electricity
summer 08 is Apr-Sep gas, weeks 14-39 electricity
winter 2008/9 is from week 40 2008 to week 13 2009 electricity

Appendix III - GB and French Electricity Prices

As Table 5 shows, UK prices as of 24 September are higher than French prices.
The UK-France premium is greater during off-peak than during peak periods.

1) GB Power Prices £/MWh

	Q4 07	Q1 08	summer 08	winter 08/09
Base Load (24 hours * 7 days per week)	37.3	47.7	40.9	45.6
Peak (12 * 5)	48.9	60.0	49.7	57.8
offpeak	30.9	40.9	36.0	38.9

2) French Power Prices €/MWh

	Q4 07	Q1 08	summer 08
Base Load (24 hours * 7 days per week)	45.6	64.3	47.8
Peak (12 * 5)	64.5	84.7	65.6
offpeak	35.1	53.0	37.8

3) Exchange Rates

€ to £
0.6975

4) French Power Prices £/MWh

	Q4 07	Q1 08	summer 08
Base Load (24 hours * 7 days per week)	31.8	44.9	33.3
Peak (12 * 5)	45.0	59.1	45.8
offpeak	24.5	37.0	26.4

5) UK premium on French prices £/MWh

	Q4 07	Q1 08	summer 08
Base Load (24 hours * 7 days per week)	5.5	2.8	7.6
Peak (12 * 5)	3.9	0.9	3.9
offpeak	6.4	3.9	9.6

Definition of terms used in the tables
Baseload denotes "flat operation" - same level 24 hours per day, 7 days per week
Peak denotes operation during the peak 12 hours of the day (07-19:00), 5 days per week
Off-Peak denotes operation during the off-peak periods (00 -07:00, 19-24:00 weekdays, and 00-24:00 weekends)

Q4 2007 is Oct-Dec 07 in the gas market, weeks 40-52 electricity
Q1 2008 is Jan-Mar 08 gas, weeks 01-13 electricity
summer 08 is Apr-Sep gas, weeks 14-39 electricity

Appendix IV: Industry Framework Developments

178. National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply-demand balances. This appendix discusses significant industry developments which have either recently concluded or may conclude during winter 2007/8.

Gas Entry Capacity Transfers and Trading

179. National Grid has obligations to release capacity ahead of the day and also within-day, on an interruptible and firm basis. National Grid has also recently put forward a UNC Modification Proposal (Mod 0159) and received approval to release additional discretionary interruptible capacity. The combined effect of the obligations and the buyback incentive seek to maximise the capacity offered at a given Aggregated Supply Entry Point (ASEP) and also the volume of gas transported away from that ASEP. If any constraint arises, National Grid endeavours to minimise costs to manage the constraint through a range of tools, such as options and prompt buybacks.

180. The recent price control settlement has sought to change the capacity regime by including a trade and transfer obligation on National Grid, under which capacity rights/obligations could increase at one ASEP and be reduced at another. On 6 September 2007 Ofgem approved a Trade and Transfer UNC Modification Proposal (Mod 0169) and an associated Methodology Statement. A two round auction will now be held ahead of this winter, which will allow Users to bid for capacity above an ASEP's obligated level. Therefore, depending on the results of the auction, this could lead to increased firm capacity being available at ASEPs such as Teesside and Easington. However, it should be noted that there would be corresponding, but not necessarily equivalent, reductions at other ASEPs. National Grid, in support of the now approved Transfer and Trade Methodology Statement, issued some indicative information on exchange rates, which showed that a moderate increase in capacity at Easington could be achieved through reducing all of the available capacity at the Isle of Grain.

Baseline Capacity Substitutions

181. Consistent with Ofgem's final proposals for the Transmission Price Control Review, National Grid is developing arrangements by which it may substitute unsold baseline capacity between entry points to avoid or minimise NTS investments required to meet incremental signals provided through long term entry auctions. This means that if baseline amounts are not purchased in the long term auctions, they may be used to meet requirements elsewhere and hence might not be available in subsequent annual and daily auctions. Users need to consider such changes in developing their bidding strategies for future auctions. The substitution Licence obligation comes into force on 2 June 2008. Therefore National Grid will be consulting on such new substitution methodologies during the first part of 2008.

Gas Market Information Provision Initiative (MIPI)

182. Following the successful development and expansion of the Information Exchange website National Grid has worked with the industry to develop a more robust and user friendly information system. This system will go live in October 2007 and will include the new information required by the introduction of UNC Proposals 97a (Physical offtake quantities at Interconnector Exit Points), 0104 (LNG stocks held at LNG Importation Facilities) and 0121 (The Provision of Ex-Post Demand Information for all NTS Offtakes). Industry introductory seminars for this new service have been held during September. National Grid is also currently working with the industry to review the information it currently provides, any new information that would be helpful and the nature in which this information is provided. This review is being undertaken as part of the UNC 140 Review Group (Review of Information Provision via the internet). This UNC Review Group is due to report to the October UNC Panel meeting.

Gas Emergency Cashout Arrangements

183. The GB gas regime is becoming increasingly reliant upon non-UKCS sources of supply. Ofgem recently chaired a series of workshops, under the heading of “Options for the design of gas emergency arrangements”, which considered amongst other things how the UK’s ability to draw upon or attract additional gas resources into the GB network throughout a Gas Deficit Emergency event (Stage 2 and higher) might be enhanced.

184. Following these workshops we have further discussed and explored the issues with Ofgem, APX Ltd and Shippers and have developed UNC modification proposal 0149 - Gas Emergency Cashout Arrangements: Keeping the On the Day Commodity Market (OCM) open during a Gas Deficit Emergency. This modification would retain the On the Day Commodity Market throughout a Gas Deficit Emergency for shipper to shipper trading and replace the current fixed emergency cashout prices with ones determined from shipper trades in the OCM. EON has also raised an alternative proposal to 0149 which effectively does the same as 0149 except that it retains the current fixed cashout arrangements. Both proposals are currently with Ofgem for determination. Both proposals suggest a 1 November 2007 implementation date.

Electricity Cash Out Review & Associated BSC Modifications

185. Ofgem is undertaking a review of the electricity imbalance price arrangements to assess the appropriateness and effectiveness of the current methodology. National Grid is fully committed to participating in this review and is actively engaged in supporting the review in order to achieve an outcome that best facilitates the effective and efficient operation of the electricity market. In parallel with the review two modifications regarding the imbalance price methodology have been proposed in the Balancing & Settlement Code (BSC). BSC modification P211 proposes the adoption of an unconstrained stack methodology, rather than the physical activity undertaken by the System Operator, to derive the imbalance price. BSC modification P212 advocates the used of a forward market index price plus a percentage offset to reflect if System Buy Price (SBP) or System Sell Price (SSP) was the main imbalance price. The proposers of both of these modifications cite the aim of the

proposals as being to introduce a methodology that better prevents non-energy balancing activity from influencing the imbalance price.

Electricity Market Information Transparency

186. Through the Demand Side Working Group, Operational Fora and an open consultation, National Grid has been progressing improvements in how market data is made assessable to the market. Based on comments received so far, National Grid has commenced work in a number of areas, working jointly with Elexon as a key provider of electricity information transparency particularly on its BMRA website.

187. In addition, responding to feedback on our demand data, we have published definitions on what constitutes demand in different contexts and are exploring ways we can increase the consistency of the demand data released to the market. We continue to explore with Elexon and the industry improvements to the availability of high level electricity market summary information in a way accessible in particular to large electricity users and electricity consumers in general. We will produce a conclusions report on our electricity information transparency consultation in October 2007.