nationalgrid

Winter 2007/8 Consultation Update Document

Executive Summary

Introduction

1. 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. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem. 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.
2. In recent years, National Grid has provided information to the participants in the gas and electricity markets by publishing an outlook for the winter ahead. For the last 2 years, recognising that our sources of data are necessarily incomplete, we 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.
3. In conjunction with Ofgem, we have decided to conduct a similar consultation process this year. In March, we published the preliminary consultation report, which summarised the key developments during the 2006/7 winter and set out the initial view of the 2007/8 winter. We received 12 responses from a broad range of industry participants. There was general support for our assumptions, and there were no areas of major disagreement.
4. This document represents the second stage of that process, containing updated analysis and seeking further views. We plan to publish the Winter Consultation Report, reflecting the feedback received from industry participants, by the end of September.

Gas

5. Last winter saw the successful commissioning of a number of major infrastructure projects facilitating the importation of substantial quantities of gas into the UK. These projects included the Langeled pipeline from Norway connecting at Easington; enhancements to the Belgian Interconnector (IUK); and the BBL pipeline linking the UK market at Bacton with Holland. In addition, Excelerate Energy commissioned its import LNG facility at Teesside, using onboard ship re-gasification technology.

6. In addition for next winter, 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.

7. 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.

8. Since our March document, we have completed our analysis of data received through the 2007 Transporting Britain's Energy (TBE) consultation process, and we have received feedback on our Initial View presented in March 2007. This document therefore incorporates updated forecasts of demand and supplies from the UK Continental Shelf (UKCS). While the latter is largely unchanged from the Initial View, the demand forecasts are now marginally higher reflecting a softening of the gas price.

9. The forecast of gas supply, including storage, represented by our Revised View is around 55 mcm/d higher than the September 2006 Base Case assumptions for 2006/7, and though the demand forecast is higher, the supply-demand balance has improved.

10. On 31 May 2007, we published our preliminary view of initial safety monitor level for 2007/8 as required under the Uniform Network Code. The total non-storage supply assumption of 370 mcm/d used for calculating the 2007/8 preliminary safety monitors is 35 mcm/d higher than the equivalent figure used in setting the 2006/7 safety monitors. This results in lower monitor levels of just 3% 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.

Demand Side Response

11. With an improved gas demand-supply balance, the requirement for gas demand response is lower than the 2006/7 Base Case. However there continues to be a requirement for both CCGT and non-CCGT demand response in cold winters, under low supply conditions.

Electricity

12. 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. 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.

13. 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. Combined Cycle Gas Turbine (CCGT) gas demand was well above the level implicit in our unrestricted demand forecasts. At current fuel 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 Overview

14. Given National Grid's role in the market, our intelligence on the gas and electricity supply-demand outlooks is wholly reliant on the data and insights that we receive from others. We received 12 responses to our Preliminary Consultation Document published in March, which will be made available on Ofgem's website.

15. A key focus of the consultation is the uncertainty surrounding the gas supply position for 2007/8. In Chapter 1, we examine the key issues associated with this background with reference to the individual supply sources and the way in which they may interact with one-another.

16. Chapter 2 sets out the latest view of the demand and generation background in the electricity market for 2007/8.

17. In Chapter 3, we present our latest assumptions underpinning future analysis of the potential for CCGT demand response in 2007/8, and we welcome insights and views through this consultation on the extent to which such assumptions are valid should the need arise next winter.

18. We invite comments on all aspects of our Revised View, but in particular we would welcome 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.

19. We would appreciate any comments on this report as soon as possible but not later than Friday 3 August.

20. Responses should be e-mailed to: andrew.ryan@uk.ngrid.com.

21. 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.

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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.

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 the demand background, 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. The Initial View was not explicitly a National Grid view; but was presented in order to provide a starting point for industry discussion and comment. In broad terms the feedback we received was generally in agreement with the assumptions we made on the supply-side.

24. We have updated our analysis and whilst we have highlighted some issues within this document we would welcome views on all aspects of our analysis, and in particular on our assumptions concerning imported gas supplies and demand growth. The analysis has been updated in two respects: first, it incorporates the latest supply and demand forecasts derived using data from the 2007 Transporting Britain's Energy (TBE) consultation process; second, the revised supply view and sensitivities have been developed to take account of these latest forecasts and industry feedback on the March document. The Revised View seeks to provide a balanced representation of industry expectations based on the information and views that we have received.

25. Previously we have sought to identify the level of demand-side response that would be required under specified supply and demand conditions and weather patterns. Whilst we continue with this approach, the anticipated improving supply position provides us with new challenges as to how supplies may be used to meet demand.

Gas demand

26. 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. The latest forecast suggests that demand will be slightly higher and this change is primarily the result of a reassessment of fuel prices and the impact this has had upon consumption. Where the latest, lower view of prices has increased our outlook on demand, such as in the power generation sector, this increase is mainly in the summer and any change in our forecast view of winter peak is restricted to within 1%.

27. 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. However, historical data is inevitably limited given that we have not experienced a particularly cold winter for many years, and certainly not whilst prices have been at or around today's levels. It is therefore reasonable to consider whether consumer behaviour would alter in the face of prolonged cold conditions, with respect to the balance between the need to remain warm and cost concerns.

28. As detailed in the March document our validation of the 2006 demand forecasts shows both the restricted and unrestricted demands giving a good fit to actual demand at different times during the winter. The variation between forecast and actual demand was largely explained by the level of power generation. Consequently, the 2007 forecasts contain 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 at the top end of the load duration curve.

Demand-side response

29. The 2007 forecast assumes that coal is the preferred fuel for power generation for winter 2007/8. 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.

30. Our Revised View of CCGT gas demand is around 54 mcm/d on peak winter weekdays, which is comparable to our summer 2006 forecast for winter 2006/7 of 53 mcm/d. As winter 2006/7 progressed, outturn CCGT demand increased from the range 55-70 mcm/d to the range 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.

31. Whilst there is little or no need for other large users to provide a demand-response in most conditions, there continues to be a need for large users to provide significant response at times when there is both cold weather and low gas supply.

Transportation capacity

32. 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.

33. 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.

34. So-called transfers and/or trades type modifications could be brought forward and potentially have an impact for this winter. An example of a potential impact is discussed briefly in paragraph 54.

Gas supply

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

UKCS gas supplies

36. 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.

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

38. We have now received and assimilated the 2007 TBE information. Table 1 shows that our revised UKCS maximum forecast, taking full account of the latest TBE data, is marginally higher than the Initial View published in March.

Table 1 – 2007/8 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2006/7		2007/8	
	Forecast	Highest	Initial View (March)	Revised View
Bacton	75	55	67	74
Barrow	24	25	23	22
Easington	16	15	15	13
Burton Point	2	4	2	2
St Fergus[1]	94	95	89	89
Teesside	30	35	28	26
Theddlethorpe	26	28	26	26
Total[2]	**267**	**257**	**249**	**252**

39. Following receipt of 2007 TBE producer information we have revised our forecast of maximum UKCS production for winter 2007/8 from 249 to 252 mcm/d. Our latest view includes a year-on-year decline of 29 mcm/d from existing fields, which is offset by incremental developments totalling around 14 mcm/d. It should be noted that there is some uncertainty over the volumes that will be available from incremental developments due to timing and commissioning issues.

40. 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. 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

[1] Excludes Vesterled
[2] 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

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.

41. 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.

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

- There would be some upside against this revised 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.

Imported gas sources

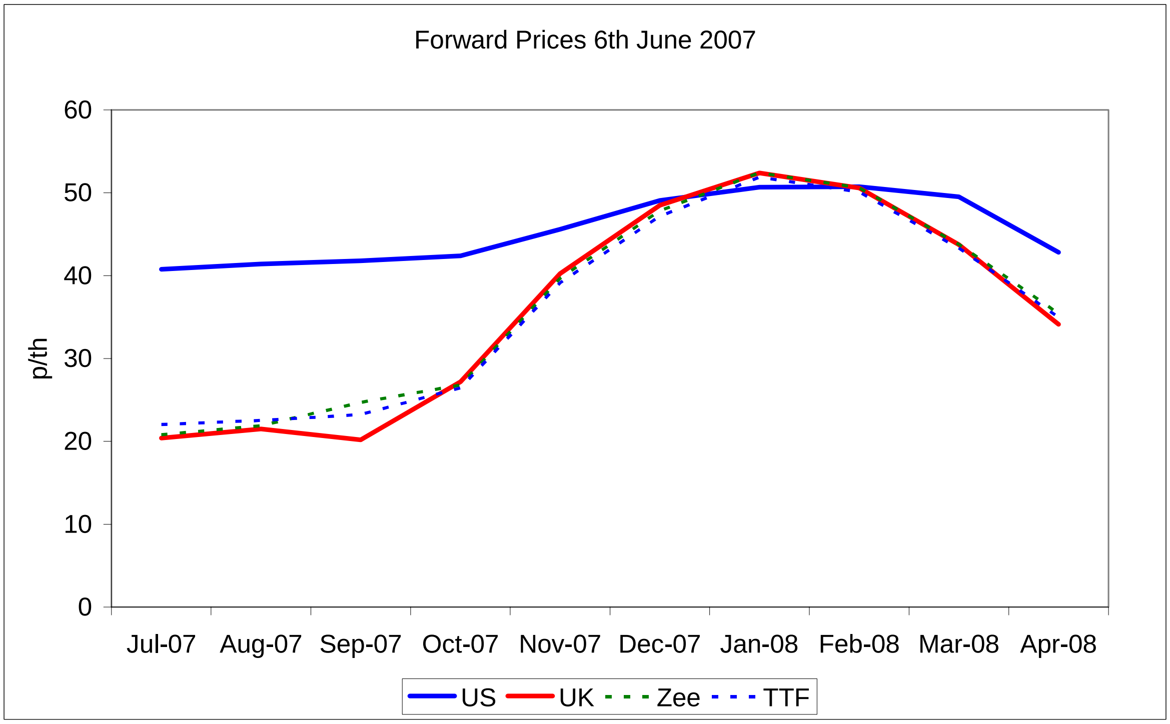
43. As the UKCS continues to decline, the UK is becoming increasingly reliant on gas delivered via new and existing importation routes to ensure security of supply. Risks associated with the delivery of these projects, and the extent to which existing infrastructure will be used, add to the overall level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

44. With the commissioning last winter of Langeled, BBL, and Teesport LNG in addition to the capacity upgrade of IUK there is undoubtedly less uncertainty over the availability of import capacity for next winter. In addition to these projects, for next winter there are two major import projects under construction at Milford Haven and further capacity expansion being made available at IUK and BBL, through 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 forecasts for next winter.

45. Figure 1 provides an updated view of forward prices for winter 2007/8 in GB, Continental Europe and in the US at the Henry Hub (HH). European prices are currently well below the equivalent HH price for parts of the winter, suggesting that the risk of cargo diversion to the United States is relatively high[3].

[3] This graph excludes any transport costs. The typical transport cost for LNG across the Atlantic is about 4 p/therm.

Figure 1 – Monthly Forward gas price comparison



Belgian Interconnector (IUK)

46. The capacity of IUK was increased last winter from 48 to 68 mcm/d. Plans are in place to further expand this to 74 mcm/d for next winter.

47. Our view for flows through IUK for next winter remain the same as we reported in the March documents, 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 1), suggesting little or no flow, developments during the winter could create market opportunities for IUK to flow in either direction;
- Although plans are in place to expand the capacity of IUK to 74 mcm/d, we are not aware of capacity enhancements on the Belgium or interconnecting networks to support imports at these rates;
- 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;
- Hence our Revised View of imports through IUK is up to 30 mcm/d through to December and up to 40 mcm/d post December. However as detailed above, these flows will only materialise if the market conditions prevail. Figure 1 below shows forward prices for NBP, TTF and Zeebrugge. With all of the European prices broadly in line for next winter, there appears to be no obvious signal as to how the IUK may flow.

BBL

48. The Dutch Interconnector (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.

49. 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, the trading arm 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.

50. Our view for flows through BBL for next winter remain the same as we reported in the March 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.

Norwegian imports

51. 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 deliveries from Ormen Lange expected to commence in October.

52. 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.

53. 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 and 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.

54. Our view for flows from Norway for next winter remain the same as we reported in the March document, namely:

- Flows of 70 mcm/d, split approximately 25 mcm/d through Vesterled and 45 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 addition volumes, though as these are uncertain these are discounted for next winter;
- 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 45 mcm/d through Langeled, there is sufficient head room in the Easington baseline (~98 mcm/d) to further accommodate both UKCS supplies to Easington and near 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 Pannel 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 transmission capability from the NTS can be directed to a certain extent to flows at Aldbrough, Easington and Hornsea as required. On this basis it is possible that gas flows above the baseline at Easington could be accommodated when Aldbrough and Hornsea flows are reduced;
- National Grid has obligations to release capacity ahead of the day and also within-day, on an interruptible and firm basis. The combined effect of the obligations and the buyback incentive seek to maximise the capacity offered at a given 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.
- 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. Although recent proposals on this were rejected, National Grid remains committed to work with shippers to develop new arrangements. Were these to be implemented for this winter, limited additional supplies may be seen at ASEPs signalled by shipper bids, for example at Easington. Depending on the exchange rates which apply, a corresponding effect (i.e. reduced supply) could be seen at other ASEPs, particularly those where shippers had not procured firm capacity in a timely manner or where interruptible capacity was not available.

Total European imports

55. 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.

LNG

56. Last winter we observed regular deliveries of LNG into Grain and the unloading of part of a cargo at Teesport for commissioning purposes. For next winter we have the possibility of additional LNG through two new terminals at Milford Haven; South Hook and Dragon.

57. Dragon is believed to be commissioning in 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 Revised View peak supply of 20 mcm/d.

58. South Hook is now reported to be commissioning in Q2 in 2008, later than reported in our March publication. 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 now later than March 2008, we are excluding deliveries from South Hook from our Revised View.

59. With South Hook now excluded from our forecast for next winter, our aggregated view for LNG next winter is now 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 1) are higher than those in the UK for parts of the winter. Under these conditions, the US could be expected to attract some or many of the cargoes that could have been expected for the UK. For this reason for our Revised View we are assuming no LNG flows through Teesport, though acknowledge there could be 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 next winter;
- If South Hook is completed earlier than now expected, this will provide a material upside to our LNG forecast;

Storage

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

61. Table 2 shows our assumed levels of storage space and deliverability for next winter. These include estimated levels of space and deliverability for Aldbrough.

Table 2 – Assumed 2006/7 storage capacities and deliverability levels[4]

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1939	526	49	3.7
Medium (MRS)	9703	485[5]	45	20
Long (Rough)	34445	455	42	75.7

Revised View

62. 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

[4] Excludes Operating Margins gas + Scottish Independent Undertakings
[5] Assumes average deliverability for Humbly Grove and includes estimates for Aldbrough

we have indicated how we believe that the Revised View of supplies should be developed to properly reflect these points. We have also highlighted the residual uncertainties for each of the supply sources and welcome further views on these issues.

63. Table 3 summarises the Revised View emerging from this consultation process, and compares these with the assumptions made in our March document and those made in respect of last winter in our Winter Outlook 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.

Table 3 – Supply assumptions incorporated into Revised View (mcm/d)

	2006/7 Base Case	**2007/8 Max Capacity**	**2007/8 Initial View**	**2007/8 Revised View**	**Days at full rate**
UKCS	240	252	224	227	
Norway	48	104	70	70	
IUK	36	74	37	37	
BBL	14	41	25	25	
LNG	13	69	46	33	
Total Non-Storage	**350**	**540**	**402**	**392**	
Short Duration Storage	49	49	49	49	3.7
Medium Duration Storage	32	45	45	45	20
Long Range Storage	42	42	42	42	75.7
Total Storage	**123**	**136**	**136**	**136**	
Grand Total	**473**	**676**	**538**	**528**	

64. Despite a decline in our UKCS forecast of nearly 10%, when compared to last winter our Revised View for non-storage supplies for next winter is now 12% 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 the IUK will be driven by market conditions.

65. As detailed in the previous supply sections, considerable uncertainty remains over all of the supply sources, as captured in Table 4 below.

Table 4 – Non-storage supply uncertainties (mcm/d)

	2007/8 Revised View	Sensitivity	Supply Change
UKCS	227	85% rather than 90% supply availability	-13
		+/- 5% forecast error	+/- 11
		Zero flow from high swing UKCS supplies[6]	-23
Norway	70	Higher Norwegian deliveries to UK	+30
		Increased Norwegian deliveries to Continent	-20
IUK	37	Maximum flows to UK experienced so far	+13
		Zero UK imports to reflect well supplied UK	-37
BBL	25	Higher flows to reflect increased capacity[7]	+10
		Lower flows to reflect shift to market conditions	-10
LNG	33	Deliveries made at Teesport	+11
		Deliveries made at South Hook	+36[8]
		Dragon – commissioning delay or NTS delays	-20
		Cargoes diverted from Grain to US	-13
Total	**392**	**Aggregated Non-Storage Supply Range**	**+111** **-147**

66. Table 4 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 Revised View. To capture this we have assumed a supply range around the Revised 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.

67. Examples of an increase of supplies of approximately 30 mcm/d could be full volumes through Langeled (assumes Vesterled retained at 25 mcm/d), 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 attractive market opportunities elsewhere or very low IUK imports.

[6] Assumes 10% of UKCS, to reflect no flow from high swing UKCS supplies into Bacton and / or possibly Barrow
[7] Assumed level, reflect lower uncertainty when compared to IUK
[8] Assumes a 25% swing above annual supply

68. The following sections provide analysis of the supply-demand position in 2007/8 assuming the Revised 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 Revised View

69. Figures 2, 3 and 4 show the Revised 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 demand that could provide a demand-side response if high prices were to materialise. As detailed in Section 3, this level of demand-side response could potentially equate to approximately 10 - 15 mcm/d. However it may materially be 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.

70. 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. 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.

71. 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 5 summarises the implied level of demand response required over the highest 100 days of demand, for the Revised View of supplies and for the extremes of the supply range.

Figure 2 – Supply availability vs average load duration curve for 2007/8

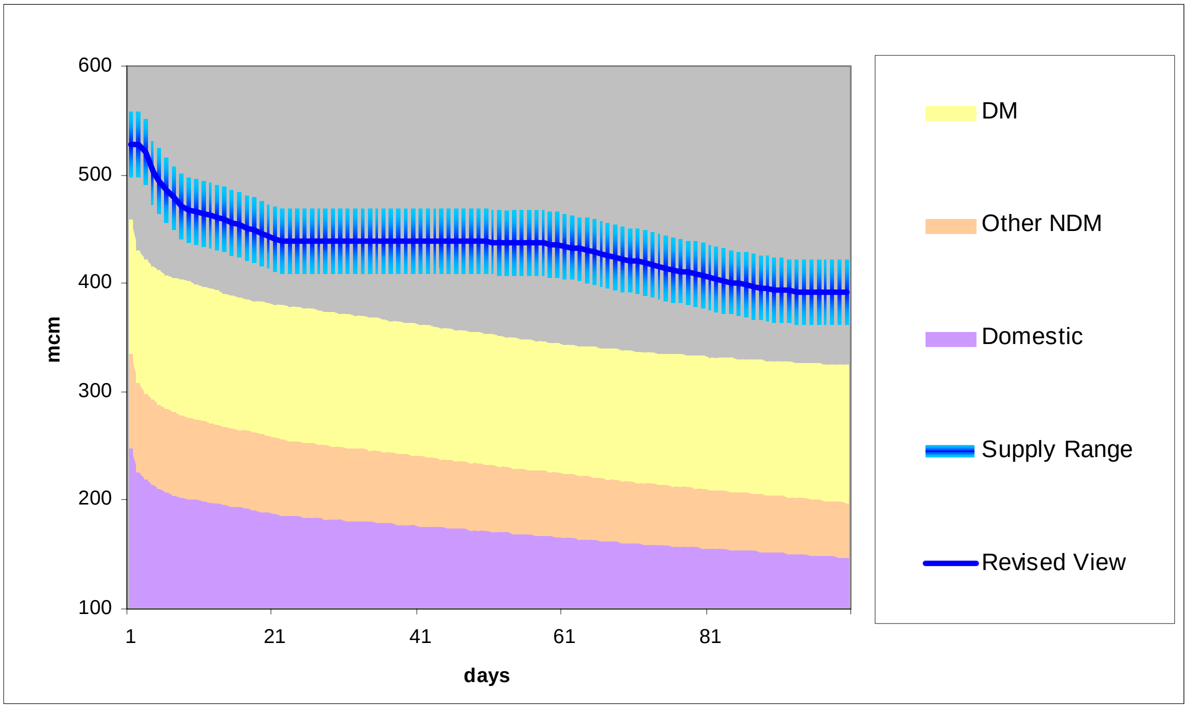


Figure 3 – Supply availability vs 1 in 10 load duration curve for 2007/8

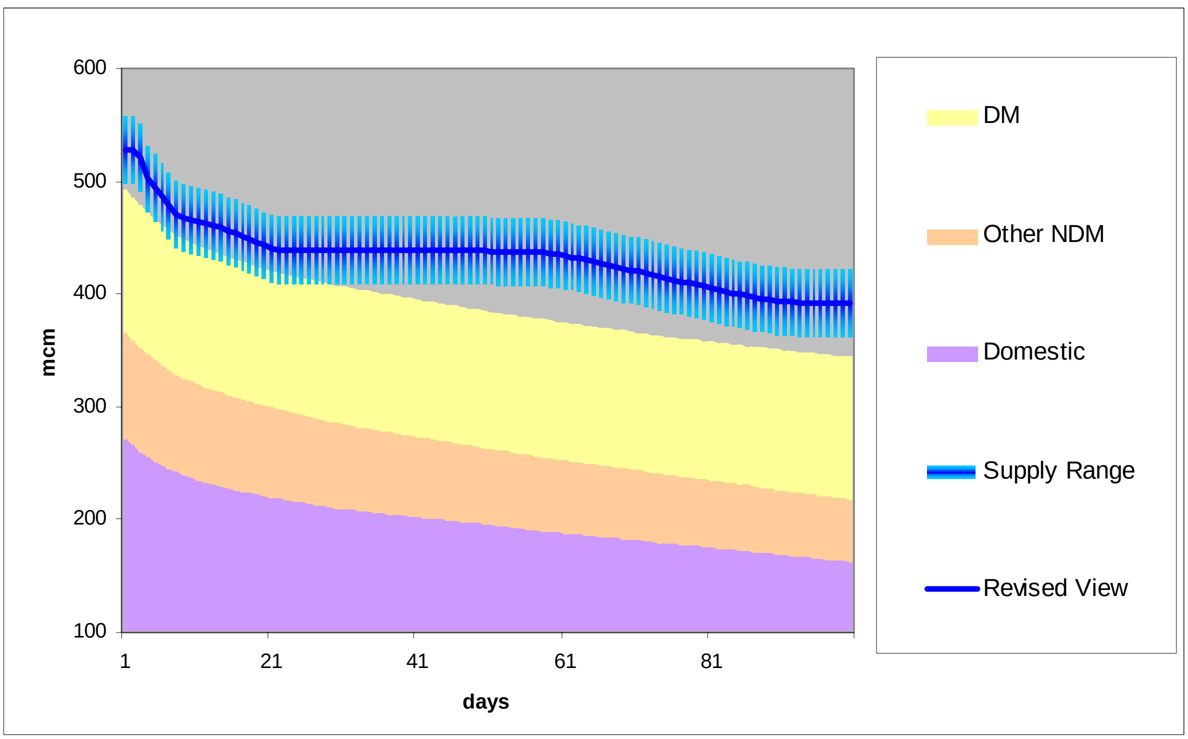


Figure 4 – Supply availability vs 1 in 50 load duration curve for 2007/8

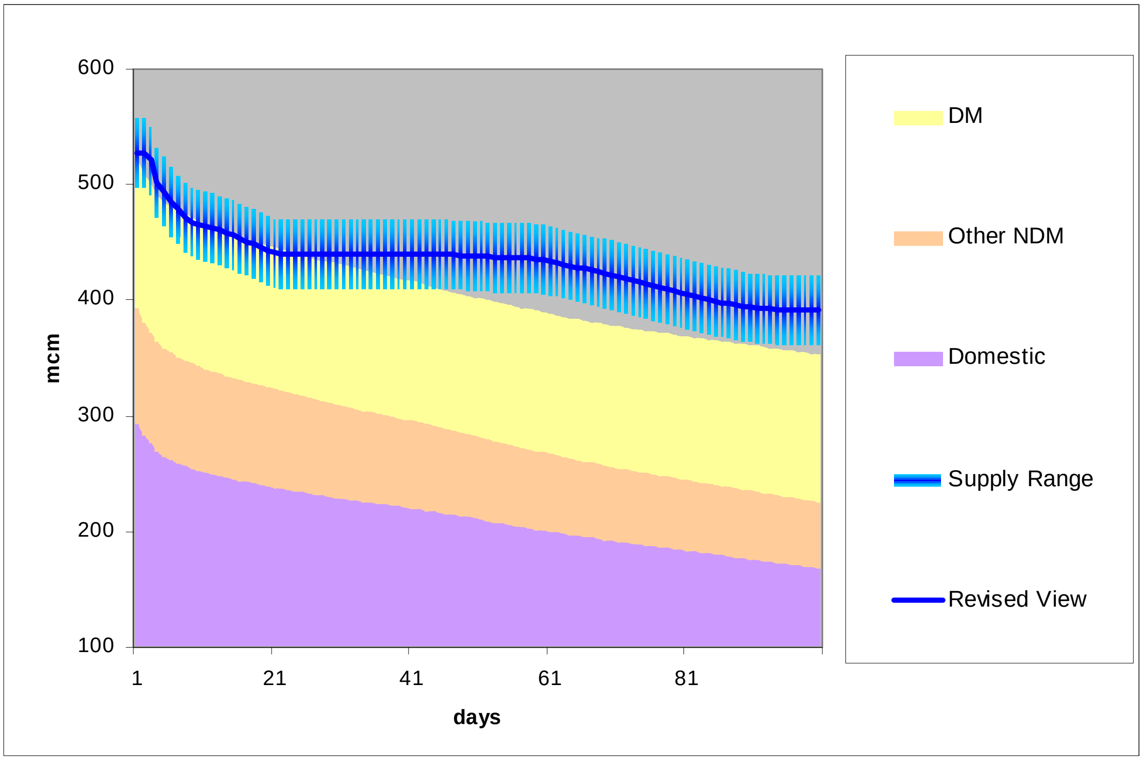


Table 5 – Demand response requirements under Revised View assumptions (bcm)

	Average	1 in 10	1 in 50
Revised View	0	0	0
Revised View +30 mcm/d	0	0	0
Revised View -30 mcm/d	0	0.17	1.01

Cold spell analysis

72. 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.

73. Figures 8 and 9 shows bar charts consisting of three levels of demand, namely those commensurate with a peak day[9], a very cold week[10] and a very cold month[11].

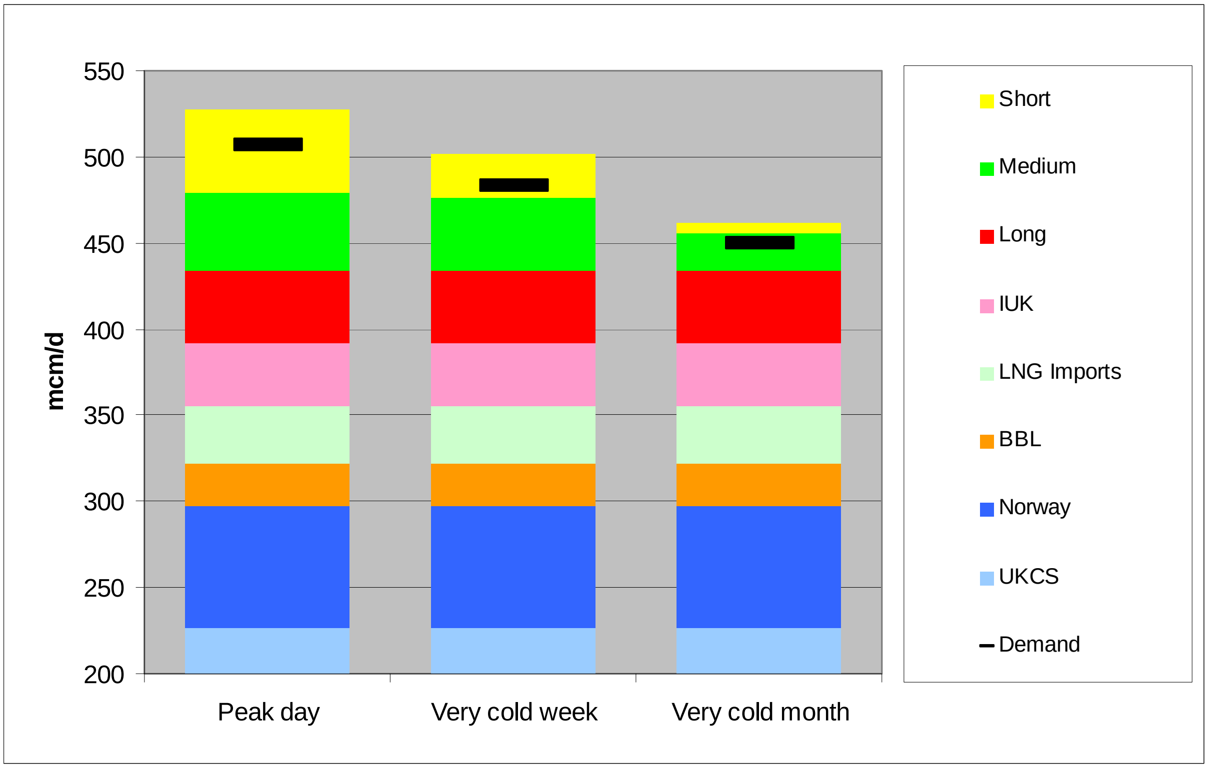
[9] Diversified demand for a 1 in 20 Peak day
[10] Average diversified demand for Days 1 to 7 on a 1 in 50 (severe) load curve
[11] Average diversified demand for Days 1 to 30 on a 1 in 50 (severe) load curve

Against these levels of demand is shown the supply availability[12] under the Revised View, and the associated level of demand response required for supply and demand to balance.

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

- a 1 in 20 peak day: -5 ºC
- a very cold week: -4 ºC
- a very cold month: -2 ºC

Figure 5 – Cold spell analysis for 2007/8, with Revised View supply assumption



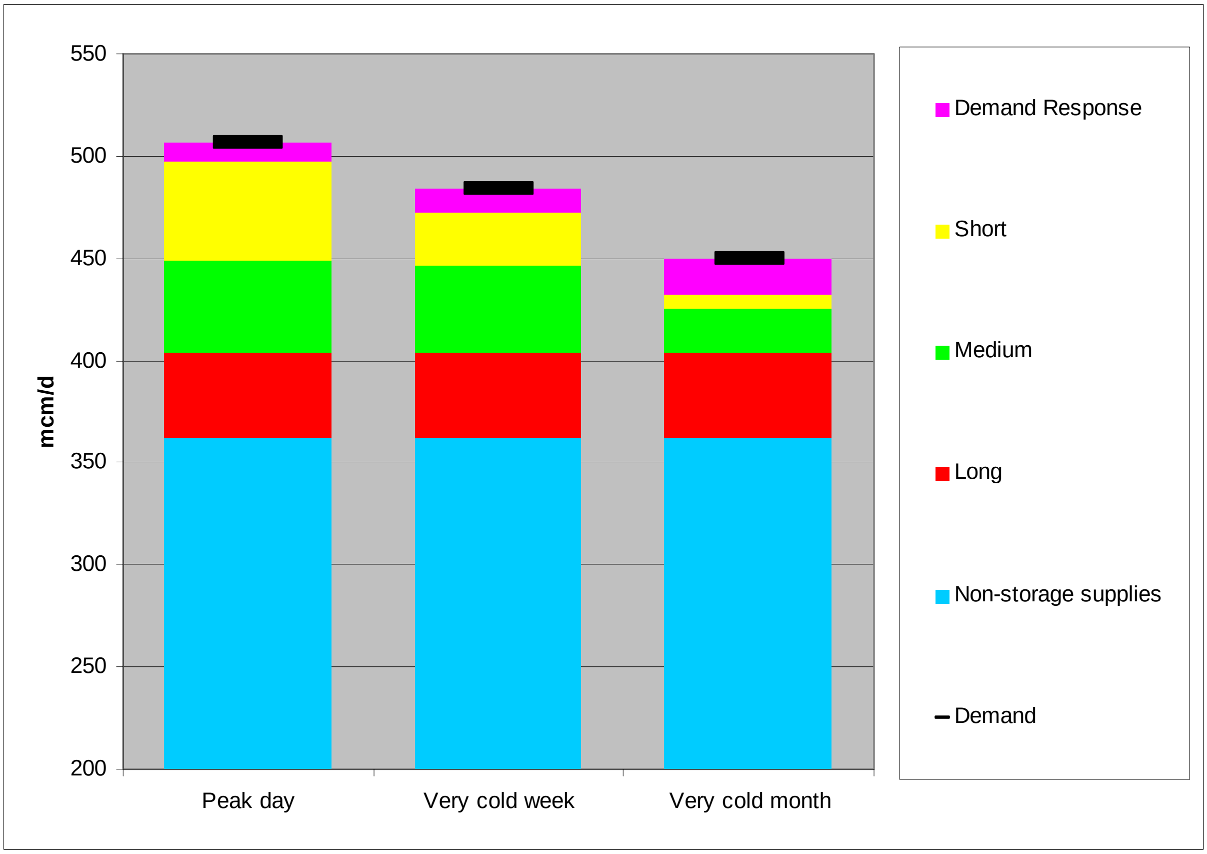
75. The analysis illustrates that for a 1 in 20 peak day with average temperatures across the country around -5 ºC, supplies are sufficient to meet demand and hence there is no demand response required.

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

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

[12] Storage deliverability is adjusted proportionally when the duration is exceeded - explain

Figure 6 - Cold spell analysis for 2007/8, at 30 mcm/d below Revised View



78. With non-storage supplies reduced by 30 mcm/d, for the 1 in 20 peak day a demand response of 10 mcm/d would be required.

79. For the very cold week and very cold month conditions, the levels of daily demand response are 12 mcm/d and 18 mcm/d respectively, reflecting the lower availability of storage stocks through depletion during the extended cold periods.

Safety monitors

80. 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).

81. 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.

82. The total non-storage supply assumption of 370 mcm/d used for calculating the 2007/8 preliminary safety monitors is 35 mcm/d higher than the equivalent figure used in setting the 2006/7 safety monitors and 22 mcm/d below the Revised View supply assumption for next winter. The 22 mcm/d difference corresponds to a supply risk of 20 mcm/d for import uncertainty and a further 2 mcm/d difference associated with

how potential flows through the Interconnector were assessed, namely assessing average flows vs a weighted winter average.

83. The resulting monitor levels shown in Table 6 are significantly below the 2006/7 monitors. These are primarily due to the higher non-storage supply assumptions.

Table 6 – 2007/8 Safety monitor space requirement

Storage type	Assumed storage space (GWh)[13]	2007/8 Safety Monitor space (GWh)	**2007/8 Safety Monitor (%)**	2006/7 Safety Monitor (%)
Long duration storage (Rough)	33445	1189	**3.5%**	16.8%
Medium duration storage (MRS)	8233[14]	0	**0.0%**	11.9%
Short duration storage (LNG)	1939	0	**0.0%**	21.8%
Total	44617	1189	**2.7%**	16.1%

84. For next winter, 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 Fora and our website.

[13] Excludes Operating Margins Gas and Scottish Independent Undertakings
[14] Excludes Aldbrough space

Chapter 2: Electricity

Electricity Demand Levels for 2007/8

85. Our latest Average Cold Spell (ACS) peak demand forecast for winter 2007/08 remains at 60.8 GW, which includes a 0.3 GW flow to Northern Ireland, as forecast in the March consultation document. 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 was no disagreement with this forecast in the responses to our March document.

86. 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 the March document, 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

87. The quoted plant margin for winter 2007/8 currently reported in the 2007 Seven Year Statement (SYS) is around 27%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 78.4 GW.

88. 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.

89. However though Langage (0.85 GW) & Pembroke (0.8 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 prior to winter 2007/8, only 0.3 GW of this is planned to be fully operational by the start of the winter.

90. The latest view of TEC capacity available for winter 2007/8 is therefore 75.6 GW.

91. The GB Demand at ACS Peak reported in the SYS is 61.5 GW, excluding station load. The latest view of plant margin is therefore 23%.

92. 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%.

93. 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.

94. Our current operational view of generation capacity anticipated to be available for winter 2007/8 is 75.5 GW. A broad breakdown of this capacity is shown in Figure 36.

95. 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.

96. 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. This data will be included in the September report.

Figure 7 – Generation Capacity, Winter 2007/8

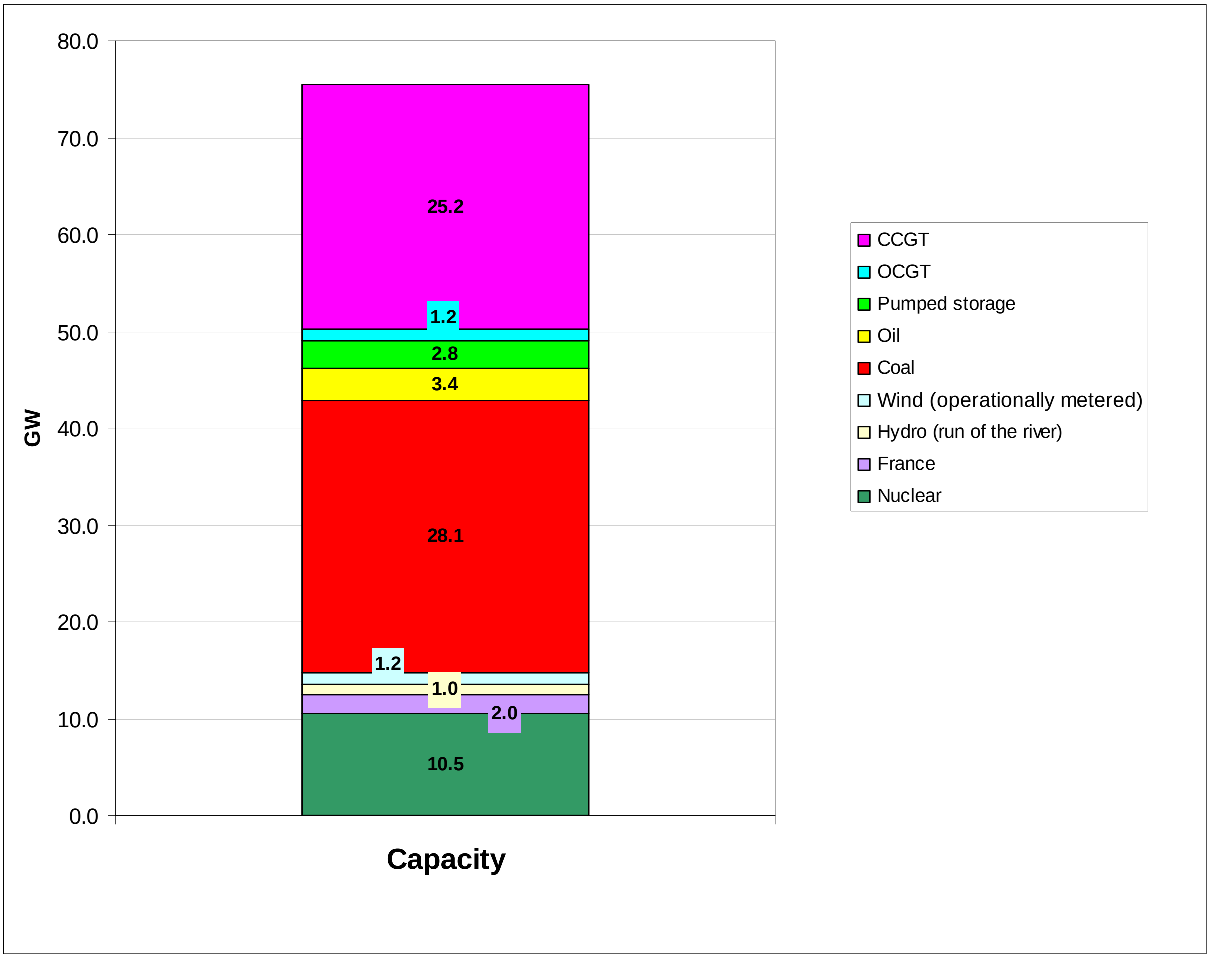


Table 7 - Mothballed Capacity, winter 2007/8

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

Contracted Reserve

97. 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.

98. 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.

99. 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.

100. For winter 2007/8, the current total level of contracted STOR reserve is 1.7 GW, 1.4 GW from generation in the BM and 0.4 GW from demand-side providers.

101. National Grid will implement prior to the winter two further STOR tender rounds in June and August 2007 covering services for the winter 2007/8 darkness peak. Communications regarding this will be through electricity operational fora and on our website.

102. 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.

103. 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

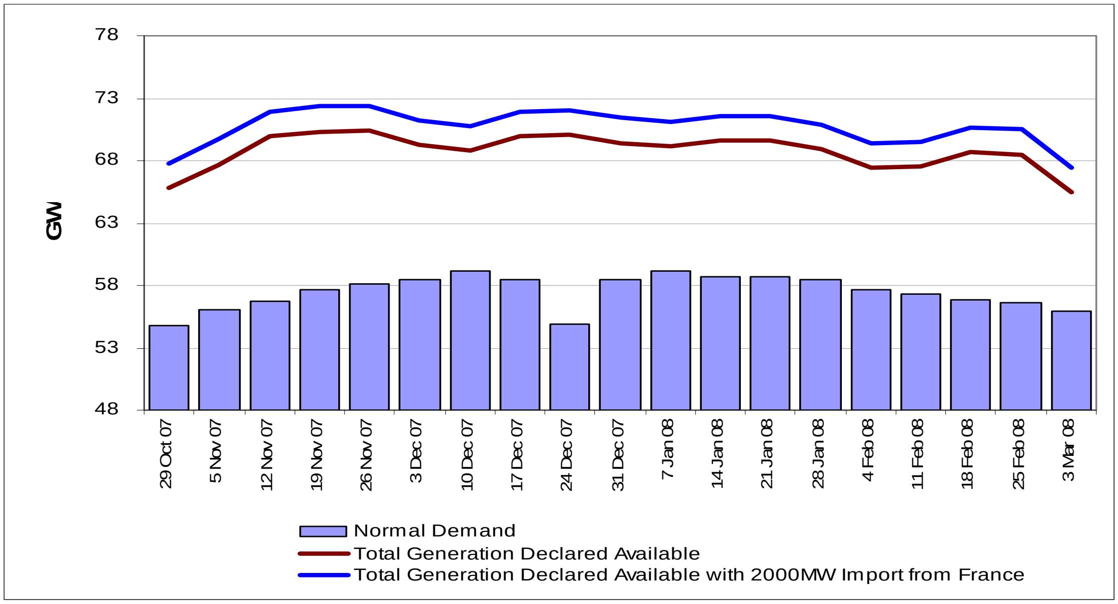
104. Figure 8 shows the normal demand forecasts, and the generator availability declared to National Grid by generators under Grid Code Operating Code 2 (OC2), both including and excluding 2 GW of delivery from the UK-France Interconnector.

105. Figure 8 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.

106. As can be seen in Figure 8, with full exports from France the excess generation over average weekly peak demand would be around 12-15 GW. However, Figure 8 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.

107. 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 8 does not reflect this requirement.

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



Scenario for Modelling Purposes

108. Based upon historic availability patterns, we have assumed generator availability rates as detailed in Table 8. The full 2 GW of capacity across the UK-France Interconnector at peak times has been assumed.

109. 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 8.

Table 8 - Assumed Plant Availability

Power Station Type	Full 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%**	

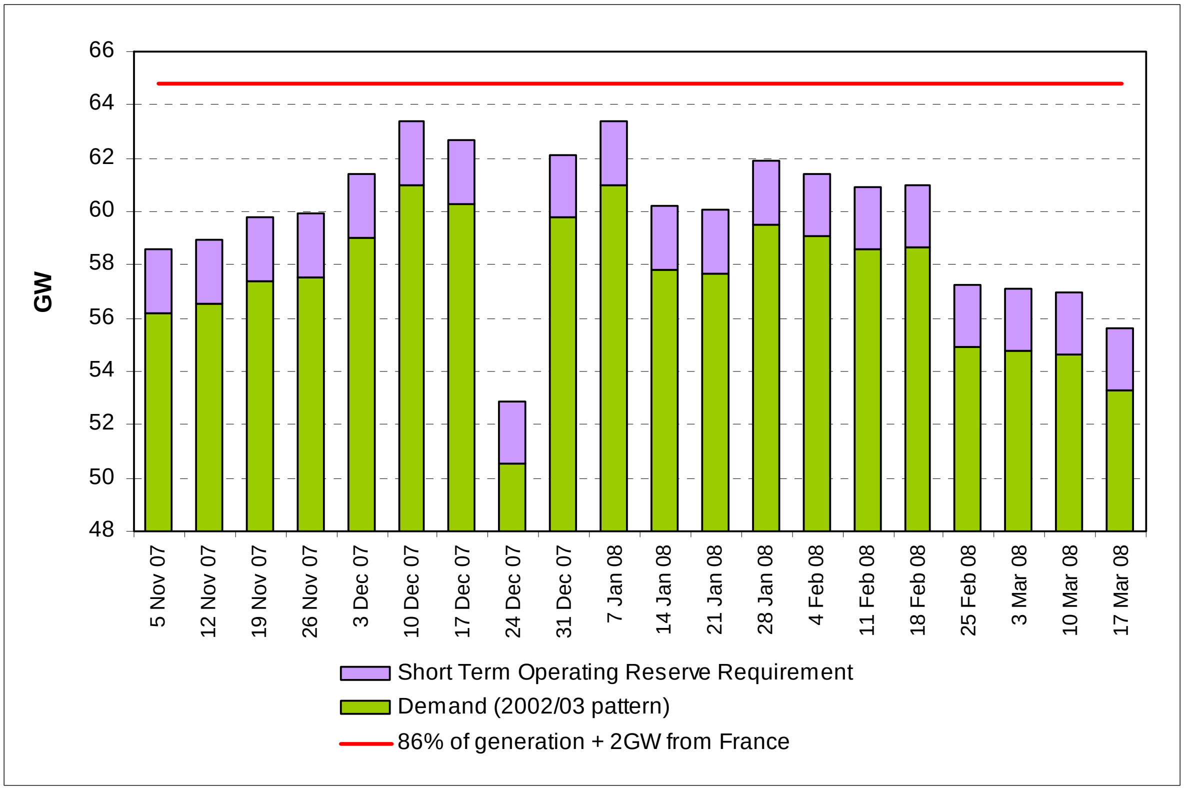
110. This scenario is used to illustrate the ability of the electricity sector to meet demand under average (typical) and 1 in 50 weather conditions, and to provide gas demand side response as detailed further in Chapter 3. The week-by-week profile of unavailability has been smoothed across the winter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

Average Winter Conditions

111. 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.

112. As illustrated in Figure 9, 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 9 – Forecast Demand under Average Weather Conditions (2002/03 Weather Pattern) and Generator Availability, Winter 2007/8

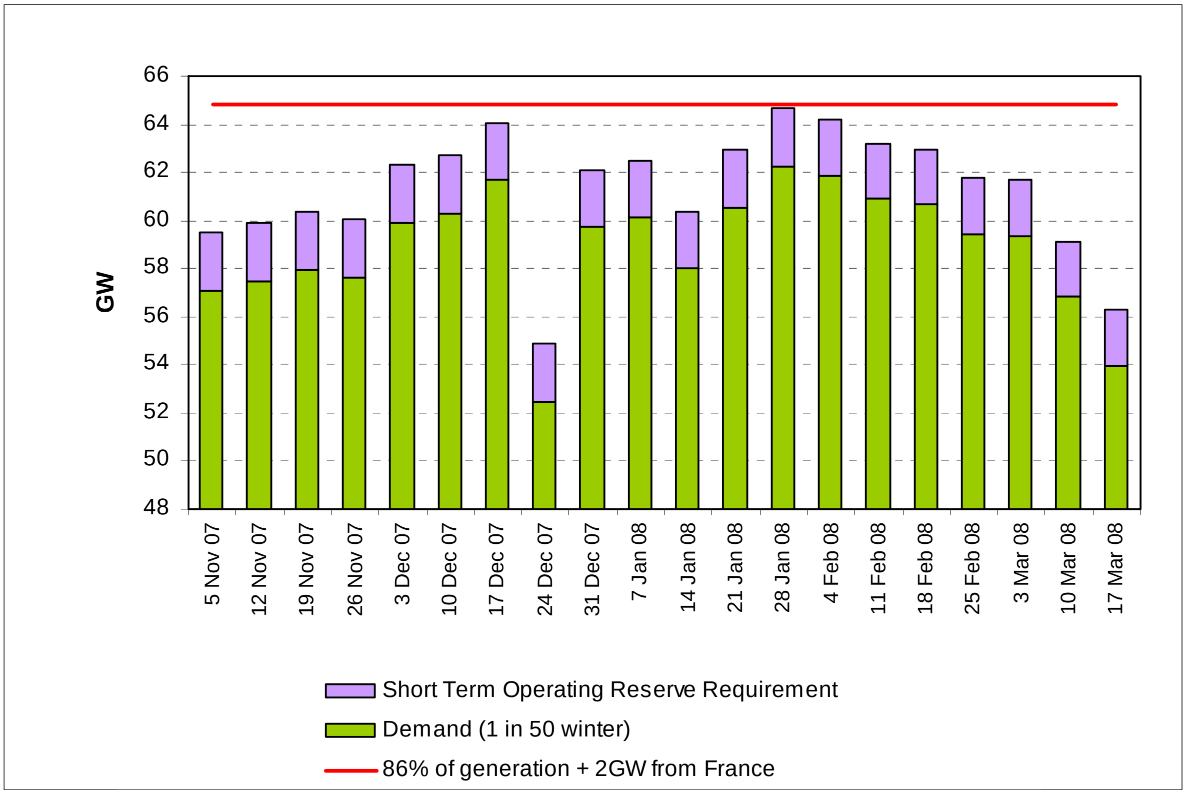


1 in 50 Cold Winter Conditions

113. In 1 in 50 cold winter conditions, where average temperatures across the country would be -2 °C for 30 days and +2 °C for 60 days, 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.

114. If these weather patterns were to occur this winter, as illustrated in Figure 10, 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 10 – Forecast Demand under 1 in 50 Weather Conditions (1946/47 Weather Pattern) and Generator Availability, Winter 2007/8



Chapter 3: Gas / electricity interactions

115. This Chapter describes our analysis of the potential gas demand response available from the power sector. 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.

116. 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.

117. 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 modelled.

118. 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

119. The maximum theoretical power generation gas demand in GB for winter 2007/8 is shown in Table 9. These figures are based on contractual limits. They include power stations that could source their gas supply from the NTS but are predominately supplied directly from offshore supplies by non-NTS pipelines. The dual-fuelled Peterhead station is included within these numbers. Figures exclude smaller embedded power generators, typically Combined Heat and Power stations, which do not participate in the Balancing Mechanism.

Table 9 – Maximum 2007/8 GB power generation demand

	Maximum gas demand (mcm/d)	CCGT capacity (GW)
NTS-connected	134.0	24.1
LDZ-connected	3.9	1.1
Total	**137.9**	**25.2**

120. CCGTs are expected to provide a maximum of 25.2 GW of generating capacity in GB for the coming winter. 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.

121. Reflecting current fuel prices, our Revised View assumes that coal will be preferred to gas with the result that our power generation gas demand forecast as discussed in Chapter 1 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

122. 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.

123. The Large Combustion Plant Directive (LCPD) limits the running hours of those stations without FGD to 20,000 hours from 1 January 2008 to 31 December 2015. However at this stage we do see any significant security of supply issues over the next 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.

124. 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;

- 3.3 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as base load[15];
- 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 10, consistent with an average availability rate of 86%.

Table 10 – Assumed plant availability factors for demand-side response analysis

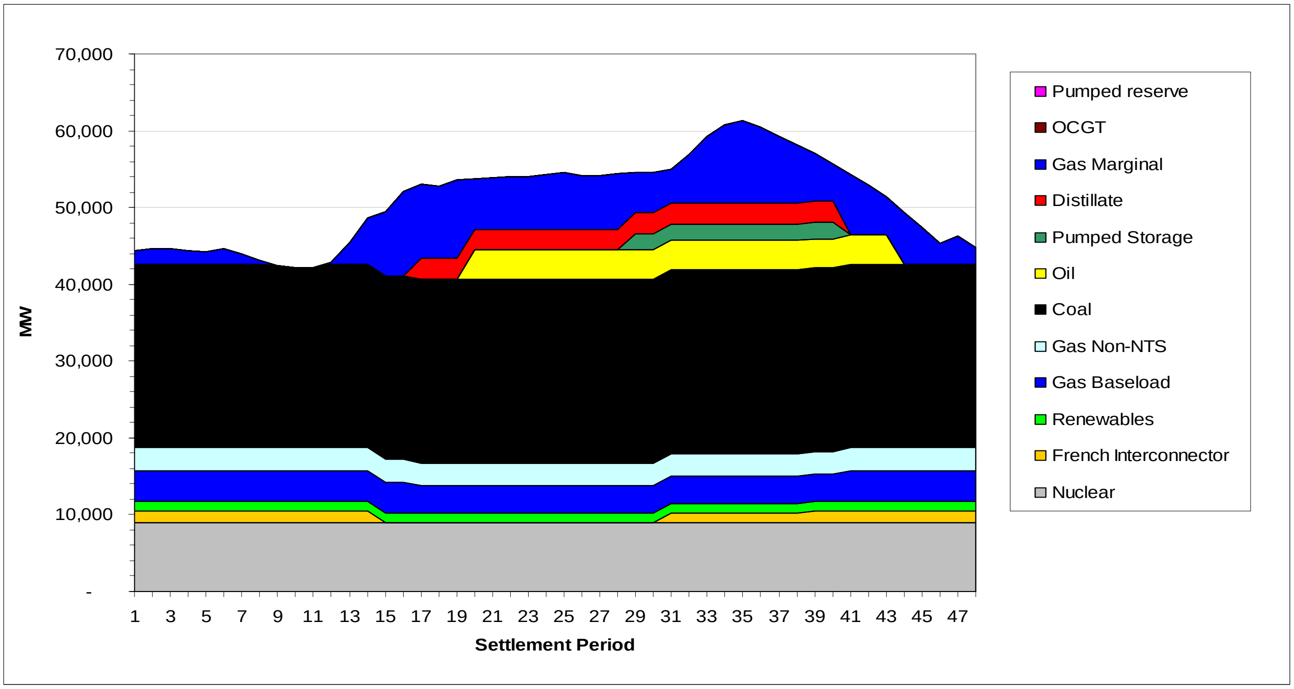
Power Station Type	Full Capacity (GW)	Assumed Availability	Assumed Availability (GW)	Model Assumptions Summary
Nuclear	10.5	80%	8.4	Baseload
French Interconnector	2.0	100%	2.0	Baseload, except 7 am to 3pm weekdays
Hydro generation	1.0	60%	0.6	Baseload
Wind generation	1.2	35%	0.4	Baseload
Coal	28.1	85%	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%**		

[15] 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.

Analysis of potential CCGT demand response – simulation results

125. Figure 11 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 11 – Potential generation profile - cold winter weekday



126. 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.

127. Tables 11, 12 and 13 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 11 – 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 12 – 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 13 – Potential CCGT demand response (bcm), Revised View 30 mcm gas supply

	Average	1 in 10	Severe
Required[16]	0.0	0.17	1.01
Potential CCGT[17]	0.0	0.14	0.31
Deficit	0.0	0.03	0.70

128. As Table 11 and 12 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 13, a demand side response of 1.01 bcm would be required of which only 0.31 bcm could be supplied by the power generation sector.

Consultation Feedback

129. Given National Grid's role in the market, our intelligence on the gas and electricity supply-demand outlooks is wholly reliant on the data and insights that we receive from others.

130. A key focus of the consultation is the uncertainty surrounding the gas supply position for 2007/8. We welcome views on all our assumptions, but in particular imported gas supply, demand growth and France-GB electricity flows.

131. We would appreciate any comments on this report as soon as possible but not later than Friday 3 August.

[16] These values represent the demand side response required where the Revised View supplies do not meet the demand. These are broadly consistent with those detailed in Table 5, but are not exact due to smoothing anomalies

[17] 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: Industry Framework Developments

132. 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 reflects ongoing industry discussions concerning such developments.

Gas Entry Capacity Transfers and Trading

133. National Grid has obligations to release capacity ahead of the day and also within-day, on an interruptible and firm basis. The combined effect of the obligations and the buyback incentive seek to maximise the capacity offered at a given 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.

134. 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. Although proposals on this were recently rejected, National Grid remains committed to work with shippers to develop new arrangements. Were these to be implemented for this winter, limited additional supplies may be seen at ASEPs signalled by shipper bids, for example at Easington. Depending on the exchange rates which apply, a corresponding effect (i.e. reduced supply) could be seen at other ASEPs, particularly those where shippers had not procured firm capacity in a timely manner or where interruptible capacity was not available.

Baseline Capacity Substitutions

135. 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. National Grid will be consulting on such new substitution methodologies ahead of the next long term auctions scheduled for September 2007.

Gas Emergency Cashout Arrangements

136. 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 an Emergency event (Stage 2 and higher) might be enhanced.

137. Following these workshops we have further discussed and explored the issues with Ofgem, APX Ltd and Shippers and have developed UNC modification 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 out for consultation. Both proposals suggest a 1 October 2007 implementation date.

Gas Market Information Provision

138. National Grid is continually seeking to improve the quality and reliability of its information provision. Significant improvements have been made over the past 2 years, and for winter 2006/7 we worked with Ofgem and the industry to enhance the quality of information that is available to the market to further promote industry participant response to the gas supply/demand position. Of particular note is the introduction of the quality of information incentives which have been placed on National Grid to improve the timeliness and accuracy of the information being made available to the gas market, and the introduction of longer term demand forecasts. These incentives are considered to have been successful in driving investment and focus to improve performance. Throughout 2007 we intend to work with the industry in reviewing the information that we currently publish and identifying any duplicated and/or obsolete data as well as any potential gaps in the data provision. In addition we intend to respond to user requirements by making the access to key data more intuitive, user friendly and reliable.

139. As the first step in the above we have raised Review Proposal 0140 - Review of Information Provision on National Grid's Information Exchange. The first meetings of this UNC Review Group were held in May and the group aims to complete this review by October.

Electricity Cash Out Review & Associated BSC Modifications

140. 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 site the aim of the proposals as being to introduce a methodology that better prevents non-energy balancing activity from influencing the imbalance price. It is expected that both these modifications will be referred to Ofgem for a decision in October or November 2007.

Access to the Transmission System – CAP131, CAP142, CAP143 and CAP144

141. CAP131 proposes that the cost-reflective liabilities that new generators currently face prior to the completion of the transmission reinforcement works required to connect them are replaced with a generic user commitment. The generic user commitment is staged with a User Commitment Amount of £1/kW (increasing to £2/kW then £3/kW) required on connection offer acceptance and a Cancellation Charge based on a multiple of the relevant TNUoS charge required following a defined Trigger Date. CAP131 also proposes that the notice period required from an existing generator prior to a reduction in capacity is increased from 5 days to 2 years. A vote on CAP131 will take place at the June CUSC panel and is then expected to go Ofgem for Authority decision.

142. CAP142 provides the ability for two power stations to trade access rights to the Transmission System for variable periods of time between four and forty-two weeks in duration, within the same Financial Year. Such trades would be subject to an exchange rate, which would be determined by National Grid, and would describe the equivalence of network capacity in different locations. This arrangement is anticipated to provide an alternative route to market when existing short-term access products i.e. STTEC and LDTEC are not available. CAP142 has recently been approved by Ofgem with an implementation date of 21 June 2007.

143. CAP143 proposes that a new access product, Interim TEC (ITEC), is introduced. A holder of ITEC would be able to connect to and use the transmission system in advance of the completion of the wider transmission reinforcements required. The associated impact of ITEC would be managed by limiting its availability to those that meet a set of pre-qualifiers, and including a number of hours for which the ITEC holders are required to declare down at no cost. CAP143 is currently out for industry consultation.

144. CAP144 proposes to extend the provisions introduced by CAP048 (Firm Access and Temporary Physical Disconnection) to include the specific circumstances when a Generator is exporting but is required to disconnect from the Transmission System in an emergency via an Emergency Instruction (EI) issued by National Grid in Balancing Mechanism timescales in accordance with the Grid Code. CAP144 is currently undergoing industry consultation.

145. CAP148 seeks to prioritise the use of the GB Transmission System by renewable generators. Under the proposal, renewable generators would be given firm access to the GB Transmission System by a fixed date and be compensated to the extent they are constrained from exercising such right by the payment of a new category of Interruption Payment. This would be irrespective of whether or not any associated deep reinforcement works have been constructed and/or commissioned by such date. The Amendment Proposal achieves this by the introduction of Deemed Transmission Entry Capacity ("DTEC"). CAP148 is currently being developed by a working group.

Transmission Access Standing Group

146. National Grid has established the CUSC Transmission Access Standing Group and is developing potential arrangements for three models: more flexible TEC trading arrangements, SO non-obligated release of additional short term capacity and cost reflective charging for TEC overrun. The Standing Group is also considering models

proposed by other industry parties. The Standing Group is due to report to the CUSC panel meeting in July.

Review of Transmission Access

147. Following the publication of the Energy White Paper, Ofgem and DTi are leading a wide reaching review of transmission access arrangements. This will include short term developments consistent with current framework. Ofgem is due to report the findings to GEMA and the Secretary of State during September 2007.

148. The review will also include medium and longer term developments for which primary or secondary legislation may be required. This will involve the definition and allocation of TEC, the way the transmission system is planned and operated, the way energy and system balancing is achieved and the governance arrangements. The review team is to provide GEMA and the Secretary of State with and interim report during December 2007 and a final report during May 2008.

Electricity Market Information Transparency

149. In November 2006, National Grid sponsored an industry workshop to discuss electricity demand forecasts. The aim of the workshop was to improve market understanding of National Grid's demand forecasts and to gauge industry views on the use of this information within individual organisations. National Grid has also engaged with the industry on the wider issues raised by Market Information through recent Demand Side Working Groups and at Operational Fora. We have now invited final comments before identifying priority areas to take forward. 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. We are looking to invest to improve the robustness of our SONAR reporting system which delivers certain information to market participants. 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 are exploring 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 report on our electricity information transparency consultation in early August 2007.

Balancing Services

150. National Grid has introduced the BM Start-Up service (replacing Warming and Hot Standby service) which allows National Grid to access MW from BM Units that would not otherwise have run, and are unable to start-up within BM timescales on the day. This service provides greater flexibility and certainty to the market participants in that it allows the generators to submit different availability rates (depending on start-up times) and ensures that the market participants will be paid the availability fees regardless of whether the unit proceeds to synchronisation. The costs incurred in creating the additional reserve availability are allocated to the periods where the requirement exists and this ensures improved cost-reflectivity. Furthermore, the

reserve creation costs feed into the imbalance prices (via the BPA - Buy Price Adjustment) which ensures improved pricing signals to the market. The market information associated with the utilisation of the BM Start-Up service (e.g. requirement periods and indicative costs) is published on National Grid's SONAR website

151. National Grid has established a single service "Short Term Operating Reserve" (STOR) to replace the existing Standing Reserve and Supplemental Standing Reserve service. This change aims to improve the clarity, consistency and efficiency of the seasonal reserve procurement arrangements.

152. National Grid has revised the weighting factors for within day allocation of STOR option fees. The revised weighting factors better reflect the recent historical utilisation of reserve. This change has ensured that a more representative value of the BSAD variable BPA will feed into the cashout prices and hence will improve the pricing signals to the market.

153. Following Ofgem approval, National Grid has implemented its proposed revised arrangements for the updating of STOR weighting factors for allocation of STOR options costs within BPA. The change incorporates an agreed calculation methodology for the weighting factors within the BSAD Methodology Statement, and to provide for the publication the STOR weighting factors on National Grid's website. The change makes the updating of STOR weighting factors more straight forward, meaning they should more closely reflect the latest data and improve the cost-reflectivity of BPA.