nationalgrid

Winter 2006/07 Consultation 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. Last year, recognising that our sources of data are necessarily incomplete, we 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 outlook report.
3. In conjunction with Ofgem, we have decided to conduct a similar but enhanced consultation process this year. This document represents the first stage of that process. We will issue another consultation paper in July, feeding back on the responses to this document, updating the analysis and seeking further views. We then plan to publish the Winter Consultation Report, reflecting the feedback received from industry participants, by the end of September.

Gas

4. The present tightness in the UK gas market, and the associated high prices, have been widely reported in recent months. Over the next two or three years, a number of major infrastructure projects are due to be commissioned, facilitating the importation of substantial quantities of gas into the UK. Some of these projects are planned to be in place for this winter: the Langeled pipeline from Norway connecting at Easington; the second upgrade of the Belgian Interconnector; and the BBL pipeline linking the UK market at Bacton with Holland. In addition, Excelerate Energy has recently announced plans to import LNG at Teesside from December 2006, using onboard ship re-gasification technology.
5. Although no new gas storage facilities are due to be commissioned before winter 2006/07, the Humbly Grove facility, which was commissioned during winter 2005/06 will be operational throughout 2006/07. With regards to the current Rough outage and ongoing HSE investigation, the successful and timely resumption of operations

at Rough and any other facility that may be impacted, is significant in the context of the supply/demand position for the 2006/07 winter.

6. A consequence of the developments in importation infrastructure is that the supply-demand outlook for 2006/07 is particularly uncertain, and it is not clear at this stage whether the position will be more or less tight than it was in 2005/06. 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 the utilisation of the infrastructure. This was well illustrated during the 2005/06 winter, when flows through the recently upgraded Belgian Interconnector fell well short of physical capability in the first half of the winter despite higher prices in the UK than on the Continent. A similar pattern of flows was observed through the newly commissioned Grain LNG terminal. Flows there were higher in the second half of the winter following Ofgem's engagement with capacity holders at Grain (including the development of Use-It-Or-Lose-It arrangements) and co-incident with a more favourable price differential between the UK and the US.

7. The uncertain supply background translates into a wide range of potential values for the 2006/07 storage safety monitors, which we are required by the Uniform Network Code to publish in May 2006. We will publish a separate note containing these initial monitor levels by 31 May 2006. In any event, we expect our thinking on the appropriate safety monitor levels to develop through the course of the summer based on market developments and feedback that we receive from the industry on the key input parameters.

Demand Side Response

8. As part of this consultation, we are seeking views on the ability of the demand-side, in particular, the Non-Daily Metered (NDM) demand, to respond by reducing demand in response to high prices, and on how this might compare with the level of response seen last winter.

Electricity

9. The outlook for the electricity market in 2006/07 appears less uncertain than that for the gas market, with the notified generation background (including the level of mothballed plant) broadly similar to that observed prior to the 2005/06 winter. Last winter the operation of the electricity market was characterised by coal generation operating at baseload, with gas providing the marginal capacity. Combined Cycle Gas Turbine (CCGT) gas demand was therefore well below the level implicit in our (unconstrained) demand forecasts. While the gas market remains tight, the reduction in gas consumption by CCGT stations will continue to be key in achieving a balance between gas supply and demand.

Consultation overview

10. 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 therefore look to market participants for information and views across a broad range of issues related to the 2006/07 winter. We will aggregate and

summarise the information that we receive, and use this to inform the next stage of the consultation process.

11. As we did last year, we provide in this consultation document analysis of the recent winter experience to set the scene for the analysis of next winter. The bulk of this analysis is contained in Annex A, with the key points summarised in Chapters 1 and 2.

12. A key focus of the consultation is the uncertainty surrounding the gas supply position for 2006/07. In Chapter 3, 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. We then illustrate the implications of these issues with scenario analysis. This focuses on a base case and a number of sensitivities, which together allow the reader to assess the potential circumstances that might develop given variations to the input parameters. As last year, the format of the analysis is to quantify the level of demand-side response that would be required under specified combinations of supply conditions and weather patterns.

13. The base case is not intended to represent a National Grid view. Its main purpose is to provide a reference point to facilitate discussion and comment. We hope that the analysis of the base case and the sensitivities will help industry participants in developing their own view of the forthcoming winter and establishing appropriate arrangements.

14. Chapter 4 sets out the latest view of the demand and generation background in the electricity market for 2006/07, and seeks respondents' input on issues surrounding mothballed plant, the operation of the French Interconnector and electricity demand management.

15. In Chapter 5, we present our latest analysis of the potential for CCGT demand response in 2006/07, and are looking for insights and views through this consultation on the extent to which such a response could be provided should the need arise next winter.

16. The high level issues on which we are seeking views are as follows (with the full list of questions contained in Annex F):

<u>Non-CCGT gas demand-side response</u>

Q1. We would welcome views on the extent to which the non-CCGT market is able to provide demand-side response both in volume and duration terms

Q2 To what extent can a general reduction in NDM demand be expected in 2006/07, given that NDM demand during the 2005/06 was typically 3-4% below the expected level?

Q3 We would welcome views on expected non-CCGT demand levels for winter 2006/07 under a range of weather conditions and, in particular, on the assumptions that should be made to determine the peak day non-CCGT demand that can be expected in winter 2006/07?

Q4. At what levels of demand would Distribution Network owners expect interruption to be triggered for capacity management purposes?

UKCS Supplies

Q5. What assumptions should be made over the maximum UKCS supply availability for 2006/07?

Q6. What implications does the cooler unit issue associated with the Rough storage incident have for UKCS supplies this winter?

Q7. What assumptions should be made over the average percentage UKCS supply availability under a period of prolonged severe conditions in 2006/07?

Gas imports

Q8. We would welcome views on whether similar monthly variations to those observed last year can be expected in winter 2006/07 from the various import sources

Q9. What assumptions should be made for levels of imported gas through the Belgian Interconnector for winter 2006/07?

Q10. What assumptions should be made for levels of imported gas through BBL for winter 2006/07?

Q11. What assumptions should be made for levels of imported gas from Norway for winter 2006/07?

Q12. What assumptions should be made for the total levels of European imports?

Q13. What assumptions should be made for LNG importation quantities in winter 2006/07?

Storage

Q14. We would welcome views on the likely patterns of use of the various gas storage facilities in 2006/07

Q15. We would welcome views on the appropriate basis for setting the 2006/07 safety monitors

Electricity market

Q16. We would welcome views on the extent to which electricity demand response might be expected given high electricity prices

Q17. What assumptions should be made over the extent to which mothballed generation will become available, and when?

Q18. To what extent is there scope for investment prior to the 2006/07 winter to provide back-up capability at existing power stations?

Q19. What assumptions should be made over the availability of nuclear generating plant?

Q20. What assumptions should be made over the level and direction of flows on the UK-France Interconnector given cold weather in both UK and Europe?

CCGT demand-side response

Q21. We would welcome views on the ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests might be theoretically achievable in a severe winter

Longer-term outlook

Q22. In addition to the questions relating to winter 2006/07, we would also welcome any views on the market outlook for winter 2007/08 and/or subsequent winters

Next steps

17. We would appreciate responses to our questions as soon as possible but not later than 9 June 2006. Please note that it is intended to include a summary of responses on a non-attributed basis in the subsequent consultation report. 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 wholesale.markets@ofgem.gov.uk).

18. Responses should be sent to:

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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.

Section A – Review of 2005/06

Chapter 1: Gas

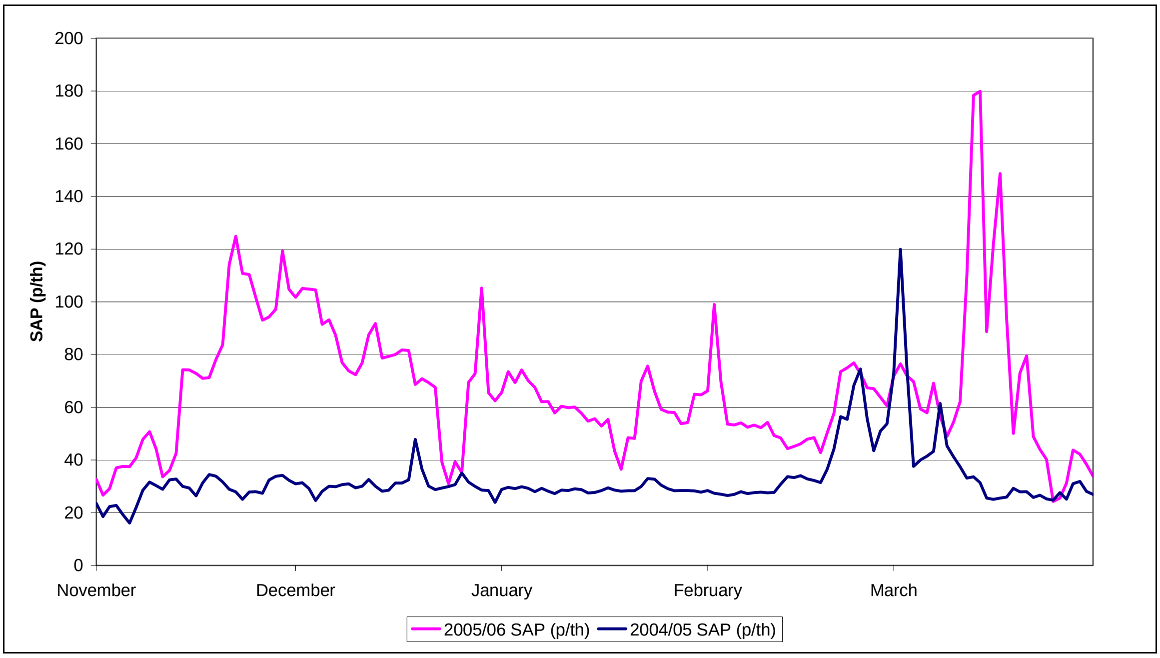
Gas Prices

19. Gas prices in 2005/06 were high compared to historical levels. Table 1 compares average, peak and minimum System Average Price (SAP) in pence per therm over winter 2004/05 and 2005/06 and Figure 1 compares the profiles.

Table 1 – Minimum, Average and Peak System Average Prices

SAP (p/th)	Minimum	Average	Peak
2004/5 Nov-Mar	16.05	32.67	119.95
2005/6 Nov-Mar	24.28	67.24	179.80

Figure 1 – 2004/05 and 2005/06 SAP Prices



Gas Demand and Demand Response

20. Figure 2 illustrates the 2005/06 winter weather compared with warm, normal and cold conditions. The measure plotted in the graph is the Composite Weather Variable (CWV), which is calculated by combining temperatures and wind speeds and transforming them to produce a weather variable that is linearly related to non-daily metered gas demand.

Figure 2 – 2005/06 Winter Weather (CWV) Overview

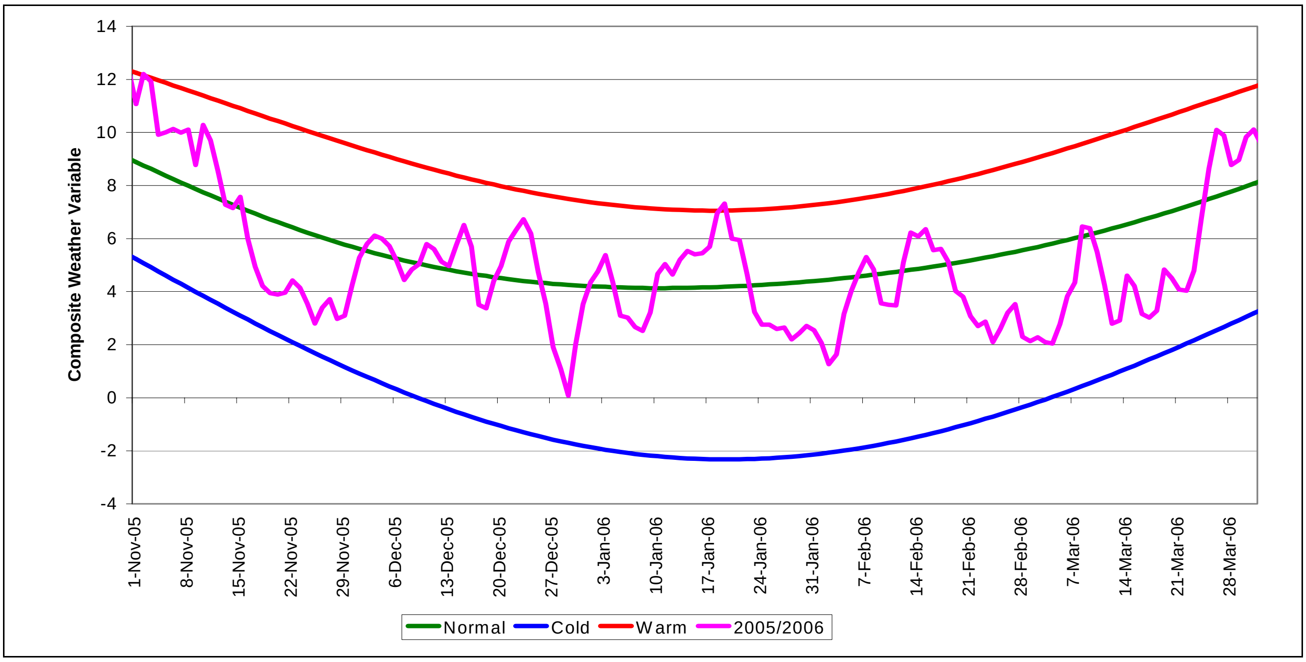
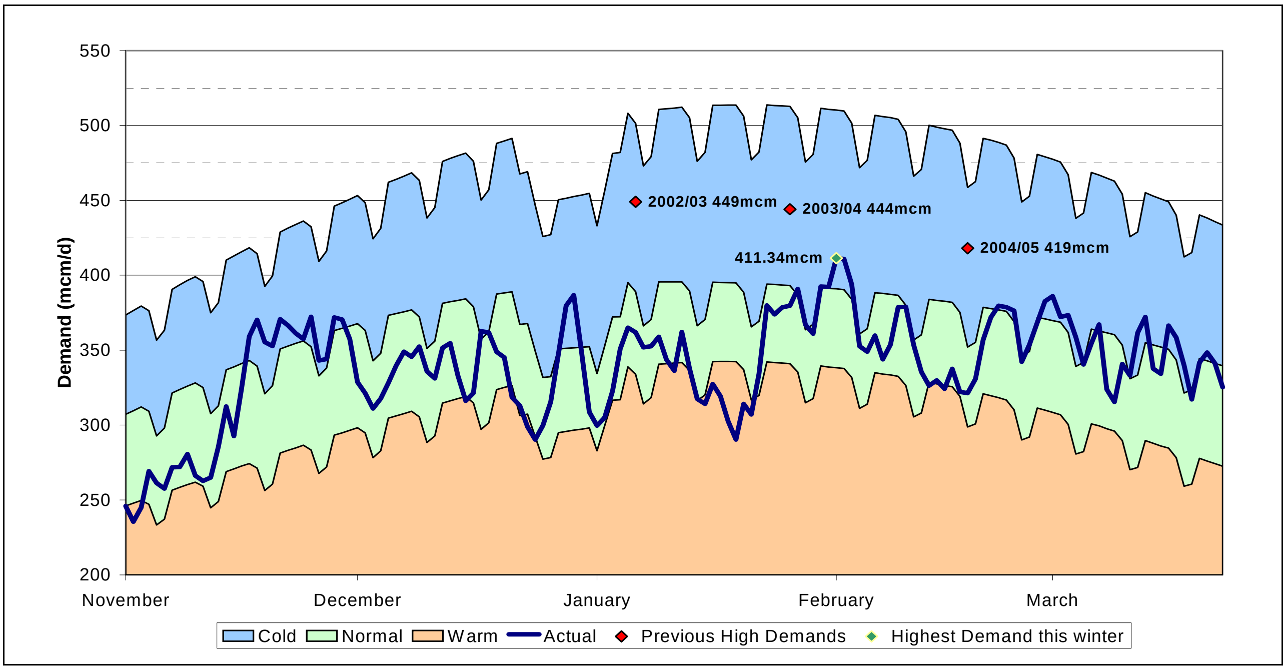


Figure 3 – 2005/06 Seasonal and Actual Demands



21. Figure 3 shows that total gas demand was typically below average levels despite 2005/06 being slightly colder than average in the period shown. This indicates a material reduction in the level of demand in response to the prevailing high prices. Similarly, without any demand response, we would have expected the highest daily demand to be significantly above the 411 mcm that was observed.

22. Over the top 100 demand days, the average level of demand-side response from Daily Metered (DM) customers was around 27 mcm/d, the majority of which came from the power sector. In addition, Non-Daily Metered (NDM) demand was typically 3-4% lower than had been forecast. Although not exposed, and therefore not responsive, to daily price fluctuations, this general NDM demand reduction may have been triggered by a combination of gas retail price rises and market sentiment (given the high profile that the gas supply position received in the media).

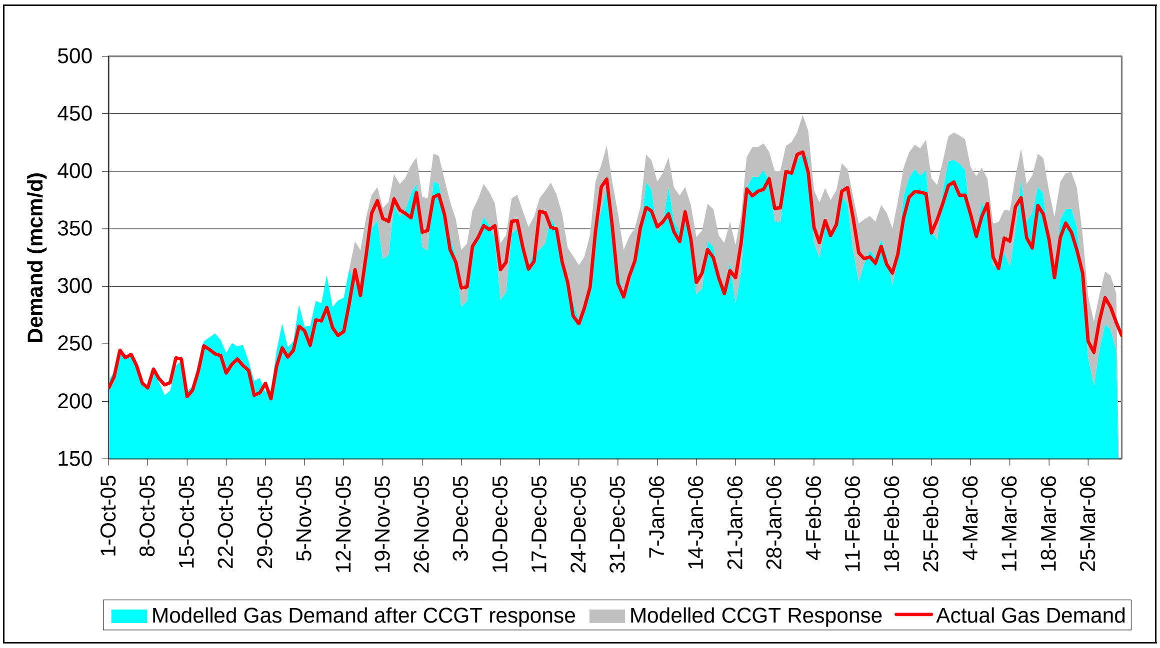
23. Table 2 below summarises the impacts by market sector, which are illustrated in more detail in Figures A4 to A8 in Annex A.

Table 2 – Demand Response by Market Sector in Winter 2005/06

Sector	Comment
NTS Power Stations	Contributed the majority of the demand response: around 20 mcm/d on average, and up to approximately 40 mcm/d when the gas price was at its highest
NTS Industrial Loads	Around 3-4 mcm/d of response evident when the gas price was at its highest
LDZ Daily Metered (DM) Interruptible	Around 5-10 mcm/d was evident when the gas price was at its highest
LDZ Daily Metered (DM) Firm	Around 2 mcm/d of response observed when gas prices were particularly high in March.
LDZ Non-daily Metered (NDM)	Demand depressed generally by around 3-4%, but (as would be expected) not in response to price spikes

24. An analysis of the relationship between demand response and System Average Prices suggests that non-power NTS-connected demands reacted to price spikes on the day that they occurred. However, there is some evidence of a lag between peaks in SAP and response from the LDZ Daily Metered Interruptible sector. More details of this analysis are contained in Annex A.

Figure 4 – 2005/06 Actual Demand Compared to Winter Outlook Simulation



25. Figure 4 shows how total demand compared with that forecast by the simulation model that we used in last year's Winter Outlook Report to assess the potential for CCGT demand-side response. In general, actual total demand shows a good fit against modelled demand after potential CCGT response has been subtracted.

Supply Summary

26. Figure 5 shows how the various gas supply sources were used in winter 2005/06. Each of these sources is considered in turn in the following sub-sections. As discussed above, a significant level of demand-side response was observed across the winter from mid-November onwards.

27. The winter can broadly be considered in four parts:

November

28. The first half of November was exceptionally mild but then changed rapidly with temperatures consistently below normal for a couple of weeks.

29. UK Continental Shelf (UKCS) supplies were still ramping up, maybe due to a combination of late returns from maintenance and delayed commissioning of new fields. The Belgian Interconnector upgrade had been commissioned earlier than planned but additional imports were generally not forthcoming despite a high price premium to Europe. Grain flows were low, possibly due to the price discount to the US in the early part of November. Consequently a significant contribution was required from long and medium range storage to meet demand.

December and early January

30. Temperatures were generally above average for the time of year with the exception of a short cold snap just before the New Year.

31. Allowing for known short-term outages, UKCS was performing broadly in line with expectations. Interconnector flows had improved but remained below expectations.

Grain was beginning to receive cargoes more regularly and flows were close to expectations when demand was elevated.

Late January and early February

32. This period was marked by another fortnight of temperatures consistently below normal for the time of year. The highest demand of the winter occurred during this period.

33. UKCS continued to perform in line with expectations. Grain was operating close to expectations with cargoes arriving most weeks. The Interconnector was also operating close to expectations. There was considerable use of long and medium range storage to meet demand and a small amount of LNG storage was used on the day of highest demand.

Post loss of Rough

34. Temperatures were above average for the first week after the loss of Rough on 16 February but then fell below normal for nearly a month.

35. UKCS initially maintained flows near expectations but then poor weather conditions offshore affected output at the beginning of March. The Interconnector and Grain both appeared to respond to the loss of Rough with imports generally close to expectations and approaching full capacity on a few days.

36. Medium and short-range storage was used extensively to replace the loss of long-range storage capacity.

Figure 5 – Supply Performance

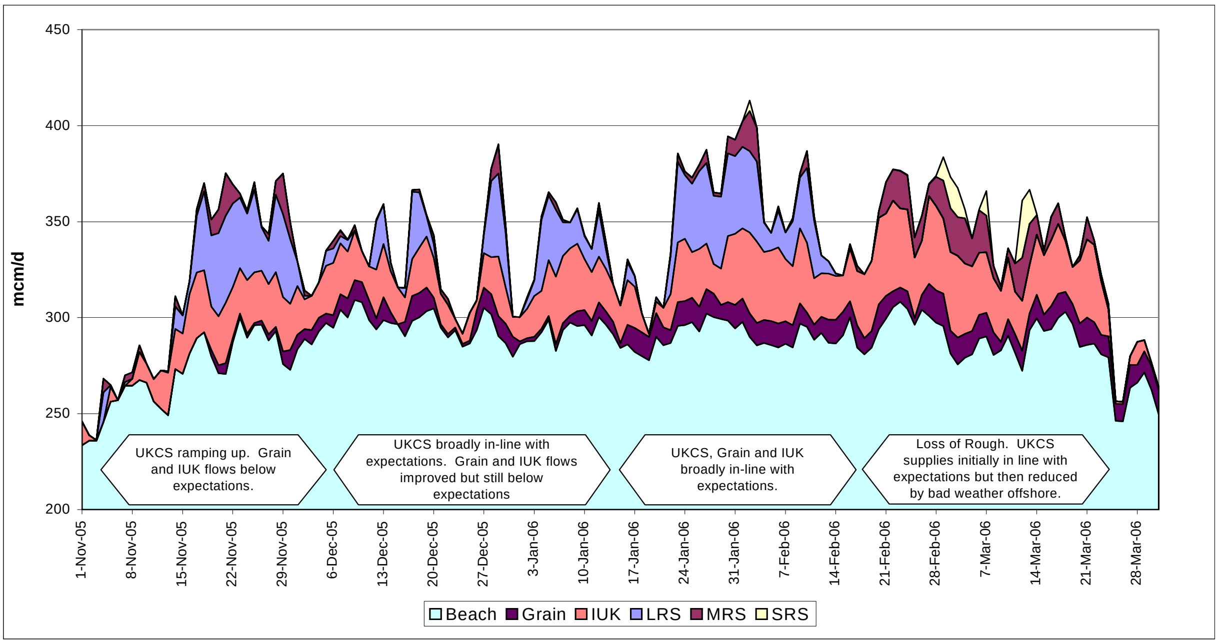


Table 3 – Beach Performance v Forecast in Winter 2005/06

	Forecast	Maximum Demand Day 2/2/06	Beach maximum 09/12/05	Terminal Max Actuals	Date of Maximum Actual
Bacton (no IC)	83	72	76	78	12-Dec
Barrow	29	19	29	30	20-Nov
Point of Ayr	2	1	4	5	20-Jan
Easington	17	17	19	20	5-Dec
St Fergus	146	123	120	131	30-Jan
Teesside	28	31	32	34	7-Dec
Theddlethorpe	23	27	29	30	17-Dec
Beach	**327**	**290**	**309**	**328**	
IC Imports	48	42	26	47	22-Feb
Grain LNG	13	12	10	17	1-Mar
Rough	42	42	0	45	21-Nov

37. The 2005/06 maximum beach forecast was 327 mcm/d. As Table 3 shows, the sum of the individual terminal maximum flows was 328 mcm/d. This measurement is normally a good test of our maximum beach forecast, so this indicates that the total forecast was robust despite variations between forecast and actuals at certain terminals.

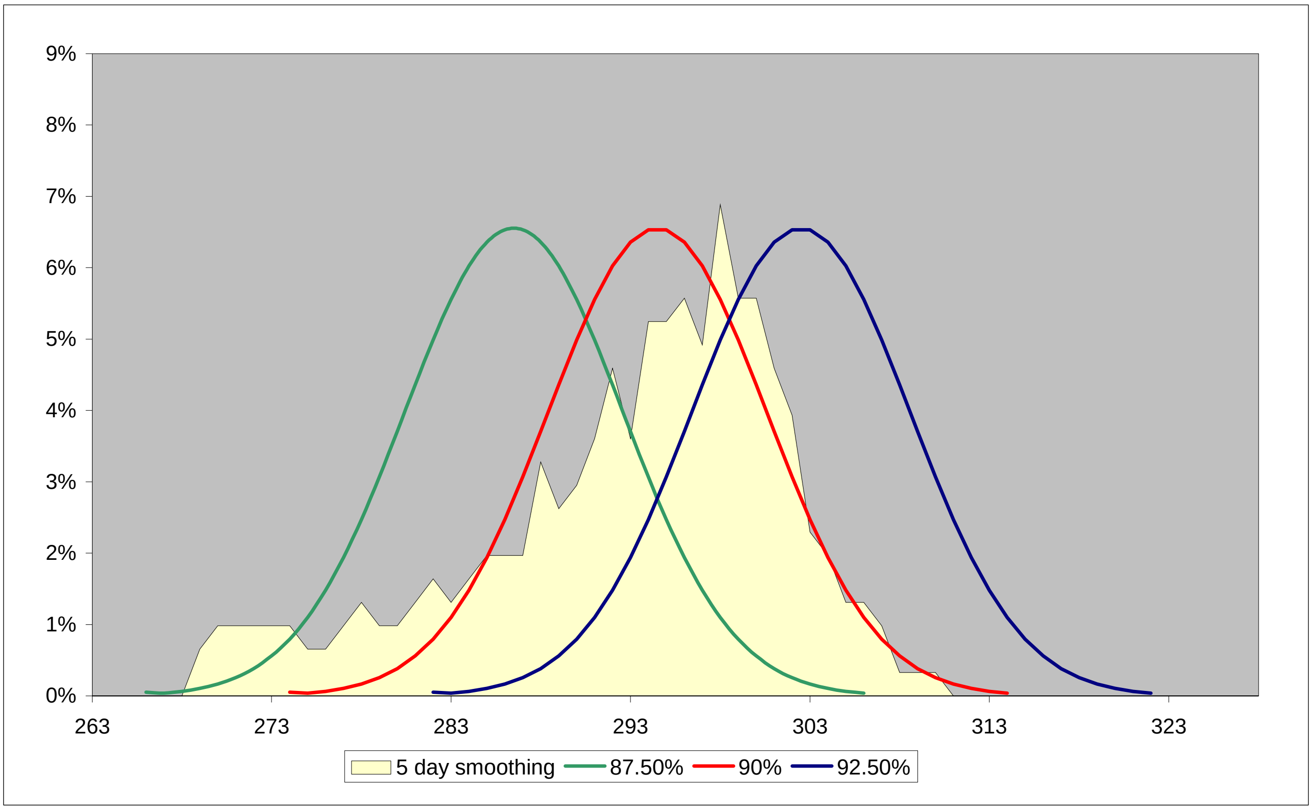
38. Beach supplies appeared to increase linearly with demand up to demand levels of around 310 mcm/d. Beyond this level of demand there was no clear relationship between beach supplies and demand with fluctuations being largely as a consequence of short-term field outages rather than demand or prices. This behaviour is illustrated in Figure A.13 in Annex A.

39. For 2005/06, we applied an availability factor of 92.5% to the maximum beach forecast in order to derive an assumed average level of beach supply under prolonged cold conditions.

40. This level was exceeded on 10 days, and the average supply for the highest 50 days of beach supply was 300 mcm/d (c. 92%). However, there were occasions, even at relatively high demand levels, when lower levels of beach supply were observed.

41. Figure 6 shows the beach supply distribution for the 61 days when demand exceeded 350 mcm/d. It can be seen that the bulk of the distribution sits between the 90% and 92.5% normal distribution curves. However, there were a few occasions when the level of beach supply was around 275 mcm/d (c. 84% of the maximum beach forecast) as a result of offshore outages, depressing the average availability to just above 90%.

Figure 6 – Probability Distribution of Beach Supplies



Belgian Interconnector Performance

42. As Figure 7 and Table 4 show, relatively low imports through this Interconnector were seen in the first half of the winter, despite strong UK price levels (in excess of those in European markets). Chapter 3 highlights potential explanations for these flow patterns.

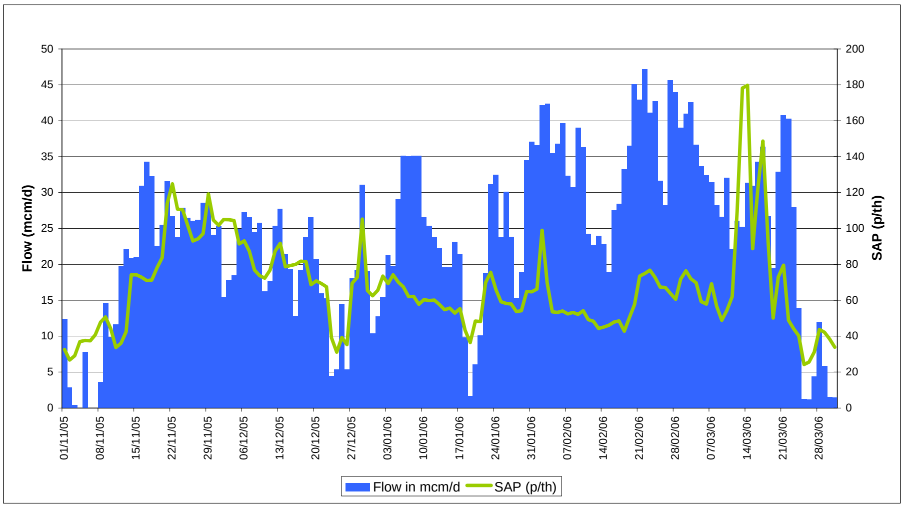
43. The highest flow through the Interconnector was 47.2 mcm/d on 22 February 2006, approaching full capacity of 48 mcm/d.

44. In general, the relationship between Interconnector flow and demand was stronger than the relationship between flow and price. For example, flows between 20 February and 3 March were above 40 mcm/d when SAP was in the range 58-77p/th. However, on 13-14 March, when SAP reached 178-180p/th, Interconnector flows were only 25-31 mcm/d.

Table 4 – Interconnector Delivery Averages

Month	Average Flow (mcm/d)
Nov	18.7
Dec	19.2
Jan	23.0
Feb	34.9
Mar	25.1

Figure 7 – Interconnector Performance



Isle of Grain LNG Terminal Performance

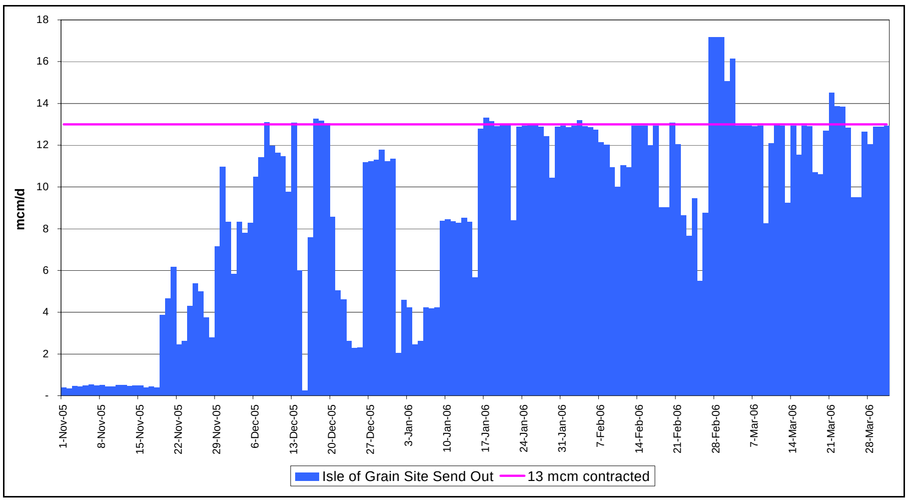
45. A comparison of Figure 7 and Figure 8 shows that flows from the Isle of Grain LNG terminal followed a similar pattern to Interconnector imports; they were well below capacity in the early part of the winter (reflecting sporadic cargo deliveries) but picked up later.

46. One explanatory factor may have been high US gas prices early in the winter in the wake of Hurricanes Katrina and Rita. Figure A.19 in Annex A shows the Henry Hub and NBP prices across the winter.

Table 5 – Isle of Grain Delivery Averages

Month	Average Site Send Out (mcm/d)
Nov	2.3
Dec	9.0
Jan	9.2
Feb	11.6
Mar	12.6

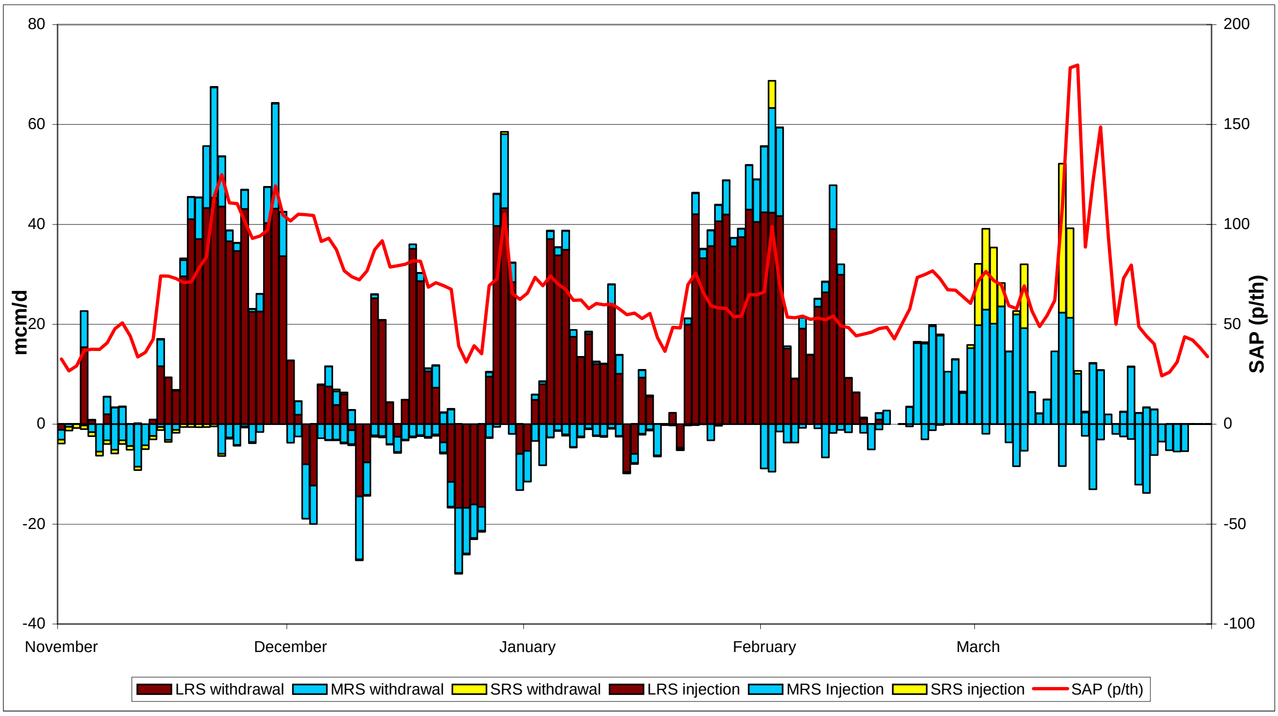
Figure 8 – Isle of Grain Performance



Storage Performance

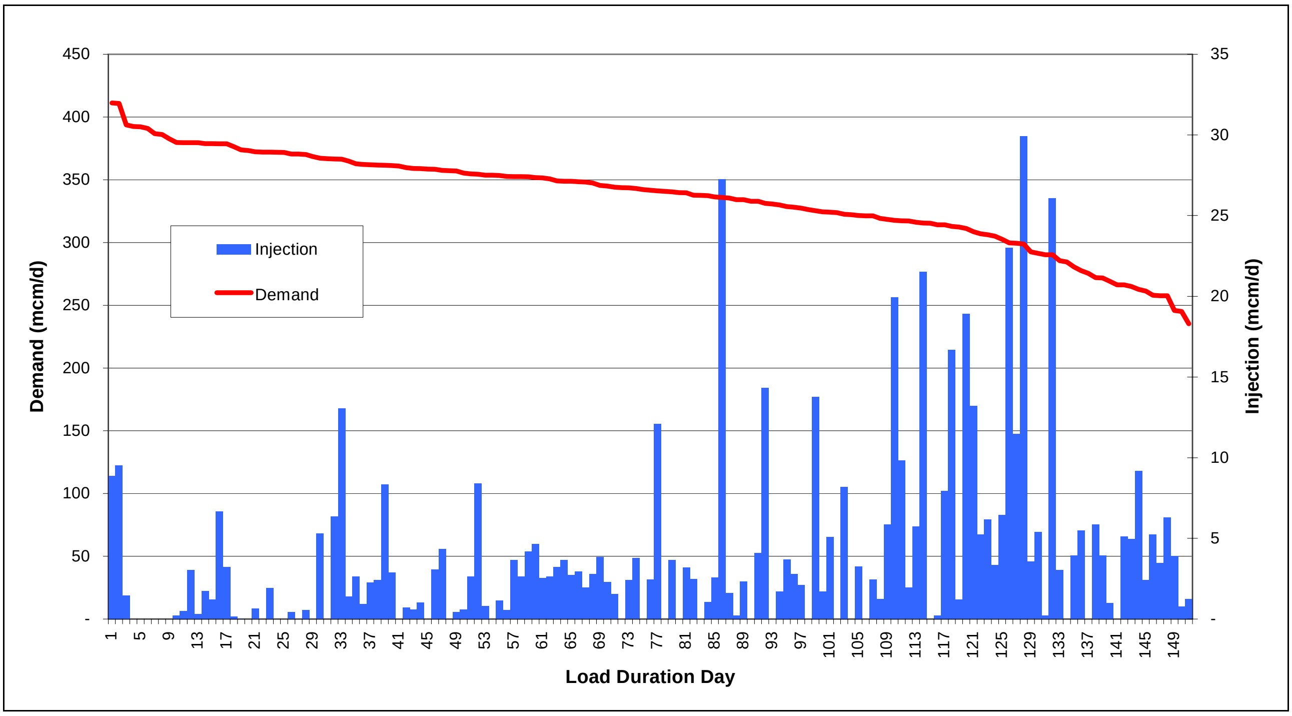
47. Figure 9 below shows the pattern of storage use in 2005/06 by type of storage facility, and the relationship between this pattern of use and price. This was similar to the patterns of use in recent winters until the loss of the Rough Storage platform on 16 February, which caused heavy reliance to be placed upon both Medium and Short Range Storage. Figures A.21 to A.23 in Annex A show the storage stock movements in each of the storage types compared with the relevant storage monitors.

Figure 9 – Storage Injections and Withdrawals v SAP



48. Figure 10 shows storage re-injection against demand during winter 2005/06. As one would expect the chart shows a clear trend of increasing storage injection for decreasing demands. The level of storage injection between 4 November (the first significant use of Rough) through to the middle of March was approximately 600 mcm (c. 15% of total storage space). However, for the 61 days of demands above 350 mcm/d, the total re-injection was just 82 mcm, highlighting the limited opportunities to inject at higher levels of demand.

Figure 10 – Storage Re-injection and Demand Levels for Winter 2005/06



Chapter 2: Electricity

Electricity Demand

49. GB demand growth between winter 2004/05 and winter 2005/06 (corrected for weather variations) was negligible. This compares with a forecast of around 1% demand growth at the time of the Winter Outlook Report 2005/06.

50. The highest electricity demand over the winter reached 60.3 GW for the half-hour ending 17:30 on Monday 29 November 2005. This compares to the highest demand of 59.5 GW over winter 2004/05. These figures are net of customer demand management and include power station own use.

51. National Grid has estimated that there was around 0.8-1.3 GW of demand management at the peak on potential triad days as large customers reduced demand to avoid Transmission Use of System Charges.

Generation Supply Build-Up

52. On a Transmission Entry Capacity (TEC)[1] basis, 75.0 GW of plant was available for winter 2005/06, giving a plant margin of 21%.

53. Following the Winter Outlook Report 2005/06, all 1.6 GW of short-term mothballed plant returned for the winter. There was no return of the 1.6 GW long-term mothballed plant.

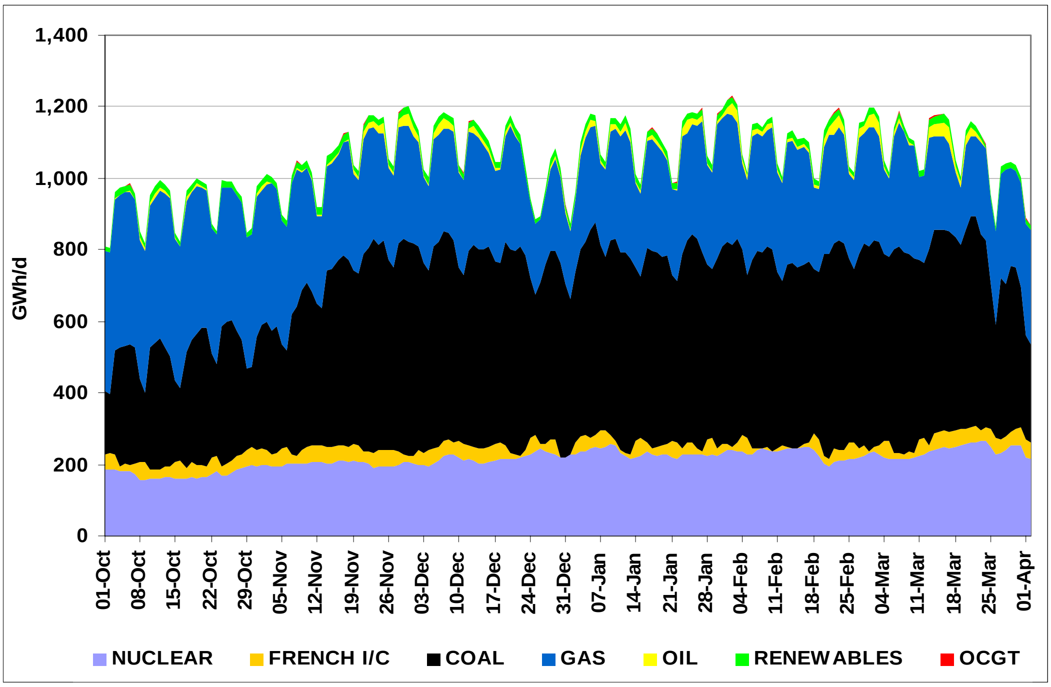
54. A notice of High Risk of Demand Reduction (HRDR) was issued by National Grid on 29 December 2005, reflecting a shortfall in declared generator availability against forecast demand. Imbalances on consumption accounts indicate that a key driver of the lack of declared generator availability was the failure by suppliers to contract fully for the amount of demand on the system (see Figure A.22 in Annex A). This highlights the need for the market to react to market signals to ensure that declared availability will meet demand.

55. Figure 11 shows the build up of generation by fuel type to meet demand for winter 2005/06. Prior to the winter, gas-fired and coal-fired stations typically delivered around 350 GWh/d and 250 GWh/d of generation supply respectively. During the winter, however, they delivered around 250 GWh/d and 500 GWh/d respectively.

56. Figure 11 indicates that coal plant was generally running at baseload and that gas was typically the marginal fuel. That behaviour was broadly in accordance with the assumptions we had made in the 2005/06 Winter Outlook Report when assessing the potential level of CCGT gas demand-side response.

[1] Under the terms of the Connection and Use of System Code, generators are required to purchase Transmission Entry Capacity (TEC) for the generation they export onto the transmission system.

Figure 11 – Daily Generation Supply Build-up, Winter 2005/06



57. Table A.13 in Annex A shows the average declared availability of each type of generation in winter 2005/06. The key points, with particular reference to the assumptions we made (in the light of consultation) in our pre-winter modelling, are:

- Nuclear availability was around 75%, significantly below our winter 2005/06 assumption of 95%;
- Coal availability was broadly in line with our modelling assumption of 85%;
- CCGT availability was also around 75%, against a modelling assumption of 95%. It should not be inferred that the modelling assumption was necessarily invalid, however, since it is likely that generators declared the availability of gas plant, as the marginal fuel type, on commercial rather than technical grounds.

58. For illustrative purposes, Figure 12 shows the generation supply build-up for the Gas Balancing Alert day (13 March 2006), while Figure 13 shows the assumed generation supply build up for the same day applying the Winter Outlook Report 2005/06 modelling assumptions.

59. The following behaviours were observed on typical weekdays, as illustrated in Figure 12.

- Oil-fired generation ran for 12 hours across the daytime, suggesting that the assumption of 8 hours running in the pre-winter modelling was slightly pessimistic;
- Some gas-fired stations generated over the daily peak but did not generate overnight, supporting the modelling assumption of gas as the marginal fuel;
- Coal and nuclear ran baseload, again as modelled.

60. Figure 12 also shows that behaviour on 13 March was unusual in one respect, which was that the UK-France Interconnector did not flow into the UK across the daily demand peak (18:00 – 19:00 or periods 36-38). This was not typical of normal winter weekday behaviour, as shown in Figure 14, and demonstrates a lack of market reaction to the circumstances prevailing that day.

Figure 12 – Actual Generation Supply Build-up, 13 March 2006

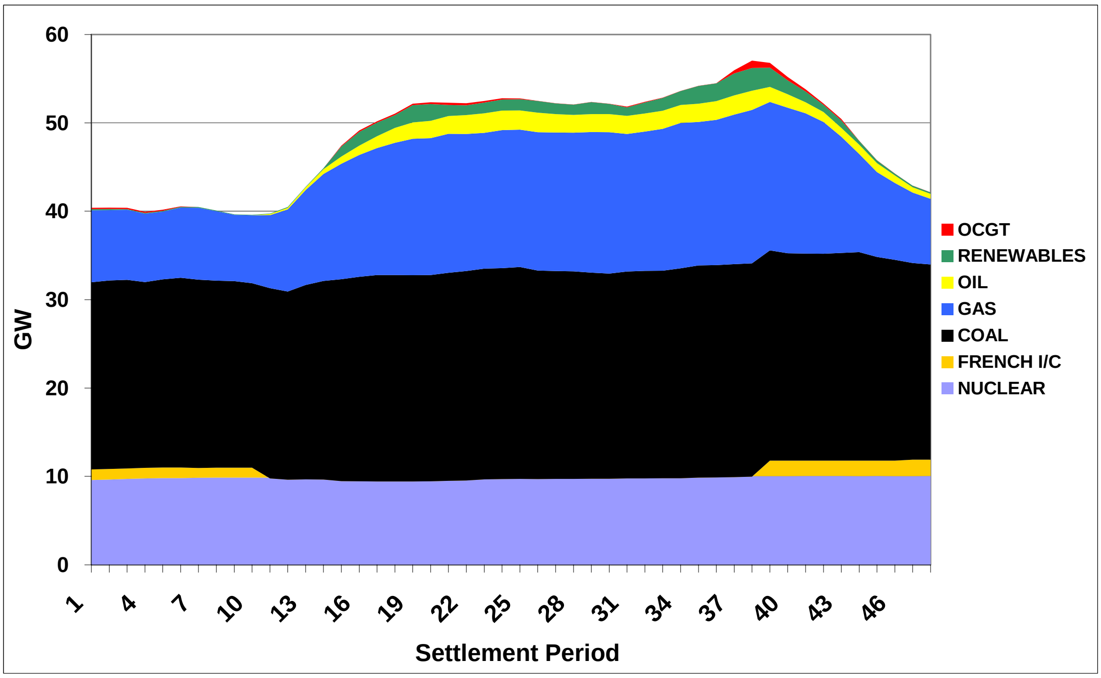
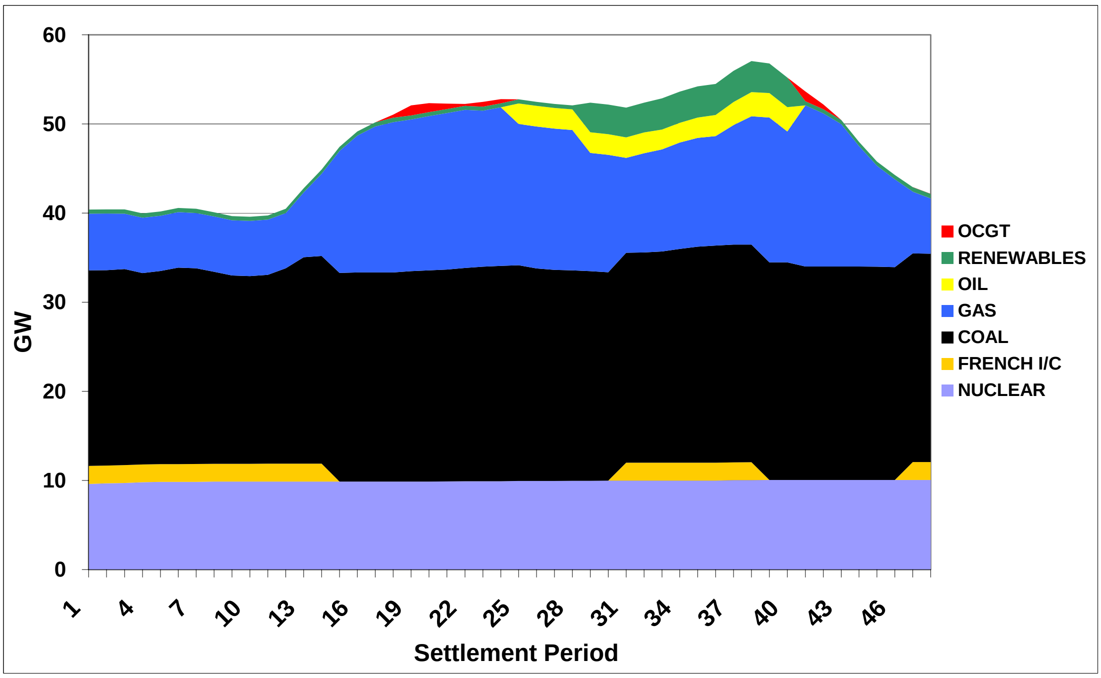


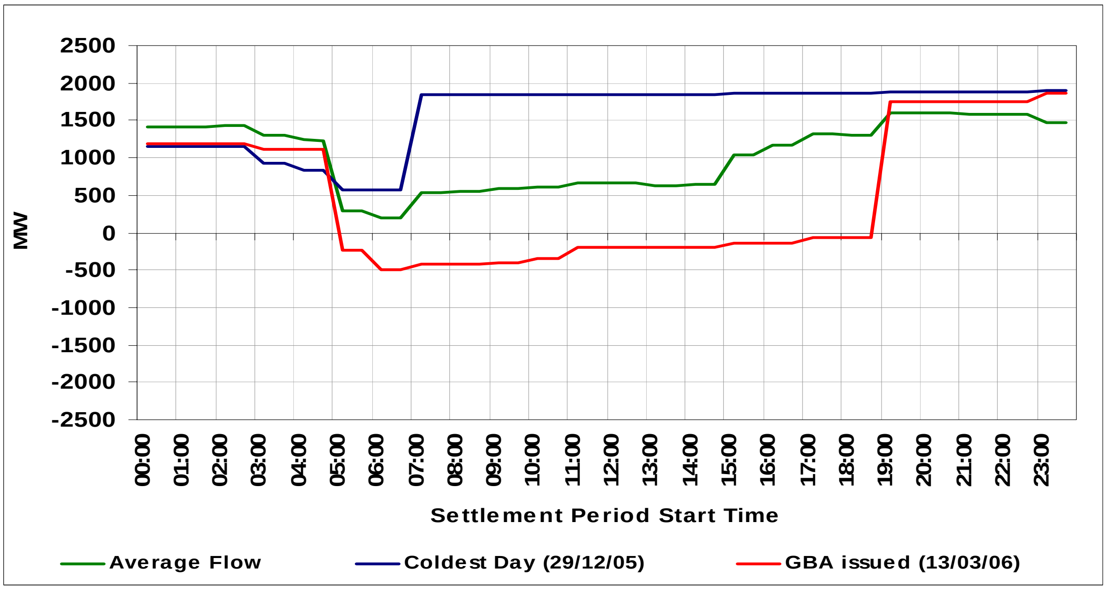
Figure 13 – Generation Supply Build-up Under Winter Outlook 2005/06 Assumptions, 13 March 2006



61. Across the winter there was a varying profile of flows on the UK-France Interconnector. This Interconnector's flows varied across the day, on occasions exporting to France in the morning before reversing direction to flow to the UK for the evening peak. This is generally consistent with UK-France price differentials. The average Interconnector profile is shown below in Figure 14, along with examples of flows on the days where an HRDR was issued (29 December) and a Gas Balancing Alert was issued (13 March). This indicates that the average flow during the Darkness Peak was around 1.4 GW import into the UK and that it reached nearly 2 GW on the day of the HRDR.

62. Figure 14 also illustrates the scope for greater Interconnector imports across the day, thereby increasing the level of gas demand-side response that could be provided by the electricity market.

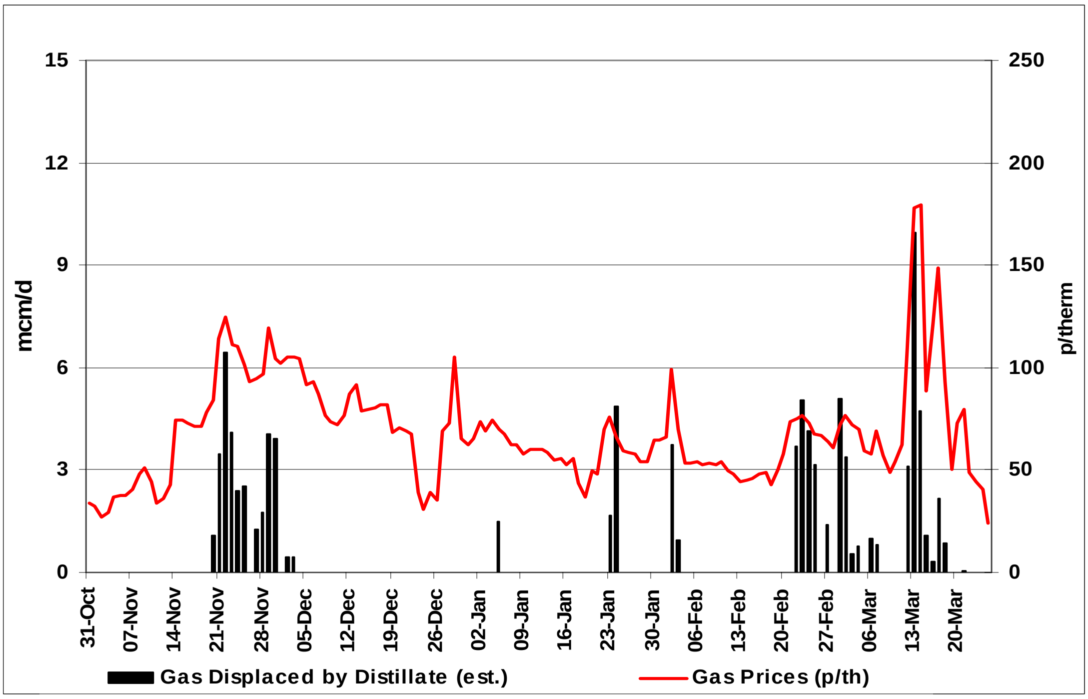
Figure 14 – UK France Interconnector Flow Profiles



Distillate Running – Gas-Power Interaction

63. Figure 15 shows the estimated level of CCGT switching to distillate running in winter 2005/06, plotted against gas price.

Figure 15 – Estimated Distillate Running with Gas Price, Winter 2005/06



64. The maximum level of estimated distillate use was on the gas day of 13 March 2006 when the Gas Balancing Alert was issued. This was 10 mcm (in avoided gas consumption terms) and followed high gas prices (approaching 200 p/th) and the outage of the Rough gas storage facility.

65. The total level of estimated distillate running throughout the winter was 98 mcm (avoided gas consumption). By comparison, our pre-winter modelling assumed a maximum of 200 mcm avoided gas consumption from distillate use. Of the 4.8 GW of distillate capability, 4.1 GW switched to distillate at some point during the winter 2005/06, i.e. 85%.

Section B – Outlook and Issues for 2006/07

Chapter 3: Gas

66. This Chapter focuses on the gas supply-demand outlook for the forthcoming winter. A significant amount of importation infrastructure is presently under construction, which will allow new sources of gas to be brought into the UK. While this response to the decline of UKCS supplies is clearly positive, there is, however, a high level of uncertainty associated with the outlook for 2006/07. 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 the utilisation of that infrastructure.

67. In this Chapter we examine issues associated with the demand background, each of the various sources of supply, and the interactions between those sources. We then illustrate the implications of these issues with analysis that focuses on a base case and a range of sensitivities. The purpose of the analysis is threefold: first, to provide reference points to facilitate discussion and comment; second, to assist industry participants in developing their own view of the forthcoming winter; and, third, to assist industry participants in establishing appropriate arrangements. The base case is not intended to represent a National Grid view.

68. As last year, the format of the analysis is to quantify the level of demand-side response that would be required under specified supply and demand conditions and weather patterns.

69. Given the experience of 2005/06 when gas availability from the various supply sources varied through the different stages of the winter, we are interested to receive views on whether similar (or other) monthly variations can be expected in winter 2006/07.

70. The potential for variations in supply availability across the winter is particularly relevant given that three new importation infrastructure projects are under construction, which will facilitate greater levels of gas flow once operational. The timing of the commissioning of these facilities is therefore a significant factor in the assessment of the supply outlook, and in any associated requirement for demand-side response.

Gas Demand

71. The demand background used for the analysis in this section is the set of demand forecasts for 2006/07 that we produced in 2005, as outlined in the 2005 Ten Year Statement[2]. This background is presented numerically in Annex B. We are presently updating our forecasts following the receipt of information during the latest Transporting Britain's Energy (TBE) consultation process.

72. It is important to note that these forecasts do not make an adjustment for potential reductions in demand that might occur in response to high prices. In particular, we have not adjusted these forecasts to include a demand response as experienced in the 2005/06 winter (and reported in Chapter 1). The demand forecasts therefore

[2] 2005 Ten Year Statement: http://www.nationalgrid.com/uk/Gas/TYS/

show the expected demand prior to the impact of high prices caused by a tight supply-demand balance. However, the typical level of demand response experienced in 2005/06 is indicated in the relevant graphs and tables for comparison purposes.

73. It should also be noted that the demand forecasts are not adjusted for potential interruption by National Grid or the other Distribution Network (DN) operators for capacity management purposes[3]. During the 2005/06 winter there was no such interruption of NTS loads, and only 0.65 mcm (0.00065 bcm) interruption by the DNs, involving 30 Network Sensitive Loads (NSLs).

Demand-Side Response

74. As part of this consultation, we are seeking views on the ability of the demand-side to respond by reducing demand in response to high prices, and on how this might compare with the level of response seen last winter.

75. An analysis of gas/electricity market interaction for the Winter Outlook Report 2005/06 suggested a significant potential for demand side response from CCGTs. As outlined in Chapter 1, this analysis was broadly validated by the experience of the 2005/06 winter, in which CCGT gas demand was typically 20 mcm/d and at times more than 35 mcm/d below the level implicit within the (unconstrained) load duration curve. This market interaction modeling has been repeated to inform this consultation.

76. In addition to the CCGT response, a material reduction in industrial sector demand was also observed at times of particularly high prices, reaching nearly 15 mcm/d on certain days and averaging around 7 mcm/d over the top 100 demand days.

Questions for consultation:

Q1. We would welcome views on the extent to which the non-CCGT market is able to provide demand-side response, both in volume and duration terms and in particular:

Q1a. The extent to which gas demand-side arrangements were in place for the 2005/06 winter (whether through interruptible contracts or otherwise)

Q1b. The extent to which such arrangements were utilised, and what triggered them (e.g. shipper v customer driven, contracted interruption v price arbitrage, response to GBA etc)

Q1c. The extent to which there is scope for investment prior to the 2006/07 winter to provide back-up capability at non-CCGT DM sites

[3] Since UNC modification 0013a, gas transporters no longer have rights to interrupt for supply-demand balancing purposes.

Q1d. The extent to which the experience of the 2005/06 winter may influence the development of such arrangements and the likely impact on the level of potential demand-side response in 2006/07

Q1e. The extent to which a permanent reduction in non-CCGT gas demand (so-called 'demand destruction') has occurred as a result of recent high energy prices

Q2. To what extent can a general reduction in NDM demand be expected in 2006/07, given that NDM demand during the 2005/06 was typically 3-4% below the expected level?

Q3. We would welcome views on expected non-CCGT demand levels for winter 2006/07 under a range of weather conditions and, in particular, on the assumptions that should be made to determine the peak day non-CCGT demand that can be expected in winter 2006/07?

Interruption

77. Arrangements between suppliers and customers have developed considerably, such that it is no longer meaningful to focus on the 'interruptible' sector in that context. Our analysis therefore shows demand broken down into three discrete market sectors, namely: Domestic, Other Non-Daily Metered (NDM) and Daily Metered (DM), rather than Firm and Interruptible.

78. The key relevance of the interruptible sector is that gas transporters have the right to curtail the demand of these customers for the purpose of capacity management. Gas transporters no longer have rights to curtail interruptible demand for reasons of supply-demand balancing. From a transmission perspective, we do not anticipate a material level of transporter-driven interruption in 2006/07, as we would expect the prevailing supply-demand conditions to create a market reaction before we would need to interrupt for capacity management purposes. Following separation of National Grid's Transmission and Distribution businesses, and the sale of four distribution networks, we no longer have access to information in respect of the likelihood of interruption for capacity management purposes at the distribution level. Further information on interruption arrangements is provided in Annex E.

Questions for consultation:

Q4 At what levels of demand would Distribution Network owners expect interruption to be triggered for capacity management purposes?

Q4a. At what level of demand are Network Sensitive Loads (NSLs) likely to be interrupted?

Q4b. At what level of demand are other interruptible loads likely to be interrupted?

Gas Supply

79. This section examines each of the potential (non-storage) gas supply sources in turn: UKCS; European imports from Holland, Belgium and Norway respectively; and

LNG. We set out the main factors associated with these supply sources and seek views on their respective prospects.

80. As outlined above, we are particularly interested to receive views on how the performance of the various supply sources might vary across the winter months.

UKCS Gas Supplies

81. 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 focusing on UKCS supplies specifically as distinct from the various import sources.

82. For the purposes of this document, our initial assessment of UKCS supplies for winter 2006/07 is based on our 2005 forecasts combined with our experience last winter and our most up to date intelligence regarding new UKCS developments. These will be updated following receipt and aggregation of 2006 TBE information. Table 6 compares our forecasts of UKCS supplies for 2005/06 and our preliminary view for 2006/07.

Table 6 – Preliminary 2006/07 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2005/06		2006/07	Comments
	Forecast	Highest	Forecast	
Bacton	83	78	76	
Barrow	29	30	26	
Easington	17	20	16	
Point of Ayr	2	5	2	Difference accounted for by local power station
St Fergus[4]	110	98[5]	92	Noticeable decline in UKCS fields observed
Teesside	28	34	28	Difference accounted for by local power station
Theddlethorpe	23	30	26	
Total	**292[6]**	**295**	**266**	

83. Though Table 6 shows a preliminary UKCS maximum supply forecast of 266 mcm/d, there is clearly a range of uncertainty associated with this, particularly given that 2006 TBE data is still to be reflected. We will update this forecast when we publish the second consultation document in July, based on 2006 TBE data.

84. Table 3 in Chapter 1 shows that our 2005/06 aggregate maximum beach forecast was largely validated by actual flows, indicating that 2005 TBE data is a reasonable starting point for 2006/07 analysis.

[4] Excludes Vesterled
[5] Estimated, based on an assumed flow of 33 mcm/d through Vesterled
[6] The total of 292 mcm/d shown for 2005/06 is equivalent to last year's maximum beach forecast (327 mcm/d) less forecast maximum flows through Vesterled.

85. The indicative 2006/07 maximum UKCS supply forecast incorporates a year-on-year decline of 36 mcm/d from existing fields. This is partially offset by incremental developments totalling around 10 mcm/d based on latest public domain information and other intelligence on those new fields that are expected to be in production for the coming winter.

86. 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. As detailed in Chapter 1, we observed beach performance last winter at an average availability of approximately 90% compared to a pre-winter assumption of 92.5%. As a starting position for the 2006/07 analysis, we have therefore incorporated an assumed average UKCS supply of 240 mcm/d (90%) into the base case.[7]

87. In addition to the uncertainty associated with the 2006 TBE process, there would be some upside against this base case assumption 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 that 90%. Possible factors that could reduce average availability might include:

- A concern that reliability may suffer in the event of poor weather conditions offshore, as observed late in the 2005/06 winter (see Chapter 1);
- The late commissioning of new fields or delays in the resumption of production following maintenance outages, resulting in reduced supply availability early in the winter;
- Within-winter decline of existing fields resulting in reduced supply availability later in the winter;
- Additional maintenance or remedial work, such as that announced by Centrica on 12 May 2006 in relation to the South Morecambe field, to address issues associated with cooler units similar to that involved in the Rough storage platform incident.

Questions for consultation:

Q5. What assumptions should be made over the maximum UKCS supply availability for 2006/07, and specifically:

Q5a. What assumptions should be made over the maximum UKCS supply availability from existing fields?

Q5b. What assumption should be made over the commissioning of new UKCS developments?

Q6. What implications does the cooler unit issue associated with the Rough storage incident have for UKCS supplies this winter?

Q7. What assumptions should be made over the average percentage UKCS supply availability under a period of prolonged severe conditions in 2006/07, and specifically:

[7] This assumes that last year's beach availability (UKCS + Vesterled) is a reasonable indicator for the UKCS on its own. We do not have access to daily Vesterled flows with which to test this assumption.

Q7a. To what extent would UKCS supply reliability decrease if poor weather is experienced offshore?

Q7b. How might UKCS supply availability vary across the winter months, and, in particular, should a lower level of availability be expected in the early part of the winter?

Imported Gas Sources

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

89. In Chapter 1, we highlight the broad pattern of imported gas flows observed last winter, and in particular the higher level of imports seen in the second half of the winter.

Question for consultation:

Q8. We would welcome views on whether similar monthly variations to those observed last year can be expected in winter 2006/07 from the various import sources

90. Three major projects are under construction with the objective of securing additional imported gas supplies for the forthcoming winter. The uncertainty associated with the individual projects is compounded by interactions between the three supply routes. The following sub-sections outline these developments and the associated issues, and seek views on the assumptions that should be made on imported gas flows.

<u>Belgian Interconnector</u>

91. The capacity of this Interconnector is presently undergoing expansion via the construction of compressors at Zeebrugge. For 2005/06, the first two compressors were commissioned, increasing the capacity from 25 mcm/d to 48 mcm/d. Two further compressors are currently being installed to raise the capacity to 68 mcm/d, with planned commissioning by 1 December 2006.

92. The rate at which the Belgian Interconnector imports during the winter period depends upon the net effect of forward and reverse flow nominations, which in turn depend upon the commercial arrangements entered into by the relevant shippers. As we illustrated in Chapter 1, flows through this Interconnector into the UK last winter were significantly below potential maximum levels, despite strong price signals, especially in the early part of the winter. A number of possible underlying reasons have been suggested for this behaviour, including:

- The inability of shippers to access gas supplies on the Continent for importation to the UK, maybe due to the concerns of European market participants over the erosion of storage stocks early in the winter;
- Transportation capacity constraints on the Continent preventing sufficient gas flows to Zeebrugge to allow full utilisation of the Interconnector;

- Problems associated with the different gas quality specifications, preventing some gas sources coming to the UK.

93. For the purposes of the 2005/06 Winter Outlook Report, and our initial safety monitor assessment, we assumed that the pre-existing Belgian Interconnector capacity would be fully utilised, plus 75% of the additional capacity. The experience of winter 2005/06 suggests that a similar assumption for 2006/07 (implying an average flow of 63 mcm/d) would be over-optimistic.

94. Since the Belgian Interconnector rarely flowed at a level close to its maximum capacity, a starting point for analysis would be to assume that, despite further expansion, average flows in 2006/07 are broadly in line with those observed in 2005/06. We have therefore built an assumed average Interconnector flow of 35 mcm/d into the base case. This implicitly reflects the possibility of a pattern of depressed flows in the first half of the winter (generally 30 mcm/d or less) with stronger flows (frequently above 40 mcm/d) in the second half.

95. Clearly, there could be some significant upside if shippers are able to source gas of appropriate quality and to secure the necessary transportation capacity on the Continent to bring it to the UK. A key downside risk is that Europe suffers a severe winter or a significant loss of supply, thereby reducing the level of gas availability for import into the UK.

Questions for consultation:

Q9. What assumptions should be made for levels of imported gas through the Belgian Interconnector for winter 2006/07, and specifically:

Q9a. What assumption should be made over the date at which the second upgrade becomes operational?

Q9b. How much gas has been contracted by shippers to import through this Interconnector into the UK and what is the nature of these contracts (duration, indexation etc)?

Q9c. To what extent might physical transportation constraints in Europe limit the level of imports into the UK through this Interconnector?

Q9d. To what extent have shippers access to the necessary European transportation infrastructure to support gas imports through this Interconnector?

Q9e. To what extent might gas quality issues restrict the level of imports into the UK through this Interconnector?

Q9f. To what extent can net flows on the Interconnector be expected to be depressed by gas export nominations?

<u>BBL</u>

96. A new Dutch Interconnector (BBL, short for 'Balgzand Bacton Line') is currently under construction by BBL Company[8]. BBL Company plans to commission the pipeline by December, with an initial capacity of around 30 mcm/d. This will increase

[8] BBL Company is a joint venture between E-ON-Ruhrgas, Fluxys and Gasunie

to around 42 mcm/d on the installation of a third compressor (planned for March 2007).

97. BBL is uni-directional, avoiding any offsetting of import flow nominations. The primary driver for its construction was a contract between Gasunie and Centrica, through which Gasunie will deliver 8 bcm/annum at the National Balancing Point to Centrica for ten years, with a winter:summer split of 5:3. This equates to roughly 27 mcm/d over the winter period. These factors suggest that, once operational, gas flows through BBL might be more predictable than those through the Belgian Interconnector. Nevertheless, for 2006/07 there remains a significant level of uncertainty over, for example:

- The eventual commissioning date given the construction risks associated with such a significant infrastructure development;
- The extent to which any delay to the availability of BBL beyond 1 December 2006 could be mitigated by alternative gas sources or importation routes;
- The utilisation rate of BBL capacity given the potential alternatives available to Gasunie to meet their contract obligations with Centrica; and
- The potential use of any BBL capacity not required to service the Centrica contract, taking account of supply availability and any transmission constraints in the Netherlands.

98. As we have illustrated above, the assumption in the Winter Outlook Report 2005/06 that new import infrastructure would operate at a 75% utilisation rate was shown to be over-optimistic in the case of the Belgian Interconnector. The fact that BBL is being developed on the back of a specific supply contract suggests that a similar assumption may not be unreasonable in this case as a starting point of analysis. Since it is unclear whether additional supplies will be available beyond the level implicit in the Gasunie-Centrica contract, we have incorporated an assumed average flow rate of 20 mcm/d (75% of 27 mcm/d) into the base case.

99. Once fully operational, the maximum upside and downside risks associated with an assumed flow of 20 mcm/d will be similar at around 20 mcm/d. However, prior to the commissioning of the third compressor, the potential upside will be around 10 mcm/d. Similarly, it is hard to envisage the full downside risk becoming reality unless commissioning of BBL was delayed beyond the end of the winter period.

Questions for consultation:

Q10. What assumptions should be made for levels of imported gas through BBL for winter 2006/07, and specifically:

Q10a. What assumption should be made over the date at which BBL becomes operational initially and the subsequent upgrade to a capacity of 42 mcm/d?

Q10b. What utilisation rate should be assumed for the BBL capacity not required to service the Gasunie-Centrica contract?

Q10c. To what extent might physical transportation constraints in Europe limit the level of imports into the UK through this Interconnector?

Q10d. To what extent have shippers access to the necessary European transportation infrastructure to support gas imports through this Interconnector?

Q10e. To what extent might gas quality issues restrict the level of imports into the UK through this Interconnector?

Q10f. What is a realistic level for sustained flows via BBL to the UK for winter 2006/07 once it is operational?

Norwegian imports

100. A new Norwegian pipeline known as Langeled is scheduled to be operational by October 2006. The pipeline from the Sleipner platform in the Norwegian North Sea to Easington has been laid and will connect to a new sub-terminal at Easington, which is currently under construction. The pipeline has a capacity of 25 bcm per year (68 mcm/d), almost tripling the total available capacity for Norwegian gas to come directly into the UK. The second leg of the Langeled pipeline, connecting the Ormen Lange field to the Sleipner platform, is scheduled to be completed in 2006 for operation in 2007/08.

101. For 2006/07, therefore, there is the possibility of incremental volumes from Norway. These will depend upon either incremental production from other Norwegian gas fields, or the diversion to the UK of Norwegian supplies that would otherwise have been exported to Continental Europe. In the latter case, it is possible that this would result in an offsetting of gas flows through the Belgian Interconnector and/or BBL. There is therefore a high level of uncertainty regarding total volumes of gas that may flow through the Vesterled and Langeled pipelines.

102. Given this high degree of uncertainty, it is difficult to find any objective rationale for a base case assumption. To stimulate discussion and comment, we have assumed an incremental volume of Norwegian gas of 15 mcm/d (with no displacement of other sources). Adding this to the 2005/06 Winter Outlook Report assumption of 33 mcm/d gives a total average Norwegian import flow of 48 mcm/d.

103. There is clearly considerable upside potential against this assumption, theoretically more than 50 mcm/d given the capacity of Langeled. Any upside, however, will depend on the availability of further Norwegian gas for the UK market without displacing gas that would otherwise have entered the UK through Vesterled, BBL or the Belgian Interconnector.

Questions for consultation:

Q11. What assumptions should be made for levels of imported gas from Norway for winter 2006/07, and specifically:

Q11a. What assumption should be made over the date at which Langeled becomes operational?

Q11b. What level of additional gas supply availability from Norway should be assumed over and above that which we have previously observed through Vesterled?

Q11c. To what extent might gas quality issues restrict the level of imports into the UK from Norway?

Total European Imports

104. The previous sub-sections have outlined the developments and issues associated with each of the gas importation routes from Europe. The construction of Langeled (completion planned by October) will increase the total (physical) import capacity from Europe by around 70 mcm/d to over 150 mcm/d. Once the second Belgian Interconnector upgrade and BBL are available (if all goes according to schedule, by December), the theoretical total import capacity from Europe (via the Belgian Interconnector, BBL, Vesterled and Langeled) will be around 200 mcm/d. This will rise further to around 215 mcm/d, on the commissioning of the third BBL compressor, targeted for March 2007. Whilst it is possible that any one source may supply at levels near its maximum at times during the 2006/07 winter, we have highlighted a number of issues that together are likely to prevent gas flows close to this maximum level.

Questions for consultation:

Q12. What assumptions should be made for the total levels of European imports, and specifically:

Q12a. What interaction between the flows through the various importation routes should we assume, e.g. the extent to which incremental Norwegian imports offset flows via the Belgian Interconnector?

Q12b. What is the total level of flow that could be expected through the Continental Interconnectors (BBL and Belgian Interconnector) given sufficiently high demand in the UK?

Q12c. What are the key risks to the timely completion and commissioning of the infrastructure projects that will facilitate additional gas supplies to the UK for the 2006/07 winter?

Q12d. As described in paragraph 175, National Grid is examining the feasibility of potential blending opportunities at the beach terminals. This work is initially focused on Bacton. To what extent do parties consider that, should such blending be possible, additional gas supplies for this winter would emerge?

LNG

105. The Grain LNG terminal commenced commercial operation on 15 July 2005 following the delivery of the commissioning cargo on 4 July 2005 by BP/Sonatrach. The facility, which has a maximum contracted deliverability of 13 mcm/d, delivered a maximum flow last winter of 17 mcm/d. Use-It-Or-Lose-It (UIOLI) provisions for the use of the shippers' capacity at Grain are in place, and enhancements are presently under development.

106. The experience of the 2005/06 winter (see Chapter 1) has demonstrated that Grain is able to provide inputs into the UK market up to 13 mcm/d in line with its contracted

maximum on a consistent basis. However, this experience also showed that events elsewhere in the world can have an impact on UK LNG imports, and that other issues such as cargo delivery logistics can prevent capacity being fully utilised every day.

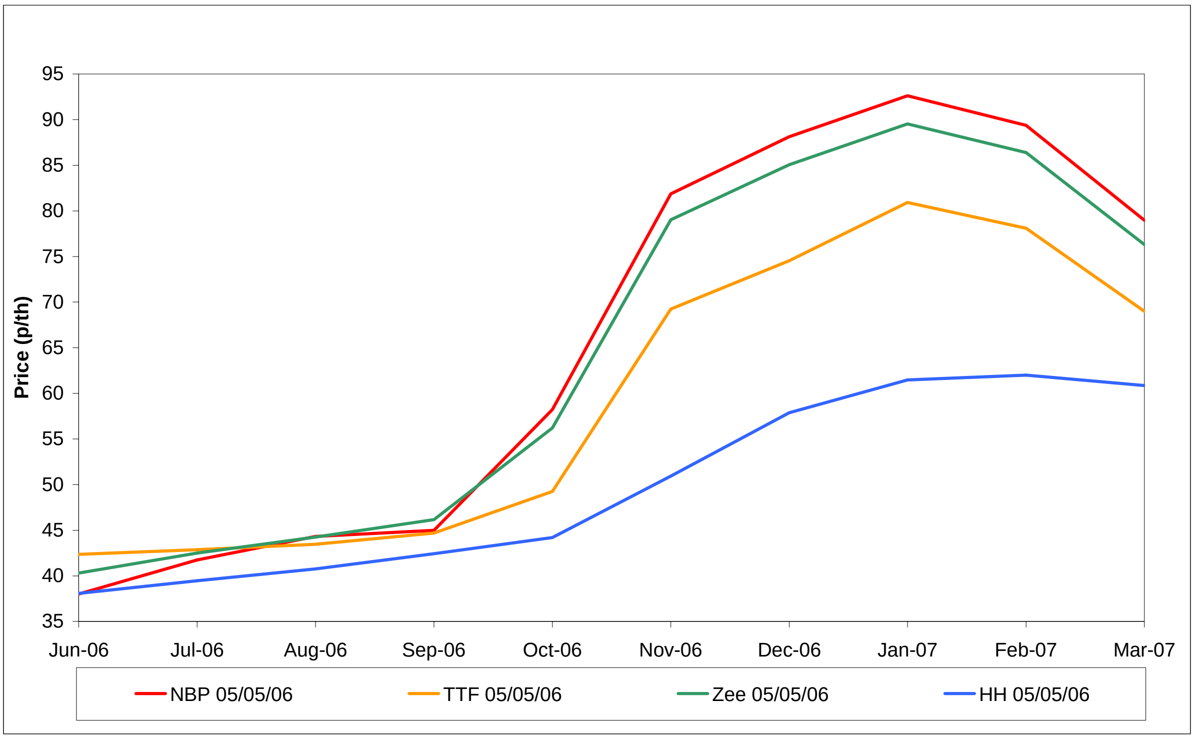
107. At present, as shown in Figure 16, forward prices in Europe (and at the UK NBP in particular) for winter 2006/07 are well above the equivalent Henry Hub (HH) price, suggesting that the risk of cargo diversion to the United States is relatively low[9]. (This was of course the position in 2005 prior to Hurricanes Katrina and Rita).

108. Excelerate Energy has recently announced plans to deliver up to 11 mcm/d of LNG at Teesside using Excelerate's 'Energy Bridge' shipboard regasification technology. They aim to be operational by December 2006, subject to receiving the necessary planning approvals and consents.

109. As a basis for discussion and comment, we have incorporated an assumption of 13 mcm/d of imported LNG into the base case. This reflects the experience towards the latter part of the 2005/06 winter, when Grain flowed regularly at around this level.

110. There is some upside associated with this assumption (albeit relatively small) given the proven maximum physical capability of Grain is around 17 mcm/d, and the possibility of additional supplies from Excelerate. The main downside risk arises from the potential for LNG cargoes to divert elsewhere in the world in response to more attractive prices. This is unlikely given forward prices at present, but the hurricanes in 2005 demonstrated the potential for unanticipated events to have a significant impact on the commercial environment.

Figure 16 – Forward Gas Price Comparison



[9] This graph excludes any transport costs. The typical transport cost for LNG across the of Atlantic is around 5 p/therm.

Questions for consultation:

> ***Q13. What assumptions should be made for LNG importation quantities in winter 2006/07, and specifically:***
>
> > ***Q13a. How are flow patterns likely to differ from those observed in 2005/06?***

Storage

111. No major changes in storage capacity are expected for the 2006/07 winter. It is anticipated that some additional deliverability will be available at Hole House Farm, and that Humbly Grove will be fully operational, having commissioned during the 2005/06 winter.

112. Following the Rough outage on 16 February 2006, Centrica Storage Limited have kept the market informed regularly over progress with the repair work and their expectations over when both injection and production operations might recommence. In their latest statements, Centrica Storage have indicated that injection is expected to resume on 1 June and production will be available no later than 1 October. These assumptions have been used within our base case. Clearly, the successful and timely resumption of operations at Rough is significant in the context of the supply-demand position for the 2006/07 winter.

113. Chapter 1 provides analysis of the use of storage last winter. (Clearly, following the incident at Rough, patterns of use were heavily distorted by Rough's unavailability). It illustrates the potential for a material level of re-injection when demand is not too high, but that the opportunities for re-injection are much more limited under colder conditions. The possibility of re-injection does, however, provide some upside to the physical capacities shown in Table 7.

Table 7 – Assumed 2006/07 storage capacities and deliverability levels[10]

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1897	526	49	3.6
Medium (MRS)	8111	345[11]	32	23.5
Long (Rough)	33675	455	42	74

Questions for consultation:

> ***Q14. We would welcome views on the likely patterns of use of the various gas storage facilities in 2006/07, and in particular:***
>
> > ***Q14a. Likely trigger dates and/or trigger prices for use of storage***
> >
> > ***Q14b. The scope for re-injection under different demand and price conditions***

[10] Excludes Operating Margins gas

[11] Assumes average deliverability for Humbly Grove

Q14c. The order in which long, medium and short range storage would be called upon in relation to marginal UKCS fields, interconnectors and LNG imports

Q14d. The extent to which UK storage stocks are reserved for UK usage, and what events may lead to them being traded on the continent

Q14e. The extent to which European storage stocks are reserved for continental use, and what events may lead to them being traded in the UK

Base Case

114. In the previous sub-sections we have outlined the basis for the assumptions incorporated into our analysis. Table 8 summarises the main assumptions, and compares these with our 2005/06 Base Case: We should stress that these 2006/07 assumptions should not be regarded as a National Grid view. They are illustrative and for the purpose of fostering discussion and comment.

Table 8 – Supply Assumptions Incorporated into Base Case (mcm/d)

	2005/06 Base Case Assumption	May 2006 Base Case for consultation purposes only
UKCS	269 (291 @ 92.5%)	240
Norway	33 (36 @ 92.5%)	48
IUK	42 (revised to 30)	35
BBL	N/A	20
LNG imports	13	13
Total	357	356

Analysis of Base Case

115. Figures 17,18 and 19 show the base case assumptions overlaid on a load duration curve of average, 1 in 10 and severe demand respectively, with demand broken down into the Domestic, Other Non Daily Metered (NDM) and Daily Metered (DM) sectors. The forecast DM demand is further broken down to show the average demand response experienced last winter, typically 20 mcm/d for CCGTs and 7 mcm/d for industrials. These load curves are presented numerically in Annex B. 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.

Figure 17 – Average Load Duration Curve Analysis for 2006/07

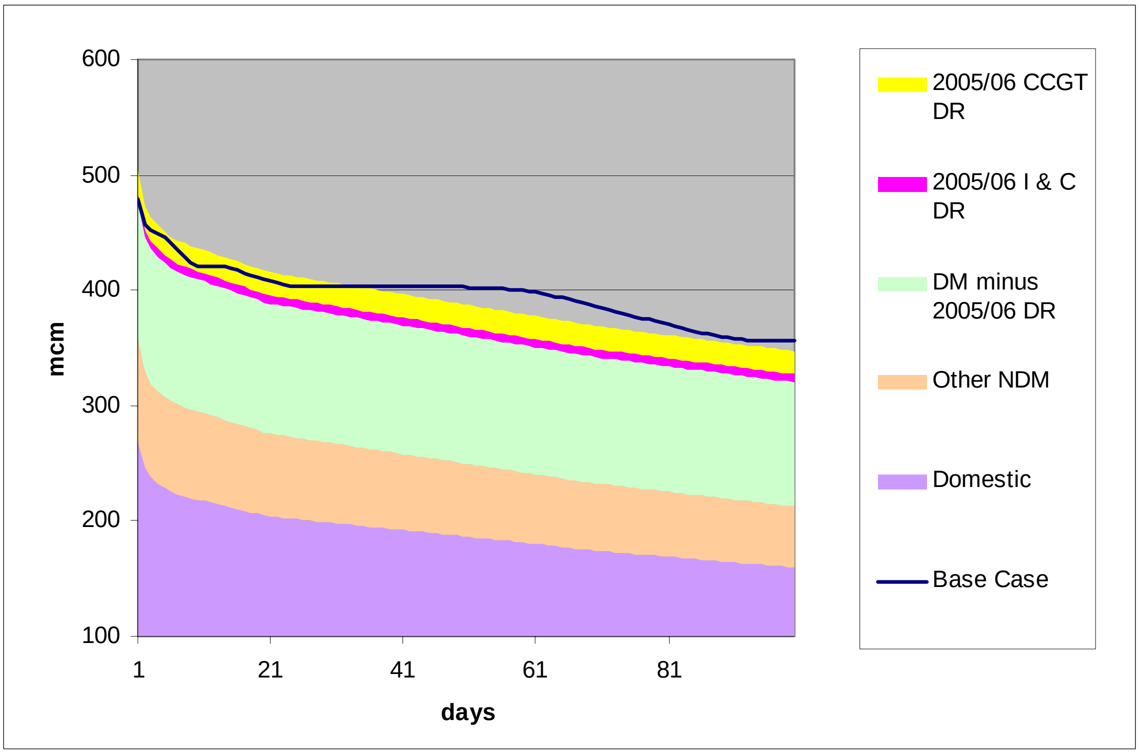


Figure 18 – 1 in 10 load Duration Curve Analysis for 2006/07

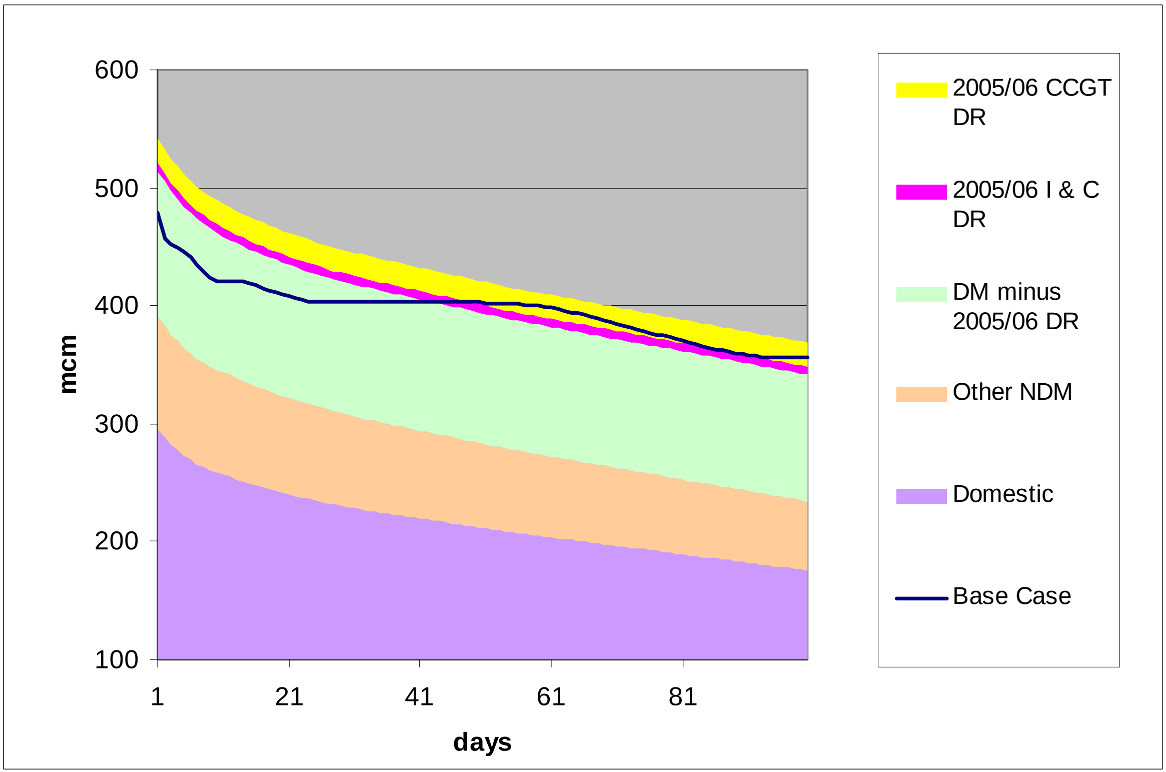
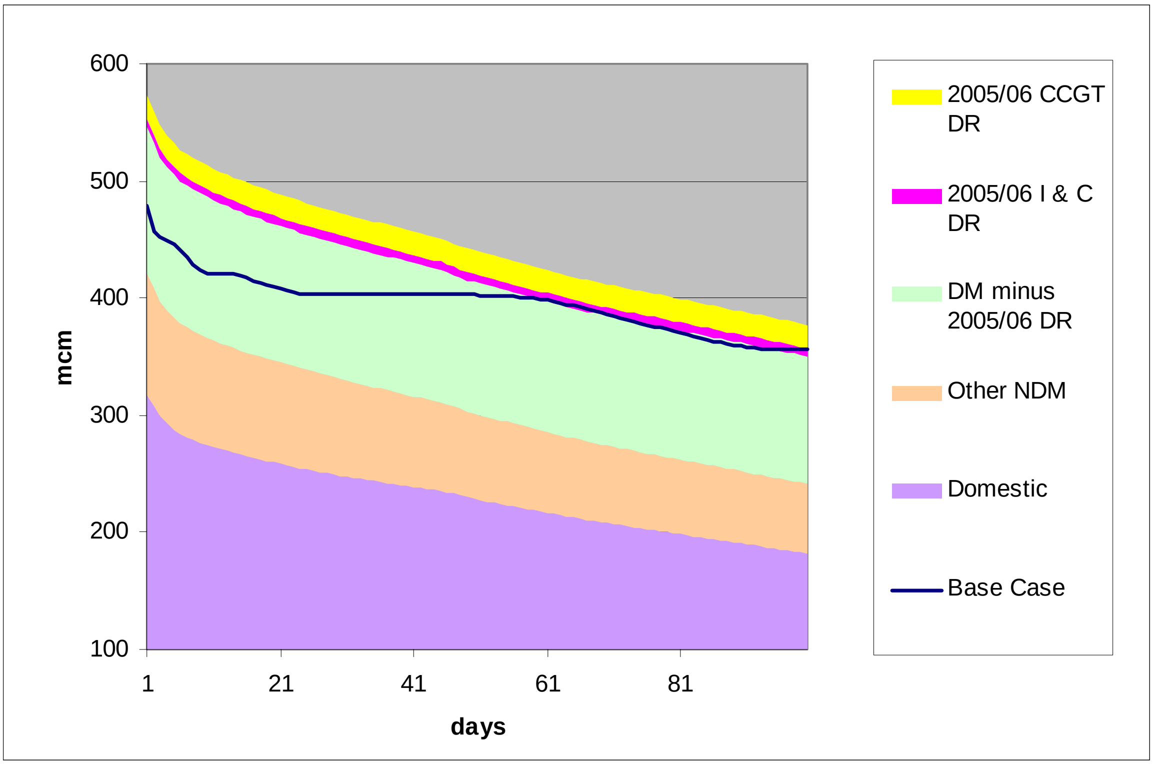


Figure 19 – 1 in 50 Load Duration Curve Analysis for 2006/07



116. Table 9 summarises the implied level of demand response required over the highest 100 days of demand, and also shows the additional demand response required over and above the average demand response experienced last winter.

Table 9 – Demand Response Requirements Under Base Case Assumptions (bcm)

	Average	1 in 10	Severe
Base case: total demand response required	0.3	3.1	5.0
Additional demand response above 2005/06 level	0.0	1.0	2.3

Cold Spell Analysis

117. 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.

118. Figure 20 shows bar charts consisting of three levels of demand, namely those demands commensurate with a peak day[12], a very cold week[13] and a very cold month[14]. Against these levels of demand is shown the supply availability[15] under the base case assumptions, and the associated level of demand response required for supply and demand to balance.

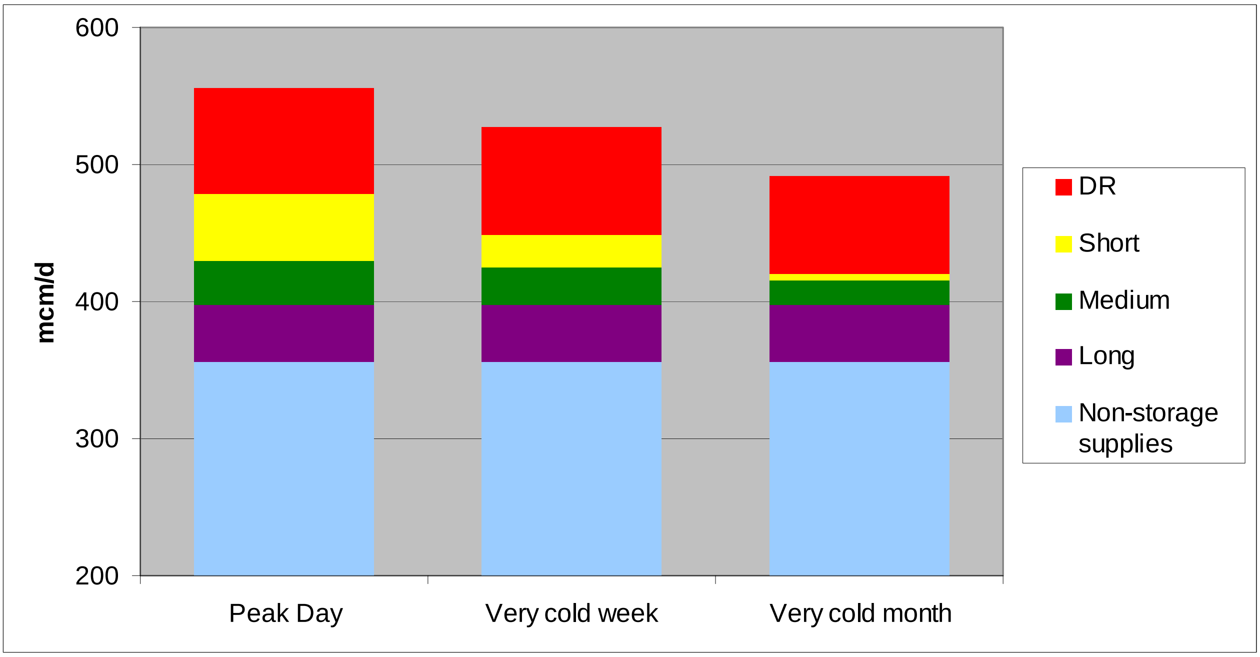
119. To give a sense of the weather conditions that these cases represent, the average temperatures across the country associated with these cold spells would typically be around:

a 1:20 Peak day: around -5 ^{o}C

a very cold week: -4 ^{o}C

a very cold month: -2 ^{o}C.

Figure 20 – Cold Spell Analysis for 2006/7 Assuming Base Case Supply Conditions



Sensitivity Analysis

120. The previous sections have set out a base case for the supply-side in the 2006/07 winter and have illustrated the implications of this base case under a range of weather conditions. They have also indicated the potential range of flows that might be observed through the various supply routes, and highlighted the key factors that will underpin actual flows.

[12] Diversified demand for a 1 in 20 Peak day
[13] Average diversified demand for Days 1 to 7 on a 1 in 50 load curve
[14] Average diversified demand for Days 1 to 30 on a 1 in 50 load curve
[15] Storage deliverability is adjusted proportionally when the duration is exceeded

121. The purpose of this section is to allow the reader to assess the implications of alternative scenarios using a set of sensitivities. Table 10 shows the impact of variations in the assumptions on the level of required demand-side response.

122. For example, if the reader believed that the average level of non-storage supplies (i.e. UKCS plus imports) was likely to be 10 mcm/d less than in the base case, the table shows that in an average winter, this would imply a requirement for demand-side response of 0.7 bcm, or 0.4 bcm more than under the base case conditions.

123. The sensitivity relating to storage cycling assumes that a percentage of storage space is utilised twice in the course of the winter. We have analysed different percentages for the different winter severities to reflect the greater opportunity for storage cycling when demand is lower.

124. Following the incident at Rough on 16 February, a degree of uncertainty exists around the stock levels at the start of winter 2006/07, particularly because of the late start to the injection season and the potential impact of variations in other sources of supply on gas availability for injection in Q4 2006. For this sensitivity analysis, we have assumed that the injection season is reduced by one month. This would result in a reduction in Rough stock of 2500 GWh, equivalent to a loss of 5.5 days duration at the Rough facility.

125. We noted in Chapter 1 that NDM demand during winter 2005/06 was generally below expectations, typically by 3-4%. We have therefore included a case in this analysis in which NDM demand is consistently lower than is presently implicit within our demand forecasts.

126. The ‘split winter’ scenario analyses a winter in which imports are depressed in the first half of the winter (30 mcm/d below the base case) but improve in the second half (10 mcm/d above the base case). For this analysis we have made the assumption that 70% of the highest demand days occur in the second half of the winter. Whilst a fairly crude assumption, this is a reasonable reflection of typical historical weather patterns, which helps to explain why the output isn’t so different from the base case. However, this load curve based analysis does not reveal the potential risk associated with the split winter scenario for storage to be depleted in the first half of the winter, thereby creating greater difficulty should cold weather occur later on.

Table 10 – Demand Response Requirements Under Different Scenarios

Case	Response (bcm)		
	Average	**1 in 10**	**Severe**
Base case +30 mcm/d non-storage supplies	0.0	0.9	2.1
Base case +20 mcm/d non-storage supplies	0.0	1.3	3.0
Base case +10 mcm/d non-storage supplies	0.0	2.1	4.0
Base case	0.3	3.1	5.0
Base case -10 mcm/d non-storage supplies	0.7	4.1	6.0
Base case -20 mcm/d non-storage supplies	1.5	5.1	7.0
Base case -30 mcm/d non-storage supplies	2.5	6.1	8.0
Storage cycling: 15% in Average winter 10% in 1 in 10 winter 5% in 1 in 50 winter	0.2	2.7	4.8
Rough injection season reduced by one month	0.3	3.3	5.2
5% less NDM demand	0.0	1.7	3.5
Split winter: Base case -30 mcm/d in 2006 Base case +10 mcm/d in 2007	0.1	3.3	5.2

Safety Monitors

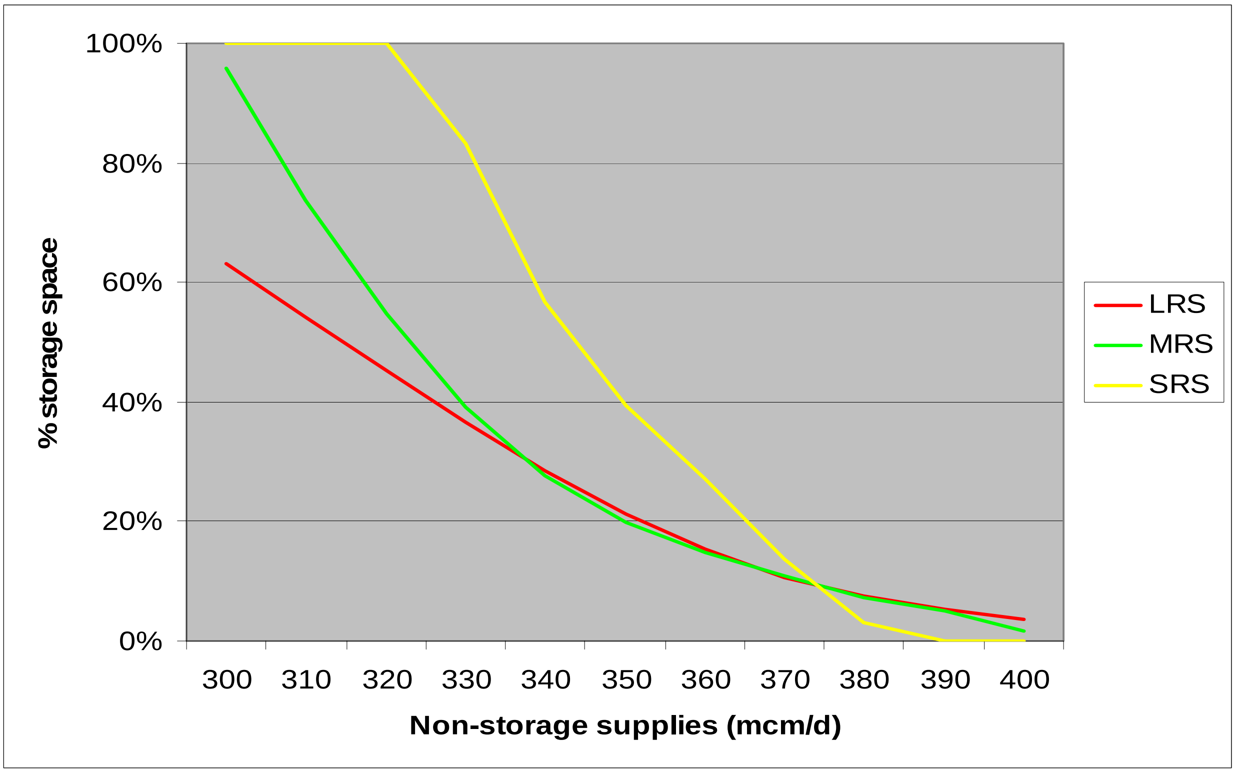
127. Safety monitors were introduced in 2004 as a mechanism for ensuring that sufficient gas is held in storage at all times to underpin the safe operation of the gas transportation system. The safety monitor concept and the way in which they operate are explained in Annex C.

128. We are in the process of considering the appropriate basis for setting the initial safety monitor levels for the 2006/07 winter. We will set these out in a separate note by 31 May 2006 as required under the Uniform Network Code (Q5.2.1).

129. At this stage, however, any assumptions used for the purpose of setting safety monitor levels should be considered tentative and preliminary. Furthermore, 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.

130. Figure 21 illustrates the initial safety monitor levels that would be required under different non-storage supply assumptions based on our 2005 demand forecasts for 2006/07. (NB this graph relates only to initial monitor levels, not to their profile across the winter). It demonstrates that the monitor levels are highly sensitive to these assumptions.

Figure 21 – Initial Safety Monitor Levels as a Function of Supply Assumptions



Question for consultation:

Q15. We would welcome views on the appropriate basis for setting the 2006/07 safety monitors

Chapter 4: Electricity

Electricity Demand Levels for 2006/07

131. Our latest Average Cold Spell (ACS) peak demand forecast for winter 2006/07 is 61.3 GW, which includes a 0.3 GW flow to Northern Ireland. No growth in demand is assumed between winter 2005/06 and winter 2006/07 as a result of continued high energy prices.

132. As discussed in Chapter 2, around 0.8-1.3 GW[16] of demand management was observed at times of peak demand in the winter of 2005/06 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 2006/07, 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.

Questions for consultation:

Q16. We would welcome views on the extent to which electricity demand response might be expected given high electricity prices, and in particular:

Q16a. How much more response might be seen compared to winter 2005/06 estimates?

Notified Generation Availability

133. The current plant margin for winter 2006/07 reported in the SYS[17] is around 21%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 76.3 GW. This is slightly higher than the reported level of generation capacity prior to winter 2005/06 as no units have released TEC and 0.9 GW of TEC has been granted to previously short-term mothballed plant.

134. This headline plant margin 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.

135. Our current operational view of generation capacity anticipated to be available for winter 2006/07 is 74.7 GW. (A broad breakdown of this capacity is shown in Figure 22).

136. The generating companies also provide us 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. This information, summarised in Table 11, suggests that a further 1.7 GW could return for the 2006/07 winter, of which 0.7 GW already

[16] This differs from the demand forecast within the SYS, which is based on customer projections and assumes no demand management

[17] 2005 Great Britain Seven Year Statement Update (Jan 2006) http://www.nationalgrid.com/uk/library/documents/sys05/mysys/updates/quarter4.pdf

has TEC. It is unlikely that a further 1.1 GW of long-term mothballed plant could make itself available for winter 2006/07.

Figure 22 – Generation Capacity, Winter 2006/07

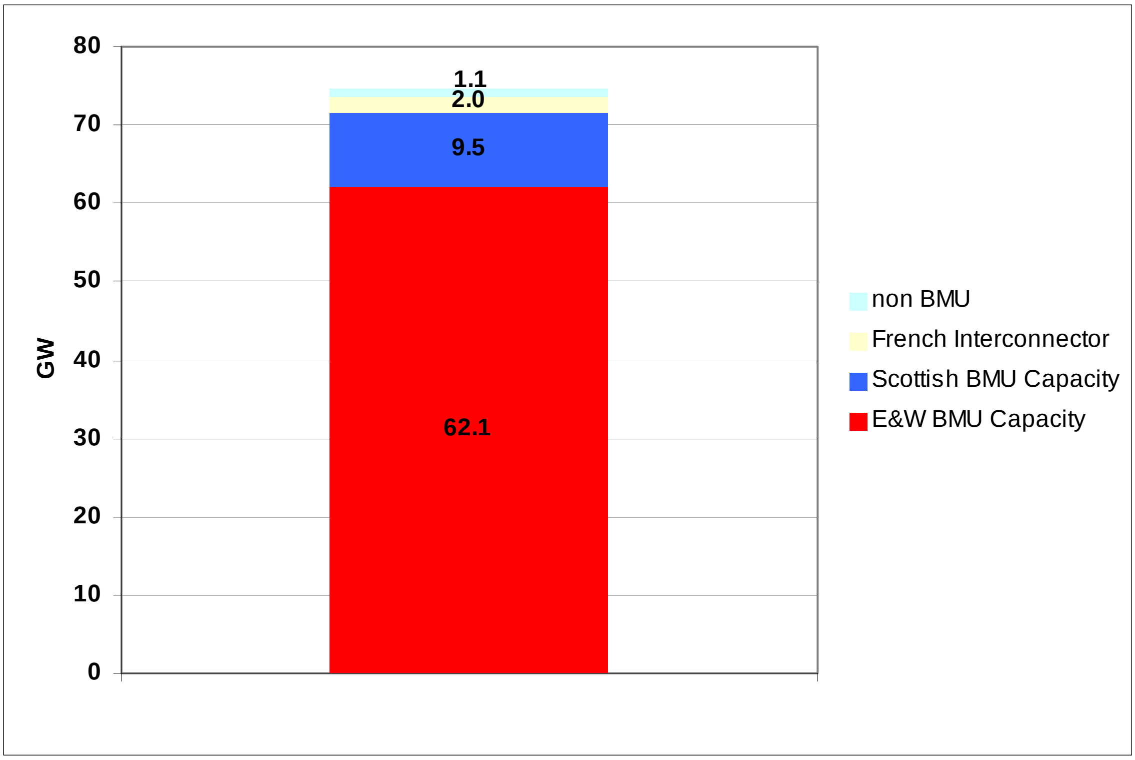


Table 11 – Mothballed Capacity, winter 2006/07

	Could Return within 3-6 months	Long Term Unavailable Plant
Generation capable of being returned within period (GW)	1.7	1.1

Questions for consultation:

Q17. ***What assumptions should be made over the extent to which mothballed generation will become available, and when?***

Q18. ***To what extent is there scope for investment prior to the 2006/07 winter to provide back-up capability at existing power stations?***

Contracted Reserve

137. At certain times of the day, National Grid needs extra power available in the form of either generation or demand reduction to be able to deal with actual demand being greater than forecast demand and plant breakdowns. This requirement is met from synchronised and non-synchronised sources. We procure the non-synchronised requirement by contracting for Standing Reserve and Supplemental Standing Reserve from a range of service providers including Balancing Mechanism (BM), demand reduction and non-BM generating plant. For winter 2006/07, the level of contracted Standing Reserve is 2.6 GW across both BM and non-BM providers.

138. National Grid currently intends to issue a Supplemental Standing Reserve Tender during late summer, for delivery in winter 2006/07 (October '06 – March '07). Communications regarding this will be through electricity operational fora and on our website[18].

139. There is a continual requirement to provide 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. 0.9 GW has been contracted already, 0.3 GW within the BM and 0.6 GW with non-BM providers.

140. National Grid continues to have Maximum Generation contracts in place for winter 2006/07, 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 2006/07

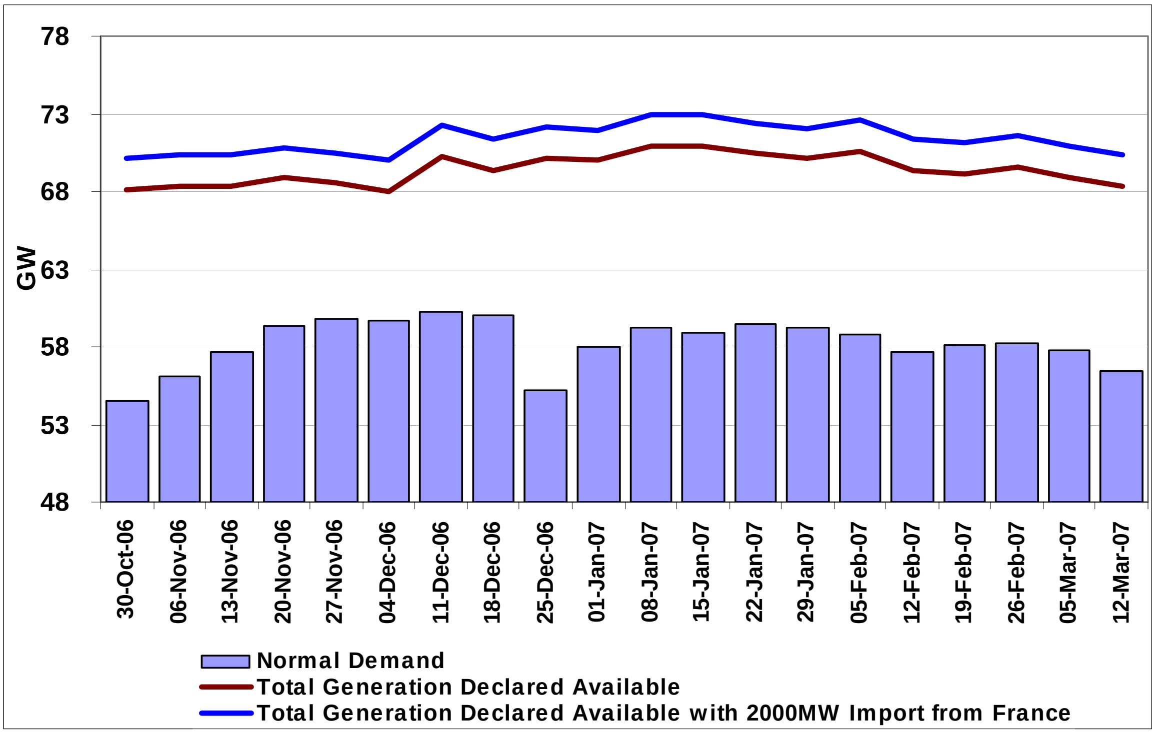
141. Figure 23 shows the normal demand forecasts, and the generator availability declared to National Grid by generators under Grid Code Operating Code 2 (OC2), both including and excluding 2 GW of delivery from the UK-France Interconnector.

142. Figure 23 illustrates a winter in which average weather conditions are experienced each week, resulting in average temperatures across the winter of 7 ^{o}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. As previously stated, 0.7 GW of generation has TEC and is being declared as unavailable throughout the winter 2006/07**.**

143. As can be seen in Figure 23, with full exports from France the excess generation over average weekly peak demand would be around 12-14 GW. However, Figure 23 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.

[18] http://www.nationalgrid.com/uk/Electricity/Balancing/tenderreports/supplementalstandingreserve/

Figure 23 – Demand and Notified Generator Availability, Winter 2006/07



144. For timescales ranging from weeks ahead down to real time, it is necessary to hold varying levels of reserve to cover for generator unavailability, 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 in Figure 23 above. The margin shown in Figure 23 does not reflect this requirement.

Scenario for Modelling Purposes

145. We have created a scenario of generator availability and used this to illustrate the ability of the electricity sector to meet demand under average (typical) and 1 in 50 weather conditions. The scenario is shown in Table 12.

Table 12 – Electricity Availability Scenario (GW)

	Assumption
Plant Availability, GW	72.7
Availability from France, GW	2.0
Return of mothballed plant, GW	1.7
Total Availability, GW	76.4
Average Assumed Availability, %	88%
Assumed Availability, GW	67.3

146. We have assumed that all short-term mothballed plant returns prior to the forthcoming winter. This seems reasonable as the same behaviour exhibited itself in

winter 2005/06 and the market conditions ahead of the 2006/07 winter are similar to those experienced prior to last winter. No return of long-term mothballed plant has been assumed.

147. For the purpose of this scenario, a typical historic rate of 88% average power station availability has been assumed, and the week-by-week profile of unavailability has been smoothed across the winter as a whole. As detailed in Chapter 1, this includes an assumed average availability of 80% from nuclear generating plant, broadly reflecting the levels of availability observed in winter 2005/06.

148. The full 2 GW of capacity across the UK-France Interconnector at peak times has been assumed within this scenario.

Questions for consultation:

Q19. What assumptions should be made over the availability of nuclear generating plant?

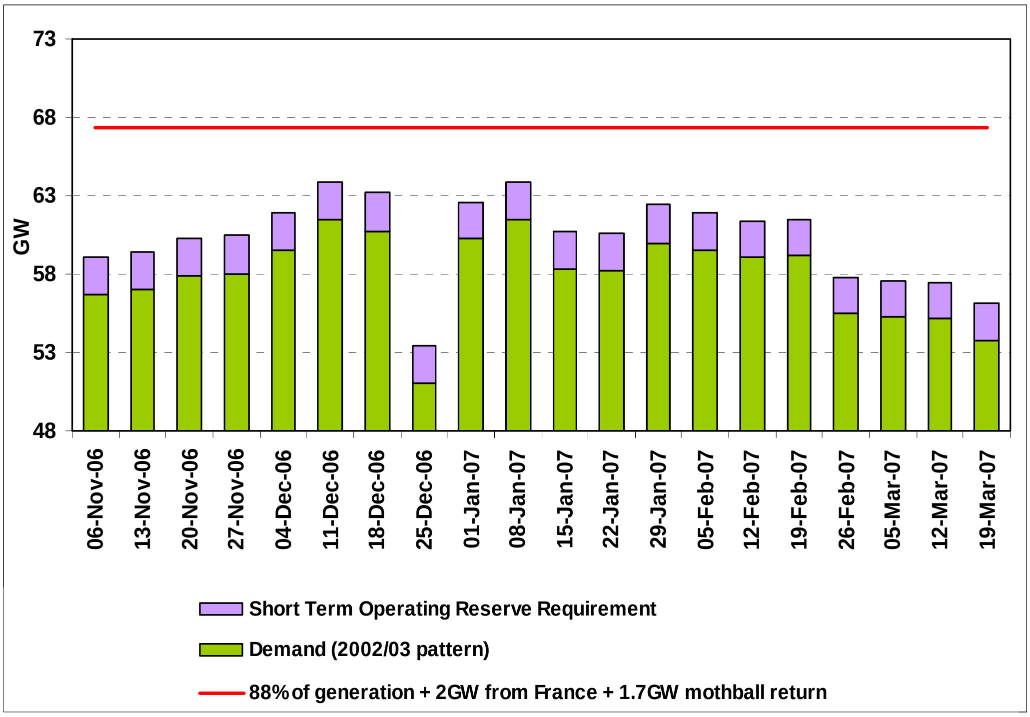
Q20. What assumptions should be made over the level and direction of flow on the UK-France Interconnector given cold weather in both UK and Europe?

Average Winter Conditions

149. To illustrate a typical winter, demand has been forecast by assuming the weather pattern of 2002/03. This is a good representation of a typical winter, with a peak winter demand of around 61.5 GW and a normal pattern of high demand spells occurring in December and January.

150. As illustrated in Figure 24, 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 24 – Forecast Demand under Average Weather Conditions (2002/03 Weather Pattern) and Generator Availability, Winter 2006/07

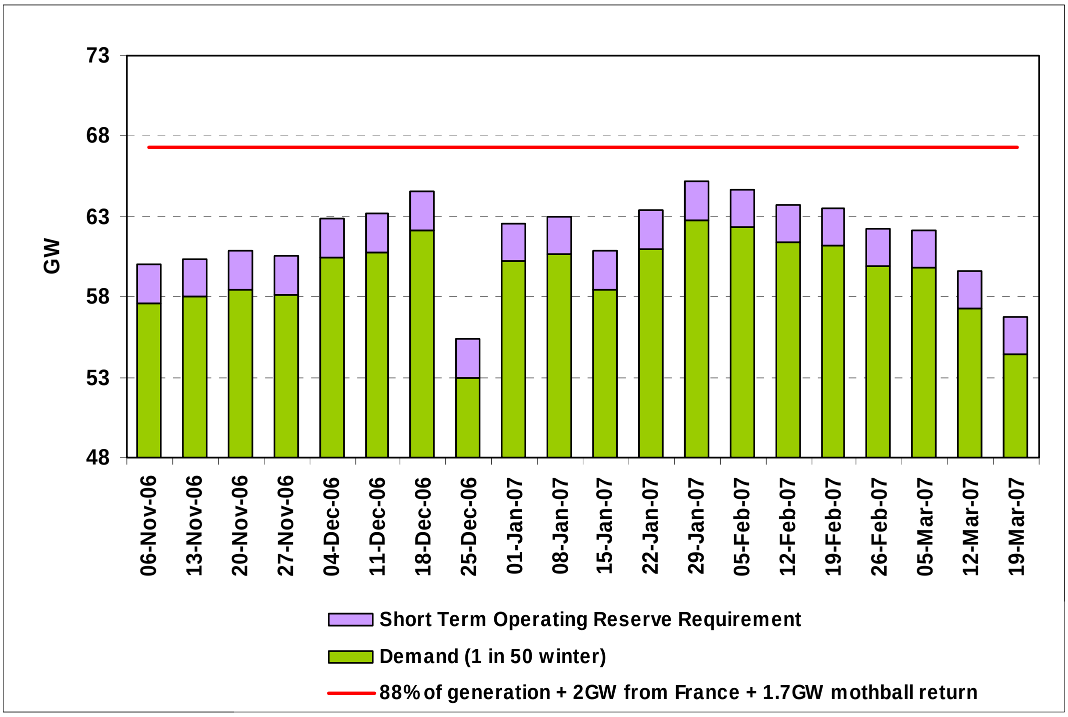


1 in 50 Cold Winter Conditions

151. 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.

152. If these weather patterns were to occur this winter, as illustrated in Figure 25, 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 25 – Forecast Demand under 1 in 50 weather conditions (1946/47 Weather Pattern) and Generator Availability, Winter 2006/07



Chapter 5: Gas/Electricity Interactions

153. 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 2005/06 winter, there were occasions when firm CCGTs commercially self-interrupted whilst interruptible power stations continued to generate.

154. 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 price of CO_2 emission allowances; the price of alternative fuels; and any environmental constraints (e.g. SO_2) that limit the extent of running on other fossil fuels.

155. Our analysis has sought to determine the potential reduction in gas demand that could be achieved through a response from CCGTs under the base case gas supply scenario 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.

156. 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. Our choice of modelling assumptions has been informed by behaviour observed during the 2005/06 winter and by information from generators regarding distillate capability from CCGT power stations.

Power Generation Gas Demand and Distillate Back-up

157. The maximum theoretical power generation gas demand in GB for winter 2006/07 is shown in Table 13. 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. The duel-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 13 – Maximum 2006/07 GB Power Generation Demand

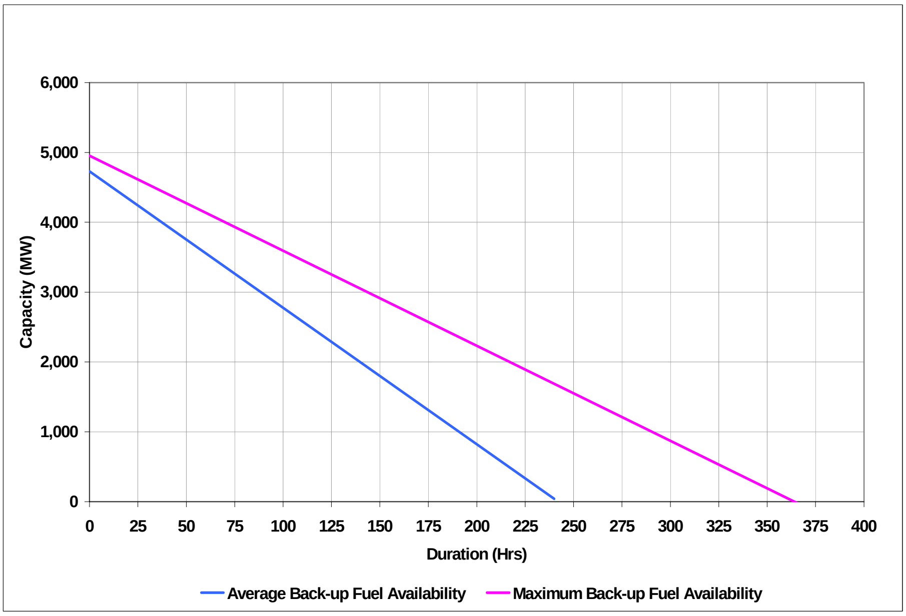
	Maximum Gas Demand (mcm/d)	CCGT Capacity (GW)
NTS-connected	117.3	23.8
LDZ-connected	5.5	1.1
Total	122.8	24.9

158. Daily consumption from CCGTs started the winter 2005/06 at around 70 mcm/d but by mid-November significant demand response had occurred reducing typical CCGT demand by approximately 20 mcm/d for the rest of the winter. The minimum CCGT demand on a mid-winter, working weekday was around 45 mcm/d. For the purpose of the simulation modelling presented here, the gas demand forecasts used were those made in May 2005. They therefore do not include any allowance for demand response seen in the 2005/06 winter. This means that the simulated potential for CCGT demand response in 2006/07 can be compared directly with the actual level of response observed in winter 2005/06.

159. In electricity generation terms, CCGTs are expected to provide a maximum of 24.9 GW of generating capacity in GB for the coming winter. Of this, 3.1 GW have access to gas through non-NTS pipelines and 4.8 GW have the capability to run on distillate (this latter number having recently been verified through consultation with the generating companies).

160. Under the terms of the Grid Code, the generating companies are required to provide us with information on their capacity to generate using back up fuel. Figure 26 summarises this information in load duration curve form, showing the decay of generation capacity available from distillate with time. The data has been aggregated and smoothed to protect the commercial positions of the individual plants. The two lines show the available generation from starting points of average fuel stocks and maximum fuel stocks.

Figure 26 – Load Duration Curves for Back Up Fuel Supplies



Analysis of Potential CCGT Demand Response - Modelling Assumptions

161. 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;

- Potential limits on the extent to which fuel stocks can be replenished;
- Limitations on the levels of switching to coal and oil as a result of environmental constraints.

162. In winter 2005/06, there was an estimated level (as reported in Chapter 2) of 98 mcm of distillate use. Our modelling assumptions from the Winter Outlook Report 2005/06 assumed that a maximum of 200 hours of distillate use was possible, this is equivalent to around 200 mcm. Given winter 2005/06 was not far from average in severity terms, we have not altered the assumption of 200 hours at this stage. We have also maintained the assumption that distillate running would be for a maximum of 12 hours a day during weekdays.

163. In winter 2005/06, coal ran as baseload, with gas generally the marginal fuel type. We have therefore rolled forward our previous assumption that gas operates as the marginal generation into the winter 2006/07 modelling.

164. Modelling assumptions that have been modified from winter 2005/06 assumptions (supported by the experience of that winter) are:

- Nuclear availability of 80% of capability is assumed, smoothed throughout the winter;
- Oil-fired Stations run on weekdays for 12 hours a-day;
- Reduction in the level of gas-fired generation running baseload.

165. A full list of the most important preliminary modelling assumptions for winter 2006/07 is as follows:

- Nuclear runs baseload – 24 hours a day, 7 days a week, at 80% availability;
- Imports into GB through the French Interconnector are available continuously overnight and during the peak 4 hours at the full rate of 2 GW - at other times the link is at float;
- 3.1 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as baseload, thereby displacing other generation;
- Around 1.6 GW of NTS-supplied CCGTs run as baseload, reflecting technical and contractual constraints such as the requirement to provide heat and power to industrial consumers. This has been reduced reflecting the winter 2005/06 experience;
- No explicit constraints relating to fuel stocks, 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 only 85%;
- Pumped storage stations generate only during the peak 6 hours of each day;
- Oil stations generate only during the peak 12 hours of weekdays;
- 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 88%.

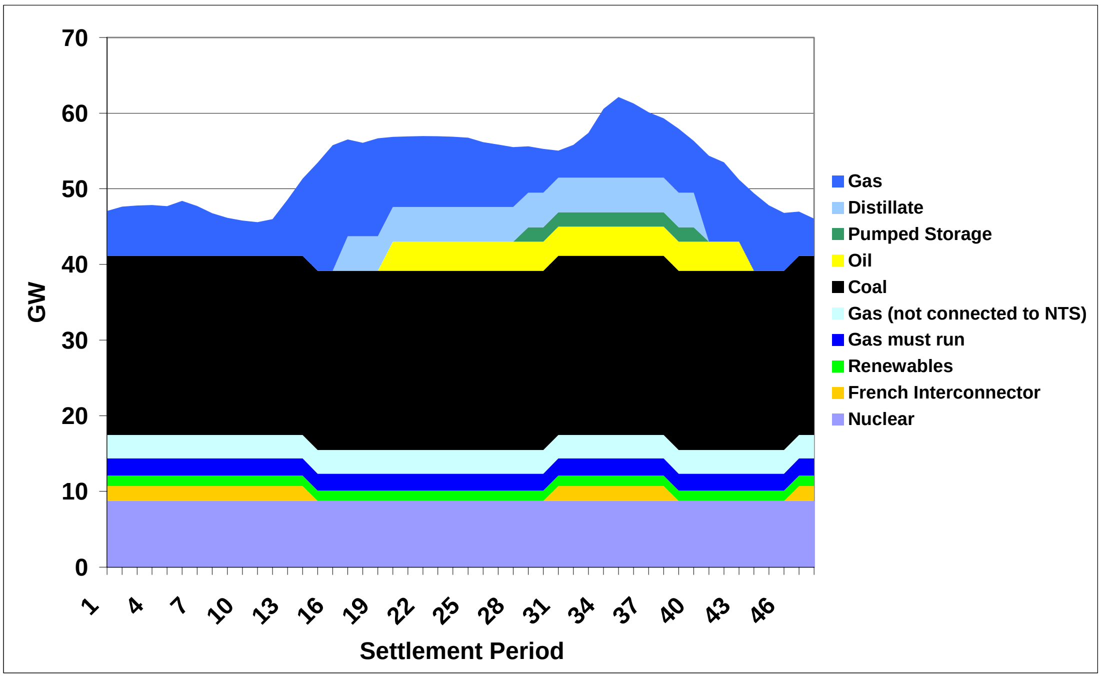
Table 14 – Assumed Plant Availability Factors for Demand-Side Response Analysis

Power Station Type	Assumed Availability
Nuclear	80%
French Interconnector	100%
Non-BM Generation (including renewables)	40%
Coal	85%
Oil	95%
Pumped storage	100%
CCGT	95%
Average availability	88%

Analysis of Potential CCGT Demand Response – Simulation Results

166. Figure 27 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 for the bulk of the day and distillate used for 12 hours around the peak demand period. (As explained above, total distillate usage across the winter has been constrained to 200 hours in the simulation model).

Figure 27 – Potential Generation Profile - Cold Winter Weekday



167. 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. Table 15 summarises the output of the simulation: estimates 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)

	Average	1 in 10	Severe
Required	0.3	3.1	5.0
Potential CCGT	0.3	2.1	2.7
Non-CCGT	0.0	1.0	2.3

Questions for consultation:

Q21 We would welcome views on the ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests might be theoretically achievable in a severe winter, and in particular on:

Q21a. Our assumptions relating to the generation running order under cold weather conditions and the associated availability factors

Q21b. The extent to which relative market prices will signal the requirement for CCGTs to continue to burn gas at peak electricity demand periods

Q21c. The ability and willingness of CCGT generators to switch to distillate

Q21d. Whether and for how long CCGTs could generate on distillate back-up and any restrictions to the replenishment of distillate stocks

Q21e. The ability and willingness of the market to replace gas-fired generation by coal and oil fired generation

Q21f. The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints, carbon emissions and fuel stocks

Q21g. How the level of CCGT response may compare with that experienced in 2005/06

Chapter 6: Industry Framework Developments

168. National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply-demand balances. This Chapter reflects ongoing industry discussions concerning such developments.

Gas Reserve Review and Demand Side Working Group discussions

169. Since January 2006, Ofgem has chaired a Gas Reserve Working Group, which has been considering the efficient procurement of the Safety Monitor requirement (generally referred to as “below the line”) and the role of the System Operator in relation to demand–side response (generally referred to as “above the line”). These issues have further been discussed and explored with Shippers and customers at the Demand Side Working Group (DSWG). Following these discussions we would anticipate working with the industry to put in place the recommendations of this review group and any consequential modifications. Areas under discussion include:

Procurement options for the Safety Monitor gas and gas reserve

170. Currently, gas protected by the Safety Monitors is the responsibility of shippers. They purchase the gas as part of their portfolio and hold it in the various storage facilities. The Gas Reserve Working Group has been considering whether or not other procurement options would better facilitate the efficient and economic provision of the Safety Monitor requirement. At the meeting of the Gas Reserve Working Group on 26 April it was agreed that the next stage in the process was for industry participants to raise Modification Proposals in relation to “above the line” issues as they saw fit. One Modification Proposal (UNC Modification Proposal 0085: Introduction of Gas Reserve Arrangements) has now been raised and is being progressed under the UNC governance.

171. The group will continue to discuss “below the line” options during the spring and summer of 2006. Various alternative options for the procurement of this gas are being considered including:

- Maintenance of the current position – referred to as Status Quo;
- The procurement of title to this gas by the System Operator (SO) or;
- The procurement by the SO of “options” for the provision and delivery of this gas.

Changes to the compensation arrangements introduced as part of UNC Modification Proposal 0071a “User Compensation for NEC Storage Curtailment”

172. The Gas Reserve Working Group is considering whether or not the changes introduced by this proposal and those of Modifications 0052 “Storage Withdrawal Curtailment Trade Arrangements in an Emergency” can be further developed to provide more efficient and economic operation of the “below the line” regime. Changes under discussion include the treatment of, and payment for the use of, constrained stored gas during any gas supply emergency and how such treatment should be reflected in any subsequent adjustment of the compensation quantity offered to the storage user.

The provision of further information relating to available supplies and forecast demand

173. The Gas Reserve Working Group and the Demand Side Working Group (DSWG) discussions are assessing the benefits of providing earlier information regarding both available supplies and anticipated demand. Such information is currently provided by various industry parties at differing times generally starting on the day before the Gas Day. The groups are considering how the provision of this information could be developed or extended to provide further benefit to market participants as a whole, including whether it may be possible and appropriate to develop some kind of incentive arrangement on National Grid. In particular, the groups are considering the potential for a 5 day-ahead demand forecast, which would facilitate consumers in making gas procurement decisions. Where it is established that additional information can and should be made available then National Grid will seek to assist in the publication of this data via our Information Exchange website.

Further facilitation of demand-side access to the market

174. Prior to the main part of the 2005/06 winter, changes were introduced (Modification 0061) to facilitate access to the Over-The-Counter (OTC) markets during a period covered by a Gas Balancing Alert. The DSWG has discussed whether or not further facilitation of demand-side access to the market is required and whether or not barriers to entry still exist.

Potential Blending Service

175. National Grid is examining the feasibility of potential blending opportunities at the beach terminals. Initially, we are investigating whether there is scope to provide a blending service at Bacton. There are a number of strands to this work: a technical feasibility study to understand how gas of different compositions would mix within the terminal; an operational assessment to identify whether any modifications would be required to the terminal infrastructure and to develop the necessary operating procedures; consideration of potential changes to the National Grid Gas safety case, for which HSE acceptance would be required; and development of associated commercial arrangements with shippers, DFOs and Interconnected parties, together with any necessary IS modifications. Given the complexity of this work there are significant challenges to the delivery of such a service for 2006/07. However, National Grid is intensely aware of the importance of this issue and, accordingly, is making every effort to try and secure such a service for the coming winter. In any event we remain committed to pushing this forward as quickly as possible and plan to engage more widely with the industry once the results of the initial technical investigations are available. We currently expect this to be around the end of June.

Uniform Network Code

Section Q Emergency Arrangements – UNC Modification Proposal 0082 “Clarificatory changes to UNC Section Q – Emergencies”

176. National Grid Transmission has recently put forward UNC Modification Proposal 0082 “Clarificatory changes to UNC Section Q – Emergencies”. This proposal, which has been developed with the industry through the UNC Transmission Workstream, seeks to realign the processes described in Section Q with those detailed in the

Network Emergency Coordinator (NEC) and National Grid Transmission Safety Cases and National Grid Transmission E1 Emergency Procedures document. It also seeks to minimise any potential for ambiguity in the wording of this section.

Information provision initiatives

177. UNC Modification Proposal 006 “3rd Party Proposal: Publication of Near Real Time Data at Sub Terminals” has now been directed to implementation. National Grid Transmission are currently working to provide the information technology infrastructure necessary to publish the information called for in the Proposal. This facility will be available in October 2006.

Balancing and Settlement Code (BSC)

Incentives to balance - P194 and P199

178. National Grid has progressed two main modifications to the BSC this year, both of which have focused on ensuring that parties have the appropriate incentives to balance, at times of system stress.

179. In P194 we proposed that the cash-out price formula should be based on the top 100 MWh of Bid/Offer Acceptances that resolve NIV (Market Imbalance), instead of the volume weighted average formula that was previously utilised. The main objective of the proposal was to provide a clearer signal to parties to parties to balance, during times of system stress. This modification has been approved by Ofgem and will take effect on 2 November 2006.

180. We also raised P199 because the existing arrangements do not recognise the act of Demand Control nor consider the distortion such an instruction may have on the metered position of participants’ energy accounts and the consequential inaccuracy of the value of NIV within the imbalance price. P199 seeks to resolve this distortion by more appropriately allocating the burden of imbalance to those who contributed to it.

Connection and Use of System Code (CUSC)

Access to the transmission system – CAP094, CAP097

181. CAP094 was implemented on 1 April 2006. This CUSC change provides the ability for plant to secure, where available, access to the Transmission System for periods of time between seven and forty-five weeks in duration, within the same Financial Year, without necessarily having to pay for a full year’s worth of access rights. These two new short term products should provide further opportunities for generators to respond to the sharper market signals that now exist, allowing generators to bring back plant in a timely and economic manner at times when it is most needed.

182. CAP097 proposes that a Distribution Network Operator must inform National Grid of any Medium Power Station and certain Small Power Stations applying to connect to that DNO’s Distribution System so that National Grid can analyse whether the Power Station has an impact upon the GB Transmission System and can ensure that where reinforcements are needed the DNO is obliged to not energise the Power Stations

connection until such work is completed. CAP097 is currently with the Authority for a decision.

Grid Code

Market information – H/05

183. National Grid continually seeks to develop modifications and amendments to the electricity framework that will enhance transparency, where such changes are economic and efficient and hence consistent with the applicable Code Objectives.

184. This year one of the initiatives that we have proposed, which has subsequently been approved by the Authority, is a Grid Code modification requiring conventional generating plant to provide outage data on a Generating unit basis and non-synchronous plant (e.g. wind farms) to submit outage data on a Power Park Module basis. This change provides National Grid with more granular outage information, which will improve the transmission system security analysis, thus enhancing efficiency of system operation.