nationalgrid

Winter 2006/07 Consultation Update Document

Executive Summary

Introduction

1. The competitive gas and electricity markets in the UK have developed substantially in recent years with successfully established 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, shippers and generators. 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 are conducting a similar but enhanced consultation process this year. In May we published our first consultation document on the 2006/07 winter[1]. We received 33 responses from a broad range of industry participants. This consultation update represents the second stage of the process. It provides feedback on the responses received to our May document, contains updated analysis and seeks further views. We plan to publish the Winter Consultation Report, taking account of the further responses that we receive, 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 few years, a number of major infrastructure projects are due to be commissioned, providing capacity for 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; the BBL pipeline between Bacton and Balgzand in The Netherlands; and Excelerate Energy's LNG project at Teesside.

[1] Winter 2006/07 Consultation Document, May 2006

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. Gas injection has resumed at Rough following the incident on 16 February, and Centrica Storage currently estimate that it will be possible to inject at sufficient rates to enable all Rough capacity sold to be filled at or around the traditional end of the injection season (i.e. 31 October). Centrica Storage also estimate that full production rates will be available by no later than 1 October. Centrica Storage have stated that these estimates remain subject to change.

6. In our May document, we noted the wide range of potential supply availability in 2006/07, reflecting not only the normal risks associated with major infrastructure projects, but also commercial uncertainties associated with the utilisation of the infrastructure. As a result, it was not clear whether the supply-demand position would be more or less tight than it was in 2005/06. Although largely qualitative, responses to the May consultation have been useful in shaping the analysis of this outlook. On the basis of these responses we have made only a small downward revision to the supply base case that we put forward for consultation. Nonetheless, a high degree of uncertainty remains, with a wide range of possible outcomes around the revised base case. This uncertainty will reduce prior to and during the winter as progress is made with the various importation projects and market behaviour is observed, and we will reflect any relevant developments in our Winter Consultation Report in late September.

7. Since our May document, we have completed our analysis of data received through the 2006 Transporting Britain's Energy (TBE) consultation process. This document therefore incorporates updated forecasts of demand and UK Continental Shelf (UKCS) supply prospects. While the latter is largely unchanged from the preliminary forecasts, the demand forecasts are materially lower, reflecting the impact of the present high level of gas prices.

8. The uncertain background translates into a wide range of potential values for the 2006/07 storage safety monitors. We publish in this document our latest assessment of the likely range within which we expect to set the monitor levels for the start of the winter. Our thinking on the appropriate safety monitor levels will continue to develop through the course of the summer based on market developments and further feedback that we receive from the industry on the key input parameters.

Demand-side response

9. As a result of the revised demand forecasts, our updated analysis indicates a lower level of required demand-side response than was shown in our May document. In part, this is because a level of response is now implicitly contained within the forecasts. To help clarify this, we have produced two forecasts this year: an 'unrestricted' forecast, in which a general reduction in the level of demand in response to underlying economic variables is recognised; and a 'restricted' forecast, which also assumes specific demand-side reductions by very large consumers based on behaviour seen last winter.

10. We are seeking views on these revised forecasts and on the prospects for demand-side response as part of this consultation.

Electricity

11. 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

12. 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. The forecasts contained in this document represent an aggregation of the information that we have received to date. We are now seeking further information, quantified where possible, and will consolidate this with the other data that we have received to form the basis for our analysis in the Winter Consultation Report.
13. A key focus of the consultation is the uncertainty surrounding the gas supply-demand position for 2006/07. In Chapter 1, we highlight the key issues associated with this background. On the supply-side, we examine the individual supply sources and the way in which they may interact with one-another.
14. Given the significant reduction in our demand forecasts, Chapter 1 also has a strong focus on underlying demand levels. We are very interested to receive views from respondents in this area, and particularly from gas suppliers in relation to their expectations for demand in the Non-Daily Metered (NDM) sector under severe weather conditions.
15. We bring supply and demand together with analysis that quantifies the level of demand-side response required under specified combinations of supply conditions, demand backgrounds and weather patterns. This analysis focuses on the revised supply 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.
16. Chapter 2 sets out the latest view of the demand and generation background in the electricity market for 2006/07. It summarises respondents' views on the questions posed in our May document, and contains updated analysis taking account of these views.
17. In Chapter 3, we present our revised analysis of the potential for CCGT demand response in 2006/07, incorporating revised assumptions based on consultation responses.
18. We have updated and included in this document most of the analysis of the 2006/07 winter that we presented in our May document. However, to avoid unnecessary duplication, we have not reproduced the analysis of the 2005/06 winter. In addition, we have added new material into the Annexes, which may be of interest to readers.

In particular, we have provided new Annexes containing: a summary of responses received to the May consultation; an explanation of developments to our demand forecasting methodology; and, an update on progress with our study of potential gas blending opportunities at Bacton.

19. The high level issues on which we are seeking views are listed below (with the full list of questions contained in Annex F). We would also welcome any further views on any of the other questions from our May consultation document:

Non-CCGT demand-side response

Q1. We would welcome views on our latest Non-Daily Metered (NDM) gas demand forecasts as set out in Annex A

Q2. We would welcome views on our latest Daily Metered (DM) gas demand forecasts as set out in Annex A

Q3. We would welcome further views on the extent to which the non-CCGT market is able to provide demand-side response, both in volume and duration terms

Q4. We would welcome updated information from Distribution Network owners on the demand levels above which interruption might be expected in winter 2006/07, both in respect of Network Sensitive Loads and other interruptible loads

UKCS supplies

Q5. We would welcome views on our revised UKCS supply forecasts

Gas imports

Q6. We would welcome further views on the assumptions that should be made for levels of imported gas through the Belgian Interconnector for winter 2006/07

Q7. We would welcome views on our revised base case assumptions in respect of imported gas through BBL for winter 2006/07

Q8. We would welcome further views on the assumptions that should be made for levels of imported gas from Norway for winter 2006/07

Q9. We would welcome views on our study into the potential for a blending service at Bacton as described in Annex C

Q10. We would welcome any further views on the assumptions that should be made for LNG importation quantities in winter 2006/07

Storage

Q11. We would welcome any further views on the appropriate basis for setting the 2006/07 safety monitors

Electricity market

Q12. We would welcome any further views on the extent to which electricity demand response might be expected given high electricity prices

Q13. We would welcome any further views on our modelling assumptions for electricity generation availability

CCGT demand-side response

Q14. We would welcome any further views on our analysis of the potential for CCGT response in a severe winter

Next steps

20. We would appreciate responses to our questions, and any further information which you consider to be of relevance to the outlook for gas and electricity this winter, as soon as possible but not later than 11 August 2006. Please note that it is intended to include a summary of responses on a non-attributed basis in the final Winter 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).

21. Responses should be sent to:

Simon Griew
Operational Strategy Manager
National Grid
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Or e-mailed to: simon.griew@uk.ngrid.com

Legal Notice

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

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

Copyright

Chapter 1: Gas

22. 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.

23. In this Chapter we examine issues associated with the demand background, each of the various sources of supply, and the interactions between those sources. In our May document we illustrated the implications of these issues with analysis that focused on a base case and a range of sensitivities. The base case did not represent a National Grid view; we presented it in order to provide a starting point for industry discussion and comment. Here, we summarise the comments that we have received on the supply-side issues, provide updated analysis and seek further views. The analysis has been updated in two respects: first, it incorporates the latest supply and demand forecasts derived using data from the 2006 Transporting Britain's Energy (TBE) consultation process; second, the supply base case and sensitivities have been developed to take account of these latest forecasts and industry feedback on the May document. The revised base case seeks to provide a balanced representation of industry expectations based on the information and views that we have received.

24. As before, 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.

Gas demand

25. The demand background used for the analysis in this section is the updated set of demand forecasts for 2006/07 that we have recently produced as part of the 2006 TBE process. These demand forecasts are materially lower than the equivalent forecasts for 2006/07 produced in 2005, which underpinned the analysis in our May document.

26. The principal reason for the reduction in the forecasts is an expectation of prices remaining at high levels throughout the 2006/07 winter, with further increases in delivered gas prices in all sectors. By contrast, our 2005 forecasts assumed that prices would start to reduce in 2006.

27. In addition, the new forecasts reflect the experience of the 2005/06 winter when Non-Daily Metered (NDM) demand was typically 3-4% below the forecast level. This data has fed through into our new NDM forecasts for 2006/07, the combined effect being that these latest forecasts are typically 7% below those produced in 2005. This represents a forecast year-on-year reduction in underlying NDM demand between 2005/06 and 2006/07 of approximately 2%.

28. Most respondents to our May document who expressed an opinion considered that the lower levels of NDM demand observed in 2005/06 were likely to recur in 2006/07

as prices remain high. A few respondents were more cautious, either expressing doubt over the price elasticity of this market or counselling caution over the extent to which this effect is built into future forecasts. A particular concern of one respondent related to the level of NDM demand that could be expected under severe conditions, with that respondent expressing the view that high prices would not affect the level of demand on the peak day.

29. The validation that we have undertaken on the revised forecasts gives us a high level of confidence that they properly reflect the historical data available to us. However, historical data is inevitably limited given that we have not experienced a particularly cold winter for many years, and certainly not whilst prices have been at or around today's levels. It is therefore reasonable to consider whether consumer behaviour would alter in the face of prolonged cold conditions, with the need to remain warm over-riding cost concerns. This is an area on which we are very interested to receive views, particularly from gas suppliers in relation to their expectations of consumer behaviour. We return to this issue in the section on safety monitors below.

30. In relation to the Daily Metered (DM) market, we have developed our methodology in order to take more explicit account of the impact of price on these consumers. This is consistent with the conclusions of a recent review of our demand forecasting methodology by Frontier Economics, carried out on behalf of Ofgem (and published alongside this consultation document). Through an examination of the historical consumption of individual large loads (including CCGTs) we have developed a 'restricted' demand forecast for 2006/07, which incorporates reduced demand levels given an assumption of high spot price levels and fuel switching. We have also derived 'unrestricted' forecasts so that a like-for-like comparison can be made between our 2005 and 2006 forecasts.

31. Our validation of the restricted demand forecast shows a good fit of modelled DM demand to actual demand over the 2005/06 winter until mid-March. Subsequently, actual demands were lower than indicated by the forecast as coal-fired generation retained a competitive advantage over gas.

32. Annex A explains the basis for these revised forecasts in detail, including the underlying price assumptions, the validation that we have undertaken and the issues raised by these revised forecasts. We are interested in any views that respondents have on this Annex.

33. It should 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[2]. 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). See 'Transportation capacity' below.

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

Questions for consultation:

Q1. We would welcome views on our latest NDM gas demand forecasts as set out in Annex A, and in particular:

Q1a. The price assumptions underpinning these forecasts, and whether they represent a reasonable view of likely outturn levels

Q1b. The approach that we have taken to validate the NDM forecasts

Q1c. How the recently observed reduction in NDM demand can be explained in behavioural terms

Q1d. The extent to which it should be assumed that these reductions in demand would be observed in the face of prolonged cold conditions

Q1e. Any additional risks or issues associated with these forecasts

Q2. We would welcome views on our latest DM gas demand forecasts as set out in Annex A, and in particular:

Q2a. The price assumptions underpinning these forecasts, and whether they represent a reasonable view of likely outturn levels

Q2b. The methodology for the development of a restricted demand forecast to incorporate reduced levels of demand in response to high spot prices

Q2c. The approach that we have taken to validate the DM forecasts

Demand-side response

34. As we outlined above, our new 'restricted' demand forecast incorporates an element of demand-side response to high prices from the DM sector (including CCGTs). Across the top 100 days of the severe load duration curve, this restricted forecast is 20-28 mcm/d lower than the 2005 (unrestricted) forecast, broadly in line with the typical level of demand response observed in the 2005/06 winter.

35. In our May consultation, we sought 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.

36. Respondents' views on the scope for additional levels of non-CCGT response in 2006/07 were mixed. On one hand, some respondents considered that increased market awareness and the development of new demand-side products could facilitate a greater level of response. Others, however, identified the possibility that some customers will seek to mitigate the impact of price volatility by locking in winter volumes at a fixed price, and that this will tend to reduce the level of demand-side

response. This was reinforced by the view that the customers who responded in 2005/06 tended to be those exposed to day-ahead prices rather than those on monthly contracts.

37. On the question of back-up fuel facilities at non-CCGT DM sites, most respondents felt that there was little scope for new investment given the uncertainty of the economics and the limited amount of time available prior to the winter.

38. In Chapter 3, we examine the potential for demand-side response from CCGTs. In particular, we have updated our modelling of the interactions between the gas and electricity markets, taking account of views expressed to us on the underpinning assumptions.

Questions for consultation:

Q3. We would welcome further 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:

Q3a. Data from suppliers on the extent to which their non-CCGT DM portfolio has entered into contractual arrangements that would facilitate such a response, and the nature of any such arrangements

Transportation capacity

39. Gas transporters have the right to curtail the demand of interruptible customers for the purpose of capacity management. In our May document we sought information from the Distribution Networks (DNs) on the demand levels at which such interruption might take place. According to those DNs who were able to respond, these 'trigger' levels for Network Sensitive Loads (NSLs) range from 77% to 98% of the relevant LDZ forecast firm peak day demand[3]. For non-NSLs, trigger levels range from 92% to 97%. This information is set out in Annex B.

40. 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. In the absence of plant failure or unexpected supply-demand patterns, the only part of the system potentially subject to demand-side constraints is the South-West. Here, there is sufficient capacity to transport forecast 1 in 20 undiversified firm peak day demand in that part of the country. In practice, as total demand approached that level, we would consider the need for interruption based on prevailing operational circumstances.

41. The rapidly changing profile of gas supplies in the UK will naturally lead to new patterns of gas flow on our transmission system. We have been asked whether we envisage entry constraints arising as a result of this in the 2006/07 winter, particularly given that the additional supply sources this winter will all enter the system on the East Coast . Annex B explains the analysis that we have undertaken on this question. In summary, it has confirmed that there is sufficient network

[3] Trigger levels are from the 2005/06 winter. DNs are in the process of updating their analysis for 2006/07, which we expect to publish in our Winter Consultation Report in September

capacity to meet anticipated flow patterns at all demand levels this winter. However, no transmission network has infinite capacity. It is therefore to be expected that constraints could arise given circumstances sufficiently different from expectations. For example, a material offshore supply loss could potentially lead to such a situation depending on how the market adjusted to this with a revised supply profile.

Question for consultation:

Q4. We would welcome updated information from Distribution Network owners on the demand levels above which interruption might be expected in winter 2006/07, both in respect of Network Sensitive Loads and other interruptible loads

Gas supply

42. The following sections examine each of the potential (non-storage) gas supply sources in turn: UKCS; European imports from Belgium, Holland and Norway respectively; and LNG. We set out the main factors associated with these supply sources, summarise the views of respondents to our May document on their respective prospects, update our analysis and seek further views on the key areas of uncertainty.

43. As before, 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

44. 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.

45. The analysis in our May document was based on our 2005 forecasts combined with our experience last winter and our most up-to-date intelligence regarding new UKCS developments. Almost all respondents who commented considered that this preliminary analysis seemed reasonable, although some noted that they would be able to comment more fully once revised TBE data had been incorporated. One respondent felt that the preliminary forecast was conservative.

46. We have now received and assimilated the 2006 TBE information. Table 1 shows that our revised UKCS maximum forecast, taking full account of the latest TBE data, is very close to the preliminary forecast published in May.

Table 1 – 2006/07 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2005/06		2006/07	
	Forecast	Highest	Preliminary Forecast (May)	Revised Forecast
Bacton	83	78	76	75
Barrow	29	30	26	24
Easington	17	20	16	16
Point of Ayr	2	5	2	2
St Fergus[4]	110	98[5]	92	94
Teesside	28	34	28	30
Theddlethorpe	23	30	26	26
Total	**292[6]**	**295**	**266**	**267**

47. Following receipt of 2006 TBE producer information we have marginally revised our forecast of maximum UKCS production for winter 2006/07 from 266 to 267 mcm/d. Our latest view includes a year-on-year decline of 36 mcm/d from existing fields, which is offset by incremental developments totalling around 11 mcm/d. It should be noted that there is some uncertainty over the volumes that will be available from incremental developments due to timing and commissioning issues.

48. For the purposes of supply-demand analysis and safety monitor assessments, it is appropriate to assume a level of UKCS supply below the maximum forecast. The chosen level should reflect the level of delivered (non-storage) UKCS gas that we might expect on average in a prolonged cold spell. Last winter, we observed an average availability of approximately 90% (compared to a pre-winter assumption of 92.5%) and we reflected this lower availability into the supply base case for consultation.[7]

49. No respondents considered that we should have retained an assumption of 92.5% availability. Many supported 90% as a reasonable basis for the analysis, while a number highlighted the risk that reliability may suffer in the event of poor weather conditions offshore, as observed late in the 2005/06 winter. One respondent noted that poor weather may hamper operations but is unlikely to cause a prolonged reduction in output unless physical damage has occurred. On the basis of this feedback, we believe that it is appropriate to retain an assumed availability rate of

[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.
[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.

90% in the base case, and to supplement this with sensitivity analysis assuming a lower level of availability.

50. We also sought views through the consultation on potential variations in UKCS supply availability across the winter months and, in particular, whether a lower level of availability should be expected in the early part of the winter. Those respondents who expressed a view believed that producers may have learnt from the experience of 2005/06 when UKCS supplies were slow to ramp up in November as demand increased rapidly.

51. Around the time that the May document was published, we were aware of the need for producers to check any cooler units similar to that involved in the incident in February 2006 on the Rough storage platform. It has subsequently emerged that the only other units of this type are at South Morecambe, where Centrica are undertaking remedial work and anticipate a return to full production in early September.

52. There remains scope for upside and downside against our revised UKCS supply forecast, for example:

- 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 than 90%;
- Supply availability early in the winter could be lower in the event of late commissioning of new fields or delays in the resumption of production following maintenance outages;
- Supply availability later in the winter could be lower given a greater than projected level of within-winter decline of existing fields.

Questions for consultation:

Q5. We would welcome views on our revised UKCS supply forecasts, and specifically:

Q5a. Views on the revised assumption for maximum UKCS supply availability

Q5b. Further views on the assumption that should be made for the average percentage UKCS supply availability

Q5c. Further views on anticipated variations in UKCS supply availability across the winter months

Imported gas sources

53. 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.

54. Three major projects are under construction with the objective of securing additional imported gas supplies from Europe 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, summarise the consultation responses on these issues and seek further views on the assumptions that should be made on imported gas flows.

Belgian Interconnector

55. The capacity of this Interconnector is presently undergoing expansion via the construction of new 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.

56. Our initial consultation focused on a number of issues that will affect the level of imports through this Interconnector. Responses were largely qualitative, with the key points made being as follows:

- No respondents expressed any doubt over the timely completion of the capacity upgrade. However, respondents were generally cautious over the extent to which this capacity may be utilised this winter;
- A number of respondents anticipated a similar pattern of flows to that seen last winter, with lower flows in Q4 2006 than Q1 2007 as European storage stocks are preserved in the first half of the winter;
- From a transportation capacity perspective, a number of respondents believed that upstream capacity constraints were a factor in limiting imports through the Belgian Interconnector. In this context, no changes in the capacity in Belgium were reported, although two respondents noted that 'de-bottlenecking' projects in Germany could facilitate slightly higher flows through this Interconnector;
- Two respondents noted the potential for discretionary gas flows through Zeepipe to be diverted to Langeled, which could reduce the level of imports through the Belgian Interconnector.

57. The weight of respondents' views pointed towards a similar level of flows to those experienced in 2005/06, with some possibility of upside. The average level of flows in the main winter months in 2005/06 was around 26 mcm/d. The assumption built into our consultation base case was an average flow of 35 mcm/d, which therefore already had a good degree of upside built into it compared with last winter (notwithstanding the fact that higher flows may have been seen in 2005/06 had demand levels been greater). This assumption is therefore consistent with the feedback that we have received and is retained in our supply base case for the purpose of this second consultation. We recognise, however, that there remains a high degree of uncertainty around this assumption and are keen to receive further views through this consultation that would inform this issue.

58. For the purpose of analysing a 'split winter' scenario, reflecting respondents' views of likely flow patterns, an average flow of 35 mcm/d is broadly equivalent to averages of 25 mcm/d in Q4 2006 and 40 mcm/d in Q1 2007 (weighted towards the latter quantity since the bulk of the high demand days would be expected in the latter quarter).

Questions for consultation:

Q6. We would welcome further views on the assumptions that should be made for levels of imported gas through the Belgian Interconnector for winter 2006/07, and specifically:

Q6a. Any quantified views on the variations in import flow levels that might be expected across the winter months

BBL

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

60. Unlike the Belgian Interconnector BBL will only flow gas towards the UK. 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.

61. In our May document we noted the significant level of uncertainty over BBL gas flows in 2006/07, and sought views on the various issues that give rise to this uncertainty. In summary, the feedback that we received was as follows:

- While some respondents had no information on the likely start time for BBL flows other than the planned commissioning date, a number of respondents noted the tight timescale associated with the construction of this Interconnector (as have BBL Company themselves in a recent announcement), highlighting the possibility of delay to commissioning. One of these considered that the situation surrounding BBL flows in 2006/07 was highly uncertain and would remain so until the construction of the infrastructure is substantially complete. Two others identified the possibility of a delay of a month or more;
- Few respondents commented on the base case assumption of an average flow of 20 mcm/d through BBL once it was operational. Two respondents felt that this assumption was appropriate. One thought it "slightly cautious" although no rationale for an alternative assumption was offered;
- Three respondents made reference to the Grijpskerk-Workum-Wieringermeer Line (GWWL) connecting Balgzand to Emden, noting that this would not be completed until later in 2007, which could potentially limit the availability of gas through BBL in 2006/07;
- The responses did not suggest an expectation that parties other than Gasunie would make significant use of BBL capacity prior to March 2007.

62. On the basis of this feedback, we have retained an assumed flow of 20 mcm/d within the base case once BBL is operational. However, we believe that an assumed start

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

date of 1 January 2007 would be more consistent with the weight of the responses. This is not to suggest that National Grid anticipates a delay to BBL, nor is this the view of BBL Company itself. It is, however, a reflection of the concerns expressed by respondents over the tightness of the construction timescales. For modelling purposes, we are seeking to ensure that the supply base case represents a balanced assessment of the supply position across the winter, reflecting respondents' views. We have therefore assumed a 1 January start date for BBL in order to construct an average BBL flow assumption for the winter as a whole. Bearing in mind that the bulk of the coldest winter days can be expected in the second half of the winter, this translates into an assumed average flow across the winter months of 14 mcm/d.

Questions for consultation:

Q7. We would welcome views on our revised base case assumptions in respect of imported gas through BBL for winter 2006/07, and specifically:

Q7a. Further views on the appropriate assumption for the date at which BBL becomes operational initially

Q7b. Views on the extent to which alternative gas sources or importation routes could be used to mitigate any delay to the availability of BBL beyond 1 December

Q7c. Further views on the appropriate assumption for the level of sustained flows via BBL to the UK for winter 2006/07 once it is operational

Q7d. Views on the extent to which physical transportation constraints in the Netherlands might limit the level of imports through BBL in winter 2006/07

Norwegian imports

63. 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 tie-in to a new sub-terminal at Easington. The sub-terminal is still 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.

64. As we noted in our May document, incremental gas volumes from Norway in 2006/07 will depend upon either incremental production from Norwegian gas fields, or the diversion to the UK of Norwegian supplies that would otherwise have been exported to Continental Europe. We sought views through the consultation on the volume of Norwegian imports that should be assumed. The main points raised by respondents were as follows:

- All respondents who expressed a view believed that Langeled would be operational by October 2006;

- Views were mixed on the extent of incremental gas production available from Norwegian fields. One respondent noted Gassco's comment that there were "no significant incremental volumes of gas this winter". Another respondent, however, believed that incremental volumes might be available from the Troll and Kristin fields;
- One respondent identified the possibility of gas swaps between Norwegian producers and other gas suppliers into Continental Europe, while others identified the potential for discretionary gas flows to Europe to be diverted into Langeled;
- Overall, some respondents were circumspect over the potential level of Norwegian imports, while three respondents felt that the assumed level of Norwegian flows in the consultation base case (48 mcm/d) was slightly cautious on the basis of the above points, quoting numbers 5 –10 mcm/d higher.

65. We recognise that there is some potential upside against the assumed average level of Norwegian imports of 48 mcm/d. A number of the points raised, however, suggest that an element of caution is appropriate since a) the extent of truly incremental gas production from Norwegian gas fields is unclear, and b) incremental flows through Langeled could have the effect of reducing flows through the Belgian Interconnector. In any case, the base case level implicitly assumes an incremental level of Norwegian imports of 15 mcm/d.

66. For the purpose of this second consultation, we have therefore maintained the assumption of 48 mcm/d of Norwegian imports. Through this consultation we are seeking further views on this issue, and in particular any further evidence to support the view that higher levels of Norwegian imports should be assumed without putting downward pressure on imports through the Belgian Interconnector.

Questions for consultation:

Q8. We would welcome further views on the assumptions that should be made for levels of imported gas from Norway for winter 2006/07, and specifically:

Q8a. Views on the level of incremental gas production that could be expected from the Norwegian Continental Shelf in 2006/07

Q8b. Views on the extent of any potential gas swaps between Norwegian producers and other gas suppliers to Europe

Q8c. Views on the extent to which diversion of discretionary gas flows from Zeepipe to Langeled should be expected

Q8d. Views on the extent to which imports through the Belgian Interconnector may be reduced as a result of the diversion of gas away from Europe and into Langeled

Q8e. Any quantified views on the variations in import flow levels that might be expected across the winter months

Total European imports

67. 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.

68. In our May document we sought views on a number of issues associated with the total levels of European gas imports. Most of the key points raised have been covered above. A further issue, however, related to gas quality, and specifically to the study that we are undertaking in relation to the potential for a blending service to be offered at Bacton. No respondents identified a significant potential for additional gas flows at Bacton through such a service although one felt that this would be beneficial in the longer term and another thought that it would be helpful to secure gas supplies in the event that operational difficulties are experienced by a sub-terminal.

69. The key conclusion of our study is that it is not feasible to provide a blending service at Bacton for the coming winter. The primary reason for this is that to facilitate such a service very significant changes would be required to the management, measurement and control systems at Bacton, which could not be put in place in time for this winter. We are, however, continuing to work on this as a possibility for future years, with a view to assessing the feasibility of providing such a service in winter 2007/08. Annex C describes our study, and the basis for this conclusion, in some detail. Once it is finalised, we also intend to publish an abridged version of the report produced for us by Advantica into the mixing of gas streams at Bacton.

Questions for consultation:

Q9. We would welcome views on our study into the potential for a blending service at Bacton as described in Annex C, and in particular:

Q9a. Views on the initial findings of the study

Q9b. An indication of the level of interest in such a service for future years, including the extent to which it may facilitate additional gas imports

Q9c. Views on whether it would be valuable to undertake a similar study for other entry points and, if so, on which entry point(s) to prioritise

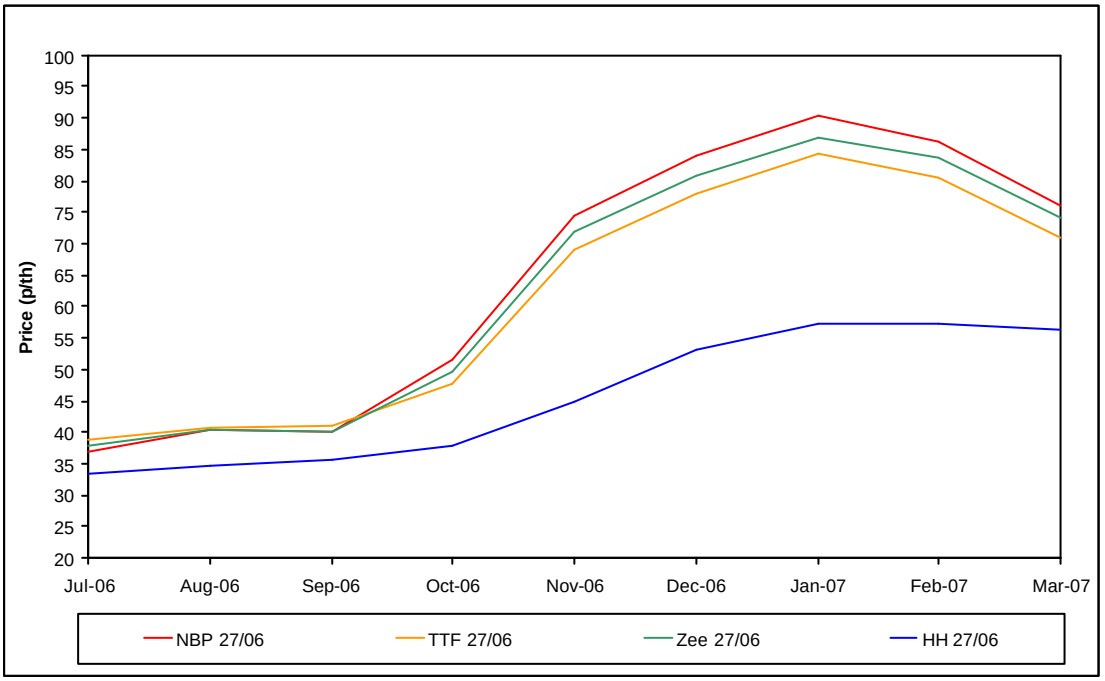
LNG

70. The Grain LNG terminal, commissioned in 2005, has a baseload contracted deliverability of 13 mcm/d and delivered a maximum flow last winter of 17 mcm/d. Daily flows greater than 13 mcm/d depend on the prevailing operational circumstances and agreement between Grain LNG and the relevant shippers. Use-It-Or-Lose-It (UIOLI) provisions for the use of the shippers' capacity at Grain are in place, and improvements have been made to the information publicly available in respect of both flows from the facility and the availability of the facility to other users. The joint capacity owners are now developing proposals for additional UIOLI arrangements.

71. The experience of the 2005/06 winter has demonstrated that Grain is able to provide inputs into the UK market 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.

72. Figure 1 provides an updated view of forward prices for winter 2006/07 in Europe (at the UK NBP in particular) and in the US at the Henry Hub (HH). European prices are currently well above the equivalent HH price, suggesting that the risk of cargo diversion to the United States remains low[9].

Figure 1 – Forward gas price comparison



73. Excelerate Energy has recently announced plans to deliver up to 11 mcm/d of LNG at Teesside using Excelerate's 'Energy Bridge' shipboard re-gasification technology.

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

They have submitted planning applications for the required pipelines, and aim to be operational by December 2006.

74. We incorporated an assumption of 13 mcm/d of imported LNG into our consultation base case, reflecting the experience towards the latter part of the 2005/06 winter, when Grain flowed regularly at around this level and noted that there was some upside associated with this assumption (albeit relatively small) given the proven maximum physical capability of Grain (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.

75. In our May document we sought views on the assumptions that should be made for LNG importation in 2006/07 and on how flow patterns are likely to differ from those observed in 2005/06. There was a general acknowledgement in the responses that the level of LNG imports would be determined by the economics of the global market. Half of the respondents who commented felt that an assumed level of 13 mcm/d was appropriate. Two respondents thought this optimistic, one noting that this depended both on market conditions and full plant availability, the other quoting 11 mcm/d as a more realistic level. On the question of flow patterns, respondents considered that Grain should operate as a baseload source, provided market conditions remained favourable towards the UK.

76. Excelerate LNG attracted fewer comments, with those who did respond on this project seeing it as a potential bonus (given the present uncertainties over planning, for example) rather than one to be built explicitly into the base case.

77. On the basis of comments received, we believe that it is appropriate to maintain an assumed average LNG importation level of 13 mcm/d in the base case. We recognise that there is downside to this assumption, particularly if global market conditions should change, however, we also note that there is upside through Excelerate LNG and the possibility of higher Grain flows on some days.

Questions for consultation:

Q10. We would welcome any further views on the assumptions that should be made for LNG importation quantities in winter 2006/07, and specifically:

Q10a. Any variations that might be expected across the winter months

Q10b. Any further information on the likely extent of daily flows at Grain above the contracted level of 13 mcm/d

Storage

78. 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.

79. Since we published our May document, injection has recommenced at Rough following the outage on 16 February 2006. Centrica Storage currently estimate that it will be possible to inject at sufficient rates to enable all Rough capacity sold to be filled at or around the traditional end of the injection season (i.e. 31 October). Centrica Storage also estimate that full production rates will be available no later than 1 October. Centrica Storage have stated that these estimates remain subject to change.

Table 2 – 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)	33220	455	42	74

80. Many respondents commented on the likely patterns of use of the various gas storage facilities in 2006/07. The predominant view was that storage use was price driven, with trigger levels (for both withdrawal and re-injection) generally based on the forward curve, but varying according to the type of storage facility and the particular circumstances of the storage users. As highlighted above, a number of respondents believe that European storage is unlikely to be released to the UK until Q1 2007.

Base case

81. In the previous sections we have outlined the main points arising from our consultation on the appropriate supply assumptions for winter 2006/07 analysis, and we have indicated how we believe that the base case should be developed to properly reflect these points. We have also highlighted the residual uncertainties for each of the supply sources and sought further views on these issues.

82. Table 3 summarises the base case assumptions emerging from this consultation process, and compares these with the assumptions made in our May document and those made in respect of last winter in our Winter Outlook Report 2005/06. The revised base case is effectively a 'split winter' scenario, as it assumes that average Belgian Interconnector imports are 15 mcm/d higher in the second half of the winter than in the first, and that BBL operates only in the second half of the winter. To translate these assumptions into average supply levels across the winter, we have made the assumption that 70% of the highest demand days occur in the second half of the winter. This is a reasonable assumption based on analysis of historical weather patterns.

[10] Excludes Operating Margins gas
[11] Assumes average deliverability for Humbly Grove

Table 3 – Non-storage supply assumptions incorporated into base case (mcm/d)

	2005/06 Base Case Assumption	May 2006 Base Case for consultation purposes only	Revised Base Case for consultation purposes only	
			Oct - Dec	Jan - Mar
UKCS	269 (291 @ 92.5%)	240	240	240
Norway	33 (36 @ 92.5%)	48	48	48
IUK	42 (revised to 30)	35	25	40
BBL	N/A	20	0	20
LNG imports	13	13	13	13
Total	**357**	**356**	**326**	**361**

83. The fact that the revised base case is largely unchanged from that which underpinned our May document is indicative of the broad level of agreement from respondents to these assumptions. However, this base case seeks to provide no more than a balanced representation of industry views on the average level of supply availability in winter 2006/07; it should be noted that a significant level of uncertainty remains over this supply outlook. This uncertainty will reduce prior to and during the winter as the various importation infrastructure projects develop and patterns of market behaviour are observed. We will reflect any relevant developments in our Winter Consultation Report in late September.

84. The following sections provide analysis of the supply-demand position in 2006/07 assuming the revised base case and utilising our latest demand forecasts. This analysis is in two forms: first, load duration curves for average, 1 in 10 and 1 in 50 weather conditions; and, second, monthly analysis of projected supply availability against a variety of demand conditions. We have also updated and refreshed the sensitivity analysis contained within our May document.

Analysis of base case

85. Figures 2, 3 and 4 show the base case assumptions overlaid on a load duration curve of average, 1 in 10 and 1 in 50 demand respectively, with demand broken down into the Domestic, Other Non Daily Metered (NDM) and Daily Metered (DM) sectors. The forecast DM demand is further broken down to show the restricted and unrestricted forecasts. The unrestricted forecast (shown by the upper line) has been produced on a consistent basis to our previous demand forecasts. The restricted forecast implicitly assumes an element of demand-side response from large DM customers, consistent with high prices and levels of fuel-switching observed in winter 2005/06.

86. These load curves are presented numerically in Annex D. 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. For the avoidance of doubt, the supply curves use the average levels of supply within the base case, i.e. they do not attempt to represent the split winter scenario that underpins these averages.

Figure 2 – Average load duration curve analysis for 2006/07

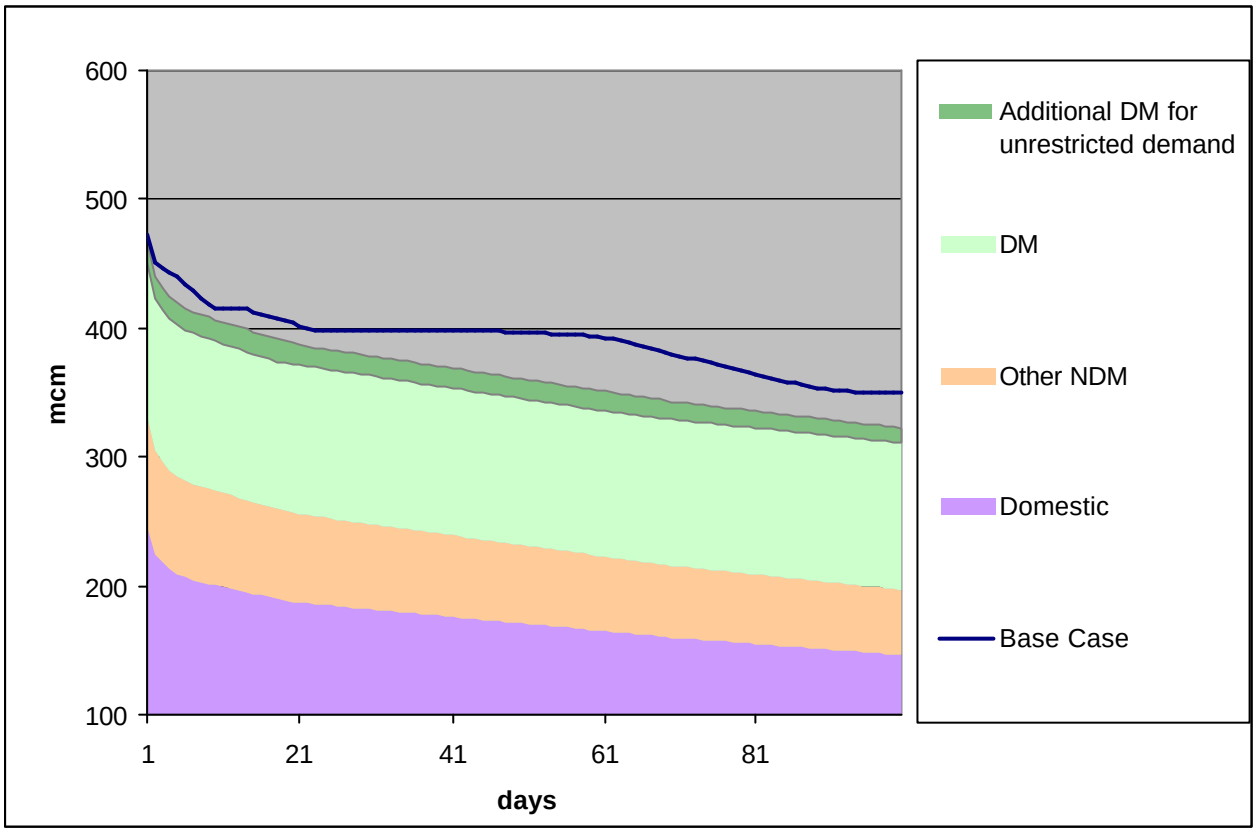


Figure 3 – 1 in 10 load duration curve analysis for 2006/07

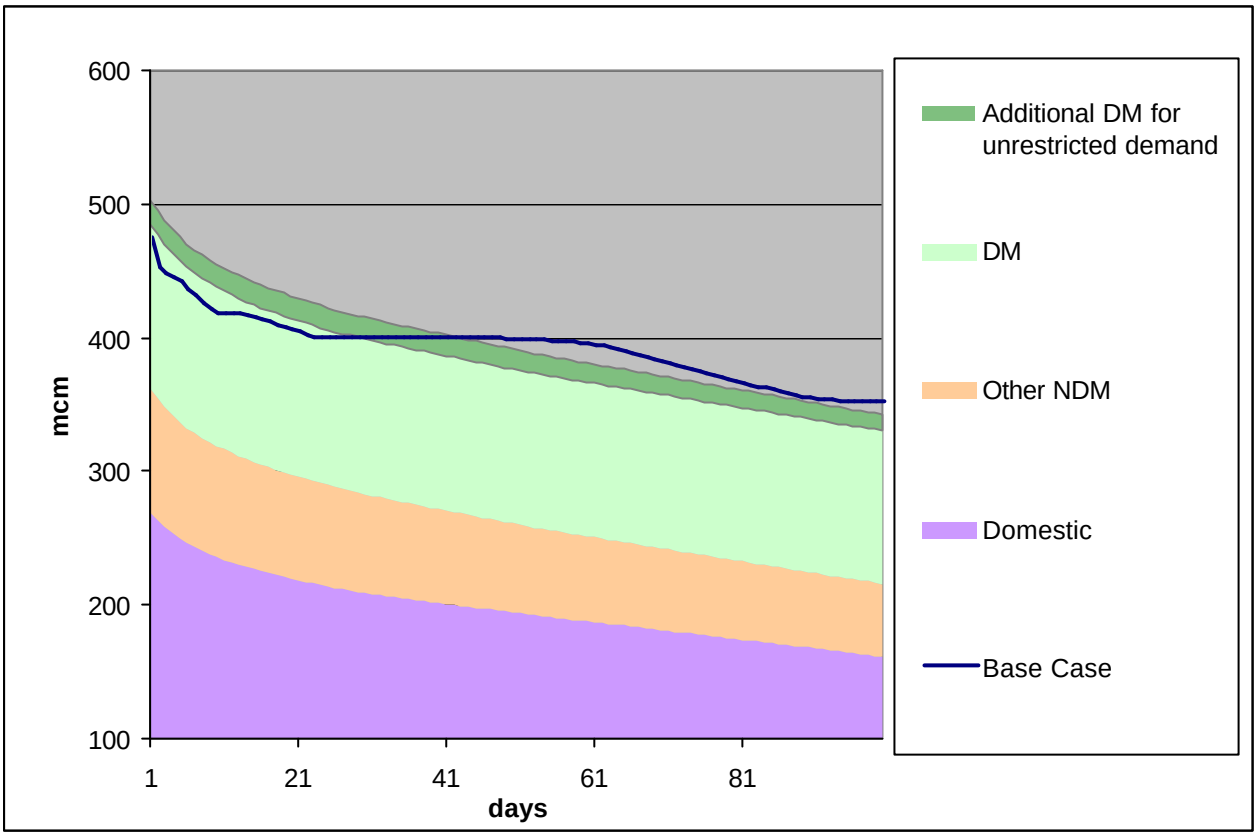
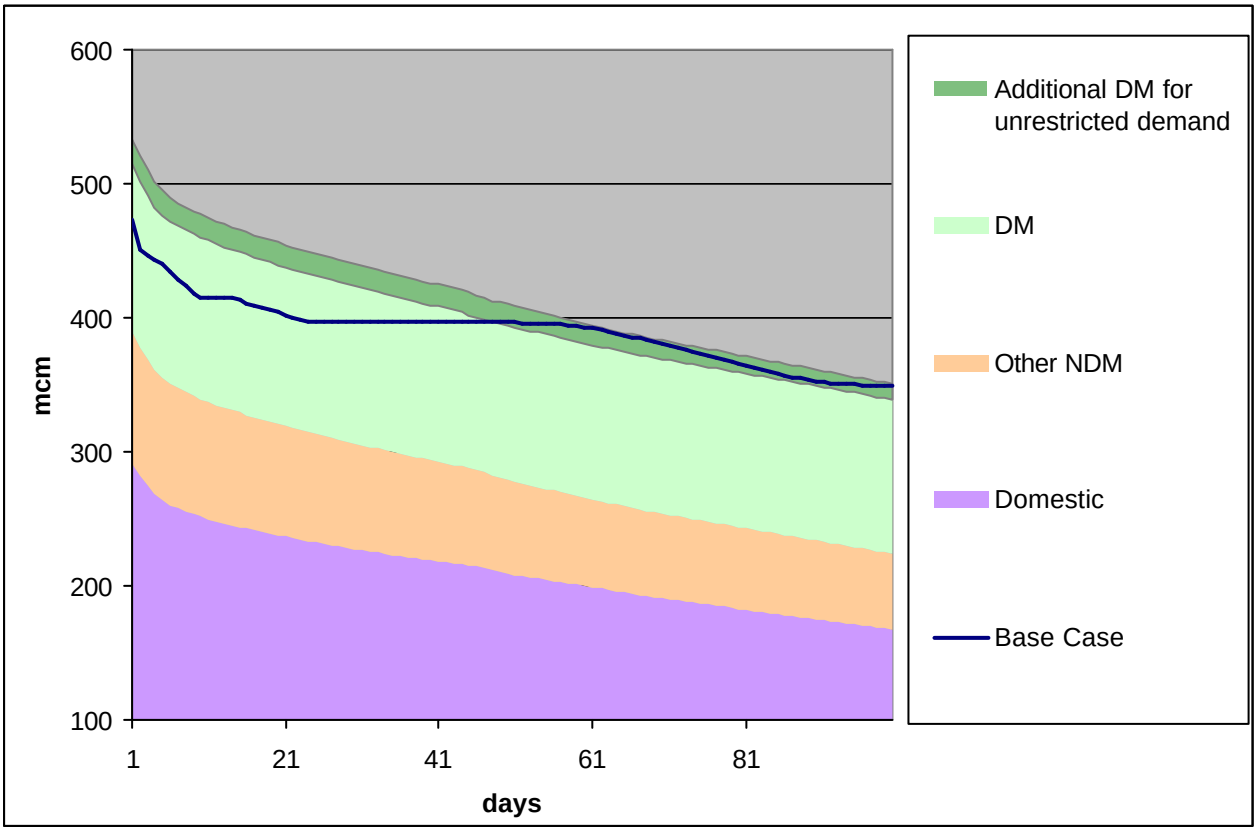


Figure 4 – 1 in 50 load duration curve analysis for 2006/07



87. Table 4 summarises the implied level of demand response required over the highest 100 days of demand against both the restricted and unrestricted demand forecasts. The equivalent analysis from our May document is also shown.

Table 4 – Demand response requirements under base case assumptions (bcm)

	Average	1 in 10	1 in 50
Base case: total demand response required (restricted)	0.0	0.4	1.3
Base case: total demand response required (unrestricted)	0.0	1.0	2.4
May 2006 Base case: total demand response required	0.3	3.1	5.0

Monthly cold spell analysis

88. 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. We have developed this analysis to provide a monthly assessment of potential supply availability against cold spell demand.

89. Figures 5 and 6 show bar charts representing the supply availability consistent with maximum physical capacity and the revised base case respectively. The former is not intended to represent a plausible scenario of supply availability. It is provided purely for reference to show clearly how the maximum physical capacity would develop over the course of the winter if all new developments meet their planned start dates.

90. On each bar, three levels of restricted demand are shown, commensurate with a cold day in that month[12], a cold week in that month[13] and a cold month[14]. It should be noted that the forecast 1 in 20 peak day[15] is higher than any of the individual cold day demands shown in these graphs. This is because the 1 in 20 peak day is based on statistical analysis of the whole winter rather than of any particular month. For reference, the restricted forecast for 1 in 20 peak day demand[16] is 499 mcm/d and the unrestricted forecast 1 in 20 peak day demand is 517 mcm/d.

[12] Demands based on fitting total demands to historical weather data and then calculating the 1 in 20 daily value in the relevant month
[13] 1 in 20 value of the seven day moving average demand for the relevant month
[14] 1 in 20 value of the average simulated demand across the relevant month
[15] 1 in 20 severity used as established industry planning standard for peak day analysis
[16] Total diversified demand for a 1 in 20 peak day

Figure 5 – Monthly cold spell analysis for 2006/7 assuming maximum physical supply capacity

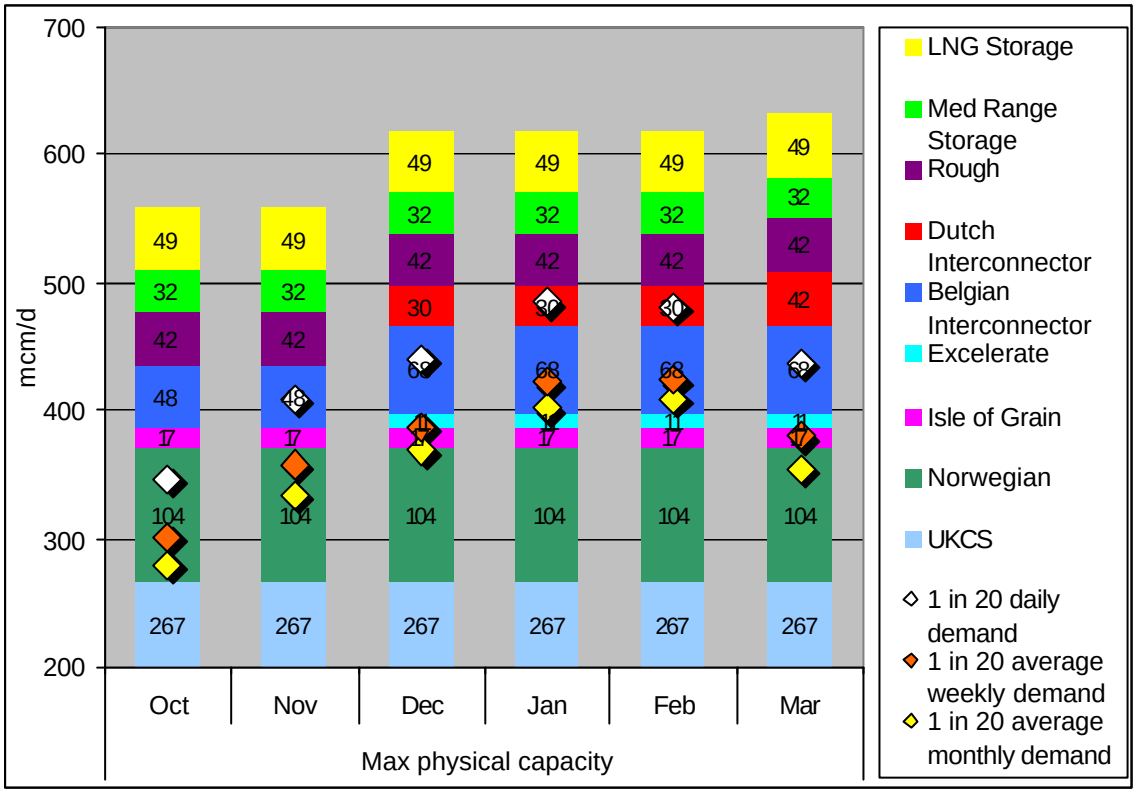
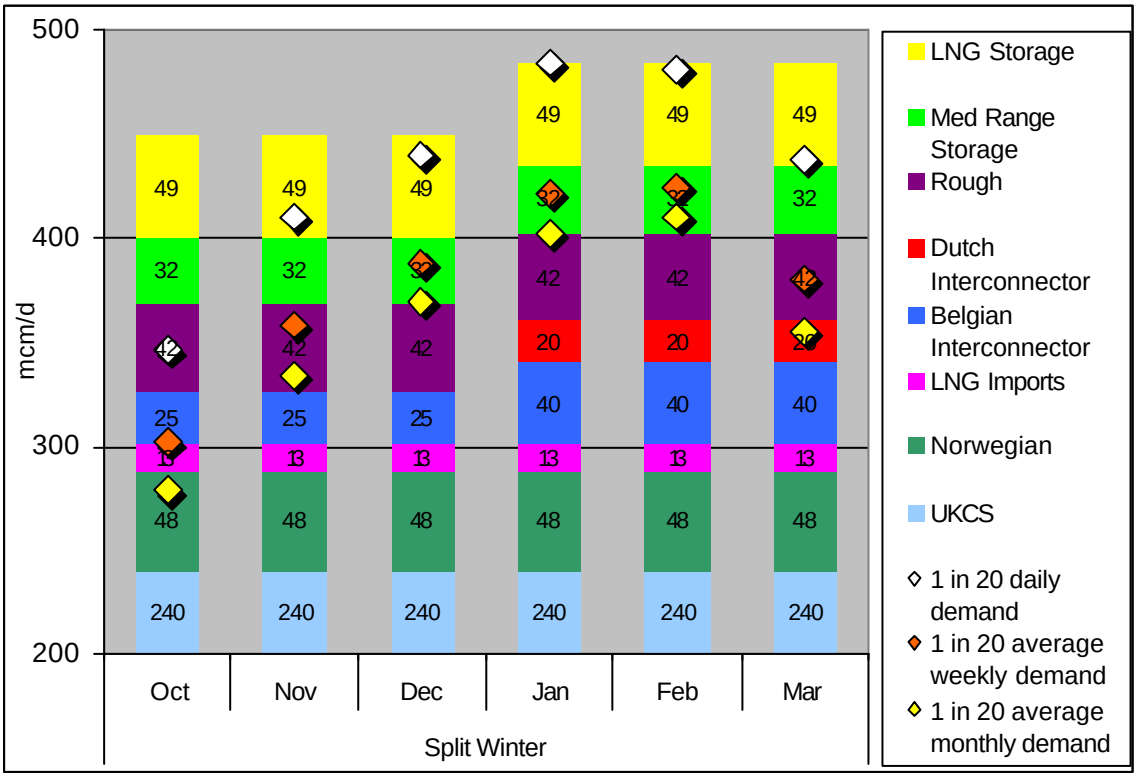


Figure 6 – Monthly cold spell analysis for 2006/7 assuming revised base case supply conditions



91. These graphs allow a number of other scenarios to be explored. In particular, sensitivities associated with the individual supply sources can be analysed by making appropriate adjustments to the relevant components of the bar charts. To aid such analysis, the data behind these charts is reproduced in Annex D.

92. It should be recognised that while the full deliverability of the various storage facilities is shown in these graphs, this depends on sufficient stocks remaining at the relevant point in time. It may therefore be valuable to explore sensitivities in which particular storage types have depleted by the late winter, for example. (Table 2 contains data on forecast storage stocks at the start of the winter).

93. Clearly, the risk of such a scenario (not revealed by the earlier load duration curve analysis) is greater if supply availability is depressed early in the winter, as this would result in a greater use of storage stocks at sufficiently high levels of demand.

Sensitivity analysis

94. The purpose of this section is to allow the reader to assess the implications of alternative scenarios on the requirement for demand-side response using a set of sensitivities. The impacts of variations in the assumptions are shown in Table 5, against unrestricted and restricted demand backgrounds.

95. 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 a 1 in 10 cold winter, this would imply a requirement for demand-side response of 1.7 bcm against an unrestricted demand background, or 0.7 bcm more than under the base case conditions.

96. 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.

97. Given the material reduction in our forecast of NDM demand, and the uncertainties that we have described associated with the basis of this forecast under very cold conditions, we have included a case in this analysis in which NDM demand is consistently higher than our revised forecast would suggest.

98. We have also included a sensitivity relating to UKCS supply availability. This assumes that availability is only 85% (rather than the base case assumption of 90%) for a period of one cold month, reflecting the potential for lower availability when poor weather is experienced offshore.

Table 5 – Demand response requirements under different scenarios

Case	Response (bcm)					
	Restricted			Unrestricted		
	Average	1 in 10	Severe	Average	1 in 10	Severe
Base case +30 mcm/d non-storage supplies	0.0	0.0	0.2	0.0	0.1	0.8
Base case +20 mcm/d non-storage supplies	0.0	0.0	0.5	0.0	0.3	1.2
Base case +10 mcm/d non-storage supplies	0.0	0.1	0.9	0.0	0.6	1.7
Base case	0.0	0.4	1.3	0.0	1.0	2.4
Base case -10 mcm/d non-storage supplies	0.0	0.8	2.0	0.0	1.7	3.4
Base case -20 mcm/d non-storage supplies	0.0	1.3	2.9	0.2	2.7	4.4
Base case -30 mcm/d non-storage supplies	0.0	2.2	3.9	0.6	3.7	5.4
Storage cycling: 15% in Average winter 10% in 1 in 10 winter 5% in 1 in 50 winter	0.0	0.4	1.3	0.0	1.0	2.3
5% more NDM demand	0.0	1.0	2.4	0.0	2.0	3.9
UKCS at 85% availability for one cold month	0.0	0.8	1.7	0.0	1.4	2.9

Safety monitors

99. On 31 May 2006, we published our preliminary view of initial safety monitor levels for 2006/07 as required under the Uniform Network Code (Q5.2.1). These initial levels were published as ranges given the high degree of uncertainty surrounding the supply-demand position.

100. Here we assess the implications for the initial safety monitor levels of our new demand forecasts and the revised base case supply assumptions described above. We still consider that the residual uncertainty is so significant that it would be inappropriate to publish spot levels at this stage. Accordingly, we have recalculated ranges within which the starting monitor levels might lie. We will of course publish single point monitor levels and the associated within-winter profiles prior to the start of the winter.

101. Of those respondents to the May consultation who commented on the appropriate basis for setting the monitor levels, one felt that the base case was “erring towards the conservative”, while another took the view that there was “a much greater probability of potential downside…..than potential upside”. Another respondent suggested that the assumptions surrounding the isolation process should be revisited, while a further respondent was concerned by the approach to the 2005/06

monitors, when we reflected supply-side uncertainty by the inclusion of a 'supply risk allowance', which was focused on the long-range storage monitor.

102. Other comments concerned the system of safety monitors more generally, with the need for transparency a common theme. In this context, we hope that this year's enhanced winter consultation process will be helpful in providing more visibility to the industry of the assumptions that will underpin the safety monitor levels.

103. It is our responsibility to keep the monitors under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do so on the basis of the information available to us. In doing so, we must recognise that the purpose of the safety monitors is to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. It is, therefore, appropriate that we adopt a prudent approach to setting the initial monitor levels. For this reason, it does not necessarily follow that the monitors would be based on the same set of base case assumptions derived through this consultation process. For example, in 2005/06 we included a risk allowance within the initial monitor levels to recognise the significant supply-side uncertainties that existed at that point in time.

104. There is clearly a material level of uncertainty surrounding all elements of the revised supply base case at present, with potential for both upside and downside against each individual assumption. However, in our view, the two key risks associated with these assumptions are as follows:

- that our revised NDM demand forecasts prove not to be accurate under very cold conditions, with demand levels reverting towards those that would have been anticipated given lower tariff prices;
- that delays are experienced in the construction and/or commissioning of new importation infrastructure.

105. Given these risks, we consider that any indicative range of initial safety monitor levels should be asymmetric around the base case (with more downside than upside). Accordingly, Figure 7 illustrates the initial safety monitor levels that would be required under different supply assumptions based on our latest demand forecasts for 2006/07. It shows an indicative range around the base case of -40 mcm/d to +20 mcm/d. Crudely, this represents a range of +/-20 mcm/d for the risks associated with supply availability through the individual supply sources, with an additional downside risk of -20 mcm/d in relation to the revised demand forecasts and new infrastructure.

106. It is clearly possible to construct a wider range of potential outcomes, but to do so would require a set of assumptions that taken together could be considered unduly optimistic or pessimistic. While we believe it is likely that the start of winter monitor levels will be set within the range shown, we cannot guarantee this at present.

Figure 7 – Initial safety monitor levels as a function of supply assumptions

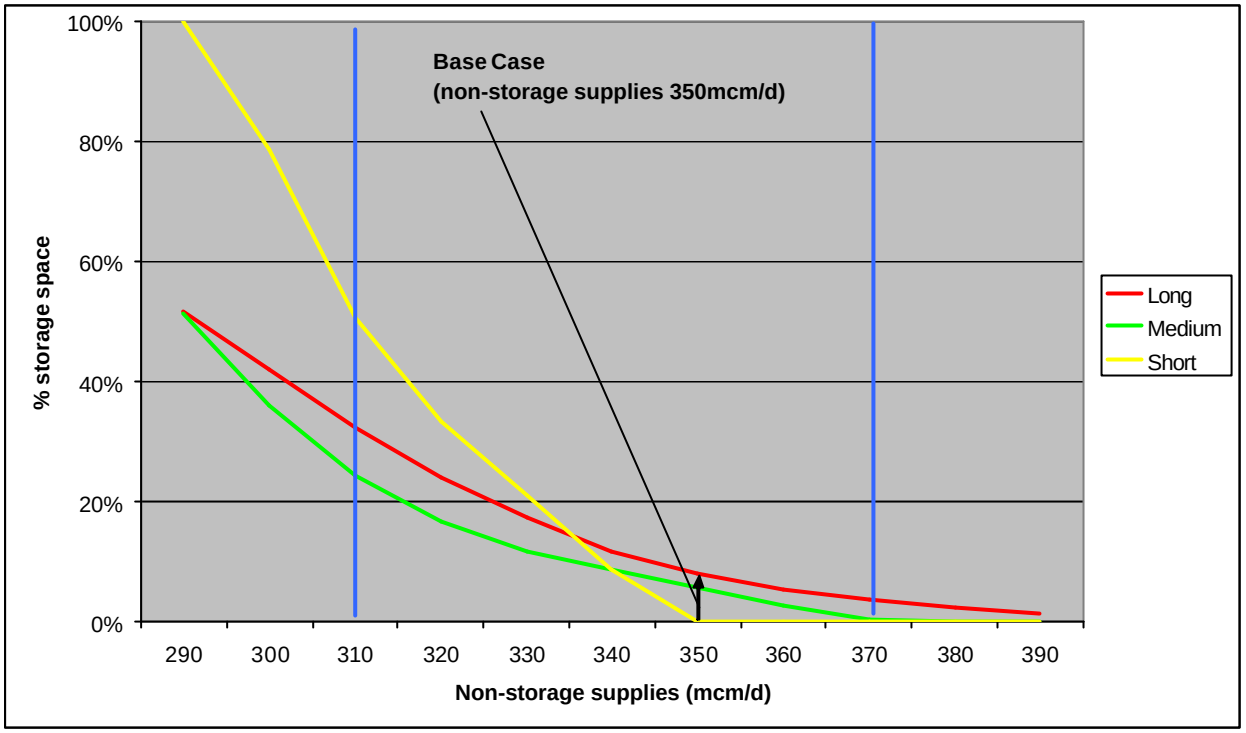


Table 6 - Safety monitor space requirement

Storage type	Assumed storage capacity (GWh)[17]	Lower supply (-40 mcm/d)	Base case (350 mcm/d supply)	Higher supply (+20 mcm/d)
		Space Requirement (GWh)		
Long duration storage (Rough)	33220	10781	2622	1130
Medium duration storage (MRS)	8111	1975	451	15
Short duration storage (LNG)	1758	893	0	0
Total	**43089**	**13649**	**3073**	**1145**
		Space Requirement (%)		
Long duration storage (Rough)		32.5%	7.9%	3.4%
Medium duration storage (MRS)		24.3%	5.6%	0.2%
Short duration storage (LNG)		50.8%	0%	0%
Total		**31.7%**	**7.1%**	**2.7%**

[17] Excludes Operating Margins Gas and Scottish Independent Undertakings

Questions for consultation:

Q11. We would welcome any further views on the appropriate basis for setting the 2006/07 safety monitors, and specifically:

Q11a. Views on the appropriate approach to mitigating the risk associated with the new NDM demand forecasts

Q11b. Views on the appropriate approach to mitigating the risk associated with new importation infrastructure

Chapter 2: Electricity

Electricity demand levels for 2006/07

107. As reported in the May consultation document, 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. Due to continued high energy prices no growth in demand has been assumed between winter 2005/06 and winter 2006/07.

108. Around 0.8-1.3 GW[18] 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, as reported in the May document, we have assumed 1 GW of demand-side response at the peak periods of the day in our demand forecasts for normal, ACS and severe conditions. The majority of responses to our May document agreed that this assumed level of demand response is reasonable, although some commented that there may be possible additional incentives for demand response with the new cash-out regime.

Questions for consultation:

Q12. We would welcome any further views on the extent to which electricity demand response might be expected given high electricity prices, and in particular:

Q12a. Views on our demand assumption for winter 2006/07

Q12b. The impact of the revised cash out regime (P194) on the level of anticipated electricity demand response

Notified generation availability

109. The current plant margin for winter 2006/07 reported in the May 2006 SYS Update[19] is around 21%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 76.3 GW[20].

110. 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.

111. Our latest operational view of generation capacity anticipated to be available for winter 2006/07 is 75.6 GW. (A broad breakdown of this capacity is shown in Figure 8).

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

[19] 2006 Great Britain Seven Year Statement Update (May 2006) http://www.nationalgrid.com/uk/Electricity/SYS/current/

[20] Including the UK-France Interconnector

112. 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. Since our May document, this information has been updated and the revised figure for generation that could return for winter 2006/07 is 0.8 GW. The change to the figure quoted in the May document is due to generators declaring themselves available for this coming winter.

113. We also reported in the May document that there is some long-term mothballed generation, all of which is unlikely to be available for winter 2006/07. Responses to our May document concurred with our assumptions that the short-term mothballed plant is likely to return whilst the long-term plant is unlikely to return for next winter.

Figure 8 – Generation capacity, winter 2006/07

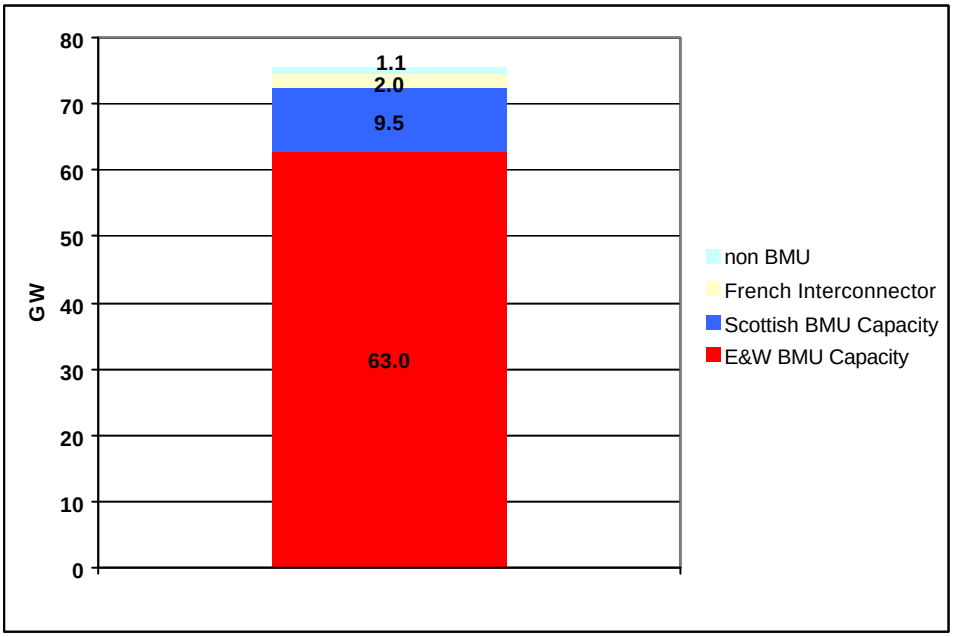


Table 7 – Mothballed capacity, winter 2006/07

	Could Return within 3-6 months	Long Term Unavailable Plant
Generation capable of being returned within period (GW)	0.8	1.0

114. In our May document, we asked if there is scope for investment prior to winter 2006/07 to provide back-up capability at existing power stations. Most respondents have said that such scope is infeasible due to the significant challenges posed by the need for physical modifications, environmental authorisations, planning, outages, etc. Information on existing back-up capability is presented in Chapter 3.

Contracted reserve

115. 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, Supplemental Standing Reserve and Fast 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.

116. National Grid issued a Supplemental Standing Reserve Tender on 3 July 2006 for delivery in winter 2006/07 (Oct 2006 – Mar 2007). Further communications regarding this will be through electricity operational fora and on our website[21].

117. 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; of which 0.9 GW has already been contracted, 0.3 GW within the BM and 0.6 GW with non-BM providers[22].

118. 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.

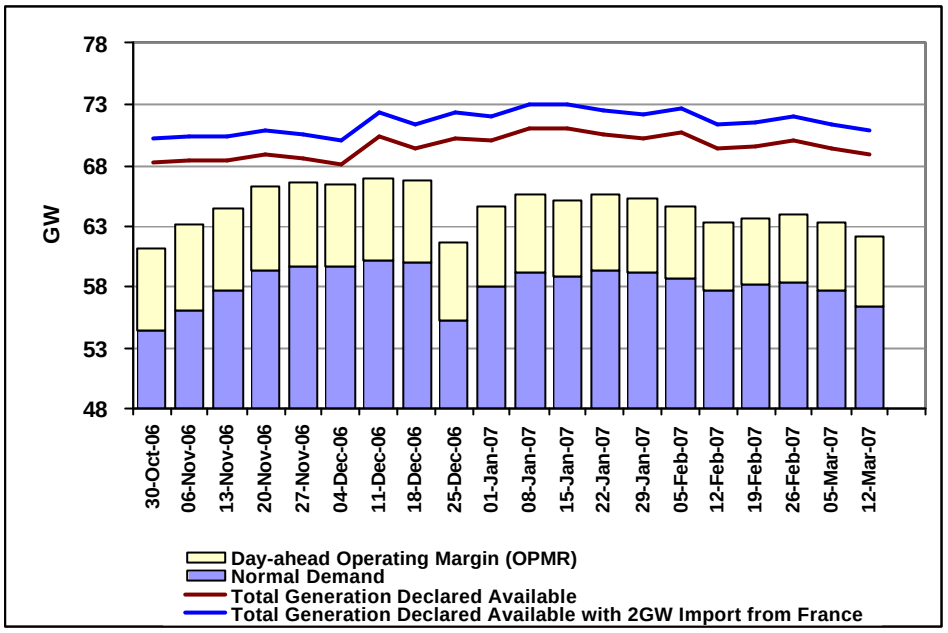
Forecast position for winter 2006/07

119. Figure 9 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. This reflects planned unavailability but does not include an allowance for unplanned generator availability.

120. As it can be seen in Figure 9, with full imports from France, the excess generation over average weekly peak demand would be around 12-14 GW. However, this 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.

[21] http://www.nationalgrid.com/uk/Electricity/Balancing/tenderreports/supplementalstandingreserve/
[22] http://www.nationalgrid.com/uk/Electricity/Balancing/services/commercial/Frequency+Response/
http://www.nationalgrid.com/uk/Electricity/Balancing/tenderreports/ffr/

Figure 9 – Demand and notified generator availability, winter 2006/07



121. 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, which is also shown for illustrative purposes in Figure 9.

Scenario for modelling purposes

122. We have created a scenario of generator availability and used this to illustrate the ability of the electricity sector to meet demand under average and 1 in 50 weather conditions. The scenario is shown in Table 8.

Table 8 – Electricity availability scenario (GW)

	Assumption
Plant availability, GW	73.6
Availability from France, GW	2.0
Return of mothballed plant, GW	0.8
Total availability, GW	76.4
Average assumed availability, %	87%
Assumed availability, GW	66.3

123. As agreed by most respondents to our May consultation document, we have assumed, based on last winter's experience, that all short-term mothballed plant would return prior to the forthcoming winter but anticipate that no long-term mothballed plant would return.

124. For the purpose of this scenario, a typical historic rate of 87% average power station availability has been assumed, and the week-by-week profile of unavailability has been smoothed across the winter as a whole.

125. In our May document, we asked specifically for views on expected average availability from nuclear generating plant. In light of feedback received on this question, we have increased our assumption from 80% to 85%. We have also revised our CCGT generation availability assumption from 95% to 90% based on further historical analysis, as a few correspondents have suggested that 95% was too high. These assumed availabilities have been incorporated in our revised analysis.

126. We also consulted on our assumption of a full 2 GW of capacity across the UK-France Interconnector at peak times. Most of the respondents who commented on this question felt that this was too optimistic, although it was also noted that import flows were not restricted to peak periods. Consistent with this feedback, our further analysis suggests that 1500 MW (75% capability) off-peak, 1250 MW (62.5% capability) between 3pm – 7pm and at float at other times reflect actual flows experienced in the past few winters, and would be reasonable assumptions for winter 2006/07. Many respondents expressed the view that the flow would depend on prices only and it is noted that current forward prices between the UK and the Continent suggest peak flow directions would be from France to UK.

Questions for consultation:

Q13. We would welcome any further views on our modelling assumptions for electricity generation availability, and in particular:

Q13a. Views on our revised assumption for the average availability of nuclear generating plant

Q13b. Views on our revised assumption for the average availability of CCGT generation plant

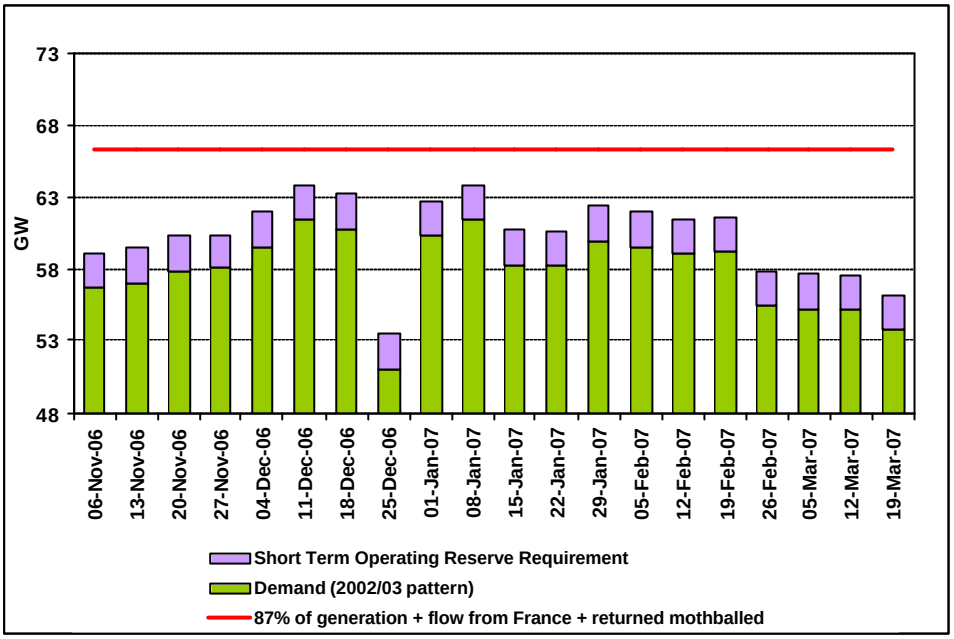
Q13c. Views on our revised assumptions regarding the level and direction of flow on the UK-France Interconnector based on historic flows and forward price differentials between the UK and the Continent

Average winter conditions

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

128. As illustrated in Figure 10, under average winter conditions, there should be more than sufficient plant to meet demand, increasing scope for the electricity sector to reduce gas consumption, thus providing a material level of demand-side response for the gas sector.

Figure 10 – Forecast demand under average weather conditions (2002/03 weather pattern) and generator availability, winter 2006/07

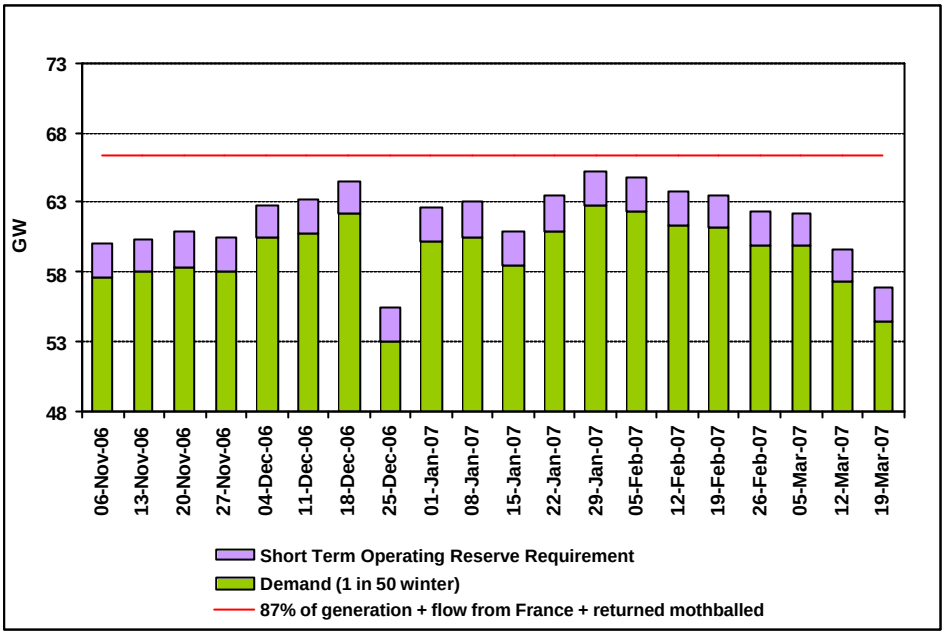


1 in 50 cold winter conditions

129. 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.

130. If these weather patterns were to occur this winter, as illustrated in Figure 11, 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. See Chapter 3 for our analysis of the extent to which CCGT demand could be reduced in a severe winter.

Figure 11 – Forecast demand under 1 in 50 weather conditions (1946/47 weather pattern) and generator availability, winter 2006/07



131. The electricity background set out in this Chapter and the gas background outlined in Chapter 1, form the basis for the analysis of the interactions between the two markets in Chapter 3.

Chapter 3: Gas / electricity interactions

132. 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.

133. 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.

134. 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.

135. 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, by feedback received on our May document and by information from generators regarding distillate capability from CCGT power stations.

Power generation gas demand and distillate back-up

136. The maximum theoretical power generation gas demand in GB for winter 2006/07 is shown in Table 9. These figures are based on contractual limits. They include power stations that could source their gas supply from the NTS but are predominately supplied directly from offshore supplies by non-NTS pipelines. The dual-fuelled Peterhead station is included within these numbers. Figures exclude smaller embedded power generators, typically Combined Heat and Power stations, which do not participate in the Balancing Mechanism.

Table 9 – Maximum 2006/07 GB power generation demand

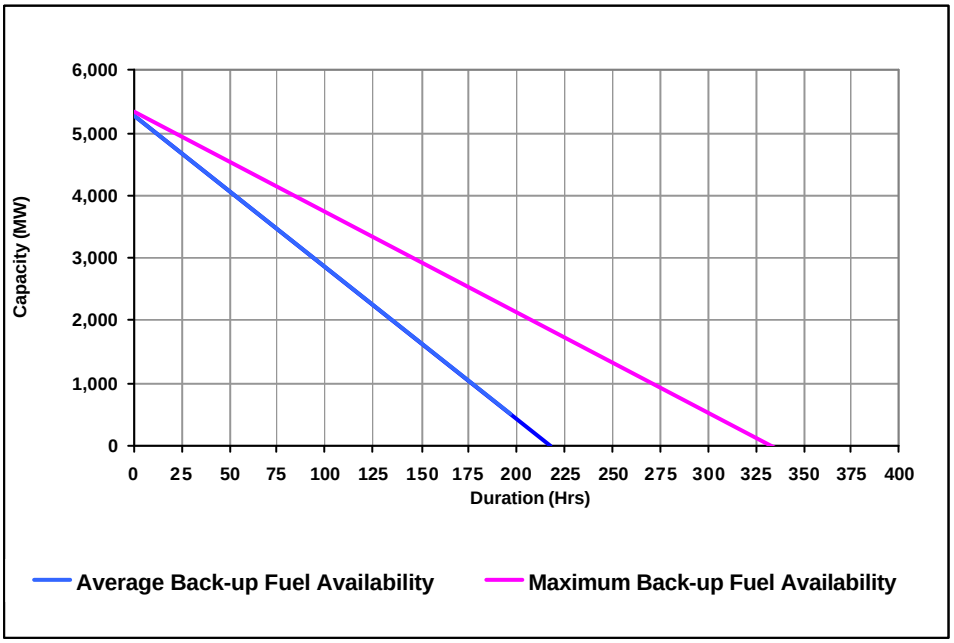
	Maximum gas demand (mcm/d)	CCGT capacity (GW)
NTS-connected	117.3	23.8
LDZ-connected	5.5	1.1
Total	122.8	24.9

137. Daily consumption from CCGTs started 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. The gas demand forecasts used for this analysis are based on our most recent calculations. The unrestricted and restricted demand forecasts have both been modelled. (See Chapter 1 and Annex A for an explanation of these two forecasts). Both forecasts are lower than the forecast of 2006/07 that we made in 2005, which underpinned the analysis in our May document. The modelled requirement for demand-side response is therefore lower than shown in the May document.

138. 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.

139. 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 12 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 12 – Load duration curves for back-up fuel supplies (smoothed)



Analysis of potential CCGT demand response – modelling assumptions

140. 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.

141. These issues were re-iterated in the responses to our May document. In addition, the following comments were also raised:

- Ability to replenish stock in prolonged severe weather conditions might be limited, in particular if stocks are delivered by road tankers;
- Behaviour might be affected by potential exposure to high imbalance costs if plant fails to generate.

142. However, there were generators who have noted that they do not foresee problems with re-stocking and that they would have similar or more distillate stock than that held in winter 2005/06.

143. In winter 2005/06, there was an estimated level (as reported in our May document) of 98 mcm (avoided gas consumption) 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. We have received a number of responses to our questions on distillate-switching ability and willingness, stock levels and potential re-stocking restrictions. This information broadly confirms our assumptions, though we are reviewing this with the feedback received from generating companies. We will adjust the assumptions if necessary in our Winter Consultation Report in September.

144. In winter 2005/06, we observed coal and nuclear running as baseload whilst gas was the marginal fuel. In our May document, we noted that this was our modelling assumption for winter 2006/07.

145. Responses to our consultation largely agreed with our assumptions. Comments that have led to revisions in our assumptions related to nuclear and CCGT availability, French imports and the extent to which CCGTs run baseload. Some respondents commented on environmental constraints, with a number suggesting that derogations and/or dispensation[23] may be required in certain circumstances (as was the case in 2005/06).

146. The following is a summary of our latest modelling assumptions for winter 2006/07, some revised based on further analysis and responses to our consultation:

- Nuclear runs as baseload – 24 hours a day, 7 days a week, with availability of 85%. This assumed availability is applied to the prevailing level of connected nuclear plant (which will be lower from January 2007 when Dungeness A and Sizewell A are decommissioned). This revised availability is based on further analysis and feedback received on our question on nuclear availability.
- Imports into GB through the French Interconnector are available off-peak (7pm-7am) at 75% of capability, the peak 4 hours (3pm-7pm) at 62.5% of capability and the link is at float at other times. This is based on analysis of historical flows and a review of forward spreads between UK and European markets. It should be noted that there is uncertainty over what the actual flows will be on the day as

[23] This would be the responsibility of the Environment Agency or the Scottish Environment Protection Agency

prompt electricity prices in individual markets will influence direction and magnitude of flow on the Interconnector;

- CCGT as marginal fuel with availability of 90%. One respondent expressed the view that 95% (assumed in the May document) was too high. Given this feedback, we have carried out further analysis and revised the availability assumption. However, it should be noted that since gas is expected to be the marginal fuel, this amendment to the assumed availability will have little effect on the output of the modelling;
- 3.1 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as baseload;
- Around 2.5 GW of NTS-supplied CCGTs run as baseload (of which 0.85 GW has the capability to run on distillate), 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 and feedback received through the consultation;
- 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 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 10, consistent with an average availability rate of 87% (marginally lower than the average availability in our May document).

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

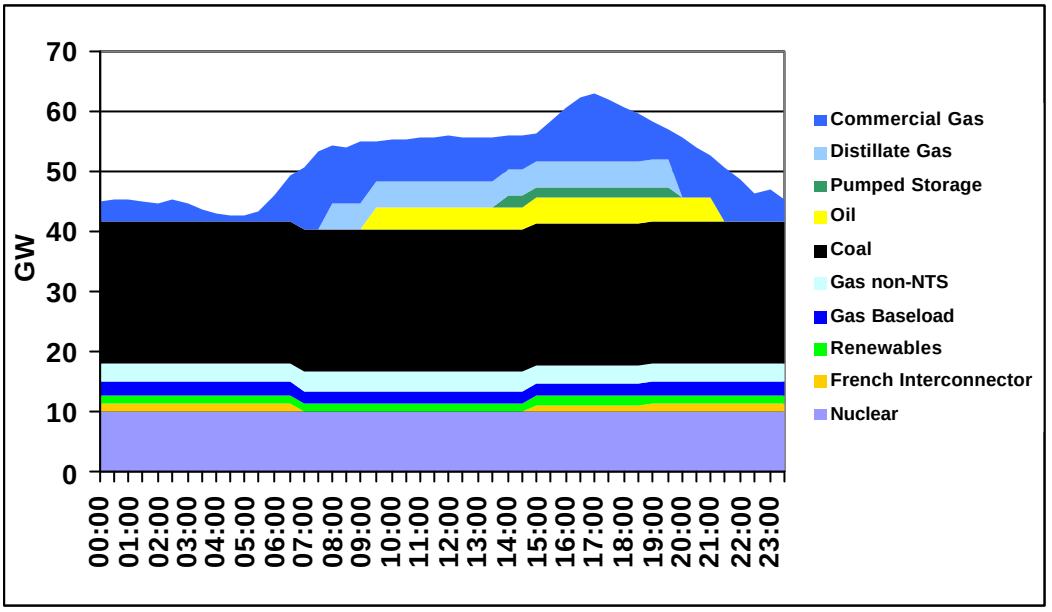
Power Station Type	Assumed Availability		Model Assumptions Summary
	GW[24]	%	
Nuclear: Oct – Dec Jan – Mar	 10.1 9.3	 85%	 Baseload
French Interconnector: Off-Peak 3pm – 7pm Other periods	 2.0	 100% 100% 100%	 1500MW (75%) 1250MW (62.5%) at float
Non-BM Generation (including renewables)	1.4	40%	Baseload
Coal	23.7	85%	Baseload
Oil	3.9	95%	12 hours over peak
Pumped storage	2.8	100%	6 hours over peak
OCGT	1.2	95%	Low merit, run occasionally
CCGT	21.9	90%	Marginal plant
Average availability		87%	

Analysis of potential CCGT demand response – simulation results

147. Figure 13 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modelling assumptions described above. It shows approximately 24 GW of coal-fired generation throughout the day, gas as the marginal fuel across the day and distillate used for 12 hours around the peak demand period. (As explained above, total distillate usage across the winter has been constrained to 200 hours in the simulation model).

[24] Does not quite tally with total assumed availability due to rounding

Figure 13 – Potential generation profile - cold winter weekday



148. 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. This analysis has been undertaken against both the unrestricted and restricted gas demand backgrounds. The difference between these backgrounds is that demand-side response is already assumed within the restricted background, consistent with behaviour observed in the 2005/06 winter.

149. Tables 11 and 12 summarise the results from 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 11 – Potential CCGT demand response (bcm), unrestricted gas demand background

	Average	1 in 10	Severe
Required	0.0	1.0	2.4
Potential CCGT	0.0	0.6	1.3
Non-CCGT	0.0	0.4	1.1

Table 12 – Potential CCGT demand response (bcm), restricted gas demand background

	Average	1 in 10	Severe
Required	0.0	0.4	1.3
Potential CCGT	0.0	0.0	0.3
Non-CCGT	0.0	0.4	1.0

150. As Table 12 illustrates, our modelling suggests that relatively little additional CCGT response (0.3 bcm) would be available in a severe winter over and above the level implicitly assumed within the restricted demand forecast. This finding is consistent with the views of some respondents, who noted that only limited scope for fuel-switching from gas to coal was feasible beyond that already observed last winter. This analysis implies that the residual requirement (1.0 bcm) would fall on the non-CCGT market.

***Questions for consultation*:**

Q14. We would welcome any further views on our analysis of the potential for CCGT response in a severe winter, and in particular:

Q14a. Further views on the revised assumptions that underpin this analysis

Q14b. Further views on the impact of environmental constraints on the potential for CCGT response, and on the potential need for any derogations or other forms of dispensation against environmental limits in the 2006/07 winter

Chapter 4: Industry Framework Developments

151. 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

152. 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 options to encourage more efficient and economic supply and demand management to mitigate the risk of entering a Gas Deficit Safety Monitor Breach Emergency (generally referred to as "above the line"). The options put forward were:

- Status quo – do nothing
- Trigger Alert - The provision of a second and earlier "Gas Alert" to highlight a tightening situation.
- Economic and efficient enhanced SO role – SO as a "single purchaser" procuring and holding a contingency reserve through demand and supply side contracts.
- SO objective function to include Security of Supply – to preserve storage.

153. These issues have further been discussed and explored with Shippers and customers at the Demand Side Working Group (DSWG) and are summarised below.

'Above the line' arrangements

154. The Gas Reserve Working Group has now completed its work in relation to the coming winter period. At the meeting of the Gas Reserve Working Group on 26 April it was agreed that if one or more industry participants felt that change was required then the next stage in the process was for them to raise Modification Proposals in relation to "above the line" issues as they saw fit. This resulted in the Modification Proposal (UNC Modification Proposal 0086: Introduction of Gas Demand Management Reserve Arrangements) being raised by Gaz de France. If approved this Proposal would enable National Grid, in its role as the Residual Balancer, to initiate a tender to purchase "demand side response" from shippers and subsequently target the cost of holding and using these contracts on a "polluter pays" principle.

155. Along with a number of industry parties, National Grid does not support this Proposal. We consider that its intent is unclear and are concerned that it would undermine the clarity of responsibility that exists at present for supply and demand management. We remain fully engaged as the proposed modification progresses under the UNC governance. The UNC Modification Proposal will be with Ofgem for decision shortly. If approved at this stage UNC text to support the proposal will be in place for this winter.

'Below the line' arrangements

156. 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. 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.

157. The Gas Reserve Working Group has concluded that as there was insufficient time to consider wider changes for this year the current Safety Monitor Regime should continue for the coming winter. However, the group will continue to discuss potential revisions to the gas reserve arrangements for winter 2007/08 during the summer and autumn of 2006.

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

158. The Gas Reserve Working Group considered whether or not the changes introduced by this Proposal and those of Modifications 0052 "Storage Withdrawal Curtailment Trade Arrangements in an Emergency" could be further developed to provide more efficient and economic operation of the "below the line" regime. Changes discussed included 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. Following these discussions, the Proposer of Modifications 0052 and 0071a felt that no further change was necessary. Following a presentation by National Grid, detailing the present compensation regime, the July 2006 UNC Transmission Workstream also considered that no further changes were required.

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

159. The Gas Reserve Working Group and the DSWG discussions also assessed 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 considered 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 response to these discussions, the Authority has recently published an initial proposals document in relation to the potential for two new incentives on National Grid. One incentive is aimed at improving the accuracy of the "before the day" 14.00 hours demand forecast relative to outturn demand and the other is aimed at improving the availability and timeliness of publication of the gas operational data on National Grid's website. The Authority is expected to publish final proposals, including a statutory licence consultation, in relation to these proposals later this month with implementation of any finalised incentive schemes to occur ahead of the coming winter. If introduced the incentives will be effective for this winter. National Grid welcomes the development of these potential incentives in response to the particular circumstances of the 2006/07 winter and we have instigated work to improve performance in these areas.

Uniform Network Code

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

160. 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. This modification proposal is with the Authority and a decision is expected shortly.

Information provision initiatives

161. Ofgem has directed the implementation of UNC Modification Proposal 006 "3rd Party Proposal: Publication of Near Real Time Data at Sub Terminals", which provides for flow information regarding deliveries of gas to the NTS system to be published every 12 minutes. National Grid Transmission is currently working to provide the information technology infrastructure necessary to publish the information called for in the Proposal. This facility will be available on 3 October 2006.

162. National Grid will also be publishing a further information stream via the operational data section of our website; longer range demand forecasts based on Met Office weather forecasts for the period up to 5 days ahead (D-5 to D-2, in addition to the forecasts for D-1 and D already published). This is intended to provide additional information in relation to our demand forecasts in the build up to each day.

Balancing and Settlement Code (BSC)

Incentives to balance - P194 and P199

163. 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.

164. 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 balance, during times of system stress. This modification has been approved by Ofgem and will take effect on 2 November 2006.

165. We also raised P199 because the existing BSC 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. P199 is currently out to industry consultation.

Connection and Use of System Code (CUSC)

Access to the transmission system – CAP094, CAP097

166. 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.

167. 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 has recently been approved by the Authority.

Grid Code

Market information – H/05

168. 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.

169. 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.