Winter 2006/07 Consultation Report

September 2006

Executive Summary

Introduction

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.

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, we supplemented our pre-existing information sources by running a consultation process to gather industry views and information on the 2005/06 winter. This year, in conjunction with Ofgem, we have conducted an enhanced consultation process. In May we published our first consultation document on the coming winter[1], and in July we published a consultation update[2]. The July document provided feedback on the responses received to our May document, presented updated analysis and sought further views. The consultation documents have been supplemented by a series of industry seminars, organised by Ofgem, focusing on the coming winter.

This document presents the outcome of the 2006/07 winter consultation process. It provides feedback on the responses that we have received to the issues raised in the consultation documents, and contains analysis of the supply and demand backgrounds in the gas and electricity markets under a range of winter weather conditions.

Overview of gas and electricity backgrounds

<u>Gas demand background</u>

In our July document, we presented revised gas demand forecasts for 2006/07, noting that these were materially lower than the forecasts that we had produced in 2005. In particular, we highlighted the reduction in forecast Non-Daily Metered (NDM) demand, consistent with the lower demand levels observed last winter. Respondents to the consultation have agreed that it is appropriate to reflect recent experience of reduced NDM demand in the forecast, although risks associated with this forecast (particularly under very cold conditions) are recognised.

We also presented in July a new 'restricted' demand forecast, which incorporated a measure of demand-side response from the Daily Metered

[1] Winter 2006/07 Consultation Document, May 2006
[2] Winter 2006/07 Consultation Update Document, July 2006

(DM) sector (mostly from gas-fired power stations) given an expectation of sustained high spot prices through the 2006/07 winter. Responses have welcomed the addition of the restricted forecast and confirmed that this provides an appropriate planning basis under current market conditions.

Gas supply sources

On the supply-side, our assessment of UKCS supply availability is unchanged: a maximum capability of 267 mcm/d, and an assumed average availability of 240 mcm/d (90%). Almost all responses to the consultation have supported these assumptions.

A number of major infrastructure projects are due to be commissioned prior to or during the 2006/07 winter, providing capacity for the importation of substantial quantities of gas into the UK. These are: 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. Since our July document, positive developments have been reported in relation to all of these projects:

- The construction of Langeled is complete, and commercial gas flows are expected in October;
- IUK have announced that the upgraded Belgian Interconnector capacity should be available from 1 October, two months earlier than originally planned;
- Construction of the offshore BBL pipeline commenced in mid-July and is now well-advanced, and good progress has been made with the compression facilities in Balgzand and the onshore facilities at Bacton;
- Excelerate Energy have received the planning approval that they require for two pipelines on Teesside.

As a result of these developments, there is now a high level of confidence that Langeled and the Belgian Interconnector upgrade will be available prior to the main winter months. In addition, the uncertainty associated with the availability of BBL and Excelerate has reduced, although both projects continue to work to tight timescales (1 December and early January respectively).

While the risk associated with infrastructure construction has reduced, there remains a significant level of uncertainty related to the utilisation rates that might be expected from the various importation facilities; a consequence of the complex interactions between the UK gas market and the European and LNG markets. This was recognised by respondents to our July consultation. However, they broadly agreed that the supply base case presented in the July document provides a balanced view of the prospective supply position for the coming winter. As a result, we have not amended the base case (summarised in Table ES.1 below) for this report. Given the residual uncertainties, the base case should not be seen as a confident prediction of the likely outcome, and we have included new analysis in this report covering a range of scenarios to illustrate possible variations away from the base case.

Table ES.1 - 2006/07 non-storage gas supply base case assumptions (mcm/d)

Supply source	2006/07 Base Case	
	Oct – Dec	Jan – Mar
UKCS	240	240
Norway	48	48
IUK	25	40
BBL	0	20
LNG imports	13	13
Total	**326**	**361**

Gas storage

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 the 2006/07 winter. The Rough storage facility has been refilling since early June following the incident on 16 February 2006, which resulted in the loss of production and injection capability. At the time of writing, Rough is 95% full and Centrica Storage anticipate that all Rough capacity sold will be filled by around the end of October. Centrica Storage also expect that full production rates will be available no later than 1 October.

Gas safety monitors

On 4 September, we published the approach that we intend to take to the 2006/07 storage safety monitors[3]. We explained our conclusion that in calculating the safety monitor levels, it is appropriate to use a more ‘cautious’ set of assumptions than the ‘best view’ when the supply-demand background is particularly uncertain.

The initial monitor levels will be confirmed by 1 October. We will then keep the level of the safety monitors under review through the course of the winter, and make further changes if it is appropriate to do so.

Electricity market

The outlook for the electricity market in 2006/07 appears less uncertain than that for the gas market. The August 2006 Seven Year Statement Update shows a headline plant margin[4] of 22%.

Last winter the operation of the electricity market was characterised by coal generation operating at baseload, with gas providing the marginal capacity. A similar pattern is anticipated for the coming winter, consistent with our restricted gas demand forecast.

[3] www.nationalgrid.com/uk/Gas/Data/storage
[4] The term ‘plant margin’ refers to the surplus of generating plant over forecast peak demand

Implications

Comparison with 2005/06 market background

Our latest restricted demand forecasts would suggest demand levels slightly lower than last winter (by around 5 mcm/d on average) given similar weather conditions. This is driven by increases in end-user prices, and an expectation (implicit within the restricted forecast) of sufficiently high spot prices to trigger similar levels of demand-side response.

On the supply-side, the Q4 2006 base case is similar (in aggregate) to the supply conditions observed in Q4 2005. However, the Q1 2007 base case is significantly higher than the supply conditions observed in Q1 2006 (even prior to the Rough incident on 16 February).

Taking the supply and demand backgrounds together, it is clear that the gas market has the potential to be less tight than last winter, provided the level of gas through the new importation infrastructure is sufficiently close to the base case assumptions (and, of course, subject to the weather).

In the electricity market, the present headline plant margin is 22% compared with an equivalent plant margin of 21% this time last year, indicating a broadly similar background.

Gas demand-side response

The weather is the key determinant of winter gas demand. We have therefore estimated the extent to which reductions in gas demand would be required under a range of winter severities, assuming the supply base case.

The Met Office statement[5] published on the same day as this report indicates an equal probability of a milder than average or colder than average winter, with a slightly higher probability than normal of an average winter. The statement also notes a signal that the winter may become colder in relation to average temperatures as the season progresses[6].

Our analysis of the supply base case indicates that if the winter is average or milder than average, little or no demand-side response would be required, even against an unrestricted demand background. However, very cold snaps can occur even in otherwise unremarkable winters. This can be seen in our analysis of historical weather patterns in Annex A, which highlights the potential for a material amount of LNG to be used and demand response to be required in such circumstances.

Our analysis of severe winter conditions indicates that even in a 1 in 50 cold winter, there would be sufficient gas to maintain supplies to domestic and other non-daily metered customers. There would, however, be a requirement for a significant demand-side response from DM customers. When measured against our restricted demand forecast this amounts to around 1.3 bcm, an average of approximately 30 mcm/d over a period of 40 days. (However, it should be noted that the restricted forecast implicitly assumes some response to high spot prices, predominantly from the CCGT sector, equivalent to around 15-20 mcm/d compared with the unrestricted forecast).

[5] http://www.metoffice.gov.uk/weather/seasonal/winter2006_7/index.html
[6] Against the Met Office's definition of winter severity, the 2005/06 winter was average

We have also undertaken simulation analysis to estimate the additional contribution that might be available from the CCGT sector to this required gas demand-side response. By difference, the residual requirement would have to come from other (non-CCGT) DM customers.

This analysis is summarised in Table ES.2.

Table ES.2 - Summary of demand-side response analysis (assuming restricted demand forecast)

Winter severity	Estimated demand-side response required (bcm)	Potential additional contribution from CCGT sector (bcm)	Approximate residual requirement as percentage of non-power DM market sector
Average	0	0	None
1 in 10 cold	0.4	0.2	15% for 25 days
1 in 50 cold	1.3	0.3	40% for 40 days

Electricity market

The projected level of generation availability would be sufficient to meet demand associated with Average Cold Spell conditions. Under 1 in 50 cold winter conditions, the projected level of generation would also be sufficient to meet demands provided that:

- we do not experience unusually high levels of plant breakdowns; and
- sufficient non-power generation gas demand response is provided by industry such that adequate CCGT generation remains available.

As can be seen in Table ES.2, our analysis of the interactions between the gas and electricity markets shows that relatively little additional CCGT response could be provided under such severe conditions over and above the level assumed in our restricted gas demand forecast.

Also in severe conditions, a relatively small reduction in the reliability of non-CCGT generation (equating to the loss of around 1 GW baseload beyond the level assumed) could require CCGTs to operate above the level assumed in our restricted forecast[7].

Next Steps and Other Information Sources

Ofgem is hosting a Winter 2006/07 Consultation Seminar in Birmingham on 27 September 2006, which will highlight the key issues identified through this consultation process. For more information, or to register, please contact wholesale.markets@ofgem.gov.uk.

[7] We have noted the recent British Energy corporate update regarding Hunterston B and Hinkley Point B. Our analysis is consistent with the latest position as we understand it.

We would welcome further information throughout the winter that would assist us in our ongoing review of the gas safety monitors. Please send this to simon.griew@uk.ngrid.com.

For the latest information on the gas supply and demand position throughout the winter, please visit our Daily Summary Report at http://www.nationalgrid.com/uk/Gas/Data/dsr

Near real-time and historic data about the electricity Balancing Mechanism is available at: http://www.bmreports.com/bwx_reporting.htm

The DTI website now contains dedicated pages on winter energy supply. These include links to various other useful sources of information. Visit: http://www.dti.gov.uk/energy/winter-supply/page32154.html

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

Contents

Chapter 1: Gas

1. This Chapter focuses on the gas supply-demand outlook for the forthcoming winter. We examine issues associated with the demand background, each of the various sources of supply, and the interactions between those sources. We summarise the feedback that we have received through the consultation process, and present our latest analysis taking account of these views.

2. The consultation process has focused particularly on two issues:
   - Our latest demand forecasts, which showed material reductions in all sectors from previous forecasts as a result of the prevailing level of prices;
   - The prospects for the new sources of imported gas, taking account of the construction projects that will facilitate these gas flows, and the expected utilisation rates of the new infrastructure.

3. This process has confirmed that the industry regards the demand background and the supply base case as an appropriate basis for analysing the coming winter. However, given the significant uncertainties that still remain, it is also important to consider how the outturn position might be different. We have therefore supplemented our assessment of the base case with revised sensitivity analysis, and some new analysis of alternative supply scenarios and weather patterns. This is explained later in this Chapter, while further detail is contained in Annex A.

Gas demand

4. In our July document, we presented a revised demand background, which we had produced as part of the 2006 Transporting Britain's Energy (TBE) consultation process. As we noted, these demand forecasts are materially lower than the equivalent forecasts for 2006/07 produced in 2005, which underpinned the analysis in our May document.

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

6. 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%.

7. 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. We therefore sought views on whether

consumer behaviour would alter in the face of prolonged cold conditions, with the need to remain warm over-riding cost concerns.

8. In general, respondents felt that our revised NDM forecasts were soundly-based. However, many echoed our concerns that there was insufficient evidence with which to assess the robustness of these forecasts at very cold temperatures, and recognised the risk that a lower level of price-sensitivity may be observed under such conditions. We have reflected these concerns in setting the 2006/07 safety monitors through the inclusion of an adjustment to the NDM forecast at temperatures below 2 degrees Celsius. We have also analysed the potential impact of a systematic under-forecast in our sensitivity analysis.

9. We have received a positive response to our revised Daily Metered (DM) demand forecast, and in particular to the development of a 'restricted' forecast, which incorporates reduced demand levels given an assumption of high spot price levels and fuel-switching. Respondents are generally content that this provides an appropriate basis for analysing the demand of this sector in the coming winter. We have, however, also derived 'unrestricted' forecasts so that a like-for-like comparison can be made between our 2005 and 2006 forecasts.

10. 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[8]. 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.

Demand-side response

11. 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.

12. We received mixed views in response to our May document on the scope for additional levels of non-CCGT demand response in 2006/07, and we have received relatively little additional feedback on this point through the July consultation. Some respondents considered that increased market awareness and the development of new demand-side products could facilitate a greater level of response. One in particular noted an increase in the proportion of its portfolio that could respond to price. However, others were more cautious, noting that the ability to increase the level of response may be limited by timescales and the need for capital investment, and that some customers may seek to mitigate the impact of price volatility by locking in winter volumes at a fixed price (which will tend to reduce the level of demand-side response).

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

13. The potential for demand-side response from CCGTs is analysed in Chapter 3. This includes analysis of a number of sensitivities, showing the potential impact of variations away from the base case.

Transportation capacity

14. 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 responded, these 'trigger' levels for Network Sensitive Loads (NSLs) range from 77% to 98% of the relevant LDZ forecast firm peak day demand[9]. For non-NSLs, trigger levels range from 92% to 97%. This information is set out in Annex B. We have not received updated information from the DNs in response to our July consultation.

15. 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.

16. The rapidly changing profile of gas supplies in the UK will naturally lead to new patterns of gas flow on our transmission system. In our July document, we addressed the question of 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. We have included our analysis of this issue in Annex B. In summary, it confirms that there is sufficient network 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 constraints depending on how the market adjusted to this with a revised supply profile.

Gas supply

17. The following sections examine each of the potential (non-storage) gas supply sources in turn: UKCS; European imports from Belgium, the Netherlands and Norway respectively; and LNG. We set out the main factors associated with these supply sources and summarise the views of respondents to our consultation on their respective prospects.

---

[9] Trigger levels are from the 2005/06 winter.

UKCS gas supplies

18. 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.

19. In July, we published our revised UKCS supply forecast, following assimilation of the recently received 2006 TBE data. This showed a maximum UKCS production forecast of 267 mcm/d, which incorporated a year-on-year decline of 36 mcm/d from existing fields, offset by incremental developments totalling around 11 mcm/d. To this we applied a 90% availability factor, reflecting the average level of availability observed in the 2005/06 winter, giving an assumed average UKCS supply of 240 mcm/d.

20. Most respondents who commented on this issue thought that the forecast was reasonable, although one respondent took the view that the forecast was “slightly cautious” with potential upside if all new fields come on stream as planned. In addition, one respondent noted that a prolonged spell of severe weather conditions could potentially have a significant effect on the movement of people and equipment necessary to maintain beach reliability. In the sensitivity analysis later in this Chapter, we have therefore included a case in which the reliability of UKCS supplies is reduced over a one-month period.

21. Our UKCS supply forecast remains unchanged from that shown in the July document, as summarised in Table 1.

Table 1 – 2006/07 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2005/06		2006/07
	Forecast	Highest	Forecast
Bacton	83	78	75
Barrow	29	30	24
Easington	17	20	16
Point of Ayr	2	5	2
St Fergus[10]	110	98[11]	94
Teesside	28	34	30
Theddlethorpe	23	30	26
Total	**292[12]**	**295**	**267**

22. There remains scope for upside and downside against our UKCS supply forecast. For example:

[10] Excludes Vesterled
[11] Estimated, based on an assumed flow of 33mcm/d through Vesterled
[12] 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.

- 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, the outturn could be lower if reduced levels of reliability are experienced (as a result of severe weather conditions or otherwise);
- 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[13];
- Supply availability later in the winter could be lower given a greater than projected level of within-winter decline of existing fields.

Imported gas sources

23. As the UKCS declines, the UK is becoming increasingly reliant on gas delivered via new importation routes. Risks associated with the delivery of these projects, and the extent to which the new infrastructure will be used, have added to the overall level of uncertainty surrounding the supply outlook in the lead up to the 2006/07 winter.

24. Three major projects have been under construction this year with the objective of securing additional imported gas supplies from Europe for the forthcoming winter. Good progress has been reported by all of these projects, and the uncertainty associated with the physical construction of these projects has reduced as their respective milestones have been accomplished. However, some risk still remains, which is compounded by uncertainties associated with the use of these supply routes and interactions between them. The following sub-sections outline these developments and the associated issues, and summarise the relevant consultation responses.

<u>Belgian Interconnector</u>

25. The capacity of this Interconnector is presently undergoing further 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 commissioning originally planned by 1 December 2006. At the time of writing, Interconnector UK anticipate that work on the upgrade will be complete by the end of September 2006.

26. In our July document, we adopted a ‘split winter’ approach to assumed flow levels through this Interconnector. This reflected views received from a number of respondents to the May consultation, who 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.

27. All except one of the respondents to the July consultation who offered views in this area supported the base case assumption, i.e. average importation rates of 25 mcm/d in Q4 2006 and 40 mcm/d in Q1 2007 (equating to an average rate of around 35 mcm/d over the top 100 days in the winter). The

[13] Remedial work on the cooler units at South Morecambe, reported in our July document, is now complete

other respondent was less optimistic, suggesting that rates of 20 mcm/d and 30 mcm/d respectively would be more appropriate.

28. Given the balance of these responses, we have not changed the assumed base case levels of Belgian Interconnector gas flows. There are, however, a number of issues that could have a material effect on the level of imports ultimately observed through this supply route:

- The weather in Europe this winter will have a direct impact on gas demand, and will therefore be a key determinant of the volume of gas available for export to the UK. Clearly, there is a risk that a cold winter in the UK would coincide with a cold winter across Europe;
- Similarly, the availability of supplies into Europe will have a direct impact on the availability of gas through the Belgian Interconnector. The reliability of the key importation routes into Continental Europe is therefore key;
- There is also a potential interaction between the level of Norwegian imports into the UK (see below), and the level of imports through the Belgian Interconnector. For example, if additional Norwegian imports arrive in the UK through the diversion of supplies that would otherwise have been exported to Continental Europe, this could have a knock-on effect on the availability of gas at Zeebrugge.

BBL

29. A new Dutch Interconnector (BBL, short for ‘Balgzand Bacton Line’) is currently under construction by BBL Company[14]. 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).

30. 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 (NBP) to Centrica for ten years, with a winter:summer split of 5:3. This equates to roughly 27 mcm/d over the winter period.

31. The supply base case on which we consulted included an assumed flow of 20 mcm/d once the pipeline is operational. We have had a fairly limited response to this assumption. While some considered it to be reasonable, two respondents felt it was optimistic while one thought it was at the “lower end of expectations”. The more pessimistic respondents highlighted transportation constraints in the Netherlands, a reference to the limitation expected in 2006/07 only, which will require gas for BBL to be sourced from the Dutch Continental Shelf. It is not clear, however, whether this will limit BBL flows below the 20 mcm/d assumption, nor even below the average daily flow implied by the Centrica-Gasunie contract[15].

32. Our supply base case incorporated an assumed start date of January 2007 for BBL to reflect concerns, expressed to us by respondents to the May

[14] BBL Company is a joint venture between E-ON-Ruhrgas, Fluxys and Gasunie
[15] It appears unlikely, however, that gas flows as high as 42 mcm/d will be feasible until later in 2007

consultation, over the tightness of the construction timescales. Responses to the July consultation have generally agreed that this is a prudent approach. As we noted in that document, an assumed start date of 1 January 2007 is not to suggest that National Grid anticipates a delay to BBL, nor is this the view of BBL Company itself.

33. On the basis of this feedback, we have retained an assumed flow of 20 mcm/d from 1 January 2007 within the base case. 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.

34. There are clearly upside and downside risks against this base case assumption.

    - On the upside is the possibility that BBL meets its construction timescale and is operational in December 2006 and/or that gas flows closer to the initial limit of around 30 mcm/d;
    - Downside risks could arise through delay beyond 1 January 2007, or if transportation constraints in the Netherlands restricted flows below the assumed level of 20 mcm/d.

<u>Norwegian imports</u>

35. A new Norwegian pipeline known as Langeled has been laid from the Sleipner platform in the Norwegian North Sea to Easington.. With construction now complete, commissioning gas flows are expected soon and commercial operations are due to commence in October. The pipeline has a capacity of 25 bcm per year (74 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.

36. 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 have received mixed views on the prospects for Norwegian imports in the course of the consultation. Some believe that there is scope for a material increase in the level of gas from Norway. This would be through a combination of de-bottlenecking of the offshore system in Norway, incremental production from existing fields and gas swaps between Norwegian producers and other gas suppliers into Continental Europe. Conversely, others believe that any incremental production will be marginal, and that further flows to the UK could lead to reduced imports through the Belgian Interconnector.

37. On balance, the responses have confirmed that our base case assumption of 48 mcm/d for Norwegian imports in 2006/07 (an increase of around 15 mcm/d from 2005/06) is reasonable. We have therefore maintained this assumption within the base case. For the reasons highlighted above, there is clearly a good deal of uncertainty around this assumption.

Total European imports

38. The previous sub-sections have outlined the developments and issues associated with each of the gas importation routes from Europe. The construction of Langeled and the second Belgian Interconnector upgrade (completion planned by October) will increase the total (physical) import capacity from Europe by around 90 mcm/d to over 170 mcm/d. Once BBL is available (if all goes according to schedule, by December), the total physical 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.

39. A related issue on which we have consulted is gas quality. More specifically, we published in July details of our study into the potential for a blending service to be offered at Bacton. The key conclusion of this was that it is not feasible to provide a blending service at Bacton for the coming winter as this would necessitate very significant changes to the management, measurement and control systems at Bacton, which could not be put in place in time. A number of respondents to the consultation welcomed this initiative, noting that the significance of the issue would increase over the next few years.

40. The issue of gas quality has also been the subject of an Ofgem workshop which was held on 13 September 2006[16]. The workshop focused on the extent to which GB gas quality specifications are likely to act as a constraint for supplies to the GB market, potential solutions and how and where these might be provided, and how costs could be most appropriately targeted. As a next step, it is understood that Ofgem intend to convene a number of industry workstreams to consider these issues further.

LNG

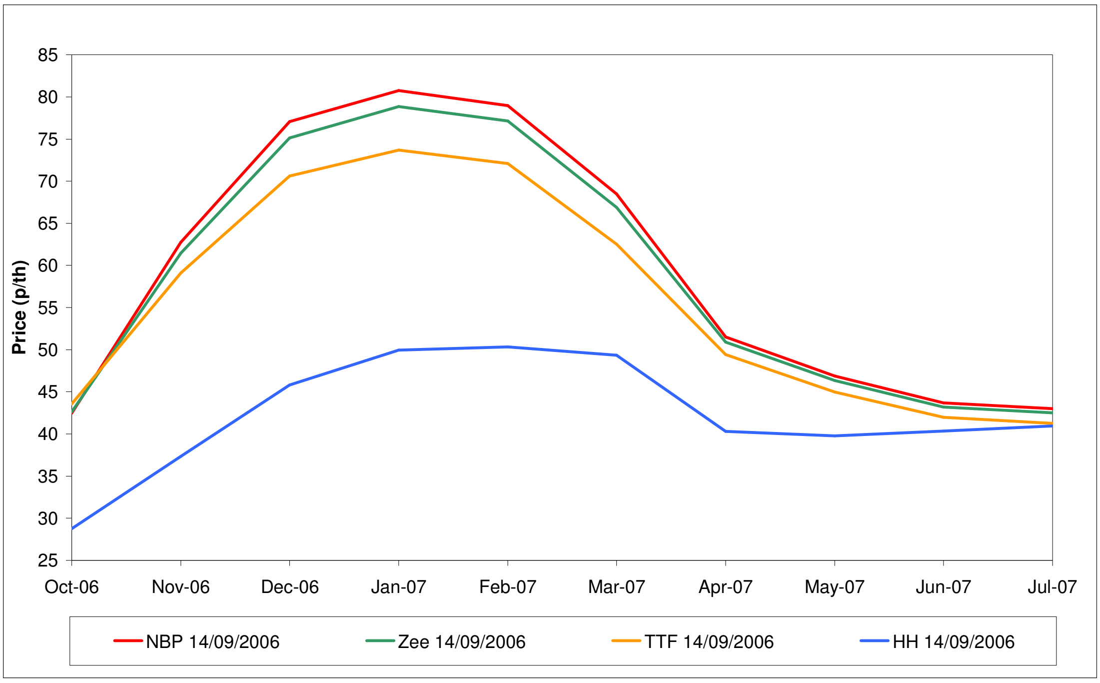
41. The Grain LNG terminal, commissioned in 2005, has a baseload contracted deliverability of 13 mcm/d and delivered a maximum flow last winter of 17 mcm/d. Daily flows greater than 13 mcm/d depend on the prevailing operational circumstances and agreement between Grain LNG and the relevant shippers. Use-It-Or-Lose-It (UIOLI) provisions for the use of unutilised 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 phase 1 primary capacity holder has recently enhanced the mechanism through which short-term firm secondary capacity can be obtained by third parties.

[16] Further detail on this workshop can be found at: http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/wholesalemarketmonitoring

42. 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.

43. 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[17]. (While the Asian markets are also significant in the context of the global LNG position, to date the US and Europe have provided competition for spot LNG cargoes that might come to the UK, while Asian countries have tended to compete between themselves for spot cargoes from other sources).

Figure 1 – Forward gas price comparison



44. Excelerate Energy have recently obtained planning permission for works associated with their project to deliver up to 11 mcm/d of LNG at Teesside using Excelerate's 'Energy Bridge' shipboard re-gasification technology. Their latest expectation is for first gas flows in early January 2007.

45. 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. We noted that there was some upside associated with this assumption given the proven maximum physical capability of Grain (around 17 mcm/d), and the possibility

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

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.

46. Most respondents have indicated that they believe an assumed level of 13 mcm/d to be reasonable. We have therefore retained that assumption for the purpose of this document. Some may consider it to be a slightly optimistic assessment of the average level of gas flow to expect from Grain. However, progress with Excelerate Energy's project, and the potential for Grain to flow at slightly higher levels than assumed, suggest that there is also a material level of potential upside against this assumption.

Storage

47. 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.

48. Storage injection recommenced at Rough in mid-July, following the outage on 16 February 2006. At the time of writing, Rough is 95% full, and Centrica Storage anticipate that all Rough capacity sold will be filled at or around the traditional end of the injection season (i.e. 31 October). Centrica Storage also expect full production rates will be available no later than 1 October.

Table 2 – Assumed 2006/07 storage capacities and deliverability levels[18]

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1897	526	49	3.6
Medium (MRS)	8111	345[19]	32	23.5
Long (Rough)	33805[20]	455	42	74.3

Base case

49. In the previous sections we have outlined the main points arising from our consultation process on the appropriate supply assumptions for winter 2006/07 analysis. We have also outlined the good progress that has been made by the various importation infrastructure projects since our July document. Recent reductions in the forward gas price for winter 2006/07 are evidence of more positive market sentiment, which may be linked to these developments. While the risk associated with infrastructure construction has reduced, there remains a significant level of uncertainty related to the utilisation rates that might be expected from the various importation facilities;

[18] Excludes Operating Margins gas
[19] Assumes average deliverability for Humbly Grove
[20] Reflects 24 August announcement from Centrica Storage regarding the release of an additional 585 GWh

a consequence of the complex interactions between the UK gas market and the European and LNG markets. This was recognised by consultation respondents. However, they broadly agreed that the supply base case presented in the July document provides a balanced view of the prospective supply position for the coming winter. As a result, we have not amended the base case for this report. This base case is summarised in Table 3.

50. This 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.

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

	2005/06 Base Case Assumption	2006/07 Base Case		
		Oct - Dec	Jan - Mar	Average
UKCS	269 (291 @ 92.5%)	240	240	240
Norway	33 (36 @ 92.5%)	48	48	48
IUK	42 (revised to 30)	25	40	35
BBL	N/A	0	20	14
LNG imports	13	13	13	13
Total	**357**	**326**	**361**	**350**

51. The following two sections provide analysis of the supply-demand position in 2006/07 assuming the supply base case and our latest demand forecasts. This analysis is in two forms: first, load duration curves for average[21], 1 in 10 cold and 1 in 50 cold weather conditions; and, second, monthly analysis of projected supply availability against a variety of demand conditions.

52. We have also identified in this Chapter a number of significant issues in relation to the various supply sources, and noted the resulting level of uncertainty over the supply position. While the base case provides a useful ‘best view’, in our opinion it is equally important to appreciate the potential for divergence away from this position, and the associated implications. Our analysis of the base case is therefore supplemented by a broadly-based scenario analysis (see ‘Scenario analysis’ below and Annex A), which illustrates the potential impact of variations in both the supply-demand background and the weather.

[21] The supply base case has not been adjusted to take account of the assumed winter severity. Some sources of supply may operate at lower levels in average or mild conditions.

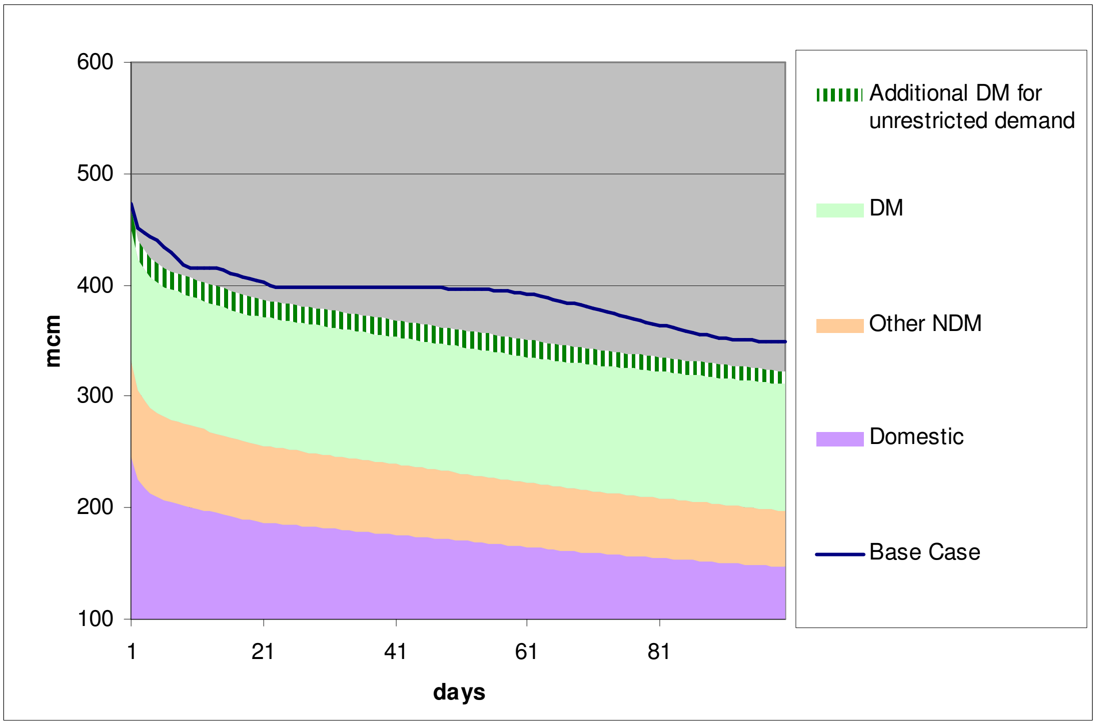
53. The level of supply-side uncertainty will reduce prior to and during the winter as the various importation infrastructure projects continue to develop and patterns of market behaviour are observed.

Analysis of base case

54. Figures 2, 3 and 4 show the base case assumptions overlaid on a load duration curve of average, 1 in 10 cold and 1 in 50 cold 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.

55. These load curves are provided in an Excel spreadsheet 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[22] [23].

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



[22] The irregular shape of the smoothed supply curve reflects limits on storage space.
[23] 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 3 – 1 in 10 cold load duration curve analysis for 2006/07

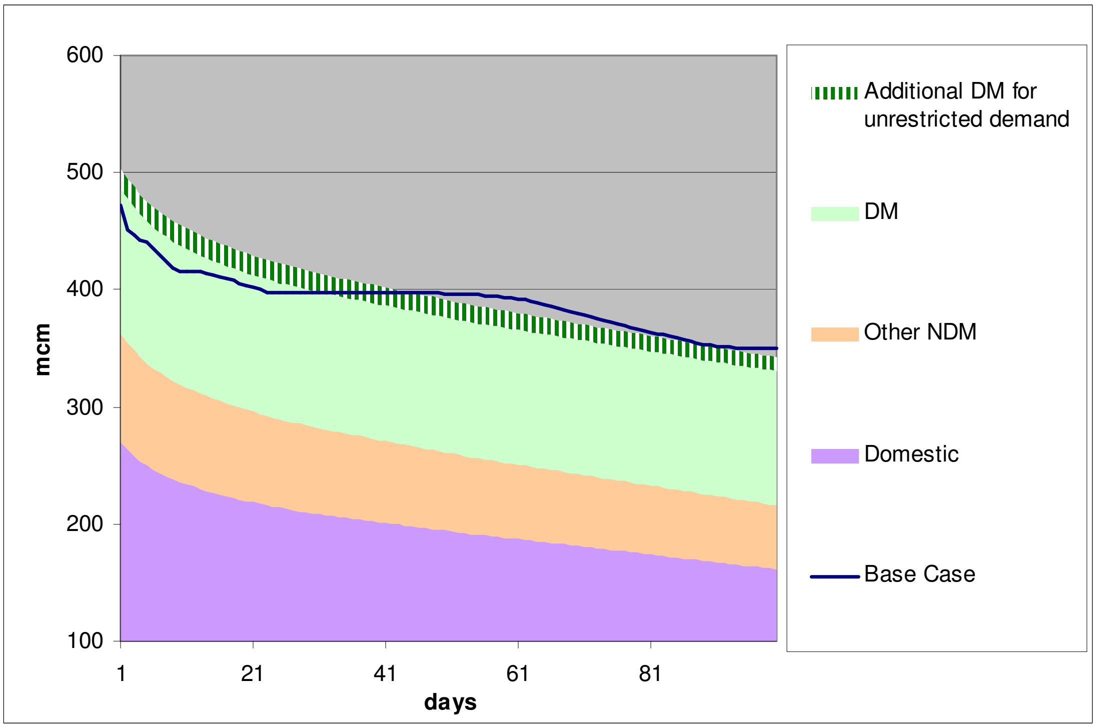
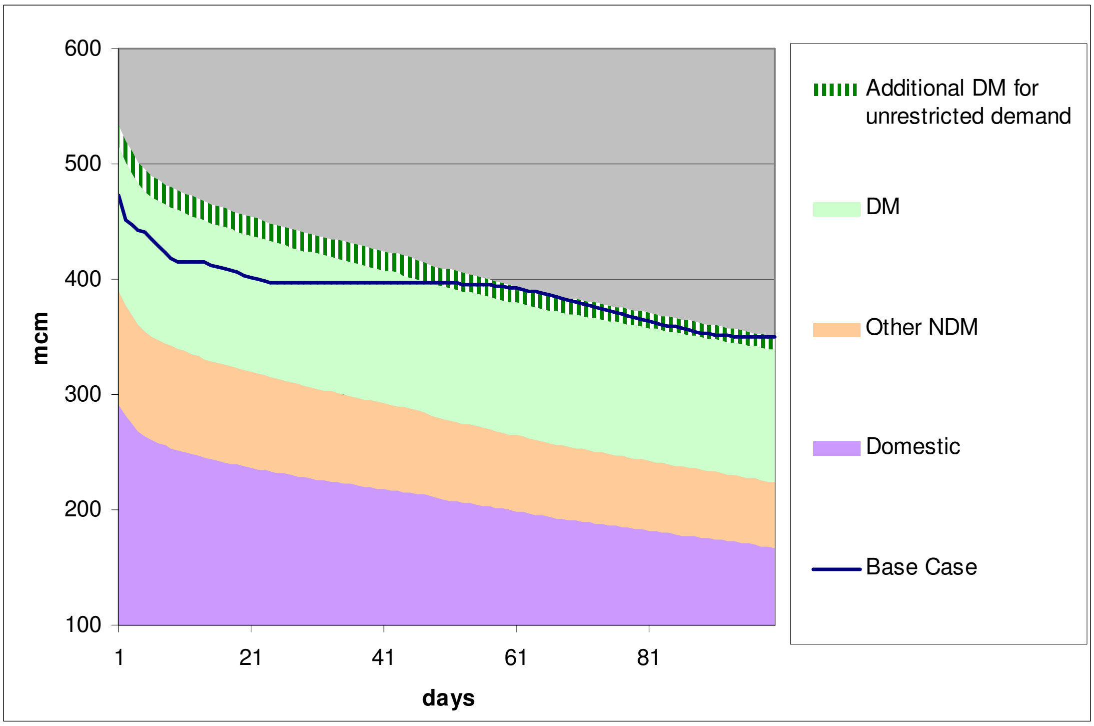


Figure 4 – 1 in 50 cold load duration curve analysis for 2006/07



56. The Met Office's latest analysis, published on the same day as this report, indicates an equal probability of a milder than average or colder than average winter, with a slightly higher probability than normal of an average winter. The

statement also notes a signal that the winter may become colder in relation to average temperatures as the season progresses. When measured against the Met Office definition, the 2005/06 winter was average[24]. This is one of the four winter weather patterns that we have examined in our winter scenario analysis in Annex A.

57. 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.

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

	Average	1 in 10 cold	1 in 50 cold
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

58. These results show that in a typical average or mild winter, little or no demand-side response would be required, even against an unrestricted demand background.

59. Our analysis of severe winter conditions indicates that in a 1 in 50 cold winter, there would be sufficient gas to maintain supplies to domestic and other non-daily metered customers. There would, however, be a requirement for a significant demand-side response from DM customers.

Monthly cold spell analysis

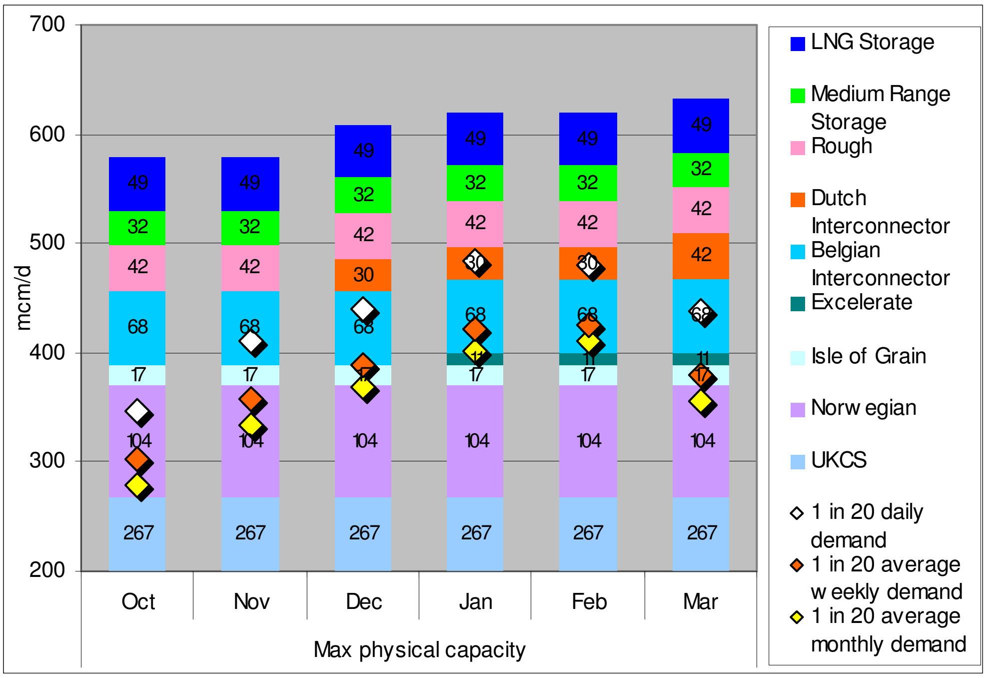
60. The analysis presented in the previous section focused on potential weather conditions across the entire winter. It is of course possible for the winter as a whole to be average (or otherwise unremarkable) but for it still to contain a short spell of very cold weather. This section therefore considers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

61. 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[25].

[24] For an explanation of the different definitions of weather severity used by the Met Office and by National Grid, see the information note at the end of Annex A
[25] Belgian Interconnector upgrade now included from October, and Excelerate from January

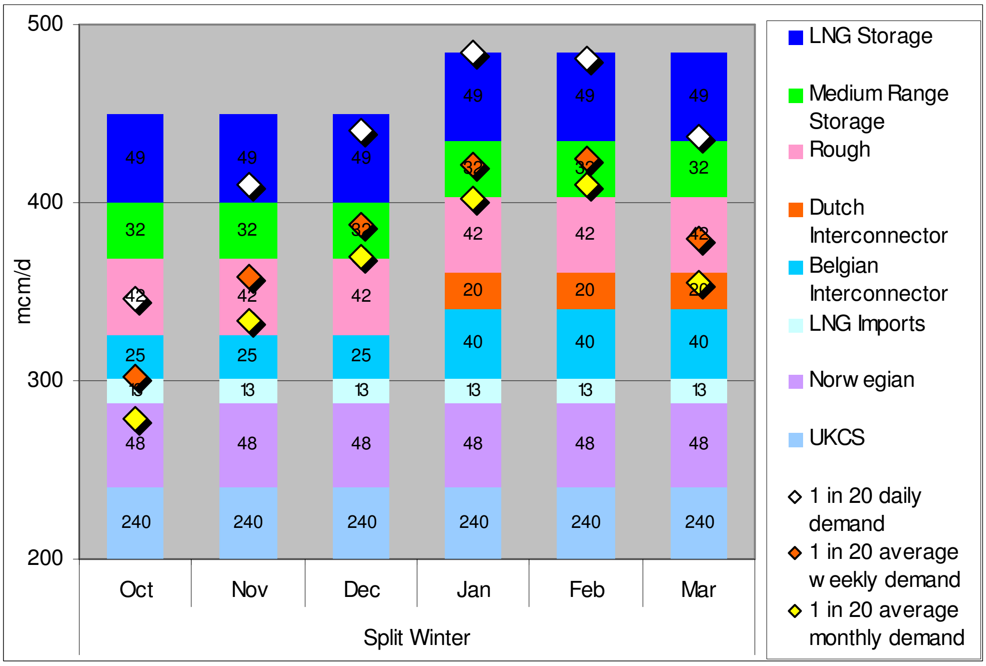
62. On each bar, three levels of restricted demand are shown, commensurate with a cold day in that month[26], a cold week in that month[27] and a cold month[28]. It should be noted that the forecast 1 in 20 peak day[29] is higher than any of the individual cold day demands shown in these graphs. This 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[30] is 499 mcm/d and the unrestricted forecast 1 in 20 peak day demand is 517 mcm/d.

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



[26] Demands based on fitting total demands to historical weather data and then calculating the 1 in 20 daily value in the relevant month
[27] 1 in 20 value of the seven day moving average demand for the relevant month
[28] 1 in 20 value of the average simulated demand across the relevant month
[29] 1 in 20 severity used as established industry planning standard for peak day analysis
[30] Total diversified demand for a 1 in 20 peak day

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



63. 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 provided in Annex D.

64. 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 space available this winter).

65. 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. This effect is illustrated in Annex A – see in particular analysis of 1995/96 winter weather conditions. The simulation of the base case clearly shows a significant use of all three storage types by the end of Q4 2006 (including over 40% of available LNG), much of which would not be required if supply availability in Q4 2006 matched that assumed in Q1 2007.

Scenario analysis

66. We have undertaken two types of additional analysis designed to allow the reader to assess the implications of alternative scenarios on the requirement for demand-side response.

67. The first identifies the impact on the demand-side response required of variations in the supply and demand assumptions. The results are shown in

Table 5, against restricted and unrestricted demand backgrounds. The range of sensitivities contained in Table 5 is wide, from a supply upside of 30 mcm/d across the winter to a supply downside of the same level. A number of these sensitivities reflect particular risks or opportunities that have been identified to us in the course of the consultation.

68. 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.

69. Given the material reduction in our forecast of NDM demand since that calculated in 2005, 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.

70. 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 cold	1 in 50 cold	Average	1 in 10 cold	1 in 50 cold
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 cold winter 5% in 1 in 50 cold winter	0.0	0.4	1.3	0.0	1.0	2.3
2% more NDM demand	0.0	0.6	1.7	0.0	1.4	3.0
UKCS availability 85% for one cold month	0.0	0.8	1.7	0.0	1.4	2.9

71. The second form of analysis involves simulating the supply and demand balance in the coming winter given a variety of real historical weather patterns.

72. We have analysed each winter since 1928/29 against the supply base case. Figures 7, 8, 9 summarise these by reference to the percentage of storage space used in each case (measured at the point at which storage stocks are lowest). As would be expected, the charts show a clear link between winter severity and simulated storage use. However, the modelling identifies the potential for a high proportion of LNG to be used even in average winters. For ease of reference, the initial safety monitor levels (as discussed below) are indicated on the charts by dotted lines.

Figure 7 – Long range storage used in historical winter simulations

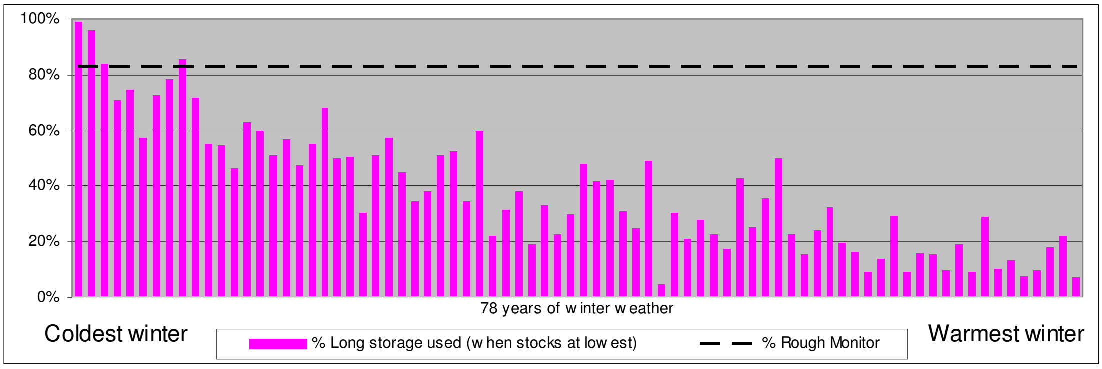


Figure 8 – Medium range storage used in historical winter simulations

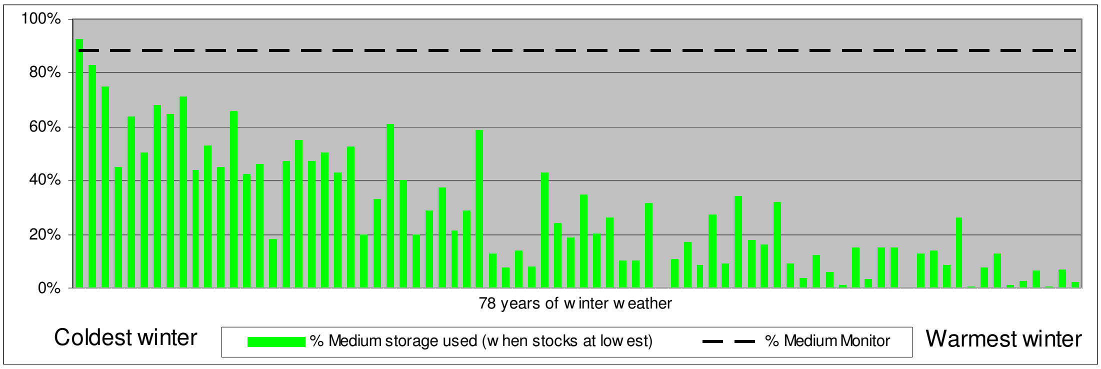
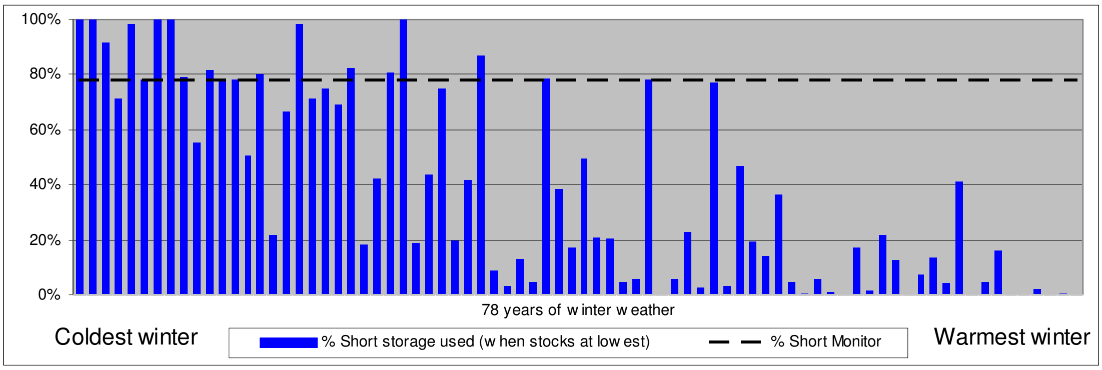


Figure 9 – Short range storage used in historical winter simulations



73. In addition, we have analysed four historical winters against six different supply scenarios. These simulations are shown in Annex A. Given the broad range of weather conditions examined in this analysis, it is to be expected that they produce a wide variety of results.

Safety monitors

74. In the July consultation, we published a range within which we believed that the start-of-winter safety monitors were likely to lie. As a result of the risks associated with the supply and demand backgrounds, this range was asymmetric around the base case. A number of respondents to the July consultation acknowledged the need for a prudent approach to the safety monitors, although some expressed concern over the limitations placed by the monitors on the use of storage.

75. On 4 September 2006, we published a note setting out our intended approach to the initial safety monitor levels for 2006/07, taking account of the winter consultation process and our latest assessment of the supply-demand position for the coming winter[31]. We explained our conclusion that a risk element should be built into the initial safety monitor levels given the material level of uncertainty associated with the supply and demand background. The calculation was therefore based on:

- a level of supply 15 mcm/d below the base case across the winter[32]; and
- our latest demand forecasts plus an additional 2% of domestic demand for the top 60 days of the 1 in 50 cold load duration curve.

76. The resulting monitor levels, which are all below the equivalent safety monitor levels in place from October 2005[33], are as follows:

[31] For the latest safety monitor information at any time please use the following link http://www.nationalgrid.com/uk/Gas/Data/storage
[32] This risk allowance was not ascribed to any particular supply source
[33] Initial safety monitor levels for 2005/06 were 23%, 13% and 26% respectively

Table 6 - Safety monitor space requirement

Storage type	Assumed storage capacity (GWh)	Space requirement (GWh)	Space requirement (%)
Long duration storage (Rough)	33805	5682	16.8%
Medium duration storage (MRS)	8111	969	11.9%
Short duration storage (LNG)	1758	383	21.8%
Total	**43674**	**7034**	**16.1%**

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

78. As we did last winter, we will keep the monitors under review (both ahead of and throughout the winter) and make adjustments if it is appropriate to do so on the basis of the information available to us. For example, if, as the winter progresses, the level of supply-side risk reduces (e.g. once all of the new infrastructure is operational), it may be possible to reduce the safety monitors at that time.

79. For further information on the calculation of the safety monitors see our safety monitor methodology document.

Chapter 2: Electricity

Electricity demand levels for 2006/07

80. Our latest Average Cold Spell (ACS) peak demand forecast for winter 2006/07 is 61.3 GW[34], which includes a 0.3 GW flow to Northern Ireland. This is unchanged from the forecast reported in our July document. Due to continued high energy prices no growth in demand has been assumed between winter 2005/06 and winter 2006/07.

81. Around 0.8-1.3 GW 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 our July 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 July document agreed that this assumed level of demand response is reasonable.

Notified generation availability

82. The current plant margin for winter 2006/07 reported in the August 2006 SYS Update[35] is around 22%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 76.8 GW[36]. This is an increase of 0.6 GW from May 2006 SYS Update, with Fawley increasing their contracted generation capacity by 0.5 GW.

83. 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.

84. Our latest operational view of generation capacity anticipated to be available for winter 2006/07 is 75.6 GW[37]. (A broad breakdown of this capacity is shown in Figure 10).

85. 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. The updated figure for generation that could return for winter 2006/07 is 0.8 GW.

---

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

[35] 2006 Great Britain Seven Year Statement Update (August 2006) http://www.nationalgrid.com/uk/Electricity/SYS/current/

[36] Including the UK-France Interconnector

[37] Position prior to closure of Dungeness A and Sizewell A on 31 December 2006 and including the UK-France Interconnector

86. We also reported in the July document that there is some long-term mothballed generation, all of which is unlikely to be available for winter 2006/07.

Figure 10 – Generation capacity, winter 2006/07

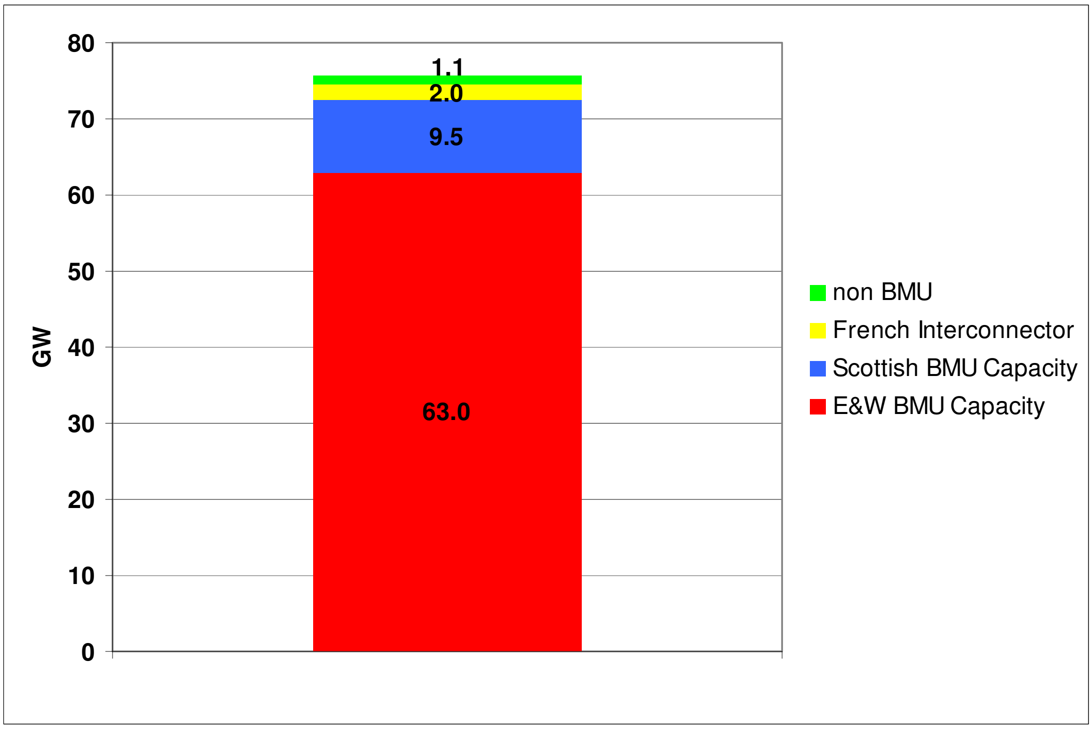


Table 7 – Mothballed capacity, winter 2006/07

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

Contracted reserve

87. 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 the 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.

88. National Grid issued a Supplemental Standing Reserve (SSR) Tender on 3 July 2006 for delivery in winter 2006/07. The deadline for tender submissions was 4 August 2006. Draft agreements based on the accepted tenders are currently being processed for final signature by 22 September. Service commencement is 2 October 2006. Further information can be found via the SSR Tender Statement Report due to be published on our website by the end of September.[38].

89. 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 this, 0.9 GW has already been contracted, 0.3 GW within the BM and 0.6 GW with non-BM providers[39].

90. 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

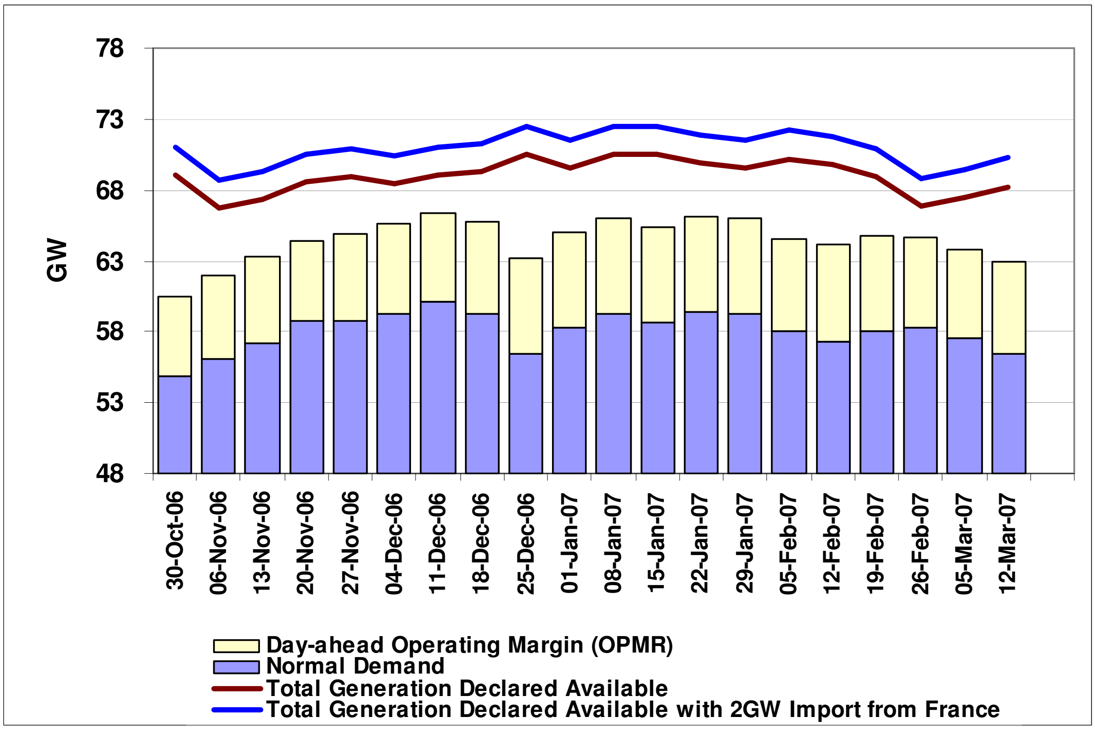
91. Figure 11 shows the normal demand forecasts and the generator availability declared to National Grid by generators under Grid Code Operating Code 2 (OC2), both including and excluding 2 GW of delivery from the UK-France Interconnector. This reflects planned unavailability but does not include an allowance for unplanned generator unavailability.

92. As can be seen in Figure 11, 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.

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

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

Figure 11 – Demand and notified generator availability, winter 2006/07



93. 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 12.

Scenario for modelling purposes

94. 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 cold weather conditions. The scenario is shown in Table 8.

Table 8 – Electricity availability scenario (GW)

	Assumption	
	Oct - Dec	Jan - Mar
Plant availability (GW)	73.6	72.7
Availability from France (GW)	2.0	2.0
Return of mothballed plant (GW)	0.8	0.8
Total availability (GW)	76.4	75.5
Average assumed availability (%)	87%	87%
Assumed availability (GW)	66.3	65.6

95. As agreed by most respondents to our May consultation document, we have assumed that all short-term mothballed plant would return prior to the

forthcoming winter but anticipate that no long-term mothballed plant would return.

96. For the purpose of this scenario, a typical historical 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.

97. In our July document, we asked specifically for views on our revised assumption for average availability from nuclear generating plant. Most respondents who expressed a view on this agreed that this revised assumption was reasonable, although one respondent felt that 80% was more realistic. We have decided to retain an assumption of 85% availability based on information received from nuclear generators and our historical analysis of nuclear generation for the past few winters. For the avoidance of doubt, our model has reflected the closure of Dungeness A and Sizewell A on 31 December 2006.

98. We have also reassessed our assumptions regarding nuclear generating plant in light of the corporate update provided by British Energy on 18 September, which referred to boiler tube issues at Hunterston B and Hinkley Point B[40]. We believe that our analysis remains consistent with the position outlined in that update. For analysis of the potential impact of a lower level of nuclear availability than assumed, see the sensitivity analysis in Chapter 3.

99. We have also retained our CCGT generation availability assumption of 90% based on historical analysis. CCGTs that we classed as "baseload gas" and "non-NTS gas" are of low merit order (i.e. used first/early) and historical data suggests that their availability has been over 90%. During peak times of the day, the availability of higher merit order CCGTs ("marginal gas") has been around 90% in past winters.

100. We have retained our assumption that flows on the French Interconnector would be 1500 MW (75% capability) off-peak, 1250 MW (62.5% capability) between 3pm and 7pm, and at float at other times. This reflects actual flows experienced in the past few winters, which respondents generally agreed was a reasonable basis for this assumption.

101. The implications of variations away from the key assumptions are explored in Chapter 3.

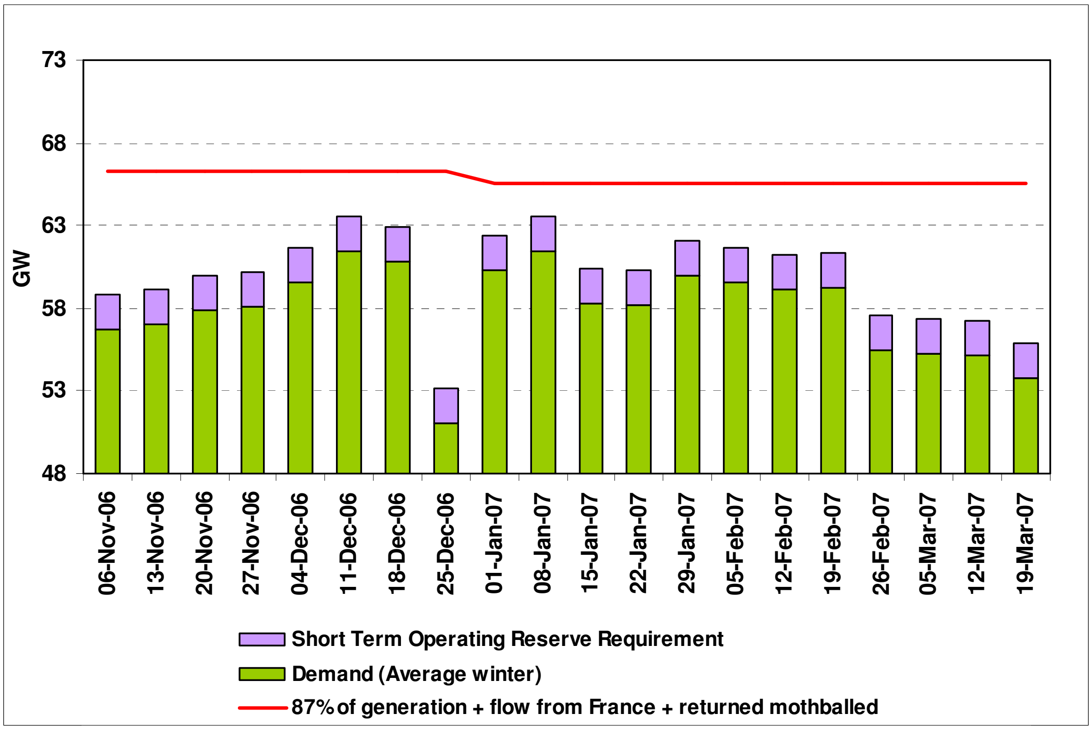
Average winter conditions

102. 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.

103. As illustrated in Figure 12, 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.

[40] Details may be found at http://british-energy.com/pagetemplate.php?pid=107

Figure 12 – Forecast demand under average weather conditions (2002/03 weather pattern) and generator availability, winter 2006/07

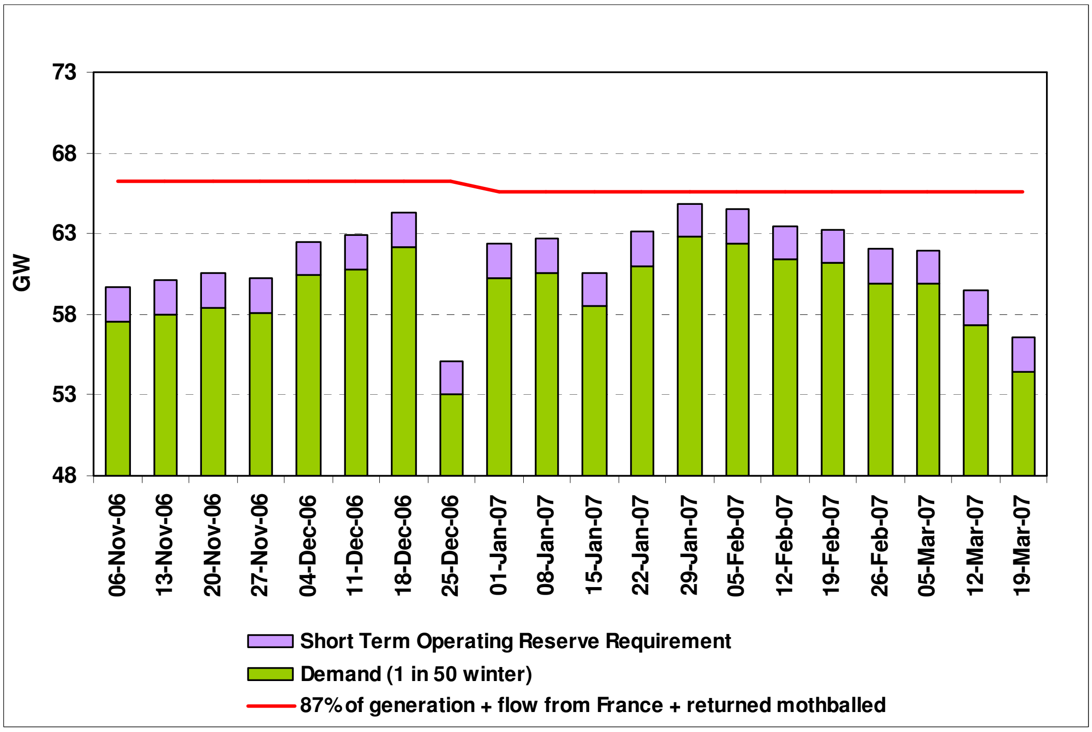


1 in 50 cold winter conditions

104. 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 cold winter, although we have no recent experience of how demand would respond to these extreme temperatures.

105. If these weather patterns were to occur this winter, as illustrated in Figure 13, 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 13 – Forecast demand under 1 in 50 cold weather conditions (1946/47 weather pattern) and generator availability, winter 2006/07



106. 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

107. 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.

108. 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.

109. 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.

110. 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 during the consultation process and by information from generators regarding distillate capability from CCGT power stations.

Power generation gas demand and distillate back-up

111. 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.

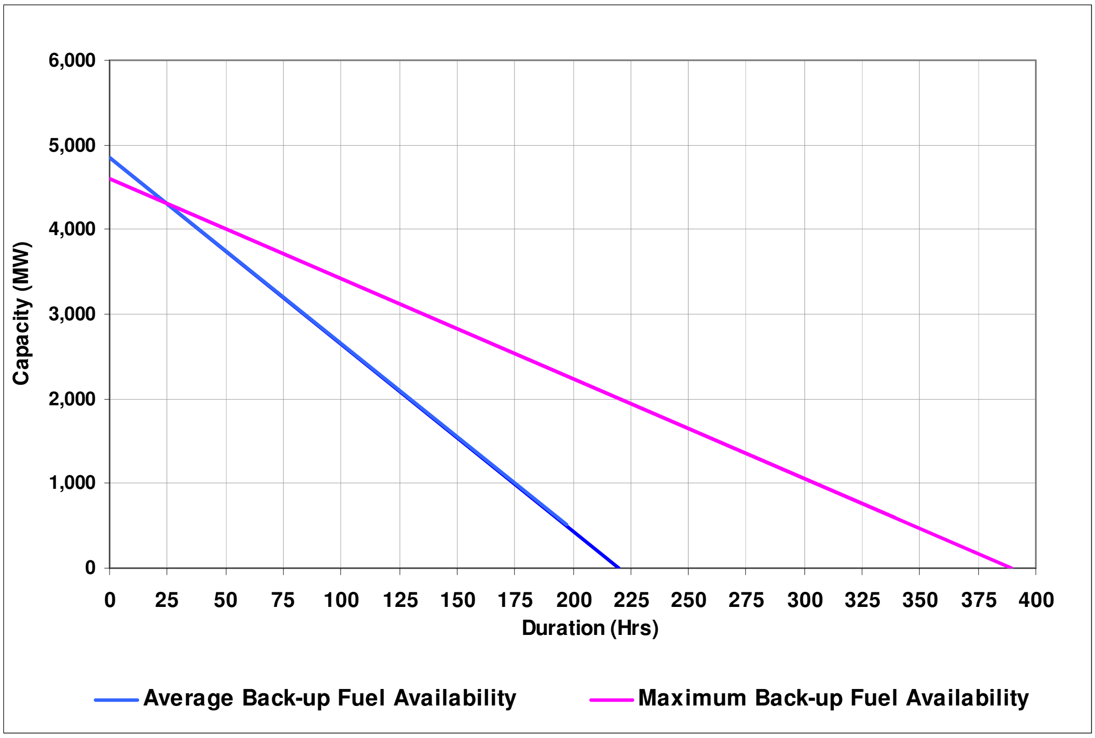
Table 9 – Maximum 2006/07 GB power generation demand

	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

112. 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, 3.3 GW have access to gas through non-NTS pipelines and 4.8 GW have the capability to run on distillate.

113. 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 14 summarises this information in load duration curve form, showing the decay of generation capacity available from distillate with time. The data, updated with new information from generators since the July document, 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 14 – Load duration curves for available generation capacity with back-up fuel capability (smoothed)[41]



[41] These are lines of best fit for irregular data, which is why they cross slightly to the right of zero

Analysis of potential CCGT demand response – modelling assumptions

114. 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;
    - Potential limitations on the ability to replenish stock in prolonged severe weather conditions, in particular if stocks are delivered by road tankers;
    - Possible impacts on behaviour of potential exposure to high imbalance costs if plant fails to generate.
115. However, there were generators who 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.
116. For winter 2005/06, we estimated that the level of distillate use was approximately 98 mcm (in avoided gas consumption). Our modelling assumptions from the Winter Outlook Report 2005/06 assumed that a maximum of 200 hours of distillate use was possible. We have received a number of responses to our questions on issues associated with distillate-switching. With this information, we have revised our modelling assumptions for generators with distillate capability. The total distillate capacity is 4.8 GW of which 4.2 GW is assumed to be commercially available (based on information received from the relevant generators). We have also grouped the stations with distillate capability into 4 groups, as shown in Table 10: Group 1 are stations which we assume would be running as baseload whilst Groups 2 – 4 have been split based on their hours of distillate running. Therefore, instead of assuming all 4.2 GW can run for 200 hours on distillate, we have, for example, modelled that Group 2 can run for nearly 300 hours whilst Group 4 can only run for 68 hours. The trigger for switching to distillate in the model is when gas demand for the day is forecast to exceed 4710 GWh (435 mcm), the level at which the supply case indicates that LNG would be required (from 1 January 2007).

Table 10 – Maximum hours of distillate running for generators with distillate capabilities

Distillate Groups	Hours of Running	GW
Group 1	290	0.6
Group 2	298	0.8
Group 3	225	1.7
Group 4	68	1.1

117. In winter 2005/06, we observed coal and nuclear running as baseload whilst gas was the marginal fuel. This remains our modelling assumption for winter 2006/07, as noted in our July update.

118. Responses to our consultation have broadly endorsed our assumptions. In the July document we noted a number of revisions to the assumptions, based on comments received to the May consultation. These 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[42] may be required in certain circumstances (as was the case in 2005/06).

119. The following is a summary of our latest modelling assumptions for winter 2006/07, some revised based on further analysis and responses to our July 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);
- 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. It should be noted that there is uncertainty over what the actual flows will be on the day as prompt electricity prices in individual markets will influence direction and magnitude of flow on the Interconnector;
- CCGT as marginal fuel with availability of 90%;
- 3.3 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as baseload. We recognise that non-NTS CCGTs may not always operate as baseload, and that therefore this assumption may not be entirely accurate. However, this is not material from the perspective of the model results since if these stations are not generating we would assume additional gas flows into the NTS and additional CCGT generation elsewhere (which would have little or no net effect);
- Around 3.7 GW of NTS-supplied CCGTs run as baseload (of which 0.6 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 revised figure is based on the inclusion of an additional CCGT within this category following further analysis of the historical operation of these CCGTs;
- 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%;

[42] This would be the responsibility of the Environment Agency or the Scottish Environment Protection Agency. The Environment Agency have indicated that they are not proposing to issue any derogations for winter 2006/07.

- 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 11, consistent with an average availability rate of 87%.

Table 11 – Assumed plant availability factors for demand-side response analysis

Power Station Type	*Assumed Availability*		*Model Assumptions Summary*
	GW[43]	**%**	
Nuclear: Oct – Dec Jan – Mar	 10.1 9.3	85%	Baseload
French Interconnector: Off-Peak 3pm – 7pm Other periods	2.0	100%	 1500MW (75%) 1250MW (62.5%) At float
Non-BM Generation (including renewables)	1.4	40%	Baseload
Coal	23.7	85%	Baseload
Oil	3.8	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%	

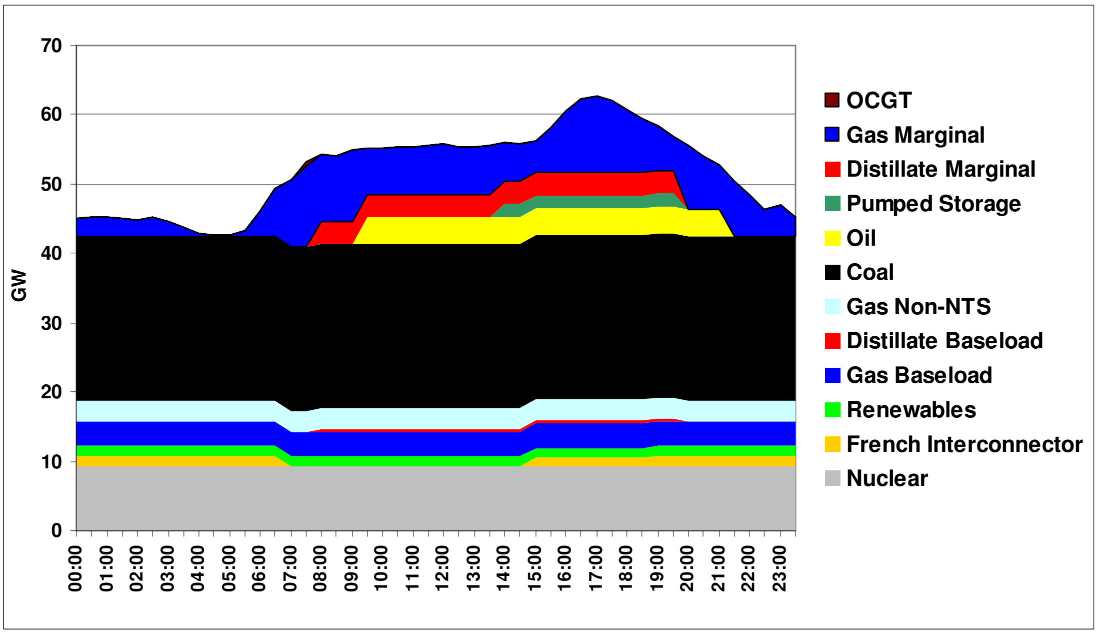
Analysis of potential CCGT demand response – simulation results

120. Figure 15 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. Total modelled distillate usage across the winter has been constrained to the hours shown in Table 11.

121. The changes in the electricity background and the modelling assumptions (outlined in Chapter 2 and this Chapter respectively) have resulted in small differences between the modelling results presented below and the equivalent results contained in our July document.

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

Figure 15 – Potential generation profile – cold winter weekday



122. The simulation results have been calculated for average, 1 in 10 cold and 1 in 50 cold weather conditions. This analysis has been undertaken against both the restricted and unrestricted gas demand backgrounds. The difference between these backgrounds is that some demand-side response is already assumed within the restricted background, consistent with behaviour observed in the 2005/06 winter when CCGTs typically consumed around 70 mcm/d until mid-November and around 50 mcm/d for the rest of the winter.

123. Tables 12 and 13 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 12 – Potential CCGT demand response (bcm), restricted gas demand background

	Average	1 in 10 cold	1 in 50 cold
Required	0.0	0.4	1.3
Potential CCGT	0.0	0.2	0.3
Non-CCGT	0.0	0.2	1.0

Table 13 – Potential CCGT demand response (bcm), unrestricted gas demand background

	Average	1 in 10 cold	1 in 50 cold
Required	0.0	1.0	2.4
Potential CCGT	0.0	0.8	1.2
Non-CCGT	0.0	0.2	1.2

124. As Table 12 illustrates, our modelling suggests that relatively little additional CCGT response (0.3 bcm) would be available in a 1 in 50 cold 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.

125. We have also analysed a number of sensitivities to examine the impact of variations to our key modelling assumptions. This analysis is summarised in Tables 14 and 15. Under both the restricted and unrestricted gas demand backgrounds and against all the sensitivities analysed there is no demand response required in average weather conditions, therefore this table focuses on results for 1 in 10 cold and 1 in 50 cold weather conditions. Of particular note are the sensitivities associated with the availability of coal, gas and oil generation:

- If coal availability is modelled at 80% (rather than the assumed level of 85%), CCGTs are found to contribute no additional demand-side response above the level implicit within the restricted demand forecast. In this scenario, which is equivalent to the loss of around 1 GW of baseload (non-CCGT) generation across the winter, there may be times when CCGT gas demand is above the level assumed within the restricted forecast in order to meet electricity demand;
- If CCGT availability is modelled at 85% (rather than the assumed level of 90%), this makes no discernible difference to the simulated level of CCGT demand response. This is to be expected since gas is generally modelled as the marginal source of generation;
- If oil generation is modelled to be available for 24 hours (when required) on weekdays (rather than the assumed duration of 12 hours), the level of simulated CCGT response rises by around 0.3 bcm. In practice, this level of oil-fired generation may be infeasible, particular for sustained periods, as a result of the various environmental limits in place at these stations. However, this analysis highlights the potential for oil-running to facilitate CCGT response on specific days of particularly high gas demand.

Table 14 – CCGT demand response – sensitivity analysis, restricted gas demand background

Case	1 in 10 cold		1 in 50 cold	
	Requirement (bcm)	Potential CCGT Response (bcm)	Requirement (bcm)	Potential CCGT Response (bcm)
Base case	0.4	0.2	1.3	0.3
Nuclear 80% availability	0.4	0.1	1.3	0.2
CCGT 85% availability	0.4	0.2	1.3	0.3
Coal 80% availability	0.4	0.0	1.3	0.0
Oil 24 hours	0.4	0.3	1.3	0.6
No distillate	0.4	0.1	1.3	0.1
Distillate unlimited stocks	0.4	0.2	1.3	0.4
+ 20 mcm/d supply	0.0	0.0	0.5	0.2
- 20 mcm/d supply	1.2	0.3	2.8	0.8
+ 2% NDM demand every day	0.6	0.2	1.6	0.4

Table 15 – CCGT demand response – sensitivity analysis, unrestricted gas demand background

Case	1 in 10 cold		1 in 50 cold	
	Requirement (bcm)	Potential CCGT Response (bcm)	Requirement (bcm)	Potential CCGT Response (bcm)
Base case	1.0	0.8	2.4	1.2
Nuclear 80% availability	1.0	0.7	2.4	1.1
CCGT 85% availability	1.0	0.8	2.4	1.2
Coal 80% availability	1.0	0.6	2.4	0.9
Oil 24 hours	1.0	0.9	2.4	1.5
No distillate	1.0	0.7	2.4	1.0
Distillate unlimited stocks	1.0	0.8	2.4	1.3
+ 20 mcm/d supply	0.3	0.3	1.2	0.8
- 20 mcm/d supply	2.7	1.8	4.5	2.4
+ 2% NDM demand every day	1.3	0.9	2.9	1.5

Chapter 4: Industry Framework Developments

126. 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 Safety Reserve Review

127. Between January and April 2006, Ofgem chaired a Gas Safety Reserve Working Group, which considered 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”). Various options were debated, which included:

- Status quo – no major changes to the current regime.
- New 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.
- Change to the SO objective function to include Security of Supply – to preserve gas storage stocks.

128. 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

129. The Gas Safety Reserve Working Group has now completed its work in relation to the coming winter period. At the meeting of the Gas Safety 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 a Modification Proposal (UNC Modification Proposal 0086: Introduction of Gas Demand Management Reserve Arrangements) being raised by Gaz de France. The Proposal aimed to require 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.

130. Along with a number of industry parties, National Grid did not support this Proposal. We considered that its intent was unclear and were concerned that it would have undermined the clarity of responsibility that exists at present for supply and demand management. Furthermore we did not believe that the proposer had demonstrated that the modification would lead to increased quantities of demand response being made available. Ofgem rejected the proposal in July 2006.

<u>'Below the line' arrangements</u>

131. 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 considered 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 were considered including:

- Status Quo – maintenance of the current position;
- 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.

The Gas Safety Reserve Working Group concluded that there was no compelling case to change the current safety monitor regime for the coming winter. However, Ofgem has stated that it will continue to consider potential revisions to the gas reserve arrangements for winter 2007/08.

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

132. 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.

Demand Side Working Group discussions

<u>The provision of further information relating to available supplies and forecast demand</u>

133. The DSWG discussions assessed the benefits of providing earlier information regarding both available supplies and anticipated demand. The group 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.

134. Forecast demand data is currently made available by National Grid at (or before) 14.00 on a D-1 (i.e. the day before Gas Day 'D') basis under the

provisions of the UNC. The DSWG considered that benefits may be achieved if National Grid were able to improve the accuracy of its demand forecasting. In addition, the group also considered that the availability of information on National Grid's website on a more timely basis would create benefits for customers by enabling them to build up a more accurate understanding of system conditions. In response to these discussions, Ofgem initiated a consultation regarding the potential implementation of new SO incentives relating to demand forecasting accuracy as well as the availability and timely updating of data on National Grid's website, for implementation ahead of the winter.

135. Following this consultation, the Authority issued a direction on 4 September which had the effect of amending National Grid's licence and introducing two new incentives on National Grid relating to these areas. The incentives will be effective from 1 October 2006 and will therefore be in place for this winter. However, the incentives are designed specifically to achieve benefits for customers this winter and will therefore be reviewed by the Authority before the end of March 2007.

136. National Grid welcomes the development of these incentives in response to the particular circumstances of the 2006/07 winter and we have instigated work to improve performance in these areas. This includes a UNC modification proposal (0100) to enable earlier provision of information to National Grid from operators proposing to offtake gas. This proposal if implemented is anticipated to lead to improvements in the 'before the day' 14:00 hours demand forecast.

137. 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.

Uniform Network Code (UNC)

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

138. In July 2006 the Authority directed the implementation of UNC Modification Proposal 0082 "Clarificatory changes to UNC Section Q – Emergencies". This proposal, which National Grid 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.

Modification Proposal 0098 / 98a - Modification to Codify Emergency Curtailment Quantity (ECQ) Methodology

139. Both Proposal 0098 (raised by EON) and its alternative 0098a (raised by National Grid) seek to place the Emergency Curtailment Quantity (ECQ)

methodology, used by all Transporters to calculate the energy reduction associated with curtailment of offtake flows instructed during an emergency, within the text of the UNC. Proposal 0098 goes further than this by amending the current methodology to include, as one of the applicable steps, assessment based upon shipper nomination in place at the time of emergency curtailment. Both of these proposals are currently with Ofgem for direction.

Modification Proposal 101 - Amendment to Demand Forecasting Timings in Relation to the Gas Balancing Alert

140. The primary objective of this proposal is to allow National Grid NTS increased opportunities, at the day-ahead stage, to issue a Gas Balancing Alert where appropriate. At present, there are only two such opportunities each day. This Proposal will allow a GBA to be issued following each demand notification and/or any ad-hoc forecast that National Grid NTS notifies to shippers. In addition this Proposal will also ensure that operational practices are consistent with the UNC by adding references to additional demand forecasts at 18:00 D-1 and 02:00 on D. It is important to note that these new UNC demand forecasting times reflect current practices. The Proposal does not amend the GBA methodology and therefore does not increase or decrease the likelihood of a GBA being issued but will ensure that the industry can be informed of the GBA without unnecessary delay. By increasing the information available to industry parties National Grid considers that this will enable a timely response to secure sufficient demand-side response in order to match supplies. This proposal is currently with Ofgem for direction.

Information provision initiatives

141. In May 2006 the Authority 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 is currently working to provide the information technology infrastructure necessary to publish the information called for in the Proposal. This facility will be available from 3 October 2006.

Balancing and Settlement Code (BSC)

Incentives to balance - P194 and P199

142. 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.

143. In P194 we proposed that the cash-out price formula should be based on the top 100 MWh of Bid/Offer Acceptances that resolve the Net Imbalance Volume (NIV - Market Imbalance), instead of the volume weighted average formula that is currently 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. Further modifications in this area (P201/202 and 205) were subsequently raised by the industry. Ofgem rejected P201/202 on 7

September 2006. An Ofgem decision on P205 is expected before 2 November 2006.

144. 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 has recently been rejected by the Authority, but there is an industry consensus that this issue needs to be considered further. Ofgem will be considering cash out issues further over the coming months, and we will seek to make an active contribution, with a view to ensuring that if an appropriate modification is agreed upon, it can be progressed in time for winter 2007/08.

Connection and Use of System Code (CUSC)

<u>Access to the transmission system – CAP094, CAP097</u>

145. 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.

146. CAP097 proposed that a Distribution Network Operator (DNO) 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, as have related Grid Code changes relating to the treatment of Licence Exempt Embedded Medium Power Stations.

Grid Code

<u>Market information – H/05</u>

147. 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.

148. 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.