National Grid Transco

A Consultation on Winter 2005/06

Introduction

1. The competitive energy market in the UK has developed substantially in recent years and has successfully established separate roles and responsibilities. In summary, the provision of energy to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. The structure and performance of the markets is the responsibility of Ofgem. National Grid Transco (NGT) has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated energy transportation requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity.

2. In recent years, NGT has sought to provide information to the participants in the gas and electricity markets in the UK by publishing an outlook for the winter ahead. This document represents a development of this process, recognising that our sources of data are necessarily incomplete. Therefore this year, instead of offering a forecast for the winter, we have decided to conduct a consultation exercise on a range of issues to help inform the industry about the likely impact of the commercial arrangements between market participants and their implications for security of supply.

3. To assist this consultation exercise, we provide observations on the 2004/05 winter and two supply scenarios for the coming winter. We analyse each scenario against a range of weather conditions, in particular against average temperatures and “severe” cold temperatures. The severe case corresponds to a 1 in 50 winter. While a winter this severe has not been experienced since 1962/63, we also discuss the implications of a 1 in 10 winter, most recently experienced in 1985/86. In addition, we consider a repeat of last year's weather. NGT is not suggesting that either supply scenario is more probable, but uses these as a basis for discussion and comment by others. However, the scenarios should assist industry participants in developing their own view of the forthcoming winter and establish appropriate arrangements. In addition to the scenarios we are also providing a range of sensitivities to enable the industry to extrapolate the potential circumstances that might develop given variations to the input conditions.

4. The bases of our scenarios reflect, in part, a variety of information provided to NGT from the gas and electricity industries and DTI. These include, for example, beach gas availability, developments in the interruptible gas market, power station availability, and the ability of some CCGTs to run on alternative fuel. However, the UK is increasingly dependent upon gas imports. Existing and planned infrastructure will link the UK much more directly with European and global energy markets, which are themselves becoming more interrelated and complex. The security of supply will
therefore significantly depend upon the commercial arrangements relating to the importation of energy and demand side response.

5. As with all scenario modelling the inputs and results are subject to wide interpretation. We are therefore seeking views and feedback from industry participants on all the most important contributing factors to security of energy supplies and anticipate being able to offer a range of possible projections in the final document. In particular we are seeking views on:

**Beach supplies**

1. The preliminary assessment of maximum beach supply availability for 2005/06
2. The average percentage beach availability that could be expected under a period of prolonged severe conditions in 2005/06, taking account of beach reliability and other factors

**Imports and storage**

3. The extent to which importation and storage infrastructure is likely to be utilised under a period of prolonged severe conditions in 2005/06 and in particular:
   a. The extent to which shippers have contracted for gas supplies to import into the UK
   b. The extent to which shippers have access to the necessary European transportation infrastructure to support gas imports through the Interconnector
   c. The potential and likelihood for European suppliers to nominate gas export flows on the Interconnector, thereby reducing the net import rate, even at times of high demand in the UK
   d. The assumptions that can be made for LNG importation quantities
   e. The level and direction of flow of the electricity interconnector that might be expected given cold weather in both UK and Europe

**Non-CCGT demand-side response**

4. The extent to which the market is able to provide the levels of demand-side response that our load duration curve and cold spell analysis indicates may be required under severe winter conditions, and in particular:
   a. The extent to which gas demand side arrangements are already in place (whether through interruptible contracts or otherwise)
   b. What scope exists for such arrangements to be put in place prior to or during the course of the winter
   c. The extent of the electricity demand response that may be expected in response to high electricity prices, and in particular whether this could be materially greater than previously experienced

**Safety monitors**

5. The appropriate basis for setting the 2005/06 safety monitors
Generation and CCGT demand-side response

6. The extent to which it might be expected that mothballed generation will become available, and when

7. The ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests may be theoretically achievable in a severe winter. In particular:
   a. Our assumptions relating to the generation running order under very cold weather conditions
   b. The extent to which the electricity market prices will be able to achieve levels compared to gas prices such that they will determine that CCGTs will continue to burn gas at peak electricity demand periods
   c. The ability and willingness of CCGT generators to switch to distillate
   d. Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks
   e. The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation
   f. The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints, carbon emissions and fuel stocks

6. We would appreciate responses to our questions as soon as possible but not later than 15 July 2005. Please note that it is intended to include a summary of responses on a non-attributed basis in the report to follow later this autumn.

7. Responses should be sent to:
   Richard Adcock
   Director of Operational Strategy
   National Grid Transco
   NGT House
   Warwick Technology Park
   Gallows Hill
   Warwick
   CV34 6DA

8. The data used in this report remains subject to revision and NGT will continue to discuss its observations with Ofgem, the DTI and other industry participants.

9. NGT remains committed to supporting the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply/demand balances. We anticipate that this consultation will assist participants in ensuring they have the appropriate commercial arrangements in place for the coming winter.
10. The consultation document is presented in four sections with the introduction and summary preceding the main body of the report. Section A contains a review of the winter 2004/5 outturn. Section B presents an overview of this coming winter. In Section C we consider electricity/gas interaction. Section D summarises the development of the commercial frameworks in both markets.

11. Electricity System Operation under BETTA commenced on 1 April 2005, and therefore all 2005/06 data is presented on a Great Britain base.

12. NGT operates the electricity transmission network under the National Grid Company Electricity Transmission licence and the gas transmission network under the Transco Gas Transporter licence. For the purpose of this report “NGT” is used to cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licences.

13. This consultation document has been prepared by NGT for, and in consultation with, Ofgem in good faith. NGT has endeavoured, as a reasonable and prudent operator, to prepare this consultation document in a manner which is, as far as possible, objective, using information collected and compiled by NGT from users of the gas transportation and electricity transmission systems together with NGT’s own forecasts of the future development of the gas transportation and electricity transmission systems. NGT considers that, to the extent that the information contained in this consultation document is derived from members of the NGT group of companies (the “Group”), the contents of this consultation document are true at the time of publication to the best of its knowledge and belief as a reasonable and prudent operator. While NGT has not sought to mislead Ofgem or any other party as to the contents of this consultation document, industry participants should rely on their own information when determining their respective commercial positions.

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Summary
Weather Review
14. The 2004/05 winter was generally mild and overall the 6th warmest over the last 77 years.

15. The England and Wales mean temperature of 7.20 °C was slightly warmer (0.4°C) than 2003/04.

Winter Review 2004/05 - Gas
16. The highest daily gas demand last winter was 4597 GWh (419 mcm) on 24 February 2005, which represents 78% of the forecast undiversified 1 in 20 peak day of 5905 GWh (538 mcm). This was 5.6% lower than the 2003/04 highest daily gas demand of 4,840 GWh (444 mcm), and 7% lower than the record demand of 450 mcm on 7 Jan 2003.

17. NGT was notified of gas interruption by shippers on 69 days during the winter, most significantly during late February and early March. Although volumes were relatively modest, this represents a 4-fold increase on the level of interruption experienced during 2003/04.

18. The highest beach delivery during the winter was 331 mcm/d. Our hindsight view would suggest that UKCS decline was greater than previously anticipated. On this basis, we have reduced our assessment of maximum beach availability in 2004/05 by 13 mcm/d to 351 mcm/d.

19. As reported last year the trend of increasing incidents of offshore supply problems has continued. On average, 53 unplanned supply reductions per month occurred last winter against 49 in the winter of 2003/04.

20. At times high depletion rates of storage were experienced, especially from late February onwards. Re-injection to storage was limited throughout the winter.

21. During the latter part of the winter, on-the-day gas prices peaked at 1.70 £/therm. This price was broadly matched on the Continent, resulting in reduced Interconnector imports.

22. The behaviour of interconnector imports during the late cold spell in March demonstrated that the level and direction of flow is heavily influenced by the differential in spot gas prices between the UK and Europe, and the commercial arrangements between European market participants.

23. Analysis of total CCGT generation output indicates a total of around 0.15 bcm of gas demand-side response was observed from the power market during the period covering 20 February 2005 to 4 March 2005. This occurred as CCGTs reduced their gas consumption at times of low electricity demand. The maximum daily response was approximately 20 mcm, 5% of national daily gas demand.
24. The highest electricity demand last winter was 54.1 GW for the half-hour ending 17:30 on Monday 13 December 2004. This compares to the highest demand of 53.5 GW for 2003/04.

25. Around 0.8-1.3 GW of demand management occurred at the peak as large customers reduced demand to avoid Transmission Use of System Charges.

26. The return from mothball of 0.7 GW of generation in November 2004 resulted in a headline capacity margin of 22%.

27. The issuing of Notice of Insufficient Margin (NISM) was at a typical rate - 5 NISMs were issued on-the-day, and 2 early NISMs on a Friday for the forthcoming Monday were published. No High Risk Demand Reduction (HRDR) was issued.

28. At the end of February there was clear evidence that the direction and level of flow on the interconnector to France was heavily influenced by the differential in electricity prices between the UK and Europe. There was evidence of increasing interaction between the UK and European markets, leading to increased volatility. This has confirmed our view that it may be inappropriate to assume full imports to UK for planning purposes.

29. Peak electricity prices reached 100 £/MWh coincident with high prices being seen across Europe. The flow from France was significantly reduced in the response to high European electricity prices. Interconnector imports to England and Wales from France and Scotland were below the full capacity of 4.2 GW, tending to be around 3.1 GW over the peak time of the day.

30. The supply and demand balance for the UK will increasingly depend upon a wide range of variables as more gas is imported from Europe, LNG importation commences, the contractual arrangements between suppliers and consumers develop, and projections of offshore production capability and reliability evolve. This combination of variables and the confidential nature of the commercial arrangements between suppliers and consumers preclude NGT making a central forecast for the winter. We are therefore providing two scenarios and a set of sensitivities, which provide a basis for discussion and comment by others. NGT is not suggesting that either scenario is more probable, however the scenarios should assist industry participants in developing their own view of the forthcoming winter and establishing appropriate arrangements.

31. Based on the UKCS decline experienced during 2004/05, our preliminary view for 2005/06 is that the maximum potential daily gas delivery at the beach will be around 336 mcm/day (28 mcm/d lower than our original projection for 2004/05). We will review this further on the basis of 2005 TBE data and industry feedback that we receive.

32. There is significant uncertainty over the level at which beach supplies could be maintained under severe conditions. The two supply scenarios are based on 95% and 90% of our maximum forecast respectively. This range is broadly consistent with the
analysis presented in this document and reflects the views expressed by a number of offshore operators. It is also consistent with a study recently undertaken for the DTI, which suggested that offshore supplies could be expected to have a reliability of around 90%. However, it is clearly possible that the ‘correct’ view lies outside this range.

33. We have also had to make assumptions in our scenarios about the level of imports through the Belgian Interconnector and through the Grain LNG terminal. Given the size and complexity of the broader markets behind these importation routes, it is not possible to determine what circumstances may or not develop. Our scenarios reflect two conditions: first, where the UK enjoys full import capability for the winter period, and secondly 100% of existing and 75% of the new importation capacity coming on line in 2005/06 is used throughout the winter. For comparison, during last winter the Interconnector imported at an average of 79% of full capacity over the 30 days of highest demand.

34. For this winter therefore, our preliminary analysis indicates that the UK will have a lower beach gas availability coupled with a demand growth of around 10 mcm/d at peak, but the potential benefit of some new sources of gas. Overall, our net preliminary assessments under Scenario 1 and Scenario 2 suggest that gas availability at peak for the forthcoming winter would be 12 and 39 mcm/d lower than for 2004/5 winter respectively (as presented in our 2004 Winter Outlook Report).

35. Our scenario analysis shows that over the winter period, even in cold weather, there will be sufficient gas to maintain supplies to domestic and other non-daily metered customers. Furthermore, in average weather conditions, only modest demand response may be required from the daily-metered sector.

36. However, significant demand response will be required if colder than average weather is experienced or gas deliveries are below our scenario levels. For example in severe weather, where national temperatures average around −2 °C over a month and +2 °C over a further 2 months (statistically a 1:50 winter), the required demand-side response could increase to 2.5 bcm under Scenario 1 and 5.2 bcm under Scenario 2.

37. We have also analysed cold spells, which could occur in an otherwise unremarkable winter. For a 1 in 20 peak day, with average temperatures across the country around -5 °C, a demand response of nearly 60 mcm/d would be required for Scenario 1 and around 90 mcm/d for Scenario 2. For a very cold week or a very cold month, the levels of daily demand response required for the two scenarios are similar to the peak day requirement, but this response would be required over these longer periods as storage stocks deplete.

38. NGT has interruption rights, which it can use to mitigate network capacity constraints. However, in severe weather it is anticipated that the prevailing supply/demand balance will normally create market reaction before network constraints become a limiting factor. This was evidenced last winter where Shipper interruption was generally initiated ahead of any network constraint needs. In developing their gas supply portfolios, shippers and suppliers should not assume that NGT will necessarily initiate interruption in the event of cold weather.

39. The DTI and Ofgem have recently published a study to review the extent to which the energy intensive industries (excluding power generation) would respond to high
prices and reduce demand. This suggests that a valuable contribution of around 10 mcm/d to the required response might be anticipated on an individual day given sufficiently high prices\(^1\). The study did not extend to analysis of whether such a response would be sustainable over a longer period. Assuming it could be sustained for two months over the winter, this would equate to a total response of around 0.6 bcm. This excludes the potential for further response from the power sector, which is described later, or other elements of the industrial and commercial sector.

40. The Uniform Network Code requires us to publish 2005/06 storage safety monitors in May 2005. Given the significant uncertainty associated with the key input assumptions, we believe that it is most appropriate to publish initial monitor levels based on the more conservative of the two scenarios, i.e. Scenario 2. This leads to initial levels of 18% for long range storage, 13% for medium range storage, and 54% for short range storage. These should be considered indicative only at this stage. These will be reconsidered in the light of feedback on this consultation document, and kept under review prior to and throughout the winter period. The monitor levels may be modified in either direction.

**Winter Scenarios 2005/06 – Electricity (Great Britain base)**

41. The winter peak demand forecast for the coming winter is 62.0 GW. The 1 in 20 peak demand forecast is 65 GW. This demand figure relates to GB demand only and does not include any interconnector flows to France or Northern Ireland.

42. The headline generation margin for Great Britain for next winter is currently around 22%, assuming full 2 GW import from France. However, the direction and level of flow on the interconnector is heavily influenced by the differential in electricity prices between the UK and Europe.

43. Of the 3.8 GW of generation currently mothballed, we understand that 2.2 GW can return within 6 months. This would provide a margin of 25%. We have been told that the remaining 1.6GW cannot physically be returned to service for this winter.

44. In combination with the scenarios we have given for gas supply we have therefore modeled two sets of conditions for electricity supply. Scenario 1 assumes that the electricity Interconnector provides 1 GW over every darkness peak and 1.2 GW of mothballed plant returns. In Scenario 2 we assume the electricity market responds to lower gas availability, with 2.2 GW of currently mothballed plant returning to service, and the full 2GW of imports is experienced throughout the winter over the darkness peaks.

45. The extent to which mothballed plant returns, and the flows on the Interconnector, will both be determined by the market. However, last winter 0.7GW of mothballed plant was returned to service immediately before last winter, and the Interconnector provided an average of 1.3GW. This is equivalent to 68% of the interconnector nameplate capacity averaging over the four hour peak demand period for the top 30 demand days.

\(^1\) This includes a direct gas response and an indirect response through reduced electricity demand resulting in lower CCGT gas demand.
46. In both scenarios, the projected level of generation availability would be sufficient to meet demands expected under average cold spell (ACS) conditions.

47. In severe winter conditions where average temperatures across the country were $-2^\circ$C for 30 days, and $+2^\circ$C for 60 days, the projected level of generation would also be sufficient to meet demands provided that we do not experience high levels of plant breakdowns, and that sufficient non-power generation gas demand response is provided by industry such that adequate CCGT generation remains available.

48. In the final outlook report for last winter NGT reflected detailed analyses of the level of demand response that might be provided by CCGTs responding to high gas prices, whilst still providing sufficient generation to meet the darkness peaks. This concluded that in very favourable conditions around 1.6 bcm might be possible.

49. NGT will re-analyse this over the summer period in relation to our two scenarios. However, to provide an initial guide, we have estimated that a response of up to 3 bcm might be achievable in a severe winter under Scenario 2 provided that the market sought to minimise CCGT gas demand throughout the winter. Specifically, this would require extensive switching from gas-fired generation to coal, those CCGTs capable of running on distillate doing so for 4 hours and 5 days a week all winter, oil generation operating for an average of 8 hours a day for 5 days a week, the full 2 GW imports from France for 4 hours over the darkness peak and overnight, and a return of 2.2 GW of mothballed plant particularly including 1 GW of non-gas-fuelled generation. For this to happen, market participants would need to make significant preparations prior to the winter.

50. Voltage reduction applied over 4 hours of the weekday darkness peaks for 30 days may deliver an additional 0.1 bcm of gas demand relief. This voltage reduction should not be discernible to domestic consumers.

Winter Outlook 2005/06 – overview of gas and electricity

51. In average weather under both scenarios there would be sufficient gas and electricity to meet demand, provided a modest gas demand response occurred if beach inputs and/or importation rates were low.

52. Under both scenarios and all weather conditions there would be sufficient energy to maintain supplies to domestic and smaller industrial and commercial consumers.

53. In colder than average conditions substantial gas demand response will be needed from the larger industrial users to maintain a balance of supply and demand.

54. In extremely severe weather (30 days averaging $-2^\circ$ C and 60 days averaging $+2^\circ$ C), with beach production averaging 90% reliability, existing import capacity at 100% utilisation, new import and storage capability at 75% capacity, a gas demand response of 5.2 bcm would be necessary.

55. For comparison, the weather experienced in 1985/86 was 1 in 11 cold. The response necessary this winter, were we to experience 1 in 10 conditions, would be approximately 3.7 bcm.
Winter Outlook 2005/06 – Transmission Networks

56. The Transco and National Grid networks have the physical capacity to meet the published transportation requirements of cold winters, due to:

- High network availability.
- Outage programme due to be completed.
- High availability of gas compressor stations.
- The benefit of continued high levels of investment in our networks.
Section A - Experience of 2004/05 – Weather

57. The 2004/05 winter was again generally mild, and slightly warmer than last year. Overall it was the 6th warmest over the last 77 years. The England and Wales mean temperature was 7.2 °C, this was 0.4 °C warmer than 2003/04.

58. October was a very wet month with mean temperatures generally close to average. November however was a very dry month with some areas only recording around a third of the average November rainfall. Mean temperatures were around 1°C to 2°C above average. December was generally dry for the first two weeks then more unsettled during the second half of the month. It became colder for a while, with some snow in the last week, but milder for the closing days. January continued mostly unsettled but was exceptionally mild and the warmest since 1990. February was mild to start with and then winter really took hold after the 18th as the wind turned to a north or easterly direction, which brought snow to many places. March mean temperatures were well above average, despite a rather cold and wintry start to the month.

59. Table 1 shows the variances from normal for the key weather variables, excluding wind speed, which drive electricity and gas demand for the period December to February. This is based on a 30-year long-term average from 180 observing sites in the UK. This shows that the averages were above normal and, based on Met Office data covering December to February, temperatures were in the upper quartile of historic data for the last 40 years. Sunshine levels for the same period were 119% of normal and, in addition, November to March rainfall levels were the lowest since the same period in 1975/76. The Met Office historic average winter temperatures are shown in Figure 1, below.

Table 1 - Winter 2004/05 Temperatures (December to February)

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<td>1.3</td>
<td>188.3</td>
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Figure 1 – Average Winter Temperatures, 1962-2005

Summary

- The 2004/05 winter was generally mild and overall the 6th warmest over the last 77 years
- The England and Wales mean temperature of 7.2 °C was slightly warmer (0.4 °C) warmer than 2003/04

2 Although it may not appear so on this chart, taking the winter as a whole 1985/86 was the coldest winter since 1962/3 as measured by us for the purpose of gas demand simulation.
Section A – Experience of 2004/05 – Gas

Gas Demand

60. The highest daily gas demand during the winter was 4597 GWh (419 mcm) on 24 February 2005, which represents 78% of the forecast undiversified 1 in 20 peak day of 5905 GWh (538 mcm). This was 5.6% lower than the 2003/04 highest daily gas demand of 4,840 GWh (444 mcm), and 7% lower than the record demand of 450 mcm on 7 January 2003.

Shipper Interruption

61. Under the terms of bilaterally negotiated commercial contracts, gas shippers have the right to commercially interrupt the gas supply to some of their customers. On 69 days last winter, shippers notified NGT of interruption, as detailed in Figure 2. Interruption was high during the later part of February and the beginning of March 2005 with a sustained peaked in the middle of this period.

Figure 2 - Shipper Interruption, Winter 2004/05

62. Overall NGT was notified of 3800 GWh (351 mcm) of shipper interruption over winter 2004/05, a 419% increase on that notified during 2003/04, as detailed in Figure 3. The vast majority (88%) of interruption was to CCGTs over recent winters, with non-power station winter interruption amounting to 500 GWh (46mcm) during 2004/05.
63. As detailed in Figure 4, the maximum daily volume of CCGT shipper interruption was between 60 and 90 GWh (5–8 mcm) over the past 3 years, whilst the maximum daily non-CCGT interruption was 15–30 GWh (1–3 mcm) over the last 2 years. This non-CCGT interruption represents less than 1% of daily peak demand.
NGT Interruption

64. A total of 192 GWh (18 mcm) of NTS demand, approximately 7% of shipper interruption, was interrupted between 7 and 11 October 2004 to resolve capacity constraint on the NTS, caused by third party damage to one of our pipelines. A total of 53 GWh (5 mcm) of LDZ demand was also interrupted for capacity management reasons.

Gas Supply

65. The highest daily gas supply occurred on 24 February 2005 at 4560 GWh (414 mcm)\(^3\). This was supplied from 318 mcm through the gas reception terminals, 76 mcm of storage and 20 mcm through the Interconnector (IUK).

66. Beach supplies reached a maximum of 331 mcm on 5th March 2005, 7 mcm lower than the maximum beach supply of 338 mcm in 2003/04. As detailed in Table 2, the aggregate of the maximum flows from each terminal was 354 mcm for 2004/05.

\(^3\) This can be different from the highest daily gas demand, the difference being accounted for by linepack.
Table 2 - Maximum Terminal Gas Supplies, mcm/d

<table>
<thead>
<tr>
<th>ASEP</th>
<th>04/05 Forecast</th>
<th>Max Demand Day 24/2/05</th>
<th>Max Beach Day 5/3/05</th>
<th>Max Actuals</th>
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<td>37</td>
<td>1-Dec</td>
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<td>Theddlethorpe</td>
<td>31</td>
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<td>23</td>
<td>24</td>
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<td><strong>Total</strong></td>
<td><strong>364</strong></td>
<td><strong>318</strong></td>
<td><strong>331</strong></td>
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<tr>
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<td>42</td>
<td>44</td>
<td>29</td>
<td>45</td>
<td>25-Feb</td>
</tr>
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</table>

67. In the October 2004 outlook report for winter 2004/05, NGT forecast that the maximum beach capability would be 364 mcm/day. We have reassessed this in the light of the winter experience and now believe that a maximum beach forecast of 351 mcm/d would have been a more appropriate reflection of underlying production capability.

68. In the 2004/05 winter, we have continued to observe an increase in the number of reported supply reductions. On average, 53 unplanned supply reductions per month occurred last winter against 49 in the winter of 2003/04.

69. As illustrated in Figure 5, beach supplies during 2004/05 tended to be below 2003/04 beach levels. However, unlike the change in the previous year, where the reduction in beach supplies was offset by an increase in Interconnector imports, this did not occur in winter 2004/05, although there were prolonged periods in which the Interconnector imported above its nameplate capacity. The highest demand was some 20 mcm lower than 2003/04 and hence in the absence of particularly high demands, it is hard to gauge the extent to which further beach gas would have been available if required. Figure 6 shows the combined beach and Interconnector supplies were on average lower in 2004/05 than for 2003/04 under the same demand conditions.

70. During the latter part of the winter, on-the-day gas prices peaked at 1.70 £/therm, this price being driven by Continental suppliers sourcing from the UK, resulting in lower Interconnector imports.
Use of Storage

71. The use of storage followed a similar pattern to winter 2003/04, with increased withdrawal from January onwards, and only limited volumes of re-injection.

72. As illustrated in Figure 7, from January 2005 gas was withdrawn from Rough continuously, and following the pattern of 2003/04 there was little re-injection. Rough started the winter with high levels of stored gas and it was not until mid February that the storage levels reached the level experienced during the corresponding period during 2003/04.
73. As illustrated in Figure 8, from January 2005 gas was withdrawn from Mid Range Storage (MRS) regularly, and following the pattern of 2003/04 there was limited re-injection. MRS started the winter with similar levels of stored gas in 2003/04, and overall had a similar pattern to withdrawal as in winter 2003/04.

74. As illustrated in Figure 9, from January 2005 gas was withdrawn regularly from Short Range Storage (SRS). SRS started the winter with lower levels of stored gas in 2003/04, and overall had a similar pattern to withdrawal as in winter 2003/04.
2003/04 due to the commissioning of import facilities at Isle of Grain, and by early March had less gas in storage than at the same point in 2003/04.

**Figure 9 – Short Range Storage Levels over winter 2004/05**

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**Gas Prices**

75. Generally the day-ahead price was between 20 p/therm and 35 p/therm, over the period October 2004-March 2005, except for the significant spikes on 20 December 2004 and across the period 21 February 2005 to 9 March 2005 as illustrated in Figure 10. For 4 March 2005 day-ahead prices peaked at 116 p/therm, coincident with gas supply concerns both in the UK and the Continent.
76. Figure 11 illustrates the extent to which increases in beach delivery were not observed as prices exceeded 50p/therm.

77. The highest beach delivery of the winter was 331 mcm occurring on Saturday 5 March 2005 when the day-ahead price was 61 p/therm. Before late February, gas prices tended to be below 50 p/therm, but beach delivery reached over 320 mcm/d. During late February and early March, prices rose to over 1 £/therm, reflecting (inter alia) European supply concerns, but little additional beach gas was delivered.

78. During the winter, on-the-day gas prices peaked at 1.70 £/therm on 3 March 2005, but as previously discussed, due to high European gas prices, the Interconnector flowed at a significantly reduced rate into the UK.
Gas - Power and European Interactions

79. The UK electricity market reacted to the gas supply concerns during late February and early March 2005, with gas-fired stations responding to high day-ahead and on-the-day gas prices by reducing gas demand. However, the electricity market was operating with tight margins during this period and hence most of the reduction in gas demand occurred through power stations generating on back-up fuels or substituting generation with coal-fired generation during lower electricity demand periods, where at times there was little premium from burning gas to generate electricity.

80. The UK gas price continues to be heavily influenced by the availability of beach supplies, storage levels and IUK flows. The ability of the UK power market to reduce demand continues to be dependent upon the ability to switch over to distillate and other fuels such as coal.

81. In addition to the interaction between the electricity and gas sectors, there were occasions last winter when the importation rates of both Continental interconnectors (gas and electricity) were restricted, reflecting market conditions in Europe. For example, cold weather and tightening generation margins across Western Europe drove European electricity prices up, at the same time as Continental gas prices were driven high due to high gas demand and supply concerns. As previously discussed IUK flows into the UK declined as the high prices in the UK were broadly matched on the Continent.

82. Though firm gas demand continued to be met across Continental Europe, resilience of European and UK energy markets to a prolonged cold spell remains unproven. The liquidity of the NBP market proved to be a source of gas for continental buyers at times of high continental demand; hence European market conditions, as reflected in European gas prices, may dictate patterns of flow on the Interconnector regardless of the UK gas price.
83. These are large and complex markets and it is not possible to determine what circumstances may or may not develop in future. In times of cold weather, it is clearly possible that UK prices will encourage gas and electricity to the UK. There must also be circumstances in which import rates would be restricted. For example, it is predictable that cold UK temperatures are often associated with cold fronts travelling through Europe.

Summary

- The highest daily gas demand last winter was 4597 GWh (419 mcm) on 24 February 2005, which represents 78% of the forecast undiversified 1 in 20 peak day of 5905 GWh (538 mcm). This was 5.6% lower than the 2003/04 highest daily gas demand of 4,840 GWh (444 mcm) and 7% lower than the record demand of 450 mcm on 7 January 2003.
- NGT was notified of gas interruption by shippers on 69 days during the winter, most significantly during late February and early March. Although volumes were relatively modest, this represents a 4-fold increase on the level of interruption experienced during 2003/04.
- The highest beach delivery during the winter was 331 mcm/d. Our hindsight view would suggest that UKCS decline was greater than previously anticipated. On this basis, we have reduced our assessment of maximum beach availability in 2004/05 by 13 mcm/d to 351 mcm/d.
- As reported last year, the trend of increasing incidents of offshore supply problems has continued.
- At times, high depletion rates of storage were experienced, especially from late February onwards. Re-injection to storage was limited throughout the winter.
- During the latter part of the winter, on the day gas prices peaked at 1.70 £/therm. This price was broadly matched on the Continent, resulting in lower Interconnector imports.
- The behaviour of interconnector imports during the late cold spell in March demonstrated that the level and direction of flow is heavily influenced by the differential in gas prices between the UK and Europe.
- A total response of 0.15 bcm was observed from the power market as CCGTs reduced their gas consumption during late February and early March 2005, at times of low electricity demand and relatively benign electricity prices. The maximum daily response was 20 mcm, around 5% of national demand.
Section A – Experience of 2004/05 – Electricity

Electricity Demand

84. The highest electricity demand over the winter reached 54.1 GW for the half-hour ending 17:30 on Monday 13 December 2004. This compares to the highest demand of 53.5 GW over winter 2003/04.

85. Figure 12 details the highest daily demand and temperature at 17:00.

**Figure 12 – Daily Temperature and Demand, Winter 2004/05 excluding Christmas**

86. This winter was mild on the whole and the highest weekday demands have been on average 500 MW less than the seasonal normal. However, once the mild weather has been reflected, the underlying year-on-year growth in demand was about 0.6 GW during winter 2004/05.

87. Towards the end of February and into the first week in March, temperatures were 4°C to 5°C colder than seasonal average. The actual metered highest demands in these weeks were 52.1 GW and 52.7 GW. NGT estimates that there was around 0.8-1.3 GW of demand management at the peak as large customers reduced demand to avoid Transmission Use of System Charges.

88. Figure 13 shows the highest winter actual demand and outturn demand corrected to ACS conditions.
Electricity Generation

89. On a Transmission Entry Capacity (TEC)\textsuperscript{4} basis, 67.7 GW of plant was available for winter 2004/05, giving a plant margin of 22%, higher than the 20% projected in October 2004 reflecting the return of mothballed plant and the lower than forecast outturn demand, corrected to ACS conditions. The NGT estimate of actual generation capacity operationally available for the winter was 66.4 GW, up from 65.6 GW projected in October, again reflecting 0.7 GW of mothballed plant returning to service in November 2004. Of this 0.7 GW, 0.6 GW was contracted by NGT via the Supplementary Standing Reserve tender to provide a reserve service between November 2004 and March 2005.

90. Figure 14 compares the generation availability declared to NGT in different timescales. The red line is the generation available as shown in the October 2004 Winter Outlook Report, which assumed full interconnector capacities of 4.2 GW but excluded 3.6 GW of then-mothballed plant. The orange line shows the generation available as declared to NGT on a weekly basis under Grid Code OC2, also assuming full interconnector capacities of 4.2 GW. The orange line reflects the return of mothballed plant and the short-term unavailability of plant across the winter. The bars show the total on-the-day availability and the interconnector imports, and the demand and Short-Term Operating Reserve Requirement (STORR) at the time of peak demand.

\textsuperscript{4} As explained further in the Glossary, under the terms of the Connection and Use of System Code, generators are required to purchase Transmission Entry Capacity (TEC) for the generation they export onto NGT’s system.
Figure 14 - Plant Availability and demand

91. Figure 14 shows that there was adequate generation plant available in real time to meet the level of peak demands and STORR. Generator outages, planned and unplanned, were around 5 – 6 GW. Further generation plant might have become available if demands had been higher.

92. The issuing of Notice of Insufficient Margin (NISM) was at a typical rate - 5 NISMs were issued on-the-day, and 2 early NISMs on a Friday for the forthcoming Monday were published. No High Risk Demand Reduction (HRDR) was issued.

93. Across the winter the interconnections with Scotland and France were importing to England and Wales at the time of peak demand each day. The average interconnector import at the time of peak demands was around 3.1 GW. The France interconnector flows varied across the day, on occasions exporting to France in the morning before reversing direction to flow to England and Wales for the evening peak. A typical interconnector profile is shown below in Figure 15, along with examples of a high swing profile, a high import profile and a low level of export across the demand peak.

94. Figure 15 describes how the flow at times of highest demand varied across the year, and details how flows from Europe responded to high continental electricity prices in late February and early March 2005.
Figure 15 - French Interconnector Flows

![Typical Business Day French Interconnector Flow](image)

- Average French Interconnector Flow
- Export over Peak (07/03)
- High Import (23/02)
- High Swing (25/11)

Figure 16 – Daily French Interconnector Flow at Darkness Peak

![French Interconnector flows over DP](image)
Prices

95. Day-ahead baseload electricity prices rose from 26 £/MWh at the beginning of October 2004 to 32 £/MWh by the first week of November, before softening a little during December where prices ranged from 25 £/MWh to 29 £/MWh, as detailed in Figure 17. Following the Christmas period, prices remained close to 25 £/MWh before the cold snap towards the end of February into early March. Record prices were witnessed over this period, as day-ahead baseload price exceeded 70 £/MWh. The prices for the 12-hour peak period have followed the same pattern, reaching 100 £/MWh on 28 February 2005. Even at this high price, flows from France were significantly reduced as European prices rose against a background of supply concerns.

Figure 17 – Day-ahead Electricity Prices

Summary

- The highest electricity demand was 54.1 GW for the half-hour ending 17:30 on Monday 13 December 2004. This compares to the highest demand of 53.5 GW for 2003/04
- 0.8-1.3 GW of demand management occurred at the peak as large customers reduced demand to avoid Transmission Use of System Charges
- The return from mothball of 0.7 GW of generation in November 2004 resulted in a headline capacity margin of 22%
The issuing of Notice of Insufficient Margin (NISM) was at a typical rate - 5 NISMs were issued on-the-day, and 2 early NISMs on a Friday for the forthcoming Monday were published. No High Risk Demand Reduction (HRDR) was issued.

At the end of February there was clear evidence that the direction and level of flow on the interconnector to France was heavily influenced by the differential in electricity prices between the UK and Europe. There was evidence of increasing interaction between the UK and European markets, leading to increased volatility. This has confirmed our view that it may be inappropriate to assume full imports to UK for planning purposes.

Peak electricity prices reached 100 £/MWh coincident with high prices being seen across Europe. The flow from France was significantly reduced in the response to high European electricity prices. Interconnector imports to England and Wales from France and Scotland were below the full capacity of 4.2 GW, tending to be around 3.1 GW over the peak time of the day.
Section B – Winter Scenarios 2005/06 – Gas

96. This section examines possible gas scenarios in the forthcoming winter, with a particular focus on the supply-demand position. In relation to our primary role of developing the transportation system to provide sufficient capacity for the 1 in 20 peak day, we can confirm that the transportation system will continue to have this capability in 2005/06.

97. Our assessment of the supply-demand outlook will be guided by the responses to this consultation document. In addition, we are in the process of analysing data that we have received in the course of the 2005 Transporting Britain’s Energy (TBE) consultation process. Through this analysis, we will derive revised supply and demand forecasts, which take account of the latest information obtained from producers, shippers, end-users, gas importers, storage operators, consultants and other interested parties.

98. The following sub-sections explain the assumptions that we have used to derive two alternative scenarios with which to assess the winter. This assessment is presented, together with an analysis of key sensitivities to these scenarios.

99. Prior to the 2004/05 winter, Ofgem and the HSE approved the removal of the ‘Top-up’ arrangements, which had been in place since the introduction of the Network Code in 1996. The Top-up monitors, against which the adequacy of storage stocks to provide for 1 in 50 winter conditions was assessed, have been replaced by ‘GS(M)R Safety Monitors’ (safety monitors).

100. As the name suggests, these new monitors are designed to underpin the safe operation of the transportation network. This change to the industry arrangements clarifies the distinction between the role of the transporter in ensuring safe system operation and the role of the market in providing security of supply. The operation of the safety monitors and the potential implications of the winter outlook for 2005/06 on the monitors are discussed later in this section.

Beach gas

101. We have reassessed the 2004/05 maximum beach forecast based on the experience of the winter. In general, we saw a lower level of beach supplies than had been envisaged, primarily due to accelerated field decline and partly as a result of delays in the availability of new developments that had been expected to come on line prior to or during the winter. Taking these points into account, our ‘hindsight-based’ May 2005 maximum beach estimate for 2004/05 is 13 mcm/d lower at 351 mcm/d.

102. Our assessments of 2005/06 beach gas availability are lower than last year’s forecast for the same period. Our October 2004 maximum beach forecast for 2005/06 was 351 mcm/d\(^5\). This represents a forecast of the maximum level of gas that we could expect at the beach given sufficient demand and assuming no outages. On the basis of operational performance last winter, our maximum beach forecast for winter 2005/06, which we have reviewed with the DTI, is now 336 mcm/d. Most of the

\(^5\) Excluding imports from LNG at Grain and through the Belgium – England Interconnector and direct supplies to certain power stations, which do not pass through NGT’s network.
difference between the current forecast of 336 mcm/d and our 2004 forecast of 351 mcm/d is accounted for by faster UKCS decline than had previously been assumed and, to a lesser extent, delays in the development of some new fields. We will review this further on the basis of 2005 TBE data and industry feedback that we receive, and will update our analysis accordingly in our report on the winter outlook, to be published in the autumn.

103. For the purpose of supply-demand balance analysis and safety monitor assessments, we believe it is appropriate to assume a level of beach supply below the maximum forecast. The chosen level should reflect the level of delivered beach gas that we might expect on average during a prolonged cold spell in a severe winter. This remains untested given the series of mild winters experienced in recent years.

104. Figure 18 shows the level of actual beach deliveries as a percentage of the maximum beach forecast for each of the last six years. The 2004/05 data is based on our hindsight-based 2004 maximum beach estimate of 351 mcm/d as described above\(^6\). It shows that the highest level of beach supply observed last winter was 94% of this revised maximum beach number.

Figure 18 - Beach deliveries as a percentage of forecast maximum beach

105. For 2004/05 winter analysis, we used 95% of the (then) maximum beach forecast, reflecting the trends highlighted in Figure 18, but assuming that higher levels of beach gas would be seen if demand was sufficiently high. This approach reflects, for example, the potential (on some days) for additional flows at the Bacton Shell Esso sub-terminal, where the contractual arrangements associated with the Sean field mean that this sub-terminal generally only flows towards the upper end of its.

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\(^6\) The 2003/04 data is also based on a hindsight view, given the substantial difference between our pre- and post-winter estimate of beach availability that year.
maximum rate at times of very high demand, but is capable of doing so for sustained periods in a severe winter.

106. Given the sensitivity of our beach analysis to the Sean field, Figure 19 shows the equivalent analysis to that in Figure 18, except that Bacton Shell Esso data has been omitted. This shows a generally higher rate of beach delivery as a percentage of forecast maximum in most of the years presented, with delivery rates at or above the 95% level on a number of days last winter.

**Figure 19 - Beach deliveries as a percentage of forecast maximum beach – Bacton Shell Esso data excluded**

107. Following the DTI’s Offshore Information Initiative, we now receive a more extensive range of information from offshore players. This includes details of their planned maintenance outages and of offshore problems as they occur. While this is helpful to us in our role as system operator, the data is not of the quality (in terms of completeness and level of definition) required to undertake an accurate assessment of beach reliability. We are therefore seeking the views of gas producers on the question of beach reliability levels as part of this consultation exercise.

108. We have, however, undertaken some detailed analysis of beach deliveries last winter in order to inform the question of what percentage of maximum beach forecast should be assumed for the purpose of supply-demand analysis. Excluding Bacton Shell Esso (for the reasons outlined above), we have plotted the distribution of beach deliveries in 2004/05 at relatively high levels of demand (using a threshold of 350 mcm/d). We have compared this with the profile that one would see in theory if each field were attempting to produce to its maximum capability at all times. To do this we have made the following assumptions:

- that each field has the same level of reliability
that each field performs independently from the others
- that, over a fixed period, each field either operates at its maximum rate or not at all
- that each field’s performance in one period is independent of its performance in all other periods

109. The graph in Figure 20 shows how the actual level of beach deliveries in 2004/05 (smoothed for clarity of presentation) compared with the theoretical distributions described above. Choosing a period of 6 hours produces a theoretical distribution similar in shape to the actual distribution experienced last winter. It can also be seen that the actual distribution lies between the two theoretical curves, which were derived using field level reliability rates of 90% and 95% respectively. The actual distribution has a mean of around 91%.

**Figure 20 – Theoretical distribution v actual distribution of beach delivery in 2004/05**

110. This analysis, although only indicative in nature, is not inconsistent with a study recently undertaken for the DTI, which suggested that offshore supplies could be expected to have a reliability of around 90%. It is also interesting to note that immediately prior to last winter, UKOOA expressed the view that a reliability rate of 95% is optimistic and that 90% would be a more reasonable figure.

111. Nonetheless, care should be taken in drawing conclusions for 2005/06 from our analysis of last winter. For example, it is not known how beach reliability might be affected by very cold weather, and in particular whether extreme weather conditions would be likely to cause more offshore problems and increase the time taken to repair faults. Also, reliability estimates derived from data excluding Bacton Shell Esso can only reasonably be applied to the whole beach portfolio if it is believed that Bacton Shell Esso will attempt to flow on a sustained basis across a severe winter.
Conversely, the 2004/05 analysis assumes all other fields would have produced at maximum if possible above the demand threshold of 350 mcm/d. If this assumption were invalid, it would suggest that beach deliveries could have been higher than the analysis indicates.

112. Given the significant uncertainty over the level at which beach supplies could be maintained under severe conditions, and the various analyses and issues highlighted above, we are this year providing two supply scenarios with which to analyse the coming winter. These scenarios assume beach supplies of 95% and 90% of our maximum forecast respectively. It is clearly possible that the 'correct' view lies outside this range. Table 4 summarises the resultant beach supply assumptions for the two scenarios.

New Importation and Storage Infrastructure

113. As the UKCS declines, new importation and storage infrastructure will play an increasing role in ensuring supply security. Equally, risks associated with the delivery of these projects, and the extent to which the new infrastructure will be used add to the overall level of uncertainty surrounding the future supply outlook.

114. The rate at which the Interconnector imports during the winter period will depend upon the net effect of forward and reverse flow nominations. This is of course fundamentally dependent upon the commercial arrangements entered into by market participants. We are therefore using this consultation exercise as an opportunity for the industry to provide insights and information relating to relevant market arrangements.

115. Our thoughts on this have been influenced by the experience late in the 2004/05 winter when the Interconnector was barely importing despite very high NBP prices. This suggests that there are credible scenarios in which such infrastructure would not operate at full capacity, even under severe conditions. The UK is becoming increasingly dependent upon gas sourced from broader markets; pipeline gas from Europe, and LNG (which competes in a world market). Conditions in these broader markets will influence the extent to which gas flows through importation infrastructure into the UK.

116. While the experience of last winter is not necessarily a good guide to next winter, over the 30 days of highest demand in 2004/05, the Interconnector imported on average at 79% of its nameplate capacity.

117. To reflect these uncertainties, our supply scenarios assume a range of utilisation rates (75% to 100%) for new importation and storage infrastructure. Since it is possible to make a case for a lower rate than 75%, we have also analysed sensitivities against each of the supply scenarios, and these are also presented below. The following sub-sections identify the respective importation and storage developments to which these assumed utilisation rates apply.

Grain LNG Imports

118. The Isle of Grain LNG facility has recently been converted into an LNG importation terminal, with commissioning expected this summer. BP/Sonatrach have purchased...
the LNG capacity at Grain, at a rate of 140 GWh/d (13 mcm/d). The physical maximum throughput of the site is 186 GWh/d (17 mcm/d).

119. For our supply scenarios (Table 4) we are assuming Grain flow rates between 75% and 100% of the contracted capacity. In addition to these scenarios, we have assessed sensitivities where Grain operates a) at its maximum deliverability and b) at no flow conditions. These are summarised in Table 4.

**Continental Interconnector**

120. Section A highlighted that the Belgium-England Interconnector again imported to the UK at levels at or above its nameplate capacity for prolonged periods during the 2004/05 winter. Section A also explained that the Interconnector reduced imports to the UK at the end of the winter in response to the increase demand for gas on the Continent. Following completion of the Interconnector enhancement project expected in December 2005, the Interconnector import capacity will increase from 8.5 to 16.5 bcm/year (in normal conditions), which equates to an increase in a nameplate capacity from approximately 25 to 48 mcm/d.

121. Our supply scenarios assume Interconnector import rates between 42 and 48 mcm/d. These values represent 75% and 100% of the capacity the enhancement project provides above that already available. In addition to these scenarios, we have assessed as a sensitivity the Interconnector operating at float (i.e. no flow in either direction). This is shown in Table 6.

**Storage**

122. Storage developments expected in 2005 are the completion of the Humbly Grove facility, and expansion of deliverability at Hole House Farm. The combined effect of these developments will be to increase storage space by 3146 GWh and deliverability by 65 GWh/d\(^7\). As for new importation infrastructure, the supply scenarios assume utilisation rates of 75% and 100% in relation to this new storage capacity.

123. Table 3 gives assumed (100% case) storage space and levels of deliverability from Short (LNG), Medium (Mid Range Storage - MRS) and Long duration storage (Rough). These exclude space for Operating Margins gas that NGT procures to provide short-term cover against operational events such as offshore supply losses, demand forecast errors and compressor trips and the 135 GWh of LNG booked for Scottish Independent Undertakings (SIU). The Medium duration figures include Hornsea, Hatfield Moor, Hole House Farm and Humbly Grove.

124. We have recently undertaken, and presented to the DTI/Ofgem Joint Energy Security of Supply Working Group, some analysis to establish the extent to which the cycling of storage facilities may be possible. This analysis suggested that there was only limited potential for storage cycling to increase the total level of usable storage space during cold winter conditions. For this reason, we do not consider it appropriate to adjust the physical storage capacities to reflect the possibility of storage cycling.

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\(^7\) Deliverability from Medium duration storage can decline with reduced space, reported deliverability is based on average conditions
Table 3 – Assumed 2005/06 storage capacities and deliverability levels

<table>
<thead>
<tr>
<th></th>
<th>Space (GWh)</th>
<th>Deliverability (GWh/d)</th>
<th>Deliverability (mcm/d)</th>
<th>Days at full rate</th>
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</thead>
<tbody>
<tr>
<td>Short (LNG)</td>
<td>1817</td>
<td>526</td>
<td>49</td>
<td>3.5</td>
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<tr>
<td>Medium (MRS)</td>
<td>8108</td>
<td>315</td>
<td>29</td>
<td>26</td>
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<tr>
<td>Long (Rough)</td>
<td>34126</td>
<td>455</td>
<td>42</td>
<td>75</td>
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</tbody>
</table>

2005/06 Supply Scenarios

125. Table 4 below summarises our supply scenarios, bringing together the respective assumptions for beach supply, Interconnector imports and storage. The left hand column of numbers shows the preliminary maximum forecast for 2005/06, and compares this against the maximum forecast for 2004/05. The other two columns show the two supply scenarios, and compare these with the scenario outlined in the 2004 Winter Outlook Report, where we assumed 95% of maximum beach, Interconnector imports (25 mcm/d) and peak storage deliverability of 131 mcm/d\(^8\). In each case the relative position is shown against two views of the 2004/05 beach forecast; that contained in the 2004 Winter Outlook Report and our hindsight-based view presented above. The relative position also assumes year on year growth in demand of 10 mcm/d.

Table 4 – 2005/06 Supply Scenarios – Peak Supplies

<table>
<thead>
<tr>
<th>Basis</th>
<th>Preliminary 2005 Max Forecast</th>
<th>Supply Scenario 1</th>
<th>Supply Scenario 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Increase</td>
<td></td>
<td>95% max beach, 100% new imports &amp; storage</td>
<td>90% max beach, ~75% new imports &amp; storage</td>
</tr>
<tr>
<td>Beach</td>
<td>336</td>
<td>319</td>
<td>302</td>
</tr>
<tr>
<td>Relative to 2004/05 (Oct 2004 view, incl. demand)</td>
<td>-38</td>
<td>-37</td>
<td>-53</td>
</tr>
<tr>
<td>Relative to 2004/05 (Hindsight view, incl. demand)</td>
<td>-25</td>
<td>-25</td>
<td>-41</td>
</tr>
<tr>
<td>Grain</td>
<td>13</td>
<td>13</td>
<td>10</td>
</tr>
<tr>
<td>IC Imports</td>
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<td>48</td>
<td>42</td>
</tr>
<tr>
<td>Total Supply ex Storage</td>
<td>396</td>
<td>380</td>
<td>354</td>
</tr>
<tr>
<td>Relative to 2004/05 (Oct 2004 view, incl. demand)</td>
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<td>-1</td>
<td>-27</td>
</tr>
<tr>
<td>Relative to 2004/05 (Hindsight view, incl. demand)</td>
<td>10</td>
<td>11</td>
<td>-15</td>
</tr>
<tr>
<td>Existing Storage</td>
<td>114</td>
<td>114</td>
<td>114</td>
</tr>
<tr>
<td>New Storage</td>
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<td>6</td>
<td>5</td>
</tr>
<tr>
<td>Total Supply inc Storage</td>
<td>516</td>
<td>499</td>
<td>472</td>
</tr>
<tr>
<td>Relative to 2004/05 (Oct 2004 view, incl. demand)</td>
<td>-14</td>
<td>-12</td>
<td>-39</td>
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<tr>
<td>Relative to 2004/05 (Hindsight view, incl. demand)</td>
<td>-1</td>
<td>0</td>
<td>-27</td>
</tr>
</tbody>
</table>

\(^8\) This includes 186 GWh/d (17 mcm/d) deliverability from Grain which we treated as a storage facility for analysis purposes in the 2004 Winter Outlook Report
126. Table 4 shows that with 95% beach and full new imports, the 2005/06 supply-demand position (excluding storage) would be comparable to that forecast for last winter. Although (against the October 2004 view) the peak position is slightly down, by 12 mcm/d, the conversion of Grain from storage to importation facility means that this source of gas supply should be available across the winter rather than just for a few days. Under Scenario 2, with lower levels of beach supply and lower levels of new imports, the supply-demand position becomes appreciably tighter.

Gas demand

127. Pending analysis of 2005 TBE data, we have based our scenario analysis on the 2005/06 demand forecasts\(^9\) that we published in December last year, as outlined in the 2004 Ten Year Statement\(^10\).

128. It should be noted that these forecasts do not make an adjustment for potential interruption by NGT for capacity management purposes nor for potential reductions in demand that might occur in response to high prices in a severe winter. As we noted in Section A, the highest level of NGT-initiated interruption in 2004/05 was around 55 GWh/d (5mcm/d), which was for operational reasons rather than during a period of high demand. In establishing their gas supply portfolios going forwards, gas shippers and suppliers should not assume that NGT will necessarily initiate interruptions for capacity management reasons in the event of cold weather.

129. The consultancy Global Insight\(^11\) has recently conducted a study for DTI and Ofgem of the potential for demand-side response in energy-intensive industries (excluding power generation). The study assessed the potential response under a range of prices. Broadly, the analysis indicated a potential gas response in the range 8 mcm/d if prices were sufficiently high\(^12\). The total size of the market that Global Insight analysed is around 25 mcm/d. As Global Insight note in their report, some commercial and public-sector demand may also respond to price, for example, if they have an interruptible gas contract.

130. The study also identified the potential for electricity demand response from the same sector. Here, the analysis indicated a potential response of 944 MW given sufficiently high power prices. Assuming that this response is sustained and that it translates directly into a reduced CCGT gas demand over 12 hours of the day, this would equate to a further reduction in gas demand of around 2 mcm/d.

Interruption

131. We noted last year that the market has in recent years moved away from traditional interruptible arrangements. Under these contracts, the customer could be interrupted by their supplier, either for the supplier’s own supply-demand balancing purposes or if called to do so by NGT, primarily for transportation capacity management purposes. We do not have access to information regarding supply

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\(^9\) Readers interested in understanding more about our demand forecasting methodology could refer to [http://www.transco.uk.com/publish/forecast/1104_Gas_Demand_forecasting_methodology.pdf](http://www.transco.uk.com/publish/forecast/1104_Gas_Demand_forecasting_methodology.pdf)

\(^10\) The Ten Year Statement can be found at [http://www.transco.co.uk/publish/tys/Ten_Year_Statement_2004.pdf](http://www.transco.co.uk/publish/tys/Ten_Year_Statement_2004.pdf)


\(^12\) Global Insight also noted that a further response might be forthcoming from the chemical industries if energy prices rose to become a multiple of their breakeven costs.
contracts, though our understanding is that the majority of interruptible contracts now stipulate interruption only where called for by NGT.

132. To reflect this change in interruptible arrangements, we are in our analysis showing demand broken down into three discrete market sectors, namely: Domestic, Other Non Daily Metered (NDM) and Daily Metered (DM), rather than Firm and Interruptible. Hence where our analysis indicates that a certain level of demand response would be required for supply and demand to balance, it is shown in the DM sector rather than assuming that it would come in the first instance from the ‘interruptible’ sector.

133. However, whilst there has been an apparent reduction in suppliers’ rights to interrupt customers, this does not preclude such contracts being entered into prior to the winter, nor does it preclude the market securing other arrangements to deliver the necessary demand response.

**Gas-fired power station demand**

134. Our power generation demand forecasts are based on analysis of the historical gas demand of these customers. In general, total power generation demand was flat across the year, with only a few occasions when there was been discernible price responsiveness. Accordingly, the severe winter load duration curve incorporates a constant daily demand in relation to this sector, broadly equivalent to the average daily historical demand, adjusted for known market changes, principally new connections. For 2005/06 we have assumed 580 GWh (54 mcm) of firm power station load and 150 GWh (14 mcm) of interruptible power station load.

135. However, as we noted in Section A, the previous two winters have provided some empirical evidence of CCGT responsiveness to gas price, with a number of stations curtailing their gas burn at relatively high gas prices in late January 2004, late February 2005 and early March 2005.

136. As further discussed in Section C, analysis implies a potential for further response from CCGTs, including those on firm transportation arrangements. The extent of this response is clearly influenced by the level of electricity demand, the availability of back-up fuels and the attractiveness to the power market of switching to non-gas fired generation, as indicated by the gas and coal spreads. Whilst there may be a potential for a high degree of price-response from CCGTs, the level of price responsiveness experienced and required to date has only been a fraction of that required to ensure a supply-demand balance in a 1 in 50 winter.

**Climate change**

137. There is now a substantial weight of evidence to suggest that climate change has resulted in a shift in average winter temperatures. Reflecting this, for the last four years we have used a 35-year weather trend as the basis of our analysis of average weather conditions, rather than using the 76 years from 1928/29, which form the

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13 The gas spread is the premium in £/MWh of the electricity price above the gas price, at an assumed efficiency of around 50%. The coal spread is the premium in £/MWh of the electricity price above the coal price, at an assumed efficiency of around 30%. Currently the coal spread is greater than the gas spread, excluding any impact of emissions.
basis of our severe winter analysis. Our latest analysis indicates that use of the 17 years weather data from 1987/88 has greater statistical validity, and whilst we have used the 35-year data set in the following analysis, we will be using this new basis for assessing average conditions in the future. However, there is no clear evidence that climate change has had an impact on severe conditions. Indeed, the coldest day since our records began in 1928/29 occurred as recently as the 1986/87 winter. Accordingly, our severe load duration curves are based on the 76-year weather history. We are conducting further analysis to test the validity of this approach.

Gas supply-demand outlook

138. The previous sub-sections have outlined our scenario bases for gas supply and demand in 2005/06. This section shows, with the use of load duration curve analysis, a view of the supply-demand outlook for the 2005/06 winter for both average and severe (1 in 50) demand conditions. Figures 21 and 22 show the supply scenarios overlaid on a load duration curve of average and severe demand respectively, with demand broken down into the Domestic, Other Non Daily Metered (NDM) and Daily Metered (DM) sectors, rather than Firm and Interruptible. For clarity of presentation, the supply scenario lines are smoothed representations of the total availability of supply (beach, imports and storage excluding OM & SIU bookings) implied by the two scenarios. The irregular shape of the smoothed supply curve reflects limits on storage space.

Figure 21 – Average load duration curve analysis for 2005/06

139. Figure 21 shows for that for average demand conditions, the supply availability associated with Scenario 1 is sufficient to meet all demand, whereas Scenario 2 implies the need for a limited demand response as quantified in Table 5.
Figure 22 – Severe load duration curve analysis for 2005/06

NGT has rights to interrupt supply to certain customers for capacity management purposes. However, under these supply scenarios it is anticipated that the prevailing supply/demand balance would normally create market reaction before network constraints become a limiting factor. In developing their gas supply portfolios, shippers and suppliers should not assume that NGT will necessarily initiate interruption in the event of cold weather.

140. Figure 22 shows for that for 1 in 50 severe demand conditions, when winter temperatures could average around −2°C over a period of 30 days, and typically +2°C for a further 2 months, under neither scenario is the supply availability sufficient to meet all demand. For Scenario 1 there would be a need for a demand response of approximately 2.5 bcm, broadly equivalent in scale to a demand response of 60 mcm/d over a period of 45 days. Scenario 2 implies a need for an even greater demand response of 5.2 bcm, roughly 30 mcm/d greater than the response in Scenario 1 throughout most of the winter.

Additional cold spell analyses

141. 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.

142. Figure 23 shows bar charts consisting of three levels of demand, namely those demands commensurate with a peak day14, a very cold week15 and a very cold month16. Against these levels of demand is shown the supply availability17 under the two supply scenarios, and the associated level of demand response required for supply and demand to balance.

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14 Diversified demand for a 1 in 20 Peak day
15 Average diversified demand for Days 1 to 7 on a 1 in 50 load curve
16 Average diversified demand for Days 1 to 30 on a 1 in 50 load curve
17 Storage deliverability is adjusted proportionally when the duration is exceeded
143. To give a sense of the weather conditions that these cases represent, the average temperatures across the country associated with these cold spells would typically be around:

- a 1:20 Peak day: around -5 °C
- a very cold week: -4 °C
- a very cold month: -2 °C.

**Figure 23 – Cold spell analysis for 2005/06**

144. The analysis illustrates that for a 1 in 20 peak day with average temperatures across the country around -5 °C, a demand response of nearly 60 mcm/d would be required for Scenario 1, which increases to nearly 90 mcm/d for scenario 2.

145. For the very cold week and very cold month conditions, the levels of daily demand response required for the two scenarios are similar to the peak day requirement, but this response would be required over these longer periods as storage stocks become depleted.

146. In Figures 24 and 25, we show the two supply scenarios set against four levels of demand. These represent average and severe conditions and projected demands for next winter based on the weather patterns experienced in 2004/05 and 1985/86\textsuperscript{18}. These winters were 1 in 15 warm and 1 in 11 cold respectively. Please note that for ease of presentation these charts, unlike Figures 21 and 22, show demand as lines and supply as coloured blocks.

\textsuperscript{18}There is a relatively minor difference between the average demand curve and the 2004/05 curve. This is because the average curve used in this analysis has been adjusted for climate change. The 2004/5 curve also appears relatively high when compared to actual demands last winter. This is being investigated further but is believed to be due to a combination of effects, notably year on year demand growth, weekend effects (many of the coldest days last winter occurred at weekends) and possible demand response that is not built into the weather derived demand simulations.
147. Figure 24 shows that the supply availability for Scenario 1 exceeds demands associated with both 2004/05 weather conditions and average temperatures. However, demand response would be required under the other two weather conditions. Figure 25 suggests the need for a demand response (to a greater or lesser degree) under all of the demand conditions.

Figure 24 – Supply Availability Scenario 1

![Figure 24](image)

Figure 25 – Supply Availability Scenario 2

![Figure 25](image)
Sensitivity Analysis

148. Table 5 shows the demand response for average and severe demand conditions for the two supply scenarios as shown in Figures 21 and 22 for the top 100 demand days.

Table 5 – Demand Response – Average and Severe Conditions (bcm)

<table>
<thead>
<tr>
<th></th>
<th>Scenario 1</th>
<th>Scenario 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Conditions</td>
<td>0.00</td>
<td>0.30</td>
</tr>
<tr>
<td>Severe Conditions</td>
<td>2.52</td>
<td>5.15</td>
</tr>
</tbody>
</table>

149. Table 5 shows the demand response is sensitive to both the severity of demand and the supply scenario. For severe demand conditions, the demand-side response ranges from 2.5 bcm under Scenario 1 to 5.2 bcm in Scenario 2. Table 6 quantifies the potential impacts of specific demand-side and supply-side sensitivities in terms of the contribution of the sensitivity to the total response requirement.

150. These scenarios and sensitivities clearly suggest that demand-side response could play a critical role in establishing a supply-demand balance in sufficiently cold winter conditions. Such a response would be driven through market arrangements between shippers/suppliers and end consumers. Through this consultation exercise we are seeking information from the market on such arrangements.
Table 6 – Demand Response – Sensitivity Analysis

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Comments</th>
<th>Response (bcm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Every 10 mcm/d of DM demand reduction</td>
<td>Full response for 100 days</td>
<td>1.00</td>
</tr>
<tr>
<td>10% response of non power DM</td>
<td>Full response for 100 days</td>
<td>0.73</td>
</tr>
<tr>
<td>10% response DM power</td>
<td>Full response for 100 days</td>
<td>0.68</td>
</tr>
<tr>
<td>Response from CCGTs</td>
<td>~30 mcm/d for top 100 demand days</td>
<td>3.00</td>
</tr>
<tr>
<td>Every 1% of higher beach supplies</td>
<td>Top 100 demand days</td>
<td>0.34</td>
</tr>
<tr>
<td>Beach performance</td>
<td>Each % reduction in beach below 90% across 100 days</td>
<td>-0.34</td>
</tr>
<tr>
<td>Interconnector floats (no flow)</td>
<td>Per week</td>
<td>-0.34 Scenario 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.29 Scenario 2</td>
</tr>
<tr>
<td>Grain imports at maximum capacity</td>
<td>Top 100 demand days</td>
<td>0.40 Scenario 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.70 Scenario 2</td>
</tr>
<tr>
<td>No imports through Grain</td>
<td>Top 100 demand days</td>
<td>-1.30 Scenario 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-1.00 Scenario 2</td>
</tr>
<tr>
<td>Winter Medium duration storage cycling</td>
<td>10% of inventory for cold winters</td>
<td>0.07</td>
</tr>
</tbody>
</table>

Implications for safety monitors

151. As we noted in the introduction to this section, safety monitors have been introduced as a mechanism for ensuring that sufficient gas is held in storage at all times to underpin the safe operation of the gas transportation system. If storage withdrawal nominations imply that one or more monitor would be breached, NGT would expect to take action to preserve storage stocks at or above the monitor level. This could involve invoking emergency procedures, including emergency interruption of daily metered customers.

152. We are in the process of considering the appropriate basis for setting the safety monitors for the 2005/06 winter. Under the Uniform Network Code we are required to publish initial monitor levels by 31 May.

153. Table 7 provides indicative initial safety monitor levels expressed as percentages of shippers’ storage stocks within the three types of storage facility. These indicative figures illustrate that the monitor levels are highly sensitive to the assumptions used for beach supplies and new imports.
154. For now, given the significant uncertainty associated with the key input assumptions, we believe that it is most appropriate to publish initial monitor levels based on the more conservative of the two scenarios, i.e. Scenario 2. This leads to initial levels of 18% for long range storage, 13% for medium range storage, and 54% for short-range storage. These should be considered indicative only at this stage. These will be reconsidered in the light of feedback on this consultation document, and kept under review prior to and throughout the winter period.

Table 7 – Indicative 2005/06 Safety Monitor Levels

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Long</th>
<th>Medium</th>
<th>Short</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1</td>
<td>7.3%</td>
<td>5.3%</td>
<td>18.2%</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>17.8%</td>
<td>13.0%</td>
<td>54.4%</td>
</tr>
</tbody>
</table>

Summary

- Our 2004 maximum beach forecast for 2004/05, based on data provided to us via the TBE process, was 364 mcm/d. We now believe that this over-stated beach availability, and our retrospective view for last winter has a maximum beach supply of 351 mcm/d.

- The highest beach supply observed last winter was 331 mcm/d, 91% of our maximum beach forecast. If our retrospective view of maximum beach supply is used this value increases to 94%, marginally below the 95% level we used for supply-demand analysis last winter. If data relating to the Bacton Shell Esso sub-terminal is excluded, this rises further to 97%.

- Decline of UKCS gas supplies continues to occur faster than previously forecast. Our latest analysis, based upon operational performance for last winter and following discussions with the DTI, suggests a maximum beach gas supply for 2005/6 of 336 mcm/d, 15 mcm/d lower than our 2004 forecast for 2005/6.

- To reflect uncertainty over beach gas availability, we have adopted alternative supply scenarios in which beach gas availability is assumed to equal 95% and 90% of maximum beach respectively, which equates to beach supplies of 319 and 302 mcm/d respectively. This range of beach gas availability is broadly consistent with the views of both the DTI and upstream companies.

- With beach supplies declining, the provision of new imports (in 2005/06 through Grain and an expanded Interconnector) will become increasingly important in meeting winter demand. For the 2 supply scenarios, we have assumed new imports between 36 and 27 mcm/d in 2005/06.

- For this winter therefore our preliminary analysis indicates that the UK will have a lower beach gas availability coupled with a demand growth of around 10 mcm/d at peak, but the potential benefit of some new sources of gas. Overall, our net preliminary assessments under Scenario 1 and Scenario 2 suggest that gas availability at peak for the forthcoming winter will be 12 and 39 mcm/d lower than for 2004/5 winter (as presented in our 2004 Winter Outlook Report).
• The combination of beach gas, new imports and storage at the levels assumed in Scenario 1 should be sufficient to meet expected demand in average winter conditions. For Scenario 2 the analysis indicates that the supply-demand position would be tighter and a demand-response of 0.3 bcm would be required

• For severe winter conditions represented by a 1 in 50 occurrence, a demand response of around 2.5 bcm would be required in scenario 1, which would be equivalent in scale to around 60 mcm/d for 45 days. A response of around 5.2 bcm would be required under Scenario 2, roughly 30 mcm/d greater than the response in Scenario 1 throughout most of the winter

• Our analysis of cold spells suggests for a 1 in 20 peak day with average temperatures across the country around -5 °C, a demand response of nearly 60 mcm/d would be required for Scenario 1, this increases to nearly 90 mcm/d for Scenario 2. For a very cold week or a very cold month, the levels of daily demand response required for the two scenarios are similar to the peak day requirement, but this response would be required over these longer periods as storage stocks become depleted

Questions for Consultation

We would welcome comments on all aspects of this section, and in particular on the following:

• The preliminary assessment of maximum beach supply availability for 2005/06

• The average percentage beach availability that could be expected under a period of prolonged severe conditions in 2005/06, taking account of beach reliability and other factors

• The extent to which importation and storage infrastructure is likely to be utilised under a period of prolonged severe conditions in 2005/06, and in particular:
  o The extent to which shippers have contracted for gas supplies to import into the UK
  o The extent to which shippers have access to the necessary European transportation infrastructure to support gas imports through the Interconnector
  o The potential and likelihood for European suppliers to nominate gas export flows on the Interconnector, thereby reducing the net import rate, even at times of high demand in the UK
  o The assumptions that can be made for LNG importation quantities

• The extent to which the market is able to provide the levels of demand side response that our load duration curve and cold spell analysis indicates may be required under severe winter conditions, and in particular:
  o The extent to which gas demand-side arrangements are already in place (whether through interruptible contracts or otherwise)
  o What scope exists for such arrangements to be put in place prior to or during the course of the winter

• The appropriate basis for setting the 2005/06 safety monitors.
Section B – Winter Scenarios 2005/06 – Electricity

Electricity Demand Levels for 2005/06 – Great Britain

155. Our Great Britain winter peak demand forecast for the coming winter is 62.0 GW. The 1 in 20 peak demand forecast is 65 GW. This demand figure relates to GB demand only and does not include any Interconnector flows to France or Northern Ireland. Reflecting our forecast export to Northern Ireland of 0.4 GW across the winter peak, the ACS peak demand forecast becomes 62.4 GW and the 1 in 20 peak day becomes 65.4 GW.

156. As discussed in Section A, around 0.8-1.3 GW of demand management was observed at times of peak demand in the winter of 2004/05 as consumers responded to high electricity prices at times of peak demand. When forecasting demand we assume this level of demand-response will continue and we have recognised this in our peak demand forecasts. For 2005/06 we have assumed 1 GW of demand side response in our demand forecasts for normal, ACS and severe conditions.

157. Given the recent run of mild winters since the introduction of NETA, and the short experience of BETTA, it is difficult to assess how the market will respond to very high demands / prices based on the observable behaviour to date, and no additional demand response has been assumed further to that observed to date.

Notified Generation Availability

158. The current forecast Plant Margin for winter 2005/06 is around 22%\(^\text{19}\), based on a TEC contracted generation capacity of 74.8 GW. A further 3.8 GW of plant has released its Transmission Entry Capacity, which could in theory choose to return, and thus increase the plant margin to around 28% on a TEC basis.

159. The current forecast of actual generation capacity anticipated to be operationally available for winter 2005/06 is 74.2 GW. This excludes 3.8 GW of plant, which has released its Transmission Entry Capacity, and is considered to be mothballed.

160. Of the 3.8 GW of mothballed plant, 2.2 GW could reasonably be expected to return for this winter under appropriate market conditions. The generating companies provided us in June 2004 with a list of the 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. Recent indications have confirmed that the 1.6 GW indicated last year as requiring greater than 6 months to return would not physically be able to return for this winter. This has fed into our operational view of the return of mothballed plant.

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\(^{19}\) The 2005 GB SYS, published on 31 May 2005, indicates a slightly higher plant margin than this. The SYS figure reflects data as 1 December 2004 and a demand forecast based on our customers’ projections. The latest figure quoted in this document is based on current data and our own demand forecast.
Contracted Reserve

161. At certain times of the day NGT needs extra power 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, provided by a range of service providers including Balancing Mechanism (BM), demand reduction and non-BM generating plant. For winter 2004/05, we contracted for 2.2 GW of Standing Reserve via an annual tender round and on an economic basis a further 0.9 GW, of which 0.6 GW was in the BM, via the Supplementary Standing Reserve (SSR) tender in November 2004. For winter 2005/06, the volume of contracted Standing Reserve is 2.2 GW, of which around 0.7 GW is provided outside of the Balancing Mechanism.

162. We are currently undertaking a review of Reserve procurement in consultation with market participants. The purpose is to review current mechanisms, products and information arrangements relating to our procurement of Reserve. The review is expected to conclude around September 2005, and may lead to recommendations for industry code modifications and/or new Reserve product development. Given the timing of the outcome of this review, the conclusions are not expected to affect the procurement of Reserve for winter 2005/06.
163. Frequency Response Services consist of automatic actions that happen within seconds in response to a large change in frequency (e.g. when a large generator trips off the system). For generators, this would normally be provided by automatic governor action on synchronised plant. The ability to provide response is mandatory under the terms of the Grid Code for large generators, but in addition to the mandatory services, contracts continue to be struck bilaterally with generators for enhanced (better than mandatory) Response and with demand-side providers. Demand-side frequency Response is initiated using low frequency relays to trip demand. In order to provide a reliable service, there has to be a reasonably steady and predictable demand so that a physical effect will occur when required.

164. NGT has Maximum Generation contracts in place for winter 2005/06 that provide potential access to a 1000 MW of extra generation in emergency situations. However, this is a non-firm emergency service and would only be used to avoid voltage reduction. Given that it is non-firm and that generation operating under these conditions normally have a significantly reduced reactive power capability which in turn can have a significant impact on transmission system security it is not included in any of our margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

Forecast Position for Winter 2005/06

165. Figure 27 reflects a winter where weather and demand are at normal / (average) levels for each week, and average temperatures across the winter are 7 °C. The generation available is the forecast availability declared to NGT by the generators under the Grid Code Operating Code 2, and reflects planned unavailability, but has no allowance for unplanned generator unavailability. As previously noted, 3.8 GW of plant has not purchased TEC and is mothballed.

166. As can be seen in Figure 27 with full exports from France the excess generation over average weekly peak demand would be around 12-14 GW. This surplus would be eroded if only 1.4 GW of imports from France are sustained over the peak demands as has occurred over the preceding two years. However, Figure 27 does not reflect the variability of weather and demand, whereby there tends to be at least a few weeks during the winter when demand is above normal and approaches and often exceeds ACS levels.
167. For timescales ranging from weeks ahead down to real time it is necessary for us to hold varying levels of Reserve to cover for generator unavailability, short term generator breakdown and demand forecast errors. On average this amounts to 6 GW required from the generation shown available in Figure 27. The margin shown in Figure 27 does not reflect this reserve requirement.

Scenarios

168. To illustrate the ability of the electricity sector to meet demand under average (typical) and 1 in 50 weather conditions, 2 availability scenarios are modelled as detailed in Table 9.
Table 9 – Electricity Availability Scenarios (GW)

<table>
<thead>
<tr>
<th></th>
<th>Scenario 1</th>
<th>Scenario 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>GB Plant Availability, GW</td>
<td>72.2</td>
<td>72.2</td>
</tr>
<tr>
<td>Flow From France, GW</td>
<td>1.0</td>
<td>2.0</td>
</tr>
<tr>
<td>Return of mothballed plant, GW</td>
<td>1.2</td>
<td>2.2</td>
</tr>
<tr>
<td>Total Availability, GW</td>
<td>74.4</td>
<td>76.4</td>
</tr>
<tr>
<td>Average Assumed Availability, %</td>
<td>90%</td>
<td>90%</td>
</tr>
<tr>
<td>Assumed Availability, GW</td>
<td>67.1</td>
<td>69.1</td>
</tr>
</tbody>
</table>

169. Scenario 1 assumes a less tight gas supply situation, so the electricity market needs to respond less. The corresponding electricity situation for Scenario 1 assumes 1.2 GW non-gas fired plant being returned from mothballed, and 1 GW from France over peak periods.

170. In Scenario 2, a situation of low gas supply as described in gas Scenario 2, the electricity market is assumed to provide additional response by returning 2.2 GW of short-term mothballed plant and delivering a full import 2 GW from France over the darkness peak and overnight throughout the winter.

171. For both scenarios, typical historic rates of 90% power station availability have been assumed, and the week by week profile of unavailability has been smoothed across the winter as a whole.

Average winter conditions

172. To illustrate a typical winter, demand has been forecast by assuming the weather pattern of 2002/03. This is a good representation of a typical winter, with a peak winter demand of around 62.4 GW and a normal pattern of high demand spells occurring in December and January. However, as demonstrated in 2004/05 other demand patterns are equally possible.

173. As illustrated in Figure 28 under average winter conditions there should be more than sufficient plant to meet demand. Under these average weather conditions there should be sufficient scope for the electricity sector to reduce gas demand and provide the limited demand side response required by the gas sector under Scenario 1.
Severe Winter Conditions

174. In severe winter conditions, where average temperatures across the country would be -2 °C for 30 days and +2 °C for 60 days, peak demand may increase in the order of 2 GW above ACS demand. The weather pattern experienced in 1946/47 is representative of such a 1 in 50 winter, although we have no recent experience of how demand would respond to these extreme temperatures.

175. If these weather patterns were to occur this winter, as illustrated in Figure 29, the anticipated electricity margin would be sufficient, provided we do not experience high levels of plant breakdowns or CCGT unavailability.
CCGTs Providing Gas Demand Response

176. As noted in Section B (Gas) and Section C, during such 1 in 50 weather conditions, there would be an increased likelihood of CCGT interruption to support the gas market.

177. In Figure 29 it can be seen that for the coldest days during the peak week, under Scenario 2 all power stations, including CCGTs, are required to satisfy our normal level of Short Term Operating Reserve. However, since the duration of the electricity peak demand is spread across a few hours in the evening, there is an opportunity outside of the peak periods for the power sector to substitute out of gas-fired generation.

178. As detailed in Section C, it is provisionally estimated that, under Scenario 2 the electricity sector could lower its gas demand by around 3 bcm in severe weather conditions provided that the market sought to minimise CCGT gas demand throughout the winter. Specifically, this would require extensive switching from gas-fired generation to coal, those CCGTs capable of running on distillate doing so for 4 hours and 5 days a week all winter, oil generation operating for an average of 8 hours a day for 5 days a week, the full 2 GW imports from France for 4 hours over the darkness peak and overnight, and a return of 2.2 GW of mothballed plant particularly including 1 GW of non-gas-fuelled generation. For this to happen, market participants would need to make significant preparations prior to the winter.
179. Any further reduction in CCGT running could only be achieved by further significant electricity demand-side response or through voltage reduction. If electricity demand were 1 GW lower across the whole day, CCGT gas consumption would by lower by 4.5 mcm. If this were to occur for 50 days, gas demand would be 0.225 bcm lower. Similar reductions in gas demand can be achieved by the application of voltage control over the peak 4 hours of the day. This voltage reduction should not be discernible to domestic consumers.

180. In a severe winter, if there were very low probability generation failures above the levels normally experienced, or CCGT non-availability in response to gas supply concerns, there may be a need to apply the existing operational arrangements whereby voltage reductions can be instructed, potentially providing additional short duration margin of around 4-6 GW, to maintain security of supply. Demand reductions can be achieved by the Distribution Network Operators (DNOs) by voltage reduction. Such a combination of low probability circumstances is improbable, and any applied voltage reductions should not be discernible to the domestic end customer.

Summary

- The winter peak demand forecast for the coming winter is 62.0 GW. The 1 in 20 peak demand forecast is 65 GW. This demand figure relates to GB demand only and does not include any Interconnector flows to France or Northern Ireland.
- The headline margin for Great Britain for next winter is currently around 22%, assuming full 2 GW of imports from France. This margin could rise to 28% if 3.8 GW of mothballed generation returns.
- Of the 3.8 GW of generation currently mothballed, we understand that 2.2 GW can return within 6 months. This would provide a margin of 25%. We have been told that the remaining 1.6GW cannot physically be returned to service for this winter.
- The direction and level of flow on the interconnector is heavily influenced by the differential in electricity prices between the UK and Europe.
- The above level of generation availability would be sufficient to meet demands expected under average cold spell (ACS) conditions.
- In severe winter conditions where average temperatures across the country were –2 °C for 30 days, and +2 °C for 60 days, electricity demand may increase in the order of 2 GW above ACS. The projected level of generation would be sufficient to meet these demands provided that we do not experience high levels of plant breakdowns, and that sufficient non-power generation gas demand response is provided by industry such that adequate CCGT generation remains available.
- Under severe weather conditions, as there would be an increased likelihood of CCGT interruption to provide a gas supply/demand balance, an increased reliance would also be placed upon those CCGTs that are able to run on distillate.
- It is provisionally estimated that, under Scenario 2 the electricity sector could lower its gas demand by around 3 bcm in severe weather conditions provided that the market sought to minimise CCGT gas demand throughout the winter. Specifically, this would require extensive switching from gas-fired generation to coal, those CCGTs capable of running on distillate doing so for 4 hours and 5 days a week all winter, oil generation operating for an average of 8 hours a day for 5 days a week, the full 2 GW imports from France for 4 hours over the darkness peak and
overnight, and a return of 2.2 GW of mothballed plant particularly including 1 GW of non-gas-fuelled generation. For this to happen, market participants would need to make significant preparations prior to the winter.

- If electricity demand were 1 GW lower across the whole day, CCGT gas consumption would be lower by 4.5 mcm. If this were to occur for 50 days, gas demand would be 0.225 bcm lower.
- If there were a combination of very low probability events (e.g. extensive generation failure/unavailability and/or severe winter demands) a balance may be achieved by applying voltage reduction over restricted periods, which should not be discernible to domestic end customers.

Questions for Consultation

We would welcome comments on all aspects of this section, and in particular on the following:

- The extent to which it might be expected that mothballed generation will become available, and when
- The level and direction of flow of the electricity interconnector that might be expected given cold weather in both UK and Europe
- The extent of the electricity demand response that may be expected in response to high electricity prices, and in particular whether this could be materially greater than previously experienced
Section C – Gas / Electricity Interaction

Power Generation Gas Demand - GB

181. The maximum contractual power generation gas demand in GB for winter 2005/06 is shown in Table 10. These figures exclude power stations whose gas supply does not pass through the NTS and smaller embedded power generators, typically Combined Heat and Power stations, which do not participate in the Balancing Mechanism.

Table 10 – Maximum Power Generation Demand 2005/2006 for GB

<table>
<thead>
<tr>
<th></th>
<th>Firm mcm/d</th>
<th>Interruptible mcm/d</th>
<th>Total mcm/d</th>
<th>Number CCGTs</th>
</tr>
</thead>
<tbody>
<tr>
<td>NTS Connected</td>
<td>68.8</td>
<td>24.2</td>
<td>93.0</td>
<td>35</td>
</tr>
<tr>
<td>LDZ Connected</td>
<td>2.5</td>
<td>2.4</td>
<td>4.9</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td>71.3</td>
<td>26.6</td>
<td>97.8</td>
<td>39</td>
</tr>
</tbody>
</table>

182. Across the main part of the 2004/05 winter, the highest daily demand from large power generation sites was only around 70 mcm. Power stations with firm transportation arrangements typically accounted for around 75% of total CCGT gas demand.

Power Stations with Alternative Fuels

183. In GB around 6.9 GW of gas-fired plant has the capability to run on alternative, back up, fuel supplies. Based upon information submitted by generating companies in England and Wales, as required by the Grid Code, the load duration curves for back up fuel capacity is detailed below:

Figure 30 – Load Duration Curves for Back Up Fuel Supplies, England and Wales
184. Figure 30 shows the decay of capacity of generation available from back up fuels with time. The data has been aggregated and smoothed to protect the commercial positions of the individual plants. The two lines show the available generation from starting points of normal fuel stocks and maximum fuel stocks. Note that this graph is not intended to suggest that all plant with back up fuel capability would run continuously on back up fuel supplies for several days or at full load. In reality different plants would adopt different commercial strategies. It would be reasonable to assume that most of this capacity would only run on back up fuel over the peak demand periods of the day.

Potential for Demand-Side Response from Gas Fired Generation

185. Gas-fired stations have the potential 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 power stations with NGT interruptible contracts, with some recent experience of firm CCGTs commercially self-interrupting. Of the total England and Wales CCGT capacity of 22 GW, around 4 GW of commercial interruption has been sufficient to maintain a balance in recent winters.

186. There has been evidence of the electricity market responding to high forward and on-the-day gas prices, but this response was for relatively short periods and on days of non-peak electricity demand and benign electricity prices. The willingness of the CCGTs to commercially interrupt themselves will be determined by the spark spread, which is itself influenced by the ability of the power generation sector to switch to other fuels and the level of electricity demand.

187. Out of a total of 24.2 GW of CCGTs currently declared available in GB for winter 2005/06, 6.9 GW have back-up fuels, most of which have interruptible transportation arrangements. In total 3.2 GW has access to gas through non-NTS pipelines.

188. Given the within-day profile of electricity demand, there is more scope for gas-fired generators to reduce their gas demand outside the peak half-hours of the day, as well as other times of low electricity demand, such as at weekends and during holiday periods.

189. As reported in the October 2004 Winter Outlook Report, we carried out a preliminary analysis to estimate the potential extent of CCGT demand reduction in England and Wales that may be possible in response to high gas prices, whilst ensuring that electricity demand continue to be met. Extending the analysis to a GB market, our updated estimate is based on simulations of gas and electricity demand under historical weather conditions, and requires a number of assumptions over the availability of plant, including the return of mothballed plant, and the potential, both physical and contractual, for generators to switch in response to sufficiently strong price signals. We would welcome feedback on our assumptions and we plan to refine our analysis over the summer, reflecting industry feedback, and to report our findings in our autumn report on the winter outlook.

190. In modelling the ability of the electricity sector to reduce gas demand, we have assumed 2 electricity supply scenarios, which reflect the assumed gas situation in the corresponding gas scenario. As Scenario 1 assumes a less tight gas supply situation, so the electricity market needs to respond less, and we assume 1.2 GW
non-gas-fired plant is returned from mothball, and 1 GW flows from France over peak periods. Under the situation of low gas supply as described in gas Scenario 2., the electricity market is assumed to provide additional response by returning all 2.2 GW of short-term mothballed plant and by importing 2 GW from France over the darkness peak and overnight throughout the winter. We have applied typical unavailability rates to the plant mix assumed in each of our 2 scenarios, as detailed in Table 11.

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

<table>
<thead>
<tr>
<th>Power Station Type</th>
<th>Assumed Availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>95%</td>
</tr>
<tr>
<td>French Interconnector</td>
<td>100%</td>
</tr>
<tr>
<td>Non-BM Generation (including renewables)</td>
<td>50%</td>
</tr>
<tr>
<td>Coal</td>
<td>85%</td>
</tr>
<tr>
<td>Oil</td>
<td>95%</td>
</tr>
<tr>
<td>Pumped storage</td>
<td>100%</td>
</tr>
<tr>
<td>CCGT</td>
<td>95%</td>
</tr>
</tbody>
</table>

191. A key assumption in the modelling was the order in which the various generators are used within the simulation analysis. The assumed ‘ranking order’ varies according to the time of day and day of week, and reflects the following factors:

- Nuclear runs baseload – 24 hours a day 7 days a week
- Under Scenario 2 that imports into GB through the French Interconnector are available continuously overnight and during the peak 4 hours at the full rate of 2 GW, rather than the recent experience of 1.4 GW, at other times we assume the link is at float. Under Scenario 1 the French interconnector operates at 1 GW, rather than 2 GW
- 3.2 GW of CCGTs directly connected to offshore gas supplies, i.e. not necessarily supplied via the NTS, would also operate as baseload, thereby displacing other generation
- Assuming no constraints applied to coal generation in terms of fuel stocks, environmental CO2/SO2 emission limits etc, coal stations are assumed to operate at a maximum load-factor of 85%
- Pumped storage stations generate only during the peak 6 hours of each day
- Oil stations generate only during the peak 8 hours of weekdays
- 6.2 GW of CCGTs run on distillate for 4 hours on weekdays
- As several OCGT units have reserve and response obligations to NGT, they are assumed to be low merit and run only very occasionally
• The market works efficiently and there are adequate and timely signals throughout the winter, such that there is sufficient notice and incentive to substitute coal and other fuels for gas.

192. Figure 31 illustrates how demand would be met under Scenario 2 on a typical cold day in a severe winter. Under these Scenario 2 conditions in a severe winter, assuming there are clear price signals encouraging the market work to efficiently and in a timely manner, it is possible for CCGTs to provide relief to the gas market by around 3 bcm over the top 100 days. Specifically, this would require extensive switching from gas-fired generation to coal, those CCGTs capable of running on distillate doing so for 4 hours and 5 days a week all winter, oil generation operating for an average of 8 hours a day for 5 days a week, the full 2 GW imports from France for 4 hours over the darkness peak and overnight, and a return of 2.2 GW of mothballed plant particularly including 1 GW of non-gas-fuelled generation. For this to happen, market participants would need to make significant preparations prior to the winter.

193. For comparison, the weather experienced in 1985/86 was around 1 in 10 cold. The response necessary this winter, were we to experience similar weather, would be approximately 3.7 bcm

**Figure 31 – Scenario 2 cold winter weekday**

194. Table 12 summarises the extent to which our modelling has indicated that the electricity sector could in theory provide relief to the gas market under the various combinations of weather and supply scenarios considered in this section.
### Table 12 – Maximum Gas Demand Relief achievable by CCGT gas demand management, bcm

<table>
<thead>
<tr>
<th></th>
<th>Scenario 1</th>
<th>Scenario 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Winter</td>
<td>None required</td>
<td>The required level of 0.3 bcm</td>
</tr>
<tr>
<td>Severe Winter</td>
<td>1.6 bcm</td>
<td>3.0 bcm</td>
</tr>
</tbody>
</table>

195. However, the ability of the markets to operate in a manner consistent with our assumptions remains largely untested given the succession of mild winters experienced in recent years, which has necessitated only a low requirement for gas demand-side response. In particular, the ability of the electricity market to switch to a significantly reduced gas demand will be entirely dependant on the right price signals triggering the appropriate response early enough.

196. As detailed in Section B, a decline of 1 GW in baseload gas-fired generation for 50 days reduces total gas demand by 0.2 bcm. 3 bcm demand response is therefore equivalent to 7 GW less baseload CCGT running for the top 100 days. Gas demand side response could also be achieved indirectly if the electricity demand response to high prices is greater than that observed to date and assumed in our modelling. However, the scale of total demand response assumed in our modelling is far in excess of that either required or seen to date.

197. We would welcome feedback on our assumptions and we plan to refine our analysis over the summer, reflecting industry feedback, and to report our findings in our autumn report.

### Summary

- Our analysis suggests that under Scenario 2 a potential contribution from the CCGT sector of 3 bcm may be theoretically possible under 1 in 50 winter conditions provided the market reacted in such a way as to minimise gas demand from CCGTs. Specifically, this would require extensive switching from gas-fired generation to coal, those CCGTs capable of running on distillate doing so for 4 hours and 5 days a week all winter, oil generation operating for an average of 8 hours a day for 5 days a week, the full 2 GW imports from France for 4 hours over the darkness peak and overnight, and a return of 2.2 GW of mothballed plant particularly including 1 GW of non-gas-fuelled generation. For this to happen, market participants would need to make significant preparations prior to the winter.
- For comparison, the weather experienced in 1985/86 was around 1:10 cold. The response necessary this winter, were we to experience similar weather, would be approximately 3.7 bcm
- This compares with an overall requirement under severe weather conditions of between 2.5 and 5.2 bcm indicated by our preliminary analysis of the 2005/06
position. We intend to review this gas-electricity interactions analysis prior to publication of our autumn report

Questions for Consultation

We would welcome comments on all aspects of this section, and in particular on the following:

- The ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests may be theoretically achievable in a severe winter. In particular:
  - Our assumptions relating to the generation running order under very cold weather conditions
  - The extent to which the electricity market prices will be able to achieve levels compared to gas prices such that they will determine that CCGTs will continue to burn gas at peak electricity demand periods
  - The ability and willingness of CCGT generators to switch to distillate
  - Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks
  - The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation
  - The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints, carbon emissions and fuel stocks
Section D – Ongoing Developments to Industry Codes and Arrangements

198. This section reflects ongoing industry discussions concerning the development of the commercial frameworks relating to security of supply.

199. There are a number of initiatives and modification proposals that have recently concluded, or which are currently in progress, in both the gas and electricity markets, that may impact upon security of supply for winter 2005/06 and beyond. This section reflects the range of industry discussions that are currently taking place, or have taken place over recent months, concerning the development of commercial frameworks relating to security of supply. However, the timescales associated with code governance processes, Safety Case submissions, and any necessary development of IT systems to implement modifications, may prohibit some of these changes taking effect before winter 2005/06.

Uniform Network Code

Imbalance Prices

200. NGT welcomes Ofgem’s announcement of a review of the current electricity and gas cash-out arrangements. We consider that the design of cash-out pricing mechanisms should strive to reflect all the costs incurred in balancing the system. The market would then have a clear signal of the costs of securing the system during the balancing period and market participants would have the incentives to try to ensure balance for low probability events.

201. A priority area for the Cash-Out Review within the gas regime is the determination of the emergency cash-out price. An actual or potential GS(M)R Safety Storage Monitor Breach can trigger a Gas Deficit Emergency (GDE). The creation of the Storage Safety Monitors, and the potential for a Monitor Breach to trigger an emergency, has made the potential of a GDE more predictable. NGT supports Ofgem's view that the prevailing emergency cash-out arrangements, where cash-out prices revert to a 30-day average of SAP, may not appropriately incentivise Users to take all actions that might avoid a GDE being triggered. NGT intends to raise a UNC Modification proposal to change the emergency cash-out prices to bring them more into line with market prices on the day of a Gas Deficit Emergency.

202. A number of other aspects of the gas emergency arrangements, including the timing of market suspension, the impact on cash-out volumes of emergency interruption and the emergency claims process, have also been discussed within the Cash-Out Review. In the event that the Cash-Out Review finds solutions that will strengthen security of supply incentives, NGT will consider raising UNC Modification Proposals in these areas.
Gas Interruption

203. Modification Proposals 0740 and 0740a are currently with Ofgem for decision. Approval of either Proposal would remove NGT’s ability to initiate interruption of demand for supply and demand management. The rationale and logic that underpins both proposals is that, by ensuring all interruption is driven through market processes, the correct signals and incentives will be in place for shippers to balance their own positions, potentially reducing the likelihood of interruption and thus increasing security of supply. If the Authority approves one of the Proposals prior to July 2005 it is likely that it could be implemented in time for this winter, although implementation would be dependent on the submission and approval of a revised GT Safety Case by the HSE.

DTI Information Provision Initiatives

204. As a consequence of the conclusions reached in its Report into the operation of the GB gas markets and high gas prices, the DTI established a joint working group (DTI, Ofgem, UKOOA and NGT) to examine the provision of offshore information to the wider market. Initially, only the provision of offshore information was considered but this was later extended to include information pertaining to the offshore/onshore ‘interface’, e.g. sub-terminals, as it was considered by some that this could also provide important signals to the market.

205. The DTI Information Initiative has consisted of three phases:

- Phase 1 – the standardisation and improved provision of operational data to NGT in relation to planned and unplanned supply reductions from upstream parties
- Phase 2 – the provision of detailed information from upstream parties to support Transco in refining its annual Transporting Britain’s Energy (TBE) processes
- Phase 3 – the agreement and progression of the categories of information, relative to the offshore/onshore interface, to be published by NGT

206. Phase 3 saw the development of four categories. These categories and the associated timescales for publication of information are detailed below:

- Category 1 - Real-time flows into the NTS at sub-terminals (from 1 July 2005)
- Category 2 - Forecast flows into the NTS at sub-terminals (from 18 March 2005)
- Category 3 - Deliverability with respect to Planned Maintenance (from 1 October 2004)
- Category 4 - Sub-terminals ‘End of Day’ flow data (from 1 October 2004)

207. The DTI working group agreed that due to confidentiality, data ownership and liability issues, Categories 1, 2 and 3 would be published on an aggregated, zonal (North/South) basis. Furthermore, due to timing and data accuracy issues, the DTI working group also agreed that data associated with Categories 1 and 2 would be published ‘within day’, on an hourly frequency.

208. The publication of this information marks the culmination of almost two years of detailed discussions, consultation, and commitment to provide equitable and timely
access to operational and commercial gas information. It is considered that its provision will increase the usefulness of published information, allowing Users to more efficiently manage their requirements and provide timely response to market needs.

**Provision of NTS Shrinkage Information**

209. NGT acknowledged that the provision of shrinkage gas information would assist those Users that wished to monitor Transco's performance, in its role as Shrinkage Provider, against the NTS SO incentives. Transco raised Modification Proposal 0692 "Provision of Shrinkage Information: Gas Procurement & Disposals" in order to facilitate the publication of such information. Following Ofgem approval, this information is now being published.

**Provision of Historic Storage Monitor Data**

210. Since October 2004 NGT have provided weekly reports of storage stock movements in relation to the storage “firm” and “safety” monitors. Following consumer request, and approval from storage operators, NGT now provides an historic account of this weekly information. This allows Users to more easily monitor trends in storage use and adjust their actions accordingly. The information can be found on the Our Services section of the Transco web-site.

**Connection and Use of System Code**

**Short Term Transmission Access**

211. CAP070 was implemented in November last year. This CUSC change provides the ability for mothballed plant to secure, where available, access to the Transmission System for short periods of time without having to pay for a full year's worth of access rights. It is hoped that the change will provide opportunity for generators to respond to the sharper market signals that now exist, allowing generators to bring plant back in a timely and economic manner at the times when it is most needed. Short Term Transmission Access has already been granted for periods during summer 2005, and 2005/06 will be the first year where Short Term Transmission Access will have been available for the whole winter.

**Intertrips**

212. The arrangements associated with the obligation to provide, and remuneration for, System to Generator Operational Intertrips have recently been discussed by the industry as part of CUSC Proposal CAP076. CAP076 seeks to clarify Operational Intertrip arrangements and is currently with the Authority awaiting a decision. Operational Intertrips are an integral and necessary part of the GB Transmission System and provide a prudent mechanism for maximising the available generation during critical/forced outages.

**Maximum Generation Service**

213. CAP071 introduced an enduring and transparent process for securing access to generation that would not be available to the System Operator under normal operating conditions. The service makes use of small amounts of extra generation that a generator may be able to supply for short periods of time over and above its
Transmission Entry Capacity (TEC) but would not offer into the normal market arrangements. The service is initiated via an emergency instruction issued by the System Operator and is delivered on a best endeavours basis. Payment and other commercial details are contained within the CUSC. NGT has Maximum Generation contracts in place for winter 2005/06 that provide potential access to a 1000 MW of extra generation in emergency situations.

**Grid Code**

**Review of Electricity Market Information**

214. The Electricity Transparency Review, carried out by NGT during 2004, has resulted in some significant changes to the information that is made available to the market. These changes have improved the visibility, clarity and understanding of system requirements whilst providing more appropriate and timely notice of control room actions. It is hoped that the changes will lead to an improvement in the ability of industry parties to interpret and adequately respond to these signals, thus increasing overall market efficiency and enhancing security of supply.

215. Some of the key changes resulting from the review include:

- Improvements to the quality, timeliness and usefulness of market forecast information;
- A change to the definition of Output Usable and treatment of Breakdown Allowance to provide consistent forecasts of plant margin.
- Increased frequency of forecast demand and availability information published on the BMRS;
- The introduction of ‘Day Ahead’ and ‘Day +1’ data that allows for a more informed position in relation to reserve requirement and plant availability; and
- More timely publication of cost and utilisation data associated with Balancing Services.

216. It is expected that, prior to this coming winter, NGT will also be in a position to publish near real time System Operational data and notification of warming instructions.

217. The transparency of information within the GB Electricity market is now widely recognised as being “world class”. It is NGT’s view that this transparency of information results in sharper market signals, which in turn should increase ability of Parties to balance their positions resulting in a subsequent increase in security of supply.

218. Following on from the improvements made to the clarity and Transparency of market information during 2004, NGT is currently chairing a working party to consider the appropriate planning information requirements under OC1 and OC2 of the Grid Code. Changes to clarify and increase the usefulness of this data will be proposed for implementation prior to winter 2005/06.
219. Much of the information that is provided by generators under the terms of OC1 and OC2 is made available to the wider industry on the BMRS via requirements within the BSC. NGT is also about to initiate discussions with the industry to identify appropriate changes to the detail and structure of the BMRS. For example, NGT believes that it may be beneficial to provide a breakdown of generation availability by plant type to give visibility of that proportion of plant that is weather dependent. These general discussions are likely to lead to a BSC Modification that changes the Grid Code planning information sent to the BMRS and results in changes to the format and structure of the BMRS itself. The aim of any change will be to improve the relevance and meaning that can be drawn from the planning information provided to the industry.

Balancing and Settlement Code

Imbalance Prices

220. NGT welcomes the opportunity to be involved in Ofgem’s Cash-Out Review. The terms of reference for the review look to identify improvements that can be made to market signals via cash-out arrangements, and potential improvements to the emergency arrangements that can be made prior to winter 2006/07.

221. One of the drivers for the initiation of the review was the industry debate and discussion that developed following the Marginal Pricing BSC Modifications (P135, P136 and P137). NGT continues to believe that current electricity market arrangements fail to deliver appropriate signals to ensure that sufficient plant is made available at times of system stress. It remains NGT’s view that one means of increasing the effectiveness of market signals would be to introduce some form of marginal pricing methodology to the calculation of electricity imbalance prices.
Appendix I – Glossary

GS (M) R Safety Monitor
GS (M) R Safety Monitors are monitors designed to ensure that sufficient gas is held in storage to underpin the safe operation of the gas transportation system. There are separate safety monitors for each storage facility type (long, medium and short duration storage) each determined by NGT under the terms of its Transco Safety Case. Total shipper gas stocks should not fall below the relevant monitor level (which declines as the winter progresses). NGT is required to take action (which may include use of emergency procedures) in order to prevent a breach of the monitors.

1 in 20 peak day gas demand
The 1 in 20 peak day gas demand is the peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters each winter being counted only once.

The 1 in 20 standard is the established security standard in the gas industry for the peak day. Under its Gas Transporter Licence, Transco is required to develop its system to have the capacity to transport 1 in 20 peak demand.

1 in 50 severe annual gas demand
The 1 in 50 severe annual gas demand is the annual demand represented by the area (above a demand threshold of zero) under the 1 in 50 load duration curve, being the curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of 50 years.

The 1 in 50 standard is the established security standard in the gas industry for severe winter planning. The Uniform Network Code requires Transco to forecast 1 in 50 system demand, and this forecast is used in its storage monitor calculations.

Total Firm Monitor
Total Firm Monitors are illustrative monitors designed to identify the storage requirements to meet firm demand under severe conditions. There are separate firm monitors for each storage facility type (long, medium and short duration storage), each determined by NGT to meet its Uniform Network Code requirements. As the monitors are illustrative, for shippers to determine their storage needs through the winter, NGT does not take any action in order to prevent a breach of these monitors.
Undiversified Demand

Diversity in the context of gas demand refers to how the demands at different points of the network are added together. To forecast undiversified demand, the peak demands are calculated for each location separately and then summed. Modelling the aggregated demands over all locations first, and then calculating peak day demand from the aggregate number, creates a forecast of diversified demand.

Electricity Demand

Unless otherwise noted, the electricity demands used in this report include pumping loads (which tend to be rare at times of peak demand), generating station demand, and flows to Northern Ireland. Exports to France at times of system peak (which tend to be rare) are excluded. Demand is also restricted (i.e. after customer demand management).

Average Cold Spell (ACS)

Under Special Condition C17 of the Electricity Licence, the licensee is required to plan, develop and operate the licensee’s transmission system in accordance with “GB Transmission System Security and Quality of Supply Standard”, Version 1 (dated November 2004) (known as the SQSS), among other standards.

The SQSS includes the following definitions:

ACS Peak Demand

The estimated winter peak demand on the NGC Transmission System for the Average Cold Spell (ACS) condition. This includes both transmission and distribution losses and represents the demand to be met by Large Power Stations (directly connected or embedded), Medium and Small Power Stations which are directly connected to the NGC Transmission System and by electricity imported into the NGC Transmission System from External Systems across External Interconnections.

Average Cold Spell (ACS)

A particular combination of weather elements which give rise to a level of peak demand within a financial year (1 April to 31 March) which has a 50% chance of being exceeded as a result of weather variation alone.

The ACS Peak Demand is used in the SQSS in the derivation of the required Planned Transfer Capacity of the Transmission System.

In order to generate the forecast ACS, the weather conditions seen in each week over a rolling historic 30-year period are analysed and a probabilistic distribution generated. The weather conditions are described using NGT derived variables for temperature, cooling power and illumination from MET Office data. The probabilistic distribution is used to generate both the average (normal) and ACS demand forecasts.

The median of the distribution of maximum winter demand corresponds to the ACS demand forecast (which typically occurs in weeks 50/51 or weeks 2/3). This ACS demand forecast has a 50% chance of being exceeded in any winter.
The Normal weekly peak demand forecast for each week is the median of the weekly peak demand distribution for that week. Multiple simulations determine this for each week using the rolling 30-year historic weather base into the NGT weekday peak demand forecast model (as published to the market on the BMRS).

Operating Reserve

Short-Term Operating Reserve Requirement (STORR) consists of Short Term Reserve (STR) and Reserve for Response. STR is the availability of generation or demand reduction maintained by NGT that can be manually instructed to allow for the effects of Electricity Demand Forecasting Errors or Generation Shortfall between the Final Planning Stage (3-4 hours ahead of Real Time) and Real Time itself. Response is necessary to manage second by second fluctuations in frequency caused by a mismatch in generation and demand. Reserve for Response is the headroom on synchronised plant necessary to deliver such Response.

Day Ahead Contingency Reserve is the additional reserve required over and above the Short Term Operating Reserve Requirement to allow for the effects of Electricity Demand Forecasting Errors or Generation Shortfall between the day ahead stage and the Final Planning Stage.

Transmission Entry Capacity (TEC)

The volume of TEC purchased by a generator sets the maximum volume of power that the Power Station can flow onto the Transmission System. TEC can be purchased on an annual basis and is applicable from 1st April each year, or on Short Term basis for periods of 4 weeks.