Winter Outlook Report 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 of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated 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, National Grid 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 year, recognising that our sources of data are necessarily incomplete, we have conducted a consultation exercise designed both to help inform the industry and also to provide us with feedback to support the production of this report.
3. Our May 2005 consultation document[1] used two supply scenarios for the coming winter as a basis for discussion and comment by others. In addition to the scenarios we also provided a range of sensitivities to enable the industry to extrapolate the potential circumstances that might develop given variations to the input conditions. The basis for the analysis in this report is a single base case, comprising assumptions regarding beach gas availability, generation availability, importation flows (gas and electricity) and gas storage.
4. The base case uses the latest information and analysis available to us. In particular, our assessment of the gas supply-demand outlook is based on our 2005 forecasts, which have been derived using data collected in the course of the 2005 Transporting Britain's Energy (TBE) consultation process. It therefore takes account of the latest information obtained from producers, shippers, end-users, gas importers, storage operators, consultants and other interested parties. The base case has also been guided by responses to our May consultation document, a summary of which is contained in Appendix 1.
5. Notwithstanding our use of a single base case, there remains a considerable level of uncertainty around the winter supply conditions. As we noted in our May consultation, 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.

[1] 'Consultation on Winter 2005/06' available at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/11584_14405b.pdf

Security of supply will therefore significantly depend upon the commercial arrangements relating to the importation of energy and demand-side response. This market backdrop inevitably creates uncertainty. We do, however, believe that the base case represents a balanced view of the data we have received.

6. Recognising that actual supply conditions could depart from the base case to a material extent, we have also updated the sensitivity analysis, which quantifies the potential impact on the supply-demand balance of a range of variations to the input parameters.
7. The focus of this report is the supply-demand outlook in the gas and electricity markets for the 2005/06 winter, and the associated interaction between the two markets. The document has four main sections. Sections A and B present an overview of this coming winter with a focus on the gas and electricity supply-demand balances respectively, whilst Section C considers the interactions between the two markets. Section D summarises developments to the commercial frameworks in both markets.
8. Electricity System Operation under BETTA commenced on 1 April 2005, and therefore all 2005/06 data is presented on a Great Britain base.
9. National Grid operates the electricity transmission network under the National Grid Electricity Transmission licence and the gas transmission network under the Transco Gas Transporter licence. National Grid also operates four of the gas distribution networks in Great Britain, although this report has been written from the perspective of our transmission activities. For the purpose of this report "National Grid" is used to cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licences.
10. This document has been prepared by National Grid for, and in consultation with, Ofgem in good faith. National Grid has endeavoured, as a reasonable and prudent operator, to prepare this document in a manner which is, as far as possible, objective, using information collected and compiled by National Grid from users of the gas transportation and electricity transmission systems together with National Grid's own forecasts of the future development of the gas transportation and electricity transmission systems. National Grid considers that, to the extent that the information contained in this document is derived from members of the National Grid group of companies (the "Group"), the contents of this document are true at the time of publication to the best of its knowledge and belief as a reasonable and prudent operator. While National Grid has not sought to mislead Ofgem or any other party as to the contents of this document, industry participants should rely on their own information when determining their respective commercial positions.

Summary

Winter Outlook - Gas

11. 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. The uncertainty arising from this combination of variables and the confidential nature of the commercial arrangements between suppliers and consumers led us to consult with the industry on a number of issues associated with the outlook for the 2005/06 winter.

12. Using the feedback received in the course of this consultation process, and our latest information and analysis derived under our 2005 TBE process, we have arrived at the following set of base case assumptions, applicable to the assessment of gas availability over a winter duration:

    - maximum daily gas delivery at the beach of around 327 mcm/d (24 mcm/d lower than our post-winter assessment of the 2004/05 maximum beach capability).
    - average beach gas availability of 92.5% of the maximum beach forecast, leading to an average beach delivery level of 303 mcm/d, consistent with the views of the DTI.
    - Interconnector imports at an average level of 42 mcm/d, equal to the present level of capacity plus 75% of the additional capacity, completion of which is now targeted for November 2005.
    - Grain LNG imports at an average level of 13 mcm/d, equal to the contracted level of capacity but less than the maximum physical capability. However, on the very highest demand days it is reasonable to assume a delivery level of 17 mcm/d, towards the maximum physical capability.
    - 75% of new and enhanced storage capacity available.

13. The net effect of the Interconnector and Grain LNG elements is an assumed average level of new imports of 30 mcm/d. While there is some upside to this, we also recognise that there may be circumstances in which daily import levels are materially lower.

14. With modest growth in the domestic sector counter-balanced by an expected reduction in demand from large consumers, our latest forecast of total demand is very similar to our forecast for 2004/05, which underpinned our 2004 Winter Outlook Report.

15. Our base case assessment suggests that gas availability at peak for the forthcoming winter will be around 20 mcm/d lower than that for the 2004/05 winter (as presented in our 2004 Winter Outlook Report).

16. Using these base case assumptions, our analysis shows that over the winter period, even in 1 in 50 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.

17. However, significant demand response will be required if colder than average weather is experienced or gas deliveries are below our base case levels. For example, in severe weather, where national temperatures average around -2 ^{o}C over a month and +2 ^{o}C over a further 2 months (statistically a 1 in 50 cold winter), the required demand-side response could increase to around 3.7 bcm, which would be equivalent in scale to over 60 mcm/d for around 60 days. If Great Britain were to experience a repeat of 1985/86 weather - the last very cold winter, statistically around 1 in 10 cold - our base case assumptions suggest a required demand-side response of 2.2 bcm.

18. 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 ^{o}C, a demand response of around 70 mcm/d would be required under the base case. 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.

19. It is unlikely that National Grid will use its interruption rights to contribute materially to this required response from large customers, as we do not have rights to interrupt for reasons of supply and demand. Our interruption rights are limited to the mitigation of network capacity constraints. Other than in specific, localised cases, we do not expect such constraints to occur in the coming winter. In developing their gas supply portfolios, it would therefore be inappropriate for shippers and suppliers to assume that National Grid would initiate interruption in the event of cold weather.

20. Since we published our May consultation document, we are aware of a number of initiatives by suppliers and consumer groups seeking to facilitate demand-side response should it be required this winter. In particular, the Demand-Side Working Group, led by Ofgem, has worked hard to identify and eliminate any barriers to demand response, and to improve the level and quality of information available to the market through the course of the winter.

21. Earlier in 2005, the DTI and Ofgem published a study by Global Insight to review the extent to which the energy intensive industries (excluding power generation) would respond to high prices by reducing 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[2]. 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.

22. Respondents to our consultation were, however, generally cautious over the extent to which customers may be prepared to curtail demand for prolonged periods.

[2] This includes a direct gas response and an indirect response through reduced electricity demand resulting in lower CCGT gas demand.

23. In our May consultation document, we published indicative initial 2005/06 storage safety monitor levels. We have reassessed these initial monitor levels on the basis of our revised supply and demand assumptions. These were recently published, and reflect initial levels of 26% for short-range storage, 13% for medium-range storage and 23% for long-range storage. We will keep the level of the safety monitors under review through the course of the winter, and make further changes if it is appropriate to do so. For example, we may have to amend the monitors if we receive new and tangible information, e.g. relating to a long-term outage of a major supply facility. Conversely, a material reduction in supply-side risk could allow the monitor levels to be reduced.

Winter Outlook – Electricity (Great Britain base)

24. The latest Seven Year Statement Update reports a plant margin of 21%. This is derived from a measure of generation availability based on generators bookings of Transmission Entry Capacity (TEC) (75.3 GW) and a forecast of Average Cold Spell (ACS) peak demand using our customers' projections (62.1 GW).

25. The National Grid forecast of ACS winter peak demand for the coming winter is 61.9 GW. The 1 in 20 peak demand forecast is 64.9 GW.

26. At an operational level, generators provide us with more detailed information about their expected availability. Using this information, there is currently 72.6 GW of capacity operationally available during winter 2005/06, assuming full 2 GW import from France. In practice, the direction and level of flow on the Interconnector is heavily influenced by the differential in electricity prices between the UK and Europe.

27. Our operational view of available generation capacity is lower than that based on TEC bookings as not all generation is available to National Grid in the Balancing Mechanism. This additional generation, however, continues to be available to the market to meet demand. There is also around 0.7 GW of generating plant that has purchased TEC but is declaring itself unavailable for this winter.

28. There is a further 3.7 GW of generation currently mothballed, of which we understand that 2.1 GW can return for this winter. We have been told that the remaining 1.6 GW cannot physically be returned to service in the required timescales.

29. Consistent with the base case for gas supply and demand, we have modelled a set of conditions for electricity supply. Our base case assumes the electricity market would respond to lower gas availability, with 2.1 GW of currently mothballed plant returning to service, and the full 2 GW of imports seen throughout the winter over the darkness peaks.

30. These assumptions anticipate strong market reaction to the prevailing circumstances. Last winter, 0.7 GW of mothballed plant was returned to service immediately before the winter, and the Interconnector provided an average of 1.3 GW over the peak periods.

31. At times of high electricity demand and high electricity prices, customers reduce their demand to avoid transmission charges ('triad avoidance') and high energy prices. Around 0.8 - 1.3 GW of such reductions has been observed in the past, and the feedback we have received supports our assumption of around 1 GW in our forecasts for normal, ACS and 1 in 50 cold conditions. This reduction in demand is likely to

occur more often given a prolonged period of cold conditions and associated high prices.

32. Taking account of the above assumptions, the projected level of generation availability would be sufficient to meet demands expected under ACS conditions. In 1 in 50 cold winter conditions, where temperatures across the country average -2 °C for 30 days, and +2 °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.

Winter Outlook– Gas-Electricity Interaction

33. We have undertaken simulation analysis to estimate the potential contribution that might be available from the CCGT sector to the required gas demand-side response. This uses our latest supply and demand forecasts and takes account of feedback received on the preliminary analysis presented in our May consultation document.

34. The analysis suggests that in a 1 in 50 cold winter, a response of 1.8 bcm (of the 3.7 bcm required) may be achievable provided the market reacted in such a way as to minimise gas demand from CCGTs throughout the winter period. Specifically, this would require extensive use of coal-fired generation, those CCGTs capable of running on distillate doing so for 200 hours, 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 2.1 GW of mothballed plant.

35. The scale of potential demand response estimated in our modelling is far in excess of that required (and therefore seen) to date, and we believe that while this potential level of response is feasible, it is towards the upper end of possibilities. There is a specific issue of environmental limits, particularly those relating to SO_2 emissions. These may have the effect of limiting the level of coal and oil-fired generation and thereby reducing the potential for CCGT response.

36. A general reduction in electricity demand due to high prices can also provide relief to the gas market, through the reduced requirement for CCGT generation. For example, a 1 GW reduction in electricity demand for 50 days may deliver an additional 0.2 bcm of gas demand relief.

37. While our analysis has identified the potential for the CCGT sector to provide a material level of relief to the gas market if required in a cold winter, it also suggests that there may be a significant residual requirement in such conditions. Table 1 summarises this analysis and illustrates the potential extent of this residual demand-side response requirement in relation to the non-power Daily Metered (DM) sector. It should be recognised that this analysis assumes an effective response from the CCGT sector throughout the winter period. A more limited CCGT response would lead to a greater requirement from the rest of the market.

Table 1 – Summary of Gas Demand-Side Response Analysis

Winter severity	Estimated demand-side response required (bcm)	Potential contribution from CCGT sector (bcm)	Approximate residual requirement as percentage of non-power DM market sector[3]
Average	0.1	0.1	None
1 in 10 cold	2.2	1.3	30% on average over 40 days
1 in 50 cold	3.7	1.8	50% on average over 50 days

[3] These are averages; requirements on individual days may be higher or lower than shown

Section A – Winter Outlook 2005/06 – Gas

38. This section examines the outlook for gas 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 National Transmission System (NTS) will continue to have this capability in 2005/06.

39. Our May consultation document set out two alternative supply-demand scenarios as a means to assess the winter, and supplemented these with an analysis of key sensitivities. Here we present a single base case together with a revised sensitivity analysis.

40. Our assessment of the supply-demand outlook is based on our 2005 forecasts, which have been derived using data collected in the course of the 2005 Transporting Britain's Energy (TBE) consultation process. It therefore takes account of the latest information obtained from producers, shippers, end-users, gas importers, storage operators, consultants and other interested parties. Our choice of base case has also been guided by responses to our May consultation document. While there remains considerable uncertainty around the winter supply conditions, we believe that the base case represents a balanced view.

41. Our May consultation document explained the potential implications of the winter outlook for the setting of the 'GS(M)R Safety Monitors' (safety monitors). As the name suggests, these monitors are designed to protect public safety by ensuring that, even in 1 in 50 winters, safe pressures can be maintained in the transportation network. This section sets out the background to the revised safety monitor levels, which are based on our latest assessment of the supply-demand outlook.

Beach Gas

42. With respect to beach gas availability, our May consultation used the following assumptions:

   - A maximum beach forecast of 336 mcm/d. The maximum beach forecast is a forecast of the maximum level of gas that we could expect at the beach[4] given sufficient demand and assuming no outages.
   - Two scenarios of average percentage beach availability under a period of prolonged cold conditions: 95% in Scenario 1 and 90% in Scenario 2. An availability rate of less than 100% is appropriate in order to take account of beach reliability and other factors that may prevent deliveries at the theoretical maximum rate throughout the winter.

43. Since the publication of the May consultation document, we have had the opportunity to complete our analysis of upstream data received in the course of the 2005 TBE consultation process. We had an excellent response again this year, to the extent that around 90% of the beach data comprising our forecast has been sourced from upstream parties. Using this data, we have revised our maximum beach forecast

[4] Excluding imports from LNG at Grain and through the Belgium – England Interconnector and direct supplies to certain power stations, which do not pass through National Grid's network.

down from 336 mcm/d to 327 mcm/d. The reduction reflects a small amount of additional decline together with an updated assessment of the prospects for new developments aiming to deliver in time for the winter.

44. In the last two years, our post-winter review has suggested that the pre-winter maximum beach forecast was overstated. For example, our reassessment of the 2004/05 maximum beach forecast based on the experience of the winter led us to adopt a ‘hindsight-based’ maximum forecast of 351 mcm/d, 13 mcm/d below the pre-winter forecast of 364 mcm/d. We have therefore questioned whether the TBE process can be expected to systematically over-forecast. We do not believe that this is the case; the key input is the source data received from upstream parties and we have noticed a more conservative approach in the data provided to us this year, suggesting that any bias in previous TBE returns may no longer be present.

45. We have discussed our forecast in detail with the DTI, whose own information supports our assessment. In addition, we have compared our forecast of 327 mcm/d against those of other industry analysts and found that we are at the low end of the range (which extends up to around 360 mcm/d). We have, however, been at the low end of the range for the last two years and found, nevertheless, that our pre-winter maximum beach forecast was overstated.

46. In our May consultation document we presented analysis of beach deliveries over the last six winters to inform the question of the availability rate that should be applied to the maximum beach forecast. The analysis illustrated the importance of the Bacton Shell Esso sub-terminal, where contractual arrangements mean that this sub-terminal generally only flows towards the upper end of its maximum rate at times of very high demand. It is, however, capable of doing so for sustained periods in a very cold winter. Inclusion of Bacton Shell Esso data in analysis of historical availability is therefore likely to be distorting in the context of a very cold winter assessment. Excluding Bacton Shell Esso data suggested an average beach availability rate in the range 90% - 95%, consistent with our two consultation scenarios.

47. Respondents to the consultation have expressed a mixture of views on this issue, although there is general agreement that it would not be realistic to assume 100%. The main difference in view lies between those who believe that prices associated with a very cold winter would be sufficient to drive beach deliveries towards the 95% level, and those who are concerned that offshore reliability could suffer if the offshore system is under strain, as might be expected in such a winter.

48. Given the range of views on this issue, and the fact that we have lowered our maximum beach forecast from 336 mcm/d to 327 mcm/d since the May consultation, we believe that an assumed availability rate of 92.5% (the mid-point of the consultation scenario assumptions) is appropriate. Applied to our revised maximum beach forecast this results in an assumed average beach delivery of around 303 mcm/d, which is consistent with the views expressed to us by a number of parties in the course of the consultation process.

New Importation and Storage Infrastructure

49. 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. For the coming winter, the following new importation and storage infrastructure is expected:

   - Expansion of the Interconnector's importation capacity from 25 mcm/d to around 48 mcm/d through the construction of compression facilities at Zeebrugge. I(UK) has recently announced that it aims to bring forward the commissioning of the expanded capacity by one month to November 2005.
   - LNG importation facilities at the Isle of Grain. National Grid completed the commissioning of this terminal in July 2005.
   - A new mid-range storage facility named Humbly Grove. This is a depleted onshore oil field with a storage capacity of approximately 290 mcm. The facility is expected to be ready for operation in the fourth quarter 2005.
   - A doubling of the deliverability rate at the existing mid-range storage facility Hole House Farm.

50. The developments since our May consultation relating to the Interconnector expansion and Grain LNG increase confidence in the ability of these facilities to flow gas as planned this winter.

51. A number of consultation respondents expressed the view that the market will deliver high levels of imported gas this winter, driven by price differentials between the UK and other markets. However, some respondents were concerned that factors other than price might dictate the patterns of gas flow in very cold conditions given the less advanced nature of liberalisation in Continental Europe.

52. Many respondents recognised that in a very cold winter the potential for coincident cold weather in the UK and Continental Europe could lead to reduced levels of imports through the Interconnector and to the diversion of LNG cargoes from Grain.

53. Supply shocks elsewhere in the world may also impact importation rates. For example, the recent hurricanes in the States caused significant disruption to US gas production and led to a sharp rise in the forward price at the Henry Hub. Prior to the hurricanes, the expectation was that price differentials would favour LNG deliveries to Europe over the US. Given the potential for loss of production to extend into the winter period, the hurricanes have increased the risk that LNG cargoes otherwise destined for Europe could be diverted to the States.

54. Given these concerns, we agree that it would be imprudent to assume full imports throughout a very cold winter. For the Interconnector, we have therefore adopted the more conservative of our consultation document assumptions (Scenario 2) of 42 mcm/d within our base case, recognising that actual flows could be expected both to exceed and fall short of this level on occasions throughout the winter. For Grain, we are assuming an average import level of 13 mcm/d. Although this is the more optimistic of the two consultation scenarios, it is below the physical capability of the facility. There is therefore potential upside as well as downside to this assumption. In

particular, it would be reasonable to expect imports of 17 mcm/d (towards the physical maximum) on the very coldest days in the winter.

55. We had very little feedback through the consultation process on the appropriate assumptions for the utilisation of new storage infrastructure planned for the coming winter. Given that the construction and commissioning of any new plant is not without risk, we are therefore adopting our base case assumption that 75% of this new storage capacity will be available.

Storage

56. Table 2 gives assumed storage space and levels of deliverability from short-range storage (LNG), medium-range storage (MRS) and long-range storage (Rough). These exclude space for Operating Margins gas that National Grid is required to procure 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 MRS duration figures include Hornsea, Hatfield Moor, Hole House Farm and Humbly Grove, with the latter two reflecting our assumption of 75% of new capacity being available.

57. As we outlined in the May consultation, we have recently undertaken 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. Further details of this analysis can be found in our July 2005 TBE document.[5]

Table 2 – Assumed 2005/06 Storage Capacities and Deliverability Levels

Storage Type	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at Full Rate
Short (LNG)	1741	526	49	3.3
Medium (MRS)	8108	315	29	26
Long (Rough)	34126	455	42	75

Summary of Base Case Supply Assumptions

58. Table 3 below summarises our base case supply assumptions, bringing together the respective assumptions for beach supply, Interconnector imports and storage. The level of forecast total supply is approximately 20 mcm/d lower than the equivalent position last winter (as outlined in our 2004 Winter Outlook Report), with the lower beach forecast partly offset by new imports and storage.

[5] Development of Investment Scenarios, available at http://www.transco.uk.com/publish/00base/TBE2005DevelopmentofInvestmentScenarios.pdf

Table 3 – 2005/06 Supply – Base Case Assumptions

Supply (mcm/d)	Maximum	Base Case Assumption	Comments
Beach	327	303	92.5% max beach
Grain	17	13	
IC Imports	48	42	75% new imports
Total Supply ex Storage	392	357	
Existing Storage	114	114	
New Storage	6	5	75% new storage
Total Supply inc Storage	512	476	

Gas Demand

59. Since our May consultation document, we have updated our 2005 demand forecasts[6] on the basis of our latest TBE data. These latest demand forecasts will be published in more detail in our 2005 Ten Year Statement in December. Our revised forecast of total demand is approximately 10 mcm/d lower than our preliminary forecast, making it very similar to our forecast of 2004/05 total demand, which underpinned last year's winter outlook report. The make-up of this total has changed, however, with forecast growth in the domestic sector negated by a reduction in the forecast of large industrial and CCGT demand as a result of increased prices.

60. Our power generation demand forecasts are based on analysis of the historical gas demand of these customers. In general, total power generation demand is fairly flat across the winter period, although there have been a few occasions when we have seen discernible price responsiveness. Accordingly, the 1 in 50 cold winter load duration curve incorporates a reasonably constant daily demand in relation to this sector, broadly equivalent to the average daily historical demand, adjusted for known market changes, principally new connections. The average power sector gas demand within our 2005/06 winter forecast is around 700 GWh/d (65 mcm/d).

61. It should be noted that our gas demand forecasts neither make an adjustment for potential interruption by National Grid for capacity management purposes nor for potential reductions in demand that might occur in response to very high prices in a very cold winter. (However, past experience of demand responsiveness to price – although limited - will have been picked up in our modelling and therefore be implicit within the forecasts).

Interruption for Capacity Management

62. The gas transmission system is designed to meet a 1 in 20 peak day level of demand. The demand on a peak day relates to those customers supplied under firm transportation arrangements but excludes those with interruptible transportation arrangements. It might therefore be anticipated that National Grid could be interrupting consumers for capacity management purposes if demand approached 1 in 20 peak day levels during the coming winter.

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[6] 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

63. However, given the prevailing gas supply forecasts, other than in specific, localised cases in the Distribution networks, we do not expect capacity constraints to occur in the coming winter.

Interruption for Supply-Demand Purposes

64. Since the Network Code was introduced, Transco's interruption rights included the ability to interrupt when demand exceeded 85% of forecast peak day. This therefore enabled Transco to interrupt for supply–demand purposes were it necessary.

65. The potential for Transco to use this right to interrupt led to concerns that this mechanism might interfere with the establishment of appropriate signals necessary for the market to balance supply and demand. We therefore raised a Network Code modification proposal (*Modification Proposal 0740a (0013a) Amendment to Transco's rights to interrupt for supply-demand purposes"),* which the Authority recently approved. This creates the clarity that interruption for supply-demand purposes is the role of shippers and suppliers. National Grid has received approval from the HSE for the revised GT Safety Case that was also required for the implementation of this Proposal. This means that we no longer have rights to interrupt for reasons of supply and demand except under emergency procedures.

66. Given the points above in relation to interruption for capacity management and supply-demand purposes, in establishing their gas supply portfolios going forward, it would be inappropriate for gas shippers and suppliers to assume that National Grid would use its contractual interruption rights in the event of cold weather.

67. We have noted previously 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 National Grid. We do not have access to information regarding supply contracts, though our understanding is that the majority of interruptible contracts in the industrial and commercial sector now stipulate interruption only where called for by National Grid.

68. 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.

Demand-Side Response

69. 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. For example, when prices are high, as may be expected under tight supply-demand conditions, customers may be able to benefit through offering their gas to National Grid via their shipper.

70. In our role as residual balancer, we will accept such offers if needed to ensure a system balance. In extreme circumstances, we would take all offers[7] to increase supply or reduce demand if necessary to maintain system pressures. Ultimately, however, in the absence of sufficient offers, we would have to initiate emergency procedures under which customers would be interrupted without compensation.

71. Since we published our May consultation document, we are aware of a number of initiatives by suppliers and consumer groups seeking to facilitate demand-side response should it be required this winter. In particular, the Demand Side Working Group, led by Ofgem, has worked hard to identify and eliminate any barriers to demand response, and to improve the level and quality of information available to the market through the course of the winter.

72. As we noted in our May consultation, earlier in the year the consultancy Global Insight conducted a study for DTI and Ofgem of the potential for demand-side response in energy-intensive industries (excluding power generation)[8]. The study assessed the potential response under a range of prices. Broadly, the analysis indicated a potential gas response of around 8 mcm/d if prices were sufficiently high[9]. The total size of the market that Global Insight analysed is around 25 mcm/d. As Global Insight noted in their report, some commercial and public-sector demand may also respond to price, for example, if they have an interruptible gas contract.

73. Responses to our consultation were mixed over the ability of the market to deliver significant levels of non-CCGT demand-side response. Some respondents suggested that only a limited number of demand-side response arrangements are in place. Others noted that the move towards gas contracts based on spot prices would provide the mechanism by which customers might decide to self-interrupt should the price rise sufficiently high.

74. The Global Insight study also identified the potential for electricity demand response from the same energy-intensive industry 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.

75. In relation to CCGT response specifically, Section C describes analysis that implies a potential for a significant level of response from this sector. 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[10]. Whilst there may be a potential for a high degree of price-response from CCGTs, the level of price

[7] Provided they would be expected to have a material impact on the system balance

[8] "Estimation of Industrial Buyers' Potential Response to Short Periods of High Gas and Electricity Prices" – May 2005, which can be found at: http://www.dti.gov.uk/energy/publications/policy/index.shtml

[9] 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.

[10] 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, even after the impact of the traded price of CO_2 emissions.

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

76. 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 basis of our 1 in 50 cold winter analysis. Our latest analysis indicates that use of the 17 years weather data from 1987/88 has greater statistical validity, and we have used this new data set in our latest analysis of average conditions. However, in the course of our recent analysis we have found no clear statistical evidence that climate change has had an impact on 1 in 50 cold conditions. Indeed, the coldest day since our records began in 1928/29 occurred as recently as the 1986/87 winter. Accordingly, our 1 in 50 cold load duration curves are based on the 76-year weather history.

Gas Supply-Demand Outlook

77. The previous sub-sections have outlined the assumptions underpinning our assessment of 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 1 in 50 cold demand conditions. Figures 1, 2 and 3 show the base case supply assumptions overlaid on a load duration curve of average, 1 in 10 cold and 1 in 50 cold demand respectively, with demand broken down into the Domestic, Other Non-Daily Metered (NDM) and Daily Metered (DM) sectors. For clarity of presentation, the supply lines are smoothed representations of the total availability of supply (beach, imports and storage excluding OM & SIU bookings). The irregular shape of the smoothed supply curve reflects limits on storage space.

78. Figure 1 shows that for average demand conditions the supply availability associated with the base case would be almost sufficient to meet all demand, with a very modest requirement for demand-side response indicated at the top end of the load curve.

79. Figure 2 shows that for demand levels associated with a 1 in 10 cold winter, the analysis suggests the need for a demand response of approximately 2.2 bcm, broadly equivalent in scale to a demand response of 50 mcm/d over a period of around 40 days.

Figure 1 – Average Load Duration Curve Analysis for 2005/06

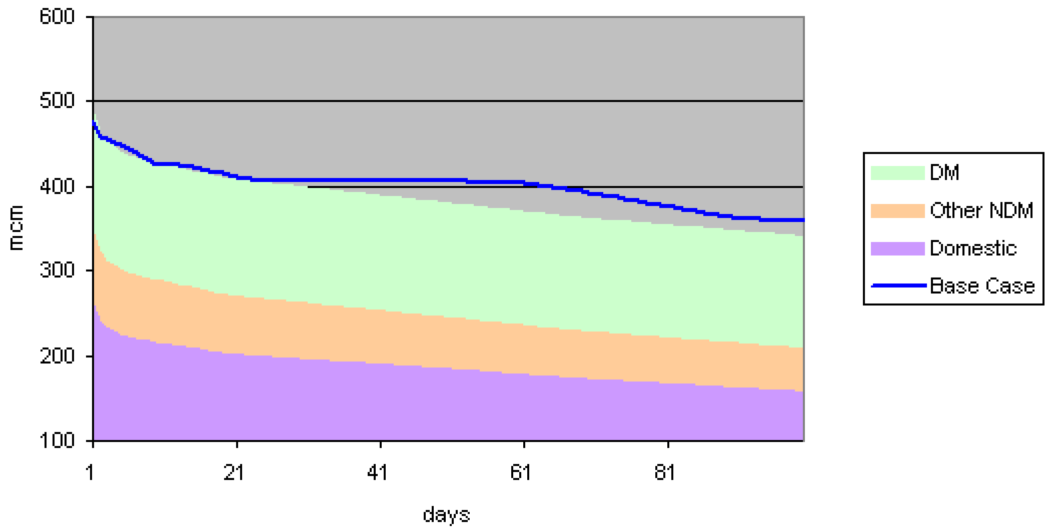


Figure 2 – 1 in 10 Cold Load Duration Curve Analysis for 2005/06

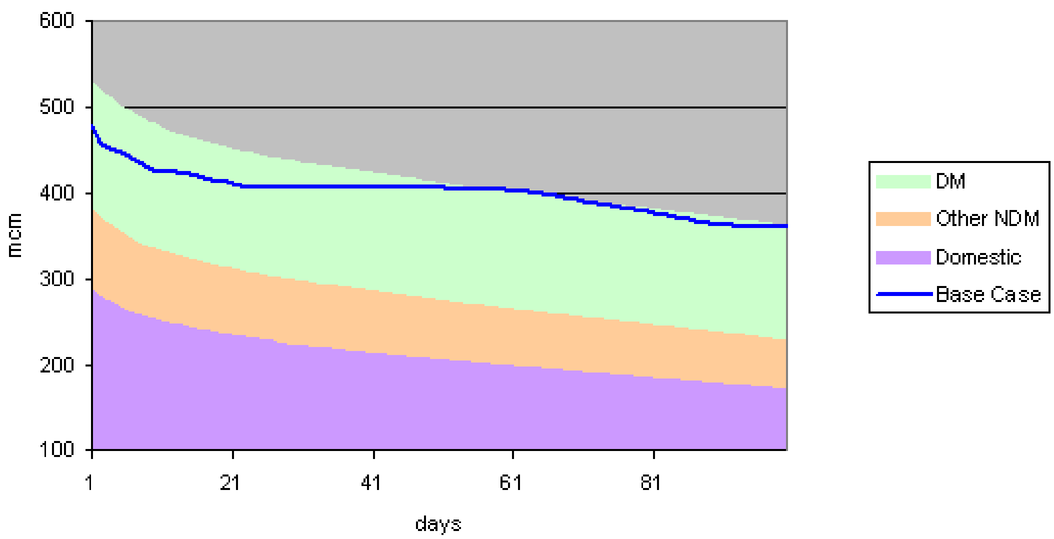
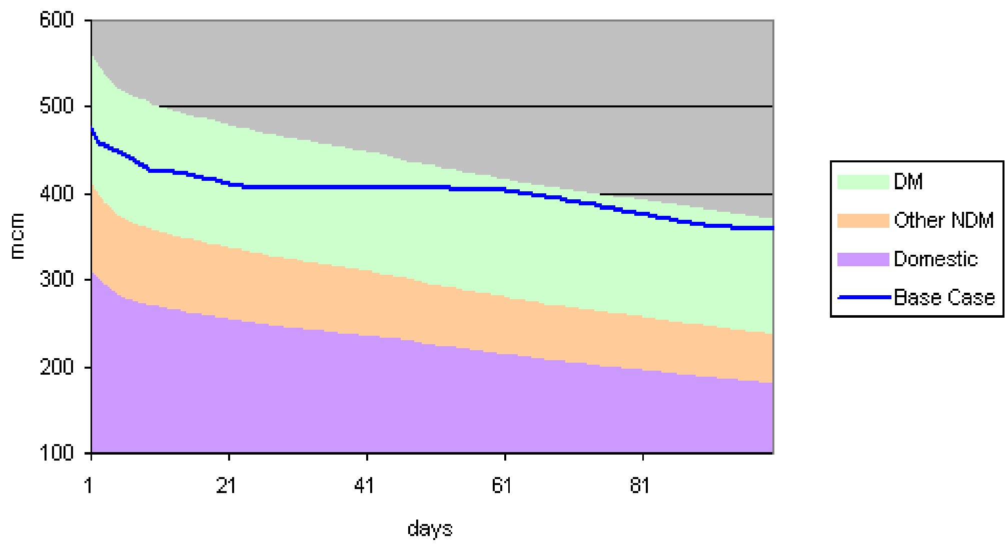


Figure 3 – 1 in 50 Cold Load Duration Curve Analysis for 2005/06

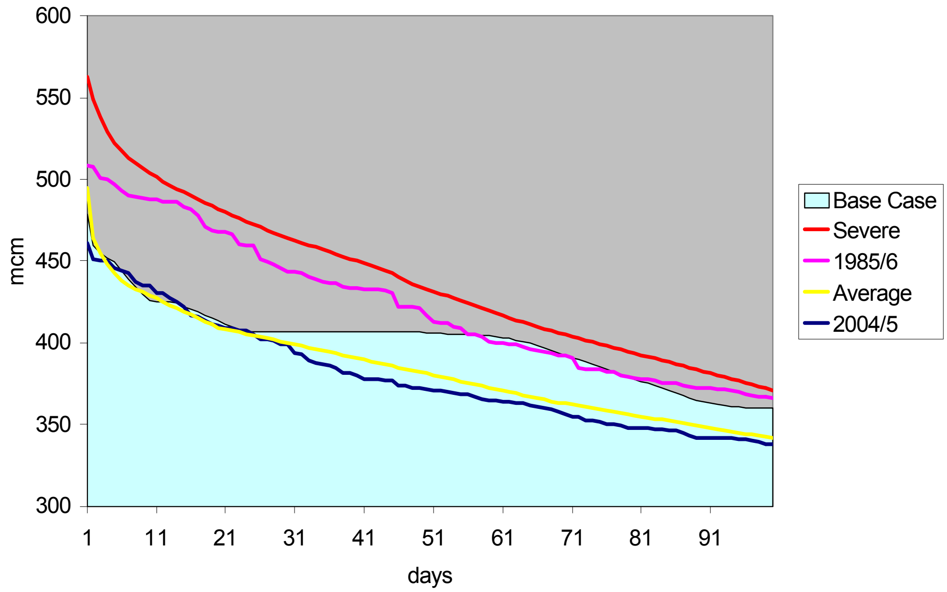


80. Figure 3 shows for that for 1 in 50 cold conditions, when winter temperatures could average around -2 °C over a period of 30 days, and +2°C for a further 2 months, supply availability would not be sufficient to meet all demand. The analysis suggests the need for a demand response of approximately 3.7 bcm, broadly equivalent in scale to a demand response of over 60 mcm/d over a period of around 60 days.

81. In Figure 4, we show the assumed levels of supply set against four levels of demand. These represent average and 1 in 50 cold conditions and projected demands for next winter based on the weather patterns experienced in 2004/05 and 1985/86. These winters were around 1 in 15 warm and 1 in 10 cold respectively. Please note that for ease of presentation these charts, unlike Figures 1, 2 and 3, show demand as lines and supply as coloured blocks.

82. Figure 4 shows that the base case supply availability is practically sufficient to satisfy demands associated with both 2004/05 weather conditions and average temperatures. However, demand response would be required under the other two weather conditions.

Figure 4 – Supply Availability for Base Case



Additional Cold Spell Analysis

83. 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.

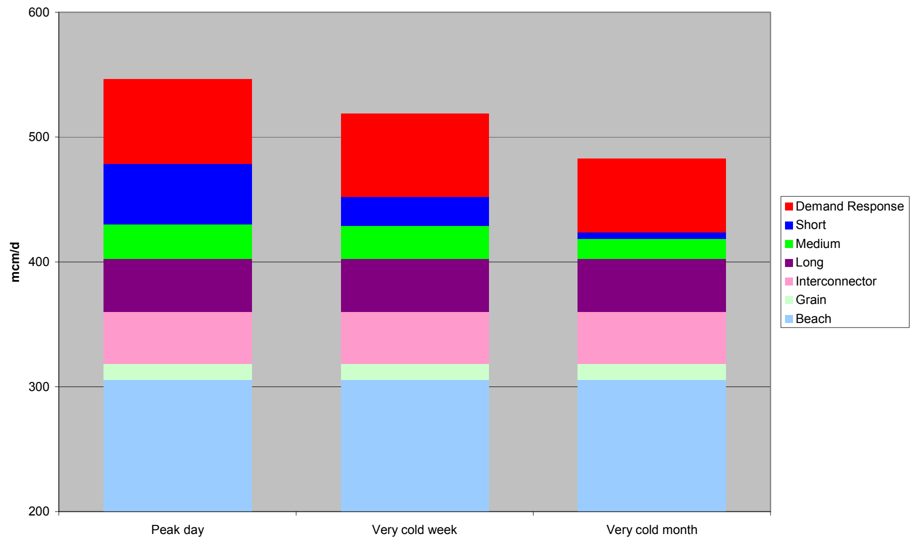
84. Figure 5 shows bar charts consisting of three levels of demand, namely those demands commensurate with a peak day[11], a very cold week[12] and a very cold month[13]. Against these levels of demand is shown the supply availability[14] under the base case, and the associated level of demand response required for supply and demand to balance.

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

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

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

Figure 5 – Cold Spell Analysis for 2005/06



86. The analysis illustrates that for a 1 in 20 peak day with average temperatures across the country around -5 ^{o}C, a demand response of nearly 70 mcm/d would be required.

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

Sensitivity Analysis

88. Table 4 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.

89. The base case analysis and the 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.

Table 4 – Demand Response – Sensitivity Analysis

Sensitivity	Comments	Contribution to Required Response (bcm)
Every 10 mcm/d of DM demand reduction	Full response for 100 days	1.00
10% response of non power DM	Full response for 100 days	0.71
10% response DM power	Full response for 100 days	0.65
Response from CCGTs	~25 mcm/d for top 100 demand days	2.50
Every 1% of higher beach supplies	Top 100 demand days	0.33
Beach performance	Each % reduction in beach below 92.5% across 100 days	-0.33
Interconnector floats (no flow)	Per week	-0.29
Grain imports at maximum capacity	Top 100 demand days	0.42
No imports through Grain	Top 100 demand days	-1.29
Winter Medium duration storage cycling	10% of inventory for cold winters	0.08

Implications for Safety Monitors

90. As we noted in the introduction to this section, the requirement to operate a system of safety monitors has been introduced to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. This is embodied in the Gas Transporter's safety case as required by the HSE. If storage withdrawal nominations imply that one or more monitor would be breached, National Grid 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. The purpose and operation of the safety monitors is explained in more detail in Appendix 2.[15]

91. In our May consultation we identified the impact of our two scenarios for the initial safety monitor levels, and we published indicative monitor levels on the basis of Scenario 2 (the more conservative of the two). This gave initial levels of 54% for short-range storage, 13% for medium-range storage and18% for long-range storage. We also noted that these were to be reconsidered in the light of feedback on the consultation document, and kept under review prior to and throughout the winter period.

[15] The methodology for calculating the safety monitors is described in our Safety & Firm Gas Monitor Methodology document, which will be updated in October to reflect the 2005/06 calculation. This can be found at: http://www.transco.uk.com/publish/forecast/Safety_Firm_Gas_Monitor_Methodology_v1.pdf

92. While some respondents supported the setting of monitors on the basis of Scenario 2 as set out in the May consultation document, others expressed significant concern at the potential impacts of monitors set at relatively high levels. In particular, concerns were expressed over the possible effect on the efficient operation of the market if storage stocks approached monitor levels.

93. We have reassessed the basis for setting the initial monitor levels using our set of base case supply assumptions as the starting point. However, we have also reassessed whether these assumptions are appropriate inputs for all aspects of the monitor setting methodology, and have concluded that two further adjustments are appropriate.

94. First, the base case assumptions represent the levels of supply that may be expected on average over a prolonged cold spell. A critical element of the methodology relates to our assumptions on the very coldest days. Here, we believe that it is reasonable to assume that Grain LNG imports would be close to their physical maximum, rather than at the base case level of 13 mcm/d. We have therefore assumed Grain imports of 17 mcm/d under these conditions. We do not, however, believe it is reasonable to assume further upside in relation to beach or Interconnector flows, since it is equally possible that there may be downside in relation to these supply sources.

95. Second, we recognise that well in advance of the main part of the winter there is a significant level of uncertainty associated with the supply-side position. In particular, as we have noted above, the impact of the hurricanes in the States is unclear, with recent market price movements suggesting that some LNG otherwise destined for Europe may be diverted to the US. To reflect this and other supply-side risks, we believe that it is appropriate to incorporate an additional volume into the long-range storage safety monitor, equivalent to that required assuming a loss of supply of 10 mcm/d across the winter period.

96. Including these two adjustments leads to the initial monitor levels shown below in Table 5. We will keep the level of the safety monitors under review through the course of the winter, and make further changes if it is appropriate to do so. For example, we may have to amend the monitors if we receive new and tangible information, e.g. relating to a long-term outage of a major supply facility. Conversely, material reduction in supply-side risk could allow the monitor levels to be reduced.

Table 5 – Revised Safety Monitor Levels

Storage Type	Safety Monitor Requirement
Short-range storage (LNG)	26%
Medium-range storage (MRS)	13%
Long-range storage (Rough)	23%

Section B – Winter Outlook 2005/06 – Electricity

97. This section examines the outlook for electricity 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 Average Cold Spell (ACS) peak demand, we can confirm that the transportation system will continue to have this capability in 2005/06.

98. Our May consultation document set out two alternative supply-demand scenarios as a means to assess the winter. Here we present a single base case.

99. Our assessment of the supply-demand outlook is based on the latest information of plant availability and demand levels. It also reflects the latest information obtained from generators, suppliers and other interested parties. Our choice of base case has also been guided by responses to our May consultation document. While there remains considerable uncertainty around the winter supply conditions, we believe that the base case represents a balanced view.

Notified Generation Availability

100. The May consultation document reported a plant margin[16] for winter 2005/06 of around 22%, based upon a Transmission Entry Capacity (TEC) contracted generation capacity of 74.8 GW. Our recent Seven Year Statement (SYS) Update[17] reports a plant margin of 21%, based upon contracted Transmission Entry Capacity (TEC) of 75.3 GW and a demand forecast of 62.1 GW, which is derived using our customers' own projections. [18]

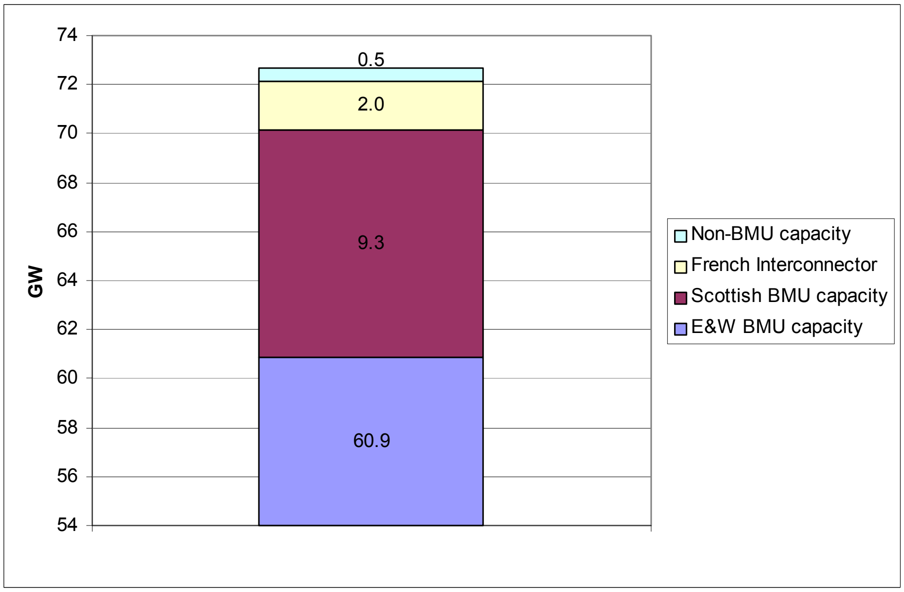
101. This headline plant margin is a useful, broad indicator of the amount of generating plant on the system for the winter. At an operational level, generators provide us with more detailed information over their expected availability. We use this to derive an operational view of generation availability, which may differ from the SYS plant margin since it will take account of:

- Planned outages within the winter.
- Restrictions on generation output, for reasons including environmental limits.
- Plant that is unavailable but that has retained its TEC.
- Embedded generation, which is excluded from our operational assessment, as it is not available to National Grid in the Balancing Mechanism, although it is of course available to the market to meet demand.

102. As illustrated in Figure 6, our current forecast of generation capacity anticipated to be operationally available for winter 2005/06 is 72.6 GW, including 2 GW from France. This is slightly lower than the forecast we published in May (73.9 GW), with the majority of the reduction accounted for by an increase in our view of the level of embedded generation.

[16] Plant margin is the excess generating capacity over forecast peak demand
[17] http://www.nationalgrid.com/uk/library/documents/sys05/mysys/updates/quarter2.pdf
[18] The SYS figure reflects data as of 31 August 2005

Figure 6 – Generation Capacity, Winter 2005/06



103. The generating companies also provide us with a list of mothballed plant, together with an estimate of the time that the plant would take to return to service from a decision being made to return.

104. This information suggests that there is 2.1 GW of mothballed plant that could return this winter, of which 0.7 GW has already purchased its Transmission Entry Capacity. An additional 1.6 GW of mothballed plant would require more than 6 months to return and hence would not physically be able to return for this winter. This position is summarised in Table 6.

Table 6 – Mothballed Capacity, Winter 2005/06

	Could Return Within 3-6 Months	Long-Term Unavailable Plant
Generation capable of being returned within period (GW)	2.1	1.6

Contracted Reserve

105. At certain times of the day, National Grid needs extra power in the form of either generation or demand reduction to be able to deal with plant breakdowns and demand forecast errors. 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 in the Balancing Mechanism (BM) and outside the BM.

106. For winter 2005/06, the volume of contracted Standing Reserve is 2.25 GW, of which around 0.7 GW is provided outside the BM. Following the recent tender for Supplemental Standing Reserve for October-March 2005/06, we have purchased an additional 236 MW of reserve (predominately from non-BM providers) based on our assessment that this represented economic and efficient procurement.

107. 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. Our initial proposals have been set out in a recently published consultation document[19], with the review expected to conclude around November 2005. Its conclusions are not expected to affect the procurement of Reserve for winter 2005/06.

108. National Grid continues to have Maximum Generation contracts in place for winter 2005/06, which provide potential access to 1 GW of extra generation in emergency situations. However, this is a non-firm emergency service and would only be used to avoid voltage reduction. Given that it is non-firm and that generation operating under these conditions normally has a significantly reduced reactive power capability (which in turn can have a significant impact on transmission system security) it is not included in any of our margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

Electricity Demand

109. In our May consultation document, our forecast of ACS peak demand for the coming winter was 62.0 GW. This demand figure related to GB demand only and did not include any Interconnector flows to France or Northern Ireland.

110. Since the May consultation, we have revised our assumptions concerning underlying demand growth and the level of embedded generation, and our GB peak demand forecast is now lower at 61.5 GW. Including our forecast export to Northern Ireland of 0.4 GW across the winter peak, the ACS peak total demand forecast becomes 61.9 GW and the 1 in 20 peak day becomes 64.9 GW[20].

111. At times of high electricity demand and high electricity prices, customers reduce their demand to avoid transmission charges (‘triad avoidance’) and high energy prices. Around 0.8 - 1.3 GW of such reductions has been observed in the past, and was assumed in our May consultation document. The feedback we have received implies there would be little further response than that observed to date, and so we continue to assume around 1 GW in our forecasts for normal, ACS and 1 in 50 conditions. This reduction in demand is likely to occur more often given a prolonged period of cold conditions and associated high prices.

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19 http://www.nationalgrid.com/uk/indinfo/balancing/mn_consultations.html

20 The latest update to the Seven Year Statement includes a customer-based ACS demand forecast of 62.1 GW, excluding station load. Including station load, the customer-based ACS demand forecast is 62.6 GW.

112. However, 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 and prices based on the observable behaviour to date, and it may be possible that there is additional demand response in addition to that observed to date. The sensitivity of the electricity and gas markets to lower electricity demand is discussed in Section C below.

Forecast Position for Winter 2005/06

113. Overall, the forecast position for winter 2005/06 has marginally deteriorated since the May consultation document with the lower demand forecast (0.5 GW) more than offset by the decline in operational capacity (1.5 GW). This decline in capacity is due to increased volumes of embedded generation, which is not available to National Grid in the Balancing Mechansim.

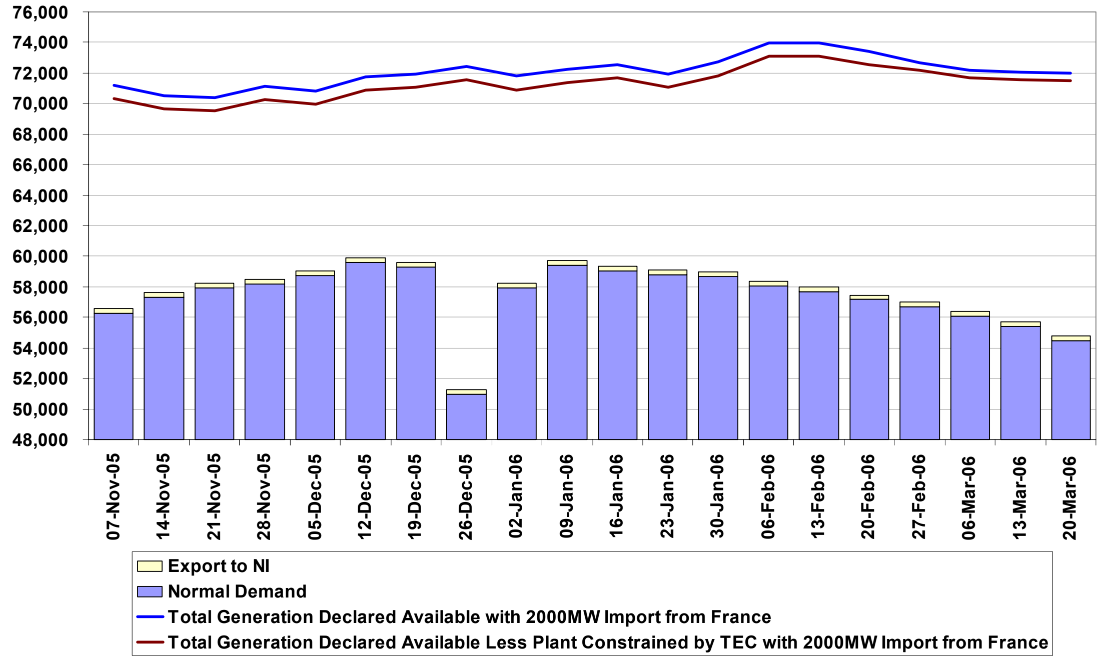
114. Figure 7 illustrates a winter in which average weather conditions are experienced each week, and average temperatures across the winter are 7 ^{o}C. It shows weekly generation availability, which is the forecast availability declared to National Grid by the generators under the Grid Code (Operating Code 2). This reflects planned unavailability but does not include an allowance for unplanned generator unavailability. At some stations, there are technical restrictions on how much electricity can be generated, the result of which is that there is around 1 GW of capacity declared available which may be inaccessible to the market in practice. A further 1 GW is declaring itself available for this winter but has not yet purchased TEC.

115. As can be seen in Figure 7, with full exports from France the excess generation over average weekly peak demand would be around 12-14 GW.

116. 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 7. The margin shown in Figure 7 does not reflect this reserve requirement.

117. However, Figure 7 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 or exceeds ACS levels.

Figure 7 – Demand and Notified Generator Availability, Winter 2005/06



118. Our electricity supply base case, summarised in Table 7, is consistent with the gas base case supply assumptions as described in Section A. It assumes that the electricity market responds to the tight position in the gas market and associated price signals by returning 2.1 GW of short-term unavailable plant prior to the winter. It also incorporates an average availability rate of 91%, reflecting historic trends. Table 9 in Section C gives a break-down of this availability assumption by type of generating plant.

Table 7 – Electricity Base Case Availability

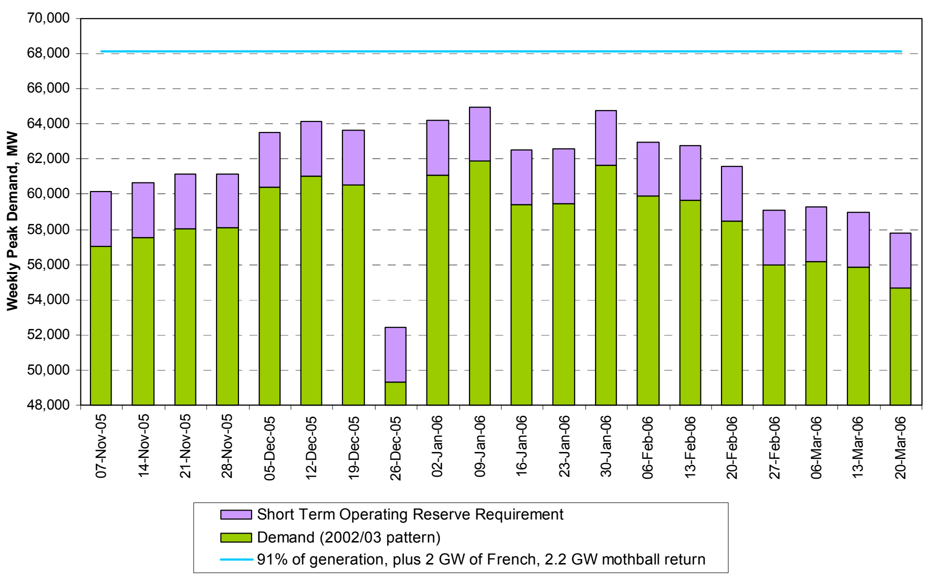
	Base Case
GB Plant Availability, GW	70.6
Availability from France, GW	2.0
Return of mothballed plant, GW	2.1
Total Availability (100%)	74.7
Average Assumed Availability, %	91%
Assumed Availability, GW	68.1

Average Winter Conditions

119. 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 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.

120. As illustrated in Figure 8, 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.

Figure 8 – Forecast Demand under Average Weather Conditions (2002/03 weather pattern) and Generator Availability, Winter 2005/06

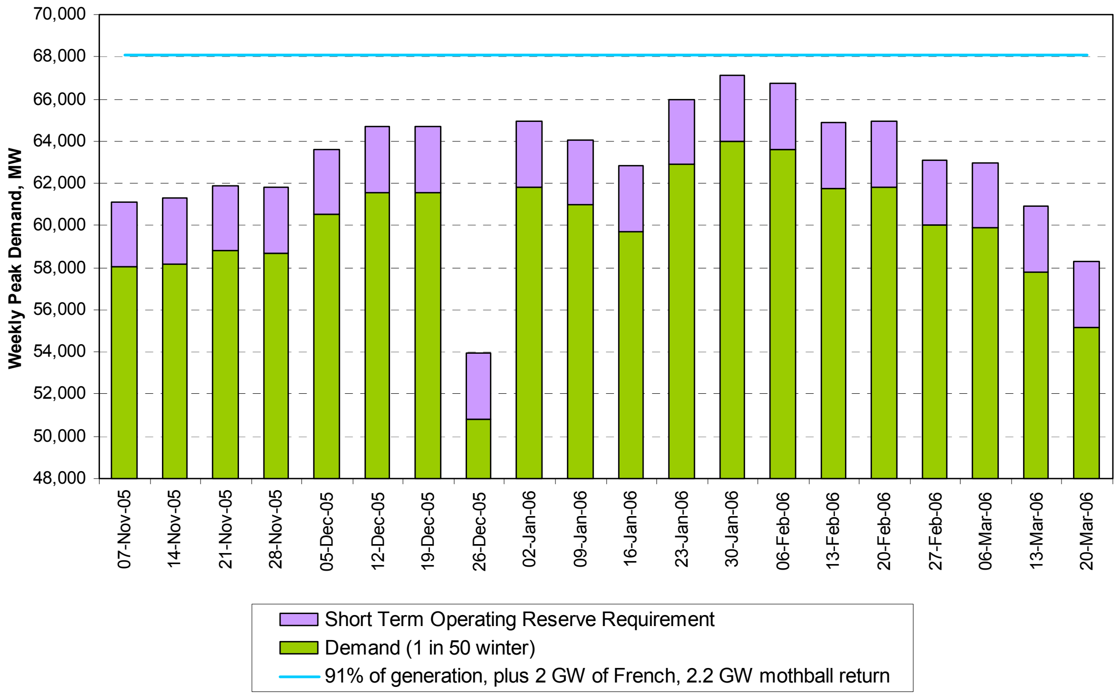


1 in 50 Cold Winter Conditions

121. In 1 in 50 cold winter conditions, where temperatures across the country would average -2 °C over 30 days and +2 °C over a further 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.

122. If these weather patterns were to occur this winter, as illustrated in Figure 9, the anticipated electricity margin would be sufficient, provided we do not experience high levels of plant breakdowns or CCGT unavailability in response to high gas prices.

Figure 9 – Forecast Demand under 1 in 50 Conditions (1946/47 weather pattern) and Generator Availability, Winter 2005/06



123. In a 1 in 50 cold winter, if there were very low probability generation failures above the levels normally experienced, or CCGT non-availability in response to gas supply concerns, we could expect to see some reduction in demand due to high prices. However, if this is insufficient, there may be a need to apply the existing operational arrangements whereby demand 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.

Section C – Gas-Electricity Interaction

Introduction

124. This Section describes our analysis of the potential gas demand response available from the power sector. Gas-fired power stations can be expected to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. This ability to arbitrage between gas and power is not restricted to those power stations that have interruptible gas transportation arrangements, with some recent experience of firm CCGTs commercially self-interrupting.

125. There has been recent evidence of the electricity market responding to high forward and on-the-day gas prices, although this response has been for relatively short periods and on days of non-peak electricity demand and benign electricity prices. 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.

126. The willingness of the CCGTs to commercially interrupt themselves will be determined by a number of factors, including: the spark spread, which is itself influenced by the ability of the power generation sector to meet demand though switching to other fuels; the price of CO_2 emission allowances; the price of alternative fuels; and any environmental constraints (e.g. SO_2) that limit the extent of running on other fossil fuels.

127. 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 at other times of low electricity demand, such as at weekends and during holiday periods.

128. Our analysis has sought to determine the potential reduction in gas demand that could be achieved through a response from CCGTs under a range of winter scenarios, consistent with the preservation of sufficient generation capacity to meet electricity demand. We have done this using detailed simulation analysis in which both gas and electricity demand and supply conditions are modelled.

129. The analysis is underpinned by a set of modelling assumptions, which together define the potential for other forms of generation to replace gas when required. Our choice of modelling assumptions has been guided by responses to our May consultation document. Recognising that in combination these assumptions are at the optimistic end of possibilities, we have examined the sensitivity of the results to changes in the individual inputs.

Power Generation Gas Demand and Distillate Back-up

130. The maximum theoretical power generation gas demand in GB for winter 2005/06 is shown in Table 8. These figures are based on contractual limits. They 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 8 – Maximum 2005/06 GB Power Generation Gas Demand

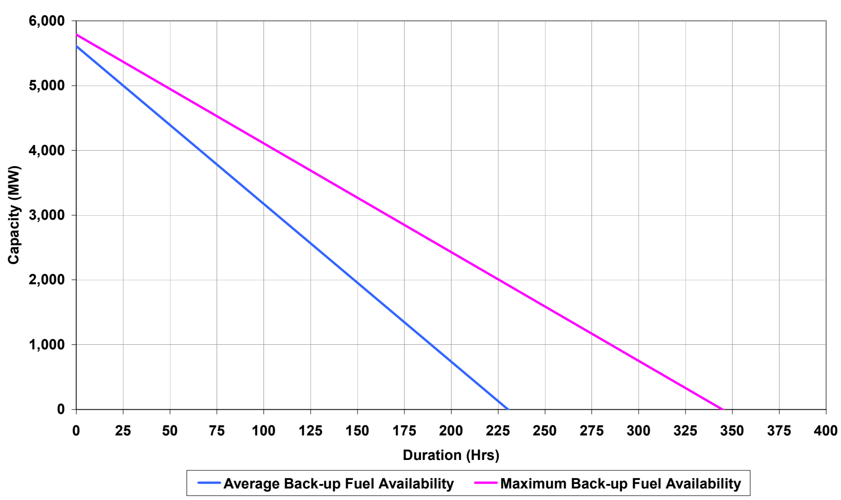
	Maximum Gas Demand (mcm/d)	Number of CCGTs
NTS-connected	93.0	35
LDZ-connected	4.9	4
Total	97.8	39

131. Across the main part of the 2004/05 winter, the highest daily demand from large power generation sites was only around 70 mcm. Based on historical experience, including that of 2004/05, our gas demand forecasts incorporate a typical daily consumption from CCGTs of around 65 mcm/d in the winter period.

132. In electricity generation terms, the CCGTs are expected to provide a total of 23.8 GW of generating capacity in GB for the coming winter. Of this, 3.2 GW have access to gas through non-NTS pipelines and 5.7 GW have the capability to run on distillate.

133. Under the terms of the Grid Code, the generating companies are required to provide us with information on their capacity to generate using back up fuel. Figure 10 summarises this information in load duration curve form, showing the decay of generation capacity available from distillate with time. The data has been aggregated and smoothed to protect the commercial positions of the individual plants. The two lines show the available generation from starting points of normal fuel stocks and maximum fuel stocks.

Figure 10 – Load Duration Curves for Back Up Fuel Supplies



Analysis of Potential CCGT Demand Response – Modelling Assumptions

134. In our May consultation document we included preliminary analysis of the potential for the electricity sector to lower its gas demand in 1 in 50 cold winter conditions assuming that the market sought to minimise CCGT gas demand throughout the winter. Responses to the consultation have informed the updated analysis presented here.

135. In summary, consultation feedback supported the principle that the electricity merit order would be determined by the relative economics of generation by different fuels. This is reflected in the key assumption underlying our analysis of potential CCGT response: that the market works efficiently with adequate and timely signals, such that there is sufficient notice and incentive to substitute coal and other fuels for gas throughout the winter. In the context of a very cold winter and a tight gas supply-demand position, this translates into an assumption that gas operates as the marginal generation fuel most of the time.

136. However, a number of respondents identified practical issues that could limit the extent of any CCGT response. Issues raised included:

- Technical risks associated with frequent switching to/from and prolonged use of distillate.
- Potential limits on the extent to which fuel stocks can be replenished.
- Limitations on the levels of switching to coal and oil as a result of environmental constraints.

137. We have modified our modelling assumptions that relate to distillate use to take account of the first two of these points, although, as the sensitivity analysis in Table 11 illustrates, the results are relatively insensitive to the assumptions associated with distillate use. The other assumptions are largely unchanged from those that underpinned the analysis in our May consultation document. The main modelling assumptions are as follows:

- Nuclear runs baseload – 24 hours a day, 7 days a week.
- Imports into GB through the French Interconnector are available continuously overnight and during the peak 4 hours at the full rate of 2 GW - at other times the link is at float.
- 3.2 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as baseload, thereby displacing other generation.
- Around 3 GW of NTS-supplied CCGTs run as baseload, reflecting technical and contractual constraints such as the requirement to provide heat and power to industrial consumers.
- No explicit constraints relating to fuel stocks, CO_2 or SO_2 emission limits, are applied to coal generation, but overall coal plant is assumed to operate at a maximum load-factor of only 85%.
- Pumped storage stations generate only during the peak 6 hours of each day.
- Oil stations generate only during the peak 8 hours of weekdays.

- 90% of the 5.7 GW of CCGTs with distillate are able to switch successfully, reflecting technical and commercial risks. These 5.2 GW of CCGTs run on distillate for 12 hours on weekdays, for a maximum of 200 hours.
- As several OCGT units have reserve obligations to National Grid, they are assumed to be low merit and run only very occasionally.
- Plant availability factors as shown in Table 9, consistent with an average availability rate of 91%.

Table 9 – Assumed Plant Availability Factors for Demand-side Response Analysis

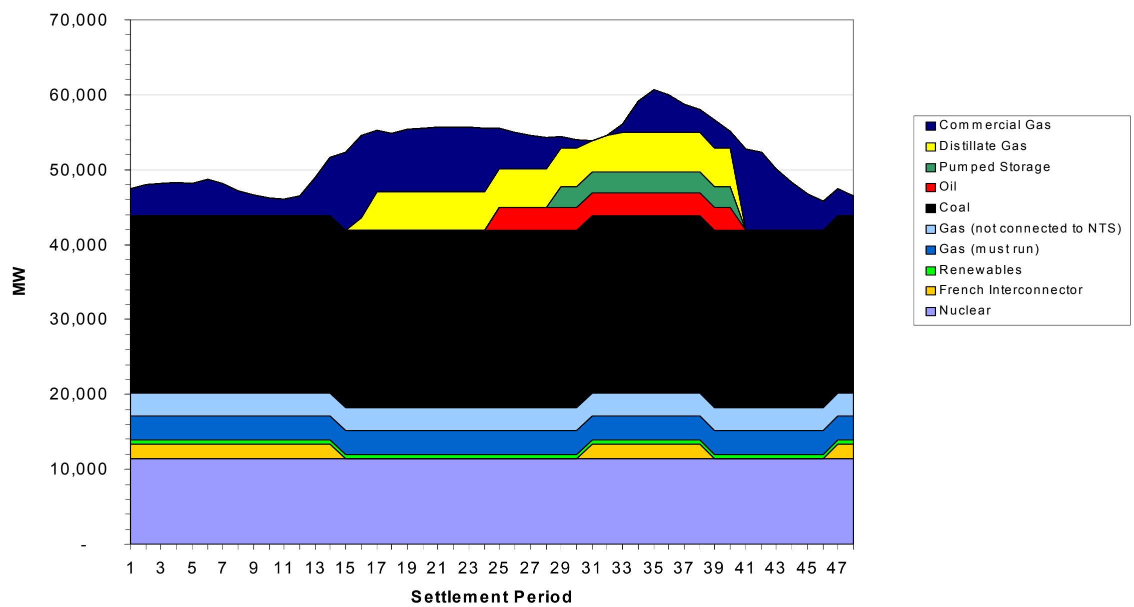
Power Station Type	Assumed Availability
Nuclear	95%
French Interconnector	100%
Non-BM Generation (incl. Renewables)	50%
Coal	85%
Oil	95%
Pumped Storage	100%
CCGT	95%

Analysis of Potential CCGT Demand Response – Simulation Results

138. Figure 11 illustrates how electricity demand could be met on a typical very cold winter day, consistent with the modelling assumptions described above. It shows approximately 24 GW of coal-fired generation throughout the day, gas as the marginal fuel for the bulk of the day and distillate used for 12 hours around the peak demand period. (As explained above, total distillate usage across the winter is constrained to 200 hours in the simulation model).

139. In Section A, we estimated the extent of the gas demand-side response that would be required under a variety of winter severities and assuming our base case supply conditions. We have used the CCGT simulation model to estimate the potential contribution of the CCGT sector to these required levels of response. The modelling results are summarised in Table 10. In the 1 in 50 cold winter case, the potential contribution of 1.8 bcm from CCGTs is equivalent to approximately 5 GW less CCGT generation than envisaged in our 2005 gas demand forecasts for much of the winter.

Figure 11 – Potential Generation Profile - Cold Winter Weekday



140. The scale of potential demand response estimated in our modelling is far in excess of that either required to date or seen to date. The ability of the markets to operate in a manner consistent with our assumptions therefore remains largely untested. In particular, the ability of the electricity market to operate with a significantly lower gas demand will be critically dependent upon the right price signals triggering the appropriate response, and for this response to be sustained throughout the winter period. We therefore believe that while this potential level of response is feasible, it is towards the upper end of possibilities.

141. One particular issue is that of environmental constraints. Although our model did not impose any limits to reflect such constraints, we have examined the outputs to assess whether it is likely that any limits would have been exceeded. This analysis suggests that SO_2 emissions may be a limiting factor should gas be displaced by coal and oil to a high degree.

142. We have also used the simulation model to assess the potential for CCGT response should we experience similar weather conditions to those that occurred in 1985/86, which was around 1 in 10 cold. In this case, the analysis indicates that a CCGT response of around 1.3 bcm may be achievable out of a total response requirement of 2.2 bcm.

143. Table 10 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 weather scenarios considered in this report.

Table 10 – Potential CCGT Demand Response (bcm)

Winter Severity	Base Case
Average winter	The required level of 0.1 bcm
1 in 10 cold winter	1.3 bcm of the required 2.2 bcm
1 in 50 cold winter	1.8 bcm of the required 3.7 bcm

144. Table 11 highlights the impact of changes to our modelling assumptions in the 1 in 50 cold winter scenario. For example, if there were no distillate running throughout the winter, the potential CCGT response would be 1.6 bcm rather than 1.8 bcm.

Table 11 – CCGT Demand Response - Sensitivity Analysis

Sensitivity	CCGT Relief (bcm)
1 GW less demand over 50 days	0.2
5% reduction in coal availability	-0.2
No distillate-fired generation	-0.2
No oil-fired generation	-0.2

Section D – Ongoing Developments to Industry Codes and Arrangements

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

146. 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.

Gas

Uniform Network Code

Imbalance Prices

147. The Authority has recently directed the implementation of UNC *Modification Proposal 0044 "Revised Emergency Cashout and Curtailment Arrangements"*. This modification is designed to address the concern that the pre-existing 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 Gas Deficit Emergency (GDE) being triggered. The modification consists of two key elements:

- modify the emergency cash-out prices to align them with the market prices on the day of a GDE and;
- assign the quantities of gas associated with actions undertaken by National Grid in a GDE (including a Potential GDE) as a Trade between National Grid and each User.

DTI Information Provision Initiatives

148. 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 (involving DTI, Ofgem, UKOOA and National Grid) 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.

149. The DTI Information Initiative consisted of three phases:

- Phase 1 – the standardisation and improved provision of operational data to National Grid in relation to planned and unplanned supply reductions from upstream parties.

- Phase 2 – the provision of detailed information from upstream parties to support National Grid 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 National Grid.

150. 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).

151. 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.

152. 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 Summary System Information

153. National Grid is currently participating in the Demand Side Working Group (DSWG), one of the aims of which is to provide additional summary system information to gas market participants on a daily basis. This information is a collation of existing information that is published in existing reports, supplemented by daily storage information as noted above. The DSWG are also endeavouring to define criteria under which a gas system alert could be issued, analogous in some respects to electricity NISM or HRDR warnings. The aim of this is to provide a signal to market participants, if required, that the supply demand position on the gas system is becoming tight to stimulate additional demand-side response. This summary system report will be published on our website.

Provision of Historic Storage Monitor Data

154. Since October 2004 National Grid has provided weekly reports of storage stock movements in relation to the safety monitors and firm gas monitors. Following consumer request through the DSWG, and approval from storage operators, National Grid will now provide these reports with after the day information on a daily basis. This allows Users to more easily monitor trends in storage use and adjust their actions accordingly. The information can be found on our website.

Electricity

Connection and Use of System Code (CUSC)

Short Term Transmission Access

155. A sub-annual transmission entry product was established in the CUSC by CAP070 in November last year. This provides the ability for mothballed plant to purchase, where available, access to the Transmission System for short periods of time at less than the cost of an annual product. 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. Recently, further Amendment Proposals (CAP092 and CAP094) relating to short-term access arrangements have been brought forward and these are currently being assessed by a working group established under the CUSC.

Intertrips

156. Arrangements for the categorisation and remuneration of System to Generator Intertrips have been implemented in the CUSC following the approval of CAP076 in June 2005. System to Generator Intertrips are an integral and necessary part of the GB Transmission System and provide a prudent mechanism for maximising generation availability during critical or forced outages, which is beneficial to security of supply.

Grid Code

Review of Electricity Market Information

157. The Electricity Transparency Review, carried out by National Grid 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.

158. 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.

- More timely publication of cost and utilisation data associated with Balancing Services.

159. Since the implementation of the above changes in 2004, National Grid has been chairing an industry working group to consider the appropriate planning information requirements under OC1 and OC2 of the Grid Code. As a result of these discussions a further Grid Code change proposal to improve the definition of Output Usable has now been approved. This further enhances consistency between short-term (up to a day ahead) and long-term (up to 5 years ahead) forecasts of generation availability.

160. 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 in accordance with the BSC. Earlier this year, National Grid initiated discussions with the industry, by raising BSC Issue 17, to identify appropriate changes to the detail and structure of the BMRS. The changes that could be made after the 2005/06 winter include:

- Alignment of the Grid Code System Zones with the BMRS Zones such that all the Zonal information corresponds to the same set of Zones, providing clearer signals to the market.
- Disaggregation of generation availability (e.g. by plant type) to distinguish 'predictable/stable' generation (e.g. gas-fired) from that which is less predictable and less stable (e.g. intermittents).
- Rationalisation of reporting timescales leading to clearer information on forecast generation availability and margins.
- Provision of demand information for reconciliation of forecast and outturned.

161. In addition to the developments outlined above, further information and transparency enhancements that will be implemented by National Grid ahead of this winter are:

- Publication of near real-time System Operation data (including for example real-time demand indication).
- Notifications of warming instructions to plant that may subsequently required to synchronise to meet operational reserve requirements.

162. We believe this information will compliment the existing market information and assist market participants in interpreting and responding to it.

<u>Balancing and Settlement Code</u>

Imbalance Prices

163. National Grid is of the view that appropriate cashout arrangements are a fundamental part of security of supply, and we continue to believe that improvements should be made to the electricity market cashout arrangements. National Grid has recently raised BSC Modification Proposal P194 to improve the signals and incentives provided by the 'Main' energy imbalance price to promote security of supply through forward market activity. The proposal has been specifically designed to accommodate

the concerns raised by market participants and Ofgem during the assessment of previous modification proposals in this area. The nature and timing of P194 should facilitate implementation ahead of winter 2006/07, to ensure that appropriate arrangements are in place to encourage plant availability and new build going forward.

164. National Grid also welcomes the opportunity to be involved in Ofgem's review of cashout arrangements in gas and electricity (the "Cashout Review"). Whilst we consider that, broadly, the cashout arrangements in the gas market are operating appropriately, we continue to believe that improvements should be made in electricity. In our view it is important that the Cashout Review concentrates on considering potential changes that have significant materiality and which can potentially enhance security of supply ahead of winter 2006/07. We believe the priorities for the review, as set out by Ofgem, are consistent with this.

Appendix 1 – Summary of Winter Consultation Responses

165. We received 15 responses to our Consultation on Winter 2005/06 document. The responses provide us with valuable additional information, which have helped us to shape the analysis contained within this report.

166. The majority of the responses were provided on a confidential basis. Therefore this section provides a summary of the issues raised and views expressed but does not attribute specific comments to individual organisations.

General Comments

167. Respondents generally welcomed the opportunity to comment upon our May consultation document, believing that the approach taken to enable all interested parties to contribute to the evaluation of security of supply for this winter was of mutual benefit.

168. A number of respondents commented that it was essential that the gas and electricity markets were allowed to operate without direct or indirect intervention from the system operator, regulator or government, so that market based mechanisms are able to respond to changing supply-demand conditions. Otherwise market confidence will be undermined and security of supply will be affected. As a corollary of this issue, a number stated that procedures in place for extreme circumstances should not overlap with market structures.

169. Several parties expressed a desire to avoid the implementation of commercial framework amendments in compressed timescales, preferring that any modifications be raised to enable sufficient time for debate.

170. There was a range of responses regarding the two scenarios presented within the consultation. Some felt Scenario 1 was optimistic, with Scenario 2 more realistic. Others felt Scenario 1 more realistic, with Scenario 2 not credible as it understated maximum available beach supplies. Others felt whilst Scenario 2 was onerous, it was not the most onerous scenario that could be considered credible.

171. There was a reasonable degree of consensus that two of the key issues for ensuring security of supply during periods of high demand in winter 2005/06 would be levels of demand-side response achieved and the levels of imported gas via the Continental interconnector and the Isle of Grain LNG importation facility.

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

172. Several of the respondents that expressed an opinion felt that 336 mcm/d seemed a reasonable figure or was only slightly optimistic. One felt 336 mcm/d was more accurate than our revised figure of 327 mcm/d, and another expressed the view that it was difficult to comment as National Grid was in a privileged position to produce a figure for maximum beach due to the data collected via the Transporting Britain's Energy consultation process.

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

173. The responses ranged from 100% to as low as 80%, the lower figure driven by concerns over reduced offshore reliability due to ageing infrastructure and difficulties operating in sustained severe weather. A number of parties felt that it would be prudent to model beach levels lower than 90% to show the effect on security of supply for the winter. One party felt 95% maximum beach was optimistic, 90% more realistic, and 85% prudent. Another felt that 92.5% was a more realistic figure.

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:

The extent to which shippers have contracted for gas supplies to import into the UK

174. Several parties commented that whilst efforts have been made to secure imported gas supplies to the UK for winter 2005/06, their arrival will be dependent on the spot gas price differential. Another stated that the extent to which a severe winter impacts the various European markets would be an important factor.

The extent to which shippers have access to the necessary European transportation infrastructure to support gas imports through the Interconnector

175. Several parties stated that many Interconnector shippers have positions in both the UK and Europe, and are likely to have access to European infrastructure, but quantifying the level is difficult. Others stated that arrangements to import gas from Continental Europe are complex and only pan-European players are likely to be able to do this. Several cited lack of clear market rules in Europe and lack of liquidity in capacity trading as issues that make access to European transportation infrastructure difficult.

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

176. Many respondents stated that price differentials across the Interconnector will determine gas flows, and that high levels of gas imports through the Interconnector cannot be assumed merely because there is high demand in the UK. One party noted the high correlation between cold temperatures in the UK and Continental Europe, thereby leading to a likely reduction in imports to the UK. Several stated that certain parties in Continental Europe may consider concerns with respect to security of supply in their domestic markets more important than potential increased profitability that may arise from selling gas in the UK. Certain parties felt that the forward curve indicated that high levels of gas will be imported into the UK via the Interconnector, near the top end of Scenario 1, i.e. 48 mcm/d, and that the figure in Scenario 2, of 42 mcm/d was unduly low. Also the events of February/March 2005, where relatively low flows were imported into the UK, should not be overstated as they resulted from a combination of exceptional circumstances. Other parties felt that

imports through the Interconnector should not be assumed to be higher than 50%, based on the events of last winter, and could well be as low as zero at times.

The assumptions that can be made for LNG importation quantities

177. Many respondents stated that price signals would determine LNG cargo destinations. LNG is an increasingly globally traded product, and if prices are higher elsewhere than in the UK, then the cargoes may not arrive in the UK. Conversely, it was also argued that most LNG ships are still operated on long-term fixed route contracts, allowing little opportunity for ships to be diverted to the UK should the security of supply position in the UK tighten. Several parties argued that the Isle of Grain importation facility was a new and complex facility, and to assume 100% imports might be optimistic. One stated that LNG supplies would be limited or zero. Others argued that 10 mcm/d (75%) was overly cautious, and that on very high demand days the facility will operate at its maximum deliverability of 17 mcm/d.

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:

The extent to which gas demand-side arrangements are already in place (whether through interruptible contracts or otherwise)

178. Responses ranged from believing that there were few demand-side arrangements in place, to a belief that the levels assumed for demand-side response within the analysis were reasonable. Several parties stated that for customers to be able to respond to a demand-side requirement there would need to be greater forward planning and more formal mechanisms need to be put in place.

179. Several respondents felt that high levels of demand-side response would be very difficult to sustain for a prolonged period. Several parties commented that sustained demand-side response at the levels indicated in the analysis for severe conditions would be potentially damaging to industrial customers and could result in permanent demand destruction. Others commented that they believed there were only a limited number of industrial and commercial customers that are capable or willing to enter into demand-side response arrangements, citing a number of reasons including loss of production, and lack of perceived benefits in undertaking demand management.

180. One respondent commented that industrial customers and some large commercial customers have moved from fixed price gas contracts to those that are market-linked, and will therefore react to market prices by reducing gas demand prior to the shipper requesting it.

What scope exists for such arrangements to be put in place prior to or during the course of the winter

181. A number of parties commented that the implementation of UNC Mod 0013a, which removes our rights to interrupt for supply-demand purposes, may lead to National Grid, as residual gas balancer, taking demand-side Offers on the OCM to satisfy a shortfall. Clear economic signals should be given to the marketplace during periods of tightening security of supply, incentivising customers who are able to provide demand-side response to switch off or reduce.

The appropriate basis for setting the 2005/06 safety monitors

182. Whilst several respondents stated that the storage monitors should be set conservatively, i.e. with the higher percentage stock levels as indicated by Scenario 2, the majority of respondents who expressed an opinion felt that the levels indicated by Scenario 1 were more realistic. A number of respondents expressed serious reservations regarding setting the monitors at levels proposed by Scenario 2, believing that setting the monitors at too high a level may well distort the operation of the market, whereby parties may be reluctant to take gas out of store, for fear of monitor breach, or perversely, may take gas out of store earlier than necessary to avoid gas being stranded.

183. Several parties requested greater transparency and industry consultation with respect to the process for and the setting of the monitors, and also the emergency arrangements with respect to suspension of markets due to a monitor breach. It was also suggested that National Grid investigate the potential for an aggregated monitor across all storage types.

184. A number of parties also stated that they did not believe that the National Emergency Coordinator should have command and control capabilities in a stage one emergency while the market is still open, as this could significantly distort the market.

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

185. The most common response to this question was that for any mothballed plant to be returned would require relevant market price signals, in particular a prolonged period of high prices in order to recover the costs of returning plant to service. One party noted that while there may be a strong signal in the forward market at present, the market is relatively illiquid and volatile, which may prevent plant owners from returning plant. In addition, a forecast sustained cold winter would allow sufficient notice for the plant to be returned, whereas a sudden cold snap would not allow sufficient notice. One party felt the figure of 2.2 GW of mothballed plant returned within six months was reasonable, whereas another party felt this figure was optimistic.

The level and direction of flow of the electricity interconnector that might be expected given cold weather in both UK and Europe

186. This question elicited a wide range of responses. Several respondents felt that the flows would be primarily dependent on the market price differentials and the level of flows either way. Others felt the flow would be in import mode and could be anywhere between zero and 2 GW. Others felt a figure between 1 GW and 2 GW was reasonable. Several pointed out that if it was very cold in UK, there was a reasonably high probability it would be cold in Europe, and hence flows from France to UK across the interconnector may be low or even zero. Another party felt that availability of French nuclear plant was an important factor, and if there was a shortage of power in Europe, then interconnector flows will be curtailed. One party

stated that even if there was a clear economic signal for electricity flows to the UK, flows may still be restricted due to security of supply concerns on mainland 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

187. Broadly speaking there was reasonable agreement with the majority of responses: electricity demand-side response would be probably of a similar magnitude to last year and was unlikely to be materially greater than this figure. Any additional demand-side response was likely to be marginal, even with very high prices. Several commented that voltage reduction must be an option of last resort, after all other actions have been exhausted.

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

188. Several respondents commented that the running order was plausible, but that price signals will ultimately influence plant availability. Several parties commented that there are a number of CCGTs on ‘take or pay' contracts and some may also be locked into long term power supply contracts, resulting in limited or no commercial incentive to load shape. In addition, some CCGTs may face risks of technical failure through aggressive load shaping, and that certain generators are not permitted to operate outside specific pre-determined operating envelopes. One party felt that Scenario 2 was unrealistic over a prolonged period, as it relied on sustained imports from the interconnector. The same party felt that Scenario 1, which required a lower level of gas demand-side response, was more realistic. One party felt that there was the potential for significant levels of CCGT to remain on across the winter evening peak, due to the approximately 12 GW of CCGT plant that has the ability to two-shift.

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

189. Several respondents noted that as generation from CCGTs is necessary for a normal winter peak demand, it is reasonable to assume that prices for peak load periods would have to increase to a level that would ensure the required generation output in peak periods. Provided the gas and electricity markets remain reasonably liquid, and are devoid of regulatory interference, the prices of electricity will move to reflect changes in the relative costs of production and the volume of demand relative to generation availability.

The ability and willingness of CCGT generators to switch to distillate

190. A number of respondents noted that there was a relatively small number of CCGTs with distillate capability, and that there is limited market experience of running plant on distillate for prolonged periods. There may also be a range of technical and environmental issues that a station would need to address when considering running on distillate for a sustained period. Any decision to run on distillate will be driven by the underlying economics of gas and distillate as fuel sources, current and anticipated future levels of stock, the relative levels of thermal efficiency, potential increased maintenance costs and likely commercial impacts associated with the technical risks of fuel switching, not least of which is the potential electricity imbalance risk incurred to CCGTs by the turbine failure risk when switchover takes place. Several parties noted that even where CCGTs have the capability to run on distillate, the plant may only have limited distillate stocks which may run out after several days or may in fact have zero stocks.

191. One party estimated that only 50% of CCGTs that in principle have back-up fuel on site could successfully switch over to generating from it, and even those that could switch would experience operational difficulties resulting in reduction in load and temporary loss from system. It was also noted that there was limited or no commercial incentive to install distillate capability.

Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks

192. A number of respondents who replied to this question felt that a demand-side response of 3 bcm for the winter, achieved by CCGTs switching from/to distillate five times a week for four hours a day for 100 days, was not feasible.

193. Stations with back-up capability usually only have stocks of between several days and two weeks of distillate, meaning that the above scenario would require high distillate delivery rates throughout the winter which has never been tested and may not be achievable. In addition there is little evidence of generators' resilience to protracted running on distillate for a number of weeks. Others commented that generators are unlikely to switch to distillate on a daily basis, rather they are more likely to run on alternative fuels for a sustained period, for example the whole day.

194. Another respondent commented that market participants will not make significant preparations prior to the winter in order to lower gas demand, as the correct price signals will not be seen in time for generators to make the necessary preparations. Environmental consideration are also likely to act as a further constraint on the amount of distillate fired generation that can be achieved, as use of distillate would increase emissions of nitrogen and other substances, relative to gas.

195. While this level of demand-side response was not achievable over the whole winter, several respondents felt that the desired levels of response were feasible for a cold snap, possibly for up to 25 days during the winter.

The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation

196. Several respondents stated that any decisions will be driven by market conditions and companies individual commercial positions, with the market allowed to function and to send the appropriate signals to market participants. Several noted that for generators that do have a portfolio of plant, the relative profitabilities of generation by differing technologies are likely to be key.

197. Several respondents felt that there was limited scope for gas to coal switching, as the current power and coal process mean that coal plant is already economically incentivised to run ahead of gas plant for the coming winter. Another felt that the desired level of switching was achievable over a short cold snap during the winter, but not for a prolonged period.

198. A number of respondents stated that the levels of switching to coal and oil would also be limited by environmental constraints. Respondents saw greater scope for gas to oil switching, with oil plant remaining the marginal form of generation, being available to replace gas plant, providing it is economically feasible.

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

199. One respondent noted that the current high winter forward prices should incentivise coal an oil generators to take all reasonable measures to maximise reliability in advance of the winter. As stated above, respondents felt that coal stations were likely to run ahead of CCGTs in the merit order, with oil fired plant able to displace gas plant to some extent. The ability of oil fired plant to run for eight hours a day for five days a week will depend on clear commercial incentives, effective fuel replenishment logistics and environmental restrictions.

200. In addition, several parties noted that there may be limits on the extent to which additional supplies of coal can be brought to power stations at relatively short notice. The carbon market is expected to remain liquid, and hence additional allowances will be procured if the prevailing power (and carbon) prices make it economical to do so.

201. One party commented that this coming winter will be the first since the introduction of the EU-ETS, which could impact the operational strategies of certain plant, with operators optimising between the costs of fuel, carbon and the price of electricity. Another factor was the potential reduction in availability of plant that had opted-in with respect to LCPD, as retrofitting FGD may curtail its operation this winter.

202. Several respondents stated that additional capacity could be made available if certain environmental constraints could be relaxed in certain circumstances, and recommended further discussions between generators, DTI, Ofgem and the Environmental Agency.

Appendix 2 – Safety Monitors

203. This appendix explains the concept of Safety Monitors: what they are and how they are operated. For a more detailed explanation of the methodology used to calculate the monitors see our web site document 'Safety and Firm Gas Monitor Methodology', this document is to be updated in October to detail the 2005/06 monitor requirements.

What are safety monitors?

204. Safety monitors were introduced in 2004 to replace the so-called 'Top-up' monitors, which had existed through the Network Code since 1996. The purpose of the Top-up arrangements was to underpin security of supply to firm customers. It did this by ensuring that sufficient volumes of gas were retained in storage throughout the winter, consistent with 1 in 50 weather demand levels. If necessary, Transco would buy gas to put in storage in order to ensure that Top-up levels were maintained.

205. In common with Top-up, the safety monitors define levels of storage that must be maintained through the winter period. However, as the name suggests, the focus of the safety monitors is public safety rather than security of supply. It is a requirement of Transco's safety case that we operate this monitor system and that we take action to ensure that storage stocks do not fall below the defined levels.

206. The levels of storage established by the safety monitors are those required to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. They ensure the preservation of supplies to domestic customers, other non-daily metered customers and certain other customers who could not safely be isolated from the gas system if necessary in order to achieve a supply-demand balance.

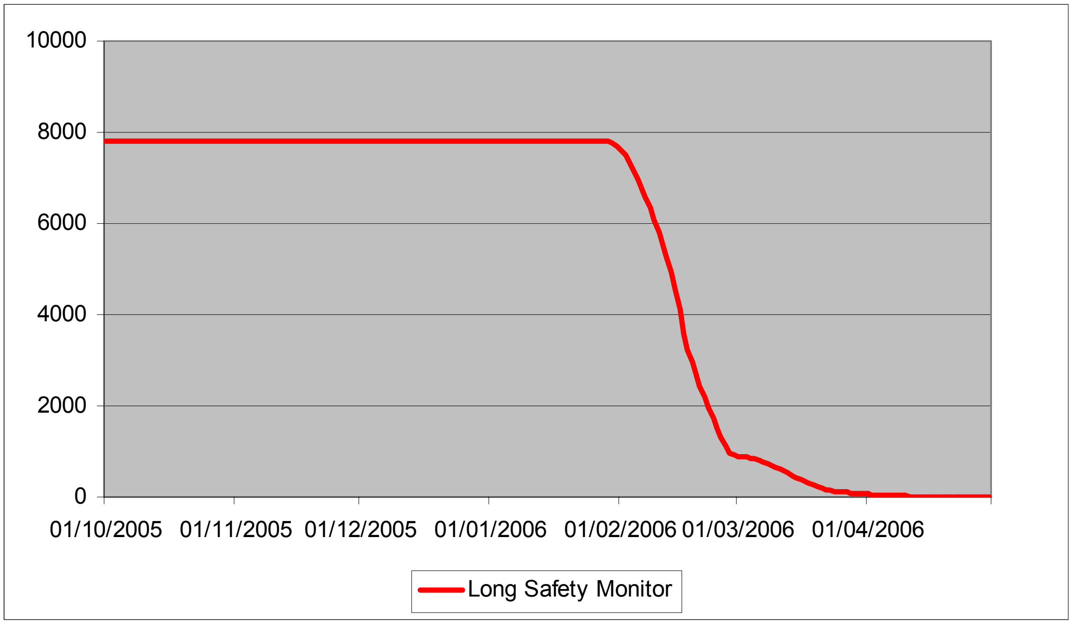
207. There are three safety monitors: one for long-range storage (Rough); one for mid-range storage (Hornsea, Hatfield Moor, Hole House Farm and Humbly Grove combined); and one for short-range storage (the four LNG facilities combined).

How are the safety monitors operated?

208. Each of the monitors has an initial level, which defines the level of gas that must be in the relevant storage facilities at the start of the winter. These levels reduce as the winter proceeds, reflecting the fact that less gas is required in store towards the end of the winter than at the start. The curve of the monitor level through the winter is known as the monitor profile.

209. The monitor profiles are calculated and published prior to the start of the winter. To calculate them, we have to make a number of assumptions relating to the supply and demand for gas over the winter period. We keep these assumptions under review throughout the winter, and we may amend the monitors given new information.

Fig 12 – Example Safety Monitor Profile – Long Duration Storage (GWh)



210. National Grid monitors the level of gas in each of the three storage facility types throughout the winter to ensure that the actual stock level does not fall below the relevant monitor level. If this were to occur, there would be insufficient gas left in storage to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. We would therefore be obliged by our safety case to take action to remedy this situation.

211. In the lead-up to such a situation, National Grid would advise the market with the objective of encouraging mitigating action. If necessary, however, the Network Emergency Co-ordinator (NEC) may require the relevant storage operators to reduce or curtail flows of gas out of storage. In this situation, we would expect the market to rebalance in order to achieve a match between supply and demand. If the NEC is called upon, there is a duty on all market participants to cooperate with the NEC who has a responsibility to take action to prevent as far as possible a supply emergency developing.

212. We would continue to provide information to the market as the situation developed. While National Grid would seek to minimise the extent of any intervention in the market, the balance between allowing the market to resolve the situation and taking action via the NEC will clearly depend on the severity of the situation and the associated timescales.