Winter Outlook Report 2010/11

Outlook for winter 2010/11

Introduction

1. This document, the final report, sets out our analysis and views for the coming winter (October 2010 to March 2011), and reflects responses received through the consultation process. The preliminary winter report and previous year final reports are published on our website at http://www.nationalgrid.com/uk/Electricity/SYS/outlook/.

Industry Feedback

2. We would like to thank the organisations that responded to the consultation. In all five responses were received, which we have reviewed and reflected in our final report. Whilst the formal consultation process has now closed, we continually seek feedback on our outlook reports to increase their usefulness to the industry and to reflect all changes in trends when they become apparent. To feed back comments on our outlook report please contact us at energy.operations@uk.ngrid.com.

Roles and Responsibilities

3. The competitive gas and electricity markets in Great Britain have developed substantially in recent years and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas and electricity to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem, whilst the Department for Energy and Climate Change (DECC) has a role in setting the legislative framework for the market.

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

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Summary

Winter 2010/11 Outlook – Gas

7. The Met Office have now ceased formal publication of their long term winter weather forecast, however their website continues to provide some long term analyses. For the period of December through to February the data presented suggests a higher probability of above average temperatures rather than below average temperatures.
8. Fuel price futures for winter 2010/11 show a small increase in oil, coal and gas with gas also retaining some price seasonality. The forward prices suggest that gas-fired generation could be the base load plant for October and November, with coal-fired generation as base load from December through to March. Due to the prospect of changes to fuel prices and in response to consultation feedback, scenarios have been developed for both gas and coal as the base load fuel for power generation. If gas was to be base load, then there should be a demand response from CCGTs if the gas price was high as a consequence of high demand or a supply shortfall.
9. US forward gas prices for the winter 2010/11 and beyond are currently much lower than those in Europe providing strong incentives to deliver spot LNG cargoes to Europe in preference to the US.
10. On a like for like basis forecast demands for winter 2010/11 are 0.5% higher than weather corrected actual demands in 2009/10. This is due to a small increase in NDM demand. The base case for demands assumes significant use of CCGTs with little upside. Much lower demands are possible with increased use of coal for power generation.
11. The peak forecast for winter 2010/11 demand is 3.8% higher than for last winter due to an increase in the weather sensitivity in the models following observations during periods of high demand last winter and an increase in the forecast for power generation.
12. For winter 2010/11 there will be higher import capacity through the completion of South Hook II at Milford Haven, the expected availability of Grain III and increases in BBL capacity.
13. The forecast for UKCS supplies for winter 2009/10 is approximately 9% lower with UKCS expected to make up typically 45% of non storage supplies during the coldest months.
14. For winter 2010/11, LNG imports again provide the biggest supply uncertainty. Whilst potential LNG flows could exceed 100 mcm/d it is expected that flows will for most of the time be much lower than this. The Base Case view for LNG imports is for average flows of 60 mcm/d within a range of 30 to 100 mcm/d. Analysis of LNG deliveries to the UK demonstrate potential upside. This is primarily due to a combination of increased LNG production / import capacity, low US gas prices and a relatively slow recovery in gas demand following the global recession.
15. Flows from Norway are anticipated to be similar if not higher levels of imports than for last winter, this is partly due to the commencement of flows from the Gjoa field to the UK via the FLAGS pipeline. As in previous winters, prioritised Norwegian deliveries to the Continent may reduce flows to the UK.

16. For BBL, similar flows to last winter are anticipated though these could be reduced through the expected introduction of interruptible reverse flow capacity. For IUK, flows are expected to respond to market needs and if other supplies are as forecast, the threshold for IUK imports may be at relatively high UK demands.
17. The preliminary view of non storage gas supplies for winter 2010/11 (for high demands) is between 342 - 412 mcm/d, with a base case view of 367 mcm/d. This is higher than last winter's initial level, with further upside potential from LNG and IUK imports.
18. The view of storage for next winter is for similar space but lower deliverability due to a combination of reduction of services at LNGS and a new means of assessing storage site deliverability based on observed performance.
19. Though the level of non storage supply (NSS) is higher than for last winter, the revised methodology for assessing NSS has resulted in similar levels of storage requirements for the Safety Monitors. These are approximately 100 mcm of storage space and 64 mcm/d of storage deliverability. The initial trigger level for the Gas Balancing Alert is also expected to be similar with the increase in NSS being offset by lower storage deliverability.

Winter 2010/11 Outlook – Electricity

20. For winter 2010/11, based on the information available for this final report, the surplus generation availability above expected electricity demand is higher than it has been in recent years. There also remains some potential upside in generation availability which is dependant upon the anticipated commissioning of several new large CCGT power stations and new wind power generation.
21. Under a normal demand scenario and base case forecast generation availability, generation surpluses are assured. Under a 1 in 20 demand scenario which might be expected in a very cold winter, generation surpluses are still considered adequate at this stage.
22. Based on data submitted by Generators, the notified of operational generation capability is 77.7 GW at the start of winter. Allowing for anticipated generation performance issues, such as planned and unplanned outages, based on historical performance this could deliver an availability of 66.3 GW.
23. The forecast Average Cold Spell (ACS) peak demand for winter 2010/11 at 57.7 GW is slightly lower than last year's outturn peak demand, adjusted for ACS conditions. This similar level of forecast demand from 2009/10 winter is supported at present by the operational demand forecasting models for which underlying demands are now stable. There remains some uncertainty about how economic factors will drive demand going forward and although demand is expected to grow again with economic recovery the continuing effect of increased embedded generation and improved energy efficiency is expected to mask some of this growth. The latest revisions to the demand forecast will be published on www.bmreports.com as winter progresses
24. Using installed generation capacity relative to ACS peak demand yields a plant margin of 35%.The more representative estimate of actual likely generation

availability at the winter peak of 66.3 GW yields an expected operational margin at the winter demand peak of 15% which assumes a 2GW import from France.

Section A - Outlook for Winter 2010/11

Gas

Met Office Weather Forecast

25. The Met Office have now ceased publication of their long term winter weather forecast however their website[1] continues to provide long term analyses. For the period of December through to February the data presented suggests:

- a 60 – 80% probability of above normal temperatures
- a 20 – 40% probability of near normal temperatures
- a 0 – 20% probability of below normal temperatures

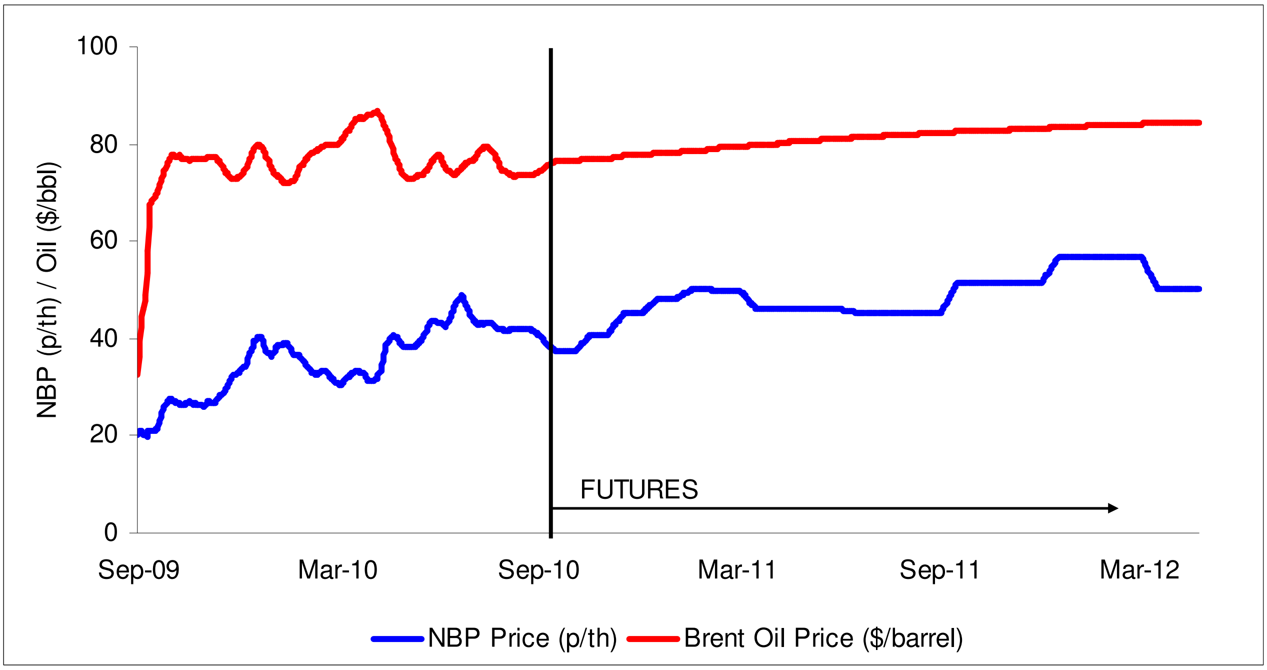
26. In terms of UK precipitation their forecasts are weighted towards above average. For Europe average temps are typically 0.5-1.5℃ above average. For North America average temps are up to 2° above average except for a cooler west coast

Fuel Prices

27. Figure A.1 shows the historical and forward UK oil and gas prices as of early September 2010. The forward oil price is slowly increasing with time due to views of economic recovery. Historically the UK gas price has been linked to the oil price with a lag of around 6 months, this is due to a degree of interconnectivity with the Continent whose long term gas contract prices are oil linked. In addition to this, there is a seasonal risk premium for the UK gas price, reflecting supply / demand fundamentals during winter months.

[1] http://www.metoffice.gov.uk/science/specialist/seasonal/probability/glob_seas_prob.html

Figure A.1 – Historic and Future Oil and Gas Prices



28. Since the recession, the extra worldwide LNG availability due to reductions in world demand and increased LNG production, has meant the oil linkage for non contracted gas has been partially broken. Over the summer months the movements in oil and gas prices have related less, corroborating the view that this linkage may remain less evident at least in the short term.

29. Many industry participants believe oil linkage will re-establish, although probably to a lesser extent, once the world economy improves. Views of when this will happen vary, typically between 2012 and 2015. In theory as the economy recovers, demand will increase and LNG will return to its (non UK) long term contracted customers. Under these conditions the UK may again become more aligned to European prices based on oil indexed contracts. There are many factors that may affect this scenario, though:

- Demand may not return to pre recession levels
- US production of unconventional gas may continue despite low US gas prices
- LNG production may continue to increase

30. Hence the UK may still have access to considerable LNG even after contracted customers take their requirements.

31. Press reports also state European gas contracts are becoming less oil linked. Whether oil linkage returns is not too relevant to the coming winter prices as full linkage is not expected to return immediately and the historic lag means that it would be unlikely to have any effect on winter 2010/11 gas prices.

32. There is currently a natural arbitrage between UK gas prices and those in the EU and the US. With US Henry Hub prices tending to provide a floor and EU oil based

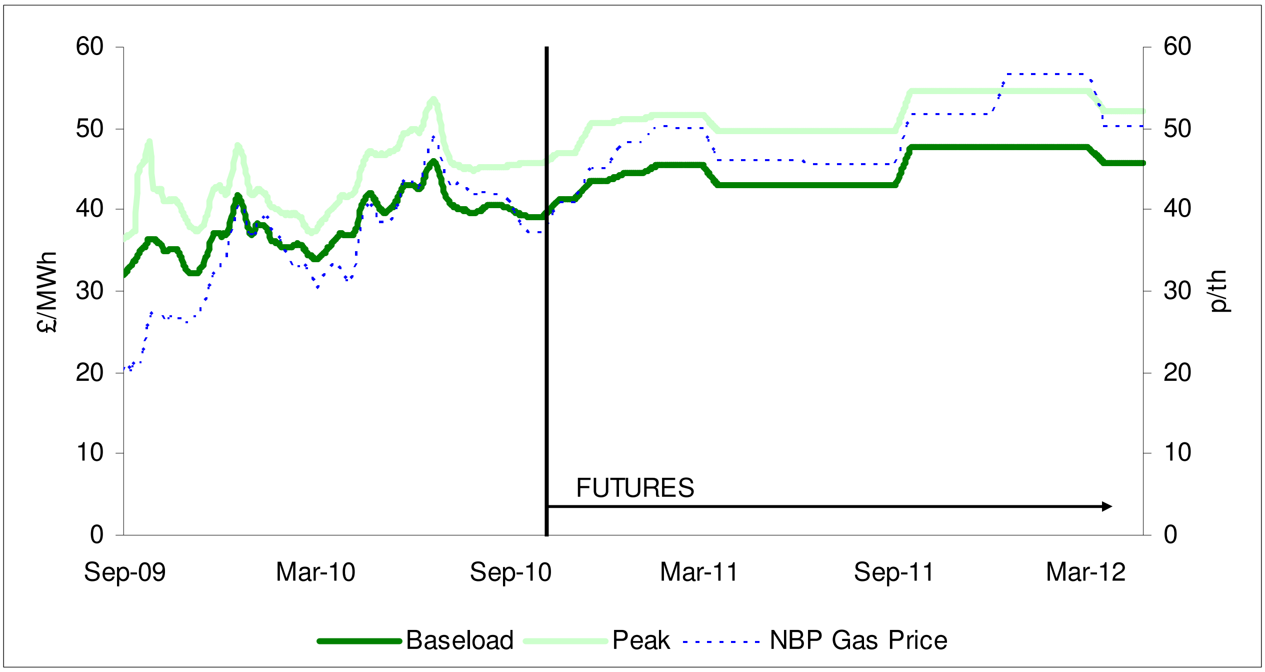
contracts providing a ceiling. These conditions are expected throughout winter 2010/11 unless short term circumstances lead to more extreme prices.

33. The main factors affecting the gas price for this winter are supply, demand, and risk sentiment in the gas markets. The forward prices for winter 2010/11 have tended to follow the near term (prompt) markets. In the last few months Norwegian flow uncertainty relating to unplanned outages before their maintenance outage period have reduced confidence in supplies. Some market commentators believe the effect of this has been overstated. This seems to have some credibility as the daily summer prices have been around 30% higher than for last winter with gas demand at times less than half of that experienced during the winter.

34. Figure A.2 shows the historical and forward UK wholesale base load and peak power prices as of early September 2010, together with the NBP gas price. Historically, there is usually a correlation between the gas and power prices. Recently, the gas price has risen relatively more than the electricity price. This is due to the summer gas price increases, power stations returning from long term outage and new power stations coming online, with more due in the coming months.

35. In the forward power markets, the seasonality in the gas price is not fully reflected due to the ability of the electricity market to switch to alternative fuels. Forward base load power prices for winter 2010/11 are typically £40 to £45/MWh.

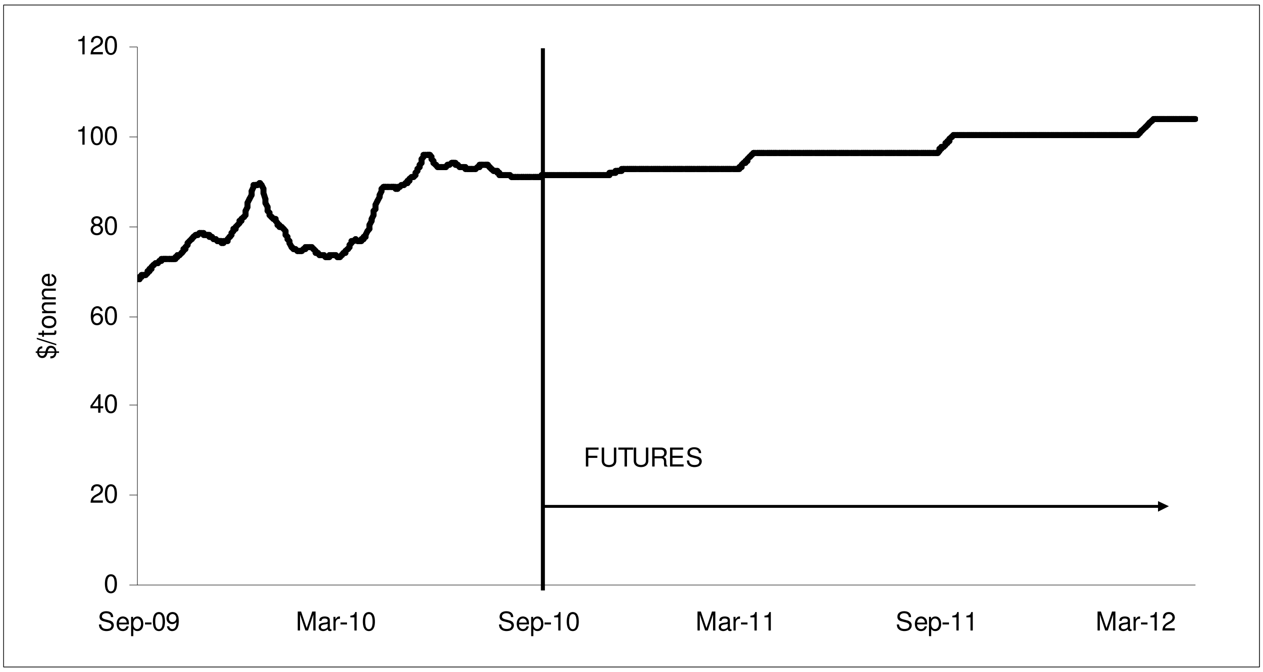
Figure A.2 – Historic and Future Power and Gas Prices



36. Coal prices have tended to reflect movements in the price of oil. There are some differences between markets due to differences in the supply chain. However similar demand fundamentals have meant they often have similar movements. The rises in forward coal prices, as with oil, reflect the view of slow steady economic recovery and the recent increases in demand most notably from China.

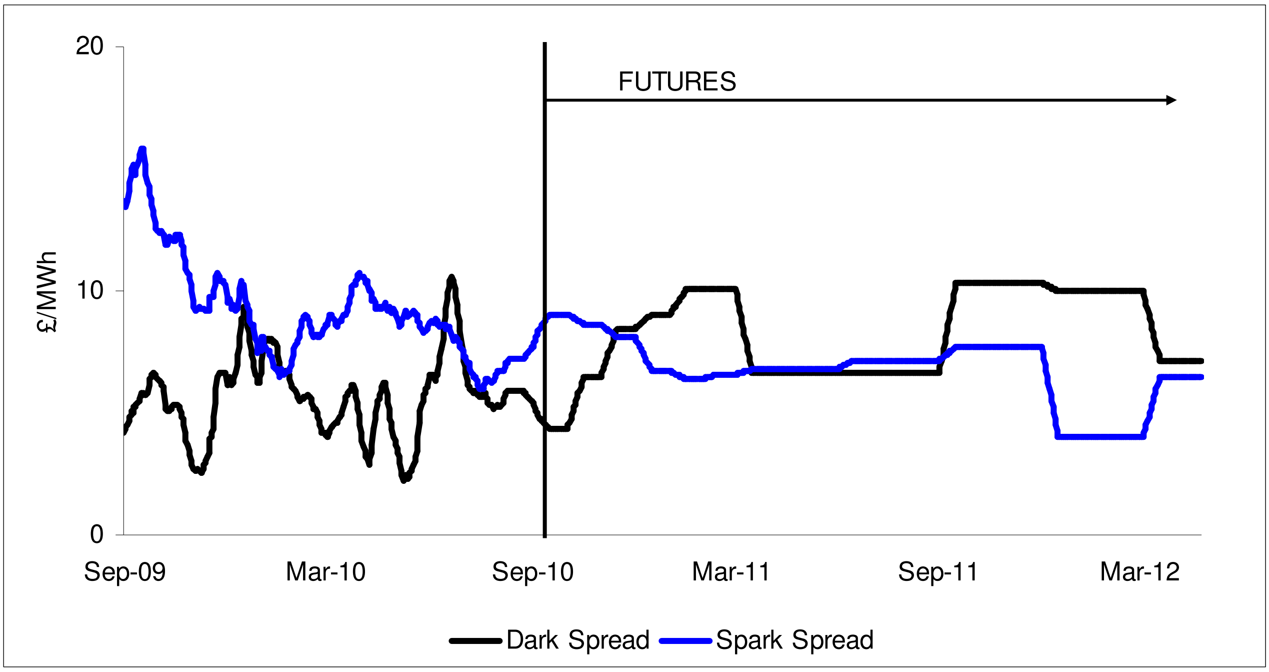
37. Figure A.3 shows the Amsterdam Rotterdam Antwerp coal price in terms of recent history and futures.

Figure A.3 – Historic and Forward Coal Prices



38. Figure A.4 shows historic and forward prices for both dark spread and spark spread. The forward prices at the start of September 2010 suggest that gas fired generation is the more attractive at the start of the winter, with coal preferred for the remainder of the winter.

Figure A.4 – Historic and Dark and Spark Spreads

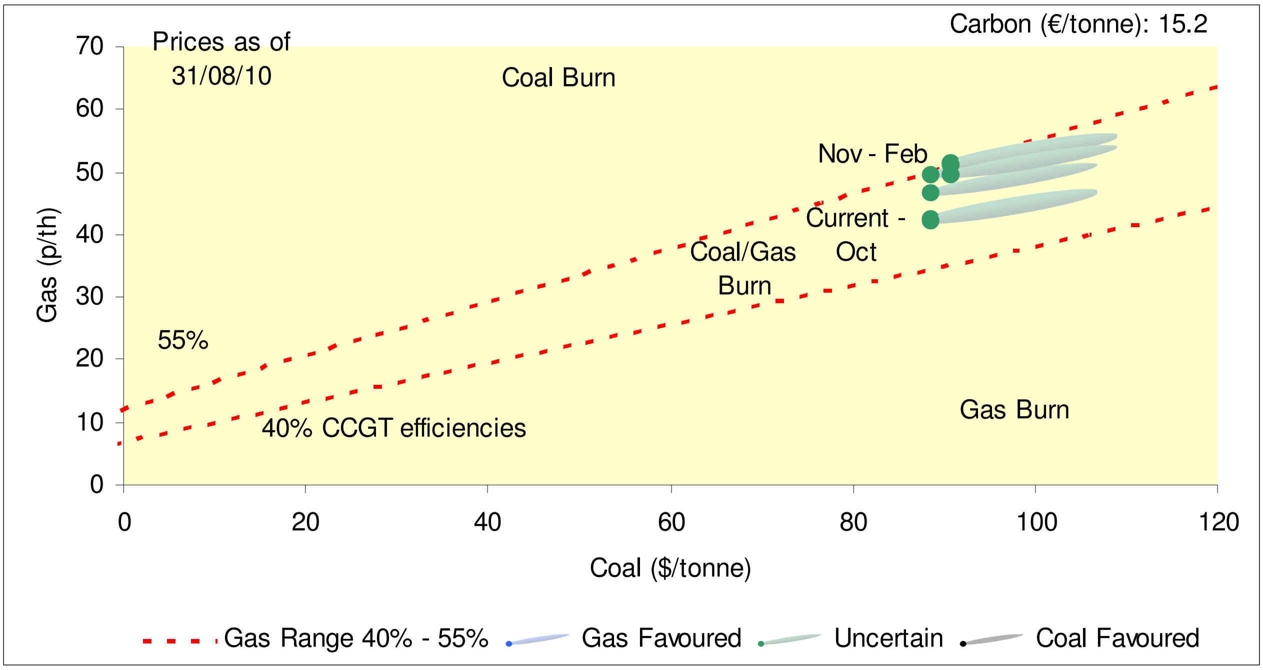


*Thermal efficiencies of gas at 50% and coal at 35% are assumed.

39. The forward prices suggest that gas-fired generation could be the base load plant for October and November, with coal-fired generation as base load from December through to March. For the last two winters, gas prices have reduced around the start of winter as supply uncertainty eased. Changes in assumptions behind the dark and spark spread calculation also have a large effect on the relative costs and hence the preferred base load generation, as demonstrated in Figure A.5.

40. Figure A.5 shows an alternative means of identifying the fuel for power generation for next winter. The chart shows forward prices for coal and gas against a backdrop of the preferred source of fuel, this in turn is based on CCGT efficiency and carbon price. The ellipses on the chart reflect relative transportation costs. Current prices suggest little to choose between gas and coal burn with CCGT efficiencies being a major factor in terms of operational economics. As future coal prices show only a modest increase compared to the bigger increase in gas prices, the bias for next winter for all but the most efficient of CCGTs moves towards coal. For gas to become base load again for the whole of next winter, the gas price needs to fall by about 5 p/therm or there needs to be a further increase in the coal price by about \$15/tonne. Other factors such as running hours for LCPD and generation portfolios will also have a major influence generation choice.

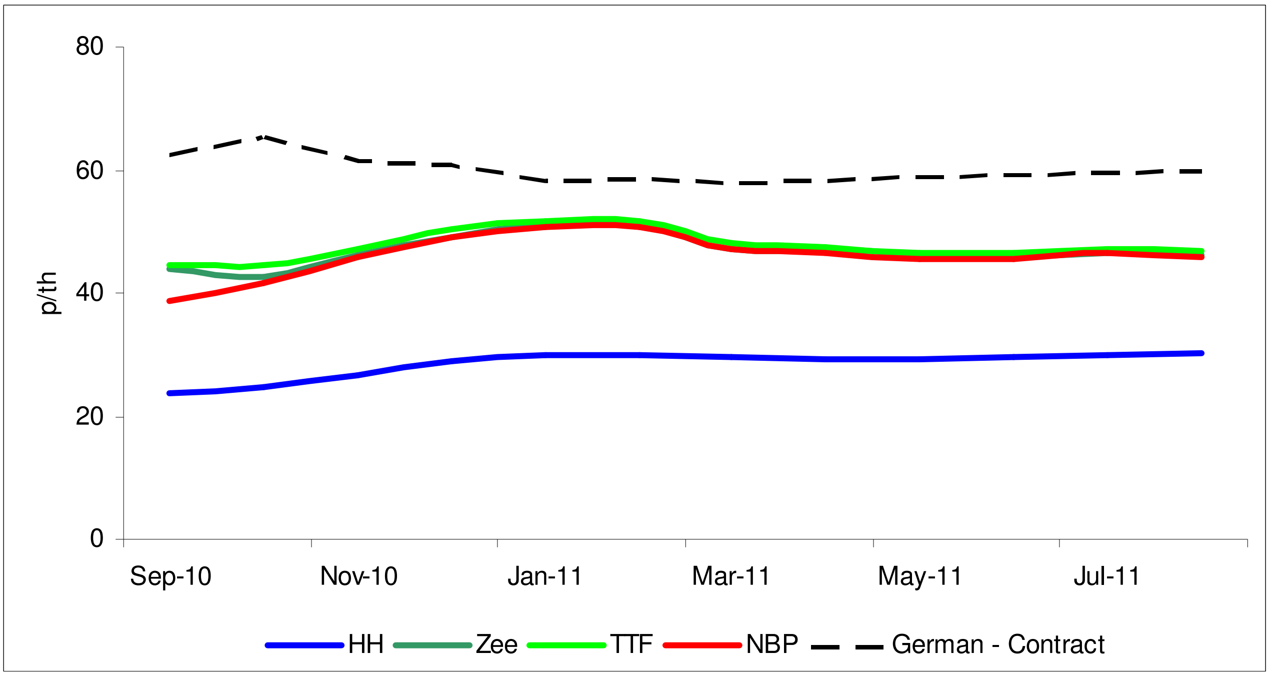
Figure A.5 – Winter 20010/11 – Gas vs Coal Generation



41. There are many factors that may influence which form of electricity generation is likely to be base load which in turn is leading to significant uncertainty For this reason and as suggested through industry feedback, through the publication scenarios for both coal and gas acting as base load generation for this winter will be explored.

42. Figure A.6 shows the forward gas prices as of early September 2010, for European markets (NBP, Zeebrugge, TTF), for the US (Henry Hub) and an estimate of oil indexed gas contracts. All the European Markets are closely linked. Henry Hub prices are significantly lower than the European Markets throughout the forward curve. In terms of spot LNG cargoes this provides a considerable incentive to deliver LNG to Europe in preference to the United States.

Figure A.6 - Forward Prices for Europe and US



*There is some interpretation on the prices shown, due to data aggregation from months and quarterly trading.

Gas Demand Forecast

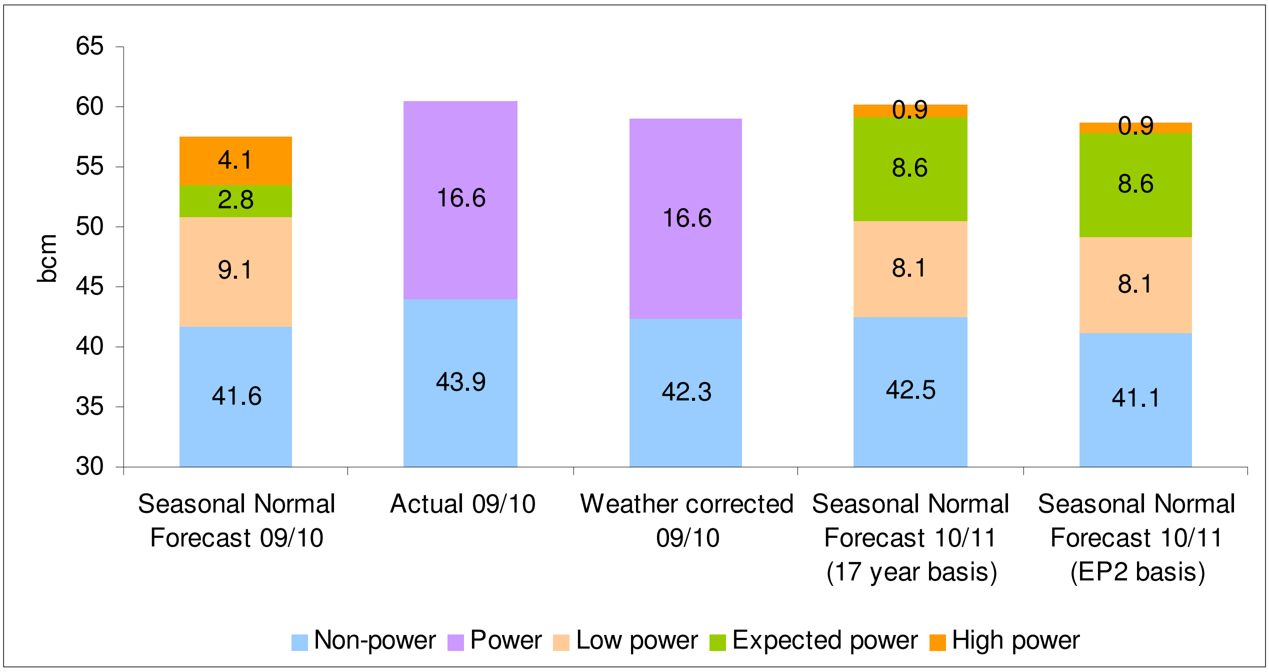
43. The key messages for the winter 2010/11 demand forecasts are a levelling off of non-power gas demand, greater uncertainty in gas demand for power generation and a step change in seasonal normal demand for NDM, this can be seen in Figure A.8.

44. Figure A.7 compares the 2010 total forecast for winter 2010/11 with the actual, weather corrected and 2009 forecast demands for winter 2009/10. The new forecast is 0.5% higher than the weather corrected demands in winter 2009/10 on a like for like 17-year seasonal normal basis.

45. From October 2010 a new seasonal normal basis[2] has been used and this subsequently reduces the seasonal normal forecast by 2.4%. The new Energy Phase 2 basis forecast is 4.5% lower than the 2009/10 actual demand. The impacts on the different market sectors are outlined in the subsequent sections.

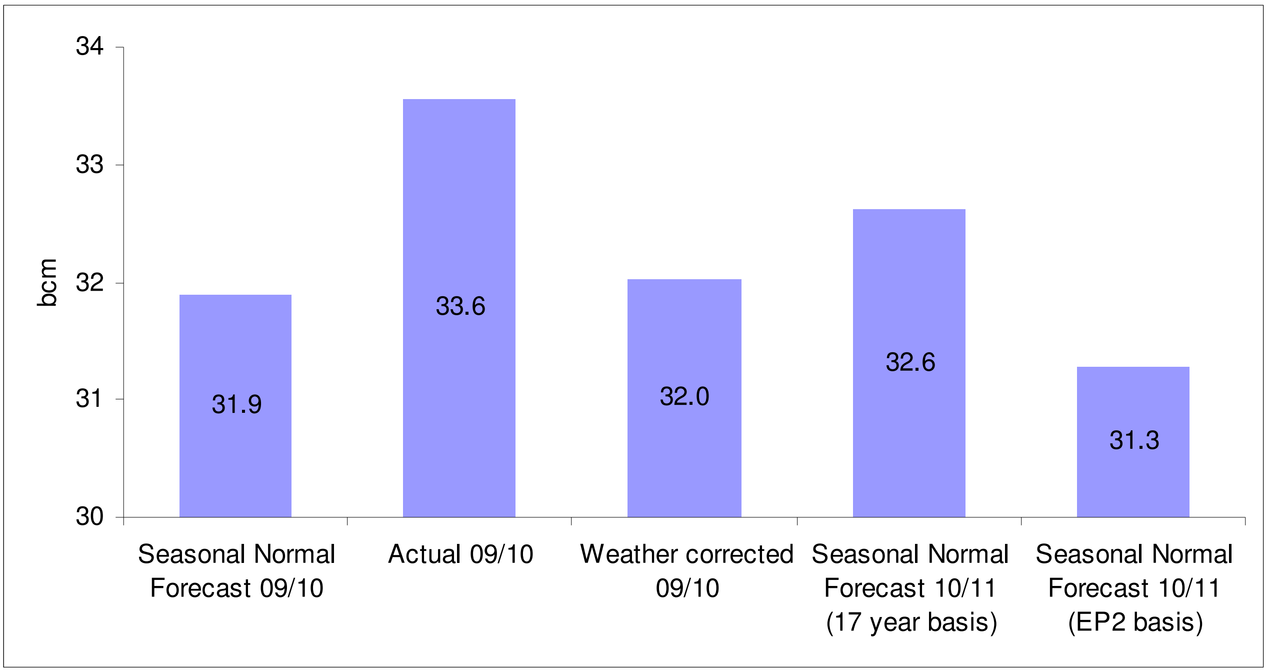
[2] Seasonal normal weather is reviewed every 5 years. The 17-year basis is the average weather from October 1987 to September 2004. The EP2 basis derives from the warming in climate that the Met Office predicted as part of the EP2 project with the energy industry.

Figure A.7 – Total Winter Demand



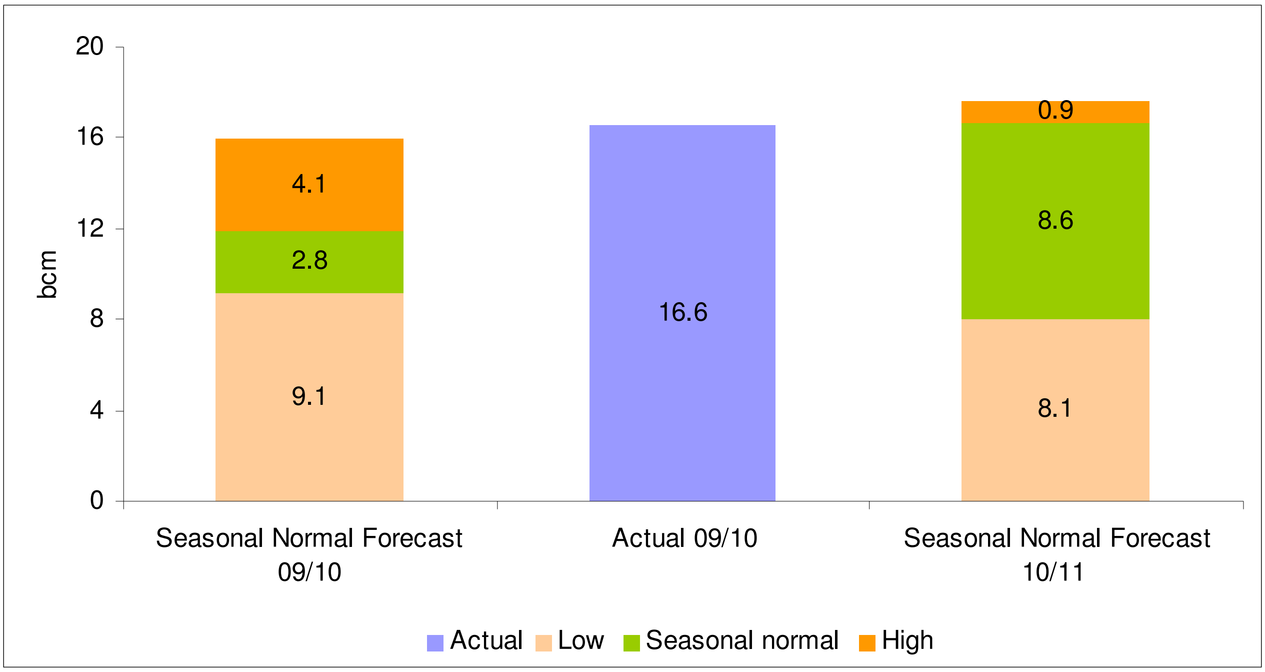
46. Figure A.8 compares the 2010 NDM forecast for 2010/11 with the actual, weather corrected and 2009 forecast demands for 2009/10. Temperature is a significant factor affecting NDM demand. On a similar weather basis NDM demand is forecast to grow by 1.9%. The change in weather basis reduces the forecast by 4% from the 17-year value and by 6.8% from the actual for 2009/10.

Figure A.8 – NDM Winter Demand



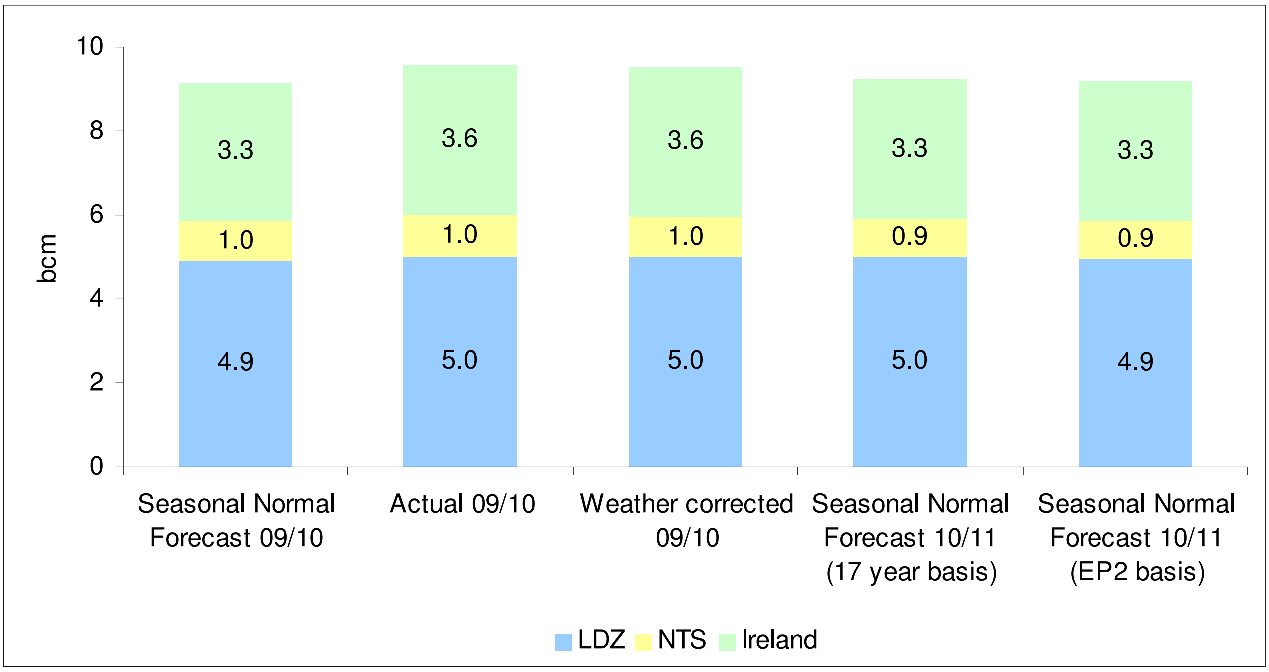
47. Figure A.9 compares the 2010 power generation forecast for 2010/11 with the actual and 2009 forecast demands for 2009/10. In the business as usual demand forecast, gas is predicted to be base load during the winter with coal providing marginal generation. However, as discussed elsewhere in this report, there are no clear signals as to whether gas or coal will dominate this winter. The base case forecast for power generation is only 0.6% higher than 2009/10 which had very high gas generation. There is a potential for a further 5.4% generation but if coal is base load the power generation demand for gas could fall by as much as nearly 50% from last winter's value.

Figure A.9 – Power Generation Winter Demand



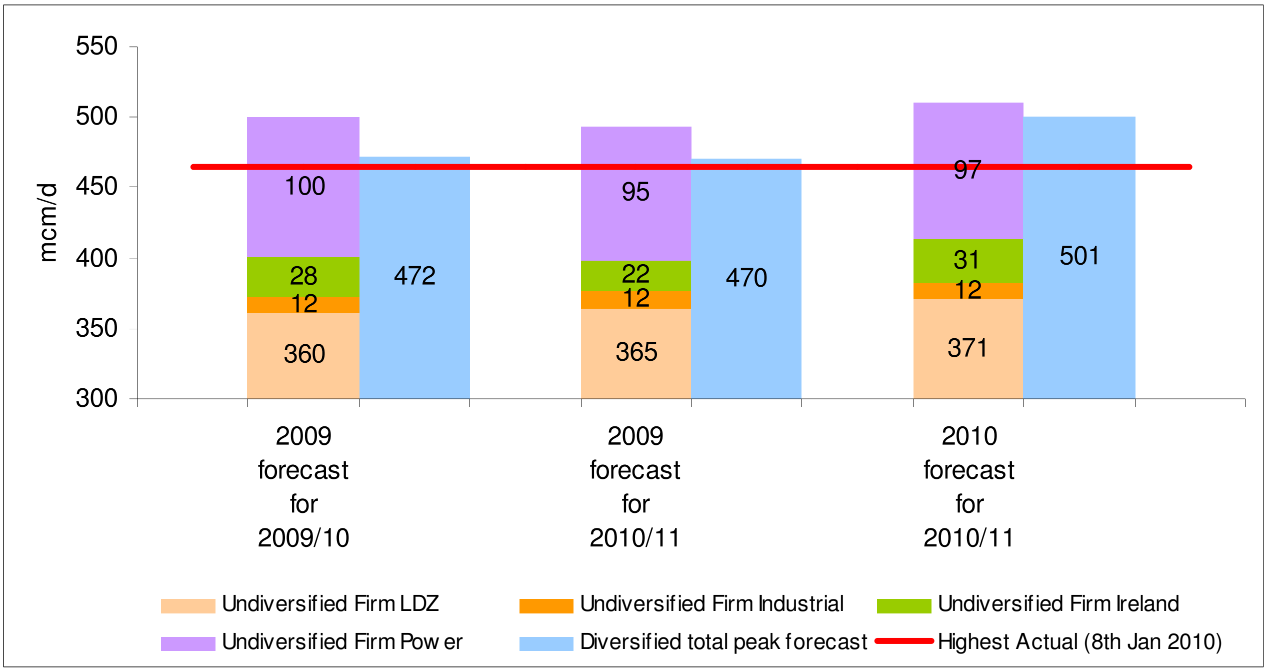
48. Figure A.10 compares the 2010 DM forecast for 2010/11 with the actual, weather corrected and 2009 forecast demands for 2009/10. The DM forecast is broken down into the three major components of LDZ daily metered (DM) demand, NTS non power and exports to Ireland. The chart shows LDZ daily metered and NTS industrial demand are expected to be at similar levels to 2009/10. Exports to Ireland experienced an increase during the very cold period of 2009/10.

Figure A.10 – Non-power DM Winter Demand



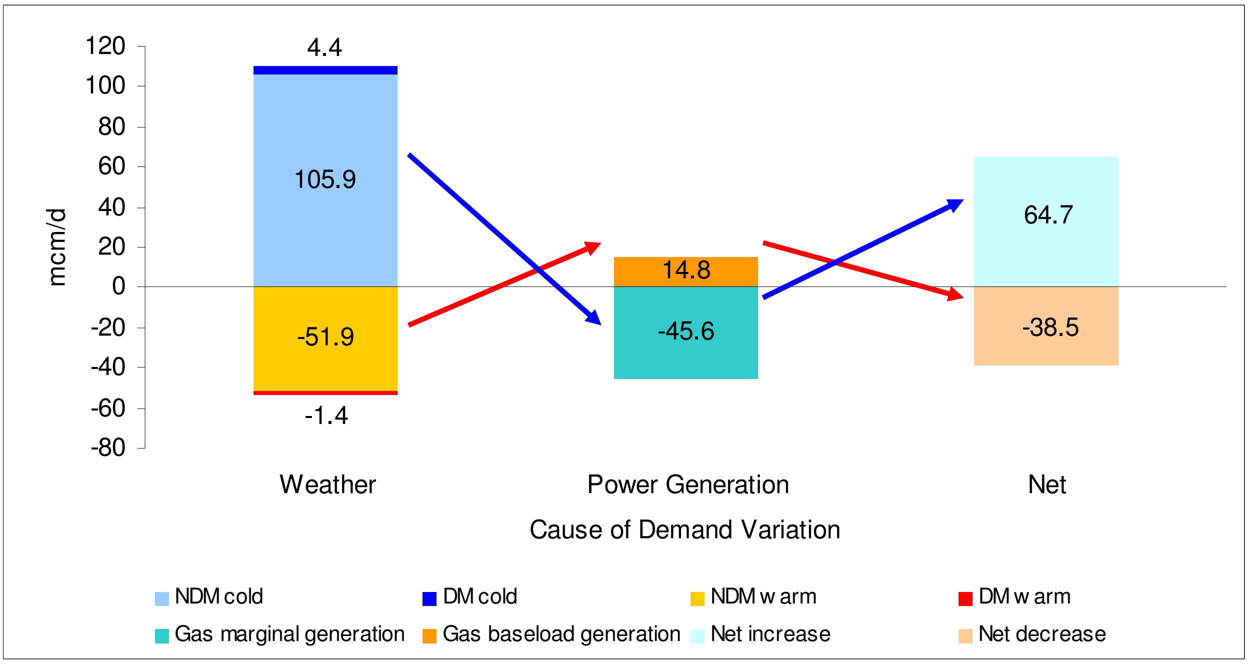
49. Figure A.11 shows that the peak day demand forecast for 2010/11 winter is 3.8% higher than 2009/10. LDZ peak forecasts are higher due to an increase in weather sensitivity in the demand models following the slight under forecast of the 2009 models for cold days in the 2009/10 winter. The increase in Irish exports is due to a change in the expected start date for the Corrib gas field. The chart shows two forecasts, one for undiversified demand (used for capacity planning) and another for diversified demand (used for operational planning). Peak day forecasts are not adjusted for climate change.

Figure A.11 – Peak Demand Forecast



50. Figure A.12 shows the main causes of variation in UK daily gas demand. Very cold weather could result in demand up to 110 mcm/day higher than seasonal normal whilst warm weather could result in demand being as much as 53 mcm/day below seasonal normal. Most of this variation in demand due to weather is in the NDM market sector. Power generation gas demand depends on the relative costs of generating using different fuels and the availability of alternative fuels. The 2010 forecasts made the assumption that during the winter gas would be marginally cheaper than coal. The ranges shown here reflect the possible variation in power generation gas demand should prices greatly favour either coal or gas generation. As discussed previously, there is currently no clear indication as to which fuel will be preferred this winter. In very cold weather high NDM demand for gas is likely to lead to higher gas prices and a switch to coal being the cheaper fuel. Power generation therefore mitigates the impacts of extreme weather on weather sensitive gas demand as shown in the net variation from seasonal normal forecasts.

Figure A.12 – Variation in daily demand



Gas Supply Forecast

51. The following sections examine each of the potential (non-storage) gas supply sources in turn: UKCS, assessment of European markets, imports from Norway, imports through IUK and BBL and LNG imports. These sections are followed by storage, an assessment of winter security and 20010/11 Safety Monitors and GBA.

UKCS gas supplies

52. The data in the Winter Outlook Consultation provided an initial view of UKCS supplies based on 2010 TBE forecasts and the most recent data regarding new UKCS developments.

53. The Table A.1 below shows a final view of the peak UKCS supplies which has been reassessed following recent flow data and additional market intelligence. All the forecasts are similar with small increases for St Fergus and Bacton being offset by similar decreases for Easington and Barrow.

Table A.1 – UKCS Peak Terminal Supply Forecast

Peak (mcm/d)	2009/10		2010/11		
	Final Winter Outlook 08/9	Highest	Initial View	Final View	Changes
Bacton	65	51	59	60	+1
Barrow	16	18	15	14	-1
Easington	11	10	13	11	-2
Burton Point	1	3	0	0	
St Fergus[3]	70	65	56	58	+2
Teesside	24	29	25	25	
Theddlethorpe	16	19	16	16	
Total	**203**	**194**	**184**	**184**	
90% Planning Assumption	183		166	166	

54. Flows from high swing fields at Bacton were not observed last winter. These have subsequently been observed at times during summer 2010. St Fergus flows were also lower than forecast last winter due to field outages.

55. As observed in previous years, but less so in 2009/10, it is probable that the final view of UKCS supplies may be exceeded at the individual terminal level due to daily diversity effects but our aggregated forecast is designed to account for these effects.

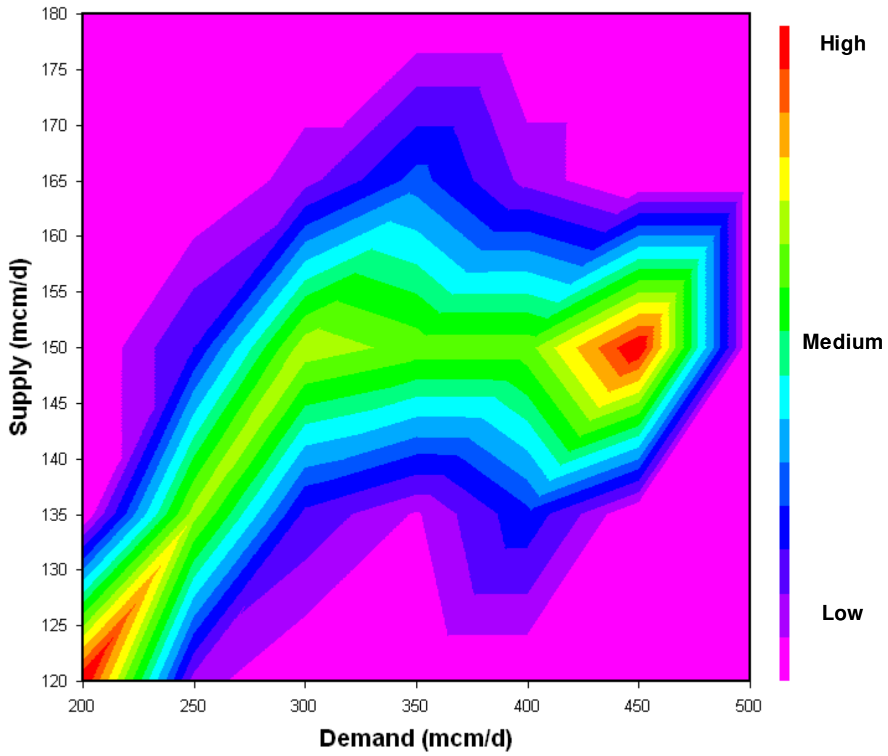
56. The net result of these changes is that the final view of UKCS supplies for winter 2010/11 remains unchanged. Taking into account decline from existing fields and additional production from new fields, the year on year peak forecast is 9% or 19 mcm/d lower than that for 2009/10. This is comparable to the trend of recent decline.

57. As in previous years it is appropriate to assume a level of UKCS supply below the maximum forecast when assessing the overall supply outlook, particularly when assessing supply-demand levels and Safety Monitor levels. The chosen level should reflect the level of delivered UKCS gas that might be expected on average during a prolonged cold spell.

58. Figure A.13 shows the range of UKCS flows into the UK last winter as a density distribution against demand. Demand from the winter months (October 2009 – March 2010) has been split into 6 demand groups ranging from the lowest demands 200-250 mcm/d, through to the highest demands above 450 mcm/d. UKCS supply is split into 4 increments of 15 mcm/d commencing at 120-135 mcm/d

[3] Excludes estimates for Vesterled, Tampen and Gjoa

Figure A.13 – Distribution of UKCS flows in winter 2009/10



59. The chart shows that for demands above 300 mcm/d there is no material increase in UKCS supply above 150 mcm/d. The increase in the supply density for demands above 450 mcm/d is due to a combination of just 4 data (demand) points and all of these corresponding to a UKCS supply between 150-165 mcm/d.

60. To reflect observed UKCS availability, an assumed availability rate of 90% for high demand conditions has been used (typically when demand exceeds 400 mcm/d). It has been acknowledged that some within winter decline of UKCS supplies may occur. However, the starting position represents typical rather than maximum winter availability. This results in a winter UKCS forecast of 166 mcm/d. Last winter the 90% UKCS forecast was met but only when adjusted for flows from high swing fields at Bacton and some extended field outages at St Fergus.

61. As highlighted above there is some scope for upside or downside against the final view of UKCS, for example:

- Lower offshore availability as a result of demanding weather conditions
- Increased risk of plant failure due to aging assets
- Higher than anticipated production decline due to increased annual production
- Higher or lower than anticipated production from new fields
- The development of new fields that on commencement of production have rapid decline

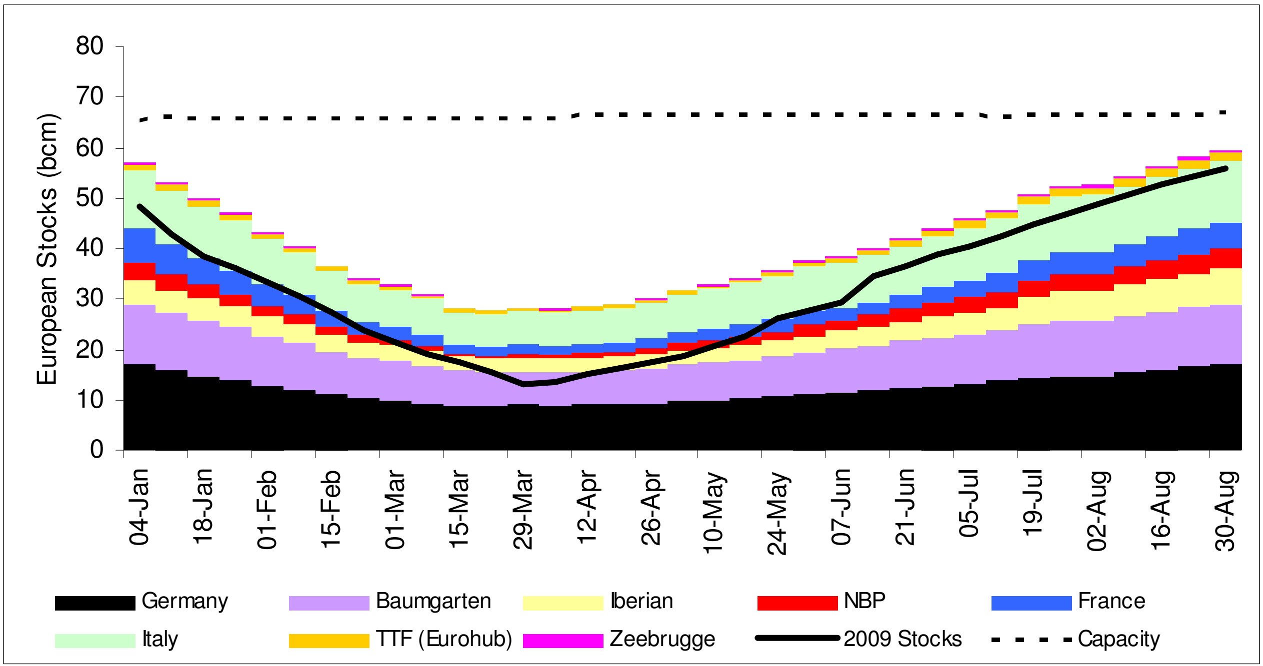
Europe

62. Information published by European gas agencies continues to improve particularly on a country by country basis. However it is still difficult to provide a comprehensive overview of the European gas market

63. There are a number of areas where it is possible to obtain complete, or near complete data, and these include Norwegian exports to the UK and Continent, LNG deliveries to Europe and Continental storage sites stocks.

64. Figure A.14 shows storage capacities and storage stock levels for storage across Europe from data extracted from the Gas Infrastructure Europe website[4]. This now represent approximately 90% of the storage capacity in Western and Southern Europe.

Figure A.14 – European Storage Capacity and Storage Levels



65. The figure shows reported European storage capacity and reported storage stock levels by 8 aggregated areas covering the largest gas markets in Western and Southern Europe. Current reported stock levels are nearly 90% full and expected to be near completely filled for the start of the winter.

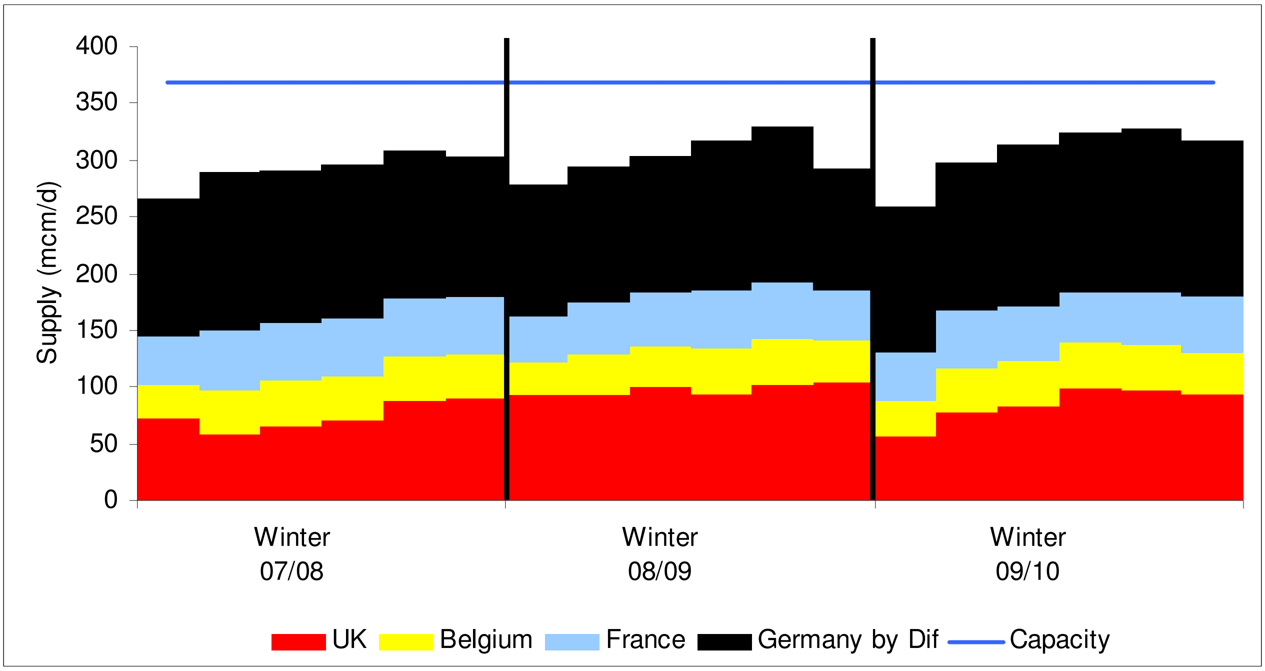
66. More storage sites are now reported compared to last year and assumptions have been made regarding 2009 stocks to enable a comparison to be made. Compared to last year it is estimated that the level of storage depletion for last winter was approximately 15 bcm less than the previous one. In terms of storage refill the current position is comparable to 2009, though the summer refill rate has been less.

[4] http://transparency.gie.eu.com/

Norway

67. Figure A.15 shows an estimate of average Norwegian monthly exports to Europe during the previous 3 winters (Oct-Mar), the data is based on the available daily flow information for Norwegian imports to France, Belgium and UK, monthly production data from the Norwegian Petroleum Directorate (NPD) with Norwegian imports to Germany determined by difference.

Figure A.15 – Estimate of Norwegian Exports by Destination



68. The chart shows small increases in aggregated Norwegian production with the UK receiving lower winter imports last winter compared to the previous year and Germany receiving more. The lower UK imports are probably due to Continental contractual conditions rather than Norwegian gas being squeezed from the UK gas market.

69. Table A.2 highlights winter volumes and load factors of gas delivered from Norway to Europe for the past two winters. The table highlights increased production approaching 1 bcm, with the UK importing 2.6 bcm less and the Continent (mainly Germany) importing 3.2 bcm more.

Table A.2 – Norwegian exports and load factors to European markets

Country	Winter 2008/09 (mcm/d)	Winter 2009/10 (mcm/d)	Capacity (mcm/d)	Winter 2008/09 Load Factor	Winter 2009/10 Load Factor
Belgium	37	38	41	90%	93%
France	47	46	52	90%	89%
Germany	121	138	151	80%	91%
UK	98	84	124	79%	68%
Total	**302**	**306**	**368**	**82%**	**83%**
Monthly Range (mcm/d)	279 – 330	260 - 328			

70. For winter 2010/11 our assumptions for Norwegian production include:

- A slight decline across many of the currently producing fields, similar to the 2% observed last year
- Troll to produce at similar levels to last year
- Ormen Lange to continue to produce at 65-70 mcm/d
- The start up of Gjoa, this field will flow directly to the UK through a new dedicated pipeline that links with the UK FLAGS pipeline.

71. In aggregate, the forecast for Norwegian production for winter 2010/11 is 57.6 bcm or a winter average of 315 mcm/d. This compares with last winter's actual flow of 56.0 bcm. For the mid winter period between December and February average flows of 330 mcm/d have been forecast.

72. A Base Case and range of flows to the Continent have been developed following the creation of field production forecasts used in conjunction with a model of the Norwegian offshore system. Forecast flows to the UK system have been determined by the difference between the flow forecast and the model.

73. Tables A.3 and A.4 show the Norwegian forecast for the 6 month winter period October to March and the 3 month period December to February respectively. The Base Case has similar flows to the Continent to those seen in winter 2009/10. For the UK the forecast has an increased flow from last winter to 93 mcm/d (101 mcm/d Dec – Feb), to account for flows from Gjoa.

74. The forecast for Norwegian imports to the UK has a range of 86-113 mcm/d. This represents a winter long average and not the daily variations that would be expected. The key drivers for these include; Continental supplies / demand (hence weather), UK and Continent storage stock levels, contractual flexibility / commitments, UK and Continental gas price and Norwegian offshore and onshore production issues.

Table A.3 – Norwegian forecast (October to March)

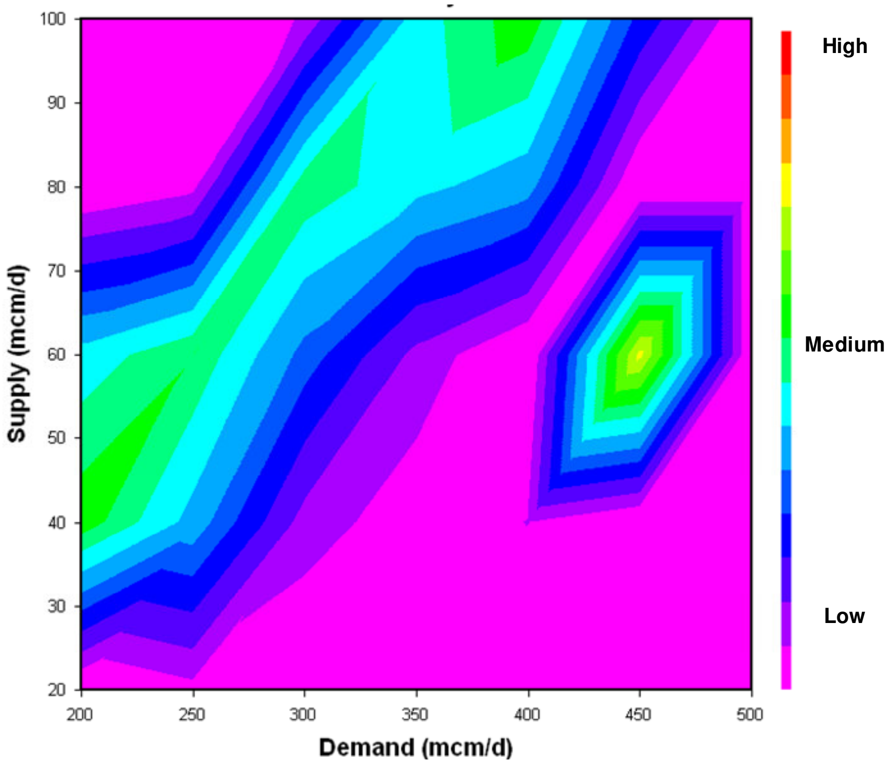
(mcm/d)	Winter 2009/10	Base Case	High	Low	Capacity
Belgium	38	37	35	39	41
France	46	48	45	50	52
Germany	138	137	122	140	151
UK	84	93	113	86	124
Total	**306**	**315**	**315**	**315**	**368**

Table A.4 – Norwegian forecast (December to February)

(mcm/d)	Winter 2009/10	Base Case	High	Low	Capacity
Belgium	40	40	39	41	41
France	46	49	45	52	52
Germany	143	140	130	151	151
UK	93	101	116	86	124
Total	**322**	**330**	**330**	**330**	**368**

75. The high / low range for Norwegian exports, these represent 6 month and 3 month average flows and do not capture the anticipated variations in daily flows. These are expected to be comparable to the high / low range as highlighted in Figure A.16 which shows the range of Norwegian flows to the UK last winter expressed as a density distribution against demand.

Figure A.16 – Distribution of Norwegian flows to UK



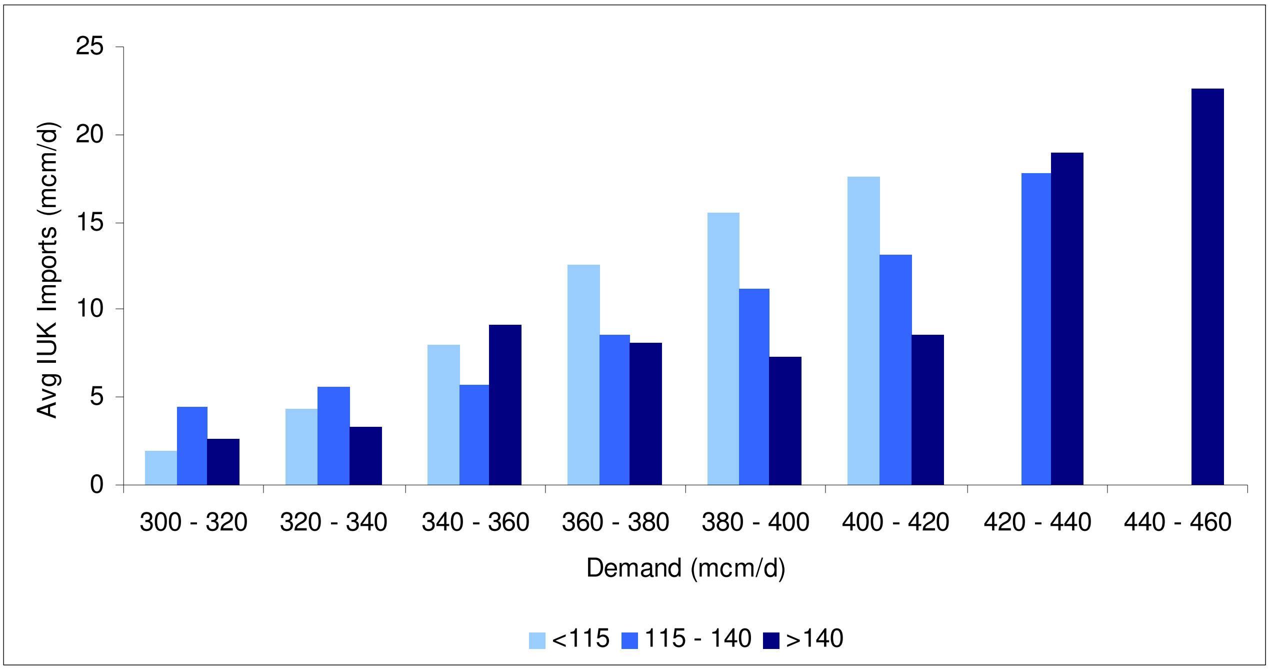
76. The chart shows that flows from Norway to the UK tend to increase in line with UK demand. The range of flows are broadly similar across all demands, typically +/- 30 mcm/d. The 'island' of supply positioned below the main area of flow represents the supply loses experienced last winter. Due to the methodology, these are overstated on the chart as for the data (demand) points above 450 mcm/d contain just 4 data (demand) points, and of these, 3 of the 4 days experienced a supply loss.

IUK

77. Figure A.17 shows IUK imports for the last three winter's (2007/8 to 2009/10) at differing levels of all other imports (Norway, BBL & LNG). This time period was chosen to reflect the increased availability of import infrastructure. The chart shows IUK flows (y-axis) against demand (x-axis) in the context of low[5] levels of other imports (less than 125 mcm/d), mid levels of other imports (125-145 mcm/d) and high levels of other imports (greater than 145 mcm/d).

[5] There are about 150 data points in the 'low' and 'mid ' categories and about 100 in the 'high'

Figure A.17 – IUK Import Flows 2007/8 – 2009/10

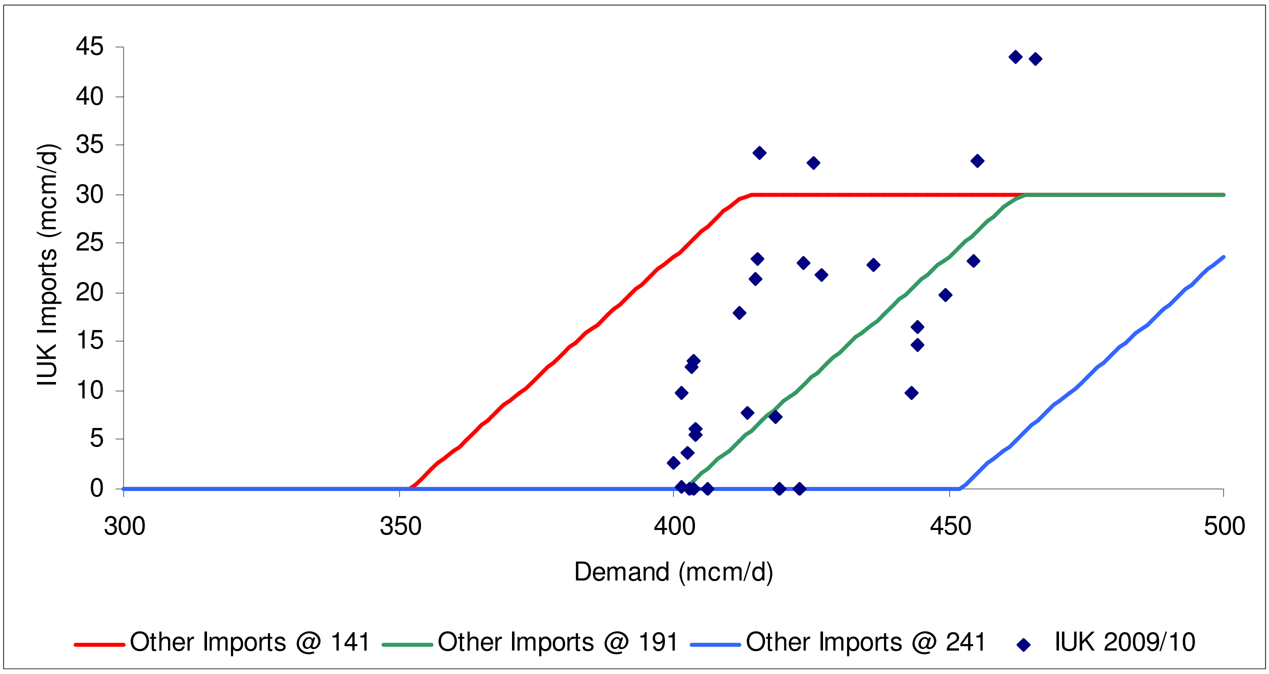


78. The chart clearly shows a general increase in IUK imports as demand increases, however the magnitude of the increase is dependent on other sources of imported gas. For the 50 days of demand (supply) in excess of 400 mcm/d over the past three winters, the average level of IUK imports is 12 mcm/d.

79. For winter 2010/11, it is again assumed that IUK will respond to UK / Continental price differentials and operate as a marginal source of supply similar to storage when UKCS and other imports have not met demand. Hence if other imports are relatively low it would be expected that this would lead to higher UK gas prices and the possibility of modest IUK imports. Conversely if the UK is well supplied with other imports (notably LNG and Norway) then lower UK prices could be expected and the prospects of IUK at float or exporting unless UK demand was relatively high.

80. Figure A.18 shows our forecast for IUK imports based on 166 mcm/d UKCS, 45 mcm/d of storage and a range of other import flows based around our Base Case of 191 mcm/d (101 mcm/d Norway, 60 mcm/d LNG and 30 mcm/d BBL) with a range of +/- 50 mcm/d. The chart shows that for low levels of other imports, IUK could commence importing at demands as low as 350 mcm/d, whilst for a well supplied UK not until demands were as high as 450 mcm/d. The relatively high threshold for IUK imports in a well supplied UK market highlights that IUK could again be at float or predominately in export mode in winter 2010/11.

Figure A.18 – IUK Import flows



81. The chart also shows actual IUK imports for last winter. The average for 'other imports' during the 84 days that IUK imported was 174 mcm/d.

82. The assumptions for IUK imports for winter 2010/11 again assumes an upper flow of just 30 mcm/d, though it is acknowledged that this could potentially be much higher. In addition, it remains prudent to consider lower IUK supply availability through to January due to uncertainties over the release of Continental storage that may be held back for Continental markets.

83. Table A.5 shows the make-up of supplies for the days of highest demand for winters 2006/7 to 2009/10. The number of days is adjusted for each winter to produce average demands of approximately 400 mcm/d.

Table A.5 – Supply make-up for highest demand days for winters 2006/7 - 2009/10

(mcm/d)	2006/7	2007/8	2008/9	2009/10
UKCS	208	209	197	158
Norway	84	86	99	97
BBL	24	36	28	32
LNG	12	4	15	55
Total NSS[6] (excl IUK)	**329**	**335**	**339**	**342**
IUK	22	12	3	10
Total NSS	**351**	**347**	**342**	**352**
Storage	49	53	58	48
Supply = Demand	400	400	400	400
No. of days	16	21	30	80

84. The table shows comparable demands for the four winters analysed though there has been a trend of higher demands as shown by the increasing number of days. The decline in UKCS has been more than offset by higher imports, from Norway and also for last winter from LNG imports. The table also reinforces the previous view that IUK is more responsive to the overall supply / demand balance. Hence, there is a relatively stable level of non storage supply including IUK imports. The relatively high flows of storage highlight the key role storage plays in meeting high levels of demand. Average storage flows were lower last winter due to the longer period evaluated to obtain the average demand of 400 mcm/d.

BBL

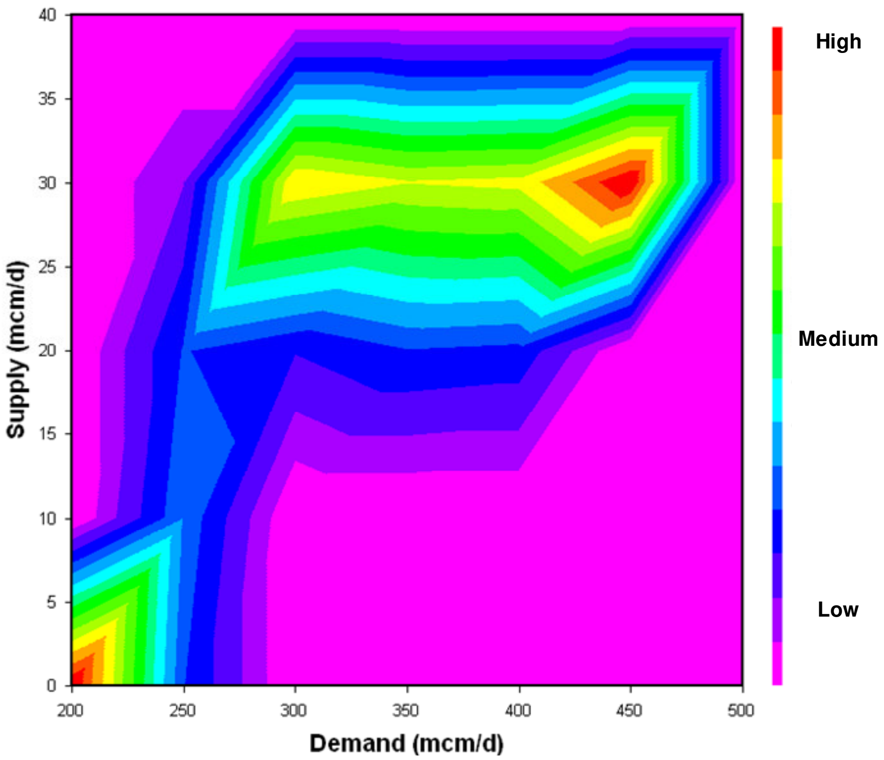
85. The installation of a fourth compressor at Balgzand will increase the technical capacity[7] of the BBL pipeline from approximately 44.1 mcm/d to 53.4 mcm/d[8]. This capacity is reported to be available from December 1st 2010.

86. From winter 2010/11 BBL will be offering Interruptible Reverse Flow (IRF) capacity, i.e. non-physical exports, whereby exports may be netted off physical imports. Besides the needs to acquire IRF capacity, shippers will also need to have in place capacity arrangements at both Bacton and in the Netherlands.

87. For forecasting flows through BBL for winter 2010/11, the increase in capacity provides a potential upside whilst the introduction of IRF may reduce flows. The current view for winter 2010/11 is for comparable flows to last winter, namely 30 mcm/d. Figure A.19 shows the range of BBL flows to the UK last winter expressed as a density distribution against demand.

[6] NSS = Non Storage Supply
[7] http://www.bblcompany.com/en/operations/available-transmission-capacity
reported capacity is 20.6 GWh/h based on a CV of 35.17 MJ/m3 (normal)
[8] Based on a CV of 39.6 MJ/m3 (standard)

Figure A.19 - Distribution of BBL flows to UK in winter 2009/10



88. The chart clearly shows that for most winter demands, flows through BBL were typically 30 mcm/d within a range of about 25-35 mcm/d.

LNG Imports

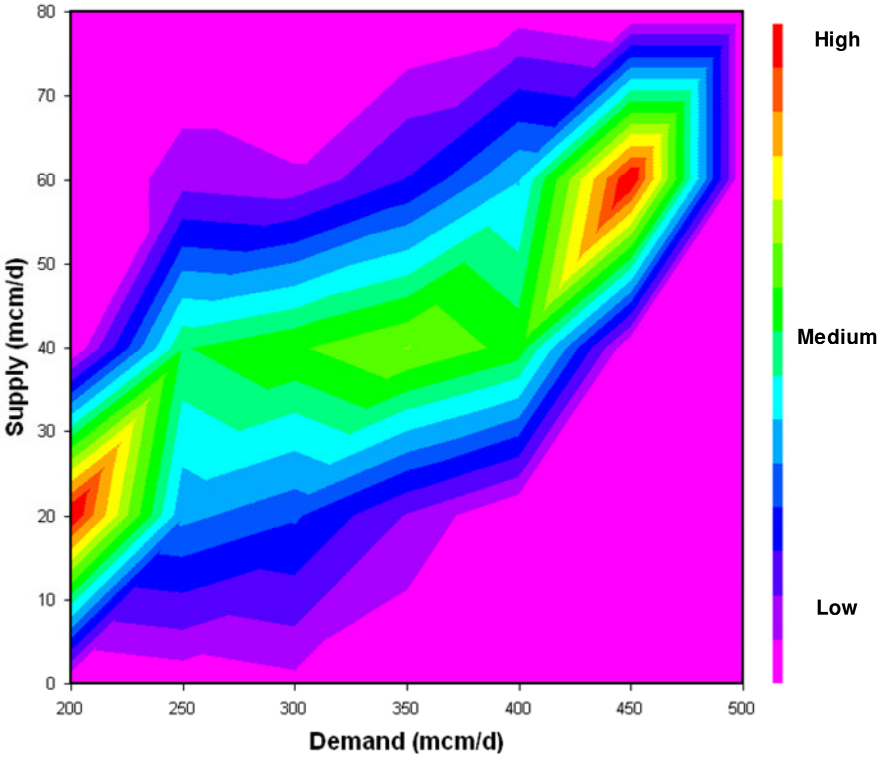
89. Last winter there was a considerable increase in LNG imports compared to previous winters. This was due to a combination of increased available import capacity and favourable economic conditions for LNG imports.

90. For winter 2010/11, further LNG import capacity is available following the commissioning of South Hook II and the expected completion of Grain III. In aggregate this will bring UK LNG import capacity to in excess of 50 bcm/year (includes Teesside GasPort), equivalent to potential daily flows in excess of 143 mcm/d.

91. Economic conditions for LNG imports to the UK for winter 2010/11 continue to be favourable with UK forward gas prices being appreciable higher than those in the US (Figure A.6). Supply / demand fundamentals are also favourable with further LNG liquefaction production brought on stream in 2010 and limited recovery in global gas demand.

92. Last winter's imports of LNG to the UK are shown in Figure A.20 as a density distribution against demand.

Figure A.20 - Distribution of LNG flows to UK



93. The chart shows a general trend of increasing LNG imports with increasing demand with daily demands as high as 80 mcm/d. The chart also shows that the range of LNG flows last winter relative to demand was considerable, typically +/- 30 mcm/d for most gas demands, tightening a little for the days of highest demand.

94. The preliminary forecast for average flows of LNG imports in June for winter 2010/11 highlighted the considerable uncertainty associated with LNG imports. In the Winter Outlook Consultation a Base Case of 60 mcm/d within a range of 30-100 mcm/d was set. This base case level has remained following further analysis and feedback from the consultation that this remains a realistic assumption. However the possibility of higher flows and higher day to day variations should not be discounted.

Final View of Non-Storage Supplies

95. The Winter Outlook Consultation provided a range of non storage supplies for winter 2009/10 and a Base Case. Industry feedback was supportive of these views and also identified the uncertainty associated with LNG and IUK imports.

96. Table A.6 shows the ranges for non storage supply for winter 2010/11, these are unchanged from the consultation. The Base Case assumes a non storage supply level of 367 mcm/d, this level of supply will be used for the initial setting of the Safety Monitors and GBA trigger level.

Table A.6 - Non-Storage Supplies

(mcm/d)	Range	Base Case
UKCS	166	166
Norway	86 – 116	101
BBL	30	30
IUK	30 – 0	10
LNG	30 – 100	60
Total	**342 – 412**	**367**

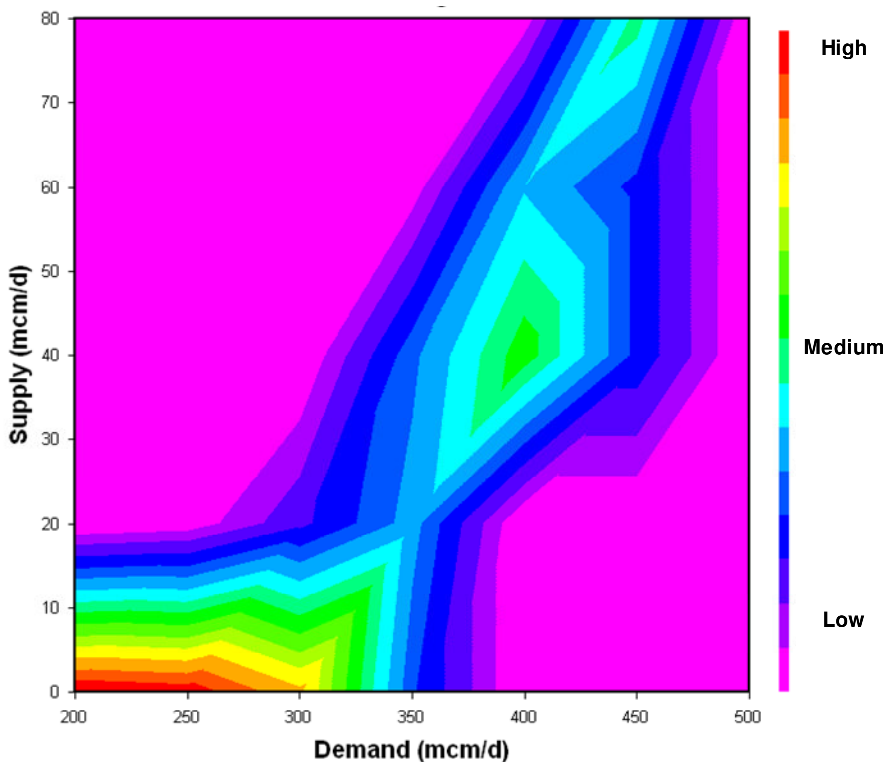
97. Note, IUK is assumed to increase as a consequence of tighter supply conditions (i.e. reacting to an increase in UK gas price). Hence the low case has higher IUK imports than the high case. For the Base Case only IUK imports are assumed when demand approaches 400 mcm/d, for conditions where the level of non storage supply is lower, higher IUK imports are assumed commencing at lower levels of demand on the basis that IUK flows are price dependent and for tighter supply conditions prices should be higher.

Storage

98. As reported in the Winter Outlook consultation, total storage use last winter (4.7 bcm) surpassed that from all previous winters. This was accounted for by 3.3 bcm from Rough (93% of pre-winter stock) and 1.3 bcm from MRS (145%) and LNGS 0.07 bcm (40%).

99. Figure A.21 shows storage use last winter as a density distribution against demand.

Figure A.21 - Distribution of Storage flows in winter 2009/10



100. The chart shows little storage use for demands below 300 or even 350 mcm/d. Storage use for demands above 350 mcm/d accounted for 90% of storage use last winter. For demands in excess of 350 mcm/d there is a strong relationship between storage use and increasing gas demand. For the increase in gas demand between 350 and 450 mcm/d the contribution of storage increases from about 15 mcm/d to 80 mcm/d. i.e. storage provided 65% of the increased supply to meet demand. The remaining 35% was met by an increase in non storage supplies, of these IUK and LNG imports tended to make the biggest contribution.

101. For next winter with similar / slightly higher levels of non storage supply it is anticipated that aggregated storage use will follow a similar pattern. The generalised view of storage use does not however reflect that most storage sites have different operating criteria reflecting their space, deliverability and injection characteristics. In addition, storage site ownership and the weather (both severity and weather patterns) will also influence storage use.

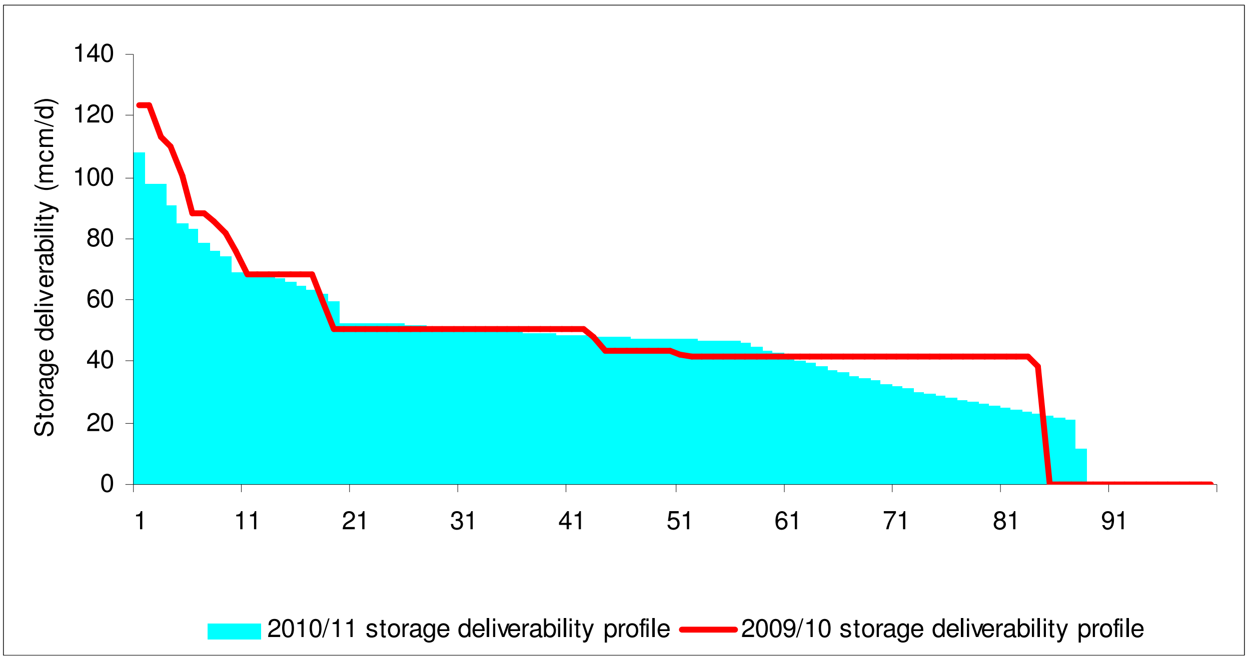
102. For winter 2010/11 there are no plans for commencement of any new storage sites. Within winter capacity at Aldbrough may be increased[9]. LNG Storage have been carrying out some essential maintenance at the Glenmavis facility over the summer, this has recently led to the identification of further work which cannot be completed before the start of the winter. In order to carry out this additional maintenance, it will be necessary to export shipper stock. Consequently LNGS do not anticipate being able to refill this stock or meet the full deliverability at the Glenmavis facility this winter. LNGS have also announce a review of future LNGS services[10].

[9] http://www.scottish-southern.co.uk/SSEInternet/index.aspx?rightColHeader=26&id=412
[10] http://www.nationalgrid.com/uk/Gas/lngstorage/What/ click on press release

103. Last winter there was significant drawdown at many of the storage sites. During the depletion of storage stocks, there was some observed decay of site deliverability. There was also observed storage deliverability that was in some instances higher and in many cases lower than that expected[11] / reported in our Winter Outlook and subsequently used for determining the Safety Monitors and GBA trigger level.

104. Consequently a site by site review of the operational performance of all storage facilities has been undertaken to improve the data for security analyses. Figure A.22 shows the revised assessment of aggregated storage deliverability for winter 2010/11 against storage duration. The 'areas' beneath the lines represent the total space. For comparison last winters data is also shown.

Figure A.22 – Storage Deliverability



105. The chart shows a similar profile for winter 2010/11 as that for last winter, however there are a few noticeable differences:

- The period corresponding to highest deliverability has been reduced. This is primarily due to less LNGS
- From Day 40 to about Day 60 there is higher deliverability and subsequently less post Day 60. This is due to the review of performance

106. Table A.7 shows our assumed levels of storage space and deliverability for winter 2010/11. Note these values reflect our review of performance from last winter and may be different to those reported by storage operators.

107. The reported storage will be used for the 2010/11 Safety Monitors and the GBA trigger. For the GBA trigger, inclusion is also subject to a minimum of 2 days duration for each storage facility and any reduction in deliverability as a result of a

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[11] Either published capacities or information provided to National Grid

decline in storage stocks. If the performance of individual storage sites is proven to be different during winter 2010/11 after careful monitoring there maybe revisions to the storage assumptions and if applicable the Safety Monitor and GBA trigger level.

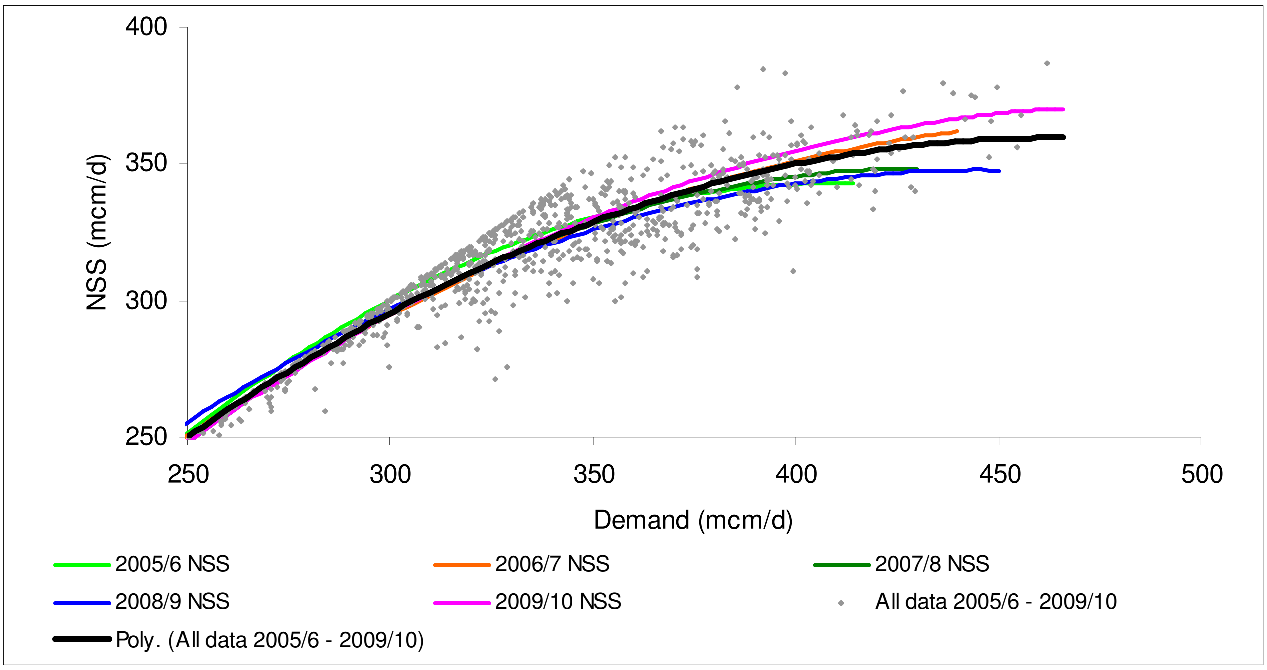
Table A.7 – Assumed storage capacities and deliverability levels

	Space[12] (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	601	253	23	2.4
Medium (MRS)	9095	441	40	21
Long (Rough)	38485	495	45	78
Total	**48181**	**1189**	**108**	
Total 2009/10	50806	1360	124	

Winter Security Assessment

108. In previous years our traditional cold spell analysis has assumed a single figure for non storage supply (NSS) for all days across the winter. In reality NSS levels increase with increasing demand. This can be seen in Figure A.23, which shows trend lines for NSS versus demand for winters 2005/6 to 2009/10. An aggregated trend line for all five winters worth of data is also shown.

Figure A.23 – NSS v demand relationship for winters 2005/6 to 2009/10



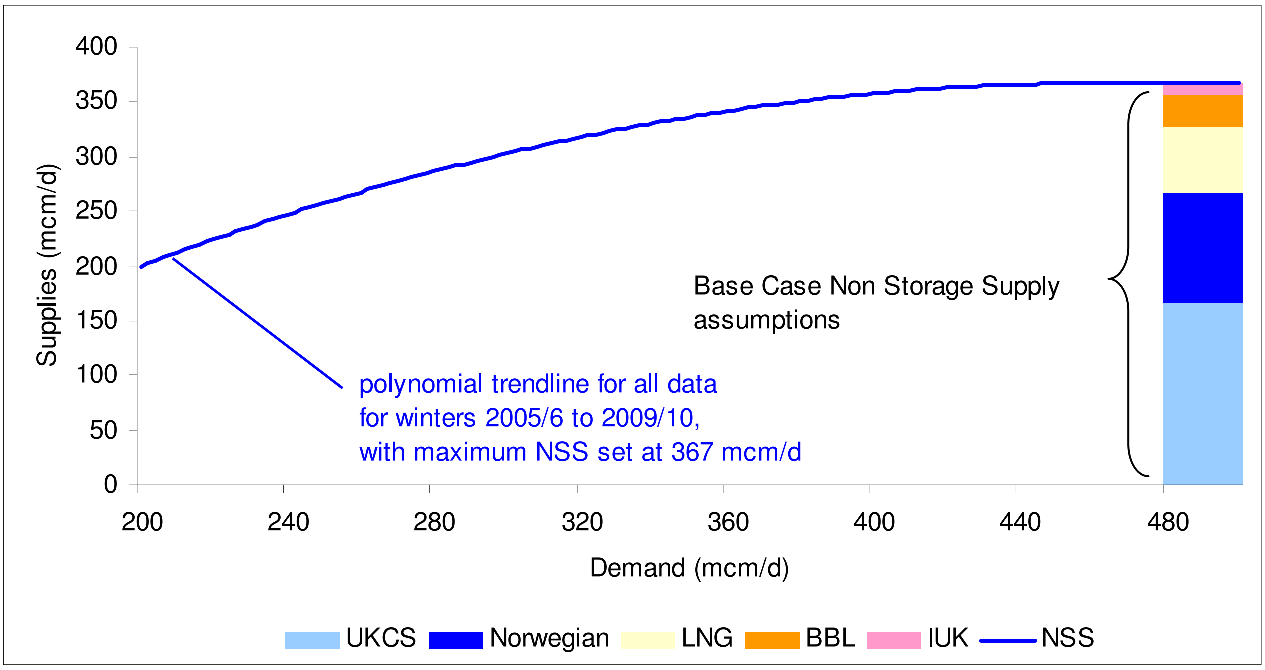
109. The chart shows the relationship of NSS vs demand where NSS tends to equal demand for demands below 300 mcm/d thereafter NSS increases at a lower rate (due to use of storage) towards an asymptotic value. The shape (not the values) of

[12] Excludes Operating Margins (OM)

the aggregated trend line forms the basis for the NSS versus demand relationship for calculating the winter security assessment (and the 2010/11 Safety Monitor).

110. Figure A.24 shows NSS versus demand, with the polynomial trend line showing supplies increasing asymptotically as demands increase, up to a maximum of the Base Case of 367 mcm/d.

Figure A.24 – Non storage supply assumptions v demand relationship



111. This approach has a number of benefits:

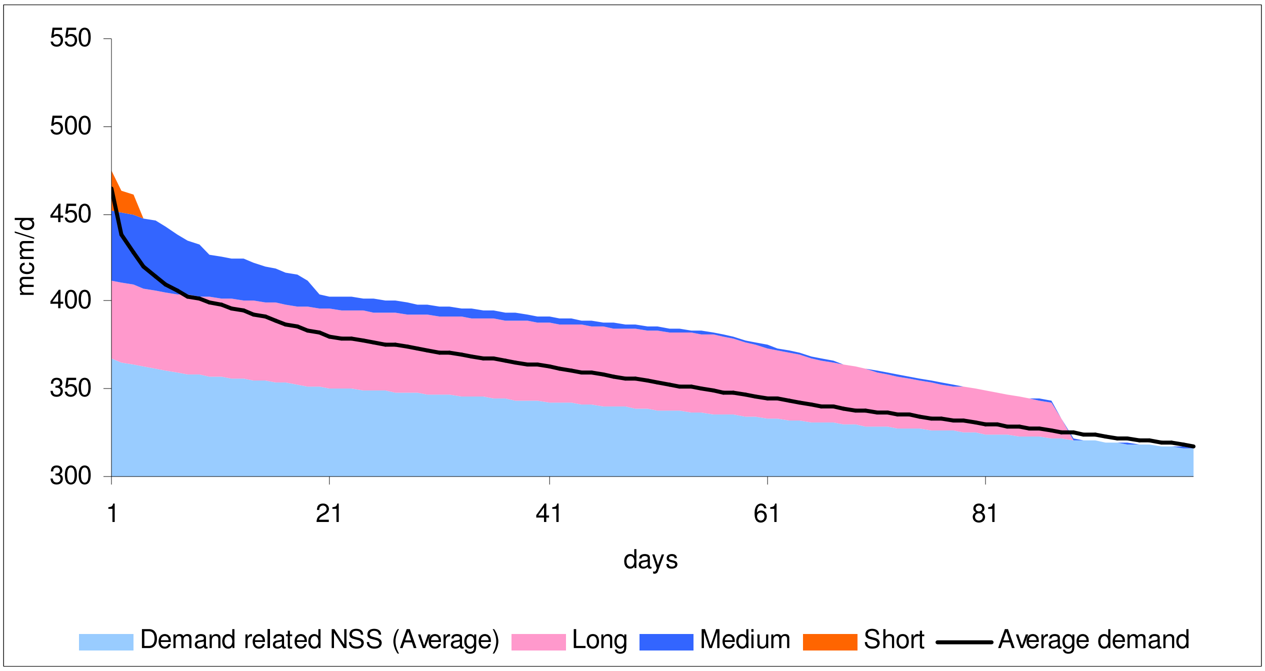
- It represents a more realistic approach to the relationship between supply (NSS) and demand
- Within winter monitoring of actual NSS levels will enable us to determine whether the NSS v demand relationship used within the Safety Monitor calculation methodology is fit for purpose. If it is found not to be, it can be revised based on the latest information. It also enables us to test our supply assumptions before experiencing high winter demands. For winter 2010/11 it is expected that this relationship will be published on our website.

112. There is considerable uncertainty regarding the make up and aggregate level of NSS. The aggregate supply position is expected to be similar / slightly higher to that experienced last winter. Table A.5 highlights our Base Case for NSS for winter 2010/11, and a range around the Base Case.

113. In addition to revising our NSS assumptions for the winter security assessment, the storage assumptions as detailed previously and shown in Figure A.22 have been modified to reflect operating performance.

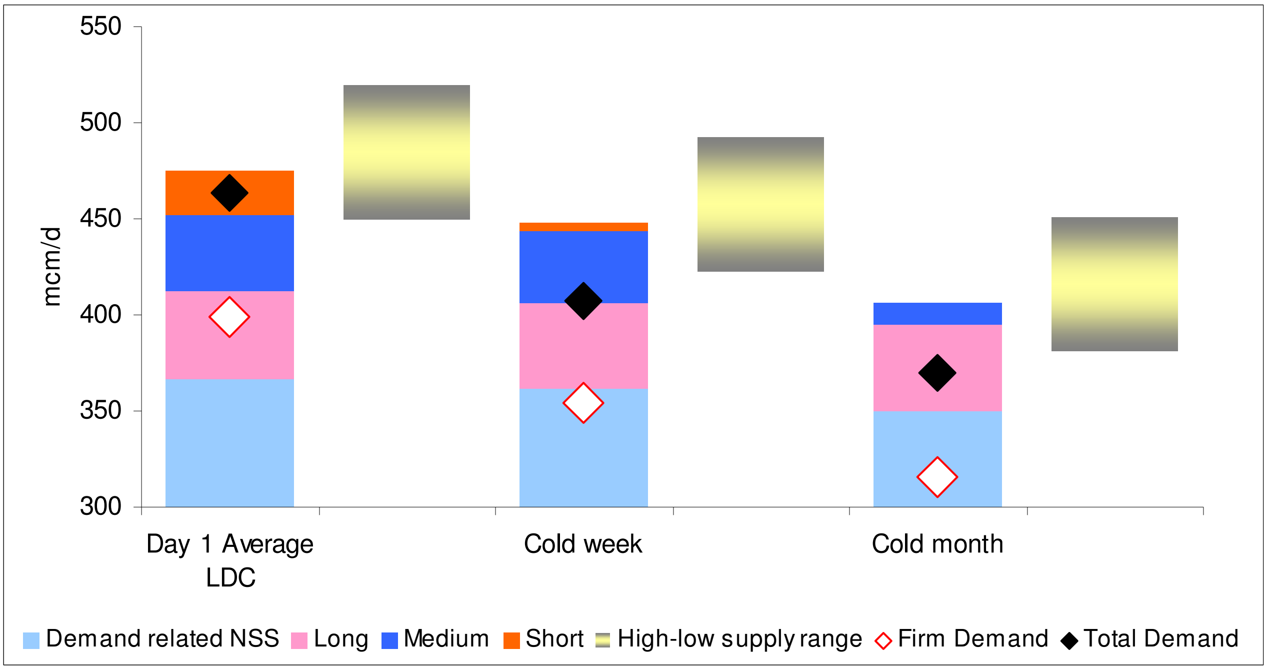
114. Figure A.25 shows the resultant supply and demand load duration curve, highlighting the demand related NSS for average demand conditions and the revised storage supply duration curve.

Figure A.25 – Supply / demand duration curve for average conditions



115. Figure A.26 shows the traditional cold spell analysis for average demand conditions based on Figure A.25, with total and firm demand for the coldest day of an average winter, a cold week within an average winter and a cold month within an average winter. The temperatures associated with these conditions are typically -2°C for the cold day, 1°C for the cold week and 3°C for the cold month. Also shown on the chart is the high-low supply range from Table A.5.

Figure A.26 – Cold spell analysis for average conditions



116. The analysis shows that for average conditions, with no unforeseen supply losses, sufficient supplies should be available to meet all demand for a cold day, a cold week and a cold month. The Base Case supply assumptions suggest that the position is similar to that for winter 2009/10, with gas demands (weather corrected) expected to be similar to last winter, and the major uncertainty due to the level of gas for power generation. On the gas supply side overall gas supply levels are forecast to be similar to last winter with upside potential for LNG imports.

117. The high-low supply range uses the upper and lower values for NSS in conjunction with the polynomial trend line for the demand / supply relationship. Even the low supply range indicates that there should be sufficient supplies to meet all demand for a cold day, week or month.

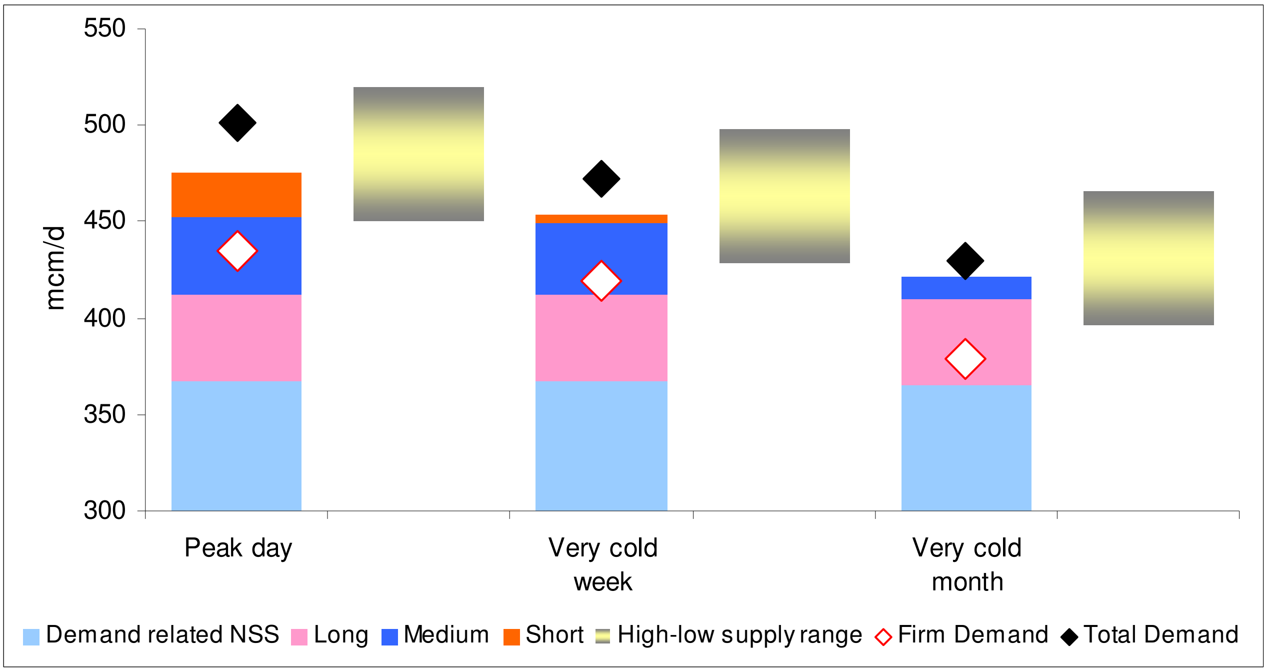
118. It should be noted that the average demand conditions reported in the above analysis are based on new EP2 basis.

119. Figure A.27 shows the cold spell analysis for severe[13] demand conditions, with total and firm demand for the peak day[14] (1 in 20), a very cold week within a severe winter and a very cold month within a severe winter. The temperatures associated with these conditions are typically -5℃ for the peak day, -3℃ for the cold week and -1℃ for the cold month. The levels of demand are matched to our Base Case view of supplies. Also shown on the chart is the high-low supply range.

[13] Severe conditions are based on 1 in 50 demand conditions. For security analysis we use diversified demands

[14] Peak day conditions are based on 1 in 20 demand conditions. A peak day does not always occur in a severe year. The coldest day in the last 80 years, January 13th 1987, was in a 1 in 3 cold winter.

Figure A.27 - Cold spell analysis for severe conditions



120. The analysis shows that for severe conditions and our Base Case view of supplies, there are insufficient supplies to meet all demand for a peak day, a very cold week and a very cold month. A demand side response would be required or alternatively additional NSS would be required for supplies to match total demand, as shown for the lower end of our high-low supply range.

121. For a 1 in 20 peak day with average temperatures across the country around -5 ºC, there is sufficient supply availability to meet all firm and most interruptible demand. Any interruption would be expected to be from shippers rather than National Grid as National Grid would only interrupt for network capacity purposes. For most circumstances there should be no requirement for any firm demand response.

122. For our Base Case view of supplies for a very cold week and very cold month analyses, all firm and nearly all interruptible demand could be met with the Base Case supply assumptions. If supplies were closer to the lower end of our high-low supply range or if storage was depleted, there would be a requirement for a higher demand side response, albeit no firm demand response for most circumstances. For higher supply availability as denoted in the high-low supply range there is the possibility to meet all demand.

Safety Monitors

123. On 31 May 2010, the preliminary view of initial Safety Monitor levels was published for 2010/11 as required under the Uniform Network Code (Q5.2.1).

124. It is National Grid's responsibility to keep the monitors under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do. In doing so, it must be recognised that the purpose of the Safety Monitors is to ensure an adequate pressure can be maintained in the network at all times and thereby

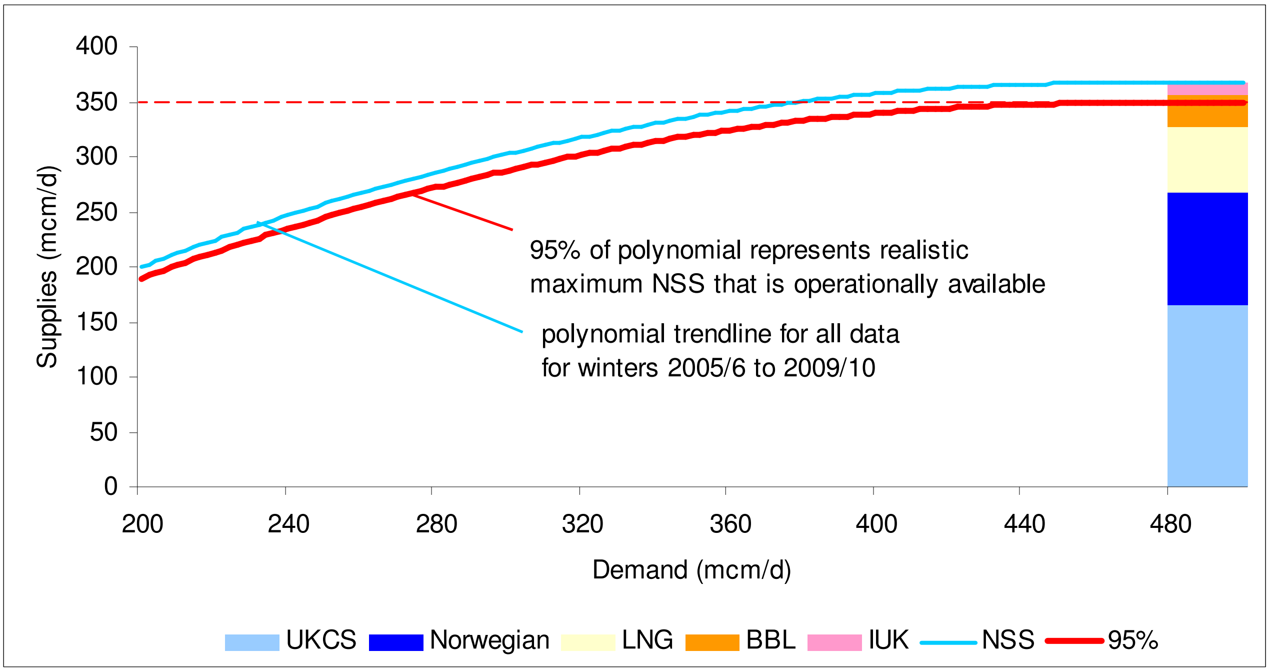
protecting public safety. It is therefore appropriate that a prudent approach is adopted in setting the Safety Monitor levels.

125. Therefore to ensure that the assumed level of NSS used for calculating the Safety Monitors will be available throughout the winter, notably at times of high demand. Figure A.23 shows trend lines for NSS versus demand for winters 2005/6 to 2009/10. An aggregated trend line for all five winters worth of data is also shown.

126. To capture most data points the trend line needs to be reduced. On analysis of previous winters lowering the trend line to 95% captures typically 95% of all data points, with those that are still below often reflected by short term supply losses as experienced on occasion last winter.

127. By applying a value of 95% to the aggregated total of NSS, the maximum value of NSS used in determining the 2010/11 safety monitors is reduced from 367 to 349 mcm/d. The resulting relationship of NSS against demand is shown in Figure A.28.

Figure A.28 – Non storage supply assumptions v demand relationship



128. The total NSS assumption used in setting the 2009/10 Safety monitors was 343 mcm/d. Hence the maximum non-storage supply assumption of 349 mcm/d used for calculating the 2010/11 Safety Monitors is 6 mcm/d higher. However care should be taken when making year on year comparisons as the NSS assumption used in calculating the 2009/10 Safety monitors was demand independent, whereas the 2010/11 Safety Monitors uses a variable NSS assumption.

129. The current Safety Monitor methodology treats all storage types equitably, by grouping all storage types/facilities together such that there is only one aggregated monitor for space. Hence operational storage space is apportioned equitably across all storage sites, including those with high cycling rates, rather than apportioning

over the historically determined three storage types, Long, Medium and Short range storage.

130. There is one space Safety Monitor and one deliverability Safety Monitor. This provides greater clarity for market participants and operational decision making.

131. The resulting Safety Monitor levels for winter 2010/11 are detailed below. These are marginally higher than the 2009/10 Safety Monitors. This is primarily due to the higher demand assumptions.

- 2009/10 Assumed storage space = 49833 GWh
- 2010/11 Safety Monitor space = 1164 GWh (2.4%), (2009/10 = 1127 GWh)
- 2010/11 Safety Monitor deliverability = 702 GWh/d, (2009/10 = 639 GWh/d)

132. Safety Monitor levels and the associated winter profiles (i.e. how the monitors reduce later in the winter) will be published on or before 1st October 2010.

Gas Balancing Alert (GBA)

133. Despite an initial view of higher non storage supplies for winter 2010/11 compared to last winter (367 vs 343 mcm/d), the initial trigger level for the 2010/11 GBA is expected to be similar to that initially set for last winter due to lower storage deliverability arising from the revised method for assessing storage deliverability (based on proven performance) and LNGS levels that are below the two day accounting rule.

134. Following on from last winter, the GBA will continue to be responsive (and visible) to actual storage stock levels for all storage sites. This should result in subsequent changes to the GBA trigger being more gradual (both up and down as storage is refilled). If storage deliverability performance for any site exceeds (or does not meet) our assumed levels for the initial GBA trigger calculation the view of the contribution from storage may change.

135. During winter 2010/11, enhanced winter feedback to the industry regarding supply assumptions and resulting changes to GBA trigger level and Safety Monitors will be published by means of our website. It is also expected that reports on the performance of non storage supplies against the preliminary view of 367 mcm/d will be published. This will be reported in a similar format to that shown in Figure 24 to enable a view of performance to be assessed against all levels of demand rather than just high demand.

Operational Overview

136. The period January to March 2010 was a challenging period in terms of managing the gas network, with a wide variety of tools successfully used. Some of these tools had not been used for a number of years, and there were minor issues with familiarity. In particular, a within day GBA had never been issued before January 2010. Industry discussions since the winter have not led to any changes in the GBA process.

137. A key feature, coincident with the cold weather, characterising the operational challenges experienced last winter was the occurrence of a number of unplanned

supply disruptions predominantly from non UKCS sources. With imported gas increasingly contributing to the wider UK gas supply mix, the impact of such unplanned events relating to these sources are harder felt due to their relative size (significant by volume) and the extended nature of the associated upstream supply chain making it more problematical in soliciting quality information to inform our operational decisions and timing of any required actions.

138. Closer to home during the peak of the cold weather in January, there were periods when we needed to take specific operational actions to support the demand in the South West of the UK. These actions included optimisation of NTS system configuration and compressor utilisation to maximise gas transportation capability into the South West which also required agreed demand transfers with the Distribution Network Operators affected (in line with section I of UNC OAD). Over the highest peak demand period further operational actions were invoked seeing NGG SO deploy a combination of Transporter interruption, locational commercial actions and withdrawal of Operational Margins gas from Avonmouth in order to meet firm capacity and assured pressure commitments.

139. Over the summer, National Grid processes have been refined in light of lessons learnt and a preparedness process is being run by National Grid pre-winter, which includes training for control room and support staff. This will ensure National Grid is in best position to deal with operational events this winter. During the early months of the winter there will also be relevant updates and reminders at the Operational Forum.

140. There are continually more dynamic supply and demand patterns across the network, and this emphasises the importance of timely and accurate information provision from across the industry,

Market Information Provision

141. National Grid's Gas Market Reporting pages at nationalgrid.com/uk/Gas/Data/ continue to grow and accommodate real time developments on the NTS. As physical and regime changes occur the industry will see these developments incorporated into the existing suite of reports and data items. Explanatory news items will accompany any updates.

142. Information on the supply / demand forecast, storage stock levels and proximity to Safety Monitor and GBA trigger levels have been consolidated and can be found in a single place at: http://www.nationalgrid.com/uk/Gas/Data/GBA/

143. Users can also subscribe to receive notification via email or text that news items have been published on the National Grid Information Provision pages by signing up at this address: http://www.nationalgrid.com/uk/Gas/Data/subscribe

Update on Provision of new NTS Capacity for Winter

144. Compared to recent years 2010/11 will see fewer major construction projects on the NTS. Although new entry and exit developments are due to connect during the 2010/11 gas year, the majority of the associated NTS capacity expansion projects have already been completed.

145. Ongoing work to facilitate the expected increase in supplies from the Milford Haven LNG importation terminals is ongoing which includes, for this winter, modifications and a replacement unit at Churchover multi-junction.

Milford Haven

146. Auction signals for Milford Haven entry capacity were received in the 2004 September and December LTSEC auctions. To provide the required capacity to transport the gas, an overall investment strategy was commenced, to include construction of pipelines, compressors and Pressure Reduction Stations (PRS).

147. The physical connections for South Hook and Dragon LNG importation terminals were completed last year and both sites commenced commercial operation during summer 2009.

148. Following completion of the new pipeline projects further work on the overall strategy continues, including a planned replacement unit at Churchover compressor station. The full commissioning of Felindre compressor station will follow the full commissioning of a further PRS at Tirley, subject to the decision of the recent planning appeal.

149. The references in the tables below relate to the map shown as Figure A.30.

Table A.8 – Project Phases Table For Works in Figure A.30

Phases

Ref	Project	Scope
A	Churchover multi-junction modifications & replacement unit	Additional unit and multi-junction modifications
B	Felindre compressor installation	Commissioning
C	Tirley PRS	Under review awaiting planning consent

East Coast Entry Capacity

150. Following significant investment in providing new East Coast entry capacity in 2006, 2007, 2008 and 2009 (2009 marking the commissioning of the Longtown flow control valve), 2010 will see the commissioning of the Easington to Paull pipeline which will complete National Grid's capacity expansion in the East Coast area following bids in the QSEC auctions.

Phases

Ref	Project	Scope
D	Easington to Paull pipeline	26km x 1200mm

South West Exit Capacity

151. Following exit capacity allocations and increased forecasts for demand in the south west area, construction of the Wormington to Sapperton pipeline is underway, which will provide increased exit capacity in the South West.

Phases

Ref	Project	Scope
E	Wormington to Sapperton	44km pipeline

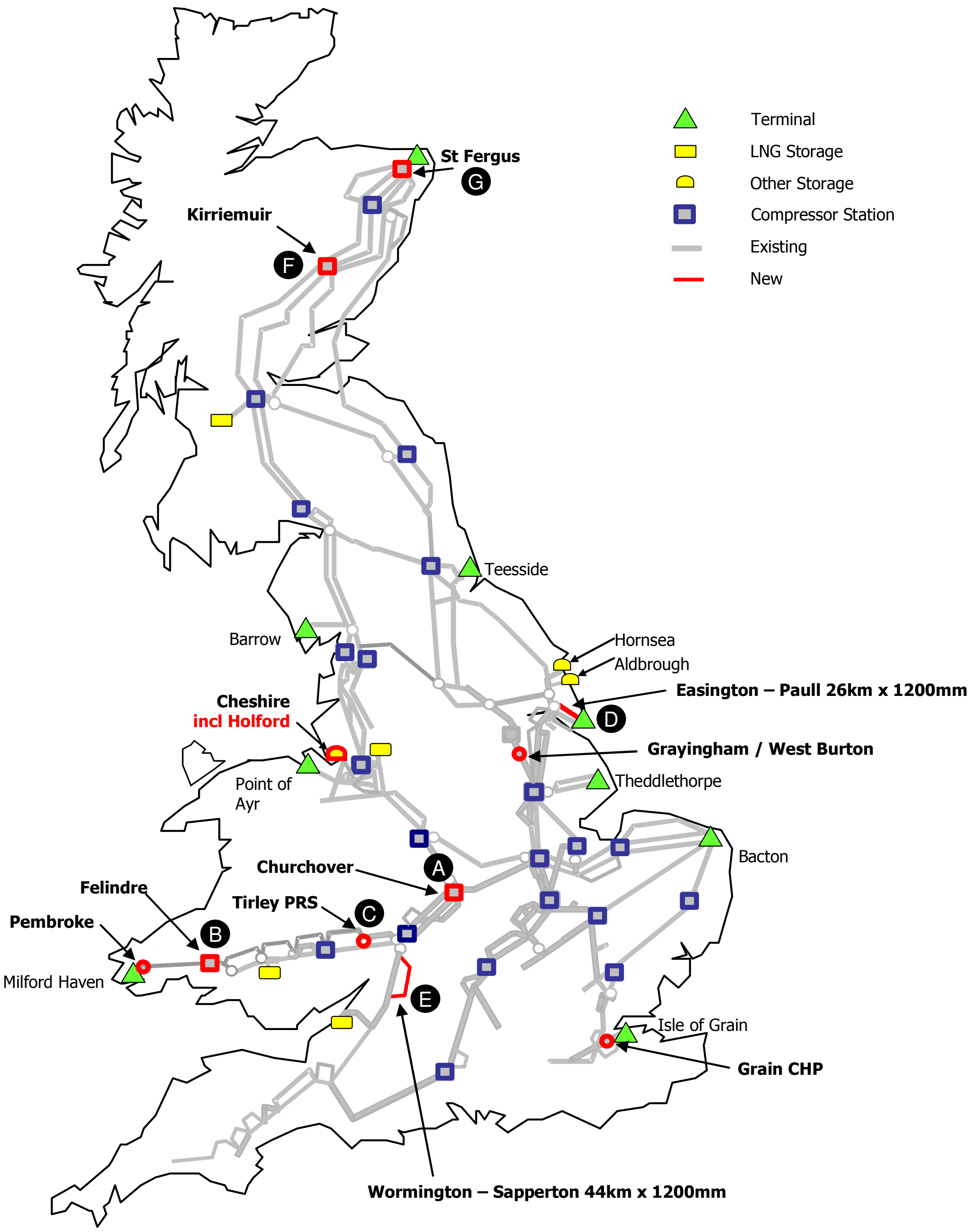
Emissions related works

152. Commissioning of two electric drive compressor projects to reduce emissions are expected to commence over the 2010/11 winter period.

Phases

Ref	Project	Scope
F	Kirriemuir	New 35MW electric unit
G	St Fergus	Two new 24MW electric units

Figure A.30 – NTS Construction Projects Due for Delivery in Winter 2010/11



New Exit Connections

153. Grain power station connected in June 2010 and new connections to West Burton and Pembroke power stations may take first gas flows during the gas year 2010/11.

154. Holford storage site is due to start to take commissioning flows from the NTS during gas year 2010/11 but is not expected to provide commercial operation within the same period.

Electricity

Electricity Demand Levels

155. The updated Great Britain Average Cold Spell (ACS)[15] winter peak demand forecast for the coming winter is 57.7GW. This is a 100MW reduction on 57.8GW ACS demand outturn of last year (which with forecasting tolerances can be considered to be a similar level).

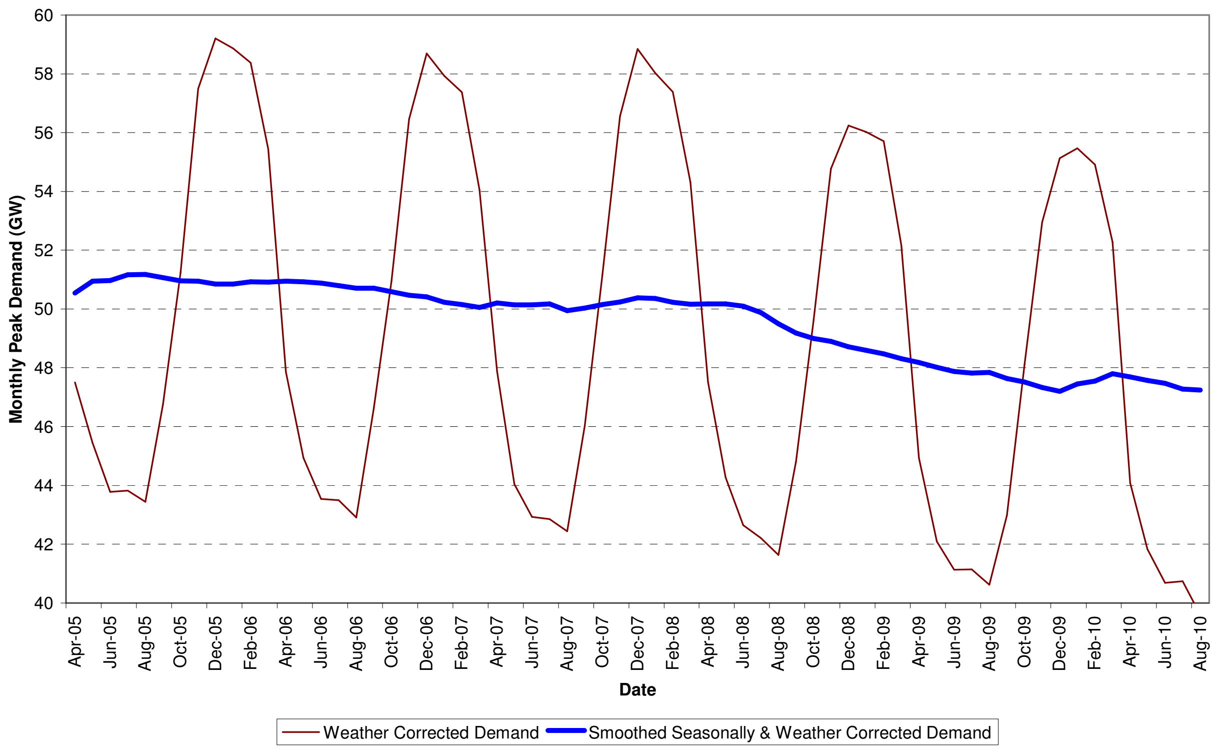
156. In 2009/10 the ACS demand outturn was 0.2GW lower than the year before, this represents a 0.3% reduction. The 2008/09 ACS demand outturn had been 2.3GW lower than the winter 2007/2008. The demand drop started to appear in mid-summer 2008 and accelerated from late summer. The decline in demand continued into 2009 but the most recent trend as indicated in the figure A.31 is that there is now a stabilisation linked with the economy.

157. The forecasts being taken forward use stable levels of economic activity, but these will be reviewed at regular intervals as more information becomes available. Particularly the pace and timing of any recovery remains a key factor for our winter 2010/11 demand predictions.

158. In addition to the economic activity related driver of demand, the pre-recession factors which have been gradually reducing demand continue to take effect. The picture going forward is uncertain and respondents confirmed this. The growth in embedded generation in distribution networks, more efficient use of energy and energy price awareness amongst consumers are seen as key factors. Continuous updates to the forecast through normal work processes are published on www.bmreports.com

[15] Annual Average Cold Spell (ACS) Conditions are a particular combination of weather elements which gives rise to a level of peak Demand within a Financial Year which has a 50% chance of being exceeded as a result of weather variation alone.

Figure A.31 – Smoothed Weather and Seasonally Corrected Normal Demand



159. The 1 in 20[16] peak demand forecast for 2010/11 is 59.0GW. The 1 in 20 demand peak represents the high demand scenario and to put this in context relate to temperatures of -1.8 ºC at 1700 hrs and -3.4 ºC at 2100 hrs. These demand figures relate to GB demand only and do not include any flows to France or Northern Ireland across interconnectors.

160. A 1 in 50 cold level demand scenario has not been presented as this is unlikely to occur based on recent history. The normal business process forecasts are based on a weekly weather based on a 30 year average[17].

161. The Normal demand Peak forecast for Winter 2010/11 is currently at 56.0GW and is revised closer to time as part of our normal forecasting activities. The most current forecast at any given time is given at www.bmreports.com. Normal demand is the demand that is expected to occur based on normal weather conditions. The normal weather conditions are calculated from an average over a 30 year period on a weekly basis. Normal demand is also the basis on which the published generation surpluses are calculated as published on www.bmreports.com.

162. The French Interconnector has traditionally imported during the system peak demand period. Generally it is appropriate to continue to treat the interconnector with France as a source of generation rather than a demand at winter peak times. The recent trend for the Northern Ireland (NI) Interconnection was either exporting to GB at a lower level than historically observed or more consistent with longer term

[16] 1 in 20 Conditions are a particular combination of weather elements which gives rise to a level of peak Demand within a Financial Year which has a 5% chance of being exceeded as a result of weather variation alone.

observations to be importing to NI at a low level. Because of the uncertainty of actual interconnector transfers on a daily basis, the assumption has been made that both interconnectors at system peak will be at float throughout this outlook analysis unless explicitly stated otherwise.

163. Around 0.5-0.7GW of demand management was be observed at times of peak demand in the winter of 2009/10 as consumers responded to high electricity prices at times of peak demand. When forecasting demand it is assumed that this level of demand response will continue and this has been recognised in the peak demand forecasts. For 2010/11 0.5GW of demand side response has been assumed in the demand forecasts for ACS and 0.7GW for 1 in 20 conditions. Demand side response is not factored into the normal weather demand forecasts, as it is not expected under normal weather conditions.

164. Other potential impacts on the system in the UK for meeting electricity demands have been considered. National Grid along with the wider energy industry, Government and industry Regulator has been planning for potential events on the system for many years. Generators have made contingency plans to keep plant available and operating to manage the risk to generation availability levels.

Notified Generation Availability

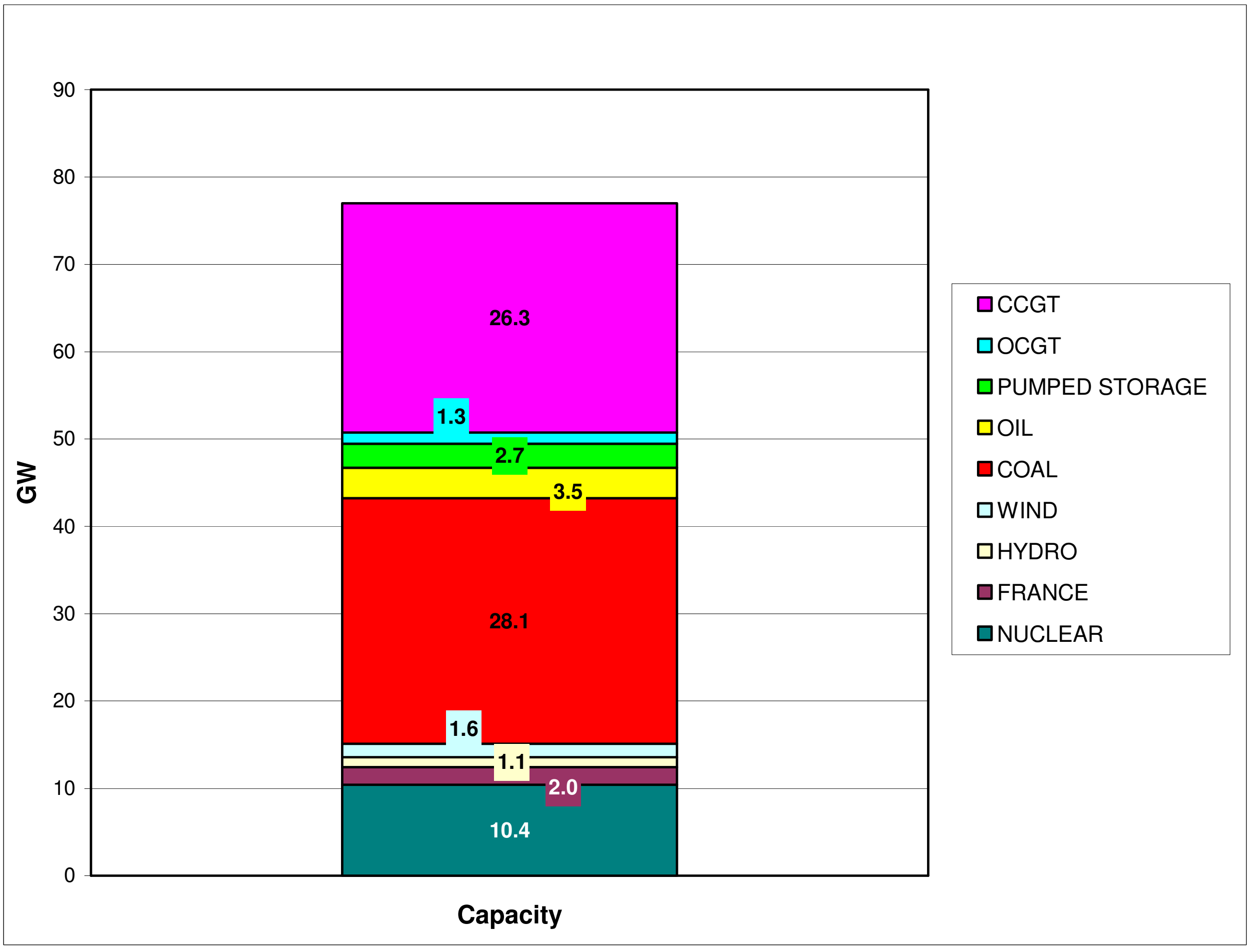
165. Based on the observed output of power stations, National Grid's current operational view of generation capacity anticipated to be available for the start of winter 2010 is 77.7 GW. This is an increase of 600 MW since June due to commissioning wind farms bringing more of their turbines into operation and new wind farms becoming visible to National Grid's metering system. A breakdown of this capacity is shown in Figure A.32[18].

166. Generation capability upside exists in the form of the new CCGTs currently undergoing commissioning or due to begin commissioning over the winter. These are Staythorpe (1700 MW), Severn Power (850 MW), Grain Units 6, 7 and 8 (1200 GW) and West Burton B (1300 MW). These stations are expected to enter full commercial operation at some point between now and the end of the winter to come. Also additional wind generation is becoming visible to National Grid over the course of the winter, although this additional capacity has a degree of uncertainty attached to it.

167. The end of winter 2010/11 operational view of generation could total up to 83 GW, dependant on how the build phase and commissioning of new CCGTs progresses and the rate at which new wind generation is being connected.

[18] Charts similar to Figure A.32 are presented in our outlook reports available on our website http://www.nationalgrid.com/uk/Electricity/SYS/outlook/ which enables identification of changes over longer periods to be analysed.

Figure A.32 – Generation Capacity Operational View



Generation Availability Assumptions

168. Table A.9 shows the generation expected to be available for each class of plant to meet the winter demand peak for 2010/11. Assumed load factors are used for wind and hydro generation instead of availability, as in both cases generation is limited by the volume of the primary energy source. The assumed availabilities remain unchanged from those proposed in the Winter Consultation Report as none of the respondents view's were significantly different from those of the consultation document. However, the total assumed availability rises from 66.2 to 66.3 GW as a result of the increased capacity of wind on the system although the overall availability reduces from 86% to 85%..

Table A.9 – Generation Availability Assumptions Made For Winter 2010/11

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.1	75%	7.6
French Interconnector	2.0	100%	2.0
Hydro generation	1.0	60%	0.6
Wind generation	2.5	10%	0.3
Coal	27.9	90%	25.1
Oil	2.7	80%	2.2
Pumped storage	2.7	100%	2.7
OCGT	1.2	90%	1.1
CCGT	27.5	90%	24.7
Total	**77.7**		**66.3**
Overall availability		**85%**	

Mothballed Generation Capacity

169. The amount of plant that is long term mothballed remains at 1.25 GW. No additional plant has been mothballed during the summer and it is not expected that any more plant will be mothballed for winter 2010/11, nor is it expected that any of the currently mothballed generation plant will be made available.

Generation Side Risks

170. A low case generation scenario has not been included as proposed in the consultation report due to the lack of any identified risk areas. Type faults can arise occasionally but they are low probability events.

Interconnector Flow Assumptions for winter

171. Until this winter the current charging methodology applicable to all users for the injection and off-take of power onto the GB transmission made no differentiation as to how that injection or off-take is achieved.

172. This year uses a change to these arrangements through the impact of the EU “Third Package” for a Single Integrated Market in Electricity. This establishes separate arrangements for the operation of interconnections between member states which do not permit access charges other than by non-discriminatory market based congestion management mechanisms.

173. A review of Interconnector Charging Arrangements was undertaken.[19] The conclusions from this review has resulted in the following proposed changes to the TNUoS Charging Methodology:

- Interconnectors are treated as envisaged in EU Regulations i.e. they are not defined as generation or consumers (demand) and thus are not liable for either TNUoS demand and generation charges;

[19] GB ECM-26 Review of Interconnector Charging, Arrangements
http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

- Interconnector flows will therefore not be included when determining the Triad demand periods upon which GB demand charges are calculated. However their capacity to import and support the GB transmission system will continue to be modeled in the transport model as they currently are.

174. Unless directed otherwise, the above proposals will be incorporated into the charging methodology statements to take effect as of 5th October 2010, applicable to the charging year beginning 1st April 2010.

175. This will leave no commercial incentive to avoid exporting from the UK on a Triad[20] day and therefore brings into play the possibility of exports to France at the time of the winter peak. As a result, forecast plant surpluses have been shown for both the French Interconnector at full export and full import in later discussions.

176. The outcome of likely transfers on the French Interconnector is established through market price differentials between the GB and French markets. This price differential changes over time and within day.

177. Current price spreads[21] between the UK and France are showing a premium of £4/MWh to France over the Baseload period (23:00 to 23:00) and a premium of £9/MWh to France over the Peak period (07:00 to 19:00). This differential would indicate favouring export from the GB to French market over winter to come. History shows us that there is always a split between the morning period (07:00 to 15:00), where the flow over winter can be up to 2000MW to France, and the afternoon period (15:00 to 19:00) where the flow to France is reduced. This is because the prices are normally higher in the UK for the Darkness Peak, whereas they are (relatively speaking) more evenly priced across the French day. It is expected that this pattern will be observed during the winter to come.

178. Historically the Northern Ireland Interconnector has followed the price spread between the two systems which have resulted in exports to Northern Ireland. During periods of high wind energy has flowed from Northern Ireland into the GB system which has resulted in either a float scenario or imports into the GB system. It is expected that over the coming winter this scenario will continue and such for the analysis float has been assumed.

179. The new Britned interconnector between the Netherlands and GB is due to start commissioning during the winter with a target commercial go-live date of April 2011. In common with new generation its potential affect has not been included on the demand and generation balance for this winter. In extreme circumstances there is the capability to request a float position if necessary for GB energy needs during the commissioning phase.

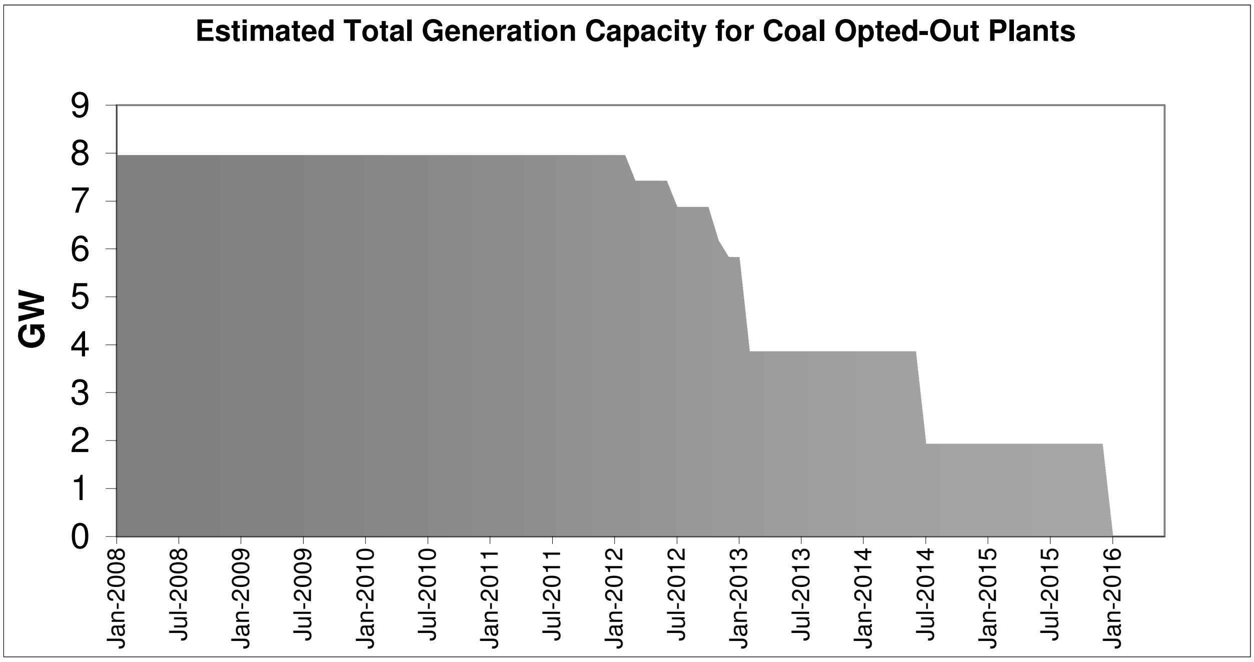
LCPD Summary for winter

180. Issues related to the limited hours under LCPD for opted out plant are unlikely to affect winter 2010/11, but could be relevant for winter 2012/13 and certainly for the following winter based on historic operation patterns. LCPD Opted out plant has 20,000 hours allowed operation until December 2015. At the current observed rates

[20] See http://www.nationalgrid.com/NR/rdonlyres/9F27FB81-711A-44E0-9476-2456945E08B0/33061/Triadcalculationmethodology.pdf for a high level view of how Triad charges work.
[21] As at mid September 2010.

of utilisation of the allowed hours, there is an implication of early closure at some power stations. The latest view of National Grid of early closure, given running patterns to date projected forward for opted out coal stations is shown in Figure A.32. The first generation anticipated to utilise its hours is in February 2012. Opted out oil stations are not shown in this chart due to their current low number of running hours relative to their 20,000 hours allowance.

Figure A.32 – Indicative LCPD Coal Opt Out Plant Closing Dates



Contracted Reserve

181. In order to achieve the demand-supply balance, National Grid procures reserve services (including frequency response) from either generation or demand side providers to be able to deal with actual demand being greater than forecast demand and to cover unplanned real time plant breakdowns. This requirement is met from both synchronized and non-synchronized sources

182. There is a requirement to procure the non-synchronized elements from a range of service providers which include both Balancing Mechanism (BM) participants, and non-BM participants. This requirement is called Short Term Operating Reserve (STOR) and is procured on an open market tender basis that runs three times per year.

183. National Grid encourages greater participation in the provision of reserve and engages with potential providers to tailor the service to meet their specific technical requirements.

184. For winter 2010/11, the total level of contracted STOR reserve is approximately 2.6GW, over 1.6GW from BM participants and nearly 1 GW from non-BM generating plant and demand reduction.

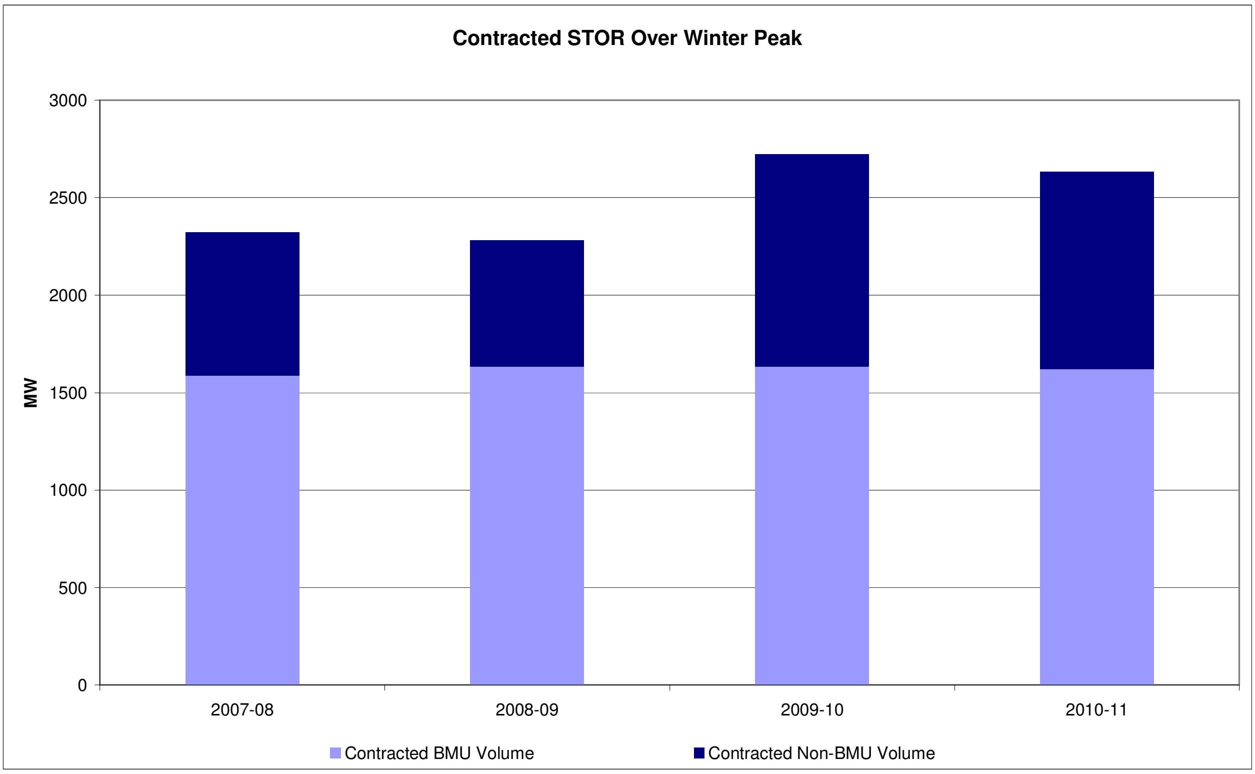
185. Last winter 2.7 GW of STOR in all was contracted, but much of that was not available over weekday peak demands and dependant on providers contracted position or availability. Total availability at the time of the winter peak last year was about 1.9GW.

186. Figure A.33 shows the contracted STOR for the winter peak over the last 4 years. Further information regarding the STOR service can be found on our website http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/STOR/.

187. In addition to STOR, there is a continual requirement to provide frequency response on the system. This can be either contracted ahead of time or created on synchronized sources within the BM. If all response holding was created in the BM, then approximately 1.5GW of reserve would be required to meet the necessary response requirement. 1.2GW of this 1.5GW reserve requirement has already been contracted, with 0.3GW from demand-side providers.

188. National Grid continues to have Maximum Generation contracts in place for Winter 2010/11, which provide potential access to 1 GW of extra generation in emergency situations. This is a non-firm emergency service and 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). Hence, it is not included in any of our generation capability and plant margin analysis. This service was available pre-NETA and similarly was never included in margin analysis

Figure A.33 - Contracted STOR for Winter Peak

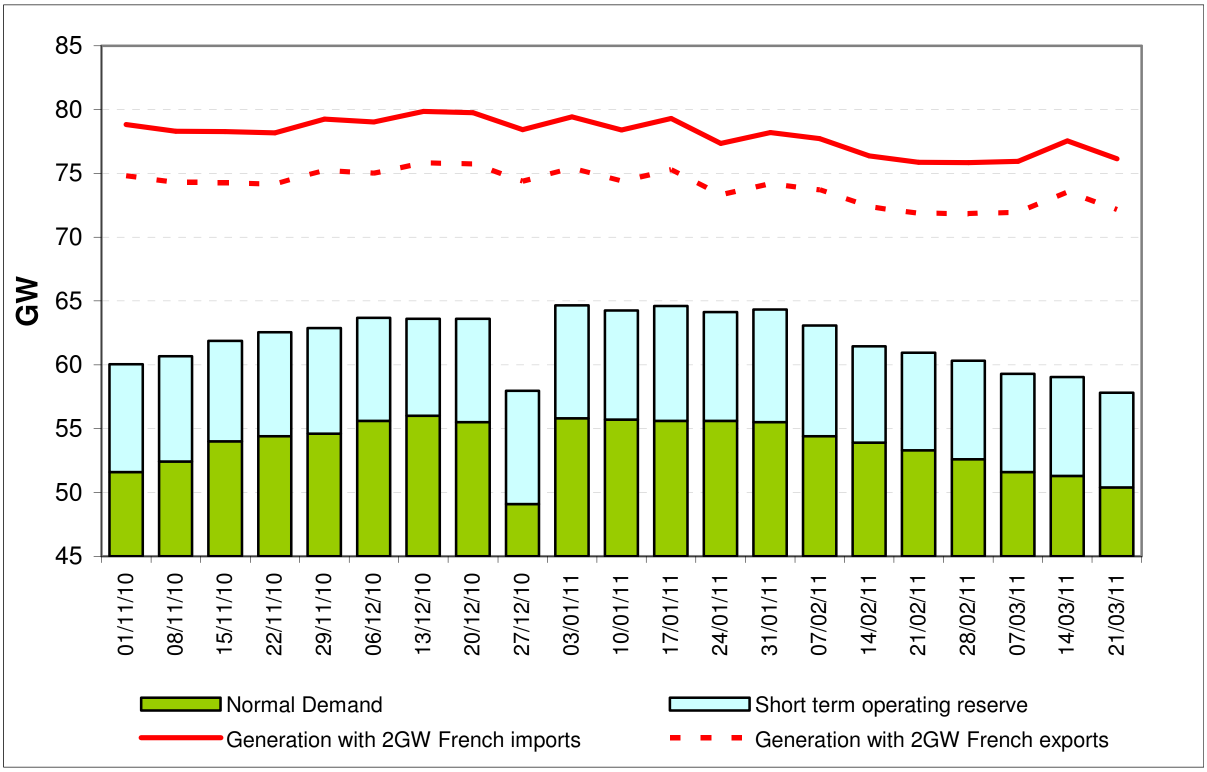


Forecast Generation Surpluses

189. Figure A.34 shows the position for the coming winter with demand based on normal weather at the time of the weekly peaks. The generation available is the availability declared to National Grid by the generators under the OC2 part of the Grid Code, and reflects planned loss of availability but has no allowance for unplanned generator unavailability.

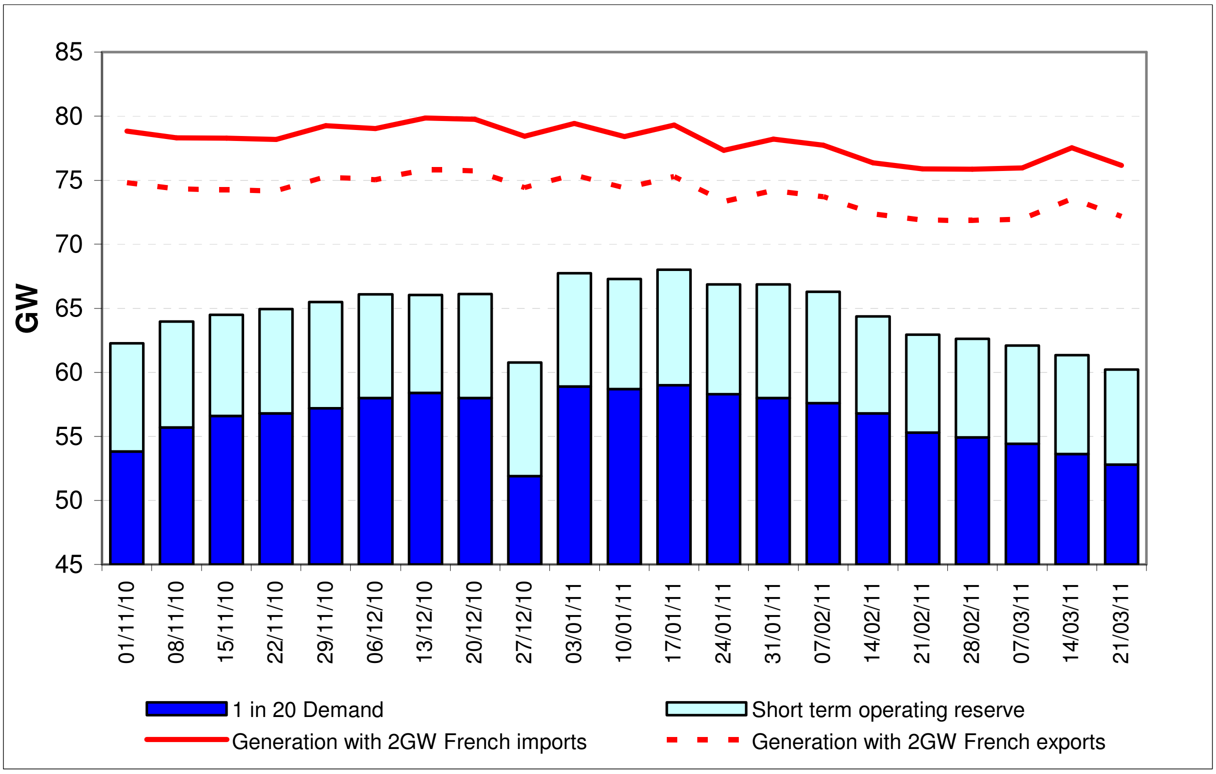
190. The figure shows there is sufficient generation to meet normal demand and our short term operating reserve requirements with a positive margin, even with exports to France on the French interconnector.

Figure A.34 - Normal Demand and Notified Generation Availability



191. Figure A.35 shows the position for the coming winter with demand at 1 in 20 levels. This shows there is sufficient generation to meet a 1 in 20 demand and our short term operating reserve requirements with an assured margin.

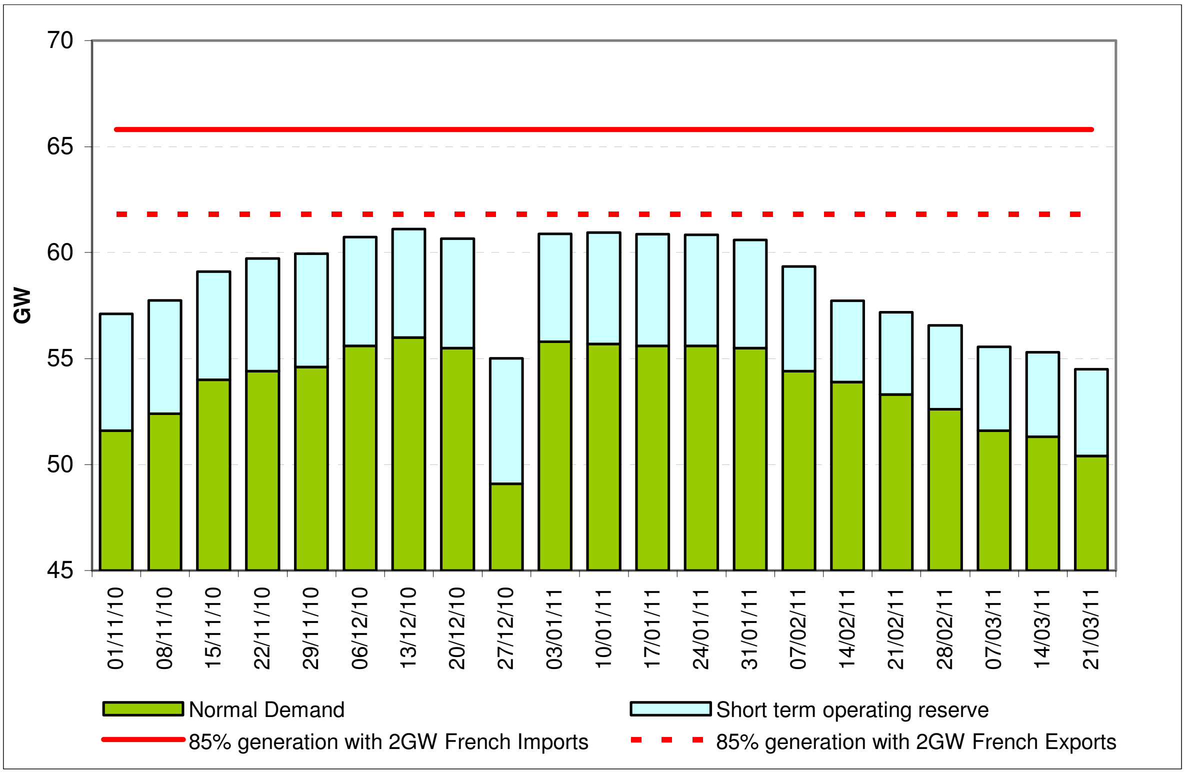
Figure A.35 - 1 in 20 Demands and Notified Generation Availability



192. Figures A.34 and A.35 use generation availability as declared to National Grid by the generators under Operating Code 2 of the Grid Code, which reflects planned unavailability, but has no allowance for unplanned generator unavailability. Earlier in this report the assumptions for the levels of actual generation availability for the demand peak have been outlined. These assumptions use historic availability achieved over historic demand peaks to indicate the combined effect of both planned and unplanned unavailability.

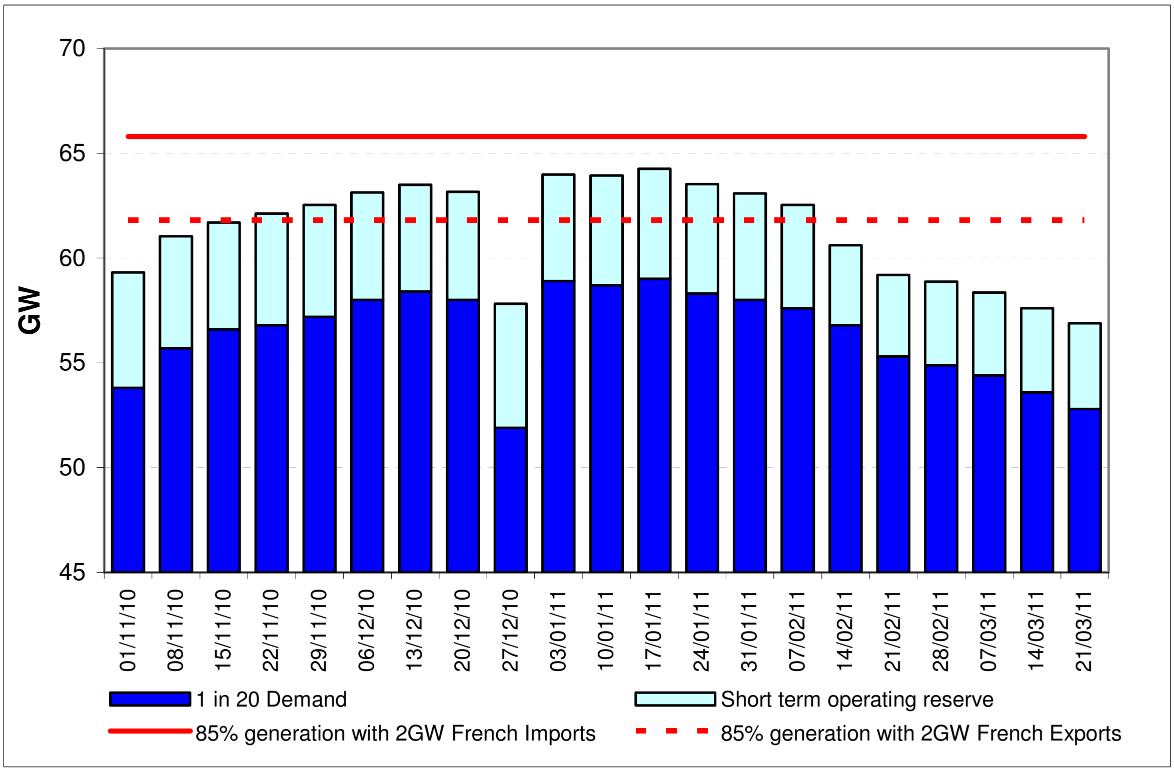
193. Figure A.36 shows normal demand plus short term operating reserve and the assumed availability of generation which is 85% of the operational view of generation capability. The chart shows there is sufficient generation to meet demand and our short term operating reserve requirements with a positive margin.

Figure A.36 - Normal Demand and Assumed Generation Availability



194. Figure A.37 compares our assumed level of generation availability with the 1 in 20 demand level scenario. This chart shows there is sufficient generation to meet demand and our short term operating reserve requirements when importing 2 GW on the French Interconnector. It also shows that for a 1 in 20 demand figure combined with 2GW of exports to France with the assumed generation availability that over the half hour demand peaks (Monday -Thursday) throughout December and January there would be potential for short term operating reserve to be eroded. In these circumstances System Warnings would be issued ahead of time as usual, it would then be expected that the market would respond accordingly.

Figure A.37 - 1 in 20 and Assumed Generation Availability



Generation Merit Order

195. The focus in this report is for meeting electricity demand and less attention is given to which types of generation are likely to be at base load, two-shifting or marginal. This issue is determined to a large degree by the market and therefore is subject to some uncertainty as market prices for winter change over time.

196. As discussed earlier the forward prices suggest that gas-fired generation could be the base load plant for October and November, with coal-fired generation as base load from December through to March there is informative analysis in detail in that part of the report[22].

[22] See Fuel Price analysis and commentary right at the start of section A of this report.

Section B - Gas/Electricity Interaction

Power Generation Gas Demand

197. This section is to investigate the relief that the electricity market can provide to the gas system when there is pressure on the gas supply whilst still meeting the projected electricity demand. This relief can be provided by the use of gas storage, gas fired power stations switching to running on distillate or power sector demand response through generation mix changes.

198. Daily gas consumption from CCGTs varied over last winter with an early winter low of 73mcm/d and a late winter high of 107mcm/d. Significant use of gas for power generation was a feature across the winter as the general profitability of gas fired generation over coal prevailed for almost every day. The period in early January where Gas Balancing Alerts (GBA's) were issued caused some gas fired power generation to be substituted by coal, but even then significant gas burn for power generation continued.

199. As discussed earlier in the document, the forward prices suggest that gas-fired generation could be the base load plant for October and November, with coal-fired generation as base load from December through to March. However prices could change, especially if there was any tightening or loosening of gas supply. For the last two winters, gas prices have reduced around the start of winter as supply uncertainty eased.

200. As is shown in this section of the report, with the base case assumptions described earlier, it demonstrates an ability to meet gas demands, even for the coldest winter in recent history.

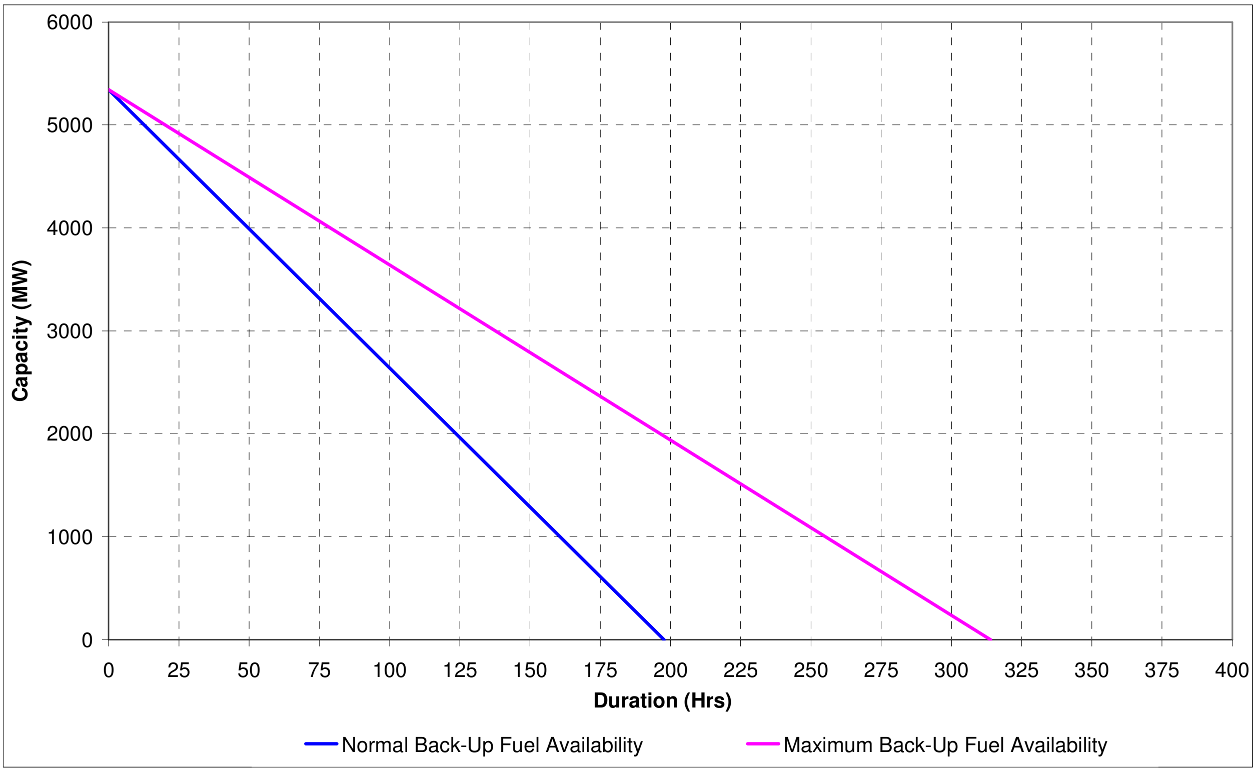
Power Stations with Alternative Fuels

201. Under the terms of the Grid Code, generating companies provide us with information on their capacity to generate using back up fuel. Using the data received, we estimate 5.3 GW have the capability to run on distillate. Out of the total 5.3 GW having back-up fuel generation capability, more than half have interruptible gas transportation arrangements.

202. Figure B.1 shows our estimation in a 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 generators. Replies to our enquiries to stations with back-up generation capability, indicated that back up fuel stock has reduced slightly compared to last year leading to a 27hrs reduction in the running duration. The two lines show the available generation capacity from starting points of normal fuel stocks and maximum fuel stocks, and assuming individual units generating at full load when running on distillate. Note, however, that this graph is not intended to suggest that all generators with back up fuel capability would run continuously on back up fuel supplies for several days or at full distillate running load. In reality different generators would adopt different commercial strategies. We currently assume that most of this capacity would only run on back up fuel for part of the gas day and that

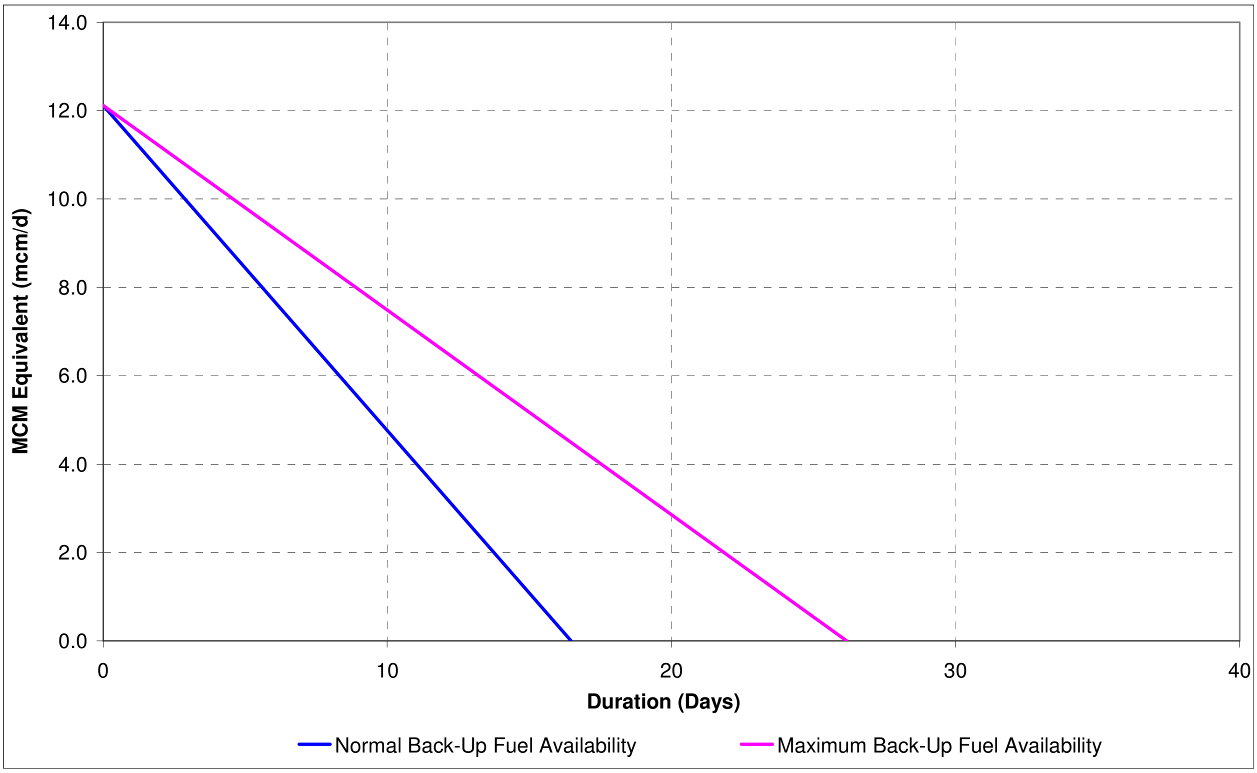
this would be during the off-peak electricity demand periods. The curves below also assume no restocking of distillate which may be possible for some stations over the period they are running on distillate.

Figure B.1 – Power Load Duration Curves for Back Up Fuel Supplies



203. Based on the distillate back up fuel data from the generating companies for 2010/11, we estimate that a total of between 92 mcm to 145 mcm gas equivalent can be displaced using distillate generation capability. This is shown in figure C.3. In 2009/10, there was an estimated total of less than 0.96 mcm equivalent distillate use around system peak days

Figure B.2 – Gas Volume Equivalent Load Duration Curves for Back Up Fuel Supplies



Potential for Gas Demand-Side Response from Gas Fired Generation

204. We continue to expect that gas-fired power stations have the potential to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. We see this effect already in action in the market in normal circumstances as the generation emphasis moves between generation types in response to economic signals. In tight gas market conditions we therefore expect high levels of generation running from other fuel types.

Analysis of potential CCGT gas demand response

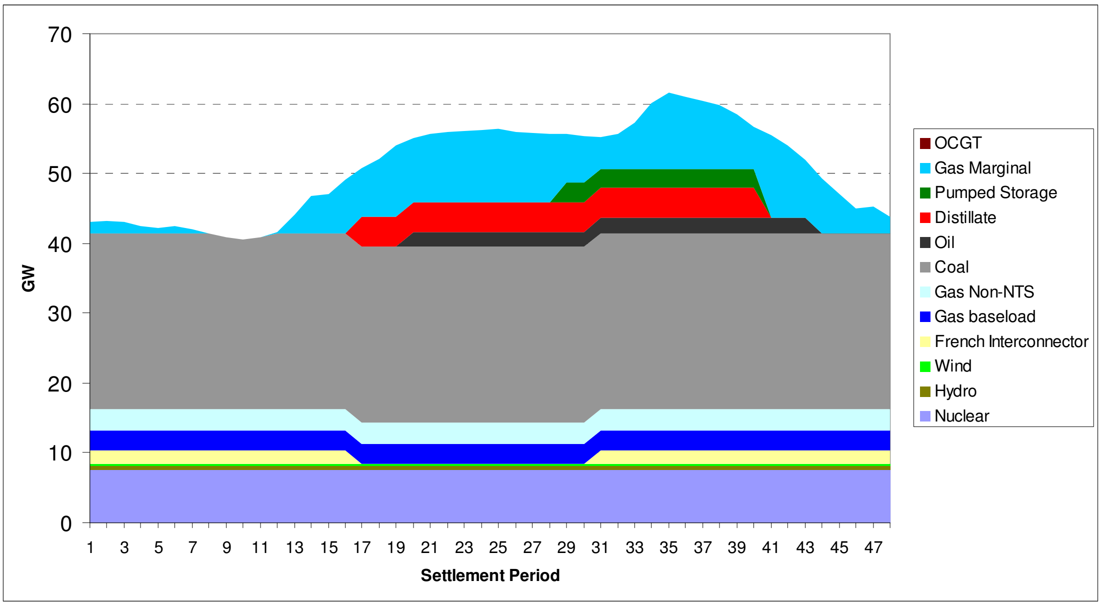
205. We have modelled the amount of relief that the electricity market can give to the gas market by switching to alternative fuels. Gas is assumed to be marginal generation throughout the winter in this analysis with switching to distillate before LNG storage is used. Table B.1 shows the merit order and plant availability used in the demand response analysis.

Table B.1 – Assumed plant availability factors for demand-side response analysis

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)	Model Assumptions Summary
Nuclear	10.1	75%	7.6	Baseload
French Interconnector	2.0	100%	2.0	Baseload, except 7 am to 3pm weekdays
Hydro	1.0	60%	0.6	Baseload
Wind	2.5	10%	0.3	Baseload
Gas Baseload	3.1	90%	2.8	Baseload
Gas Non-NTS	3.5	90%	3.2	Baseload
Coal	27.9	90%	25.1	Baseload
Oil	2.7	80%	2.2	12 hours over peak
Pumped Storage	2.7	100%	2.7	6 hours over peak
Distillate	4.8	90%	4.3	175 hours
Gas Marginal	16.1	90%	14.5	Marginal plant
OCGT	1.2	90%	1.1	Low merit, run occasionally
Total	**77.1**		66.3	
Average availability		**86%**		

206. Figure B.3 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modelling assumptions described in Table B.1. It shows approximately 25.1 GW of coal-fired generation throughout the day, gas as the marginal fuel across the day and distillate used for 12 hours around the peak demand period.

Figure B.3 – Potential generation profile – 1 in 20 cold winter weekday



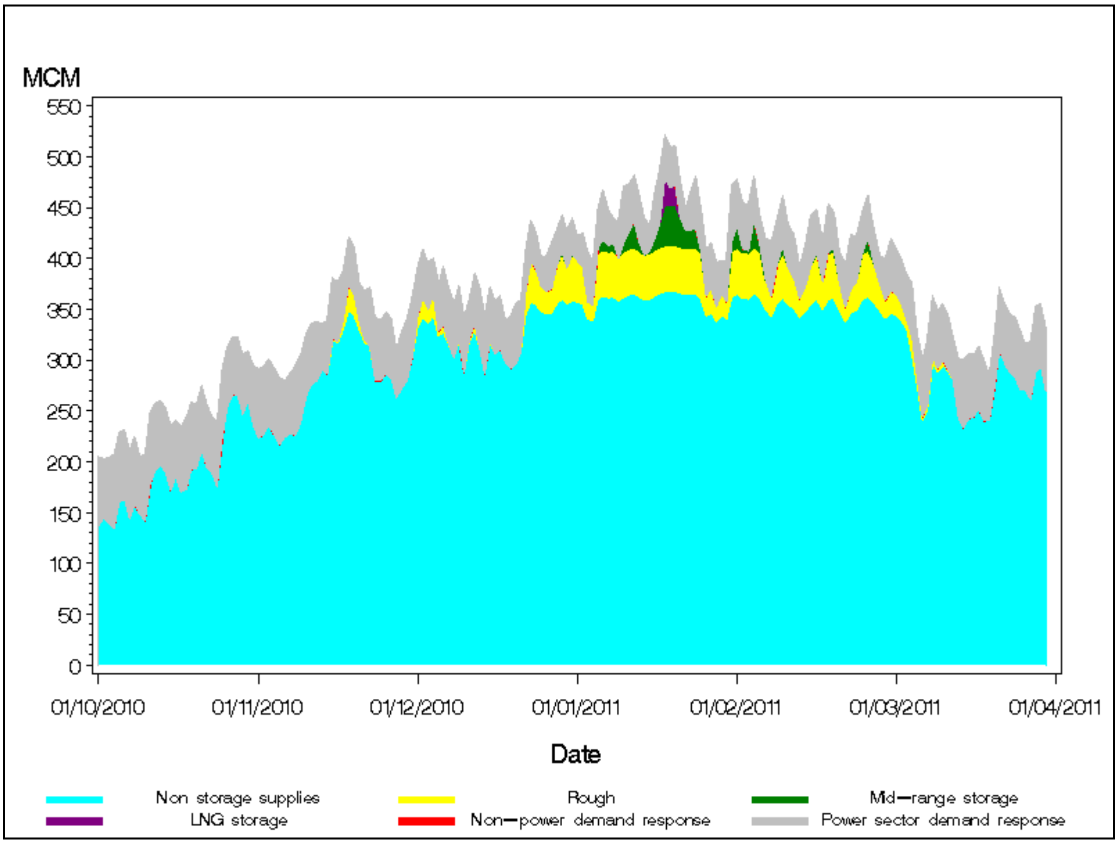
207. The ability of the markets to operate in a manner consistent with our assumptions remains largely untested given the succession of mild winters experienced in recent

years and the plentiful supplies of cheap gas in 2009/10, which have necessitated only a low requirement for gas demand-side response. In particular, the ability of the electricity market to switch to a significantly reduced gas demand will be entirely dependant on the price signals triggering the appropriate response.

208. The most significant use of distillate occurred in the winter of 2005/6 of up to 9 mcm/d. This analytically derived daily use of distillate corresponds well to a relatively high utilisation of the daily capability we believe there exists across the CCGT generation fleet. We empirically link the basis of Figures B.2 (technical capability to burn distillate) and B.3 (analysed distillate use) which reflect two different approaches to assessing capability giving some comfort in the assessment of power sector relief to the gas market.

209. We continue to believe that the switch to distillate would occur based on a gas price signal but there may be practical issues about how much switching would actually take place.

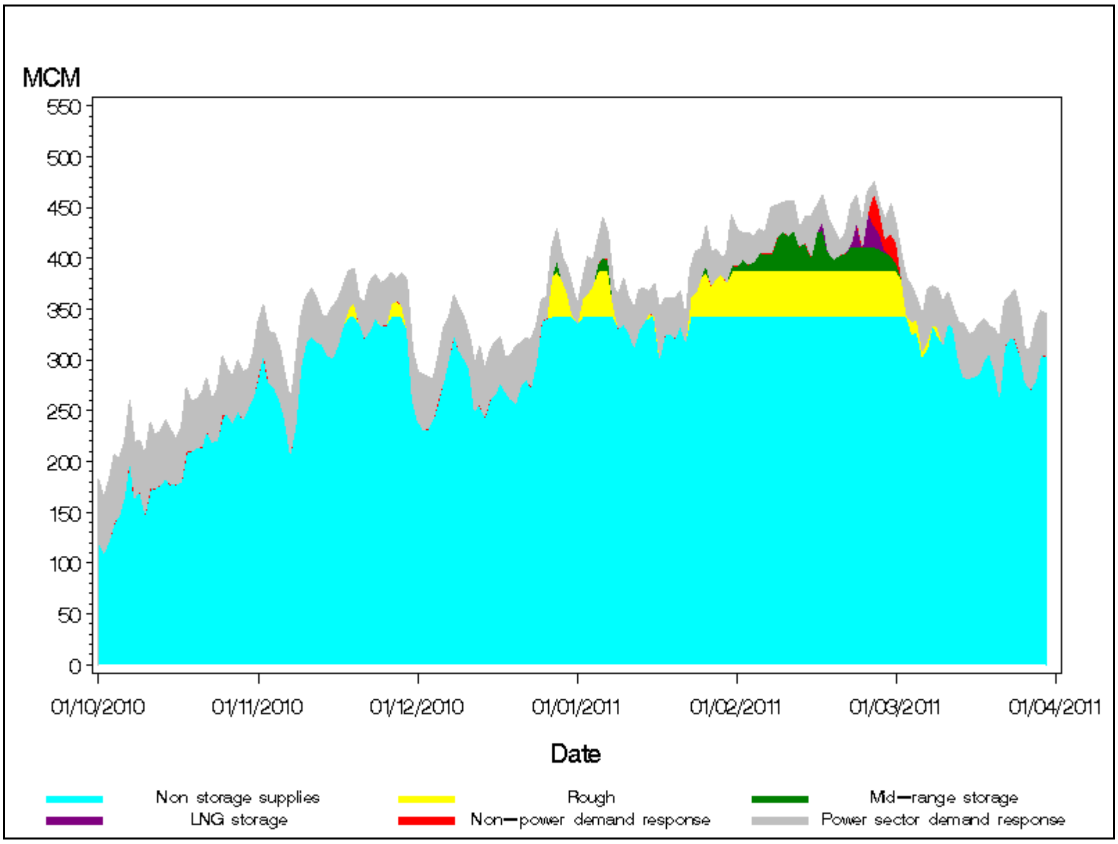
Figure B.4 – Theoretical gas supply build-up, base case, 1962/3 winter



210. The low generation, low supply case is less able to cope with a cold winter. 1985/6, the coldest winter since 1962/3, was 1 in 12 cold but it ended with the second coldest February in the last 82 years. Figure B.5 shows the impact of 1985/6 weather. It shows that it is the combination of the number of cold days with very little relief from the power market on the highest demand days that would cause a problem, if 1985/6 weather was to be repeated. The non-power demand response area shown in red is the amount of demand that cannot be supplied under the

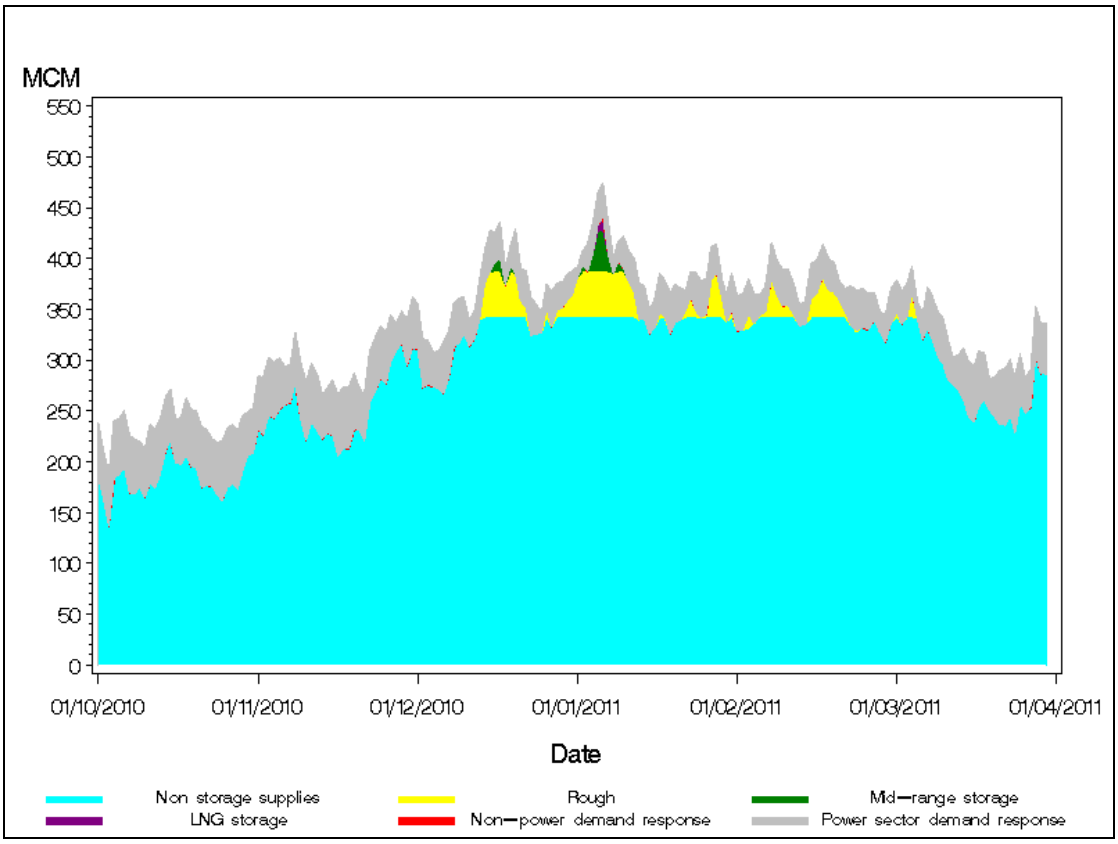
central supply case. This demand reduction would be expected to be managed by shippers not National Grid. This demand reduction includes shipper interruption and self interruption due to high prices. It is likely to occur from the first days of high demand, which would allow the use of LNG and mid-range storage to continue for longer.

Figure B.5 – Theoretical gas supply build-up, low generation, low supply, 1985/6 winter



211. Figure B.6 shows that for a less extreme cold winter even the low generation, low supply scenario will be able to cope. 2009/10 was the coldest December to February in the last 30 years.

Figure B.6 – Theoretical gas supply build-up, low generation, low supply, 2009/10 winter



Section C - Industry Framework Developments

Introduction

212. National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply-demand balances. This chapter reflects ongoing industry discussions, the detail of which can be found on our website or the relevant industry code administrators' website.

Gas

Entry Credit Arrangements

213. Modification Proposal 0246 "Quarterly NTS Entry Capacity User Commitment" was raised by National Grid NTS as a consequence of discussions within Review Group 0221. EDF Energy (0246A) and British Gas Trading (0246B) raised alternative Modification Proposals and all three proposals were submitted to Ofgem in May 2009.

214. On 3 June 2010 Ofgem decided to reject all three proposals but the Authority agreed that Shippers should not be able to defer security commitments without any consequence (an aspect of all 3 proposals) and have indicated that they would welcome a further proposal to address this specific issue.

215. After careful consideration, National Grid NTS has raised UNC332 to amend UNC TPD Section B 2.2.15 to remove the ability for a User to defer the provision of the required security and therefore, for this User's Registered Quarterly NTS Entry Capacity to lapse . We expect that the Authority will make a decision on the proposal before the end of 2010.

National Grid Gas NTS Licence: Special Condition C27 – Balancing Arrangements

216. In April 2010, National Grid NTS consented to a new Special Condition C27. This new Condition requires National Grid NTS, in conjunction with the industry to:

- Review the default cash out values that were introduced into the UNC in 2000 with a view to updating the existing values from April 2011[23].
- Develop an NTS Linepack product and if considered appropriate, implement such a Linepack product from October 2011.

217. National Grid NTS has subsequently initiated UNC Review Group 0291 C27 – Balancing Arrangements in order to facilitate industry discussion and development of both elements of its C27 obligations. Review Group 0291 commenced in May 2010 and it is anticipated to conclude in Q3 2010.

[23] See Special Condition C27(3): "The licensee shall use reasonable endeavours to introduce updated values of the "System Marginal Buy Price" as such term is defined in Section F 1.2.1(a)(i) of the licensee's network code as at 1 April 2010 and the "System Marginal Sell Price" as such term is defined in Section F 1.2.1(b)(i) of the licensee's network code as at 1 April 2010, by 1 April 2011 in consultation with shippers and other interested parties."

218. Following discussion of various options relating to potential changes of the default cashout prices National Grid NTS has also raised Modification Proposal 0333 “Update of the default System Marginal Buy price and System Marginal Sell Price” which seeks to amend the current default cashout prices to better reflect the costs associated with managing shipper imbalance positions through linepack changes. The proposal seeks to introduce a revised set of default cashout prices by 1st April 2011 as required by National Grid NTS Licence condition C27.

219. Industry discussion on the development of a NTS Linepack product are continuing within the Review Group with various strawmen being developed and considered with a view to bringing forward a UNC Modification Proposal for Ofgem’s consideration in due course.

Facilitation of 3rd party connected NTS Storage

220. There are several offshore storage facilities being cited for development that are likely to be indirectly connected to the NTS. These 3rd party connected NTS storage facilities are not currently recognised within the commercial and operational arrangements.

221. In conjunction with the Gas Storage Operators Group (GSOG), National Grid NTS has been assessing the implications that the introduction of NTS non-directly connected storage facilities might have on those existing arrangements, for example, the UNC and Storage Connection Agreements.

222. National Grid NTS is mindful of DECC’s recent implementation of the Gas Offshore Storage & Gas Unloading Licensing regime and we have agreed to support GSOG in its development of a UNC Modification Proposal (and associated agreements) that will seek to recognise these 3rd party connected NTS storage facilities.

Facilitation of new types of entry facilities to the NTS

223. During the summer of 2010 National Grid NTS has been working with attendees at the UNC Transmission Workstream to consider and develop potential arrangements that could facilitate the connection of a new type of entry facility. The type of facility in question is a Coal Bed Methane site which would be unable to meet Gas Safety (Management) Regulations (GS(M)R gas quality parameters without first offtaking some gas from the NTS to then mix or “co-mingle” with their new supplies to achieve a GS(M)R compliant gas prior to redelivering the compliant mix back into the NTS. Over the coming months National Grid NTS intends to continue this collaborative work by developing a set of business rules that could facilitate such a connection and then, if appropriate, move to proposing a modification to the UNC.

Entry Capacity

224. In August 2010 Modification Proposal 0295 was implemented. This modification clarifies the allocation of within day entry capacity. Any entry capacity bids placed at an Aggregate System Entry Point (ASEP) within day will be processed by National Grid NTS on an hourly basis irrespective of whether the bid is allocated or not.

Entry Capacity Substitution

225. At the last PCR Ofgem introduced an obligation for National Grid NTS to undertake Entry Capacity Substitution. Under this license obligation National Grid NTS seeks to substitute unsold Non-Incremental Obligated Entry Capacity from entry points (donor entry points) to other entry points (recipient entry points) where Incremental Obligated Entry Capacity is required to be released in accordance with the Incremental Entry Capacity Release methodology statement. Where substitution is applied this will result in the available capacity being reduced at the donor entry point and the amount of investment required to satisfy the incremental capacity release at the recipient entry point being lower than would be the case without substitution.

226. Following workshops and informal and formal consultations, the Entry Capacity Substitution methodology statement became effective on the 8th December 2009.

227. Reports on the outcome of both the application of entry capacity substitution and the retainer process held in 2010 can be found on National Grid's website: http://marketinformation.natgrid.co.uk/Gas/CapacityReports.aspx

228. In August/September 2010 National Grid NTS undertook a consultation on proposals for a revised Entry Capacity Substitution methodology statement as part of the annual review process. If approved by the Authority this will be effective from November 2010.

Exit Reform

229. Transitional exit arrangements allow Users to purchase exit capacity with a latest effective date of the 30th September 2012.

230. In January 2009 the Enduring NTS offtake arrangements were implemented effective from April 1st 2009 allowing Users to purchase exit capacity effective from 01 October 2012 onwards. The initialisation processes and first July increase applications and reduction notices for Enduring Exit (Flat) Capacity were held offline in 2009.

231. The first phase of the Gemini Exit Reform system has now gone live and this allowed Users to carry out certain enduring activities online during the July 2010 application window. Phase 1 functionality allows:

- Online Application for Enduring Exit (Flat) Capacity (July 2010 process)
- Online Notice of reduction of Enduring Exit (Flat) Capacity (July 2010 process)
- Online Application for Annual Exit (Flat) Capacity (July 2010 process)
- Ad-Hoc / ARCA Enduring Exit (Flat) Capacity applications

232. Additional Enduring Exit functionality will be introduced through future phased releases of the Gemini Exit Reform system commencing with the introduction of Transfer and Full Assignment processes for August 2011. (An implementation date for Partial Assignments has not yet been determined.)

233. A number of UNC modifications to enhance the Enduring Exit regime have been implemented in 2010. Details of these can be found on the joint office website: www.gasgovernance.co.uk

234. Further detail on Exit Reform can be found on a dedicated section of our website: http://www.nationalgrid.com/uk/Gas/OperationalInfo/endureexitcap/

Exit Capacity Substitution and Exit Capacity Revision

235. At the last PCR Ofgem introduced obligations for National Grid NTS to undertake Exit Capacity Substitution and Exit Capacity Revision. Exit Capacity Substitution and Revision would only apply to Exit Capacity from 1 October 2012 onwards i.e. the enduring exit period.

236. Regular workshops have been held with the Industry in 2010, to discuss the most appropriate way to introduce these obligations. The workshop presentations and minutes can be found on our website: http://www.nationalgrid.com/uk/Gas/Charges/statements/transportation/ExCapSubMS/

237. An informal industry consultation was held from 30 June 2010 to 6 August 2010.

238. National Grid NTS has a licence obligation to submit its proposed Exit Capacity Substitution and Revision Methodology Statement to the Authority by 4 January 2011. This submission will follow a second, formal, industry consultation. If approved implementation will be from the July 2011 application window.

Entry Charging Review

239. During 2009, National Grid NTS launched a fundamental review of entry charging principles. This was in response to growing industry concern about the increasing rate of the TO entry commodity charge. In 2009 National Grid NTS started to analyse the existing and potential future entry capacity procurement and has continued to develop charging proposals with the industry in 2010.

240. An initial outcome of the review resulted in the development of a charging consultation and the subsequent development of two UNC mod proposals, namely:

- Charging consultation GCM19
- UNC Modification 0284 - Removal of the Zero Auction Reserve Price for Within-day Daily NTS Entry Capacity (WDDSEC)
- UNC Modification 0285 -"Use it or lose it"(UIOLI) Interruptible Capacity only to be released when there is at most 10% unsold firm entry capacity

241. All of the above proposals were vetoed however further discussions will be held with the industry regarding the issues raised by the proposals and alternatives may be developed.

Exit charges

242. A key area developed in 2009 was the methodology by which NTS Exit Capacity prices will be determined with changes having been implemented in March 2009 for

the setting of NTS Exit (Flat) Capacity charges from 1st October 2012 post exit reform. This area is subject to review in light of the indicative charges produced.

Electricity

Balancing & Settlement Code relevant proposals / issues
Electricity Market Information

243. BSC modification P243 was approved by the Authority on the 20th January 2010 and will be implemented on the 4th November 2010. P243 will provide a more detailed forecast of generator availability, by publishing Output Usable data broken down by 'fuel types' and by BMU on the Balancing Mechanism Reporting System (BRMS). It is anticipated that greater transparency on plant availability is likely to better facilitate price discovery and market competition.

244. P244 will complement the existing near real-time information providing data relating to the Netherlands-England Interconnector (BritNed) on the BMRS, which is scheduled to become operational in early 2011. P244 also makes allowances in the BSC for future Interconnector data to be incorporated into the BMRS without the need for a Modification Proposal.

Transmission Losses

245. The final report for BSC modification P229 was issued to the Authority on the 12th March 2010 for decision. P229 seeks to change the Transmission Losses arrangements in the BSC so a Transmission loss Factor (TLF) for each BSC Season is calculated for each TLF Zone (Currently TLF = 0). Under P229 TLF Zones would be created based on 14 Grid Supply Point (GSP) groups, with historical data used to annually calculate each TLF per BSC Season per TLF Zone. This modification is with the Authority for decision. If agreed, the modification will be implemented 12 - 18 months after the Authority decision.

Frequency Response from Interconnectors

246. The Grid Code obliges DC Converters (interconnectors between GB and other markets) to provide mandatory ancillary services; this includes frequency response. With the connection of BritNed in early 2011 a review of the CUSC and BSC was undertaken by the Frequency Response Working Group. The group concluded that a number of changes were required to facilitate the provision and settlement of the mandatory ancillary service of frequency response from interconnectors. From the groups conclusion, National Grid raised two modifications; P259 in the BSC and CAP182 in the CUSC.

247. P259 - Provision of Applicable Balancing Services Volumes for Interconnectors proposes to change the BSC to treat interconnectors in the same way as other providers of mandatory frequency response by improving the method of allocating Applicable Balancing Services Volume Data (ABSVD) for interconnectors. In addition, the modification proposes that similar market data is published for interconnectors as it is for other providers of mandatory frequency response on the BMRS.

248. CAP182 - Provision of Frequency response from Direct Current (DC) Converters. There are a number of references within the CUSC to apparatus providing mandatory frequency response, however these reference do not currently include DC Converters. CAP182 seeks to include DC Converters into all the relevant references within the CUSC and the Mandatory Service Agreement to ensure that there equitable arrangements with all providers of mandatory frequency response.

Grid Code relevant proposals / issues
Consultation A/10: Generator Grid Code Compliance

249. Grid Code Amendment Consultation, A/10, intends to improve the transparency and consistency of the process of ensuring generators connecting to the transmission system comply with the Grid Code connection conditions. The proposals standardise and codify the process into the Grid Code. The Grid Code Consultation closed on 18th June 2010 and ten responses were received. The proposals are currently being reviewed, in light of several themes expressed in the responses, to assess whether enhancements should be considered by the industry.

250. Consequential code changes have been identified as being required to the Distribution Code and CUSC. A Distribution Code Consultation was published on the 15th June 2010 and a corresponding CUSC Amendment Proposal (CAP181) was raised at the March 2010 CUSC Panel, with a Working Group established shortly after. Previously a code change had also been anticipated for the Distribution Connection and Use of System Agreement (DCUSA), although this is no longer thought to be required. These consequential changes relate to Licence Exempt Embedded Medium Power Stations (LEEMPS) who are not directly connected to the transmission system but are still required to undergo the compliance process.

Connection and Use of System Code (CUSC) relevant proposals / issues
CAPs 148, 167 and 170

251. CUSC Amendment Proposal (CAP) 148 seeks to prioritise the use of the GB Transmission System by renewable generators. Under the proposal, renewable generators would be given firm access to the GB Transmission System by a fixed date and be compensated to the extent they are constrained from exercising such right by the payment of a new category of Interruption Payment. This would be irrespective of whether or not any associated deep reinforcement works have been constructed and/or commissioned by such date. The Amendment Proposal achieves this by the introduction of Deemed Transmission Entry Capacity (“DTEC”). CAP148 has a long lead time and, if approved, it would be at least three years before holders of DTEC connected to the system. CAP148 was sent to the Authority for decision in December 2007. Ofgem issued an Impact Assessment in July 2008 setting out the Authority’s minded-to decision to reject each of the CAP148 variants. A further consultation was issued in April 2009 which considered the impact of the Authority’s change in statutory duties, particularly the elevation of the sustainable development duty, following the commencement of the Energy Act 2008.

252. CAP167, Definition of a threshold(s) associated with a request for a Statement of Works, seeks to amend the CUSC to provide definitive clarification in the assessment of whether a small embedded power station development (or the aggregate effect of multiple projects) has a significant impact on the GB transmission system. This clarification is provided by way of MW threshold(s), which are derived based on transparent criteria for determining whether there could be a significant impact, which determine whether a DNO is required to request a Statement of Works. CAP167 was sent to the Authority for decision in February 2009.

253. The Authority's position on CAPs 148 and 167 (and similarly for the Transmission Access Review related CUSC Amendment Proposals 161 to 166 and CAP168) is under review in the light of DECC's position on Transmission Access as further detailed below.

254. CAP170 seeks to introduce a new category 5 System to Generator Operational Intertripping Scheme to cover intertrips capable of being armed with respect to a derogated non-compliant transmission boundary. It was raised by National Grid on the basis that at derogated non-compliant transmission boundaries the need to take action to manage constraints is more onerous than at compliant transmission boundaries. As such, the use of intertrips (assuming it is more economic than alternative Bid-Offer action to constrain generation pre-fault) is a necessity rather than an occasional tool in order to maximise flows across the derogated non-compliant transmission boundary. CAP170 was granted urgent status and proceeded straight to consultation by the company. CAP170 was sent to the Authority for decision in March 2009, with the Authority issuing an initial Impact Assessment in May 2009. In July 2009, the Authority published a further consultation on National Grid's updated costs savings forecast, with respect to CAP170, for the period 2009/10, followed by a further consultation in January 2010 on the competition issues relevant to CAP170. The Authority is continuing to consider this proposal; the latest anticipated date for a decision is Q3 2010 (Oct – Dec 2010).

Transmission Access Review: Implementation of "Connect & Manage"

255. Transmission access has proved to be a major barrier to new generation, due to a historic 'invest then connect' system, under which new plants had to join the access 'queue' on a first come, first served basis, and wait for all relevant reinforcement of the wider network to be completed before they could join the network and start generating. This led to an extensive queue of prospective new projects, with some plants offered connection dates as late as 2025.

256. In order to address this problem, the Government and Ofgem published a report of the Transmission Access Review (TAR) in June 2008, which set out the need to reform grid access rules to support the connection of new renewable and other generation.

257. Following the publication of the TAR, the industry and Ofgem worked intensively through a series of working groups to consider options for improving grid access. During this process it became clear that the industry process would not be able to agree a solution in time to ensure enduring rules are in place to help meet the wider

goals of meeting carbon reduction targets. The Government took powers in the Energy Act 2008 to enable it to intervene if necessary, and in July 2009, following recommendations from Ofgem and industry representatives, the Secretary of State for Energy and Climate Change announced that he would use those powers to reform grid access.

258. DECC has since carried out two consultations on the future of the access arrangements to the GB transmission system. This process culminated in July 2010 with the publication of DECC's decision to introduce a 'Connect and Manage' regime with enhanced User Commitment. "Connect and Manage" allows new users to gain access to the system when a minimum amount of local works have been completed. The direct consequence of this early access is likely to be increased system constraints. The costs associated with these will be shared across all users through existing BSUoS non-locational arrangements. The existing incentives on the System Operator will continue to ensure these incremental costs are minimised.

259. The revised regime is largely a formalisation of the process that National Grid had been operating through Interim Connect and Manage since Spring 2009. However, there are a number of changes to definitions that seek to add certainty and may result in earlier connection, particularly those around local works required prior to connection. It is also proposed to change the derogation process to self derogation rather than with Ofgem. User Commitment is also changing through the formalisation of interim connect and manage. The notice period which connected Generation parties are required to give National Grid for a reduction in Transmission Entry Capacity (TEC) was 5 days' notice, but will now be extended to 1 year and 5 days' notice. The DECC User Commitment proposals do not impact on the liabilities for pre-commissioning generation.

260. The code changes required to introduce the "Connect and Manage" regime were made on 11th August 2010.

Developments to the interface between the System Operator and Transmission Owners

261. National Grid undertook an informal consultation exercise in September 2009 to seek views on a range of potential approaches to enhancing the role of transmission companies within the existing SO/TO arrangements. The consultation looked at the timeliness of connections to the transmission networks and measures to contribute to the minimization of network constraint costs.

262. As a result of the consultation, work is being progressed to develop the outage planning and investment planning interfaces between the SO and TOs. This work is focussing on the timing and extent of interaction; and on the required level of data exchange to support that interaction.

263. Changes to the STC and its associated STCPs to allow for more communication and data exchange regarding constraints and outage planning between the Scottish TOs and National Grid, were proposed at the July 2010 STC Committee meeting under STC Amendment Proposal CA039 and are currently being reviewed together by the Scottish TOs and National Grid.

BM System Replacement

264. National Grid has proposed to replace the Balancing Mechanism (BM) system with a global best-practice IT system using up to date technologies and a go live date in 2013. Communication with stakeholders continues with updates provided through our Operational Forums as well as other routes. A second consultation is planned during Q4 2010 to gain further industry input into the project to ensure we continue to meet our customer needs.

Implementation of a new Cross Border Balancing on the England-France Interconnector (IFA)

265. National Grid and the French transmission system operator (RTE) are implementing further improvements to the Cross Border Balancing (CBB) tools between France and GB markets. The new CBB arrangements will provide increased flexibility for both RTE and National Grid and represent a key step in improved market coupling between France and GB. These changes go live on 1st December 2010. The key features of the new arrangements for system to system operator trades are the introduction of hourly prices for hourly energy blocks. As energy will be priced in hourly blocks and called off close to the actual hour of delivery, the prices in future are going to be more reflective of the prevailing system conditions in France and GB. We also requested a longer notice/duration service be implemented and requested the inclusion of a 2hr duration CBB product with a 2hr lead time in addition to the 1hr product, to enable NGET to continue utilising the CBB arrangements for broader system balancing purposes and avoid commitment of alternative more costly actions. We have agreed an “extension solution” to the 1hr product initially developed with RTE, allowing the acquiring TSO to secure a 2hr delivery. If the service volume is not available for the second hour then the delivering TSO will deliver energy through the “extension“ service and settle at a pre-agreed Excess Energy Price. This solution will be in place until April 2012. Any extension of these arrangements beyond this date would require a common agreement between Ofgem, CRE, National Grid and RTE