Winter Consultation Report 2009/10

A review of winter 2008/09 & preliminary outlook for winter 2009/10

Introduction

1. This document, the consultation report, sets out our preliminary analysis and views for the coming winter and presents a number of questions to market participants. Ofgem plans to hold a seminar for industry parties in early September in London, following which the final report will be issued in week commencing 28th September 2009. This report and the final report will be published on our website at http://www.nationalgrid.com/uk/Electricity/SYS/outlook/.

2. The report also covers a review of last winters experience and we share a review of our assumptions for last winter in the light of the actual winter events. This review is an important part of planning for next winter through learning from our recent experience and the report gives other stakeholders a route to share their insights and perspectives.

Industry Feedback

3. As this is a consultation report we are also seeking industry feedback. The deadline for responses to this consultation report is **4pm**, **11th September 2009**.

4. Responses should be e-mailed to energy.operations@uk.ngrid.com. It helps us to consider your responses to this report if you address specific questions we raise where appropriate as well as provide more general feedback on your views of the winter to come. To assist you we are providing an excel table version of the consultation questions on our website into which your responses can be added before returning the worksheet to us. The excel table can be found on our website at http://www.nationalgrid.com/uk/Electricity/SYS/outlook/. Where requested, we will treat information provided to us on a confidential basis. Alternatively, respondents may send confidential information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.

5. Unless specifically asked not to by respondents, we will share all feedback received with Ofgem. Respondents can request that their information is marked confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

Roles and Responsibilities

6. 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 regulatory framework for the market.

Legal Notice

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

8. 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 Review 2008/09 – Gas

10. 2008/09 was an average winter in terms of our 81 year data set, but cold relative to recent winters being the coldest winter since 1993. The winter was characterised by some colder weather at the start of November, December, January and February. No one day was exceptionally cold, the coldest day on 6th January having a national average temperature of -1.5°C (CWV of -0.1).

11. Despite the colder weather, demands (excluding IUK exports) in winter 2008/09 were lower than those in winter 2007/08. On a weather corrected basis demands in all market sectors were lower with an overall reduction of 6%. This reduction was attributed to a combination of the effects of the recession and improving energy efficiency measures.

12. The commencement of the Russia Ukraine dispute in early January resulted in higher UK demands as IUK exported gas to the Continent as a consequence of a well supplied position from UKCS, imports and notably storage withdrawals. During this period there was some increase in the UK gas price but compared to previous 'supply shocks' the price movements were relatively benign.

13. Gas supplies were broadly in line with our forecasts. Though declining by nearly 10%, UKCS supplies made up 55% of demand. Due to lower deliveries to the Continent, Norwegian supplies to the UK were above our pre-winter forecast and made up nearly 30% of demand.

14. The highest day of supply was 448 mcm/d on 6th January, in aggregate there were 9 days of supply in excess of 400 mcm/d and 67 days in excess of 350 mcm/d. Average demand for the highest 100 days of demand was 365 mcm/d, just 3 mcm/d higher than in 2007/08.

15. Whilst Balgzand Bacton Line (BBL) imports were in line with our forecast, IUK imports were limited to just a few short periods and IUK was in export mode for most of the winter, notably during the Russia Ukraine dispute.

16. Our concerns over the uncertainty around the timing of new LNG imports from the new importation terminals at Milford Haven were again realised with Dragon and South Hook still not operational during the winter period. Grain Phase 2 was commissioned in December and LNG imports through Grain made an important contribution during the high demand periods of January and February.

Winter Review 2008/09 – Electricity

17. The most significant factor from last winter was that demands outturned lower than were expected before the full extent of the impact of the current recession became evident. We saw weekly peak demands over the winter around 2 GW lower on a weather corrected basis than we would have seen in the absence of the recession effect.

18. In terms of generation availability we saw a small contribution from wind generation at the time of the demand peak, underlining the need to discount the availability of intermittent generation types. We also experienced a low contribution from nuclear generation coincident with the time of the peak demand. The lower nuclear availability was, we believe, an exceptional event but highlights the risk that generation availability issues can and do occur.

19. However, despite what has been a different winter to that which was expected on the demand side particularly, the winter peak demand was met by the market through its normal function together with our normal system operator balancing mechanism.

20. The highest electricity demand over the winter reached 59.1GW for the half-hour ending 17:30 on 6th January 2009. This compares to the highest demand of 60.6GW and 58.1GW over winter 2007/08 and 2006/07 respectively. The relatively high outturn demand compared to previous winters, despite the downward pressure of the recession, is due to the actual weather which was relatively cold in recent historic terms.

Winter 2009/10 Outlook – Gas

21. Fuel price futures show an increase in the oil and coal price with gas also increasing albeit retaining a seasonal profile. The seasonal pricing of gas suggests coal will be the winter base load plant with gas fired generation as the marginal plant. UK and Continental gas prices are very close and are higher than those in the US providing an incentive to deliver spot LNG cargoes to Europe in preference to the US.

22. Forecast demands for next winter are 2.5% lower than weather corrected actual demands in 2008/09. This is due to the further reductions in NDM demand and lower forecasts for gas consumption in power stations due to a combination of gas prices, lower electricity demand and expected higher availability of non gas fired power generation.

23. Due to decline, our forecast for UKCS supplies for next winter is approximately 6% lower with UKCS expected to make up typically 50% of non storage supplies.

24. From Norway we anticipate higher UK imports as Norway's offshore production continues to increase. However we again acknowledge the potential for higher deliveries to the Continent at the expense of the UK. For BBL we expect similar performance to last winter though this could be lower if commercial arrangements for non physical reverse flow are introduced. For IUK we again expect flows to respond to market needs but due to a combination of lower UK demands and possibly more LNG, anticipate that the threshold for IUK imports may be at relatively high UK demands.

25. For next winter, LNG imports provide us with the biggest supply uncertainty, though we anticipate that both Milford Haven facilities will be operational. Whilst potential LNG flows from Grain and Milford combined could exceed 100 mcm/d we expect flows will for most of the time will be lower than this. For consultation purposes we have assumed a provisional range of 10-60 mcm/d with average flows of 30 mcm/d. Compared to previous winters there are reasons to be more optimistic about LNG

deliveries to the UK, this is due to a combination of increased LNG production, global recession (includes possibility of releasing cargoes from the Far East) and relatively high European gas prices.

26. Our preliminary view of non storage gas supplies for next winter is between 336-386 mcm/d, with a base case view of 343 mcm/d. This is comparable to last winter's level of non storage supply, with further upside potential from LNG and IUK imports.

27. With similar levels of non storage supply and lower levels of demand, our preliminary assessment of storage requirements for the Safety Monitors for next winter is lower at just 2.7% of total storage space.

28. For next winter we have made numerous changes to the Safety Monitor determination process replacing three storage types with a single storage type. We have also made a commitment to improve market information relating to Safety Monitor levels and the short term supply demand position. Some of these changes are anticipated to be captured in a UNC code modification. Whilst this will not change the monitor requirements we believe the changes will enable the market to operate more effectively, as there will be greater clarity regarding the necessary safety monitor space and deliverability requirements.

Winter 2009/10 Outlook – Electricity

29. For next winter, based on the information available at this consultation report stage, the surplus generation above expected electricity demand is materially more comfortable than we have seen in recent years. The availability of generation relative to demands could also further substantially improve over the course of the winter itself. This improvement is dependant upon the commissioning of several new large CCGT power stations and expected increases in wind power generation capability taking place. An improved generation mix also gives greater flexibility across the generation fleet.

30. Our expectation of operational generation capability is 76.9GW at the start of winter, which we calculate delivers a 66.0 GW expected availability allowing for generation performance issues.

31. The Average Cold Spell (ACS) peak demand for winter to come of 57.8 GW is very marginally below last years outturn peak demand adjusted for ACS conditions.

32. Using installed generation capacity relative to ACS peak demand yields a plant margin of 33%, excluding any potential imports from France. The more representative estimate of actual likely generation availability at the winter peak of 66.0 GW yields an operational capacity headroom at the winter demand peak of 14%.

33. Setting the ACS demand forecast along side the generation availability figures shows comfortable electricity availability for winter to come. We show in this report that it should be possible to comfortably meet even our 1 in 20 probability demands plus our short term operating reserve.

34. We reforecast electricity demand on a regular basis and expect to update our demand expectations over the summer for the winter to come. These updates will be reflected in the final winter outlook report. We also regularly receive generation

availability information from operators and this report takes a snap shot in time based on the information we have at this point. Key information such as generation surpluses and demand forecasts are reviewed and updated for changes on a weekly basis and published on www.bmreports.com. Readers of this consultation report may also find it useful to obtain updates of key metrics on a regular basis from bmreports.

35. There is an increased level of uncertainty in our demand forecasts as we are beginning to see a slowdown in the rate of decline of electricity demand. We believe this is an indication that the economy is beginning to stabilize as the recession shows signs of deceleration. However, drawing any firm conclusions about whether demand will further reduce from here or if it will have started to increase by the winter to come is extremely difficult. We hope to be in a more favourable situation with greater clarity on the behaviour of electricity demand and with more information about economic activity levels and trends by the time of the final winter report publication in September 2009.

Contents

Section A
Experience of 2008/09

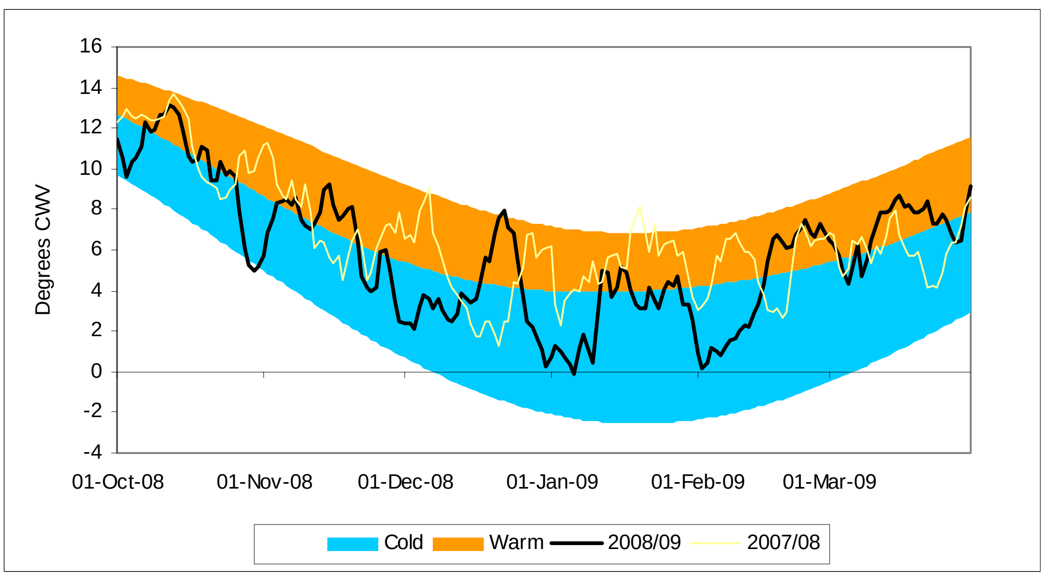
Weather

36. The 2008/09 winter severity, based on the 81 winters starting from October 1928, was average for both the 6 month period from October to March and the 3 month period from December to February.

37. The 2008/09 coldest day, based on the 81 winters starting from October 1928, was 1 in 4 warm. The coldest day was January 6th with a national average temperature of -1.5°C (CWV of -0.1°).

38. Figure A.1 illustrates the 2008/09 winter compared with the 2007/08 winter and warm, normal and cold conditions. The measure plotted in the graph is the Composite Weather Variable (CWV), which is calculated by combining temperatures and wind speeds and transforming them to produce a weather variable that is linearly related to non-daily metered gas demand.

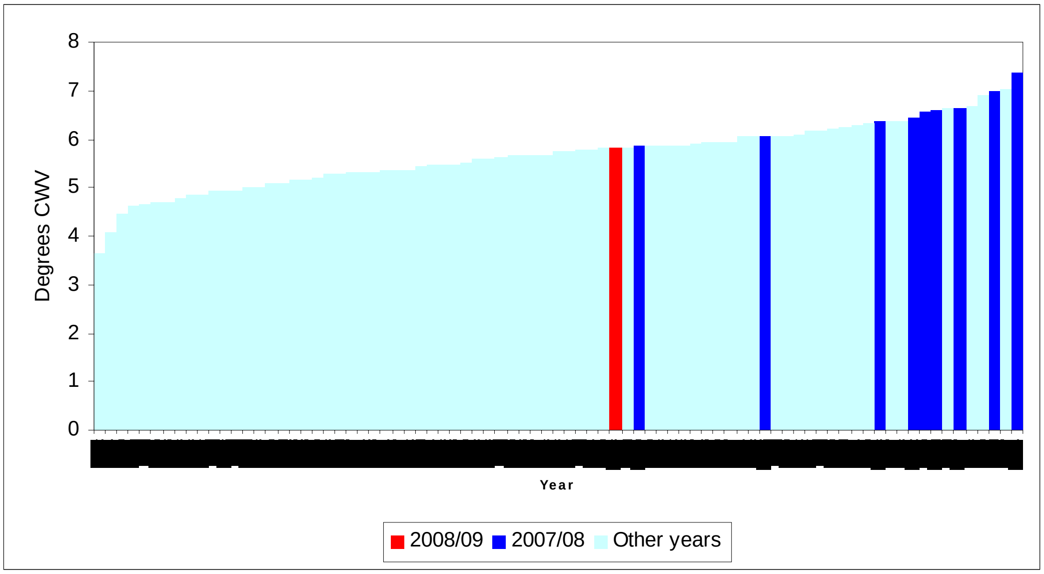
Figure A.1 – 2008/09 Winter Weather (CWV) Overview[1]



39. Figure A.2 compares the mean composite weather for the October to March period with previous winters. The chart highlights the recent trend of warmer winters and indicates that last winter was the coldest since 1995.

[1] The cold and warm values are realistic daily ranges for each day of the winter. For further information please refer to http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

Figure A.2 – Mean National Composite Weather for October to March



Gas

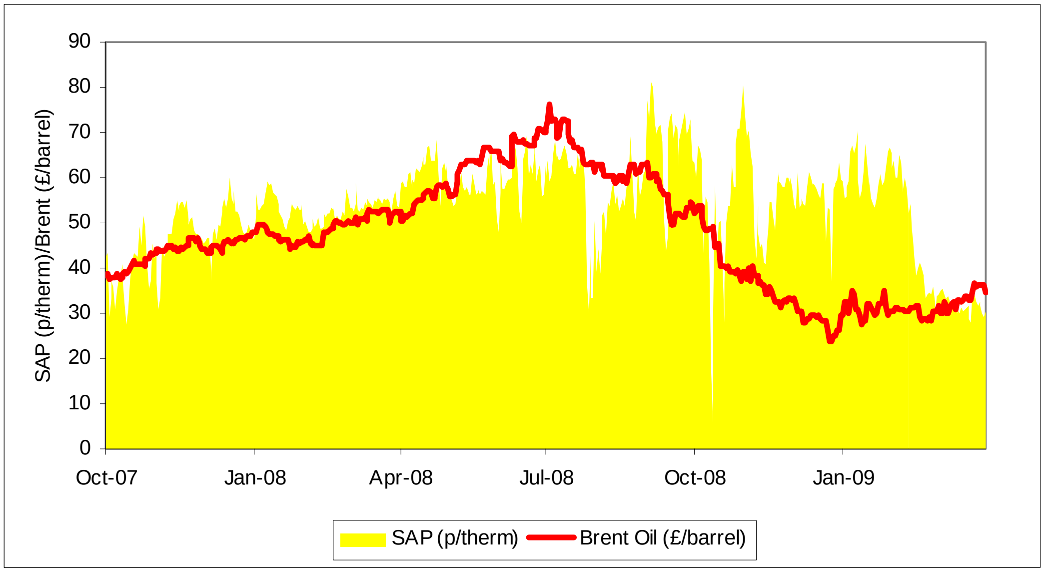
2008/09 Fuel Prices

40. The System Average Price (SAP) for gas reported by National Grid is very closely related to on the day NBP prices. Figure A.3 shows SAP and the Brent oil price for the period October 2007 to March 2009. SAP has generally remained steady in winter 2008/09 until mid February 2009. Before mid February it was generally in the 50-60p/th range, it then dropped to an average of just over 30p/th.

41. Changes in world energy markets and the economy have caused unusual changes in SAP this year. The high strength in oil markets last summer resulted in high summer gas prices. The collapse of oil prices post July 2008 was offset by the seasonal increases of gas price moving towards winter. This lead to SAP being relatively stable throughout 2008 and into 2009 despite the Russia Ukraine dispute in January.

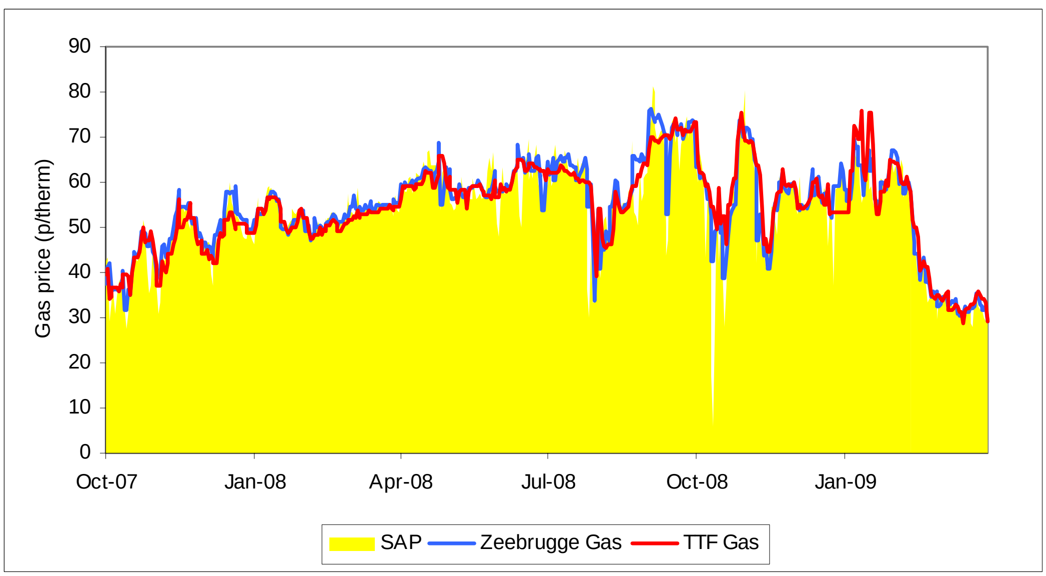
42. A combination of factors, namely, the resolution of the Russia Ukraine dispute, lower demands associated with warming weather and the earlier drop in oil price (the link between SAP and oil price is strong, but lagged by several months, due to the strong link to Continental prices through high import volumes), caused the gas price to roughly half from mid February to the start of April. Supply in winter 2008/09 generally met demand relatively comfortably, so there were no supply demand issues affecting price despite significant depletion of storage.

Figure A.3 – SAP and oil prices from October 2007



43. With the Dutch and Belgian gas markets linked to the UK via the BBL and IUK pipelines respectively, European prices at the Zeebrugge and TTF hubs have been relatively consistent with UK prices as illustrated in Figure A.4.

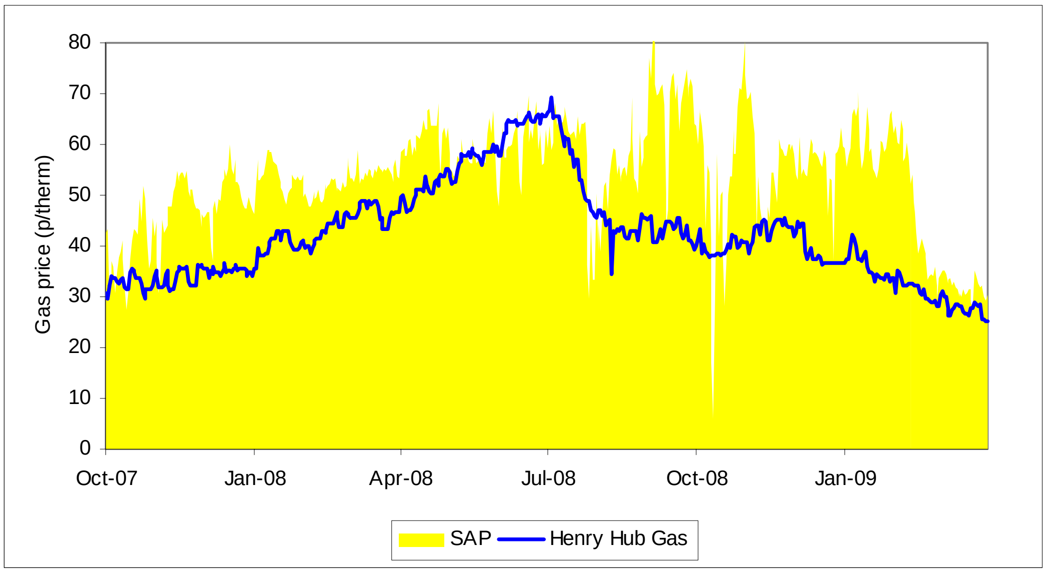
Figure A.4 – UK and European Gas Prices



44. Figure A.5 compares SAP to the Henry Hub price in the United States. The Henry Hub price decreased in line with the oil price falls since July 2008, whereas the seasonal effect and oil price lag meant the NBP SAP fell later in mid February. This lead to SAP being significantly higher priced than Henry Hub for most of the winter. These conditions made the UK a more attractive destination for spot LNG cargoes than the United States.

45. Prices for spot LNG cargoes delivered to the Far East were reported to be above SAP and other Continental prices, with prices well above 60p/therm for most of the winter period. This was sufficient for diversion of some LNG from the Atlantic basin to the Far East. Some LNG did arrive in the UK though due to an excess from reduced world demand, and commissioning of new LNG production.

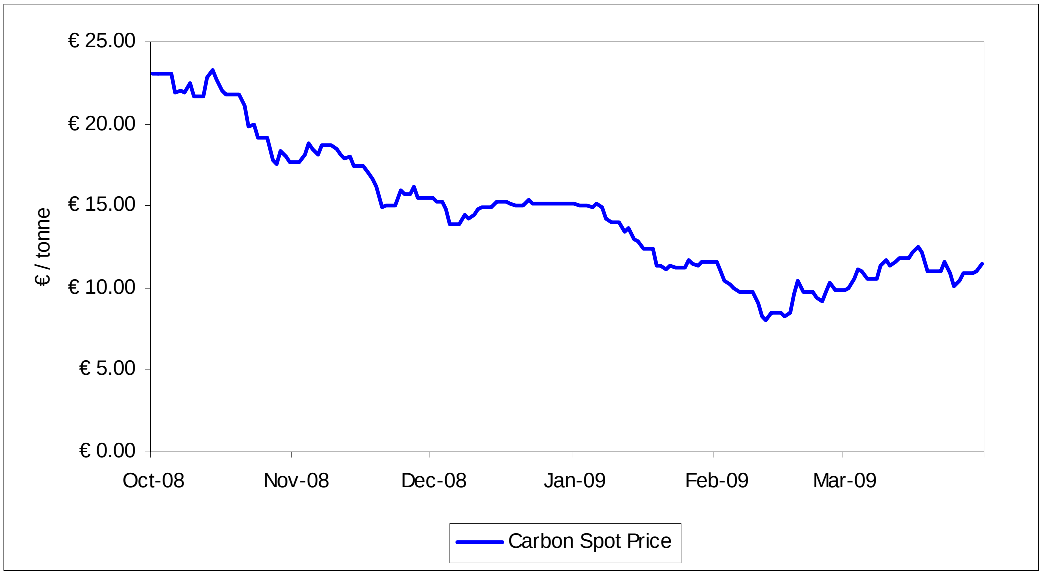
Figure A.5 – UK and Henry Hub Prices



46. Figure A.6 shows carbon prices for the winter. Carbon prices reflected the economic downturn and reduced through to February due to reduced demand for permits from lower industrial demand. There was a view in the market that the lowest point of €8/tonne was lower than fundamentals should have taken it as some industrial companies sold off carbon permits to raise revenue, as they could not get credit from financial institutions.

47. A higher carbon price benefits gas-fired generation when compared with coal-fired generation due to the higher carbon emissions associated with burning coal.

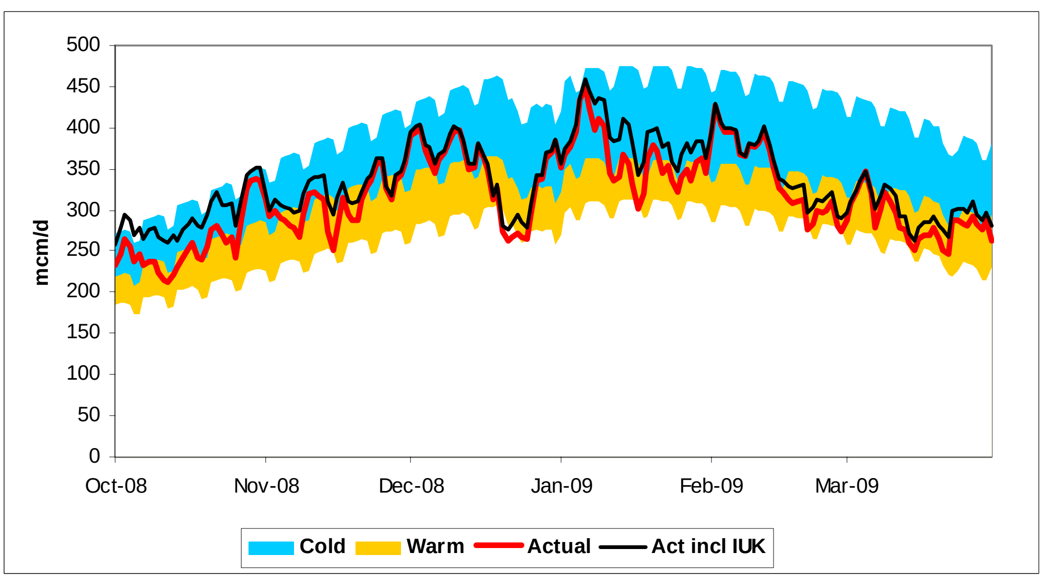
Figure A.6 – Carbon Prices



2008/09 Gas Demand

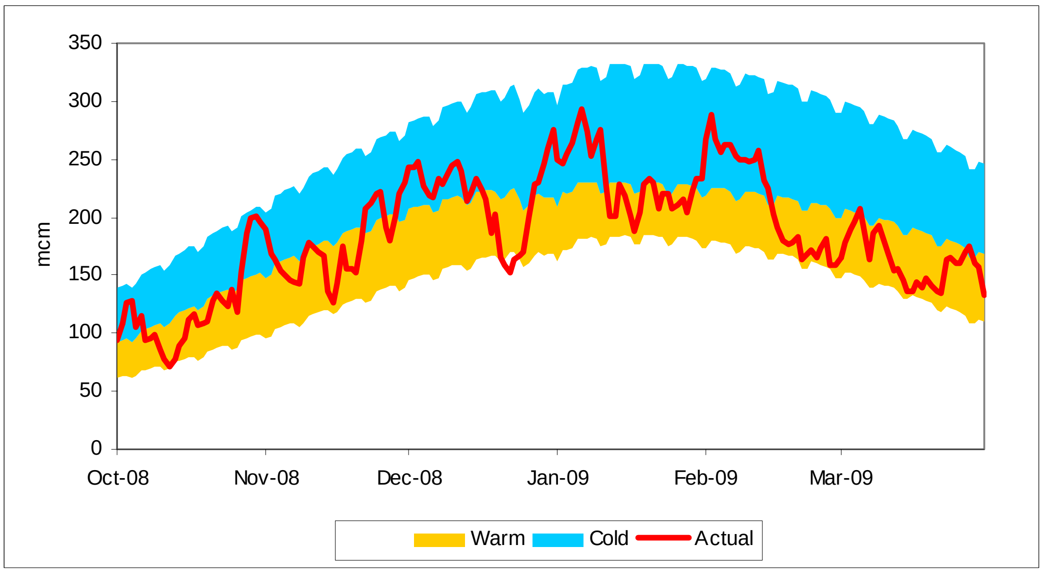
48. Figure A.7 compares total demand, excluding Interconnector exports and storage injection, with seasonal normal, cold and warm demand. Also shown is the demand line that includes IUK exports. These were most noticeable between October and November when UK demand was relatively low and again in January when the Russia Ukraine dispute erupted. The latter resulted in unprecedented levels of exports when assessed in relation to high UK demand.

Figure A.7 – 2008/09 Seasonal and Actual Demands



49. The chart shows that actual demand was generally within the forecast bands. The biggest deviations from seasonal normal forecasts were the low demand levels at the start of the Christmas holiday period and the high demand in the cold weather at the start of January. Figure A.8 shows the same graph for the most weather sensitive load band, non-daily metered demand. NDM demand was lower than seasonal normal for much of the second half of the winter. The periods when the demand was higher than normal were when the weather was much colder than normal, in the first week of January and first two weeks of February as shown in figure A.1.

Figure A.8 – 2008/09 NDM Seasonal and Actual Demands



50. NDM demand did not start to deviate from forecast until the end of September. This is illustrated in figure A.9. This also shows a bigger deviation in the second half of the winter. Figure A.10 shows that weather was not a factor in the size of the model error.

Figure A.9 – 2008/09 NDM model error from 2008 forecasts

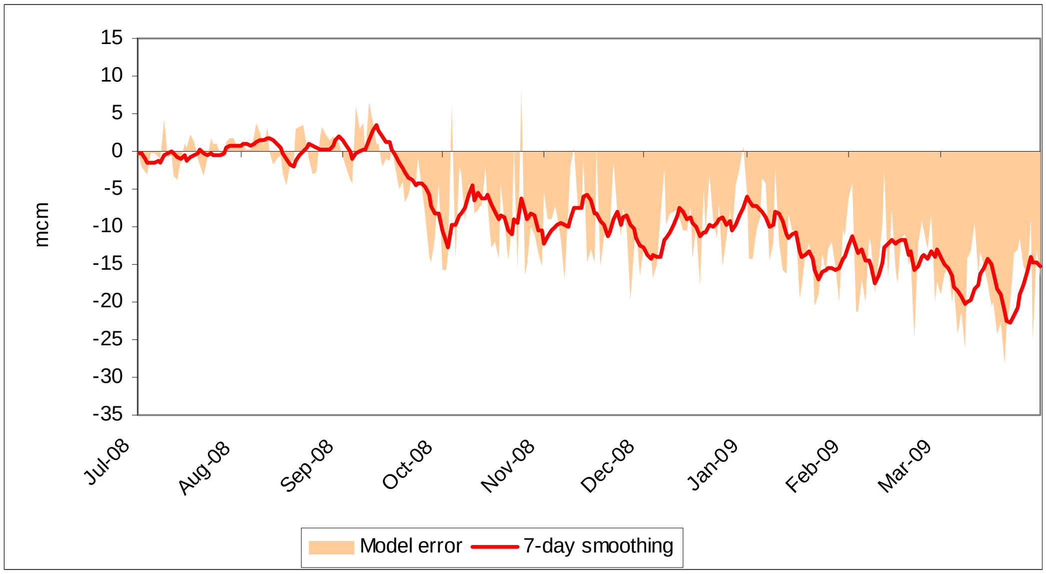
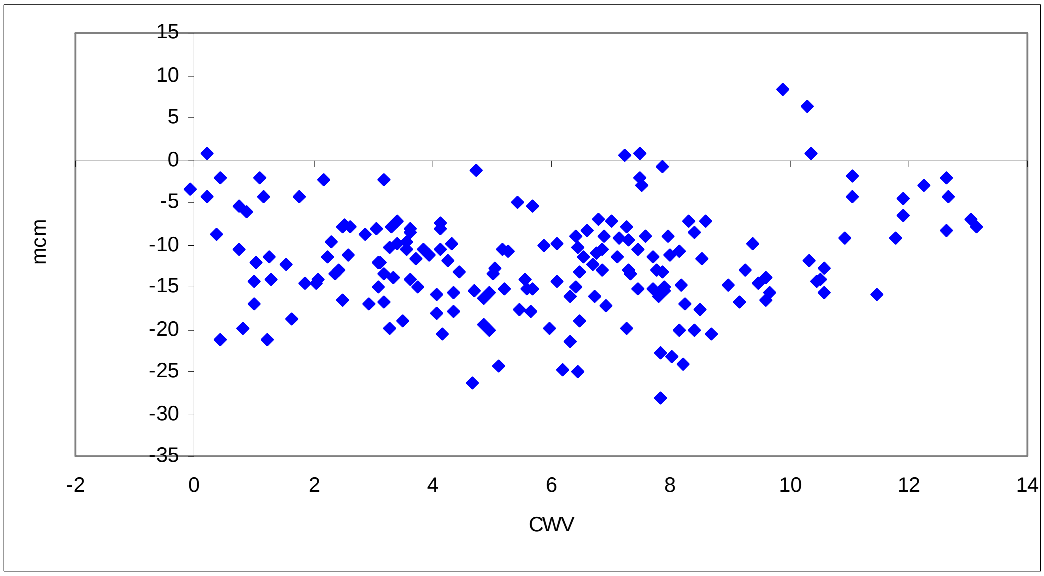


Figure A.10 – 2008/09 NDM model error from 2008 forecasts



51. Figure A.11 shows some significant increases in DM and NTS demand compared to forecast. Removing Interconnector exports, figure A.12, shows the demand model to be reasonably accurate fro the first half of the winter with the impact of the recession causing demand to fall away from mid-January. There is very little weather variation in demand in these market sectors as highlighted by the small difference between the cold and warm forecasts.

Figure A.11 – 2008/09 DM and NTS Seasonal and Actual Demands including IUK

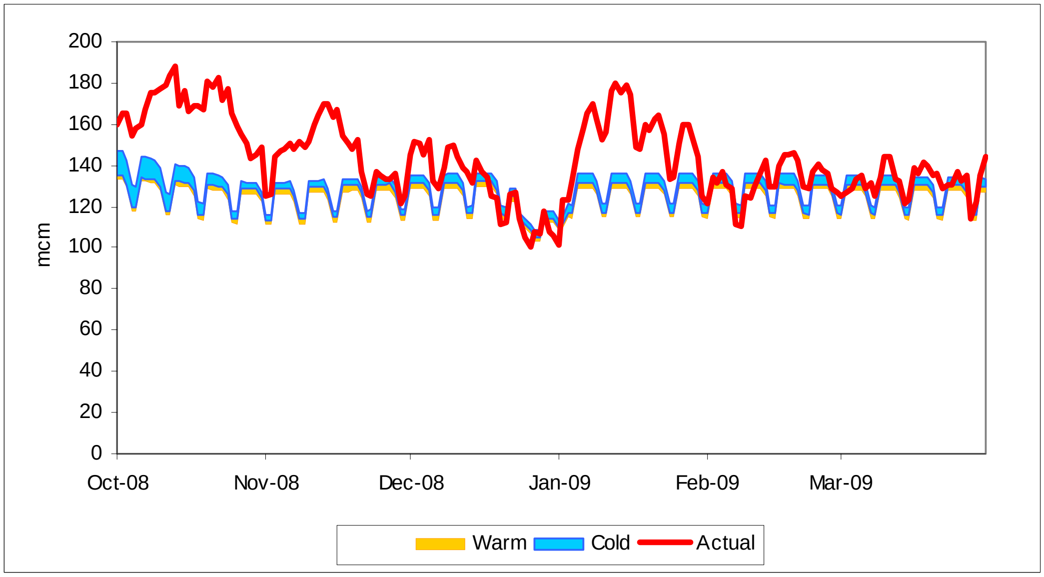
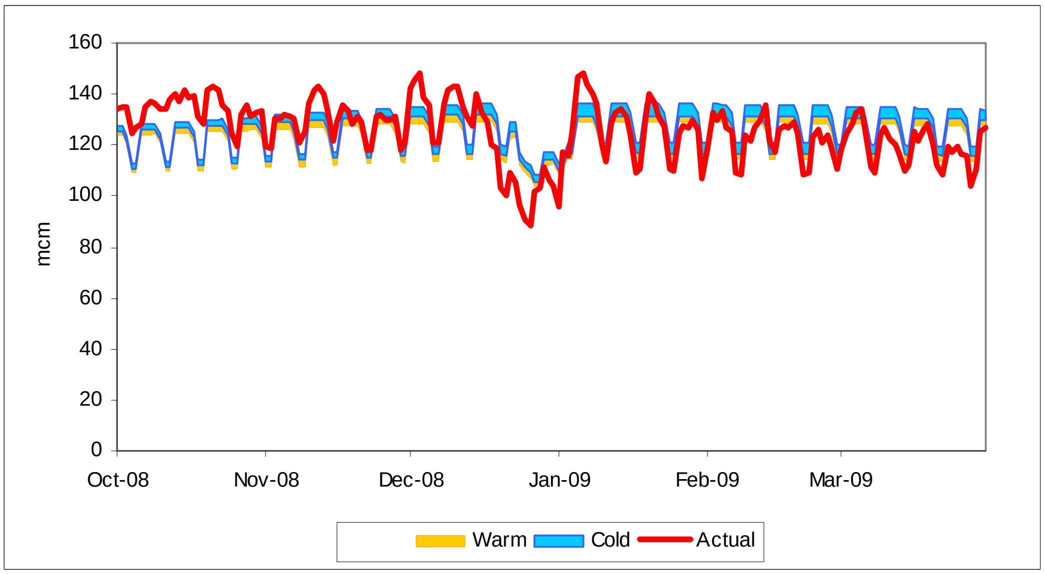
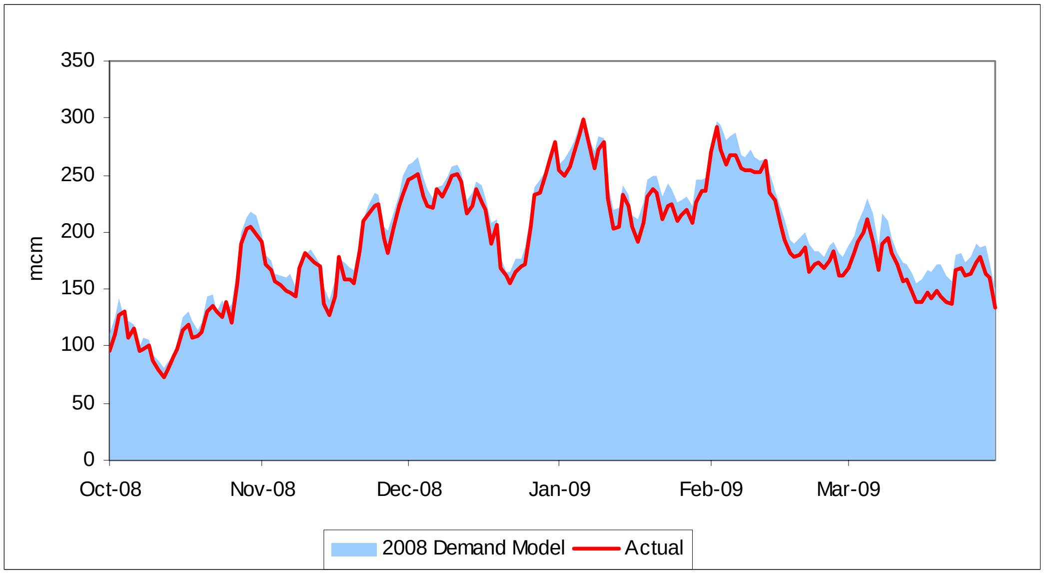


Figure A.12 – 2008/09 DM and NTS Seasonal and Actual Demands excluding IUK



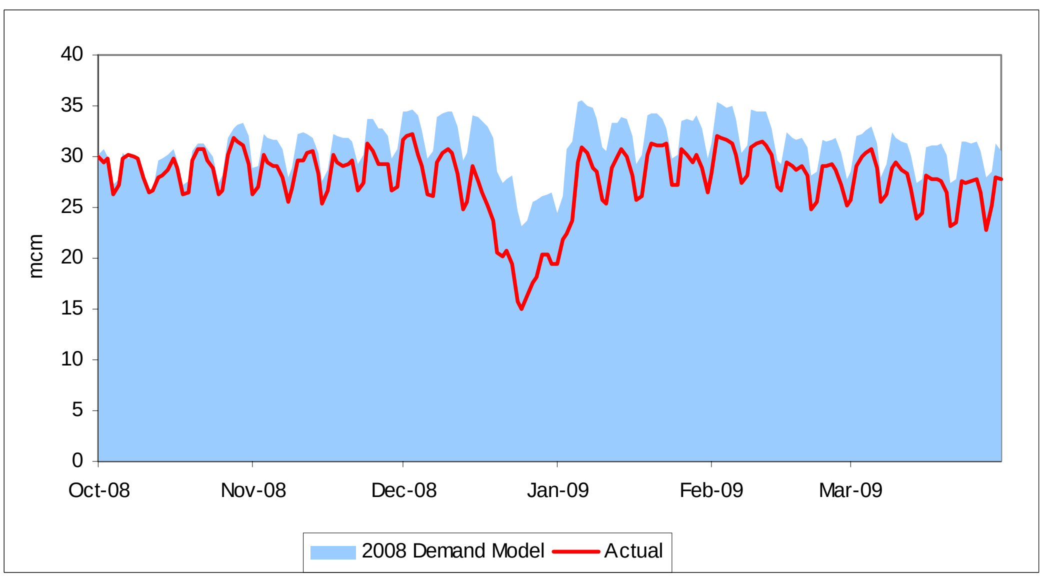
52. Figure A.13 compares actual NDM demand with the demand modeled from actual weather and the 2008 demand forecast model. The graph shows that actual demand was below that predicted by the model by an average of 6%. However at times of highest NDM demand, the difference was considerably less.

Figure A.13 – 2008/09 Actual NDM Demand



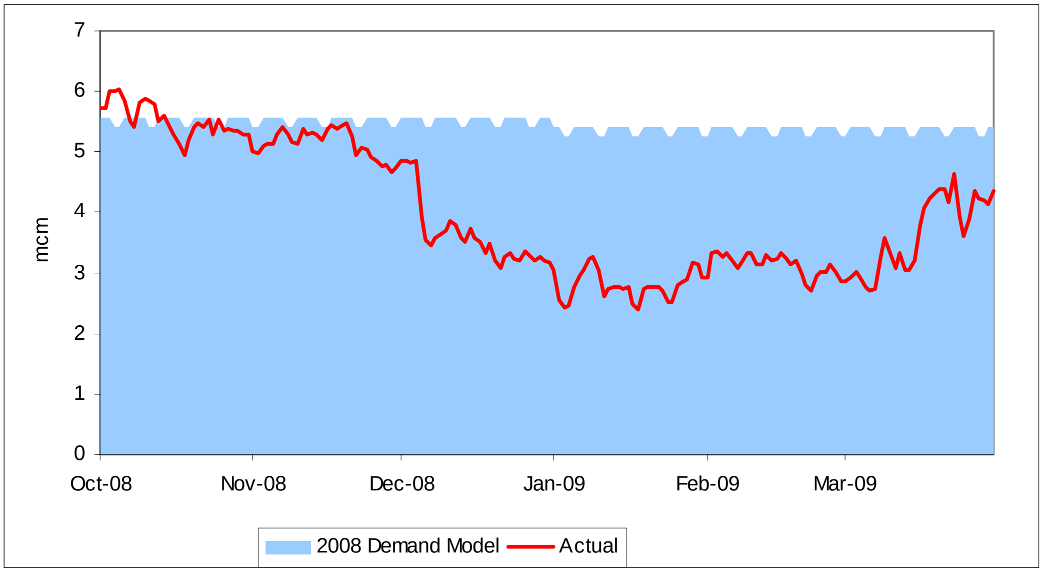
53. A similar graph for LDZ daily metered non-power demand (Figure A.14) shows that the actual demands were very close to the model values in October but then fell by an average of about 10%.

Figure A.14 – 2008/09 Actual LDZ DM Non-power Demand



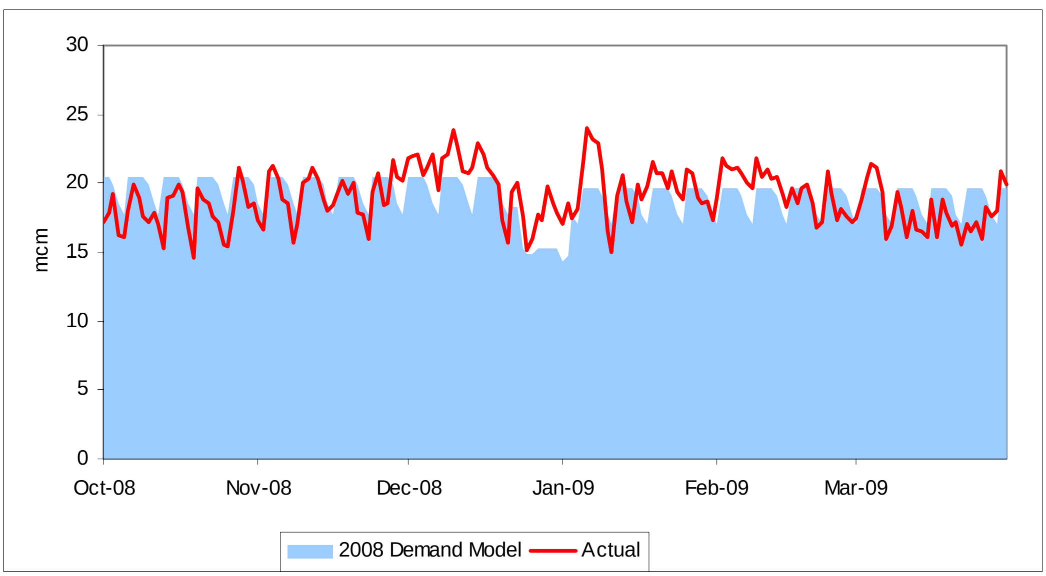
54. Figure A.15 shows the same information for the NTS Industrial market sector. The large drop in demand from February through to March was mostly due to 2 large loads.

Figure A.15 – 2008/09 Actual NTS Industrial Demand



55. Figure A.16 shows that exports to Ireland were close to forecast levels.

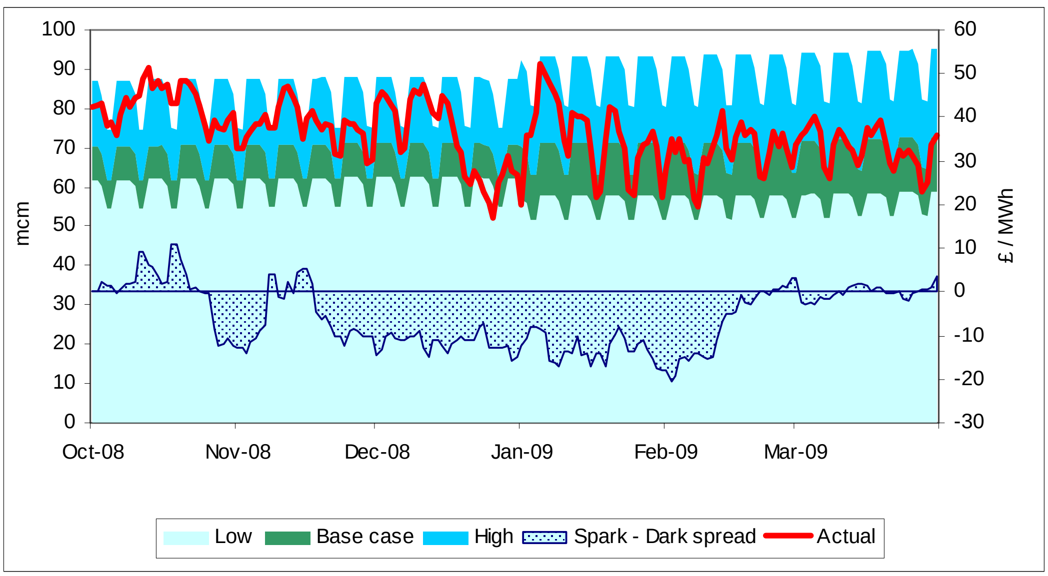
Figure A.16 – 2008/09 Actual NTS Exports to Ireland



56. Figure A.17 shows actual power station demand compared to the 2008 forecast. Power generation forecasts are based on ranking orders for a three month period. The 2008/09 winter is split into two 3-month periods; from October to December and from January to March. The green area shows our seasonal normal forecast. This is the ranking order expected to prevail over the 3 month period. The high and low represent the range over which we expected power generation demand could vary in the 3 month period. The red line is the actual power generation gas demand.

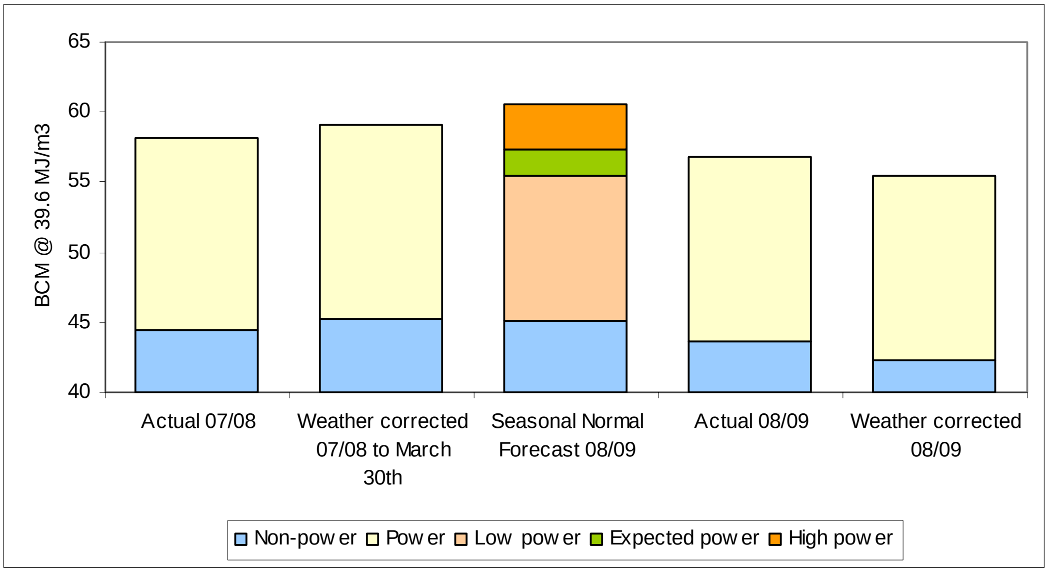
57. The 2008 forecasts assumed that gas would be marginal generation during the winter and base load over the summer. For the first 3 months of the winter the actual gas burn was higher than the base case forecast primarily due to lower availability of other generation plant.

Figure A.17 – 2008/09 Actual Power Station Demand



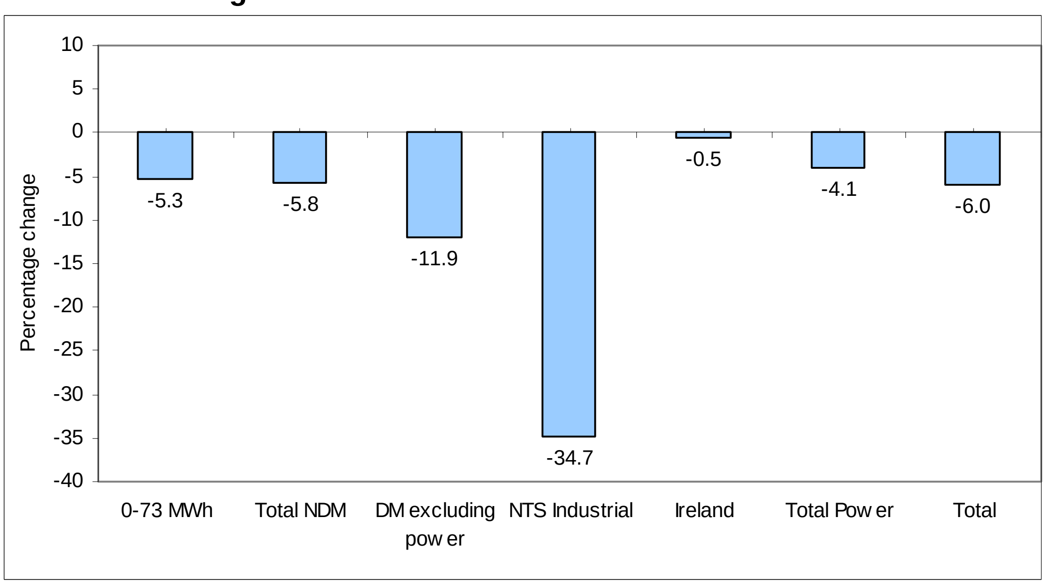
58. Figure A.18 compares the 2008/09 actual, forecast and weather corrected winter demand with 2007/08 actual demand. Note the y-axis is offset to highlight relatively small differences. 2008 was a leap year so to compare the same number of days as 2008/09 the weather corrected 2007/08 figures were calculated to March 30th.

Figure A.18 Total Winter Demand



59. The 2008/09 non-power forecast was 0.5% below the 2007/08 weather corrected demand. The power base case forecast was 11% lower than 2007/08 with the low and high power generation forecasts giving a range from 24% lower to 13% higher. The 2008/09 actual demand was 2.4% lower than 2007/08 actual demand. 2008/09 weather corrected demand was 6% lower than 2007/08 weather corrected demand. Figure A.19 shows the percentage change in weather corrected demand for October to March 2008/09 compared to October to March 30th 2007/08.

Figure A.19 Percentage reduction in weather corrected demand



2008/09 Gas Supply

60. Table A.1 summarises the make-up of gas supplies for winters 2006/7, 2007/08 and 2008/09 by supply source. The table shows that actual supply / demand (i.e. non weather corrected) was higher than in the previous two winters. With a further decline of approximately 8% in UKCS supplies, the increase in supply / demand was met primarily through a 13% increase in imports, notably from Norway. Compared to winter 2007/08, imports from the Continent were lower whilst LNG imports were higher as was use of storage.

Table A.1 – Gas Supply, Comparison of 2006/7, 2007/08 and 2008/09 by Source

	2006/7		2007/08		2008/09	
	bcm	%	bcm	%	bcm	%
UKCS	37.1	64%	36.0	60%	33.3	55%
Norway[2]	12.9	22%	13.7	23%	17.8	29%
Continent	3.5	6%	6.7	11%	4.6	8%
LNG	1.9	3%	0.7	1%	1.6	3%
Storage	2.4	4%	3.5	6%	3.9	6%
Total	**57.7**		**60.5**		**61.1**	

61. Table A.2 shows the make up of supplies for winters 2006/7, 2007/08 and 2008/09 by terminal. Supplies through Bacton, Easington and St Fergus accounted for 80% of all supplies. Whilst St Fergus continued to receive most supplies, Easington had the largest increase due to higher Norwegian imports through Langeled. Supplies through Teesside were also higher though both Barrow and Theddlethorpe were lower.

Table A.2 – Gas Supply, Comparison of 2006/7 and 2007/08 by Terminal

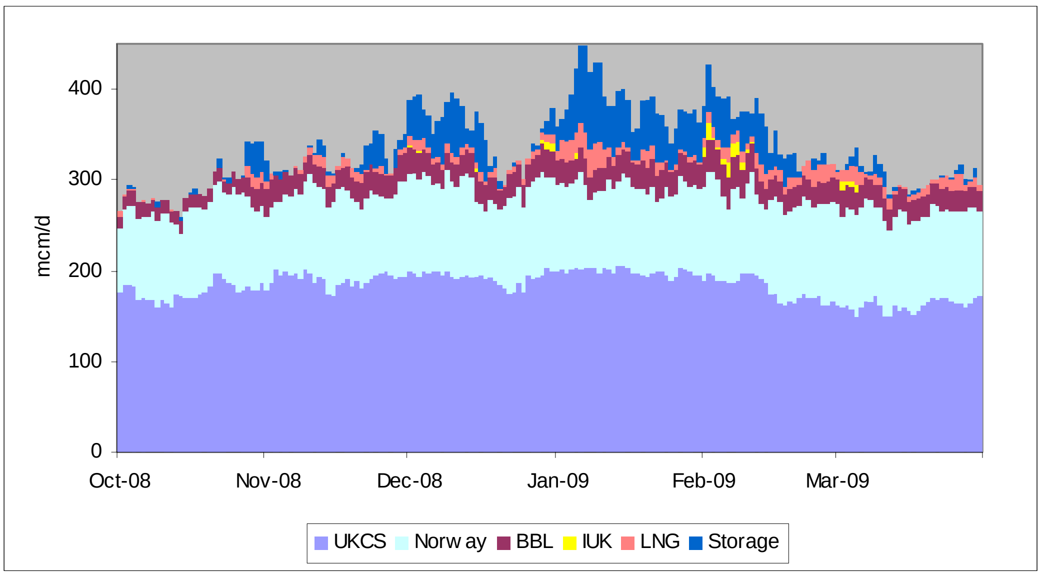
	2006/7		2007/08		2008/09	
	bcm	bcm	%	bcm	bcm	%
Bacton	12.1	21%	15.8	26%	13.9	23%
Barrow	1.7	3%	3.3	5%	2.1	3%
Grain	1.9	3%	0.7	1%	1.6	3%
Easington[3]	11.8	21%	12.8	21%	15.1	25%
Point of Ayr	0.3	1%	0.2	0%	0.1	0%
St Fergus	19.8	34%	18.9	31%	19.6	32%
Teesside	4.8	8%	3.7	6%	4.4	7%
Thed'pe	4.4	8%	4.3	7%	3.3	5%
Storage[4]	0.8	1%	0.8	1%	1.1	2%
Total	57.7		60.5		61.1	

[2] Includes estimates for Vesterled and Tampen
[3] Includes Rough
[4] Excludes Rough

62. Figure A.20 shows how the various gas supply sources were used in winter 2008/09 against actual demand. Each of these supply sources is considered in turn in the following sub-sections.

63. The highest day of supply was 448 mcm/d on 6th January, in aggregate there were 9 days of supply in excess of 400 mcm/d and 67 days in excess of 350 mcm/d. Average demand for the highest 100 days of demand was 365 mcm/d, just 3 mcm/d higher than in 2007/08.

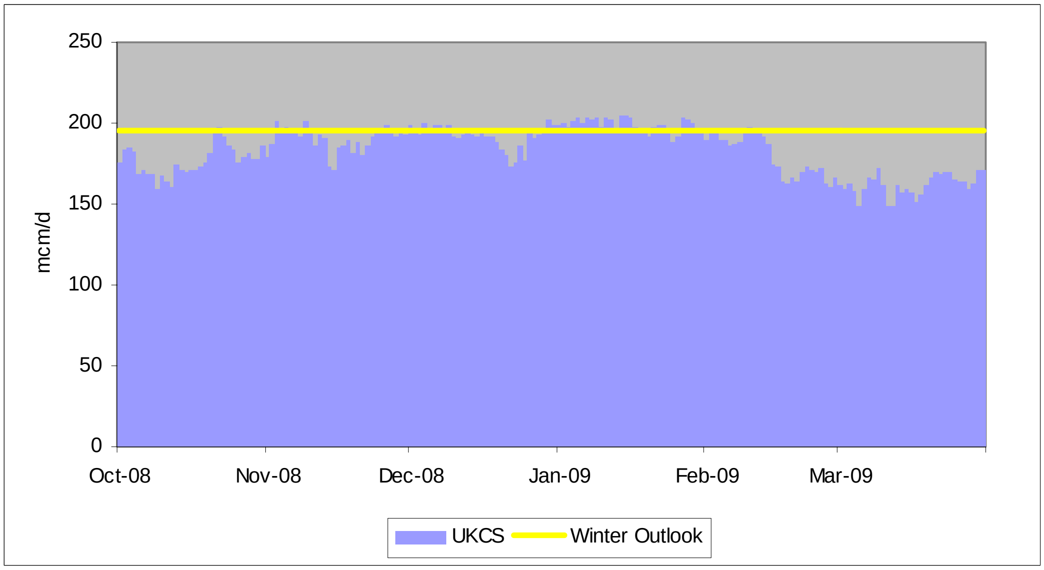
Figure A.20 – 2008/09 Supply Performance



UKCS Supplies

64. Our aggregated forecast for UKCS supplies for last winter was 216 mcm/d, this was 11% lower than our forecast for the previous winter. For operational purposes we assume 90% availability for UKCS supplies, resulting in an operational forecast of 195 mcm/d, this forecast is also used in setting the Safety Monitors. Figure A.21 shows flows from the UKCS last winter and our operational forecast.

Figure A.21 – 2008/09 UKCS Supplies



65. The chart shows that for most of the winter UKCS supplies were very steady and in line with our operational forecast. Only during the milder weather of October and mid February to March and during the lower demand associated with the Christmas period did the UKCS flow at lower levels. This also highlights that for most of last winter the high swing fields associated with Barrow and at Bacton Shell-Esso were probably flowing.

66. Average flows from the UKCS across the 6 month winter period were 183 mcm/d and for the 100 days of highest demand 192 mcm/d. Table A.3 shows the 2008/09 Winter Consultation Base Case peak forecast of UKCS supplies by terminal and the actual terminal supplies for the day of highest UKCS supplies (15th January 2009) and the highest day for each terminal.

Table A.3 – 2007/08 UKCS Supplies by Terminal

Peak (mcm/d)	Forecast	Actuals	
	Base Case	Highest UKCS	Highest Terminal
Bacton	66	62	66
Barrow	17	17	18
Easington	13	9	14
Point of Ayr	1	0	4
St Fergus[5]	78	75	80
Teesside	23	23	30
Theddlethorpe	18	19	21
Total	**216 (195)**	**205**	**232**

[5] Excludes estimates for Vesterled and Tampen

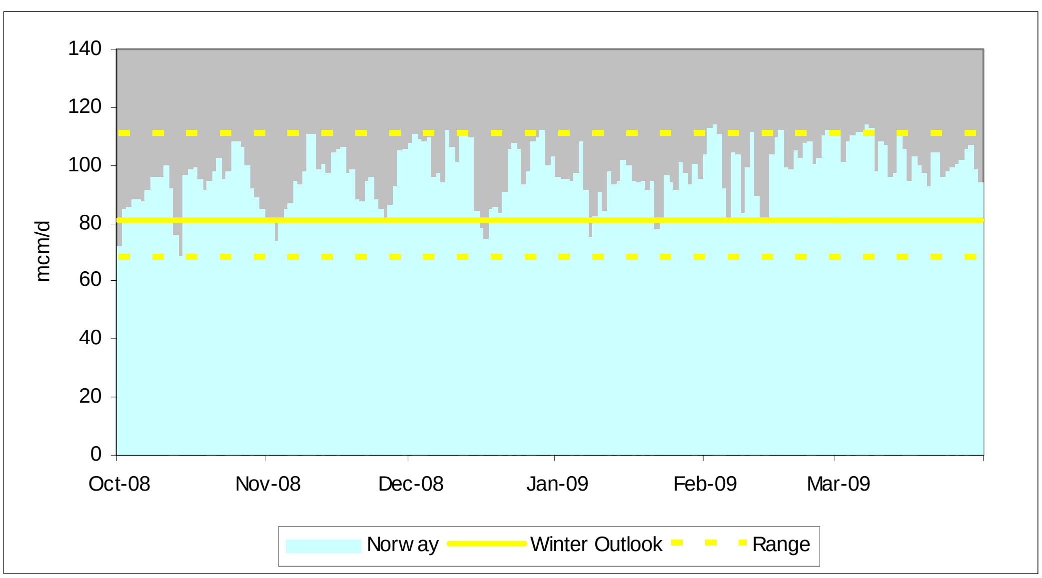
67. The table highlights that the day of highest UKCS supplies of 205 mcm/d was below the forecast of 216 mcm/d but above the operational forecast of 195 mcm/d, this together with flows for the 100 highest demand days (192 mcm/d) are the most suitable benchmarks for this forecast. A comparison of our 216 mcm/d forecast should be made against the aggregated highest terminal flows (232 mcm/d). This is well aligned to every terminal forecast except Teesside and Point of Ayr where actual flows on occasion were higher due to local power stations not taking 'direct' gas. Hence in summary, our UKCS forecast for last winter was very robust.

Norwegian Imports

68. Our forecasts for Norwegian imports to the UK for winter 2007/08 were subject to numerous uncertainties including increased Norwegian production from Ormen Lange, contractual obligations and transportation options regarding delivery to the Continent in Germany, France and Belgium. To capture this uncertainty we produced a Central View of Norwegian flows to the UK (81 mcm/d) and a range (68-111 mcm/d) based on high flows to the Continent (thus low UK flows) and low flows to the Continent (thus high UK flows).

69. Figure A.22 shows Norwegian flows through Langeled and our aggregated estimates for Norwegian imports to St Fergus through Vesterled and the Tampen Link.

Figure A.22 – 2008/09 Norwegian Imports to UK

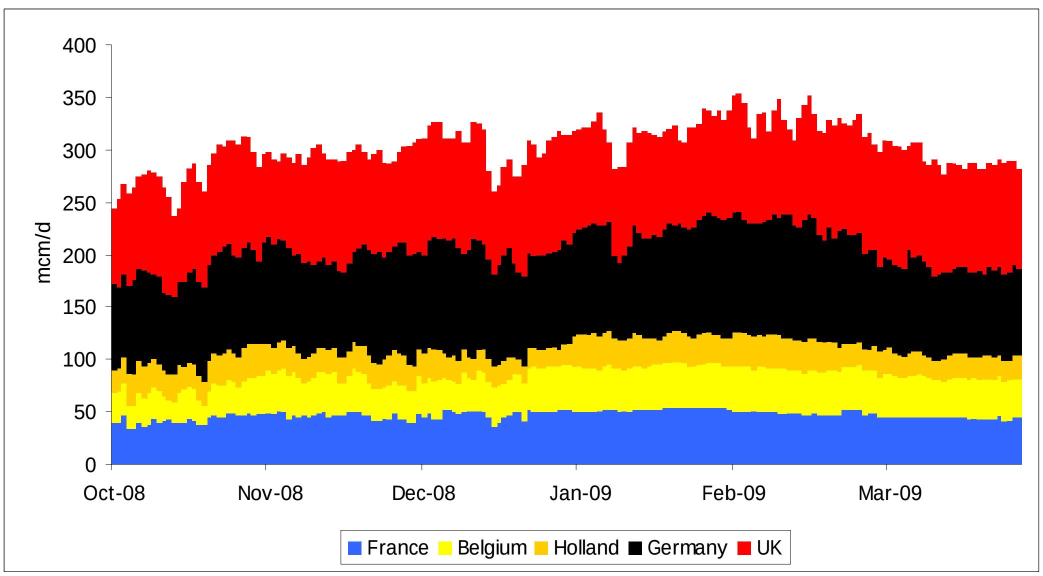


70. The chart shows that Norwegian flows were generally within our anticipated range and for most of the winter somewhere between our Central View and our high range. Average Norwegian flows across the 6 month winter period were 98 mcm/d within a range of 69 -114 mcm/d.

71. Besides the option to flow gas to the UK, Norwegian gas is also exported to Germany, France and Belgium. Publicly available flow data for Norwegian exports is now more complete than reported last year and daily flow information representing about 90% of daily import flows is now available from Zeebrugge (Fluxys data), Dunkerque (GRTgaz data), some of the flows entering Germany at Emden and Dornum and the UK[6]. In addition, Norwegian production data is reported on a monthly basis by the Norwegian Petroleum Directorate (NPD).

72. Figure A.23 shows our estimate of daily Norwegian exports to the UK and the Continent during winter 2008/09. The chart shows that Norwegian production tended to increase as the winter progressed before declining with the onset of milder weather from mid February. Our estimate for average flows was 302 mcm/d with peak flows estimated at approximately 350 mcm/d. Whist at times flows to the UK were reduced (possibly due to contractual commitments) this was far less than in the previous winter. A plausible explanation behind this was the high contractual price on the Continent compared to a lower priced NBP i.e. Continental buyers took less gas and as a consequence Norwegian flows towards the UK were higher.

Figure A.23 – 2008/09 Norwegian Exports to UK and the Continent



73. Table A.4 shows our estimate of winter Norwegian exports between 2006/7 and 2008/09. The table shows a further increase in Norwegian production last winter. This was primarily due to higher flows from Ormen Lange that more than offset lower production from Troll. As detailed previously, the table also shows reduced volumes delivered to the Continent with exports to the UK at an all time high.

[6] Langeled only

Table A.4 – Estimate of Norwegian Exports 2005/6 to 2007/08

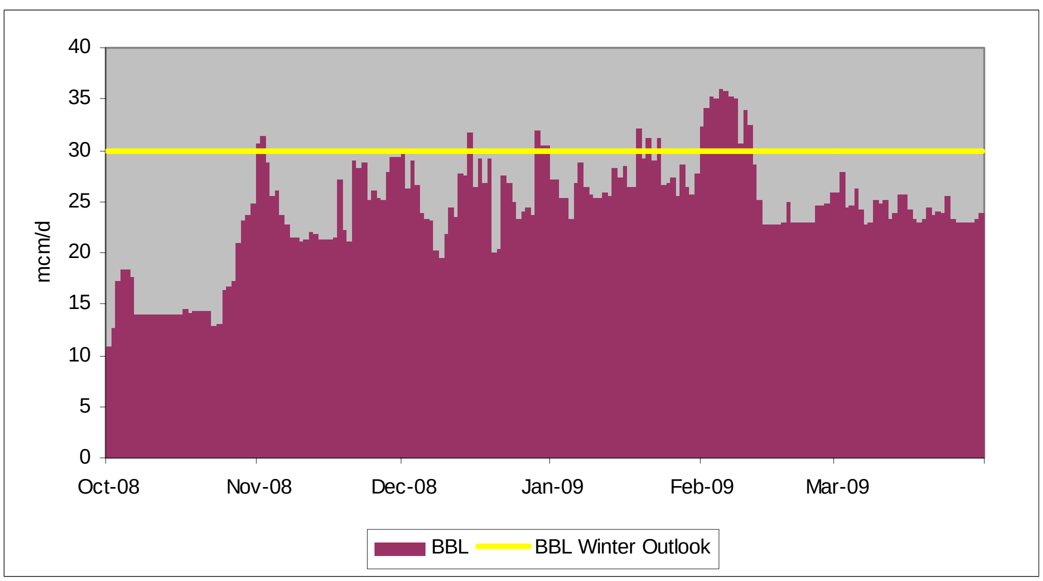
(mcm/d)	Capacity 2008/09	Winter 2006/7	Winter 2007/08	Winter 2008/09	2008/09 Utilisation
Belgium	41	33	37	37	90%
France	52	43	50	47	91%
Germany	151	108	130	121	80%
UK[7]	124	71	74	98	79%
Total	**368**	**255**	**292**	**302**	**82%**

Continental Imports - BBL

74. For winter 2008/09 we forecast that BBL flows to the UK would be relatively stable at 30 mcm/d. This was based on winter flows of the Gasunie Centrica contract and the possibility of additional flows from other shippers.

75. Figure A.24 shows BBL flows for winter 2008/09. Average flows between November and March were 26 mcm/d, marginally below our forecast. Compared to previous winters, flows through BBL showed greater variation though this variation was not necessarily related either to UK supply demand fundamentals or market prices.

Figure A.24 – 2008/09 BBL Imports to UK



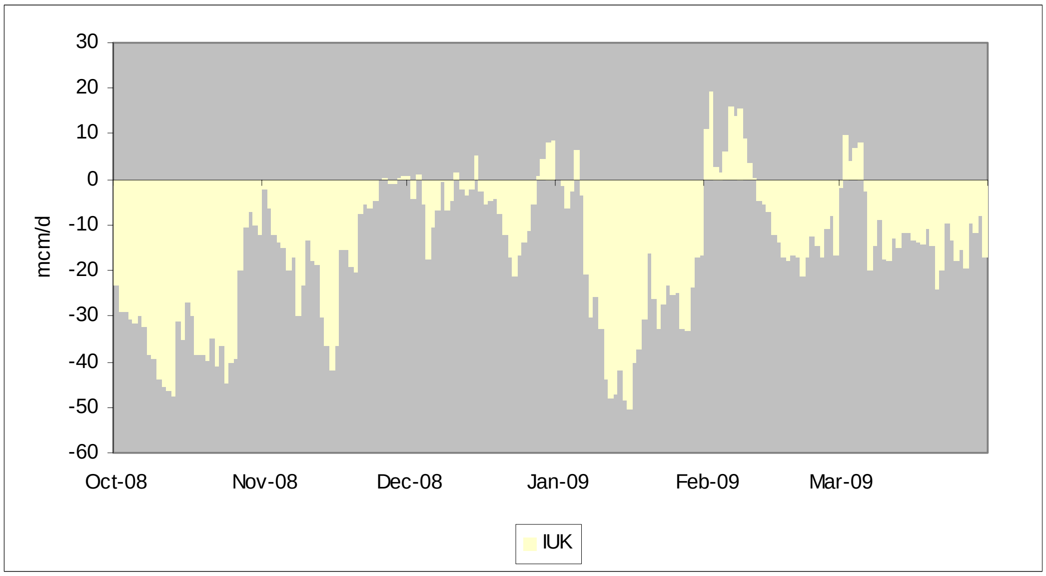
Continental Imports - IUK

76. For winter 2008/09 we forecast that IUK would operate as the marginal source of supply similar to storage when UKCS and other imports could not meet demand. We only assumed a peak flow of 20 mcm/d and stressed that IUK flows would be dependent on the availability of other supplies.

[7] Includes Tampen capacity assumed at 18 mcm/d, this will step up as FLAGS ullage increases

77. Figure A.25 shows IUK import and exports flows for winter 2008/09. In aggregate imports were just 0.2 bcm and exports 3.0 bcm. The highest flow for IUK imports was 19 mcm/d in early February.

Figure A.25 – 2008/09 IUK Imports & Exports



78. The chart for IUK is dominated by exports, for specific periods of the winter IUK responded to a series of conditions / events:

- During the period from October through to the end of December IUK exports gradually declined as UK demand and NBP prices generally increased. During this period the UK NBP price was believed to be well below the Continental contract price.
- In early January with high UK demand and higher NBP prices, IUK briefly went into import mode.
- This was short lived as the commencement of the Russia Ukraine dispute in January resulted in an extended period of exports with relatively little increase in the NBP price.
- In early February with the Russia Ukraine dispute resolved and high UK demand, IUK again reverted to imports
- In mid February with the onset of mild weather in the UK, the UK gas price fell dramatically. With NBP prices again believed to be well below the Continental contract price IUK again reverted to exports for the remainder of the winter period.

79. Whilst our peak forecast for IUK imports was briefly met, the concept that IUK would respond to UK market conditions was again challenged. Not for the first time, this highlighted that the UK could always be a source of supply to the Continent

(albeit at a price), but such market conditions for import flows are not yet fully reciprocal.

LNG Imports

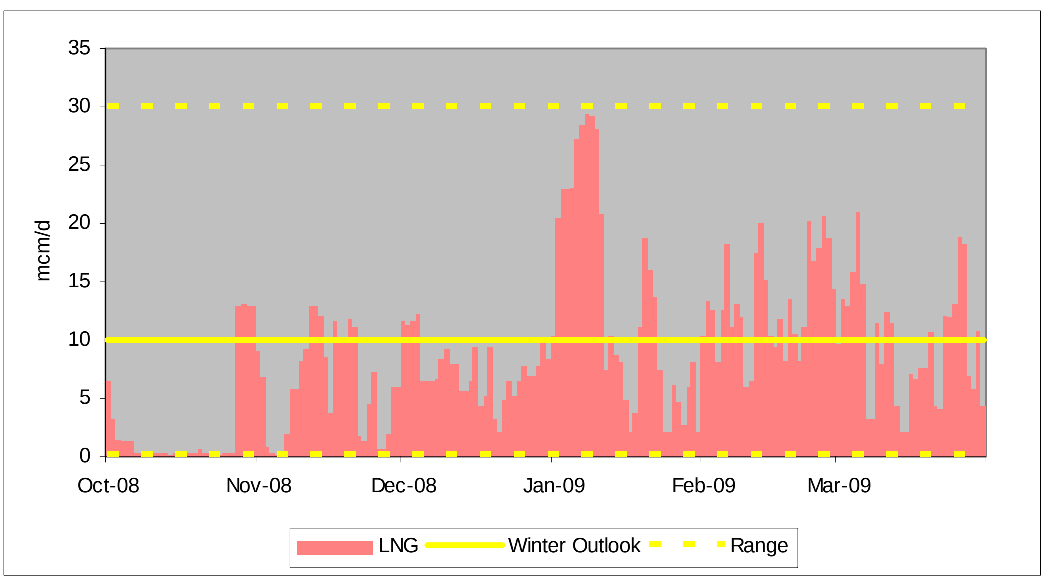
80. Our forecast for LNG imports for winter 2008/09 highlighted considerable uncertainties. These included further delays in commissioning for both Milford Haven terminals, commissioning of Grain II, delivery of spot cargoes to Teesside GasPort and global market conditions impacting deliveries to Grain I. To capture this uncertainty we assumed LNG imports of just 10 mcm/d but identified a range between 0 and 30 mcm/d.

81. During the winter our cautious view for LNG imports were realised, as whilst Grain II was commissioned in late December, neither Milford Haven terminals were commissioned and there were no LNG deliveries through Teesside GasPort.

82. Figure A.26 shows LNG imports through Grain. From November onwards Grain received regular cargoes of LNG and post November flows averaged 10 mcm/d with a peak flow of nearly 30 mcm/d. The chart clearly shows the impact of Grain II in early January at the start of the Russia Ukraine dispute.

83. One of the reasons for more LNG cargoes to Grain was falling gas demand in both the Far East and the Continental markets. With low US gas prices, Grain was an obvious choice for importers. Indeed, these conditions have subsequently continued even with a much lower UK gas price.

Figure A.26 – 2008/09 Grain LNG Imports

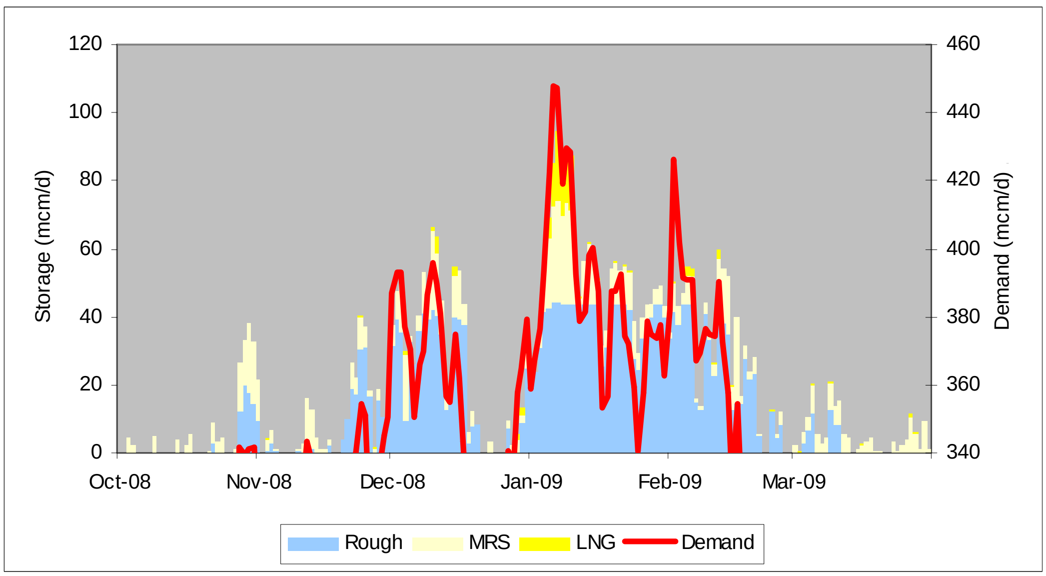


2008/09 Storage Performance

84. Our forecast for storage for winter 2008/09 again included the possibility of some flows from the Aldbrough salt cavity facility. This was expected to become partially operational during the winter. For the Safety Monitor assessment, we excluded Aldbrough from our forecasts.

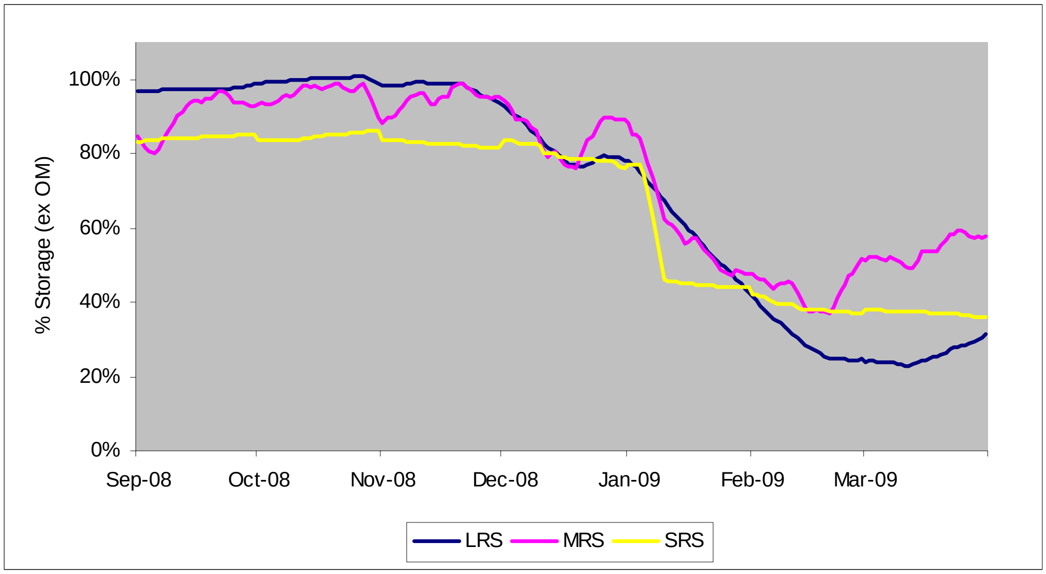
85. Figure A.27 shows storage withdrawals over the winter in terms of Rough, MRS and LNG storage. The chart also shows demand on a similar albeit offset scale (based on our forecast for non storage supplies) to highlight the close relationship between storage withdrawals and demand.

Figure A.27 – 2008/09 Storage Withdrawals



86. The above chart does not highlight the decay of storage stocks, notably LNG and MRS as a consequence of relatively high use in January. This is shown in Figure A.28 that shows % storage stocks (based on highest stocks recorded less Operating Margins)

Figure A.28 – 2008/09 Storage Stocks



87. Table A.5 details storage space, storage withdrawals and storage injection during the winter. The table highlights the relatively high use of all storage types including LNG. The table also shows high levels of storage cycling, notably for MRS sites. Rough is also shown to have relatively high levels of injection however only 80 mcm of this was between December and mid February during the Christmas period.

Table A.5– 2008/09 Storage Utilisation

	Reported Space (mcm)	Withdrawal (mcm)	Injection (mcm)	Reported Deliv. (mcm/d)	Highest Deliv.[8] (mcm/d)
Rough	3281	2751	545	42	44
MRS[9]	907	984	859	49	32
LNG	203	122	12	49	33

2008/09 Operational Overview

88. Over the course of any winter period National Grid NTS puts into action robust processes, procedures and strategies to aid in the safe, reliable and efficient operation of the NTS. This section is designed to provide an insight into the issues

[8] Aggregated by site
[9] Includes an allowance for Aldbrough

that impacted system operation during last winter and includes detail regarding some of the operational measures.

Interruption

89. Winter 2008/09 required no transporter or emergency interruption to customers supplied directly from the NTS. Although shippers may call interruption at NTS sites, National Grid has little visibility of this and relies on notification of interruption from shippers.

Network Infrastructure

90. The final sections of the Trans Pennine pipeline, from Asselby to Pannal and Easington to Ganstead, were completed for winter 08/09 adding an extra 94 km of 1200 mm pipeline to the NTS operating at pressures up to 75bar. The entire investment scheme reaching from Easington in the East to Nether Kellet in the West alleviates pressure constraints in the Easington area.

91. The South West Reinforcement Project extended the NTS from Kenn near Exeter to Choakford near Plymouth. The new 63 km pipeline was built following investment drivers to deliver offtake capacity for the new Langage power station near Plymouth and includes 2 DN offtakes and an industrial offtake in addition to the feed for Langage.

92. Additionally, 25 km of pipeline between Aylesbeare and Kenn was duplicated to provide the extra necessary transmission capability required for these new demand sites

93. Feeder 9 was extended by 31 km to provide the additional capacity required for the new Marchwood power station

94. To provide additional capacity at Isle of Grain ASEP, Feeder 18 has been duplicated from Grain to Shorne and Gravesend.

Capacity Management

95. To ensure firm entry rights can be honoured, scaling back of interruptible rights occurs when notified or anticipated inputs outstrip firm rights and/or NTS capability. Buy Backs are undertaken if it is necessary to bring aggregate daily firm holdings within the physical capability of the NTS to protect its integrity.

96. The concept of being able to restore interruptible rights was introduced in time for Winter 2008/09. This allows National Grid scope to restore previously scaled interruptible rights if conditions allow.

97. For Winter 2008/09 it was necessary to initially scale back 100% of interruptible capacity for one day in December 2008 at Easington. The interruptible capacity was fully restored effective from 14:00 hrs. No further scale backs occurred at any entry points within the Winter 2008/09 period.

Transfer and Trades (T&T)

98. In April 2008 UNC MOD 187a "Alterations to the RMSEC Auction to Accommodate Transfer and Trade of Capacity between ASEPs" was approved by Ofgem with effect from 1st of June 2008. The modification introduced an enduring Transfer and Trade regime to facilitate the trade and transfer of firm capacity at and across ASEPs on a monthly basis.

99. Table A.6 shows the impact (both decreases and increases) on the firm release obligation of ASEPs as a result of transfers between ASEPs for the Winter 2008/09 months.

Table A.6 Trade and Transfer Impact on Firm release obligation

GWh/d	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09
Easington	-	9.8	83.1	102.3	42.2	17.3
Hatfield Moor Storage	-	9.7	7.4	7.5	7.5	6.8
Hornsea Storage	-	-	-5.3	-	-2.8	-
Theddlethorpe	-	-19.5	-85.3	-109.8	-46.8	-24.1
Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Discretionary release of Firm capacity

100. UNC MOD 216 was approved by Ofgem effective from August 2008. The modification enabled National Grid to release firm capacity outside of the normal auction mechanisms by holding Discretionary System Entry Capacity (DRSEC) auctions as and when required.

101. In Winter 2008/09 three DRSEC auctions were held making available firm capacity at several ASEPs for the winter months. The quantity of firm capacity released via the DRSEC in response to User demand is detailed in table A.7.

Table A.7 Quantities of Discretionary Firm Entry Capacity sold

GWh/d	Month	Baseline	Non Obligated
EA	Nov-08	0.0	53.9
EA	Dec-08	0.0	108.3
EA	Jan-09	0.0	136.3
EA	Feb-09	0.0	137.2
EA	Mar-09	0.0	85.5
HT	Dec-08	2.9	0.0
HT	Jan-09	8.8	0.0
HT	Feb-09	5.9	0.0
HT	Mar-09	2.9	0.0

102. The DRSEC capacity was largely sold as non-obligated at Easington. This capacity was made available due to the early delivery of infrastructure which was in place for much of the Winter 2008/09 period.

Discretionary release of Interruptible capacity

103. Under UNC Modification 159 National Grid has the option of releasing interruptible capacity at its discretion. This was intended to assist National Grid in maximising the capacity offered and utilised at an ASEP.

104. A number of criteria need to be fulfilled before this interruptible capacity is released. Available capacity at an ASEP would need to be utilised prior to additional capacity being released. During Winter 2008/09 Easington was the only supply point that qualified for discretional Interruptible capacity release. Table A.8 shows the maximum amount of additional discretional interruptible capacity released at Easington in Winter 2008/09.

Table A.8 – Maximum Release of Additional Discretional Interruptible Capacity

GWh/d	Nov	Dec	Jan	Feb	Mar
Easington	154.7	158.2	81.1	240.2	376.1

Questions for consultation

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

QA1. *We welcome views on the contributing factors behind the reduction in gas demand and are these likely to be permanent?*

QA2. *What proportion of this reduction in weather corrected gas demand is due to consumer behaviour such as turning down the thermostat and what proportion is due to long-term efficiency measures such as loft insulation and condensing boilers?*

QA3. *Are the changes in consumer behaviour a temporary response to high prices and the credit crunch or a long term response to climate change?*

QA4. *We welcome views on our assessment of UKCS supplies and in particular our view that for the majority of the winter most UKCS supplies were operating at or near maximum flow.*

QA5. *We welcome views on our assessment, that high Norwegian flows were delivered to the UK due to Continental buyers taking less gas due to high prices*

QA6. *We welcome views on the drivers behind BBL flows*

QA7. *We welcome views on the ability of the UK to provide a source of gas for exports to the Continent and to what extent these arrangement for UK imports are reciprocated, also would IUK have imported more if the UK gas price was higher*

QA8. *Were global gas markets responsible for higher LNG import flows?*

QA9. *What were the key drivers behind storage use this winter. At the time of the Russia Ukraine dispute was storage used to sustain IUK exports?*

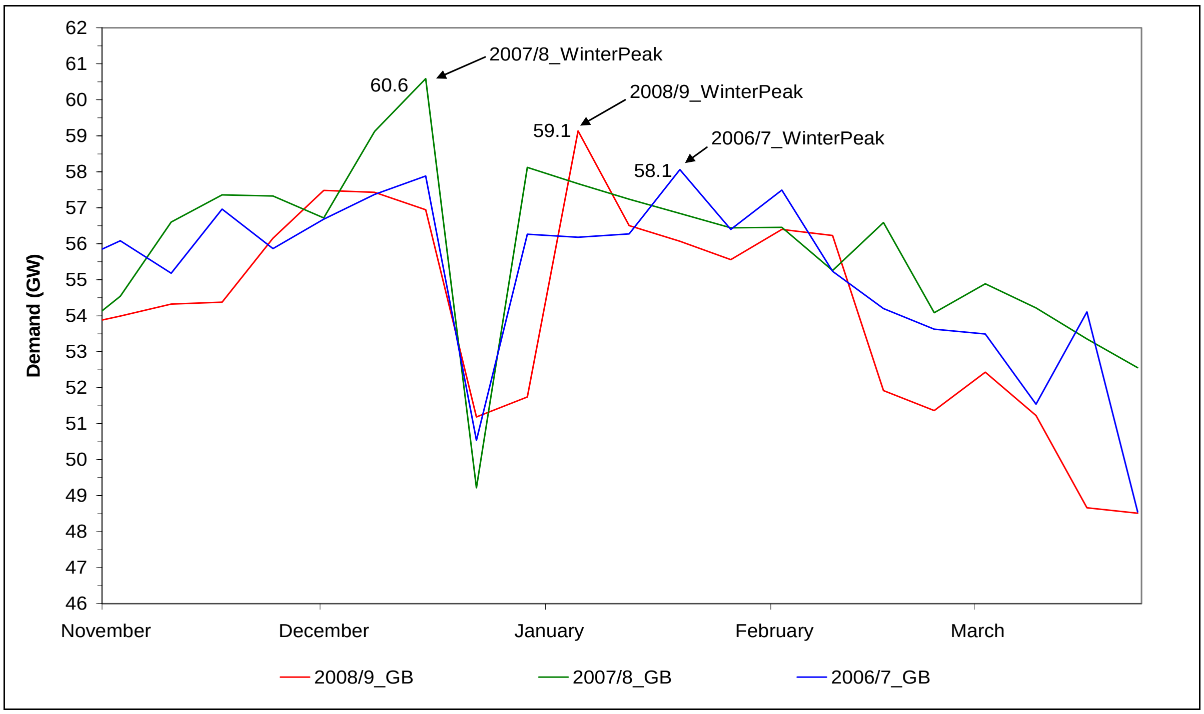
Electricity

2008/09 Electricity Demand

105. Unless otherwise stated, demand discussed in this report excludes any exports to France and Northern Ireland. There is discussion of exports to France and Northern Ireland later in this section.

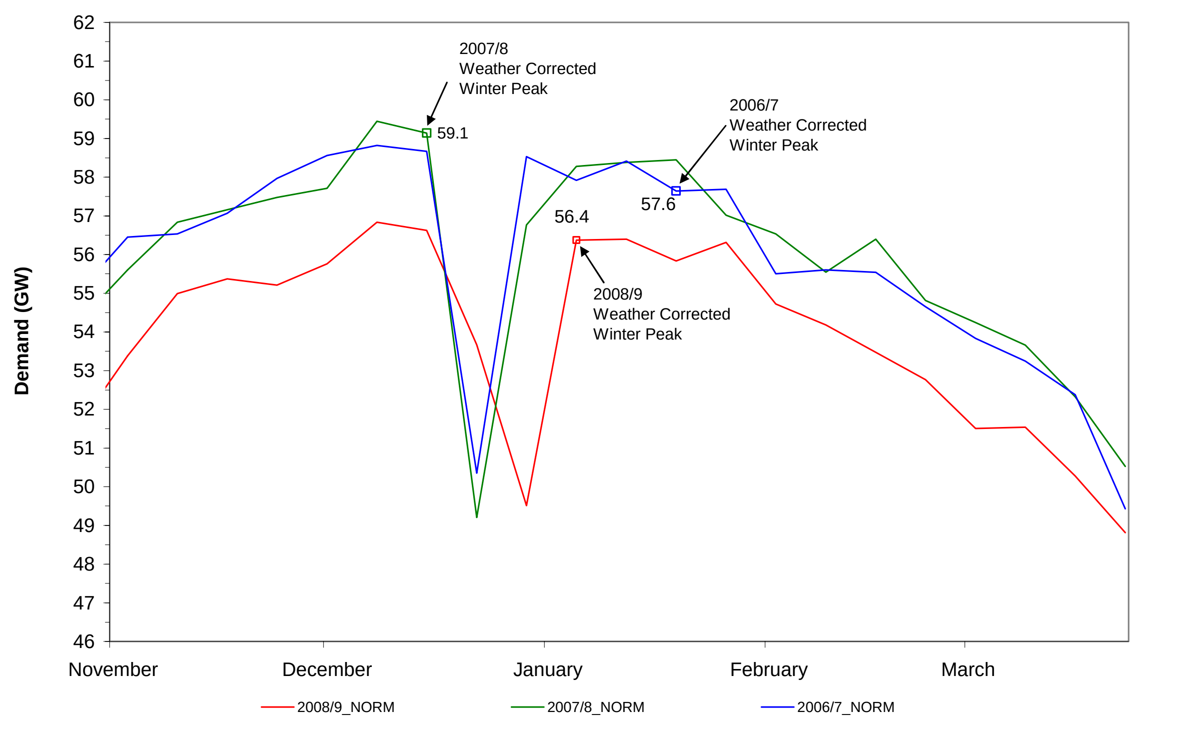
106. The highest electricity demand over the winter reached 59.1GW for the half-hour ending 17:30 on 6th January 2009. This compares to the highest demand of 60.6GW and 58.1GW over winter 2007/08 and 2006/07 respectively. This is shown in Figure A.29.

Figure A.29 – Weekly Peak Demand for the Last Three Winters



107. We have corrected outturn demands for weather to observe underlying demand trends under average weather conditions, based on a 30 year average. Figure A.30 below shows normalised weekly peak demands for 2008/09 (red), 2007/08 (green) and 2006/07 (blue) for comparison.

Figure A.30 – Weather Corrected Weekly Peak Demand for Last Three Winters



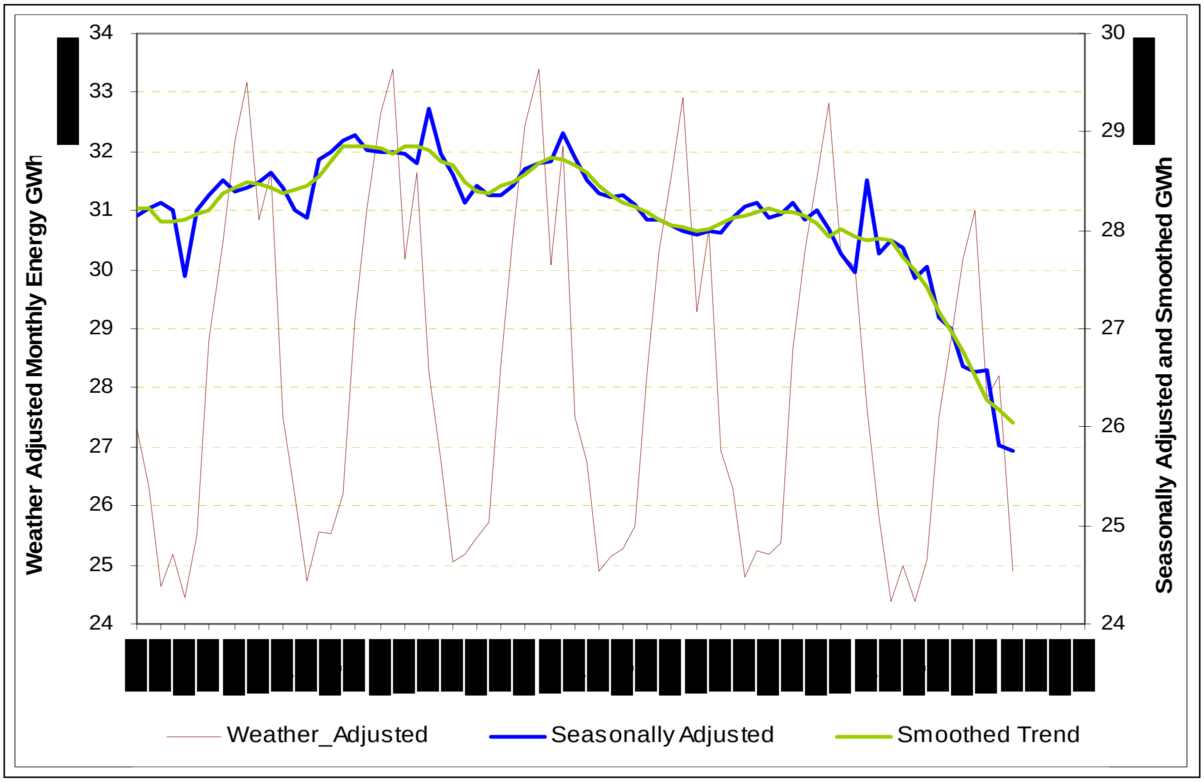
108. Weather corrected weekly peak demand indicated that winter peaks would have happened two weeks before Christmas for the last three winters had the weather been normal for the time of year. The actual outturn peak demand of 59.1 GW for 2008/09, experienced post New Year during a cold snap was 56.4 GW, when corrected to normal weather conditions. The actual outturn weather corrected peak demands for winter 2007/08 and 2006/07 were 59.1GW and 57.6 GW respectively. The graph clearly shows that the underlying demand in 2008/09 was much lower than the previous two years. The demand reduction was 2.0GW on average at each weekly peak except Christmas and New Year weeks due to non-alignment of bank holidays.

109. At the actual outturn demand peak we estimate that there was around 0.8-1.3 GW of demand management as large customers reduced demand to avoid Transmission Use of System Charges. The amount of demand side response is difficult to measure so we estimate it. It is likely that the current economic slowdown had an impact on the amount of demand side management, as a number of end-users we believe undertake this type of action have either reduced their demand or have ceased production, either temporarily or permanently.

110. Figure A.31 shows the seasonally adjusted demand trend over the last 6 years. The graph indicates a general reduction in demand from 2005. The steepest descent coincided with the economic recession and started in the last two quarters of 2008 when UK economic growth became negative. The decline for the pre-

recession period is due to a combination of factors including the growth in generation embedded in distribution networks, response to high energy prices and more efficient use of energy.

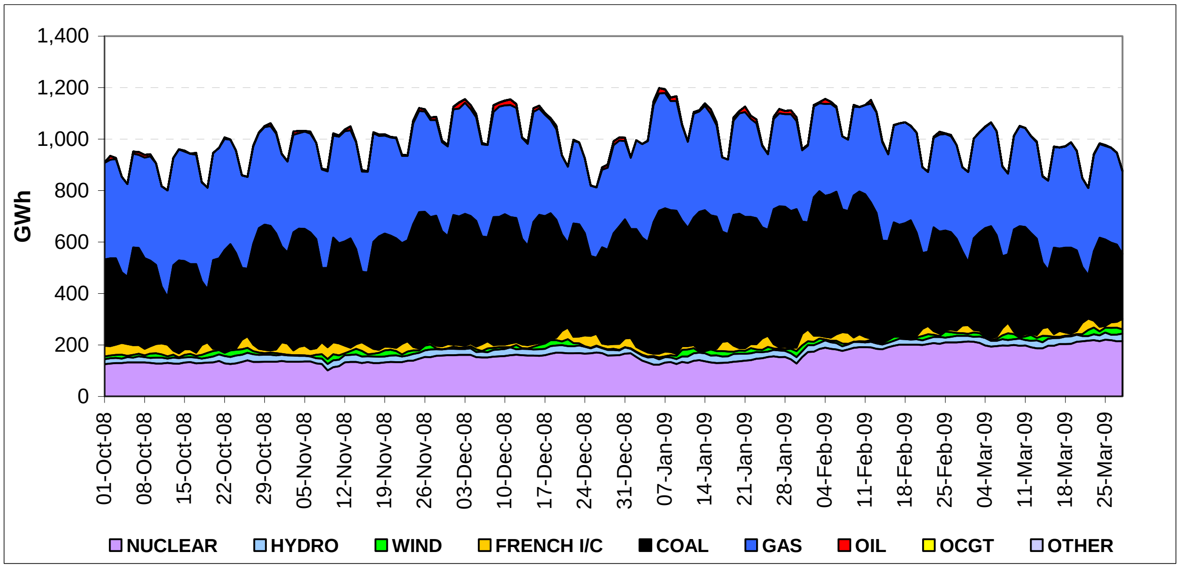
Figure A.31 – Weather and Seasonally Corrected Energy Demand



2008/09 Electricity Generation Capacity

111. Figure A.32 shows the actual 2008/09 generation mix. Between mid-November and mid-February coal was providing a greater proportion of the total generation than gas. This corresponds to a period of higher gas prices. Outside this period, gas-fired generation was a greater percentage of the total than coal. Oil fired generation was running on most week days over the winter and even on a number of weekends. The GB-France interconnector contributed a similar total volume to the previous winter but the daily energy imported was more varied between zero and maximum. As winter progressed we saw the return of several nuclear generation units which is reflected in the gradual increase in the volume of energy coming from nuclear generation.

Figure A.32 – 2008/09 Generation Mix by Fuel Type



112. A more detailed view of the amount of electricity generated by wind is shown in Figure A.33. This data is based on the wind farms that are currently visible to National Grid through operational metering. These wind farms have a total capacity of approximately 1487 MW. The output varied between 3 MW and 1180 MW with an average of 436 MW. This gives an average load factor of 29% over the period. From a security of energy supply perspective the key issue is the uncertainty and variability of output and the average load factor is of limited use. What can be observed from the data below is two periods of low wind output over several days in early November 2008 and early January 2009. Both of these periods were relatively cold for the time of year and coincided with relatively high electricity demands.

113. Figure A.34 highlights that at the times of peak electricity demand over the last three successive winters wind power output has been relatively low compared with average load factors. Because of this issue we have undertaken further work with Edinburgh University to identify a capacity credit approach using a risk based approach which we outline later on in this report and propose to move to on an ongoing basis.

Figure A.33 – 2008/09 Half Hourly Average Wind Generation

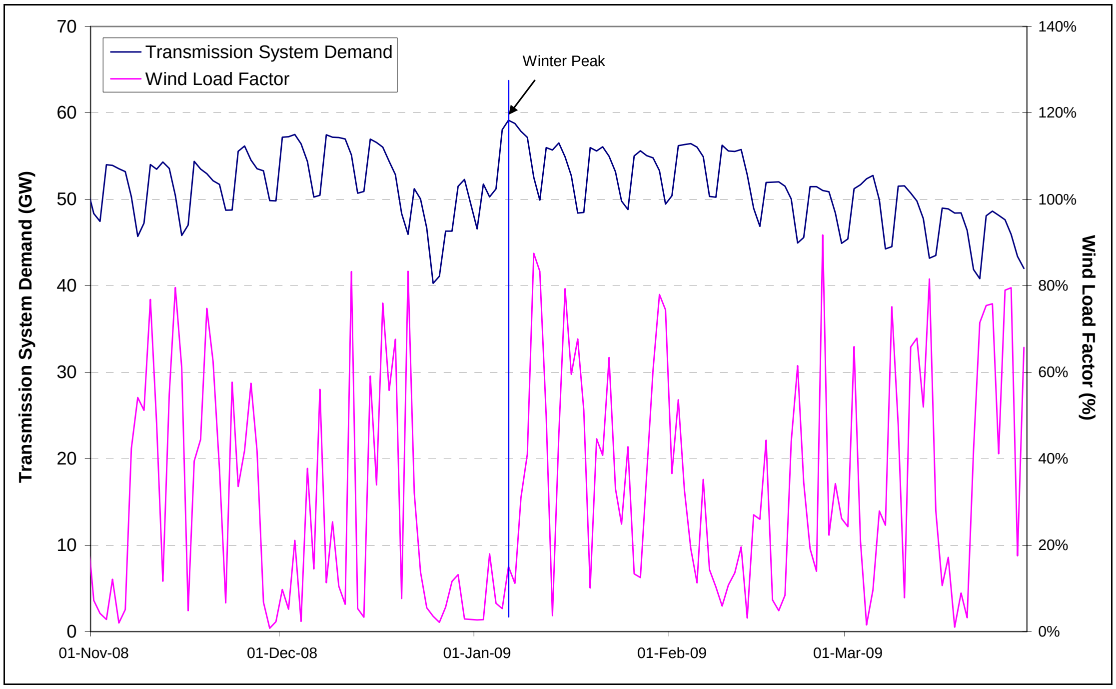
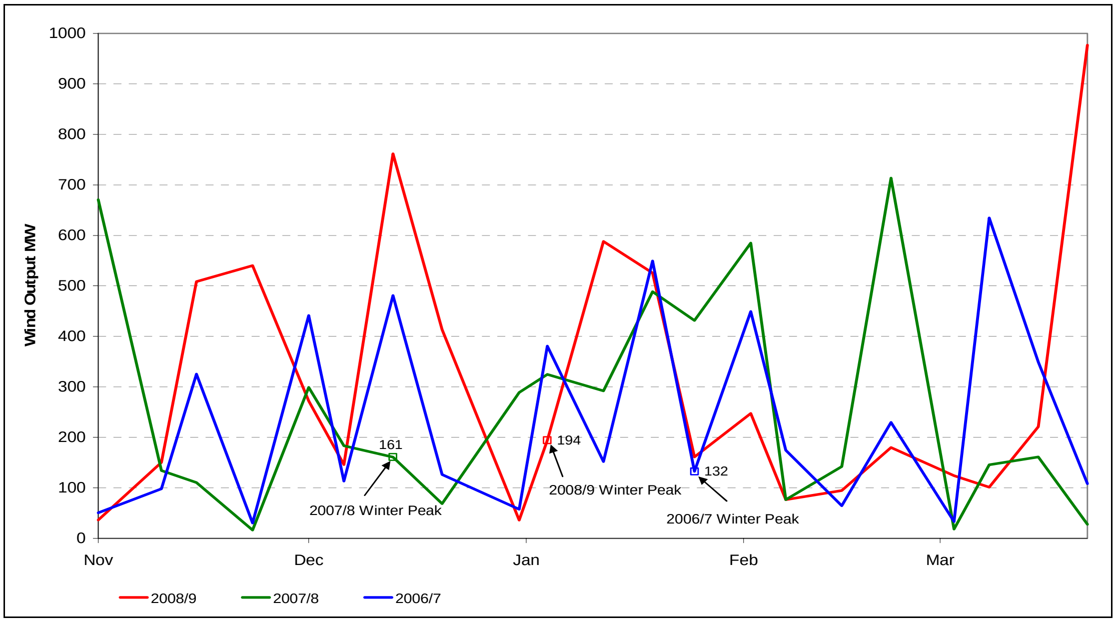


Figure A.34 – Wind Generation at Weekly Demand Peak for the last 3 Years



114. Table A.9 gives a summary of wind power generation volumes as operationally metered by National Grid for the last three winters. The volume of wind power generation itself is not particularly a key metric for us from a system operation

perspective itself, but here it is a useful indicator of the growth in the impact of wind power with its inherent uncertainty and volatility. This illustrates what is becoming more of a feature for us in managing electricity security of supply.

Table A.9 Wind Generation Volumes Over Winter 2008/09

	Wind Generation GWh	% increase on prior year
2006/7	1031	
2007/08	1097	+6%
2008/09	1549	+41%

115. We have also reviewed our assumed availabilities against the actual availabilities for each type of generation at the winter demand peak that we had assumed for last winter. Table A.10 shows the results of this analysis against the central and low cases we adopted for last winter.

116. We treated our low case as our likely outturn case as winter progressed and it became increasingly likely that nuclear generation was unlikely to return in time to contribute to meeting the winter peak. The main facets of the low case were lower availability assumed from nuclear generation and zero wind generation output at the time of demand peak. The outturn availabilities for nuclear at 51% were lower still than our low case scenario of 65%. Gas fired generation were lower than the low case scenario by 4% of availability, but they were balanced out by higher availabilities for coal, oil and hydro. Wind generation output was at 13% at the time of the demand peak, ahead of the 0% assumption we made in the low case but once again as last year this strikes a cautionary note for energy planning and operational security of supply as wind output can be and often is low at the time of highest energy demand. The overall plant availability turned out to be 83% at the time of the winter peak, which was in line with our low case scenario. The low case was 3 percentage points of total capacity below the central case.

117. Note that for wind and hydro generation in table A.10 that the basis of assumed availability is different to that for other fuel types as it is actual load factor at the time of the demand peak and not technical declared availability as in both cases availability of input energy to the generation is a more limiting factor. In turbine availability terms we expect that wind turbine technical availability was in the high ninety percentage level range, but this has very little significance if the wind is not at a speed where they can generate at full output.

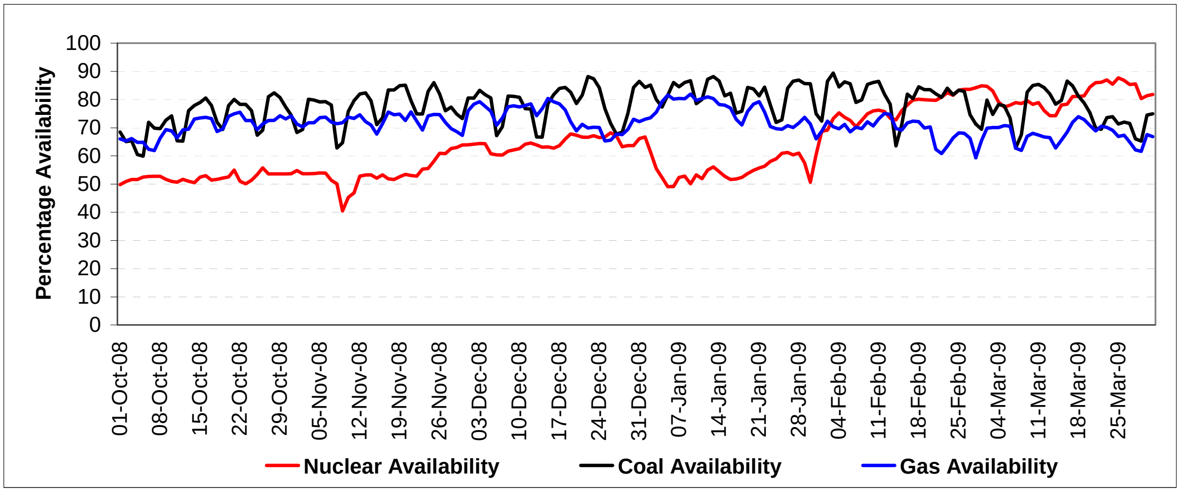
118. The four nuclear units (two units at each of Hartlepool and Heysham) that were out of service in the previous winter due to problems with the Boiler Closure Units were still out of service at the time of the winter peak. Announcements were made by British Energy about the return dates of these generation units. The first unit did not return until late January 2009 and the last was not back in service until mid March 2009.

Table A.10 – 2008/09 Assumed and Actual Availability of Generation Plant

Power Station Type	Assumed Availability at Demand Peak (Central case)	Assumed Availability at Demand Peak (Low case)	Actual Availability at Demand Peak
Nuclear	80%	65%	51%
French Interconnector	100%	100%	100%
Hydro generation	60%	60%	92%
Wind generation	35%	0%	13%
Coal	85%	85%	92%
Oil	95%	95%	97%
Pumped storage	95%	95%	98%
OCGT	95%	95%	77%
CCGT	90%	90%	86%
Overall	86%	83%	83%

119. The outturn availabilities over the course of the winter by main fuel type are shown in Figure A.35. These can be compared with the availabilities at the winter peak shown above. The chart shows how the nuclear availability generally improved as the winter progressed, although there was a drop in nuclear availability in January. The availability of the coal fired plant remained reasonably consistent across the winter period and was generally higher than the gas fired plant. Gas plant availability was at its maximum just before and just after Christmas but began dropping off from the end of January. The increase in availability in January of gas generation was probably due in a substantial part to lower nuclear availability. At that time gas was more marginal than coal and hence had relatively more unused capacity at the time of the lower nuclear availability and so the market switched from nuclear to gas fired generation.

Figure A.35 – Generation Availability by Main Fuel Types

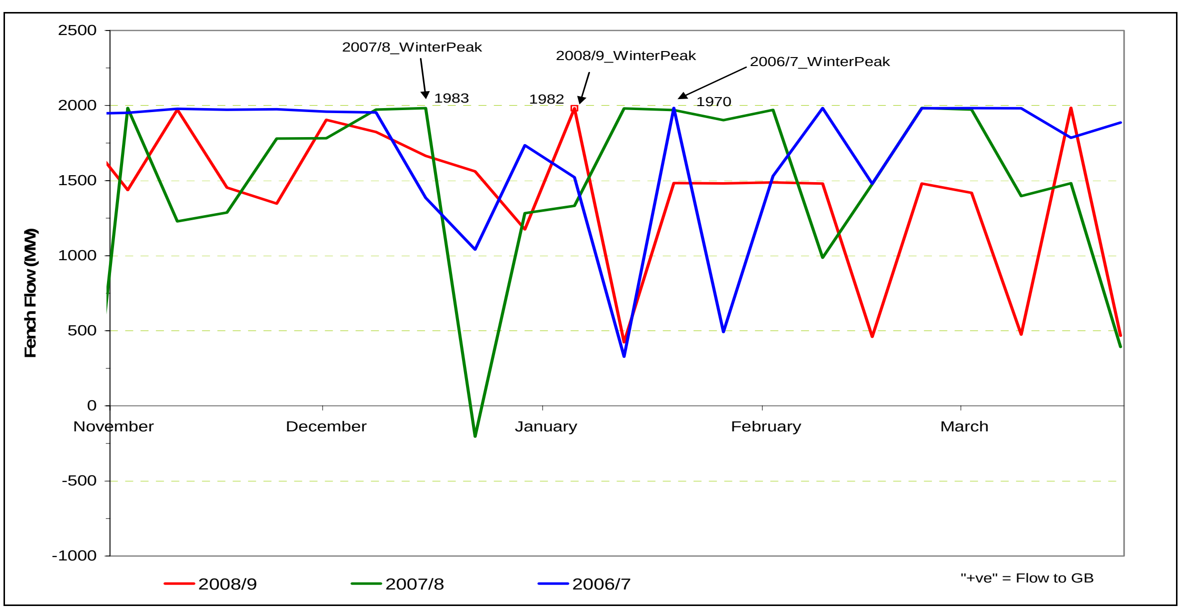


2008/09 Interconnector Flows

120. The GB market currently has two electricity interconnectors: one to France and one to Northern Ireland.

121. The GB-France interconnector can deliver up to 2 GW in either direction. Figure A.36 shows French interconnector actual flow for the last three winters at GB weekly demand peak. The graph indicates that the import level from France in the last three years during system peak demand half hours were very similar at close to full import.

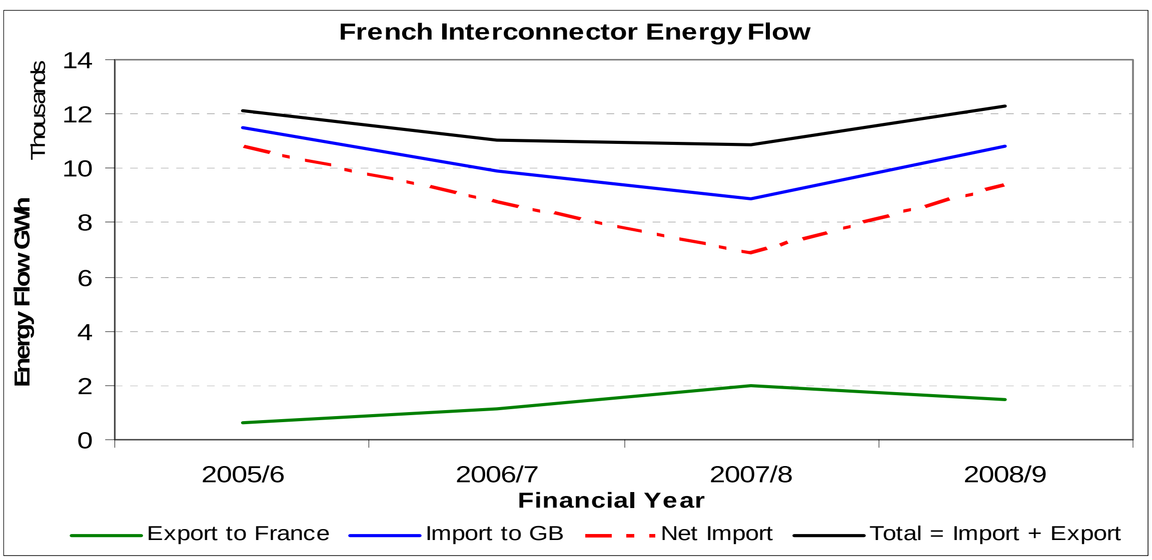
Figure A.36 – French Interconnector Flow at Weekly Peak Demand



122. We have also analysed the overall import/export situation for the interconnector. Figure A.37 gives a summary of the annual import/export energy exchange between France and GB since BETTA, including both natural market flows and actions taken by National Grid as system operator. Our actions impacting interconnector flow are relatively small in terms of overall energy so do not distort the market trends observed. The net import from France has reduced since BETTA, until last year and also seen a gradual reduction in gross total energy exchanged, again until the last year when gross energy volumes exchanged set a new post BETTA high level.

123. Recent improvements in the way system operator to system operator services are priced were introduced earlier this year so they are more cost reflective[10]. The improvements in cost reflectiveness are already leading to changes in the usage pattern of the interconnector for system management reasons. Overall we still see these changes that have already been introduced as neutral or positive for energy security of supply.

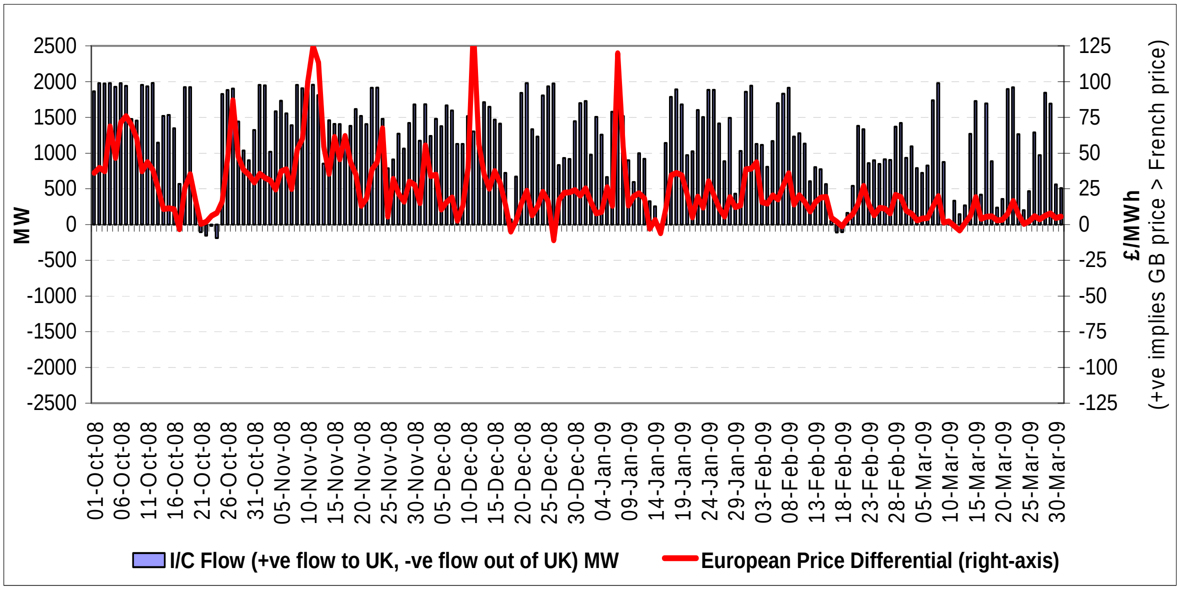
Figure A.37 – French Interconnector Annual Import/Export GWh since BETTA



124. For 2008/09 we have analysed the flow over the period of weekly peak GB demand and the relationship between this and GB to France power price differentials. Figure A.38 shows that during periods of power having a higher value in the GB market relative to France, we continue to see that power flows into the GB market. There are some developments in the commercial regime for the France to GB interconnector expected to take place later this year, outlined in more detail in Section D.

[10] See http://www.nationalgrid.com/NR/rdonlyres/ABA52106-0F74-402F-AF40-A88BBB9DB6A7/32187/Forum_Update_Newsletter_Feb2009.pdf for a fuller explanation.

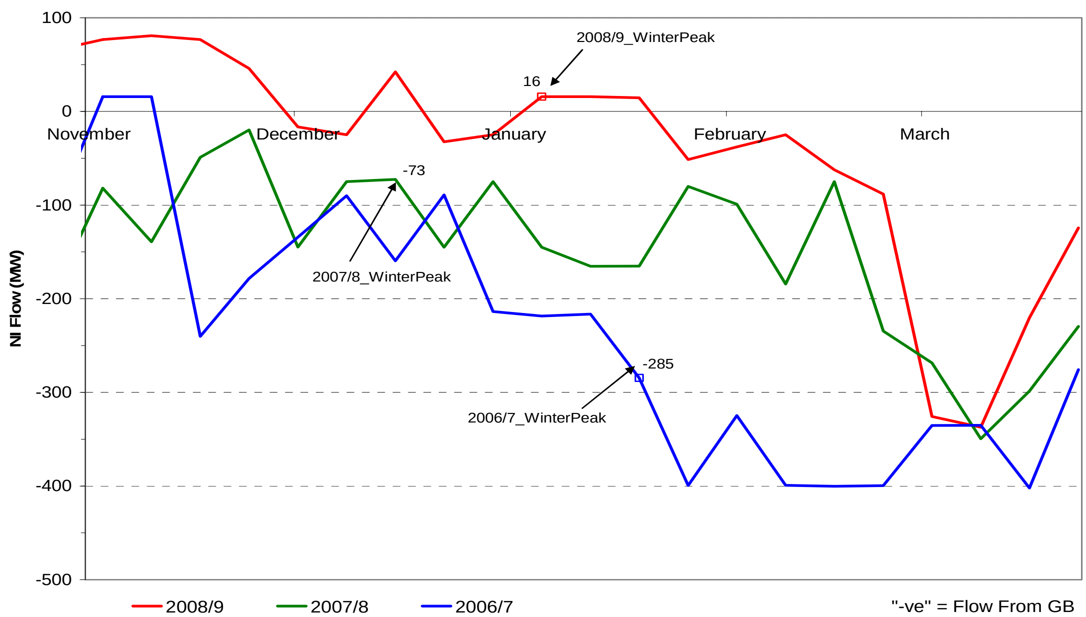
Figure A.38 – French Interconnector Transfers and European Price Differentials



125. The interconnector between GB and Northern Ireland (NI) is smaller than that between GB and France and has tended to predominantly export power from GB to NI, though this seems to have changed last year. The Moyle interconnector can physically flow 500 MW to NI and 500 MW to GB, though Transmission Entry Capacity (TEC) contractually limits the flow to GB to 80 MW whilst the flow to Ireland can be up to the technical capability.

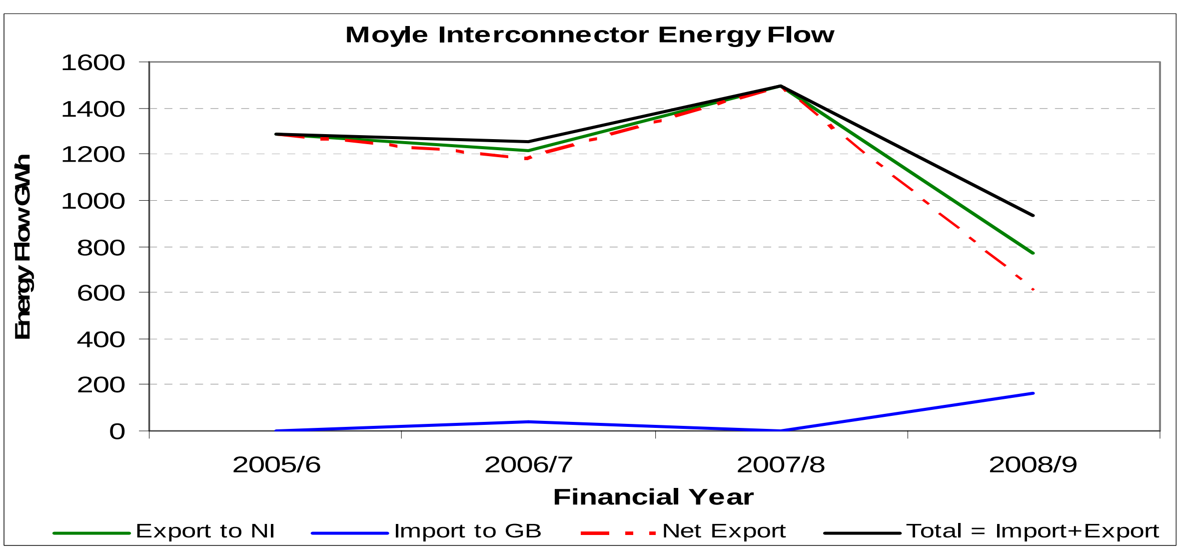
126. Historically, across the winter there has been an export from GB to NI of around 60-400 MW. However for the first time, GB imported 16MW from Northern Ireland at last year's system peak demand period instead of exporting as in previous years. This is shown in Figure A.39.

Figure A.39 – NI Interconnector Flow at Weekly Peak Demand for Last Three Winters



127. We examined the overall import/export situation for the Moyle interconnector. Figure A.40 gives a summary of the annual import/export energy exchange between Northern Ireland and GB since BETTA. The export from GB to NI had substantially reduced last year while the opposite happened to the import. The total energy volume was also significantly lower last year as a result. We had assumed for last winter that NI may require exports from GB at times of peak demand which tend to be correlated for both systems.

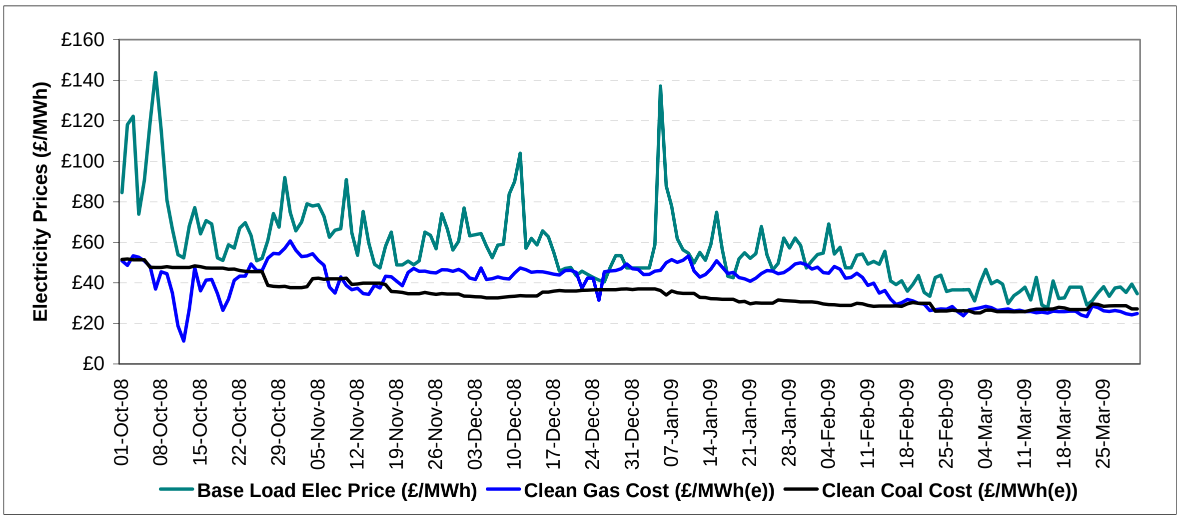
Figure A.40 – NI Interconnector Annual Import/Export Energy since BETTA



2008/09 Prices and Merit Order

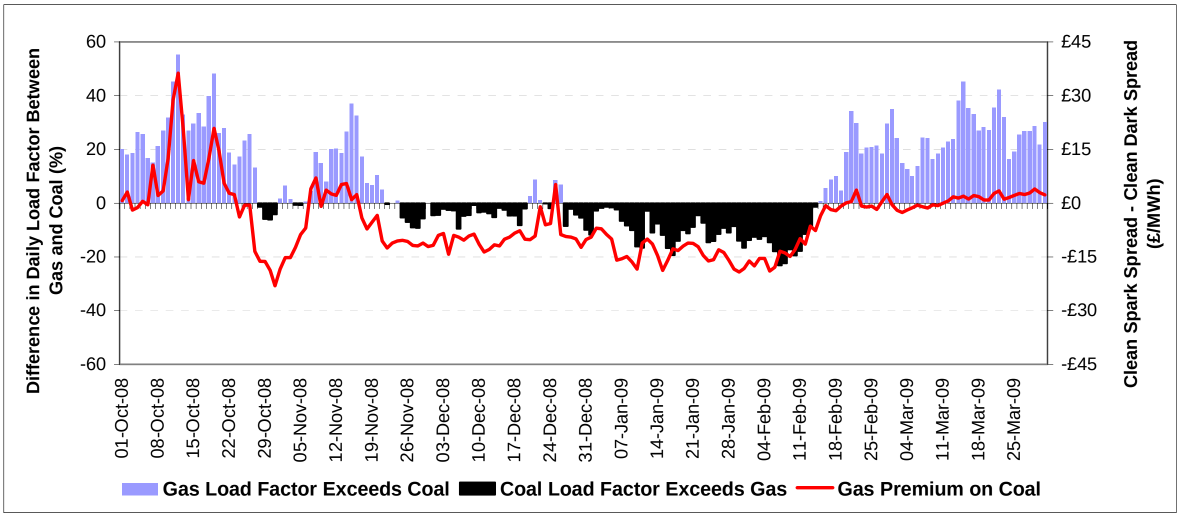
128. Day ahead baseload electricity prices were relatively volatile throughout the winter but the general trend though the period was for them to reduce, as can be observed in Figure A.41 below. Price spikes for baseload power correspond with periods of power market tightness due to higher demands for the time of year and/or short term reductions in generation availability.

Figure A.41 – Baseload Electricity Prices and Clean Gas/Coal Costs



129. Analysis of electricity clean spark and dark spreads reflects the pattern of generation operation with increased output from coal relative to gas fired power stations during periods when the clean coal generation costs are lower than clean gas generation costs. For the core of winter, excepting Christmas, coal maintained an economic advantage over gas and therefore ran at a higher load factor than gas stations. From mid February our analysis shows only a relatively small differentiator between clean gas and coal costs but as Figure A.42 shows this was coincident with higher load factor running switching from coal to gas.

Figure A.42 – Baseload Electricity Prices and Clean Gas/Coal Costs



LCPD Update

130. The Large Combustion Plant Directive (LCPD), which came into force on 1st January 2008, has impacted the operation of generation to which it applies. However from an operational perspective this change has now become part of our baseline landscape. The potential security of supply issues for last winter we outlined in our final report related to late compliance of some power stations and the nature of the derogation regime. There were certain limited and low probability circumstances which may have negatively impacted the ability of these stations to contribute to meeting demand or to be available for local transmission system security of supply reasons. During Winter 2008/09 there were very few instances where these LCPD issues with an impact on security of supply crystallized and in any event a way forward was found to mitigate the risk in discussion between the Environment Agency, Ofgem and National Grid.

131. Moving forward to Winter 2009/10, the late compliance with the LCPD is now no longer a significant issue due to either completing the fitting of Flue Gas De-sulphurisation (FGD) or other means being found to enable compliance.

Operational Overview

132. We experienced three days where NISMs (Notice of insufficient margins) were issued during Winter 2008/09. A summary of these can be seen in Table A.11.

133. NISMs are our lowest level of “system warning”. A NISM relates to an erosion of the level of “contingency” reserve we hold and does not indicate itself that demand cannot be met in real time. Contingency reserve requirements reduce as we approach real time due to lower uncertainty around demand levels and lower expectations of aggregate generation failures. In some cases NISMs can therefore be cancelled as we approach real time. No High Risk Demand Reduction (HRDR),

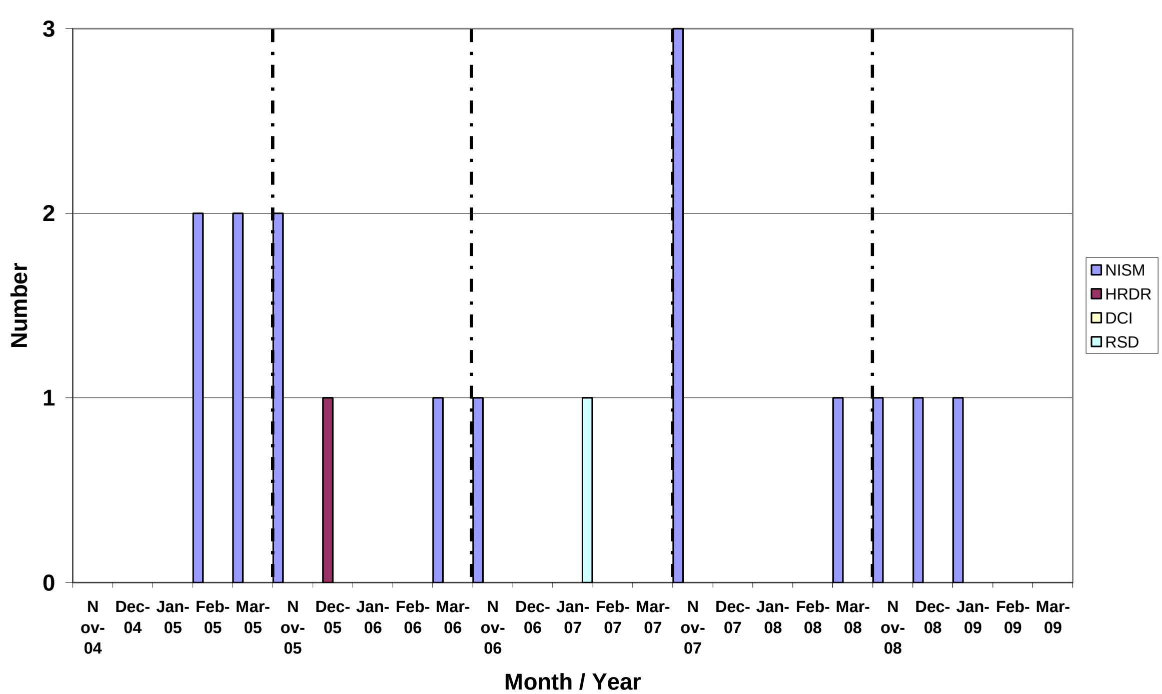
Demand Control Imminent (DCI) or Risk of System Disturbance (RSD) warnings were issued in 2008/09. System warnings[11] are a normal part of our operational interaction with the market and whilst we experienced three days where warnings were issued, there is no cause for concern.

Table A.11 – System Warnings Summary for 2008/09

Date	Type	Shortfall MW (max indicated)	Shortfall from	Shortfall to
08/11/08	NISM	1900	1600	1930
11/12/08	NISM	1000	1600	1900
15/01/09	NISM	650	1600	2000

134. Figure A.43 shows the pattern of system warnings over the last five winters and illustrates that winter 2008/09 was similar to previous winter experiences in terms of numbers and types of system warnings we issued.

Figure A.43 – Historic Experience of System Warnings Issued



[11] System warnings can be found on http://www.bmreports.com/bsp/bsp_home.htm as the first item on the new summary page along with an outline explanation of warning types.

Questions for consultation

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

QA10. Do you believe that electricity demand side response capability has materially reduced due to the economic slowdown? Are you able to quantify this impact with supporting information and relate it to an overall GB estimate of end user demand response and share this with National Grid?

QA11. Do you agree that the main driver of demand reductions recently seen is the recession? Do you believe demands will return in due course to pre-recession levels and when might this be expected to take place?

QA12. Do you identify other significant factors driving interconnector behaviour in addition to technical availability and relative energy prices between interconnector markets. Has anything particular changed last year for the medium term?

QA13. What actions were taken by the market to contribute towards meeting demand at times when we issued system warnings? Were there any limitations on any actions the market took at times of system warnings and what could or should be done to address any limitation, if identified?

QA14. Was sufficient key information available on the operational view of electricity demand and supply to enable market participants to be aware of electricity system balancing issues? If you believe additional key information should be provided please outline what other information would assist the market and outline the scale of potential benefit.

Section B
Outlook for 2009/10

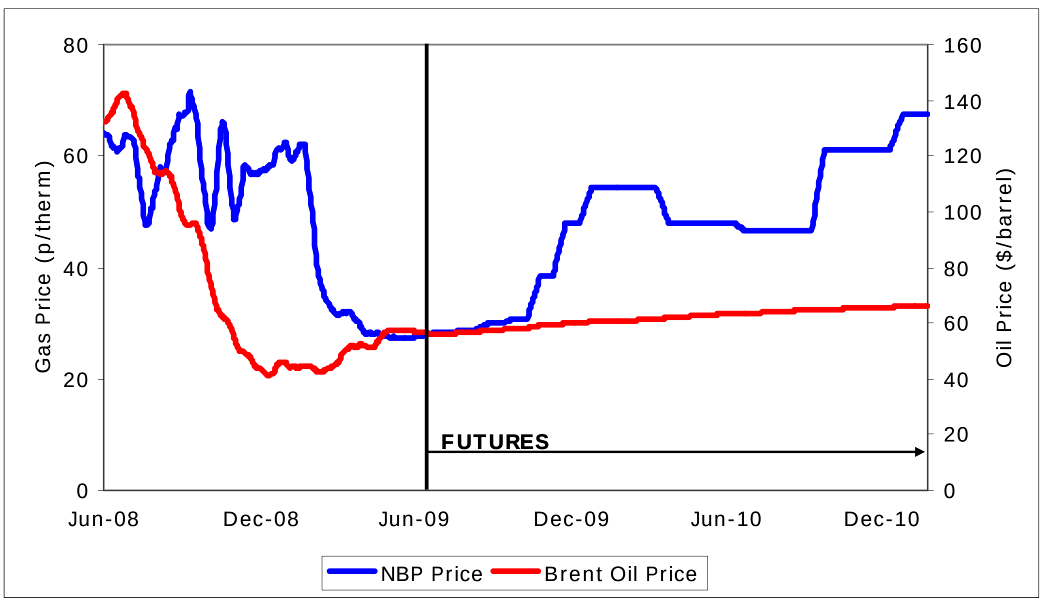
<u>Gas</u>

2009/10 Fuel Prices

135. Figure B.1 shows the historical and forward UK oil and gas prices as of mid May 2009. The oil price is slowly increasing over time due to views of slow steady economic recovery. Historically gas price has been strongly linked to oil price, due to high interconnectivity with the Continent whose long term gas contract prices are oil linked. There is a lag on this linkage thought to be around 6 months, on top of which there is a seasonal risk premium for winter months UK gas price.

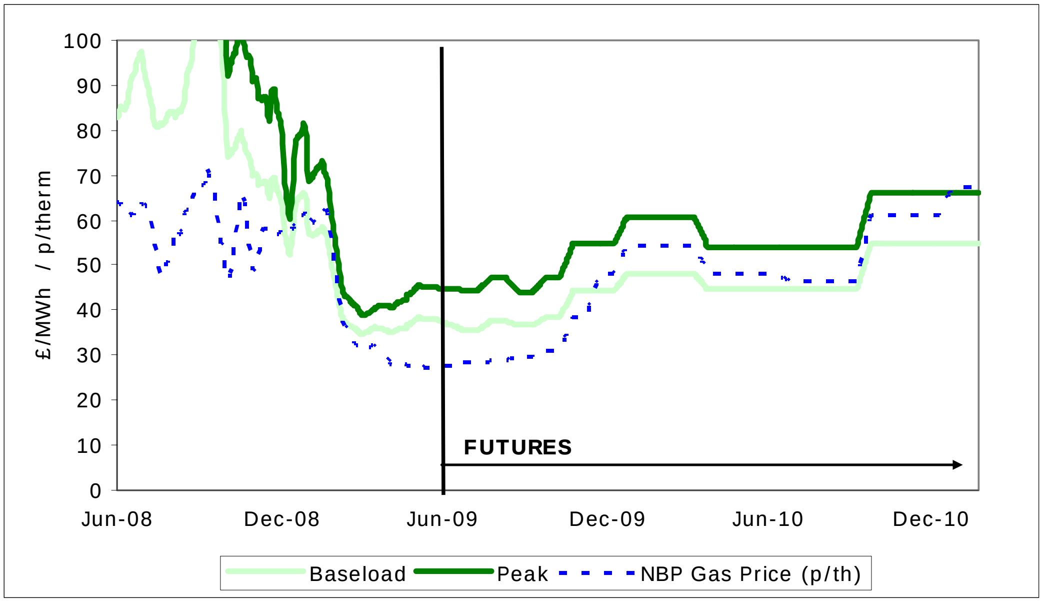
136. This appears to be corroborated by the history and future prices in the chart, however summer 09 appears relatively low when compared to prices further forward.

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



137. Figure B.2 shows the historical and forward UK wholesale base load and peak power prices as of early May 2009, together with the NBP gas price. Historically, there is usually a strong correlation between the gas and power prices and only when there have been demand or supply issues specific to the power market has there been any deviation away from this trend. This occurred for a few months over summer 08, mainly due to significant nuclear outages, finishing in October 08. In the forward power markets, the seasonality in the gas price is not fully reflected, due to the ability of generation to switch to coal. Forward base load power prices for winter 2009/10 are typically £55 to just over £60/MWh.

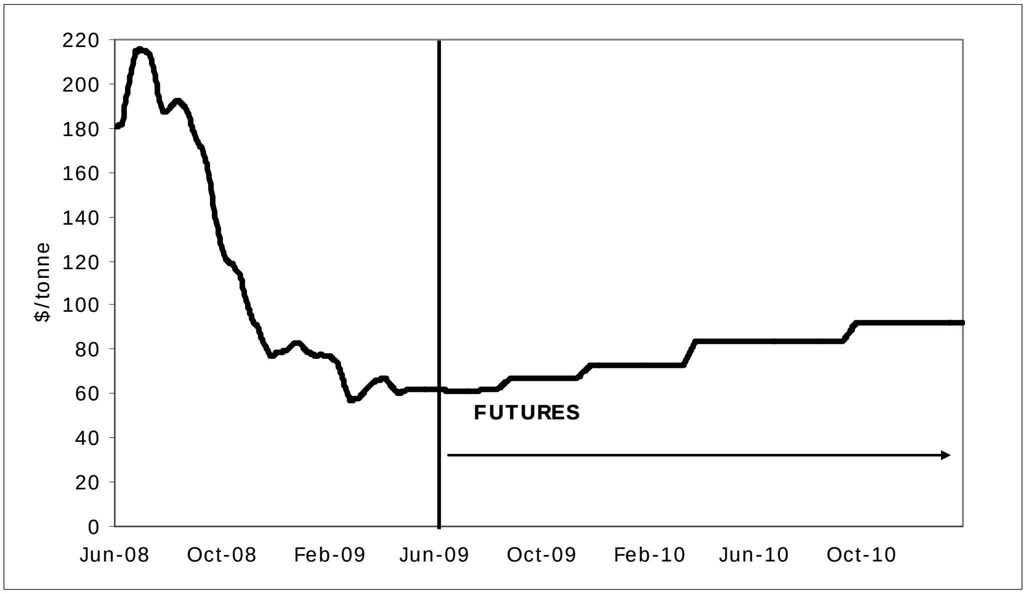
Figure B.2 – Historic and Future Power and Gas Prices



138. The oil, gas and power prices have been mirrored by movements in the price of coal. The peak in July 08 was driven by strong global demand, particularly in China and India, coupled with a shortage of available capacity and freight. Since then, the economic downturn has restricted demand particularly from China and India, two of the main users of coal, and the main world manufacturers of goods, which has in turn caused the price to drop to the May price of $60/tonne. The rises in forward prices, as with oil, reflect the views of slow steady economic recovery.

139. Figure B.3 shows the ARA CIF[12] coal price with forward prices reflecting the continuing strong demand, mainly driven by the growing number of power plants being commissioned across Asia.

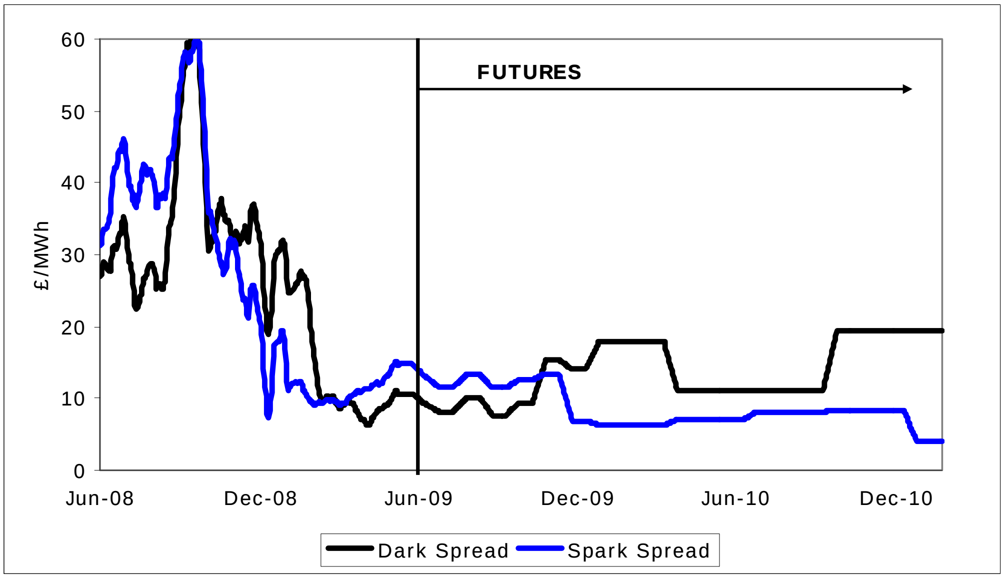
Figure B.3 – Historic and Future Coal Prices



140. The current relatively low gas price is benefiting gas-fired power generation when compared with coal-fired generation in the UK, for the rest of the summer. From then on, a higher gas price results in coal fired generation as the more attractive of the two.

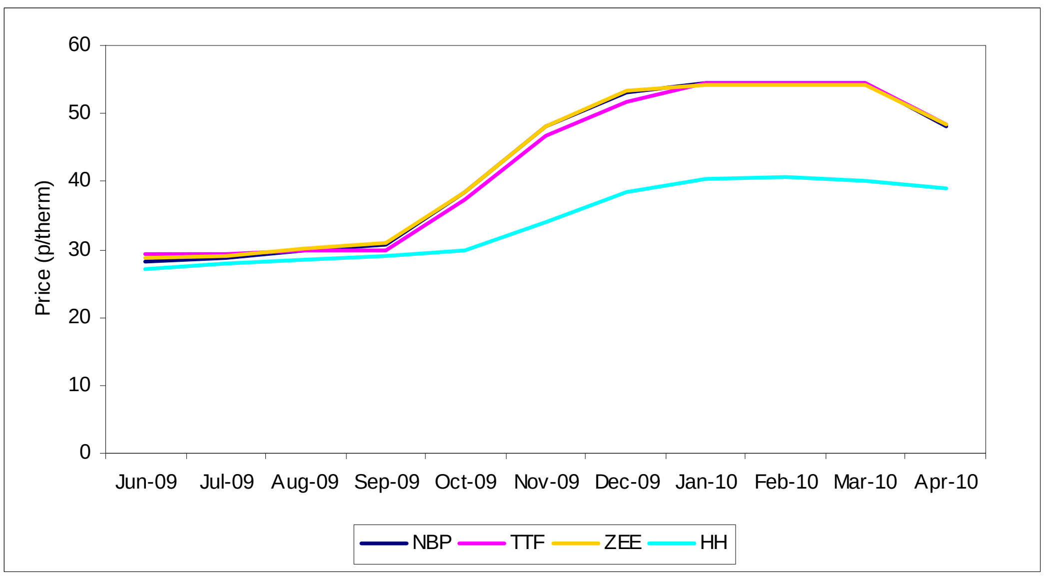
141. The forward curve shows a dark spread of £15-18/MWh compared with a spark spread that falls to around £7/MWh in winter 2009/10. These forward prices suggest that coal-fired generation will be the base load plant over the coming year, with gas-fired generation as the marginal plant. Traditionally, gas has been the base load plant during the summer months when the seasonal gas price has been lower, with coal the base load plant during the winter. This is the case for calendar year 2009 but the high price for gas in Summer 2010 means that based on current forward prices coal should be the base load for the whole year.

Figure B.4 – Historic and Dark and Spark Spreads



142. Figure B.5 shows the forward gas prices as of early May 2009, for European markets (NBP, Zeebrugge) and for the US (Henry Hub). Unlike previous winters, the NBP is not at a slight premium to the other Continental markets. Though Henry Hub prices are higher than current levels, the European winter prices are at a further premium of about 15 p/therm. In terms of spot LNG cargoes this provides a considerable incentive to deliver LNG to Europe (notably the UK and Zeebrugge) in preference to the United States. However recent ample supplies of LNG tankers have had the effect of converging US and European prices. This is shown by the forward prices for summer 2009 being almost the same. This could suggest a convergence of US and European prices for next winter and possibly beyond.

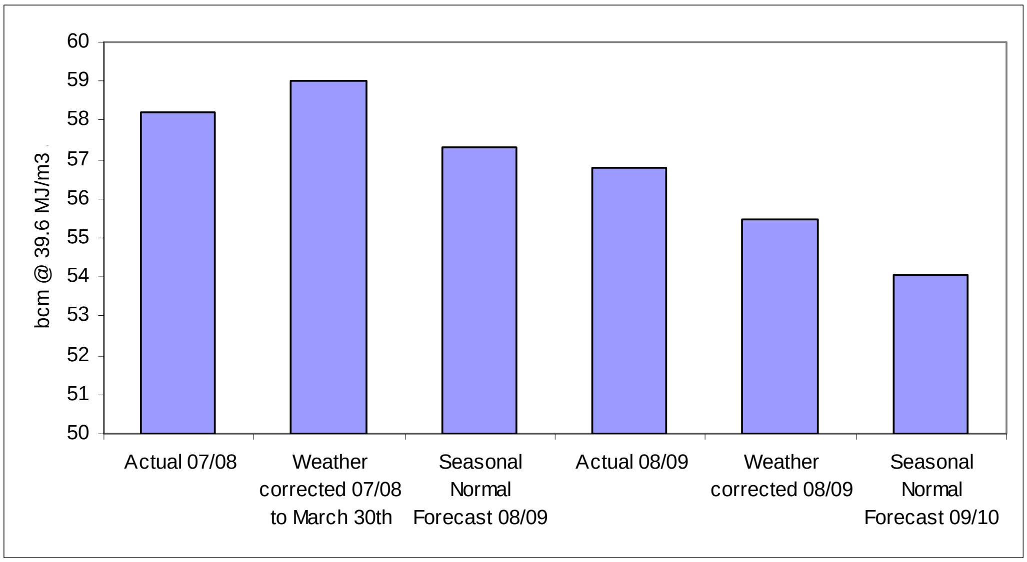
Figure B.5 - Forward Prices for Europe and US



2009/10 Gas Demand Forecast

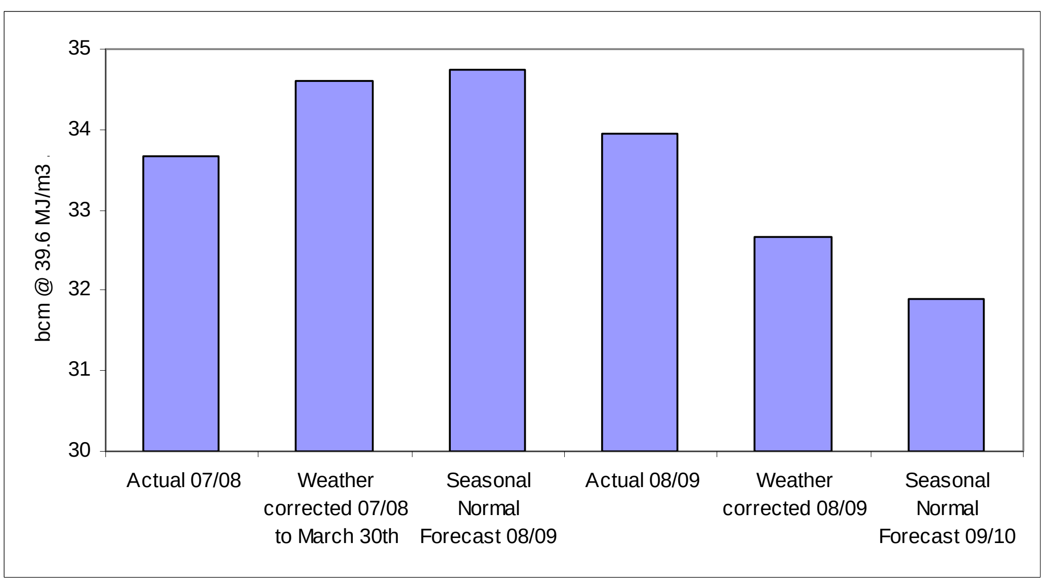
143. Figure B.6 shows that the total winter forecast for 2009/10 is 2.5% lower than the weather corrected demand in the 2008/09 winter.

Figure B.6 – Total Winter Demand



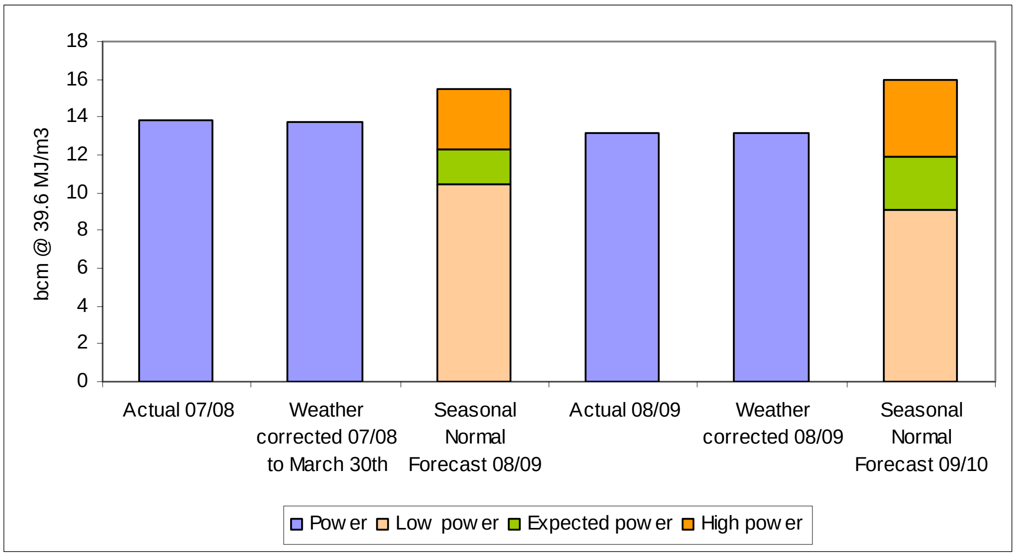
144. The NDM forecast for 2009/10 is also 2.5% lower than the weather corrected NDM demand in winter 2008/09 as shown in Figure B.7.

Figure B.7 – NDM Winter Demand



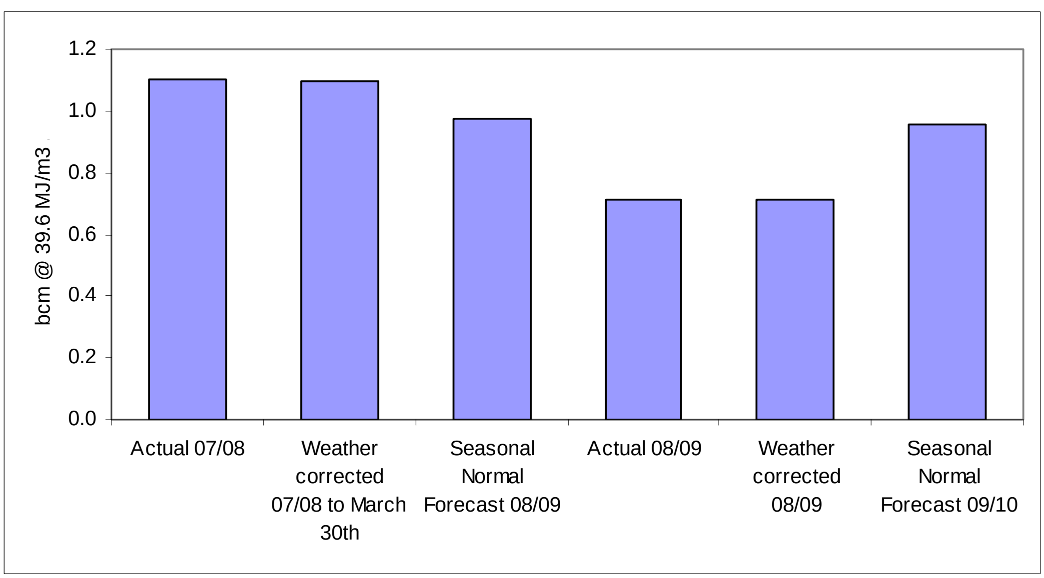
145. Gas is assumed to be the marginal fuel for power generation for the 2009/10 winter. Figure B.8 shows the 2009 gas-fired generation forecast for 2009/10 to be almost 10% lower than the actual demand in 2008/09. This difference is mainly due to a lower forecast for electricity demand, higher nuclear availability and higher opted-in coal plant availability.

Figure B.8 – Power Generation Winter Demand



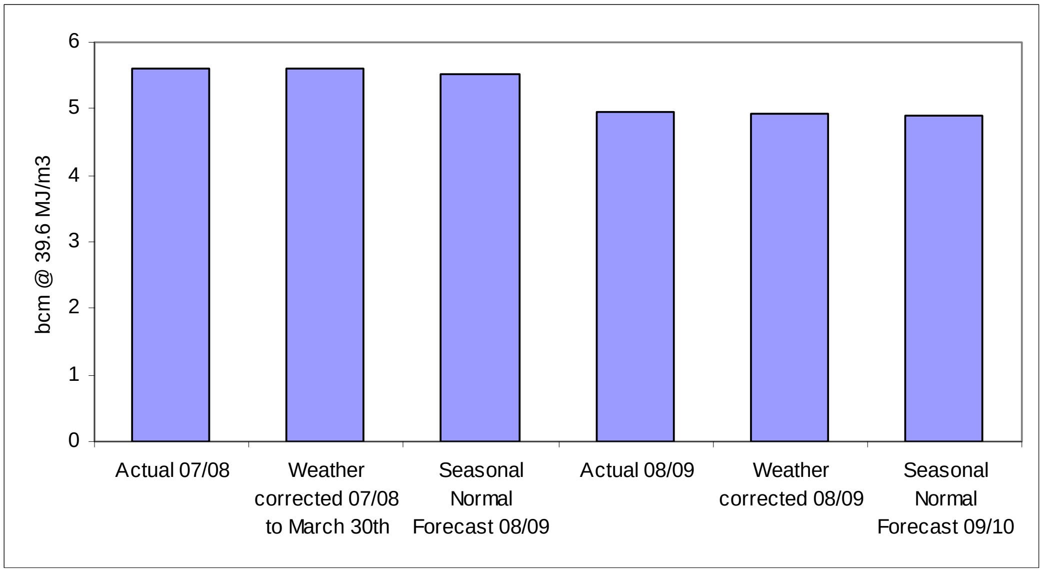
146. Figure B.9 shows that NTS industrial demand is forecast to be between the 2007/08 and 2008/09 demand levels following the return of the sites that switched off in 2008/09.

Figure B.9 – NTS Industrial Winter Demand



147. Non-power daily metered demand is expected to be similar to 2008/09 winter demand levels as illustrated by Figure B.10.

Figure B.10 – Non-power LDZ Daily Metered Winter Demand



2009/10 Gas Supply

148. This section examines each of the potential (non-storage) gas supply sources in turn: UKCS and imports from Norway, the Continent and LNG. As in previous winters, there is considerable uncertainty in both the source and the level of imported supplies for next winter; our initial view is appreciably influenced by our experience last winter. This should not be seen as a definitive view at this stage but a means for industry engagement and consultation.

UKCS Gas Supplies

149. For the purposes of this document, our initial assessment of UKCS supplies for winter 2009/10 is based primarily on industry feedback we have recently received from our 2009 TBE consultation. Table B.1 compares our UKCS supply forecasts, from the 2008/09 Winter Outlook and our initial view for 2009/10.

Table B.1 - Preliminary 2009/10 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2008/09		2009/10
	Final Winter Outlook 08/09	Highest	Initial View
Bacton	66	66	65
Barrow	17	18	15
Easington	13	14	12
Point of Ayr	1	4	1
St Fergus[12]	78	80	70
Teesside	23	30	25
Theddlethorpe	18	21	15
Total	**216**	**233**	**203**
90% Planning Assumption	194		183

150. UKCS supplies performed well over the winter 2008/09 period in line with our forecast.

151. Table B.1 shows a provisional UKCS maximum supply forecast of 203 mcm/d for Winter 2009/10. This figure may be updated pending completion of ongoing analysis and receipt of more data and feedback: Any revisions are expected to be incorporated into our annual 'Development of Investment Scenarios' paper in July, or in the final Winter Outlook report due to be published in September.

152. Our Winter 2009/10 figure of 203 mcm/d represents a 6% decline against the Winter 2008/09 figure of 216 mcm/d. In previous years we have reported declines typically between 5% and 10%.

153. For the purposes of supply-demand analysis and for security planning, we assume an operational forecast of UKCS supply below the maximum forecast. For this purpose we intend to continue to use an availability of 90%, resulting in a UKCS planning assumption for next winter of183 mcm/d.

Table B.2 – Derivation of 2009/10 UKCS Maximum Forecast

	mcm/d
2008/09 Winter Forecast	**216**
Forecast Decline from existing fields	-28
Forecast production increase from existing fields	+12
Forecast production increase from new fields	+3
2009/10 Winter Forecast	**203**

154. UKCS peak production from current fields is forecast to fall by 28mcm/d between winter 2008/09 and winter 2009/10. Offsetting this fall is a small increase in production due to come from new fields (~3mcm/d), but also an increase from existing fields driven by the following factors:

- A number of fields which started in the last few years are still in the process of increasing production

[12] Excludes estimates for Vesterled and Tampen

- The high price environment of the last few years has contributed to further incremental investment

155. There are many factors that may increase or in particular decrease our UKCS supply forecasts. These include:

- An increased tendency for producing fields to maintain production all year round rather than “preserving” gas for the winter. This has the effect of accelerating field decline
- The current recession and relatively low price environment may affect UKCS production levels
- Lower availability through poor weather conditions offshore
- The late commissioning of new production or delays in the resumption of production following maintenance outages may result in reduced supply availability early in the winter
- Within-winter decline of existing fields resulting in reduced supply availability later in the winter

Norwegian Imports

156. Last winter saw further production increases at Ormen Lange but these were partially offset by a significant outage at Kvitebjørn and the associated Visund field due to a ruptured pipeline. For this winter we are anticipating Ormen Lange to increase from last winter’s average of 50 mcm/d towards its plateau production of 70 mcm/d, which is forecast in 2010.

157. In order to forecast Norwegian flows to the UK for next winter we first need to estimate total Norwegian production and assess flows to the Continent. Table A.4 shows for the winter period our estimates of average Norwegian exports to the Continent and UK since 2006/7. Our estimate of Norwegian production for next winter is approximately 6% higher at 319 mcm/d with the increase in Ormen Lange and greater availability of Kvitebjørn the primary reasons for the higher forecast.

158. Due to the potential variation in Continental flows we have created a range around the central case to highlight the resulting variations in flows this can cause to the UK. For the central case we have assumed an increase in load factors across the Continent from last year with levels similar to those seen in 2007/08. The upper and lower ranges around the central case are based on the range (over the last 4 years) of observed load factors to each of the Continental countries that receive Norwegian supplies.

159. Table B.3 shows a possible range for Norwegian exports based on our production estimate of 319 mcm/d, this puts our central case for UK flows at 105 mcm/d for the winter, 7 mcm/d higher than observed last winter. The range highlights a modest upside to the forecast if Continental supplies are lower than expected and a greater downside if they are higher; the range for Norwegian flows to the UK is 88-118 mcm/d.

Table B.3 – Winter 2009/10 Estimates of Norwegian Exports

(mcm/d)	Central	High flows to Continent	Low flows to Continent
Belgium	37	39	35
France	49	52	45
Germany	128	140	121
UK	105	88	118
Total	**319**	**319**	**319**

Continental Imports

160. Last winter, we again observed relatively stable flows through BBL but IUK was significantly more variable, with exports far exceeding imports. Day to day flow variations for IUK were at times greater than 15 mcm/d.

161. For BBL we anticipate that commercial arrangements for interruptible non physical reverse flow (i.e. non-physical exports) should be in operation. This may result in BBL flows becoming more sensitive to the UK and possibly Continental market needs.

162. Whilst we expect BBL will at times flow at similar levels to last year's peak of 35 mcm/d, for planning purposes our forecast is for flows of 25 mcm/d. This is based upon the observed flows from last winter of nearly 30 mcm/d with a 5 mcm/d allowance for the potential impact of commercial reverse flows.

163. Last winter we observed limited IUK imports though on one occasion IUK imports approached 20 mcm/d. For most of the winter there were significant IUK exports even at times when UK demand was in excess of 400 mcm/d. The driver for exports during this period was the Continent's call for gas during the Russia Ukraine dispute. At other times there were also significant exports believed to be driven by a NBP price that was believed to be significantly below the oil-indexed contracted price creating an incentive to minimise the take of contractual volumes on the Continent and maximise IUK exports.

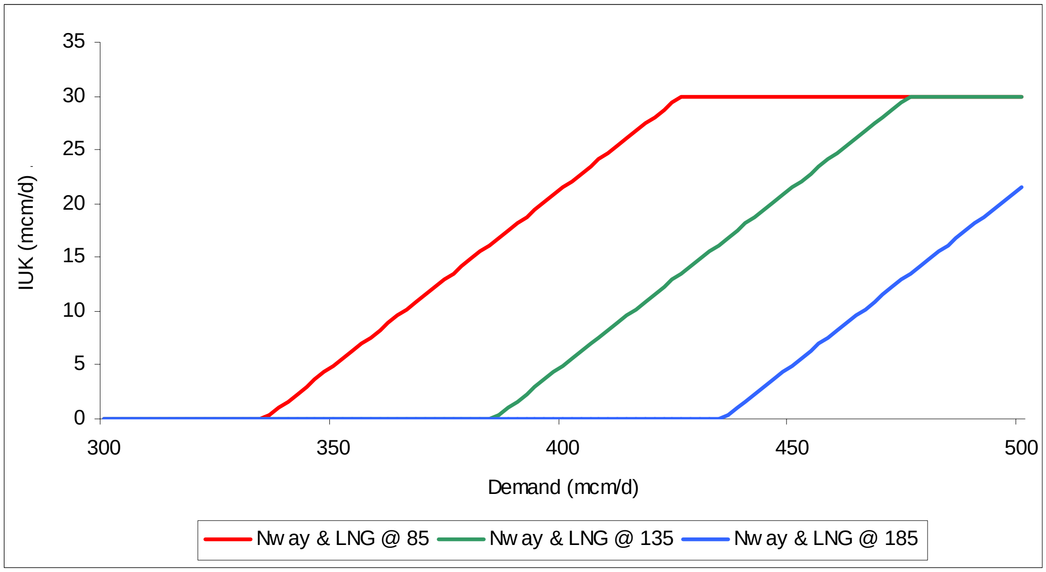
164. In previous winters IUK has behaved as a marginal source of supply when UKCS and other imports have not met UK demand. We again expect this behaviour to continue, with storage and to a lesser extent IUK acting as the supply balancer to the meet UK demand. Hence if imports from Norway or LNG are relatively high we would expect little or no IUK imports, conversely higher IUK imports if Norwegian or LNG imports are low.

165. Figure B.11 shows our forecast for IUK imports based on 183 mcm/d UKCS, 25 mcm/d BBL, 42 mcm/d of storage and a range of Norwegian and LNG import flows based around our central case of 135 mcm/d (105 mcm/d Norway & 30 mcm/d LNG) with a range of +/- 50 mcm/d. The chart shows that for low levels of Norwegian and LNG imports, IUK could commence importing at demands as low as 340 mcm/d, whilst for a well supplied UK not until demands were as high as 440 mcm/d. The relatively high threshold for IUK imports also suggests that in a well

supplied UK market, that IUK could again be in predominately export mode next winter.

166. Though IUK can import up to about 70 mcm/d, we have assumed for security planning (not capacity planning) a maximum import level of 30 mcm/d. Of course this arbitrary level could be exceeded if market conditions were favourable.

Figure B.11 – IUK Import flows



167. Though not shown on Figure B.11, we believe that it remains prudent to consider lower IUK supply availability up to December due to uncertainties over the release of Continental storage that may be held back for Continental markets.

LNG Imports

168. Winter 08/09 (Oct-Mar) saw a total of 22 cargos delivered into Grain, with total flows from Grain exceeding 1.5 bcm over the period, more than double the volumes seen for the equivalent period in 07/08.

169. Grain Phase II was available for commercial operation on 30th December 08, with flows exceeding the base load 13 mcm/d first phase capacity on the 2nd January 09. January 09 saw the Russia Ukraine dispute escalate resulting in the highest monthly flows through Grain to date, with peak daily flows in the month just under 30 mcm/d.

170. South Hook LNG terminal was not available during winter 08/09 with first NTS flows on the 9th April 09, the terminal has not yet been declared commercially available with two of the five tanks operational and the remaining three expected to be

completed by the end of the year. Total NTS flows from South Hook into the NTS have totaled 290 mcm by the end of May 09.

171. The capacity for South Hook Phase I is 10.5 bcm/year equivalent to a base load deliverability of 29 mcm/d, with Phase II having similar capacity.

172. Dragon LNG terminal has not yet commissioned with commissioning believed to be completed prior to Winter 2009/10. Capacity for Phase I is 6bcm/yr equivalent to base load deliverability of 16 mcm/d.

173. All of these facilities will be capable at times of exceeding these base load deliverabilities. The capacity release obligation for Milford Haven for next winter is approximately 90 mcm/d. The capacity release obligation for Grain for next winter is approximately 38 mcm/d.

174. With Grain Phase II commissioned and South Hook Phase I undergoing commissioning, the capacity uncertainty for Winter 2009/10 lies with Dragon and South Hook Phase II.

175. Capacity for Winter 2009/10 is in the range of 67 to 112 mcm/d. The lower range based on Grain I + II and South Hook Phase I, and the upper range additionally including Dragon and South Hook Phase II. In terms of LNG capacity the UK will be entering Winter 2009/10 in a more comfortable position than previous years, notwithstanding that LNG deliveries, as in previous years, will continue to be subject to global supply / demand forces.

176. To manage the supply uncertainty surrounding LNG we are proposing at this stage of our winter consultation to consider a wide range but below the nameplate capacity, namely from 10 to 60 mcm/d. This therefore identifies periods of both low flow and high flow from Grain and both Milford Haven facilities. We acknowledge that flows could be much higher than these but 60 mcm/d does represent twice the highest ever LNG import flow recorded to date and the equivalent of nearly a full cargo (81 mcm) from a standard 135,000 m3 vessel.

177. We also acknowledge that flows of LNG imports through Teesside GasPort are possible. These provide a further upside to our range.

Storage

178. During next winter we expect the Aldbrough storage facility to become operational, though we are not expecting design flow rates until after 2009/10. Storage space at Hole House Farm is also expected to increase.

179. Table B.4 shows our assumed levels of storage space and deliverability for next winter.

Table B.4 – Assumed 2009/10 storage capacities and deliverability levels

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1970	390	36	5
Medium (MRS)	10086	515	47	20[13]
Long (Rough)	35580	455	41	78
Total	47636	1360	124	35

Preliminary View of Supplies Winter 2009/10

180. In the previous sub-sections we have outlined the basis for the assumptions incorporated into our analysis. Table B.5 summarises the supply range and our Base Case, and compares these with the 2008/09 forecasts and actual flows. We should stress that these 2009/10 ranges and Base Case should be regarded as provisional with the primary purpose of fostering discussion and comment.

Table B.5 – Preliminary View of Non Storage Supplies Winter 2009/10

(mcm/d)	2008/09 Range	2008/09 Top 100	2008/09 Highest	2009/10 Range	2009/10 Base Case
UKCS	195	192	205	183	183
Norway	68 - 111	98	114	88 – 118	105
BBL	30	27	36	25	25
IUK	30 - 10	2	19	30 – 0	0[14]
LNG Imports	0 - 30	11	29	10 – 60	30
Total	323 - 376	330	403	336 – 386	343

181. Based on the supply assumptions detailed in the previous supply sections, Table B.5 suggests that the non-storage supply availability for next winter is again uncertain, notably in terms of deliveries of LNG imports and to a lesser extent Norwegian supplies. The availability of each of these supplies is expected to influence IUK imports.

[13] 20 days represents an average. Actual range is far greater
[14] IUK shown as zero but assumed to import as demands exceed 385 mcm/d

Safety Monitors

182. Safety monitors were introduced in 2004 as a mechanism for ensuring that sufficient gas is held in storage at all times to underpin the safe operation of the gas transportation system.

183. The safety monitors define levels of storage that must be maintained through the winter period. The focus of the safety monitors is public safety rather than security of supply. It is a requirement of National Grid's safety case that we operate this monitor system and that we take action to ensure that storage stocks do not fall below the defined levels.

184. This section on safety monitors is consistent with the industry note we issued on 31 May 2009 as required under the Uniform Network Code (Q5.2.1).

185. Following Winter 2008/09, we have reviewed the safety monitor methodology. We are proposing a number of revisions to the calculation of the monitor and enhancements to the dissemination of safety monitor information throughout the winter. We believe that the proposed changes (part met through UNC code modifications) will:

    - Improve information provision to the market with respect to safety monitor requirements
    - Enable the market to operate more effectively, as there will be greater clarity regarding the necessary safety monitor space and deliverability requirements
    - Enhance Security of Supply and the market's ability to plan and thereby efficiently deal with supply "shocks"

186. It should be noted that the proposed changes do not increase the total safety monitor storage requirement. The new methodology calculates the total safety monitor storage space requirement as a single entity rather than broken down into Long, Medium and Short storage requirements. This results in the production of a single safety monitor. In addition a safety monitor deliverability requirement will be calculated. There are a number benefits to adopting this approach:

    - The creation of a Total Safety Monitor classification that aggregates all safety monitor storage space requirements ensures that all storage facilities are treated equitably
    - The production of a deliverability monitor alongside the space monitor will provide the marketplace with greater information in terms of the overall capability of available storage types and hence enhance security of supply by more accurately reflecting the likely changes in overall storage capability during the course of the winter should certain storage types be exhausted

187. Whilst the Total Safety Monitor storage space requirement would replace the Long, Medium and Short safety monitor requirements, these classifications of storage would be kept for stock reporting purposes. The proposed revisions to the safety monitor methodology would result in an increase in relevant information available to the market and plans are currently in house to significantly improve market

information relating to the security of supply outlook for the entire winter period as it progresses.

188. The safety monitor requirement is highly dependent on the non-storage supply level. There is considerable uncertainty regarding the make up and aggregate level of non-storage supplies. The overall supply position is expected to be similar to that experienced last winter. However there is significant movement in the forecasts for the individual supply components.

189. We are forecasting further declines in the UKCS, as well as a reduction in our IUK forecast due to the considerable uncertainty in forecasting IUK volumes, with the potential for IUK exports to the Continent if the UK is well supplied or if there is additional demand on the Continent, as witnessed with the dispute between Russia and Ukraine in Winter 2008/09. We have increased our Norwegian forecast to reflect increased Norwegian production, as well as a significant increase in LNG imports, with the potential for both terminals at Milford Haven to be operational. There is in addition considerable upside to the LNG forecast.

190. Table B.6 shows the non-storage supply assumptions used in calculating the safety monitors. The supply assumptions used for the Safety Monitors were produced in May as we were finalising our preliminary 2009 supply forecasts. Hence they are very close but not identical to our Base Case supply assumptions detailed in Table B.5.

Table B.6 – Safety Monitor non-storage supply assumptions

mcm/d	2009/10 Safety Monitor	2009/10 Base Case
UKCS	180	183
Norway	95	105
BBL	25	25
LNG	30	30
IUK	10	0
Total	340	343

191. The demand background used for the analysis in this section is our latest set of demand forecasts for 2009/10 that we produced in May 2009. This latest 2009 forecast for Winter 2009/10 demands is roughly 5% lower than our 2008 forecast for Winter 2009/10. With the overall supply position expected to be similar to that experienced last winter, the lower levels of forecast demand have reduced safety monitor levels for Winter 2009/10.

192. Table B.7 shows the total safety monitor space requirement on the basis of the assumptions outlined above.

Table B.7 – Total Safety Monitor Space Requirement

	Total storage capacity (GWh)	Space requirement (GWh)	Space requirement %
Total	**47126**	**1289**	**2.7%**

193. It is our responsibility to keep the safety monitor under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do so on the basis of the information available to us. In doing so, we must recognise that the purpose of the safety monitors is to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. Ideally the passage of time before next winter and the outcome of this consultation may provide further clarity on expected levels of supply for next winter.

Winter 2009/10 Update on Provision of new NTS Capacity

194. Compared to recent years 2009/10 will see significantly fewer construction projects on the NTS. Although several new sites, both entry and exit, are due to commission during the 2009/10 gas year the majority of the associated capacity expansion projects have already been completed.

195. Ongoing work to facilitate the expected increase in supplies from the Milford Haven LNG Importation terminals will include projects at Cilfrew and Treadow, as well as modifications and a replacement unit at Churchover multijunction.

Milford Haven LNG Terminals - New & Modified Pressure Reduction Stations.

196. This project is part of the overall investment strategy to provide capacity to transport gas from the new LNG importation terminals at Milford Haven, following auction signals for Milford Haven capacity received in the 2004 September and December LTSEC auctions.

197. The new Feeder 28 connecting Milford Haven to the NTS is fully commissioned. The commissioning of Felindre Compressor Station will follow the full commissioning of the new entry points and a further Pressure Reduction Station at Tirley.

198. The physical connections for South Hook and Dragon LNG Importation Terminals were completed last year. Both sites are expected to commence commercial commissioning during summer 2009.

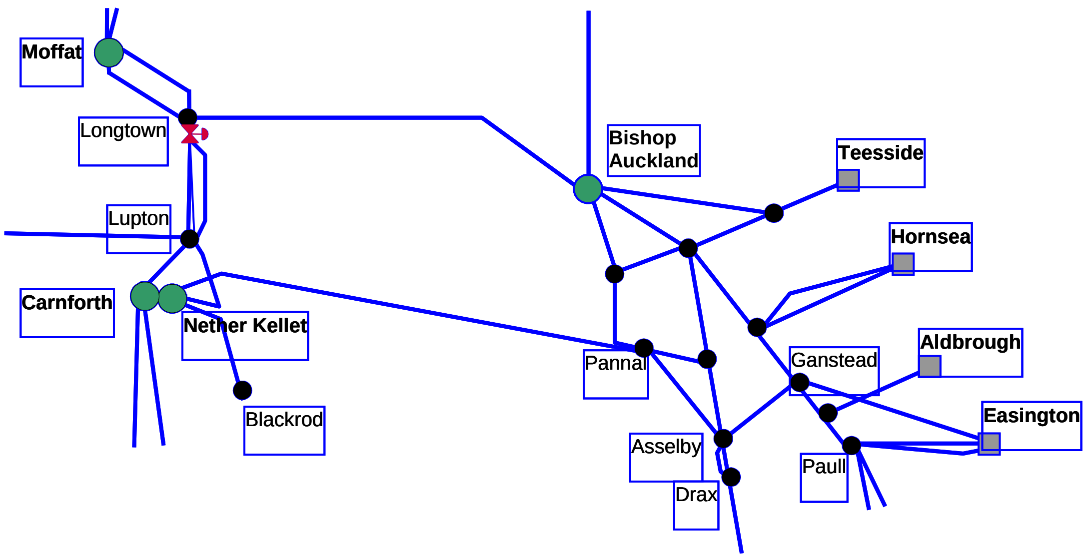
The references in the tables below relate to the map shown as Figure B.12.

Phases

Ref	Project	Scope
A	Churchover MJ modifications & replacement unit	Additional Unit and multi-junction modifications
B	Felindre Compressor Station	Commissioning
C	Cilfrew PRS	Commissioning
D	Tirley PRS	Under review awaiting planning consent

East Coast Entry Capacity

199. Following significant investment in providing new East Coast entry capacity in 2006, 2007 and 2008 (2008 marking the completion of the Trans Pennine link from Easington to Carnforth), 2009 will see the commissioning of the Longtown flow control valve, which will provide National Grid with increased control flexibility. The timing of this commissioning is dependant on sufficient flows through the station.



Phases

Ref	Project	Scope
E	Longtown Regulator	Commissioning new flow control valve

New Exit Connections

200. During the gas year 2009/10, it is expected that both Langage and Marchwood power stations and Aldbrough storage will become fully operational, after having connected to the NTS and taking limited commissioning gas last year. New connections to Staythorpe Power Station and Murco Oil Refinery at Milford Haven are also expected to be completed with first gas flows in 2009/10.

LNG Storage

201. Dynevor Arms LNG has been decommissioned and Partington, Avonmouth and Glenmavis LNG have re-declared their deliverability, shown in the table below. The total deliverability in 2009/10 for LNG Storage will be 35.9 mcm/d compared to 48.5 mcm/d last year.

Site	2008/2009 Deliverability	2009/2010 Deliverability
Partington LNG	20.3 mcm/d	14.2 mcm/d
Avonmouth LNG	14.4 mcm/d	13.2 mcm/d
Glenmavis LNG	9.3 mcm/d	8.5 mcm/d
Dynevor Arms LNG	4.5 mcm/d	N/A

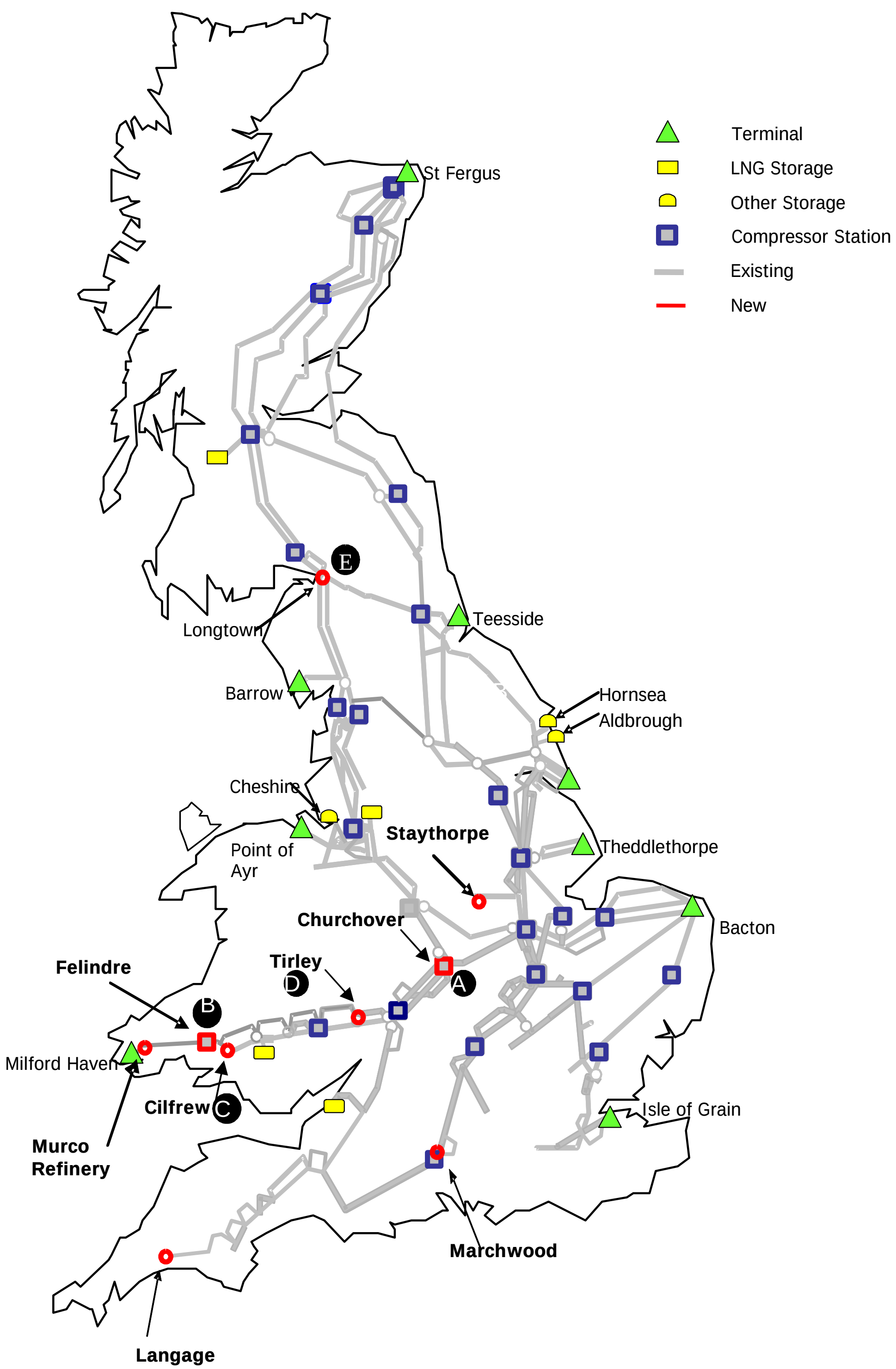
Market Information Provision Initiative (MIPI)

202. National Grid's market information pages on 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.

203. 2009 should see the second phase release of our MIPI system (the website platform on which our publication systems sit). MIPI Phase 2 is currently under development and is due for release in November 2009. Changes and improvements will include functional enhancements, data rationalisation and the delivery of new or revised data requirements.

204. National Grid is committed to keeping our customers informed of these and other developments and will be engaging in a series of customer workshops from August 2009 in addition to our existing communications channels. For further information please contact: 01926 656474 or view our news pages at http://www.nationalgrid.com/uk/Gas/Data/News/.

Figure B.12 – NTS Construction Projects Due for Delivery in Winter 2009/10



Questions for consultation:

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

QB1. Will there be further reduction in NDM gas demand due to the recession or efficiency savings in winter 2009/10?

QB2. Will the NDM demand lost due to short-term actions return on a very cold winter's day?

QB3. What drivers may influences the gas price in winter 2009/10? What factors may set floor and ceiling prices?

QB4. Do you agree with our high level view of lower UKCS supplies and increased Norwegian imports to the UK albeit dependent on Continental flows?

QB5. What assumptions should be made for levels of imported gas through BBL and IUK for winter 2009/10?

QB6. What assumptions should be made for levels of imported LNG through Grain, Milford Haven and Teesside for winter 2009/10?

QB7. We would welcome comments on our 2009/10 Preliminary View, and thoughts on how we can reduce or manage the resulting supply range.

QB8. We would also welcome comments on our changes to the Safety Monitor determination and our plans to improve related market information for next winter.

QB9. What are your views on future UK gas security of supply following the 08/09 winter experience? What if any changes are required to incentives and/or obligations?

QB10. What level of information on the overall gas supply and storage position in continental Europe do you require in order to effectively and efficiently meet your customer requirements in the UK? Where and by whom should this information be provided?

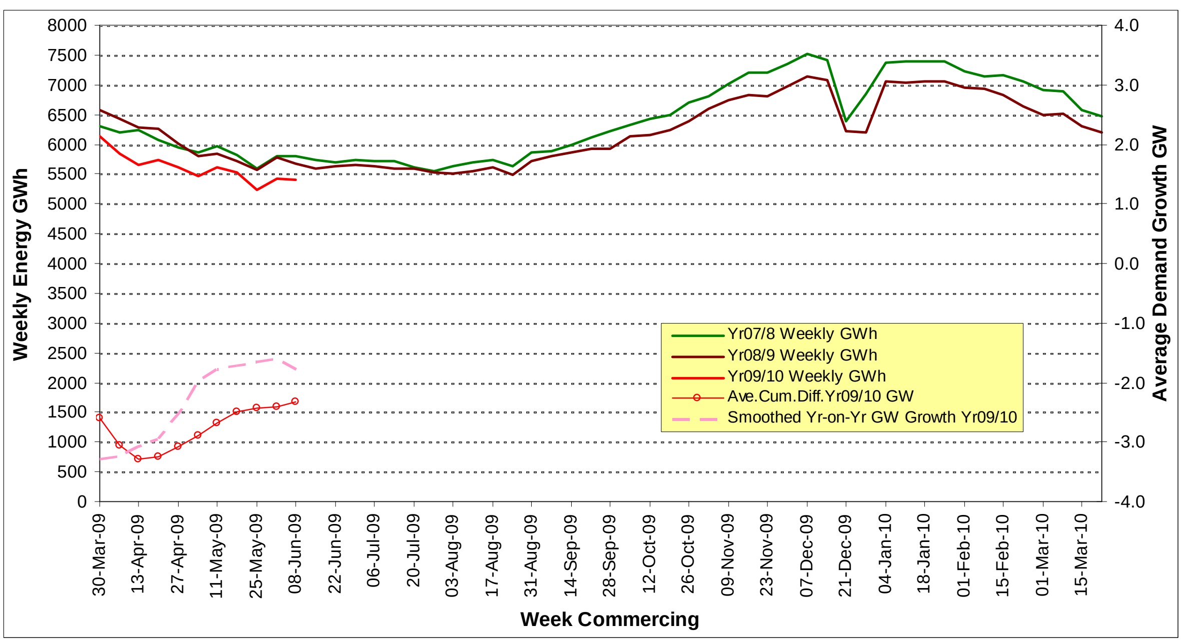
Electricity

Electricity Demand Levels for 2009/10 – Great Britain

205. Last year, we saw a 2.3GW lower ACS demand outturn than the year before. This represents a 3.8% reduction from the year before. The demand drop started to appear in mid-summer and accelerated from late summer as shown in Figure B.13. The decline in demand continued into 2009 but the most recent trend as indicated in the figure is that the decline may be stabilizing and the rate of decline is actually decelerating.

206. Our Great Britain Average Cold Spell (ACS)[15] winter peak demand forecast for the coming winter is 57.8GW. This is 0.2GW less than the 58.0GW ACS demand outturn of last year, assuming the electricity demand decline caused by current economic crisis was essentially reflected in the existing demand drop observed to date. There will be other factors which may drive demand lower such as growth in embedded generation in distribution networks, more efficient use of energy and the uncertain timing and pace of economic recovery. We continue to review our forecast as our normal work process and publish regular updates on www.bmreports.com.

Figure B.13 – Weekly Energy Trends Using Weather Corrected Demand



207. The 1 in 20[16] peak demand forecast is 59.2GW. The 1 in 20 demand peak represents our high demand scenario. These demand figures relate to GB demand

[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.

[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.

only and do not include any flows to France or Northern Ireland across interconnectors.

208. As discussed in Section A, the French Interconnector was traditionally importing during the system peak demand period and we believe it is appropriate to continue to treat the interconnector with France as a source of generation rather than a demand at peak times. The recent trend for the Northern Ireland Interconnection was either exporting to GB at a lower level than historically observed or more consistent with longer term observations to be importing to NI at a low level. We have therefore made the assumption that both interconnectors at system peak will be at float and readers of the analysis here can overlay their best assumptions if different on demand or generation availability.

209. In Section A, we also estimated around 0.8-1.3GW of demand management observed at times of peak demand in the winter of 2008/09 as consumers responded to high electricity prices at times of peak demand. When forecasting demand we assume this level of demand-response will continue and we have recognised this in our peak demand forecasts. For 2009/10 we have assumed 1GW of demand side response in our demand forecasts for ACS and 1 in 20 conditions.

Notified Generation Availability 2009/10

210. 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 2009 is 76.9 GW. A breakdown of this capacity is shown in Figure B.14.

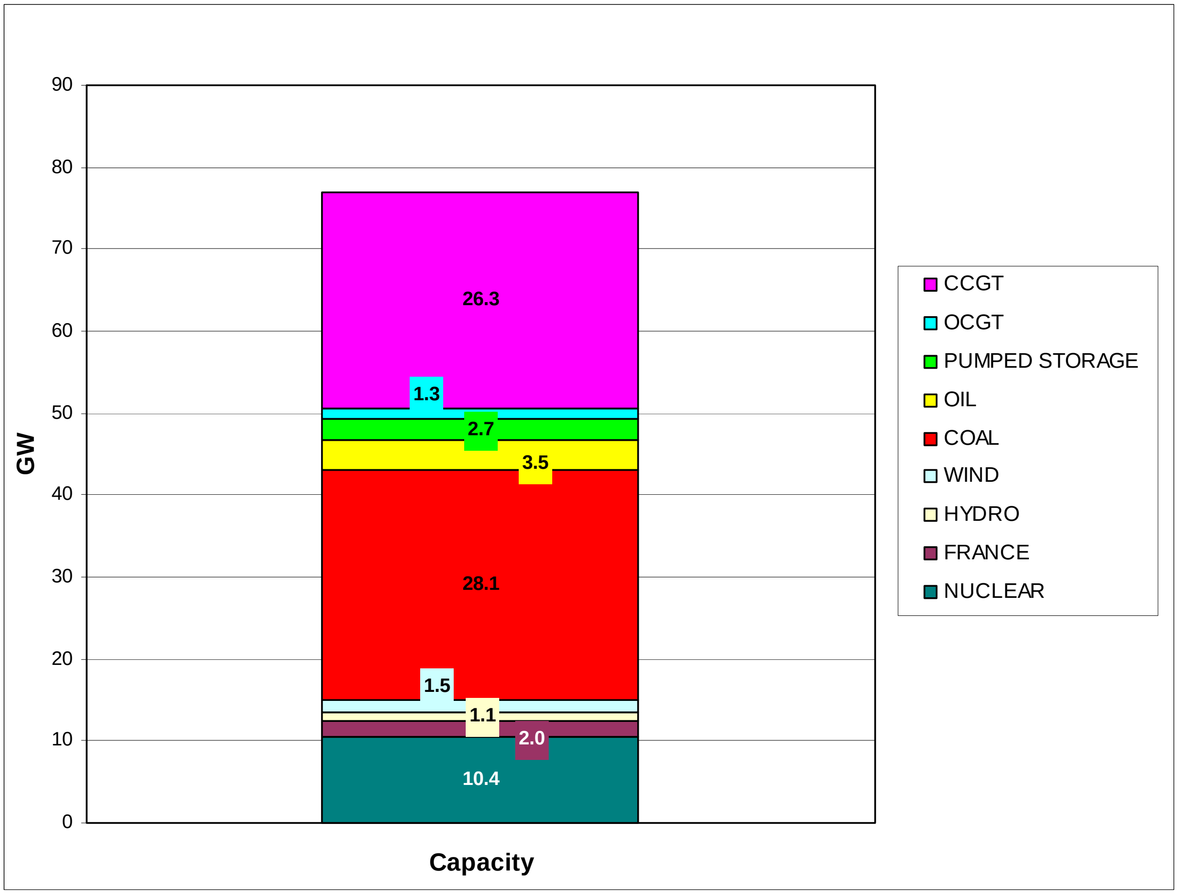
211. In addition to the 76.9 GW we could see around 250 MW of wind generation capacity progressively become available between now and the start of winter. This generation is currently being built and we have limited operational transparency of the firmness of progression of this generation towards operation, so have not included it in our starting figure.

212. Some generation capability upside exists in the form of Langage (0.9GW), Immingham Phase 2 (0.5 GW) and Staythorpe C (1.7 GW) which could be entering full commercial operations at some point during the winter to come. Also we expect to see an additional 300MW of wind generation over the course of the winter, although this additional within winter wind generation has a degree of uncertainty attached to it. Recent labour relations issues between companies and their contractors working on large engineering projects, including power stations could impact on the timing of realisation of the generation upside noted here.

213. Our end of winter 2009/10 operational view of generation could total up to 80.6 GW, dependant on how the build phase and commissioning of new CCGT's progresses and the rate at which new wind generation is being developed.

214. The total ORC at 76.9 GW for winter to come has increased from the summer outlook position mainly due to the addition of Marchwood to the CCGT category.

Figure B.14 – Generation Capacity Operational View 2009/10



Generation Availability Assumptions 2009/10

215. We have reviewed our forward looking availability assumptions based on last winter and they have proved generally robust at the aggregate level. Nuclear performance over last winter's demand peak was in historical terms very low though we believe this level of performance is unlikely to be repeated to a similar extent. We would particularly like to receive market views on the likely performance of Nuclear generation in winter to come through this consultation.

216. We have undertaken work over the last year to assist us in developing an operational assumption for a capacity credit for wind in line with our security of supply obligations for meeting the peak winter demand. We undertook this work with Edinburgh University and a paper will be presented shortly[17].

217. With the current level of ACS demand forecast for winter 2009/10 and the base case generation availability assumptions, the resulting operational energy planning

17 The paper will be published later this year by P.E. Olmos Aguirre, C.J. Dent Member, IEEE, G.P. Harrison and J.W. Bialek, 'Realistic calculation of wind generation capacity credits', Cigre/IEEE PES Symposium on 'Integration of Wide-Scale Renewable Resources into the Power Delivery System', Calgary, 2009.

capacity credit of wind calculated using our project with Edinburgh University is 27%. This capacity credit value will be used in our base case for 2009/10 but we note that it exceeds recently observed contributions from wind.

218. The methodology Edinburgh University have developed with our input gives us a platform to move forward with a more robust approach to energy security planning than our prior average load factor approach of 35% for wind achieved and will be refined over the summer. Developing a more rigorous approach to calculating a wind operational capacity credit is important in the context of increasing amounts of wind generation being developed as we move forward. The current stage of work with Edinburgh University has been completed and is encapsulated in the paper referred to above.

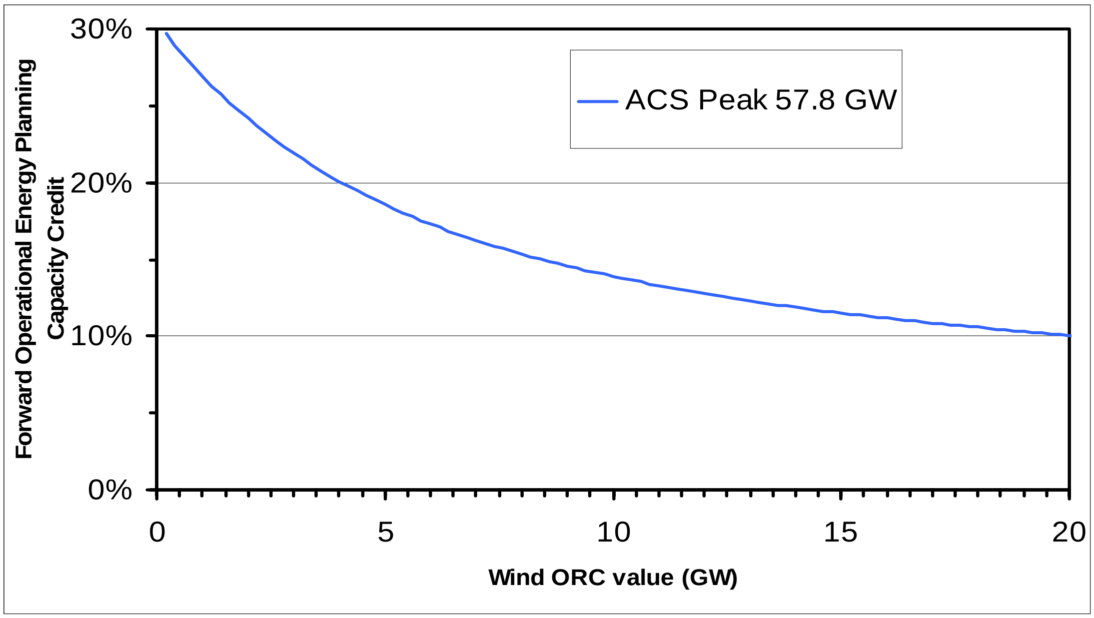
219. We have identified some additional refinements to our approach and some sensitivity to base assumptions that we may seek to investigate as we move forward and could be reflected in the final winter outlook report to be published later this year if progress permits[18]. The approach may overstate the capacity credit given the relatively low amounts of wind generation currently commissioned.

220. Figure B.15 shows the capacity credit curve for the coming winter's ACS peak forecast and base case generation availability assumptions for non-wind generation types. The modeling approach is to calculate how much extra demand a volume of wind power generation can support, giving us a capacity credit figure, whilst maintaining the same level of risk to meeting total energy demand in line with our security of supply standards. Our approach is underpinned by operational GB data for the actual wind farms output so well grounded in the specifics for our capacity and behaviour of wind farms.

221. Figure B.15 shows the resulting operational energy planning capacity credit of wind for a given peak demand of 57.8 GW with a wide range of installed capacities of wind power generation. The curve illustrates how the operational energy planning wind capacity credit quickly declines with increasing levels of installed wind generation capacity, before the rate of decline with increased capacity tails off.

[18] The paper is referenced in footnote 17, and will be published shortly.

Figure B.15 – Forward Operational Energy Planning Wind Capacity Credit



222. Hydro generation, which here includes small generation that is run of river, has an assumed availability of 60%. This compares with an observed load factor of 90% at times of winter peak demand last year and 73% in 2007/08. OCGT's also had an outturn availability of 77% compared with our assumption of different outturn availability to our assumptions. We have retained our base assumptions for 2009/10 based upon the fact that these have generally been robust over prior years and that changes in the availability for these fuel categories is of low materiality to the overall picture. We have focused our efforts on refining the wind assumed availability figure rather than the 60% assumption for hydro generation as hydro is not forecast to increase significantly in capacity. We continue to focus on the operational energy planning capacity credit of wind as the more material issue so do not propose further investigation into hydro generation capability at this time.

223. Table B.8 therefore shows our assumed generation availabilities at the time of winter demand peak for 2009/10.

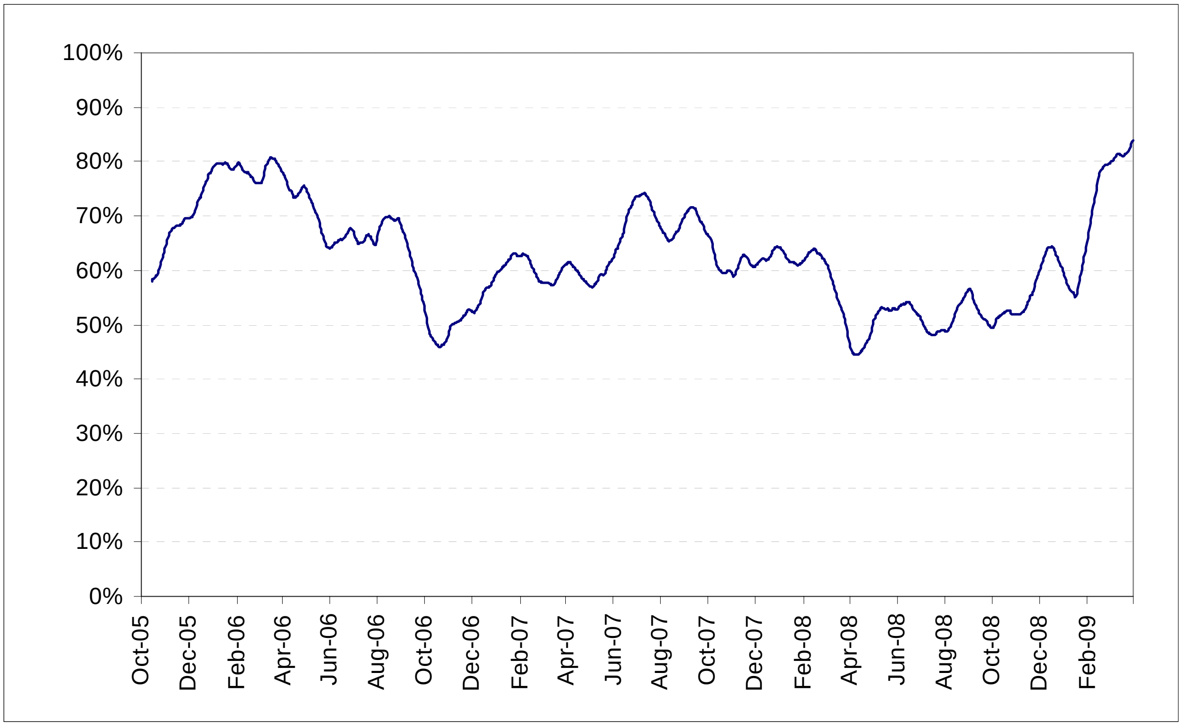
Table B.8 – Generation Availability Assumptions Made For Winter 2009/10

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.4	80%	8.4
French Interconnector	2.0	100%	2.0
Hydro generation	1.1	60%	0.7
Wind generation	1.5	27%	0.4
Coal	28.1	85%	23.9
Oil	3.4	95%	3.3
Pumped storage	2.7	95%	2.6
OCGT	1.3	95%	1.2
CCGT	26.2	90%	23.6
Total	**76.9**		**66.0**
Average availability		**86%**	

Nuclear Availability Assumptions

224. One area of potential uncertainty is the performance of the nuclear generation fleet. We have analysed historic availability of nuclear power stations for the last three winters shown in figure B.16. Availability has been lower than normal over the last two winters due to technical issues impacting several units of a particular design simultaneously. By the end of last winter nuclear availability returned to 80% for the first time since the winter of 2005/06. Although the output of some of some stations remains capped at a level below their full rating, it seems that the technical problems have been resolved and so an availability of 80% has been assumed for the coming winter. We are continuing to monitor the performance of the nuclear generation fleet over the summer.

Figure B.16 – Historic Nuclear Generation Availability



Mothballed Generation Capacity

225. The amount of plant that is long term mothballed has increased slightly to 1.25 GW from last year's level. We do not expect any other plant to be mothballed for winter 2009/10, though with lower electricity demands as a result of the economic slowdown, new CCGT plant commissioning and LCPD restrictions on some marginal plant the possibility of some mothballing should not be completely ruled out at this stage. We do not expect any of the currently mothballed generation plant to become available for this winter.

Generation Side Risks

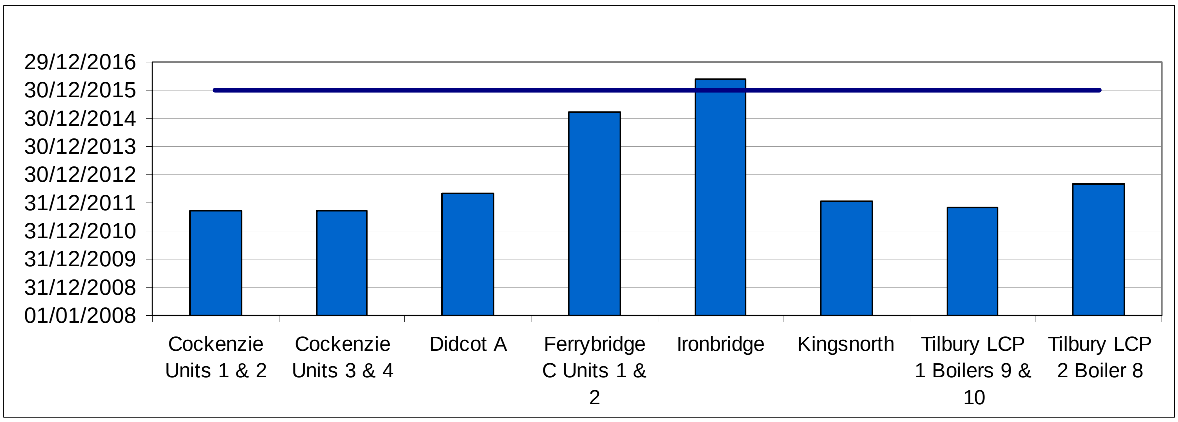
226. For the coming winter we are not proposing at this stage to provide a "low case" generation scenario. This is because we have not identified a specific risk area such as for nuclear generation late returns from outage which existed last winter. Generation capability risks appear lower and more generic for the coming winter at this stage. Type faults/generic safety issues can arise occasionally or key power station mechanical plant may fail from time to time. Capacity restrictions through these kinds of risks and issues are only potentially onerous if they happen to coincide with periods of relatively high demands and they are low probability events.

227. It remains credible as recent history has shown that over the 2009/10 demand peak that wind power output is low. If wind power output is discounted to zero over the winter demand peak, available generation reduces by 400 MW (27% of

1.5 GW capacity). Hence in the current environment the impact of no wind is of low materiality for this winter.

228. Issues related to the limited hours under LCPD for opted out plant are unlikely to affect this winter, but could be relevant for next winter 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 of utilisation of the allowed hours there is an implication of early closure at some power stations. Our latest view of early closing, given running patterns to date projected forward for opted out coal stations is shown in Figure B.17. We have not shown opted out oil stations in this chart due to their current low number of running hours relative to their 20,000 hours allowance.

Figure B.17 – Indicative LCPD Coal Opt Out Plant Closing Dates



Contracted Reserve

229. In order to achieve the demand-supply balance, National Grid procures reserve services from either generation or demand side providers to be able to deal with actual demand being greater than forecast demand and to cover last minute plant breakdowns. This requirement is met from both synchronized and non-synchronized sources.

230. We procure the non-synchronized requirement 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.

231. 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.

232. For winter 2009/10, the expected total level of contracted STOR reserve is approximately 2.1GW, over 1.6 GW from BM participants and nearly 0.5 GW from non-BM generating plant and demand reduction.

233. Prior to the winter, there will be two further STOR tender rounds covering services for the winter 2009/10 darkness peak; the results of which will be published at the end of August and mid November. Communications regarding

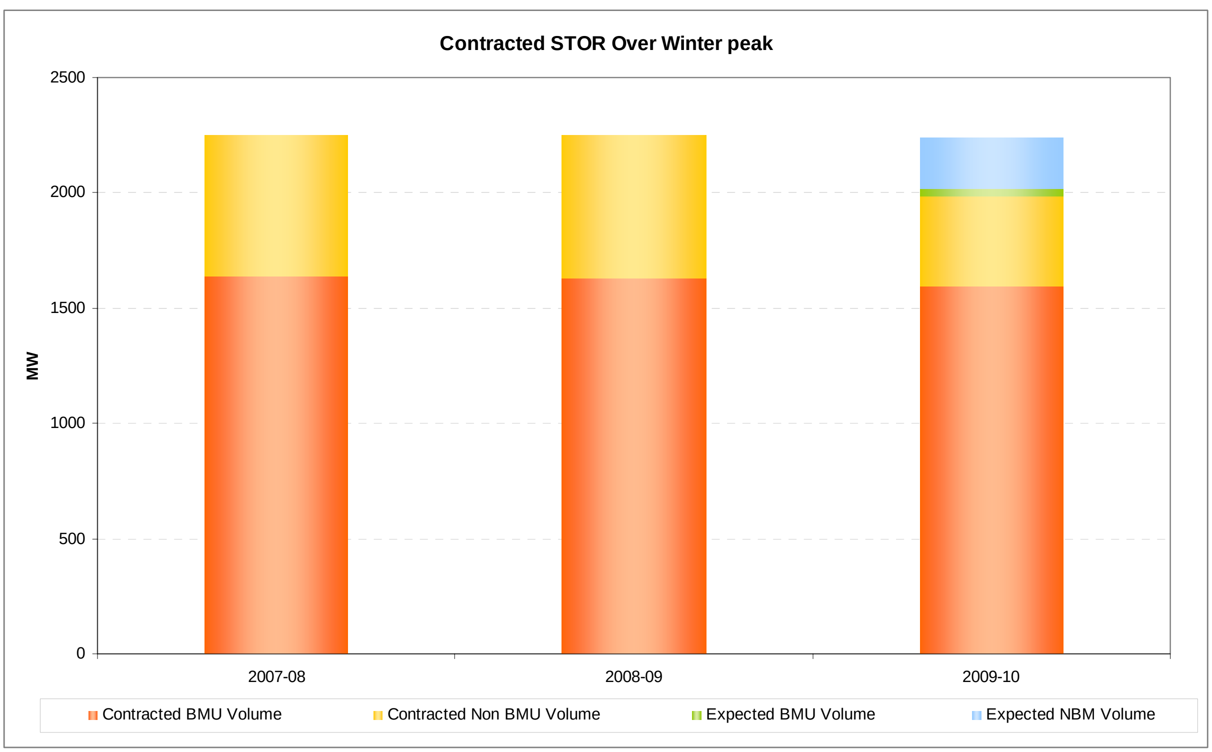
this will be through electricity operational forums and on our website http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/STOR/.

234. Figure B.18 shows the contracted STOR for the winter peak over the last 3 years. National Grid expects to contract a further 250MW of STOR taking into account units which have become unavailable due to the economic downturn.

235. 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. 1GW of this 1.5GW reserve requirement has already been contracted, with 0.2GW from demand-side providers.

236. National Grid continues to have Maximum Generation contracts in place for Winter 2009/10, 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 B.18 Contracted STOR for Winter Peak 2009/10

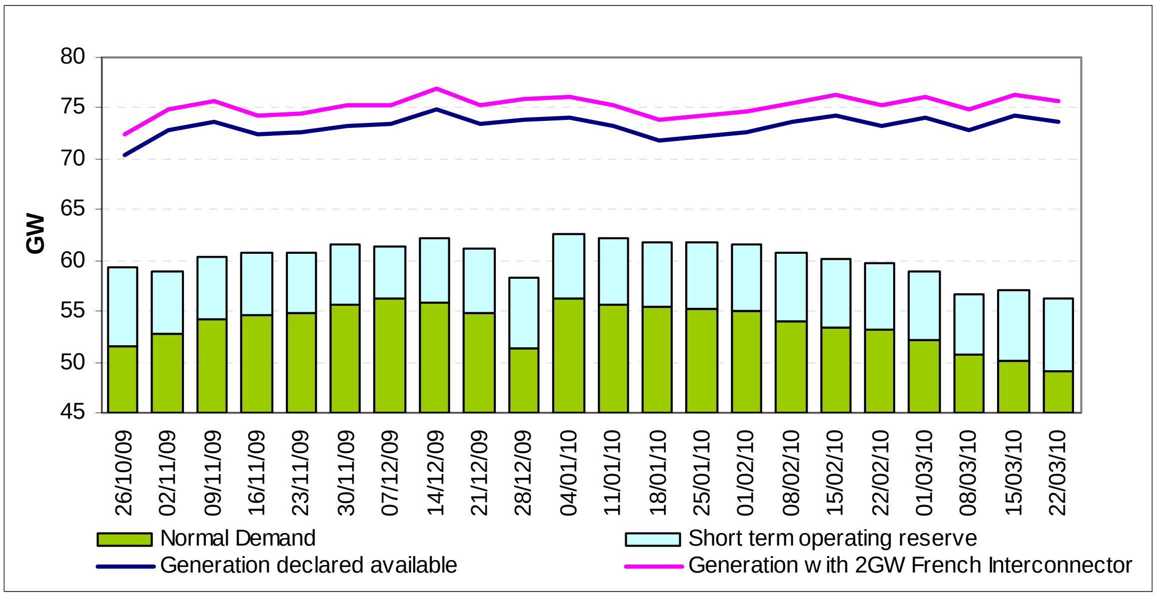


Forecast Generation Surpluses 2009/10

237. Figure B.19 reflects a winter where weather and demand are at normal levels for each week. The generation available is the availability declared to National Grid by the generators under Operating Code 2 of the Grid Code, and reflects planned unavailability, but has no allowance for unplanned generator unavailability.

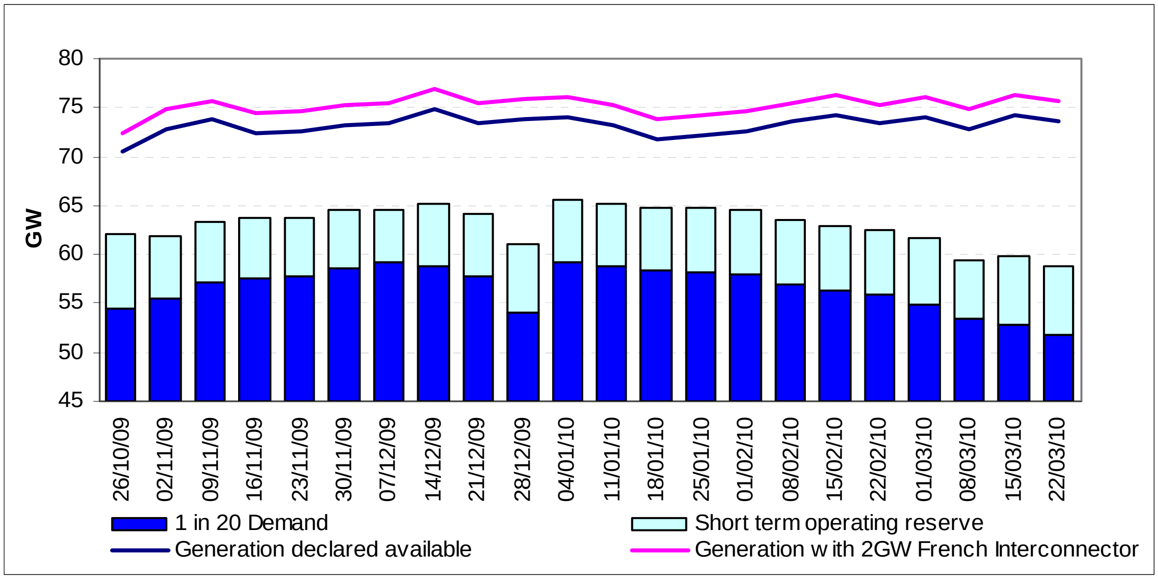
238. Demand in Figure B.19 is based on no interconnector exports to France and Ireland in line with our base assumptions at the time of the daily peak. As the figure shows based on normal demands and notified availability there is sufficient generation to meet demand and our short term operating reserve requirements comfortably, even without imports from the French interconnector.

Figure B.19 - Normal Demand and Notified Generation Availability



239. Figure B.20 reflects a winter where weather and demand are at 1 in 20 levels for each week. As the chart shows based on 1 in 20 demands and notified availability there is sufficient generation to meet demand and our short term operating reserve requirements comfortably.

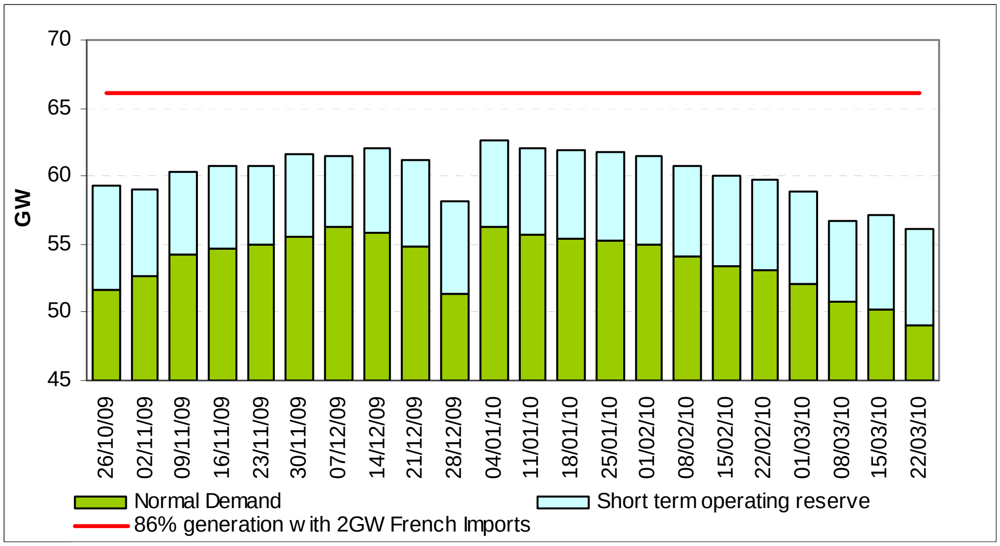
Figure B.20 - 1 in 20 Demand and Notified Generation Availability



240. Figure B.19 and Figure B.20 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. We have outlined our assumptions earlier in this report for the levels of actual generation availability we expect at the time of demand peak, which use historic availability achieved over historic demand peaks to indicate the combined effect of both planned and unplanned unavailability.

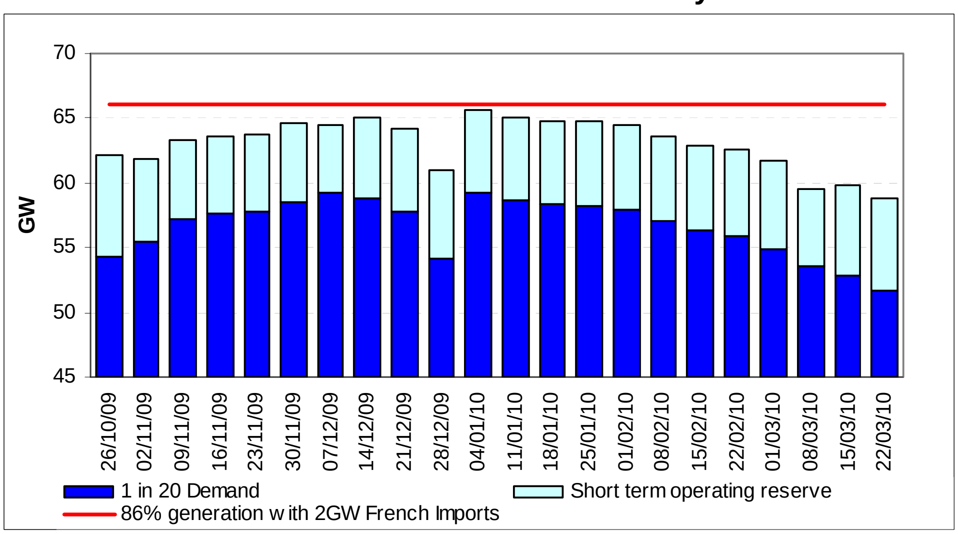
241. Figure B.21 shows our average weather condition driven demands (normal demand), plus our short term operating reserve and our assumed availability of generation which is 86% of our operational view of generation capability plus 2GW of import from France. As the chart shows based on normal demands and using generation availability based on these assumptions there is sufficient generation to meet demand and our short term operating reserve requirements comfortably.

Figure B.21. Normal Demand and Assumed Generation Availability



242. Figure B.22 takes the 1 in 20 demand level scenario but uses our assumed level of generation availability which as above allows for unplanned unavailability. This figure shows that 1 in 20 demand levels can be met including meeting our short term operating reserve in full.

Figure B.22 - 1 in 20 and Assumed Generation Availability



243. For the winter to come we do not propose developing specific scenarios to cover an increase in electricity demand if economic recovery were to be more rapid than anticipated as we believe it is unlikely a material effect could be seen by the time of the likely winter peak demands in December 2009 or January 2010. We are seeking views on what stakeholders foresee as credible scenarios we should present in our final outlook report either on the demand or generation aspect.

Should new information come to light before the final winter report is published we may introduce new scenario(s) in response to what we observe or consultation feedback.

Generation Merit Order 2009/10

244. This report section focuses on the outlook for meeting electricity demand and is less directly concerned from this perspective with the generation merit order itself. Which power generation type contributes to meeting demand is determined to the greatest extent by the market and therefore is subject to significant uncertainty as market prices for winter change over time.

245. The best guide is current forward prices for fuel and carbon for the winter to come, noting the caveat that we may see relative economics of gas and coal change significantly. At this stage, based on forward prices prevailing at the start of June for winter 2009/10 there is a marked difference between Q3 and Q4 merit order with gas preferred over coal for Q3 and coal preferred over gas for Q4. We will update our analysis of fuel and carbon prices during the summer and include our findings in the final report to be published at the end of September.

Questions for Consultation

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

QB11. The level and direction of flow of the electricity interconnector that might be expected given cold weather in both UK and Europe;

QB12. The appropriate capacity credit to apply to wind generation towards meeting a demand peak and the improved approach we are taking using our work with Edinburgh University;

QB13. The accuracy of our generation availability assumptions for all fuel types;

QB14. Our forecast of peak electricity demand and the validity of the drivers we identify behind this demand reduction;

QB15. Will any additional generation be placed into a mothballed state before the close of winter 2009/10?

QB16. Do you expect that new CCGT's particularly will become available over this coming winter and are you able to share your expectations of their timing?

QB17. Are there any key drivers of generation availability that are changing for winter 2009/10?

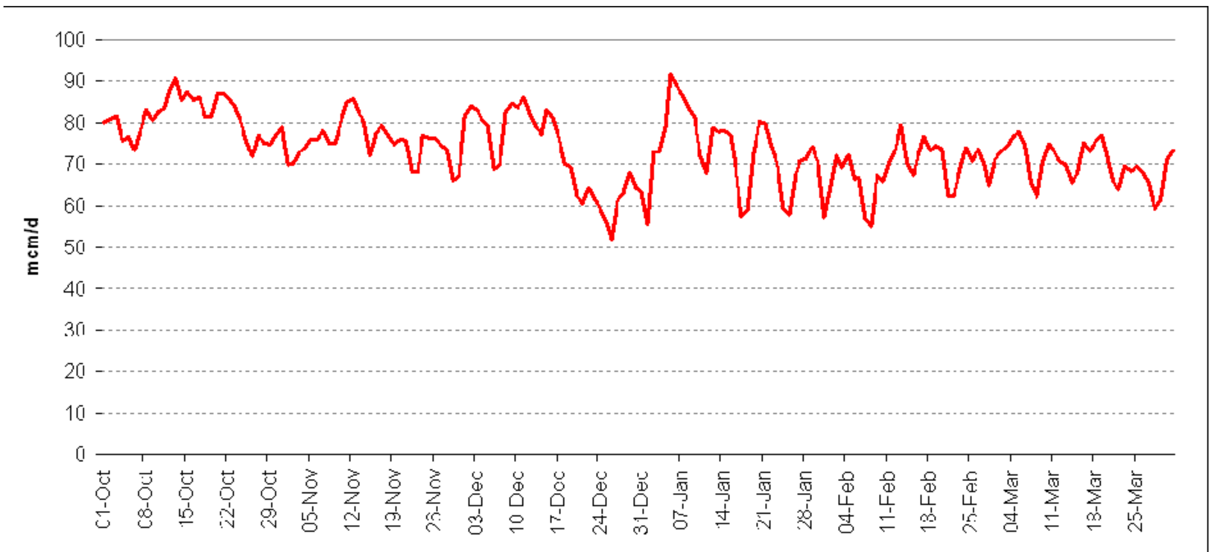
QB18. Should any specific scenarios of either demand or generation availability be added to the analysis in the final report and what scenarios do you think most credible?

Section C
Gas/Electricity Interaction

Power Generation Gas Demand

246. Daily gas consumption from CCGTs has varied over last winter with a Christmas period low of 52mcm/d followed shortly afterwards by a 93mcm/d high in early January across the winter. In the last three months of 2008 consumption was at around 85mcm/d on weekly peak demand days. After Christmas, this dropped to about 75~80 mcm/d reflecting the declining economic situation in the UK and relative commercials of gas and coal generation as well as increased nuclear generation coming progressively online.

Figure C.1 – Gas Consumption for Power Generation



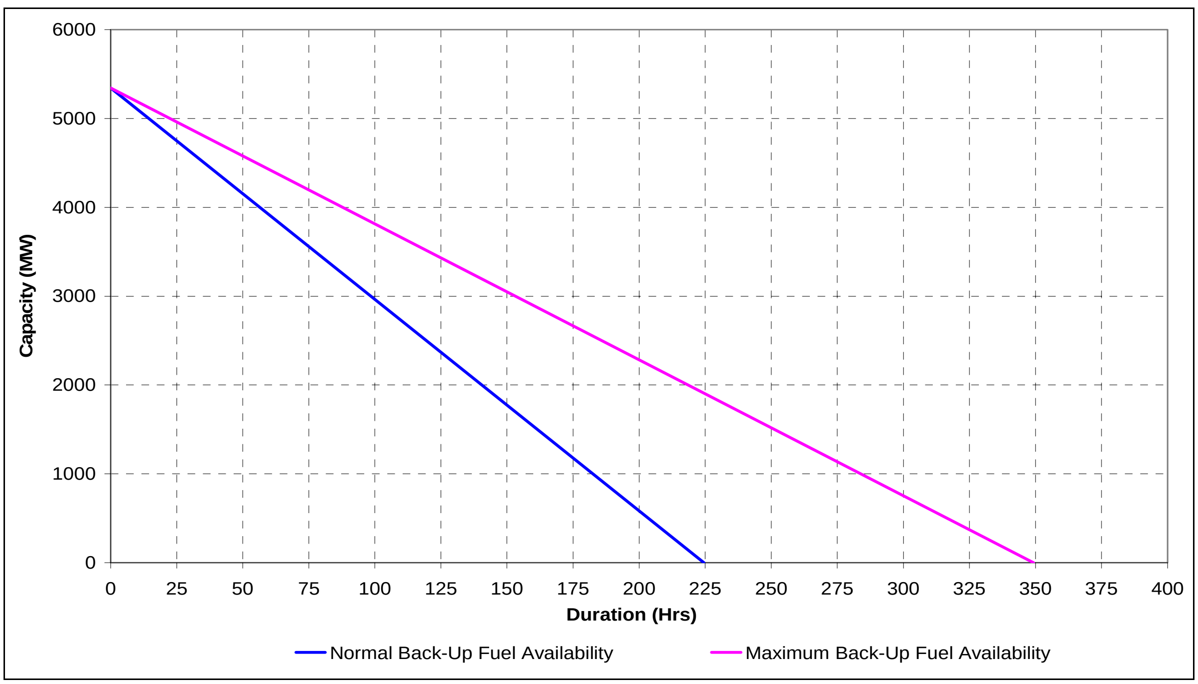
Power Stations with Alternative Fuels

247. 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 which is slightly lower than last year's estimation of 5.4 GW. Out of the total 5.3 GW having back-up fuel generation capability, more than of half of which have interruptible gas transportation arrangements.

248. Figure C.2 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. 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

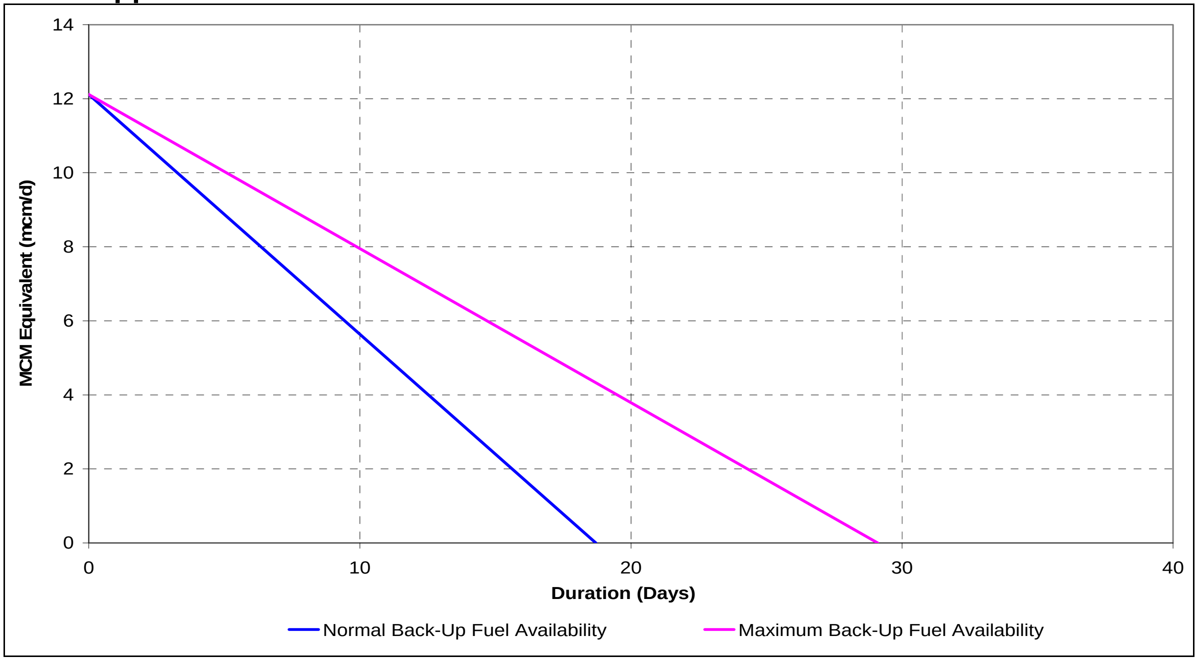
load when running on distillate. Note, however, that this graph is not intended to suggest that all generators with back up fuel capability would run continuously on back up fuel supplies for several days or at full distillate running load. In reality different generators would adopt different commercial strategies. We currently assume that most of this capacity would only run on back up fuel over the peak demand periods, though its also equally likely that generators could run off peak on distillate. Our assumption is made because we have not seen any real experience of how power stations that run on distillate operate in recent history and a range of outcomes are possible. The key consideration is the amount of gas demand from power stations that can be displaced within the gas day should this become necessary so timing in the electricity day is less critical. 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 C.2 – Power Load Duration Curves for Back Up Fuel Supplies



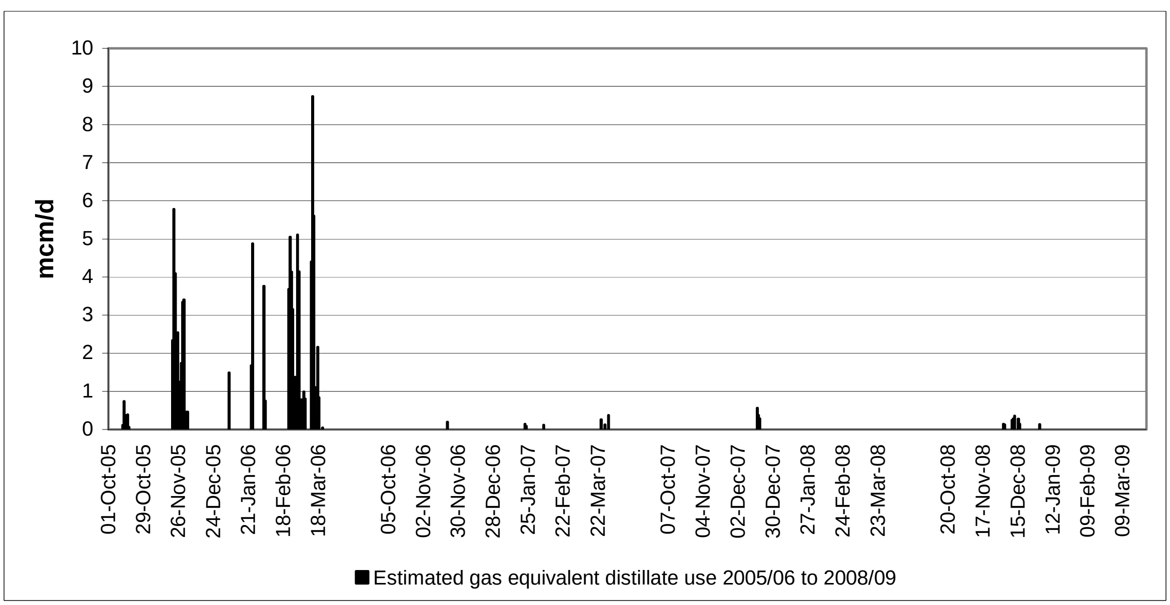
249. Based on the distillate back up fuel data from the generating companies for 2009/10, we estimate that a total of between 110 mcm to 175 mcm gas equivalent can be displaced using distillate generation capability. This is shown in figure C.3. In 2008/09, there was an estimated total of less than 1.0 mcm equivalent distillate use around system peak days. Figure C.4 shows the mcm/d equivalent levels of distillate fired power generation for last winter.

Figure C.3 – Gas Volume Equivalent Load Duration Curves for Back Up Fuel Supplies



250. We have also estimated historic distillate use over previous winters. This shows very little use of distillate in the last three winters, but up to 9 mcm/d of relief has been seen in the past. Historic use of distillate for winters in 2006/07 onwards has been restated in figure C4 compared to similar charts we have previously published as we have refined our analysis approach for this winter outlook report and see benefit in ensuring data is shown on a consistent basis for the period shown.

Figure C.4 – Estimated Historic Distillate Use in Term of mcm/d Relief to Gas Demand



Potential for Demand-Side Response from Gas Fired Generation

251. 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.

Analysis of potential CCGT gas demand response

252. A number of respondents have previously identified practical issues that could limit the extent of any CCGT response. We welcome feedback through our consultation on these and related issues associated with gas power stations providing relief to the gas sector. Issues raised included:

- Technical risks associated with frequent switching to/from and prolonged use of distillate;
- Limitations on the levels of switching to coal and oil as a result of environmental constraints and LCPD considerations;
- Ability to replenish stock may be difficult, especially in prolonged severe weather conditions and if stocks are delivered by road tankers;

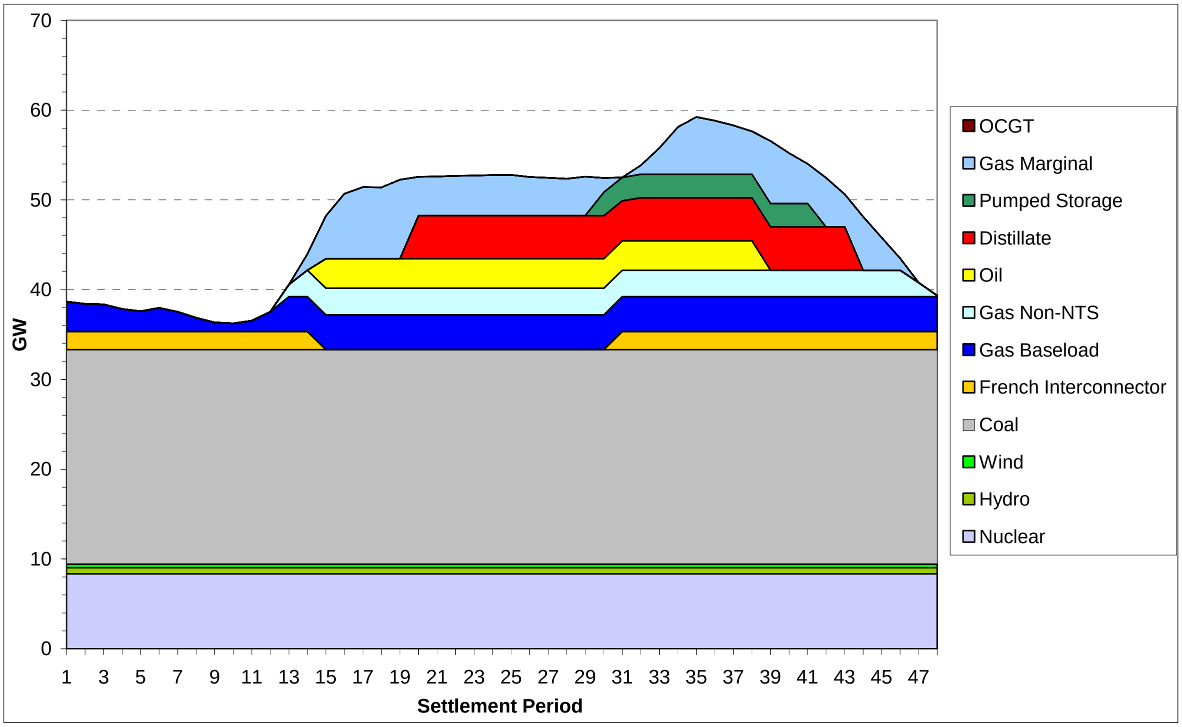
253. We have though modeled the amount of relief that gas power stations switching to distillate could provide to the gas market. Using the assumption that distillate capable gas power stations ran for 12 hours per day gives at least 10 mcm/d of gas relief for up to 4 days based on normal and full distillate stocks. The charts here assume no restocking of distillate which we expect would take place as stocks are depleted over a number of days

Table C.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	10.4	80%	8.4	Baseload
French Interconnector	2.0	100%	2.0	Baseload, except 7 am to 3pm weekdays
Hydro	1.1	60%	0.7	Baseload
Wind	1.5	27%	0.4	Baseload
Gas Baseload	4.3	90%	3.9	Baseload
Gas Non-NTS	3.3	90%	3.0	Baseload
Coal	28.1	85%	23.9	Baseload
Oil	3.4	95%	3.3	12 hours over peak
Pumped Storage	2.7	95%	2.6	6 hours over peak
Distillate	5.3	90%	4.8	175 hours
Gas Marginal	13.3	90%	12.0	Marginal plant
OCGT	1.3	95%	1.2	Low merit, run occasionally
Total	**76.9**		66.0	
Average availability		**86%**		

254. Figure C.5 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modeling assumptions described in table C.1. It shows approximately 23.9 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 C.5 – Potential generation profile – 1 in 20 cold winter weekday



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

256. The most significant use of distillate occurred in the winter of 2005/06 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 C.3 (technical capability to burn distillate) and C.4 (analyzed distillate use) which reflect two different approaches to assessing capability giving some comfort in the assessment of power sector relief to the gas market.

257. 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.

258. In this consultation report we have not provided an in-depth assessment of gas power interaction inline with previous consultation reports but we expect to update this section in the final winter consultation report in late September.

Questions for Consultation

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

QC1. Our initial view of gas/power interaction risks given the broad context of increased comfort with potential gas and electricity supplies, and lower gas and electricity demands, is that there is a lower risk than recent previous winters of needing to reduce gas fired electricity generation. To assist us in our analysis we welcome views on the market scenarios we should model and the likelihood of the situation taking place. Scenarios could include high gas export to Europe over a pro-longed period coincident with high gas demands, or gas supply terminal failure coincident with sustained high gas demands?

Please comment upon: -

QC2. Our assumptions relating to the generation running order under very cold weather conditions;

QC3. The extent to which electricity market prices will be able to achieve levels compared to gas prices such that they will determine that CCGTs will continue to burn gas at peak electricity demand periods;

QC4. The ability and willingness of CCGT generators to switch to distillate;

QC5. Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks;

QC6. The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation;

QC7. The extent to which increased levels of other fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints and fuel stocks;

Section D
Industry Framework Developments

Introduction

259. 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.

Gas

Exit Reform

260. Current arrangements allow Users to secure capacity until 30 September 2012.

261. Enduring NTS offtake arrangements allowing Users to secure capacity from 01 October 2012 onwards have now been implemented.

262. Applications can be made as follows:

- Users can apply for Enduring capacity in the Annual July Application Window or via an Ad-hoc process.
- Developers can apply for Enduring capacity via the ARCA process.
- Annual, Daily and Offpeak capacity can also be obtained in the Enduring regime.
- Further detail on Exit Reform can be found on a dedicated section of our website www.nationalgrid.com/uk/Gas/OperationalInfo/endureeexitcap/

Exit Capacity Substitution

263. Ofgem introduced an obligation for National Grid to undertake Exit Capacity Substitution. Exit Substitution would only apply to capacity from 1 October 2012 onwards i.e. the enduring period.

264. Regular workshops will be held with the Industry to discuss the most appropriate way to introduce this obligation. National Grid will publish a timetable in December 2009 for future Exit Substitution workshops.

265. National Grid has a licence obligation to submit an Exit Capacity Substitution Methodology Statement to the Authority by 4 January 2011.

Entry Capacity Substitution

266. Ofgem introduced an obligation for National Grid to undertake Entry Capacity Substitution. Under this obligation National Grid will seek to substitute unsold Non-incremental obligated Entry Capacity to other entry points where Incremental obligated Entry Capacity is required to be released.

267. In order to meet the aims of this obligation regular workshops with the Industry are being held.

268. National Grid has a licence obligation to submit an Exit Capacity Substitution Methodology Statement to the Authority by the 7th September 2009 and if approved Entry Capacity Substitution will be implemented on 01 March 2010

Amendment to QSEC and AMSEC Auction timetables

269. On 29 May 2009 Ofgem approved Modification Proposal 230AV which moves the QSEC Auction from September to March each year. This will be implemented on 01 January 2010. The modification retains the September 2009 QSEC before moving the QSEC to March on a permanent basis. It is also retains the AMSEC auction in February with a shortened transaction period from the current 2 years to 18 months. This results in Incremental NTS Entry Capacity being released from 1 October at the start of the winter period when flows increase.

Review of the UNC Post-Emergency Arrangements

270. In February 2009, National Grid initiated an industry review of the prevailing UNC post-emergency arrangements. The objective of the review is to consider primarily what UNC changes could be made to the post-emergency claims process that would improve the definition and give greater clarity in this area. It is anticipated that any such changes would provide confidence to shippers that they are able to recover their costs for providing additional non-UKCS supplies and/or demand side reduction following a Network Gas Supply Emergency (Gas Deficit Emergency).

271. Once the review of the UNC post-emergency claims process is complete (June 2009), National Grid will raise a UNC Modification Proposal with an implementation date of October 2009.

Electricity

Balancing & Settlement Code relevant proposals / issues

Electricity Market Information

272. The Authority approved BSC modification P226 for implementation on the 25th June 2009. P226 will enhance the visibility of key Large Combustion Plant Directive (LCPD) emission limit/allocations and operating hours data by publishing such data on the Balancing Mechanism Reporting System (BMRS). It is anticipated that increased visibility of LCPD data will allow market participates to make more informed economic decisions.

Transmission Losses

273. BSC modification P229 is currently being developed. 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. However P229 is not expected to impact winter 09/10 as it is unlikely to be implemented within such time frames.

Incentives to balance

274. The Authority approved BSC modification P217 for implementation on the 5th November 2009. P217 will alter the calculation of the main electricity imbalance price by removing any premium associated with balancing services taken for the purpose of resolving transmission constraints. To achieve this, National Grid must identify in real time, balancing services taken to resolve transmission constraints, and also provide balancing service adjustment data (BSAD) as individual trades. This modification will result in imbalance prices that more closely reflect the short term value of energy.

Black Start / Fuel Security Code (FSC) – Market Suspension/Recovery

275. National Grid raised two BSC modifications to improve the Black Start and FSC procedures and compensation arrangements, including the derivation of a single imbalance price, following a Black Start Period or FSC event. P231 provides greater granularity on market restoration processes, including clarity of roles and responsibilities of relevant parties, whilst P232 addresses post-event settlement processes, including the development of a price calculation methodology applicable to Black Start Periods and Fuel Security events. Ofgem approved both P231 and P232 in June 2009 for implementation in November 2009.

Connection and Use of System Code (CUSC) - CAP148, CAP167 and CAP170

276. 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 is currently with Ofgem for Authority decision and following the Authority Impact Assessment of July 2008 (setting out the Authority's minded-to decision to reject each of the CAP148 variants) a further consultation has been issued. This seeks to consult on 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.

277. 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. CAP167 is currently with the Authority for decision.

278. 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 is currently with the Authority for decision, with the Authority having issued an Impact Assessment to consult on the proposal with the industry.

Grid Code relevant proposals / issues

279. On 27th May 2008, exceptional loss of generation led to the operation of the first stage of the national low frequency demand disconnection scheme. After an investigation by the Energy Emergency Executive Committee (E3C), two Working Groups were formed, one to investigate the effectiveness of the Low Frequency Demand Disconnection scheme and the other to assess the performance of embedded generation during the incident.

280. It was agreed at May 2008 Grid Code Review Panel (GCRP) to establish a joint Grid Code and BSSG (Balancing Service Standing Group) Working Group. The Working Group would be tasked with reviewing the technical requirements and commercial mechanism applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

281. As part of the work to facilitate synchronous generating units who wish to operate above rated MW, we have developed, with the industry, an amendment (A/09) for the required commercial arrangements. The arrangements define the required technical obligations and ensure system security for generator operating above rated MW whilst maximising the frequency and consistency to do so. The proposals were approved by the Authority and were implemented on 1st May 2009.

BM System Replacement

282. 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 of mid 2012. Last year, National Grid consulted with the industry on the proposed BM replacement and the industry comments were fed into the System Requirements Specification. National Grid is currently evaluating the vendor responses, and the vendor evaluation process is likely to go into early 2010.

Implementation of a new Congestion Management System on the England-France Interconnector (IFA)

283. In order to comply with the Congestion Management Guidelines[19] National Grid Interconnector Limited (NGIL) and the French transmission system operator (RTE)

[19] The Congestion Management Guidelines, published in the Official Journal on 11 November 2006 (OJ L 312, 11.11.2006, p. 59-65), set the congestion management framework in the EU. They entered into force on 1 January 2007 and are annexed to Regulation (EC) 1228/2003 of the European Parliament and of the Council, of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.

are planning to implement a Capacity Management System (CMS) on the IFA in summer 2009. The key features of the new system will be Use it or Sell it (UIOSI) for long term capacity, Use it or lose it (UIOLI) for day ahead capacity, five re-nomination points within day and two intraday auctions. Ofgem, National Grid Electricity Transmission (NGET), NGIL, RTE and the French energy regulator (CRE) are currently discussing whether certain tools could be made available to national system operators in order for them to maintain operational security and balance their systems in an economic and efficient manner. These tools are currently being discussed and will need to be compliant with the Congestion Management Guidelines and be agreed between all parties.

Appendix 1 – Consultation Questions

We will provide an excel table version of the questions posed in this consultation on our website at http://www.nationalgrid.com/uk/Electricity/SYS/outlook/ which can be downloaded for responses to be added before being returned to us and/or Ofgem.

	Gas - Winter Review
QA1	We welcome views on the contributing factors behind the reduction in gas demand and are these likely to be permanent?
QA2	What proportion of this reduction in weather corrected gas demand is due to consumer behaviour such as turning down the thermostat and what proportion is due to long-term efficiency measures such as loft insulation and condensing boilers?
QA3	Are the changes in consumer behaviour a temporary response to high prices and the credit crunch or a long term response to climate change?
QA4	We welcome views on our assessment of UKCS supplies and in particular our view that for the majority of the winter most UKCS supplies were operating at or near maximum flow.
QA5	We welcome views on our assessment, that high Norwegian flows were delivered to the UK due to Continental buyers taking less gas due to high prices
QA6	We welcome views on the drivers behind BBL flows
QA7	We welcome views on the ability of the UK to provide a source of gas for exports to the Continent and to what extent these arrangement for UK imports are reciprocated, also would IUK have imported more if the UK gas price was higher
QA8	Were global gas markets responsible for higher LNG import flows?
QA9	What were the key drivers behind storage use this winter. At the time of the Russia Ukraine dispute was storage used to sustain IUK exports?
	Electricity - Winter Review
QA10	Do you believe that electricity demand side response capability has materially reduced due to the economic slowdown? Are you able to quantify this impact with supporting information and relate it to an overall GB estimate of end user demand response and share this with National Grid?
QA11	Do you agree that the main driver of demand reductions recently seen is the recession? Do you believe demands will return in due course to pre-recession levels and when might this be expected to take place?
QA12	Do you identify other significant factors driving interconnector behaviour in addition to technical availability and relative energy prices between interconnector markets. Has anything particular changed last year for the medium term?
QA13	What actions were taken by the market to contribute towards meeting demand at times when we issued system warnings? Were there any limitations on any actions the market took at times of system warnings and

	what could or should be done to address any limitation, if identified?
QA14	Was sufficient key information available on the operational view of electricity demand and supply to enable market participants to be aware of electricity system balancing issues? If you believe additional key information should be provided please outline what other information would assist the market and outline the scale of potential benefit.
	Gas - Winter Outlook
QB1	Will there be further reduction in NDM gas demand due to the recession or efficiency savings in winter 2009/10?
QB2	Will the NDM demand lost due to short-term actions return on a very cold winter's day?
QB3	What drivers may influences the gas price in winter 2009/10? What factors may set floor and ceiling prices?
QB4	Do you agree with our high level view of lower UKCS supplies and increased Norwegian imports to the UK albeit dependent on Continental flows?
QB5	What assumptions should be made for levels of imported gas through BBL and IUK for winter 2009/10?
QB6	What assumptions should be made for levels of imported LNG through Grain, Milford Haven and Teesside for winter 2009/10?
QB7	We would welcome comments on our 2009/10 Preliminary View, and thoughts on how we can reduce or manage the resulting supply range.
QB8	We would also welcome comments on our changes to the Safety Monitor determination and our plans to improve related market information for next winter.
	Electricity - Winter Outlook
QB9	The level and direction of flow of the electricity interconnector that might be expected given cold weather in both UK and Europe;
QB10	The appropriate capacity credit to apply to wind generation towards meeting a demand peak and the improved approach we are taking using our work with Edinburgh University;
QB11	The accuracy of our generation availability assumptions for all fuel types;
QB12	Our forecast of peak electricity demand and the validity of the drivers we identify behind this demand reduction;
QB13	Will any additional generation be placed into a mothballed state before the close of winter 2009/10?
QB14	Do you expect that new CCGT's particularly will become available over this coming winter and are you able to share your expectations of their timing?
QB15	Are there any key drivers of generation availability that are changing for winter 2009/10?

QB16	Should any specific scenarios of either demand or generation availability be added to the analysis in the final report and what scenarios do you think most credible?
	Gas/Power Interaction
QC1	Our initial view of gas/power interaction risks given the broad context of increased comfort with potential gas and electricity supplies, and lower gas and electricity demands, is that there is a lower risk than recent previous winters of needing to reduce gas fired electricity generation. To assist us in our analysis we welcome views on the market scenarios we should model and the likelihood of the situation taking place. Scenarios could include high gas export to Europe over a pro-longed period coincident with high gas demands, or gas supply terminal failure coincident with sustained high gas demands?
QC2	Our assumptions relating to the generation running order under very cold weather conditions;
QC3	The extent to which electricity market prices will be able to achieve levels compared to gas prices such that they will determine that CCGTs will continue to burn gas at peak electricity demand periods;
QC4	The ability and willingness of CCGT generators to switch to distillate;
QC5	Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks;
QC6	The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation;
QC7	The extent to which increased levels of other fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints and fuel stocks;

RO1	Other Feedback can be entered here or sent separately
RO2	Other Feedback can be entered here or sent separately
RO3	Other Feedback can be entered here or sent separately
RO4	Other Feedback can be entered here or sent separately