Winter Consultation 2013/14

Introduction

1. This document sets out our analysis and views for the coming winter. Previous outlook reports are published on our website[1]. The document is separated into two main sections, a review of last winter and a consultation on the outlook for the coming winter. At the end of each section there are consultation questions relating to Gas and Electricity, four consultation sections in total. National Grid would welcome feedback on these specific points and also welcomes industry and wider participant views on all points raised in this document. All consultation questions and other views should be sent to commercial.operation@nationalgrid.com by Friday 16 August 2013.

Industry Feedback

2. We continually seek feedback on our outlook reports to increase their usefulness to the industry and to reflect changes when they become apparent. To feed back comments on our outlook reports please contact us at commercial.operation@nationalgrid.com

Roles and Responsibilities

3. 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.

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[1] http://www.nationalgrid.com/uk/Electricity/SYS/outlook/ and http://www.nationalgrid.com/uk/Gas/TYS/outlook/

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

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Winter Review 2012/13 - Key Details

Fuel Prices	
Relatively stable coal and oil prices, declining carbon prices, rising gas and electricity prices. There were significant spikes in gas prices during March 2013 (eventually peaking at over £1/therm)	
Gas	
Highest demand 16 January 2013	393 mcm/d[2]
Gas demand depressed throughout winter due to power generation economics favouring coal burn	
2012/13 supply trends - lower UKCS (decline) and LNG (Far East demand), similar Norway, higher Continent and storage (prolonged winter period)	
Electricity	
Peak demand 12 December 2012 half hour ending 17:30	56.4 GW
Actual generator availability at the peak	83%

[2] NTS Demand

Winter Outlook 2013/14 - Key Details

Fuel Prices	
Forward energy prices for next winter are broadly flat with the exception of some seasonality in gas prices. The continuation of high gas prices relative to coal strongly favours coal as the preferred source of fuel for power generation	
Gas	
Peak gas demand forecast (1 in 20 diversified demand)	511 mcm/d
The peak forecast now allows for high power generation as well as cold weather	
Little change in winter demand forecast for 2012/13 with gas for power generation expected to remain low	
2013/14 supply forecasts – similar flows for UKCS and Norway, both LNG and Continent uncertain and subject to demand / prices, some additional (flexible) storage expected	
2013/14 safety monitor requirements are approximately 2.4% of total storage space compared to about 5% in 2012/13	
Electricity	
Forecast Normal Demand – winter peak	55.1 GW
Forecast 1 in 20 Demand – winter peak	59.0 GW
Forecast Generator Capacity at start of winter	77.1 GW
Notified Generation Availability[3] at winter peak with zero net interconnector flow	73.7 GW
Forecast surplus with notified generation availability and normal demand at winter peak	17 %
Assumed Generation Availability[4] at winter peak with median wind and zero net interconnector flow	59.8 GW
Forecast surplus with assumed generation availability and Average Cold Spell demand at winter peak	6 %[5]

[3] Notified generation availability is submitted by generators, assumes optimum wind and reflects planned generator outages

[4] Assumed generation availability is estimated using historic average generator breakdown data and median wind to de-rate the notified availability to give a central view of what generator availability will be this winter

[5] In line with Ofgem's Electricity Capacity Adequacy Report's 2013 reference scenario for 2013/14

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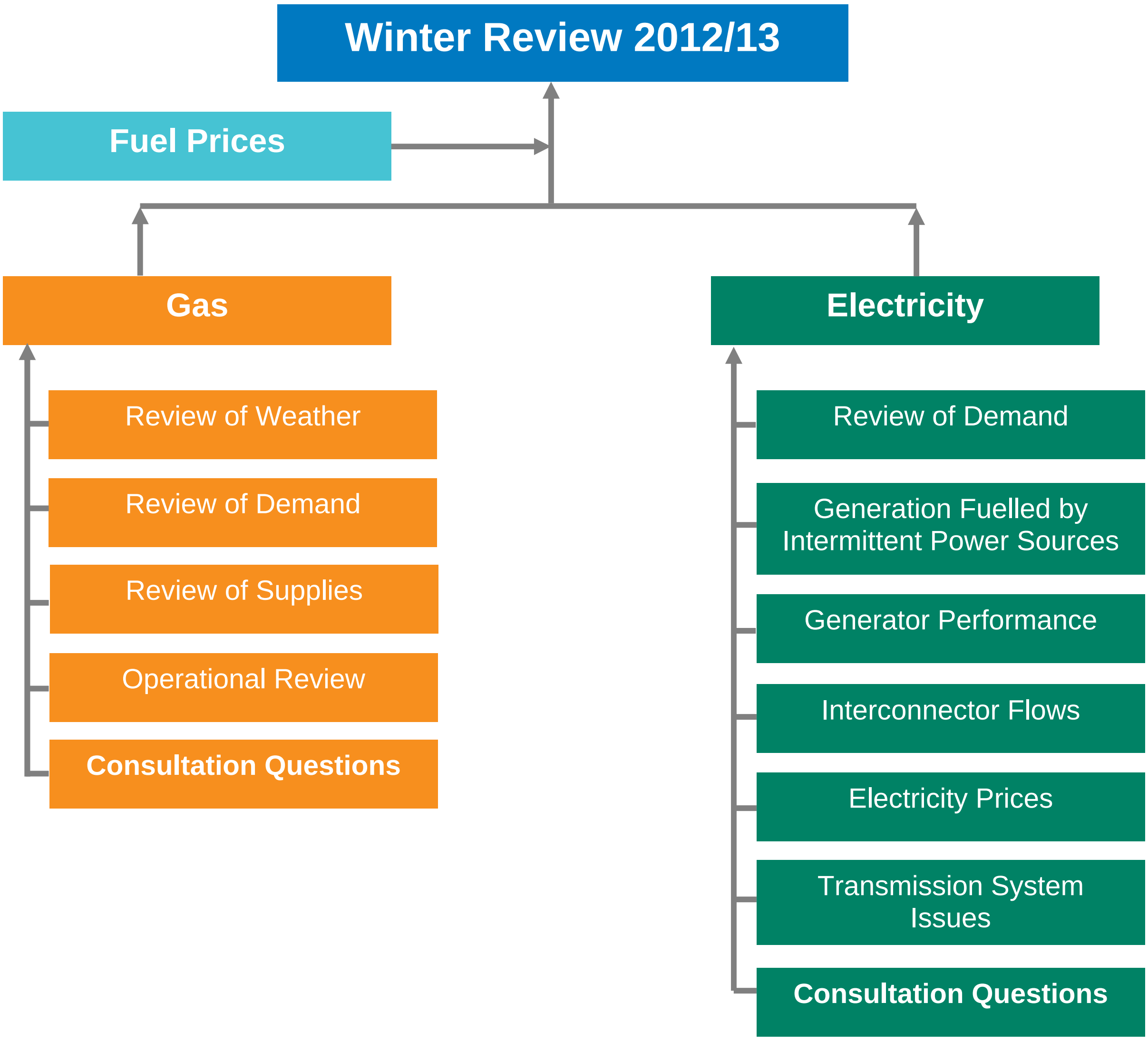
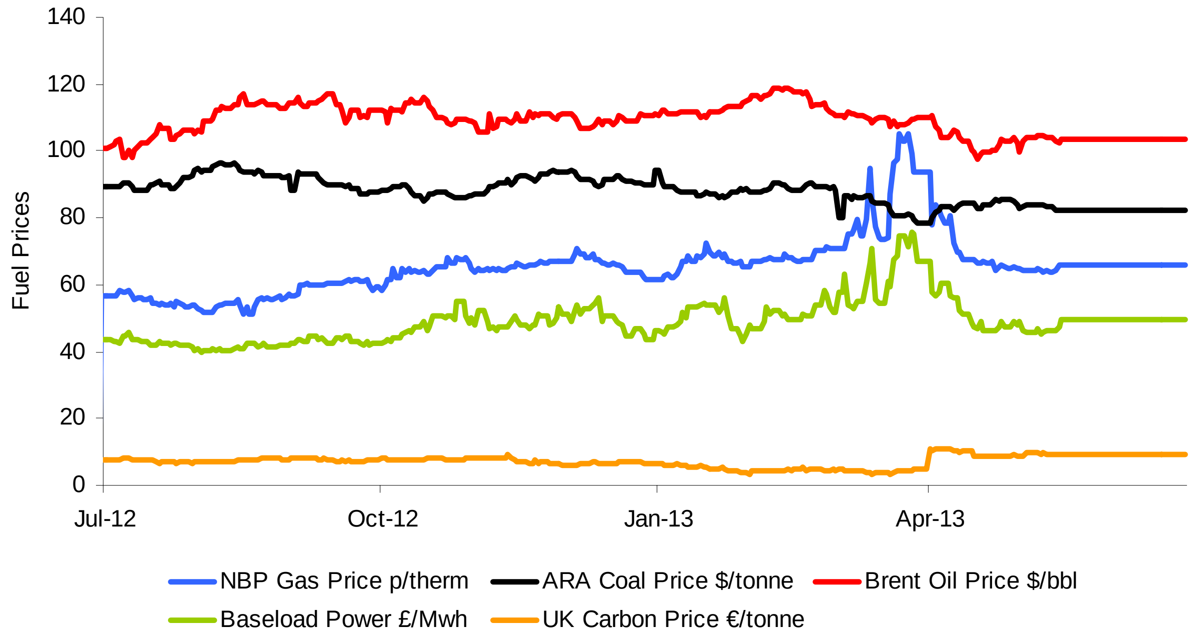
Winter Review 2012/13



Fuel Prices

7. **Figure F1** shows energy prices for the 12-month period between July 2012 and June 2013.

Figure F1 - Energy Prices since July 2012



8. The chart shows a differing picture over the last 12 months for the various fuels, with slight declines in the price of coal but significant rises in both gas and baseload power that has tracked the gas price.

9. Oil prices have been relatively stable over the previous 12 months, remaining between $100 -$120/bbl with an overall increase of ~4%.

10. After significant declines in previous years, coal prices have been relatively stable throughout the year, showing an overall decline of less than 10%.

11. UK gas prices have been rising for most of the last 12 months, gaining over 15% in value.

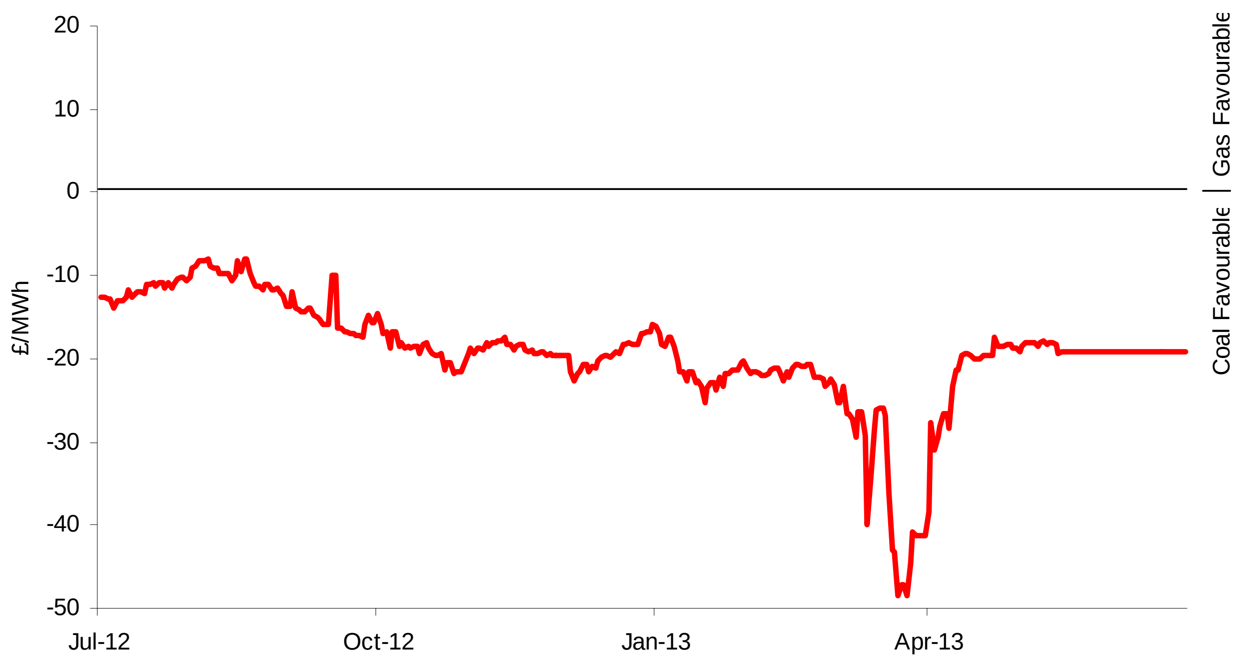
12. During mid-March 2013 there were significant rises in gas prices, eventually peaking at over £1/therm. There were a number of contributing factors to this spike, including unseasonably high demand, low levels of storage stocks and a lack of Liquefied Natural Gas (LNG) deliveries. Prices remained at these levels until the end of March, when falling demand and the arrival of several LNG cargoes combined to see prices start to fall to the levels they were at the start of the month.

13. Electricity prices have generally followed the gas price over the last 12 months both across the year, with a rise of almost 15%, and during the March spike.

14. Carbon prices on the European Trading Scheme (ETS) have continued to decline over the previous 12 months falling by almost 50% to under €4/tonne. From 1 April 2013 the UK has applied a Carbon Price Support of £4.94/tonne (~€5.8/tonne) which when added to the ETS price leads to an effective price of around €9.40/tonne, over 20% higher than a year ago.

15. **Figure F2** shows the relative dark and spark spreads, indicating whether gas or coal was favoured for electricity generation over the last 12 months.

Figure F2 – Relative power generation economics



16. Power generation economics have been strongly favoured towards coal for all of the previous 12 months and, with gas prices rising over the period, the difference between the spark and dark spreads has almost doubled to about £20/MWh. The spike in the gas price during March saw the difference in the spreads peak at just under £50/MWh.

17. Whilst the chart shows a strong bias for coal generation, there are other factors at play that determine the precise generating mix, these include power station generating efficiencies, ownership and the portfolio of energy companies.

Gas

Overview

18. This section reviews winter 2012/13 in terms of gas demand, supply and operational experience.

Review of Weather

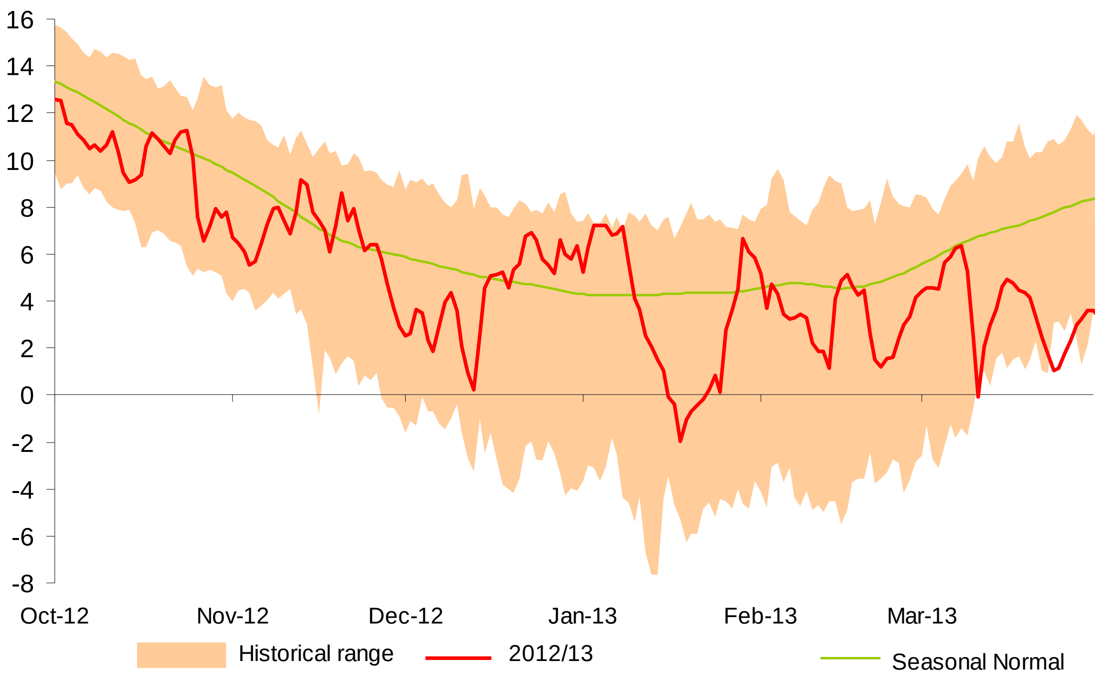
19. The 6 months from October 2012 to March 2013 were colder than seasonal normal condition with a protracted cold spell in February and March.

20. The 6 month period from October to March was the twenty second coldest when compared to the last 85 winters and the coldest in the last 20 years. The coldest day was on 18 January and was average in severity when compared to the last 85 years.

21. For the 3 month mid-winter period from December to February, the severity was average. Unseasonal cold weather was observed in the shoulder months of October, November and especially March. Consequently, observed non-daily metered gas demand, consumers most sensitive to weather, was 13% higher than seasonal normal demand over the winter period.

22. **Figure W1** compares the winter 2012/13 weather in terms of Composite Weather Variable (CWV) with the daily maximums and minimums since October 1928. The seasonal normal line has been adjusted for climate change and is not the average of the historical values.

Figure W1 – Winter Composite Weather 2012/13

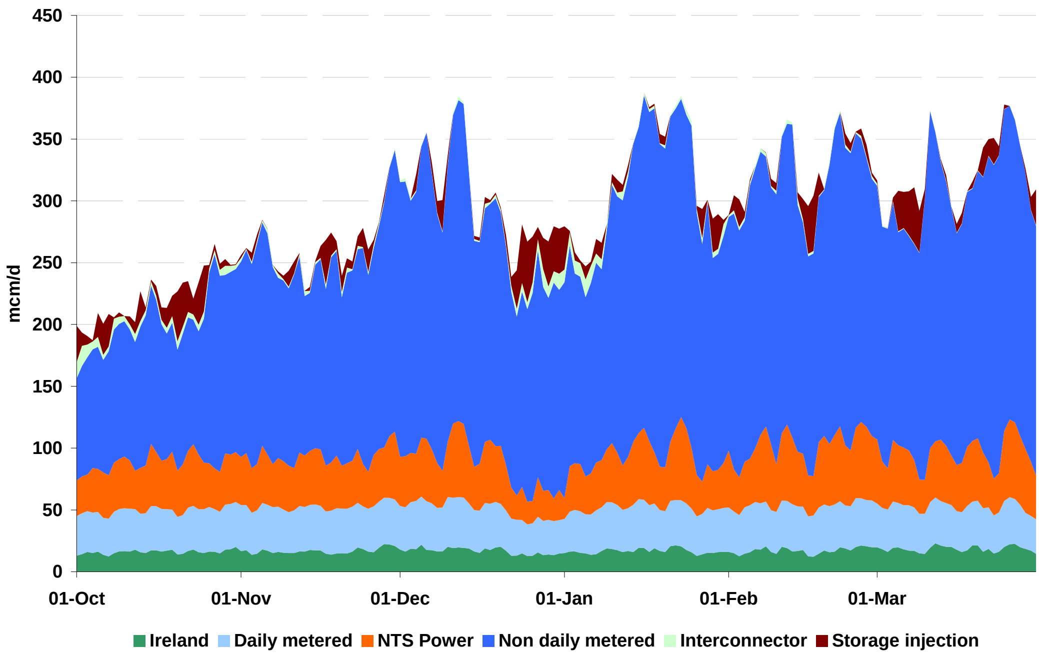


Review of Demand

23. The highest demand day in winter 2012/13 was 16 January 2013 with a demand of 393 mcm/d. This was lower than the high demands seen in recent winters due to a combination of a modest coldest day and lower gas burn for power generation.

24. **Figure G1** shows the gas demand for winter 2012/13.

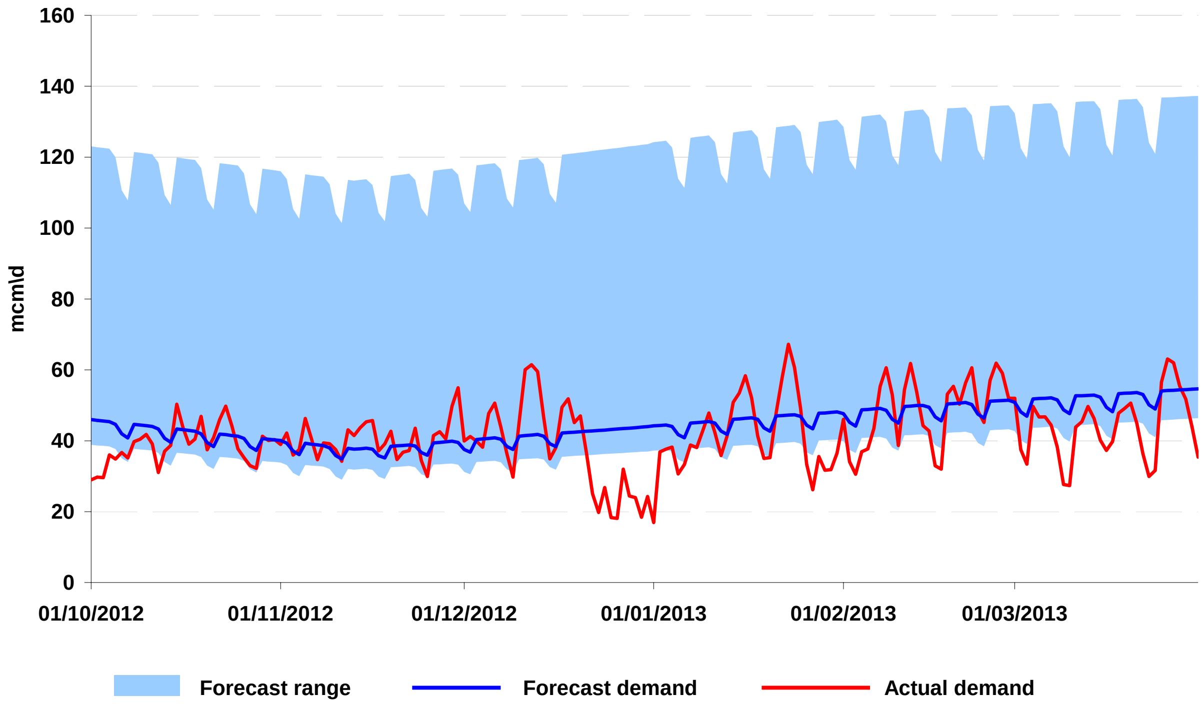
Figure G1 - Winter Gas Demand 2012/13



25. The chart shows relatively low demands for much of the winter, however the cold spell from mid February and throughout March 2013 extended the period of high demands beyond those normally experienced.

26. **Figure G2** shows the National Transmission System (NTS) connected power generation demand for winter 2012/13 together with the pre-winter base case forecast and high and low forecast ranges to reflect plausible generation merit orders depending on whether gas is base load or marginal generation.

Figure G2 - Winter Power Generation Demand 2012/13



27. The chart shows that power generation was broadly aligned to the forecast with coal at near base load conditions for much of the winter. Coal was predicted to be the primary source of fuel for power generation as a result of favourable coal prices relative to gas.

28. The review of gas supplies section shows the demand associated with IUK exports and storage injection in more detail.

Review of Supplies

29. **Table G1** summarises the make-up of gas supplies for winters 2010/11, 2011/12 and 2012/13 by supply source.

Table G1 – Winter Gas Supply by Source

	2010/11		2011/12		2012/13	
	bcm	%	bcm	%	bcm	%
UKCS	24	39%	21	39%	16	30%
Norway	15	25%	16	31%	18	34%
Continent	5	9%	4	8%	9	17%
LNG	13	21%	8	15%	4	8%
Storage	4	7%	3	6%	6	11%
Total	**62**		**53**		**53**	

30. For winter 2012/13 the table shows:

- Further decline in UK Continental Shelf (UKCS)
- Higher levels of imports from Norway and the Continent
- Less LNG
- Increased usage of storage than in 2011/12

31. **Table G2** shows the make up of supplies for winters 2010/11, 2011/12 and 2012/13 by terminal.

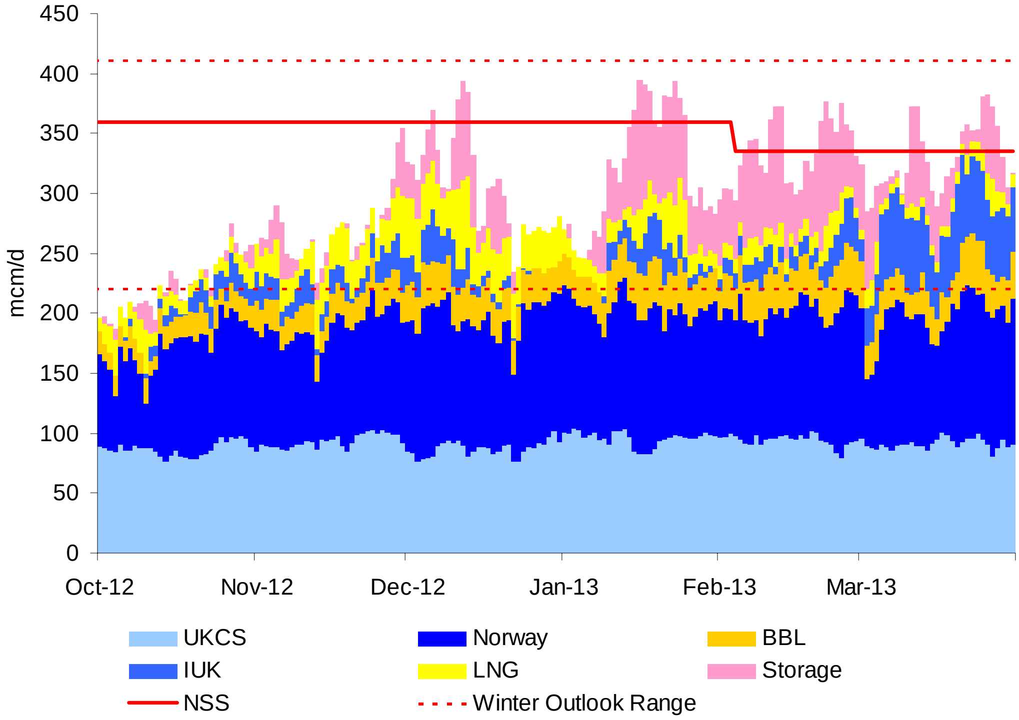
Table G2 – Winter Gas Supply by Terminal

	2010/11		2011/12		2012/13	
	bcm	%	bcm	%	bcm	%
Bacton	13	20%	12	22%	13	25%
Barrow	2	3%	2	3%	1	2%
Grain	4	6%	3	5%	1	2%
Easington	15	24%	14	27%	17	32%
Milford H.	9	15%	5	10%	3	6%
Burton P.	0.2	0%	0.2	0%	0.5	1%
St Fergus	12	19%	11	21%	12	23%
Teesside	4	6%	3	5%	2	4%
Thed'pe	3	4%	2	3%	1	2%
Storage	1	2%	1	2%	2	4%
Total	**62**		**53**		**53**	

32. For winter 2012/13, the table shows similar flows at most terminals with the main exceptions being lower flows through the Grain and Milford Haven LNG terminals.

33. **Figure G3** shows the gas supply by source for winter 2012/13; each of the supply sources is considered in turn in the following sub-sections.

Figure G3 - 2012/13 Gas Supply



34. The chart also shows forecast range of Non Storage Supply (NSS) and the NSS as used in the calculation of the Gas Margins Notice. The NSS forecast represents an upper expectation of supply associated with cold weather / high demands. The NSS figure was modified from its original level of 359 mcm/d, during February 2013 to 345 mcm/d. The modification to the NSS level was primarily driven by lower levels of imported LNG arriving into the UK and lower UKCS, this was part offset by higher imports from the Continent through both BBL and IUK.

35. The average level of NSS over the winter period was 265 mcm/d, for the 38 days of demand above 350 mcm/d the average level of NSS was 301 mcm/d. This was below the forecast (359 mcm/d) and modified (345 mcm/d) level. These levels were never really tested due to a combination of modest albeit sustained demands and high utilisation of gas storage throughout the winter period that at times depressed the use of NSS.

36. The highest day of supply was 395 mcm/d on 16 January 2013, there were no days of supply in excess of 400 mcm/d (3 in 2011/12) and 38 days in excess of 350 mcm/d (17 in 2011/12). Average supply for the highest 100 days of supply was 337 mcm/d, 17 mcm/d higher than in 2011/12.

37. Whilst there were no very high days of gas demand, the prolonged winter period to the end of March provided an extended period of unseasonal high demands. At the beginning of March storage stocks were depleted to just 20%, as between January and February storage flows were relatively high (average 56 mcm/d) despite modest demands (average 326 mcm/d).

38. During March, the combination of unseasonal high demands and depleted UK storage levels were compounded by low LNG deliveries / stocks. This coupled with

limited flexibility from UKCS and Norway resulted in a material increase in the UK gas prices (over £1/therm). To meet UK demand there was a substantial increase in Continental gas imports (BBL and in particular from IUK – record highs). This combination of high gas demand, limited flexibility from storage and other non storage sources and dependence on Continental imports, meant that UK gas market was exposed to unplanned operational issues as was experienced with the unplanned outage at the IUK import facility at Bacton.

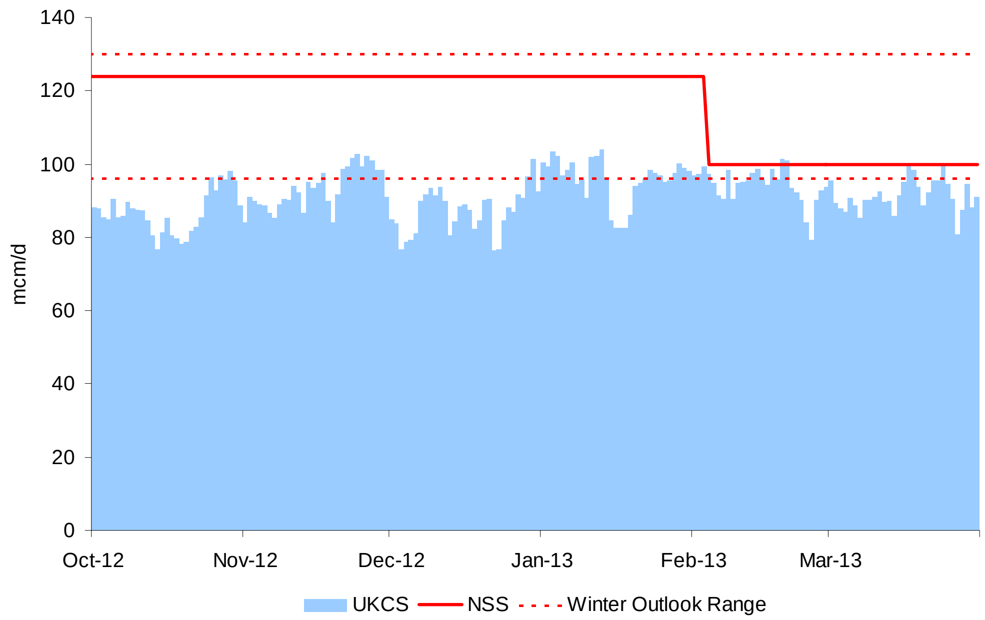
39. The factors impacting the deliverability of non storage supplies and storage are considered in turn in the following sub-sections. In addition to our specific consultation questions, National Grid would welcome any comments on the events during winter 2012/13, including, how well the market responded and what could be done to enhance security of supply.

UKCS Supplies

40. The UKCS range as reported in the Winter Outlook document was 96 -130 mcm/d. For setting the level of NSS utilised in the Gas Margins Notice calculation an initial level of 124 mcm/d was used. This was subsequently modified, during February 2013, to 100 mcm/d. The modification reflected delays in the development of new production fields and the non-return of fields from production outages.

41. **Figure G4** shows our UKCS forecast range from last year's Winter Outlook report, and actual flows from the UKCS during winter 2012/13. For most of the winter, UKCS supplies were close to the lower value set for the Winter Outlook range.

Figure G4 – 2012/13 UKCS Supplies (est. Vesterled/Tampen flows deducted)



42. Average flows from the UKCS across the 6-month winter period were 91 mcm/d and 92 mcm/d for the 100 days of highest demand. **Table G3** shows the 2012/13 Winter Outlook peak forecast of UKCS supplies by terminal and the actual terminal supplies

for the day of highest UKCS supplies (13 January 2013) and the highest day for each terminal.

Table G3 – 2012/13 UKCS Supplies by Terminal

Peak (mcm/d)	Winter Outlook Forecast	Actuals	
		Max UKCS Day	Max Terminal
Bacton	38	28	30
Barrow	10	7	11
Burton Point	2	3	4
Easington	14	7	12
St Fergus[6]	38	35	40
Teesside	25	14	15
Theddlethorpe	11	10	13
Total	**138**	**104**	**125**
(90% Op Forecast)	**124**		

43. The table highlights that the day of highest UKCS supplies of 104 mcm/d were lower than the maximum operational forecast of 124 mcm/d (90% of peak forecast). A comparison of our 138 mcm/d forecast should be made against the aggregated highest terminal flows (125 mcm/d). For both comparisons UKCS supplies were below our forecast, notably for Bacton (non return of fields on outage) and Teesside (delays to field commissioning).

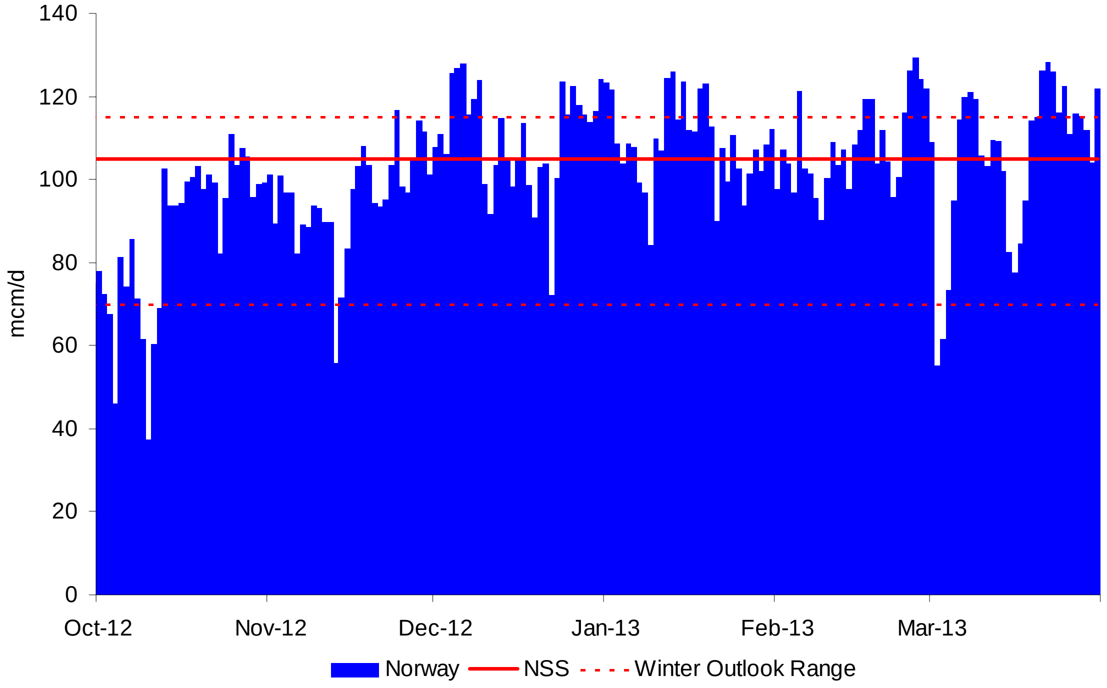
Norwegian Imports

44. Our forecasts for Norwegian imports to the UK for winter 2012/13 were subject to numerous uncertainties notably contractual obligations and transportation options regarding delivery to the Continent in Germany, France and Belgium. To capture this uncertainty a central view of Norwegian flows to the UK was produced within a range (70-115 mcm/d) based on high flows to the Continent (thus low UK flows) and low flows to the Continent (thus high UK flows).

[6] Excludes estimates for Vesterled, Tampen and Gjoa

45. **Figure G5** shows Norwegian flows through Langeled and our aggregated estimates for Norwegian imports to St Fergus through Vesterled and the Norwegian flows via the FLAGS pipeline.

Figure G5 - 2012/13 Norwegian Imports to UK

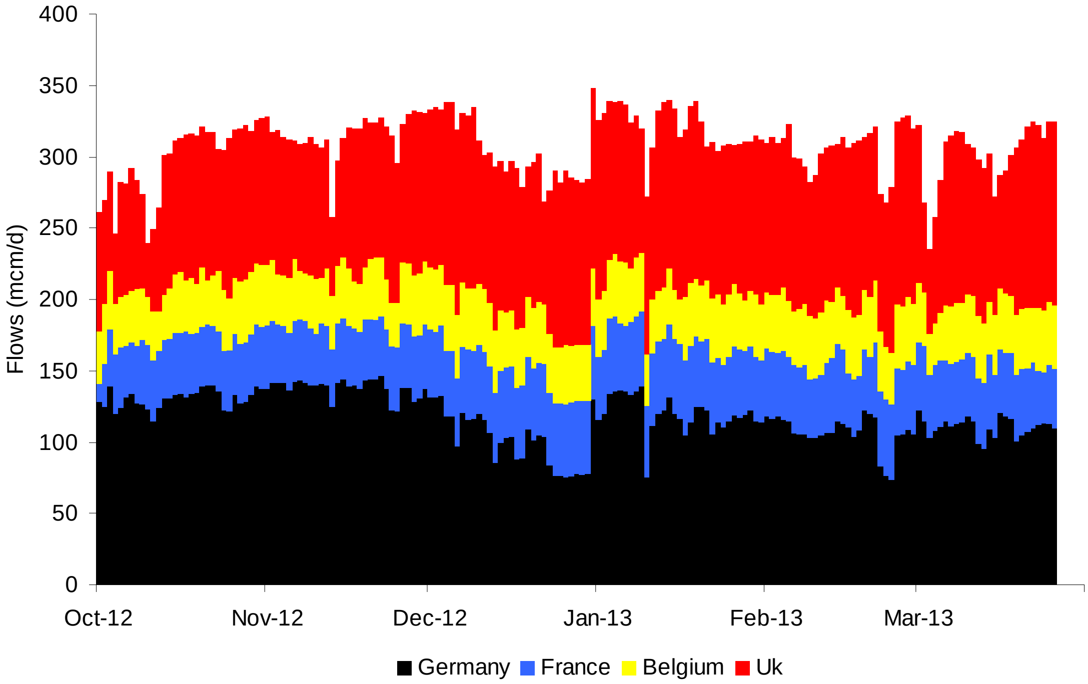


46. The chart shows that Norwegian flows were generally within our anticipated range. Average Norwegian flows across the 6-month winter period were 102 mcm/d, which was slightly below our NSS forecast at 105 mcm/d. The NSS level was reviewed during the winter period, although Norwegian flows had performed well, the level was not altered given occasional Norwegian production outages experienced within the winter.

47. The chart also shows occasional periods of supply outages notably in early March. These occurrences did not coincide with unseasonably high demand later in March when storage was largely depleted and LNG flows were restricted.

48. Besides the option to flow gas to the UK, Norwegian gas is also exported to Germany, France and Belgium. **Figure G6** shows our estimate of daily Norwegian exports to the UK and the Continent during winter 2012/13.

Figure G6 - 2012/13 Norwegian Exports to UK and the Continent



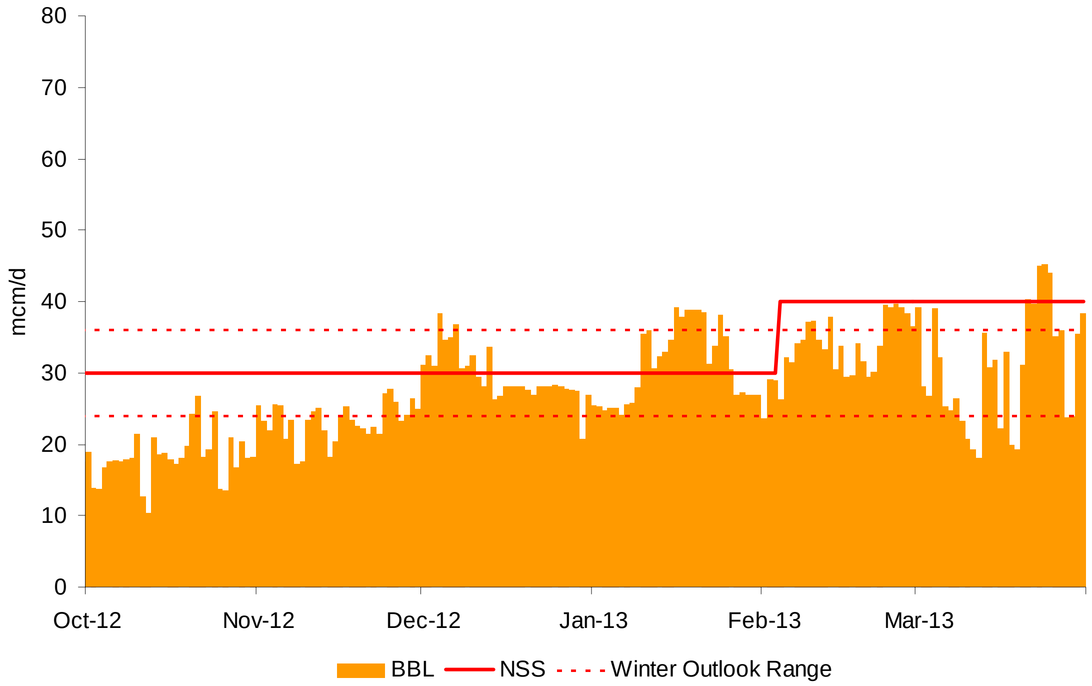
49. The chart shows little seasonality in Norwegian production. The average level of Norwegian production across the 6-month winter period was 322 mcm/d and 330 mcm/d for December to February. These flows are in line with the pre-winter forecasts of 320 and 340 mcm/d respectively.

50. The chart also clearly shows that when the Norwegian production suffered supply losses, flow reduction was experienced both in the UK and the Continent, notably Germany. This shift from primarily just the UK, may be as a consequence of recent contractual re-negotiations with existing consumers on the Continent, aligning with the general market trend of moving to more ‘spot-price’ contracts and increased liberalisation of the European gas market.

Continental Imports - BBL

51. **Figure G7** shows BBL flows for winter 2012/13. Flows were generally within our 24-36 mcm/d forecast range for much of the winter averaging ~27 mcm/d across all the winter and 31 mcm/d for December to February.

Figure G7 - 2012/13 BBL Imports to UK



52. Factors that could have accounted for the increased BBL flows to the UK include: relatively low Continental gas demands, high Continental storage levels along with little or no commercial reverse flow. During the tight supply position in late March a further response from BBL was observed with record flows of 45 mcm/d close to the pipeline capacity of approximately 48 mcm/d.

Continental Imports – IUK

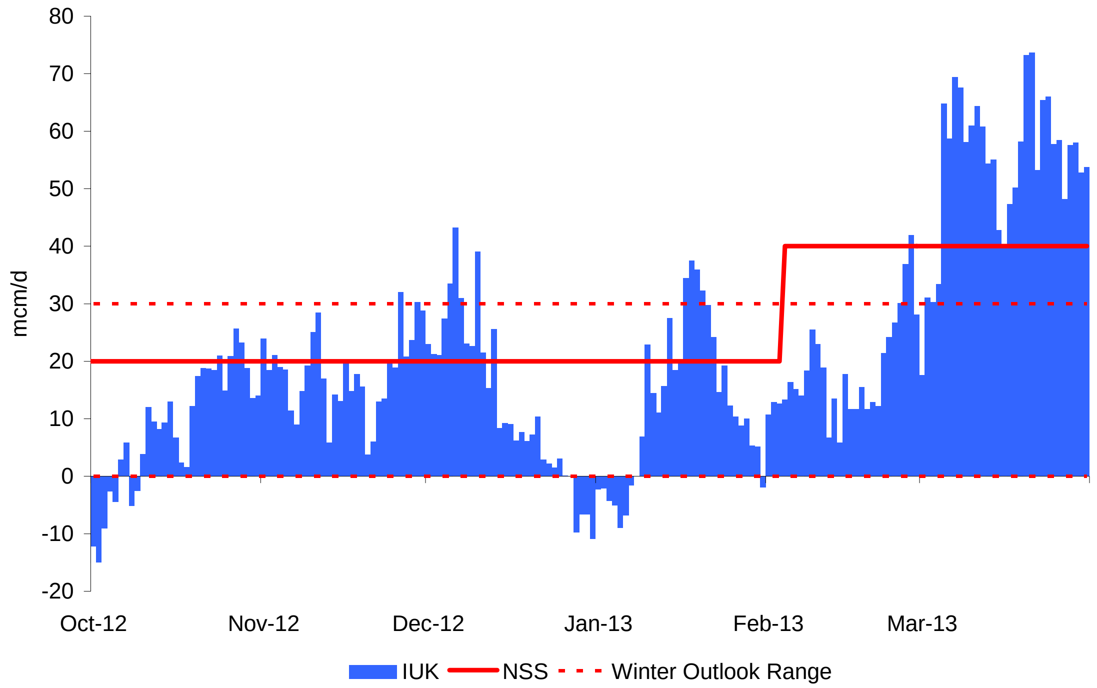
53. As in previous winters, IUK was forecast as the marginal source of non-storage supply and would, in terms of operation, be similar to storage when UKCS and other imports could not meet demand with potential upper flows of 30 mcm/d. IUK flows were expected to be dependent on demand (price) and the availability of other supplies, notably, other imports.

54. **Figure G8** shows IUK import and export flows for winter 2012/13. IUK imports were forecast to be between 0 - 30 mcm/d although potential upside was identified.

55. Due to a combination of sustained demands arising from a prolonged winter and limited LNG imports, IUK spent the majority of the winter in import mode and only on occasion reverted to UK exports. In aggregate, IUK imports were 3.8 bcm and exports were only 0.12 bcm

56. The NSS figure for IUK was modified from its original level of 20mcm/d, during February 2013 to 40 mcm/d. The modification to the NSS level was reflective of significant increased responsiveness provided by IUK during the December and January.

Figure G8 - 2012/13 IUK Imports & Exports

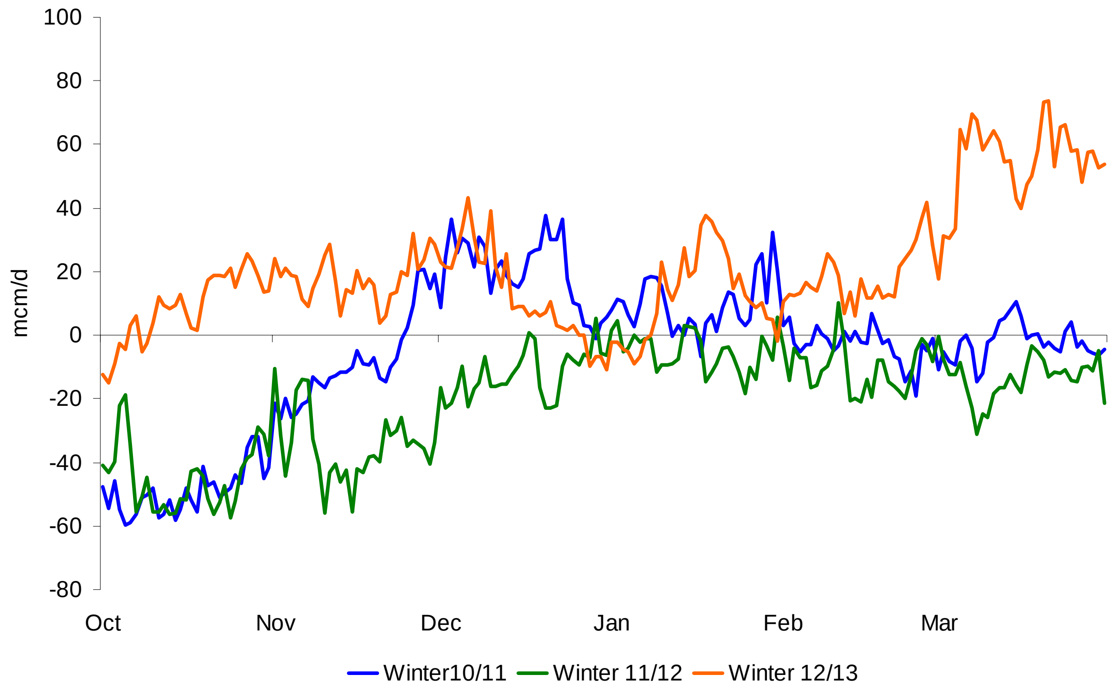


57. During March with unseasonal cold weather providing relatively high demands, a tight supply position developed as UK storage was largely depleted and LNG supplies appeared to be restricted due to limited deliveries. This resulted in a material increase in the UK gas price to at times over £1/therm. To meet UK demand there was a surge of IUK imports up to the pipeline capacity of 74 mcm/d. This far exceeded the previous highest of 47 mcm/d in 2006.

58. This increased dependence on IUK import during March, meant that the UK gas market was even more exposed to unplanned operation issues. During the morning of 22 March 2013 there was a total loss of IUK, this resulted in a spike in the within-day UK gas price to £1.50/therm as the market responded to the prevailing conditions. IUK returned in the afternoon and the supply position recovered. Whilst the supply position on the day was obviously ‘tight’, the main exposure was a longer term outage of IUK as alternative supplies to make-up for any prolonged loss, namely LNG and storage were both relatively depleted.

59. **Figure G9** shows IUK imports and exports over the last 3 winters.

Figure G9 - IUK Imports & Exports Winter 2010/11, 2011/12 & 2012/13



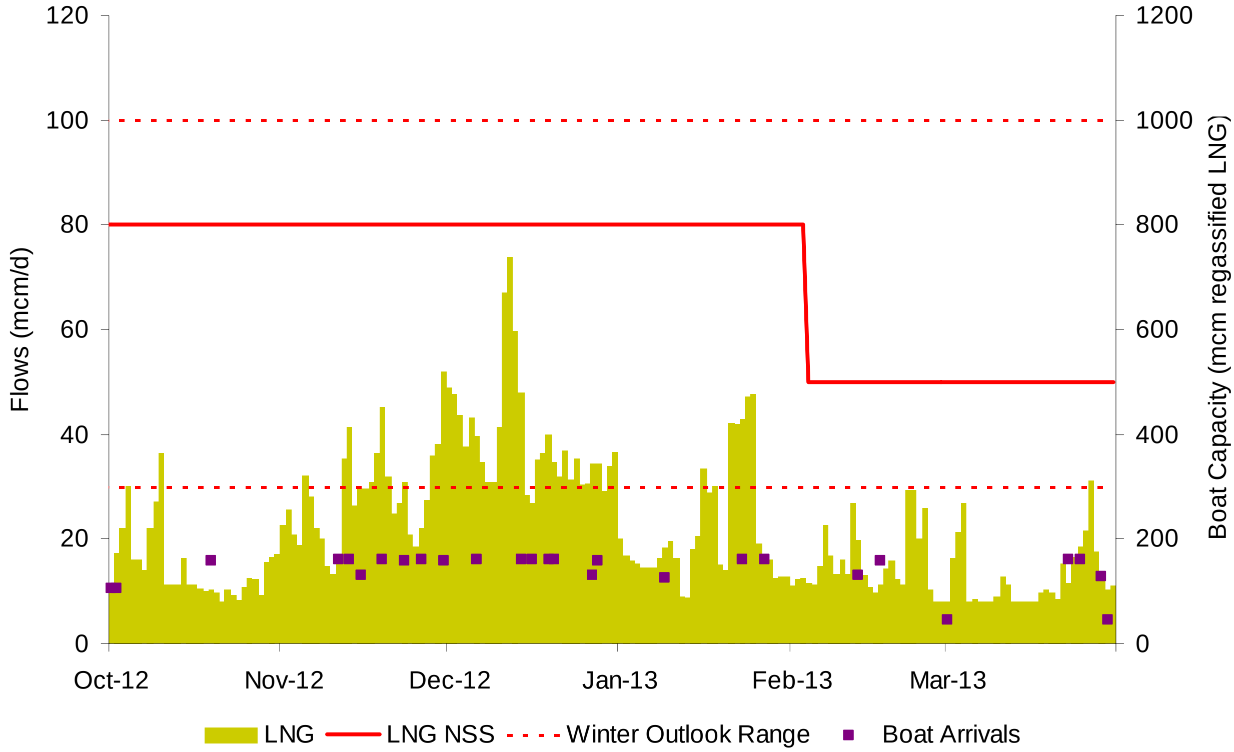
60. The chart shows significant periods of IUK exports during winters 2010/11 and 2011/12, reflecting strong LNG imports (winter 2010/11) and lower gas demand and mild winter period (winter 2011/12). The chart illustrates the significant flexibility that IUK can provide, noticeably the record imports provided by the IUK during late winter 2012/13, responding to depleted UK storage and lower than anticipated UKCS and LNG flows.

LNG Imports

61. The forecast range for LNG imports for winter 2012/13 highlighted considerable uncertainties, hence an assumed range between 30 and 110 mcm/d, with flows of 80 mcm/d expected at times of high demand.

62. **Figure G10** shows LNG imports through Grain and Milford Haven and our forecast range.

Figure G10 - 2012/13 LNG Imports



63. The chart shows considerable variation in day-to-day LNG flows ranging from ~8 to 74 mcm/d with an average flow of 22 mcm/d. For significant periods throughout the winter, LNG flows were significantly below our forecast range. The NSS figure was modified from its original level of 80 mcm/d, during February 2013 to 50 mcm/d. The modification to the NSS level was reflective of lower than anticipated LNG deliveries and subsequent flows during January 2013.

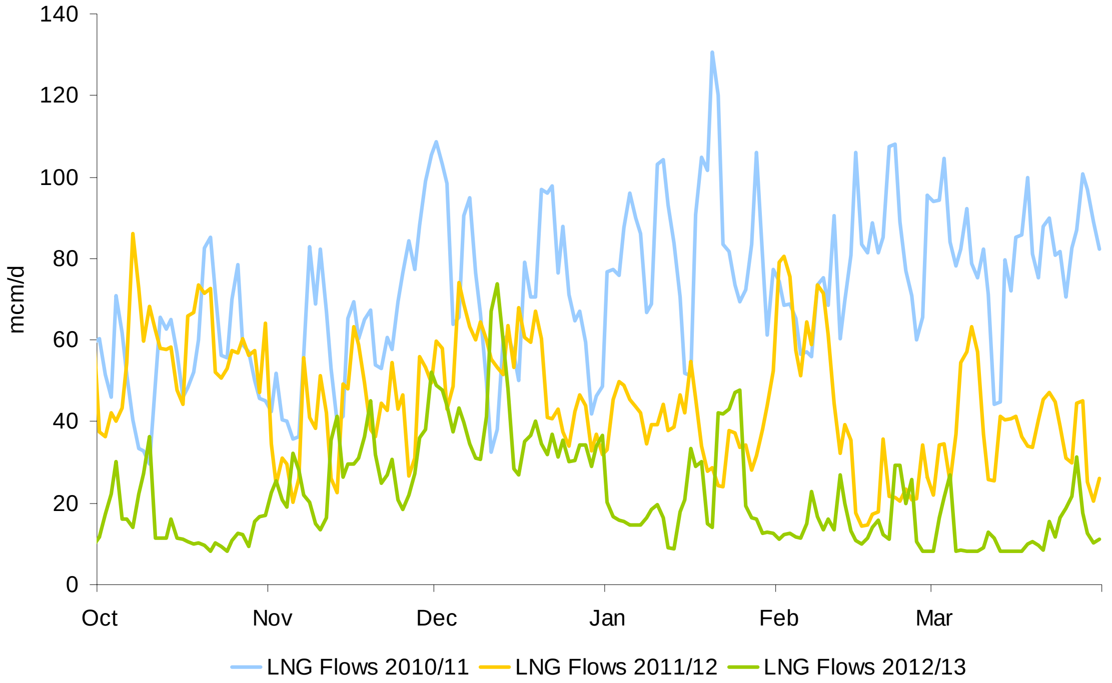
64. The chart shows some (albeit limited) increased response from LNG in December 2012 (in line with the delivery of new LNG supplies), but a minimal response during the prolonged cold spell in March 2013. This was believed to be due to a combination of low LNG stocks and limited deliveries.

65. LNG did provide a limited response to the IUK outage (22 March 2013). However considering the price at £1.50/therm and the tightness of the market the response of LNG appeared to be, at best, measured.

66. LNG imports were approximately 4 bcm, of which 1.4 bcm was through Grain and 2.6 bcm through Milford Haven. This was around 50% lower than the 8.2 bcm in 2011/12 (and much lower than the 13 bcm in 2010/11). The reduction was probably due to higher demand and prices in the global market being underpinned by sustained Asian gas demand, notably in Japan, and increased gas demand in China. In China, annual gas demand has grown rapidly to about 140bcm of which about ~22 bcm is sourced from LNG.

67. **Figure G11** shows UK LNG imports over the last 3 winters.

Figure G11 - LNG Imports Winter 2010/11, 2011/12 & 2012/13



68. The chart shows variable levels of LNG imports for all winters. LNG flows were significantly lower in winter 2012/13, following the trend experienced in the previous year.

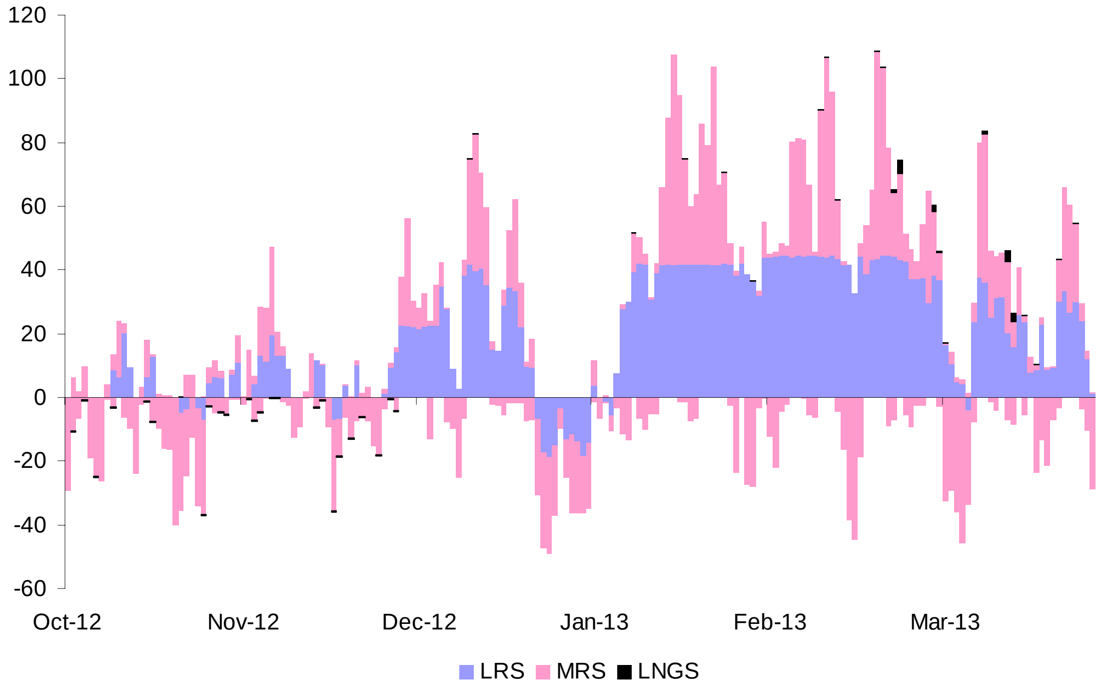
2012/13 Storage Performance

69. Storage deliverability for winter 2012/13 was approximately 108 mcm/d, this was slightly higher than for winter 2011/12. This increase was mainly due to the start-up of the Holford storage facility. The delayed commissioning of Hill Top Farm, during the winter, did not provide the anticipated up-side in storage deliverability.

70. Storage space was higher in winter 2012/13 than last winter due to an increased declaration for Rough, as well as extra space at Holford and Aldbrough.

71. **Figure G12** shows storage withdrawals and injections over the winter in terms of Rough, Medium Range Storage (MRS) and LNG storage.

Figure G12 - 2012/13 Storage Withdrawals and Injection

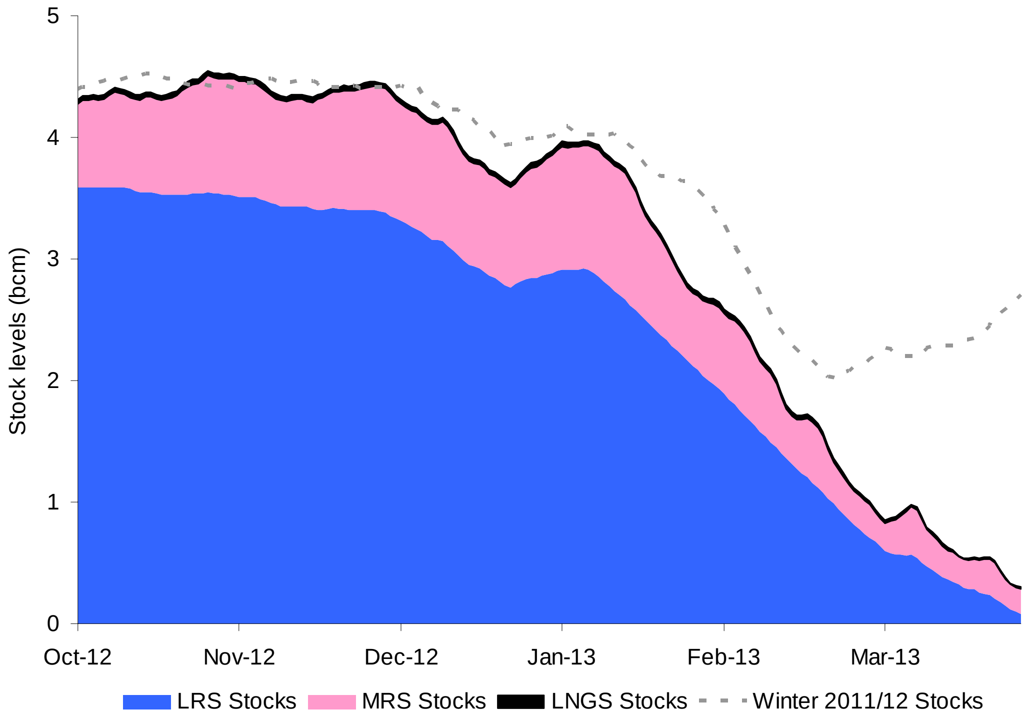


72. The chart shows:

- MRS withdrawal and injection throughout the winter (including many days of both withdrawal and injection). For the 6 month winter period, aggregated MRS withdrawals were 2 bcm compared to 1.5 bcm injected.
- The withdrawals from Rough were relatively low for the early part of the winter period when reduced demands mitigated withdrawals, before increasing during December 2012. There was some injection during the festive period, in line historic norms.
- From early January to early March withdrawals from Rough remained close to capacity, this reduced site stocks from about 80% to 20%. After a brief respite withdrawals continued throughout March, such that by late March Rough was essentially depleted and producing cushion gas rather than stored gas. This meant that it was unable to fully respond to relatively high gas demand and prices experienced during March due to the prolonged winter period and outages experienced at other non storage supplies.
- The prolonged winter period also delayed the start of the injection season to April 2013.
- LNG storage was used little throughout the winter period. For the 6 month winter period, withdrawals were 25 mcm compared to 9 mcm injection.

73. **Figure G13** shows the level of storage stocks through the winter.

Figure G13 - 2012/13 Storage Stocks

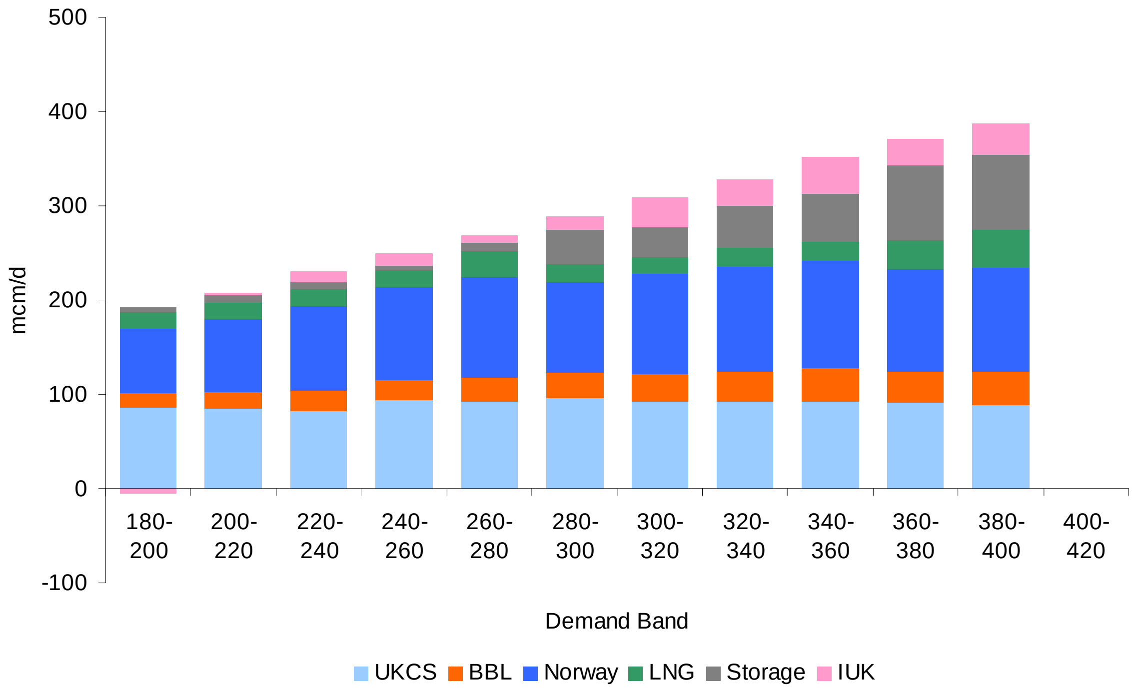


74. The chart shows little change in stocks during the early part of the winter period primarily due to mild weather but appreciable decline in stock levels from December onwards. By late February total stocks fell to 1 bcm (around 20%), compared with 2 bcm in 2011/12, 1.2 bcm in 2010/11 and 0.6 bcm in 2009/10. The stock levels reduced further during March 2013 to 0.25 bcm (just 5%).

2012/13 Supply Flexibility

75. In recent years the changing supply mix with increased reliance on imports has provided a 'new order' on how supplies are utilised to meet high demands. However, Winter 2012/13 saw a change back to the historic norm of storage and IUK imports providing the majority of the supply flexibility to meet variable demand. This is demonstrated in the charts, **Figure G14** and **Figure G15**.

Figure G14 – Supply Make-up Winter 2012/13 (all demand)

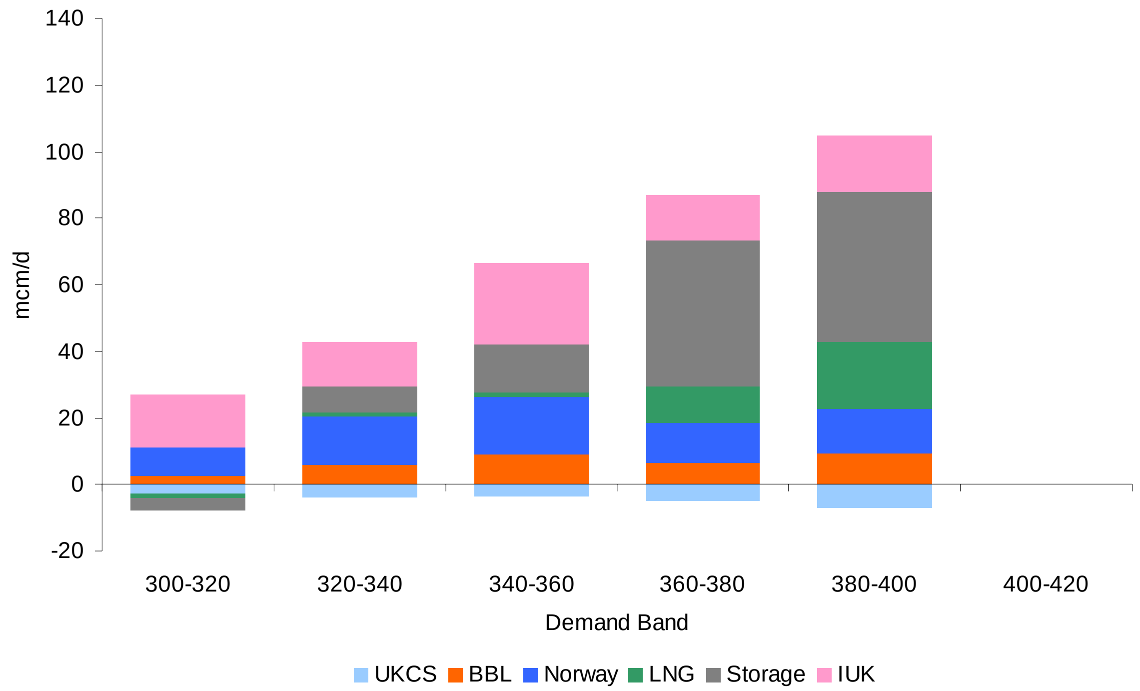


76. The chart displays the mean make-up of supplies by supply type in demand bands of 20 mcm/d increments. As demand increased:

- UKCS remained flat (i.e. no swing or seasonality);
- Norway, BBL and LNG imports showed some limited swing or seasonality ;
- IUK was in import mode for the majority of the winter providing appreciable swing;
- Storage showed the highest levels of swing despite limited availability in March.

77. The prolonged winter period was without any days of exceptionally cold weather (coldest day was only average cold) seen in previous years. Coupled with lower demand for gas fired power generation, this resulted in no days where gas demand exceeded 400 mcm/d. This was the first winter since winter 2000/01 where demands have not exceeded 400 mcm/d.

Figure G15 – Incremental Supplies Winter 2012/13 (Demand above 300 mcm/d)



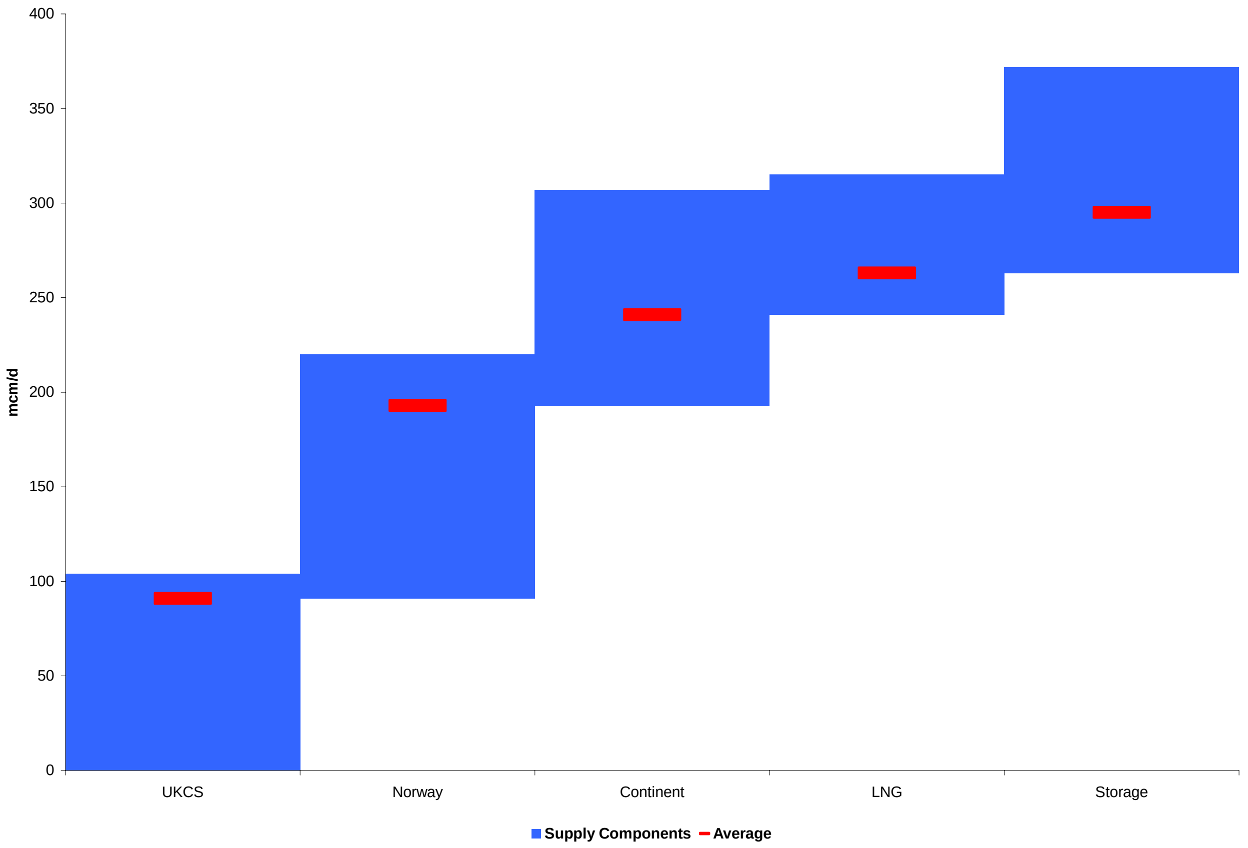
78. The chart displays the incremental make-up of supplies by supply type in demand bands of 20 mcm/d increments for demand above 300 mcm/d. This incremental approach identifies those supplies that are responsive / flexible. As demand increased above 300 mcm/d. The chart shows:

- UKCS declined (field decline within winter);
- Minor changes in BBL flows;
- A modest response from Norway and some LNG for the highest demands;
- A significant response from IUK and an even greater response from storage.

79. This approach however masks the fact that in late March with storage nearing depletion, the majority of flexible supply / response came from IUK and not from storage.

80. The level of flexibility, variance and uncertainty in the supply mix is illustrated in **Figure G16**. The chart shows that each of the five supply components can provide approximately 100 mcm/d of gas into the UK and the average flows experienced over winter 2012/13.

Figure G16 - Gas Supply Component Variances



81. The position of the average within the band highlights the degree of flexibility that each supply component can provide. The closer the average is to the top of the band the lower the flexibility. Hence the chart shows UKCS as having the lowest flexibility and storage the highest.

82. The exact supply mix over the winter period is dependent on various commercial (contractual arrangements), market (global supply and demand for gas) and production (development of new fields, outages) arrangements which may impact the deliverability of any one component on a given gas day.

83. Given the commercial and global market arrangements impacting the LNG and Continent component, there is a high degree of uncertainty regarding the exact nature of these supply flows to the UK. LNG, Continent and storage all have the capability of providing flexibility and seasonal swing within the supply mix.

84. The past few winters have illustrated and underpinned the high level of variation between LNG and Continent (in particular IUK) deliveries (please refer to **Figure G8** and **Figure G10**), with LNG flows strong during winter 2010/11 and Continent flow providing the flexibility within winter 2012/13.

Operational Review

85. NTS Operations were influenced by the prolonged cold winter experienced this year which extended higher levels of NTS gas demand well into April 2013. The supply challenge in response to the extended high NTS demand requirement was exacerbated by a limited response from LNG which meant that additional requirements were placed on the other elements of the UK supply mix. This was primarily met from storage supplies, which led to the depletion of storage stocks and deliverability towards the end of the winter period, and from imports from mainland Europe and Norway.

86. The weather over the winter period was generally colder than last year, however gas demand was at a similar level or lower than last year through the October to December period, primarily due to lower levels of gas-fired power generation caused by the price differential between coal and gas. The extended cold snap from mid January led to demands picking up to above seasonal normal levels although daily gas demands did not exceed 400mcm/d on any day.

87. Distribution Network demand increased this winter in comparison to the same period last year, driven by the colder weather, with the demands for industrial users, Moffat and storage remaining consistent with previous years. The increase seen in Distribution Network demand was not reflected in the overall demand due to the reduction in power station demand and also in IUK export flows which reduced from last year due to its predominant import configuration over the winter period. The impact of these changes to the demand profile could potentially explain the tight supply margins seen over the winter as suppliers may have factored out additional requirements for gas for power generation and export from their portfolios.

88. From a supply perspective, LNG imports were notably reduced from the levels seen in previous years, despite higher UK gas prices. LNG market intelligence would suggest this was mainly as a result of high Asian gas prices attracting LNG shipments to Japan and China. Due to the extended duration of cold weather and the lower levels of LNG additional pressure was placed on UK gas storage and interconnectors. This resulted in storage stocks and deliverability being depleted to very low levels as both LRS and MRS accounted for a greater percentage of supply than the previous two winters. Despite this, storage remained a key contributor to meeting demands throughout the cold period.

89. The volume of gas delivered from Europe via the IUK and BBL interconnectors was significantly higher than seen previously, with daily record entry flows being seen at both interconnectors over the winter period. This is in significant contrast to last year when IUK operated in export mode every day from February. These extremely high levels of supply through Bacton did on occasion result in the need for constraint management actions to be taken to manage localised pressures and ensure the continued safe operation of the system. Constraint actions were also taken at St Fergus for similar reasons.

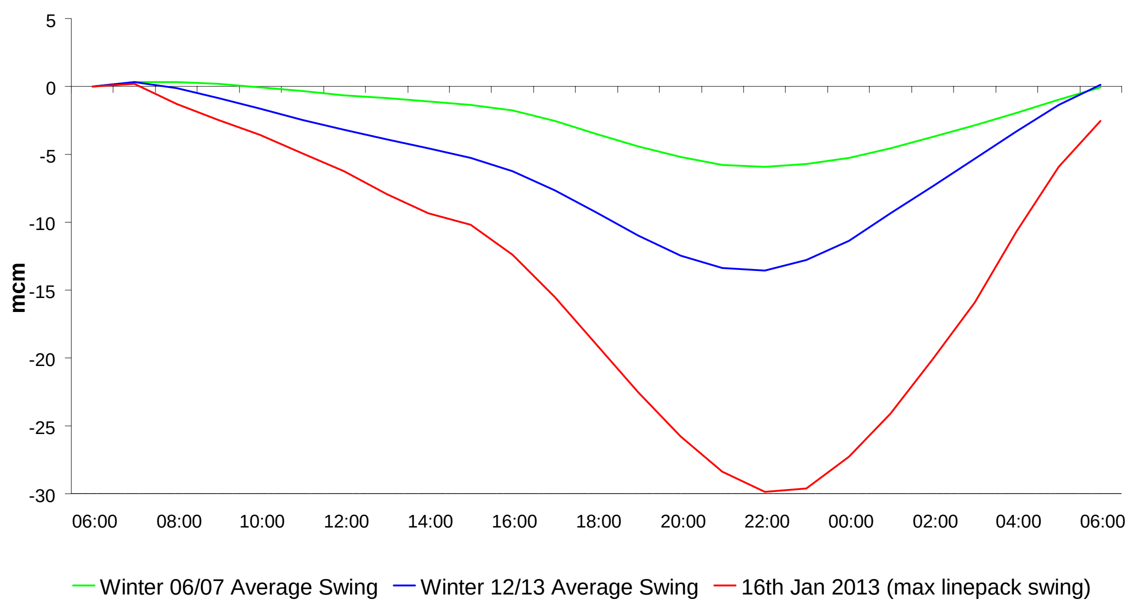
90. UKCS supplies remained a stable supply source, although slightly reduced from previous years. Norwegian supplies remained strong throughout the winter period, and for much of the period were higher than last year. We did however experience

Norwegian supply losses on a number of occasions, but all of these were effectively managed through suitable market response.

91. Another notable aspect of the winter from an operational perspective was the continuing increase in within day supply and demand profiling and frequent and rapid storage site transitions between injection and withdrawal. This has led to a number of operational issues including ability to accurately forecast end of day positions, increasing levels of line-pack utilisation and frequent requirements to revise operational strategies and compressor operations. A good example of this is from analysis of within day line-pack swing which suggests that this has increased by 200% from the position of 10 years ago and by between 10 – 20% from last year.

92. **Figure G17** shows the average within day linepack swing.

Figure G17 – Average Within Day Linepack Swing



93. The chart shows the within day average linepack swing for 2006/07 and 2012/13. The red line is an example of one of the peak linepack swing days seen this winter. As can be seen, the average linepack swing has increased as users are increasingly utilising the flexibility of the network and associated commercial products to vary flows within day. This is increasing the requirement on the System Operator to undertake a much wider range of sub-daily operational processes and contingencies in order to maintain the safe operation of the system.

94. Power station demand was lower than in previous winters, following the trend of recent years, as fuel prices continue to favour coal generation over gas. Electricity generated from gas was approximately 50% of the levels seen 3 years ago. This winter did however see the closure of 3 coal-fired power stations (at Cockenzie, Didcot and Kingsnorth) and the combination of these plant closures and a cold spell in the early months of 2013 did result in slightly higher power station demands in the second half of the winter. Higher levels of wind generation also suppressed gas power station demand with this winter seeing record half hourly and daily wind

generation totals. On 30 December 2012 total wind generation exceeded that of gas for the first time (see also **Figure E5**).

95. Two notable industry regime changes were implemented via modifications to the Uniform Network Code prior to this winter's operations:

- The Enduring NTS Exit Capacity Arrangements[7] went live in October 2012 which introduced a daily auction based capacity procurement mechanism (alongside the enduring and annual application processes already implemented) and removed the concept of interruptible exit capacity users. A number of new commercial constraint management tools were also introduced as of October which were utilised successfully on a couple of occasions over this winter to manage potential NTS exit constraints.
- The other regime change focused on revising the external information provision for forecast or actual physical end of day national imbalance positions. Two new information provision options were implemented to replace the existing 'Gas Balancing Alert' (GBA). The first a 'Margins Notice' provides the industry with a day-ahead notification of a forecast supply deficit should forecast NTS demand exceed assumptions made on NTS supply. The second, a 'Gas Deficit Warning' can be issued at the discretion of the Transmission System Operator in advance of, or during, the gas day and indicates there is a significant risk to achieving the end of day NTS balance position. Neither of these new information provision options were issued during the winter period.

[7] http://www.nationalgrid.com/uk/Gas/OperationalInfo/endureexitcap/

Consultation Questions - Gas - Review

Number	Question
GQ1.	The forecast levels of Non Storage Supplies (NSS) were not attained last winter. Was this due to the availability of supply or were there other factors to consider, for example storage use suppressing NSS?
GQ2.	IUK imports reached an all time high last winter, was this due to a change in the use of Continental storage? If yes, do you believe this is a long term change, a one-off or a consequence of being late in the winter?
GQ3.	LNG deliveries to UK were lower during winter 2012/13 compared with 2011/12. What were the key factors influencing lower UK LNG flows and why was the response from LNG muted during the period of unseasonal demand and high prices in March?
GQ4.	During the cold spell in March 2013, LRS did not fully respond to higher than normal demand due to heavy utilisation during January and February 2013. What were the drivers for the heavy use of storage during this period?

Electricity

Overview

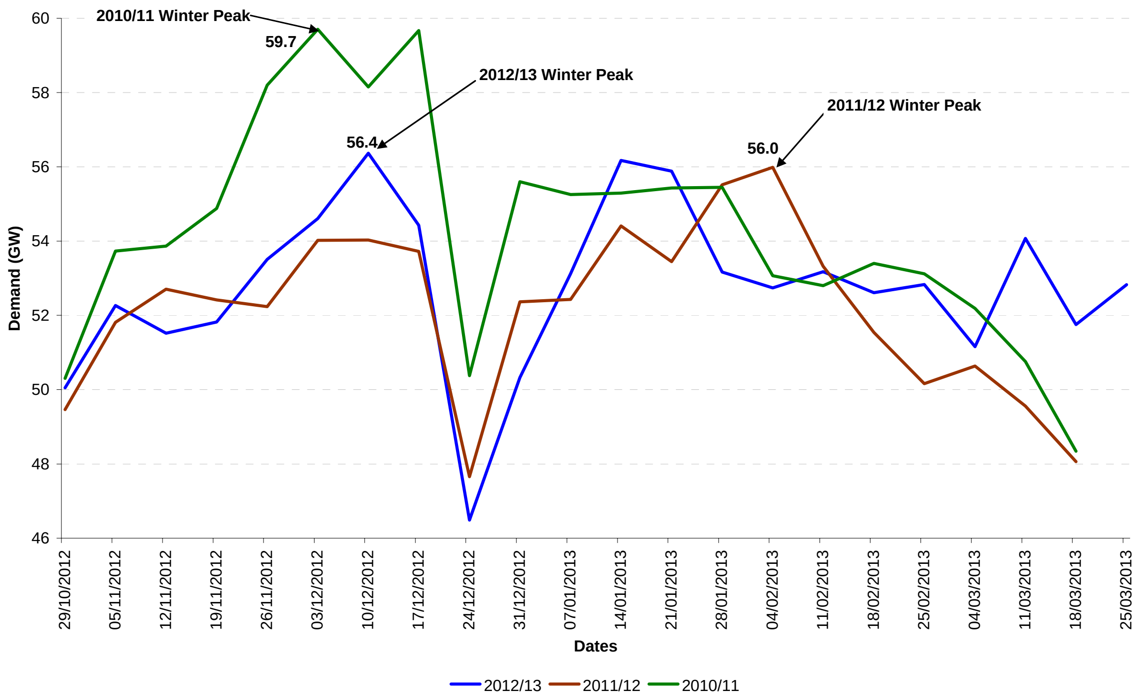
96. This section of the report reviews the last winter, 2012/13, for electricity, focussing on demand, generation and interconnection. In general margins were adequate for the duration of the winter, with favourable interconnector flows and generation availability broadly consistent with forecasts.

Review of Demand

97. Unless otherwise stated, demand discussed in this report excludes any exports to France, The Netherlands and Ireland but does include station load and exports from the Transmission System to meet GB demand. The value of station load is assessed from time to time at national level and a standard value is adopted for BST and GMT periods. Currently station load is assessed at 600 MW in GMT and 500 MW in BST.

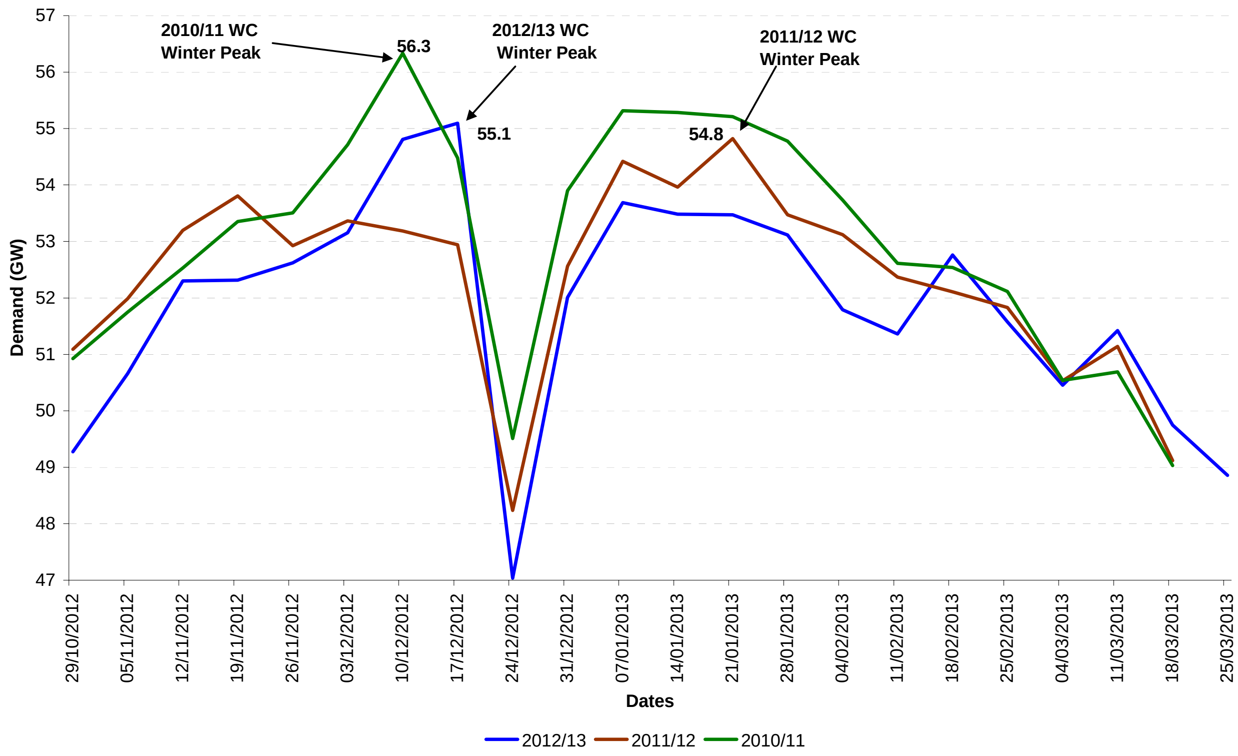
98. The highest electricity demand over the winter was 56.4 GW for the half-hour ending at 17:30 on 12 December 2012. There was a warm spell over Christmas, but other than that the winter was colder than normal, and March was particularly cold, with the final two weeks being 6°C colder than typical. The last three years' winter demands at a weekly resolution are shown in **Figure E1.**

Figure E1 - Weekly Peak Demand for the Last Three Winters



99. To understand the underlying demand trends for average weather conditions the out-turn demand for the last three winters has been weather corrected. This can be seen in **Figure E2**.

Figure E2 - Weather Corrected Weekly Peak Demand for Last Three Winters



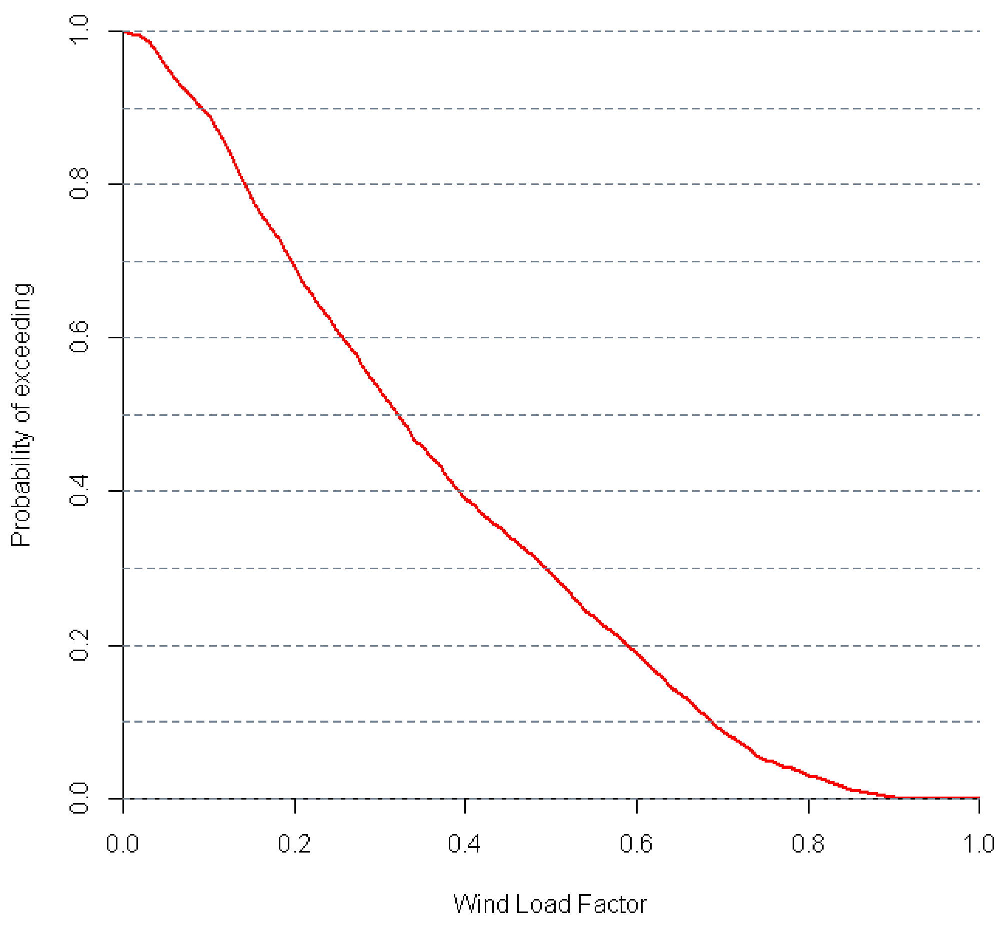
100. Some companies actively reduce their demand for electricity over peak periods to reduce their electricity charges. In previous years the cumulative effect of this reduced national peak demands by approximately 700 MW. Our analysis indicates that on some days last winter this Customer Demand Management (CDM) over the peak demand periods rose to 1,200 MW.

101. Underlying demand over the winter period 2012/13 was comparable to the previous year, but showed no signs of returning to pre-recession levels. This is partly explained by economic reasons including the high cost of energy and the state of the economy, but increasing quantities of unmetered small scale renewable generation must also be playing their part.

Generation Fuelled by Intermittent Power Sources

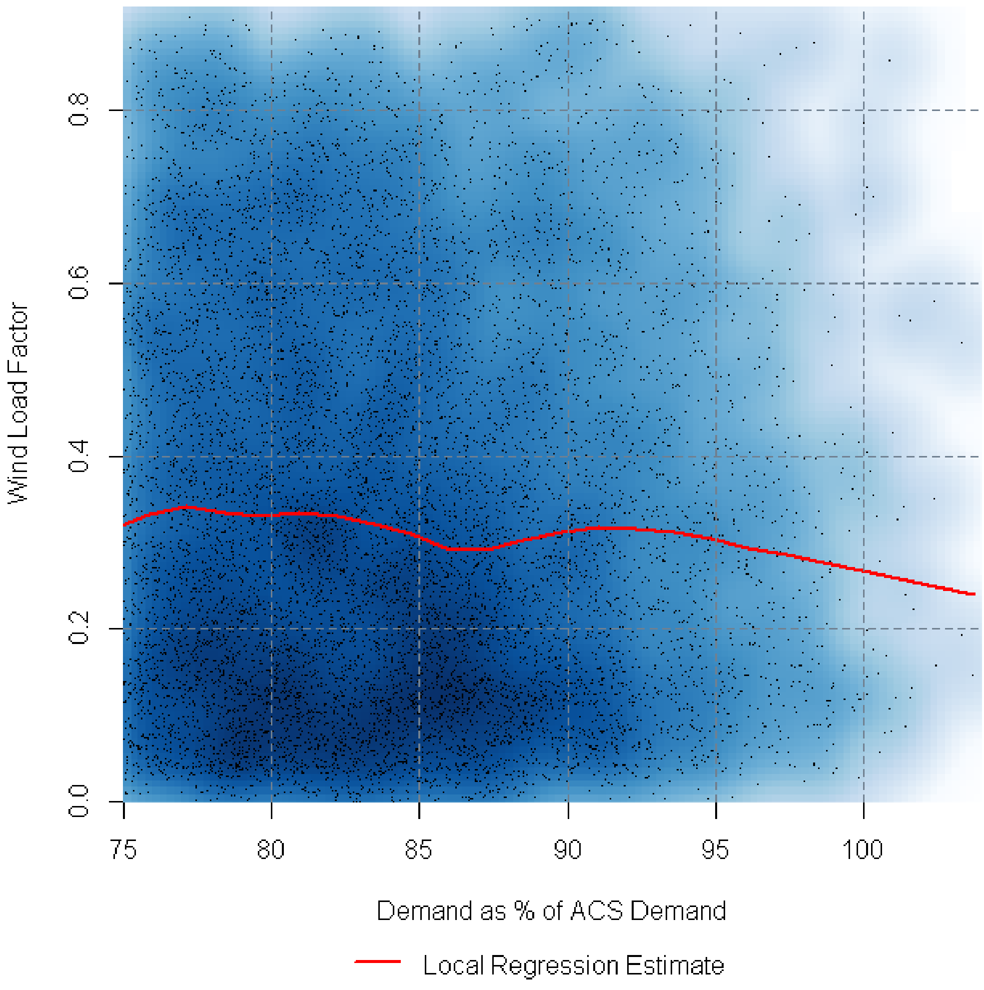
102. **Figure E3** shows historic wind farm load factor distribution during winter (November – March). The median wind load factor is 32%; based on this it is reasonable to assume that half of the time the load factor will be less than 32%. Similarly there is a 20% chance that the load factor will be below 14.2% and a 10% chance that the load factor will be below 9.1%.

Figure E3 – Winter Wind Load Factor



103. **Figure E4** shows, for the past five years, the wind load factor plotted against the corresponding demand expressed as a percentage of that year's Average Cold Spell (ACS) demand. A local regression line has been added to show the dependence of the average wind load factor as demand changes. The highest demands tend to have lower average wind load factors.

Figure E4 – Wind Load Factor against Demands for Last Five Winters

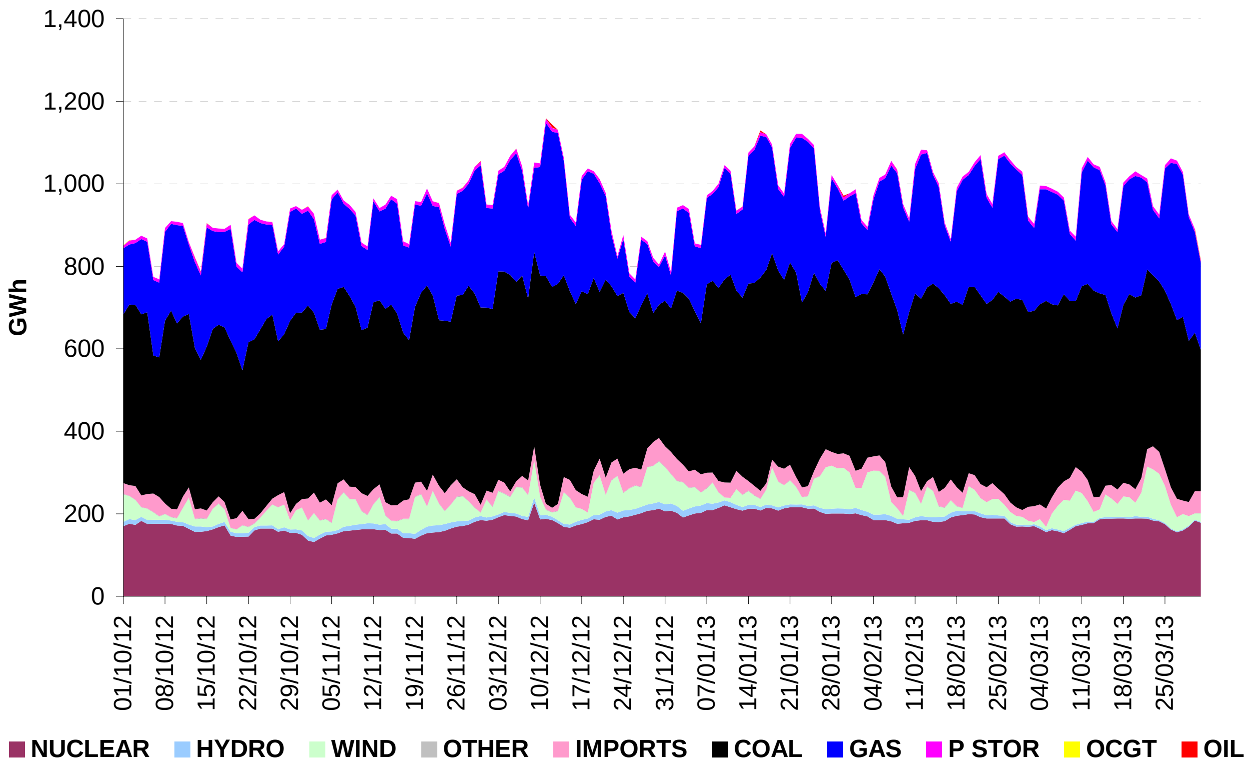


104. This is evidence that the distribution of wind load factor is dependent on the demand level. This means that at winter peak the average load factor is expected to be less than the average load factor for winter as a whole. The physical explanation for this is that the highest demands are more likely to occur when a high pressure system is sitting over the British Isles, giving low temperatures and still air conditions.

Generator Performance

105. **Figure E5** shows the outturn 2012/13 generation mix. Coal fired generation provided the greatest proportion of the total generation. Coal generation continued to be cheaper than gas due to the relative price difference between the two fuels. Oil fired generation ran on 10 days over the winter including the winter peak on 12 December 2012.

Figure E5 – Winter 2012/13 Generation Mix by Fuel Type



106. Looking across the range of generation sources, the assumed availabilities from last year's Winter Outlook Report are compared with the actual availabilities at the winter peak. This data is presented in **Table E1**.

107. For wind and hydro generation the basis of the assumed availability is different to that for other fuel types as it is the actual load factor at the time of the demand peak and not technical notified availability as in both cases availability of input energy is the limiting factor.

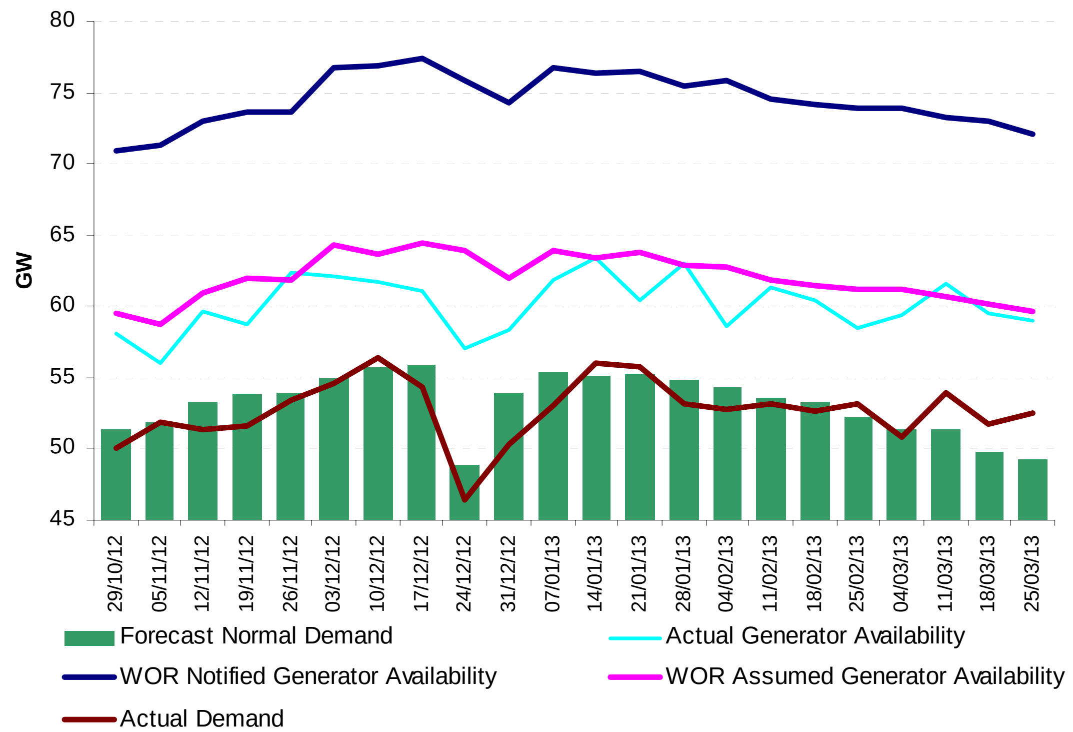
108. Overall the actual availability at the winter peak on 12 December 2012 was in line with the assumed value of 83%. Coal plant availability was higher than assumed but the interconnectors were restricted due to one bipole being out of service on the French link. For all the other fuel types, actual availability was close to the assumed value.

Table E1 – Winter 2012/13 Assumed and Actual Availability of Generation Plant

Power Station Type	Assumed Availability at Demand Peaks	Actual Availability at Demand Peak
Nuclear	84%	83%
Interconnectors (IFA & BritNed)	100%	67%
Hydro generation	75%	77%
Wind generation	10%	9%
Coal	85%	92%
Oil	85%	100%
Pumped storage	98%	99%
OCGT	94%	96%
CCGT	87%	86%
Overall	**83%**	**83%**

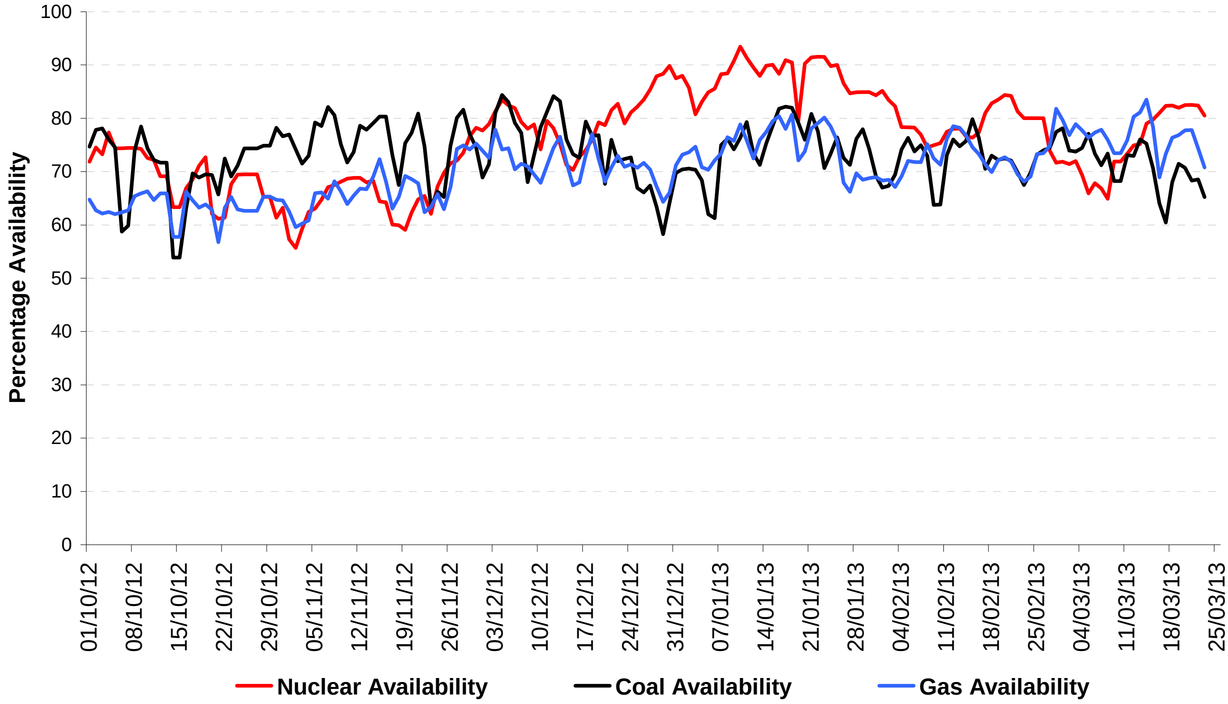
109. **Figure E6** shows actual generator availability across the winter against that assumed in last year's Winter Outlook Report (WOR). Overall generator availability was slightly lower than forecast. Another way of describing this is that last winter there was a slightly higher breakdown rate than the average of the preceding three winters (as the forecast breakdown rate is based on the last three years' data).

Figure E6 – Winter 2012/13 Actual Generator Availability



110. Looking at the main fuel types across the whole winter period **Figure E7** shows the availability of the Nuclear, Coal and Gas generation.

Figure E7 – Winter 2012/13 Generation Availability by Main Fuel Types



Interconnector Flows

Interconnectors

111. IFA[8] has a maximum capability of +/-2000MW, however over the winter it was subject to numerous outages and operational restrictions due to the ongoing valve replacement programme. This resulted in a decreased capability for most of the period. BritNed[9] has a maximum capability of +/-1000MW and operated with this capability over the majority of the winter. Price differentials between the three markets (Britain, Netherlands and France) have been the main driver for flows across IFA and BritNed; lower prices on the Continent have resulted in flows into Britain for the majority of the time. On weekdays, the flow to Britain reduced over the morning pick-up (due to day ahead hourly price spreads) but returned to import over the British evening peak. The profile was generally full import over the weekends.

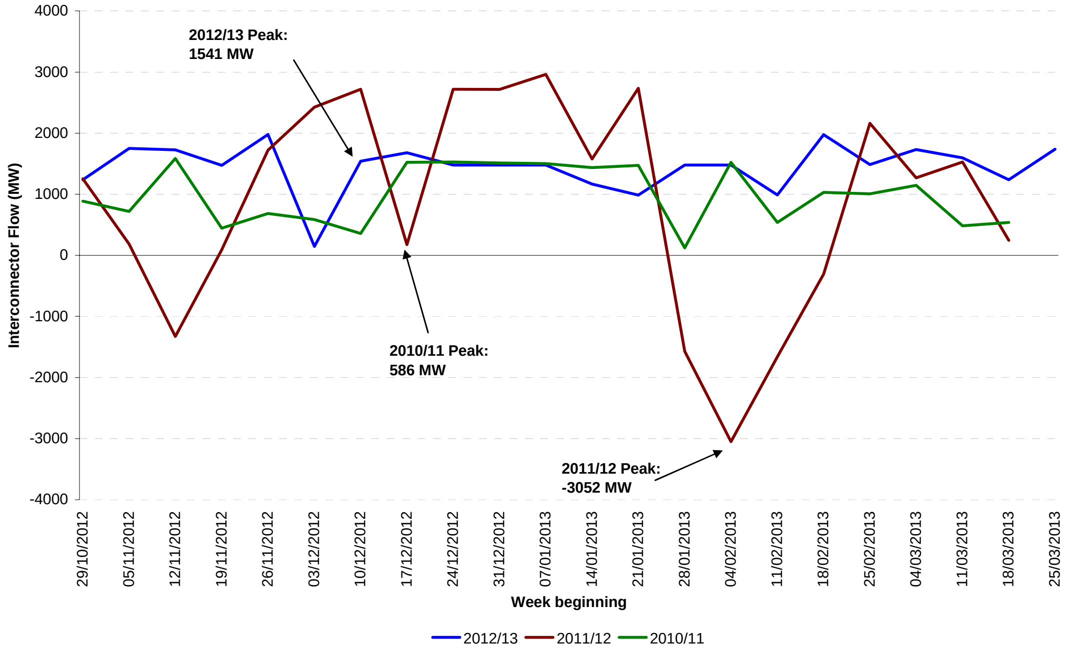
112. EWIC[10] began commercial operation on the 21st of December 2012, initially only operating at +/-250MW but offering a maximum capability of +/-500MW after an outage and further testing in March 2013. The Moyle Interconnector[11] has a reduced

8 IFA (Interconnexion France Angleterre) connecting Britain with France
9 BritNed connecting Britain with the Netherlands
10 EWIC (East-West Interconnector) connecting Britain with Ireland
11 The Moyle connecting Britain with Northern Ireland

capability of +/-250MW from +/-500MW due to a fault with one of the cables. This is anticipated to be repaired in four to five years time. Irish prices have, on average, been higher than prices in Britain causing power mainly to be exported into Ireland.

113. **Figure E8** shows the combined interconnector flow for the last three winters at the British weekly demand peak. Last winter flows over the peaks were limited due to the capability of IFA; also the trend was for net imports into Britain. In general, cheap German power weighed on the French and Dutch prices and there were no major upward Continental price spikes. The largest upward British price spikes occurred in March due to the tightening gas supply. Over the Christmas period we saw large downward price spikes on the Continent due to unseasonably warm weather and an oversupply of renewable generation.

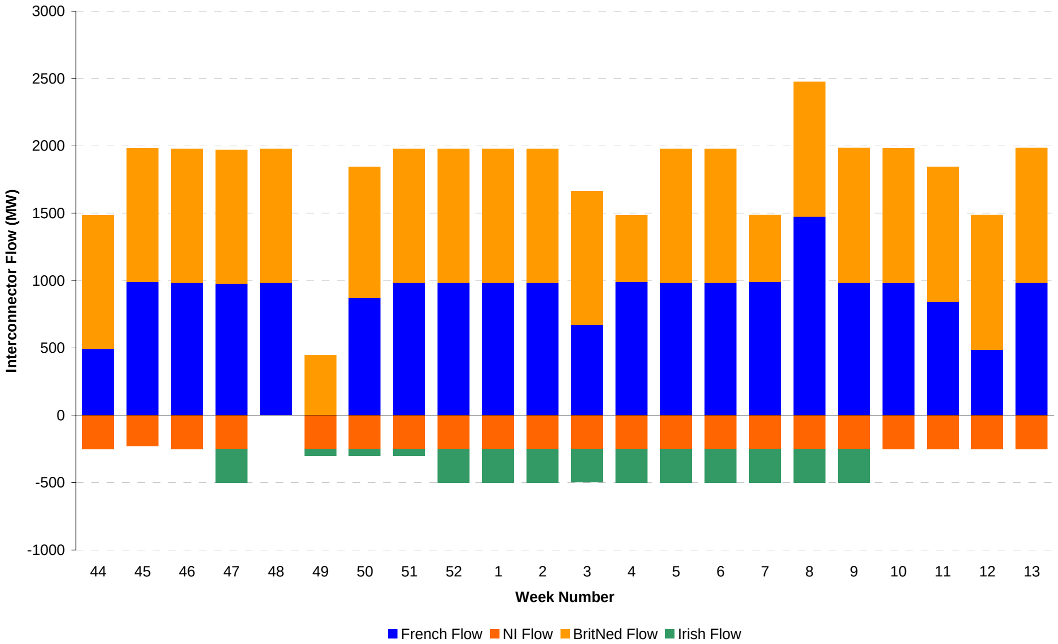
Figure E8 - Combined Interconnector Flow[12] at Weekly British Peak Demand



[12] BritNed commenced commercial operation on 1 April 2011, EWIC commenced commercial operation on 21 December 2012

114. **Figure E9** shows the breakdown by interconnector of the flows at the weekly demand peaks during winter 2012/13. It shows net imports from the Continent and net exports to Ireland.

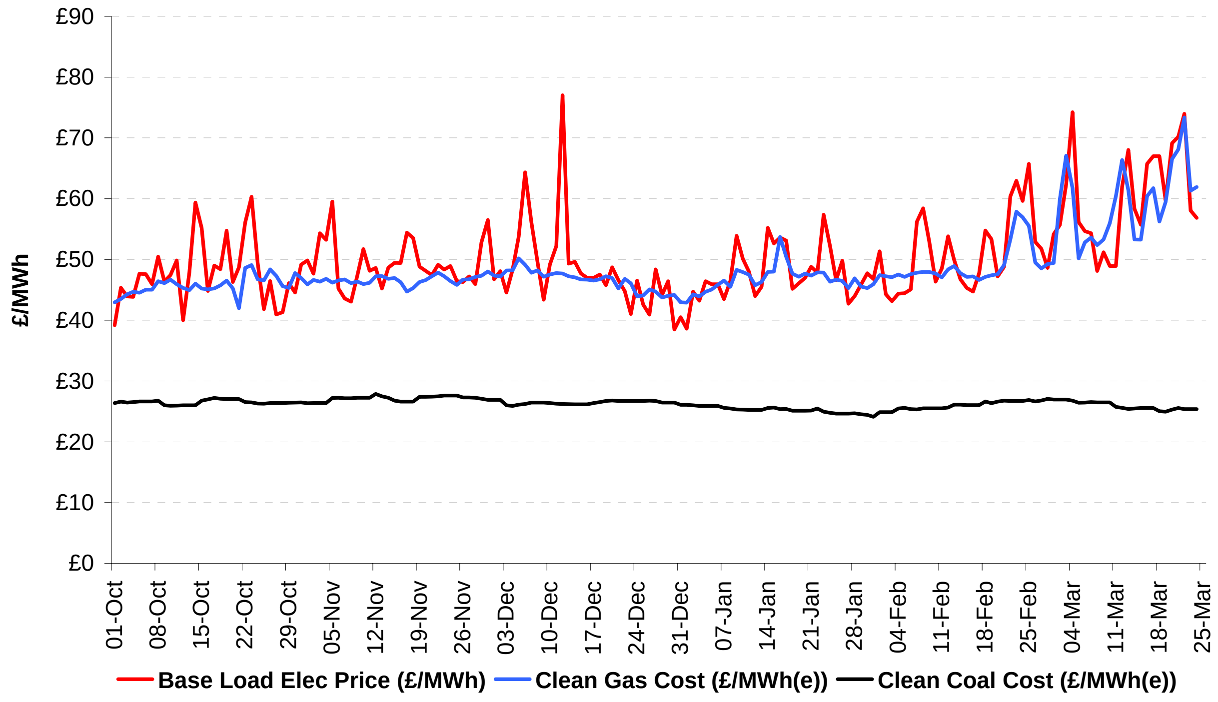
Figure E9 – Interconnector Flows at Weekly GB peak Demand 2012/13



Electricity Prices

115. The generation costs for coal and gas last winter are compared to the day ahead base load electricity price in **Figure E10**. The electricity price movements were generally in line with the cost of gas generation apart from some spikes, particularly on 12 December, the day of highest electricity demand. The cost of coal fired generation remained significantly lower than the cost of gas fired generation throughout the whole winter.

Figure E10 - 2012/13 Base Load Electricity Prices and Clean Gas/Coal Costs



Transmission System Issues

116. The relevant Transmission Owners continue to develop their transmission systems[13] in the north of the country in parallel with the ongoing connection of new generation. This brings forward the decarbonisation benefit of the renewable generators being connected, but means that it is likely that wind generation output will continue to need to be curtailed[14] going forwards. The historic amount of output and historic estimated curtailment of large[15] wind farms is shown in **Table E2** and **Table E3**.

13 The Electricity Ten Year Statement illustrates the future development of the National Electricity Transmission System http://www.nationalgrid.com/uk/Electricity/ten-year-statement/

14 Please see paragraphs 223 and 224 of the 2012/13 Winter Outlook for a description of how transmission constraints affect wind output. This can be found at http://www.nationalgrid.com/uk/Electricity/SYS/WinterOutlook/

15 Large as defined by the Grid Code is >100MW in England and Wales, >30MW in Southern Scotland and >10MW in Northern Scotland. Apart from a few exceptions, wind farms that are not large are not included in these figures

Table E2 – Metered Wind Farm Output

GWh	Apr – Sep 2011	Oct 2011 – Mar 2012	Apr – Sep 2012	Oct 2012 – Mar 2013
NW Scotland (B1)	681	1,140	673	1,041
Remainder of Scotland	1,481	2,915	1,769	2,837
England and Wales	2,060	3,131	3,048	5,152
Total wind output	**4,221**	**7,186**	**5,491**	**9,030**

Table E3 – Estimated[16] Volume of Wind Farm Curtailment

GWh	Apr – Sep 2011	Oct 2011 – Mar 2012	Apr – Sep 2012	Oct 2012 – Mar 2013
NW Scotland (B1)	28	137	41	15
Remainder of Scotland	29	13	8	10
England and Wales	0	0	0	0
Total wind curtailment	**57**	**150**	**49**	**25**

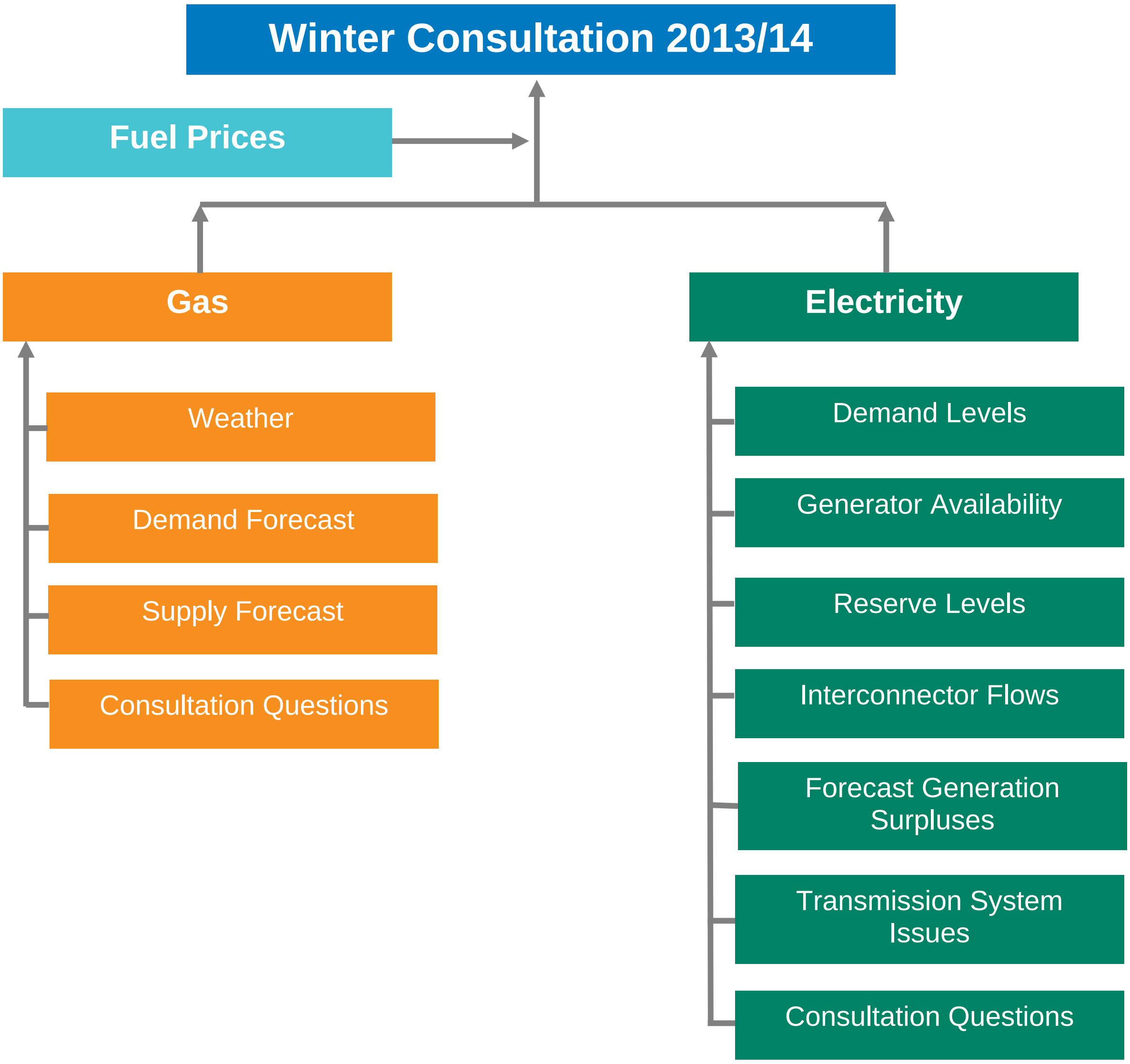
117. Wind Farm load factor last winter was not as high as the winter before (2011/12), with similar wind output being metered in Scotland in each winter despite increased capacity in winter 2012/13. Volumes of curtailment in Scotland have decreased from those seen in 2011/12, reflecting increased transmission system capacity. In England and Wales there has been a significant increase in wind farm capacity, principally due to a number of offshore projects commissioning. This has driven the higher energy output seen from wind farms in England and Wales last winter.

[16] The volume of wind curtailment is an estimated figure as there is currently no metered measure of the lost opportunity. A combination of Physical Notification data and forecast output is used to estimate this volume.

Consultation Questions - Electricity - Review

Number	Question
EQ1.	What further analysis of the winter peak would be useful for the winter consultation/outlook?
EQ2.	Do you have any other feedback that you'd like us to take into account?

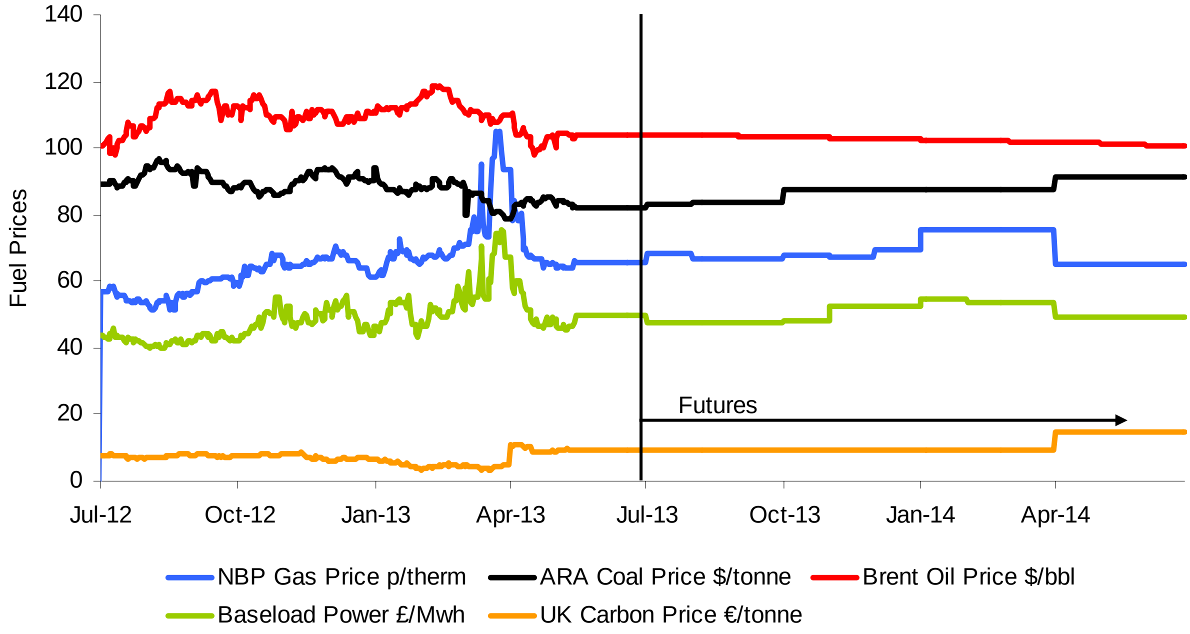
Winter Consultation 2013/14



Fuel Prices

118. **Figure F3** shows historic energy prices and future prices as of 24 June 2013. These prices should reflect the markets' view of energy related risks, such as the continued tensions in North Africa and the Middle East, Japan's and other Asian markets appetite for high LNG imports and the global economic outlook.

Figure F3 - Historic and Future Energy Prices



119. The forward gas price shows some seasonality with the Q1 (Jan-Mar) price about 10p/th above the summer price. The UK gas price is at a similar level to other European hub prices, although slightly below the estimated oil-indexed contract price.

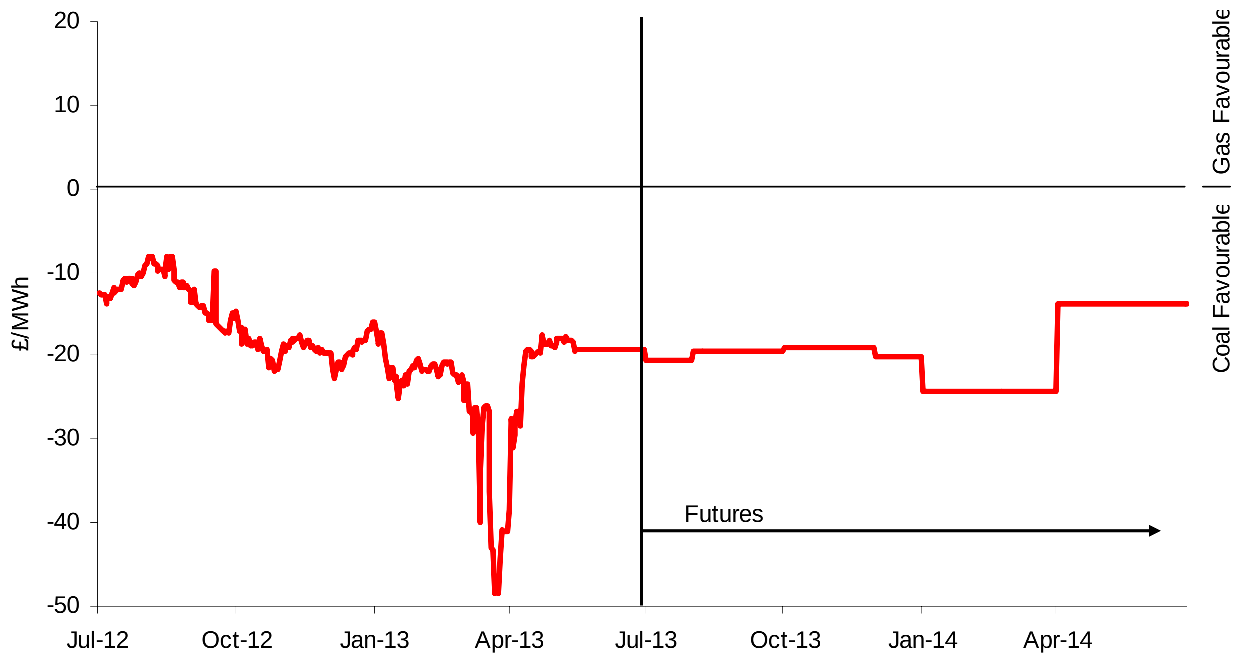
120. On a global basis US prices continue to be significantly below UK prices at below 25p/th, due to high levels of domestic production and the limited linkage to global gas markets. Asian prices remain significantly above the UK gas price, ranging between 90-110p/th. This should mean that Asia will again be the preferred market for most flexible LNG cargoes in Winter 2013/14.

121. Oil and coal prices are set by global markets, so are unlikely to be significantly impacted by events in the UK. Electricity prices tend to be determined by the marginal source of generation, for Winter 2013/14 this is anticipated to be gas, as was the case in 2012/13.

122. The increase in the Carbon Price Support to £9.55 in April 2014 is not expected to have a significant impact on power generation economics given the relative gas and coal prices.

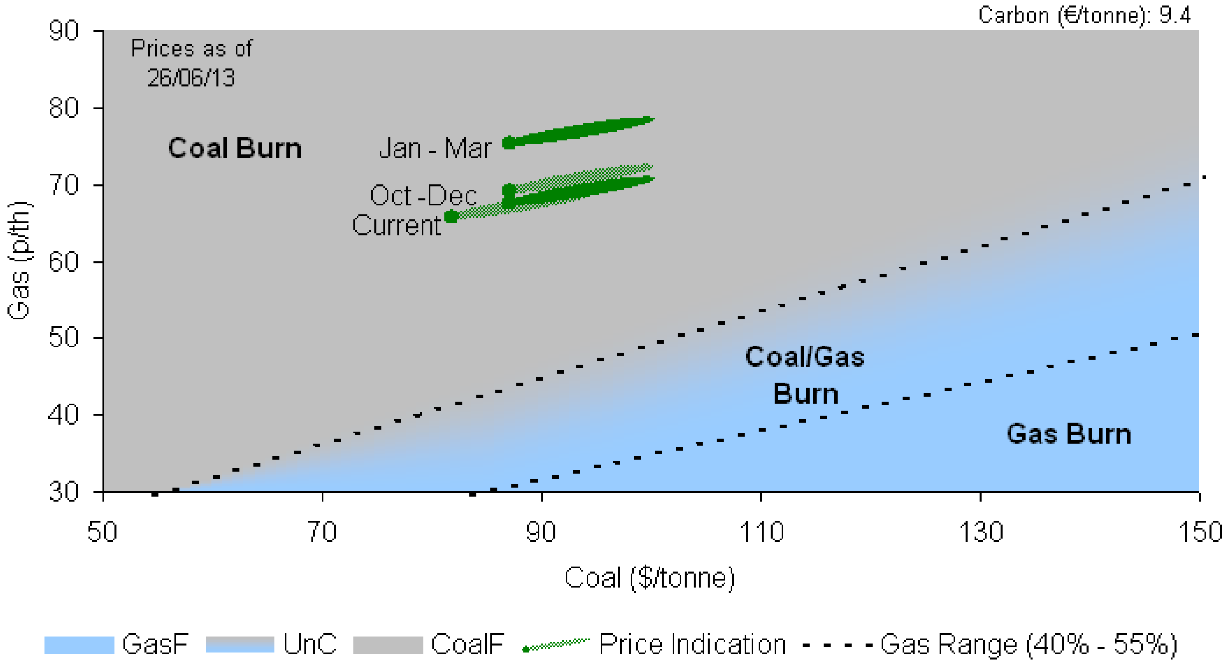
123. **Figure F4** shows the relative dark and spark spreads, showing whether gas or coal is favoured for electricity generation next winter. This assessment of the relative prices includes the cost of carbon in the UK, after taking into account the Carbon Price Support. The current futures indicate coal should be strongly favoured over gas throughout the winter.

Figure F4 – Relative power generation economics (1)



124. **Figure F5** shows the relative economics of coal versus gas burn for power generation for next winter on a monthly basis.

Figure F5 - Relative power generation economics (2)



125. The analysis strongly suggests that coal should be the favoured source of fuel for generation for next winter. Although for individual generators other factors may also impact their decisions.

126. For gas to become the preferred source of fuel for power generation next winter, the gas price needs to fall by about 50%, or there needs to be a doubling of the coal price, alternatively there needs to be a 10 fold increase in the carbon price to around €60/tonne.

Gas

Overview

127. This chapter covers the gas supply-demand outlook for the forthcoming winter together with an update on the Safety Monitors and provision of new NTS capacity.

Weather

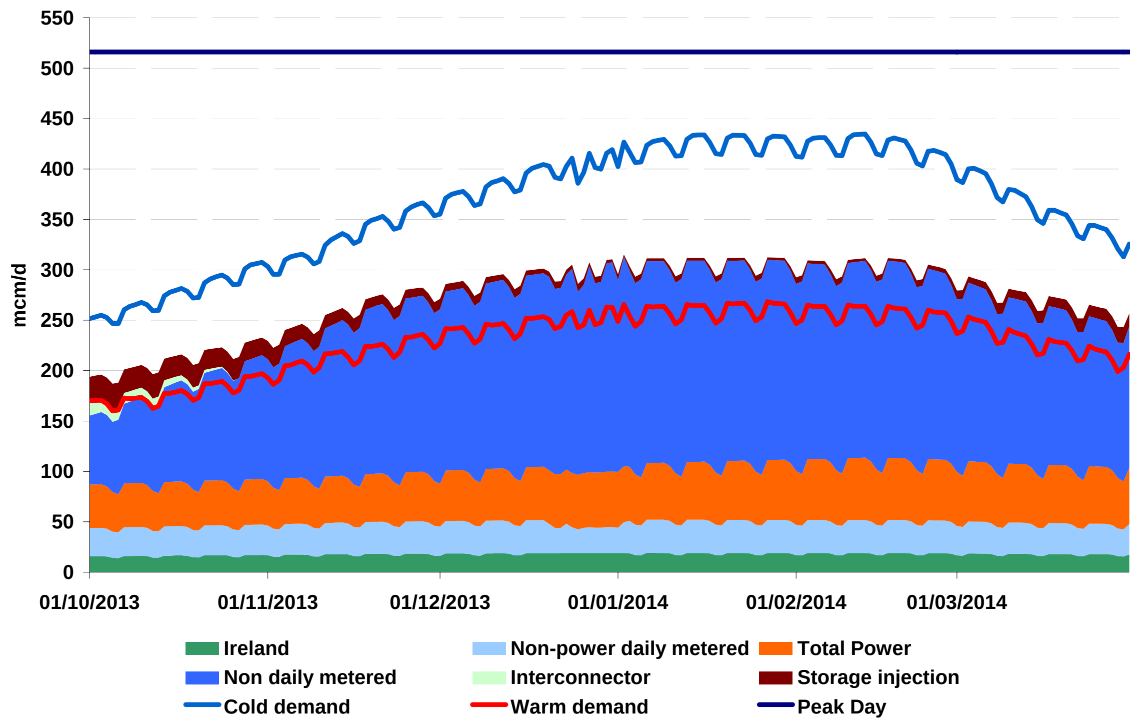
128. Information relating to winter weather for 2013/14 will be issued in the Winter Outlook Report in October.

Demand Forecast

129. The 2013/14 winter demand forecasts are similar to the 2012/13 weather corrected demands. Gas for power generation is forecast to be the marginal generation in 2013/14.

130. **Figure G18** shows the forecast gas demand for winter 2013/14 based on seasonal normal demand. In addition, lines to represent cold and warm demand are also shown. These lines represent the influence of weather rather than any demand changes associated with, for example, power generation economics.

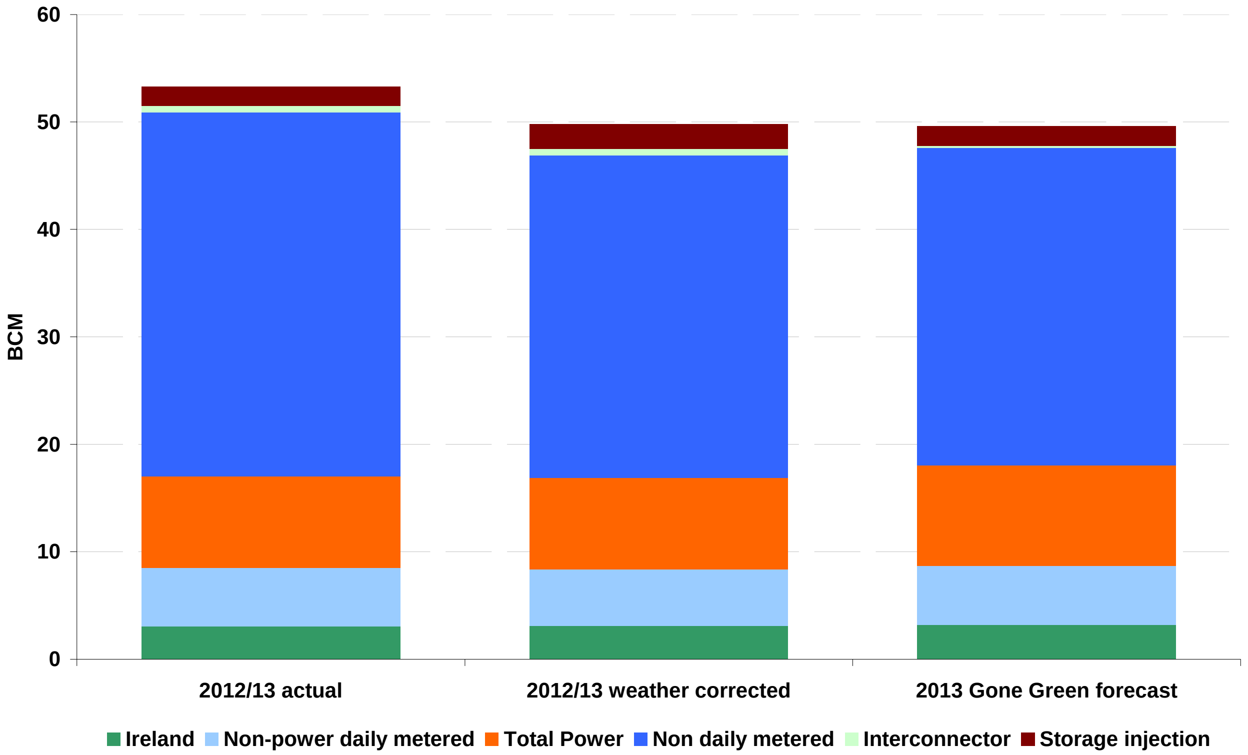
Figure G18 - Forecast Gas Demand Winter 2013/14



131. The chart shows seasonal normal demand peaking just above 300 mcm/d. In reality, peak winter demands will be appreciably higher than this, as for much of the winter, temperatures can be expected to be colder than seasonal normal temperatures.

132. **Figure G19** shows the actual and weather corrected demand for last winter and also the Gone Green forecast demand for winter 2013/14.

Figure G19 - Forecast Gas Demand October 2013 to March 2014



133. The chart shows:

- The impact of weather correction on the 2012/13 NDM demand
- Little difference between weather corrected 2012/13 and the winter forecast for 2013/14. The only noticeable difference being the forecasts for storage injection for which there is considerably uncertainty.

134. **Table G4** shows the historic actual and weather corrected demand for winters 2010/11 through to 2012/13 and the forecast for winter 2013/14.

Table G4 - Forecast Gas Demand- October to March 2013/14

October to March winter	2010/11		2011/12		2012/13		2013/14
bcm	Actual	Weather corrected	Actual	Weather corrected	Actual	Weather corrected	Forecast
NDM	34.2	31.4	28.2	29.9	33.9	30.0	29.5
DM + Industrial	5.8	5.8	5.3	5.3	5.4	5.3	5.5
Ireland	3.6	3.6	3.0	3.1	3.1	3.1	3.2
Total Power	12.5	12.4	9.9	9.9	8.6	8.5	9.3
Total demand	**56.6**	**53.7**	**46.7**	**48.4**	**51.2**	**47.2**	**47.6**
IUK export	2.1	2.1	4.4	4.4	0.6	0.6	0.2
Storage injection	1.8	1.8	2.3	2.3	1.8	2.3	1.8
GB Total	**60.5**	**57.6**	**53.5**	**55.2**	**53.5**	**50.1**	**49.6**

135. On a weather corrected basis, the table shows some decline in power generation and IUK exports in recent years. Power generation remained low due to fuel prices continuing to favour coal generation over gas. IUK was importing as a result of a higher non-daily metered demand throughout the winter months and lower LNG imports. Our forecast for 2013/14 shows a modest return in power generation demand. Generation demand continues to assume fuel prices favouring coal yet also reflects the reduction in coal and oil capacity since 2012/13.

136. **Table G5** shows the daily average demand for last winter and the forecast demand for winter 2013/14. The table also shows the actual range of demand experienced last winter and a forecast range.

137. The low forecast range for weather sensitive loads is based on a very warm early October[17] day, Ireland, IUK and storage on historic data and power on our low gas scenario.

138. The high forecast range for weather sensitive loads is based on a very cold January day, Ireland on our peak day forecast, IUK and storage on historic data and power on our high gas scenario.

[17] For the December to February range in Table G6, the very warm day applies to early December

Table G5 - Forecast Daily Gas Demand- October to March 2013/14

October to March winter mcm/d	Daily average			Actual range		Forecast range	
	2012/13 actual	2012/13 weather corrected	2013 forecast	2012/13 low	2012/13 high	2012/13 low	2012/13 high
NDM	186	165	162	82	278	36	313
DM + Industrial	30	29	30	21	35	23	37
Ireland	17	17	18	12	23	14	22
Total Power	47	47	51	21	71	32	65
Total demand	281	259	263	157	387	119	435
IUK export	3	3	1	0	16	0	30
Storage injection	10	13	10	0	49	0	45
GB Total	**294**	**275**	**274**	**189**	**389**	**160**	**435**

139. **Table G6** shows a similar table to **Table G5** but is based on the mid-winter months of December to February.

Table G6 – Forecast Daily Gas Demand – December to February 2013/14

December to February winter mcm/d	Daily average			Actual range		Forecast range	
	2012/13 actual	2012/13 weather corrected	2013 forecast	2012/13 low	2012/13 high	2013/14 low	2013/14 high
NDM	209	192	191	145	278	117	313
DM + Industrial	30	30	31	21	35	23	37
Ireland	17	17	18	12	22	15	22
Total Power	47	47	55	21	71	36	65
Total demand	304	288	297	207	387	215	435
IUK export	4	4	0	1	14	0	30
Storage injection	9	10	5	0	49	0	45
GB Total	**317**	**301**	**302**	**241**	**389**	**227**	**435**

140. The ranges in the tables highlight the considerable variation that exists for essentially all demand sectors even for the main winter months of December to February.

141. **Figure G20** and **Table G7** show the highest ever day[18] of demand in December 2010 and the 1 in 20 peak day demand forecasts for winter 2013/14. The biggest difference in the demands is through the accounting methodology for power generation.

Figure G20 - 1 in 20 Peak Day Gas Demand 2013/14

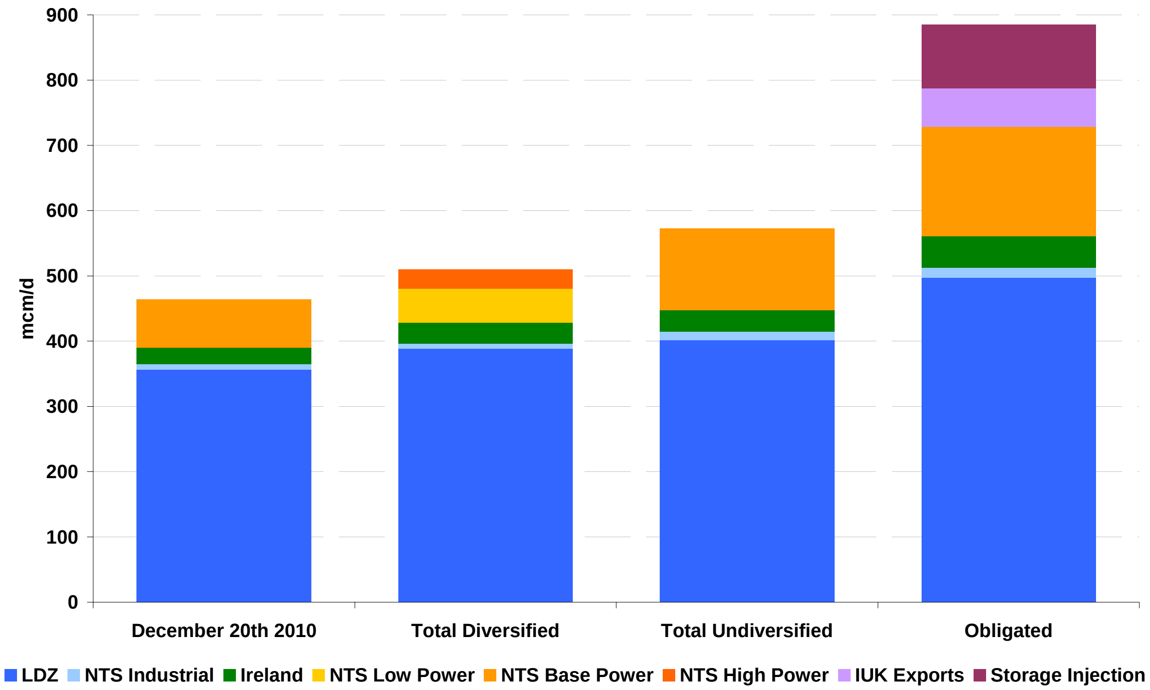


Table G7 – 1 in 20 Peak Day Gas Demand 2013/14[19]

		2013/14 Gone Green Forecast		
mcm/d	December 20th 2010	Total Diversified	Total Undiversified	Obligated
LDZ	356	388	402	497
NTS Industrial	9	8	13	15
Ireland	25	33	33	48
NTS Power	74	82	125	167
IUK Exports	0	0	0	59
Storage Injection	0	0	0	98
Total	**465**	**511**	**572**	**885**

18 The 20 December 2012 was only marginally higher than 8 January 2010 excluding NTS shrinkage

19 Demand data can differ between different sources for a number of reasons including classification, CV and closeout date. Power generation classifications are: in tables G4 to G6 the LDZ connected power stations at Fife, Derwent, Shoreham, Barry, Severn Power and Fawley are included in the total power category but in G7 they are included in LDZ demand. Grangemouth and Winnington NTS offtakes are included in total power in G4 to G6 but NTS industrial in G7. Immingham and Shotton Paper are classified as NTS power stations for all 3 tables.

142. Due to the price assumptions, the Gone Green base case forecast for gas-fired power generation is relatively low. For the 1 in 20 peak, the high case forecast for power generation is now used. This assumes lower gas prices relative to coal, and lower availability of non-gas generation such as nuclear and wind. For the 2013/14 Gone Green forecast, this increases the power generation component of the diversified peak day forecast by 29 mcm from 52 mcm to 82 mcm.

Supply Forecast

143. 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 and feedback through our Future Energy Scenarios[20] (FES) consultation process. This should not be seen as a definitive view at this stage but a means for industry engagement and consultation.

UKCS Gas Supplies

144. For the purposes of this document, our initial assessment of UKCS supplies for winter 2013/14 is based primarily on industry feedback recently received from our 2013 FES consultation. **Table G8** compares our UKCS outturn from Winter 2012/13 and our initial view for 2013/14.

Table G8 - Preliminary 2013/14 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2012/13		2013/14
	Winter Outlook	Highest	Initial View
Bacton	38	30	29
Barrow	10	11	9
Burton Point	2	4	2
Easington	14	12	9
St Fergus[21]	38	40	36
Teesside	25	15	15
Theddlethorpe	11	13	11
Total	**138**	**125**	**110**
90% Op Forecast	124		99

145. **Table** G8 shows a provisional UKCS maximum supply forecast of 110 mcm/d for Winter 2013/14. This is below the equivalent forecast for Winter 2012/13. Last winter's forecast was not met due to delays in the development of new production fields and the non-return of fields from production outages.

20 Formerly known as Transporting Britain's Energy (TBE) consultation process. FES documents can be found at http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/

21 Excludes estimates for Vesterled and Tampen

146. For Winter 2013/14 a number of new fields are forecast to come on-stream before or during winter, noticeably at Easington and Teesside. Bacton flows include the return of the Elgin field.

147. For the purposes of supply / demand analysis and for security planning, a lower operational forecast of UKCS is used. For this purpose, an availability of up to 90% is used, resulting in a UKCS planning assumption for next winter of 99 mcm/d. This is essentially the same as the highest day for Winter 2012/13 at 104 mcm/d.

Norwegian Imports

148. Norwegian imports to the UK flow through two dedicated import pipelines: Langeled to Easington and Vesterled to St Fergus and two additional offshore connections: Gjoa and the Tampen Link, both to the UKCS FLAGS pipeline to St Fergus.

149. In order to forecast Norwegian flows to the UK for next winter, an estimate of total Norwegian production is made, based on historical trends and expectations for the coming winter. An estimate of likely Continental flows is then made, which takes into account historical ranges along with expectations for this winter. As was the case in the Winter Outlook, there is now also an estimate for Norway's own-use gas, which is largely used in industry but also includes some domestic, industrial and power generation.

150. Due to the potential variation in Continental flows, a range of Norwegian flows to the UK is calculated based on observed load factors to each of the Continental countries that receive Norwegian supplies. For winter 2013/14, our preliminary forecast of Norwegian supplies to the UK is 105 mcm/d within a range from 60 to 130 mcm/d.

151. **Table G9** shows the forecast range of Norwegian exports for winter 2013/14. Also shown is a higher estimate of Norwegian flows for the mid-winter period to account for supply seasonality.

Table G9 – Winter 2013/14 Estimates of Norwegian Exports

(mcm/d)	High flows to Continent	Low flows to Continent	Central	Central (mid winter)
Norway	20	20	20	20
Belgium	40	35	38	40
France	48	45	47	50
Germany	130	105	120	125
UK	82	115	95	95
Total	**320**	**320**	**320**	**330**

Continental Imports

152. Supplies through the BBL pipeline were more responsive to the UK market conditions last winter providing some seasonal flexibility over the 6 month period; this may have been due to the commercial arrangements for interruptible non-physical reverse flow

(i.e. non-physical exports). This trend may continue for Winter 2013/14 with BBL again showing some response to UK market conditions.

153. For planning purposes, our preliminary forecast for BBL for next winter flows is 35 mcm/d. This is a higher forecast than last winter and reflects the experience gained last winter on high demand days.

154. Previous winters have shown IUK to be responsive to the following factors:

- Gas price
- UK demand
- Availability or rather non-availability of other non-storage supplies
- Storage flows / stocks

155. The high levels of imports seen last winter were consistent with these assumptions as a combination of sustained demand (arising from a prolonged winter), limited LNG imports and depleted storage stocks increased the need for significant IUK imports.

156. For next winter, these relationships are anticipated to generally hold true again with IUK importing when the UK has a market need for additional supplies above those supplied by most but not all other sources. Under certain conditions, for example, low storage stocks, high UK gas prices, or supply losses, then IUK could be expected to import at lower demands. Conversely, if storage stocks were high, UK gas prices low or supply availability was higher than anticipated, then expectations of IUK imports would be limited.

157. Our forecast for IUK imports next winter reflects this uncertainty regarding the availability of other non-storage supplies, notably LNG. This winter, the availability of storage, particular at the beginning of the winter period, may also influence IUK imports to the UK.

158. Our view of IUK flows is based on its behaviour during last winter. Given the uncertainties over the availability of other non storage supplies, a value of 40 mcm/d has been used for what IUK could be expected to provide on a cold day with associated high gas demands. Whilst this is lower than that experienced last winter, the level may be modified should higher or lower flows be observed during the winter period.

LNG Imports

159. Last winter, as shown in **Figure G11**, the UK received a lower level of LNG imports than winter 2011/12. Our view is that LNG imports will remain suppressed due to the high levels of demand in Japan and other Far East markets. The broad movements of LNG reflect the higher prices paid in these markets compared to the UK, Europe and the US. Forward prices suggest this trend will continue through this coming winter.

160. In terms of attracting LNG with other competing markets, gas prices in the UK remain much higher than those in the US; other European traded markets tend to be comparable with the UK.

161. **Table G10** shows some of the factors which may support higher or lower LNG imports:

Table G10 – Factors affecting LNG imports

Higher LNG Imports	Lower LNG Imports
Increased global production	Higher global LNG demand
Return of some nuclear power in Japan	High LNG demand in the Far East, especially Japan and increasing demand in China
Potentially lower LNG demand in the US and Spain, with the possibility of higher reloads	Possible nuclear outages in South Korea over winter 2013/14
	More LNG to Gate (Netherlands) or Zeebrugge (Belgium)

162. To manage the supply uncertainty surrounding LNG, a wide range is considered, namely from 8 to 100 mcm/d. This is consistent with recent historic LNG winter flows. At times of higher demand, it is anticipated that LNG flows will increase (last winter the maximum LNG flow was 74 mcm/d), although as experienced last winter there is a high level of uncertainty regarding LNG's responsiveness to UK market conditions.

163. The range, therefore, identifies periods of both low flow and high flow from Grain and both Milford Haven facilities. Flows of LNG imports through Teesside GasPort provide a further upside to the range.

Storage

164. For next winter, extra storage space is available from the Aldbrough and Holford storage facilities. The Stublach facility is expected to be online for first gas during the winter period, with commercial operations expected in spring 2014.

165. Based on assessments of current storage sites, deliverability for next winter is approximately 136 mcm/d (1498 GWh/d), which is an increase on last winter. This is mainly due to the increased deliverability assumptions for Holford and Aldbrough.

166. **Table G11** shows our assumed levels of storage space and deliverability for next winter. Currently, Rough is filled to about 46%, MRS is filled to around 72%, and Avonmouth, the only remaining LNG storage site, to about 22%. Overall storage levels are lower than this time last year and reflect the depleted status of storage at the end of the winter period and the delayed start to the injection period. However, it is anticipated that the majority of storage facilitates will be filled before they are required next winter.

Table G11 – Assumed 2013/14 Storage Capacities and Deliverability Levels[22]

	Space (GWh)	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (mcm/d)[23]	Duration[24] (Days)
Short (LNG)	511	2.6	150	13.6	3.4
Medium (MRS)	12690	720	863	78.5	15
Long (Rough)	40300[25]	279	485	44.1	83
Total	**53501**	**1002**	**1498**	**136**	
Total 2012/13	50965	889	1186	108	

167. The expected start up of Hill Top Farm later this year could add up to 146GWh/d of extra deliverability and 285GWh of storage capacity, with additional deliverability and capacity becoming available in later years.

22 This table represents our operational assumptions and is based on proven performance. Reported deliverabilities may be different to 'name plate' capacities. Space includes 814 GWh Operating Margins and excludes Hill Top Farm which will be included when operational

23 Assumed a standard CV of 39.6MJ/m^3

24 Duration based on Space / Deliverability, excludes within winter refill

25 This represents maximum capacity and is not a stock forecast: the actual stock level heading into winter will be determined by market conditions

Preliminary View of Supplies Winter 2013/14

168. In the previous sub-sections, we have outlined the basis for the assumptions incorporated into our analysis. **Table G12** summarises the supply range and our supply forecast for a 'cold day'[26]. Also shown are the actual 2012/13 ranges for the six month period and for when demand exceeded 350 mcm/d. We should stress that these 2013/14 ranges and forecasts for supplies for a cold day should be regarded as provisional with the primary purpose of fostering discussion and comment.

Table G12 – Preliminary View of Non Storage Supplies Winter 2013/14

(mcm/d)	2012/13		2013/14	
	Range	350+ Range	Range	Cold Day[27]
UKCS	76 – 104	79 – 102	76 - 110	99
Norway	37 – 129	90 – 129	60 -130	105
BBL	10 – 45	18 – 45	10 - 45	35
IUK	0 – 74	7 - 74	0 - 74	40
LNG Imports	8 – 74	8 – 74	8 -100	50
Total	**131 – 426**	**202 - 424**	**154 - 459**	**329**
Storage	**0 – 109**	**9 – 109**	**0 - 136**	
Total inc. Storage	**131 - 535**	**211 - 533**	**154 - 595**	

169. Based on the supply assumptions detailed in the previous supply sections, **Table G12** suggests that the non-storage supply availability for next winter is again uncertain, notably in terms of deliveries of LNG and Continental imports and, to a lesser extent Norwegian supplies. For Winter 2013/14 there is additional deliverability from storage facilities, although uncertainty remains as to how it will be used and therefore its availability throughout the winter period.

[26] A day approaching 0 degrees CWV
[27] A day approaching 0 degrees CWV

Preliminary Safety Monitor

170. The safety monitor is a mechanism for ensuring that sufficient gas is held in storage at all times to underpin the safe operation of the gas transportation system. The safety monitor defines the level of storage that must be maintained through the winter period.

171. The focus of the safety monitor 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.

172. This section on the safety monitor is consistent with the industry note we issued in early June 2013.[28]

173. There continues to be considerable uncertainty regarding the make-up and aggregate level of non storage supplies. As stated previously, LNG imports in winter 2012/13 were lower than in the previous winter, and going forward there remains considerable uncertainty regarding the level of individual supply components, most notably LNG.

174. The focus of the safety monitors is public safety and hence, it is prudent to ensure that the assumed level of NSS will be available throughout the winter, notably at times of high demand. Our assumption of NSS for calculation of the safety monitors is based upon a weighted rolling average of the last five years of NSS. Analysis of previous winters' data shows that assuming an availability of 95% captures typically 95% of all data points, with those that are still below often the result of short term supply losses.

175. The demand background used for the analysis in this section is our 2012 demand forecasts for 2013/14. Our final view of demands and supplies for next winter will be detailed in our Winter Outlook Report document to be published in October; these levels will be used as the basis for setting the final safety monitor level by 1 October.

176. **Table G13** shows the total safety monitor space requirement on the basis of the assumptions outlined above.

Table G13 – Total Safety Monitor Space Requirement

	Total storage capacity (GWh)	Space requirement (GWh)	Space requirement %
Total	53501	1280	2.4%

177. 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

[28] http://www.gasgovernance.co.uk/monitors

time before next winter and the outcome of this consultation may provide further clarity on expected levels of supply for next winter.

Winter 2013/14 Update on Provision of New NTS Capacity

178. Emissions related works - Work continues on the new 35MW electric drive compressor unit at Kirriemuir, the two 24MW electric drive units at St Fergus and the 35MW electric drive unit at Hatton as part of National Grid's drive to reduce compressor station emissions. The new units are anticipated to become operational for Winter 2013/14.

Consultation Questions - Gas – Outlook

Number	Question
GQ5.	What do you feel are the key factors that will set the UK gas price at times of high demand this winter?
GQ6.	The relative economics of gas versus coal generation for next winter and beyond strongly favour coal. What factors may result in a higher gas burn?
GQ7.	Should 1 in 20 peak demand forecasts include power generation gas demand at high case or base case levels? Should IUK exports at peak also be considered?
GQ8.	Despite recent history of decline in the UKCS, we are predicting similar levels for winter 2013/14 to those in winter 2012/13. This is due to the new developments offsetting decline from more mature fields. Do you agree with these views?
GQ9.	Like last winter, the biggest uncertainty regarding imports is for LNG. What assumptions should be made for levels of imported LNG to the UK for next winter? Will Asian LNG demand rise further, will other Far Eastern markets take more LNG and what about LNG production? Please consider these issues or comment on other LNG related factors.
GQ10.	Given the higher imports last winter we have increased our forecast for IUK imports at times of high demand, what factors do you believe are necessary for the UK to receive these levels of imports, and are these levels dependent on the timing within the winter?

Electricity

Overview

179. This section sets out the current forecast for winter 2013/14.

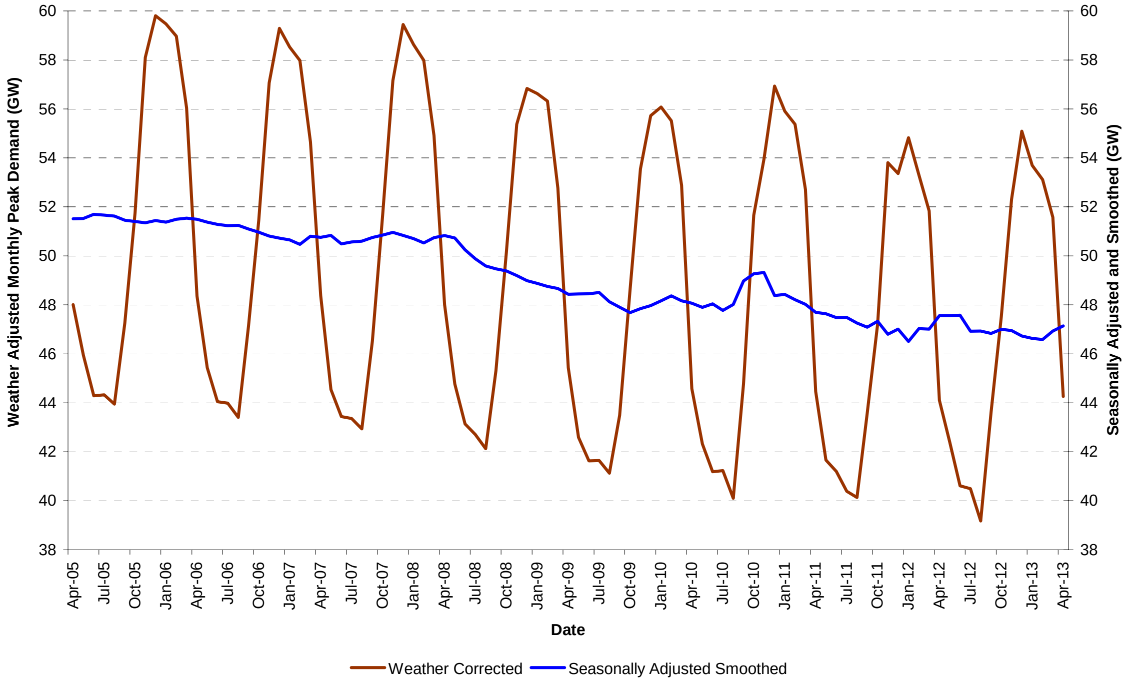
Demand Levels

180. Unless otherwise stated, demand discussed in this report excludes any exports to France, The Netherlands and Ireland but does includes station load and exports from the Transmission System to meet GB demand.

181. Generation from small[29] and medium[30] embedded wind and solar sources for which National Grid does not receive metering significantly affects demand levels. National Grid demand forecasts now account for this variability by using weekly mean load factors for the various fuel types. National Grid makes estimates of the amount of this non-visible variable generation using statistical techniques, but receives no direct data.

182. **Figure E11** shows the weather and seasonally corrected demand levels for the last eight years. The effect of the economic downturn of 2008-2010 can be clearly seen. A second slowdown in the economy occurs from April 2011 to February 2012. Since then monthly seasonally adjusted peak demands have levelled out.

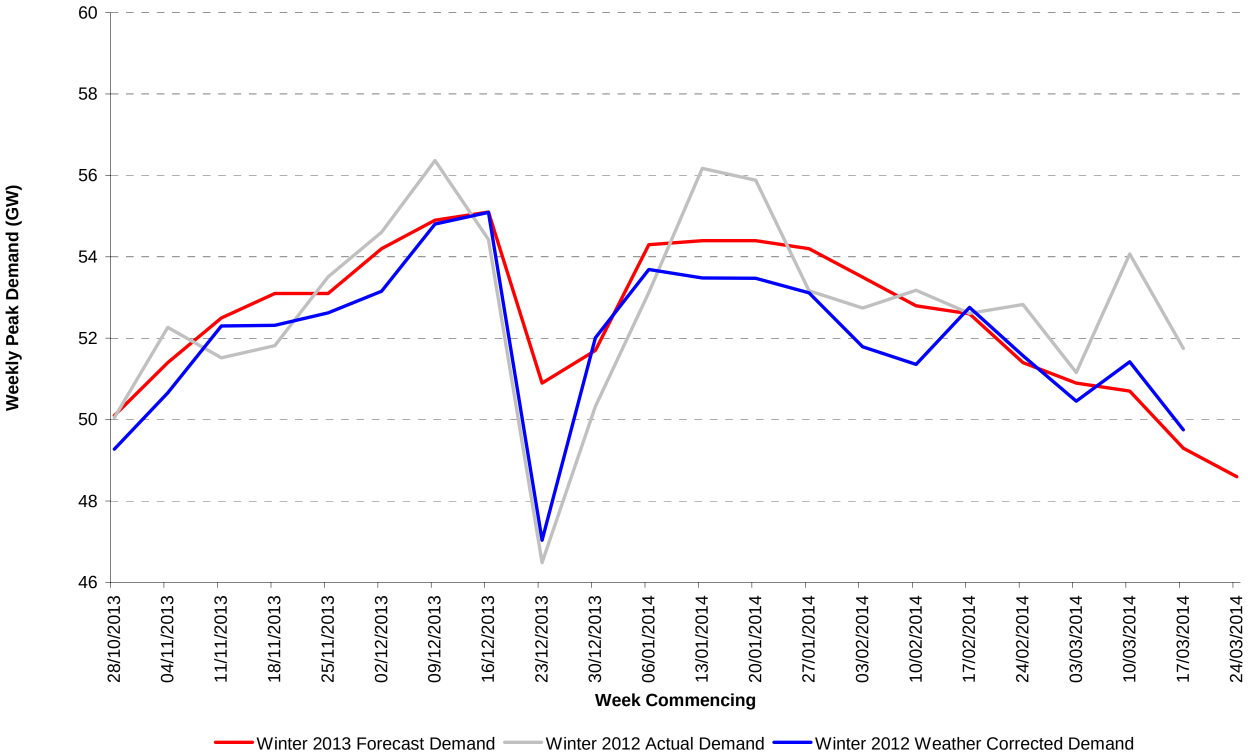
Figure E11 - Weather Corrected and Smoothed Seasonally Corrected Demand



[29] Small defined by the Grid Code: <50MW in England & Wales, <30MW in South Scotland, < 10MW in North Scotland.
[30] Medium defined by the Grid Code: between 50MW and 99MW in England and Wales.

183. **Figure E12** shows last winter's actual demand, weather corrected demand and the demand forecast for the coming winter. The most current forecast at any time is given on the **BMRS**[31]. The forecast for Christmas week is higher than last year as Christmas falls on a Wednesday this year. The highest demand forecast for Christmas week will likely be on Monday 23rd before the holiday week starts in earnest. Last year Christmas day fell on a Tuesday, with the demands on the Monday being suppressed as it was Christmas Eve.

Figure E12 - Previous year's outturn and forecast for 2013/14



184. The weather corrected normal demand peak forecast for winter 2013/14 is currently at 55.1 GW. This is comparable to the forecast last year of 55.3 GW and the weather corrected demand outturn of 55.1 GW.

185. 1 in 20 conditions are a particular combination of weather elements which give 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. The 1 in 20 demand peak is forecast to be 59.0 GW.

Generator Availability

Generation Capacity

186. Based on the observed output of power stations, our current operational view of generation capacity anticipated to be available for the start of winter 2013/14 is 77.1

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31 www.bmreports.com

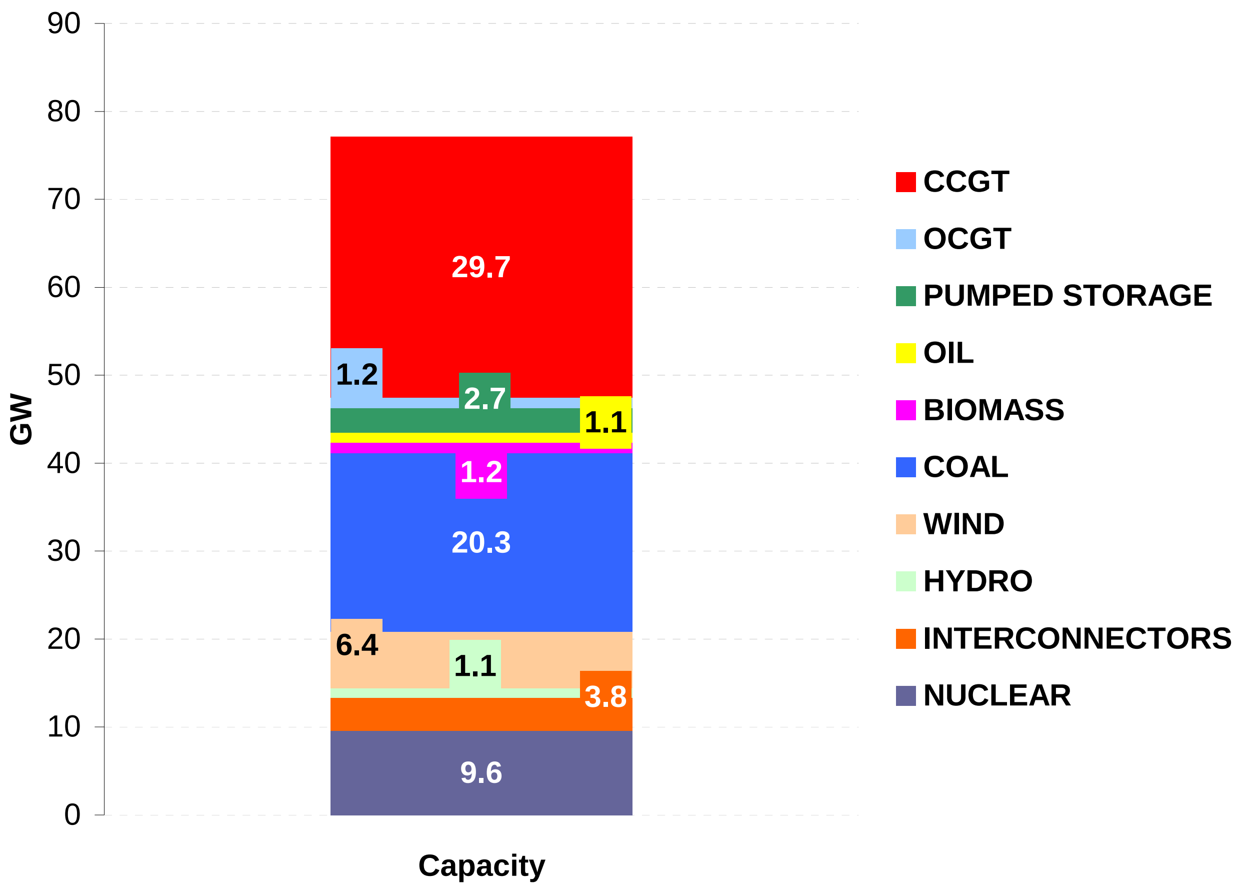
GW as shown in **Figure E13**. This is an increase of 530 MW from the capacity available at the start of the summer as reported in the Summer Outlook Report.

187. This is due to a combination of gains and losses. There are gains due to the return of Shoreham, the commissioning of the second unit at West Burton B and an increase in wind generation capacity. These gains are partially off-set by reductions in capacity due to Ironbridge and one unit at Drax converting to biomass. In addition, Tilbury is expected to run out of LCPD hours before the start of the winter.

188. It is worth noting that the capacity of 77.1 GW is 2 GW less than at the start of last winter. Excluding wind, capacity has fallen from 74.5 GW at the start of last winter to 70.7 GW at the start of this winter.

189. There is potential for further gain once commissioning of the last unit at West Burton B is completed but there are also further potential losses if Littlebrook were to follow other oil fired plant and close and/or if Ferrybridge Units 1 and 2 exhaust their remaining LCPD hours before the start of the winter.

Figure E13 - Generation Capacity Operational View for the Start of Winter 2013/14



Generation Availability Assumptions

190. **Table E4** shows the assumed losses based on the average losses of the previous three winters. The losses take account of breakdowns, shortfalls and any reduction in primary energy source such as wind and water. They do not allow for planned outages as these have already been accounted for in the notified availability. Figures quoted are all means, other than those for wind, which are median and tenth percentile figures.

191. From **Figure E3** it is clear that national wind load factors vary from close to zero to 90% of capacity. Median wind output has been chosen to illustrate a central case and the tenth percentile to illustrate low wind conditions. Although illustrative, this approach is limited given the forecast growth in wind capacity.

Table E4 - Assumed Losses of Generation Availability for Winter 2013/14

Power Station Type	Assumed losses
Nuclear	16%
Interconnectors	0%
Hydro generation	21%
Wind generation (median)	68%
Wind generation (low)	91%
Coal + biomass[32]	15%
Oil	13%
Pumped storage	3%
OCGT	5%
CCGT	14%
Total (low wind)	**20%**

192. The assumed losses in **Table E4** are applied to the generator notified availability and this data is then used to calculate the forecast generation surplus shown subsequently in **Figure E15** and **Figure E16**.

Effect of LCPD on generation capacity

193. Limited running hours under the Large Combustion Plant Directive, LCPD, for opted out plant have resulted in the closure of 7000 MW of coal and oil fired generation capacity. Tilbury, although converted to biomass, is expected to use up its remaining hours this summer. The remaining opted out LCPD units are Ferrybridge Units 1 and 2, the two Ironbridge units (also converted to biomass) and the two Littlebrook oil fired units. The total capacity of these units is 3000 MW. Of these units, only Ferrybridge could potentially use up its remaining hours before the end of winter.

[32] There is not yet sufficient data to report biomass assumed losses separately to coal

Mothballed Plant

194. Currently Keadby, Teesside 1 and 2, Roosecote and Barking 2 are mothballed or similarly unavailable to generate this winter. If any of these units were to return this winter margins would improve. However there may be a risk that other older CCGT plant is mothballed ahead of the winter due to the current marginal economics of power generation from gas.

Reserve Levels

195. 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.

196. There is also an additional reserve requirement to meet wind generation output uncertainty. This reserve held by National Grid specifically to manage the additional variability brought about by wind generation output being lower than expected. Its value varies based upon a function of the expected wind output through each period of the day and the requirement is mainly met from synchronized sources.

197. 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. 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.

198. For winter 2013/14, our present level of contracted STOR reserve is approximately 2.7GW, approximately 1.8 GW comes from BM participants and 0.9 GW comes from non-BM generating plant and demand reduction units. Approximately 0.6 GW of the contracted volume of non-BM generating plant and demand reduction units are to provide a committed STOR service, the remainder are contracted to provide a flexible STOR service.

199. Prior to the winter, there will be two further STOR tender rounds covering services for the winter 2013/14 darkness peak; the results of which will be published at the end of July and at the beginning of November. Communications regarding this will be through electricity operational forums and on our website.[33]

200. National Grid expects to contract more STOR to provide reserve service over the winter, but the contracted amount will be small. Last winter we contracted about 3.5 GW of STOR over the darkness peak period in all, but much of that was not available over weekday peak demands, and dependent on providers contracted position or availability. Total availability at the time of the top 20 winter peak demands last winter was 2.31 GW. Allowing for seasonal influences and any one-off events, the amount of contracted STOR that will actually contribute to the operational reserve requirement at the winter 2013/14 darkness peak is expected to remain consistent with last winter (2012/13).

[33] http://www.nationalgrid.com/uk/Electricity/Balancing/services/STOR/

201. 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 1.9 GW of reserve would be required to meet the necessary response requirement. 0.7 GW of this 1.9 GW reserve requirement has already been contracted, with 0.14 GW from demand-side providers.

202. National Grid expects to contract more frequency response to provide response service over the winter. Last winter we contracted about 1 GW of frequency response over the darkness peak period in all, but much of that is dependent on providers contracted position or availability.

203. National Grid continues to have Maximum Generation contracts in place for Winter 2013/14, which provides potential access to up to 1 GW[34] 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.

Interconnector Flows

204. The North West Europe (NWE) price coupling of regions project (Central West Europe, Nordic and GB) is currently scheduled for delivery in November 2013. This will introduce an implicit day ahead auction across all interconnectors in the group (including BritNed and IFA). We expect this to introduce greater volatility of flow nominations in these timescales due to the increased sensitivity of flows to price spreads.

205. The spreads on the curve for winter 13/14 indicate net imports to GB over BritNed and IFA, however day ahead price volatility will significantly impact any long term flow forecasts. Exports to Ireland are expected to continue, however if trading arrangements become more flexible we expect to see more instances of flow reversal during periods of high wind.

Forecast Generation Surpluses

206. This section looks at the amount of Generation Surplus available through four scenarios using the methodology that has historically been used in the Winter Outlook publications and a methodology aligned with the UK Future Energy Scenarios[35] (UKFES) and Ofgem's Capacity Assessment Report[36]:

- A benign scenario: Normal demand and notified generation availability
- Two central scenarios: Normal demand and assumed generation availability

  Average Cold Spell (ACS) demand and assumed generation availability

[34] In an emergency situation only a proportion of this is likely to be able to be used due to the consequent loss of reactive power capability
[35] http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/
[36] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

- An arduous scenario: 1 in 20 demand and assumed generation availability

207. Normal demand is based on average weather conditions.

208. 1 in 20 demand is based on severe weather that would only be expected in 1 winter out of 20.

209. ACS demand is the yearly peak demand that in any year the maximum demand in that year has a 50% probability of being above the ACS figure because of weather variability alone.

210. The notified generation availability is the current declared availability which is submitted to National Grid through the requirements of Operational Code 2 in the Grid Code. The assumed generation is derived from the assumed losses set out in **Table E4** being applied to the notified generation availability.

211. Each of the following charts has an amount of demand (green bars) and the required operational reserve (orange bars). The solid lines show the generation availability with a range of assumptions on interconnector and wind contribution. The Moyle interconnector is not included in these maximum import and export capabilities as the margin analysis treats exports to Moyle as additional demand in Scotland, which in turn allows for a greater amount of generation to be exported from Scotland.

212. The Operating Reserve in **Figure E15** and **Figure E16** is less than the Operational Planning Margin Requirement (OPMR) in **Figure E14**. This is because assumed losses have been applied to the notified generation in **Figure E15** and **Figure E16**, which means that:

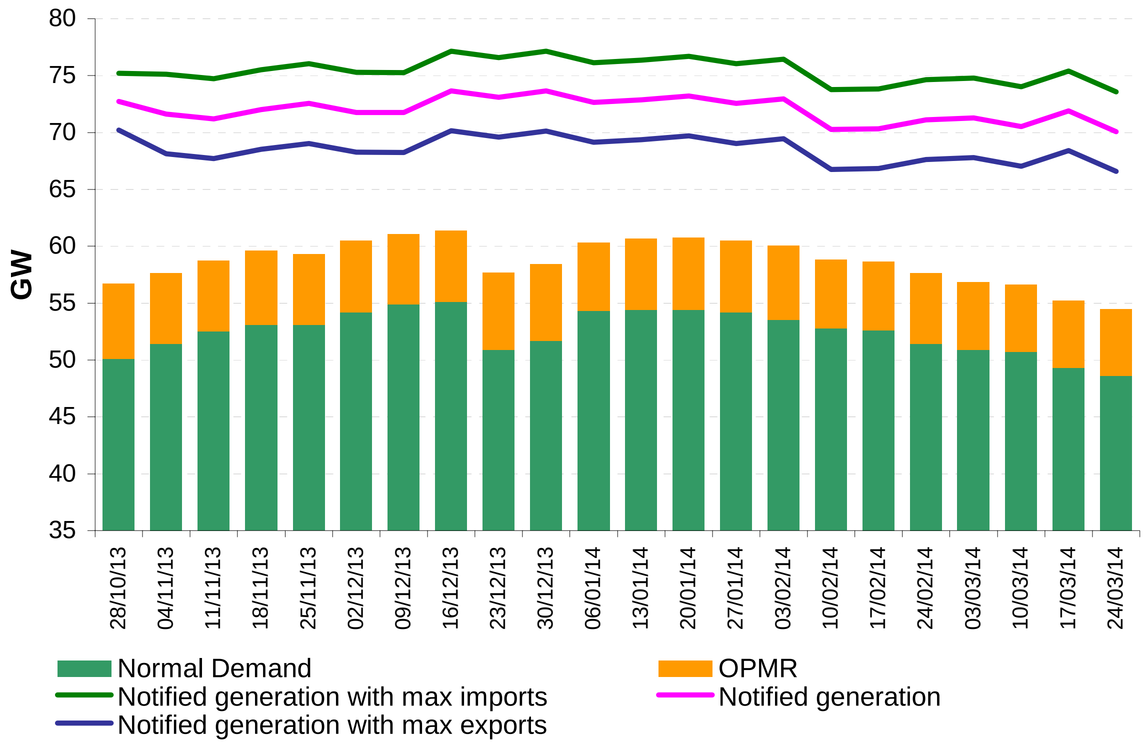
    - the capacity that is unavailable to National Grid is reduced
    - the contingency reserve can be removed
    - the average breakdown component of the OPMR can be removed

    The cumulative effect of these is a noticeable reduction in the reserve requirement.

Normal Demand, Notified Generation

213. **Figure E14** shows Normal Demand and the notified generation availability. All generation (including wind and hydro) is treated the same in this chart, reflecting the capacity planned to be available assuming no fuel source limitations. This chart shows that there is adequate margin under these conditions. With interconnectors at float – the minimum generation surplus across the winter is 15% in the week commencing 9 December; the surplus is 17% for the winter demand peak in the week commencing 16 December. The surplus is the amount of generation available above the amount required to meet the demand and reserve requirements. It is represented as a percentage of the total available generation. In effect this chart reflects "best case" conditions, i.e.: no breakdowns and full output from wind and hydro power stations and is equivalent to the data published on www.bmreports.com.

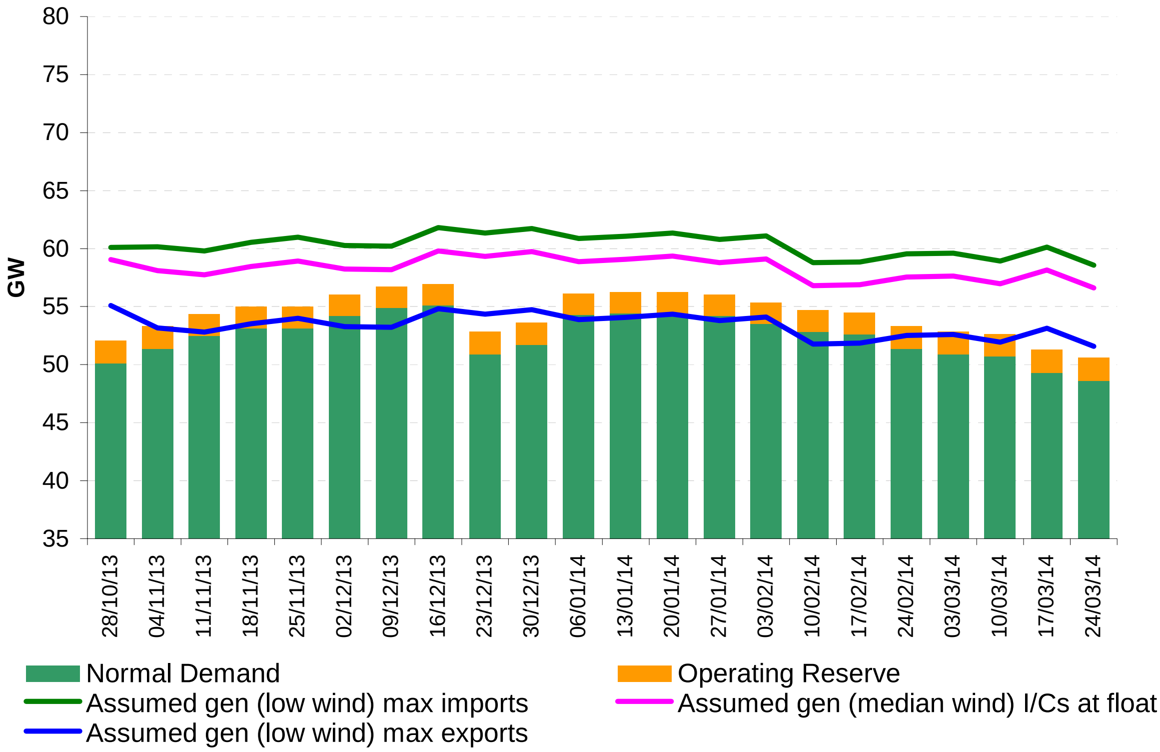
Figure E14 - Normal Demand and Notified Generation Availability



Normal Demand, Assumed Generation

214. The pink line in **Figure E15** shows the assumed generation availability based on median wind compared to Normal Demand and reserve as shown by the bars. The surplus on this basis is 5% with the interconnectors at float[37] at the time of the forecast peak demand in the week beginning 16 December. In this week the assumed generation availability is 59.8 GW. The minimum surplus across the winter is currently 3% for the week beginning 9 December. Should there be low wind output the chart shows that full interconnector exports would not be able to be accommodated for several weeks across the winter.

Figure E15 - Normal Demand and Assumed Generation Availability



[37] "Interconnectors at float" mean's zero net interconnector flow

Average Cold Spell Demand, Assumed Generation

215. The methodology historically used for assessing electricity generation plant surplus in the Winter Consultation and Winter Outlook follows broadly the same principles as undertaken for the Ofgem Capacity Assessment Report and the UK Future Energy Scenarios (UKFES). However there are a number of differences. Appendix 1 details the differences between the margin calculation methodologies used in this Winter Consultation and the UKFES. The most important differences are that the two methodologies use:

- different generator availability datasets, with each dataset being suited to the timeframes being analysed in each report. In the case of the UKFES the generator availability dataset is suited to a long term outlook reflecting assumptions on the life of current generators and new build generators. For the Winter Consultation it is suited to short term operation timescales based on current generators' notified availability submissions
- different demand forecasts, the UKFES is based on the Average Cold Spell[38] (ACS) demand forecast, suitable for medium and long term capacity adequacy. The Winter Consultation is based on the Normal Demand forecast, suitable for a short term season ahead operational outlook
- different reserve assumptions, again suited to the different timescales

216. The unrestricted ACS demand forecast for this winter is 57.3 GW. The Winter Outlook has historically quoted the restricted ACS demand forecast, which is 56.1 GW for this winter (this figure accounts for Customer Demand Management).

217. Using the UKFES margin calculation aligned methodology (i.e. using the restricted ACS forecast, using the UKFES reserve assumptions and calculating the margin as a proportion of demand instead of generation) with this winter's assumed generation availability at peak gives:

- a 6% margin forecast for this winter's peak assuming median wind
- a 3% margin forecast assuming 1 in 10 low wind.

These are very similar to the forecasts for this winter quoted in the UKFES; the small difference is due to having the slightly different generator availability datasets as inputs.

[38] In any year the maximum demand in that year has a 50% probability of being above the ACS figure because of weather variability alone

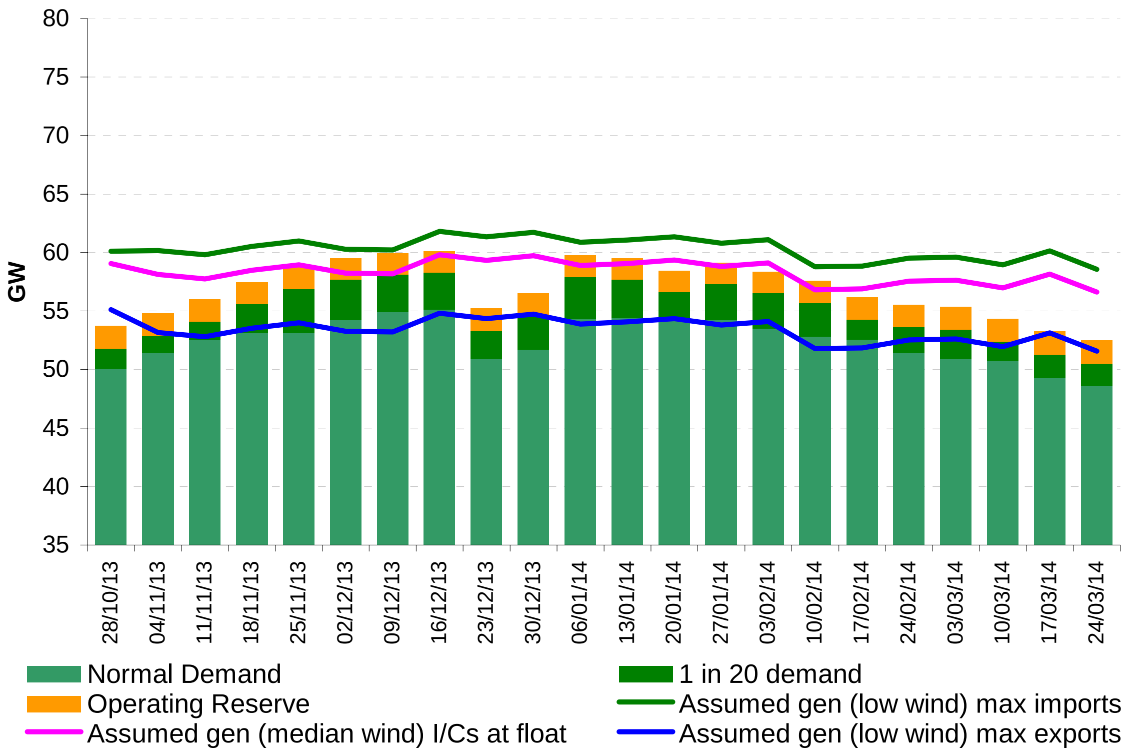
1 in 20 Demand, Assumed Generation

218. The pink line in **Figure E16** shows the assumed generation availability based on median wind and interconnectors at float compared to unrestricted 1 in 20 Demand[39] and reserve as shown by the bars. Note that if demands were this high, we would expect to see some voluntary Customer Demand Management (CDM). Our forecast levels of CDM are based on the levels seen last year and are expected to be up to 1.2 GW. **Figure E16** shows unrestricted demands, i.e.: they do not include our expected reduction due to customer demand management.

219. If there were no CDM, the pink line shows reserve levels would be eroded if 1 in 20 demands were experienced at any time during the peak winter period. With the current generator planned outage pattern, this erosion of reserve would be severe in the weeks beginning 2 and 9 December. If there were 1.2 GW of CDM across the affected months, then reserve levels would only be slightly eroded in the weeks beginning the 2 and 9 December.

220. Interconnector imports or higher wind output would improve margins, whilst interconnector exports or lower wind output would exacerbate this position. Note that in this chart the navy line representing low wind and maximum exports is notional as even if interconnectors could not be traded to improve flows there are provisions to reduce interconnector exports if demand control were necessary.

Figure E16 - 1 in 20 Demand and Assumed Generation Availability



[39] Historically unrestricted 1 in 20 demand levels have been quoted in the Winter Consultation and Outlook publications. We have maintained this convention in this Winter Consultation, however if volumes of CDM continue to increase, there may be benefit in reviewing this.

Forecast Generation Surpluses – Key Risks

221. The key risks to the forecast surpluses are:

- Demand being higher than forecast
- Very cold weather / low wind
- Generator availability losses being higher than assumed
- Uncertain timing of the remaining LCPD plant closures
- An increase in the volume of mothballed plant

222. A figure of 9% has been used for the low wind generation scenario for the winter peak. 10% of the time the wind output is likely to be lower than this. However, this would result in only a small reduction in the surplus.

223. There are potential upsides that could increase forecast surpluses and off set the downside risks, which include demands being lower than forecast, the possible return of mothballed gas plant and generator availability losses being less than those assumed.

224. Utilising interconnector capacity to reduce exports or increase imports through trading would provide a means of restoring any negative surplus but this may be limited by the tradable volumes available, market forces and any system constraints. If adequate levels of imports could not be secured, other mitigating actions would need to be taken to increase generation and/or reduce demand.

Transmission System Issues

225. The historic amount of output and curtailment of large wind farms is shown in the Winter Review section in **Table E3** and **Table E4**. This gives an indication of possible curtailment levels due to transmission constraints this winter. However actual curtailment levels will depend on actual wind strength, rainfall (due to related output from hydro power stations), transmission system capability, demand and generation availability, as well as wind farm capability to deliver ancillary services which help to keep the electricity system secure (if wind farms deliver these services cost effectively, conventional generators that would otherwise have been required on to provide these services could be curtailed instead).

226. As demands are higher in the winter, we don't expect there to be any issues with the system voltage profile, other than possibly over the Christmas period. This will be reviewed in more detail for the Winter Outlook Report.

Consultation Questions - Electricity - Outlook

227. National Grid would welcome comments on anything contained in the consultation report. In particular comments on the following questions would be most welcome.

Number	Question
EQ3.	What is your current expected growth in demand levels?
EQ4.	What levels of Customer Demand Management do you expect will be delivered over the highest demand peaks by your customers?
EQ5.	If your company has generation in a mothballed state: what might lead you to return it to service and how long would it take to do so?
EQ6.	Do you consider there is any generation that may be at risk of being put into a mothballed state or decommissioned before the end of next winter and how great is this risk?
EQ7.	If there were very cold conditions across Western Europe, what would you expect the flow on the Interconnectors to be over the GB demand peak?
EQ8.	Do you have the flexibility to run your CCGT's on distillate and, if so, for how long?
EQ9.	The margin calculation methodology used in the UKFES has been included alongside that which has traditionally been used in the Winter Outlook. Each methodology has been developed to deliver the best reporting with the best input data for their different time horizons. This results in slightly different margin figures being reported in each document for the coming winter. Changing either methodology will result in loss of historical continuity. Should we aim to harmonise the methodologies completely, should we aim for a partial harmonisation, or should we keep the methodologies distinct?
EQ10.	What further analysis, detail and scenario work do you consider would be beneficial for the Winter Outlook?

Appendix 1 - Margin Calculation Methodologies

228. Margin calculations in the Winter Consultation and those within the 2013 UK Future Energy Scenario (UKFES) publication are slightly different. **Table E5** details the similarities and differences.

Table E5 - Comparison of Margin Calculation Methodologies

	UKFES	Winter Consultation
Time Horizon	The UKFES looks from winter ahead to many years in the future	The Winter Consultation only looks at the coming winter
Generator Capacity (other than wind and hydro)	Based on forecast generator capacities (from the current generation mix, their expected operating life and assumptions of future new generator build), which are de-rated to account for losses due to planned unavailability and breakdown unavailability	Based on generator notified availabilities (under OC2 of the Grid Code) which include planned outages. These are de-rated to account for average breakdown losses
Wind	Two measures are used: • "1 in 10" low wind • Equivalent firm capacity[40] (EFC)	Two measures are used: • "1 in 10" low wind • Median wind[41]
Hydro	• Based on analysis of historic data	• Based on analysis of historic data
Small Embedded Generation (invisible to National Grid)	Estimations included in both the Generator Capacity and the Demand figures	Not included in the Generator Capacity figures and the forecast Demand figures are reduced by their estimated output.
Demand Definition	Includes: • Irish interconnector exports Excludes: • Continental interconnector exports • Station demand	Includes: • Station demand Excludes: • All interconnector exports

[40] Equivalent Firm Capacity (EFC) – this de-rating factor changes over time in relation to how much wind capacity is installed. Rather than looking at the historic peak half hour to derive a de-rating factor for wind this methodology adopts a statistical risk based view over the full winter period. For further information explaining the theory behind the EFC, see: http://pio.sagepub.com/content/226/1/33

[41] Median wind is marginally higher than EFC wind with current installed capacities

	UKFES	Winter Consultation
Types of Demand	• Average Cold Spell demand	• Normal demand • "1 in 20" demand • Average Cold Spell demand[42]
Reserve	• Reserve requirements for the largest single loss of generation	Reserve requirements vary depending on the scenario, including: • Operational Planning Margin Requirement (OPMR) • Adjusted OPMR (operating reserve) for de-rated scenarios • Reserve requirements for the largest single loss of generation[43]
Margin Calculation	Demand and reserve requirements are subtracted from generator availability and expressed as a percentage of demand and reserve. A number of different figures are quoted depending on inputs	Demand and reserve requirements are subtracted from generator availability and expressed as a percentage of generator availability for the traditional winter outlook calculations (normal demand & notified generation, normal demand & assumed generation, 1 in 20 demand & assumed generation). For the UKFES aligned calculation (ACS demand & assumed generation) it is expressed as a percentage of demand and reserve. A number of different figures are quoted for each depending on inputs

[42] In this Winter Consultation for the purposes of the UKFES margin aligned calculation
[43] In this Winter Consultation for the purposes of the UKFES margin aligned calculation