nationalgrid

Winter Outlook 2013/14

October 2013

Introduction

Welcome to our 2013/14 edition of the Winter Outlook Report. This annual publication provides a detailed analysis of the supply demand position for the coming winter for both gas and electricity.

This report includes our latest analysis and views and incorporates the responses received through the winter consultation process, initiated with the publication of the Winter Consultation 2013/14 document. Previous winter outlook reports are published on our website[1].

National Grid sits at the heart of the UK energy landscape, as both the transporter and operator of the gas and electricity transmission networks. Whilst there is always uncertainty as we enter a winter – be that the make up of gas supplies; the severity of the winter weather; or the likely electricity generation mix – I believe the UK's energy market has the capability to deliver. Additionally, I am confident National Grid has the right mix of physical assets, operational and commercial tools and people to ensure that consumers will continue to receive the energy they need reliably, efficiently and safely.

We continually seek feedback on our outlook reports to increase their usefulness to you. If you have any comments, please contact us at: commercial.operation@nationalgrid.com

Chris Train
Director, Market Operation
National Grid

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

Executive Summary

Gas

Gas Supply and Demand

In the UK, we have significant diversity of gas supplies and capacity well in excess of maximum demand.

For winter 2013/14, we forecast peak gas demand at 511mcm/d. This takes into account predicted high gas demand for power generation (82mcm/d) as well as 1 in 20 cold weather conditions.

The maximum supply forecast to the UK is 594mcm/d - over 100mcm/d more than the highest demand we've experienced on the network (465mcm/d in January 2010). While it is very difficult to forecast what the makeup of supplies will be for the coming winter, with each year having its own unique supply patterns, it is clear that the combination UK supplies and a diverse range of import capacity, combined with a mixture of storage types has performed well over the last eight years.

We receive less than half of our total gas supplies from the UK Continental Shelf (UKCS) or North Sea. We receive supplies via pipelines from Norway, and continental gas through the IUK interconnector and BBL pipelines. We also have facilities to receive liquefied natural gas (LNG) shipments, as well as gas storage.

Gas Storage

Gas storage makes up about 10 percent of the overall gas supply mix over the winter period (October to March).

This winter, the maximum amount of gas in storage that can be delivered into the network each day is forecast to be 135mcm/d. This has increased slightly compared to the amount available last year owing to the Holford and Aldbrough gas storage sites increasing the amount they can deliver into the network on any given day.

Electricity

Electricity Demand

Our peak weather corrected electricity demand forecast for this winter is 54.8 GW; this is our demand forecast should the weather be the same as long term average weather conditions. In any winter, however, there are milder spells and colder spells which drive fluctuations in demand around the weather corrected demand forecast. We forecast the peak Average Cold Spell (ACS) electricity demand to be 56.3 GW this winter.

Weather corrected peak electricity demand has been decreasing since 2005. It is likely that this is due to energy saving measures, a move away from heavy industry to less energy intensive industrial activity, increasing volumes of small embedded generation and increased customer demand management.

Executive Summary

Generation Capacity

Our forecast mid winter generator capacity is 74.7 GW. Over the mid winter period there are currently no major planned generation outages. This planned availability is likely to be reduced by unforeseen plant breakdowns and by fuel source availability limitations for hydro and wind generation. Because of this, we apply a 'de-rating' calculation looking at what the actual generator availability may be. We estimate that actual generator availability in the peak weather corrected demand week will be 60.5 GW. This figure includes our assumption of 750 MW imports from the continent.

Interconnector Flows

There is 3.8 GW of interconnector capacity available this winter. Interconnector flows are largely driven by price spreads, therefore the market dictates which way the interconnectors flow. Current price spreads indicate flows in from the continent and out to Ireland over the winter. Our central forecast assumes that we have 750 MW exports to Ireland and 750 MW imports from the continent at peak demand.

Actual flows over the winter may well vary widely from this central forecast depending on British and interconnected market conditions.

Electricity Margins

For this winter, taking the latest data into account, our central forecast of electricity margin against peak (ACS) demand is 5%, broadly in line with the level published in Ofgem's Capacity Adequacy analysis in June[2]. If, however, we have average weather throughout the winter, our central forecast of margin is 8%.

Electricity margins have decreased from historically high levels over the last few years. This has been driven by the effects of the Large Combustion Plant Directive legislation and economic pressure on older gas fired power stations (which has caused them to close or mothball). This has been partially offset by the fall in peak demands, increasing wind generation and construction of new gas fired power stations. Whilst our central forecast of margin is 5% against ACS demand, actual margins will depend on actual demand, actual generator availability and actual interconnector flows in real time.

Operational Tools

As System Operator, we are not complacent and we have a range of operational tools available to keep the system operating reliably and efficiently should either the gas or the electricity market experience any issues this winter.

[2] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013

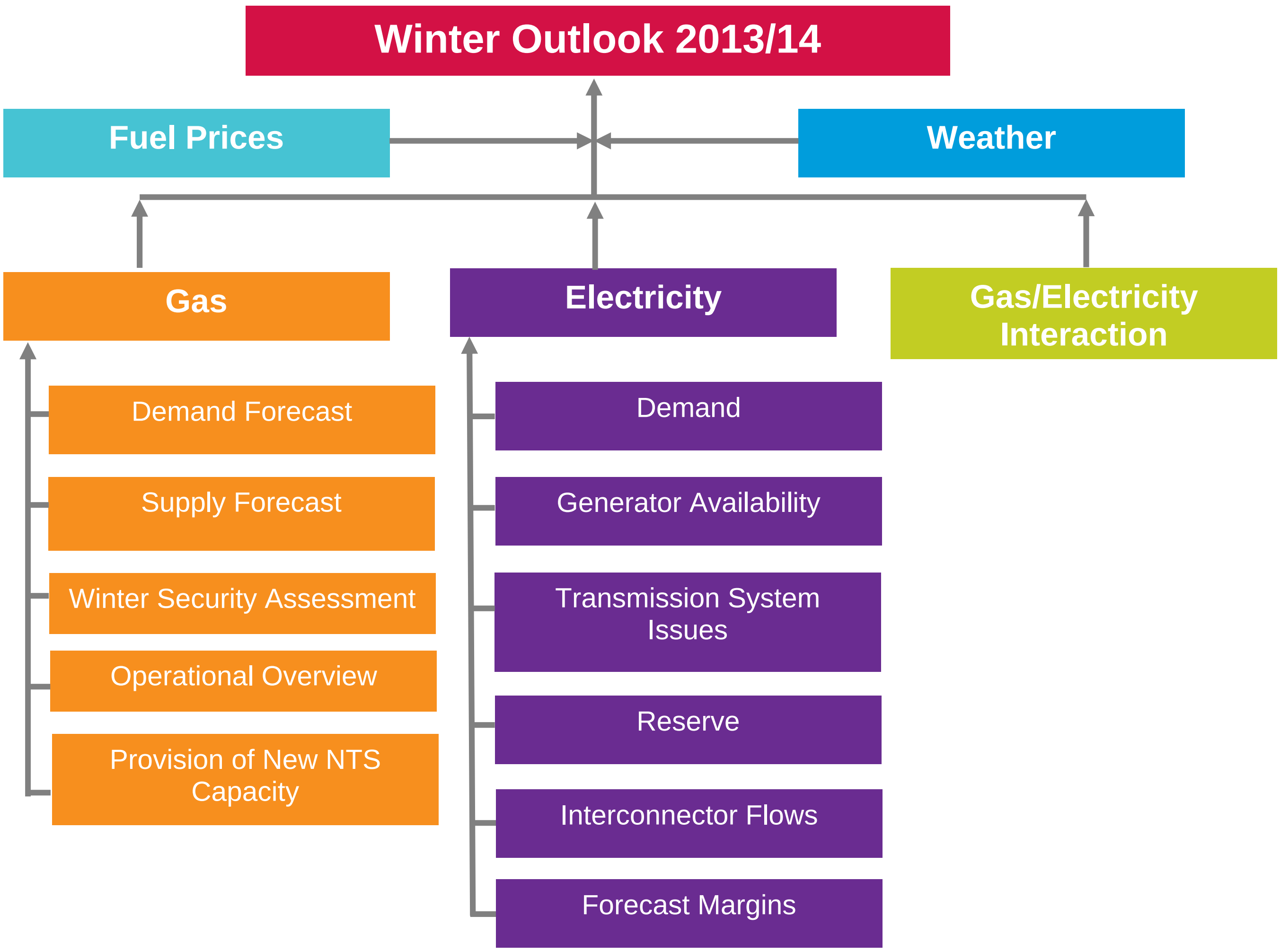
Executive Summary

Winter Outlook 2013/14 - Key Statistics

Fuel Prices	
Forward energy prices for winter 2013/14 strongly favour coal rather than gas as the preferred source of fuel for power generation	
Gas	
2013/14 peak gas demand forecast – for security planning this assumes a high level of gas demand for power generation (82 mcm/d) as well as 1 in 20 cold weather conditions	511 mcm/d
2013/14 Non-storage supply forecasts – some supply uncertainty in all components, more than last year, but in line with values seen last winter	154-459 mcm/d
2013/14 storage deliverability – increase on last winter due mainly to increased deliverability assumptions for Holford and Aldbrough	135 mcm/d
2013/14 Safety Monitor space requirements lower than winter 2012/13 (4.6%)	1.9%
Electricity	
Peak weather corrected demand forecast[3]	54.8 GW
Average Cold Spell (ACS) demand levels forecast	56.3 GW
1 in 20 demand levels forecast	58.0 GW
Generator capacity[4]	74.7 GW
Assumed generation availability at winter peak[5]	60.5 GW
Central forecast derated[6] **margin:**	
▪ Against weather corrected demand	8%
▪ Against ACS demand	5%

[3] Note that the peak weather corrected demand forecast, ACS demand level forecast and the 1 in 20 demand level forecast all use our base case interconnector flow for this winter of 750 MW imports from the continent and 750 MW of exports to Ireland and all use Transmission System Demand
[4] Excludes interconnector capacity
[5] Includes our assumption of 750 MW imports from the continent
[6] For wind power stations Equivalent Firm Capacity (EFC) is used, consistent with Ofgem's Capacity Adequacy analysis approach. This is a measure of how much 100% reliable generation would be required to replace the installed wind generation while maintaining the same level of system security

Document Structure



Contents

Weather

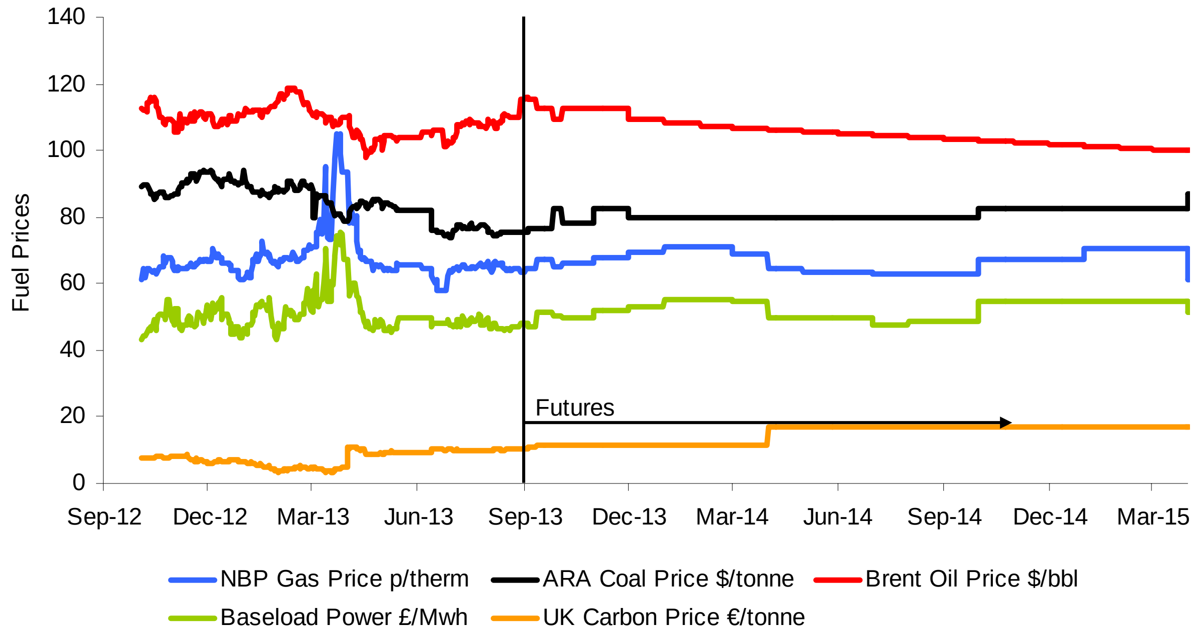
1. The Met Office has ceased publication of their long term winter weather forecast. The Met Office web site contains a short text based description of the weather up to 30 days ahead[7] and guidance for contingency planners up to 3 months ahead[8]. The latest 3 month outlook for October to December indicates that as a whole uncertainty is large with above- and below-average temperatures both equally probable.
2. Last winter's weather illustrated the variability of winter weather. The 6 months from October 2012 to March 2013 were colder than normal (22nd coldest when compared to the last 85 winters) with a protracted cold spell in February and March. Whilst the severity of the 3 month mid-winter period from December to February was average, unseasonal cold weather was observed in the shoulder months of October, November and particularly March.
3. Early warning of severe weather can be obtained from month-ahead ensemble forecasts. The European Centre for Medium Range Weather Forecasts[9] specialises in producing these forecasts. Products based on them are available from a number of weather service providers. Fifty separate forecasts are produced showing the range of possibilities. The greater the number of forecasts showing the same outcome, the greater the possibility of that outcome.
4. Energy demand is weather sensitive, particularly residential gas demand. We manage this uncertainty by analysing a range of potential weather severities for the coming winter. For gas we consider the impact on demand of an average winter and a severe (1 in 50 year) winter, as well as a 1 in 20 peak day. For electricity we consider the peak weather corrected demand, Average Cold Spell (ACS) demand and the 1 in 20 demand.

7 http://www.metoffice.gov.uk/public/weather/forecast/
8 http://www.metoffice.gov.uk/publicsector/contingency-planners
9 (ECMWF http://www.ecmwf.int/)

Fuel Prices

5. **Figure F1** shows historic energy prices for the 12 months prior to September 2013 and forward prices through to March 2015.

Figure F1 – Historic and forward energy prices[10]

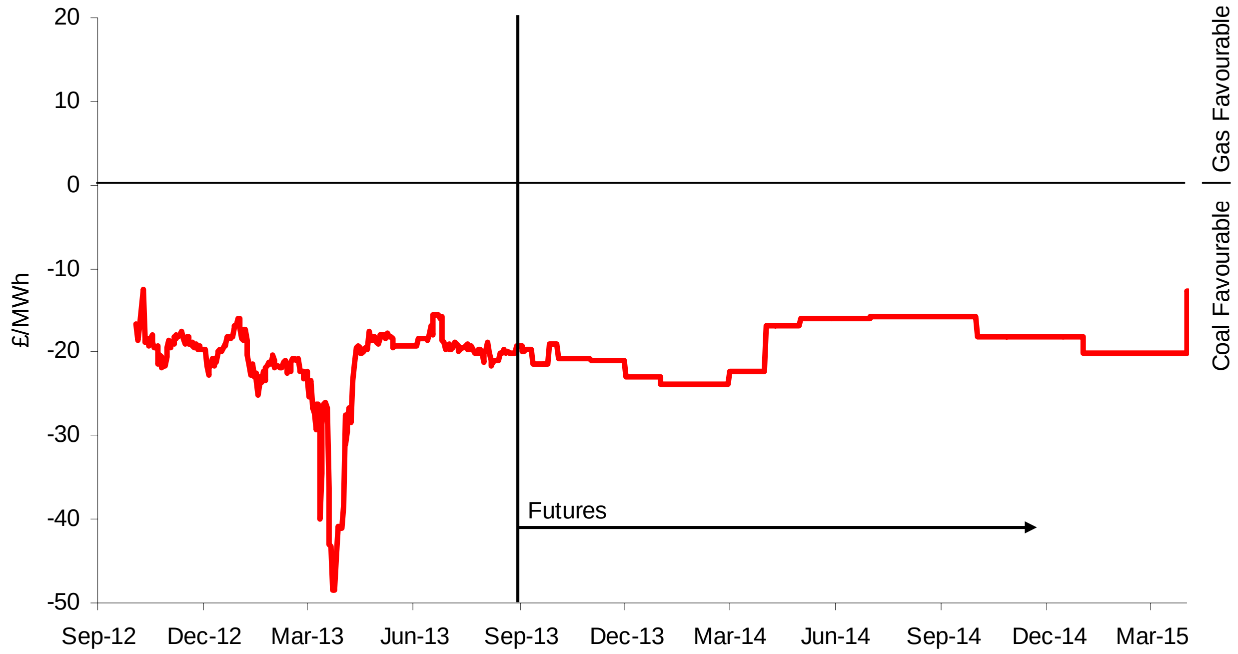


6. Most fuel prices saw relatively modest movements over the previous 12 months with gas and electricity showing rises of 12% and 7% respectively while the oil price fell by 5%. Coal continued the downward trend of recent years falling just under 20% to ~$70/tonne.
7. While carbon prices on the European Trading Scheme (ETS) fell by almost 50% the Carbon Price Support of £4.94/tonne (~€5.8/tonne) saw UK prices rise by 25% to ~10€/tonne.
8. While the gas price during the majority of the winter was similar to summer levels there were significant increases during March as relatively high demands and tight supplies saw prices in the region of £1/th for almost 2 weeks.
9. **Figure F2** shows the relative clean dark and clean spark spreads, showing whether gas or coal is favoured for electricity generation. These costs include the costs for carbon.

[10] Historic prices show a 1 week rolling average of spot prices

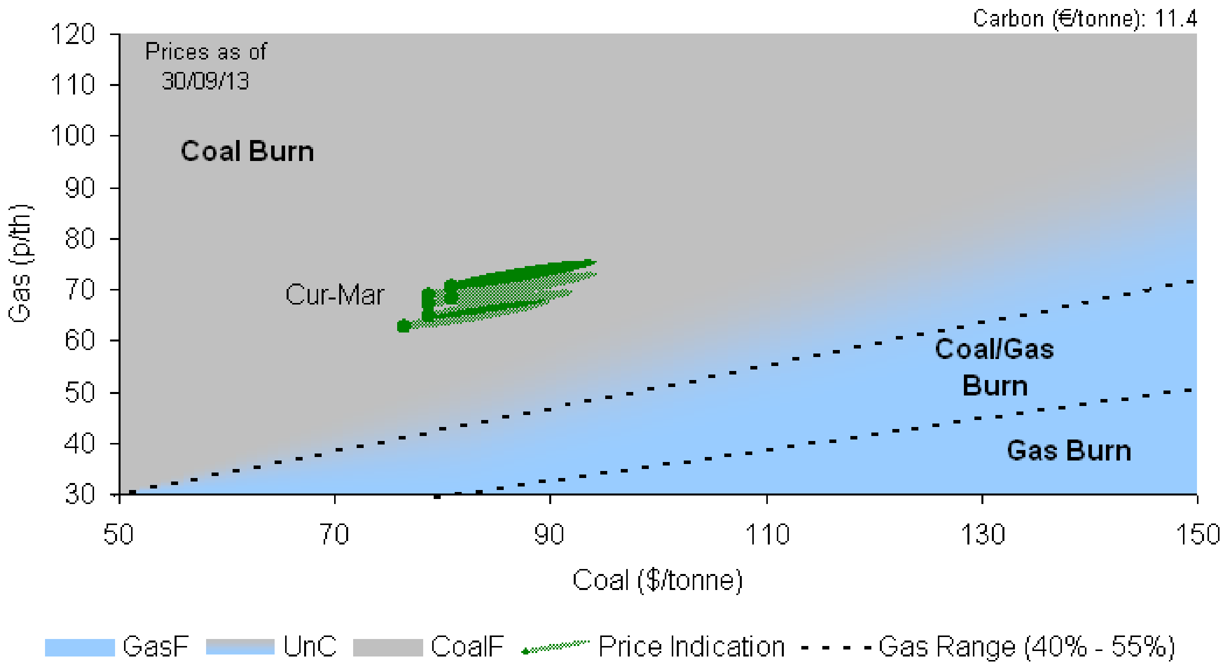
Fuel Prices

Figure F2 – Relative power generation economics (1)



10. For the whole of the previous year the prices have strongly favoured coal generation over gas with spreads of over £10/MWh. The forward prices for winter 2013/14 suggest this is likely to continue with coal generation strongly favoured over gas. This is further supported in **Figure F3** where the economics are shown relative to fuel costs and power generating efficiencies.

Figure F3 – Relative power generation economics (2)[11]

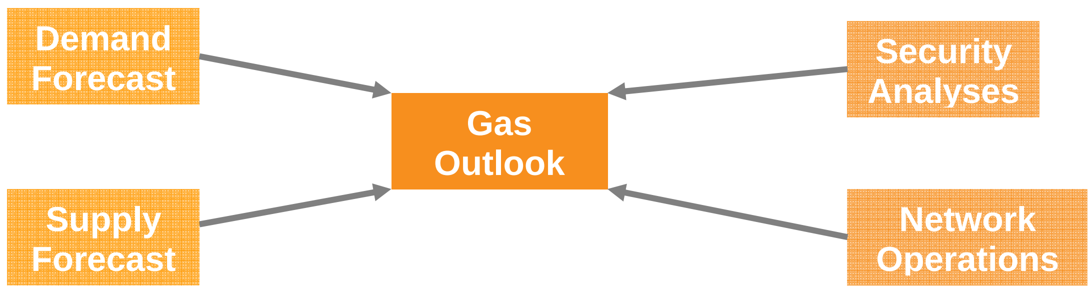


11. The chart shows how the forward prices for winter 2013/14 strongly favour coal burn over gas. For gas and coal to be equitable the gas price for winter 2012/13 needs to fall by about 40% or around 30p/therm, alternatively there needs to be a further increase in the coal price by about $80/tonne (a near doubling).

12. Whilst the price of coal and gas are influential in terms of power generation, other factors such as running hours for LCPD, plant availability and generation portfolios will also influence fuel choice.

[11] Gas fired power station efficiencies are assumed to be roughly 40% for Open Cycle Gas Turbines (OCGTs) or Combined Cycle Gas Turbines (CCGTs) operating in open cycle mode. CCGTs operating in combined cycle are assumed to be in the range of 50-50% efficient.

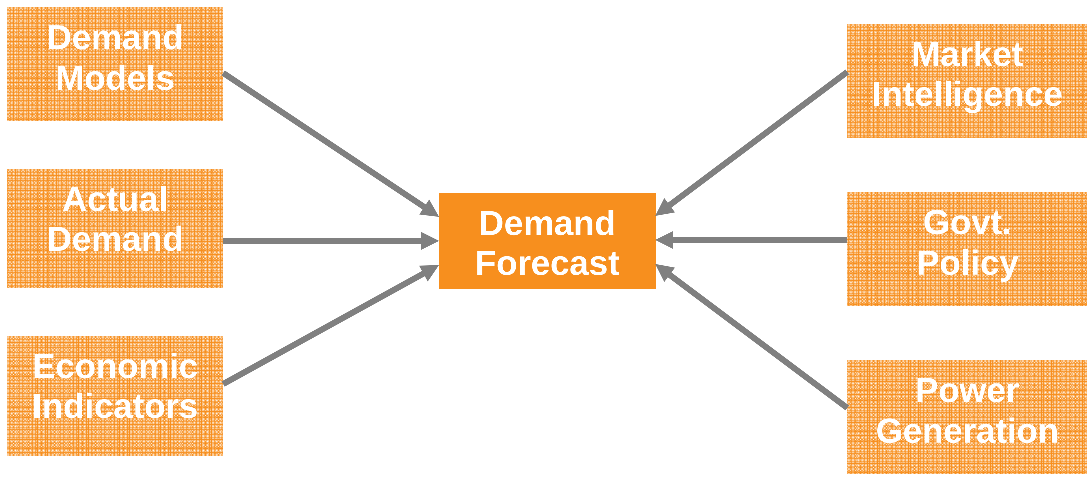
Gas



Overview

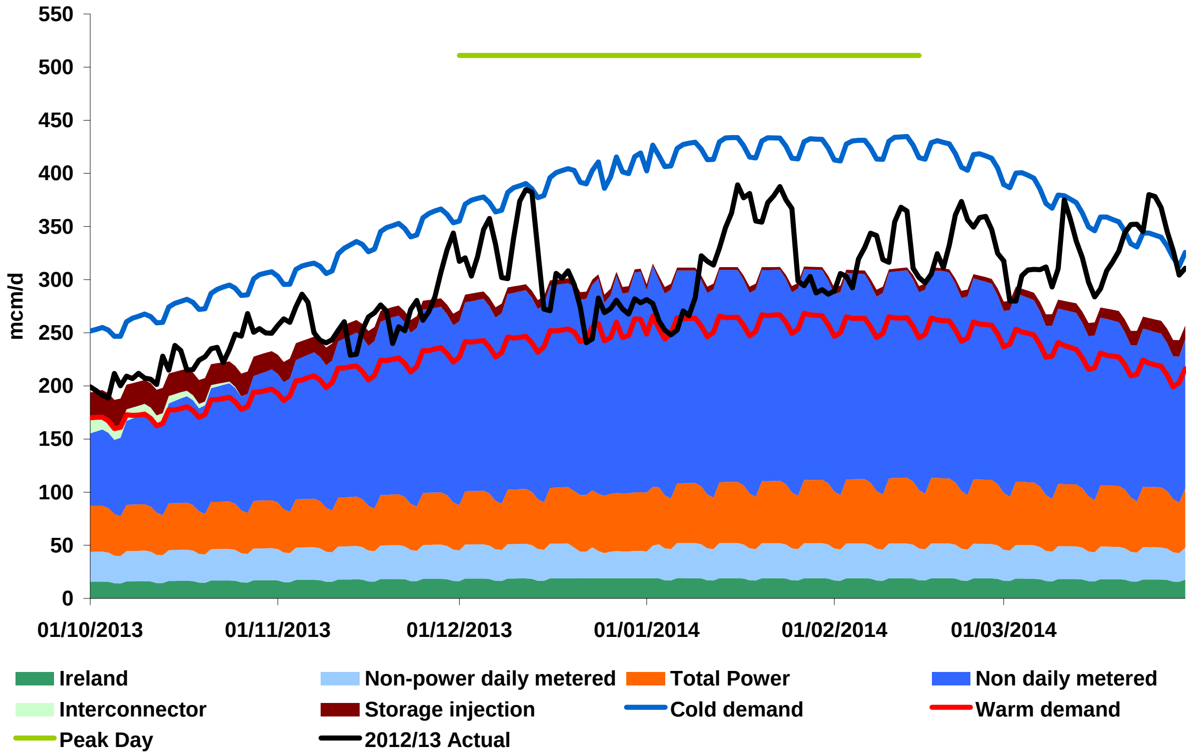
13. This chapter covers the gas supply-demand outlook for the winter 2013/14 together with an update on the Safety Monitors, an operational perspective and provision of new NTS capacity.

Demand Forecast



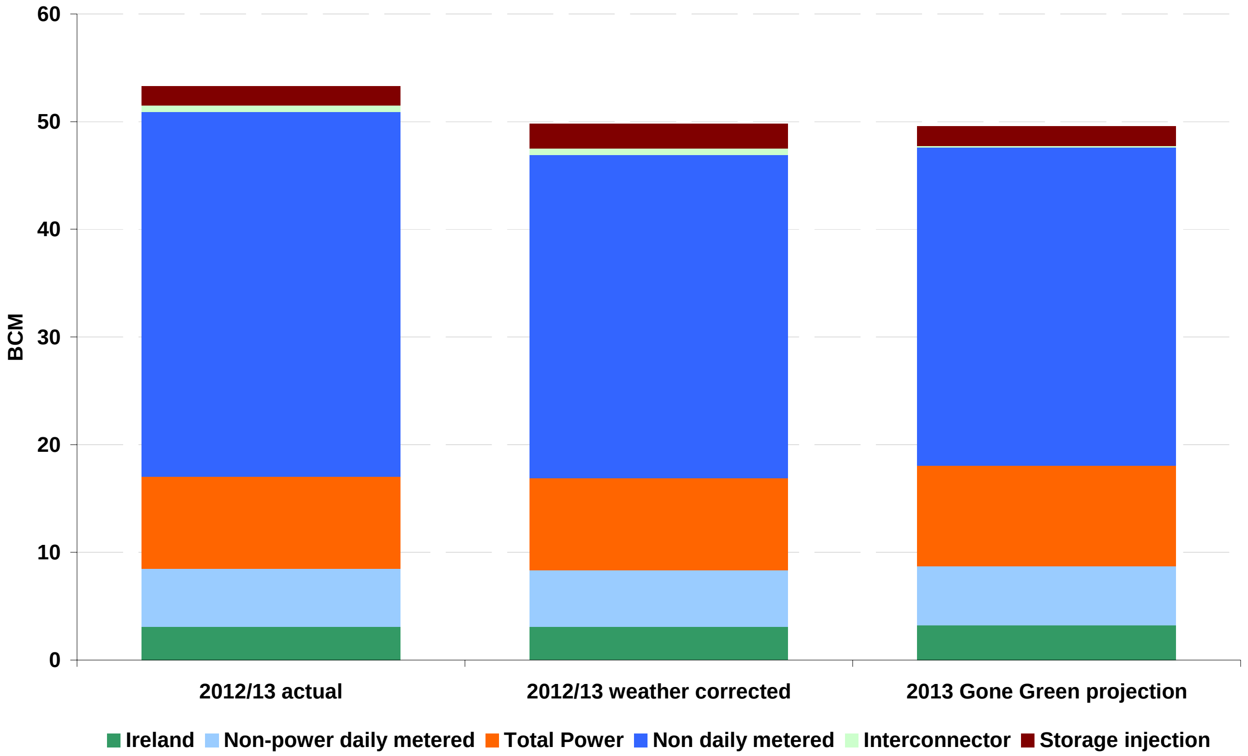
14. The demand forecasts presented in this document are essentially the same as those reported in the Winter Consultation.
15. The 2013/14 winter demand forecasts are similar to the 2012/13 weather corrected demands. Gas for power generation is forecast to be the marginal generation in 2013/14.
16. **Figure G1** 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 G1 - Forecast Gas Demand Winter 2013/14



17. The chart shows seasonal normal demand peaking just above 300 mcm/d. In reality, the highest 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. The peak day forecast demand of 511 mcm/d is significantly higher then the cold demand curve, as the peak day assumes colder weather, leading to higher non-power daily metered (residential) demand and power station demand of 82 mcm/d.
18. **Figure G2** shows the actual and weather corrected demand for last winter and also the Gone Green projected demand for winter 2013/14.

Figure G2 - Forecast Gas Demand October 2013 to March 2014



19. The chart shows:

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

20. **Table G1** shows the historic actual and weather corrected demand for winters 2010/11 through to 2012/13 and the forecast for winter 2013/14.

Table G1 - Forecast Gas Demand- October to March 2013/14

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

21. 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. Rather than exporting, 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.

22. **Table G2** 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.

23. The low forecast range for weather sensitive loads is based on a very warm early October[12] day, Ireland, IUK and storage on historic data and power on our low gas scenario.

24. 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.

[12] For the December to February range in Table G3, the very warm day applies to early December

Table G2 - Forecast Daily Gas Demand- October to March 2013/14

October to March winter mcm/d	Daily average			Actual range		Forecast range[13]	
	2012/13 actual	2012/13 weather corrected	2014 forecast	2012/13 low	2012/13 high	2013/14 low	2013/14 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	82
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**

25. **Table G3** shows a similar table to **Table G2** but is based on the mid-winter months of December to February.

Table G3 – 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	2014 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	82
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**

26. 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

[13] Note that Total demand is not the sum of the individual components, as they will not all be high on the same day

27. **Figure G3 and Table G4** show the highest ever day 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 G3 - 1 in 20 Peak Day Gas Demand 2013/14

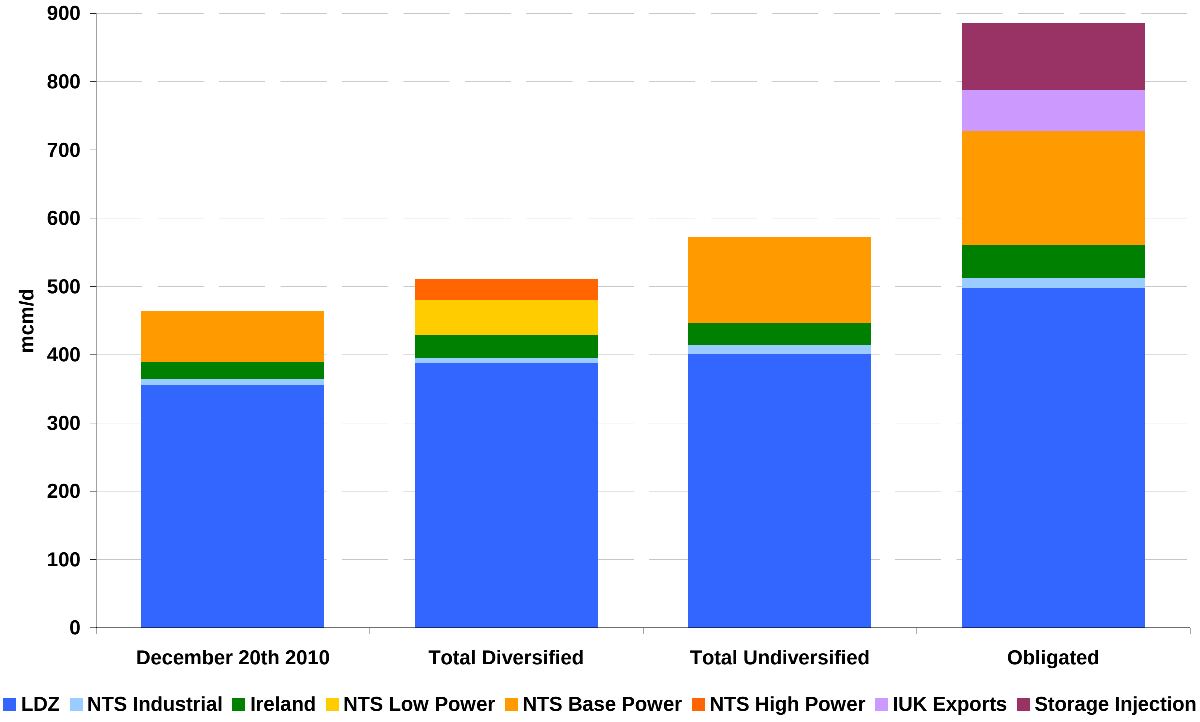


Table G4 – Peak Day Gas Demand 2013/14[14]

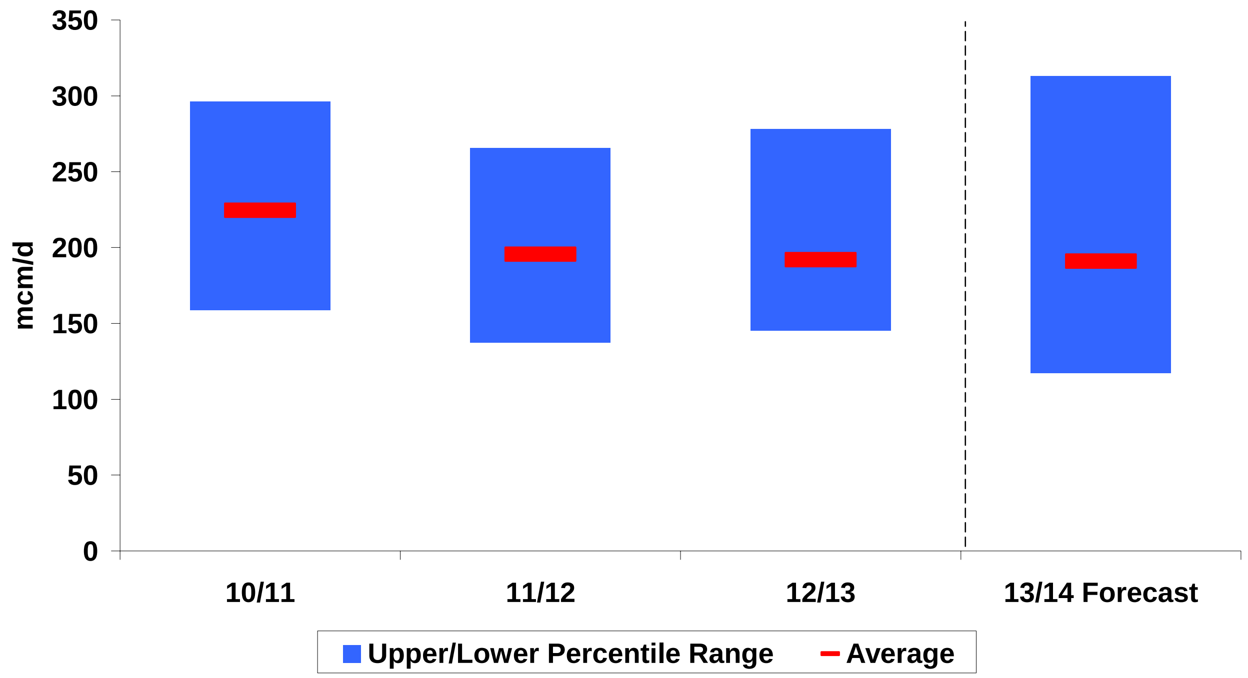
mcm/d	December 20th 2010	2013/14 Forecast 1:20 Total Diversified	1:20 Total Undiversified	Obligated
LDZ	356	388	402	497
NTS Industrial	9	8	13	15
Ireland	25	33	33	48
NTS Power	74	82	125	167
IUK Exports	0	0	0	59
Storage Injection	0	0	0	98
Total	**465**	**511**	**572**	**885**

14 Demand data can differ between different sources for a number of reasons including classification, CV and closeout date. Power generation classifications are: in tables G1 to G3 the LDZ connected power stations at Fife, Derwent, Shoreham, Barry, Severn Power and Fawley are included in the total power category but in G4 they are included in LDZ demand. Grangemouth and Winnington NTS offtakes are included in total power in G1 to G3 but NTS industrial in G4. Immingham and Shotton Paper are classified as NTS power stations for all 3 tables.

28. Due to the price assumptions, the 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 projection, this increases the power generation component of the diversified peak day forecast by 30 mcm/d from 52 mcm/d to 82 mcm/d.

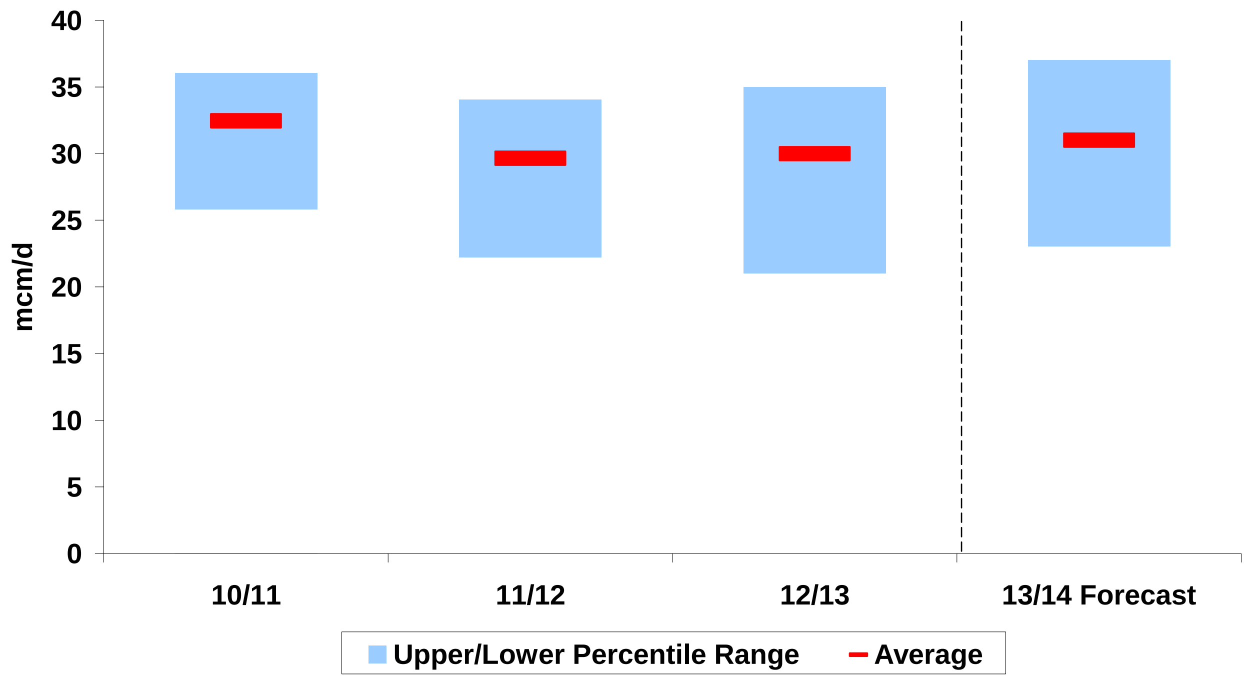
29. **Figures G4 to G7** show daily demand ranges for the 3 months from December to February for the last 3 winters compared to forecasts for December 2013 to February 2014. The historic data has not been weather corrected.

Figure G4 – NDM Historic Demand and 2013/14 Forecast



30. The 2013/14 NDM average forecast is similar to 2012/13. The pronounced variation around this value is driven by the weather.

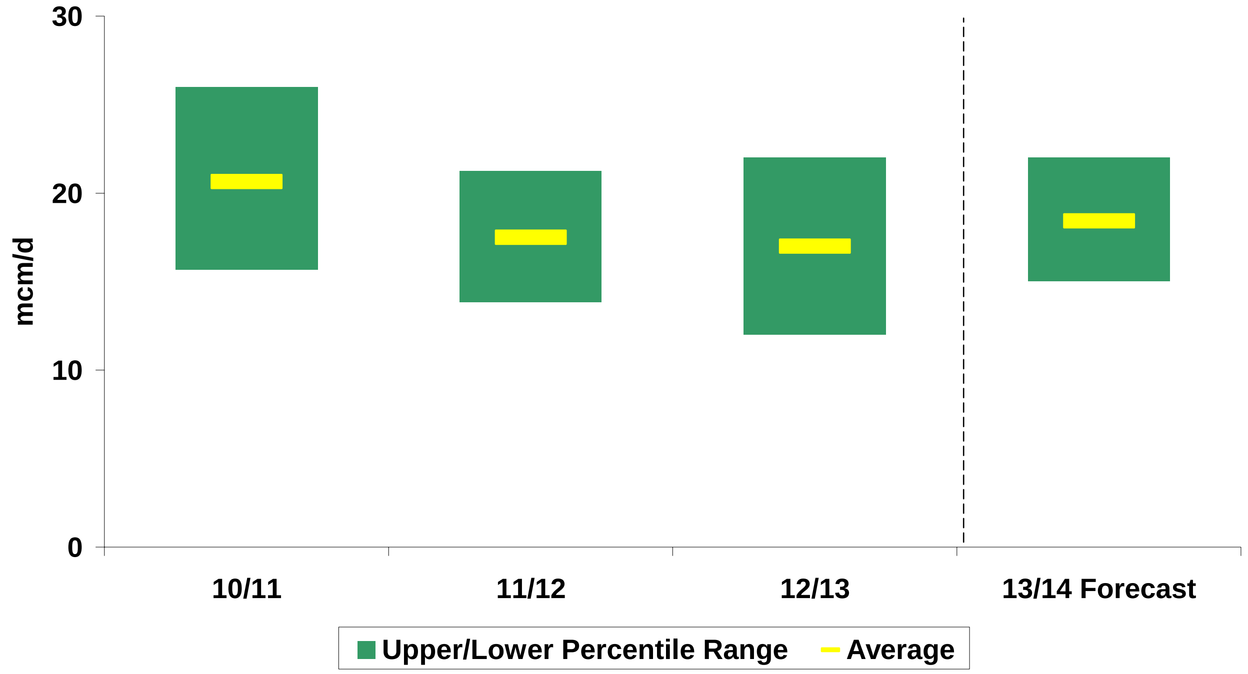
Figure G5 – Historic DM & Industrial[15] Demand and 2013/14 Forecast



31. The Non-power daily metered demand is expected to be similar to previous years.

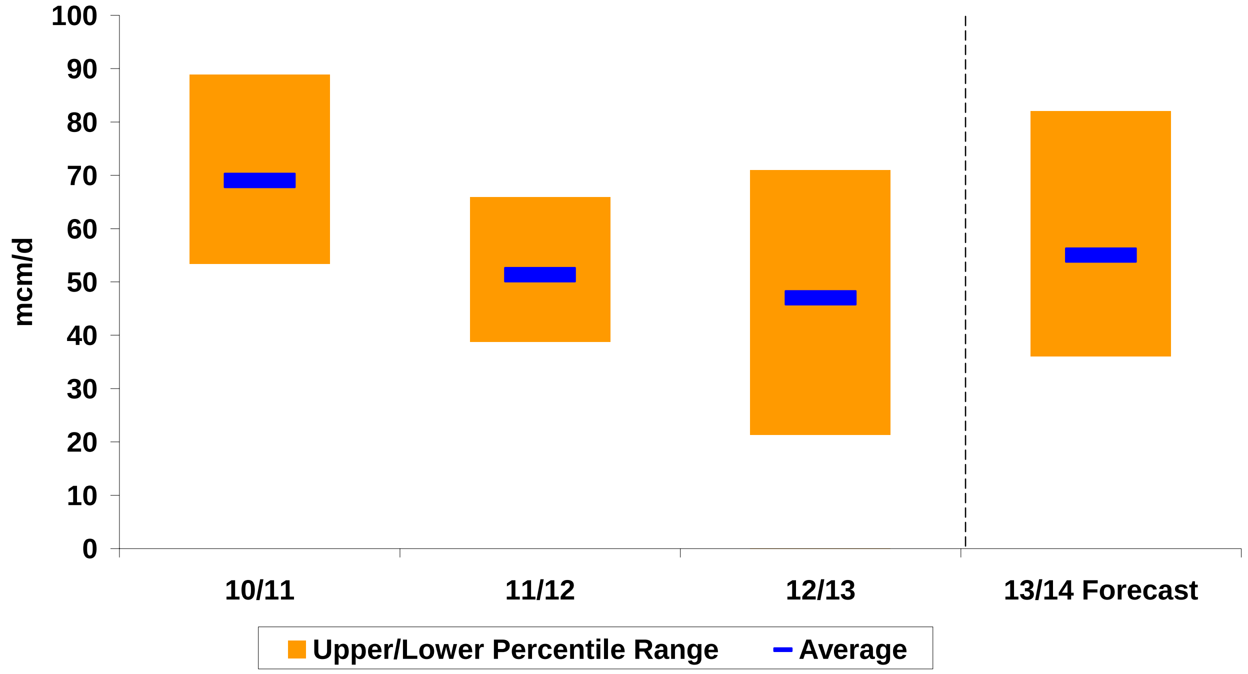
[15] Excludes power generation

Figure G6 – Historic Ireland Exports and 2013/14 Forecast



32. Exports through to Ireland are predicted to be similar to last year.

Figure G7 – Historic Power Generation Demand and 2013/14 Forecast



33. Power generation is expected to be higher than 2012/13 due to LCPD plant closures but prices continue to favour coal with gas as marginal plant. Should prices materially differ and favour gas it is possible that the upper boundary may increase above 82mcm/d, however; Figure G7 shows just the central range based on gas as marginal plant only.

Supply Forecast

34. This section briefly reviews the forecasts from last winter then 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 the winter. Our final view is influenced by our experience last winter and feedback through Future Energy Scenarios (FES[16]) and Winter Consultation.

35. **Table G5** shows our 2012 Winter Outlook forecasts for last winter, for high demand days (>400 mcm) and various measures of actual flows.

Table G5 – Winter 2012/13 non storage supplies by supply source

mcm/d	UKCS	Norway	BBL	IUK	LNG	Total
Winter Outlook 2012 Dec - Feb	113	95	28	8	45	289
Average Dec - Feb	92	109	31	15	26	273
Winter Outlook 2012 400+ mcm/d	124	105	30	20	80	359
Highest day (each supply)	104	129	45	74	74	426
Highest day (total supplies)	82	112	39	20	33	287

36. Winter 2012/13 did not follow recent patterns in that there were no days with supply in excess of 400 mcm/d. The highest supply, 395 mcm/d, was on 16th January, within the 'traditional' December to February winter period, but conditions were more challenging in March when prolonged cold weather led to an extended period of unseasonal high demands which, coupled with depleted storage stock levels and low levels of LNG stock and tanker deliveries led to unprecedented levels of continental imports.

37. UKCS did not perform as well as we had expected, due to delays in development of new fields and the return of fields from production outages. LNG supplies over the winter were lower than expected, though the highest supply was close to our 400+ mcm/d forecast. The remaining supplies all exceeded expectations, significantly so in the case of IUK.

38. The concept of examining single high demand days was less useful this winter as individual supplies reached high levels on different days in response to market conditions, but not simultaneously as demand was never particularly high.

39. The measures that we have used in previous Winter Outlook reports, average performance for the three months December to February and data for days when the total demand is in excess of 400 mcm/d are not very useful this year as they fail to capture any of the days experienced last winter. For winter 2013/14 the forecast for peak gas demand is lower than for winter 2012/13.

40. For 2013/14 we have used a different measure for the high supply day, and instead of showing supplies on a 400 mcm day we have shown supply on a 'Cold Day', one where the national average Composite Weather Variable (CWV) is around 0 degrees. For the measure of range we have used the whole winter rather than the December to February subset.

[16] http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

UKCS Gas Supplies

41. The Winter Consultation provided an initial view of UKCS supplies based on our 2013 Future Energy Scenarios and the most recent data regarding new UKCS developments**.** Responses to the Consultation were supportive of this position and there have been no significant further developments since publication, so our final view, as shown in **Table G6** is unchanged from the initial view.

Table G6 - 2013/14 UKCS forecast maximum supply by terminal

Peak (mcm/d)	2012/13			2013/14
	Forecast	Outturn	Max UKCS day	Final View
Bacton	38	30	28	29
Barrow	10	11	7	9
Burton point	0	4	3	2
Easington	14	12	7	9
***St Fergus**	38	40	35	36
Teesside	25	15	14	15
Theddlethorpe	11	13	10	11
Total	**136**	**125**	**104**	**110**
90% Op. Forecast				99

*Excludes estimates for Vesterled and Tampen

42. **Table G6** shows a provisional UKCS maximum supply forecast of 110 mcm/d for Winter 2013/14. This is 19% lower than the equivalent forecast for Winter 2012/13 but is comparable to the 104 mcm seen on the day of highest UKCS supply last winter.

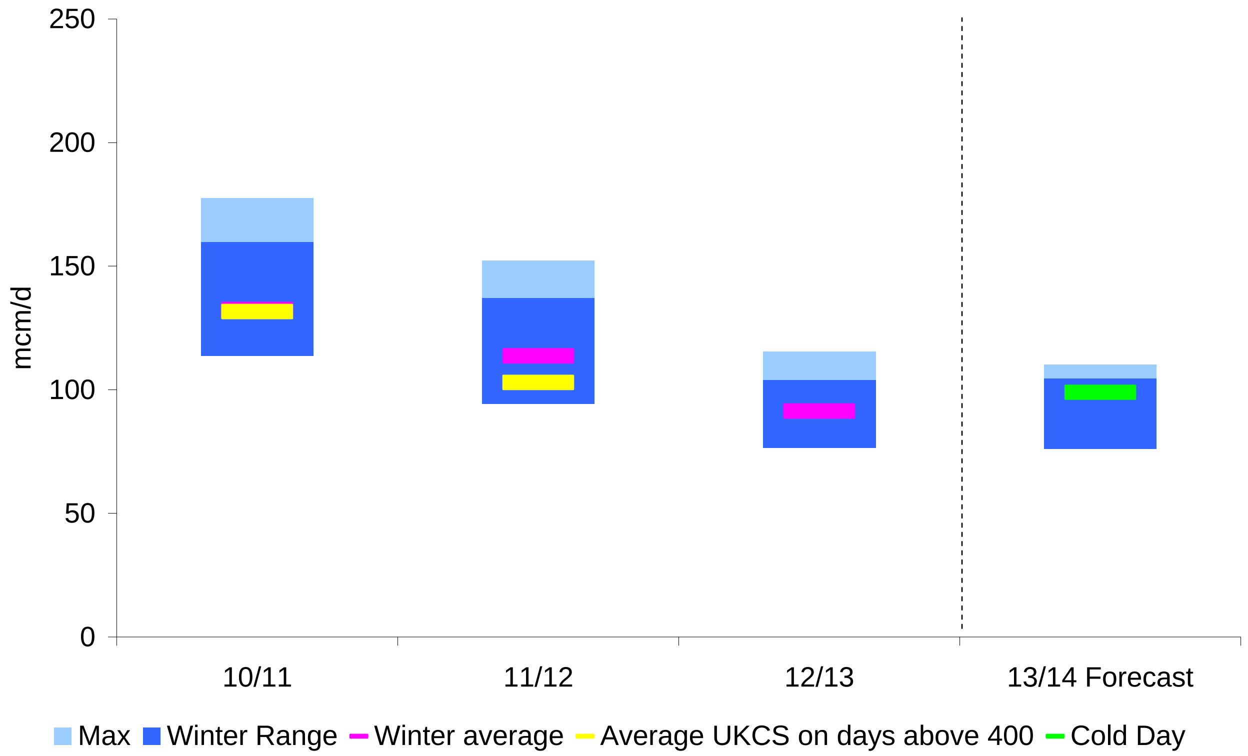
43. The forecast decline of 19% is greater than in recent years but reflects last winters peak flows that were below expectations due to delays in development of new fields and protracted outages at fields expected to return to production.

44. Our assessment of new UKCS developments coming on stream in 2013/14 amount to nearly 10 mcm/d. As in recent winters we expect UKCS supplies to operate at a high load factor and therefore exhibit limited flexibility in terms of any increase in supply.

45. 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 90% is used, resulting in a maximum UKCS planning assumption for winter 2013/14 of 99 mcm/d.

46. **Figure G8** shows historic UKCS flows for winters 2010/11 through to 2012/13, together with the winter forecast for 2013/14. For 2010/11 and 2011/12 the high demand marker is the historical average of days with demand in excess of 400 mcm/d but for 2012/13 as discussed previously, there were no days with flows in excess of 400 mcm, and the highest supplies for any source did not necessarily correspond with particularly high demand so no marker for a high supply day has been shown. For 2013/14 the high demand marker is the ‘Cold Day’.

Figure G8 – UKCS historic flows and 2013/14 forecast



47. The chart shows progressive decline of UKCS and very tight ranges for all winters, illustrating the limited flexibility of UKCS supplies.

48. The 2013/14 forecast range for UKCS is shown as 76 -105 mcm/d. The winter average forecast is 90 mcm/d with 99 mcm/d expected on the newly defined Cold Day.

Norwegian Imports

49. Flows from Norway last winter were generally within our anticipated range. There were occasional outages but also days when flows reached record levels. Responses to the Winter Consultation generally support the view that flows could be high again this winter given the right market conditions.

50. For the countries that take Norwegian gas we have created two cases, high flows to Belgium, France and Germany with consequential lower availability for the UK, and low Continental flows with higher availability for the UK. Norway's own consumption of gas is fairly modest and is the same in each of the two cases.

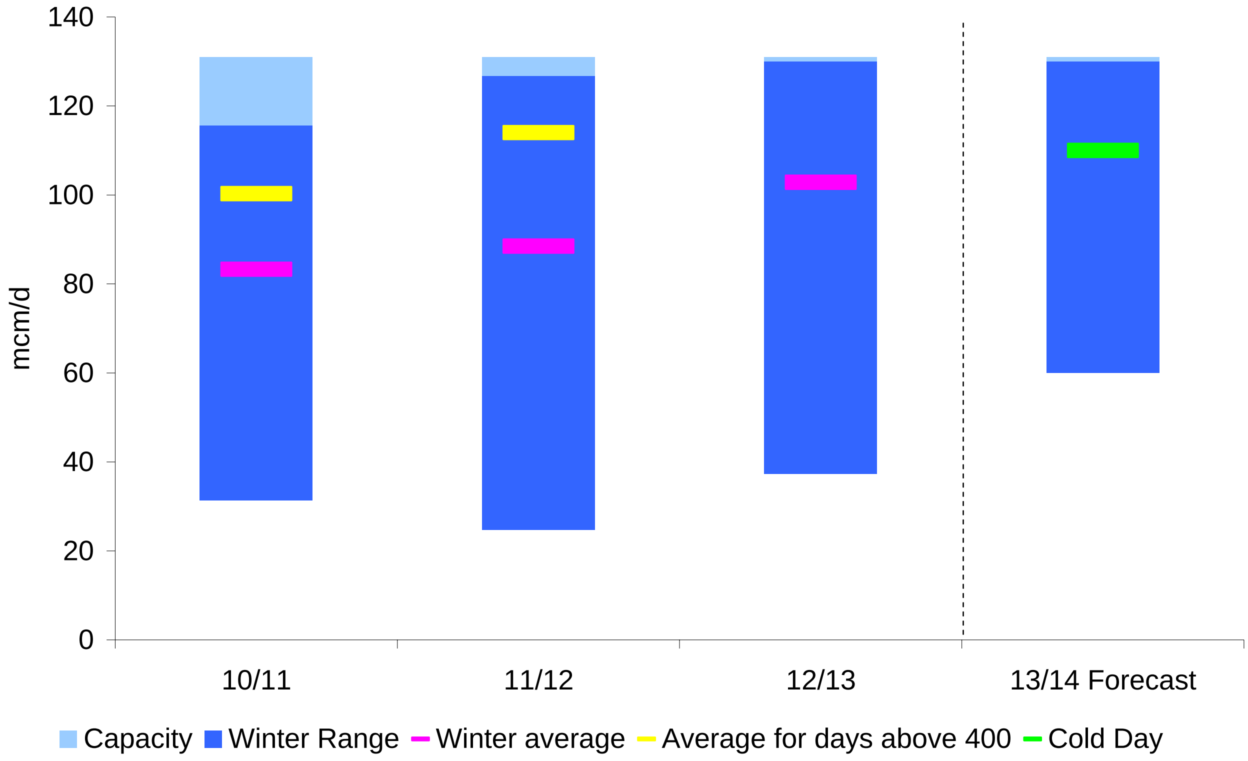
51. **Table G7** shows the forecast range of Norwegian exports for winter 2013/14. Also shown is an estimate of flows for the mid-winter period to account for supply seasonality, and the total capacity for each route. This year there is little potential upturn in mid winter as there are continuing problems with a compressor on the Troll platform. However, the Norwegian system has considerable flexibility so there remains the potential for significant variation in day to day flows.

Table G7 – Winter 2013/14 estimates of Norwegian exports

(mcm/d)	High flows to Cont	Low flows to Cont	Central	Capacity
Norway	20	20	20	
Belgium	40	35	38	41
France	50	40	47	52
Germany	130	95	120	151
UK	80	130	95	131
Total	320	320	320	375

52. **Figure G9** shows historic Norwegian flows for winters 2010/11 through to 2012/13, together with the winter forecast for 2013/14 and the capacity for Norwegian exports to the UK.

Figure G9 – Norwegian historic flows and 2013/14 forecast

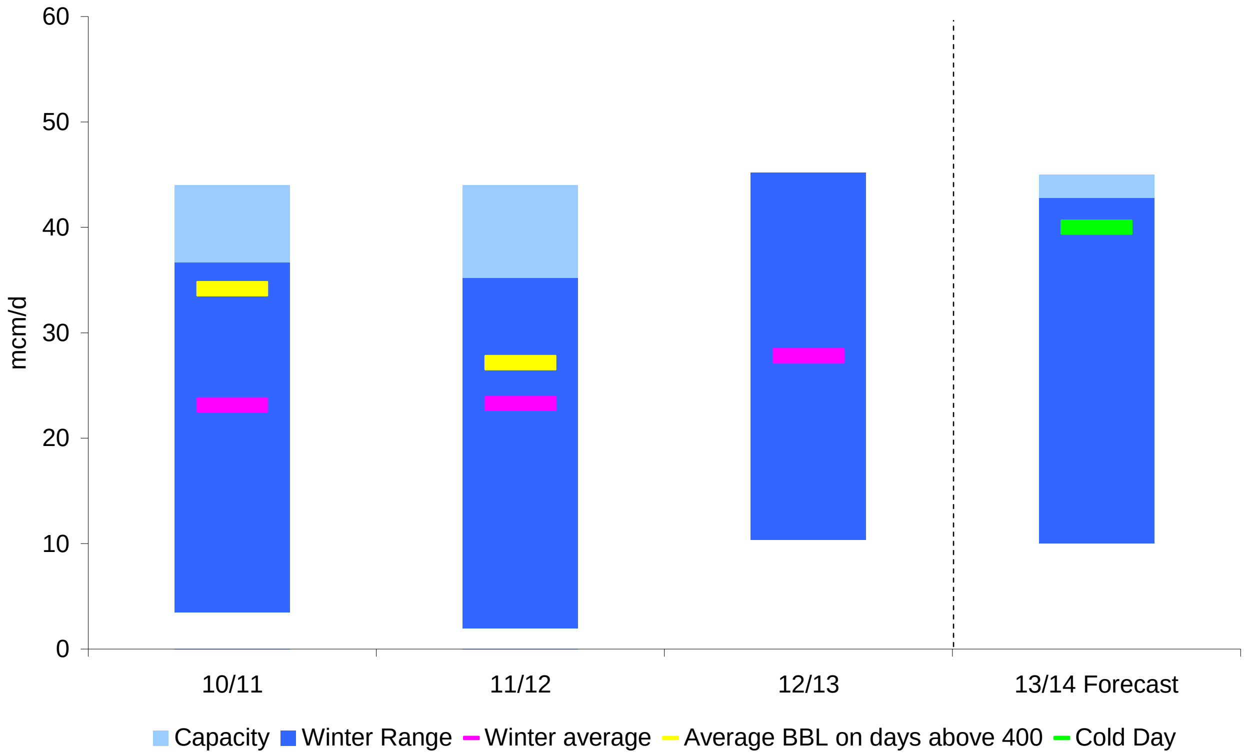


53. Since 2010/11 there has been an increase in average flows to the UK from Norway, the range for 2012/13 shows that supplies reached maximum capacity

Continental Imports – BBL

54. **Figure G10** shows historic BBL flows for winters 2010/11 through to 2012/13, together with the winter forecast for 2013/14 and the capacity for BBL. Data are also shown in table G10

Figure G10 – BBL historic flows and 2013/14 forecast



55. The chart shows that flows through BBL were at times close to maximum capacity in winter 2012/13 indeed, the highest flow was over 6 mcm/d higher than the any previous flow. As a result, the maximum flow in our forecast range for 2013/14 is higher than previous years, at 95% of capacity.

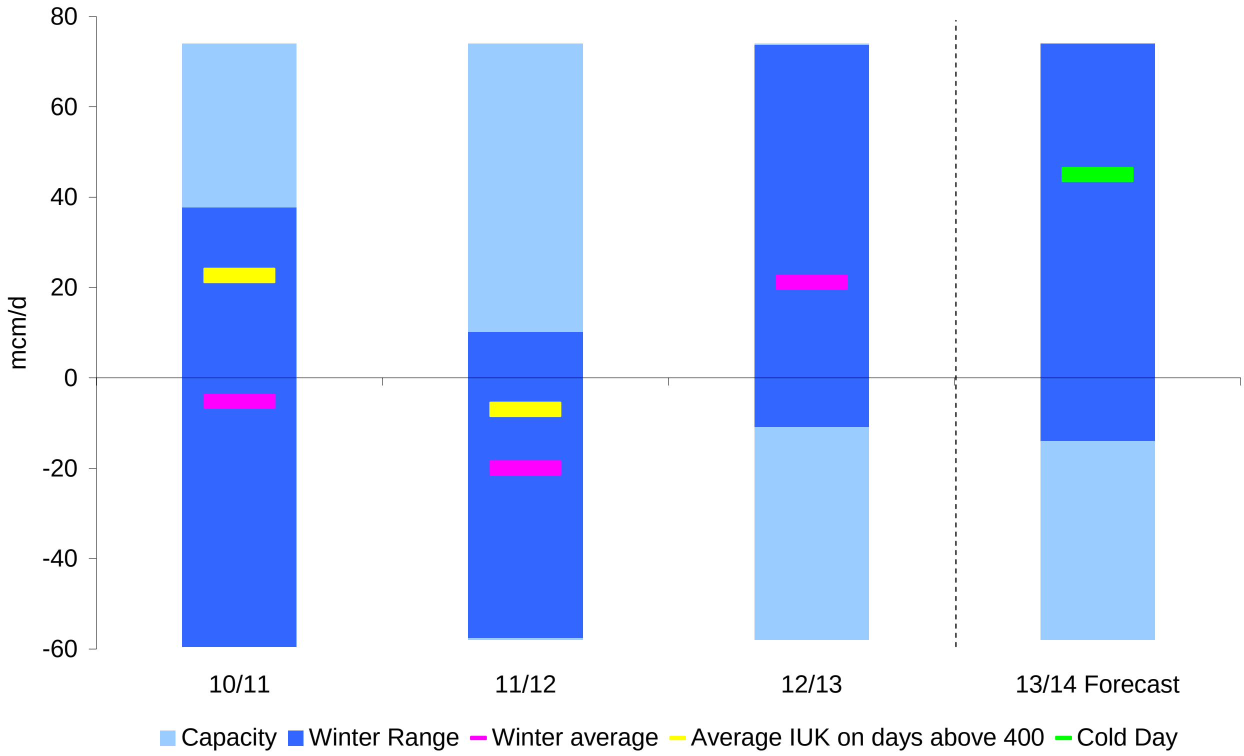
Continental Imports – IUK

56. Last winter IUK responded to a combination of external factors including; price, UK and continental demand, and the availability of other supplies. High demand in March combined with depleted storage levels led to record flows to the UK

57. Responses to the Winter Consultation generally support our view that high flows would be possible again this winter given sufficiently high prices and depending on the market conditions and storage levels in the UK and the Continent.

58. **Figure G11** shows historic IUK flows for winters 2010/11 through to 2012/13, together with the winter forecast for 2013/14 and the capacity for UK imports. Data are also shown in table G10

Figure G11 – IUK historic flows and 2013/14 forecast



LNG Imports

59. Winter 2012/13 saw a further decrease in LNG imports compared with the two previous winters. Winter Consultation feedback continues to highlight the uncertainty of LNG imports, but also indicated LNG is likely to remain suppressed over winter 2013/14. This is primarily dictated by higher demand and prices in the Far East and potentially South America. Forward prices indicate this trend may continue through the coming winter.

60. In terms of attracting LNG cargoes, NBP prices remain significantly higher than US prices, however whilst the NBP is similarly priced to European markets, prices in the Far East remain substantially higher, and are likely to be the preferred market for most traded and spot LNG.

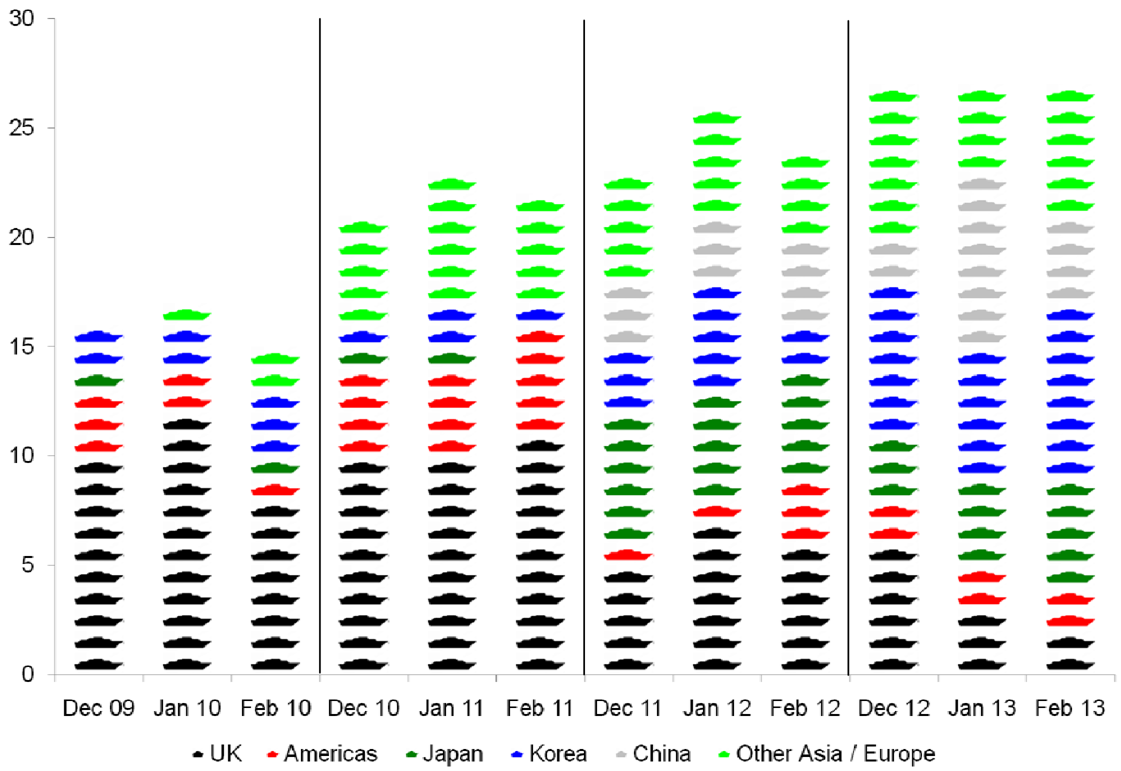
61. **Table G8** shows some of the factors which may increase or decrease global LNG availability, thus support higher or lower UK LNG imports:

Table G8 – Factors affecting global LNG availability over winter 2013/14

Increased LNG availability (Potentially higher UK imports)	Lower LNG availability (Potentially lower UK imports)
Increased global production capacity	Additional demand from new import countries (for example Singapore and Israel)
Increased coal burn in Japan with the commissioning of new power stations	Decline in LNG available for export, for example Egypt and Indonesia
Possibility of limited Japanese nuclear restarts over winter 2013/14	Strong demand in Asia, primarily Japan, China and South Korea
Possibility of higher reloads from Spain	

62. **Figure G12** shows the activities of the top 30 most frequent LNG tankers to the UK since 2009. This does not cover all deliveries to the countries shown, but only those by the most frequent UK bound tankers.

Figure G12 – Destinations of regular UK LNG tankers since 2009
Source: Lloyd's List Intelligence[17]



[17] www.lloydslistintelligence.com

63. The chart shows:
    - A decline in these vessels visiting the UK since 2009
    - A decline in these vessels serving the US since 2010/11
    - Vessels which used to almost exclusively serve the UK were increasingly diverted to Japan during winter 2011/12, and further diversions to China and South Korea were observed during winter 2012/13.

64. Global LNG demand grew by 1% in the 12 months to July 2013, compared with the previous 12 months. China's demand over this period increased by approximately 18% while demand in Europe fell by a similar percentage.

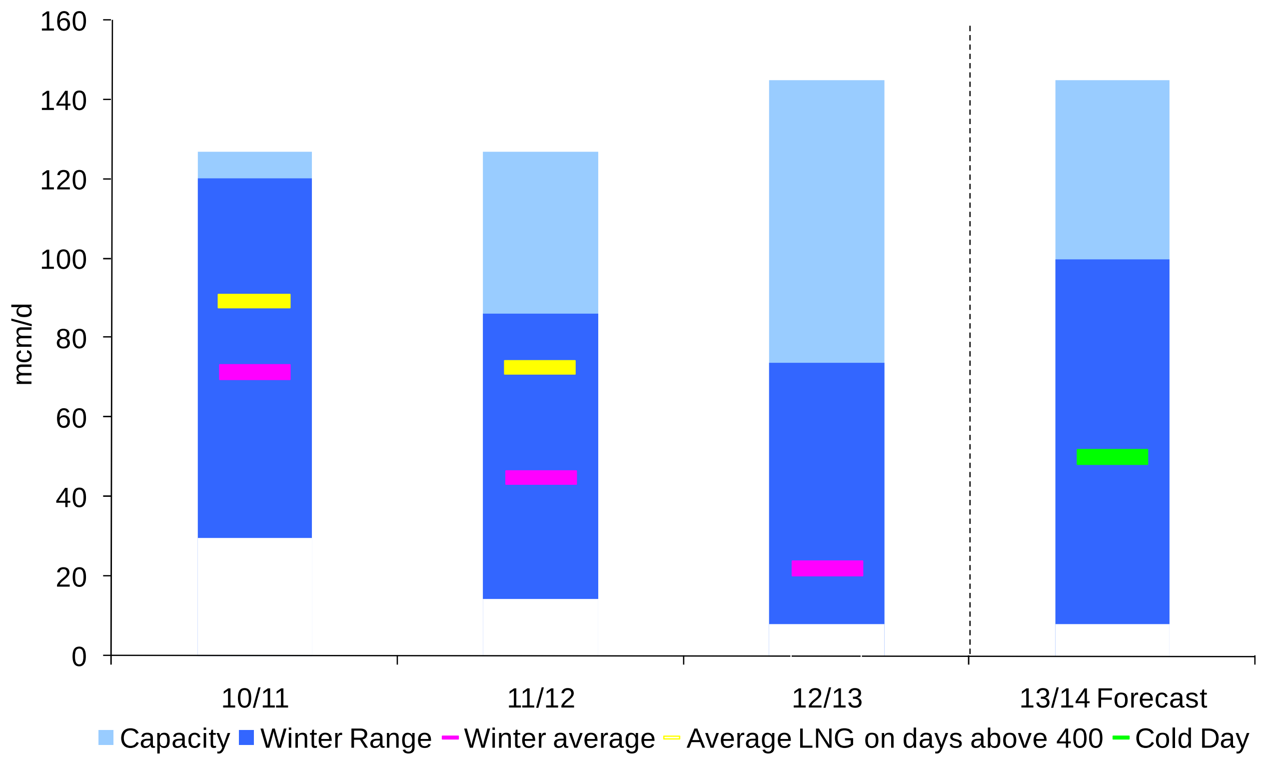
65. In Japan, gas fired power stations continue to run at high load factors as a result of nuclear shutdowns following the 2011 earthquake and tsunami. While there is the possibility of limited nuclear restarts over winter 2013/14, these may displace oil generation rather than gas. Additional coal generation was commissioned this year, and increases in gas generation capacity are planned.

66. In terms of LNG supply, 2013 saw the start of the Angola LNG project, and the re-start of the Skikda facility in Algeria. Whilst most of this LNG may be sold to other markets, it still represents an overall increase in global production capacity. This must be balanced with declining LNG exports in North Africa and parts of Asia. As last winter showed, global supply outages can also have a significant effect on the global LNG market.

67. To manage the supply uncertainty surrounding LNG, a wide range is considered, from 8mcm/d (approximate boil off levels) up to potentially 100mcm/d under favourable conditions. However, as observed last winter, there is still considerable uncertainty over the responsiveness of LNG to UK market conditions.

68. **Figure G13** shows historic LNG imports for winters 2010/11 through to 2012/13 together with the winter forecast for 2013/14. Teesside GasPort is excluded from these charts as it has supplied only a small quantity of gas in this period.

Figure G13 – LNG historic flows and 2013/14 forecast



69. The chart highlights that the average flow last winter was appreciably lower than in the previous two winters. The average flow was also quite close to the bottom of the range, indicating that there were few days with high flows.

70. The range identifies periods of both high and low flow from both Grain and Milford Haven. Flows through Teesside GasPort provide an upside to the range.

Storage

71. Storage capacity has increased for winter 2013/14, due principally to extra space at Aldbrough and Holford. Hill Top Farm is expected to start commercial operations this winter. The Stublach site, currently under construction, is expected to have the first two cavities available for commissioning purposes this winter, but commercial injection / withdrawal is not expected until summer 2014.

72. Based on assessments of currently operational storage sites, deliverability for next winter is approximately 135mcm/d (1488 GWh/d) which is an increase on last winter due mainly to increased deliverability assumptions for Holford and Aldbrough.

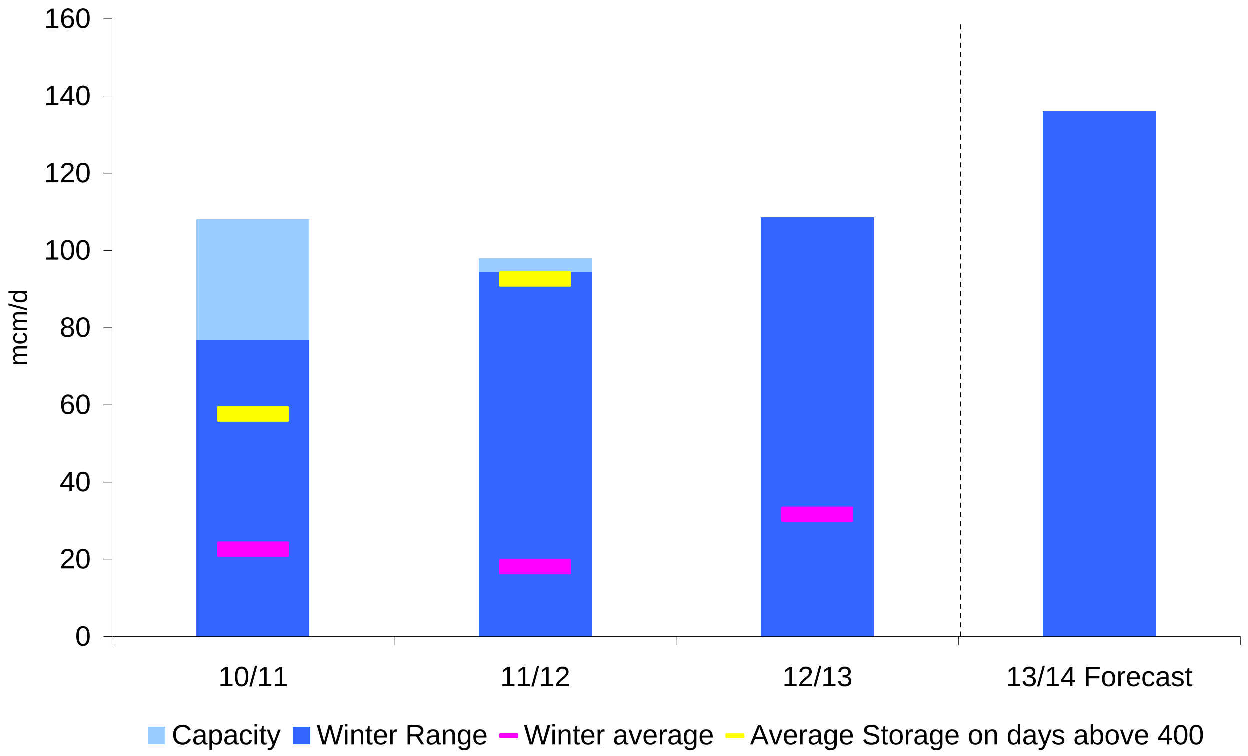
73. **Table G9** shows our assumed levels of storage space and deliverability for winter 2013/14. As of late September total GB storage is 80% full, with the expectation that for winter 2013/14 storage stocks will be at similar levels to previous winters.

Table G9 – Assumed 2012/13 storage capacities and deliverability[18]

	Space (GWh)[19]	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (mcm/d)[20]	Duration (Days)[21]
Short (LNG)	511	2.6	150	13.6	3.4
Medium (MRS)	12316	720	853	77.6	14
Long (Rough)	40300	279	485	44.1	83
Total	**53127**	**1002**	**1488**	**135**	
Total 2012/13	50965	889	1186	108	

74. **Figure G14** shows historic storage flows for winters 2010/11 through to 2012/13 together with the winter forecast for 2013/14

Figure G14 – Storage historic flows and 2013/14 forecast



[18] This table represents our operational assumptions and is based on proven performance. Reported deliverabilities may be different from 'name plate' capacities. Space includes 814GWh of Operating Margins and excludes Hill Top Farm, which will be added when operational. GWh to mcm conversions assumes a CV of 39.6 MJ/m^3.
[19] Please note these represent maximum capacity and are not stock forecasts. The actual stock levels heading into winter will be determined by prevailing / market conditions.
[20] Assumes a standard CV of 39.6MJ/m^3
[21] Duration based on Space / Deliverability, excludes within winter refill

75. The chart highlights two interesting features:

- An increase in storage use and deliverability since 2011/12
- The broad range of flows from storage, highlighting supply flexibility

Final View of Supplies Winter 2013/14

76. The previous sub-sections outlined the basis for the assumptions incorporated into the forecasts.

77. **Table G10** summarises the 2013/14 forecasts in terms of a supply range and the forecast value on a Cold Day (see paragraph 40 for definition). Actual flows from last winter are shown for comparison.

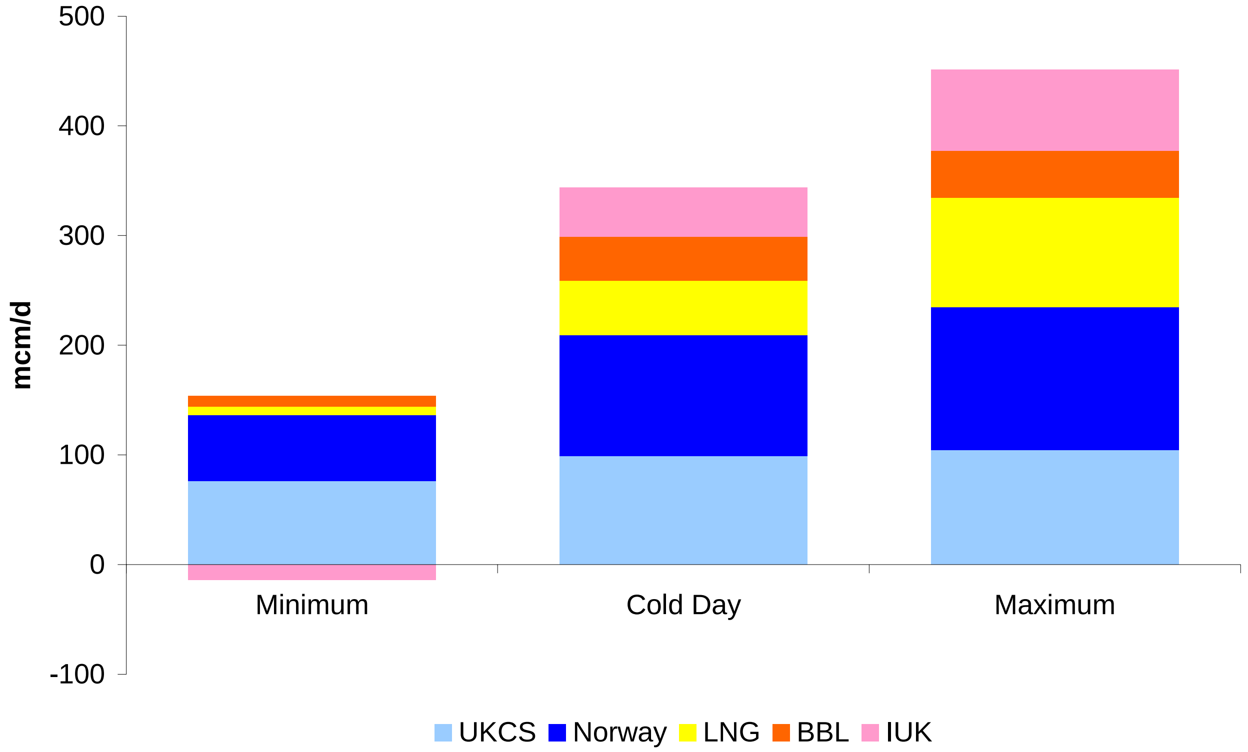
Table G10 – Final view of non storage supplies winter 2013/14

	2012/13 Actual		2013/14 Forecast	
(mcm/d)	Range	350+ Range	Range	Cold Day
UKCS	76 - 104	79 – 102	76 - 110	99
Norway	37 - 129	90 – 129	60 - 130	110
BBL	10 - 45	18 – 45	10 - 45	40
IUK	0 - 74	7 – 74	0 - 74	45
LNG Imports	8 - 74	8 – 74	8 - 100	50
Total	**131 - 426**	**202 – 424**	**154 - 459**	**344**
Storage	0 - 109	9 – 109	0 - 135	
Total inc. Storage	**131 - 535**	**211 – 533**	**154 - 594**	

78. The table highlights some supply uncertainty in the forecast for all components, this is more than for last year's forecast for all supply sources except UKCS, but broadly in line with values seen last winter.

79. **Figure G15** shows an assessment of supplies for a minimum flow day, a maximum flow day and the Cold Day. Minimum Flow day is an assumption of the lowest flows expected from each individual supply source on any given day (154 mcm/d). Maximum flow day is an assumption of the highest flows expected from each individual supply source on any given day (459). The cold day assumption is 344mcm/d. All these assumptions exclude Gas Storage.

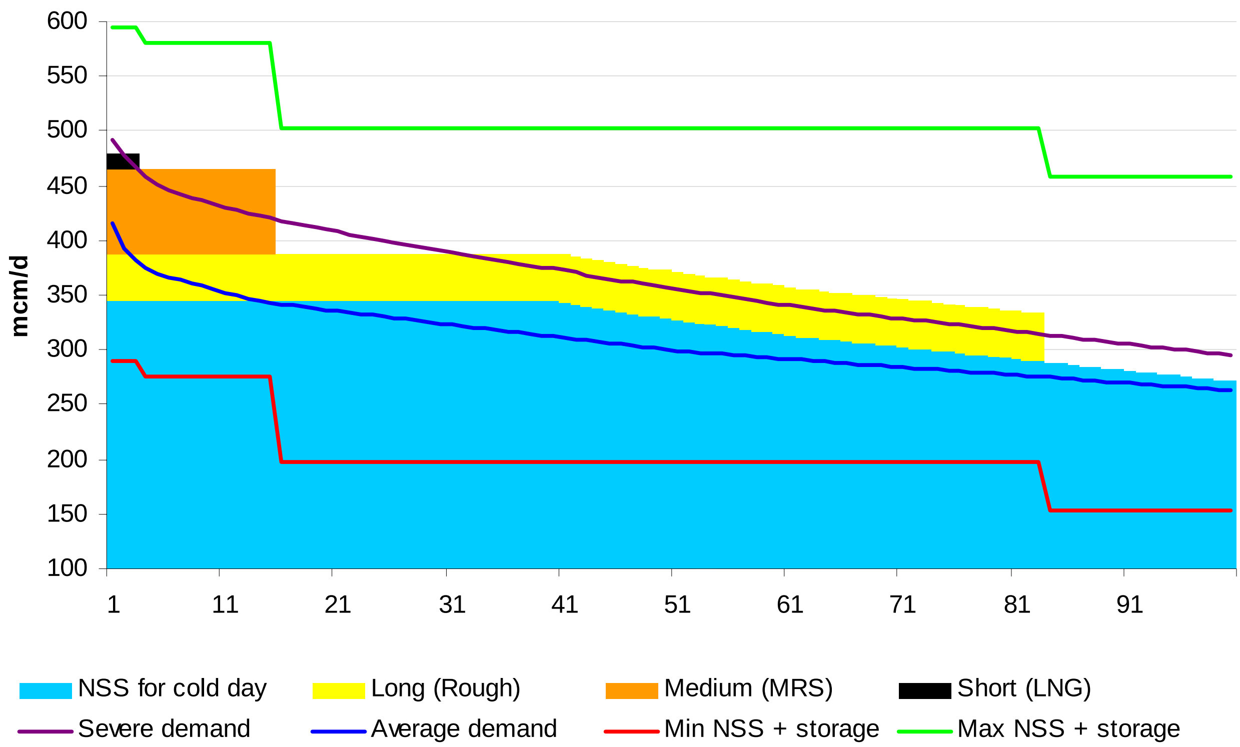
Figure G15 – Winter 2013/14 non storage supply forecasts for minimum, maximum and Cold Day



Winter Security Assessment

80. **Figure G16** provides a graphical representation of the final view of supplies for winter 2013/14, as shown in **Table G10**.

Figure G16 - Final view of supplies for winter 2013/14



81. The chart shows demand duration curves for the winter for both average and severe conditions. The highest demand within a severe winter is approximately 490 mcm/d, with 25 days with demands above 400mcm/d. The highest demand for an average winter is approximately 415 mcm/d, with only one day with demands above 400 mcm/d. Of course, in reality, even an average winter could have a number of days with demands at 400 mcm/d, or even higher.

82. The blue area represents non storage supply (NSS). For cold days, where the Composite Weather Variable approaches 0 degrees CWV, NSS is 344 mcm/d, as shown in **Table G10**. This represents a level of demand of roughly 375 mcm/d, which is exceeded by around 40 days on the severe demand duration curve.

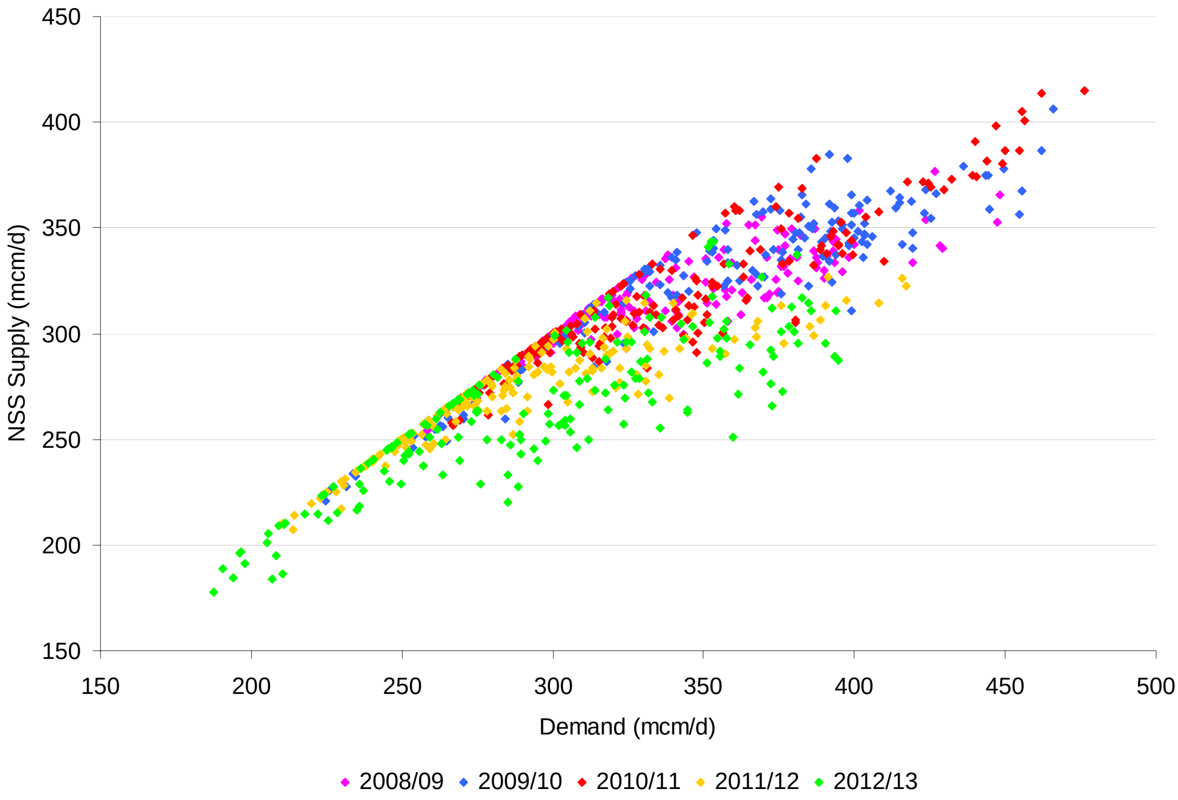
83. Above the blue area representing NSS there are three areas coloured yellow, orange and black representing Long (Rough), Medium (Mid Range) and Short (LNG) storage respectively. Maximum storage deliverability is 135 mcm/d. It can be seen that at certain times the purple line (severe demands) is above the top of the coloured areas and at others below, suggesting that on certain days either more NSS or additional storage would be required to meet all demand during a severe winter. However this is not a cause for concern, as the green line represents our view of maximum NSS (459mcm/d) plus storage, which results in a combined

total of 594 mcm/d, over 100 mcm/d higher than the highest demand forecast within a 1 in 50 severe winter.

84. Clearly the high level of uncertainty regarding NSS availability makes any quantitative assessment of winter security difficult. A more qualitative approach may therefore be more appropriate.

85. **Figure G17** shows historic levels of non storage supply (NSS) versus demand for the last five winters

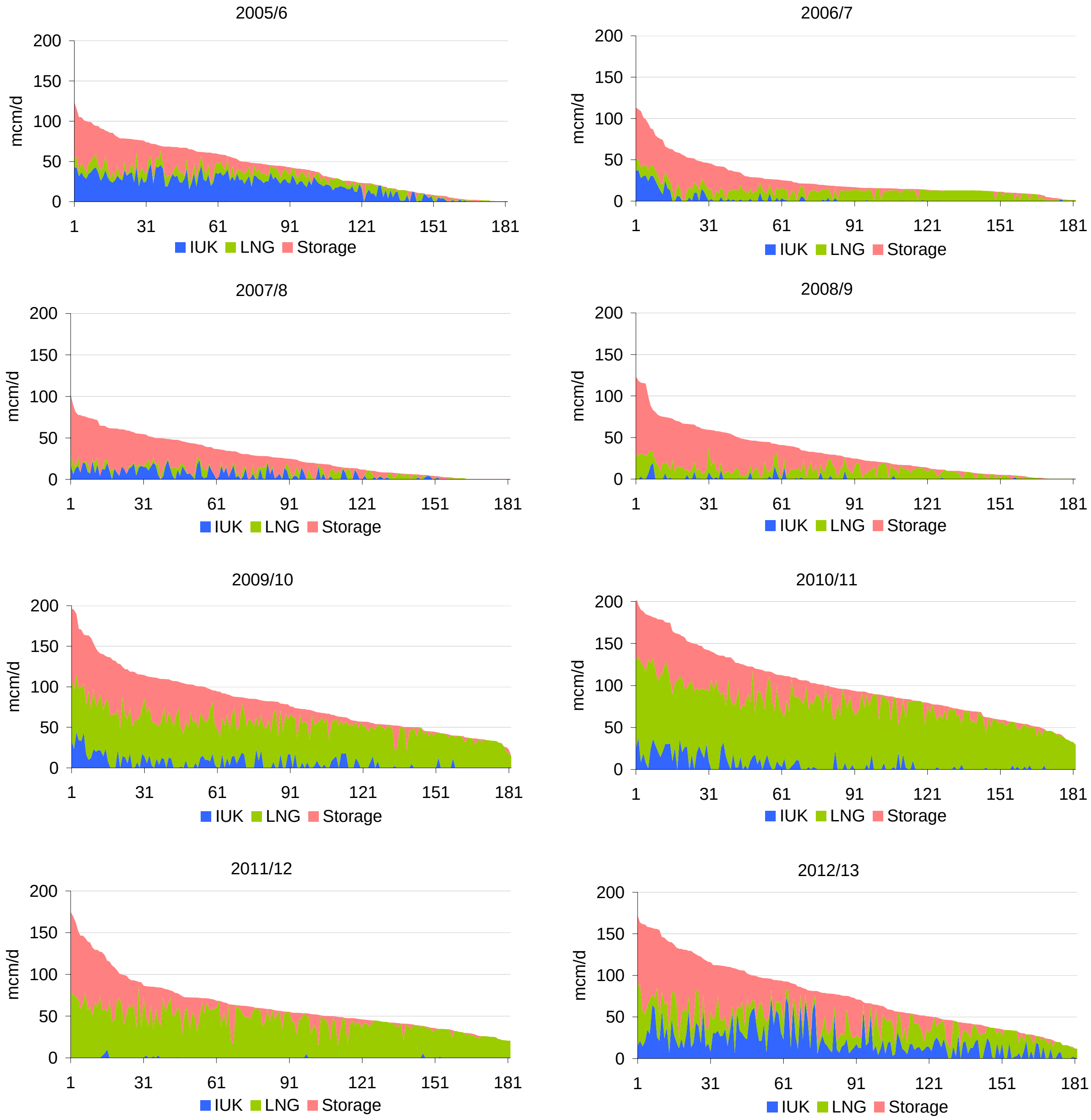
Figure G17 - Non storage supply (NSS) versus demand for the winters 2008/9 to 2012/13



86. The chart shows the significant variations in NSS, both within winter and from one winter to the next. For example both 2010/11 and 2009/10 winters recorded many days of NSS above 350 mcm/d, and even the occasional day where NSS was greater than 400 mcm/d. Winter 2012/13 never saw NSS levels reach 350 mcm/d and much greater variations in levels of NSS for a given level of demand.

87. How both NSS and storage supplies have evolved over the last few years is shown in more detail in the following series of charts. They highlight the levels of the most flexible supplies, namely, LNG, IUK and storage used throughout the winter. UKCS, Norwegian and BBL supplies have been excluded, as these have tended to be more stable both within winter and from one winter to the next, although we acknowledge that there have been variations, with for example UKCS declining and BBL flows responding more commercially.

Figure G18 - Supply duration curves for IUK, LNG and storage for winters 2005/6 to 2012/13



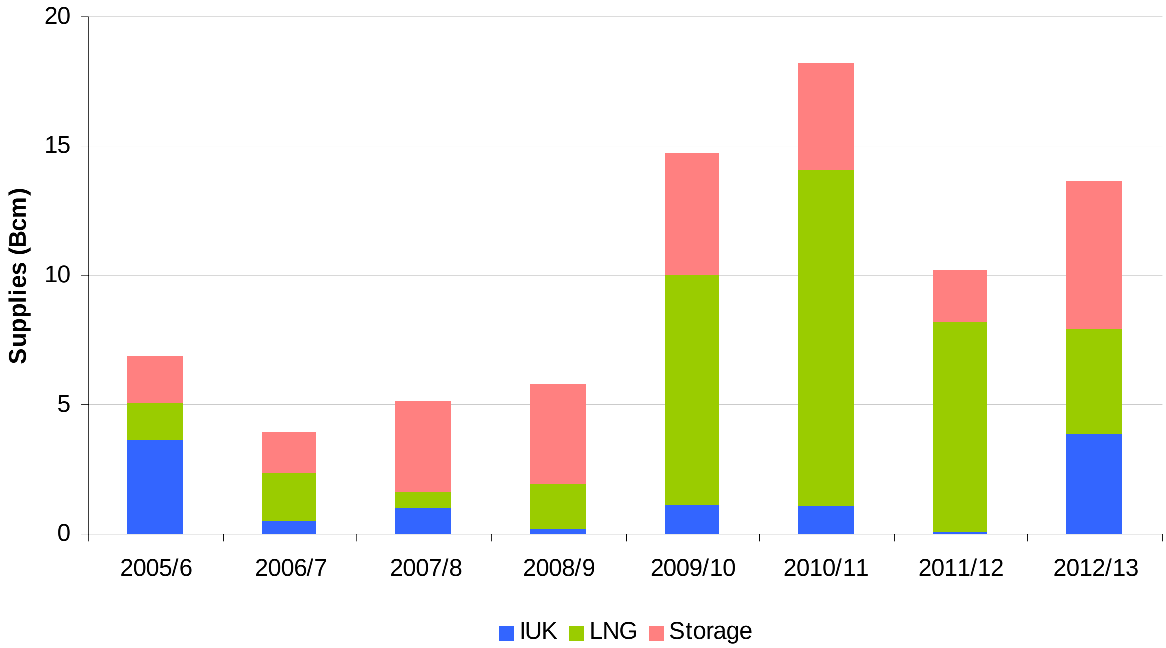
88. The charts highlight a number of points:

- **2005/6** – (1 in 4 warm winter) Limited LNG import capacity at Grain. Highest IUK import volumes since operations commenced in 1998. Storage dominates. No Langeled or BBL pipeline. Loss of Rough in February 2006.
- **2006/7** – (Greater than 1 in 85 warm winter) Lower requirement due to milder winter, leading to lower requirement from IUK. Storage dominates. Langeled pipeline operational (but no flows from the Ormen Lange field). Some BBL imports.

- **2007/8** – (1 in 14 warm winter) Modest requirement. Commercial flows from Norwegian Ormen Lange field commence.
- **2008/9** – (Average winter) Modest requirement. Dominated by storage. Limited IUK requirement. Expansion of Grain LNG import capacity.
- **2009/10** – (Average winter) Commercial flows commence from LNG facilities at Milford Haven (South Hook and Dragon). Significant increase in LNG import volumes.
- **2010/11** – (Average winter) Expansion of LNG import capacity at South Hook. Further increase in LNG import volumes.
- **2011/12** – (Greater than 1 in 85 warm winter) Mild winter resulting in low demand, reduced LNG but still significant. Limited storage volumes.
- **2012/13** – (1 in 4 cold winter) Further reductions in LNG, highest ever use of storage, and highest use of IUK since 2005/6.

89. The results are summarised in the following chart, showing total supplies of IUK, LNG and storage over the eight winters.

Figure G19 - Supplies of IUK, LNG and storage over winters 2005/6 to 2012/13



90. The chart highlights a number of points:

- IUK imports have varied considerably from one winter to the next, with 2012/13 seeing the highest levels of imports via IUK since 2005/6
- LNG imports increased significantly in 2009/10, peaking in 2010/11, then fell in 2011/12, then fell again in 2012/13
- Significant increase in storage use in 2012/13

91. The chart highlights how the volumes and the relative shares have changed considerably year on year. This has been driven by a range of factors, including:

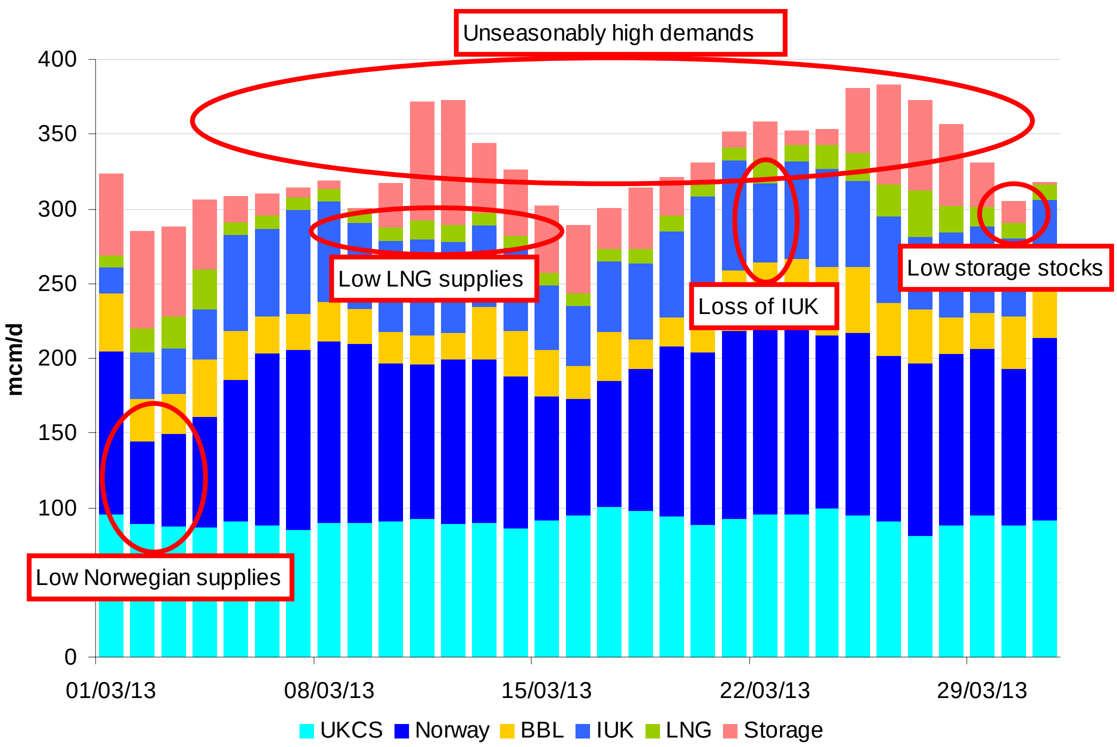
- The global LNG market

- Price differentials in the UK and continental European markets
- Market access to continental supplies including storage
- Severity of the winter, both in the UK and Europe

92. A combination of multiple events, such as unseasonably high demands coincident with a sustained supply loss could potentially create challenging conditions, but the market has always delivered, with its diversity being a key asset. Whilst it is very difficult to forecast what the makeup of supplies will be for the coming winter, with each year having its own unique supply patterns, it is clear that the combination of a diverse range of import capacity, combined with a mixture of storage types has performed well over the last eight years.

93. This can be shown by examining the month of March from winter 2012/13. **Figure G20** shows the supply demand balance for that particular month.

Figure G20 - Daily supply/demand balance for March 2013



94. The chart highlights a number of events throughout the month:

- Unseasonably high demands for the month with daily CWVs approximately 3.5 degrees CWV colder than expected for March, resulting in demands roughly 50 mcm/d higher than seasonal normal for each day of the month, and on certain days considerably higher
- Loss of IUK supplies on 22 March, albeit the issue was resolved within day
- Low Norwegian supplies in early March due to various issues on the Norwegian gas transportation network

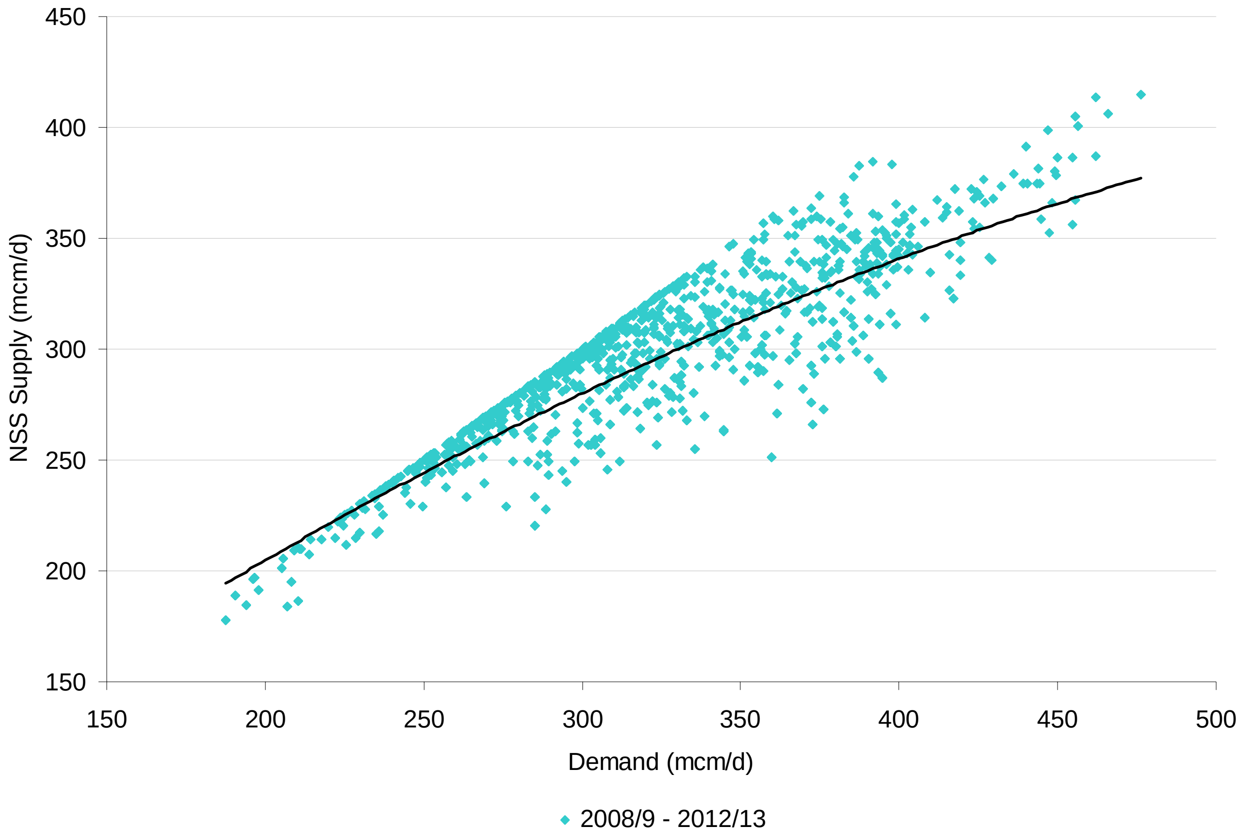
- Low LNG supplies due to a tight global LNG market and limited tanker deliveries to replace depleted stock
- Low storage stocks, as storage had been used extensively earlier in the winter

95. If a number of these events had been more serious, for example a more severe, sustained loss of IUK or Norwegian supplies, coincident with another event such as unseasonably high demands or very low storage stocks this could have presented an even more challenging scenario.
96. In conclusion, whilst the winter 2012/13 showed how the UK benefits from high levels of import capacity and diversity of supply, multiple, coincident events within a winter could still prove challenging.

Safety Monitors

97. On 6th June 2013, the preliminary view of initial Safety Monitor levels was published for 2013/14 as required under the Uniform Network Code (Q5.2.1).
98. It is National Grid's responsibility to keep the monitor under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do so. It should be noted that the purpose of the Safety Monitors is to ensure an adequate pressure can be maintained in the network and thereby protecting public safety. It is therefore appropriate that a prudent approach is adopted in setting the Safety Monitor levels.
99. **Figure G21** shows historic levels of non storage supply (NSS) versus demand for the last five winters.

Figure G21 - Non storage supply (NSS) versus demand for the winters 2008/9 to 2012/13



100. **Figure G21** shows the NSS versus demand assumption for winter 2013/14, based on an analysis of the last five winters. This continues the approach of using a variable NSS assumption which is demand dependent. This more accurately reflects the flexible supply options available within the UK. It is important that the assumed level of NSS used for calculating the Safety Monitors is available throughout the winter, notably at times of high demand. Hence in calculating the Safety Monitors, NSS at lower levels (95%) are used.

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

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

103. The resulting Safety Monitor levels for winter 2013/14 are detailed below. The primary driver for the decrease in the safety monitor requirement is a revision to the NSS calculation methodology for next winter.

- 2013/14 Assumed storage space = 53127 GWh
- 2013/14 Safety Monitor space = 1017 GWh (1.9%), (2012/13 = 2359 GWh)

- 2013/14 Safety Monitor deliverability = 633 GWh/d, (2012/13 = 672 GWh/d)

104. Safety Monitor levels and the associated winter profiles (i.e. how the monitors reduce later in the winter) will be published in early October 2013.

Operational Overview

Operational Challenges

105. The key operational challenges for winter 2013/14 are expected to be associated with managing day to day supply uncertainties, unplanned events and increasing within day linepack variation driven by the relatively unpredictable supply and demand environment.

106. Supply sources continue to evolve as UK Continental Shelf (UKCS) gas supplies decline and the UK's reliance on imports increases. The decline in UKCS supplies and subsequent increase in import capability has materially changed the UK's gas supply landscape and fundamentally changed the dynamics of supply from that of near predictability to considerable uncertainty.

107. If, as is anticipated, LNG imports continue at the similar relatively low levels as those seen during winter 2012/13, their will be a strong reliance on storage and imports from mainland Europe and Norway. The volume of gas delivered from Europe via the IUK and BBL interconnectors last winter was significantly higher than seen previously, with daily record entry flows being seen at both interconnectors, and will potentially see these high flows into Bacton again subject to the appropriate commercial and demand drivers.

108. Such high flows into Bacton, in alignment with the reliance on Norwegian flows via Langeled into Easington are likely to result in the majority of gas being supplied into the UK coming in through Easington and Bacton. Last winter we saw over 57% of winter supplies being delivered via these two terminals, which is in contrast to the historic profiles of high St Fergus flows and a north to south network configuration.

109. Last winter saw a strong bias towards coal burn over gas for power generation due to the price differential between coal and gas. This meant gas took the role of the marginal source of generation, resulting in lower overall demand levels but far more within day demand volatility and this bias is expected to continue for the forthcoming winter. Higher levels of wind generation are also expected, with last winter seeing for the first time a day where total wind generation exceeded that of gas, and with gas fired power generation expected to provide cover for wind intermittency, there is an expectation of further utilisation of NTS linepack to cover these short term demand swings on generating plant.

110. Over recent years we have seen a continuing increase in within day supply and demand profiling and relatively frequent and rapid storage site transitions between injection and withdrawal. With further increases in deliverability from medium range storage sites available this winter we expect to see this behaviour continue and potentially increase.

111. These changes alongside the changes to the supply environment have increased the day to day, and the within day demand volatility and have resulted in a notable trend towards later reconciliations of daily balance, with start of day offtake and flow notifications provided being less reflective of outturn flows.

112. These effects lead to a number of operational issues including the ability to accurately forecast end of day positions, increasing levels of linepack utilisation and frequent

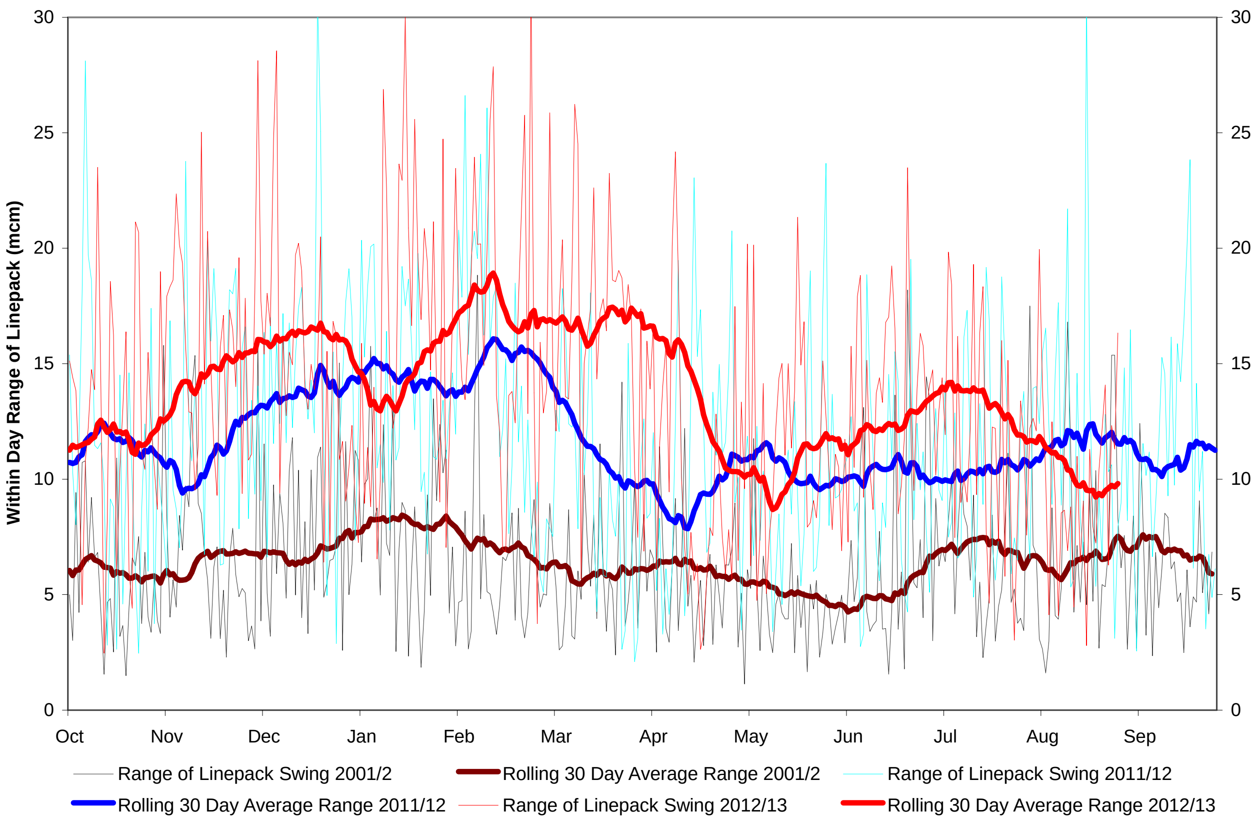
requirements to revise operational strategies, network configurations and compressor operations.

113. These factors are resulting in having to manage much greater linepack swings on the NTS. Large linepack changes are caused when the the rate of supply entering the network is at variance to the demand being taken from the network. These variations lead to greater operational challenges, manifesting particularly with respect to the management of within day linepack and NTS pressures within safe and agreed operational tolerances, and delivering capacity obligations in line with customer requirements.

114. Effective management of Linepack within the NTS is key to enabling National Grid to meet end of day and within day customer demands of the network, while also enabling us to meet our statutory obligations for pressure, accommodate increasing within day dynamic characteristics driven by new and much more fast responsive supply and demand sources now interacting across energy markets and, at the same time accommodating a much more credible range of contingency margin for unplanned events.

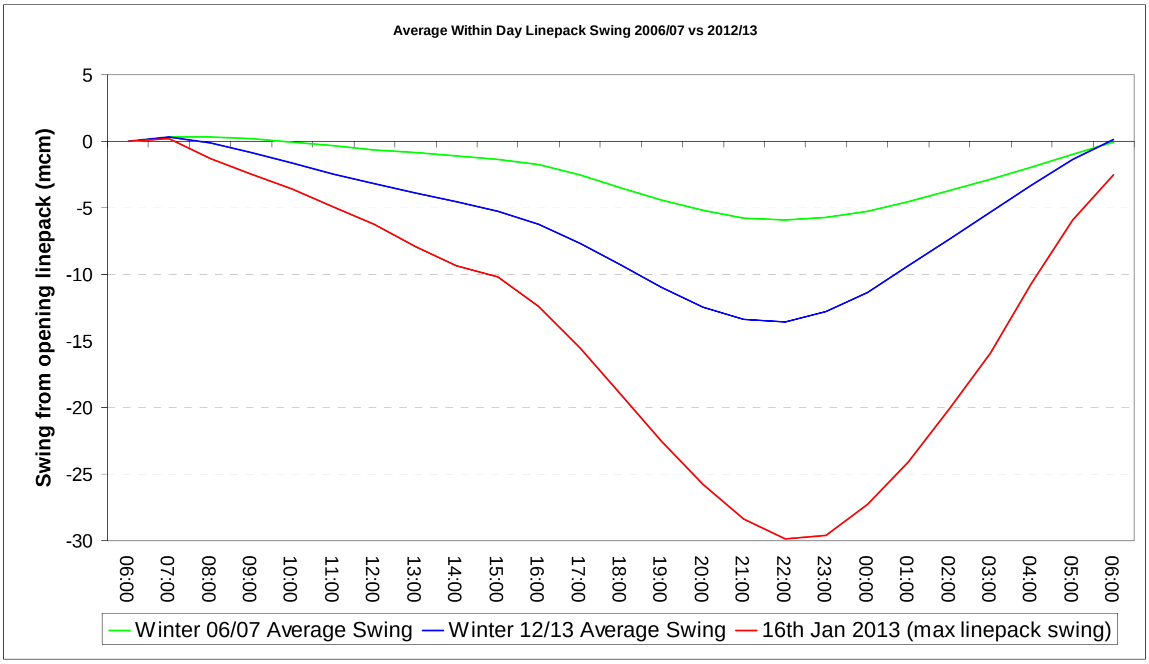
115. National Grid are continuing to develop our forecasting and operational tools and capabilities to allow us to support customers requirements in this area, however as demand for within day flexibility continues to grow and the operational reality moves further away from the 1/24th flat profile supply that underpins the design of the network, there is also a risk that there will be times that this cannot be accommodated and within day restrictions may need to be applied to maintain safe operation of the system.

Figure G22 – Comparison of within day max-min range of NTS Linepack (mcm)



116. **Figure G22** shows both the daily range and the 30 day average linepack swing seen on the NTS in 2001/02, 2011/12 and for 2012/13 and suggests that this linepack swing has increased by 200% from the position of 10 years ago and by between 10 – 20% from last year.

Figure G23 – Average within day linepack swing

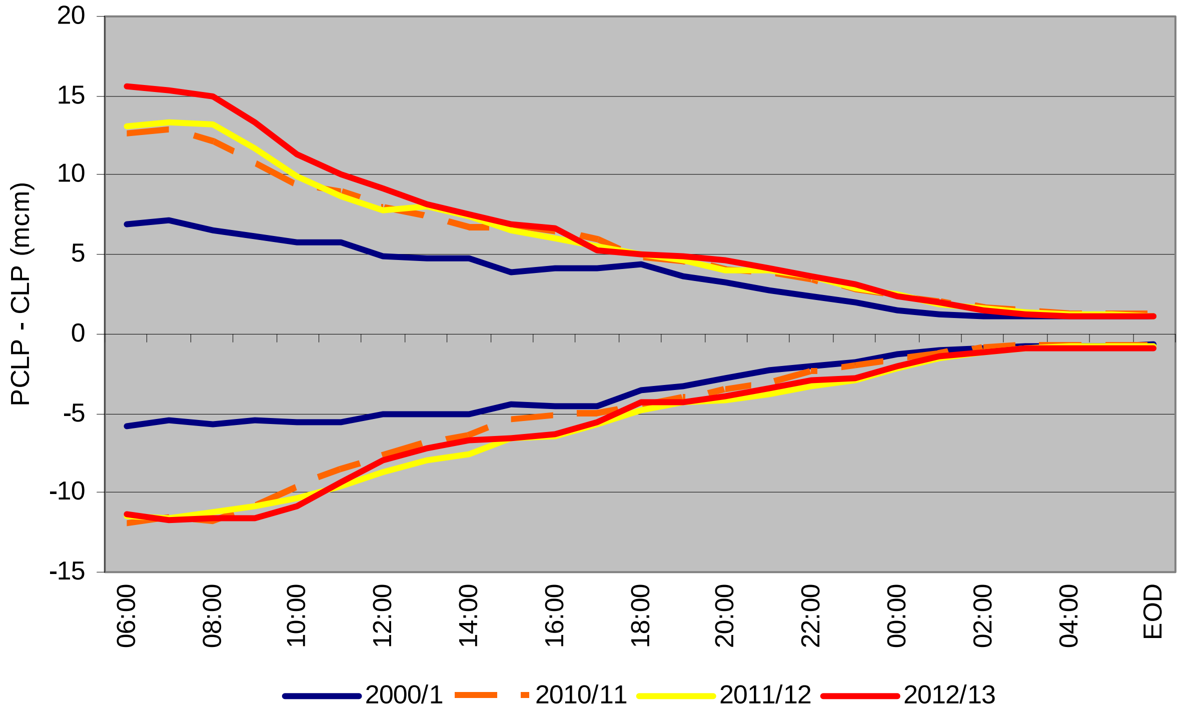


117. **Figure G23** shows the within day average linepack swing for 2006/07 and 2012/13. The red line is an example of one of the peak linepack swing days seen this winter.

118. 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.

119. In order to manage the NTS safely and efficiently, it is essential that information provision to the system operator is timely and accurate, with market participants operating in accordance with the information they have submitted.

Figure G24 – PCLP – CLP on days of no Residual Balancing



120. **Figure G24** shows the aggregated network user notifications that feed into the end of day market indicator, Projected Closing Linepack (PCLP).This shows that at the start of the gas day there is a significant and growing level of inaccuracy in daily flow forecasts and that this error is not fully resolved until very late in the gas day. This increasing trend is evidence of the changing ways that users are operating, and leads to increasing operational challenge for the system operator due to the increasing uncertainty as to when and where supplies will be brought into the NTS.

121. In summary the combination of fundamental changes to flow patterns of supply and demand on the NTS, within day supply and demand profiling and reduced accuracy of aggregate user notifications have all increased the operational challenges faced in managing the NTS.

122. Should issues arise on the NTS during the winter period National Grid has a range of operational and commercial tools at its disposal to ensure safety and security of operation. In most cases we would normally expect to manage most issues that occur through utilization of operational solutions such as network reconfiguration and re-optimization of compressor running strategy. These actions have limited or no direct impact on network users, however at times these may be insufficient and commercial tools such as restriction of network flexibility, capacity actions and locational balancing actions may be required to ensure that the safety and security of the system is maintained.

123. From a national balancing perspective National Grid continues to act as the residual balancer and carries out balancing trades when there is a risk that the end of day system balance, and hence linepack levels, will be outside of expected tolerances (based on information provided from customers). This is a normal activity and history suggests that National Grid will take these actions on around 1 day in 3. When balancing issues become severe, National Grid can issue further information to the market via a Margins Notice or Gas Deficit Warning to

highlight the issue in sufficient time for market participants to take effective action to remedy any imbalance.

Margins Notice / Gas Deficit Warning

124. Two new information provision options were implemented, although not utilised last winter to replace the '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 of achieving the end of day NTS balance position.

125. National Grid offers a subscription service for Gas Deficit Warning via SMS and email from the link at the following page: http://www.nationalgrid.com/uk/Gas/Data/

Market Information Provision

126. National Grid's Gas Operational Data details extensive data and real time information. As physical and regime changes occur, the industry will see these developments incorporated into the existing suite of reports and data items.

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

Update on Provision of new NTS Capacity for Winter 2013/14

Emissions related works

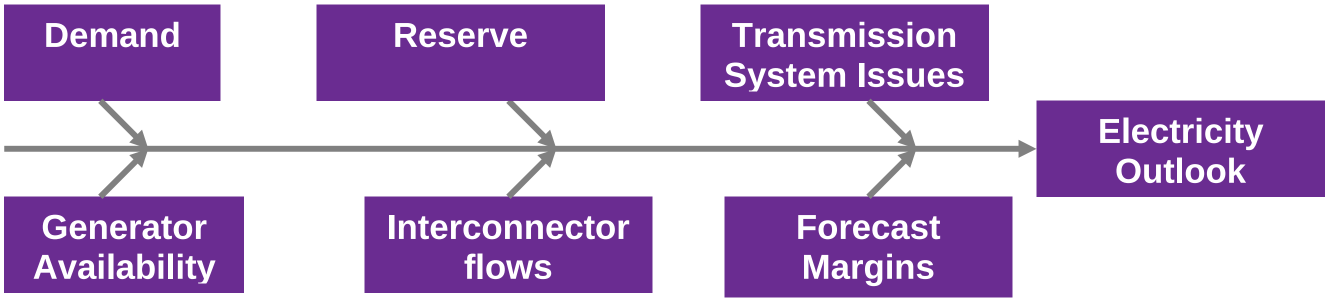
128. Work continues on the new 35 MW electric drive compressor unit at Kirriemuir, two units at St Fergus and one at Hatton. Kirriemuir and Hatton are expected to be commissioned before the end of 2013 with St Fergus following during the first quarter of 2014.

Industrial Emissions Directive

129. A number of National Grid's gas driven compressor stations will be subject to revised emissions limits under the Industrial Emissions Directive (IED). Initial Engineering Works are under way to evaluate the preferred technical solutions for each affected site.

New Exit Connections

130. A new NTS exit connection has been commissioned on Feeder 21 at Hill Top in Cheshire for a new storage facility.



Overview

131. This chapter sets out our current electricity forecast for the winter 2013/14. We look at the four major areas of variability which affect the outlook for this winter: demand for electricity, conventional generation variability, wind variability and interconnector flow. We also have a section describing reserve, which we use to manage these areas of variability and a section on Transmission System Issues.

132. Based on feedback that we have received from the Winter Consultation and due to the increasing importance of interconnectors and renewable power generation, we have made a number of changes to the Winter Outlook this year:

- We now use Transmission System Demand
- We have updated our margin forecast methodology
- We have improved our modelling of unmetered embedded generation
- We have adopted a base case interconnector flow for this winter of 750 MW imports from the continent and 750 MW of exports to Ireland

These changes are discussed in more detail in the following sections.

Demand

133. In previous reports, demand included station load, but excluded exports to France, The Netherlands and Ireland. In this year's report, unless otherwise stated, demand now includes interconnector exports. This is Transmission System Demand (TSD) as defined in the Grid Code[22].

134. Our base case forecast of exports at peak demand are 0 MW to France and the Netherlands, and 750 MW to Ireland. This base case for interconnector exports is also used for weather corrected demands. Interconnector imports are treated separately.

[22] The Grid Code can be found at http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/gridcodedocs/

135. The methodology for calculating weather corrected demand remains largely unchanged. A 30 year average of each relevant weather variable is constructed for each week of the year. This is then applied to linear regression models to calculate what the demand would have been with this standardized weather. However, the treatment of unmetered embedded generation has changed, as outlined in the next section.

Unmetered Embedded Generation

136. There is an increasing volume of embedded wind and solar generation for which National Grid receives no metering. This generation has the same effect as negative demand for the System Operator.

137. Account is now taken of the (estimated) amount of unmetered embedded generation from wind and solar generation. Demand forecasts beyond the horizon of detailed daily weather forecasts and weather corrected demands are adjusted to take account of a standardized weekly amount of embedded generation. In order to enact this improvement in the weather correction methodology, new models have had to have been applied to historic data, which has resulted in small changes in the historic weather corrected demand series.

138. In addition, Average Cold Spell (ACS) and 1 in 20 demands, whether historic or forecast, use the appropriate standardized weekly value for unmetered embedded wind and solar generation.

Customer Demand Management (CDM)

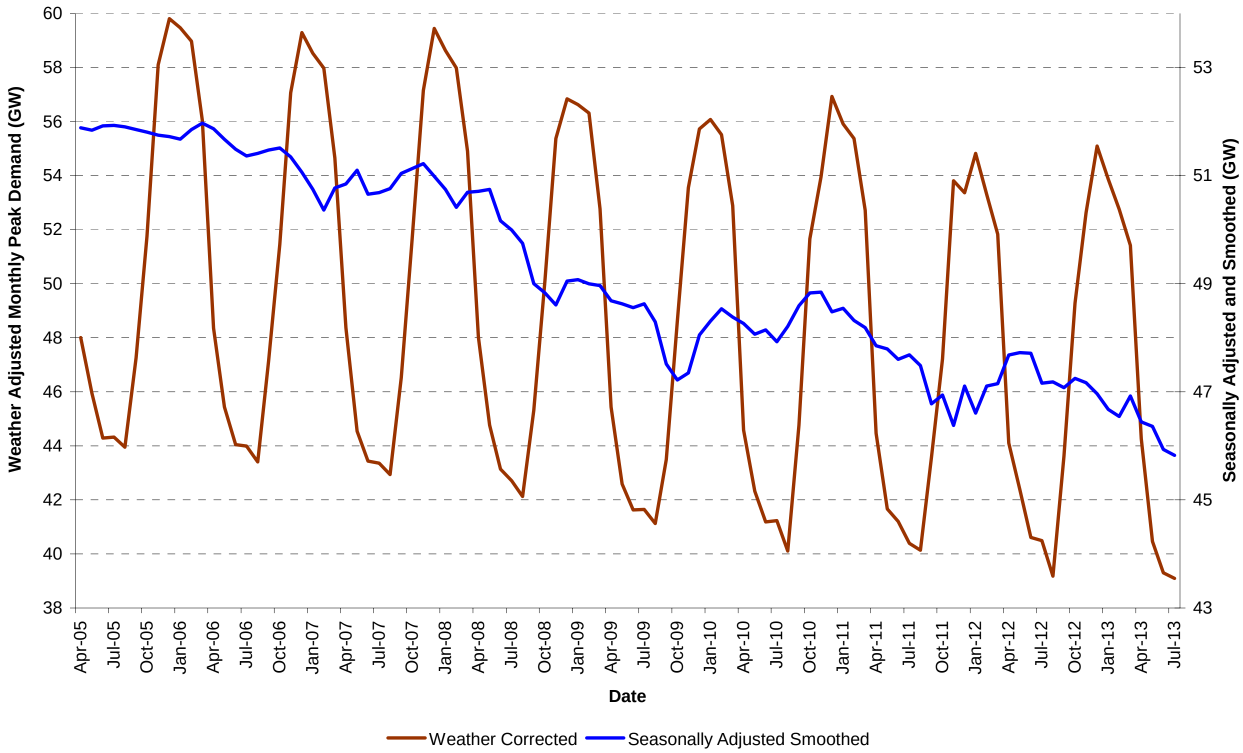
139. Average Cold Spell (ACS) and 1 in 20 demands are quoted as restricted demands, which means they take into account the estimated amount of CDM[23] on the highest demand days. At present we estimate this to be 1200 MW.

[23] Customer demand management is defined in the Grid Code: http://www.nationalgrid.com/NR/rdonlyres/5DFDEFEB-DDBC-4381-8DE5-4B2087AC6AC8/62004/4_GLOSSARY__DEFINITIONS_I5R4.pdf

Demand Levels

140. **Figure E1** shows the weather corrected and seasonally adjusted demand levels (excluding interconnector exports) for the last eight years. There is an upturn in demand levels from February to June 2012, which may be due to the unusually wet summer and the floods. This aside, the general trend in peak demand is downward. Given that statistical review of GDP figures shows that the economy has been broadly flat across the period, it seems likely that the decline in peak demand is due to energy saving measures and a move away from heavy industry to less energy intensive industrial activity. Our assumption for this coming winter is that underlying demand will remain flat at current levels.

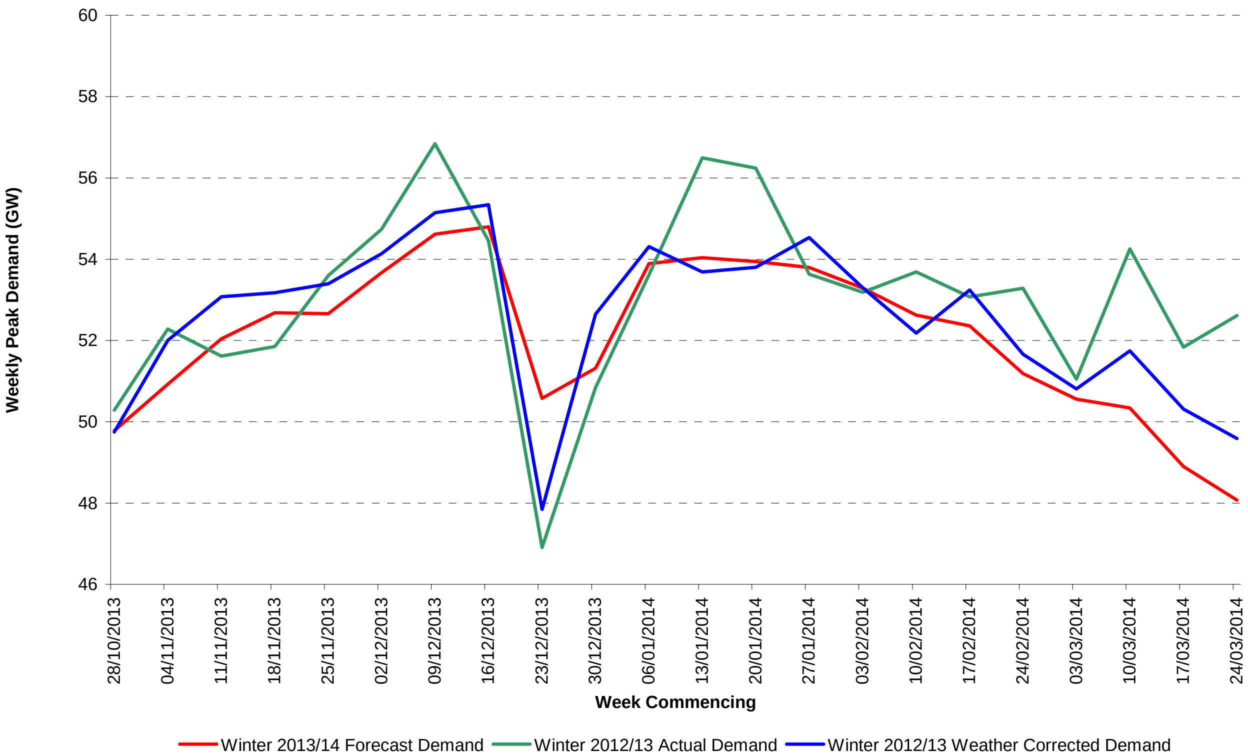
Figure E1 - Weather Corrected and Smoothed Seasonally Corrected Demand



141. **Figure E2** shows the previous year's actual demand and weather corrected demand, and the demand forecast for the coming winter. The most current forecast at any time is given on the **BMRS**[24], although for direct comparison the base case interconnector export of 750 MW needs to be added to the BMRS figure. The forecast for Christmas week is much higher than the outturn in 2012 because Monday to Friday of Christmas week 2012 lay in the Christmas holiday period, whereas in 2013 the Monday of Christmas week is a full working day.

[24] www.bmreports.com

Figure E2 - Previous Year's Outturn and Forecast for 2013/14



142. We forecast three measures of demand for the coming winter as demand for electricity is significantly affected by the weather. These three measures of demand indicate our forecast levels and variability of demand. Our weather corrected demand forecast applies should we have the same weather as long term average weather conditions. In any winter, however, there are milder spells and colder spells which drive fluctuations in demand around the weather corrected demand forecast; this drives our Average Cold Spell (ACS) forecast. We also include a 1 in 20 forecast to reflect our demand forecast if we were to experience an unusually cold year.

143. Our current peak weather corrected demand forecast for this winter is now 54.8 GW compared to the weather corrected demand forecast from the Winter Consultation of 55.5 GW (once the interconnector demand and allowance for weather corrected embedded generation are accounted for). The differences in the demand forecast between the consultation and this report are due to recent experience of a decrease in the weather corrected demands over this summer.

144. The Average Cold Spell demand forecast (ACS) is the yearly peak demand level that has a 50% chance of being exceeded in the forecast year. The restricted ACS figure is the value we expect to see after any Customer Demand Management has occurred on the highest demand day. For winter 2013/14 the (restricted) ACS forecast is currently 56.3GW, compared to an equivalent figure of 56.9 GW at the time of the Winter Consultation.

145. 1 in 20 conditions are a particular combination of weather conditions 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 (restricted) 1 in 20 demand peak is forecast to be 58.0 GW compared to an equivalent figure of 58.6 GW in the Winter Consultation.

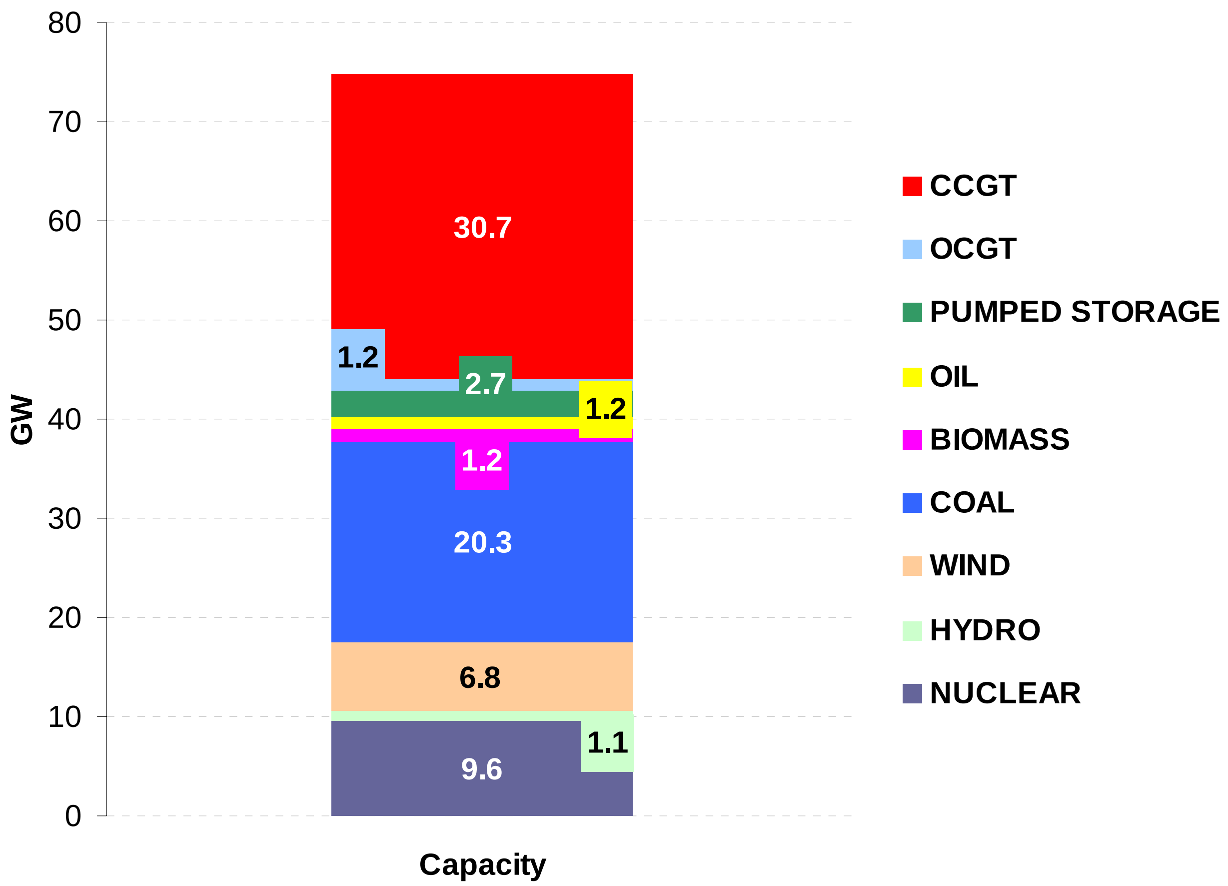
Generator Availability

Generation Capacity

146. There is 3.8 GW of Interconnector capacity which, in previous reports, has been included in our generation capacity figures. Excluding this Interconnector capacity our current forecast for operational generation capacity anticipated to be available at the winter peak for 2013/14 is 74.7 GW. This mid-winter forecast is based on the observed output of power stations and represents an increase in the capacity from the start of the winter of 73.9 GW. The forecast increase of 0.8 GW is due to the expected commissioning of the third unit at West Burton B and an increase in wind capacity. A breakdown of this generation capacity is shown in **Figure E3**, noting that the equivalent figure in previous reports:

- showed the capacity at the start of winter, whereas this figure shows the forecast mid winter capacity
- included interconnector capacity, whereas this figure does not include interconnector capacity

Figure E3 – Operational Generation Capacity Forecast for the winter peak 2013/14



Large Combustion Plant Directive (LCPD)

147. The capacity forecast assumes that Ferrybridge Units 1 and 2 will have enough hours remaining under the LCPD regime to maintain availability over the winter period. The only other LCPD opted out power stations remaining available are Ironbridge and Littlebrook, which will not be limited by their remaining hours this winter.

Unavailable CCGT Generation

148. We estimate that 2.7 GW of CCGT generation has been declared unavailable for the winter 2013/14 for different reasons. This includes Keadby and Teesside, but does not included Barking 2, which we now expect to be available this winter.

Transmission System Issues

Voltage

149. As demands are higher in the winter, we do not expect there to be any issues with the system voltage profile, other than over the Christmas period, where it is likely that there will be a requirement for strategic generation to run during low demand periods in the south of the country.

Transmission System Reinforcement

150. The relevant Transmission Owners continue to develop their transmission systems[25] 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[26] when it becomes economic to do so going forwards.

151. The historic amount of output and historic estimated curtailment of large[27] wind farms is shown in **Table E1** and **Table E2**. 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).

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

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

[27] 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 E1 – 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 E2 – Estimated[28] 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**

152. **Table E3** shows the relative proportion of wind curtailed to the total output had wind not been curtailed. This proportion is highest behind the B1 boundary[29] which is due, to an extent, to the limitations of this boundary. The ongoing Beauly Denny work will relieve this transmission limitation when it completes in the fourth quarter of 2015[30], however, in the meantime, the transmission circuit outages that are required to perform this ongoing work will have an adverse impact on curtailment. The Electricity Networks Strategy Group (ENSG) website gives more detail on the range of transmission system reinforcement projects across the country.

Table E3 – Proportion of Wind Farm Curtailment

GWh	Apr – Sep 2011	Oct 2011 – Mar 2012	Apr – Sep 2012	Oct 2012 – Mar 2013
NW Scotland (B1)	3.9%	10.7%	5.7%	1.4%
Remainder of Scotland	1.9%	0.4%	0.5%	0.4%
England and Wales	0%	0%	0%	0%
Total wind curtailment	**1.3%**	**2.0%**	**0.9%**	**0.3%**

[28] 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.
[29] Boundary details can be found in the Electricity Ten Year Statement which can be found at http://www.nationalgrid.com/uk/Electricity/ten-year-statement/
[30] Based on the Electricity Networks Strategy Group information available (June 2013) at https://www.gov.uk/government/policy-advisory-groups/electricity-networks-strategy-group

Reserve

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

154. We also hold an additional reserve to meet wind generation output uncertainty. The amount we hold varies with expected wind output and the period of the day; this requirement is met from synchronized and non-synchronized sources.

Short Term Operating Reserve

155. We procure the non-synchronized reserve 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.

156. For winter 2013/14, our present level of contracted STOR 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.

157. The last STOR tender round covering services for the winter 2013/14 darkness peak has now been held; the results of which will be published at the beginning of November. Communications regarding this will be through electricity operational forums and on our website.[31]

158. 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 the flexible volume was not available over weekday peak demand periods. This flexibility allows us to pay only for what we need and for what is available. 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).

Reserve for Frequency Response

159. 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 on gas and coal-fired units in the BM, then approximately 1.9 GW of reserve would be required to meet the necessary response requirement. 1 GW of this 1.9 GW reserve requirement has already been contracted, with 0.14 GW from demand-side providers.

160. National Grid will look 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. Details of current status can also be found at our website[32].

[31] http://www.nationalgrid.com/uk/Electricity/Balancing/services/STOR/
[32] http://www.nationalgrid.com/uk/Electricity/Balancing/services/frequencyresponse/ffr/

Maximum Generation

161. National Grid continues to have Maximum Generation contracts in place for Winter 2013/14, which provides potential access to 1 GW of extra generation in emergency situations. This is a non-firm emergency service and generation operating under these conditions normally has a significantly reduced reactive power capability (which, in turn, can have a significant impact on transmission system security). Hence, it is not included in any of our generation capability and plant margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

Interconnector Flows

162. Interconnector flows are closely correlated with price spreads; however, with the effects of the weather, plant breakdowns and increased penetration of renewable generation there is significant volatility of power prices close to real-time. This results in significant uncertainty for any long-term flow forecast.

163. The North West Europe (NWE) day ahead coupling regime[33] is scheduled for go-live in November. This will increase the correlation between prompt power prices and interconnector flows and is therefore likely to make flows more volatile between different days.

Ireland

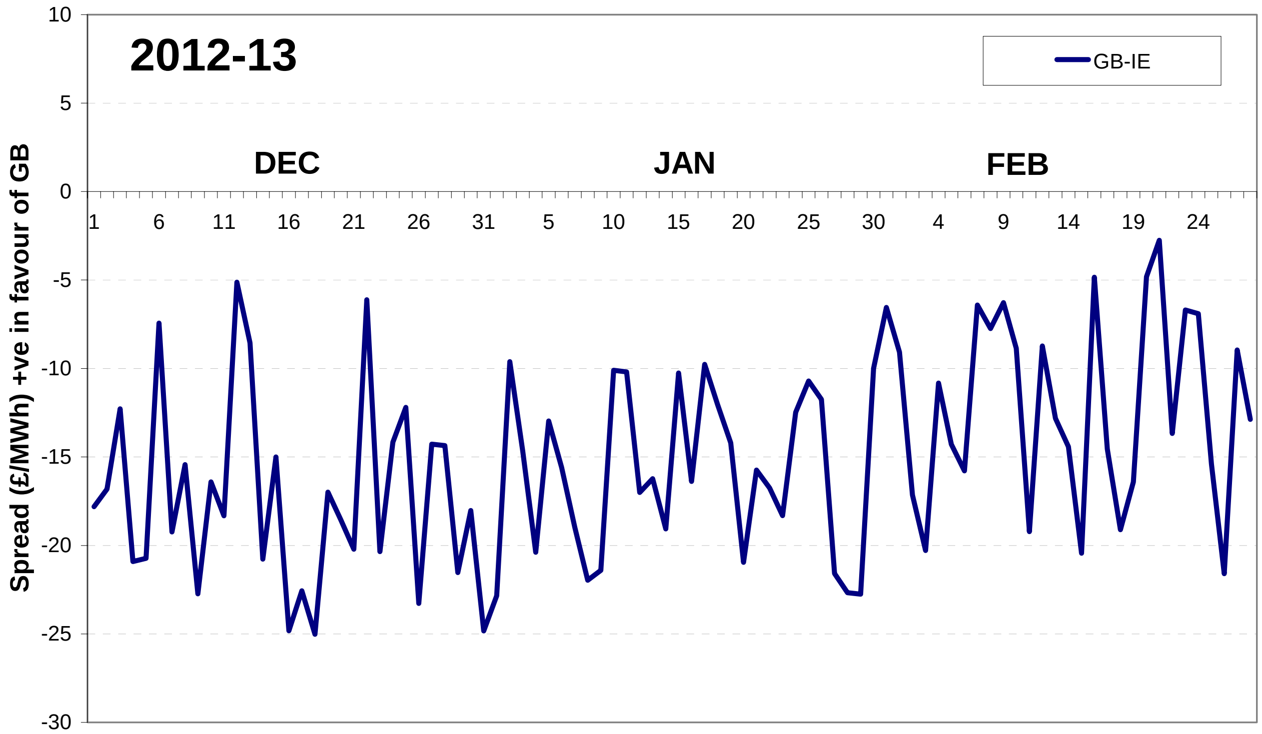
164. The interconnector to Northern Ireland (Moyle) is at a capability of +/-250MW and is expected to remain at this level for another 4 - 5 years until the cable is replaced. A prudent estimate from Mutual Energy suggests commissioning of the cable to +/-500MW in autumn 2017.

165. East West Interconnector (EWIC) is expected to be at full capability (+/-500MW) throughout this winter.

166. **Figure E4** shows the Ex-Ante 2 Irish price – Day Ahead GB price spread at the time of GB peak price for last winter. This winter we expect both Moyle and EWIC to see a net flow from GB to Ireland, this is likely to reduce or even import to GB during periods of high wind power output in Ireland.

[33] https://www.entsoe.eu/about-entso-e/market/regional-cooperation/

Figure E4 – 2012/13 Mid Winter Irish – GB Price Spread at time of GB Peak Price



France and The Netherlands

167. Interconnexion France Angleterre (IFA) has experienced significant periods of reduced capability during the replacement of the thyristor valves. This work resulted in the annual availability for 2012/13 dropping to 54%. IFA is expected to be at full capability (+/-2000MW) for this winter apart from a scheduled 16 day outage (+/-1000MW) in October. BritNed (+/-1000MW) is expected to be at full capability throughout this winter.

168. Current forward prices for this winter in France and Netherlands are very similar but are both at a large discount to GB forward prices; therefore we expect flows to be net import to GB on IFA and BritNed throughout the winter as shown in **Table E4** and **Table E5**.

Table E4 – Forecast Weekday Continental Interconnector Flows

Time (Oct-Mar)	Forecast Flow minimum (+ve to GB)	Forecast Flow maximum (+ve to GB)
23:00 – 07:00	0 GW	+3 GW
07:00 – 23:00	-2 GW	+3 GW

Table E5 – Forecast Weekend Continental Interconnector Flows

Time (Oct-Mar)	Forecast Flow minimum (+ve to GB)	Forecast Flow maximum (+ve to GB)
23:00 – 23:00	+1 GW	+3 GW

169. The day ahead price spreads at the time of GB peak price between GB and France and the Netherlands are shown for 2011/12 in **Figure E5** and for 2012/13 in **Figure E6** as well as the GB temperature difference from GB normal temperatures. These show that prices have generally been in favour of flows into GB, however there have been a number of occasions when this has not been the case, most notably in early February 2012 when cold conditions in GB and the continent saw price spreads favouring flows to both the Netherlands and France. France saw new record demands during this period.

Figure E5 – 2011/12 GB – French / Dutch Price Spread at time of GB Peak Price

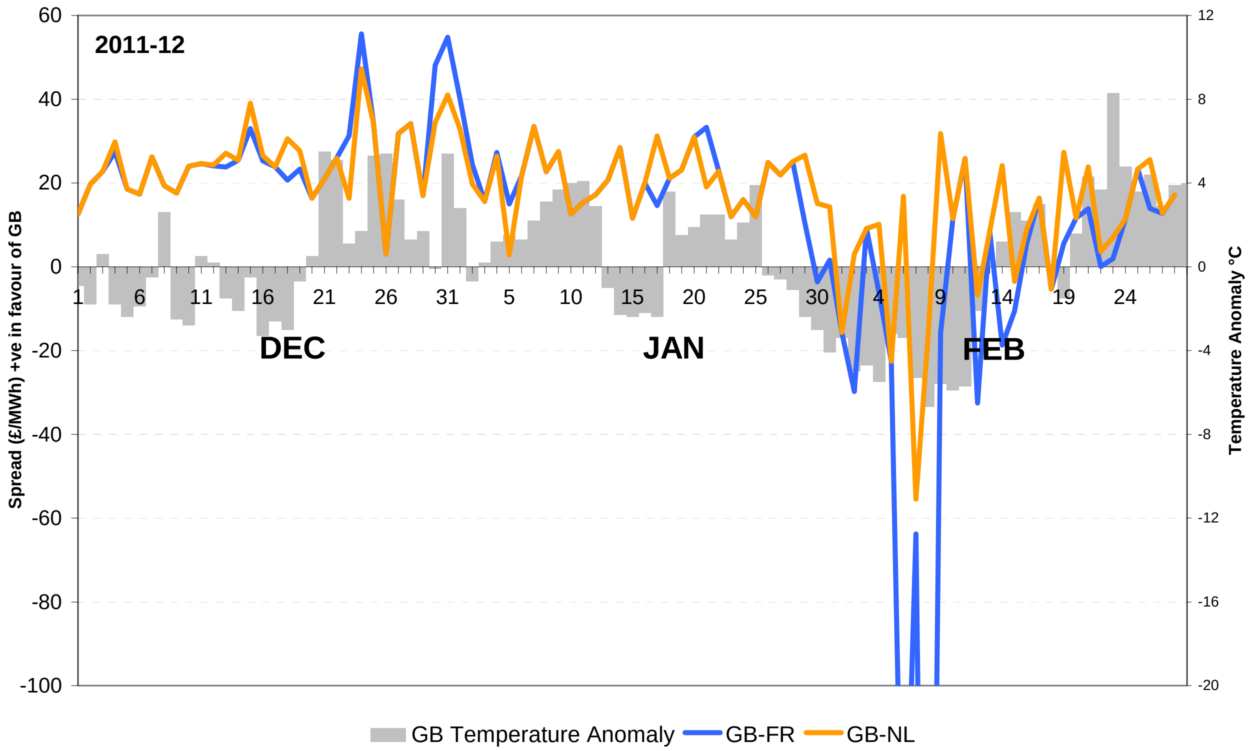
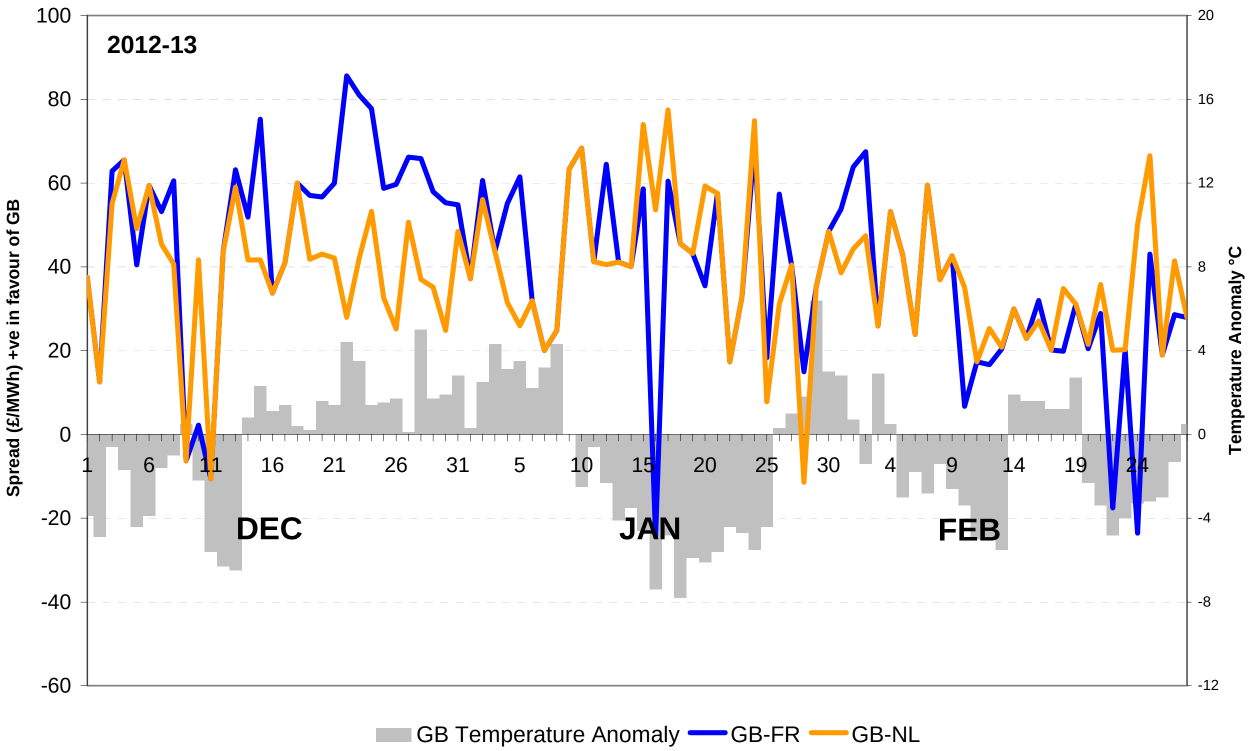
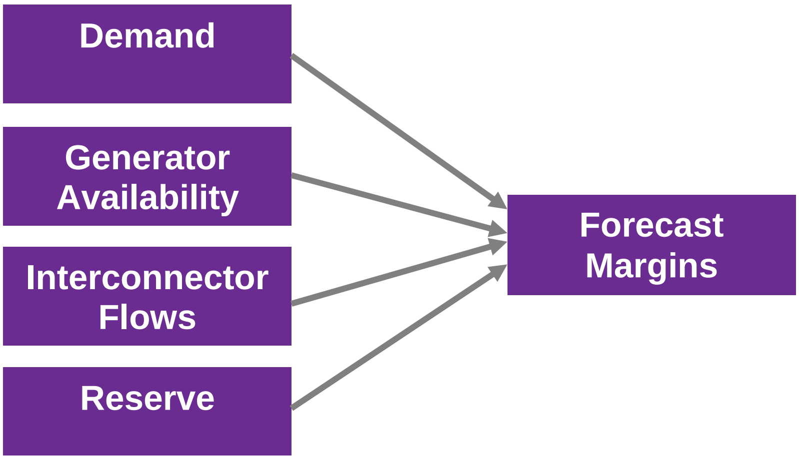


Figure E6 – 2012/13 GB – French / Dutch Price Spread at time of GB Peak Price



170. We have used this historical price information and our forecast flow for the current winter to create our base case scenario of 750MW import from the continent and 750MW export to Ireland. We also include an arduous case in our Forecast Margins section to illustrate what the effect on margins will be should we see similar conditions to February 2012 with all the interconnectors exporting at their maximum capability.

Forecast Margins



171. This section looks at the forecast margins for this winter. Firstly a "Clean Forecast" is described, which uses data that is largely unadjusted. This presents the margins in a similar way to how information is published on www.bmreports.com. We then build a central forecast making assumptions based on historic evidence for the four main areas of variability (interconnector flow, generator variability, wind variability and demand variability). Finally an arduous scenario is described, which has full interconnector exports at peak demand.

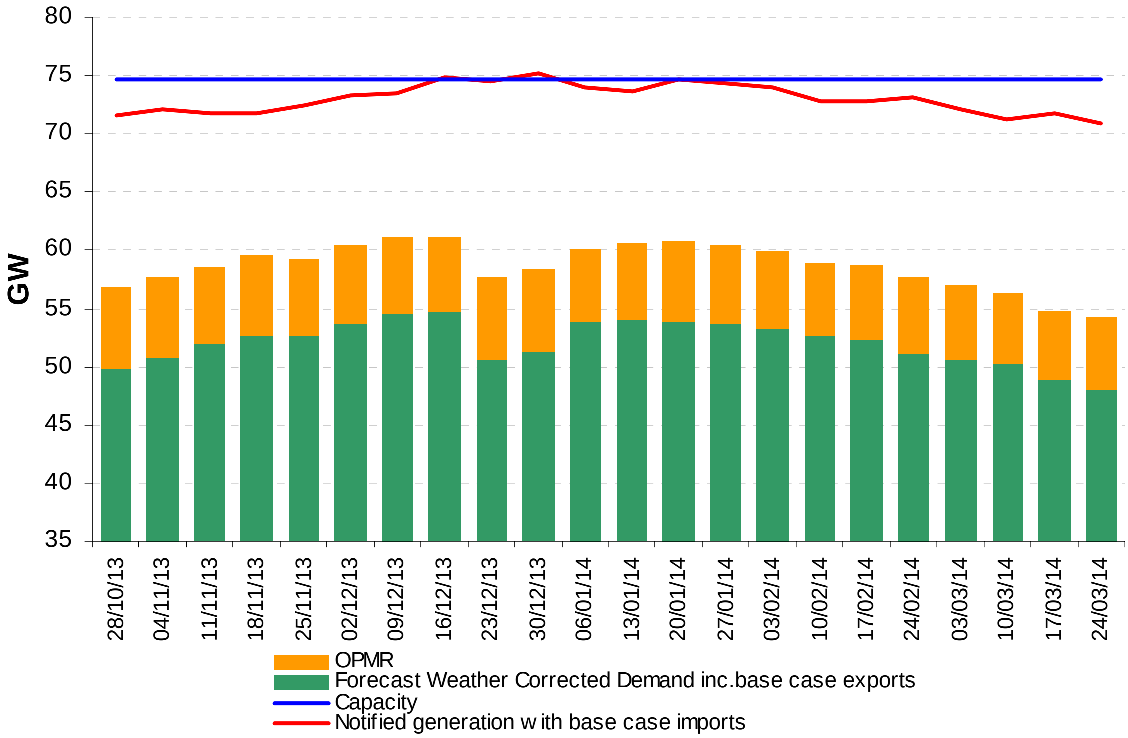
Clean Forecast

172. **Figure E7** shows forecast demand and the notified generation availability for our base case.

- As discussed earlier, demand used is Transmission System Demand which, for our base case, includes 750 MW exports to Ireland
- The generator availability figures include our base case assumption of 750 MW of continental interconnector imports
- As this is based on notified generation the wind generation component assumes maximum wind generation
- The reserve requirement shown is the Operating Planning Margin Requirement[34]
- This chart presents the margins in a very similar way to how information is published on www.bmreports.com; the only exception being that interconnector imports and exports are not included in the forecast on www.bmreports.com
- This year we have also included the forecast generator operational capacity in **Figure E7**. The difference between this line and the generation notified availability shows the volume of generation that has planned outages over the winter. The volume of notified planned outages over the winter peak period is small, with some planned unavailability in the shoulder periods.

[34] Details on OPMR can be found at http://www.nationalgrid.com/uk/Electricity/Data/reserve/bmrs/about.htm

Figure E7 - Forecast Demand and Notified Generation Availability



Central Forecast

173. Our central forecast uses the base case assumption of 750 MW exports to Ireland (included in the demand figures) and a 750 MW import from the continental interconnectors. We assume average conventional generation breakdown losses and we de-rate the wind using Equivalent Firm Capacity. We measure margins against both weather corrected demand and ACS demand.

Reserve Assumptions

174. In our central forecast we only include the reserve requirement for frequency response, which we have to carry to ensure the system is resilient to generation losses which may happen at any time. As mentioned in the Reserve section if all frequency response holding was created on gas and coal-fired units in the BM, then approximately 1.9 GW of reserve would be required to meet the necessary response requirement. However a number of the contracts we have agreed provide frequency response more efficiently than this. After allowing for the effects of these contracts to provide frequency response services - the net frequency response reserve requirement is 1.2 GW.

Generation Availability Assumptions

175. Our generation forecasts are based on the generator notified availabilities which are submitted by the generation companies in accordance with Operational Code 2 of the Grid Code. These notified availabilities include planned generator outages. Generators may suffer breakdowns or losses close to real time. **Table E6** shows the assumed availability after accounting for average losses. The average losses are calculated for each fuel type from the last three winters' data. Note that due to primary energy source limitations, we calculate the loss rate for Wind and Hydro differently:

- For Hydro power stations the assumed availability is based on average output, at winter peak demand, over the last three winters. If there is more rain than the last three years, this availability rate will be pessimistic, with the converse also being true
- For Wind power stations Equivalent Firm Capacity[35] (EFC) is used. This is a measure of how much 100% reliable generation would be required to replace the installed wind generation while maintaining the same level of system security

  This wind modelling approach combines the risk from wind variability with the other conventional risks, e.g.: high demand or low availability of conventional generation. When the installed wind is a small proportion of total generation the main risk to system security comes from the conventional risks and the EFC is very close to the mean load factor for wind generation. In the coming years, as the installed wind capacity grows as a proportion of total generation, the risk that the variability of the wind will affect system security grows, and wind's contribution to system security, and hence the EFC, will decrease.

Table E6 - Assumed Generation Availability for Winter 2013/14

Power Station Type	Assumed Availability
Nuclear	84%
Hydro generation	79%
Wind EFC (base case)	25%
Wind EFC[36] (max interconnector export)	29%
Coal + biomass	85%
Oil	87%
Pumped storage	97%
OCGT	95%
CCGT	86%

[35] Equivalent Firm Capacity is a model output from a Monte Carlo simulation. For further information explaining the theory behind the EFC, see: http://pio.sagepub.com/content/226/1/33
[36] The wind EFC increases slightly because in this scenario, with maximum interconnector exports, system risk is not such an extreme event

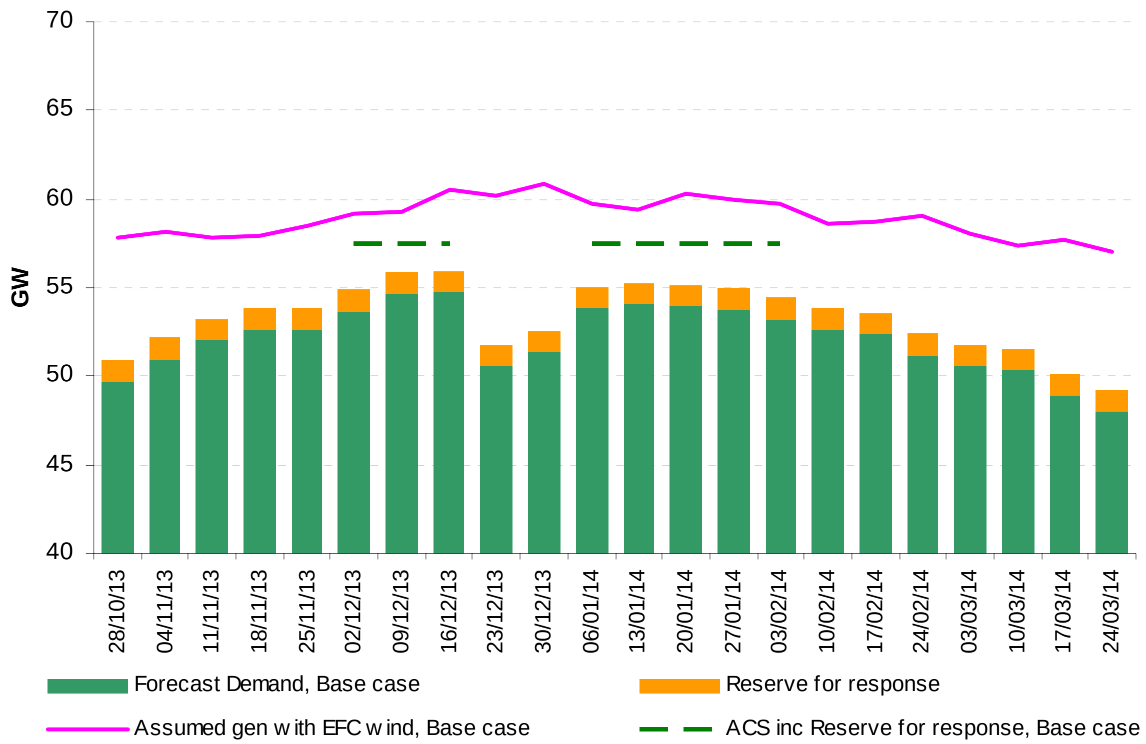
<u>Central Forecast</u>

176. **Figure E8** shows our central margin forecast over the winter using the interconnector, conventional and wind generator assumptions described above against our forecast weather corrected demand and restricted ACS demand forecasts. The base case 750MW interconnector exports to Ireland are included in the demand figures and the 750 MW continental interconnector imports are included in the generation figures.

177. The green and orange bars respectively show the mean forecast peak demand and reserve requirement for each week. The green dotted line shows the (restricted) ACS demand including the 1.2 GW reserve requirement. There is a 50% chance that, because of weather variability, the demand and reserve level will reach ACS at peak during one week in the winter. Historical data shows that ACS has never been observed to occur before the first week in December, after first week in February, or during the Christmas fortnight.

178. The peak forecast demand occurs in the week commencing 16 Dec 2013. In this week our assumed generation availability is 60.5 GW, giving a margin against forecast demand of 8% and with a margin against ACS demand of 5%. This slight reduction from the forecast margin of 6% in the Winter Consultation is due to a number of marginal changes, including a lower demand forecast, Barking 2 coming available, less availability assumed from wind generators, modelling updates and rounding.

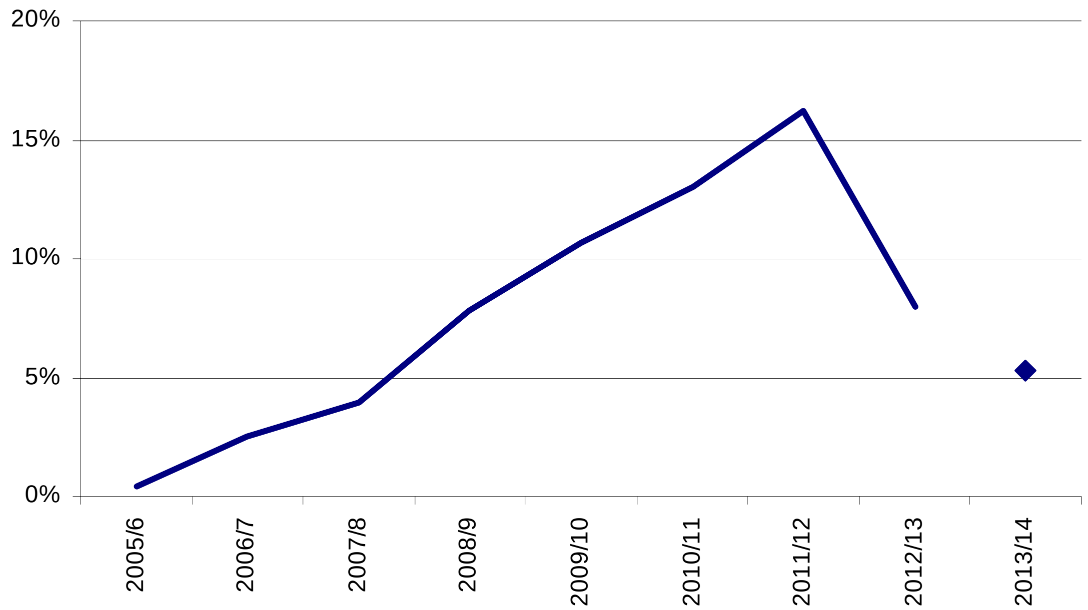
Figure E8 – Central Forecast Margins



Historic Context

179. To give some context to these forecast margins we have included **Figure E9**, which shows what the equivalent central forecast figures would have been since winter 2005/06 using the current generator assumptions applied to historic generator capacities, using the current interconnector assumptions and the current calculation methodology. (**Figure E9** does not show what the actual historic forecast margins were as the current assumptions would have been different to those made historically.) This chart initially shows increasing forecast margins driven by increasing generator capacity and decreasing demand forecasts. The last two years see forecast margins decreasing due to a decrease in generation capacity.

Figure E9 – Equivalent Forecast Margins against ACS Demand using Current Margin Calculation Methodology

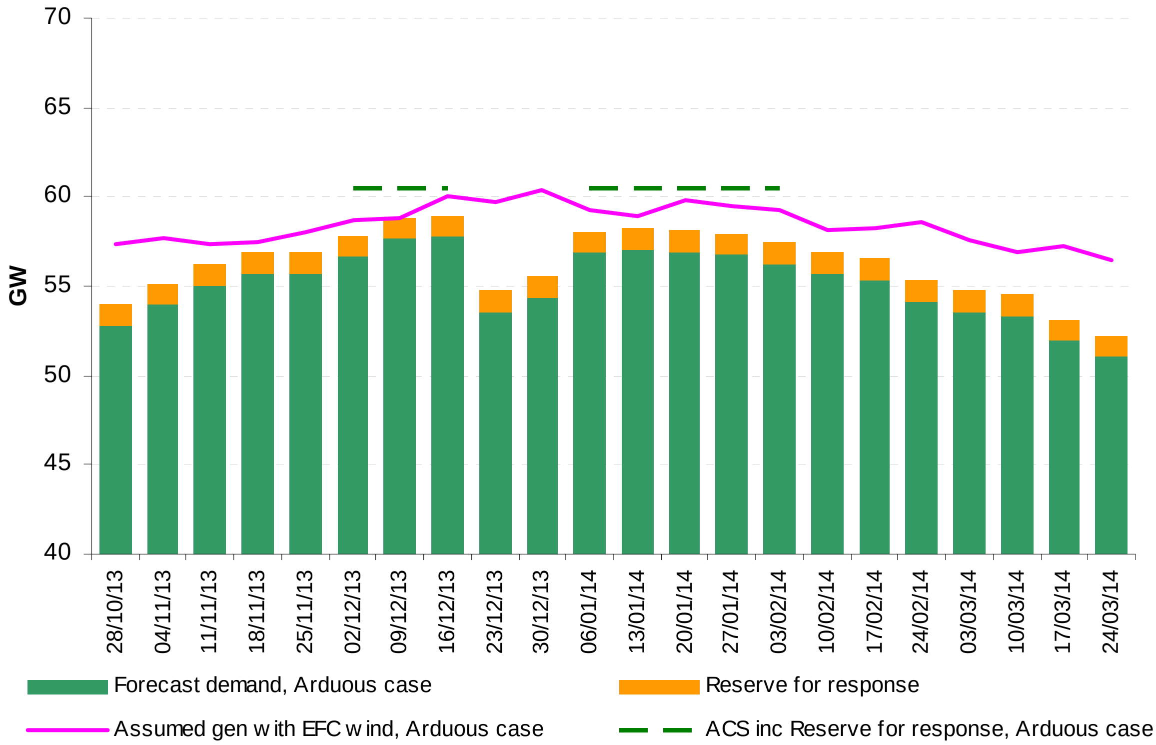


Arduous Forecast

180. In our arduous forecast we use the same assumptions as our central forecast, with the exception that we assume full exports on all interconnectors. This increases the demand by 3 GW from that seen in our central forecast and reduces the generation availability by 750 MW (due to the lost continental interconnector imports). The wind EFC increases slightly because in this scenario, with maximum interconnector exports, system risk is not such an extreme event.

181. **Figure E10** shows the margin forecast in this arduous scenario. There is a 50% chance that the demand and response level will reach the ACS level (the green dotted line) at peak during one week in the winter.

Figure E10 – Arduous Forecast Margins



182. From **Figure E10** if full interconnector exports were to occur with weather corrected demand levels in GB, then margins are forecast to be positive across the winter. If demand were to out turn at the forecast ACS demand during the winter then **Figure E10** shows that margins are likely to be negative, with shortfalls ranging between 400 MW and 1,700 MW. However domestic consumers will not be affected by this level of shortfall as there are a number of mitigating actions that we, as system operator, can take before a loss of load occurs. These include voltage reduction, use of the max gen service and the emergency assistance service from interconnectors.

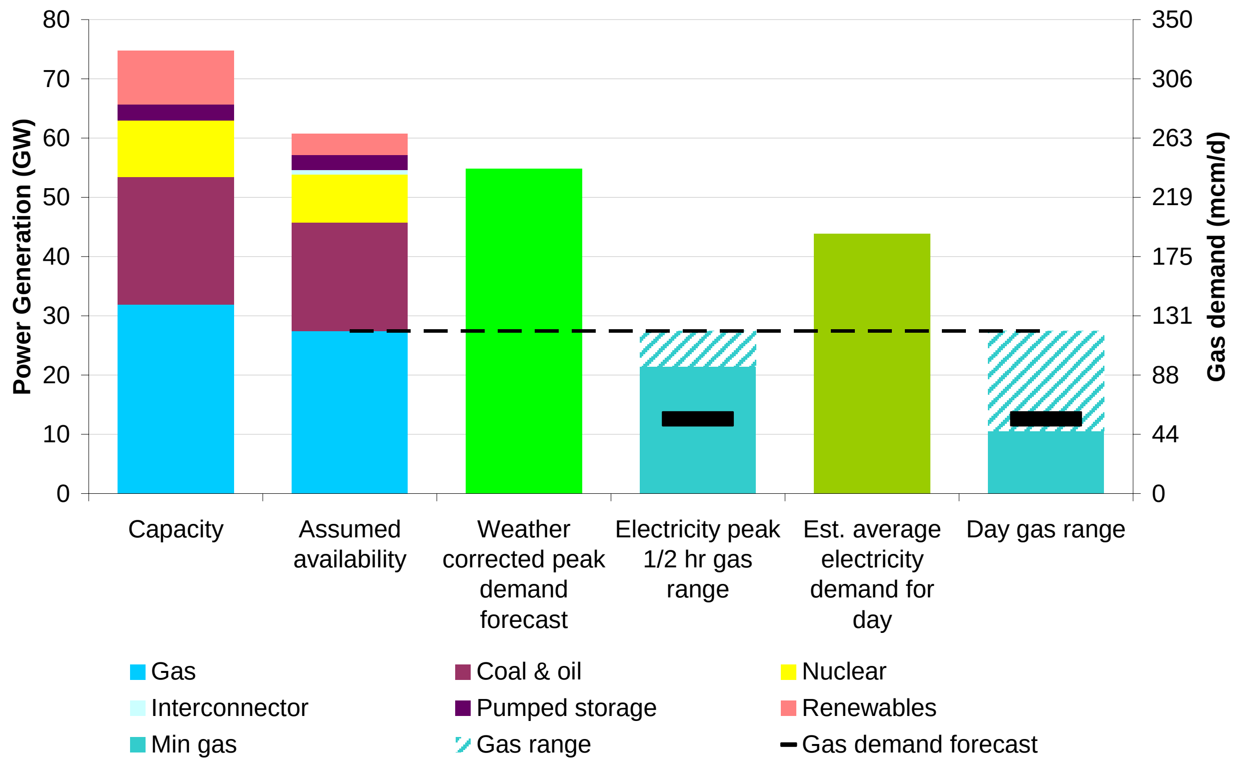
183. We do not have sufficient data to calculate the likelihood of this scenario, as interconnector arrangements have recently changed and because we do not have all the French and Dutch market and weather data. This scenario has been included due to observations of interconnector spreads and flows experienced in February 2012, when France experienced record demands with their temperatures being 10ºC below average. Broadly, the likelihood of this happening in any given year is low.

184. In this event, or in situations approaching this, our reserve levels would not be met. System warnings, such as the Notification of Insufficient System Margin, would be issued ahead of time to inform the market and to encourage an increase in available generation or reduction in demand. It is worth noting that **Figure E10** assumes average generation losses; if generation losses happened to be less than average then margins would improve, with the converse also being true.

185. This section evaluates the interaction between the electricity and gas markets. The first approach looks at gas electricity interaction from an electricity perspective and considers what is the potential minimum and maximum gas demand for gas fired power stations on the peak electricity demand day, both for the peak weather corrected demand forecast for the half hour and for the whole day. This is shown in **Figure GE1**. The second approach looks at gas electricity interaction from a gas perspective, focusing on a cold day and the potential total gas demand resulting from the potential minimum and maximum demand for gas fired power stations. This is shown in **Figure GE2**.

186. **Figure GE1** shows electricity generation capacity, assumed generation availability, peak weather corrected electricity demand and estimated daily average electricity demand, and the resultant gas demand for gas fired power generation for the peak half hour and the day.

Figure GE1 - Power generation capacity, availability, demand and resultant gas demand



187. Working from left to right, the first column shows our current forecast for operational generation capacity anticipated to be available at the winter peak for 2013/14 of 74.7 GW. This figure excludes interconnector capacity.

188. The second column shows the assumed de-rated generation availability within our electricity base case, based on the assumed availabilities shown in **Table E6**, with wind availability set at the base case Equivalent Firm Capacity level of 25%. It also includes our base case assumption of 750MW interconnector imports from the continent. This gives a gas fired generation availability of 27.4 GW, highlighted by the blue area and the dotted black line. If all the gas fired generation plant ran at 100% load factor for the whole day, this would equate to gas demand of 120 mcm/d. This is shown by reading the dotted black line off the right hand vertical axis.

189. The third column shows the weather corrected peak demand forecast for winter 2013/14 of 54.8 GW, which includes our base case assumption of 750 MW interconnector exports to Ireland.

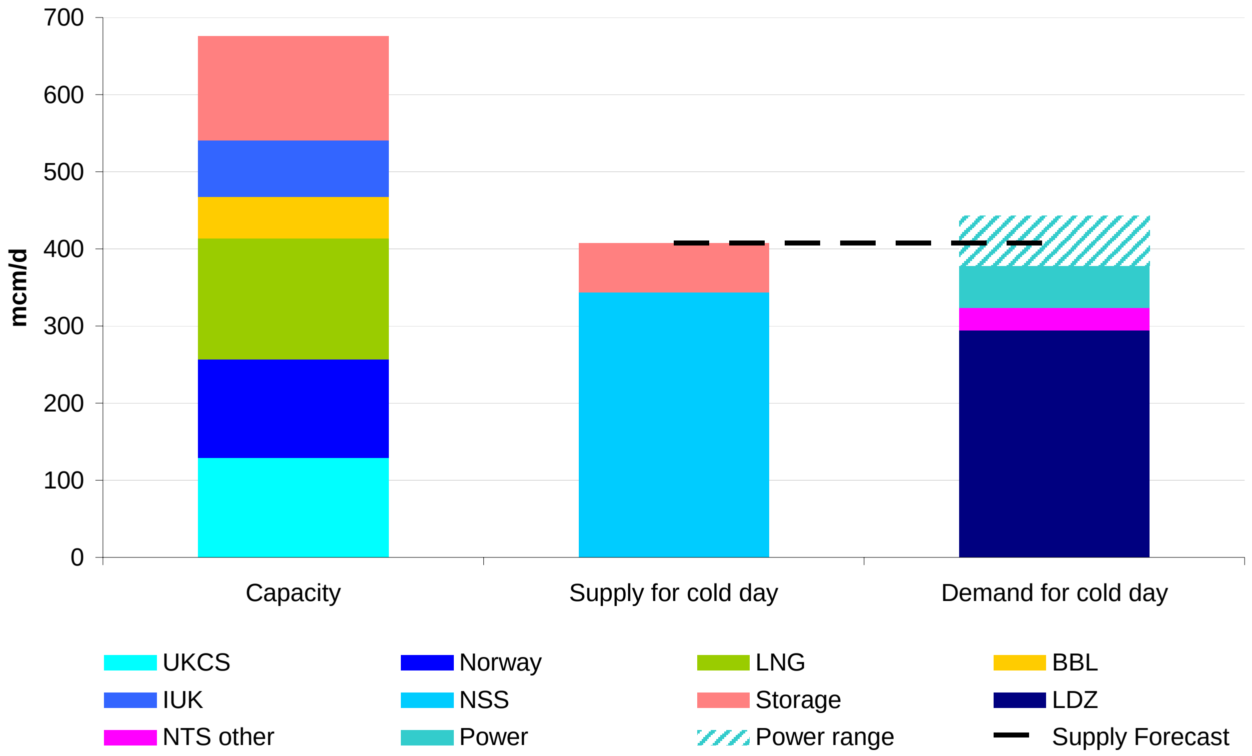
190. The fourth column shows the potential range of power station gas demand for the electricity peak half hour demand shown in the third column. If all other non-gas fired generation performs at maximum assumed availability (as shown in the second column), then the minimum gas fired generation for the half hour is 21.5 GW, as shown by the solid blue area. If gas fired generation operates at maximum assumed generation for the half hour, then the maximum gas fired electricity generation output is 27.4 GW, as shown by the top of the blue striped area. This equates to an instantaneous gas supply range of 94 to 120 mcm/d for the half hour. The black line shows our average power generation gas demand forecast for winter 2013/14, as shown in **Table G3**, which is 55 mcm/d. This equates to gas fired power generation of around 12.6 GW. Clearly for the peak electricity demand half hour there is a significant increase in gas supply required above our average power generation gas demand forecast to meet even the minimum requirement, that is an increase from 55 mcm/d to 94 mcm/d.

191. The fifth column shows the average daily power station gas demand for the day that includes the forecast weather corrected peak demand. This is estimated to be a daily average of 44 GW.

192. The sixth column shows the potential range of gas demand for the day where electricity demand averages 44GW. If all other non-gas fired generation performs at maximum assumed availability, then the minimum gas fired generation for the half hour is 10.5 GW, and the maximum is 27.4 GW, which equate to an instantaneous gas supply range of 46 to120 mcm/d. Again the black line shows our average power generation gas demand forecast for winter 2013/14, which is 55 mcm/d. This equates to gas fired power generation of around 12.6 GW. For the 44 GW average electricity demand for the day our cold day gas power demand forecast of 55 mcm/d is sufficient to meet the minimum requirement of 46 mcm/d, but there is a significant increase in gas supply required over our average power generation demand forecast to meet the maximum requirement of 120mcm/d.

193. The next chart looks at gas and electricity system interaction from a gas perspective. **Figure GE2** shows gas supply capacity, forecast supplies for a cold day and potential gas demand on that day.

Figure GE2 – Supply capacity, cold day supplies and cold day demand



194. The left hand column shows the theoretical maximum supply capacity for the winter at just under 680 mcm/d. This is over 85 mcm/d higher than the figure of 594 mcm/d shown in **Table G10** that represents a potential maximum supply for the coming winter.

195. The middle column shows the level of supply that we believe is likely on a cold day, that is a day approaching 0 degrees CWV. This consists of 344 mcm/d of NSS (as shown in **Table G10**) and approximately 64 mcm/d of storage, giving a total supply of 408 mcm/d.

196. The right hand column shows the forecast level of demand on a cold day, which is roughly 379 mcm/d, with gas fired power station demand at 55 mcm/d (our average power generation gas demand forecast for winter 2013/14, as shown in **Table G3**). Hence gas supplies should comfortably cover the gas fired power generation demand under these circumstances, as shown by the dotted black line being above the bottom of the blue striped area representing gas fired power station demand range. However, as shown previously in **Figure GE1**, a significant increase in gas supply would be required if all gas fired power stations were to operate at maximum for the day, resulting in an increase in gas fired power station demand from 55 mcm/d to a theoretical maximum of 120 mcm/d, leading to total gas demand for the day of 443 mcm/d. However, as previously stated, gas fired generation is currently forecast to be the marginal plant, and for this to change would require a very dramatic shift in the current relative power generation economics of gas and coal fired plant, as shown in **Figure F3**.

Appendix

Appendix 1 - Margin Calculation Methodologies

Margin calculations in the Winter Outlook and those within the 2013 UK Future Energy Scenario (UKFES) publication are slightly different. The table below details the similarities and differences.

Comparison of Margin Calculation Methodologies

	2013 UKFES	2013/14 Winter Outlook
Time Horizon	The UKFES looks from winter ahead to many years in the future	The Winter Outlook 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) and generator stations' Transmission Entry Capacity (TEC). These forecasts are de-rated to account for losses due to planned unavailability and breakdown losses	Based on generator notified availabilities (under OC2 of the Grid Code) which include planned unavailability. These notified availabilities are de-rated to account for average breakdown losses
Wind	Two measures are used: ▪ "1 in 10" low wind ▪ Equivalent Firm Capacity[37] (EFC)	Only EFC is used, noting that this value varies depending on other assumptions
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: ▪ National demand ▪ Irish interconnector exports Excludes: ▪ Continental interconnector exports ▪ Station demand (as this is netted off the generating power station's TEC)	Is Transmission System Demand, which includes: ▪ National Demand ▪ Interconnector exports ▪ Station demand

[37] 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

Appendix

	2013 UKFES	2013/14 Winter Outlook
Types of Demand	▪ Average Cold Spell demand	▪ Weather corrected demand ▪ Average Cold Spell demand ▪ 1 in 20 demand
Reserve	▪ Reserve requirements for the largest single loss of generation	▪ Reserve requirements for the largest single loss of generation
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 for each depending on inputs	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 for each depending on inputs

Roles and Responsibilities

The competitive gas and electricity markets in Great Britain have developed substantially in the last decade and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas and electricity to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; second, as system operator of the transmission networks, for planning and safe real time operation of the networks together with 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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