



nationalgrid

Summer
Outlook
2014

April 2014

Roles and Responsibilities

National Grid owns the high-voltage electricity transmission network in England and Wales and is the System Operator of the high-voltage electricity transmission network – the country's power motorways - for the whole of Great Britain. We are responsible for managing the flows of electricity to homes and businesses on a real time basis.

We don't generate the power - neither do we sell it to consumers. We all pay our bills to energy suppliers, who buy enough electricity to meet their customers' needs from the power stations and other electricity producers.

Once that electricity enters our network, our job is to 'fine tune' the system to make sure supply and demand match second by second.

On the gas side, we are the system owner and operator of the gas transmission network for the whole of Great Britain, responsible for managing the flow of gas to homes and businesses.

Like electricity, we do not own the gas we transport and neither do we sell it to consumers, that again is the responsibility of energy suppliers and shippers.

Together, these networks connect people to the energy they use.



Welcome to our 2014 edition of the Summer Outlook Report, which provides a detailed examination of the supply demand position for the coming summer for both electricity and gas.

This report, which we produce annually, includes our latest views and analysis. We continually seek feedback on the Summer and Winter Outlook Reports to increase their usefulness to you. We have been producing the Summer Outlook Report since 2008, and over the years it has evolved to reflect developments in the energy market, as well as incorporating your ideas and suggestions.

The UK energy market continues to evolve, with ever more interest in the energy supply demand picture over the coming years, and I'm very keen to ensure that the outlook reports provide you with the information and analysis that is of real value to you.

I really hope you will provide us with your thoughts on how we can improve the Outlook Reports. We look forward to hearing your views on the content, structure and/ or how we engage with you.

We produce the outlook reports for your benefit: please help us make them the most effective we can.

A handwritten signature in black ink that reads "C O'Hara".

Cordi O'Hara
Director, UK Market Operation
National Grid

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. 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.

While the make up of gas supplies can vary significantly from one day to the next for summer 2014 we expect similar levels of imports from Norway and supplies from the UK Continental Shelf (UKCS) as seen in recent summers. We expect fewer liquefied natural gas (LNG) cargoes to the UK than in 2013 as Asia continues to dominate the global LNG market, in particular Japan, South Korea and increasing demand in China. Flows from the continent to the UK via interconnectors are expected to be similar to those seen in recent summers.

We forecast a wide range of gas demand for summer 2014 to account for the possibility of colder than normal seasonal conditions, as experienced in 2013. We forecast an average summer daily gas demand of 176 mcm/d. However, we also forecast a minimum demand forecast of 85 mcm/d on a mid summer day and a maximum demand forecast of 350 mcm/d on a cold April day, that is over three times higher.

Potential Disruption to Russian Imports

The analysis within this document does not assume there will be any disruption to the exports of Russian gas. While we don't expect any disruption to Russian gas, we continue to monitor the situation and assess what impact, if any it could have on UK supplies.

Gas Storage

Overall demand for net storage injection over summer 2014 is expected to be much lower than summer 2013, reflecting the different conditions in winter 12/13 and winter 13/14. Demand throughout winter 13/14 has been low and there has been comparatively little use of storage.

Electricity

Electricity Demand

Since 2006 the demand on the transmission system has been dropping consistently. This is partly due to the generation connecting to the lower voltage distribution networks (known as embedded generation) which includes renewables and smaller scale conventional

Executive Summary

sources of generation. There are also reductions in energy usage, due to energy efficiency measures and behavioural change. We believe this is likely to continue.

Our peak weather corrected summer demand for the high summer period of June, July and August is 38.4 GW. This is our demand forecast should the weather be the same as long term average weather conditions. The summer minimum demand, which is expected to occur on a Sunday at around 05:00 to 06:00 in the morning in late July, is forecast to be 19 GW.

Generation Capacity

Our forecast for expected generation capacity at the start of the summer is 76.4GW including interconnectors. The capacity could be less than this if more gas stations are mothballed during the summer.

Electricity Margins

The minimum generating availability over the summer is 43.1 GW. Apart from the unlikely case of very high interconnector exports, margins are forecast to be adequate throughout the summer.

Interconnector Flows

The current price spreads between GB and EU indicate that full imports are expected on the IFA and BritNed interconnectors. During times of high wind in Ireland, particularly overnight, there is the potential for imports to GB.

System Operation during periods of low demand (summer minimum)

As System Operator, managing periods of low electricity demand is just as important as managing the high demands we see in winter. While the low electricity demands in summer can be mainly met by base load generation such as nuclear and combined heat & power (CHP) these generators are not as flexible.

During periods of low demand, we need a number of flexible generators available to us so that we can manage any unforeseen events on the network. Examples being the loss of the largest generator, or a significant loss of demand. We also need to cater for demand forecast errors and wind forecast errors. Having flexible generation such as most large wind farms (now participating in the Balancing Mechanism) available to us means that we can respond quickly to any event and ensure the reliability of the network.

That said, while we need flexible generation available, we may not need it all of the time. Therefore, there may be times when we need to take actions during low demand periods to constrain both conventional (gas and coal) and wind generators to keep the system secure. This is not uncommon during summer months.

Executive Summary

As demand drops over the summer and fewer flexible generators run overnight, it will be necessary to call upon large wind farms to provide these services. We encourage those wind farms and generators that currently do not meet their obligations to provide these services to do so as it will help us manage periods of low demand more efficiently and economically.

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 summer.

Key Statistics

Fuel Prices

Overall, wholesale energy prices have decreased slightly since April 2013. Gas and electricity prices showed some volatility during March 2013 due to the unseasonably cold weather and gas supply issues, but have remained relatively stable since then. Oil prices have shown a slight downward trend over the last 12 months. Gas Prices remained between 60-70p/therm between July 2013 and December 2013 but have since decreased to below 60p/therm.

Forward prices show a slight decrease for oil, there is some winter seasonality for gas and base load power, as well as a marginal increase for coal.

For power generation, current fuel prices strongly favour coal burn over gas for the summer and beyond.

Gas

Demand forecast (maximum) – cold April day	350 mcm/d
Demand forecast (minimum) – mid summer day, limited exports / storage injection	85 mcm/d
Average summer demand – similar to 2013 actual average demand	176 mcm/d
Summer supplies – forecasts assume similar UKCS and Norway with lower LNG	32 bcm

Electricity

Maximum demand level (during high summer)	38.4 GW
Generator capacity	76.4 GW
Lowest assumed generator availability at time of weekly demand maximum, excluding interconnectors (during high summer)	43.1 GW
Forecast minimum positive surplus at time of weekly demand maximum, based on normal demand, assumed generator availability and excluding interconnectors (during high summer)	1.6 GW
Minimum demand level	19.0 GW
Forecast minimum negative surplus at time of weekly demand minimum, based on normal demand and high inflexible generation output	1.7 GW

Stakeholder Engagement

Stakeholder Engagement

We have been producing the Summer Outlook Report since 2008 and the Winter Outlook Report for over a decade. The outlook reports have evolved over the years, as the UK market has developed and as our stakeholders have provided feedback on how to improve the reports. We believe now is the time to start a review of the Summer and Winter Outlook Reports.

We are keen to hear your views:

- How do you use the Summer and Winter Outlooks?
- Are they of value to you?
- What is important to you within the Outlooks?
- How could they be improved?
- How can we improve our engagement with you?
- How should we engage with you to ensure we receive the most relevant information? For example, would you prefer face to face meetings, electronic surveys, webinars, workshops at Operational Forum meetings or written consultations?

We intend to abide by the following process:

- We will not change content until we have a clear understanding of what is of value to our stakeholders and what isn't. We will not make any major changes to content within the 2014 Summer Outlook Report, and 2014/15 Winter Consultation Report and 2014/15 Winter Outlook Report.
- We will consult fully with our stakeholders throughout 2014 before we make any major changes to content for the 2015 Summer Outlook Report, and 2015/16 Winter Consultation Report and 2015/16 Winter Outlook Report.

We want to ensure that the outlook documents provide maximum value to all our stakeholders. We can only do this by incorporating your views on how they can be improved.

Please contact us with your thoughts, views and opinions and/or answers to the questions above at:

commercial.operation@nationalgrid.com

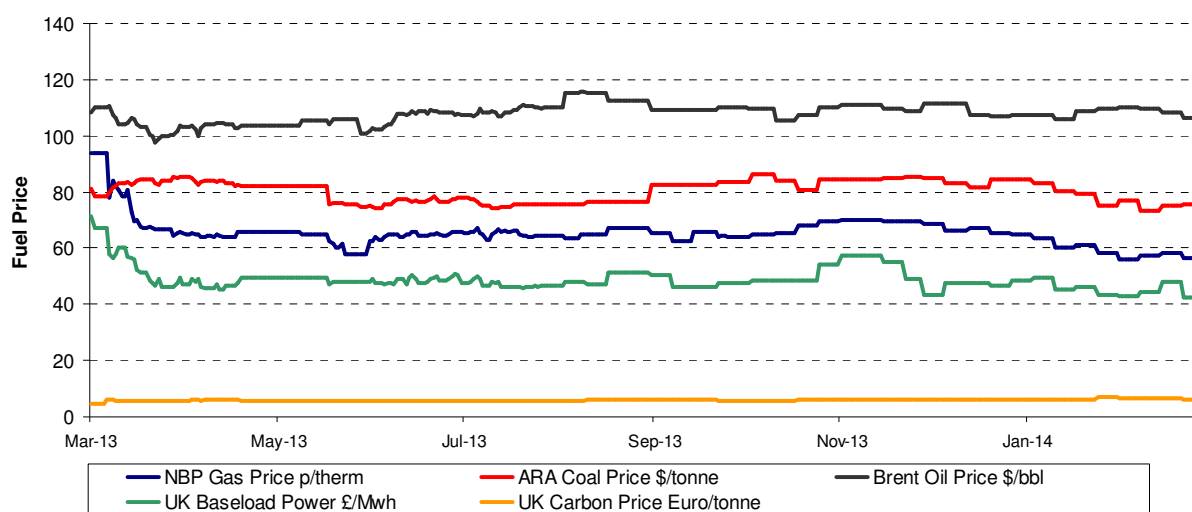
Alternatively, please call Gary Dolphin, Market Outlook Manager on 01926 65 6210

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Fuel Prices

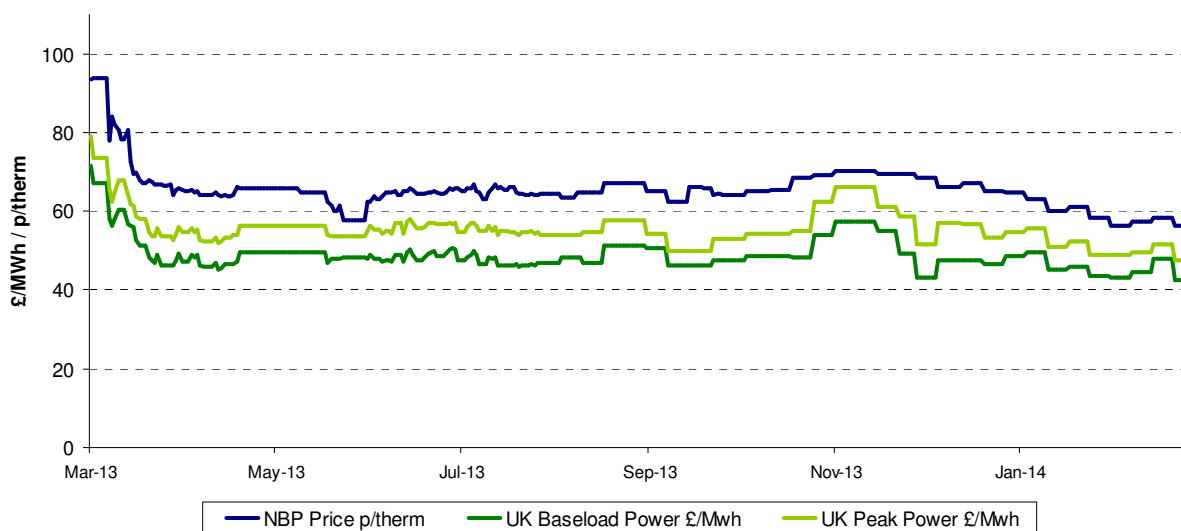
1. **Figure F1** shows the recent history of energy prices for coal, oil, gas, power and carbon.

Figure F1 - Energy Prices: History



2. The chart shows a mixed picture of energy prices over the last 12 months:
 - Oil prices steadily decreased to around \$100/bbl by April 2013, before increasing and have remained relatively stable since September 2013 at around \$106-110/bbl.
 - Coal prices have slowly declined during the last 12 months falling by around \$7/tonne to below \$80/tonne.
 - Gas prices showing a slight premium in winter 2013-14 of around 5p/therm compared to summer 2013 gas prices.
 - Power prices have continued to be closely aligned with UK gas prices over the previous 12 Months, as shown in **Figure F2**.
 - The spot price for the EU Allowances (EUAs) for carbon remained between €5.60 - €6.00/tCO₂ from April 2013 to February 2014. From February 2014 the spot prices have increased to over €6.00/tCO₂.

Figure F2 – UK Gas and Electricity Prices: History



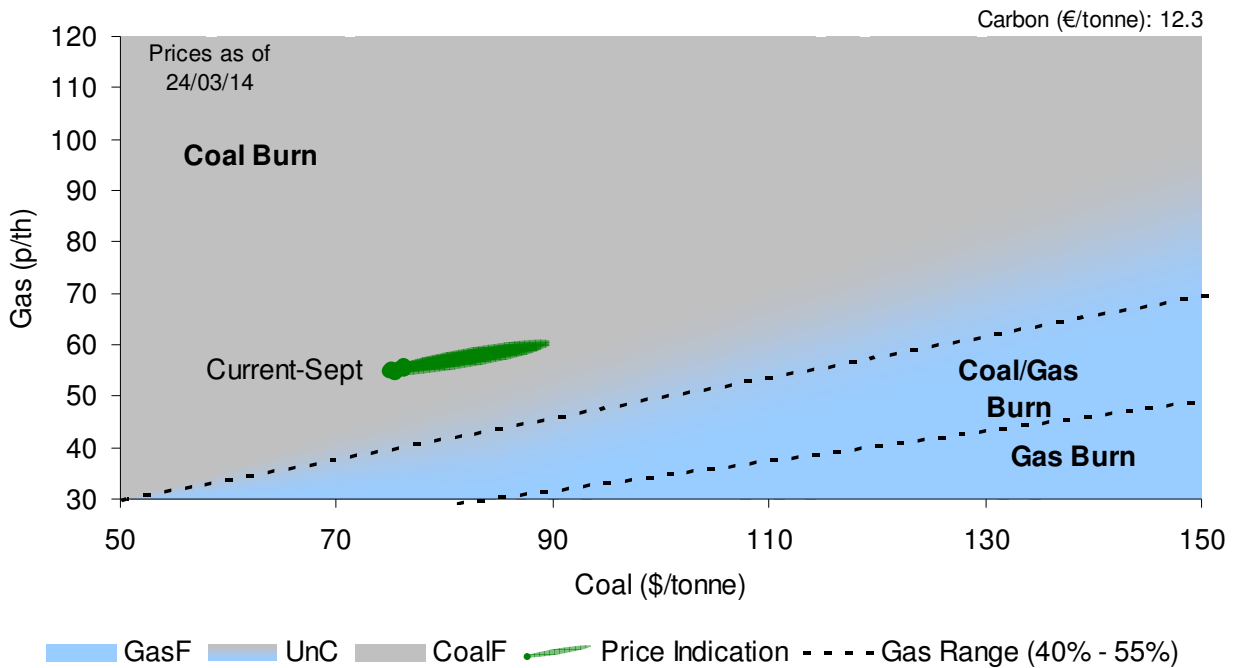
3. In terms of forward prices:

- Oil prices are expected to slowly trend downwards throughout 2014 to below \$105/bbl by the end of the year.
- Coal prices are expected to remain fairly flat during the summer at around \$75-\$80/tonne but increasing slightly for winter 2014.
- Gas prices are expected to remain fairly flat during the summer but increase for Winter 2014/15.
- Power prices are expected to closely following the UK gas prices.
- European Union Emission Trading System (EUETS) carbon prices remain very low and flat.

From 1st April 2013 a carbon price support (CPS) was applied to fossil fuels used for electricity generation via the Climate Change Levy (CCL), this was in addition to the EUETS. The rate for 2013/14 was set in the 2011 Budget at £4.94/tonne CO₂ equivalent. From 1 April 2014, the CPS rates of CCL and fuel duty will be equivalent to £9.55/tonne CO₂.

4. **Figure F3** shows how the prices of coal and gas affect the choice of fuel for power generation. The green markers show forward prices of coal and gas from April to September. Markers in the upper section of the chart, where the gas price is high, indicate that coal will be the favoured fuel. Markers in the bottom right section indicate that gas would be the preferred fuel, whilst for markers between the two dotted lines the choice of fuel will depend on the efficiency of the power station.

Figure F3 - Relative power generation economics



5. The chart shows a very strong bias throughout the summer period for coal to be the favoured source of fuel for power generation over gas despite the introduction of the carbon price support. The chart also highlights that a price reduction of at least 20p/therm for gas or a price increase of about \$50/tonne for coal would be needed to shift the economics to a more balanced position.
6. This simplified approach does not fully address other factors such as individual station efficiencies, generators' portfolios (including fuel stocks and contracts), environmental restrictions under the Large Combustion Plant Directive (LCPD) and plant outages. All of these will affect the amount of gas fired generation in the summer.

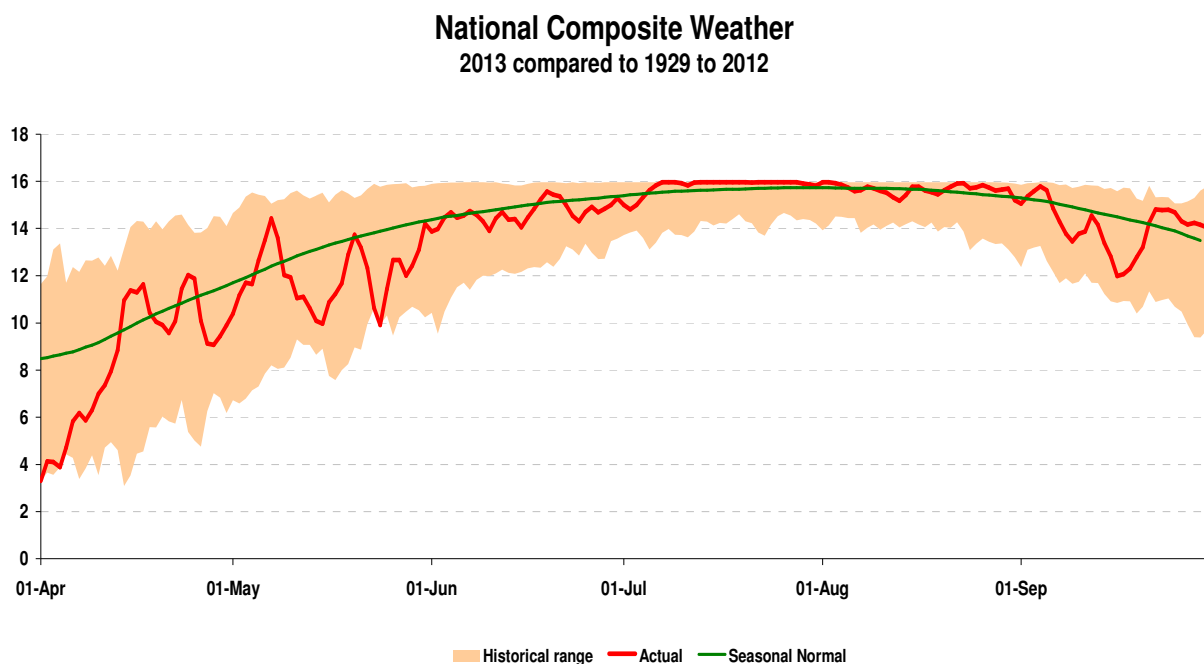
Gas

- This chapter covers the gas supply-demand outlook for the forthcoming summer. Despite storage injection and Continental exports, demands during mid summer are about half those in the winter. Supply availability during the summer is generally high but at times is reduced due to periods of maintenance and this can result in relatively high flow ranges in terms of supply source and entry terminals.

Weather

- The Met Office has ceased the free publication of their long term winter weather forecast. The Met Office web site contains a short description of the weather up to 30 days ahead¹ and guidance for contingency planners up to 3 months ahead².
- Figure G1** shows the historical Composite Weather Variable (CWV, essentially a proxy for temperature), seasonal normal conditions and actual conditions for summer 2012. The CWV is capped at 16°C as there is little or no influence of temperature sensitive gas demand above this. This means that in the warmer months (June, July and August) there is very little variation in CWVs.

Figure G1 - Summer Composite Weather (2013 compared to 1929 – 2012)



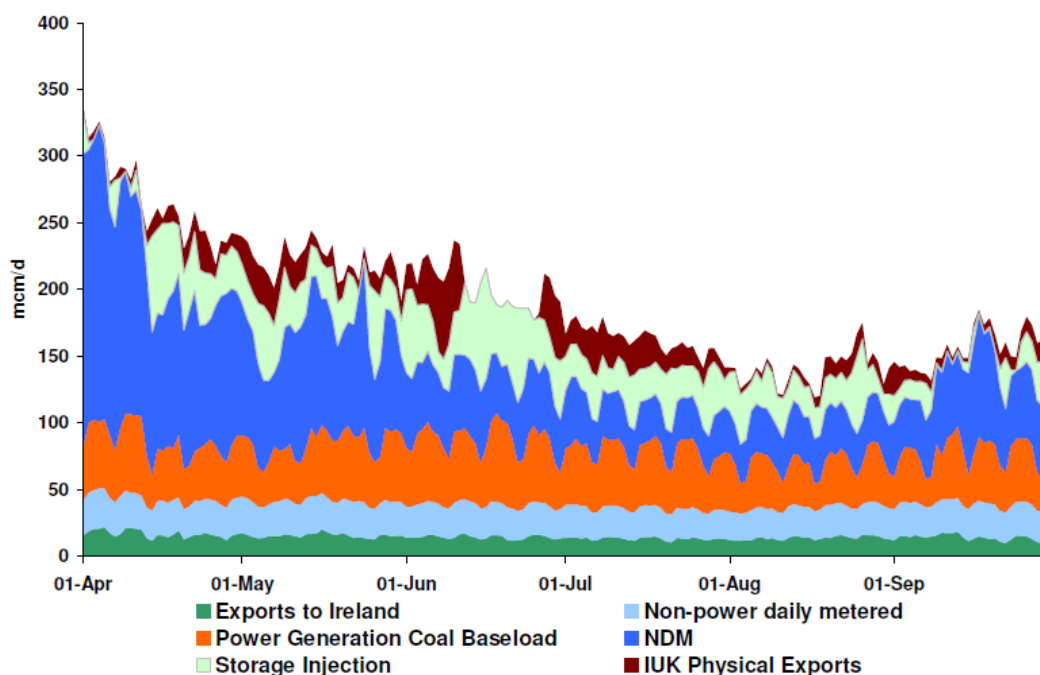
¹ <http://www.metoffice.gov.uk/public/weather/forecast/?tab=map&map=SignificantWeather>
² <http://www.metoffice.gov.uk/publicsector/contingency-planners>

10. **Figure G1** shows that colder conditions are essentially restricted to April, May and, to a lesser extent, September. Hence only in these months are the weather sensitive gas demands (non daily metered i.e. domestic) noticeably influenced by the weather.
11. For summer 2013, April and May were colder than seasonal normal conditions with seasonal normal conditions returning in June. The cooler conditions resulted in a delayed switch off for weather sensitive heating demand.

Demand Forecast

12. **Figure G2** shows the actual demands in summer 2013. Interesting features are:
 - Exports to Ireland, DM demand and power station demand were all relatively stable across the summer.
 - NDM demand remained very high until mid April due to a prolonged winter and demands tracked seasonal conditions from May with a pick up in September.
 - Storage injection was limited through April and increased as NDM demand fell throughout the summer period.
 - The lowest demand was experienced in early August as a warm spell kept NDM demand levels down.

Figure G2 - Actual Summer Gas Demand 2013



- 13. **Figure G3** and **Table G1** show the forecast for summer 2014. Power loads are based on coal remaining the lower cost fuel for generation.

Figure G3 - Forecast Gas Demand Summer 2014

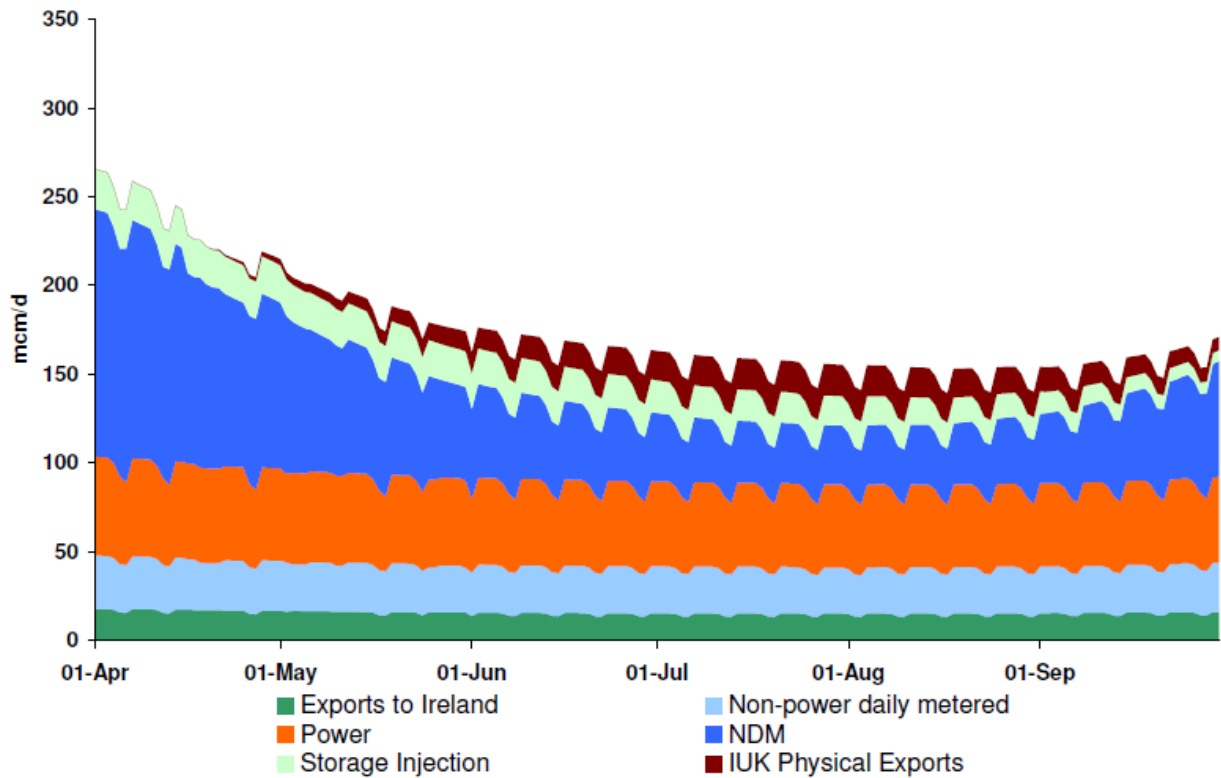
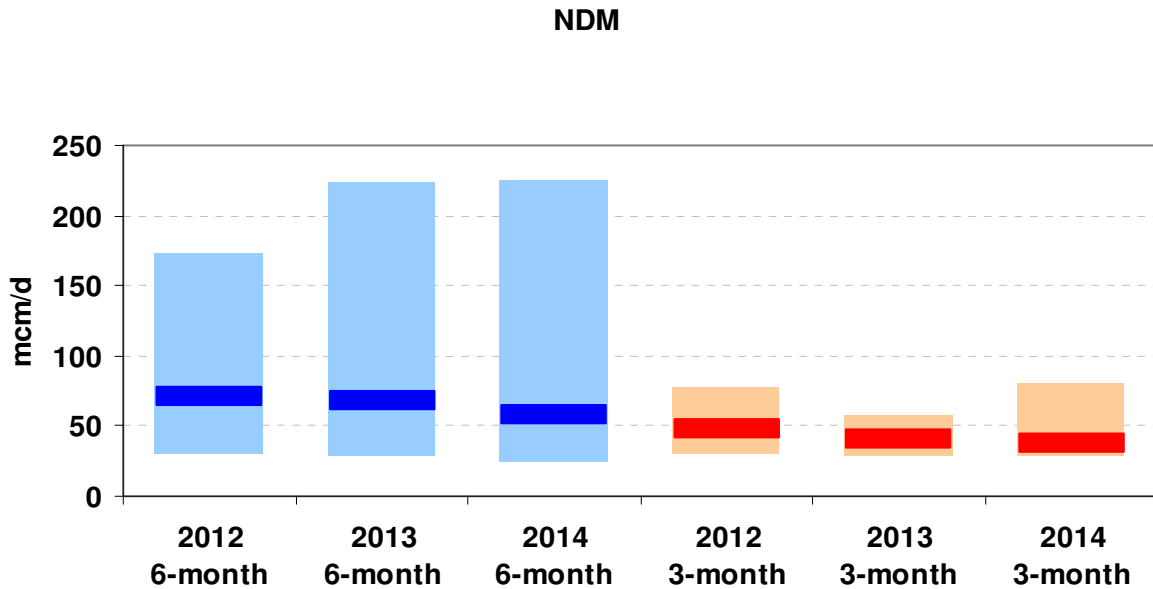


Table G1 - Forecast Average Daily Gas Demand for Summer 2014 (mcm/d)

April to September mcm/d	Daily average 2013			Actual range		Forecast range	
	2013 actual	2013 weather corrected	2014 forecast	2013 low	2013 high	2014 low	2014 high
NDM	67	60	57	28	222	25	225
DM + Industrial	24	23	26	20	30	20	35
Exports to Ireland	15	14	15	10	22	10	25
Total Power	42	42	47	21	67	20	100
Total Demand	150	142	148	86	326	85	350
IUK export	14	14	11	0	58	0	60
Storage Injection	29	29	17	0	83	0	85
GB Total	191	156	176	93	348	85	350

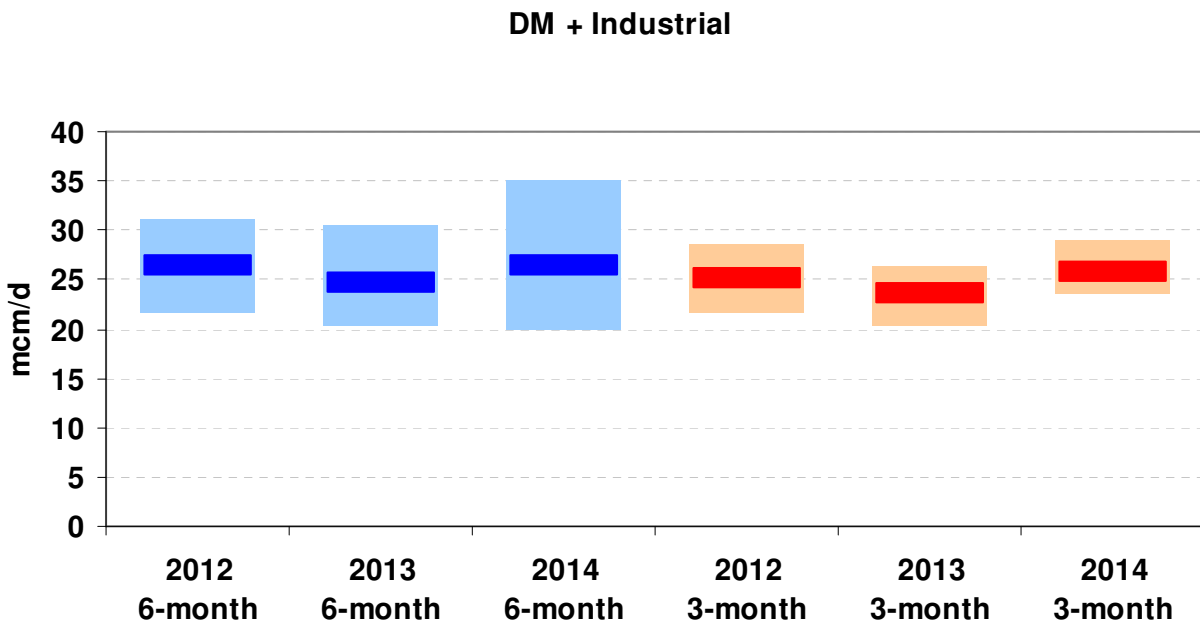
14. **Table G1** shows the daily average and forecast range in demand compared with the actual values in 2013. The 2014 forecast average values are derived using seasonal normal conditions.
15. For NDM daily demand we have used the previous 30 year weather history to identify the possible range of demand for 2014.
16. It is evident that the 2013 summer period was colder than seasonal normal summer periods resulting in a higher than average summer NDM demand. However, Great Britain has experienced a wider range of demand variations in the past. Accordingly, the forecast range for 2014 remains wide to account for the possibility of conditions experienced in 2013 (**Figure G4**).
17. **Figure G4** to **Figure G7** show the summer demands for NDM, DM and Industrial, exports to Ireland and power generation for the last two years and the forecast for 2014. Each chart shows a line to represent the average and a shaded area to show the range in daily demand. The blue bars show the figures for the 6 months from April to September and the brown bars show the figures for the 3 warmest months from June to August.

Figure G4 – Forecast NDM Gas Demand



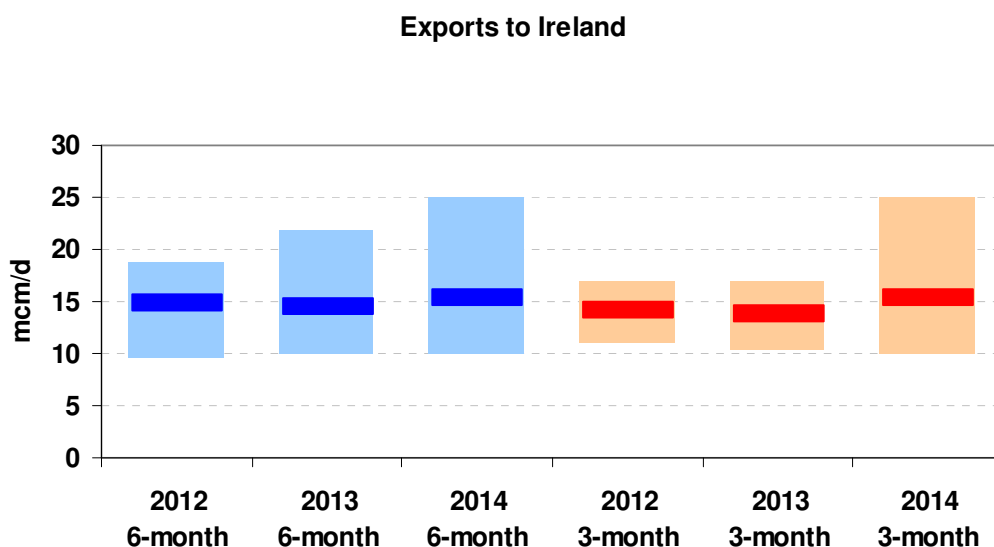
18. **Figure G4** shows the impact of colder weather on NDM demand in the shoulder months compared to the warmest months of the summer. Historic weather shows that Great Britain may experience high NDM gas demands particularly in April, however; demand in July can fall significantly towards the lower end of the range.

Figure G5 – Forecast DM and Industrial Gas Demand



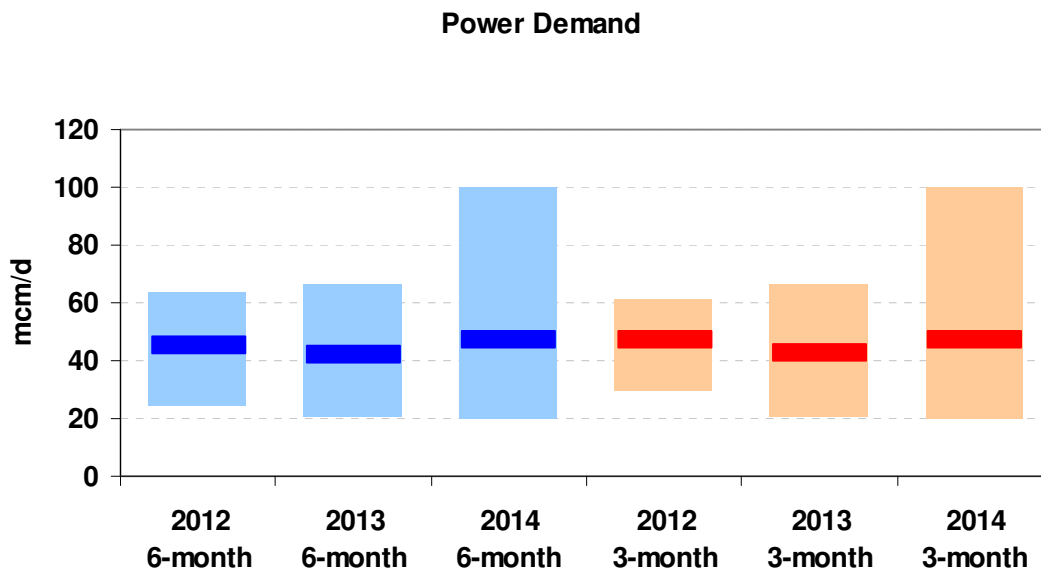
19. **Figure G5** shows relatively tight ranges highlighting limited weather sensitivity for DM and Industrial demand.

Figure G6 – Forecast Exports to Ireland Gas Demand



20. **Figure G6** shows exports to Ireland for 2014 remaining consistent with 2012 and 2013 demand levels. The wide range for the 2014 forecast is related to the high level of gas demand used in power generation across the Republic of Ireland, Isle of Man and Northern Ireland relative to other demands. Similar to Great Britain, gas generation in Ireland operates as marginal plant and may experience variations in demand associated with the outputs from non-dispatchable plant.

Figure G7 – Forecast Power Generation Gas Demand



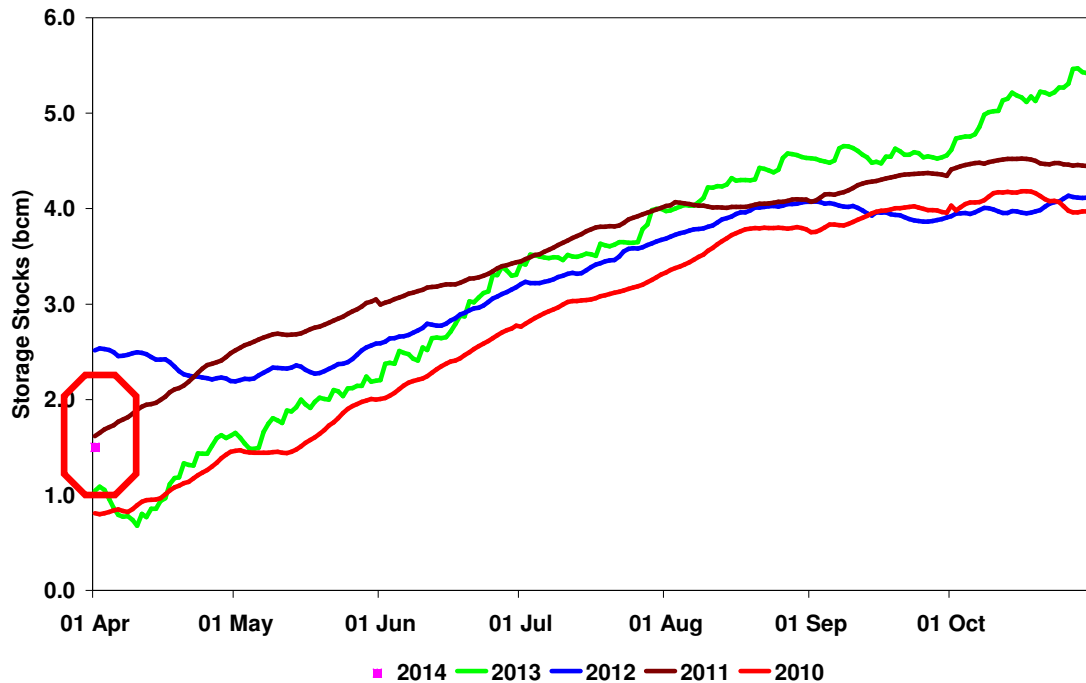
21. **Figure G7** shows the possibility of a considerable range in terms of the power generation demand forecasts for 2014. If power generation gas demand reverts to base load or on days with limited renewable power supply, then demand may tend towards a higher level. We note that should current gas and coal prices be maintained into the summer it will be more economical to generate using coal resulting in lower demands similar to those experienced in 2012 and 2013. The average use of gas is anticipated to be higher than in 2013 due to closure of coal plant.
22. There were closures of coal and oil units at Cockenzie, Didcot, Fawley, Uskmouth (one unit) and Tilbury along with Teesside (gas CCGT) during 2013. The remainder of the units are scheduled for closure at Uskmouth in the Spring of 2014.

Table G2 - Total Volume of Summer Demand for 2013 and Forecast for 2014 (bcm)

Bcm	Summer total		
	2013 actual	2013 weather corrected	2014 forecast
NDM	12.3	11.0	10.5
DM + Industrial	4.5	4.4	4.8
Exports to Ireland	2.7	2.6	2.8
Total Power	7.7	7.7	8.7
GB Total	27.4	25.9	27.1
IUK Export	2.6	2.6	2.0
Storage Injection	5.3	5.3	3.1
Total	35.0	33.5	32.3

23. **Table G2** shows a forecast of the total volume of summer gas demand in 2014 that are similar to the 2013 levels. This is driven by lower assumptions of NDM demand offset by a higher power generation demand that is expected to compensate for plant closures during 2013.
24. Overall demand for net storage injection over summer 2014 is expected to be much lower than summer 2013, reflecting the different conditions in winter 12/13 and winter 13/14. Stock levels in early April 2013 reached a very low level following an extended cold spell. In contrast, demand throughout winter 13/14 has been low and there has been comparatively little use of storage. The commissioning of the Hill Top Farm and Stublach sites may increase storage injection demand further.
25. **Figure G8** shows the refill of storage during the last 4 summers and the storage level as of the start of April 2014. The stock level at the start of April 2013 was approximately 2bcm.

Figure G8 - Summer Storage Stocks 2010 – 2013

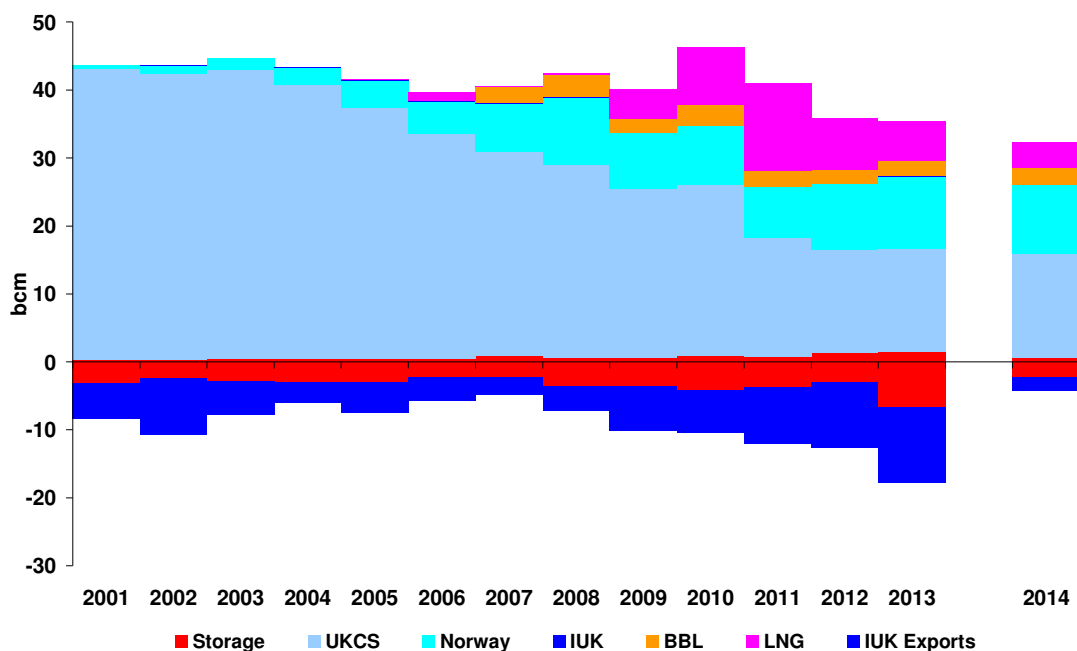


26. IUK exports were 2.1 bcm in summer 2013, the lowest in the previous decade; this was despite significant demand for storage injection on the Continent. For summer 2014 IUK exports are forecast to be slightly lower than 2013 at around 2 bcm, due in part to lower demand for storage refill in Continental Europe and fewer LNG cargoes to the UK. While IUK is anticipated to be a net exporter over summer 2014 the prospect of imports at times should not be discounted.

Supply Forecast

27. **Figure G9** shows the make up of summer supplies by supply source since 2001 and also the forecast for 2014. The forecast for 2014 is based primarily on recent trends of summer supply.

Figure G9 - Historic and Forecast Summer Gas Supplies by Source



28. **Figure G9** shows:

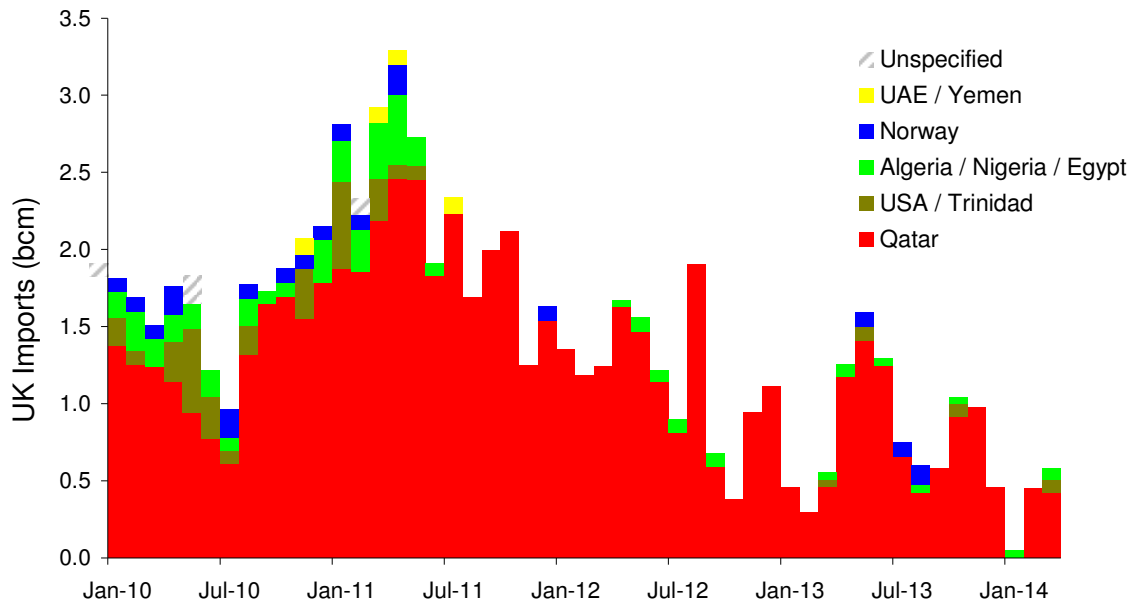
- Slightly lower levels of summer supply / demand of about 32bcm for summer 2014 compared to last year on a weather corrected basis
- Similar imports from Norway and supplies from the UKCS, with slightly less LNG

29. Some new LNG production started from Algeria and Angola in 2013. In 2014, new LNG production is expected in Algeria, Papua New Guinea and Australia. Although the start up of the Angola project may provide some relief to the European markets, it is thought that Asia remains the most likely destination for delivery of Angolan LNG.

30. Global LNG demand is expected to continue to increase in 2014. Asia will continue to dominate the LNG market with Japan and South Korea accounting for over half of all worldwide LNG demands. Chinese LNG demand in 2014 is expected to increase by over 15%.

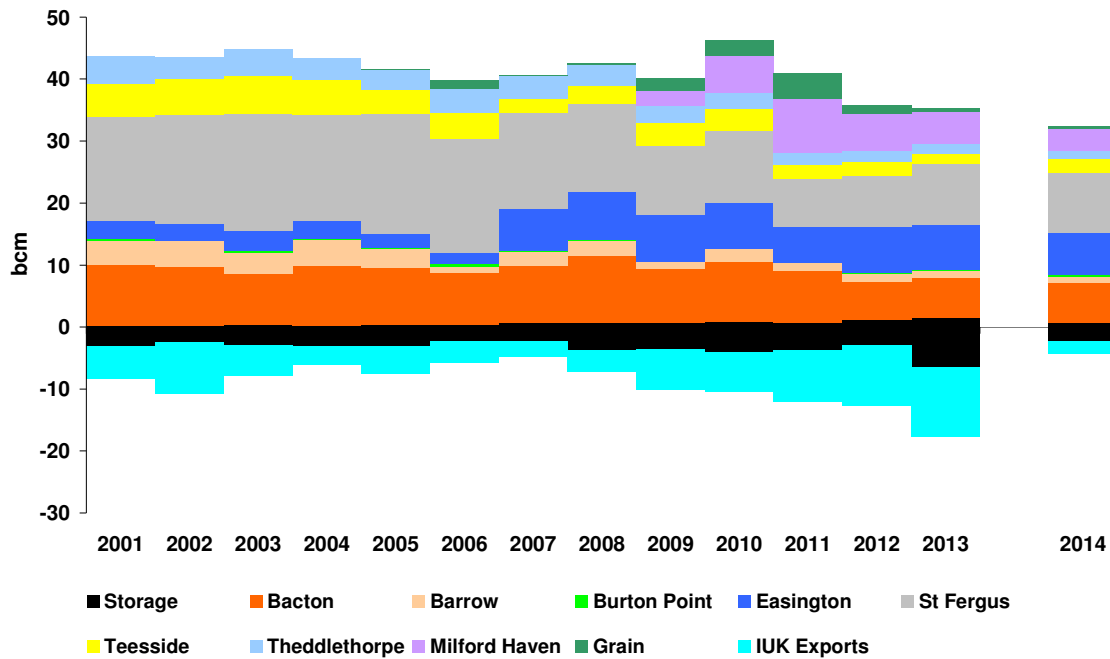
31. For summer 2014 we anticipate potentially more Asian LNG demand with no material change to nuclear power plant re-opening in Japan, hence LNG flows to the UK and Europe may continue to be low. European LNG demands are expected to decrease in 2014. Spain is expected to continue to be the largest European importer of LNG.

Figure G10 – LNG Supplies to the UK 2010 - 2014



32. **Figure G10** shows the source of UK LNG supplies since January 2010.
- Although new Angolan LNG could be sent to the UK, Qatar is likely to remain the largest supplier over the summer period.
 - Volumes of LNG delivered to the UK in 2013 were ~60% lower than in 2011.
 - For summer 2014, we expect UK LNG imports to continue to be low as a consequence of low system demands and low system prices expected in the UK this summer.
33. **Figure G11** shows the make up of summer supplies by terminal since 2001 and also the forecast for 2014. The chart shows:
- A decline at most terminals over the last ten years, apart from Easington where summer flows have remained reasonably constant since the commissioning of Langeled in late 2006.
 - Variable levels of entry at Grain and Milford Haven. As indicated above, there is considerable uncertainty here.

Figure G11 - Historic and Forecast Summer Gas Supplies by Terminal



34. **Table G3** shows entry flows by supply source for the past four summers and the forecast for summer 2014.

Table G3 - Historic and Forecast Summer Gas Supplies by Source

(bcm)	UKCS	Norway	LNG	Continent	Storage	Total
2010	25	9	8	3	1	46
2011	18	7	13	2	1	41
2012	15	10	8	2	1	36
2013	15	11	6	2	2	35
Average	18	9	9	2	1	40
2014	15	10	4	2	1	32

35. **Table G4** shows the same data broken down by entry terminal.

Table G4 - Historic and Forecast Summer Gas Supplies by Terminal

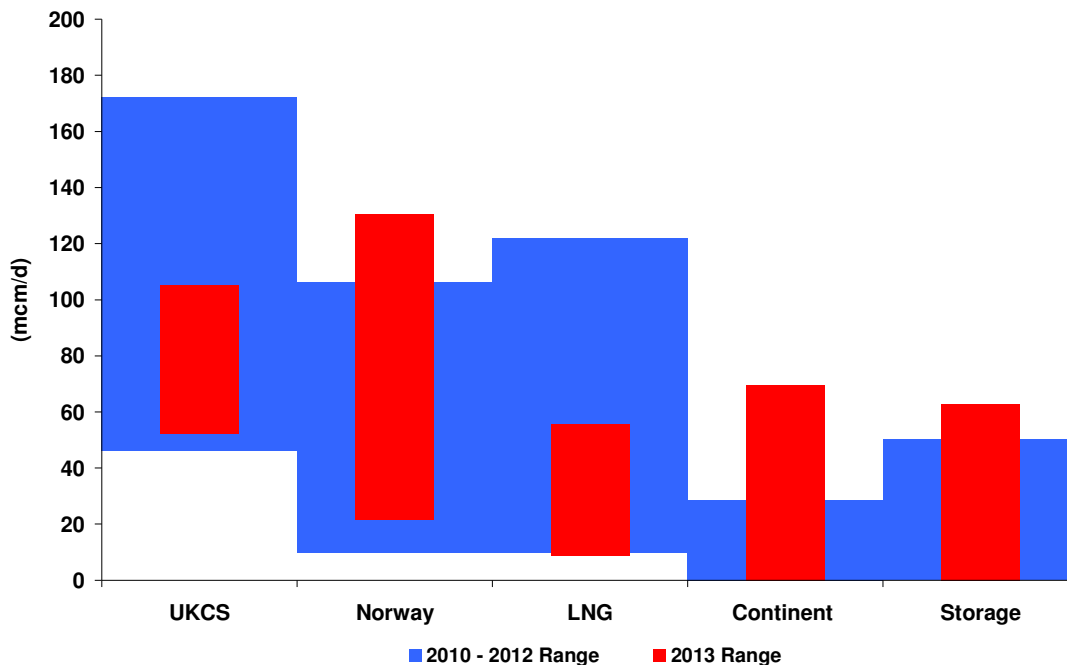
(bcm)	Bac	Bar	BuP	Eas	IOG	M H	St F	Tee	The	Storage	Total
2010	10	2	0	7	2	6	12	4	3	1	46
2011	8	1	0	6	4	9	8	2	2	1	41
2012	6	1	0	7	1	6	8	2	2	1	36
2013	7	1	0	7	1	5	10	2	2	1	35
Average	8	1	0	7	2	7	9	2	2	1	40
2014	6	1	0	7	0	3	10	2	1	1	32

Key:

Bac	Bacton
Bar	Barrow
BuP	Burton Point
Eas	Easington
IOG	Isle Of Grain
MH	Milford Haven (Dragon and South Hook combined)
St F	St Fergus
Tee	Teesside
The	Theddlethorpe

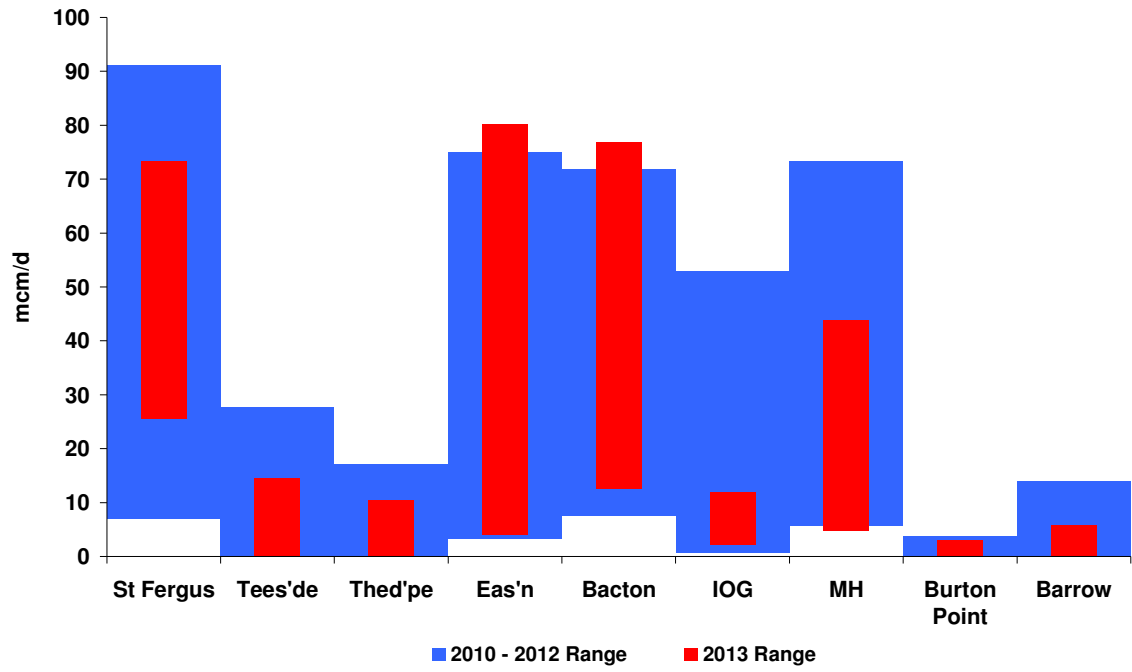
36. **Figure G12** shows the summer supply ranges by supply source from 2010 to 2012 with the ranges for 2013 shown separately. The chart shows for 2013 a lower and tighter range for UKCS and LNG. Norwegian flows in 2013 encompassed a similar range to the recent past, though both maximum and minimum values were higher, and the total Norwegian supply, as shown in **Table G3** was higher than in any of the preceding three years. The range of flows of continental gas far exceeded those of recent years, but this is slightly misleading as the maximum value was recorded on the first day of April, in a period of unseasonal cold weather. Excluding the first week of April gives a range with a maximum value of 43 mcm/d, still higher than recent years, but by no means as extreme. Total Continental supply through the summer was not significantly higher than recent years. For 2014, the range of continental flows is expected to be more in line with the recent historical average. The total supply from LNG is expected to be lower than 2013, but the maximum range will be driven by operational requirements, such as the need to reduce volume in tanks before the arrival of a new shipment rather than by demand for gas. Supplies for UKCS and Norway are expected to be similar to last year.

Figure G12 - Summer Supply Range by Source



37. **Figure G13** shows similar ranges by entry terminal. For 2013, it shows a lower and tighter range for many terminals. The maximum flow at Bacton was slightly higher than the recent past, due to the high Continental flows in early April as discussed in the previous paragraph. Similarly, the maximum flow at Easington reflects high Norwegian flows through Langeled in early April. For summer 2014 Easington and Bacton might be expected to experience flows more typical of recent years. Isle of Grain and Milford Haven will be driven by operational requirements rather than gas demand as described above. Flows at the remaining terminal are expected to be similar to last year.

Figure G13 - Summer Supply Range by Terminal



Summer 2014 NTS Maintenance Programme & Network Expansion

38. To ensure a high level of safety and reliability in operation, it is essential that a system of inspection and maintenance exists for assets associated with the transmission of natural gas. Effective maintenance is essential to minimise the safety and environmental risks caused by failure of pipelines and plant.
39. In accordance with National Grid's Gas Transporter Safety Case, maintenance activities shall comply at all times with any statutory or legislative requirements, in order to meet legal obligations. These practices are robustly designed and seek to minimise overall operating cost by increasing the useful life of pipelines and plant, reducing the risk of failure and reducing the risk of emergency repairs.
40. There was no major capacity expansion for 2013/14 on the NTS, however projects to upgrade the gas quality monitoring and communications on the network have continued and shall continue through 2014/15.
41. Following last years in line inspection results the pipeline feature inspection programme continues to investigate any results which are deemed to require a visual inspection in line with National Grid pipeline integrity policies.
42. The planned programme of in line inspection operations continues for 2014, however the number of inspections per year has returned to normal levels.
43. National Grid's maintenance plan includes the impact of network reinforcement, annual maintenance programme and supply outages. Published documents can be found on the National Grid website at: <http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/maintenance/>
44. The documents detail Aggregated System Entry Points (ASEP) capabilities for each month, based on Seasonal Normal Demand conditions for the period where scheduled maintenance has most impact on capability. The figure has been generated by National Grid and assumes the particular ASEP is favoured at the expense of other terminals. Where no volume has been given, this indicates that the maintenance scheduled has no adverse effects on the ASEP capability.

Electricity

45. This chapter covers the electricity supply-demand outlook for the forthcoming summer. Demands during the summer are around two thirds of winter demands. There also tends to be a high level of generation unavailability during the summer months due to maintenance and lower prices.

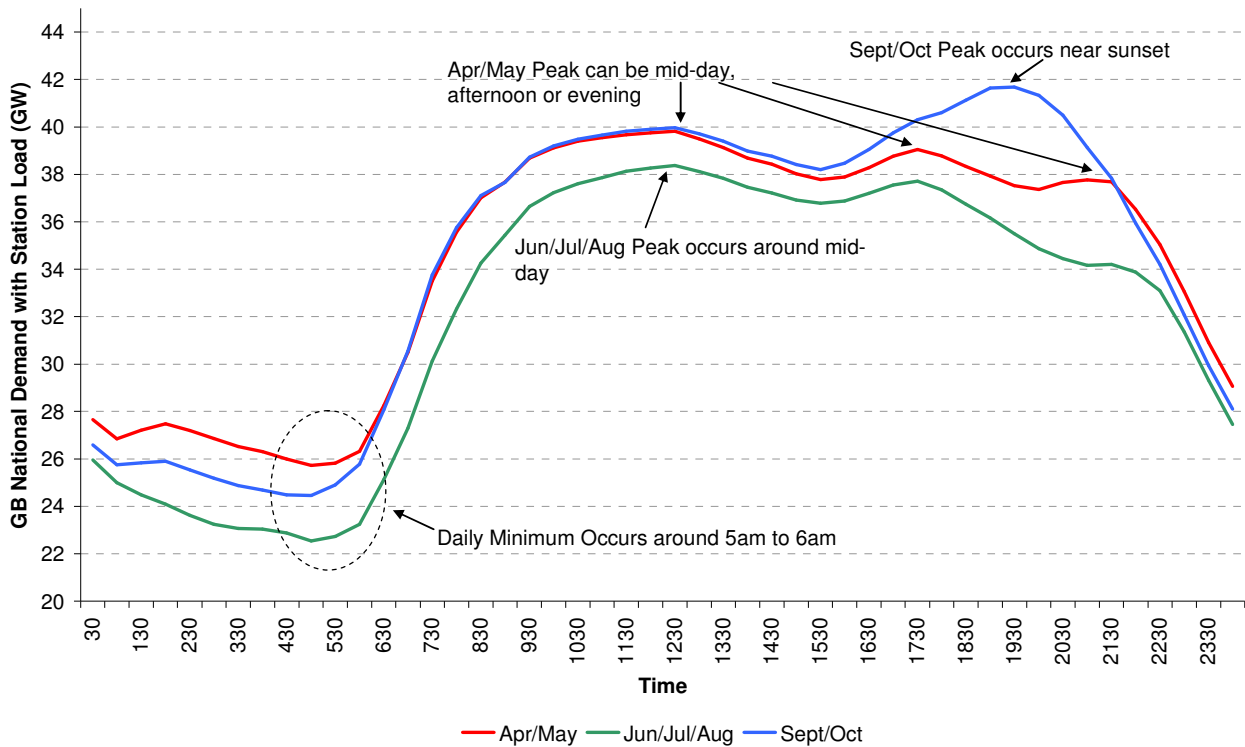
Demand Levels

46. Unless otherwise stated, demand discussed in this report excludes any flows to or from France, Netherlands and Ireland.

Summer Electricity Demand Profiles

47. **Figure E1** depicts the average daily demand profile of summer months. The figure shows that the daily peak figure that is used throughout the rest of the report does not necessarily occur at the same time of the day throughout the summer.
- During April and May demand is reasonably flat across the working day, but there is a higher chance the demand will peak in the late afternoon, dependent upon weather conditions
 - In the high summer (June, July and August) demand is also reasonably flat across the working day (08:00 - 18:00) with a strong tendency to peak at mid-day
 - During September and October the daily peak occurs in the evening due to the earlier lighting effect
 - The daily minimum occurs around 05:00 - 06:00 throughout the summer

Figure E1 - Half hourly Demand Profiles



Summer Electricity Demand Levels during High Summer (Jun to Aug)

48. The forecast demand level for BST 2014 is approximately 500 MW lower than for 2013. This is due to general decline in the underlying demand level. This is demonstrated by **Figure E2** and **Figure E3** which show weather and seasonally corrected peak demand and energy since 2005. GDP is also shown for reference. The forecast will continue to be updated as part of our normal process and will be published on www.bmreports.com³.

³ <http://www.bmreports.com/bsp/BMRSSystemData.php?pT=WEEKFC>

Figure E2 - Monthly Peak Demand and GDP: Weather and Seasonally Corrected (2005 to Present)

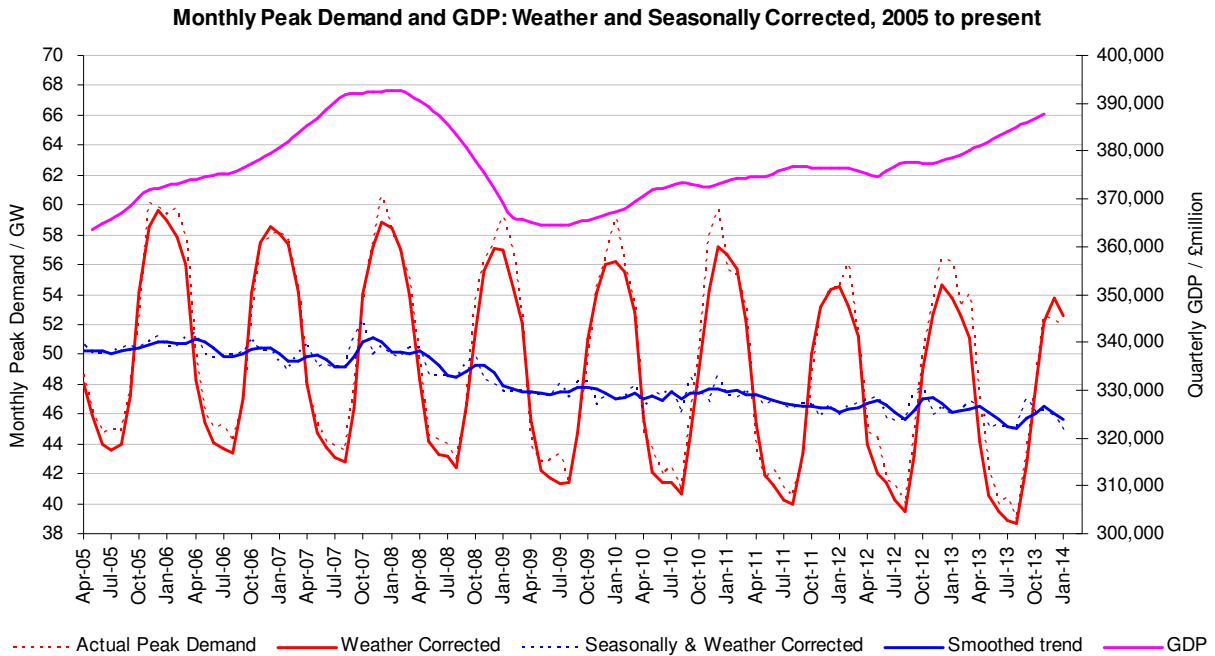
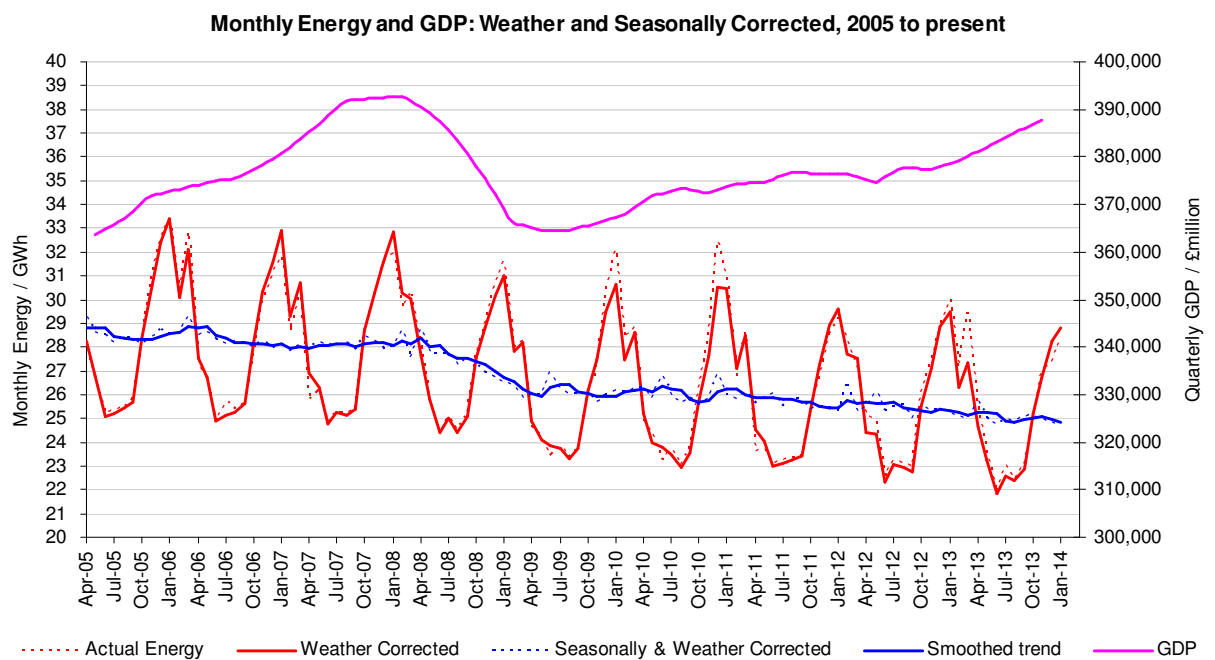


Figure E3 - Monthly Energy and GDP: Weather and Seasonally Corrected (2005 to Present)

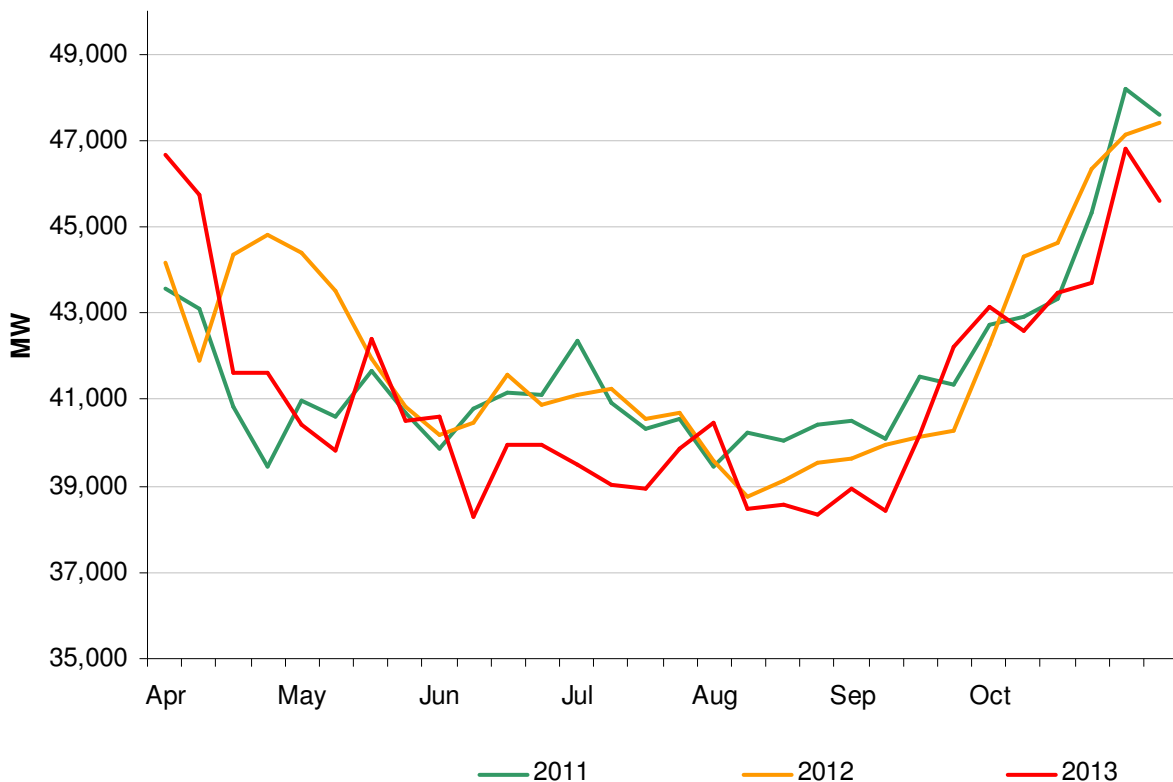


49. Over the period both demand and power supply have fallen steadily. The charts show there is no direct correlation between GDP and demand or power supply. Demand has been dropping consistently since 2006; a long time prior to the 2008 recession. The credit crunch event did have an impact on demand and there is a clear step change in demand levels in Q4 2008. However, after this one-off event demand continued to fall despite a prolonged period of economic growth.
50. The fall in the underlying demand level is partly due to increases in embedded generation; this includes renewable sources such as wind and solar, but also smaller scale conventional sources of generation. In addition there has also been a real reduction in GB energy usage. This may be down to efficiency measures and behavioural change. The drop in demand level is sustained and likely to continue. The effect has therefore been incorporated into the 2014 forecast.

Summer Peak Demands

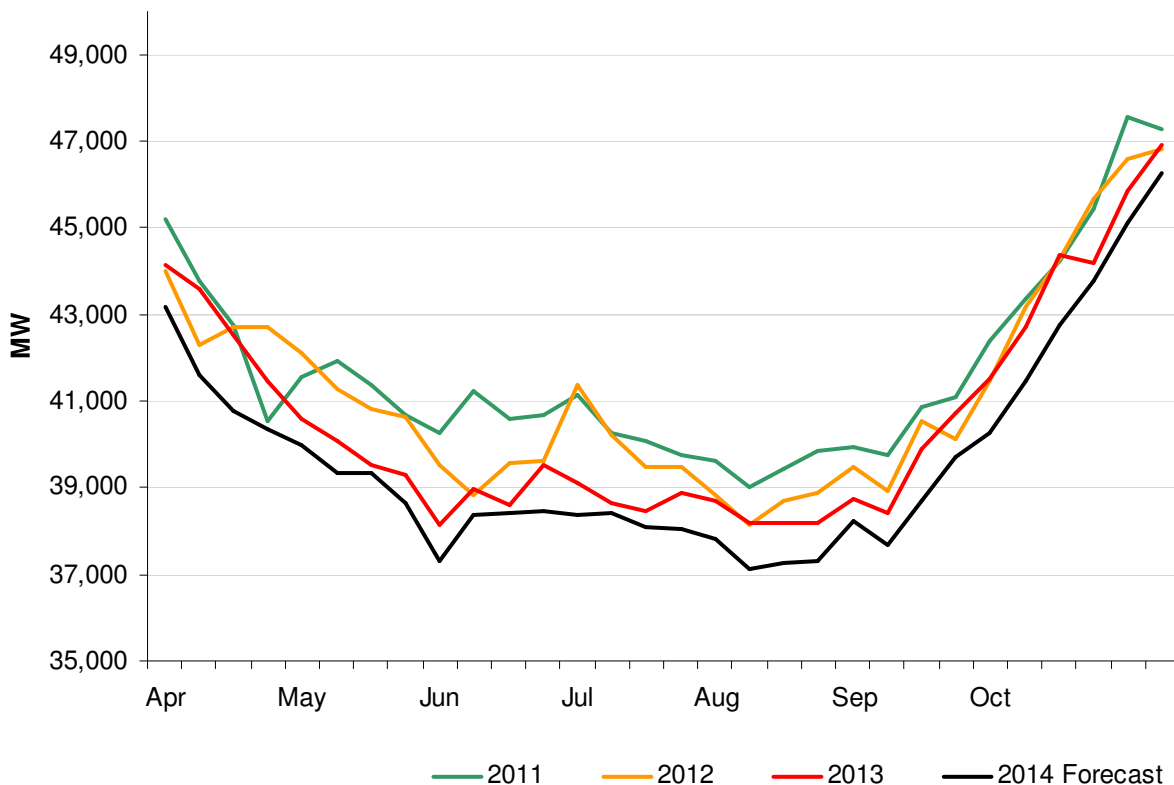
51. **Figure E4** shows the previous 3 years' weekly summer demand peaks. The increase in weekly peak demands in April – May 2012 is probably accounted for by the exceptional heavy rain and flooding.

Figure E4 - Weekly Peak Demand of Previous 3 Summers



52. **Figure E5** shows the forecast demand levels for 2014. For the high summer period of June, July and August, the peak weather corrected summer demand for 2014 is expected to be 38.4 GW against an actual weather corrected outturn of 39.5 GW for 2013.

Figure E5: Weather Corrected Weekly Peak Demand for the Past 3 Summers' and Forecast Demand for Summer 2014



Summer Minimum Demands

53. The summer minimum demand is expected to occur on a Sunday around 05:00 to 06:00 in late July. **Figure E6** shows the actual weekly minimum demands for the past three summers. **Figure E7** shows the weather corrected weekly minimum demands for the last three years as well as the forecast minimum demands for summer 2014. The minimum demand for summer 2014 is forecast to be 19.0 GW compared to a weather corrected minimum of 19.4 GW in summer 2013.

Figure E6: Actual Weekly Minimum Demand for the Past 3 Summers

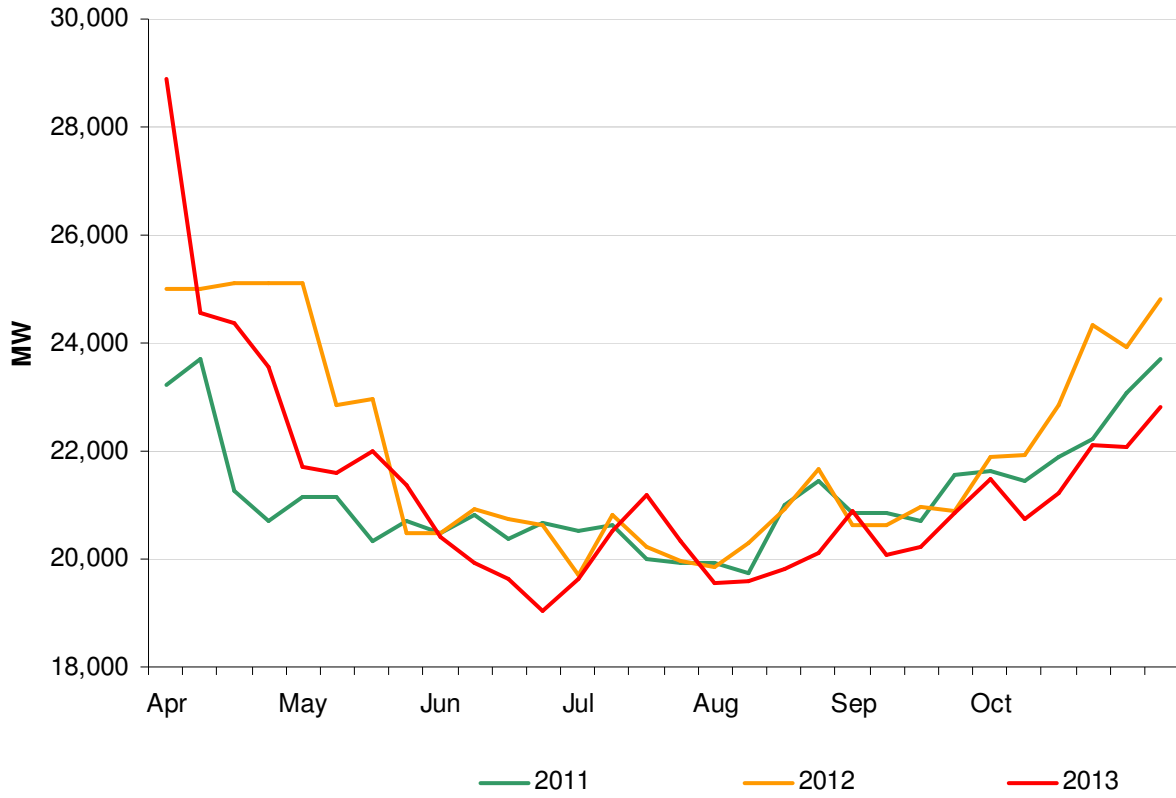
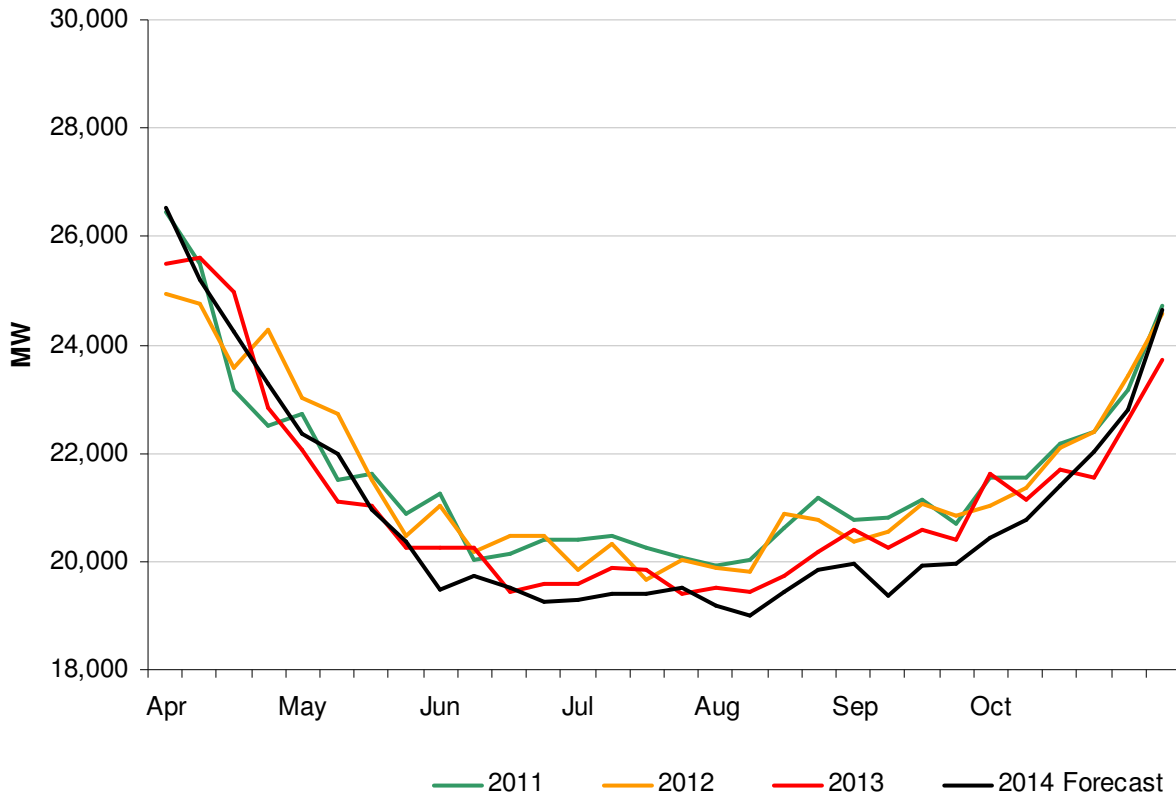
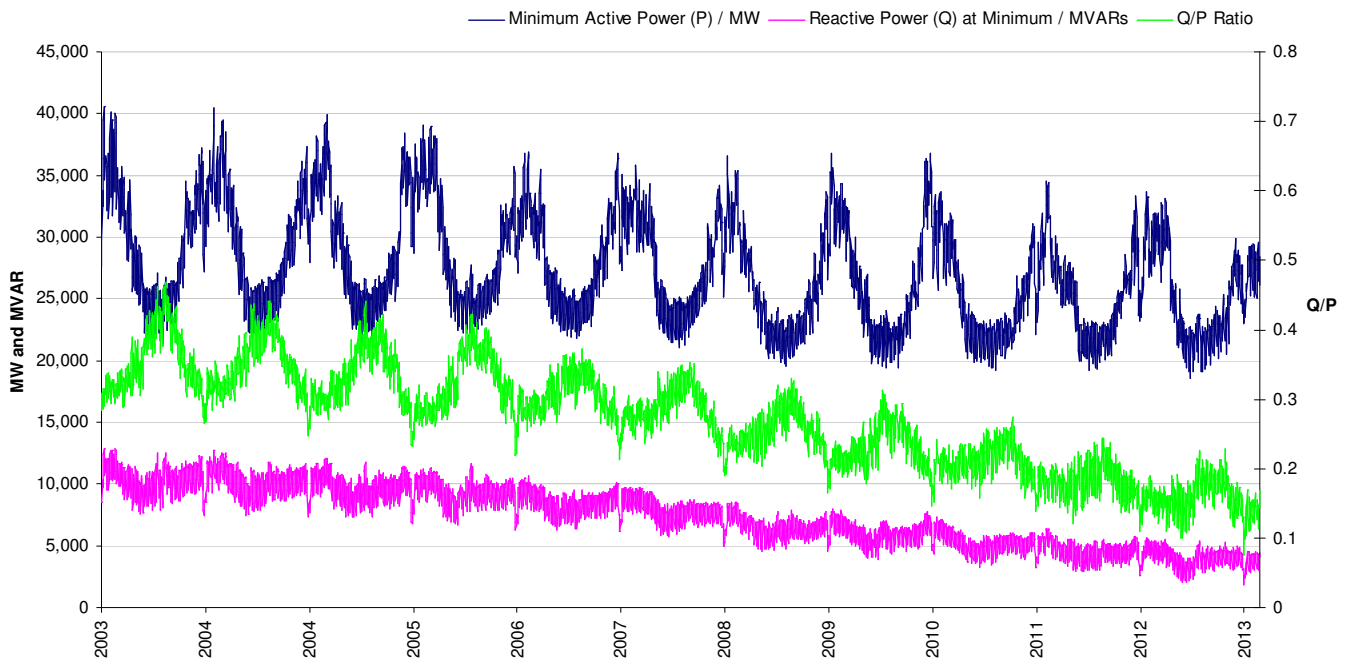


Figure E7: Weather Corrected Weekly Minimum Demand for the Past 3 Summers, and Forecast Demand for Summer 2014



54. There has been a decline in the summer minimum demand since 2006. This is shown in **Figure E8**. The chart shows actual active MW (P), reactive MVAR (Q), and the ratio of MVARs/MW (P/Q). This has steadily declined over the period and this trend is expected to continue through 2014.

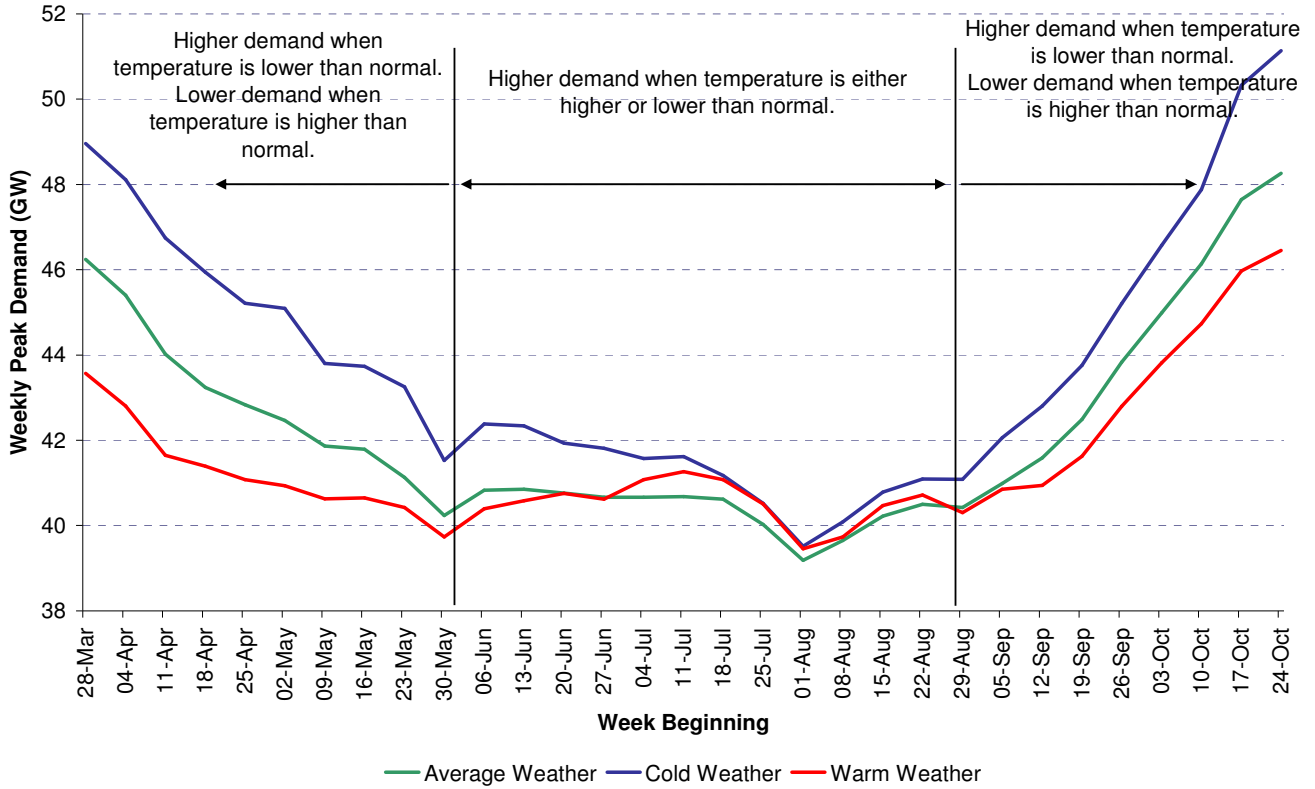
Figure E8: Long Term Active and Reactive Power Trend



Electricity Demand Variation due to Weather

55. Demand response to weather conditions varies during the year and also varies over different years as demand characteristics change. **Figure E9** depicts the relationship between summer demand and weather, at different times of the summer based on historic demand and weather data.
- Demand is generally higher when the temperatures are colder. This is normally between April and mid-June, and also from September onwards.
 - In high summer, mid-June to mid-August, the temperature is often close to the comfort temperature of 16-17 degrees. Either an increase or decrease in the temperature will cause the demand to increase.

Figure E9 - Electricity Demand under average, warm and cold conditions



Generation Fuelled by Variable Power Sources

56. **Figure E10** shows the mean load factor of wind generation by month and trading period across 2013. The data is taken from directly connected wind farm operational metering. Month is plotted on the vertical axis and trading period on the horizontal axis, with Period 24 corresponding to the half hour ending at noon. The mean annual load factor for 2013 was 31%.
57. For comparison **Figure E11** shows the mean load factor of wind generation for the period 2010 – 2012. The mean summer load factor over this period was 23%.

Figure E10: Average Wind Power by Settlement Period and Month: 2013

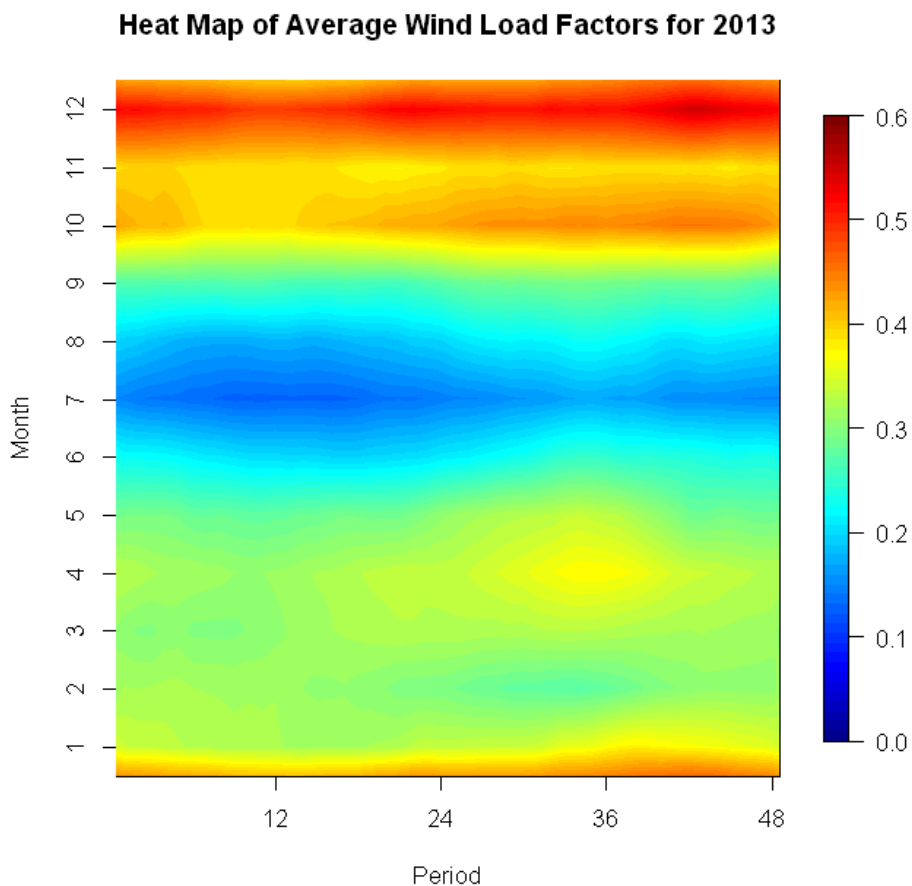
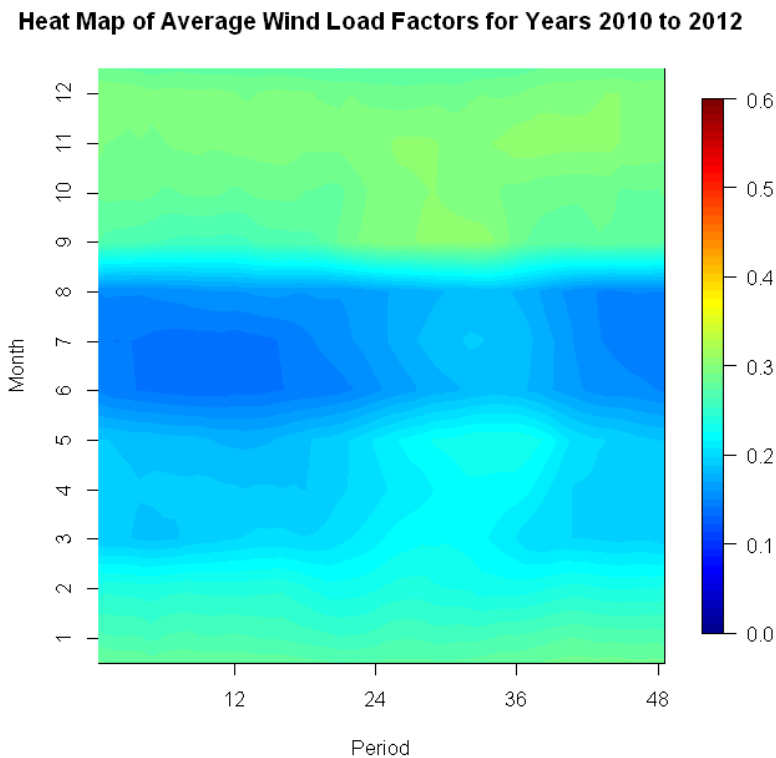


Figure E11: Average Wind Power by Settlement Period and Month: 2010-2012



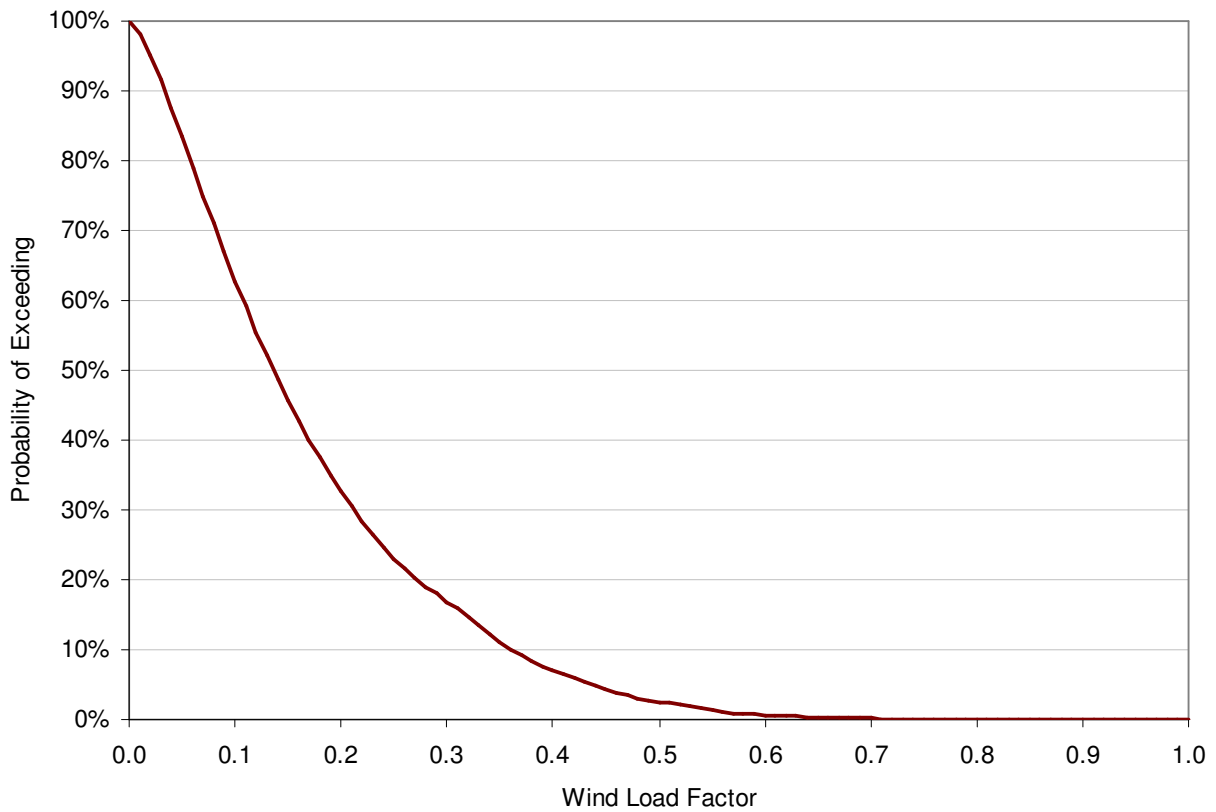
58. Seasonal mean load factors for 2013 are compared to mean load factors for 2010-2012 in **Table E1**. The nature of the wind fleet has changed over the period 2010-2013, with more geographical spread and more offshore wind installed in 2013 compared to 2010.

Table E1 – Comparison of Seasonal Wind Load Factors

Mean Load Factor	2010 - 2012	2013
Winter	26%	39%
Spring	20%	32%
Summer	16%	19%
Autumn	29%	36%

59. **Figure E12** shows historic wind farm load factor distribution during the daytime in high summer (June to August). The median wind load factor is 14%; based on this it is reasonable to assume that half of the time the load factor will be less than 14% during the day. Similarly there is a 20% chance that the load factor will be below 6.1% and a 10% chance that the load factor will be below 4% during the day. Another way of describing this is that in one of the next ten years the wind farm load factor is likely to be less than 4% at the summer demand peak.

Figure E12: Wind Load Factor Summer Daytime: Probability of exceeding a given wind load factor



60. The lowest average load factors occur overnight in the summer period. During 2013 the lowest summer overnight load factor was 0.001 (0.1%). However, high winds do occur during periods of low overnight demand during summer. The lowest demands usually occur early on Sunday morning between mid-June and mid-August. **Figure E13** shows the chance of the wind load exceeding a given value during at least one of these low demand periods. The median figure is a load factor of 39%. This represents the typical largest wind load factor expected during one of the low demand periods in any year and is used in the low demand scenario analysis later in this document.

Figure E13: Wind Load Factor at Demand Minimum: Probability of exceeding a given wind load factor on at least one of the 2014 summer demand minimums

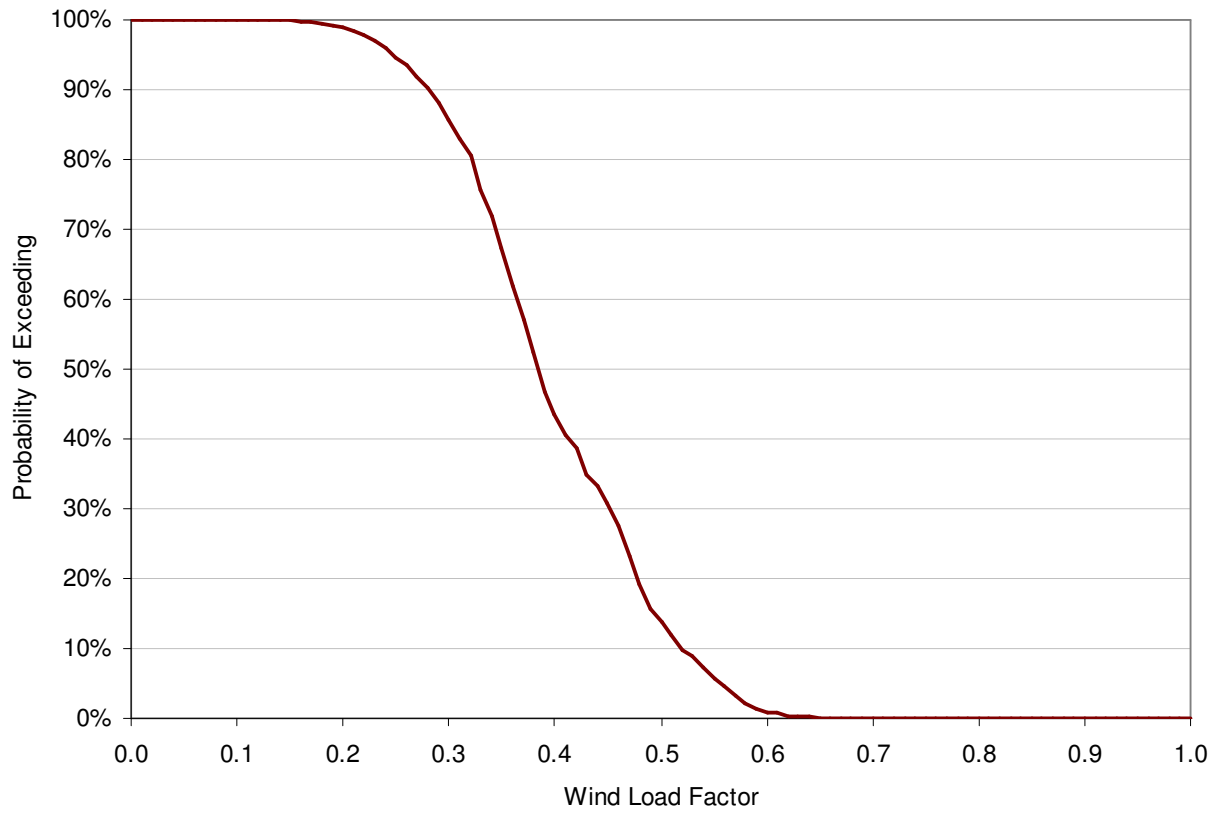
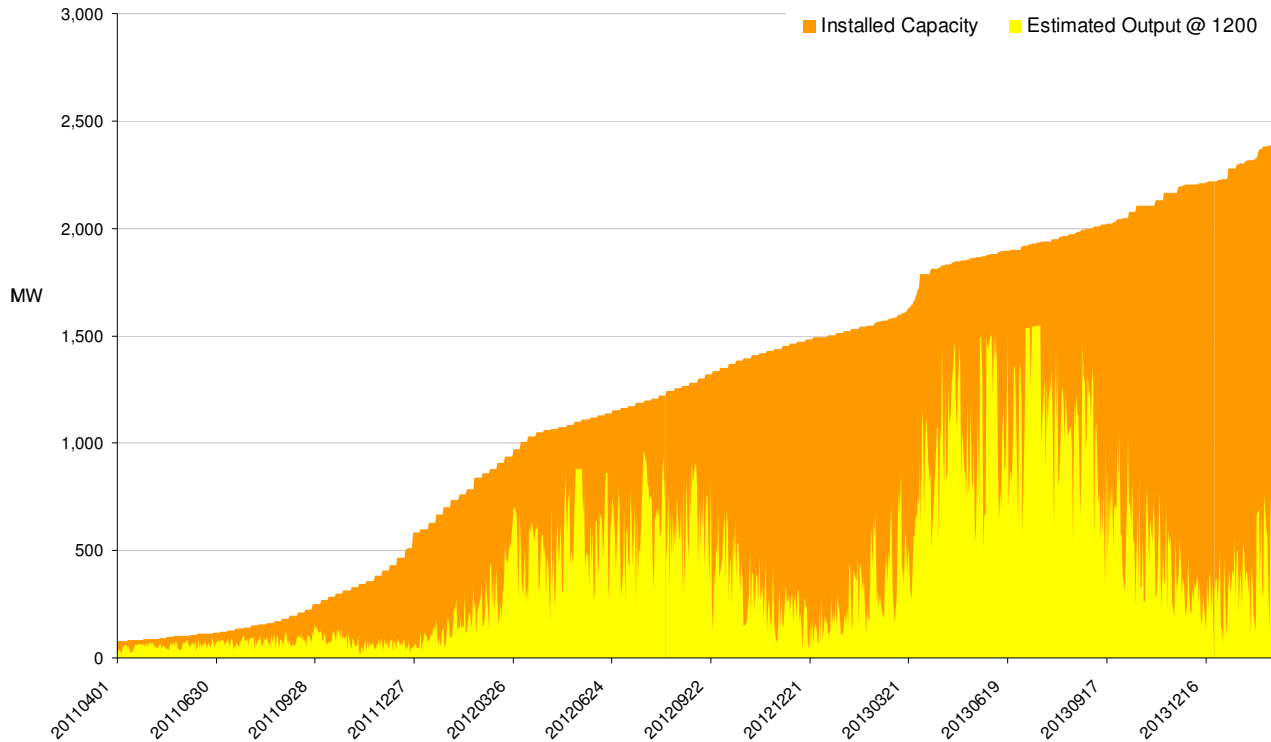


Figure E14: Total Photo-Voltaic (PV) Capacity and Estimated Generation: April 2011 to present day



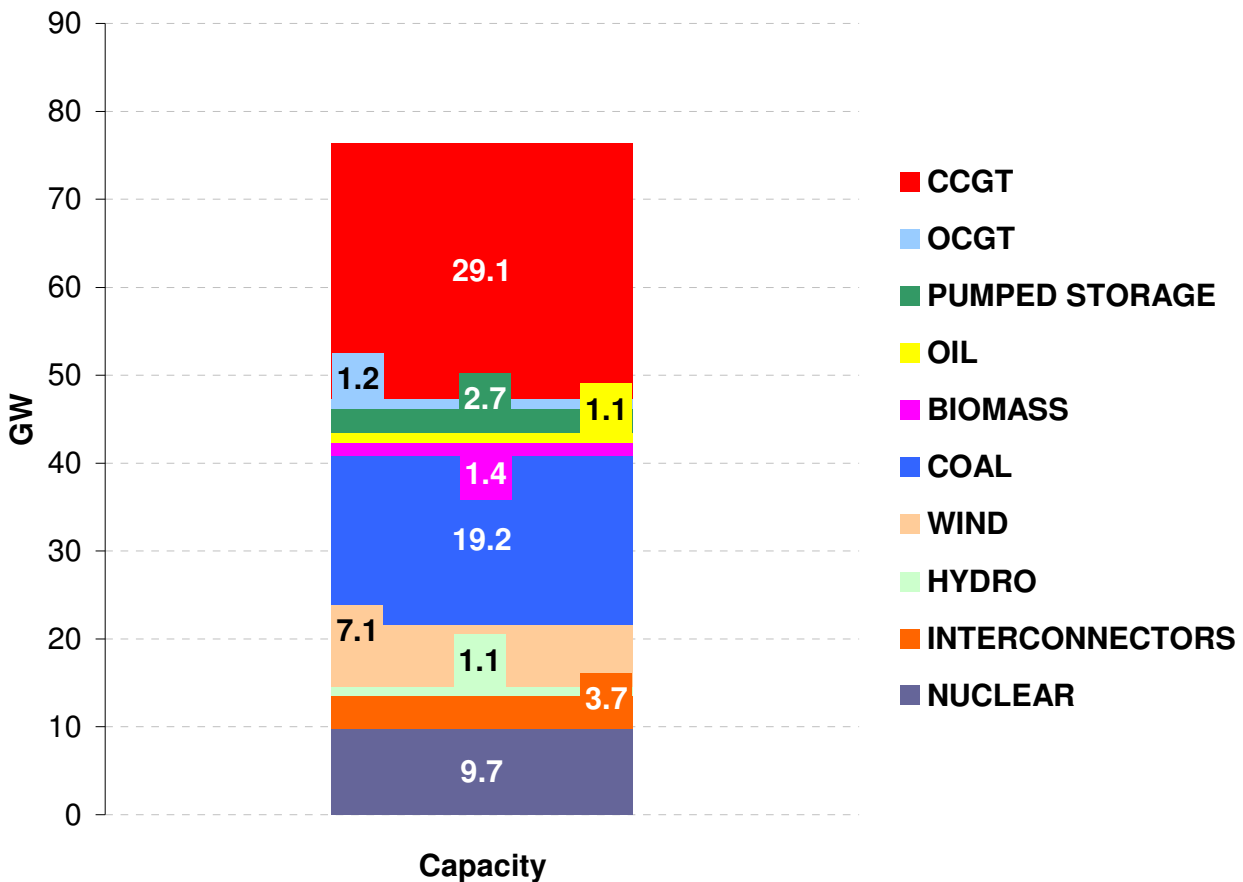
61. PV capacity has grown substantially since the Feed-in Tariff was introduced in 2010; the UK total is now up to 2,400 MW. **Figure E14** shows this growth for the period since April 2011. Also shown is an estimate of the output based on actual weather data. Embedded PV generation is experienced as a suppression of the National Demand. The effect is significant and as such National Grid now incorporates estimates of total PV generation in to its National Demand forecast.

Generator Availability

Generation Capacity

62. **Figure E15** shows the expected generation capacity at the start of the summer, which has dropped by 1.3 GW to 76.4 GW, including interconnectors, since the Winter Outlook Report. This is due to decreases resulting from the expected closure of Ferrybridge (Units 1 and 2) and Uskmouth (Units 14 and 15) plus the temporary withdrawal of two CCGT plants (Peterhead 1 and Barking 1). These decreases have been partially offset by the inclusion of the last unit at West Burton B now that it is fully commissioned, the return of Barking and further wind generation⁴ added to the system. The capacity could fall further as there is a risk of more gas stations being mothballed during the summer. These changes are all based on latest market information as of March 2014.

Figure E15 - Generation Capacity - Summer 2014

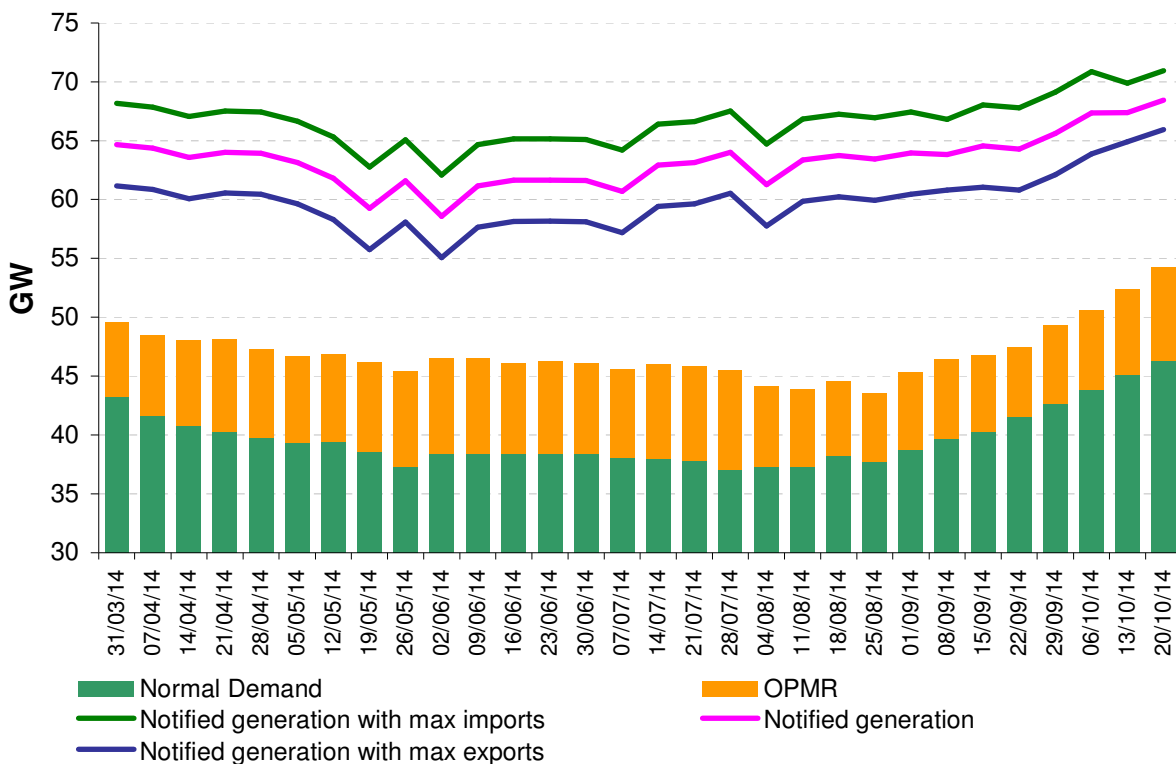


⁴ The capacity of wind when the data was produced (March 2014) was 1200MW higher than last year.

Generation Availability

63. As usual over the summer period there will be a significant generation outage programme that will reduce the amount of available generation plant. Generation surplus, which is the excess of generation availability over demand and reserve requirements, is published on www.bmreports.com⁵.
64. **Figure E16** shows normal demand and notified generation availability. As such, the chart assumes optimum wind and no generator breakdowns. The minimum surplus would be 12.0 GW in the week beginning 2nd June with the interconnectors at float.

Figure E16 - Notified Generation Availability



⁵ <http://www.bmreports.com/bsp/BMRSSystemData.php?pT=WEEKFC>

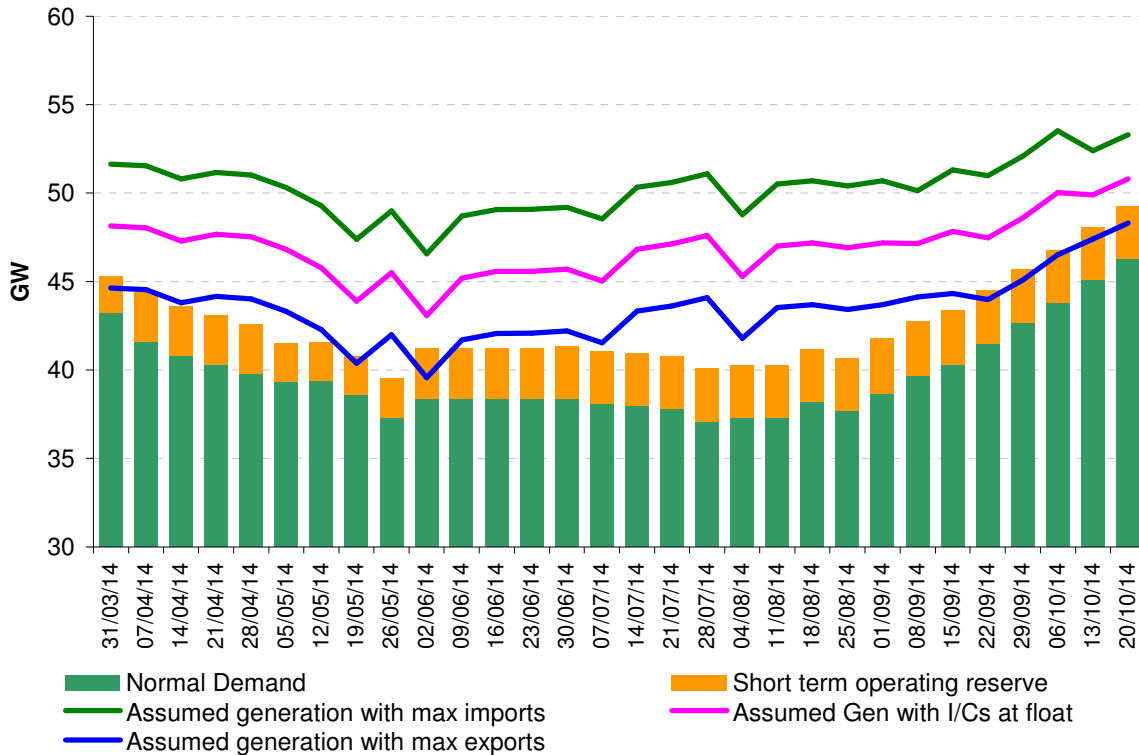
- 65. **Table E2** shows the assumed losses based on the historic summer average breakdown rate for the different types of generation (other than wind and hydro).
- 66. For wind farms the assumed “losses”, periods of unavailability, are based on **Figure E12**. This shows the median wind farm load factor for summer daytimes to be 14% and therefore the median “losses” to be 86% as stated in the table.
- 67. For hydro generation, assumed losses are based on historic generated output at the time of the daily peak over the summer to reflect the dependency on water availability.

Table E2 - Assumed Losses of Generation Availability for Summer 2013

Power Station Type	Assumed losses
Nuclear	12%
Interconnectors	0%
Hydro generation	59%
Wind generation	86%
Coal + biomass	20%
Oil	15%
Pumped storage	5%
OCGT	14%
CCGT	19%
Overall	24%

- 68. The assumed losses in **Table E2** are applied to the notified availabilities declared to National Grid by Generators under Grid Code Operating Code 2 (OC2) to calculate the assumed generation availability shown in **Figure E17**. The chart also superimposes notified French, BritNed and East-West Interconnector capabilities in both import and export directions. The interconnector to Northern Ireland has been excluded from the interconnector capabilities as it is normally exporting at full capacity and is accounted for as an addition to the forecast demand in Scotland.

Figure E17 - Assumed Generation Availability



- 69. The short term reserve requirement is forecast to be a maximum of 3.1 GW and is included in **Figure E17** as operating reserve.
- 70. The minimum generating availability over the summer is 43.1 GW in week commencing 2nd June. The surplus in this week is forecast to be 1.8 GW, assuming the interconnectors are at float. The minimum surplus is 1.6 GW and this occurs in the very last week of the BST period, week commencing 20th October.
- 71. The chart shows that for the week beginning 2nd June it would not be possible to provide maximum export on the interconnectors without eroding the reserve requirement. This would also be the case at the start and end of the BST period.
- 72. If it looked likely that there would be an erosion of reserve due to high interconnector export flow, trading on the interconnectors would be considered as a way to reduce exports. If the position could not be rectified by trading, a Notification of Insufficient System Margin (NISM) warning would be issued to inform the market and to encourage an increase in available generation or reduction in demand.
- 73. Apart from the unlikely case of very high interconnector exports, **Figure E17** shows margins are forecast to be adequate throughout the summer.

Interconnector Flows

74. Full availability is expected on BritNed throughout 2014, EWIC has a planned short outage in early September and IFA is reduced to 1 bipole (+/-1000MW) for 16 days in March and again for 12 days in October. The Moyle interconnector is reduced to 1 pole (+/-250MW) due to a cable fault, the earliest expected return date is late 2016.
75. The current spreads between GB and EU for summer 2014 are slightly wider (EU to GB direction) than this point last year indicating again that full imports are expected on IFA and BritNed. 40% of weekdays saw imports to GB reduce below 500MW during the morning hours (generally 05:00-07:00); this is expected to remain similar for summer 2014.
76. Day ahead market coupling has now been implemented, which was expected to make the flows more volatile. However, current observations would suggest that flows have remained relatively stable.
77. Flows on EWIC and Moyle are expected to continue to flow from GB to Ireland the majority of the time. Only during times of high wind in Ireland (particularly overnight) are flows expected to reduce from full export and could potentially start importing to GB.

System Operation during Low Demand Periods

78. During periods of low demand a number of flexible generators are required to:
 - Maintain sufficient frequency response⁶ to ensure that the system can withstand the largest generation or demand loss
 - Maintain positive and negative regulating reserve levels to cater for demand forecast error, wind forecast error, generation and demand losses
79. In addition, during periods of low demand, two other factors may affect generator balancing decisions, in that we have to:
 - Maintain the voltage profile across the country within specified limits
 - Maintain sufficient system inertia⁷
80. The impact of these four issues in the coming summer is that it is likely that we will need to take a number of actions during low demand periods on conventional and wind generators to keep the system secure. These issues are discussed in more detail below.

⁶ Frequency response requirements increase as the demand falls due to the relative size of the largest loss increasing and due to demand itself being slightly frequency sensitive

⁷ When there is an instantaneous demand or infeed loss inertia acts to slow down the rate of change of frequency in the timescales before frequency response takes effect

Regulating Reserve and Frequency Response

81. Generators which are currently less flexible include:
- Nuclear generation
 - Combined Heat and Power (CHP) stations
 - Some hydro generators which either have water level management obligations or have BELLA⁸ connection agreements
 - Some wind farms, which either choose not to participate in the Balancing Mechanism or have BELLA connection agreements or are not large⁹
82. Interconnectors provide a variety of frequency response services and, in some cases, limited System Operator to System Operator trading.
83. The remaining generators are more flexible, including most large wind farms. Most large wind farms are now participating in the Balancing Mechanism and some are providing the Ancillary Services required by the Grid Code (frequency response and reactive power). We call on these services when more economic options have been used up.
84. We have modelled the amount of inflexible generation that we can reasonably expect to be running at the time of the weekly minimum demand to quantify the likelihood of us needing to ask less flexible generators to alter their output during these periods. Our assumptions on the load factors for the different categories of generator and interconnectors during low demand periods are shown in **Table E3**. Our assumed load factor for inflexible wind farms is based on **Figure E13**, which shows that for the days where we might reasonably expect the lowest demand to occur, we can expect the wind load factor to be 39% on at least one of these days.

Table E3 – Inflexible Load Factor Assumptions at Minimum Demand

Power Station Type	Load Factor
Nuclear	0.88
Inflexible fossil fuel	0.90
Inflexible hydro	0.10
Inflexible wind	0.39
Irish Interconnectors	-1.0
BritNed	0.70
IFA	0.50

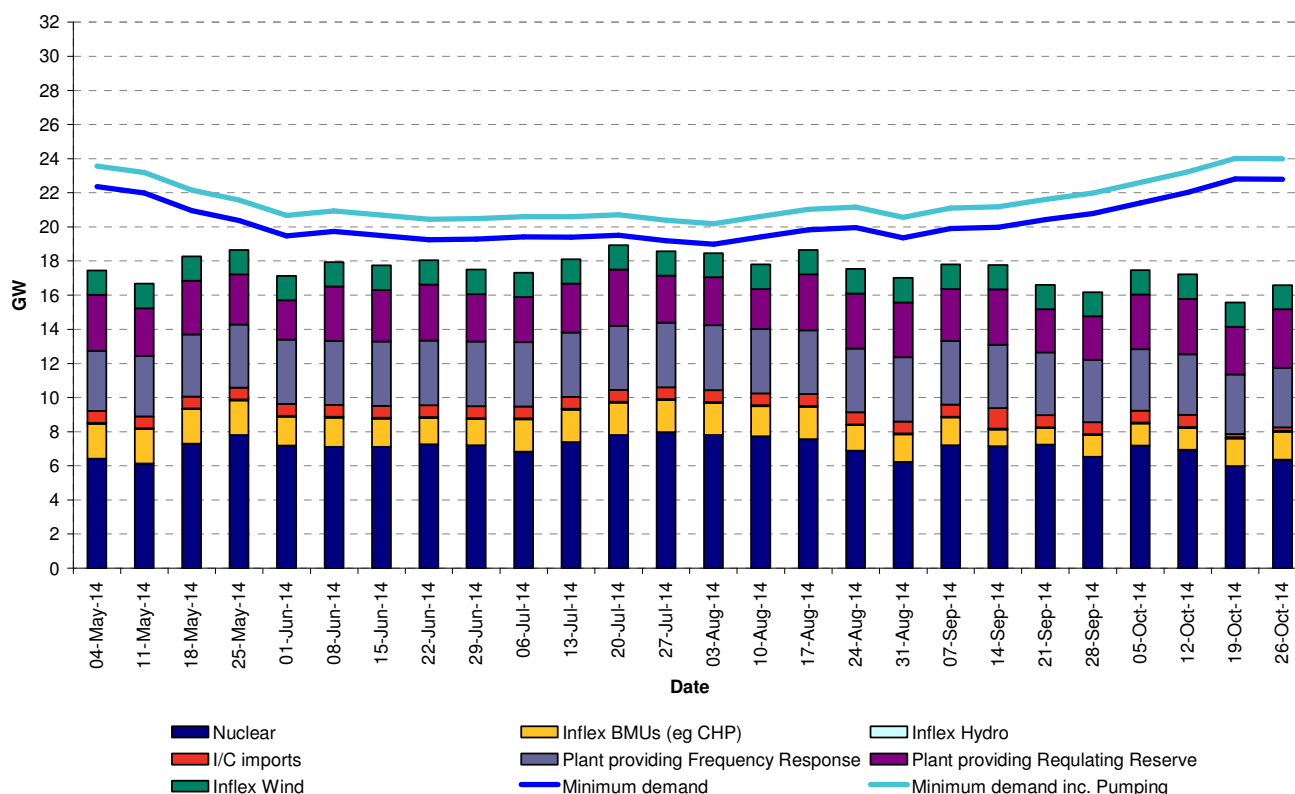
⁸ Bilateral Embedded Licence Exemptible Large Power Station Agreement

<http://www.nationalgrid.com/uk/Electricity/OLDGettingConnected/dnoConnected/agreements/>

⁹ As defined by the Grid Code. Virtually all generators which are not large do not have a connection agreement (relationship) with National Grid. Small embedded generators meet local demand, reducing the amount of demand seen by the transmission system. Small wind farms are modelled explicitly as their output is not related to demand.

85. **Figure E18** shows the cumulative minimum output profile from less flexible generators. This is based on the load factors in **Table E3** and the generators' OC2 availability submissions. This profile includes the synchronised plant required to meet our frequency response and reserve requirements. The weekly minimum demand profile is also shown, together with pumping demand at an assumed load factor of 50%.
86. **Figure E18** shows that there should not be a requirement to ask inflexible generators to reduce their output this summer. However for several weeks the margins are small, with the smallest margin being 1.7GW in the three weeks commencing 20th July to 3rd August. Actual margins will depend on conditions and plant running on the day. We will keep these margins and assumptions under review during the summer and will inform and engage with inflexible generators if necessary.

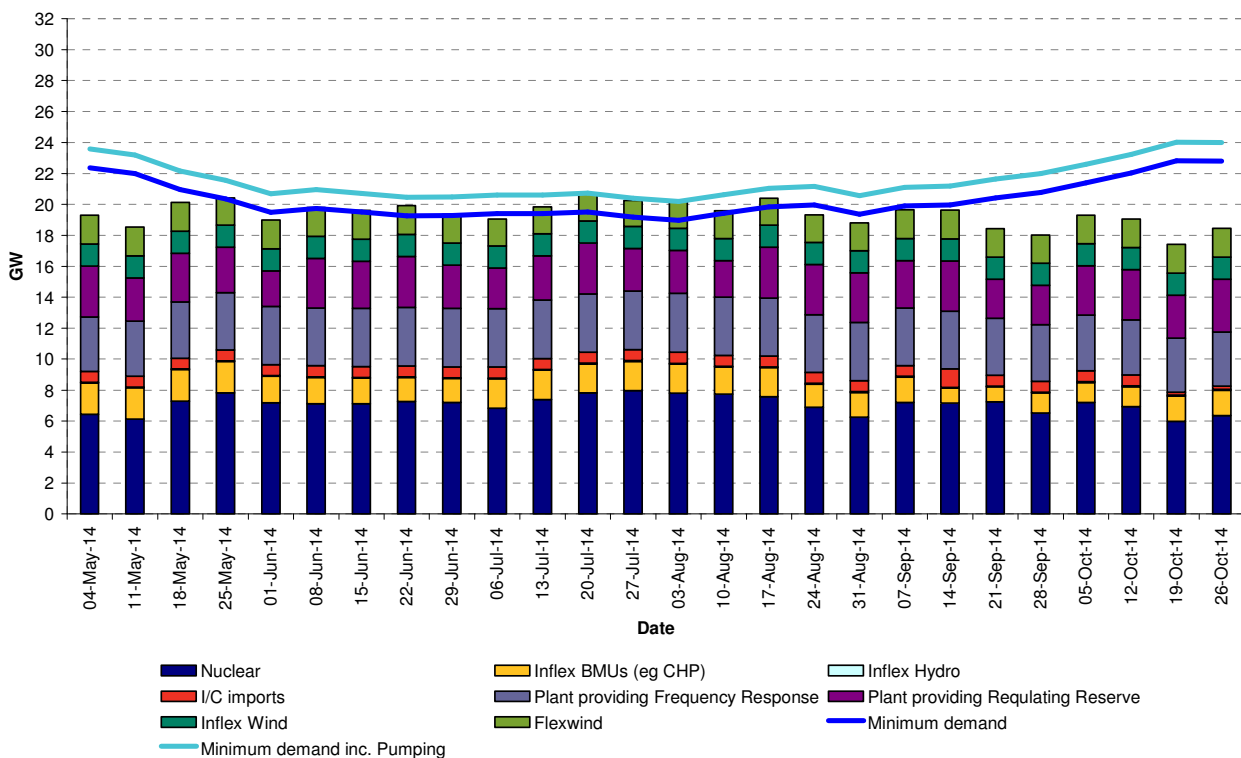
Figure E18 – Weekly Minimum Demand and Generation Profiles



87. With increasing installed wind capacity it has become economic to carry a proportion of regulating reserve on large wind farms when it is windy. This has resulted in the occasional short curtailment instruction being issued to wind farms over the last few months. The number of these short curtailment instructions given to wind farms is likely to increase as the demand drops towards the summer minimums and fewer flexible generators run overnight (historically the principal reason for curtailing wind output has been for transmission constraints – see section on Transmission Issues).

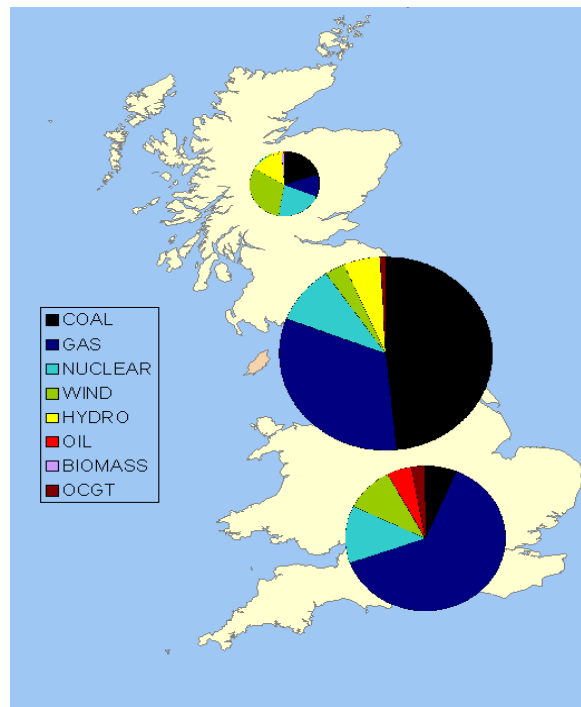
88. In **Figure E19** flexible wind farm output has been added, assuming the same load factor of 39%. **Figure E19** shows that if flexible wind did not contribute to meeting the frequency response requirement and the regulating reserve requirement there is a reasonable chance that it will be curtailed this summer for energy reasons. If wind did contribute to meeting the frequency response and regulating reserve requirement then the effect on this chart would be a reduction in the size of the flexible wind block, with the wind farms displacing some of the conventional generation that provide these services. Initially high frequency response and negative regulating reserve are likely to be the most economic services for wind farms to provide as they don't involve pre-emptively de-loading the generator. Provision of low frequency response and positive regulating reserve would involve de-loading the wind farm before it could provide the service.
89. We encourage those wind farms and generators that currently do not meet their obligation to provide frequency response to do so as it will help us manage these low demand periods more efficiently and economically. In addition, we encourage the submission of cost reflective prices for the provision of frequency response. On an hourly basis, currently it is cheaper to shutdown some generators and wind farms completely, rather than to carry frequency response on them.

Figure E19 – Weekly Minimum Demand and Generation Profiles Including Flexible Wind Output



90. **Figure E20** shows the geographical location of generation divided by fuel type, with 16% of the generation capacity in Scotland, 48% of the capacity in the North of England and Wales and 36% of the capacity in the South of England and Wales. If, as forecast, the relative cost of generating electricity from coal is less than that from gas, it is likely that the South will see a greater proportion of its generator capacity two shifting overnight. This combined with the declining reactive power demand, means that during low demand periods there may be import constraints to ensure that generation is synchronised to maintain the voltage profile in some parts of the country. We encourage those wind farms and generators that currently do not meet their obligation to provide reactive power to do so as this will help us manage these low demand periods more efficiently and economically.

Figure E20 – Geographic split of generation by fuel type



91. Most wind farms and interconnectors do not contribute to system inertia, due to electronic decoupling. Synchronous generators do contribute towards system inertia; their contribution reflects the physical design of the machine. Inertia acts to slow down the rate of change of frequency when there is an instantaneous demand or infeed loss in the timescales before frequency response takes effect. A Grid Code Working Group¹⁰ has been addressing this issue. During low demand periods when there are high levels of interconnector imports and high levels of wind farm output, there will be fewer conventional machines synchronised to the system. Should there be insufficient system inertia during these periods, additional synchronous machines will need to be synchronised to ensure the system remains secure.

¹⁰ <http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/freqresp/>
<http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/freqrespTSG/>

92. During low demand periods it may be that actions on one generator solves more than one of the four issues discussed above, for example, synchronising a generator in a particular region to support the local voltage profile may contribute to ensuring there are sufficient machines synchronised to meet the system inertia requirements. It may also be that actions are not taken on some generators for the same reason, for example, a number of conventional generators had notified us that they planned to run overnight may be left running and a wind farm may be curtailed to resolve an energy imbalance because the conventional generators were carrying frequency response and the wind farm in question could not carry frequency response. We will take actions in economic order to operate the system securely and efficiently at all times.

Transmission Issues

93. 2014 sees the continuation of major works across the system to increase network capability. This work, being carried out by the relevant Transmission Owners, is to construct or rebuild major sections of the transmission system in Scotland and the North of England, to deliver additional transmission capacity to transport energy from new renewable generation (wind) in Scotland.
94. Additionally, significant outages are required for reinforcement works within South Wales, the South East, and the Flow South boundary primarily to facilitate generation connections.
95. The network outages to undertake the work will reduce the available transmission system capacity between Scotland and England, as well as between the North and South of England, South Wales, and in the South East.
96. To manage the resulting constraint volumes, to resolve these constraints efficiently and effectively we will use a combination of:
- contracts to limit the output of certain power stations
 - arming of intertrips to automatically disconnect generation in the event of a transmission fault
 - actions on the day in the Balancing Mechanism
 - trades
97. These transmission system reinforcements form part of a substantial development of the networks to accommodate new generation and to replace assets to ensure the continued reliable performance of the GB transmission system. Details of planned reinforcements are shown in National Grid's Electricity Ten Year Statement¹¹.

¹¹ <http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/>

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