nationalgrid

Winter Outlook 2014/15

October 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.

Introduction

Each winter throws up its own challenges for the country's energy sector and I fully expect the coming winter will be no different.

As the country's System Operator for the gas and electricity transmission networks, we will work alongside power generators, energy suppliers, gas shippers, analysts, government and the regulator to meet the challenges posed by even the most arduous cold weather conditions.

And as part of that, we have pulled together a vast amount of information that will help inform the market as we head into the coming winter. As well as our own analysis and data, the outlook report includes feedback from a range of stakeholders across the sector, and I'd like to thank them for taking the time to do so.

This report is not a prediction of what could or will happen, but a factual analysis of how the energy sector looks based on the information we currently have. Of course, we don't have a crystal ball and can never second guess what could happen. What we do know is that we have taken steps to make sure we are ready and have the tools we may need.

Based on the work we've done, it's clear the country has the ability to meet its energy needs in a cold winter. But we cannot be complacent and will be monitoring the situation closely right through to spring next year.

For gas, the numbers point to the market being well supplied and able to cover any cold spells. We must always be mindful of geopolitical events, and with that in mind, have looked at the impact of any curtailment of supplies from Eastern Europe.

As implementation of the new Capacity Market and Contracts for Difference under EMR draws closer, it's a well reported fact that electricity margins are tighter than they have been for a number of years. The electricity chapter discusses this in more detail and highlights how the market could respond to address this situation.

Thank you for taking the time to read this year's report. I hope you find it helpful and please do let us have any comments or feedback.

You can join the debate in real time on Twitter using #NGWinterOutlook or on our LinkedIn Future of Energy page or email us at commercial.operation@nationalgrid.com.

Cordi O'Hara
Director, Market Operation
National Grid

Executive Summary

We consulted industry through our Winter Consultation Report (WCR) and used the stakeholder feedback to inform our analysis on the security of supply for the coming winter. The results of that analysis are presented in this Winter Outlook Report (WOR). The forecasts show that we have the technical capability, network capacity and operational tools at our disposal to keep the lights on and the gas flowing.

Secure gas supplies under normal conditions

The GB gas regime is a very mature and liberalised market attracting a very diverse range of gas sources.

Across the typical winter range of operating conditions there is a positive gas security of supply position this year, with gas supplies, storage and network capacity well in excess of maximum expected demand.

Our analysis and stakeholder consultation has shown that gas demand for winter 2014/15 is expected to be similar to last year, at 47.5 bcm (October – March) including a comparable forecast of power station demand. Average cold day demand is forecast at 400 mcm/d with an exceptionally cold (1 in 20 years[1]) peak demand forecast at 499 mcm/d.

The maximum potential non-storage supply (NSS) is 488 mcm/d which when combined with current storage deliverability of 129 mcm/d gives a maximum supply potential of 617 mcm/d, significantly higher than the forecast peak day and 1 in 20 years demand.

For an average cold day the NSS supply is forecast to be 344 mcm/d. This figure is a key component of our operational within winter reporting and is updated throughout the winter based on actual flows and any market intelligence we receive.

The provisional UK Continental Shelf maximum supply forecast is marginally below the equivalent forecast for last winter. Norwegian and continental imports are expected to be similar to last year, although continental flows will depend on a number of other factors. Liquefied natural gas (LNG) shipments are included in the NSS forecast and has the capability to supply up to 130 mcm/d this winter.

Gas storage makes up approximately 10% of the overall gas supply mix over the winter period of October to March. At the start of the winter, storage deliverability is 129 mcm/d. This has the potential to increase over the winter if the new storage projects at Hill Top Farm and Stublach are available.

Europe-wide uncertainty

The current uncertainty surrounding Eastern European gas supply stability due to the enduring tensions between Russia and Ukraine, could lead to curtailment of gas supplies in to Europe. Whilst the GB market does not receive gas from Russian directly, there is the potential for wider European impact, which could impact gas flow across the whole of Europe.

[1] Statistically forecast exceptionally cold conditions that are expected to occur once every 20 years.

Executive Summary

We have worked with Ofgem, DECC and the EU on stress tests to assess the impact that may be experienced under different scenarios. The analysis assessed low and high levels of disruption:

- Gas flowing through Ukraine is disrupted and some is diverted via Yamal and Nord Stream pipelines.
- All gas flowing from Russia to Europe is disrupted.

Both these cases were tested against average winter and very cold conditions.

The results of the analysis show that under average winter conditions, gas demand under both low and high levels of disruption can be met as normal, with much of the replacement gas coming from liquefied natural gas (LNG) imports.

Only for the most extreme scenario with cold winter conditions and full disruption of gas from Russia would trigger a need for further market actions; for example, reduced exports to the continent, maximised liquefied natural gas (LNG) imports, and/or demand-side reduction.

Under all curtailment scenarios we have sufficient transmission network capacity. However, it is likely that we could require increased deliveries of LNG over and above recent experience. This gas would be expected to be diverted from other markets, such as Asia or South America, and would be at a price premium to the current GB market price for winter gas.

Tightening electricity margins and new balancing services

This year electricity margins have decreased compared to previous years, due to planned generator closures and breakdowns. There is also still some uncertainty on generators returning from outage as we enter the winter period. As GB System Operator it is prudent we take account of such uncertainty and so, in discussion with Ofgem and DECC, we are procuring two new balancing services[2] Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR) to manage the risk for this winter.

In June we successfully secured 319 MW of DSBR. In September we tendered for SBR to mitigate the generation changes and remaining uncertainty and have offered contracts to three power stations. The total procurement of these New Balancing Services provides an additional de-rated capacity of 1.1 GW to the availability of generation for this winter.

Electricity margin calculations

This year we are presenting the risks to security of supply by two methods:

- A de-rated margin and Loss of Load Expectation comparable with that presented in Ofgem's Capacity Assessment report.
- Operational de-rated margins, deterministic weekly margin calculation.

Loss of Load Expectation and Capacity Assessment Report

[2] These are Demand Side Balancing Reserve (DSBR) to encourage demand side participation in the market and Supplemental Balancing Reserve (SBR) to contract with otherwise uneconomic generation to stay open or return from mothball.

Executive Summary

The Secretary of State for Energy has set a Reliability Standard of 3 hours Loss of Load Expectation (LOLE) as part of the implementation of the Capacity Market from autumn 2018/19. LOLE is not a measure of the loss of supply or length of blackouts. It is a statistical measure of the risk across the whole winter where National Grid as System Operator, may have to take extra actions to ensure supply meets demand. National Grid has access to a range of tools to mitigate the effects of otherwise unmet demand – either by bringing on extra generation or reducing demand.

The analysis of LOLE takes into account maximum generator availability over the key winter period incorporating historic breakdowns, demand distribution and assumptions on interconnector flows. Ofgem's Capacity Assessment Report[3] published in June 2014 showed a base case LOLE of 0.5 hours for the coming winter, with sensitivities giving a range from 0 to 2.3 hours. Since then a number of generation plants (Ferrybridge, Barking, Ironbridge) have become unavailable due to either closure or unexpected events. This has increased the WORs indicative LOLE to 1.6 hours.

1.6 hours is still within the 3 hours LOLE Reliability Standard. However, uncertainty remains regarding further plant closures and the planned maintenance schedule of key generation plants (Heysham, Hartlepool, Ferrybridge).

Operational de-rated margins

The mid-winter generation capacity[4] is assumed to be 71.2 GW, which when taking into account availability and historic performance, is de-rated to 58.2 GW for margin analysis.

Taking into account historical weather patterns, we forecast peak electricity demand for this winter to be 53.6 GW. Milder and colder spells are expected to drive fluctuations. More arduous Average Cold Spell (ACS) electricity demand, which is demand conditions with a 50% chance of being exceeded, is expected to be 55.0 GW this winter.

The ACS peak demand margin is 4.1% across the winter period assuming market response to high demands, there are some days outside peak where the margin could be lower due to generator outages.

Neither method takes into account DSBR or SBR, but presents the base position prior to procurement of balancing products or market response. As these measures sit outside the market and are only to be called on if necessary; the additional capacity is not factored into the margin calculations. When the New Balancing Services are factored into the margin calculations the de-rated margin increases to 6.1% for the winter and 0.6 hours LOLE.

As with previous Winter Outlook Reports, we also undertake deterministic weekly margin projections based on weekly demand forecasts and planned outage and performance data supplied by generators.

[3] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-2014
[4] Maximum indicated availability from current information submissions, including 750MW of interconnector imports.

Executive Summary

Winter Outlook 2014/15 - Key Statistics

Gas		
	Non- storage supply capacity	**488 mcm/d[5]**
Cold Day Demand	**Cold day storage deliverability**	**129 mcm/d**
	Cold day demand	**400 mcm/d**
	Surplus	**217 mcm/d**
1 in 20 Demand	**1 in 20 storage deliverability**	**129 mcm/d**
	1 in 20 peak gas demand forecast	**499 mcm/d**
	Surplus	**118 mcm/d**
Electricity		
	Mid-winter generator capacity[6]	**71.2 GW**
ACS Demand	**De-rated generation availability[7]**	**58.2 GW**
	ACS demand	**55.0 GW**
	Reserve	**0.9 GW**
	Margin	**2.3 GW**
	% Margin	**4.1%**
	Loss of load expectation (Reliability Standard = 3 Hours)	**1.6 hours**
ACS Demand with New Balancing Services	**Additional de-rated capacity**	**1.1 GW**
	% Margin	**6.1%**
	Loss of load expectation (Reliability Standard = 3 Hours)	**0.6 hours**

Note: Margin calculations show the position before balancing actions to inform market participants of the likely need to supply such services, such as STOR, SBR and DSBR.
Terms used above are described in our Glossary available on our website[8].

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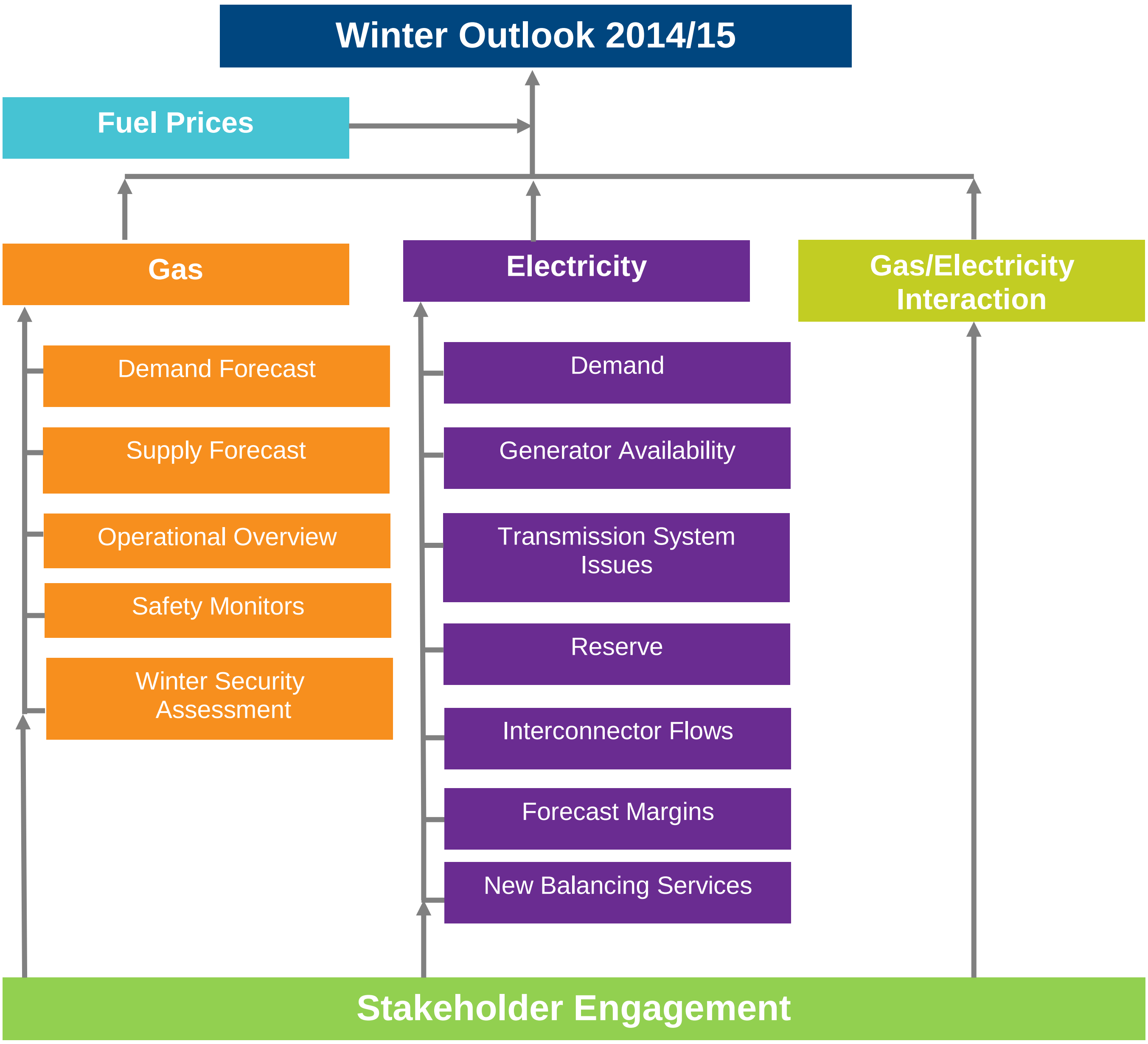
[5] Million cubic metres per day
[6] Maximum indicated availability for December and January from current information submissions, including 750MW of interconnector imports.
[7] At the times of ACS demand forecast, including 750MW of interconnector imports.
[8] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

Document Structure



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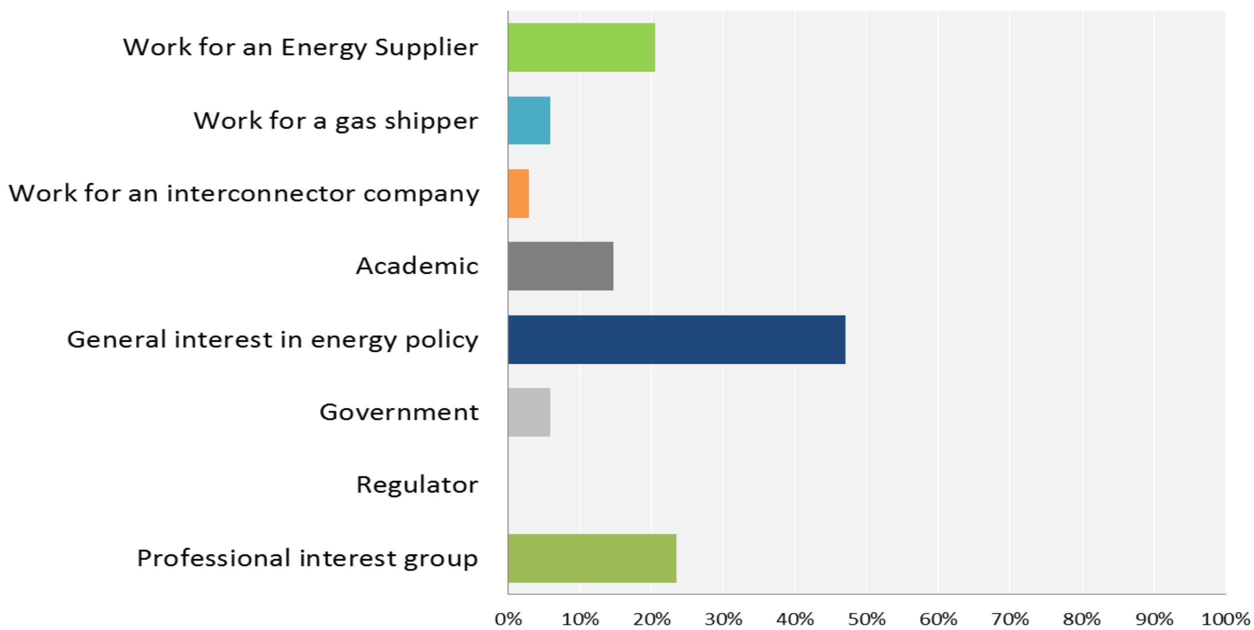
Winter Consultation

1. The Winter Outlook Report (WOR) is developed annually by National Grid, informed by the input of stakeholders through their responses to the Winter Consultation Report (WCR). In the WCR we present an updated Winter Review of what happened over the previous winter, together with a series of questions designed to understand the views of our stakeholders on the gas and electricity security of supply outlook for the coming winter. This feedback is then used to inform the methods and assumptions used for our forecasts of security of supply, the results of which are published on an annual basis in the WOR.

Enhanced Engagement

2. We enhanced and improved our stakeholder participation in the Winter Consultation this year beyond the traditional route of publishing the WCR and requesting formal responses from stakeholder organisations. We have used our experience and broader range of stakeholder contacts gained through the Future Energy Scenarios consultation process to drive improvements in our engagement.
3. We received four responses to the WCR in the traditional manner by email with company header, which is comparable to last year's consultation process. A summary of those responses can be found at on our website[9].
4. Our enhanced method of conducting an online survey on both the methods used and our assumptions increased the response rate tenfold, from a broader range of stakeholders.
5. As shown in **Figure 1**, respondents with a broad range of interests participated in the online survey. This is the largest total number and broadest range of respondents involved in a GB Winter Consultation.

Figure 1 – Consultation Respondents by Group



[9] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

Increasing Value

6. The report is clearly valued by our stakeholders, with 85% of respondents rating the Winter Outlook Report at least 3 or higher on a scale of 1-5 for usefulness (5 being the highest).
7. **Figure 2** below shows how we have responded to your feedback to further improve the WOR so that it meets your needs to an even greater extent and accurately represents the views of the industry and other key stakeholders.

Figure 2 – Your Feedback and Our Response

You said…	We did…
Stakeholders were not engaging with the process, with a low number of responses to recent Winter Consultation Reports.	Enhanced and broadened engagement, enabled by the online questionnaire.
The report is technical and a glossary would be useful.	Developed an accessible and plain English glossary of terms, as well as fact sheets on a few important topics[10].
Only a slight increase in gas fired power generation will change gas demand from last year.	Updated our forecast using latest plant availability.
Gas prices will increase over the winter.	Assumed higher gas prices for the coming winter.
Consider a range of potential outcomes for the gas market due to the Ukrainian dispute.	Presented analysis of the capability of the gas market under four scenarios.
Use margin calculations and LOLE for electricity security of supply forecasts.	Included whole winter view in LOLE and a week by week detailed margin calculation.

[10] See http://www2.nationalgrid.com/media/reports/

Fuel Prices

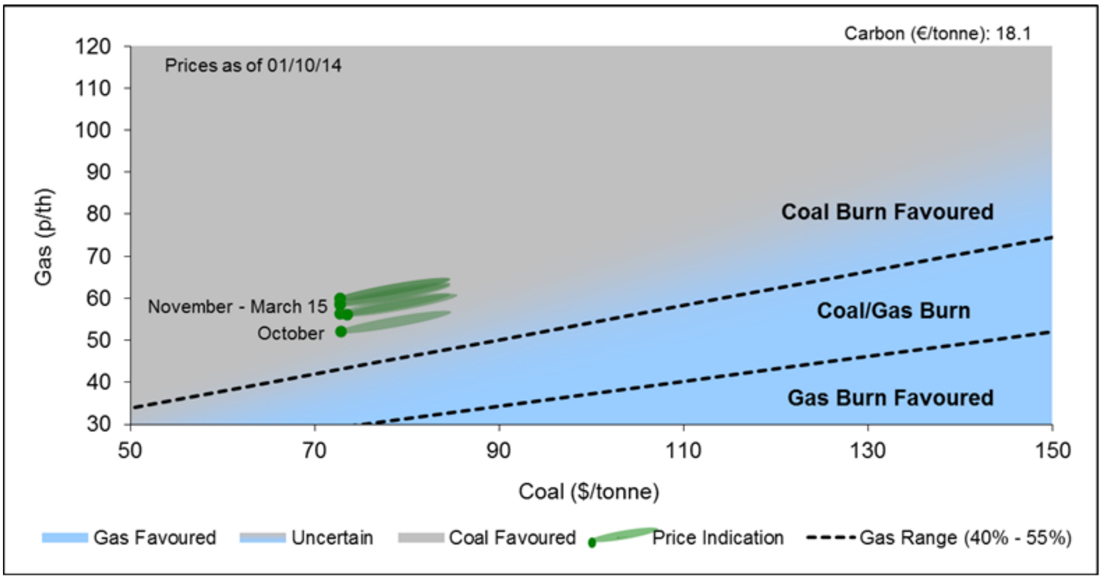
Forward energy prices for winter 2014/15 indicate that coal is expected to be favoured over gas as the preferred source of fuel for power generation.

8. Fuel prices underwent relatively strong movements over the last 12 months. For the period of October 2013 to September 2014, coal and oil prices decreased by ~8%, baseload electricity prices decreased by ~9% and gas prices fell by ~20%.
9. Carbon prices on the European Trading Scheme (ETS) increased by ~20% over the previous 12 months to over €6.30/tonne. Additionally the Carbon Price Support increased on 1st April to £9.55/tonne. These changes have increased the total UK carbon costs by ~£5/tonne.

Relative power generation economics

10. For most of the previous year the prices have favoured coal burn for power generation.
11. The impact of the increase to the Carbon Price Support from 1st April has significantly increased the cost of coal fired generation and reduced the gas/coal price differential.
12. The gas used for power generation increased during the summer as gas prices declined and became more economical for power generation. In addition there were some outages to coal and nuclear power stations through the summer months, which may have influenced the increase in the gas used for power generation.
13. The prices for winter 2014/15 suggest coal as being the favoured fuel for power generation. This is further supported in **Figure 3** where the economics of relative fuel costs and power generating efficiencies are shown. These costs include the costs for carbon. The rising price through the winter is in line with stakeholders' expectations, with 70% of respondents to our survey saying that they anticipate an upward trend in prices.

Figure 3 – Relative Power Generation Economics [11]



[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 50-55% efficient.

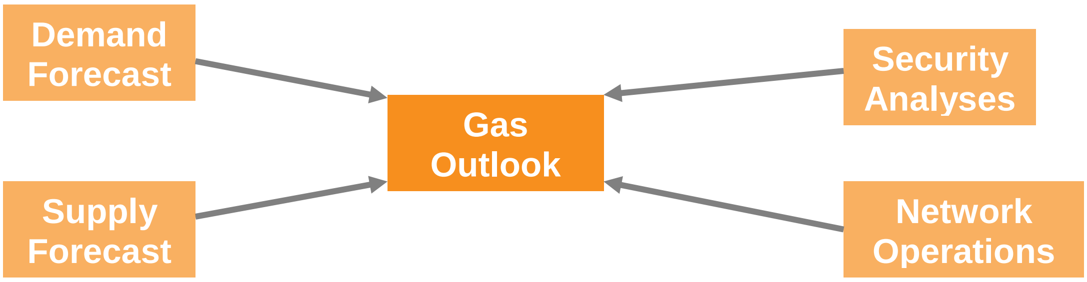
Fuel Prices

14. The chart shows how the forward prices for Winter 2014/15 favour coal burn over gas. For gas and coal to be equitable the gas price for winter 2014/15 needs to fall by approximately 20p/therm (from the current forward prices) to around 40p/therm, alternatively there needs to be a further increase in the coal price by about $50/tonne.
15. Whilst the price of coal and gas are influential in terms of power generation, other factors such as running hours for IED/LCPD, plant availability and generation portfolios will also influence fuel choice.

Gas

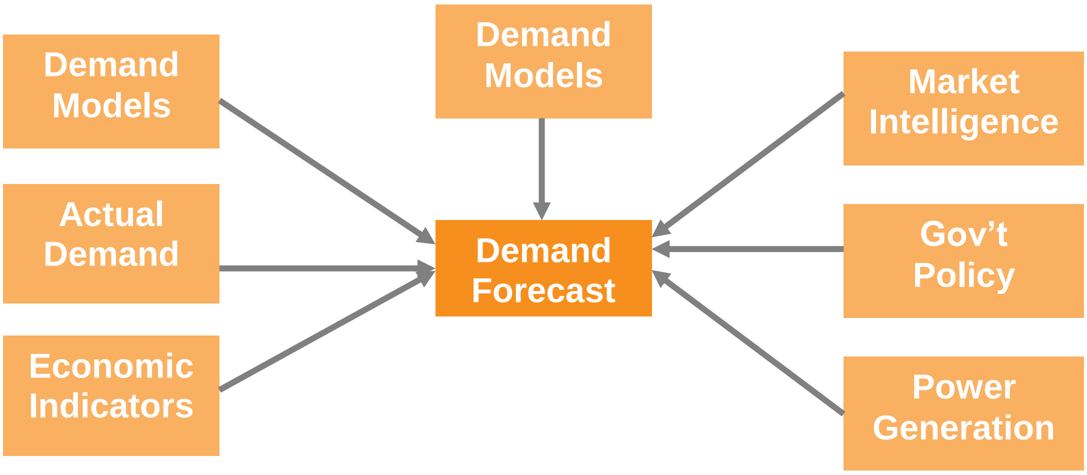
Overview

16. This section covers the gas supply and demand outlook for the winter 2014/15 together with an update on the safety monitors, an operational overview and a security of supply assessment.



Demand Forecast

Gas demand is forecast to be slightly higher than last winter.

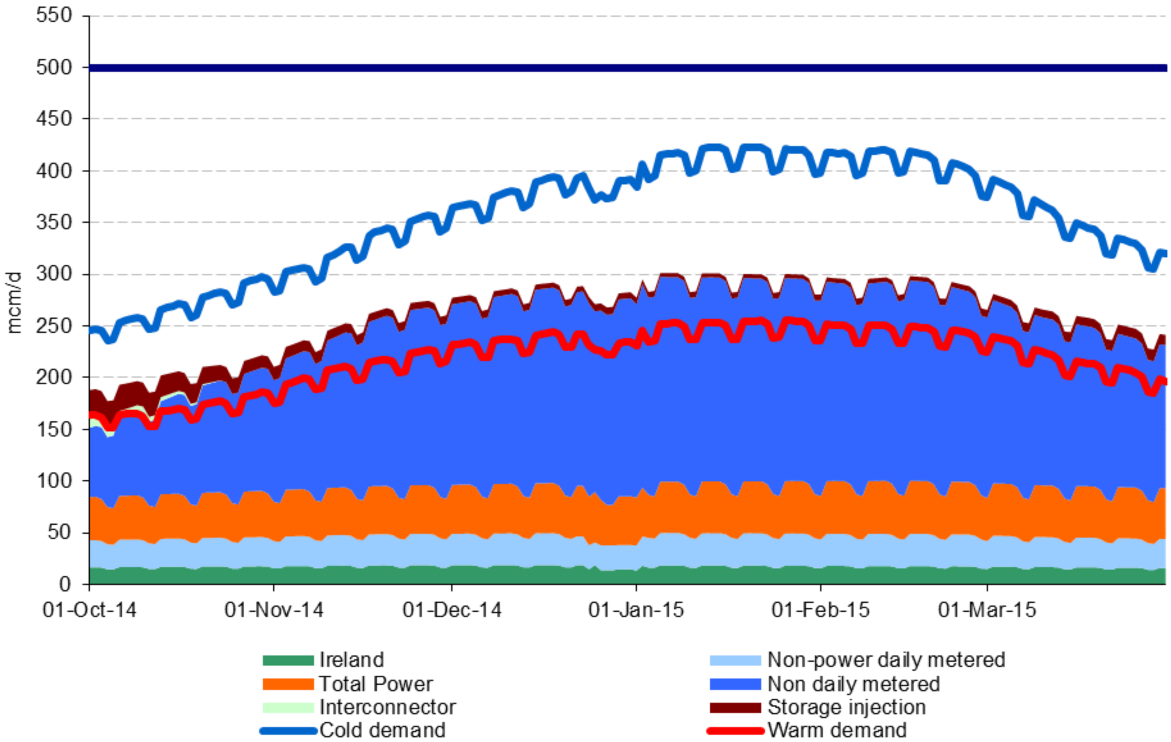


17. The 2014/15 winter demand forecasts are similar to the 2013/14 weather corrected demands. Gas for power generation is forecast to be the marginal generation in 2014/15.

18. Our forecasts for 2014/15 are based on our No Progression scenario taken from our Future Energy Scenarios. No Progression was selected because the peak day (1 in 20) over the winter of 2014/15 was the highest level across the range of our scenarios and therefore represents the tightest market in which to analyse the resilience of the system.

19. **Figure 4** shows the forecast gas demand for winter 2014/15 based on seasonal normal demand. In addition, lines to represent cold and warm demand are shown. These lines represent the influence of weather rather than any demand changes associated with, for example, power generation economics.

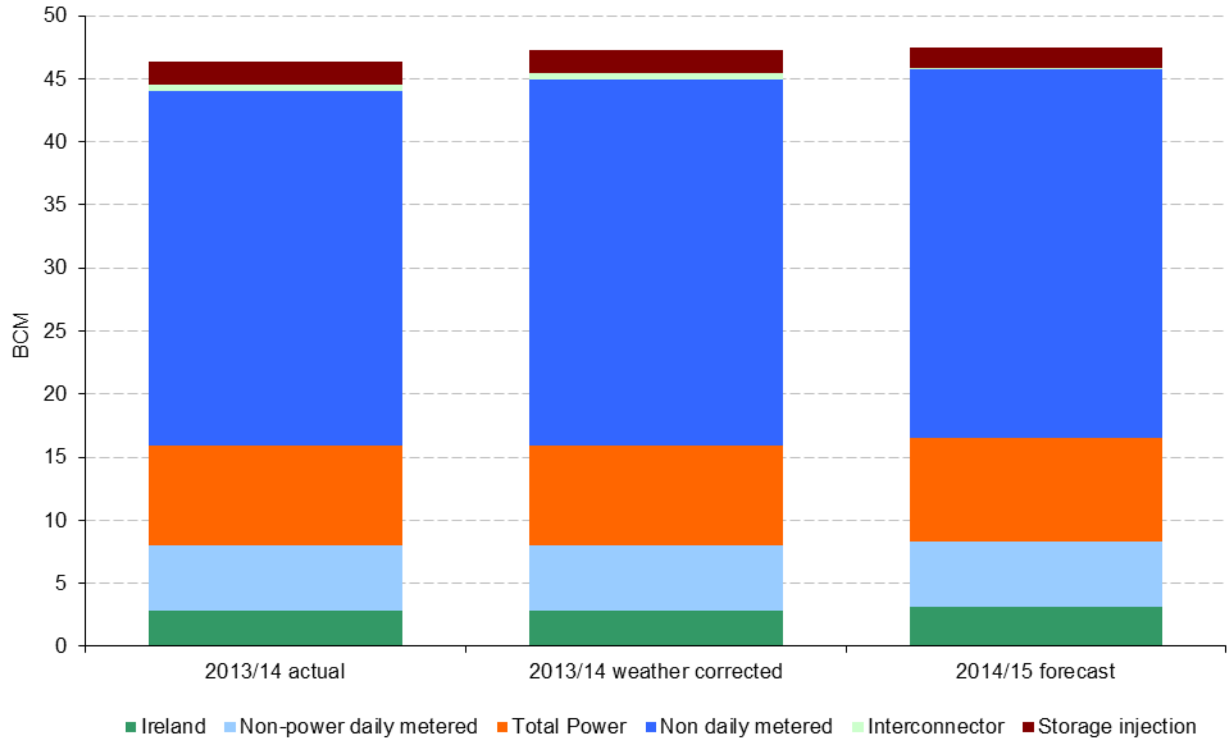
Figure 4 – Forecast Gas Demand Winter 2014/15



20. The chart shows seasonal normal demand peaking around 300 mcm/d. Peak winter demands may be appreciably higher than this as temperatures can be colder than seasonal normal temperatures. The peak day forecast demand of 499 mcm/d is significantly higher than the cold demand curve, as the peak day assumes colder weather, leading to higher demand from sectors that are sensitive to weather conditions (e.g. residential, other building and industrial sectors). It also includes power station demand of 79 mcm/d.

21. **Figure 5** shows the actual and weather corrected demand for last winter and the forecast demand for winter 2014/15.

Figure 5 – Actual and Forecast Gas Demand – October to March, 2013/14-2014/15



22. The above chart shows the 2013/14 non-daily metered (NDM) demand is not significantly lower than weather corrected despite the fact that the 6 months from October 2013 to March 2014 were warmer than normal. This is because weather correction has a greater impact on cold weather, with only a limited impact on warm weather. Little difference between weather corrected 2013/14 and the winter forecast for 2014/15.

23. **Table 1** shows the historic actual and weather corrected demand for winters 2011/12 through to 2013/14 and the forecast for winter 2014/15.

Table 1 – Actual and Forecast Gas Demand – October to March, 2011/12-2014/15

October to March winter bcm	2011/12 Actual	2011/12 Weather corrected	2012/13 Actual	2012/13 Weather corrected	2013/14 Actual	2013/14 Weather corrected	2014/15 Forecast
NDM	28.2	29.9	33.9	30.0	28.1	29.0	29.3
DM + Industrial	5.3	5.3	5.4	5.3	5.1	5.2	5.2
Ireland	3.0	3.1	3.1	3.1	2.9	2.9	3.1
Power generation	9.9	9.9	8.6	8.5	7.9	7.9	8.3
Total demand[12]	**46.7**	**48.4**	**51.2**	**47.2**	**44.2**	**45.2**	**45.8**
IUK export	4.4	4.4	0.6	0.6	0.6	0.6	0.1
Storage injection	2.3	2.3	1.8	1.8	1.8	1.8	1.6
GB Total	**53.5**	**55.2**	53.5	49.5	46.6	47.5	47.5

24. On a weather corrected basis, the table shows some decline in power generation and IUK exports in recent years. Power generation remains low due to fuel prices continuing to favour coal generation over gas. IUK was importing as a result of a lower LNG imports.

25. In our 2014 Winter Consultation Report we asked: “Discounting weather, what are your views regarding any material changes in residential, industrial and commercial gas demand over the winter period compared with winter 2013/14?” You told us:

    - Up (27.5%).
    - Down (27.5%)
    - Stay the Same (45%)

26. Although our Future Energy Scenarios[13] show a gradual long term downward trend, we anticipate no material change this winter compared to last winter on a seasonal normal basis.

27. We also asked: “What are your views on power generation gas demand relative to winter 2013/14?” To this question you responded:

    - Up (50%)
    - Down (17.5%)
    - Stay the same (32.5%)

28. During the summer gas used for power generation increased due to a decline in gas prices and as a result of a number of outages on coal and nuclear plant. However, the current forward market indicates a switch back to coal as being the favoured fuel for power generation and we are expecting the majority of plant to return from outages. Our forecast for 2014/15 therefore shows a slight increase in power generation demand compared to actual demand for last year.

29. The high forecast range for weather sensitive loads is based on a very cold January day; whilst Ireland is set according to our peak day forecast. IUK and storage demands are based on high historic observations. Power assumes our high gas-fired generation scenario.

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12 Totals also include Shrinkage
13 www.nationalgrid.com/fes

30. The high forecast range for weather sensitive loads is based on a very cold January day; whilst Ireland is set according to our peak day forecast. IUK and storage demands are based on high historic observations. Power assumes our high gas-fired generation scenario.

31. **Table 2** shows the daily average demand for last winter and the forecast demand for winter 2014/15. The table also shows the actual range of demand experienced last winter and a forecast range.

32. The low forecast range for weather sensitive loads is set according to the demand expected on a very warm early October[14] day. Ireland, IUK and storage demands are based on low historic observations, whilst power assumes our low gas-fired generation scenario.

33. The high forecast range for weather sensitive loads is based on a very cold January day; whilst Ireland is set according to our peak day forecast. IUK and storage demands are based on high historic observations. Power assumes our high gas-fired generation scenario.

Table 2 – Actual and Forecast Daily Gas Demand – October to March, 2013/14-2014/15

October to March winter	Daily average			Actual range		Forecast range	
mcm/d	2013/14 actual	2013/14 weather corrected	2014/15 forecast	2013/14 low	2013/14 high	2014/15 low	2014/15 high
NDM	155	159	161	53	219	32	309
DM + Industrial	28	28	29	21	33	20	36
Ireland	16	16	17	11	21	10	21
Power generation	43	43	45	20	68	13	75
Total demand	**243**	**248**	**254**	**116**	**327**	**110**	**425**
IUK export	3	3	1	1	20	0	30
Storage injection	10	10	9	0	65	0	65
GB Total	**256**	**261**	**263**	**164**	**330**	**150**	**425**

34. **Table 3** shows a similar table to **Table 2** but is based on the mid-winter months of December to February.

14 For the December to February range in **Table 3**, the very warm day applies to early December

Table 3 – Actual and Forecast Daily Gas Demand – December to February, 2013/14-2014/15

December to February winter	Daily average			Actual range		Forecast range	
mcm/d	2013/14 actual	2013/14 weather corrected	2014/15 forecast	2013/14 low	2013/14 high	2014/15 low	2014/15 high
NDM	179	188	189	147	219	120	309
DM + Industrial	29	29	29	21	33	20	36
Ireland	16	16	17	12	20	10	21
Total Power	43	43	47	20	67	13	75
Total demand	**268**	**277**	**284**	**216**	**327**	**200**	**425**
IUK export	2	2	0	1	6	0	30
Storage injection	6	6	5	0	44	0	45
GB Total	**276**	**285**	**290**	**227**	**330**	**215**	**425**

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

36. **Figure 6** and **Table 4** show the highest ever day of demand in December 2010 and the 1 in 20 peak day demand forecasts for winter 2014/15. The biggest difference in the demands is through the accounting methodology for power generation.

37. For comparison, the highest demand day in winter 2013/14 was 30 January 2014 with a demand of 323 mcm/d. An explanation of this demand is given in our 2014 Winter Consultation Report.

Figure 6 – 1 in 20 Peak Day Gas Demand 2014/15[15]

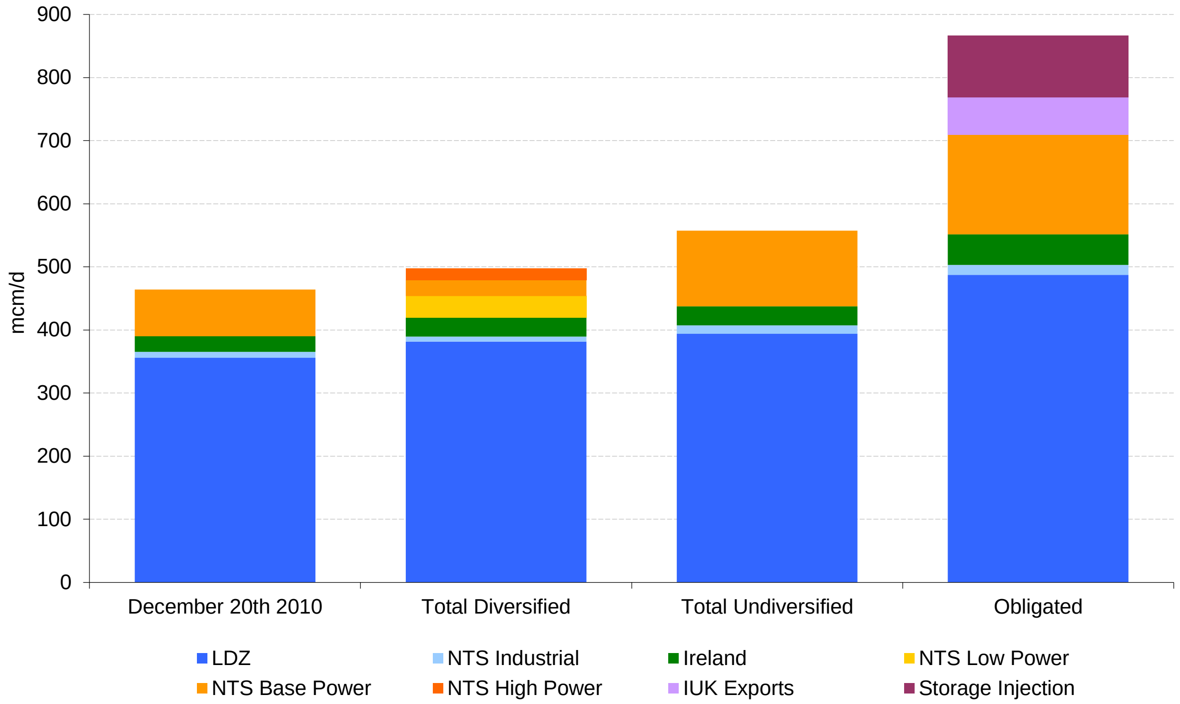


Table 4 – 1 in 20 Peak Day Gas Demand 2014/15[16]

mcm/d	20 Dec 2010	2014/15 Forecast Total Diversified	2014/15 Forecast Total Undiversified	Obligated
LDZ	356	382	394	487
NTS Industrial	9	8	13	16
Ireland	25	30	30	48
NTS Power	74	78	120	158
IUK Exports	0	0	0	59
Storage Injection	0	0	0	98
Total	**465**	**499**	**557**	**866**

[15] Diversified peak demand is the demand that could be expected for the country as a whole on a very cold day, whereas Undiversified peak demand is the peak day demand calculated for each LDZ and NTS site independently, and then added together. Obligated is the total amount of Capacity that National Grid is required to make available on every day of the year.

[16] Demand data can differ between different sources for a number of reasons including classification, CV and close-out date. Power generation classifications are: in **Table 1** to **Table 3,** the LDZ connected power stations at Shoreham, Barry, Severn Power and Fawley are includesd in the total power category; but in **Table 4**, they are included in Local Distribution Zone (LDZ) demand. Grangemouth and Winnington NTS offtakes are included in total power in **Table 1** to **Table 3** but NTS industrial in **Table 4**. Immingham is classified as NTS power stations for all 3 tables.

38. Due to the price assumptions, the base case forecast for gas-fired power generation is relatively low. For the 1 in 20 peak, a high case forecast for power generation is used. This assumes lower gas prices than our base forecast, and lower availability of non-gas generation such as nuclear and wind. For the 2014/15 forecast, this increases the power generation component of the diversified peak day forecast to 78 mcm.

Supply Forecast

Gas supply forecasts similar to those for winter 13/14.

GB storage expected to be full by the start of winter.

Significant range of supply options to meet peak demands.

39. This section examines each of the potential gas supply sources in turn. As in previous winters, there is considerable uncertainty in both the source and the level of imported supplies for next winter. Our view has been influenced by our experience last winter, feedback through our Future Energy Scenarios[17] (FES) consultation process and responses to the Winter Consultation document[18] published in July. The discussion in this section is all centred on a case where there is no effect on supplies to GB as a result of the situation in Ukraine. A separate section on page 28 discusses the possible effects of disruption to Russian imports.

UKCS Gas Supplies

40. **Table 5** shows our forecast for UKCS flows for winter 2014/15 together with the forecast made in last year's Winter Outlook and the maximum flows observed. Note, the actual flows are the highest seen at each terminal through the winter and did not occur simultaneously; the highest observed aggregate UKCS flow was 117 mcm.

[17] FES documents can be found at http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Future-Energy-Scenarios/

[18] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34787

Table 5 – UKCS Maximum Flow Forecast by Terminal

Peak (mcm/d)	2013/14 Winter Outlook	2013/14 Actual Range	2014/15 Forecast
Bacton	29	16 - 30	27
Barrow	9	0 - 7	9
Burton Point	2	0 - 4	1
Easington	9	6 - 12	9
St Fergus[19]	36	7 - 45	37
Teesside	15	4 - 23	15
Theddlethorpe	11	0 - 14	11
Total	**110**		**109**
90% Op Forecast	99		99

41. **Table 5** shows a provisional UKCS maximum supply forecast of 109 mcm/d for winter 2014/15. This is marginally below the equivalent forecast for winter 2013/14.

42. A number of new fields are forecast to come on-stream before or during winter, including the first gas from West of Shetland. These are not quite enough to offset the decline in existing fields at Bacton and Burton Point.

Norwegian Imports

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

44. In order to forecast Norwegian flows to GB for next winter, an estimate of total Norwegian production is made, based on historical trends and expectations for the coming winter. An estimate of likely Continental flows is then made, which takes into account historical ranges along with expectations for this winter. There is also an estimate for Norway's own-use gas, which is largely used in industry but also includes some residential use and power generation.

45. Due to the potential variation in Continental flows, a range of Norwegian flows to GB is calculated based on observed load factors to each of the Continental countries that receive Norwegian supplies. For winter 2014/15 our forecast of Norwegian supplies to GB, averaged over the whole winter, is between 82 mcm/d and 115 mcm/d, with a central estimate of 95 mcm/d as shown in **Table 6.**

[19] Excludes estimates for Vesterled and Tampen

Table 6 – Winter 2014/15 Estimates of Norwegian Exports

(mcm/d)	High flows to Continent	Low flows to Continent	Central	Cold Day
Norway	20	20	20	20
Belgium	40	35	38	38
France	48	45	47	47
Germany	130	105	120	125
GB	**82**	**115**	**95**	**110**
Total	320	320	320	340

Continental Imports

46. Supplies through BBL in winter 2013/14 were reliable but due to the low demand they did not show the same range as in the previous winter's more demanding conditions.

47. There is however no evidence to suggest that in a more challenging winter than 2013/14 BBL would not perform as required, so for planning purposes our forecast for BBL for next winter flows is unchanged at 40 mcm/d.

48. IUK has been shown to respond well to the price differential between NBP and Zeebrugge, which is in turn dependent on demand, availability of supplies and storage levels and flows in Great Britain and north-west Europe.

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

50. Our forecast for IUK imports next winter reflects this uncertainty regarding the availability of other non-storage supplies, notably LNG.

51. Our view of IUK flows is based on its behaviour during the last two winters. Given the uncertainties over the availability of other non-storage supplies, a value of 45 mcm/d has been used for what IUK could be expected to provide on a cold day with associated high gas demands.

LNG Imports

52. Winter 2013/14 saw a slight decrease in LNG imports compared with the previous winter. This was primarily due to lower GB demands and higher prices in the Far East.

53. In terms of attracting LNG cargoes, NBP prices remain significantly higher than US prices. LNG prices in the Far East have decreased over the summer but still remain higher than the GB, and are likely to be the preferred market for most traded and spot LNG.

54. There is the possibility of some Japanese nuclear power restarts over winter 2014/15, but these are likely to displace oil generation rather than gas generation initially.

55. **Table 7** shows some of the factors which may increase or decrease global LNG availability, thus supporting higher or lower GB LNG imports.

Table 7 – Factors Affecting Global LNG Availability over Winter 2014/15

Increased LNG availability (Potentially higher GB imports)	Lower LNG availability (Potentially lower GB imports)
Increased global production capacity	Liquefaction outages limit LNG supply
Return of some nuclear power in Japan displacing some gas powered generation	High LNG demand in the Far East, especially Japan, South Korea and China
Increasing volumes of LNG re-exports	Increased LNG to South America
Milder weather in Far East reduces LNG demand in Asia.	Lower LNG prices in Asia result in LNG displacing other fuels

56. In 2014 new LNG supplies started (or are due to start) from Papua New Guinea, Australia and Algeria. Whilst most of this LNG is likely to be sold to other markets, it still represents an overall increase in global production capacity. However, this should be balanced with declining LNG exports in North Africa and parts of SE Asia.

57. To manage the supply uncertainty surrounding GB LNG, a wide range is considered, from 8mcm/d (approximate boil off levels) up to potentially 130mcm/d under favourable conditions. However, as observed last winter, there is still considerable uncertainty over the responsiveness of LNG to GB market conditions. Additional LNG imports to GB would be subject to global availability and would likely require higher GB prices. Increasing gas demands and higher gas prices in Asia result in ~75% of LNG being delivered to Asian markets.

Storage

58. There is the potential for extra storage in the coming winter from the medium range sites Stublach and Hilltop.

59. Based on assessments of current storage sites, deliverability for next winter is approximately 129 mcm/d (1420 GWh/d).

60. **Table 8** shows our assumed levels of storage space and deliverability for next winter. Stocks in medium and long range sites were on track to be full for the start of winter, the current stocks can be found on the National Grid website.[20]

[20] http://www2.nationalgrid.com/UK/Industry-information/Gas-transmission-operational-data/Supplementary-Reports/

Table 8 – Assumed 2014/15 Storage Capacities and Deliverability Levels[21]

	Space (GWh)	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (mcm/d)[22]	Duration[23] (Days)
Short (SRS)	677	3	143	13	5
Medium (MRS)	12,572	709	824	75	15
Long (Rough)	40,700[24]	420	455	41	89
Total	53,949	1,132	1,422	129	

Non Storage Supply and Margins Notice; Winter 2014/15

61. In the previous sub-sections, we have outlined the basis for the assumptions incorporated into our analysis. Our view of supplies for the winter, and in particular the Non Storage Supply (NSS) is used in the determination of the trigger levels for the Margins Notice[25], issued when there is a potential or actual risk to the end of day NTS physical system balance, as discussed further in 94.

62. **Table 9** summarises the supply range and our supply forecast for a 'cold day'[26]. Also shown are the actual 2013/14 ranges for the six month period. The forecast ranges and the cold day value are based on observation of maximum flows seen over recent winters or on cold days. As we discussed in the Winter Consultation, there was little cold weather in winter 2013/14 and the highest demand was 329 mcm/d. As a result we have had to base the maximum values and the cold day analysis on observations from earlier winters. Responses to the winter consultation generally supported this view, though some respondents felt that the LNG level was too high, while others thought it was too low.

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

[22] Assumed a standard CV of 39.6MJ/m^3

[23] Duration based on Space / Deliverability, excludes within winter refill

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

[25] http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/gas-deficit-warnings-and-margins-notices/

[26] A day approaching 0 degrees CWV

Table 9 –Non Storage Supplies Winter 2014/15

(mcm/d)	2013/14 Actual Range	2014/15 forecast Range	Cold Day
UKCS	65 – 106	76 - 109	99
Norway	47 – 127	60 -130	110
BBL	3 – 45	10 - 45	40
IUK	0 – 27	0 - 74	45
LNG Imports	8 – 44	8 -130	50
Total			344
Storage	0 – 86	0 - 129	

Maximum flows by terminal

63. So far we have discussed ranges of expected flows and flows on a cold day, but with no indication of location.

64. **Table 10** shows an indication of the maximum flow expected at each terminal, together with the flow on a cold day. The UKCS flows from **Table 9** have been allocated to terminals, but for some of the other flow types this is not possible. For example **Table 9** shows a flow of 50 mcm/d for LNG on a cold day but our analysis does not allocate this between Milford Haven and Isle of Grain. For non UKCS flows

65. **Table 10** shows the maximum capacity instead of the forecast maximum flow.

Table 10 –Maximum Flows by Terminal Winter 2014/15

(mcm/d)	Forecast maximum flow*	Flow on Cold Day
Bacton	151	111
Barrow	9	8
Burton Point	2	2
Easington ex. Rough	78	76
St Fergus	97	74
Teesside	17	17
Theddlethorpe	9	8
Isle of Grain	59	15
Milford Haven	86	35
Total	508	344

*or official capacity

Russia/Ukraine Dispute

There is sufficient capability in the GB market to cope with any disruption.

LNG is the most likely source to provide additional supplies to cover for any losses.

Only in the case of a disruption to all Russian gas in a cold winter would market actions be required.

66. With the ongoing tensions between Russia and Ukraine there has been significant interest in the potential impact of an interruption to imports of gas from Russia into Europe. In response to this National Grid, in conjunction with DECC and Ofgem, have carried out some stress tests to assess how the GB energy market would be impacted by any such disruption. In addition to assessing the impact on the GB we are also collaborating with both the European Commission and ENTSO-G[27] to quantify the impacts across Europe.

67. Alongside the political tensions there is also an ongoing contractual dispute between Gazprom and Naftogaz over unpaid bills and the price of Russian gas exports. The failure to settle this dispute resulted in Russian gas imports into Ukraine being halted on 16th June 2014, although gas destined for other European markets has continued to be transited across Ukraine.

Analysis

68. The analysis tests the impact to GB gas supply and demand for both average and cold demands with an interruption to gas transited across Ukraine along with a wider disruption to gas supplies from Russia.

Figure 7 - Scope of Analysis

Stress Test	Level of disruption	
Severe Winter	Ukraine only	Full Russian curtailment
Average Winter	Ukraine only	Full Russian curtailment

69. The supplies and demands modelled have been designed to represent plausible patterns that could be expected for both disruption scenarios. The approach has also been designed to be consistent with the wider European assessments where required.

70. In order to evaluate against typical winter conditions the demands have been based on historical weather patterns, as this captures the impact of volatile demands driven by changeable weather that other demand models do not. For average conditions 1975/76 (average) weather patterns were used as these were the best match for the criteria for a wider European assessment, the cold conditions are based on 1985/86 (1 in 14 cold).

[27] European Network of Transmission System Operators for Gas

71. Gas supply sources have been modelled with a prescribed merit order; this method assesses the capability of the system but does not attempt to forecast likely flow patterns. The merit order applied is the following

   a. UKCS
   b. Norway
   c. BBL
   d. LNG
   e. Storage

72. **Table 101** details the supply/demand assumptions applied in the analysis, which have been based on analysis of historical flows and market intelligence along with our own assessment of likely interactions with other markets.

Table 11 – Non Storage Supply (NSS)

(mcm/d)	No disruption	Ukraine disruption	Russia disruption
UKCS	99	99	99
Norway	110	110	98
BBL	40	25	10
IUK Imports	45	0	0
LNG Imports	50	120	120
Total NSS	**344**	**354**	**327**
IUK Exports	**0**	-35	-58
NSS – IUK	***344***	***319***	***269***
***Storage*[28]**	***147***	***147***	***147***

73. For the Ukraine disruption scenario we have assumed that Russia increases volumes through other routes, such as the Nord Stream pipeline into Germany and the Yamal pipeline into Poland. In this scenario it is assumed that the physical capacity to re-route Russian gas via other routes is fully utilised. This is likely to result in significant volumes of gas in northern Europe limiting the diversion of Dutch and Norwegian imports away from GB. IUK exports are based on those observed during the January 2009 disruption, although the overall loss to Europe in this case is expected to be lower.

74. The scenario for a disruption of all supplies of gas from Russia to Europe results in more significant reduction in supply and this is likely to allow greater diversions of Dutch and

[28] Since the stress test was carried out in the summer National Grid has updated its view on the deliverability of GB storage available in the winter to 129 mcm/d, as used elsewhere in the document, however this change would not have a significant impact on the results of this analysis.

Norwegian imports away from GB. IUK exports have been assumed at the maximum capacity in order to test the impact this would have on the GB supply/demand balance.

75. In both cases LNG is expected to be the primary source of additional supply which is likely to require significantly higher prices than the current winter forward prices. These prices are also likely to incentivise other producers, such as Norway and The Netherlands to maximise their production throughout the winter.

76. Based on current stock levels, GB storage is assumed to be full at the start of winter for all scenarios.

Results

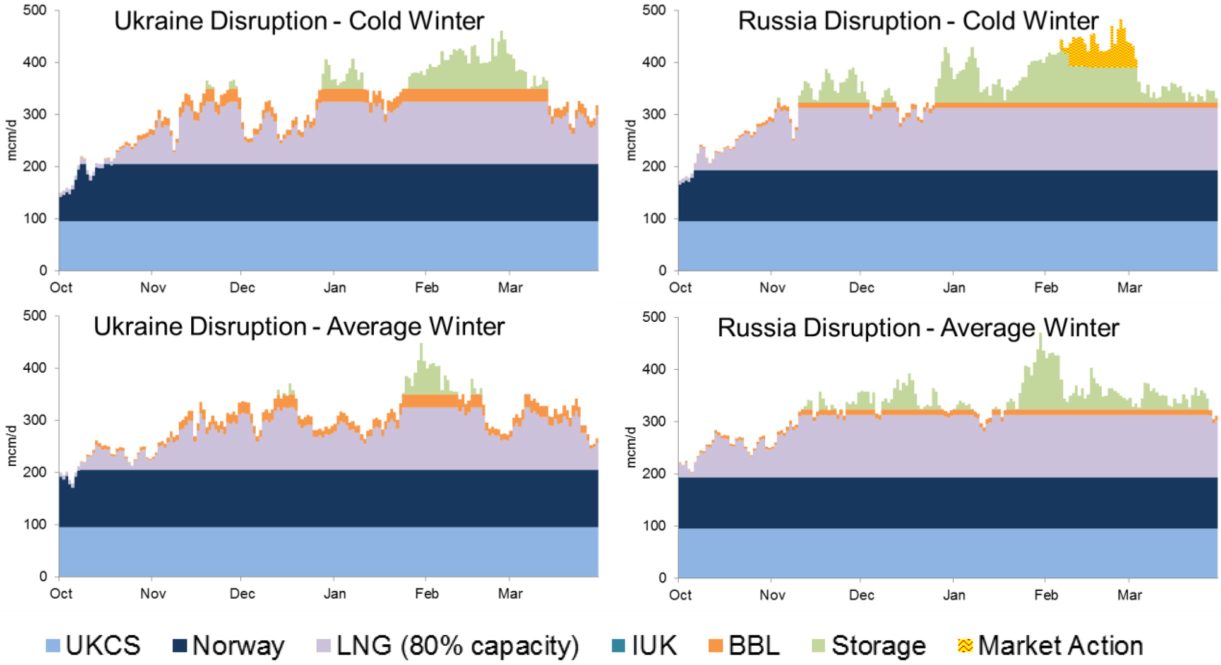
77. At average demands there is sufficient capability for the GB gas system to meet all required demands, both domestic and expected exports to continental Europe and Ireland, for either disruption scenario. This is also the case for cold demands if only gas supplies transited via Ukraine are impacted.

78. At cold demands for a wider disruption of gas from Russia the initial modelling identifies some requirement for further market actions. For the entire winter this equates to around 1.2 bcm with a daily maximum of slightly over 90 mcm. In this scenario there are a number of ways in which the market could respond to ensure that the supply/demand balance is maintained.

    a. On the supply side there could be increased imports attracted to GB which could come from a combination of additional LNG imports or from pipeline sources such as BBL or Norway.

    b. On the demand side there could also be reductions in demand both from demand side response from the industrial and power users alongside a reduction in export through IUK.

Figure 8 – Results of Russia/Ukraine Analysis



Operational Overview

Day to day supply uncertainties, unplanned events and within day Linepack variations are the key operational challenges this winter.

Operational Challenges

79. The key operational challenges for winter 2014/15 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.

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

81. 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.

82. 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 behavior continue and potentially increase.

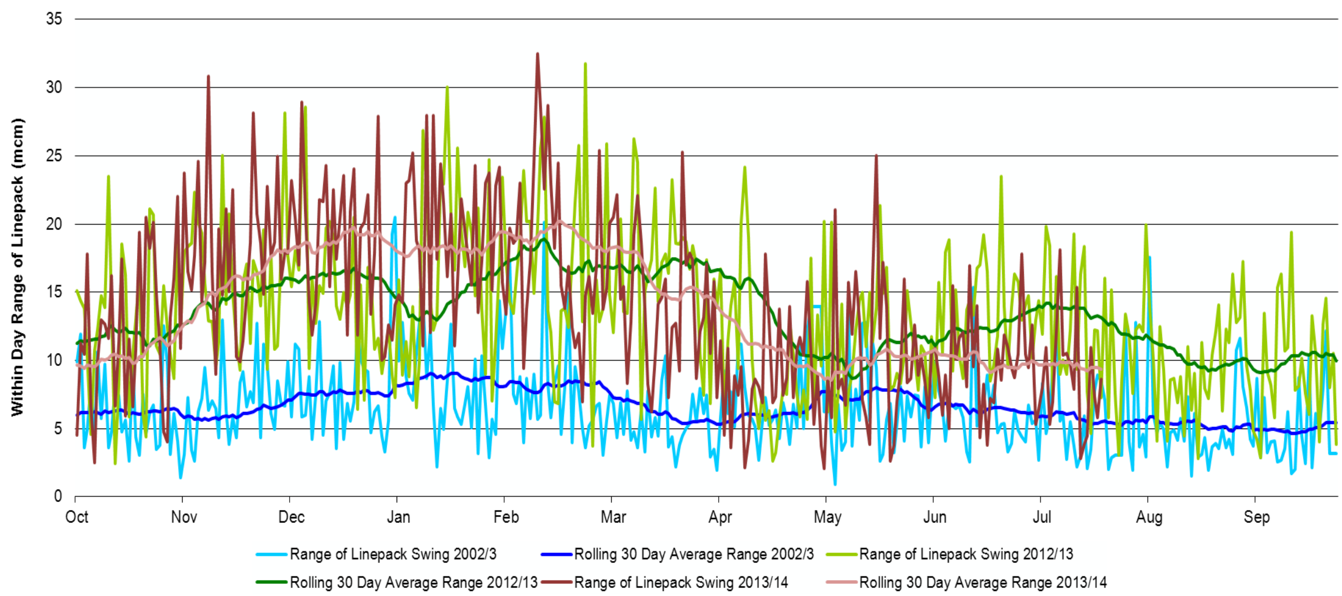
83. These changes alongside the changes to the supply environment have increased the day to day, and the within day Linepack volatility and have resulted in a notable trend towards later reconciliations of daily balance, with start of day offtake and flow notifications provided being less reflective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

84. 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 through the course of a day.

85. These factors are resulting in having to manage much greater Linepack swings on the NTS. Large Linepack changes are caused when 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 NTS pressures within safe and agreed operational tolerances, and delivering capacity obligations in line with customer requirements.

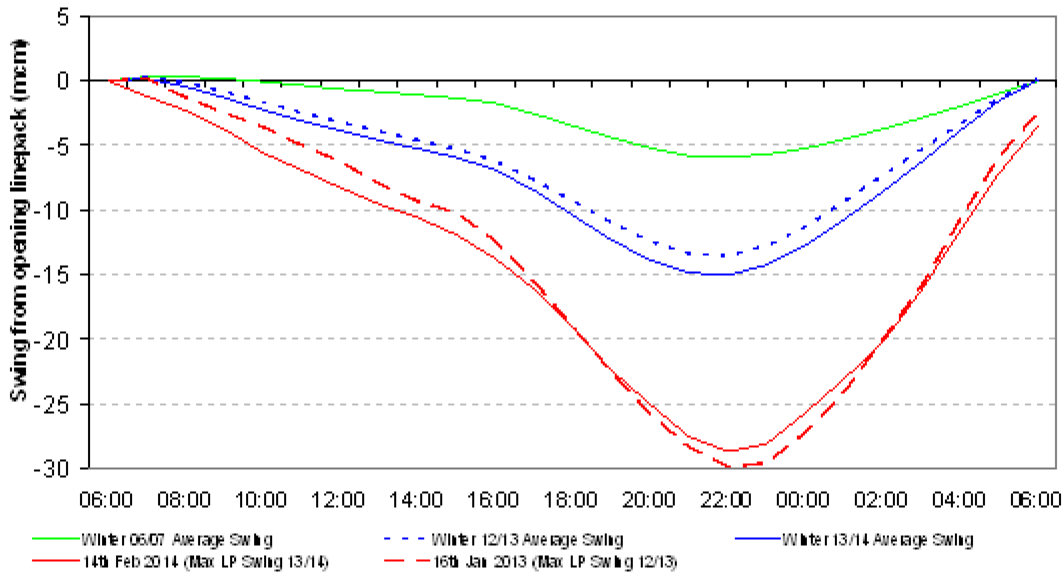
86. As demand for within day flexibility continues to grow and the operational reality moves further away from a steady hourly (the $1/24^{th}$) flat profile supply across the day that underpins the design of the network, there will be times when it cannot be accommodated and within day flexibility restrictions may need to be applied that ensure users operate within their contractual parameters.

Figure 9 – Comparison of Within Day Max-Min Range of NTS Linepack (mcm)



87. **Figure 9** shows how the use of Linepack flexibility continues to rise with the average swing on the Network increasing by 30% during 2013/14 and is now more than 250% greater than the levels seen in 2006/7.

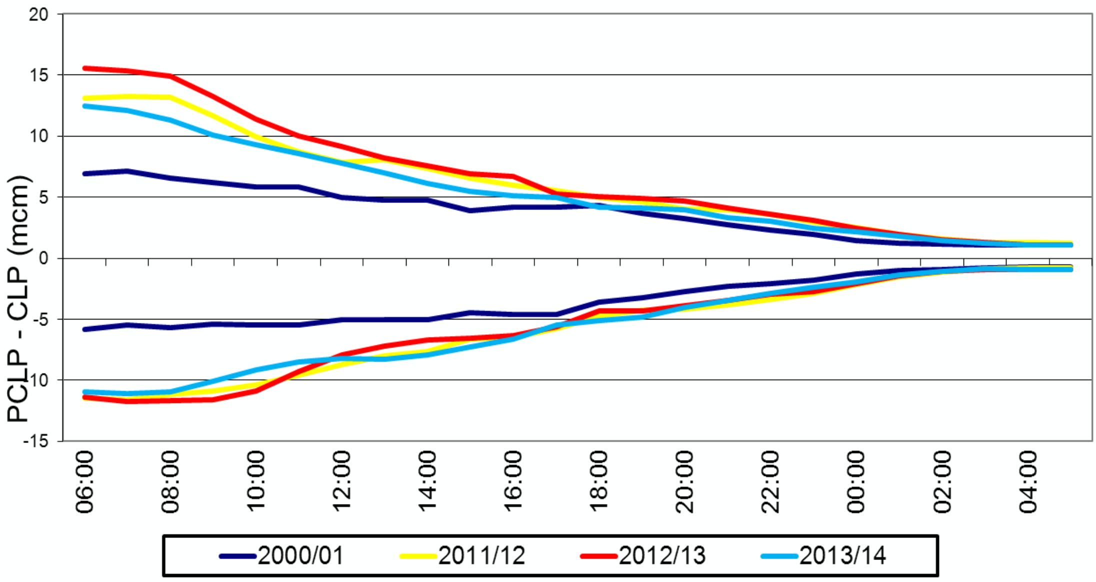
Figure 10 – Average Within Day Linepack Swing



88. **Figure 10** shows the average daily Linepack swing for 2006/07, 2012/13 and 2013/14. The red line shows the highest swing seen on a particular day for each of the past two years.

89. 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 11– Predicted Closing Linepack – Closing Linepack on Days of No Residual Balancing



90. **Figure 11** 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 trend is evidence of the changing ways that users are operating, and leads to increasing operational challenges for the system operator due to the increasing uncertainty as to when and where supplies will be brought into the NTS.

91. 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.

92. If issues should 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 utilisation 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.

93. 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 approximately 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

94. Although yet to be used, these information provision options were implemented in 2012 to replace the 'Gas Balancing Alert' (GBA). The '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 capability. 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 not achieving the end of day NTS balance position.
95. National Grid offers a subscription service for Gas Deficit Warning via SMS and email from the link at the following page: http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/gas-deficit-warnings-and-margins-notices/

Market Information Provision

96. 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.
97. 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://www2.nationalgrid.com/uk/industry-information/gas-transmission-operational-data/

Safety Monitors

The 2014/15 Winter Safety Monitor has been set at 754 GWh of space with 504 GWh/d of deliverability; meeting the requirement for protecting consumers.

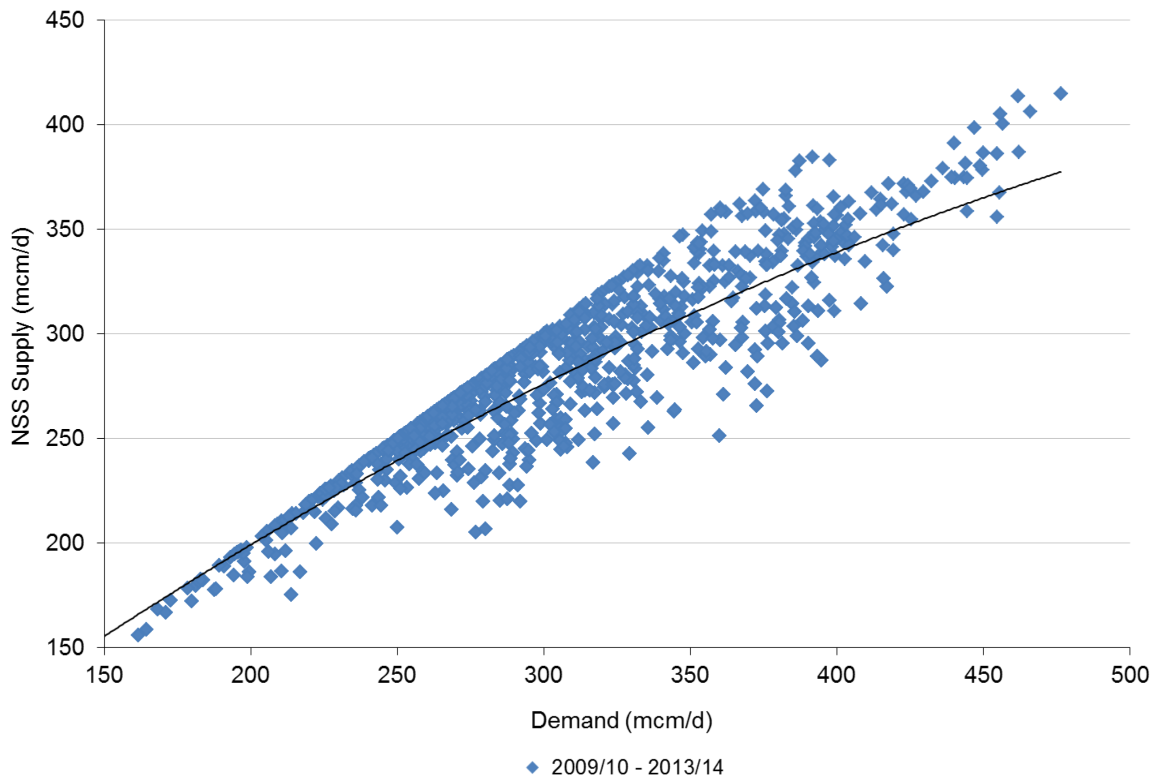
98. On 12th August 2014, the preliminary view of initial Safety Monitor levels was published for 2014/15 as required under the Uniform Network Code (Q5.2.1).

99. The purpose of the safety monitor is to ensure that sufficient gas is held in storage to support those gas consumers whose premises cannot be physically and verifiably isolated from the gas network within a reasonable time period.

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

101. **Figure 12** shows historic levels of non-storage supply (NSS) versus demand for the last five winters.

Figure 12- Non Storage Supply (NSS) versus Demand for the Winters 2009/10 to 2013/14



102. **Figure 12** shows the NSS versus demand assumption for winter 2014/15, 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 GB. 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.

103. The current Safety Monitor method 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.

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

105. The resulting Safety Monitor levels for winter 2014/15 are detailed below. The primary driver for the decrease in the safety monitor requirement is a revision to the NSS calculation methodology.

- 2014/15 Assumed storage space = 53949 GWh
- 2014/15 Safety Monitor space = 754 GWh (1.4%), (2013/14 = 1017 GWh)
- 2014/15 Safety Monitor deliverability = 504 GWh/d, (2013/14 = 633 GWh/d)

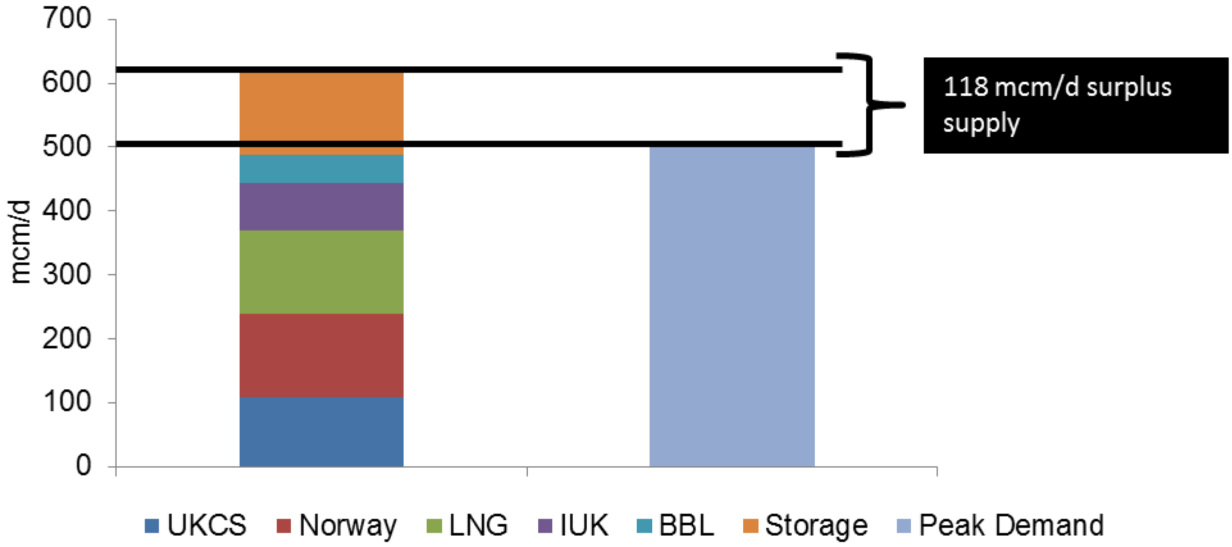
106. Safety Monitor levels and the associated winter profiles (i.e. how the monitors reduce later in the winter) will be published in October 2014.

Winter Security Assessment

GB infrastructure can meet gas demand under severe weather conditions for a protracted period, even with a single large import infrastructure failure.

107. Under normal operating conditions there are no abnormal concerns for gas security of supply this winter. **Figure 13** shows that there is a potential supply surplus of around 118 mcm/d over the 1 in 20 peak demand of 499 mcm/d.

Figure 13 – Potential Supply Surplus



108. To further assess the security of the gas system for the coming winter we have carried out some analysis on how demands could be met under severe weather conditions, both with normal supplies and in the case of a supply disruption.

109. Severe conditions represent 1-in-50 demand conditions over four durations:

- The peak day[29,] on average -5°C;
- The coldest week, on average -3°C;
- The coldest month, on average -1°C; and
- The coldest three months, on average 1.5°C.

110. Supply disruption represents a loss of the largest single piece of gas supply infrastructure (the Milford Haven to Felindre pipeline, an 86 mcm/d supply loss) this is consistent with the N-1[30] test used to assess gas security in the EU.

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

111. The demand is split into the following three categories:

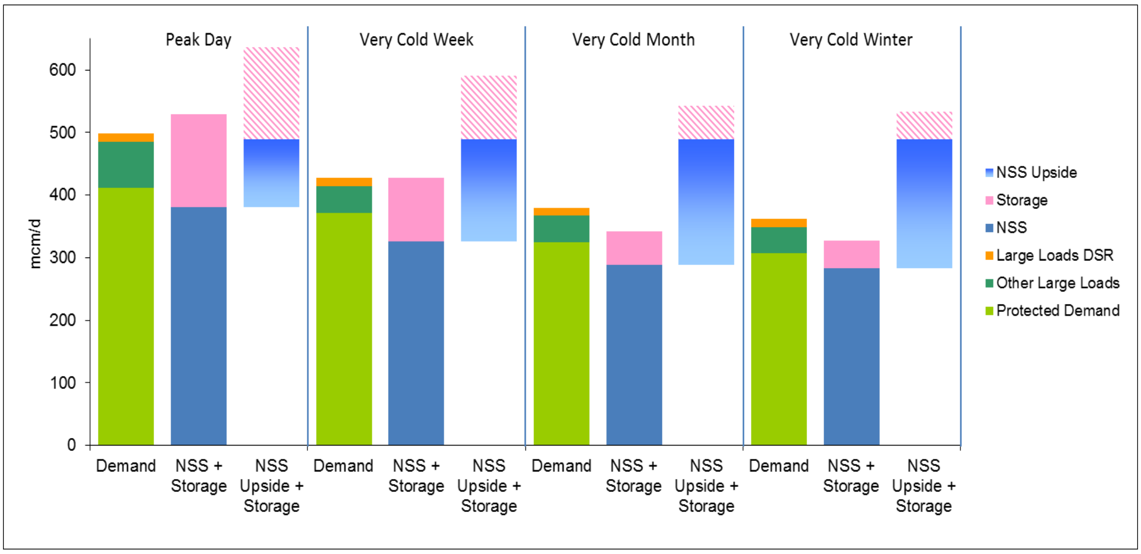
- Light Green: 'Protected demand': all customers protected by National Grid's Safety Monitor[31];
- Dark Green: 'Other large loads': Large loads that are not expected to respond to a short-term increase in gas price;
- Orange: 'Large loads DSR': Large loads that are expected to respond to a short-term increase in the gas price and therefore provide a demand side response (DSR).

112. After consultation with Ofgem along with our own internal analysis the available DSR has been assessed as 13 mcm/d, the majority (10 mcm/d) of this is from the power sector. There is a potential upside to this if non gas generation has a higher availability than our current assumptions, for each additional GW available for other generators DSR increases by approximately 4.5 mcm/d.

113. The supply is split both between non-storage supply (NSS) and storage and our central assumptions for normal conditions and the potential upside available to the market.

114. The available storage reduces for the longer duration spells as storage stocks deplete throughout the winter, there is a potential upside to this were NSS to be maximised both to preserve stocks and allow greater levels of re-injection.

Figure 14 - Demand Analysis under Severe Winter Conditions with No Supply Disruption



115. **Figure 14** shows how supply and demand would be balanced in a severe winter for the peak day, a very cold week, a very cold month and over the winter as a whole. The initial supply

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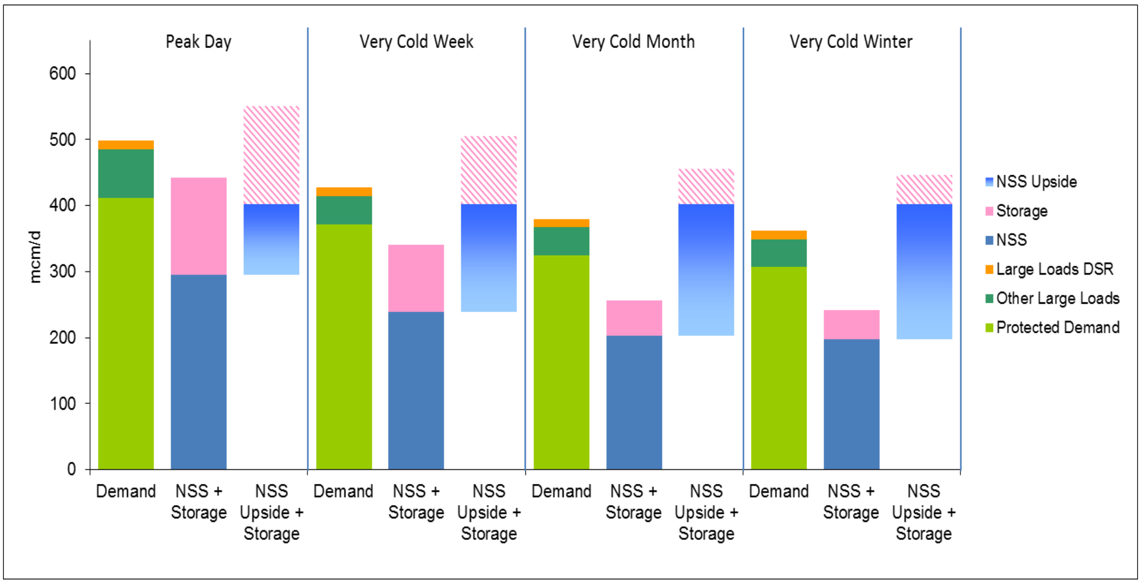
[30] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of supply and repealing Council Directive 2004/67/EC.

[31] Protected demand' includes all loads up to 5860MWh non-daily metered (including residential and small business consumers), non-daily metered flows to Ireland, and priority load. Priority load is split into three categories: Category A includes any customer where disruption could lead to loss of life (e.g. hospitals, care homes); Category B includes those that would have been in Category A except that they have signed interruptible contracts (because they have access to alternative generation) and can continue to use gas during the time it takes for them to switch to the alternative; and Category C, customers where interruption would lead to damage in excess of £50 million.

assessment in the second column is based on our central assumptions for NSS and the level of storage that would be available under severe conditions, this storage reduces in the longer durations as the stocks are depleted as storage is used.

116. For both the peak day and for a cold week there is sufficient storage to meet the demand without a need to increase non-storage supplies from our central assumption. For the longer duration cold spells additional NSS would be required to meet demand. The third column shows that there are sufficient potential supplies available to turn up to meet the demand.

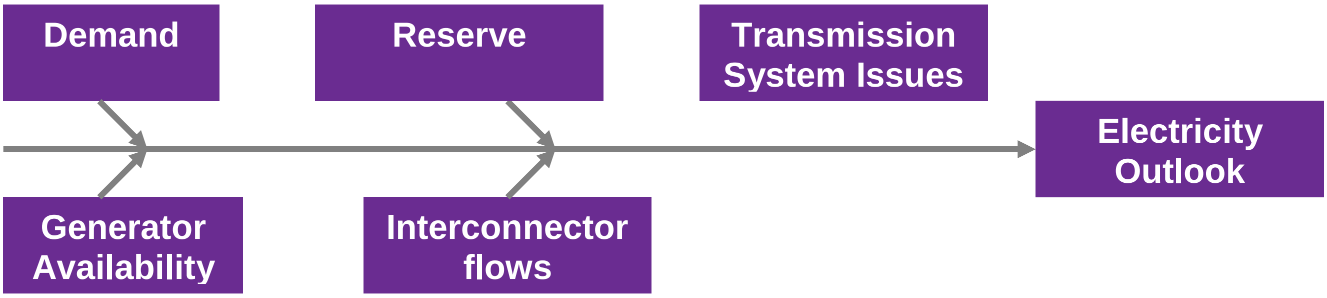
Figure 15 – Demand Analysis under Severe Winter Conditions with Supply Disruption



117. For all the durations in this case some additional NSS would be required to meet demand, but as can be seen in the third column there are sufficient potential supplies available to meet the demand.

118. The results of this analysis are in line with expectations as you would expect some sort of market response, either through additional supplies or DSR, to be required to meet demand during a prolonged cold spell or in the case of a major supply loss.

Electricity



Overview

119. This chapter sets out our current electricity forecast for the winter 2014/15. 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 flows. We also have a section describing reserve, which we use to manage these areas of variability and a section on transmission system issues. The final two sections bring together the picture of electricity margins and outline our actions to manage tighter margins with the additional measures that we are taking this winter.

Demand

For this coming winter underlying demand will remain flat.

There is an increasing volume of embedded wind and solar generation.

120. In this year's report as per last year's, demand now includes interconnector exports. This is Transmission System Demand (TSD) as defined in the Grid Code[32].

121. The 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.

122. 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 standardised weather.

Unmetered Embedded Generation

123. There is an increasing volume of embedded wind and solar generation for which National Grid receives no metering. This generation is equivalent to reducing demand at the transmission level, as seen by the System Operator.

124. Account is now taken of the estimated amount of unmetered embedded generation. Demand forecasts beyond the horizon of detailed daily weather forecasts and weather corrected demands are adjusted to take account of a standardised weekly amount of embedded generation.

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

125. In addition, Average Cold Spell (ACS) and 1 in 20 demands, whether historic or forecast, use the appropriate standardised weekly value (850MW) for unmetered embedded generation.

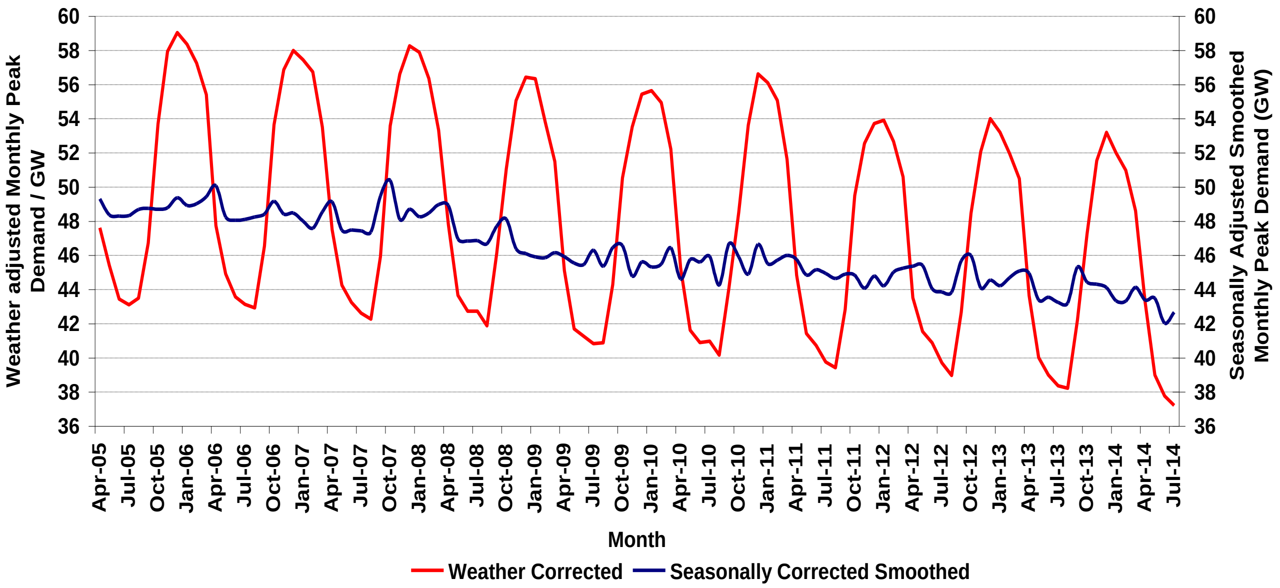
Customer Demand Management (CDM)

126. Average Cold Spell (ACS) and 1 in 20 demands are quoted as restricted demands, which means that they take into account the estimated amount of CDM[33] on the highest demand days. At present we estimate this to be 1200 MW on days of Triad Avoidance.

Demand Levels

127. **Figure 16** shows the weather corrected and seasonally adjusted smoothed demand levels for the last nine years. The general trend in peak demand is downward. Given that statistical review of positive gross domestic product (GDP) figures shows that the economy has been better than recent years, it seems likely that the decline in peak demand is due to energy saving measures, increase in embedded generation 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.

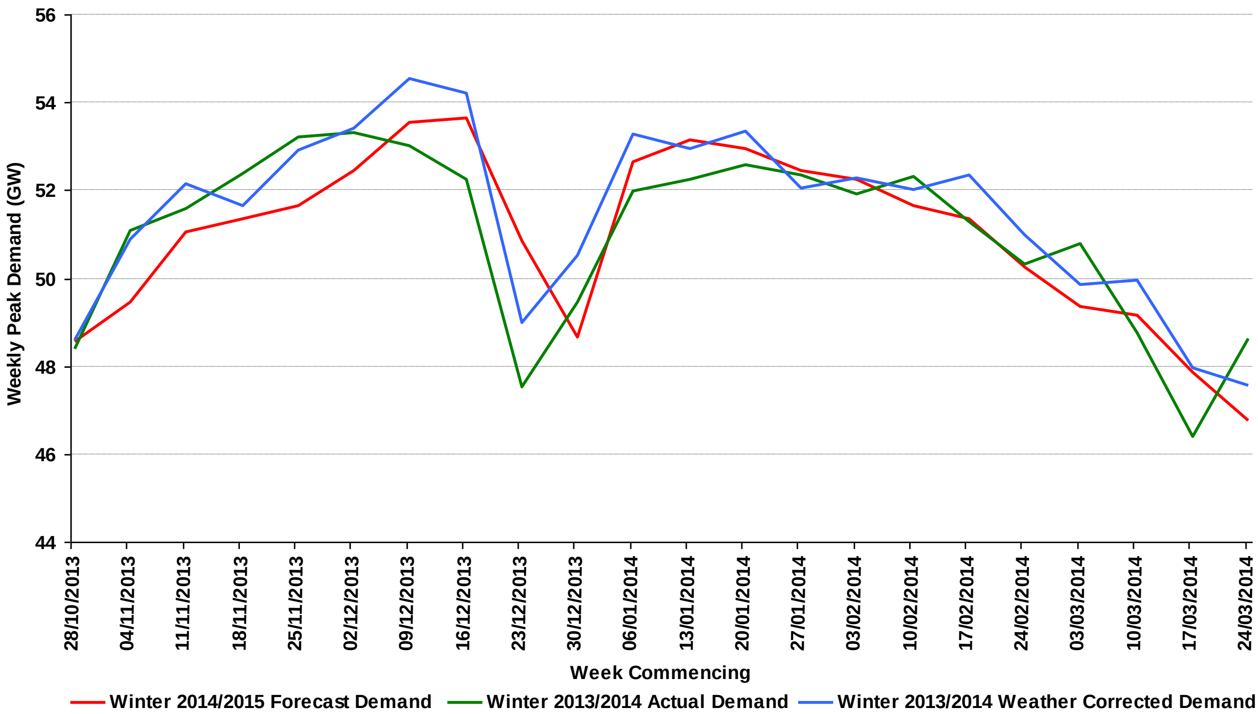
Figure 16- Weather Corrected and Smoothed Seasonally Corrected Demand



128. **Figure 17** shows the previous year's (2013/14) actual demand and weather corrected demand, and the demand forecast for the coming winter (2014/15). The most current forecast at any time is given on the BMRS[34], 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 2013 because of Christmas coming on the 4th day of week in 2014 as compared to the 3rd Day in 2013. In 2014, the Monday of the Christmas week is assumed to be a full working day.

[33] Customer demand management is defined in the Grid Code: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34851
[34] www.bmreports.com

Figure 17- Previous Year's Outturn and Forecast for 2014/15



129. 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. However, in any winter 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 winter.

130. Our current peak weather corrected demand forecast for this winter is now 53.6 GW compared to the weather corrected demand forecast at the time of publishing the Winter Consultation Report of 54.0 GW. The differences in the demand forecast between the consultation and this report are due to increase in embedded generation over the summer.

131. The 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 2014/15 the (restricted – see paragraph 126) ACS forecast is currently 55.0 GW, compared to an equivalent figure of 55.5 GW at the time of the Winter Consultation Report.

132. 1 in 20 conditions are a particular combination of weather conditions that 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 56.3 GW compared to an equivalent figure of 57.4 GW at the time of the Winter Consultation Report.

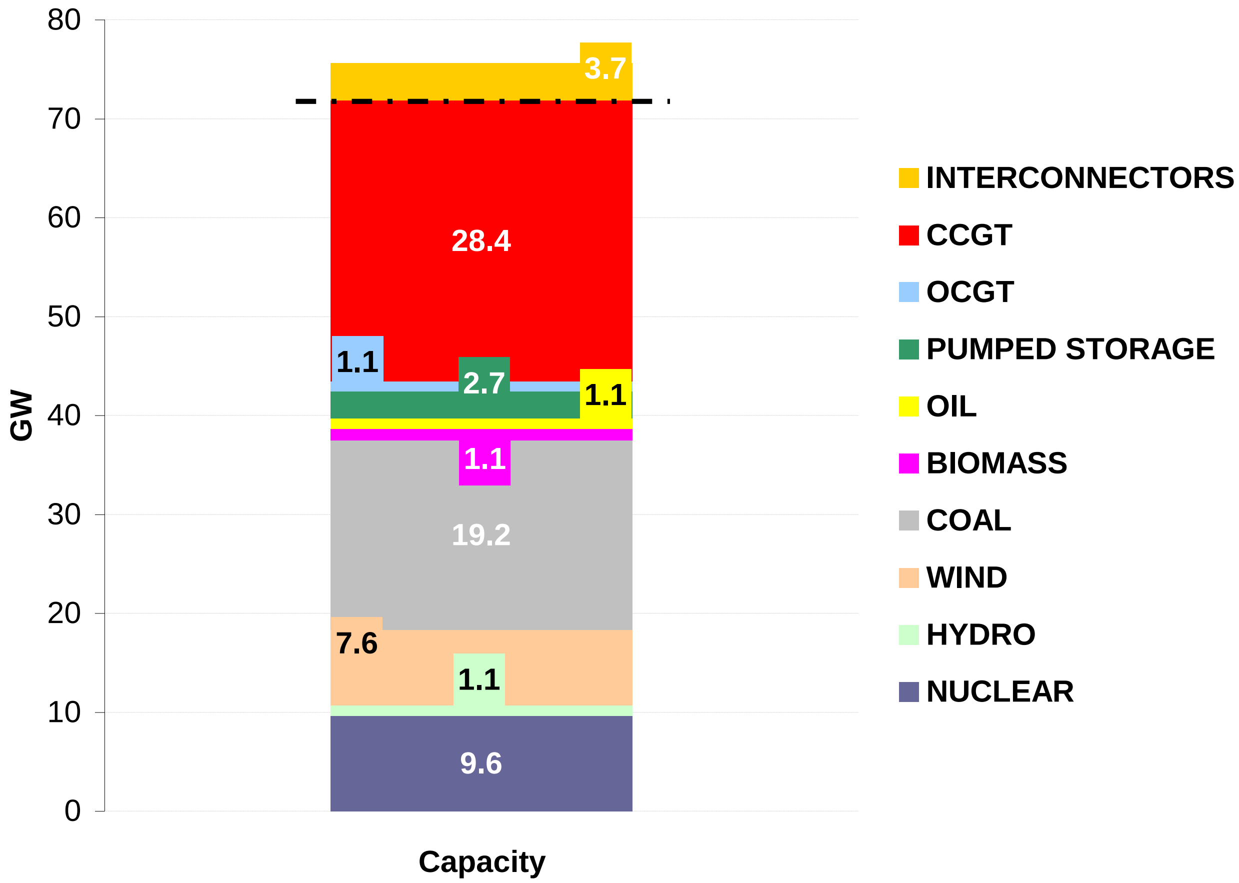
Generator Availability

Margins may be tight this winter following plant closures, particularly if we experience interconnector exports to Europe or low wind.

Generation Capacity

133. **Figure** 18 shows a breakdown of the maximum generation capacity that is expected to be available, based on current information submissions. Our current forecast for installed operational generation capacity anticipated at the winter peak for 2014/15 is 71.9 GW. There is also 3.7 GW of installed interconnector capacity.

Figure 18– Operational Generation Capacity Forecast for the Winter Peak 2014/15



Large Combustion Plant Directive (LCPD)

134. The only LCPD opted out power stations remaining available are Ironbridge unit 2 and Littlebrook, which will not be limited by their remaining hours this winter.

Transmission System Issues

It is likely that strategic generation will be run overnight to maintain system voltage.

Margins are not expected to be restricted by transmission constraints this winter.

135. This section describes some of the transmission system issues expected this winter that could have an adverse effect on system margins. There are no specific issues expected apart from a small curtailment of wind generation in Scotland. This is not expected to affect system margins this winter.

Voltage

136. There is likely to be a requirement for strategic generation to run during overnight periods in the south of the country to maintain the system voltage profile. We do not expect there to be any issues with the system voltage profile in Scotland, other than over the Christmas period, where it is likely that there will be a requirement for strategic generation to run overnight. This is standard and does not have an impact on power flows to households and businesses.

Transmission System Reinforcement

137. The relevant Transmission Owners continue to develop their transmission systems[35] 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[36] when output exceeds transmission capacity.

138. The historic amount of output and historic estimated curtailment of large[37] wind farms is shown in **Table 12.**

139. **Table 13** 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 to be on to provide these services could be curtailed instead).

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[35] The Electricity Ten Year Statement illustrates the future development of the National Electricity Transmission System http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

[36] 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://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

[37] 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 12 – Metered Wind Farm Output

GWh	Apr – Sep 2012	Oct 2012 – Mar 2013	Apr – Sep 2013	Oct 2013 – Mar 2014
NW Scotland (B1)	673	1,040	966	981
Remainder of Scotland	1,769	2,837	2,120	5,283
England and Wales	3,048	5,152	4,300	7,912
Total wind output	**5,491**	**9,030**	**7,386**	**14,177**

Table 13 – Estimated Volume of Wind Farm Curtailment

GWh	Apr – Sep 2012	Oct 2012 – Mar 2013	Apr – Sep 2013	Oct 2013 – Mar 2014
NW Scotland (B1)	41	15	77	65
Remainder of Scotland	8	10	180	0
England and Wales	0	0	2	158
Total wind curtailment	**49**	**24**	**260**	**223**

Reserve

2.3GW of Short Term Operating Reserve (STOR) has been procured to date.

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

141. We procure the non-synchronized requirement from a range of service providers which include both Balancing Mechanism (BM) participants, and non-BM participants. This requirement is called Short Term Operating Reserve (STOR) and is procured on an open market tender basis that runs three times per year. National Grid encourages greater participation in the provision of reserve and engages with potential providers to tailor the service to meet their specific technical requirements.

Short Term Operating Reserve

142. For winter 2014/15, our present level of contracted STOR reserve is approximately 3.5 GW, approximately 1.5 GW comes from BM participants and 2 GW comes from non-BM generating plant and demand reduction units. Approximately 0.5 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.

143. Last winter approximately 3 GW of STOR was contracted over the darkness peak period in all, but much of that was not available over weekday peak demands, and dependent on providers contracted position or availability. Total availability at the time of the top 20 winter peak demands last winter was 2 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 2014/15 darkness peak is expected to remain consistent with last winter (2013/14).

144. 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 synchronised sources within the BM. If all response holding was created in the BM, then approximately 1.9 GW of reserve would be required to meet the necessary response requirement. 0.7 GW of this 1.9 GW reserve requirement has already been contracted, with 0.14 GW from demand-side providers.

Reserve for Frequency Response

145. National Grid expects to contract more frequency response to provide response service over the winter. Last winter we contracted about 0.9 GW of reserve for response over the darkness peak period in all, but much of that is dependent on providers contracted position or availability.

Maximum Generation

146. National Grid continues to have Maximum Generation contracts in place for Winter 2014/15, which provides potential access to up to 740MW[38] of extra generation in emergency

[38] In an emergency situation only a proportion of this is likely to be able to be used due to the consequent loss of reactive power capability.

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.

Interconnector Flows

Net exports from GB to Ireland expected.

Net imports from continent expected based upon current forward prices.

147. Interconnector flows are closely correlated with price spreads. However with the effects of the weather, plant unavailability 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.

148. The North West Europe (NWE) day ahead coupling regime is now live. Intraday trading on both IFA and BritNed interconnectors is still via explicit capacity auctions with a 2-4 hour gate closure, so the full impact of within-day price volatility upon flows to and from the continent is not yet being felt. Currently therefore, average price spreads during EFA (Electricity Forward Agreement) block 5 (i.e. 15:00-19:00 GMT) are the best indicator of interconnector behaviour at GB demand and price peak.

Ireland

149. The interconnector to Northern Ireland (Moyle) is at a capability of +/-250MW and is expected to remain at this level for another 3 - 4 years until the cable is replaced. A prudent estimate from Mutual Energy[39] suggests commissioning of the cable to +/-500MW in autumn 2017.

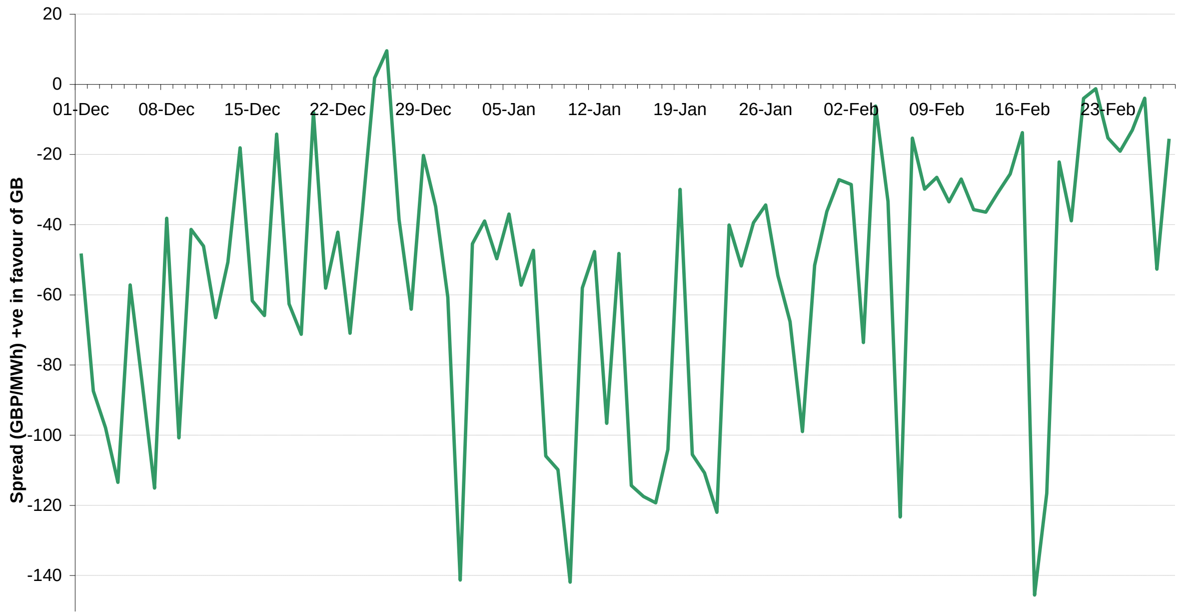
150. East West Interconnector (EWIC) is expected to be at full capability (+/-500MW) throughout this winter.

151. **Figure 19** shows the Ex-Ante 2 Irish price[40] – Day Ahead GB price spread during EFA 5 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.

[39] http://www.mutual-energy.com/Media/Press_Archive/decision_on_repair.php

[40] Power can be bought in Ireland at three timescales. This refers to the second trading window, which is day ahead.

Figure 19 – 2013/14 Mid-Winter Irish – GB Price Spread during EFA 5



France and the Netherlands

152. Interconnexion France Angleterre (IFA) was at full capability (+/-2000MW) last winter apart from two bipole outages of roughly three weeks each (+/-1000MW) in October and March. Only one bipole outage, for two weeks in October, is currently expected for the coming winter. BritNed (+/-1000MW) was at full capability throughout last winter and is expected to be for this coming winter as well.

153. Current forward prices for this winter in France and the 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 14** and **Table 15**.

Table 14 – Forecast Weekday Continental Interconnector Flows

Time (Oct-Mar)	Forecast Flow (+ve to GB)		
	Minimum	Median	Maximum
23:00 – 07:00	0 GW	+3 GW	+3 GW
07:00 – 23:00	-2 GW	+2.5 GW	+3 GW

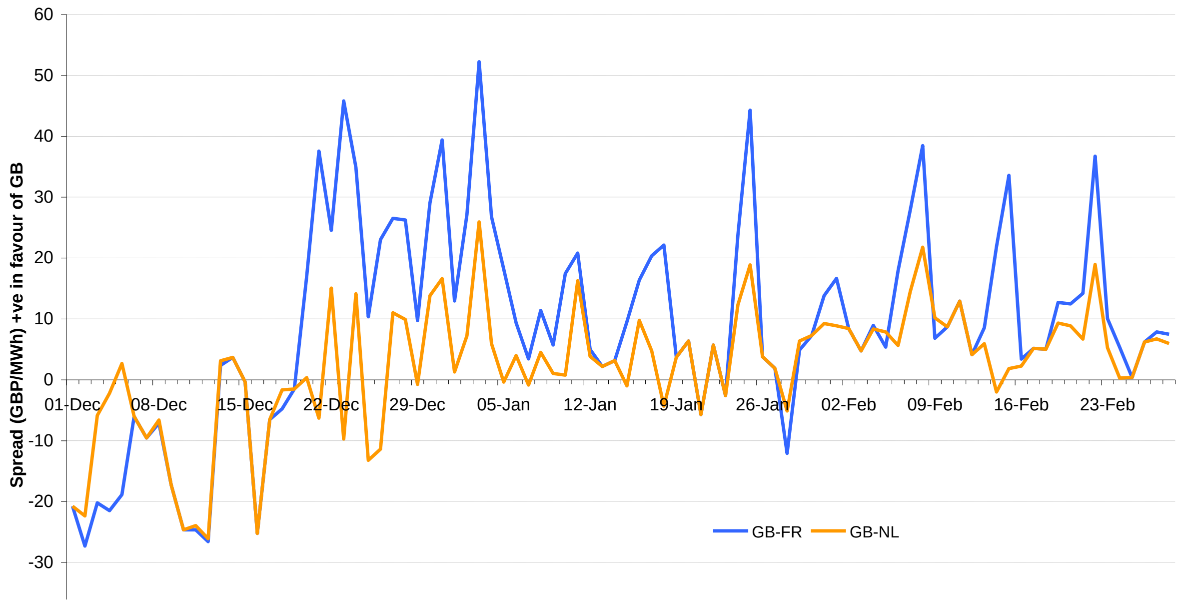
Table 15 – Forecast Weekend Continental Interconnector Flows

Time (Oct-Mar)	Forecast Flow (+ve to GB)		
	Minimum	Median	Maximum
23:00 – 23:00	+1 GW	+3 GW	+3 GW

154. The day ahead price spreads during EFA 5 between GB and France and the Netherlands are shown for 2013/14 in **Figure 20**. These show that prices have generally been in favour of flows into GB, with the exception of December 2013 where unexpected low plant availability in France coupled with a cold spell caused the flow to be reversed. A similar occurrence is not expected for this winter, but a pessimistic 'full export' scenario has been factored into our

Forecast Margins section to illustrate the impact on margins should it occur at a time of peak demand.

Figure 20 - 2013/14 GB - French / Dutch Price Spread during EFA 5

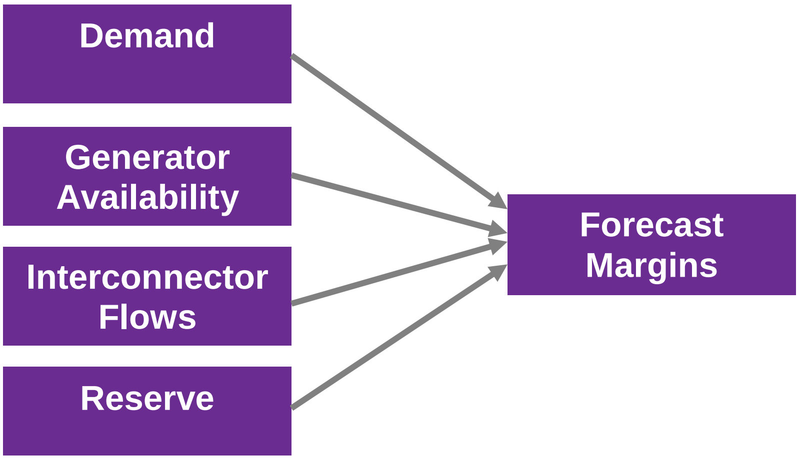


155. We have used this historical price information and our forecast flow for the current winter to create a base case scenario of 750MW import from the continent and 750MW export to Ireland for the Forecast Margins section. From previous experience on the peak this could be considered as a conservative view hence the other scenarios, one of which is a ‘full import’ case. Based on current forward prices, we could see this for the majority of the time.

156. We intend to monitor flows closely as implementation of the EU target model continues, which we expect to improve the efficiency of flows to better reflect market signals. In particular, this will be the first winter with North West Europe day-ahead market coupling in place and monitoring how flows are impacted will support more confident and accurate projections next year.

Forecast Margins

Margins may be tight following unavailability caused by unexpected events and closure of some plant.



Introduction

157. The Winter Outlook Report has traditionally used a deterministic approach to assess each week of the winter on a granular operational basis, taking into account individual generator performance and outage plans as notified to us. This is shown in the Weekly Analysis section from page 53 and gives a view of the weekly margins, assuming planned generator outages go ahead according to data submitted to National Grid up to the first week of October.

158. Stakeholders conclusively told us through responses to the Winter Consultation Report that the deterministic Weekly Analysis is useful, but that they would also value a probabilistic, whole winter view, similar to the Capacity Assessment Report published by Ofgem[41].

Winter Overview

159. The Secretary of State for Energy has set a Reliability Standard of 3 hours Loss of Load Expectation (LOLE) as part of the implementation of the Capacity Market from autumn 2018/19. LOLE is a statistical measure of the risk across the whole winter of demand exceeding supply. This takes in to account generator availability, historic breakdowns and assumptions on interconnector flows. Ofgem's Capacity Assessment Report published in June 2014 showed a LOLE 0.5 hours for the coming winter and a 6.7% de-rated margin, with a range of ~4% to ~10.7% based on sensitivities.

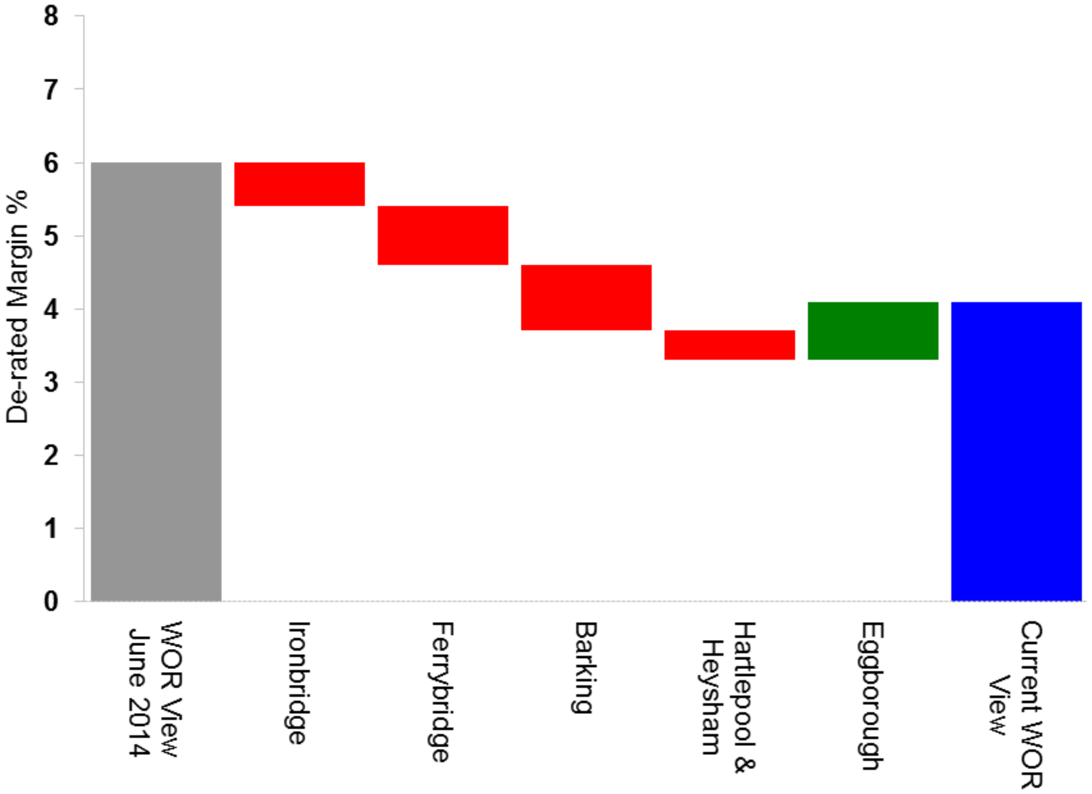
160. Unexpected events such as fires at Ironbridge and Ferrybridge power stations, partly offset by the return of a unit at Eggborough power station, have had an impact on the volume of plant available for this winter. In addition, Barking power station announced its intention to close, and the nuclear power stations at Hartlepool and Heysham were shut down for

[41] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-2014

investigations into a fault identified on a boiler unit. We have also seen slight gains from a number of OCGT plants. These issues introduced uncertainty into the winter outlook, prompting National Grid to take the precautionary step of launching a tender for SBR for this winter. A volume requirement was not identified at the time of this tender due to the uncertainties outlined above. Instead, any additional volume requirement would be determined as part of the Winter Outlook Report analysis, with SBR contract offered to plant to make up this requirement.

161. Barking has since confirmed that they will not be available for this winter. SSE have indicated that they expect one of the two units damaged by fire at Ferrybridge will return by November. EdF have confirmed that one unit at Heysham and one unit at Hartlepool will return at the beginning of November, with Hartlepool 1 returning at the end of November. The remaining Heysham unit will not return until the end of the year. All will return at approximately 20% reduction in capacity.

Figure 21 – Impact of Unexpected Events on De-Rated Margin

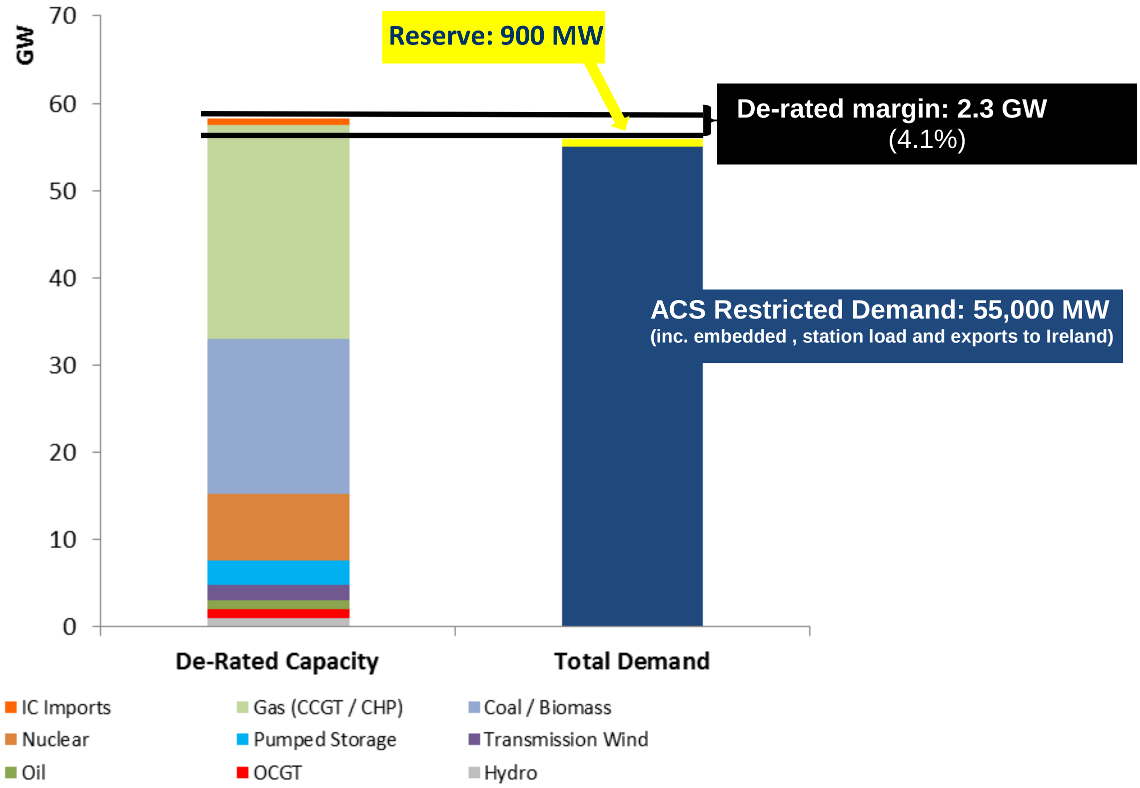


162. The de-rated margin and corresponding LOLE figure is calculated using the maximum generation capacity submitted by each unit available over weeks that have historically contained the Average Cold Spell (ACS) demand, taking account of any statutory outages. The generation mix is then de-rated according to technology type using historical de-rating factors to take account of breakdowns and shortfalls. The de-rated capacity is then compared to the ACS Restricted demand including 900MW of basic reserve requirement; this gives a margin figure which is then converted into a LOLE by referencing scenarios

produced in the Capacity Assessment Report. This comparison with the Capacity Assessment work assumes market response on tight days on all plant, except for nuclear.

163. This has increased the indicative LOLE produced in the WOR, which is comparable to the Capacity Assessment, to 1.6 hours and a 4.1% de-rated margin. This still comfortably meets the 3 hours LOLE Reliability Standard, as shown in **Figure 22.** The increase in LOLE (and decrease in de-rated margin) since the publication of the Capacity Assessment Report is due to the decrease in generation capacity shown in the water fall diagram below.

Figure 22 – Comparison of De-Rated Capacity with ACS Demand



164. Some considerable uncertainty remains regarding further plant closures and the maintenance schedule of key generators, such as the plants mentioned above. As GB System Operator it is prudent we take account of such uncertainty and so, in discussion with Ofgem and DECC, we are procuring New Balancing Services (SBR and DSBR[42]) to manage the risk for this winter. These are discussed at the end of this section.

[42] These are Demand Side Balancing Reserve (DSBR) to encourage demand side participation in the market and Supplemental Balancing Reserve (SBR) to contract with otherwise uneconomic generation to stay open or return from mothball.

Weekly Analysis and Forecasts

165. This section presents the deterministic week by week view, using the most recent data that has been made available to us.

166. Any market response to high demand and subsequent flexibility of generator outages is not taken into account in this analysis.

167. We take into account forecast demand including a level of operating reserve that would need to be held and calculate a de-rated margin for each week. A detailed comparison of the two methods is included in Appendix 1.

168. The rest of this section looks at the forecast margins for this winter. Margins are defined as the difference between the level of demand including a level of reserve held. We will look at three cases in this section. Firstly, a “Clean Forecast” is described, which uses data that is largely unadjusted. This presents the margins in a similar way to how we publish Balancing Mechanism information[43] on the BM Reports website. Secondly, we build a “Central Forecast” making assumptions based on historic evidence for generator variability and wind variability on a weather corrected demand forecast and include interconnector sensitivities. Finally, an “Arduous Forecast” is described, which has assumed generator variability and wind variability against a 1 in 20 peak and ACS demand forecast, again with interconnector sensitivities.

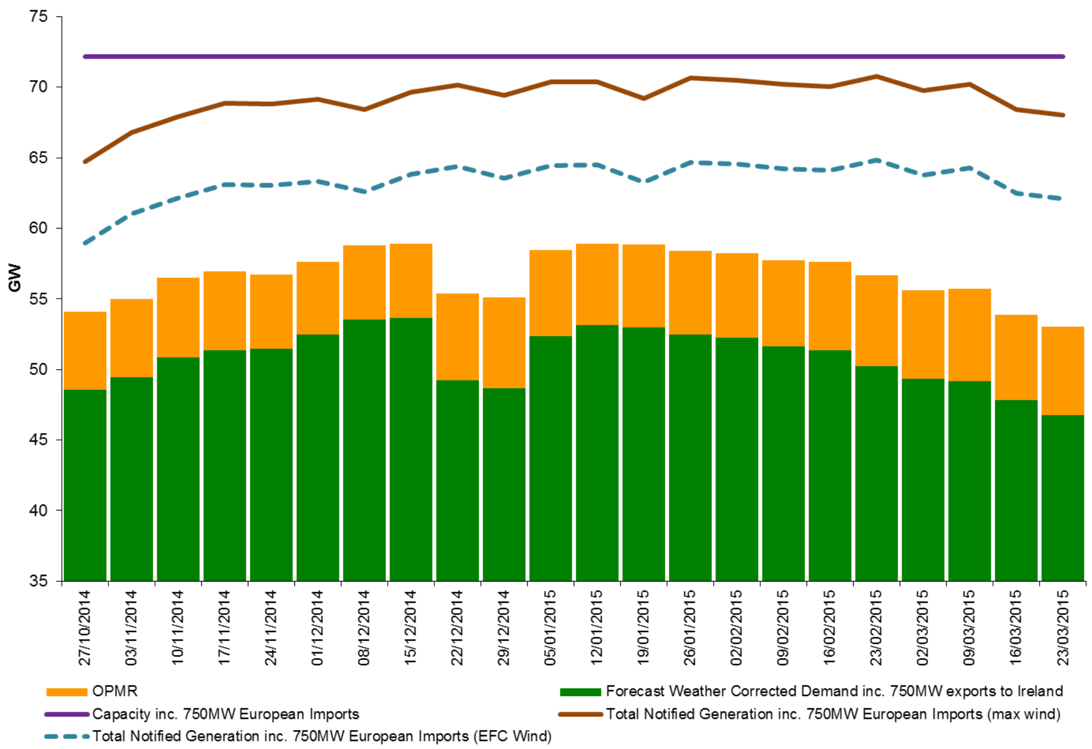
Clean Forecast

169. **Figure 23** shows forecast demand and the notified generation availability for our base case before any de-rating is applied. This is provided to show the maximum notified generation capacity over winter, and is not used in any of the margin calculations.

- As discussed earlier, demand used is Transmission System Demand which, for our base case, includes full exports to Ireland (currently 750MW).
- The generator availability figures include our base case assumption of 750 MW of European 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 (OPMR)[44].
- This chart presents the margins in a very similar way to how information is published on the BM Reports website; the only exception being that interconnector imports and exports are not included in the forecast on the BM reports website.
- We have also included the forecast generator operational capacity which includes base case imports of 750MW in **Figure 23**. 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.

[43] www.bmreports.com
[44] Details on OPMR can be found at http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Codes-principles-methodologies/Methodologies/

Figure 23 – Clean Forecast



Weekly Margin Analysis

170. The below analysis is based on the following assumptions for reserve and generation availability.

Reserve Assumptions

171. In both the Central Forecast and the Arduous Forecast we use an Operating Reserve level that is less than the OPMR shown in **Figure 23**. This is because assumed losses have been applied to the notified generation meaning that the following can be removed from the original OPMR figure:

- The capacity that is unavailable to due to constraints.
- The contingency reserve as this is not carried within 24hrs.
- The average breakdown component of the OPMR as this is included in the de-rating factor.

The cumulative effect of these is a noticeable reduction in the reserve requirement leaving, the Standing and Regulating Reserve requirement (referred to as Basic Reserve Requirement) and the Reserve for Frequency Response (FR) requirement.

- We have a requirement to carry Reserve for Frequency Response to ensure the system is resilient to generation losses that may occur 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 Frequency 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 0.9 GW and this is the figure we have used for each week in the forecasts.

- The remaining amount of operating reserve after removing the requirement for Frequency Response 0.9 GW is Standing and Regulating reserve called Basic Reserve.

The surplus figures quoted from this point on are based on the demand and Reserve Requirement for Frequency Response as this is what is required to be met to ensure that demand reduction does not occur. If the assumed generation level is less than the demand plus the total reserve requirement (the Basic Reserve requirement plus the FR reserve requirement) then this shows the risk of system warnings described below in paragraph 185.

Generation Availability Assumptions

172. 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 16** shows the assumed availability after accounting for average losses and short falls expected during high demand periods, these figures are calculated for each fuel type from the last three winters' data except the loss rate of wind power.

173. For wind power stations, Equivalent Firm Capacity (EFC) is used. This is a measure of how much 100% reliable generation would be required to replace the installed wind generation whilst maintaining the same level of system security.

174. 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 as well as wind's contribution to system security, which will have the affect of decreasing EFC.

Table 16 - Assumed Generation Availability for Winter 2014/15

Power Station Type	Assumed Availability
Nuclear	90%
Hydro generation	88%
Wind EFC	23%
Coal + biomass	90%
Oil	79%
Pumped storage	98%
OCGT	97%
CCGT	87%

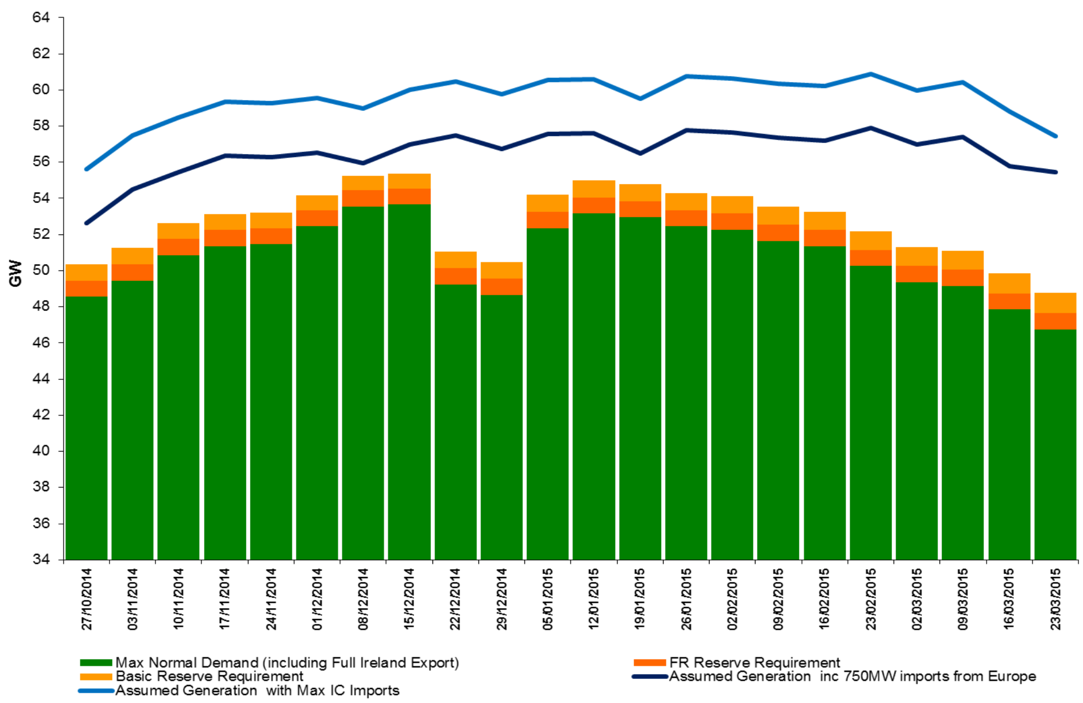
Central Forecast

175. Our central forecast uses the base case assumption on the interconnectors. This is full exports to Ireland (currently 750 MW added to the demand figures) and a 750 MW import from the European interconnectors. It also shows the sensitivities of full imports on the European interconnectors (plus 750 MW export to Ireland) and full exports on all interconnectors. We assume average conventional generation breakdown losses and we de-rate the wind using Equivalent Firm Capacity[45]. We measure margins against the forecast weather corrected demand including a level of operating reserve.

176. **Figure 24** shows our central margin forecast over the winter using the assumptions described above on interconnectors, conventional and wind generator, against our forecast weather corrected demand. These assume planned outages occur as planned with no market response to tighter days. The base case 750MW interconnector exports to Ireland are included in the demand figures shown by the green bars and the 750 MW continental interconnector imports are included in the generation figures are shown by the dark blue line.

177. The green and orange bars show the forecast peak demand and reserve requirement for each week respectively. The impact of full European interconnector imports is also shown by the light blue line.

Figure 24 – Central Forecast Margins



178. The peak forecast demand is shown to occur in the week commencing 15th Dec 2014 although the week with lowest forecast margin is week commencing 8th Dec 2014, this is due to a greater number of units being on planned outage in this week. For the week

[45] Equivalent Firm Capacity is a model output from a Monte Carlo simulation. For further information explaining the theory behind the EFC, see paragraph 173 and http://pio.sagepub.com/content/226/1/33

commencing 8th Dec our base case margin (for the Frequency Response Reserve requirement to be met) is 1,510 MW which is approximately 2.7% and with maximum European imports this becomes 7%. With the base case interconnector flows and weather corrected demand and any interconnector import level above this we can meet demand and the full reserve requirement.

179. A level of interconnector exports could be maintained over some weeks, however it would not be possible to provide full interconnector exports over all weeks of the winter.

180. In the unlikely event that the amount of generation does not meet the amount of demand for a period of time, there are a number of enduring mitigating actions that National Grid can take. For example the emergency assistance service from interconnectors, where we can call upon extra power flows from the continent if available. As well as the use of the maximum generation service (see paragraph 146) and voltage reduction.

New Balancing Services

In addition to the traditional methods used to manage security of electricity supplies, we have developed a set of measures to help us to manage the uncertainty and tightening margins coming into this winter. This is designed to be a stepping stone to the full implementation of the Capacity Market in 2018/19.

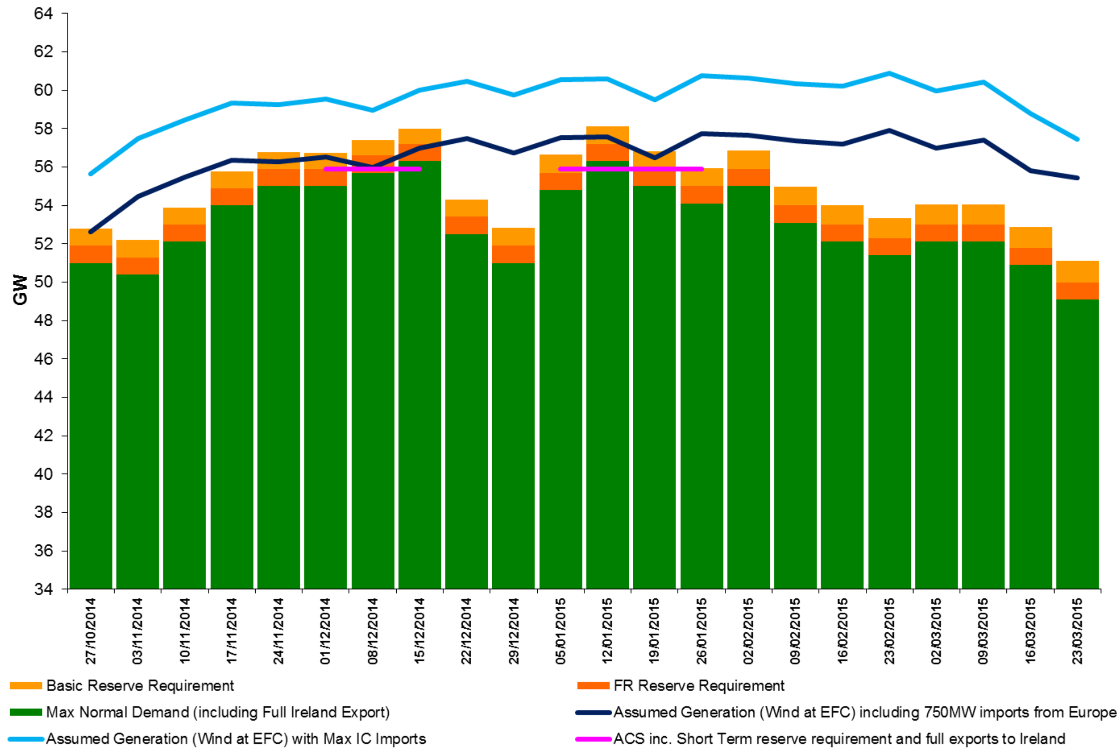
The measures are Demand-Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR), which provide National Grid (as System Operator) the option of accessing additional capacity if it is needed. As these measures sit outside the market and are only to be called on if necessary; the additional capacity is not factored into the margin calculations within this section, so the picture for weeks that appear tight is less so than it may appear in the analysis. These measures are outlined in more detail on page 59 below.

Arduous Forecast

181. In our arduous forecast we use the same assumptions as our central forecast but with a 1 in 20 demand. This means there is a 5% chance that the demand will reach this level on average over the winter. The same interconnector sensitivities as above are also shown.

182. **Figure 25** shows the margin forecast in this arduous scenario. The Average Cold Spell (ACS) demand is also shown on the chart which has a 50% chance, because of weather variability, that the demand including the FR reserve requirement will reach the ACS level (the purple solid line) 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.

Figure 25 – Arduous Forecast Margins



183. From **Figure 25** if the base case float interconnector scenario was to occur, we would have a positive margin (against the Frequency Reserve requirement) on all weeks for ACS demand levels and on most weeks for the 1 in 20. When considering assumed generation against the 1 in 20 demand scenario, we would be unable to meet our Basic Reserve requirement on two weeks for the base case interconnector scenario and would have a 2.8% margin with European interconnectors at full import. Under ACS demand conditions, we would be able to meet our Basic Reserve requirement based on the current outage plan and no market response for the base interconnector case and with full interconnector imports would see a margin of 4.1%.

184. For the 1 in 20 or ACS demand, a level of interconnector exports would be manageable but maximum export to the continent and Ireland would not be possible. National Grid, as System Operator, would need to take mitigating actions to avoid any loss of load. These include the emergency assistance service from interconnectors, maximum generation service and voltage reduction. We do not have sufficient data to calculate the likelihood of a full export scenario, as interconnector arrangements have recently changed and because we do not have all the French and Dutch market and weather data.

185. In the event where our full reserve levels would not be met. System Warnings, such as the Notification of Insufficient System Margin (NISM), 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 25** assumes average generation losses; if generation losses happened to be less than average then margins would improve, with the converse also being true.

New Balancing Services

Ofgem approved additional measures have been procured to help manage uncertainty.

319 MW of DSBR and 2.6 GW of SBR are being procured for the winter.

Overview

186. The Ofgem Capacity Assessment Reports published in June 2013 and June 2014 highlighted a potential deterioration in electricity security of supply in the mid-decade period. In response, we developed two new balancing services, namely Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR), to provide additional tools to be used in balancing the transmission system in the unlikely event that there is insufficient capacity available in the market to meet demand. These measures were approved by Ofgem in December 2013.

187. We subsequently developed a set of methodologies to determine how much, if any, of these reserves are required and how we would go about procuring them. These methodologies were approved by Ofgem in June 2014 and are available on our website[46].

Initial Volume Requirement

188. National Grid assessed the security of supply outlook over the next four years and, by applying the approved Volume Requirement Methodology, established a maximum volume of DSBR and SBR to procure from the market over this period. This was based on the equivalent volume of additional capacity that would be required to achieve the Government's Reliability Standard of 3 hours LOLE against a range of credible scenarios and sensitivities. This analysis was based on our updated Future Energy Scenarios, which is available on our website[47] and the results published in an open letter to the industry on 10th June 2014.

189. The maximum de-rated volume requirement for the 2014/15 winter was identified as 330 MW. This requirement was to be met by undertaking a pilot of the new DSBR service. A DSBR tender was launched in June 2014 and ran for 7 weeks. Contracts were awarded to a

46 http://www.nationalgrid.com/uk/electricity/additionalmeasures
47 www.nationalgrid.com/fes

variety demand side providers representing a total volume of 319 MW across 431 individual sites. We are pleased with the results of the tender; this represents an encouraging start for the new service, broadly meeting the headline requirement we set out to achieve.

The Revised Volume Requirement

190. As mentioned in paragraph 160 to 164, some unexpected issues have introduced uncertainty into the outlook for this winter, prompting National Grid to take the precautionary step of launching an SBR tender for this winter. A volume requirement was not identified at the time of this tender due to the uncertainties outlined above. Instead, any additional volume requirement would be determined as part of the winter outlook analysis, with SBR contract offered to plant to make up this requirement.

191. Given this information, we have reassessed the volume requirement for this winter.

192. The 2014/15 SBR tender process closed on 30th September 2014. A total of 5.4 GW of SBR was tendered by 8 organisations, representing 26 units across 13 sites.

193. The tenders received have been subject to economic assessment and consequently SBR contracts are currently being finalised with the following three power stations:

- Littlebrook
- Rye House CCGT
- Peterhead CCGT

194. Together with the DSBR procured, these will provide an additional 1.1 GW of de-rated capacity to that assumed available in our base case, increasing the de-rated margin from 4.1% to 6.1%, and reducing the LOLE from 1.6 hours to 0.6 hours.

195. This capacity will no longer be available in the market, but held in reserve to be despatched only as a last resort in the event that there is insufficient plant available in the market to meet demand. We are working with each SBR provider to finalise contracts and ensure that the additional capacity procured is made available by November 2014.

Coal fired still favoured over gas fired for power generation; based upon current forwards prices.

As gas fired generation reduces, opportunity for gas demand turn down from gas fired power stations becomes limited.

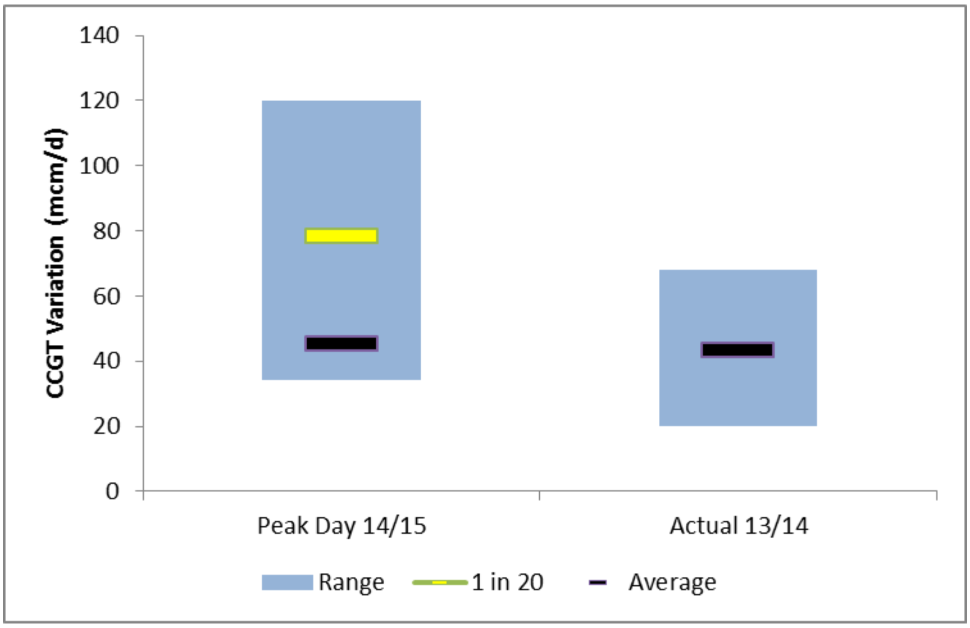
Greater opportunity for demand turn up as gas fired generation becomes back up generation for renewables.

187. This section evaluates the interaction between the electricity and gas markets. Electricity generation impacts gas demand via CCGT generation, whereas gas demand does not impact electricity generation. Electricity generation is the element that has the highest potential impact on gas demand; both day on day and within day. As gas fired power generation is increasingly being used as backup for wind generation, gas demand is experiencing higher day to day and within day volatility.

188. As current prices indicate coal generation will be favoured over gas for most of the winter there is limited scope to reduce gas demand under normal conditions as the stations running are likely to be those required to meet electricity demand. Some demand side response (DSR) would be available from gas power stations switching to alternative fuels such as distillate.

189. **Figure 26** shows the potential range of demand for gas fired power stations. For the peak day for winter 14/15 and the actual range experienced in winter 13/14. The potential range on the peak day is 86 mcm/d with the potential for about 40 mcm/d of additional demand if all CCGTs were to run and about 40 mcm/d downside if non-gas fired generation availability is higher than expected. Outside the peak day there is less potential for demand to reduce with only an 11 mcm/d downside on the estimated average demand of 45 mcm/d and up to 75 mcm/d upside.

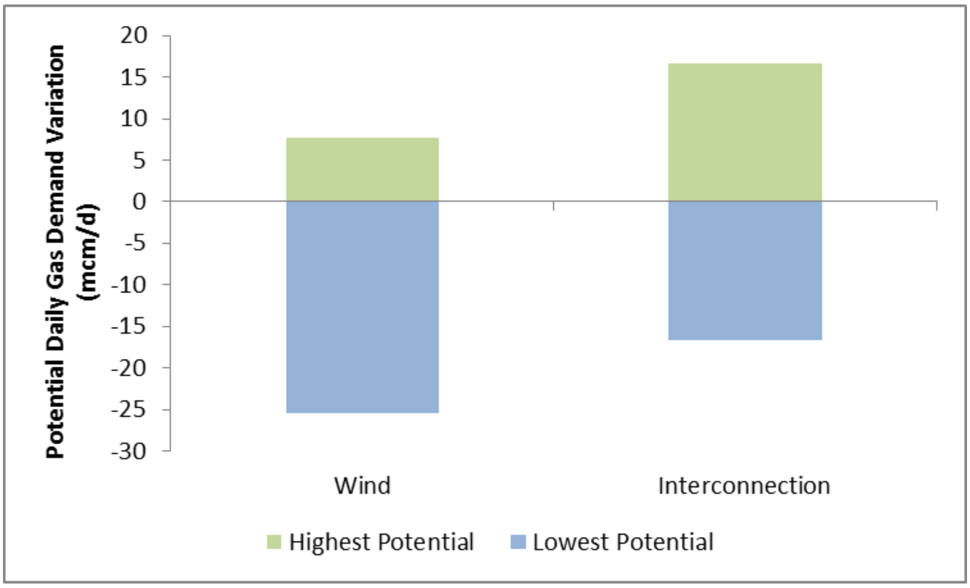
Figure 26 – Gas Power Station Demand Potential Ranges, Forecast and Recent History



190 The ranges in the chart are based on the availability assumptions detailed in **Table 16**, should non gas generators have higher availability than these then there is the potential for lower gas demand from power generation, especially on the peak day.

191 **Figure 27** shows the potential daily variations for gas fired power generation acting as backup for wind, or as a result of a change in flows on the electricity interconnectors.

Figure 27 – Potential Ranges of Gas Fired Generation Acting as Backup to Wind Generation and Interconnectors



192. For wind there is considerably more downside than upside. This is in relation to the availability assumptions detailed in Table 16 as these are dependent on wind the potential variation could be the entire range of over 30 mcm/d. A similar potential variation could also be caused by a change in direction of the electricity interconnectors.

Appendix 1 - Margin Calculation Methodologies

Ofgem's Capacity Assessment uses a stochastic model to calculate the LOLE and de-rated margin for National Grid's 2014 Future Energy Scenarios. The Winter Outlook Report uses a deterministic approach to assess each week of the winter on a more granular operational basis taking into account individual generator performance and outage plans (de-rating) as notified to us.
We take into account forecast demand, operating reserve that would need to be held and we calculate a de-rated margin for each week.

A comparable de-rated margin figure of 5.4% is produced from Winter Outlook Report data by comparing max de-rated OC2 availability for the winter against ACS demand, in a similar way to Ofgem's Capacity Assessment. This figure is slightly lower than the de-rated margins stated for the 2014 UK Future Energy Scenarios (UKFES) in Ofgem's report.

The method used in the Winter Outlook Report does not produce an LOLE figure directly. However, using the detailed results tables in Ofgem's Capacity Assessment, a de-rated margin of 5.4% is equivalent to an LOLE of 1hr.

The table below details the similarities and differences between the two methodologies.

Comparison of Margin Calculation Methodologies

	2014 UKFES & Ofgem Capacity Assessment Report	2014/15 Winter Outlook
Time Horizon	The UKFES looks from winter ahead to 2050.	The Winter Outlook only looks at the coming winter.
Generator Capacity (other than wind)	Based on projected 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 projections are de-rated to account for average winter losses due to outages. This produces one maximum de-rated capacity value for the whole winter.	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. This produces a different assumed generator capacity on a weekly level. Includes assumed interconnector imports
Wind	Equivalent Firm Capacity (EFC)	Equivalent Firm Capacity (EFC)
Small Embedded Generation (invisible to National Grid)	Embedded wind 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.

	2014 UKFES & Ofgem Capacity Assessment Report	2014/15 Winter Outlook
Demand Definition	Includes: ▪ National demand ▪ Demand met by embedded wind generation Excludes: ▪ Interconnector exports (net GB interconnector flows at peak are assumed to be zero for the UK FES: 750 MW imports from the continent and 750 MW exports to Ireland) ▪ 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
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 a single generator availability and expressed as a percentage of demand and reserve giving a single value for the whole winter.	Demand and reserve requirements are subtracted from generator availability each week and expressed as a percentage of demand and reserve. So the lowest margin value is based on the week that has the combination of highest demand that occurs on the lowest assumed generator availability for the winter. A number of different figures are quoted for each depending on inputs.
Updated	Using data compiled in March 2014.	Last updated in August 2014 using the latest generator submitted data and generation intelligence.

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