Winter Review and Consultation

2017

JUNE 2017

How to use this interactive document

To help you find the information you need quickly and easily we have published the *Winter Review* as an interactive document.

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This will take you to the contents page. You can click on the titles to navigate to a section.

A to Z
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Hyperlinks are highlighted in bold throughout the report. You can click on them to access further information.

Welcome to our *Winter Review and Consultation Report*. This report draws together our analysis of the supply and demand of both gas and electricity for winter 2016/17 along with our initial view of the winter ahead.

Winter 2016/17 was an average winter as far as temperatures go, but colder than we've experienced over the last two winters. Both the gas and electricity networks continued to deliver a reliable supply of energy to the consumer without the use of our additional reserve services for either.

As we mentioned in our *Summer Outlook Report*, the gas network now sees increasing variability in how gas comes onto and flows through the network, and how it is used throughout the day. Last winter we experienced significant changes to the supply patterns compared to previous winters. Less storage was available along with low levels of LNG. As a result supplies were dominated from other sources, principally the UK Continental Shelf and Norway. As supply patterns vary, moving gas from where it enters the network to where it is needed requires us to take additional actions. In this report we explore the challenges this creates in operating the system.

For electricity, we continued to benefit from reliable GB supply sources, including good wind generation during peak hours. Coal-fired generation was significantly lower than previous winters with gas generation increasing to meet the supply requirements. With the reduction in available nuclear generation in France during November and December, the GB market continued to respond well to tighter supply conditions. As a result we did not need to dispatch contingency balancing services to help balance the electricity system.

Looking ahead to next winter, we have included in this report a preliminary supply outlook for gas and the anticipated generation margin for electricity. We hope this information helps to inform the debate and provide an early view of what we might expect next winter.

The responses we receive from the *Winter Consultation* provide us with valuable insight on the winter ahead. Your views really are important to the development of our *Winter Outlook Report* and help to make sure we provide a well-informed outlook to the industry.

In addition to seeking your views of supply and demand for this winter we have added some new questions this year. As this is the first full year of the Capacity Market we are particularly interested in knowing if the electricity analysis in our *Winter Outlook Report* needs to change. For gas, we continue to seek your feedback on our cold day forecasts and how reduced storage capacity may affect your operating plans.

Our *Winter Review and Consultation* is just one in a suite of documents from the System Operator exploring the future of energy. I encourage you to read our other publications. In them you can find out more about the evolution of the energy landscape, and how we're working with our stakeholders to build and operate the gas and electricity systems of the future. To find out more, and register for email updates, go to our **website**.

Thank you for taking the time to read this year's *Winter Review and Consultation*. We want to make sure our publications are as useful to you as possible, so please let us know what you think. You can email your feedback to us at **marketoutlook@nationalgrid.com**, join the debate on Twitter using **#NGWinterOutlook** or subscribe to our **LinkedIn Future of Energy page**.

Phil Sheppard
Director of SO Operations

Contents

Executive summary

The *Winter Review and Consultation* is an annual publication delivered by National Grid. The report compares winter 2016/17 with our forecasts, and presents a first look at security of supply for the electricity and gas systems for winter 2017/18. It is designed to help the energy industry to understand what happened and begin to prepare for the winter ahead.

The consultation is designed to gather valuable stakeholder insight, in order to inform our analysis for the 2017/18 *Winter Outlook Report*. The consultation closes on 14 July.

Overview: Electricity winter 2016/17

As anticipated in our *Winter Outlook Report*, there were sufficient generation and interconnector imports to meet demand across the winter.

Weather corrected transmission system demand was 50.9GW for 2016/17, 1.1GW lower at peak than forecast in our *Winter Outlook Report*. Transmission system demand was consistently lower throughout the winter in comparison to winter 2015/16 despite the colder weather. Transmission demand is influenced by temperature, wind, interconnector flows and embedded generation plus customer demand management. For winter 2016/17 the difference was predominantly caused by a drop in weather corrected demand and an increase in non-weather related embedded generation.

Generation availability last winter was broadly in line with our forecast range. Where actual output was lower than our forecast in some weeks of November, this was predominantly caused by the loss of half the capacity (1GW) of Interconnexion France-Angleterre (IFA). Customer demand management peaked at 2GW last winter, similar to the levels we experienced in winter 2015/16. However, the number of days that customer demand management occurred did increase, from 36 in 2015/16 to 48 last winter. Gas-fired generation, as a proportion of total generation, increased significantly last winter. It accounted for nearly half of GB's electricity production over the winter, compared to around a third last year. This growth was driven by fuel price movements, making gas more economical to run than coal, and a reduction in available coal generation. As a result coal-fired generation provided only 12 per cent of total supply, compared to 20 per cent in winter 2015/16. Over the winter, there was a higher output from wind generation than forecast during peak hours. Across the winter as a whole, wind provided 10 per cent of the total energy generation which was similar to winter 2015/16. With the exception of pumped storage, plant reliability across all generation types was higher than the levels used in our assumptions.

Interconnector imports were lower than winter 2015/16, mainly due to the unexpected IFA outage. Interconnector flows were also more volatile on IFA than in previous winters, due to the high prices in Continental Europe that were driven by the unprecedented low nuclear output in France. Unplanned interconnector outages also limited the capacity on EWIC, the interconnector to the Republic of Ireland.

Executive summary

Overview: Electricity winter 2016/17 *(continued)*

Ahead of winter 2016/17, we procured 3.5 GW of contingency balancing reserve (CBR) to support system balancing. Margins were not as tight as forecast, with good generation supply and lower than forecast transmission demand. No CBR plant was warmed or used last winter. We were close to warming supplemental balancing reserve (SBR) plant on 31 October and 7 November. On both of these days a Capacity Market Notice (CMN) was issued and Balancing Market (BM) prices spiked.

Overview: Gas winter 2016/17

As anticipated in our *Winter Outlook Report*, there was sufficient gas available from a variety of sources to meet demand throughout winter 2016/17. Gas was the most profitable fuel for electricity generation for much of the winter.

The total gas demand for winter 2016/17 was 50.3 bcm (weather corrected), higher than forecast in our *Winter Outlook Report*. This was as a result of increased gas demand for electricity generation which increased to around 30 per cent more than winter 2015/16. As forecast in our *Winter Outlook Report*, exports to both Ireland and Continental Europe were significantly lower than last year. With restricted stock at the Rough long-range storage facility, we were unsure how medium-range storage would be used. We experienced shippers cycling more between injection and withdrawal than in recent years, increasing storage injection by 50 per cent, from 1.2 bcm in winter 2015/16, to 1.8 bcm this year.

Gas supplies from the UK Continental Shelf (UKCS) and Norway were higher than the previous two winters, but within our forecast ranges. With greater global availability of liquefied natural gas (LNG), we expected levels arriving in GB to be higher last winter. However, we experienced the opposite, mainly due to an increase in prices on the East Asian market. Deliveries to GB had averaged 37 mcm/day in September but fell to just over 5 mcm/day on 1 October and then remained low until the beginning of March.

Although diversity of supply benefits GB gas security, the varied sources can reduce the predictability of flows and requires greater operational flexibility to manage them. For winter 2016/17, we saw an increase in changes to within day demand profiles and a continuous high supply of gas from the UK Continental Shelf and Norway along with decreased LNG supplies. Such variability in supply patterns and within-day supply and demand changes create increasing operational challenges characterised by supplies dominating from the North and East of GB. While last winter we experienced similar linepack swings to winter 2015/16, some linepack swings were magnified when other connected loads were more changeable. For example, last winter the volume and variability of gas demand from Combined Cycle Gas Turbine (CCGT) generators was much higher than for winter 2015/16. With reduced flows of LNG entering the gas transmission network, supplies from UKCS and Norway increased. This changed the volume of gas entering the system at each entry point. For example, a larger proportion of the gas supply entered the network at St Fergus in Scotland, while flows through South Hook in Wales were significantly lower. The result was a greater requirement for within day movement of stock from the north to the south of the network to balance regional supply and demand requirements. Other gas customers, including mid-range storage and interconnectors, have also been more responsive to market changes. As a result, we are continuing to work with the industry to understand their flexibility requirements.

Stakeholder engagement

Our outlook reports present our short-term analysis of gas and electricity supply and demand. They are designed to stimulate a conversation with the energy industry. The feedback we receive from a broad range of stakeholders, underpins the development of our outlooks.

We want to make sure that our reports continue to improve and provide you with the right information to support your business planning. To do this we would like to know what you think of this report. You can share your feedback via the short survey on our **website** or by emailing us at **marketoutlook@nationalgrid.com**.

Winter 2017/18 overview

Here we look ahead to winter 2017/18 and present our initial view of security of supply for the electricity and gas systems. The consultation is designed to gather valuable stakeholder insight to help inform our analysis for the 2017/18 *Winter Outlook Report*. The consultation closes on 14 July.

Electricity
The de-rated margin range for this winter is 3.7 to 4.9 GW. This equates to a loss of load expectation (LOLE) of 0.25 and 0.05 hours per year respectively.

Our electricity analysis presents a probabilistic assessment of security of supply for winter 2017/18. Our analysis is based on our EMR 5-year Base Case.

Winter 2017/18 is the first delivery year of the Capacity Market. The de-rated margin includes the capacity that was procured by a competitive auction process as part of the Capacity Market 2017-18 Early Auction. For more information on the assumptions used in calculating this margin please see the Electricity market outlook section later in this report.

Gas
Our gas analysis presents a preliminary view of gas supplies for winter 2017/18. Based on this analysis we expect there to be sufficient gas available from a range of sources to meet winter 2017/18 demand.


3.7 to
4.9 GW
De-rated
capacity margin


Diverse
gas
supplies

Our publications

The outlook reports present our short-term analysis of gas and electricity supply and demand for the following six months. The reports are designed to support the energy industry's preparations for the season ahead. We'll be publishing our *Winter Outlook Report* 2017/18 in October.

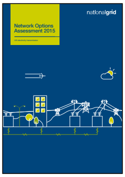
The outlook reports form part of a suite of publications from the System Operator on the future of energy. Each of the documents in this suite aims to inform the energy debate by identifying a particular issue and is shaped by engagement with the industry.

The starting point for much of our analysis is the *Future Energy Scenarios (FES)*. This document considers the potential changes to the demand and supply of energy from today out to 2050. The network and operability changes that might be required to operate the electricity system in the future are explored in the *Electricity Ten Year Statement*, *System Operability Framework* and *Network Options Assessment*. For gas, these issues are considered in the *Gas Ten Year Statement* and *Future Operability Planning* publications.

For 2017, we have added a new publication to our suite of documents; the *System Needs and Product Strategy*. This document was published in June 2017. It is designed to provide better market information and transparency in how we operate the system, and deliver a clear view of our future system needs, including the tools and services we will require.

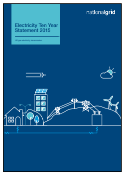
You can find out more about any of these documents by clicking on their front covers below or by visiting our **Future of Energy webpage**. To be the first to hear about publications and associated events, you can sign up to our mailing list via the website.

The key SO publications in 2017 and 2018



Network Options Assessment
January 2017

The options available to meet reinforcement requirements on the electricity system.



Electricity Ten Year Statement
November 2017

The likely future transmission requirements on the electricity system.

Summer Outlook Report
April 2017

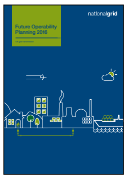
Our view of the gas and electricity systems for the summer ahead.

Gas Ten Year Statement
November 2017

How we will plan and operate the gas network, with a ten-year view.

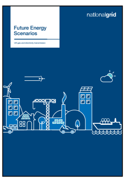
System Needs and Product Strategy
June 2017

Our view of future electricity system needs and potential improvements to balancing services markets.



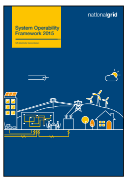
Future Operability Planning
November/December 2017

How the changing energy landscape will impact the operability of the gas system.



Future Energy Scenarios
July 2017

A range of plausible and credible pathways for the future of energy from today out to 2050.



System Operability Framework

How the changing energy landscape will impact the operability of the electricity system.

Winter Outlook Report
October 2017

Our view of the gas and electricity systems for the winter ahead.

National Grid’s role

National Grid owns and manages the gas and electricity networks that connect homes and businesses to the energy they need.

We own and manage the high voltage electricity transmission network in England and Wales. We are also the System Operator of the high voltage electricity transmission network for the whole of Great Britain, balancing the flows of electricity to homes and businesses in real time.

We don’t generate electricity and we don’t sell it to consumers. It is the role of energy suppliers to 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 are balanced on a second-by-second basis.

On the gas side, we own and operate the high pressure gas transmission network for the whole of Great Britain. We are responsible for managing the flow of gas to homes and businesses’, working with other companies to make sure that gas is available where and when it is needed.

We do not own the gas we transport and neither do we sell it to consumers. That is the responsibility of the energy suppliers and shippers.

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

Chapter one

Electricity

This chapter sets out how electricity supply and demand in winter 2016/17 compared to our forecasts. It details our analysis of demand, generation and interconnector flows. It also outlines the services that were in place to support system balancing.

The chapter contains the following sections:

- Winter view
- Operational view
- Interconnected markets
- Fuel prices for electricity generation.

Electricity winter view

The winter view analysis in our *Winter Outlook Report* provided a probabilistic assessment of security of supply for the entire winter period. This helped to inform the procurement of contingency balancing reserve (CBR) in the form of supplemental balancing reserve (SBR).[1]

CBR services were designed as a transitional product to provide additional reserve in the mid-decade period. As we transition to the Capacity Market, 2016/17 was the last year that we procured these services. We will therefore not be procuring SBR or demand side balancing reserve (DSBR) services for winter 2017/18 or in future years.

Key messages

- We procured contingency balancing reserve to assist in system balancing over winter 2016/17.
- As a result of lower than forecast demand and reliable GB generation we did not use our contingency balancing reserve last winter.

Key terms

- **Contingency balancing reserve (CBR):** there are two types of reserve services: supplemental balancing reserve and demand side balancing reserve. They were developed to support system balancing by enabling National Grid to access additional reserve, held outside of the market.
- **Supplemental balancing reserve (SBR):** a balancing service where generators make their power stations available between 6am and 8pm on weekdays between November and February, when they would otherwise be closed or mothballed.
- **Demand side balancing reserve (DSBR):** provides an opportunity for large consumers or owners of small embedded generation to earn revenue by contracting to reduce demand or provide generation when required. During winter 2015/16, the service was available between 4pm and 8pm on weekday evenings between November and February. No DSBR was procured for winter 2016/17.
- **Electricity margin notification (EMN):** a notification issued to generators, interconnected system operators and suppliers to advise there is a likelihood that there will be an inadequate margin of reserve capacity available. The purpose is to make the recipients aware and request that additional reserve capacity is made available.
- **Capacity market notice (CMN):** Is a signal to the market that the risk of a System Stress Event in the GB electricity network is higher than under normal circumstances.

[1] https://www.ofgem.gov.uk/publications-and-updates/decision-remove-supplemental-balancing-reserve-and-demand-side-balancing-reserve-cost-recovery-arrangements-201718

Electricity winter view

Procurement of contingency balancing reserve

Contingency balancing reserves are balancing services that allow National Grid to access additional capacity. They are held outside the market and so a system notification must be issued before these services can be called upon.

To make sure we had the right tools to help us balance the system, in December 2015 we identified a requirement to procure contingency balancing reserve services for winter 2016/17. The Volume Requirements Methodology[2], which uses our FES Central Forecast and a range of sensitivities approved by Ofgem[3], was used to determine the amount of reserve services to procure.

On 29 February 2016 we confirmed that we had procured 3.5 GW (de-rated) of SBR. In August 2016 we announced that we would not be procuring DSBR for the winter ahead. The DSBR tender responses we received, indicated minimal volumes were available across the peak period and it was therefore uneconomical to procure for winter 2016/17.

As a result of lower than forecast demand and reliable GB generation, we did not need to use our contingency balancing reserve services last winter.

[2] http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/Methodologies/ https://www.ofgem.gov.uk/publications-and-updates/decision-201617-sbr-procurement-methodology-and-2016-18-volume-requirement-methodology

[3] https://www.ofgem.gov.uk/publications-and-updates/decision-contingency-balancing-reserve-sensitivities-winter-201617

Dispatching contingency balancing reserve

We experienced seasonal normal temperatures in winter 2016/17. Whilst overall wind levels were about the same as those we experienced in winter 2015/16, on average they were higher than normal in the late afternoon and across the peak evening hours. Overall, wind generation continued to provide around 10 per cent of total GB generation. As we explore in the Operational View section of this report, actual generation availability broadly matched our forecast across the winter. The only exception was in November, where an unplanned interconnector outage caused a loss of 1 GW of available supply.

Last winter, some of the power stations providing SBR services required up to 48 hours' notice before they could begin to generate. As a result, startup instructions would be required for these generators if there was a possibility that they would be needed. We came close to instructing these SBR generators on 31 October and 7 November. On both of these days, a Capacity Market Notice (CMN) was issued. In response, balancing market (BM) prices increased and the market responded positively with a number of generators making additional megawatts available. Sufficient generation was therefore available to meet both demand and reserve requirements. As a result of the market response, the CMN was withdrawn and the SBR capacity was not required.

Electricity operational view

This section provides an overview of the supply and demand experienced last winter on the transmission system.

Key messages

- Weather corrected transmission system demand was 50.9 GW. This is 1.1 GW less than forecast in our *Winter Outlook Report*. Actual transmission system demand was 51.6 GW.
- Transmission system demand levels were lower than forecast in our *Winter Outlook Report*. This was caused by a number of factors, including a reduction in weather-corrected demand and increases in embedded non-weather related generation and customer demand management.
- Generation and interconnector imports were sufficient to meet demand.
- Gas-fired generation provided almost four times the energy output of coal generation over the winter.

Key terms

- **Transmission system demand (TSD):** demand that National Grid as System Operator sees at the points of connection to the distribution networks. It includes demand from power stations that are generating electricity (station load) and interconnector exports.
- **Weather corrected demand:** demand expected or out turned with the impact of weather removed. You can read more about how weather corrected demand is calculated in the glossary.
- **Embedded generation:** any generation that is connected directly to the local distribution network, as opposed to the transmission network. It includes combined heat and power schemes of any scale. Generation that is connected to the distribution system is not usually directly visible to National Grid and acts to reduce demand on the transmission system.
- **Customer demand management (CDM):** where industrial or commercial users change their pattern of energy consumption. This may be to avoid using energy during peak times.

Overview

Weather corrected demand was lower than forecast in our *Winter Outlook Report*. Generation and interconnector imports were sufficient to meet demand across the winter based on the weather we experienced.

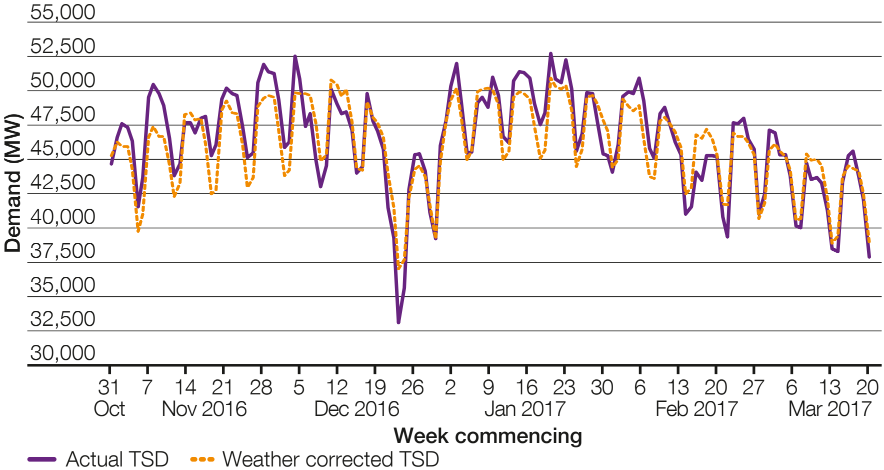
Demand

In our *Winter Outlook Report*, we expected normalised transmission system demand to peak in mid December at 52.0GW. Actual demand peaked at 51.6GW on 5 December, whilst weather corrected transmission system demand peaked at 50.9GW on 24 January. This was predominantly caused by a reduction in weather-corrected transmission demand, and an increase in customer demand management (CDM). Table 1.1 shows the peak and minimum actual and weather corrected transmission system demands for winter 2016/17. Figure 1.1 shows daily actual and weather corrected unrestricted[4] transmission system demand.

Table 1.1
Demand outturns

	Actual transmission system demand (GW)	Weather corrected transmission system demand (GW)
Peak demand	51.6	50.9
Minimum demand	19.5	21.9

Figure 1.1
Daily actual and weather corrected unrestricted transmission system demands



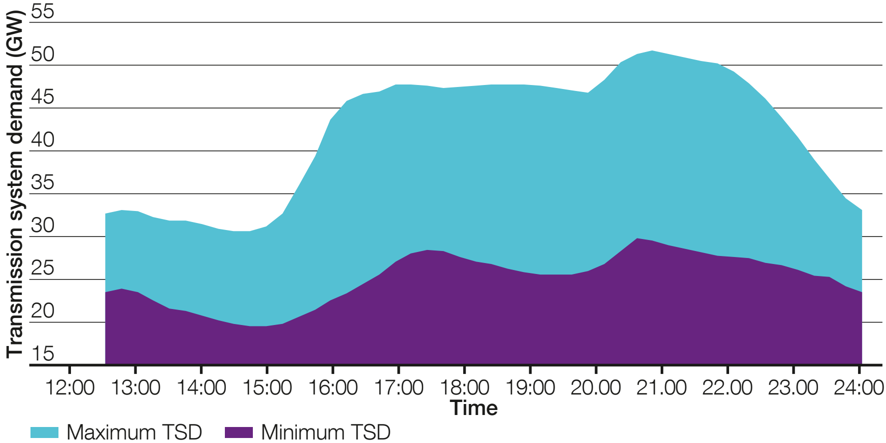
[4] Unrestricted transmission system demand does include the effect of CDM

Electricity operational view

Figure 1.2 shows the daily minimum and maximum range of half hourly demand for winter 2016/17. It illustrates the lowest and highest demand seen on the transmission system. Maximum demand (51.6 GW) happened on 5 December 2017 for the half hour ending 17:30, when it was -3.3°C colder than the seasonal normal.

Minimum demand over the winter was 19.5 GW on 25 December 2016 for the half hour ending 05:30, when it was 4°C warmer than seasonal normal. This is the second lowest winter demand we have experienced since 2005, the lowest being 19.4 GW on 25 December 2015.

Figure 1.2
Half hourly transmission system demand during winter 2016/17

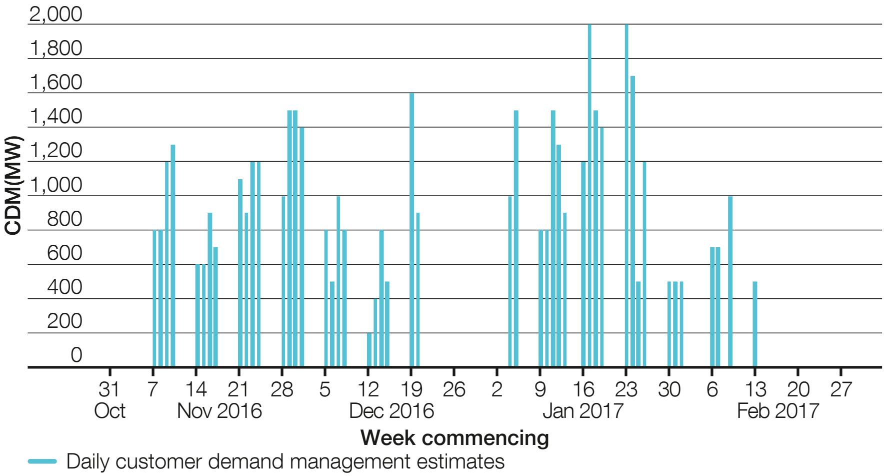


Customer demand management

Customer demand management (CDM) occurs when industrial or commercial users choose to change their pattern of energy consumption, typically to reduce energy use during peak periods. By avoiding these peak periods, they reduce their transmission and distribution[5] charges. This includes Triad avoidance.

Figure 1.3 shows an estimate of CDM across the winter. It is based on estimates determined from analysis of the drop in weather-corrected demand at peak times. It is not based on supplier, customer or aggregator submitted demand reduction data.

Figure 1.3
Daily customer demand management estimates



Our analysis suggests that during winter 2016/17, CDM typically ranged between 0.5 and 1.5 GW, reaching 2 GW on the highest demand days. This was similar to the levels seen in winter 2015/16. However the number of days that CDM occurred last winter increased by a third, from 36 days to 48.

[5] Triads are the three half-hourly settlement periods with the highest system demand. They are used by National Grid to determine charges for demand customers with half-hour metering and payments to licence exempt distributed generation. Triads can occur in any half-hour on any day between November and February. They must be separated from each other by at least ten full days.

Electricity operational view

Figure 1.4
Customer demand management and number of days where peak demand was reduced in winter 2016/17

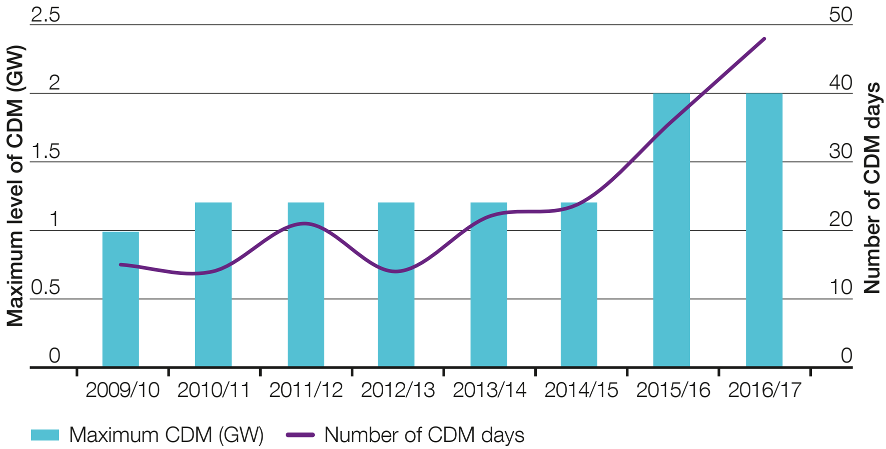


Table 1.2 indicates that an element of Triad avoidance occurred on every day where CDM was observed last winter. The number of Triad avoidance days increased from 35 in winter 2015/16 to 48 last winter.

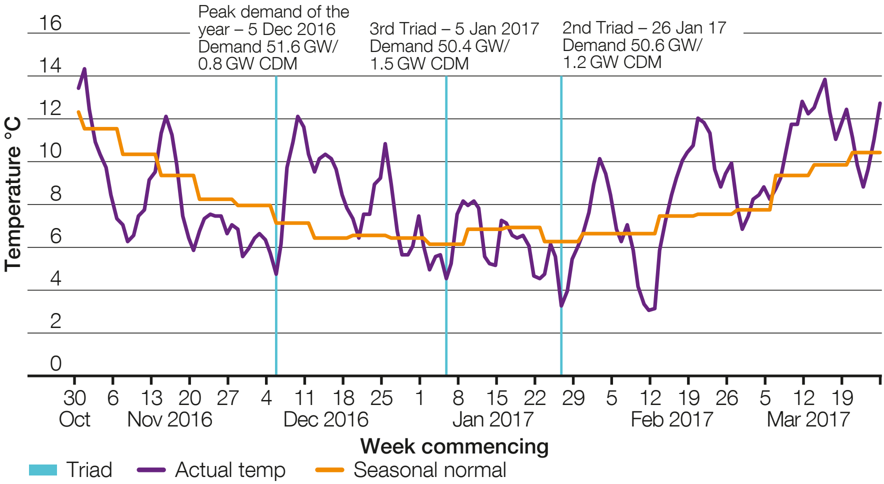
Table 1.2
Three peak demands forming Triad (based on operational data)

Date	Restricted TSD (GW)	CDM (GW)	Unrestricted TSD (GW)
5 December 2016	51.6	0.8	52.4
5 January 2017	50.4	1.5	51.9
26 January 2017	50.6	1.2	51.8

Figure 1.5 provides a comparison between average actual temperature at 17:00 hours during winter 2016/17 and weekly seasonal normal temperatures at 17:00. For clarity seasonal normal weather is a measure of average weather over the last 30 years.

On the three Triad days, when demand peaked, temperatures were below the seasonal normal average. At the actual peak demand of the year, on 5 December 2016, the temperature was 3°C colder than the seasonal normal average. Subsequent Triad peaks, on 5 January 2017 and 26 January 2017, were 2.5°C and 3.2°C colder than normal respectively. These colder temperatures, along with less CDM (presumably because the days were not foreseen as potential Triad days), were important drivers in why the days became Triad days.

Figure 1.5
Actual vs seasonal normal temperature at peak demands



Electricity operational view

Figure 1.6
Weather corrected energy volume comparison over the last two years (TWh)

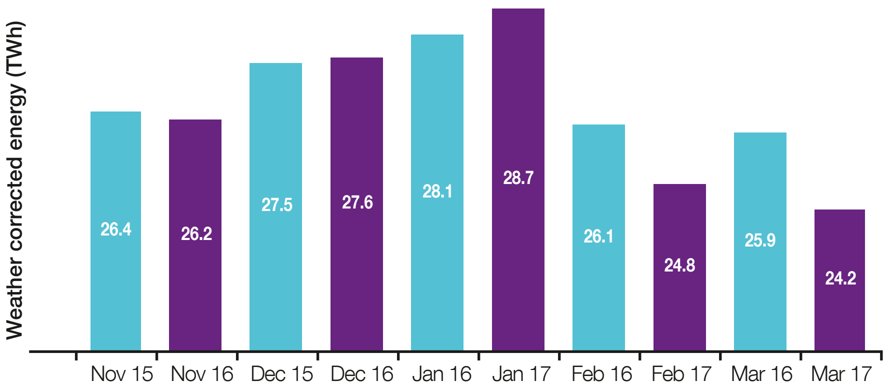


Figure 1.6 compares the monthly weather corrected energy volume for winter 2016/17 and winter 2015/16. During winter 2016/17, a total of 131.5 TWh of energy was transmitted, compared to 134 TWh during winter 2015/16. The decrease is due to the growth in electricity from non-grid connected, embedded or distribution generation.

Actual generation availability

The levels of generation and interconnector imports from Continental Europe were sufficient to meet demand across winter 2016/17. Our forecast generation was based on three interconnector scenarios: low imports of 500MW, medium base case of 1,800MW and full interconnector imports of 3,000MW. In figure 1.7, these scenarios are compared to the actual generation available in each week for winter 2016/17, both with and without SBR and including actual interconnector imports. Actual imports were closest to the medium imports scenario, occasionally dropping to the low import or full export scenarios. For a more detailed analysis please see the interconnector section on pages 28 to 32.

Figure 1.7
Winter 2016/17 actual generation availability

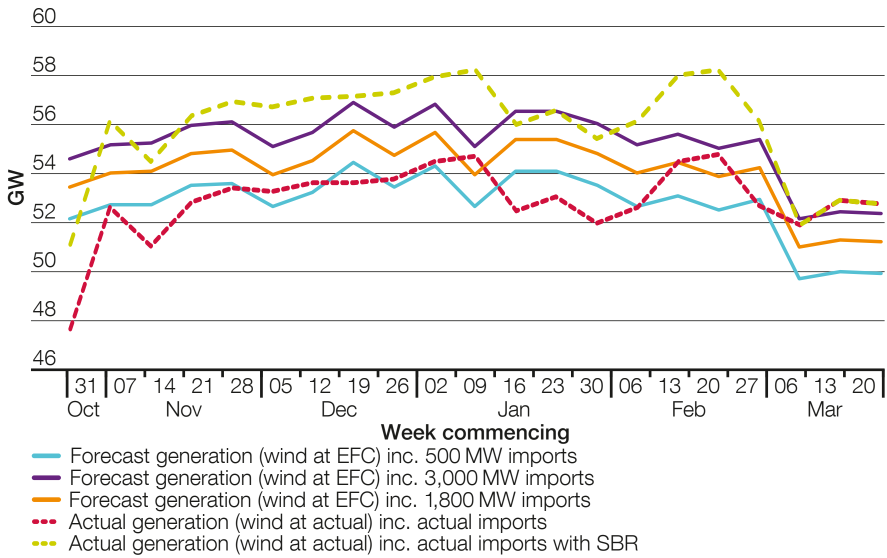


Figure 1.7 also shows that our forecast range broadly matched the generation seen each week. Where actual output was lower than our forecast, in some weeks of November, this was predominantly caused by the loss of half the capacity of IFA, the interconnector to France.

Actual outputs were higher than our forecasts from the 16 February, when IFA returned to its full capacity of 2 GW, and import levels increased. Across the winter, GB benefitted from reliable electricity generation; this is discussed in more detail later in this chapter.

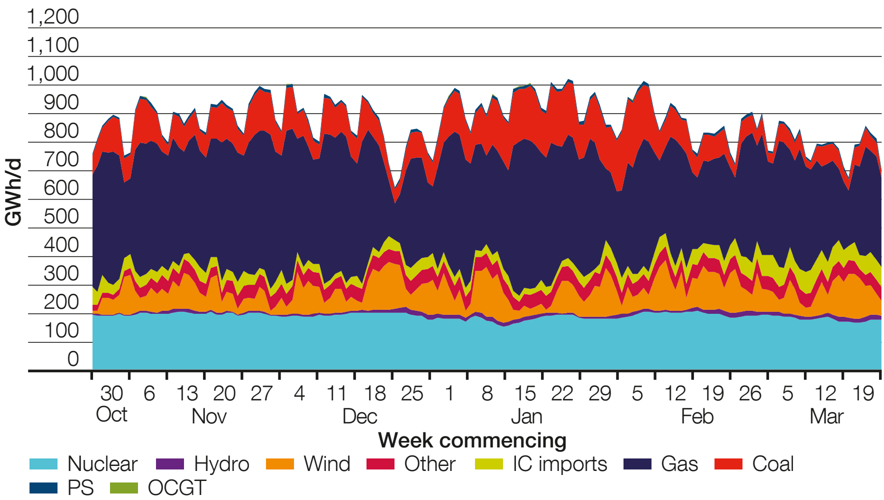
Generator output

Figure 1.8 shows the generation that ran in winter 2016/17 by fuel type. Gas-fired plant provided almost four times the energy output of coal-fired plant. This was a result of two factors: a reduction in coal generation capacity (coal generation capacity had dropped by approximately 5 GW compared to last winter) and fuel prices. You can read more about our analysis of fuel prices on page 33 to 36 of this report.

Gas-fired generation accounted for 45 per cent of GB's electricity output over the winter, compared to 34 per cent last year. Coal-fired generation dropped from 20 per cent to 12 per cent. Similarly, interconnector imports reduced from 8 per cent to 5 per cent, mainly due to the unexpected IFA outage. Wind provided 10 per cent of total generation, similar to winter 2015/16.

Electricity operational view

Figure 1.8
Winter 2016/17 generation output by fuel type



Breakdown rates

Table 1.3 provides more detail on the contribution of each fuel type to the total energy produced last winter. It compares the assumed breakdown rates by fuel type to the actuals observed during peak demand periods. Data provided by generators does not assume unplanned outages, restrictions and breakdowns, so when assessing forward margins we apply breakdown rates based on historical analysis for the last 3 years. This is based on how generators performed on average during peak demand periods.

Table 1.3
Winter 2016/17 energy contribution, assumed and actual breakdown rates of generation plant

Power station type	Energy contribution	Assumed breakdown rate	Actual breakdown rate
Nuclear	21%	11%	5%
Hydro generation	1%	10%	9%
Coal + biomass	12% + 5%	13%	5%
Pumped storage	1%	2%	4%
OCGT	0%	4%	3%
CCGT	45%	11%	6%

The out-turn breakdown rates were lower than the forecast. This could have been due to forecast price spikes which would have incentivised units to maximise availability in order to capture these prices, or to avoid an imbalance. The actual breakdown rate of nuclear generation was lower than the assumptions used in our forecast, which included higher nuclear unavailability in 2014/15. However the outturn was in line with the level we experienced last year.

The actual breakdown rate of coal generation was much lower than our assumption. This was partly due to a forecast based on previous years breakdown rates, which included commercial decisions to reduce output prior to closures. Coal power stations ran less last winter, which reduced the chance of breakdown. Plant reliability is affected by the number of 'start-ups'. The actual breakdown rate of CCGT generation was lower than our assumption. We believe this is a reflection of the gas fleet responding to market signals during high demand periods.

The differences in breakdown rates we experienced last winter had minimal impact on our overall forecast as they were offset by the outage of one of the bipoles on IFA, the interconnector to France.

What we said in our *Winter Outlook Report*	What actually happened	Why there was a difference
Normalised demand is expected to peak in mid December at 52.0GW.	Normalised demand peaked at 50.9GW on 5 December, 1.1GW lower than expected.	Increases in non-weather related distribution generation and CDM reduced demand.
The week commencing 9 January will have the lowest level of operational surplus.	The lowest level of operational surplus was in the week commencing 5 December.	The level of operational surplus was lower earlier than expected due to a restriction on the French interconnector.
We expect there to be sufficient generation and interconnector imports available to meet normalised demand throughout the winter.	There were sufficient generation and interconnector imports to meet normalised demand without the use of Contingency Balancing Reserve (CBR).	

Interconnected markets

Interconnection between both Continental Europe and Ireland allow flows of electricity to and from the GB network. This chapter examines the factors that affected these flows over last winter.

Key messages

- Unplanned outages limited the capacity on the interconnectors to both France and Ireland for long periods last winter.
- Interconnector imports were lower and the interconnector flows were more volatile than in winter 2015/16. This was mainly due to an unexpected outage on Interconnexion France-Angleterre (IFA) and due to the high prices in France.
- The higher prices in France were due to an unprecedented low nuclear output in France.

Key terms

- **Import:** interconnectors flowing electricity into GB.
- **Export:** interconnectors flowing electricity out of GB.
- **Net import/export:** sum of total generation flowing via interconnectors either into or out of GB.

Overview

Interconnectors link the Great Britain (GB) transmission system to the electricity systems of France, the Netherlands and Ireland. The total interconnection capacity is 4 GW. Flows on the interconnectors are driven by the differential between prices in the markets on either side of the interconnector. In our *Winter Outlook Report*, based on analysis of forward prices, we expected there to be a net import of electricity from Continental Europe to GB. We anticipated that there would be a net export of electricity from GB to Ireland.

Interconnector performance

All the electrical links between GB and other markets are high voltage direct current (HVDC) interconnectors. During last winter, the interconnection capacity between GB and its neighbouring countries was significantly reduced due to unplanned outages.

Interconnexion France-Angleterre (IFA) is a 2 GW interconnector between GB and France. Due to an unplanned outage, capacity was reduced to 1 GW from 20 November 2016 until 16 February, when capacity was increased to 1.5 GW. Full capacity was restored on 1 March.

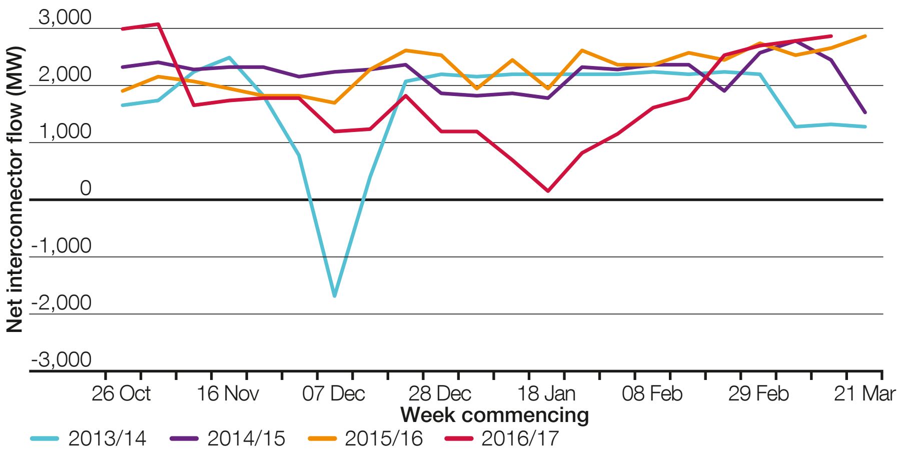
Britned is a 1 GW interconnector between GB and the Netherlands. As expected, Britned was available at full capacity for the entire winter.

EWIC (East-West Interconnector) is a 500 MW interconnector between GB and the Republic of Ireland. In our *Winter Outlook Report*, we expected EWIC to be unavailable from the end of September 2016 until the 28 February 2017. It actually returned to full capability in late December, 2 months earlier than expected.

Moyle is a 500 MW interconnector between GB and Northern Ireland. It was available at full capacity until the end of February. On 28 February an unplanned outage reduced capacity to 250 MW. It remained at this reduced capacity until the end of the winter.

The interconnector flows for the last four winters can be seen in figure 1.9. It shows that total imports in winter 2016/17 were lower than previous years.

Figure 1.9
Combined interconnector flows at weekly GB peak demand



Interconnected markets

Figure 1.10 shows the interconnector flows during GB peak demand periods. Full import from the Netherlands to GB was experienced for most of the peak periods. IFA was not always at full import from France to GB during November and December. This was due to the unavailability of nuclear units in France resulting in a rise in the French wholesale price.

In the week commencing 18 January, there were exports during peak times from GB over IFA. This was due to a cold spell in France combined with the ongoing nuclear outages. As expected, there were net exports from GB to Ireland during peak times.

Figure 1.10
Individual interconnector flows at weekly GB peak demand 2016/17

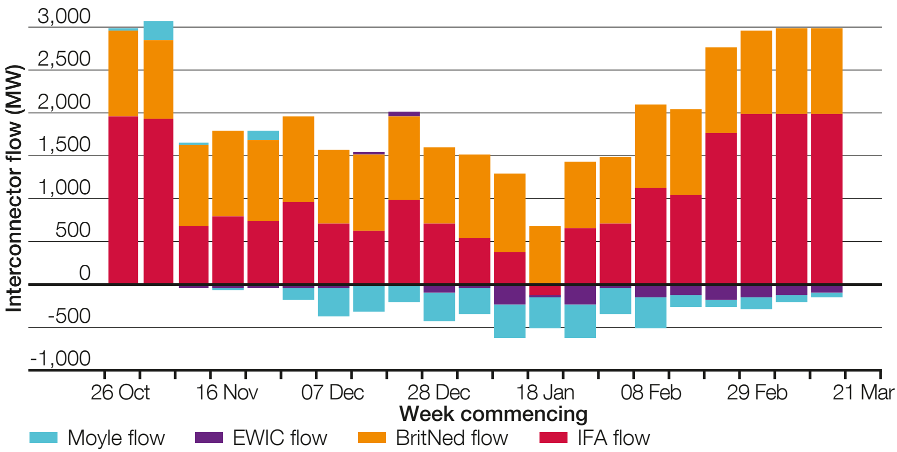
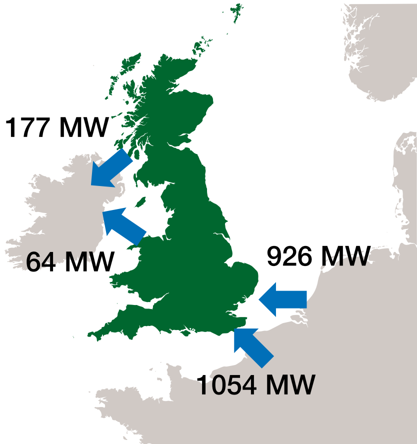


Figure 1.11
Average interconnector flows for GB weekly peak demand in winter 2016/17



Market prices

In our *Winter Outlook Report* we explained how the North West Europe (NWE) day-ahead coupling regime had resulted in increasing price convergence between the Netherlands, Belgium, France, Austria and Germany. GB electricity prices have remained consistently higher than in Continental Europe. Last winter, the price differential between GB and the Continental European markets was lower than previous winters due to record high prices on the Continent. Average day ahead prices in GB were significantly higher than previous winters, increasing from £41/MWh to £61/MWh at peak periods. The higher GB prices in early November and most of December were mainly due to the low nuclear output in France, resulting in lower imports. Prices also spiked in late January due to a spell of cold weather in Continental Europe.

Interconnected markets

What we said in the *Winter Outlook Report*	What actually happened?	Why was there a difference?
For winter 2016/17, we expect there to be a net flow of power from Continental Europe to GB at peak times, occasionally not at full import.	There was a net flow of power from Continental Europe to GB at peak periods. There were regular flows from GB to France over IFA outside of the peak periods. Interconnection capacity was reduced for much of the winter due to an outage on IFA.	The unprecedented low nuclear output in France caused regular spikes on power prices in Continental Europe. An unplanned outage of IFA reduced output further.
We expect there to be a net flow of power from GB to Ireland during peak times. This may be reversed during periods of high wind in Ireland.	There was a net flow of power from GB to Ireland during peak times and flows from Ireland to GB during overnight periods and periods of high wind in-feed. Interconnection capacity was reduced for much of the winter due to outages on EWIC and Moyle.	Flows were lower than expected due to low levels of demand on the Irish system, high wind levels in Ireland and outages on EWIC and Moyle.

Fuel prices for electricity generation

Analysis of fuel prices helps us to understand the economics of electricity generation. During winter 2016/17 gas-fired units featured ahead of coal units in the electricity generation merit order.

Key messages

- Gas-fired generation was more profitable than coal-fired generation for most of the winter, except for a week at the beginning of February.
- Carbon prices remained stable across the winter, only fluctuating slightly with the exchange rate on the ETS market.

Key terms

- **Generation merit order:** The order in which generators appear is based on how cost-efficient they are in producing energy, compared to other generator units.
- **National balancing point (NBP) gas price:** the wholesale gas market in Britain has one price for gas, irrespective of where it has come from. This is called the national balancing point price of gas. It is usually quoted in pence per therm.
- **EU Emissions trading scheme (ETS):** a European Union trading scheme that allows participants to buy and sell greenhouse gas emission allowances.

Overview

Fuel prices can have a significant influence on generation supply patterns. Generating companies may choose to sell forward (possibly a number of years or seasons ahead of delivery) based on profitability of their particular generating plant. However, subject to market liquidity, there is always the option to trade in and out of positions should profitability fluctuate in response to changing fuel prices and spreads. The actual generation mix is also influenced by short-term profitability in the months, weeks and days ahead of delivery, and generally this short-term profitability signal determines which plants will eventually run on the day to meet demand.

Our analysis of the cost of production of electricity, shows that gas was more profitable than coal-fired generation for winter 2016/17.

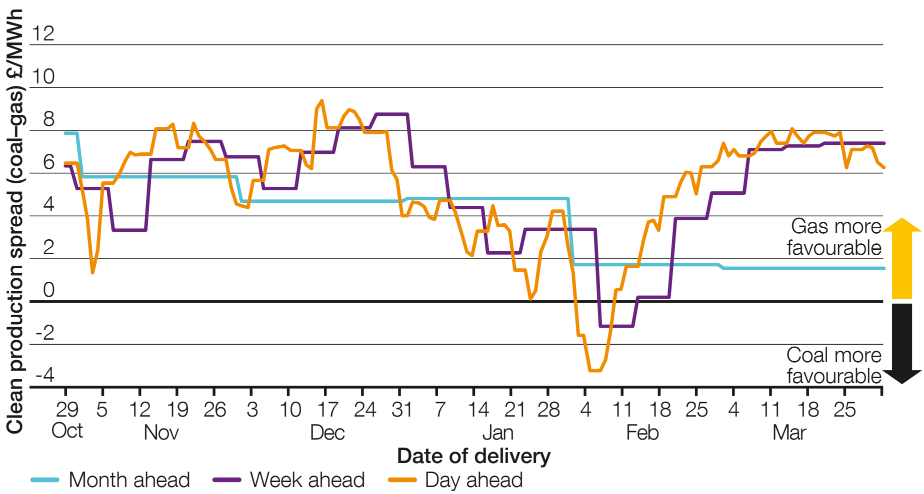
Fuel prices for electricity generation

Review of the impact of fuel prices on electricity generation

Our analysis of the differential between the cost of producing electricity from coal and gas-fired generation at different trading timescales for winter 2016/17 can be seen in figure 1.12. These include the cost of carbon. The differential is the difference in the estimated average cost of coal-fired generation minus the estimated average cost of gas-fired generation at month, week and day ahead timescales. A positive value shows that gas was the most profitable fuel for electricity generation, while a negative value indicates that coal was more profitable.

For the majority of the winter, our analysis suggests that gas-fired generation was approximately £5 per megawatt hour (MWh) more economical than coal. The only exception was at the end of January going into the first few days of February when the price of gas peaked. For this limited period coal became the more profitable fuel source in prompt timescales. A reduction in short term gas price for February improved the profitability of gas from month ahead to day ahead delivery and this was sustained into March.

Figure 1.12
Differential between the cost of producing electricity from coal and gas-fired generation at different trading timescales for winter 2016/17



Assumptions

This analysis should only be used as an indication of profitability. Actual fuel costs, the specific cost of fuel transportation and specific generation efficiencies will impact the cost of producing electricity.

1. Generation efficiency

Power stations have different efficiencies for converting input fuel into electricity output. Generation efficiencies can vary, with actual efficiencies ranging from between 42 to 58 per cent for gas and 30 to 39 per cent for coal. For our analysis, we have used a gas-fired power stations efficiency of 49 per cent and a coal-fired generation efficiency of 36 per cent.

2. Fuel prices

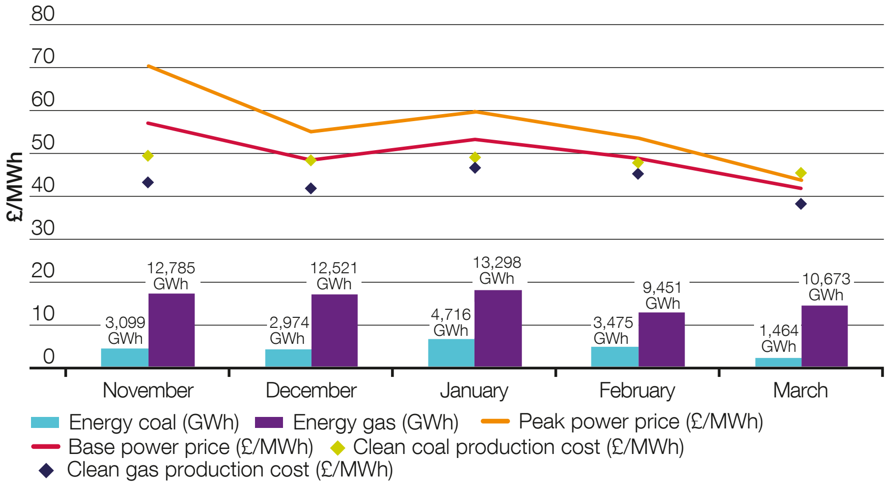
Our analysis assumes fuel is purchased at the time of use. Fuel, especially coal, may have been bought in advance, reducing or increasing actual fuel costs. For coal-fired generation, fuel transportation costs beyond shipping to the UK could further reduce profitability.

Figure 1.13 shows the average cost for coal and gas-fired generation for each month during the winter period. It assumes the same generation efficiency as figure 1.12 and provides information on the average electricity power price for that month for the peak (7am to 7pm) and the baseload (24 hour running) electricity products.

Where the production cost is below the power price line, the energy produced for that product is profitable. Our analysis shows that overall, the cost of gas-fired generation was lower than coal. In November power prices increased and, excluding coal transportation costs, both fuel types were profitable for peak and baseload. From December to February both fuel types remained profitable for both products, although coal for baseload, excluding coal transportation costs, was only marginally profitable in December. In March the gap between the peak and baseload prices narrowed as prices declined. As a result, coal was unprofitable for both products at this time and the volume of energy produced from coal fell.

Fuel prices for electricity generation

Figure 1.13
Estimate of the average cost of production from coal and gas each month over winter 2016/17, against the market price of electricity and the energy produced



What we said in the *Winter Outlook Report*	What actually happened?	Why was there a difference?
Based on forward prices, gas-fired generation is expected to be more profitable than coal-fired generation in October 2016. From December, the price difference between gas and coal becomes narrower and this is likely to continue for the remainder of the winter.	Gas was more profitable than coal for most of the winter. Although the price of coal reduced, it was only more competitive for around one week from the end of January when gas prices spiked.	

Chapter two

Gas review

This chapter sets out how gas supply and demand in winter 2016/17 compared to our forecast. It details our analysis of fuel prices and outlines how we are managing the flexibility requirements of our customers.

The chapter contains the following sections:

- Demand
- Supply
- System operability.

Gas demand

This section provides an overview of gas demand last winter. To understand the factors affecting gas demand, we explore storage injection, levels of gas-fired electricity generation and the weather.

Key messages

- Gas demand in most categories, other than gas for electricity generation, was close to our forecasts in our *Winter Outlook Report*.
- Low gas prices and reduced imports of electricity increased gas demand for electricity generation.
- The highest gas demand was 372.2 mcm on 26 January.

Key terms

- **Non-daily metered (NDM):** a classification of customers where gas meters are read monthly or at longer intervals. These are typically residential, commercial or smaller industrial consumers.
- **Daily metered (DM):** a classification of customers where gas meters are read daily. These are typically large scale consumers.
- **Weather corrected demand:** demand calculated with the impact of the weather removed. This is sometimes known as 'underlying demand'. Weather is one of the main drivers of the difference in demand from one day to the next. We take out the impact of weather to understand other important underlying trends.
- **Seasonal normal conditions:** a set of conditions representing the average that we could reasonably expect to occur. We use industry agreed seasonal normal weather conditions. These reflect recent changes in climate conditions, rather than being a simple average of historic weather.
- **Composite weather variable (CWV):** temperature explains most of the variation in gas demand but a better fit can be obtained by including other variables. The combination of temperature and other weather variables is called the composite weather variable.

Chapter two

Gas demand

Overview

The total gas demand for winter 2016/17 was higher than we forecast in our *Winter Outlook Report*. Gas demand for electricity generation was higher than expected. There was also more cycling of storage, as shippers refilled the medium-range storage facilities to accommodate the absence of Rough, the long-range storage facility.

Actual and weather corrected gas demand

Gas demand projections from our *Winter Outlook Report* are shown in Table 2.1, together with the actual outcome. Our forecasts were based on seasonal normal conditions which represented the average weather we could reasonably expect during the winter period. These forecasts can be compared with the weather corrected demand results. We have also included the actual demand, with no weather correction, which can be compared with the supply table (table 2.2) on page 47[1].

Table 2.1
Demand forecasts and outcome for winter 2016/17

Demand in bcm	2015/16 weather corrected demand	2016/17 forecast	2016/17 weather corrected demand	2016/17 actual demand
NDM	29.6	29.5	29.7	29.3
DM + Industrial	4.7	5.0	5.0	5.0
Ireland	2.6	1.4	1.6	1.6
Total for electricity generation	10.4	11.1	13.8	13.8
Total demand	**47.4**	**47.1**	**50.3**	**49.9**
IUK export	2.7	0.8	0.8	0.8
Storage injection	1.2	1.2	1.8	1.8
GB Total	**51.3**	**49.1**	**52.9**	**52.5**

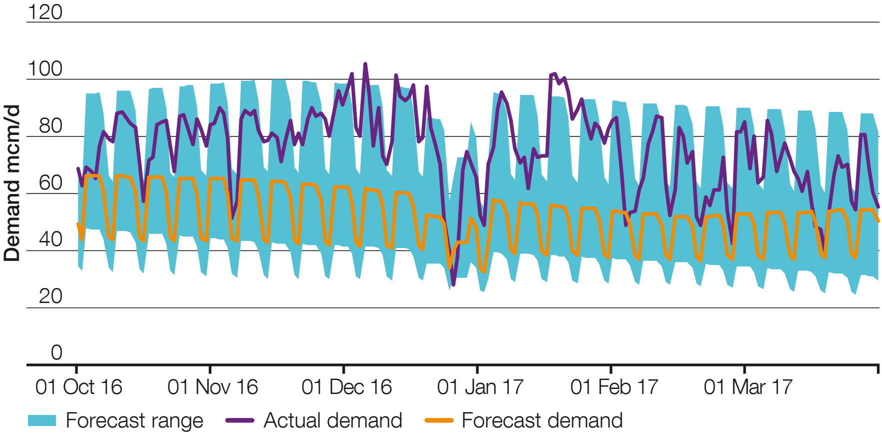
Table 2.1 illustrates that in most cases, demand over the winter was close to our forecast value. For weather sensitive demand, notably in the Non-Daily Metered (NDM) sector, the weather corrected demand was close to the actual demand. This was because the weather was close to the expected seasonal normal value and therefore little weather correction was applied. We discuss the weather in more detail at the end of this chapter.

[1] Our weather correction method treats consumer types differently. For example, residential customers show great sensitivity to weather, while large industrial processes show little weather sensitivity. We cannot tie supply sources to customer types so we cannot produce weather corrected values for the gas supply tables.

Gas demand for electricity generation

In our *Winter Outlook Report* we said that we expected gas-fired generation to be more profitable than coal-fired generation for much of the winter. While this was true, we did not anticipate that lower electricity imports from France would lead to greater gas-fired generation in the GB market. This is discussed further in the electricity chapter. Gas demand for electricity generation is shown in figure 2.1. This shows that in December and January there were days where gas demand exceeded our expected range.

Figure 2.1
Forecast and actual gas demand for electricity generation

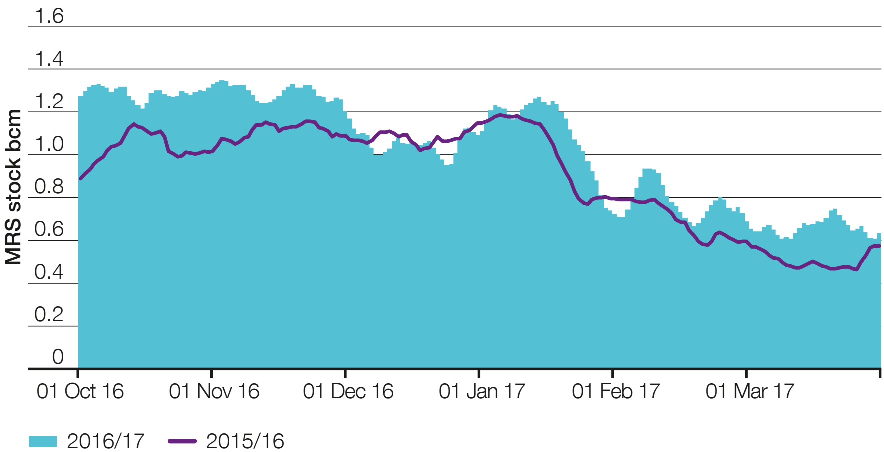


Chapter two

Gas demand

Injection into storage was higher than expected in our *Winter Outlook Report*. We said that we were not sure how medium-range storage would be used over the winter. This was because we did not know how the restricted stock of gas at the Rough storage facility would impact other storage behaviour. What we saw was an increase in cycling between injection and withdrawal from medium-range storage compared to recent years. Figure 2.2 compares the medium-range storage stock for winter 2016/17 with winter 2015/16.

Figure 2.2
Stock held in medium-range storage in winters 2015/16 and 2016/17



Weather review

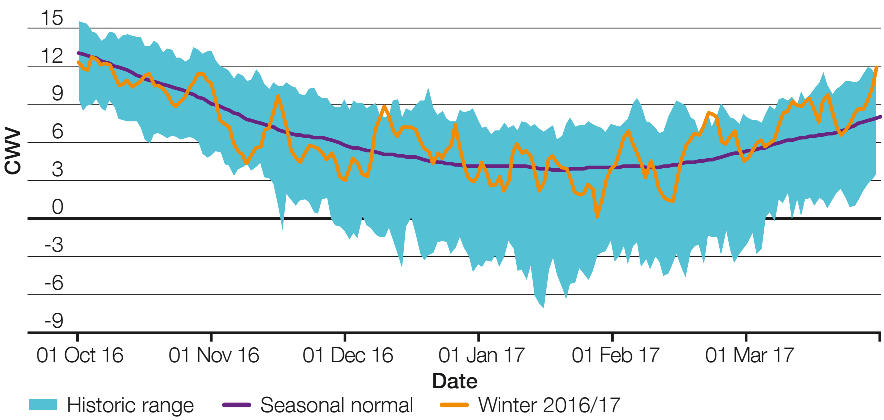
Gas demand for space heating is very sensitive to the effects of weather. We combine temperature, wind speed and seasonal effects in a single quantity called the composite weather variable (CWV) and use this in our analysis.

Last winter winter was only marginally warmer than average. This contrasts with winter 2015/16 which was exceptionally warm.

The coldest day in winter 2016/17 was on 26 January.

The CWV for the winter is shown in figure 2.3. This chart shows that the coldest days were in late January and mid-February. These were far warmer than the coldest days in the historical range.

Figure 2.3
National CWV for winter 2016/17 and the historic range

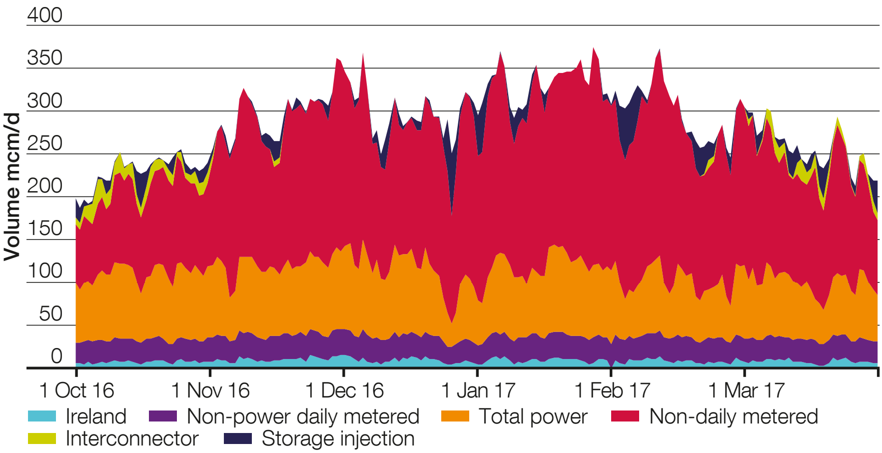


Chapter two

Gas demand

The effect of the weather is shown in figure 2.4. The only category to show any significant dependence on the weather is the non-daily metered NDM sector. In the gas supply chapter we consider daily demands of 350 mcm to be a cold day which we use to assess supply performance in cold weather. Figure 2.4 shows that a demand of 350 mcm was only reached on a few isolated days. The highest demand seen last winter was 372.2 mcm on 26 January. This was the coldest day last winter.

Figure 2.4
Gas demand by sector



What we said in our *Winter Outlook Report*	What actually happened?	Why was there a difference?
Gas exports to Ireland are expected to be lower than winter 2015/16.	Exports of 1.6 bcm were significantly lower than the 2.6 bcm seen in winter 2015/16.	
Gas exports to Continental Europe are expected to be lower than winter 2015/16.	Exports were 0.8 bcm, significantly lower than the 2.7 bcm seen in winter 2015/16.	
Gas demand for electricity generation is expected to be higher than winter 2015/16.	Gas demand for electricity generation was 13.8 bcm, higher than the 10.4 bcm in 2015/16 and also higher than our forecast of 11.1 bcm.	Increased gas for electricity generation, as a result of the unplanned outage of IFA.

Supply

This section looks at the variable sources of supply we experienced entering GB last winter. It also discusses the unpredictability of the gas import market.

Key messages

- Sufficient gas was available to meet demand for winter 2016/17, with gas supplied from a wide range of sources.
- There was a slight increase in supply from the UK Continental Shelf (UKCS) for the second year running. This was due to a number of new fields starting production.
- Flows through BBL did not exceed 20 mcm/day after the end of November, when long term capacity contracts expired.
- LNG deliveries were lower than we have seen for many years. Flows exceeded 20 mcm/day on only one occasion between October and the end of February.
- Supplies exceeded 350 mcm to meet demand on several days during the winter period with high flows experienced from the north and east of GB.

Key terms

- **UK Continental Shelf (UKCS):** made up of the areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
- **BBL:** this gas pipeline runs between Balgzand in the Netherlands and Bacton in the UK.
- **IUK:** the Interconnector (UK) Limited is a gas pipeline connecting Bacton in the UK and Zeebrugge in Belgium.
- **Liquefied natural gas (LNG):** formed by chilling gas to -161 °C so that it occupies 600 times less space than in its gaseous form.
- **Long-range storage:** sometimes also referred to as seasonal storage, long-range storage is used to balance supply and demand between winter and summer. Gas is put into storage in the summer when demand is low and withdrawn in the winter when demand and prices are higher. There is one long-range storage site on the national transmission system: Rough, situated off the Yorkshire coast. Rough is owned by Centrica.
- **Medium-range storage:** these commercially operated sites have shorter injection/withdrawal times. This means they can react quickly to demand, injecting when demand or prices are lower and withdrawing when they are higher.
- **National balancing point (NBP) gas price:** the wholesale gas market in Britain has one price for gas, irrespective of where it has come from. This is called the national balancing point price of gas. It is usually quoted in pence per therm.

Supply

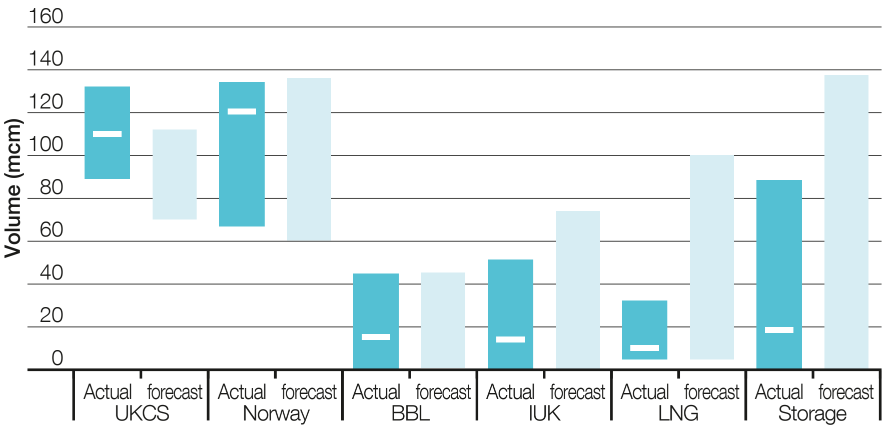
Overview

As anticipated in our *Winter Outlook Report*, there was sufficient gas available to meet demand for winter 2016/17, although characterised by restricted supplies from long-range storage and low deliveries of LNG.

Gas supplies by source

Supplies for winter 2016/17 are compared to our forecasts in figure 2.5. The darker coloured bars show the range of actual daily flows by source, with the average level shown by the white lines. The paler coloured bars show the forecast range from our *Winter Outlook Report*.

Figure 2.5
Actual and forecast supplies by source



In any winter, storage supplies are expected to show the greatest variability of all of the supply sources. Supplies can range from no flow to maximum flow, from all facilities, at times of high gas demand or price. The forecast in our *Winter Outlook Report* reflected this potential range. For the UKCS and Norway, the forecast ranges were based on analysis carried out for our Future Energy Scenarios in summer 2016. This analysis was informed by feedback from energy industry stakeholders. The wide range in the forecasts for IUK, BBL and LNG reflects the uncertainty of the import market. Our forecast ranges for continental imports were based on actual flows in recent winters, supported by market intelligence and responses to our *Winter Consultation*.

Figure 2.6 shows the daily gas supply for the winter. This is complemented by table 2.2 which shows the total supply for winter 2016/17, compared with the previous two winters.

Figure 2.6
Daily gas supply

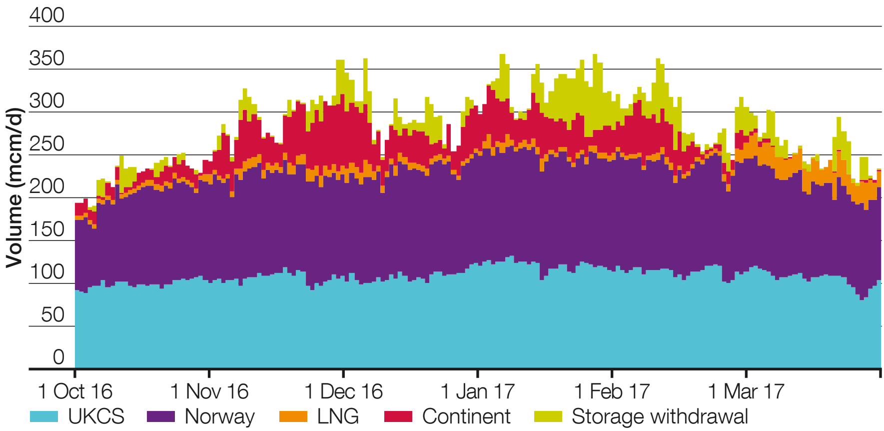


Table 2.2
Gas supplies for winter 2016/17 and previous years

	2014/15		2015/16		2016/17	
	bcm	%	bcm	%	bcm	%
UKCS	16	33	18	36	20	38
Norway	18	38	18	36	22	42
Continent	4	8	3	6	5	10
LNG	5	10	6	13	2	4
Storage	5	10	4	8	3	6
Total	**48**		**49**		**52**	

Supply

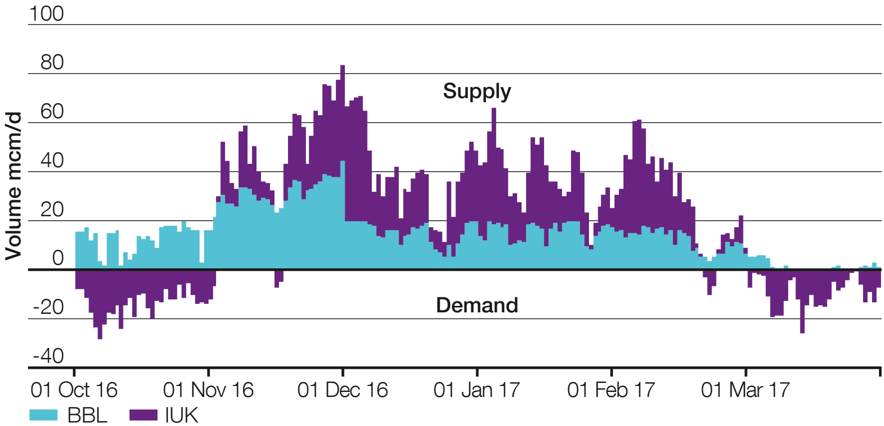
UK Continental Shelf and Norway

As we see from table 2.2, supplies from the UKCS and from Norway were both higher than for the previous two years. Production from the UKCS has temporarily increased after many years of decline. Increased production at Laggan and Tormore, in the west of Shetland area, together with new developments at Alder and Cygnus more than offset the decline from other fields. Production on the Norwegian Continental Shelf was similar to the previous year. However, prices in the GB market were higher than continental prices which encouraged more Norwegian gas into GB. Because of the increased supplies from UKCS and Norway, we experienced higher flows from the north and east of GB than anticipated.

Continental Europe

Supplies from Continental Europe through the IUK and BBL interconnectors were higher than the last two winters. In our *Winter Outlook Report*, we said that the forward prices at the National Balancing Point (NBP) and the Zeebrugge hub in Belgium suggested that we would see flows from Belgium to GB from early 2017. In fact, the prices moved to support IUK imports from Belgium as early as November. Imports continued through to the beginning of March. Figure 2.7 shows combined flows through the interconnectors. The negative flows in October and March are exports through IUK to Belgium.

Figure 2.7
Flows through BBL and IUK interconnectors

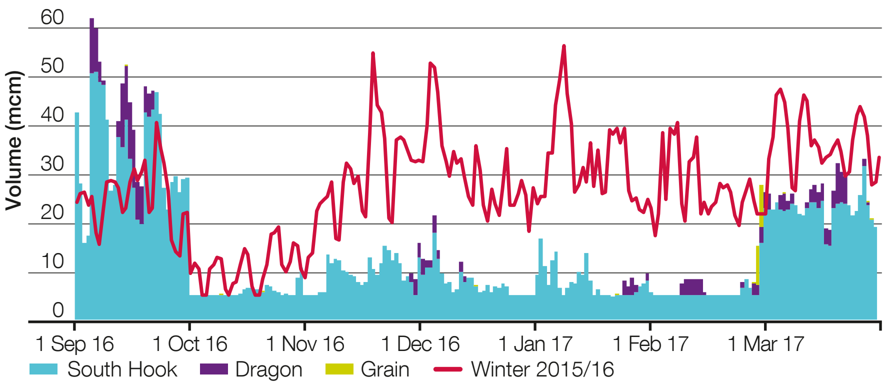


In our *Winter Outlook Report* we suggested that flows through BBL would be lower than winter 2015/16 as a result of continuing restrictions at the Groningen gas field in the Netherlands. The total actually delivered through BBL was lower than winter 2015/16. However, this was not entirely due to the Groningen restrictions. At the beginning of December some of the long term capacity contracts held by shippers in BBL expired. As a result, contracted volumes dropped from around 40 mcm/day to 20 mcm/day. BBL offered extra capacity for sale on the short term market, but flows failed to materialise. The effect of the changes in contracted volumes can be seen in figure 2.7. This shows flows increasing through October and November to around 40 mcm/day and then dropping to 20 mcm/day. After contracts expired, flows did not exceed 20 mcm/day.

LNG

In our *Winter Outlook Report* we forecast good supplies of LNG for the winter. Market commentators have been talking for some time about the increase in supplies to North West Europe as a result of increased production capacity around the world. However, LNG deliveries fell from an average of 37 mcm/day in September to approximately 5 mcm/day at the beginning of October. Several factors contributed to this decline, namely outages in Australian LNG production facilities, nuclear outages in South Korea and strong Chinese demand. Figure 2.8 shows deliveries remained low until the beginning of March. To illustrate how uncharacteristically low LNG flows were from the beginning of October, we have included September data. As a comparison, we have also included total LNG flows from winter 2015/16.

Figure 2.8
LNG flows by terminal



Chapter two

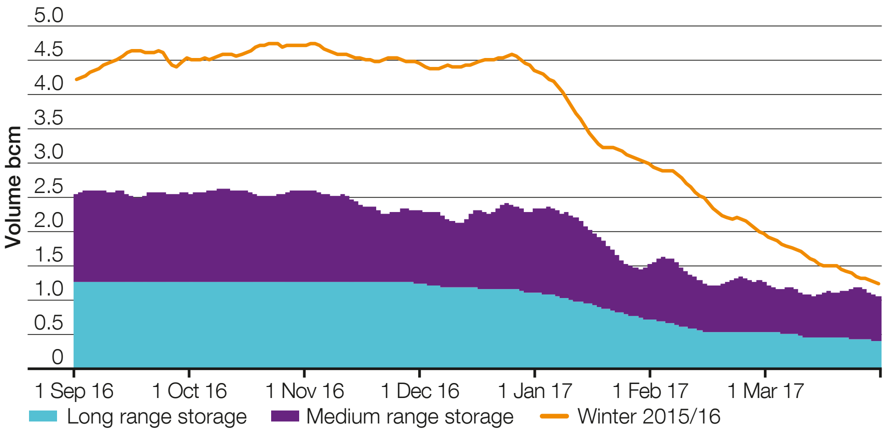
Supply

During the winter, the price of gas on the East Asian markets rose sharply and available LNG was sent there, rather than to North West Europe. By the beginning of March, the East Asian price had fallen and more gas began to flow to the GB market.

Storage

In our *Winter Outlook Report* we discussed the technical problems at the Rough long-range storage facility. The restrictions at Rough meant no gas was injected into the facility last winter, and there were no gas withdrawals until early December. The Centrica Storage website[2] provides more information on the restrictions at Rough over winter 2016/17. Stock levels in long-range and medium-range storage are shown in figure 2.9.

Figure 2.9
Stock levels in storage



[2] http://www.centrica-sl.co.uk/regulation/remit/2015-33

Gas supply in cold weather

In our *Winter Outlook Report* we published a forecast for each component of the Non Storage Supply (NSS) at times of high demand. We use this analysis to help us decide whether we should issue a Margins Notice[3] to the industry. A Margins Notice provides the industry with a day-ahead notification of a potential imbalance between supply and demand; this allows sufficient time for market participants to respond.

Table 2.3 shows our forecast range for each supply type, together with the cold day forecast and the actual range for winter 2016/17. The column '350+ range' shows the range of demand on the days of the winter when demand exceeded 350 mcm. You can see that the maximum supply from most sources coincides with the high demand days.

Table 2.3
Cold day forecast and actual supply (mcm/d)

	Forecast		Actual	
	Range	**Cold day**	**Range**	**350+ Range**
UKCS	70 – 118	107	89 – 132	100 – 130
Norway	60 – 136	115	67 – 134	115 –134
BBL	0 – 45	35	0 – 45	14 – 45
IUK	0 – 74	45	0 – 51	5 – 45
LNG	5 – 100	50	5 – 32	5 – 21
Total NSS		**352**		
Storage	0 – 130		0 – 88	40 – 88

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

Supply

On gas day 04 December we experienced maximum flows through IUK into GB. This did not correspond with the biggest price spread between the NBP and Zeebrugge hubs. On this particular day, deliveries of gas from the UKCS, Norway and storage were all slightly lower than seen on days with similar demand levels. Correspondingly, although LNG did not respond strongly to demand over the winter period, on 4 December they provided their highest flows of winter, exceeding 20 mcm/day. In this instance both IUK and LNG supplies were needed to satisfy demand. These two examples illustrate the challenges in forecasting the quantities of imported gas supplies.

What we said in our *Winter Outlook Report*	What actually happened?	Why was there a difference?
We expect there to be sufficient gas available from a range of sources to meet winter 2016/17 demand.	There was sufficient gas available.	
There may be less gas flowing via the BBL interconnector.	BBL flows dropped from 3 bcm in winter 2015/16 to 2.7 bcm.	
There might be higher LNG flows in 2016/17 than 2015/16.	LNG flows dropped to 5 mcm/d from 1 October and remained low until the beginning of March. Total flow for last winter was 2 bcm, compared with 6 bcm in 2015/16.	LNG was sent to other markets which offered a higher price.
The price differential between the GB and Belgian markets in early 2017 may be enough to support greater flows from Belgium to GB.	Prices supported imports from early November to early March. We anticipated the direction of flow, but our timing was slightly out.	

System operability

This section examines the challenges associated with planning and operating the gas system in response to supply and demand variability to meet the changing needs of our customers.

Key messages

- Last winter network flows varied from our forecasts. This was due to higher demands and variable supply patterns.
- Within-day linepack swings were similar to those experienced in 2015/16.
- These factors have resulted in the need to adopt different operational strategies and asset utilisation to meet customer requirements.

Key terms

- **National transmission system (NTS):** a high pressure gas transportation system consisting of compressor stations, pipelines, multi-junction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to pressures of 94 barg.
- **Linepack:** the volume of gas within the national transmission system (NTS) pipelines at any one time.
- **Linepack swing:** the difference between the amount of gas in the system at the start of the day and at the lowest point during the day.
- **Interconnector:** gas interconnectors connect gas transmission systems from other countries to the national transmission system (NTS) in England, Scotland and Wales. There are currently three gas interconnectors that connect to the NTS. These are: IUK which connects to Belgium, BBL to the Netherlands and Moffat to the Republic of Ireland, Northern Ireland and the Isle of Man.

Overview

During winter 2016/17 gas supplies into the UK continued to be variable. We experienced a high concentration of flow from Scotland and lower inputs of LNG than anticipated in our *Winter Outlook Report*. The variable supply and demand pattern seen last winter meant that more compression was used, compared to winter 2015/16, in order to ensure demand and pressure obligations were met.

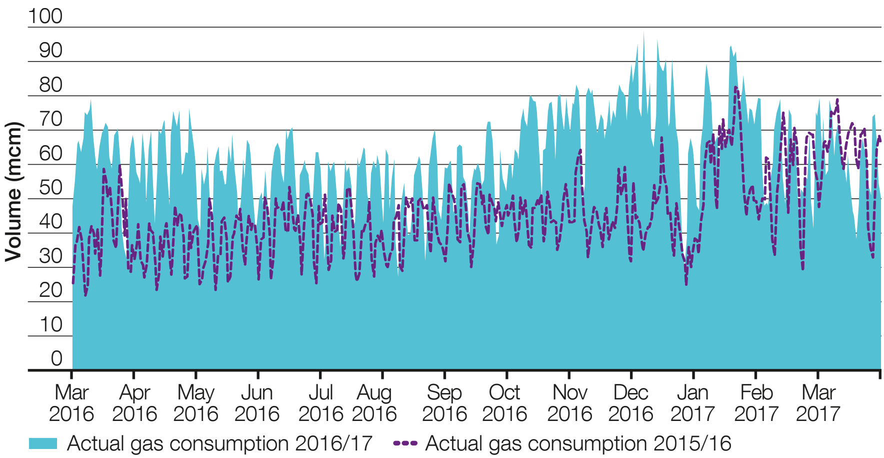
Chapter two

System operability

Operability challenges resulting from winter supply and demand patterns

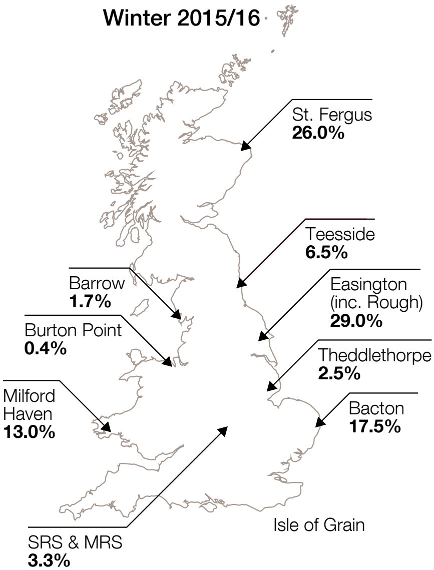
Last winter we experienced very different supply and demand patterns than those experienced in previous years. As a result, gas flows in the network also changed. As discussed in the gas demand chapter, demand was higher than forecast in our *Winter Outlook Report*. The increased demand was mainly from the power generation sector in response to commercial drivers and lower electricity imports from Continental Europe.

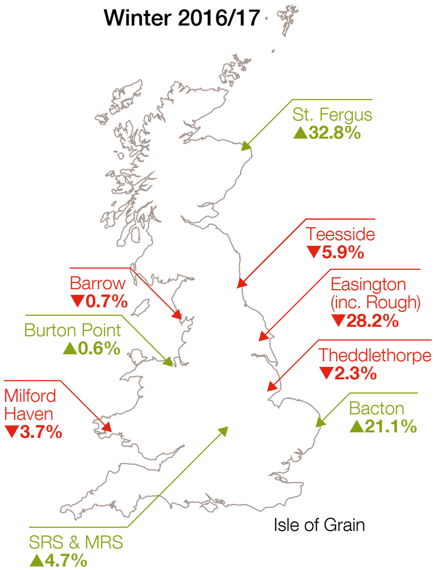
Figure 2.10
Gas consumption for power generation 1 March 2016 to 31 March 2017, compared to the same period last year



With lower than forecast flows of LNG and restrictions at the Rough storage facility, we experienced higher gas supplies from the UKCS and Norway. This resulted in high gas flows from three terminals situated in the north and east of the country. Collectively, they accounted for 82 per cent of total gas throughput in winter 2016/17, compared to 73 per cent in winter 2015/16.

Figure 2.11
Gas supplies over winter 2016/17 compared to the previous winter



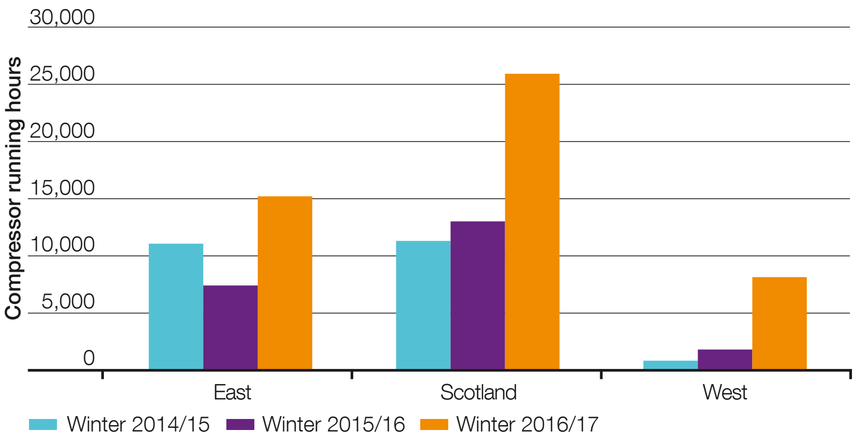


Increased supplies through these terminals caused a high concentration of gas in the north and east of GB. This meant that we needed to increase the use of compression, to drive the gas to the south and west of the country. The use of additional compression to manage the concentration of supply meant an increase in compressor running hours.

In figure 2.12 we can see, for example, the significant increase in compressor usage for winter 2016/17 in Scotland and the east, where we experienced very high flows. Information on the previous two winters has been included to illustrate just how significant the increase in compressor running hours were last winter.

System operability

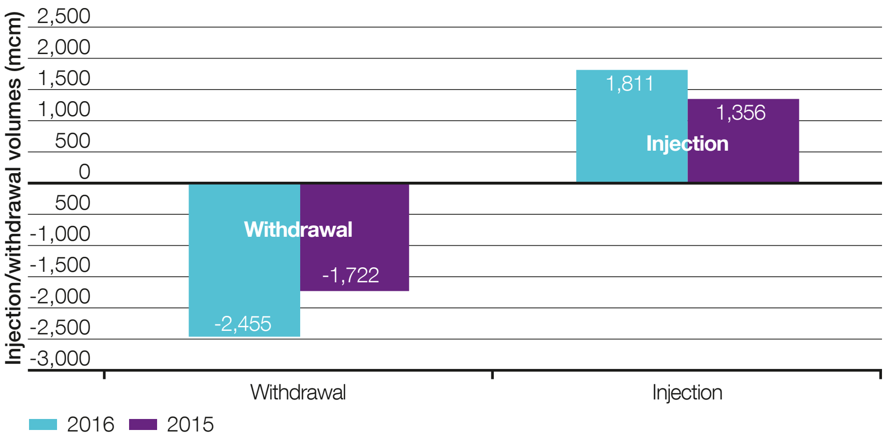
Figure 2.12
Compressor running hours for winter 2014/15 to winter 2016/17



Within-day operability challenges

For winter 2016/17, changes in the market increased the need for a more agile and dynamic network to enable customers to respond to market opportunities. For example, gas-fired generation was highly reactive to short term market prices in November, early December and January. Similarly, medium-range storage showed increased cycling of injection and withdrawal last winter. This was due to a combination of restrictions at Rough and in response to short term changes in market demand. Figure 2.13 illustrates the injection and withdrawal volumes for medium-range storage for the last two years. It shows that there was a 34 per cent increase in the volume injected into store, and a 43 per cent increase in the volume withdrawn. Changes to within-day operations require a reconfiguration of the system and compressor strategy which takes time, the effects of which are not always immediate.

Figure 2.13
Medium-range storage injections and withdrawal volumes



At a national level, the variability of supply and demand within-day can result in changes to the amount of gas in the network; this is referred to as, National Transmission System (NTS) linepack. Last winter the system experienced linepack swings of a similar magnitude to winter 2015/16 as a result of customers responding to market opportunities. Large swings in linepack can mean that customers may experience increased pressure in areas where the gas is more concentrated and reduced pressure in areas where the gas is less. As a result, we need to continue to allow for a dynamic range of supply and demand assumptions in our planning and configuration of the network. In the system operability case study that follows, we explore in more detail the impact of increased levels of gas in localised areas.

Summary

Since the gas transmission network and associated contractual rules have historically been designed to operate with steady supply and demand profiles, it can be challenging to respond to the needs of agile energy markets. Over the winter period, we made continual revisions to both our commercial and operational strategy. These focussed on reducing the time taken to increase compressor availability to facilitate within-day changes. In situations such as this, we ensure that the network is configured effectively to meet safety and contractual obligations.

System operability

What we said in our *Winter Outlook Report*	What actually happened?	Why was there a difference?
Increased within day changes to gas demand as customers respond to movements in GB and European gas and electricity prices.	There was a significant increase in gas-fired electricity generation as a result of lower levels of available coal-fired generation, lower than expected imports from continental Europe and short term electricity price movements.	
The ability to predict daily supply patterns will become increasingly challenging due to varying supply sources in response to changing prices.	Increased supplies into Scotland and the east of GB presented challenges in system operation. Lower LNG flows and restrictions at Rough created a variable supply pattern.	

System operability case study

This case study focusses on a particularly challenging day which occurred in September 2016. It was chosen to illustrate how unplanned supply losses can affect linepack levels, pressures as well as compressor operating strategy.

Headlines

- Unplanned supply losses and prevailing supply and demand patterns resulted in a forecast of low system pressures.
- Buy actions were taken to deliver additional supplies on to the system.
- Increased supplies focused at the Milford Haven terminal created high pressures in South Wales.
- Local actions were required to safely manage pressures.

Key terms

- **Linepack:** is the volume gas in the NTS and is essential for the safe management of system pressures. The level of linepack fluctuates throughout the day depending on supply and demand imbalances.
- **Predicted Closing Linepack (PCLP):** is the amount of linepack forecast to be in the NTS at the end of the gas day.
- **National Transmission System (NTS):** the high pressure gas transportation system consisting of compressor stations, pipelines, multi-junction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to pressures of 94 barg.
- **Within day:** defined as any operation that takes place during the 'gas day' (05:00 to 04:59).
- **Profiling:** the rate at which gas is put into or taken off the transmission system during the gas day. A flat profile corresponds to a consistent rate across the day.

Overview

In our *Winter Outlook Report*, we discussed the need for increased within-day flexibility of the National Transmission System (NTS) as we experience more supply and demand profiling. As we mentioned earlier, the increase in profiling places a greater focus on our operational and commercial strategies to manage this, and to ensure we can accommodate any unforeseen large supply losses and/or rapid demand changes.

As the System Operator (SO) of the NTS, our primary concern is safety. It is crucial that we make sure that NTS gas pressures stay within safe and acceptable limits.

Chapter two

System operability case study

National Grid's role as the Residual Balancer

In addition to making sure that the system is safe, we act as the residual balancer of the GB gas market. If there is too much gas in the system, then pressure will increase. Likewise, too little gas in the system and the pressure will drop. This means that we need to monitor and control gas supply and demand, making sure the NTS remains within efficient operational limits to allow us to deliver the level of service that we have agreed with customers. If we are not confident that shippers will balance[4] the gas market, we may step in and take action to ensure gas pressures remain within acceptable limits.

This case study looks at how unplanned supply losses caused a decline in the level of linepack in the system and the measures we took to maintain NTS pressures.

The scenario

At the beginning of Gas Day, 5 September 2016, the actual physical NTS stock (linepack) opened at 326 mcm which was at the lower end of the operating plan for the day. This was because of ongoing supply losses at the St Fergus and Bacton terminals which had started the day before.

During the early morning, demand exceeded supply causing linepack to reduce further. Figure 2.14 shows at 10:00, the end of day closing position predicted a loss of 47 mcm of linepack which was outside of the planned operating range for the day. A linepack deficit early in the gas day is not unusual. On this particular day, it was a combination of actual linepack levels falling and the scale of the predicted deficit at the end of the day, which resulted in the need for early intervention.

What actions were taken?

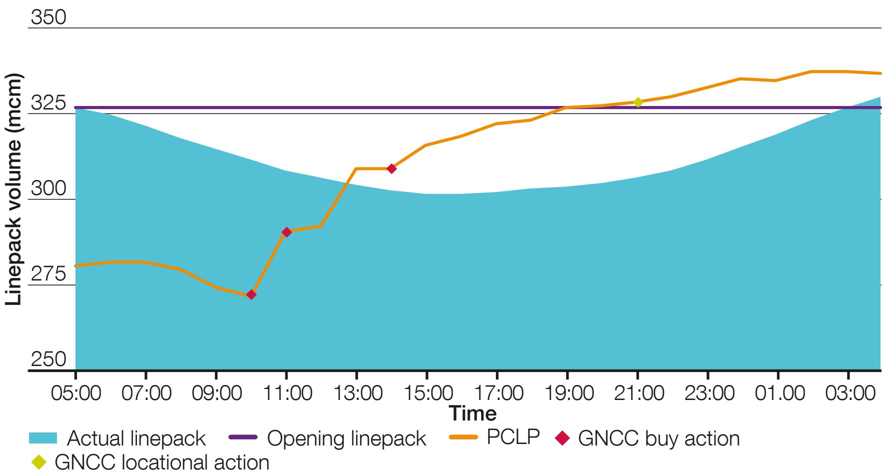
To address the supply and demand imbalance, we needed to take action at a National level. The decision was made to take a 'buy' action to bring gas on to the system and to encourage the market to respond. As the morning progressed we took a further two buy actions. Together, these actions resulted in the following market responses:

- Storage sites switched from injection to withdrawal.
- Supplies from the Milford Haven terminal increased to a rate of 78 mcm/day.

These responses were successful in bringing gas onto the system. Figure 2.14 shows the predicted closing linepack steadily rising after we took balancing actions. However, the increase in supply from Milford Haven presented a new network challenge requiring local actions in South Wales.

[4] Further information on balancing the system can be found at: http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/

Figure 2.14
Linepack volumes 4 and 5 September



Why were local actions needed as well?

The significant increase in flows from the Milford Haven terminal resulted in forecast pressures in South Wales to be above the maximum safe operating pressure of the pipeline. To address this, we undertook the following local actions:

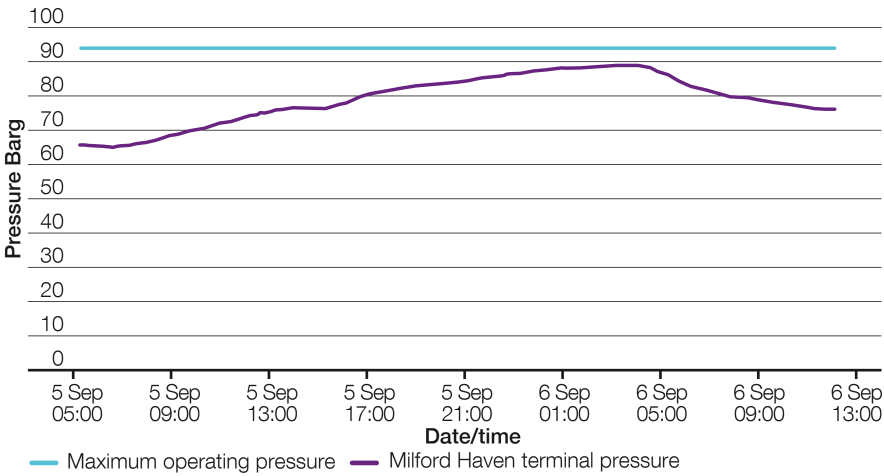
1. We requested the early return to service of compressor units from planned maintenance. This helped to reduce pressure in the local area by moving the gas away from South Wales.
2. We reduced the amount of non-firm capacity at Milford Haven.
3. We took a locational trade to sell gas to local demand.

By midnight, supplies at the Milford Haven terminal had started to reduce and, together with the help of the local actions, pressure began to fall. Figure 2.15 illustrates the pressure steadily rising at Milford Haven on 5 September. It shows the pressure edged close to the maximum operating pressure of the pipeline and, following the local actions taken, the pressure begins to reduce in the early hours of the morning.

Chapter **two**

System operability case study

Figure 2.15
Pressure profiles in the Milford Haven area on 5 September 2016



Summary

This case study demonstrates the within-day challenges that increasingly occur in our operation and planning of the NTS, and how we deal with unplanned disruptions. These challenges are set against a backdrop of customer requirements for a more agile network, using assets designed for steady state operation and a market regime designed for an end-of-day balanced position.

Chapter three

A first look at electricity for the coming winter

Our electricity analysis presents our assessment of security of supply for winter 2017/18. With the Early Auction completed, this is the first main delivery year for the Capacity Market (CM)[1]. We have adapted the information supplied in this section to reflect this change.

Historically, we have expressed the system margin as a gigawatt (GW) figure, and as a percentage of the transmission system demand. National Grid's focus has traditionally been on the transmission system because only a relatively small proportion of total generation was connected to the distribution system. This year we are publishing the percentage margin on an underlying demand (UD) basis[2]. This is used for the CM target capacity recommendation in our annual *Electricity Capacity Report*. It treats transmission connected generation and distribution connected generation in a consistent manner.

For comparison, margin analyses on a transmission demand (TD) and underlying demand basis are individually detailed in this section.

Key messages

- The de-rated margin range for this winter 2017/18 is 3.7 to 4.9GW, equivalent to a loss of load expectation (LOLE) of 0.25 – 0.05 hours per year respectively.
- On an underlying demand basis, this equates to a margin range of 6.2% to 8.2%.
- On a transmission demand basis, as used in previous years, the margin range equates to 7.2% to 9.9%.
- There are some generators which are currently available but were not successful in the capacity market. These units may not be available this winter and this uncertainty is reflected through the use of a margin range.

Key terms

- **Generation margin:** the sum of de-rated supply sources declared as being available during the time of peak demand plus support from interconnection, minus the expected demand at that time and basic contingency reserve requirement. This can be presented as either an absolute GW value or a percentage.
- **Loss of load expectation (LOLE):** a statistical metric used to describe electricity security of supply. It is an approach based on probability and is measured in hours per year. It measures the risk across the whole winter of demand exceeding supply under normal operation. It does not mean that there will be a loss of supply for x hours per year. It gives an indication of the amount of time across the whole winter that the System Operator may need to call on a range of emergency balancing tools to increase supply or reduce demand. In most cases, loss of load risk could be managed without significant impact to end consumers.

[1] The GB reliability standard has been set by Government at 3 hours LOLE per year.

[2] This is the demand definition of end user consumption applied in the National Grid Electricity Capacity Report to derive the recommended capacity to secure in the CM auctions – for underlying demand details see Chapter 3 of the following link: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf

Key terms *(continued)*

- **De-rating factors:** these are scaling factors applied to the maximum technical capability that account for breakdowns, planned outages and any other operational issues that may result in power stations not being able to generate at their normal level. They are based on the historic availability of plant during peak periods.
- **Capacity Market (CM):** as part of the Electricity Market Reform (EMR) programme, winter 2017–18 is the first delivery period for capacity contracted as part of the Early Auction. More information on the CM can be found using the **EMR** link.

GB margin assessment as we enter the first Capacity Market year

The *Winter Consultation* and *Winter Outlook* documents report the de-rated margin as a GW number and as a percentage of demand. Historically the percentage margin has been reported based on the transmission system demand. Using this approach, conventional generation connected to the distribution system (i.e. embedded non-wind) is treated as a reduction in demand rather than an increase in generation.

This has little impact on the margin quoted on a GW basis. However, the percentage margin calculated in this way will vary depending on the split of generation between the transmission and distribution systems. The growing volume of distribution connected generation makes it increasingly difficult to compare percentage margins between years. The issue can be explained using the scenario in the box below.

Consider a system where the underlying peak demand is 60 GW and the total de-rated generation on the system is 65 GW. This gives a system margin of 5 GW. Now consider 2 scenarios. In Scenario 1, all of the generation is connected to the transmission system whilst in Scenario 2, 55 GW is transmission connected and 10 GW is distribution connected.

In Scenario 1, the transmission-connected generation is 65 GW and the transmission peak demand is 60 GW, giving a de-rated margin of 8.3%.

In Scenario 2, the transmission-connected generation is 55 GW and the transmission peak demand is 50 GW, giving a de-rated margin of 10%.

The percentage margin in Scenario 2 is larger which might imply that Scenario 2 delivers greater security of supply than Scenario 1. However, the margin on a GW basis is identical and both scenarios deliver the same security of supply. Expressing the margin in this way has the potential to be confusing and is not in line with the CM approach which treats distribution and transmission generation identically from a security of supply perspective. Historically, the volumes of distribution-connected generation have

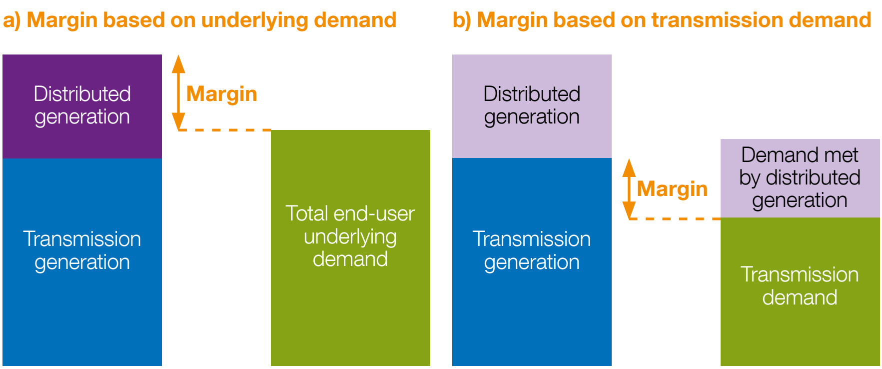
A first look at electricity for the coming winter

been relatively low and so therefore quoting margins on a transmission demand basis has not been an issue. However, with the move to the capacity market, and the significant increase in distribution-connected generation, it is appropriate to adopt an alternative approach based on underlying demand. This will allow a straightforward comparison of percentage system margins between years. Using this new approach, distribution-connected generation is treated as generation rather than as a reduction in demand. All other elements of the margin calculation remain the same. The percentage margin is based on underlying demand and so the generation split is irrelevant. In both scenarios used earlier, the margin on this basis is 8.3%.

In this document the de-rated margins will be quoted based on both the historical and the new approach. In the following sections we refer to the old approach as transmission demand (TD) margin and the new approach as underlying demand (UD) margin.

We welcome your views on when we should move to using only the new approach.

Figure 3.1
Illustrating the difference between Transmission and Underlying Demand margins



De-rated margin and loss of load expectation

The results of our analysis provisionally estimates a credible range of de-rated capacity margin in winter 2017/18 of between 3.7 and 4.9 GW. The lower and upper values in this range equate to an LOLE[3] of between 0.25 and 0.05 hours per year respectively, which is comfortably within the GB Reliability Standard requirement.

This is the first full year of the Capacity Market and there are several generators which are currently available in the market this winter which did not secure a 2017/18 CM contract.

An adverse change in market conditions could reduce the available (non-CM) generation capacity between now and the winter. Therefore quoting a range for system margin at this time is prudent.

Table 3.1 below indicates that the 3.7 and 4.9 GW margin range corresponds to 6.2%-8.2% on a UD basis, or 7.2%–9.9% on a TD basis. We also provide the same TD and UD breakdown for winter 2016/17 as an historical comparison. More detail on the calculation of these figures is explained below.

Table 3.1
A summary of margin forecasts for winter 2017/18 compared to winter 2016/17

	2016 *Winter Outlook* view of winter 2016/17	2017 *Winter Consultation* view of winter 2017/18	
		Lower Range	Upper Range
De-Rated Margin	3.4 GW	3.7 GW	4.9 GW
Margin as a % of transmission demand (TD)	6.6%	7.2%	9.9%
Margin as a % of underlying demand (UD)	5.7%	6.2%	8.2%

The forecast de-rated margin in winter 2017/18 is higher than the forecast in the *Winter Outlook* 2016/17 primarily due to the capacity procurement levels in the Early Auction. In addition, plant availability in winter 2016/17 was generally higher than recent years, which is reflected in the updated de-rating factors. The upper end of the range represents the scenario where some additional non-CM contracted plant may remain available to participate in the balancing market.

[3] The GB reliability standard has been set by Government at 3 hours LOLE per year.

A first look at electricity for the coming winter

Modelling assumptions – the Base Case

Our analysis is based on the EMR 5-year Base Case. This set of supply side and demand side input assumptions is taken from the 2017 Future Energy Scenarios, and is the starting point for the margin and LOLE analysis. This Base Case provides the upper limit of the 2017/18 margin range reported in the summary table of margin forecast for this winter.

The Base Case includes some eligible capacity that did not receive a capacity contract in the 2017/18 Early Auction. However, we have performed a sensitivity analysis for the Base Case and our analysis reflects the possibility that some of this capacity may not be available in the winter if it is uneconomical. This sensitivity analysis provides the lower limit of the 2017/18 margin reported in table 3.1 above.

The margin figures presented here are a current best estimate of the 2017/18 outlook. We should have a clearer view of any market changes later this year. Further model development will also continue this summer to refine the analysis presented. The final margin forecasts will be included in the figures published in our *Winter Outlook Report 2017*, in October.

Generation assumptions

There are three categories of generation used to calculate both TD and UD margins. These are (1) transmission connected generation; (2) wind generation connected to the distribution network; and (3) conventional generation connected to the distribution network and demand response.

For the TD margin calculation, we use transmission connected generation and wind generation connected to the distribution network. This is equal to 74.6 GW of maximum technical capacity. We then reduce this generation capacity by applying de-rating (or assumed availability) factors to account for breakdowns, planned outages and any other operational issues that may result in plant not being able to generate at full capacity. These de-rating factors[4] are calculated based on historic availability on high demand days during the winter period. Table 3.2 below details the assumed plant availabilities used.

The calculated de-rated transmission and embedded wind generation capacity is 54.7 GW. Interconnectors, which are discussed in more detail later, are excluded from this total.

For the UD margin calculation, we use all three categories of generation. We use the same numbers as before for transmission connected generation and wind generation connected to the distribution network. For the contribution from conventional generation connected to the distribution network at time of peak demand, we use a combined total of 10.2 GW; this includes an estimate for Customer Demand Management (CDM). This gives a total of 64.9 GW UD generation to feed into the UD de-rated margin assessment, Interconnectors are excluded from this total.

[4] The de-rating factor for wind is based on its equivalent firm capacity (EFC). The EFC is a measure of its overall contribution to security of supply over an entire winter and will vary depending on the tightness of the calculated margin. The EFC value in the table below relates to the 4.9 GW upper end of our forecast margin range – the EFC may be higher if the margin is towards the lower end of our forecast. You can read more about EFC and how we use this in our analysis on page 23 of our 2016 *Winter Outlook Report*. http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

Table 3.2
Assumed availability for each type generation

Generation type	Assumed availability
CCGT	88.5%
Coal and biomass	87.6%
Hydro	87.9%
Nuclear	85.2%
OCGT/Diesel	94.8%
Pumped/Battery storage	96.1%
Tidal	22.0%
Wind EFC	17.7%

Interconnector assumptions

This year we have assumed a total of 3.6GW of interconnector capacity will be available for imports, and 4GW for exports. Based on our modelling of GB and neighbouring energy markets, we have assumed 2.4GW of net import flows to GB for winter 2017/18. This is made up of 2.1GW of imports from Continental Europe and 0.3GW of imports from Ireland.

Demand assumptions

As mentioned previously, over the last few years we have seen an increase in the amount of generation connecting to the distribution networks and higher levels of customer demand management (CDM) during peak demand periods. This has led to a decline in demand levels as seen by the transmission system.

To calculate the TD margin, conventional generation connected to the distribution network (and CDM) are treated as negative demand. Here we assume an average cold spell (ACS) peak demand of 51.2GW. In order to cover the largest contingent in-feed loss, we add 0.9GW of reserve to the ACS peak demand. The total TD forecast ACS peak demand, including reserve, for winter 2017/18 is expected to be 52.1GW. This value excludes any interconnection flows.

For the UD margin, we again need the assessment of the contribution from conventional generation connected to the distribution network and CDM at time of peak demand. As above, for winter 2017/18, we estimate this to be 10.2GW, which when added to the TD 51.2GW demand figure, gives a total UD forecast ACS peak value of 61.4GW. Adding 0.9GW of reserve gives a total of 62.3GW. This demand also excludes any interconnector flows.

Chapter three

A first look at electricity for the coming winter

Stakeholder engagement

The importance of embedded generation and demand response modelling in the GB security of supply assessment is clearly growing.

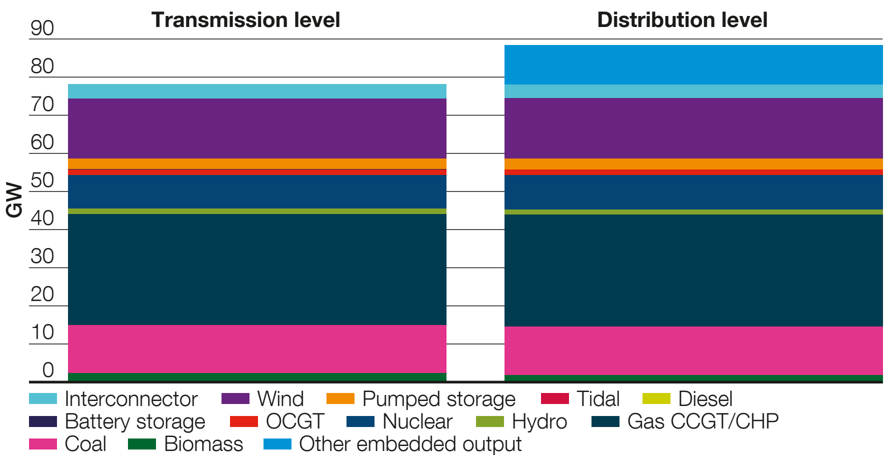
We are continuing to work with the industry and other stakeholders to better understand the behaviour of embedded generation, which is not directly visible to us, so that we can enhance our modelling of this in future analysis.

We are also continuing to promote demand side opportunities through our **Power Responsive programme** and expect further growth in this area.

Overall capacity summary

Figure 3.2 contains a summary of maximum technical capacity by fuel type for this winter. This information is used for both the UD and TD assessments. It also includes interconnector import capacity and expected output contribution from non-wind embedded sources at time of system peak. The fundamental difference is the contribution from embedded sources in the UD assessment version.

Figure 3.2
Generation capacity by fuel type, as well as expected embedded generation contribution, for winter 2017/18



A first look at gas supplies for the coming winter

This section explores our preliminary view of gas supplies for the forthcoming winter. We are keen to hear your views of our provisional analysis, especially our cold day forecast.

Key messages

- Based on our preliminary analysis we believe there will be a wide range of potential supply sources to meet demand for winter 2017/18.

Key terms

- **UK Continental Shelf (UKCS):** made up of the areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
- **BBL:** a gas pipeline running between Balgzand in the Netherlands and Bacton in the UK.
- **IUK:** the Interconnector (UK) Limited is a gas bi-directional pipeline connecting Bacton in the UK and Zeebrugge in Belgium.
- **Liquefied natural gas (LNG):** natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161 °C so that it occupies 600 times less space than in its gaseous form.

Overview

Based on our preliminary analysis, we expect that there will be sufficient gas available this winter to meet demand. GB's gas demand is expected to be met from a wide range of supply sources. The analysis presented here should be regarded as provisional; it is intended to encourage discussion and comment. The analysis will be revised for our *Winter Outlook Report*, to reflect the latest market information and the responses we receive to the Consultation. We would particularly welcome views on our cold day forecasts.

Centrica Storage has announced that the Rough long-range storage site will be unavailable for injection before May 2018. Withdrawal is suspended from May to September 2017. Stocks in the facility were reduced this spring so, even if withdrawal restarts in September, little gas will be available for withdrawal in winter 2017/18. This information has been reflected in our analysis. For the most up to date information on Rough availability please see the Centrica Storage website.

A first look at gas supplies for the coming winter

Chapter three

Gas supplies

Our preliminary view of gas supplies for winter 2017/18 is shown in table 3.3. This shows the ranges within which we expect all of the supply types to flow. The observed ranges from winter 2016/17 are shown for comparison, along with the flows on the days last winter when demand exceeded 350 mcm.

The ranges for the different supply types represent the minimum and maximum that we might expect. The maximum values would not all occur simultaneously, but reflect experiences in recent years. The ranges are very wide, reflecting the variability in supply patterns. For example, on the day of peak supply in winter 2016/17, Norway provided 133 mcm, just short of the maximum value, while LNG and IUK both provided close to their minimum values seen all winter.

Table 3.3
Preliminary view of supplies for winter 2017/18 (mcm/d)

	2016/17		2017/18	
	Observed Range	350 + Range	Forecast range	Cold day
UKCS	89–132	100–130	70–118	107
Norway	67–134	115–134	60–136	125
BBL	0–45	14–45	0–20	20
IUK	0–51	5–45	0–74	45
LNG	5–32	5–21	5–100	50
Storage	0–88	40–8	0–132	
Total NSS				347

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

Cold day forecasts

Table 3.3 shows the forecast for a cold day. The cold day is taken from the average load duration curve. Load duration curves are published every year in our *Gas Ten Year Statement*.

The non-storage supply (NSS) total for the cold day forecast is used to determine the trigger levels for the Margins Notice[4]. A Margins Notice is a day-ahead notification to inform transmission system users of a potential supply and demand imbalance, highlighting it in sufficient time for market participants to take effective action.

If we set the NSS level too low there is a danger that the Margins Notice trigger level will be reached too easily, leading to possible market actions when none are needed. On the other hand, if we set the level too high, it is possible that the Margins Notice trigger level will not be reached in a situation when action from the market is required.

The cold day forecast for UKCS is based on information received from producers as part of our annual *Future Energy Scenarios* stakeholder engagement process.

The Norwegian cold day forecast is higher than last year's value. It is based on performance last winter and expected performance in winter 2017/18.

For winter 2016/17 we lowered our BBL cold day forecast, from 40 mcm/day to 35 mcm/day, in response to stakeholder feedback. The highest flow seen was 45 mcm/day, in November. At the beginning of December some long term capacity contracts for BBL expired, after this flows never exceeded 20 mcm/day. At the time of writing we are not aware of any new capacity contracts being signed for BBL this winter, therefore we have set the cold day forecast at 20 mcm/day.

The IUK cold day forecast is unchanged from last year. We have set the maximum forecast flow at 74 mcm/day. This is the physical import capacity of the interconnector. This level was reached in March 2013 when storage stocks were depleted after a long cold spell.

Deliveries of LNG in winter 2016/17 were very low. However flows have increased since March 2017. Current market intelligence suggests that there will be plenty of LNG available in winter 2017/18. As a result, we have left the LNG cold day forecast unchanged at 50 mcm/day since it is a good representation of recent winters prior to 2016/17.

Chapter four

Consultation questions

Your responses to the consultation questions will underpin the development of our 2017/18 *Winter Outlook Report* and help us to make sure we provide a well-informed and accurate outlook to the industry.

To guide you to the sections where we feel you could add the most value, we've divided the consultation questions into sections. Below is a summary of what each of these sections covers and a guide to who might want to respond. We welcome feedback from all of our stakeholders so this should only be considered as a guide.

Responses can be emailed to us at **marketoutlook@nationalgrid.com** or completed online via the survey on our **website**. Please make sure that you share your views before the consultation closes on 14 July.

	Section	**What this section covers**	**Who might respond**
	General	How we can improve 2017/18 *Winter Outlook Report*	All of our stakeholders
Electricity	Demand	How our analysis is used and participation in demand management	Industrial and commercial customers, and demand aggregators
Electricity	Operational view	Generation capacity and operating strategy	Generators and industry commentators
Electricity	Interconnected markets	Interconnector flows and European markets	Electricity interconnectors and industry commentators
Gas	Fuel prices	Trends in fuel prices	Industry commentators
Gas	Demand	Expected trends in gas demand	Industrial and commercial customers, generators and suppliers
Gas	Supply	Our gas supply projections	Gas shippers, producers and infrastructure operators
Gas	System operability	Operability of the gas transmission network	Industrial and commercial customers, gas shippers, producers and infrastructure operators

General

1.1	What aspects of our *Winter Outlook Report* are important to you? What do you use this information for?
1.2	What further analysis, detail or scenario work do you think would be useful in our *Winter Outlook Report*? Why is this information important to you?
1.3	The energy landscape is evolving at a rapid rate. To help you understand the implications for your company or the wider market, are there any changes you would like us to cover in an educational piece within our *Winter Outlook Report*?
1.4	What would you change about our *Winter Outlook Report* if you could?

Consultation questions

Electricity

Number	Question
Demand	
2.1	Do you use the demand analysis in our *Winter Outlook Report*? What do you use this analysis for?
2.2	Did your organisation, either independently or as part of an aggregator group, participate in demand management in winter 2016/17? What factors influenced your decision to do this? (For example Triad avoidance, market prices.) What revenue streams were you hoping to access by doing this? How important are these benefits to your organisation?
2.3	If you participated in demand management during winter 2016/17, did you do this by generating on site or by shifting your demand?
2.4	If you participated in demand management during winter 2016/17, over what periods did you do this? What was the maximum amount that you reduced your demand by?
2.5	If you participated in demand management during winter 2016/17, did you shift your demand by more or less than in previous years?
2.6	Do you expect your organisation, either directly or as part of an aggregator group, to participate in demand management during winter 2017/18? What factors will influence your decision?
2.7	If you expect to participate in demand management during winter 2017/18, will you do this by generating onsite or by shifting your demand?
2.8	In comparison to winter 2016/17, do you think that the peak level of demand management in winter 2017/18 will increase or decrease? What makes you believe this? How much generation would you expect to respond to periods of high demand?
2.9	Has the Power Responsive programme influenced your participation in demand management?
2.10	Have you been made aware of demand management opportunities via other information sources? If so, please tell us which ones.
2.11	In our 2016/17 *Winter Outlook Report*, we simplified the presentation of our demand analysis in response to your feedback. Is there anything we have removed that you still require?
Operational view	
2.12	Does your operational view analysis influence when you schedule outages?
2.13	If your company has transmission-connected generation that is currently unavailable to the market, what might lead you to return it to service and how long would it take you to do so? What generation type is this?
2.14	‘Long notice’ refers to generator units that have taken the commercial decision not to generate every day. These units may have a notice period of up to 48 hours before they can begin to generate. If your generator has a proportion of its capacity at long notice, do you expect to change this in the future? What factors would influence your decision?
2.15	Plant breakdown rates were lower than expected in winter 2016/17. Why do you think this was? Do you expect this to continue?

Number	Question
Interconnected markets	
2.16	How do you expect weather conditions in Continental Europe to impact on interconnector flows to GB in winter 2017/18?
2.17	How would you expect further changes to the generation mix in Continental Europe to affect the flow on the interconnectors to GB?
2.18	In its 2017 finance bill, France outlined plans to set a carbon price floor of approximately 30 Euros per tonne. What impact do you think this might have on interconnector flows?
2.19	Do you have any market intelligence on the expected market conditions in other European countries that may affect interconnector flows to or from GB for winter 2017/18?
2.20	How would you expect unexpected low output in nuclear generation in the French market to impact your operations during winter 2017/18?
Fuel prices	
2.21	How do you expect gas prices will trend over winter 2017/18? How do you think this will compare to coal prices?
Winter view and the Capacity Market	
2.22	Winter 2017/18 is the first full year of the Capacity Market (CM). Does this affect the information and analysis you need from our *Winter Outlook Report*? We are interested to hear your views on the future scope for our winter assessment of security of supply, and it's alignment with the CM. Would the presentation of a CM consistent margin be helpful?
2.23	In our future outlook reports, we intend to only present the margin on an Underlying Demand (UD) basis. This would mean that we would no longer include commentary and analysis on the Transmission Demand (TD) margin in the Winter View section. We are interested in hearing your views on this.

Consultation questions

Gas

Demand	
3.1	Do you expect gas demand for power generation to increase or decrease in winter 2017/18, compared to winter 2016/17? What makes you believe this?
3.2	Do you expect there to be any significant changes in industrial and commercial gas demand for winter 2017/18, compared to winter 2016/17? What makes you believe this?
3.3	Discounting for weather, do you think there will be any significant changes in gas demand over winter 2017/18, compared to winter 2016/17? Why do you believe this?
3.4	Do you expect to see any change to gas exports from the UK over the coming winter? What factors do you believe will influence this?
3.5	Under what conditions would you expect to see increased exports from IUK this winter?
Supply	
3.6	What are your thoughts on our gas projections are for winter 2017/18?
3.7	Imports through BBL did not exceed 20 mcm/day after 1 December 2016 when long term capacity contracts expired. Can you see any conditions under which BBL flows might exceed this level in winter 2017/18?
3.8	Are there any issues related to European supply and demand which you feel could have an impact on gas flows to and from the GB market over winter 2017/18?
3.9	LNG deliveries were very low during winter 2016/17. Do you think this pattern will be repeated in winter 2017/18, or will we see more typical, higher flows?
3.10	How would the prospect of a cold winter, combined with reduced storage stocks, affect your operating strategy for winter 2017/18?
3.11	How do you expect medium-range storage to operate in winter 2017/18 in the absence of Rough?
3.12	In our *Winter Outlook Report* we consider various scenarios affecting security of supply. Are there any scenarios we haven't previously considered which you feel should be?
System operability	
3.13	Do you foresee any changes or volatility to flow patterns during the forthcoming winter? If so, what do you believe might cause these changes?
3.14	Would you expect to see a change in the way gas-fired generation operates this winter in comparison to winter 2016/17? What factors do you think will influence these changes?
3.15	How will changes to gas-fired plant operations affect your operating strategy for winter 2017/18?
3.16	How do you think changes to the Capacity Market and increased renewable generation will impact CCGT operations?

Chapter five

Glossary

Word	Acronym	Section	Description
BBL	BBL	Gas	A gas pipeline between Balgzand in the Netherlands and Bacton in the UK. You can find out more at **www.bblcompany.com**
billion cubic metres	bcm	Gas	Unit of volume used in the gas industry. 1 bcm = 1,000,000,000 cubic metres
BritNed		Electricity	BritNed Development Limited is a joint venture of Dutch TenneT and British National Grid that operates the electricity link between Great Britain and the Netherlands. It is a bi-directional interconnector with a capacity of 1,000MW. You can find out more at **www.britned.com**
Combined cycle gas turbine	CCGT	Various	A power station that uses the combustion of natural gas or liquid fuel to drive a gas turbine generator to produce electricity. The exhaust gas from this process is used to produce steam in a heat recovery boiler. This steam then drives a turbine generator to produce more electricity.
Composite weather variable	CWV	Gas	A single measure of daily weather. It is the combination of temperature and other weather variables, including wind speed. The purpose of CWV is to define a linear relationship between the weather and non-daily metered gas demand.
Compressor		Gas	Compressors are used to move gas around the transmission network through high pressure pipelines. There are currently 68 compressors at 24 sites across the country. These compressors move the gas from entry points to exit points on the gas network. They are predominately gas driven turbines that are in the process of being replaced with electric units.
Contingency balancing reserve			Services developed to support system balancing by enabling National Grid to access additional reserve held outside of the market. There are two types: demand side balancing reserve and supplemental balancing reserve.
Daily metered	DM	Gas	A classification of customers where gas meters are read daily. These are typically large scale consumers.
Demand side balancing reserve	DSBR	Electricity	Demand side balancing reserve (DSBR) is a balancing service that has been developed to support National Grid in balancing the system. DSBR provides an opportunity for large consumers or owners of small embedded generation to earn money through a combination of upfront payments and utilisation payments by contracting to reduce demand or provide generation when required. The service may be required for short periods between 4pm and 8 pm on weekday evenings between November and February.
Demand side response	DSR	Various	A deliberate change to an industrial and commercial user's natural pattern of metered electricity or gas consumption, brought about by a signal from another party.
East West Interconnector	EWIC	Electricity	A 500MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more at **www.eirgridgroup.com/customer-and-industry/interconnection/**
Embedded generation		Electricity	Power generating stations/units that don't have a contractual agreement with the national electricity transmission System Operator (NETSO). They reduce electricity demand on the transmission system.
Equivalent firm capacity	EFC	Electricity	An assessment of the entire wind fleet's contribution to capacity adequacy. It represents how much of 100% available conventional plant could theoretically replace the entire wind fleet and leave security of supply unchanged. EFC is currently assumed to be 22%.
EU Emissions Trading Scheme	ETS	Gas	An EU wide system for trading greenhouse gas emission allowances. The scheme covers more than 11,000 power stations and industrial plants in 31 countries.
European Union	EU	Various	A political and economic union of 28 member states that are located primarily in Europe.

Word	Acronym	Section	Description
Future Energy Scenarios	FES	Various	The *FES* is a range of credible pathways for the future of energy out to 2050. They form the starting point for all transmission network and investment planning, and are used to identify future operability challenges and potential solutions. You can find out more at **http://fes.nationalgrid.com/**
Gigawatt	GW	Electricity	A measure of power. 1 GW = 1,000,000,000 watts.
Great Britain	GB	Various	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
Grid supply points	GSP	Electricity	A connection point between the transmission system and the distribution system.
Interconnector (UK) Limited	IUK	Gas	A bi-directional gas pipeline between Bacton in the UK and Zeebrugge in Belgium. You can find out more at **www.interconnector.com**
Interconnector		Gas	Gas interconnectors connect gas transmission systems from other countries to the national transmission system (NTS) in England, Scotland and Wales. There are currently three gas interconnectors that connect to the NTS. These are: ■ IUK interconnector to Belgium ■ BBL to the Netherlands ■ Moffat to the Republic of Ireland, Northern Ireland and the Isle of Man
Interconnector		Electricity	Electricity interconnectors are transmission assets that connect the GB market to Continental Europe and Ireland. They allow suppliers to trade electricity between these markets.
Interconnexion France-Angleterre	IFA	Electricity	The England-France Interconnector is a 2,000 MW link between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).
Linepack		Gas	The volume of gas within the national transmission system (NTS) pipelines at any time.
Linepack swing		Gas	The difference between the amount of gas in the system at the start of the day and at the lowest point during the day.
Liquefied natural gas	LNG	Gas	Natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161˚C so that it occupies 600 times less space than in its gaseous form. You can find out more at **www2.nationalgrid.com/uk/Services/Grain-lng/what-is-lng/**
Load		Various	The energy demand experienced on a system.
Long-range storage		Gas	There is one long-range storage site on the national transmission system; Rough, situated off the Yorkshire coast. Rough is owned by Centrica. The site mainly puts gas into storage (‘injection’) in the summer and takes gas out of storage in the winter.
Medium-range storage		Gas	These commercially operated sites have shorter injection/withdrawal times. This means they can react quickly to demand, injecting when demand or prices are lower and withdrawing when they are higher.
Megawatt	MW	Electricity	A measure of power. 1 MW = 1,000,000 watts.
Million cubic meters	mcm	Gas	Unit of volume used in the gas industry. 1 mcm = 1,000,000 cubic metres
Moyle		Electricity	A 500 MW bi-directional interconnector between Northern Ireland and Scotland. You can find out more at **www.mutual-energy.com**
National balancing point (NBP) gas price	NBP	Gas	Britain's wholesale NBP gas price is derived from the buying and selling of natural gas in Britain after it has arrived from offshore production facilities. The wholesale market in Britain has one price for gas, irrespective of where it has come from. It is usually quoted in pence per therm. You can find out more at **https://www.ofgem.gov.uk/gas/wholesale-market/gb-gas-wholesale-market**

Glossary

Word	Acronym	Section	Description
National electricity transmission system	NETS	Electricity	High voltage electricity is transported on the transmission system from where it is produced to where it is needed throughout the country. The system is made up of high voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single System Operator (SO).
National transmission system	NTS	Gas	A high pressure gas transportation system consisting of compressor stations, pipelines, multi-junction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to pressures of 94 barg.
Non-daily metered	NDM	Gas	A classification of customers where gas meters are read monthly or at longer intervals. These are typically residential, commercial or smaller industrial consumers.
Non storage supply	NSS	Gas	All gas supplies to the national transmission system excluding short, medium and long-range storage.
Normalised demand		Electricity	Demand assessed for each week of the year based on a 30 year average of each relevant weather variable. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.
Notification of Inadequate System Margin	NISM	Electricity	A routine notification issued to generators, interconnected system operators and suppliers to advise there is a likelihood that there will be an inadequate margin of reserve capacity available. The purpose is to make the recipients aware and request that additional reserve capacity is made available.
Off peak firm capacity		Gas	Off peak capacity is made available to the market at offtake points where it can be demonstrated that firm capacity is not being utilised.
Operational Code 2 data	OC2	Electricity	Information provided to National Grid by generators. It includes their current generation availability and known maintenance outage plans. You can access the latest OC2 data throughout the year on the BM Reports website at **www.bmreports.com**
Open cycle gas turbine	OCGT	Various	Gas turbines in which air is first compressed in the compressor element before fuel is injected and burned in the combustor.
Peak		Various	The maximum requirement of a system at a given time, or the amount of energy required to supply customers at times when need is greatest. It can refer either to a given moment (e.g. a specific time of day) or to an average over a given period of time (e.g. a specific day or hour of the day).
Predicted closing linepack (PCLP)		Gas	The amount of stock expected to be in store in the NTS at the end of the gas day.
Profiling		Gas	The rate at which gas is put into or taken off the transmission system during the gas day. A flat profile corresponds to a consistent rate across the day.
Residual balancer		Gas	Users of the gas system are incentivised to balance supply into, and demand from, the network. If this balance is not expected to be achieved on any given day, the System Operator (National Grid), as residual balancer, will enter the market and undertake trades (buys or sells) to seek to resolve any imbalance.
Seasonal normal demand		Gas	The level of gas demand that would be expected on each day of the year. It is calculated using historically observed values that have been weighted to account for climate change.
Station load		Electricity	The onsite power station requirement, for example for systems or start up.

Word	Acronym	Section	Description
Supplemental balancing reserve	SBR	Electricity	Supplemental balancing reserve (SBR) is a service that has been developed to support National Grid in balancing the system. Contracts are set up between National Grid and generators to make their power stations available in winter, where they would otherwise be closed or mothballed.
System Operator	SO	Various	An entity entrusted with transporting energy in the form of natural gas or electricity on a regional or national level, using fixed infrastructure. The SO may not necessarily own the assets concerned. For example, National Grid operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power.
Terawatt hour	TWh	Electricity	A measure of electrical energy often used for metering large amounts of electricity. 2 TWh = 2,000GWh
Transmission system demand	TSD	Electricity	Demand that National Grid as System Operator sees at grid supply points (GSPs), which are the connections to the distribution networks. It includes demand from the power stations generating electricity (the station load).
Triad		Electricity	Triads are the three half-hourly settlement periods with the highest system demand. Triads can occur in any half-hour on any day between November and February. They must be separated from each other by at least ten days.
Underlying demand		Electricity	A measure of demand that removes the effect of weather and the day of the week.
UK Continental Shelf	UKCS	Gas	The UK Continental Shelf (UKCS) comprises those areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
United Kingdom of Great Britain and Northern Ireland	UK	Various	A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland.
Weather corrected demand		Electricity	The demand expected or out turned with the impact of the weather removed. 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.
Weather corrected demand		Gas	The demand expected with the impact of weather removed. Actual demand is converted to demand at seasonally normal weather conditions, by multiplying the difference between actual CWV and expected CWV by a value that represents demand sensitivity to weather.
Winter Outlook Report	WOR	Various	The *Winter Outlook Report* is published each year in October by National Grid to show the expected security of supply position on both the gas and electricity systems for the coming winter. It is the product of the Winter Consultation process and is based on data supplied by the industry, market insight and analysis.

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