Energy market investigation

Descriptive statistics – generation and trading

6 March 2015

This is one of a series of consultative working papers which will be published during the course of the investigation. This paper should be read alongside the updated issues statement and the other working papers which accompany it. These papers do not form the inquiry group's provisional findings. The group is carrying forward its information-gathering and analysis work and will proceed to prepare its provisional findings, which are currently scheduled for publication in May 2015, taking into consideration responses to the consultation on the updated issues statement and the working papers. Parties wishing to comment on this paper should send their comments to energymarket@cma.gsi.gov.uk by 18 March 2015.

The Competition and Markets Authority has excluded from this published version of the working paper information which the Inquiry Group considers should be excluded having regard to the three considerations set out in section 244 of the Enterprise Act 2002 (specified information: considerations relevant to disclosure). The omissions are indicated by [✂].

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Introduction

1. This paper sets out a number of descriptive statistics about the upstream energy market. We provide some comments on these statistics to outline the current state of the market. The statistics are presented under four categories:

   (a) Electricity generation.

   (b) Electricity and gas consumption.

   (c) Trading and wholesale markets.

   (d) Balancing mechanism.

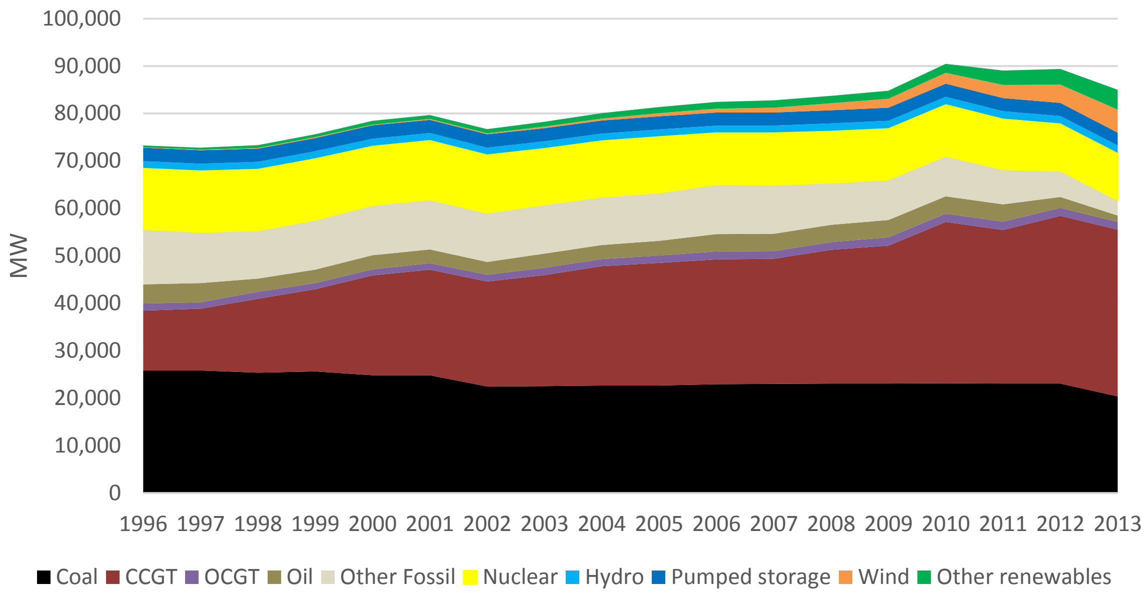
Electricity generation

2. The generation capacity of UK power stations over the past 18 years has been predominantly fossil fuel based (see Figure 1). Coal and combined-cycle gas turbine (CCGT) plants have accounted for a significant proportion of capacity, although there have been some recent closures of coal fired power stations, mainly in response to the Large Combustion Plant Directive (LCPD) directive.[1] The capacity of renewables has started to increase, especially from 2010.

[1] Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants. See Legal and Regulatory Overview working paper.

FIGURE 1

Generation capacity by technology (1996 to 2013)

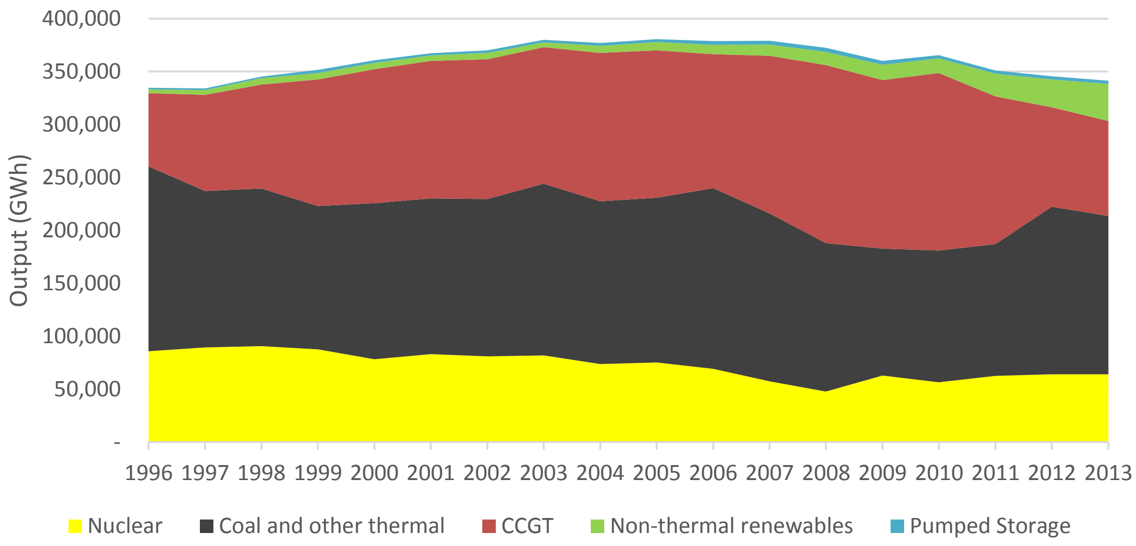


Source: DECC (2014) *Electricity: chapter 5*, Digest of United Kingdom energy statistics (DUKES), Table 5.6.

3. While the capacity data shows which power stations have been built and which have closed down, the data in Figure 2 indicates which power stations have been producing electricity (ie which power stations are in merit). Over the past 18 years, the trend has been for coal plants to reduce output while CCGT output expanded. This reversed between 2011 and 2012 due to the price of coal falling relative to gas so that CCGT plants became the marginal plant, and coal plants were run as baseload generation. Nuclear output has remained relatively constant over this period, while renewable output has expanded, and is starting to make a significant contribution to overall output (although still smaller than the output of nuclear, CCGT and coal/other thermal).

FIGURE 2

Annual output by technology



Source: DUKES 2014, Table 5.1.3.

4. While domestic generation accounts for the great majority of output in Great Britain (GB), GB also imports and exports electricity from and to neighbouring markets. Figure 3 shows GB's current level of interconnectivity with other markets.

FIGURE 3

GB interconnectors

Number on Map	Inter-connector	Connects to	Capacity (MW)
Operational Interconnectors			
1.	IFA	France	2000
2.	Moyle	Northern Ireland	450
3.	BritNed	The Netherlands	1200
4.	EWIC	Ireland	500
		Total	**4150**

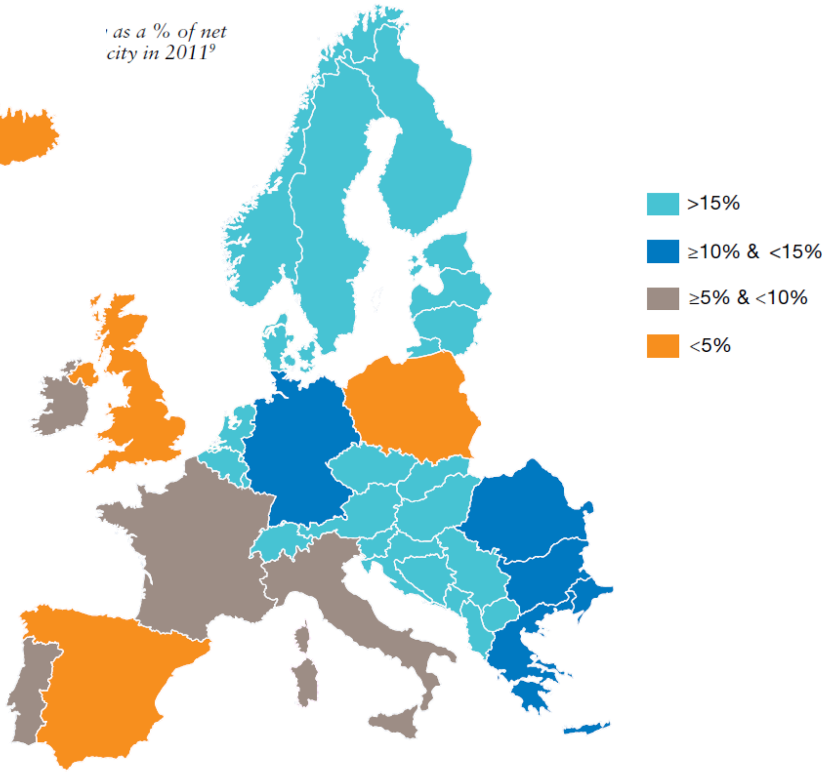
Source: CMA analysis, National Grid Interconnector Register and 10 year plan.

5. There are currently four interconnectors in GB. Their total capacity accounts for around 5% of GB's generating capacity. While the two interconnectors with mainland Europe usually import electricity (in 2013 average net imports from BritNed and IFA were 60% of potential operating capacity[2]), the two interconnectors to Northern Ireland and the Republic of Ireland generally export. Total net imports contributed 3.9% of electricity supply in 2013.[3] GB has a low level of interconnectivity compared to other EU countries (see Figure 4).

[2] Source: DUKES 2014, Table 5B.
[3] Source: DUKES 2014, paragraph 5.6.

FIGURE 4

Import capacity as proportion of net generation capacity (2011)

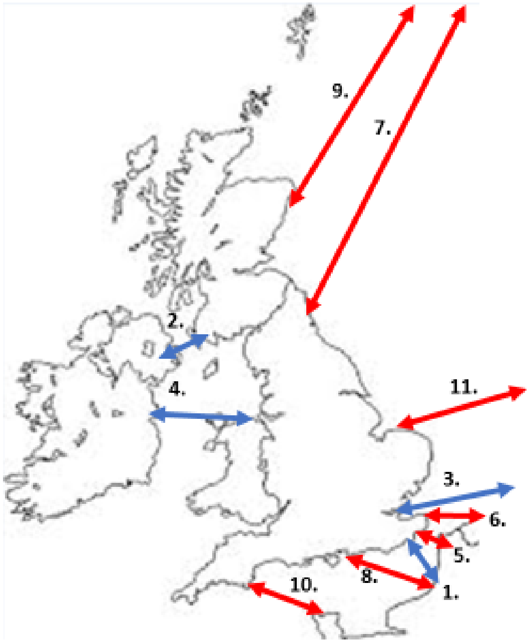


Source: ENTSO-E Ten Year Network Development Plan 2012, page 214.

6. GB has among the lowest levels of interconnector capacity in Europe, compared to its total generation capacity. This is partly due to GB being an island. There are, however, a number of projects being planned which seek to increase interconnector capacity (see Figure 5). If all projects were to go ahead, this could add a further 7,850 MW capacity which would account for around 15% of GB generation capacity.

FIGURE 5

Operational and proposed interconnectors*



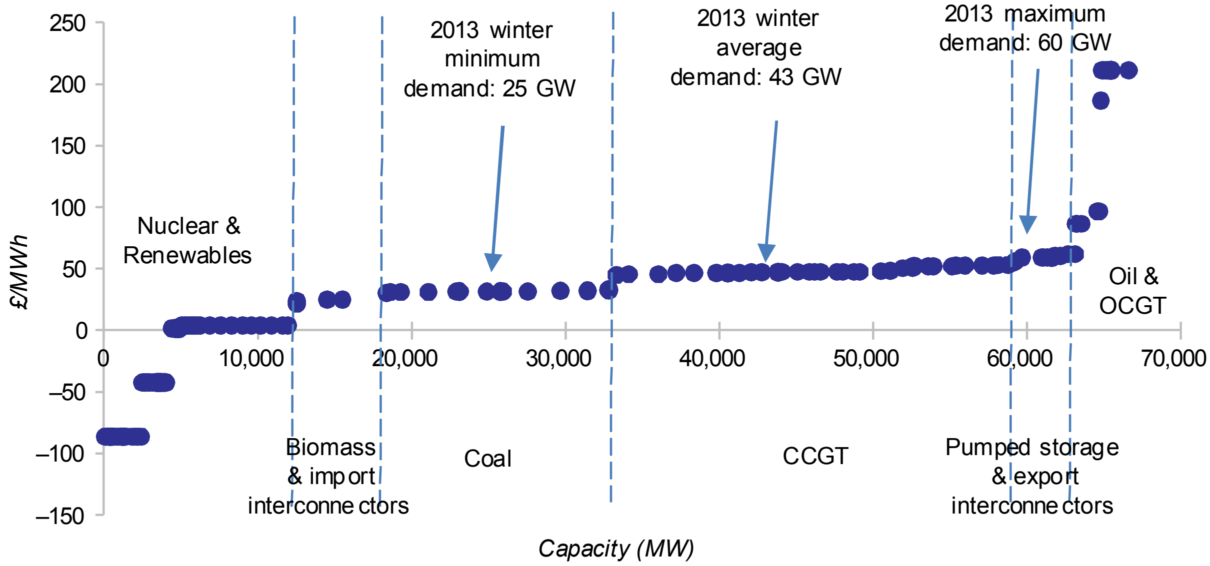
Number on Map	Inter-connector	Connects to	Capacity (MW)	Date of completion (estimate)
Operational Interconnectors				
1.	IFA	France	2000	
2.	Moyle	Northern Ireland	450	
3.	BritNed	The Netherlands	1200	
4.	EWIC	Ireland	500	
Proposed Interconnectors				
5.	Eleclink	France	1050	Oct 16
6.	Nemo	Belgium	1000	Oct 18
7.	NSN	Norway	1400	Oct 19
8.	IFA 2	France	1000	Oct 19
9.	North-connect	Norway	1400	Oct 21
10.	FAB	France	1400	Dec 20
11.	Energinet	Denmark	1000	Oct 20
		Total	**12000**	

Source: CMA analysis, National Grid Interconnector Register and 10 year plan.
*Proposed interconnectors are only those that feature on the interconnector register. We are aware that there are other interconnectors that are being considered.

7. All the generation capacity in GB (including interconnectors) can be stacked up in order of marginal cost of each power plant. This provides a snapshot of the merit order of the plants in GB based on current relative fuel costs (see Figure 6).

FIGURE 6

Merit order of GB generators (31 October 2013)*



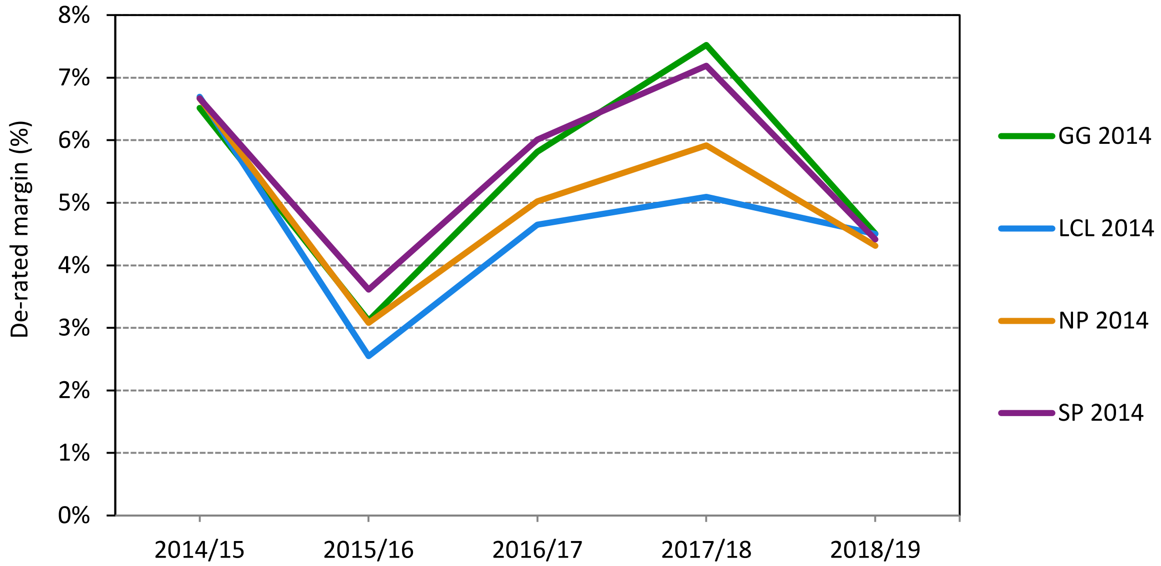
Source: CMA UMP model.
*This model has placed pumped storage at the end of the CCGT stack. Approaches to modelling pumped storage vary.

8. On a typical winter day, the marginal plant will be a CCGT plant. At winter peaks, open-cycle gas turbine (OCGT) and oil plants may be called upon (although relatively rarely). If plants have unexpected outages at peak demand, it can lead to times of system stress. The safety net from entering times of system stress is measured by the capacity margin. This is the spare capacity remaining at peak demand, expressed as a percentage of peak demand. The forecast capacity margins over the next five years is shown in Figure 7 with the associate loss of load expectations[4] in Figure 8. This is based on four different modelling scenarios that National Grid uses to forecast the future demand: GG = Gone Green, LCL = Low Carbon Life, NP = No progression, SP = Slow progression.[5]

[4] Loss of load means that generation is less than demand under normal operating conditions. National Grid still has a variety of tools available to ensure there are no power shortages (see Figure 14 of 2014 Capacity Assessment, Ofgem).
[5] For more information on the scenarios, see National Grid's UK Future Energy Scenarios 2014.

FIGURE 7

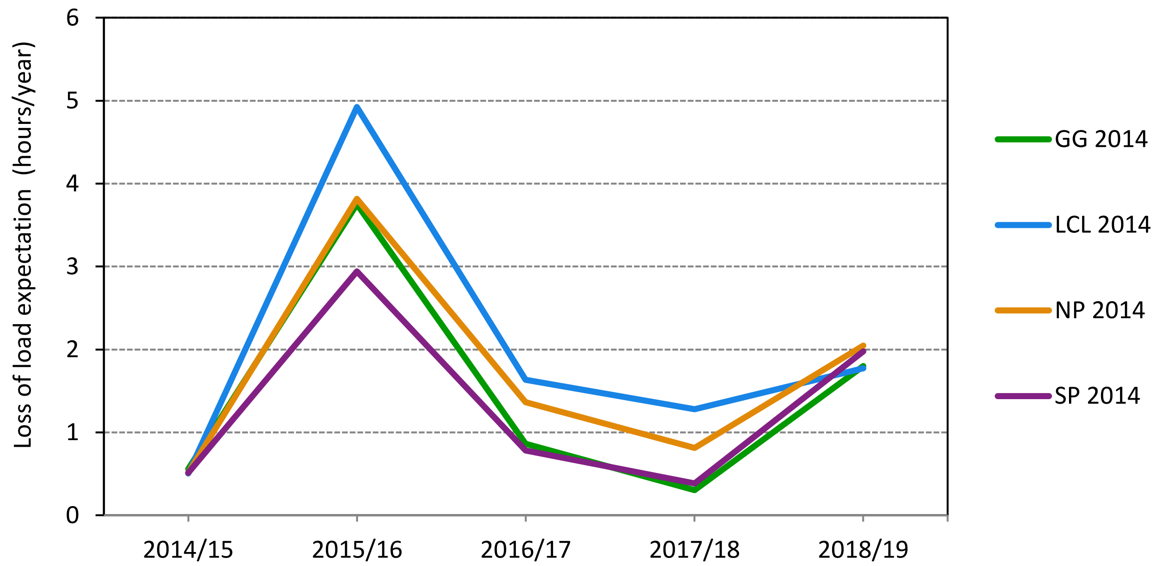
De-rated capacity margins (2014/15 to 2018/19)*



Source: Figure 4, Electricity Capacity Assessment Report 2014, Ofgem.
*The de-rated capacity margin is the capacity margin adjusted to take account of the availability of plant specific to each type of generation technology. It reflects the probable proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons).

FIGURE 8

Loss of load expectations (2014/15 to 2018/19)



Source: Figure 5, Electricity Capacity Assessment Report 2014, Ofgem.

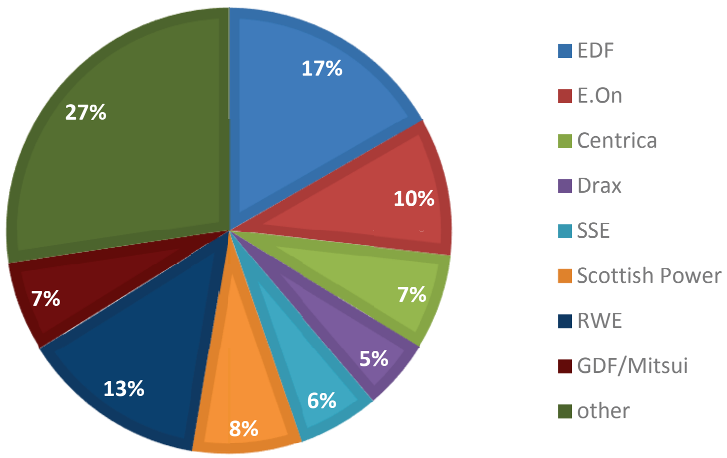
9. Figures 7 and 8 show that National Grid anticipates that the capacity margins in 2015/16 will be particularly tight, with higher associated loss of load expectations.

Generation market shares

10. The market shares of the major generators are set out below. Figure 9 shows market share by installed capacity, while Figure 10 shows market shares by output. Interconnectors are excluded.

FIGURE 9

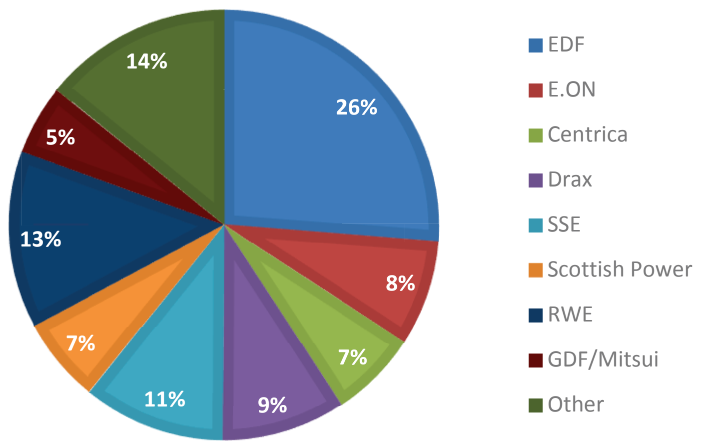
Shares of generation capacity (May 2014)*



Source: DUKES 2014, Table 5.10.
*DUKES Table 5.10 lists operational power stations. Mothballed plants are not included. Plants with output limited are included at the new limited output capacity.

FIGURE 10

Shares of generation output (2013)



Source: Ofgem, National Report 2014.

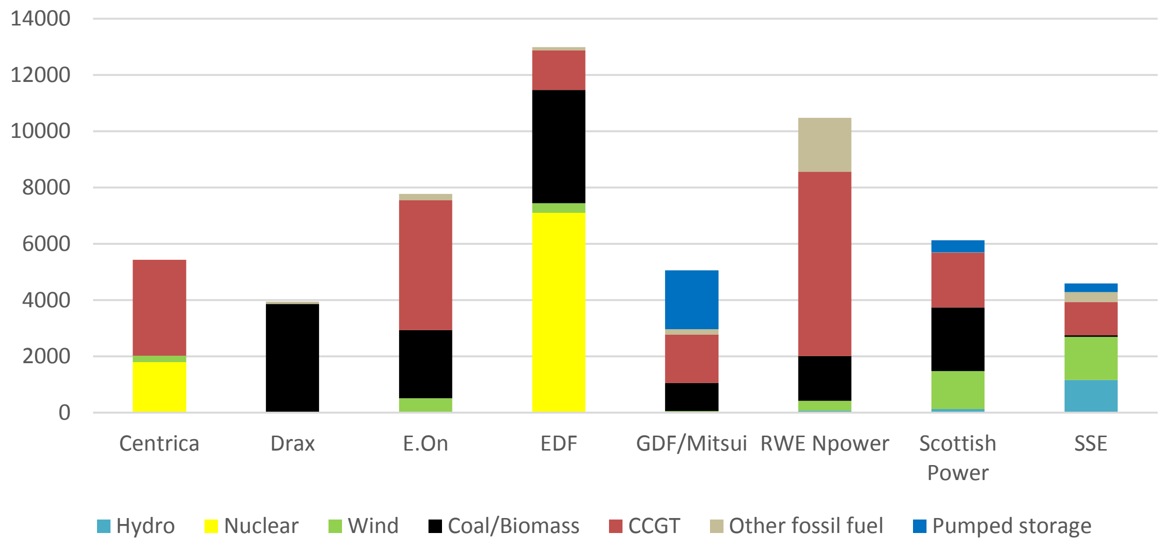
11. While EDF Energy accounts for 17% of capacity, due to its nuclear plants, it accounts for a greater proportion of output (26%).[6] E.ON is in a reverse position where it accounts for 10% of capacity but only 8% of output.

12. Figure 11 shows the major generators' capacity in 2014. The technology mix of the major generators varies between parties, with EDF Energy in particular having a fleet of nuclear plants and Drax only having coal/biomass plants.

[6] Although the capacity data is for May 2014, we do not consider that capacity data would have been significantly different in 2013.

FIGURE 11

Generation capacity by party and technology (2014)*



Source: DUKES 2014, Table 5.10.
*We have allocated 20% of the nuclear capacity of EDF Energy to Centrica, in line with ownership arrangements. We have summed GDF and Mitsui capacity as there is significant joint ownership of a number of power plants.

13. Figure 12 compares each party's generation output, by technology, with its actual retail consumption. For each party, this shows a net position. If the net position is above zero, the party is considered to be long. This means it generates more than its customers consume. Similarly if the net position is negative, the party is considered to be short and will typically need to buy electricity.

FIGURE 12

Consumption, output and net electricity position by party (2012/13)

[✂]

Source: [✂]

14. As a comparison, Figure 13 shows the net position of the major shippers in gas. Here the Six Large Energy Firms are all major purchasers of gas, including Centrica, which has the largest gas production assets of those firms.

FIGURE 13

Estimated physical positions (consumption, output and net gas position) by party (2012/13)*

[✄]

Source: [✄]
*[✄]

Electricity and gas consumption

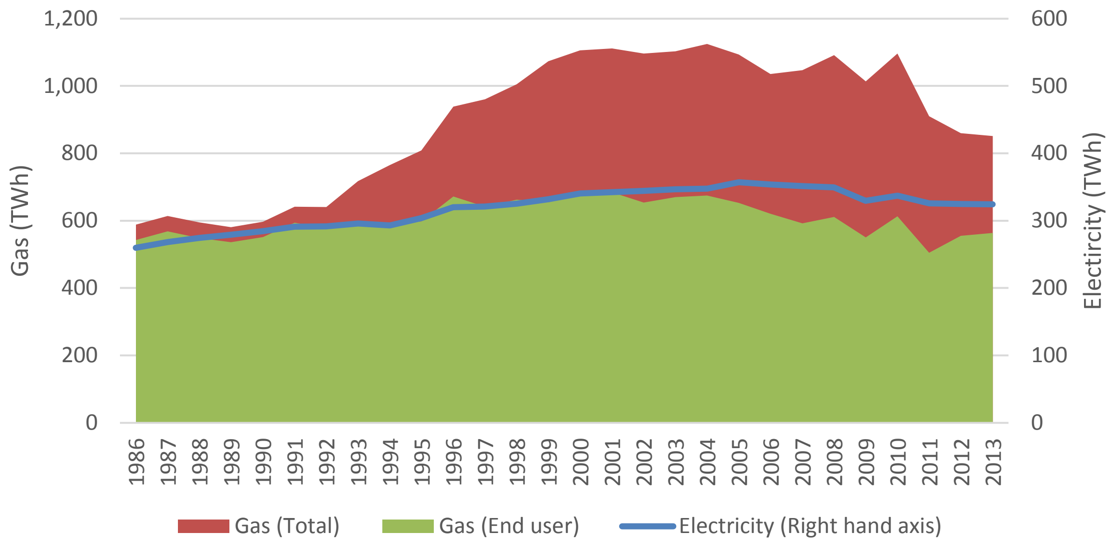
15. This section outlines some consumption statistics for electricity and gas. In particular it looks at the yearly and quarterly gas and electricity consumption statistics, and then intra-day electricity consumption.[7]

16. Figure 14 shows the yearly electricity consumption and gas (total and end-user) consumption.[8] The patterns of electricity consumption and gas (end-user) consumption have some similarities – they rose gradually for a period and then started to fall, especially around 2008 – although electricity consumption has increased relative to gas over this period. Total gas consumption follows a different pattern, due to an increase in gas demanded by power stations in the mid-1990s. Total gas consumption in this period was around two to three times higher than electricity demand.[9]

[7] Gas consumption is measured on a daily basis, whereas electricity is measured half-hourly.
[8] The main difference between total and end user gas consumption is that total consumption includes consumption by gas fired power stations.
[9] However, as a unit of gas is cheaper than the equivalent unit of electricity, this difference will be less marked from a consumer's perspective.

FIGURE 14

UK electricity and gas consumption

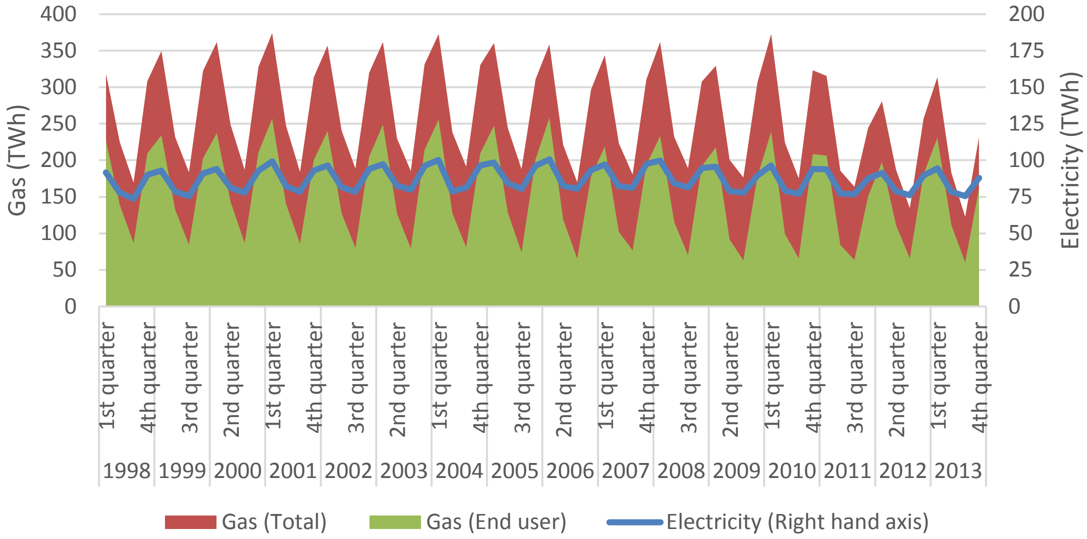


Source: DUKES, Table 5.1.2 (electricity) and DECC (gas).

17. Energy consumption can vary significantly by season. Both total and end-user gas consumption are much higher in winter than in summer (see Figure 15), driven primarily by domestic heating needs. The pattern is similar for electricity, but not as pronounced (partly because a smaller proportion of electricity is used for heating).

FIGURE 15

Quarterly gas and electricity consumption

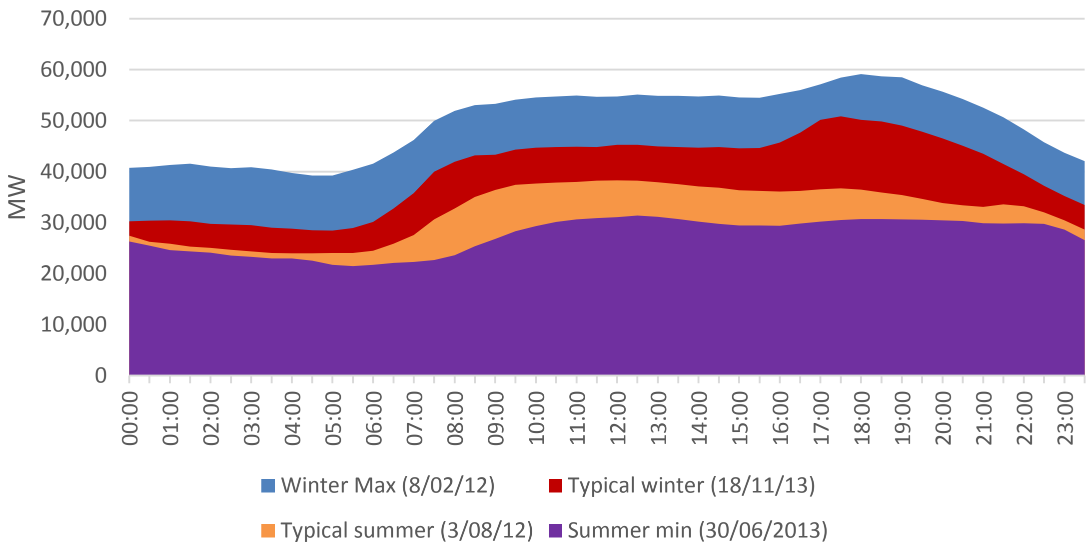


Source: DECC monthly energy statistics, Tables 4.1 and 5.5.

18. Both electricity and gas consumption can vary considerably within a single day. However, as there is a greater ability to store gas, it is not measured or traded by half hour. Figure 16 shows the intra-day electricity consumption on a series of representative days. Notably, electricity consumption on a summer day is typically relatively flat but slightly higher during the day, whereas in winter, there is a more pronounced daytime shape and an evening peak where the highest demand is around 5pm to 7pm.

FIGURE 16

Intra-day electricity consumption



Source: Elexon.

Trading and wholesale markets

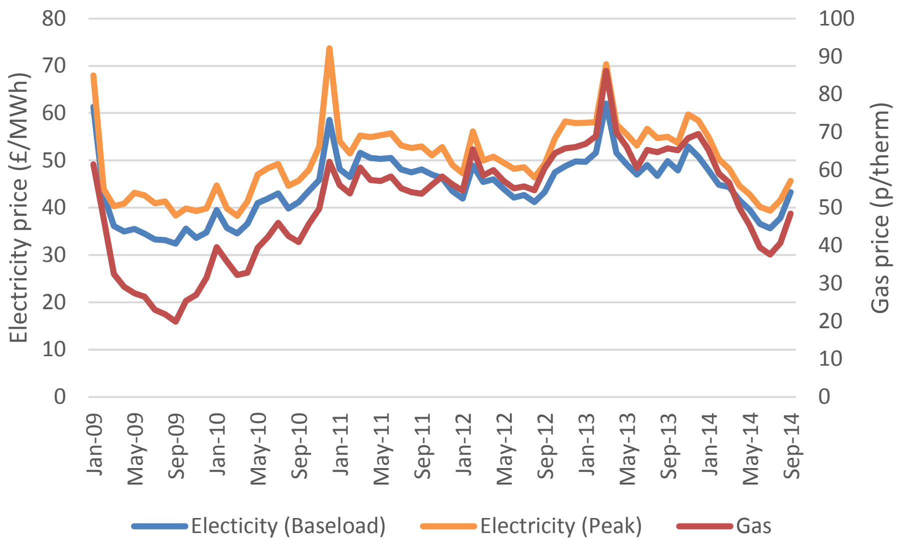
19. This section provides data on the traded markets for electricity and gas. It first provides data about the price of certain products and spreads between electricity and fuel prices. Finally, it looks at volumes traded and bid-offer spreads in wholesale power markets.

Energy prices and spreads

20. Figure 17 shows gas and electricity prices between January 2009 and September 2014. Gas has been the marginal fuel for much of this period and, therefore, the electricity prices often follow the shape of the gas prices. Electricity baseload is a product delivered in a constant quantity throughout the day; peak is a product delivered between 7am and 7pm on weekdays.

FIGURE 17

Monthly average of day ahead gas and electricity prices



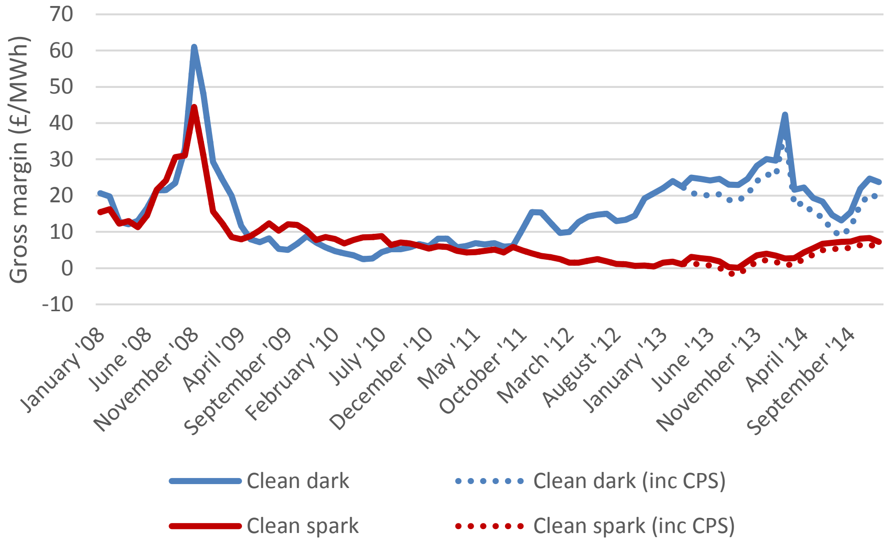
Source: Bloomberg, ELUBDHAD, ELUPDHAD, NBPGDAHD.

21. Of great significance to thermal generators are spreads between power prices and fuel/input costs. Figure 18 shows the spark spread (the theoretical gross margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity[10]) and the dark spread (gross margin of a coal plant[11]). The clean spreads include the costs of carbon permits and, additionally, the carbon price support (CPS).

[10] Taking into account fuel efficiency factors. These vary between plants, but a standard fuel efficiency factor of 49.13% is used in the UK. All other costs (operation and maintenance, capital and other financial costs) must be covered from the spark spread.
[11] Again, a standard fuel efficiency factor is used to calculate this (35%).

FIGURE 18

Average month ahead spark and dark spreads (January 2008 to December 2014)*



Source: ICIS Heren average of month ahead clean spark and dark spreads (not weighted).
*Average of month ahead clean spark and dark spreads. See footnotes 16 and 17 for efficiency assumptions.
CPS is set by HM Government. For more information, see HMRC (2012), Carbon Price Floor: Further Legislative Provisions and Future Rates.

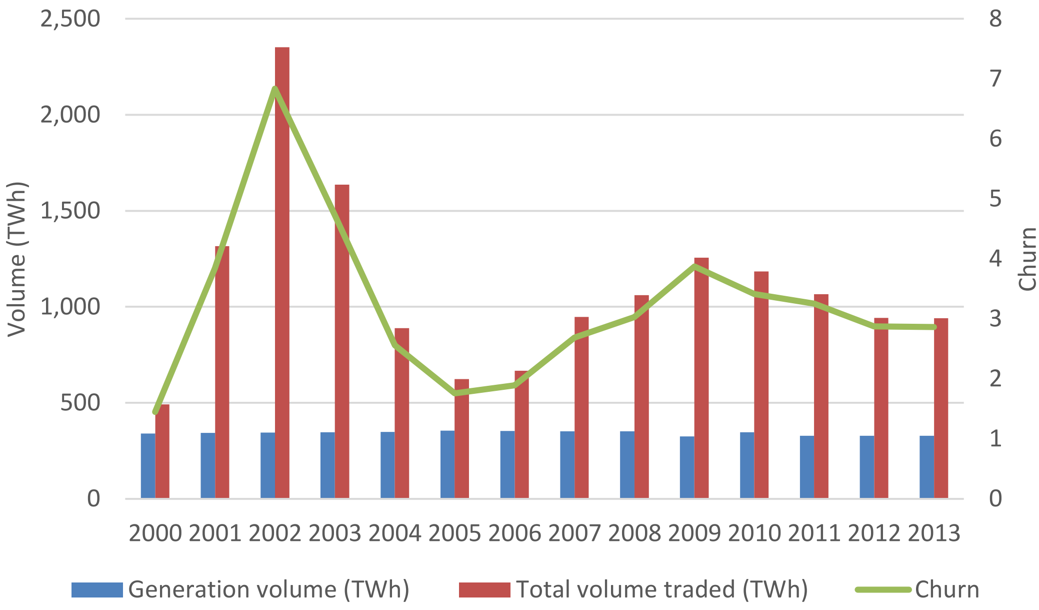
22. Until October 2011, spark and dark spreads had been relatively close, with the marginal technology changing between coal and gas. Since then, dark spreads have been greater than spark spreads, reflecting the relative position of CCGT and coal plants in the merit order. As CPS is increased by the government, the positions of coal and gas in the merit order are expected to reverse around 2016/17, although there is a degree of uncertainty over when this point will be reached due to external factors affecting the relative price of gas and coal.

Traded volumes, churn and bid-offer spreads

23. This section presents some general statistics about the volume of trading, churn and proportion of trading ahead for different product types. Figure 19 shows the generation volume and total traded volumes of electricity for GB's wholesale electricity market. Churn, which is a measure of the total volume traded as a proportion of volume consumed, has been around three since 2007, although it was higher in 2002/03.

FIGURE 19

Traded and generated volumes and churn in GB electricity markets



Source: Ofgem (response on 22 October 2014).

24. Churn in gas trading is higher, being over ten for much of the last five years (and even higher on ICE exchange and trading through LEBA[12]).

FIGURE 20

Traded volume and churn on GB gas markets

[✂]

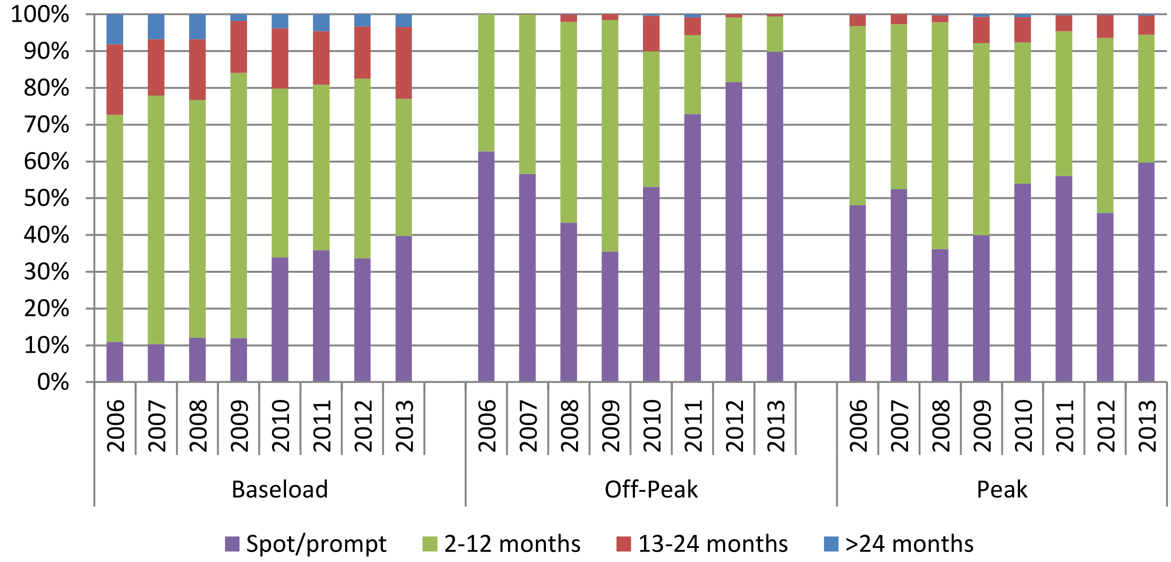
Source: [✂]
Note: [✂]

25. The volumes traded on the electricity market also vary by how far ahead trading occurs. Figure 21 shows the proportion of trades for baseload products,[13] as well as all Peak and Off-peak products.[14] The majority of trading takes place within a year of delivery, with much trading in Peak and Off-peak products being concentrated in the spot/prompt market (shortly before delivery). Other than baseload, there is little trading over a year ahead.

[12] ICE is the Intercontinental Exchange. LEBA is the London Energy Brokers Association.
[13] Baseload is a product that provides the same level of electricity in every half-hour period.
[14] Peak products are those for delivery on weekdays between 7am and 7pm, and Off-peak products for delivery at other times.

FIGURE 21

Trading ahead of delivery in selected electricity products



Source: Ofgem (liquidity final proposals – Figure 13, p.45).

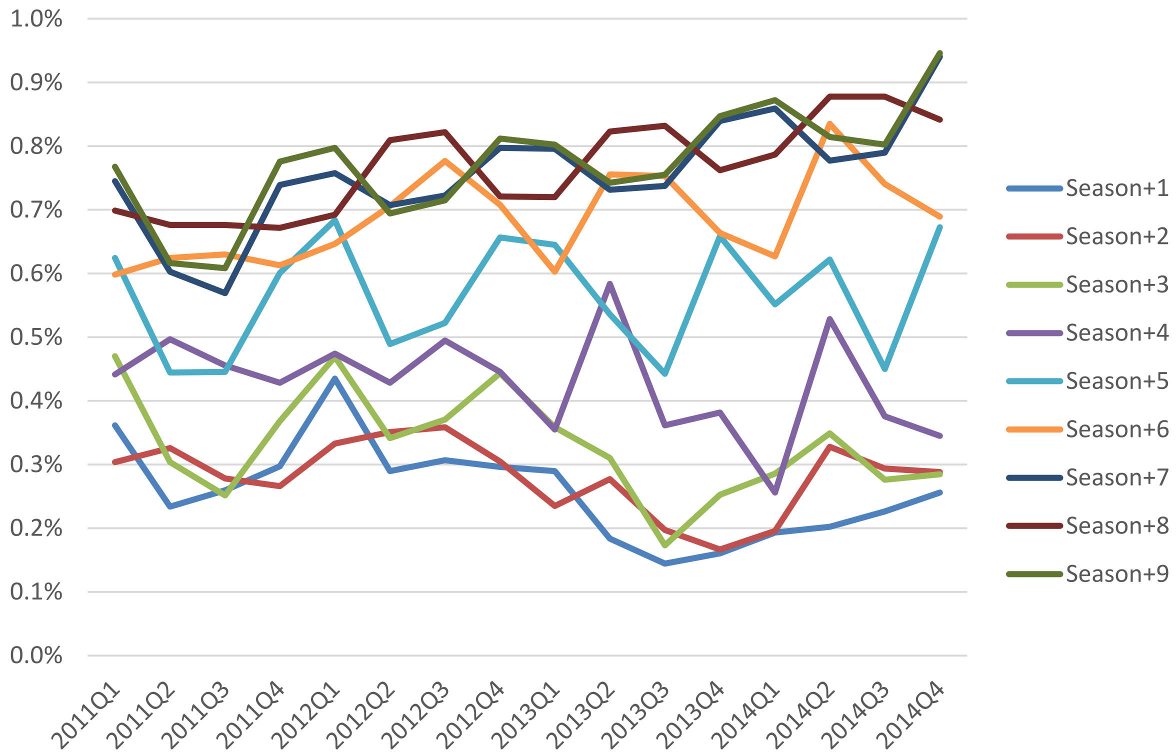
26. Another indicator of liquidity is the size of bid-offer spreads (the difference between the price at which traders are willing to buy and the price at which they are willing to sell). The smaller the spread, the more confidence market participants can have in the price, and the greater their willingness to trade ahead of delivery. Figure 22 illustrates these for Seasonal gas products (ie those that deliver over six months), which are widely traded, and Figure 23 gives the equivalent for electricity (separately for Baseload and Peak products). These are based on ICIS Heren closing bid and offer prices.

27. In general, spreads get wider the further out from delivery the product is. Gas spreads are lower than the equivalent electricity spreads. Gas spreads have remained fairly stable over this period, with a slight widening of spreads in products further from delivery. Electricity products closest to delivery (the front three seasons) have seen spreads tighten, and can be expected to remain low as a result of Ofgem's Secure and Promote licence conditions,[15] but products further ahead of delivery have maintained relatively high spreads.

[15] See Liquidity working paper.

FIGURE 22

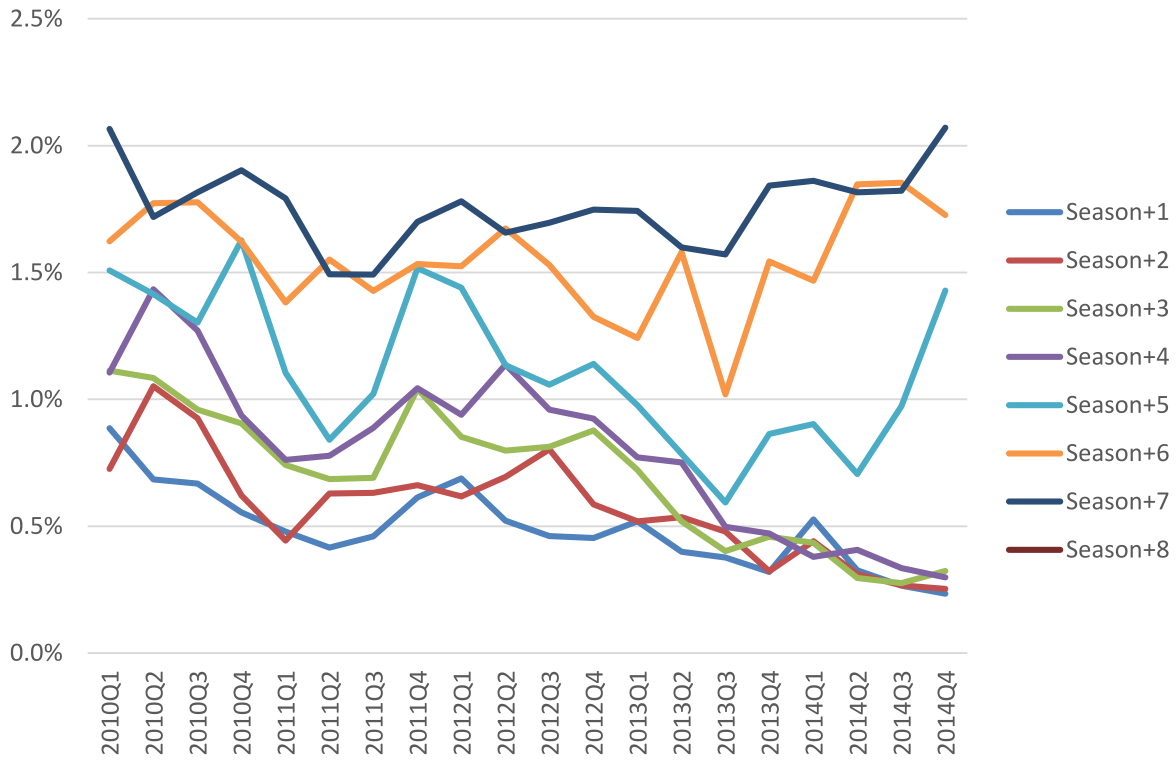
Bid-offer spreads for gas (Seasonal products)



Source: ICIS Heren data, CMA analysis.
Note: Average spreads by quarter based on data for every weekday (not weighted).

FIGURE 23a

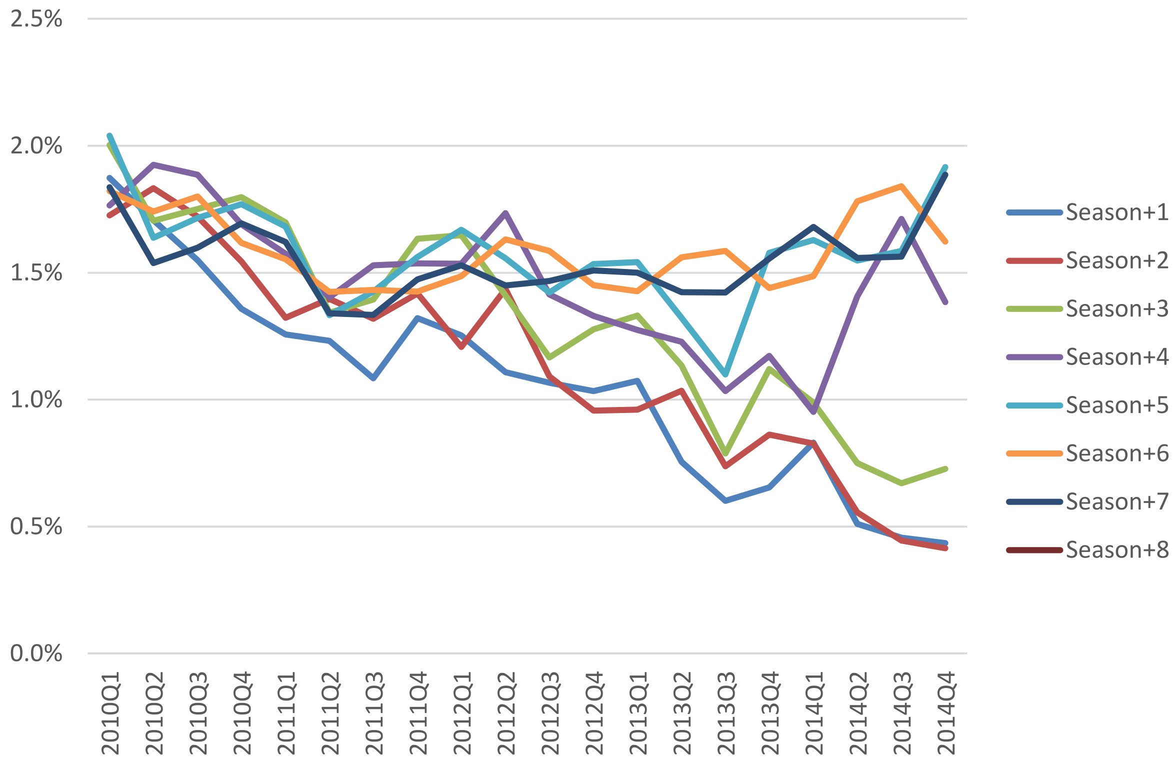
Bid-offer spreads for electricity (Seasonal Baseload products)



Source: ICIS Heren data, CMA analysis.
Note: Average spreads by quarter based on data for every weekday (not weighted).

FIGURE 23b

Bid-offer spreads for electricity (Seasonal Peak products)



Source: ICIS Heren data, CMA analysis.
Note: Average spreads by quarter based on data for every weekday (not weighted).

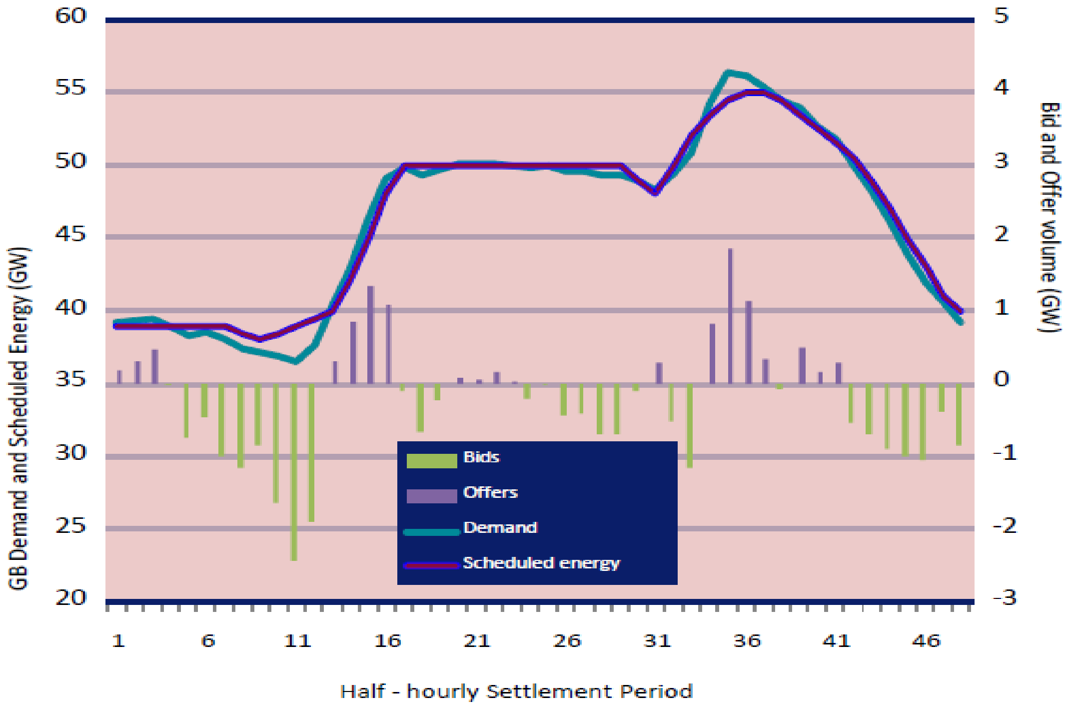
Balancing mechanism

28. The balancing mechanism is a tool National Grid uses to balance electricity supply and demand close to real time. It is needed because electricity cannot economically be stored and must be generated at the time of demand.

29. Where National Grid predicts that there will be a discrepancy between the amount of electricity produced and that which will be in demand at a particular time, it may accept a 'bid' or 'offer' to either decrease or increase generation (or vice-versa with consumption). The balancing mechanism is used to balance supply and demand continuously, with the resulting integrated energy identified in each half-hour trading period of every day. An example day of actions is shown in Figure 24.

FIGURE 24

Balancing mechanism – example day



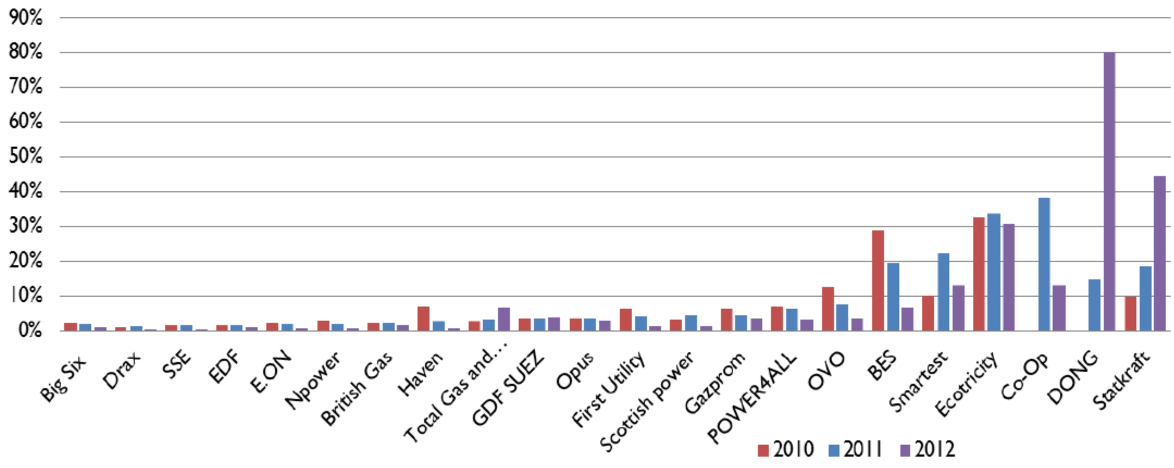
Source: Cornwall Energy.

30. Under the current electricity market arrangements in GB, if a market participant generates or consumes more or less electricity than it has contracted for, it will pay (or receive) an 'imbalance price', or 'cash-out' price, for the difference. This can have a significant impact on the operating costs of market participants.

31. Figure 25 sets out the size of the imbalances as a proportion of volume for a number of parties. Imbalances tend to be low for many large and vertically integrated generators and suppliers. However, [✂].

FIGURE 25

Average annual electricity imbalance (2010 to 2012)*



Source: Cornwall.
*The original chart uses the term 'Big Six' to refer to the Six Large Energy Firms (SSE, EDF Energy, E.ON, RWE npower, British Gas and Scottish Power).

32. Figure 26 shows the total imbalance costs for a number of suppliers and the implied impact on consumer bills. It shows that the Six Large Energy Firms have larger imbalance costs than other parties. However, once this is divided by the number of customers they have, the charges amount to less than £5 per customer per year for the majority of suppliers. The major exceptions appear to be [✂].[16] Even then, these charges account for a relatively small proportion (5.6% and 2.6% respectively) of the average consumer electricity bill.

FIGURE 26

Size of imbalance costs and customer cost per year by energy supplier (April 2013 to March 2014)

[✂]

Source: [✂]

[16] [✂]