Contents

Weak demand takes the bite out of the British capacity crunch

This latest analysis by Bloomberg New Energy Finance shows that weak power demand, high levels of new build and life extensions for nuclear plants will mean that the UK should be able to keep the lights on the rest of this decade.

- The UK continues to experience feeble demand for electricity since industrial production collapsed following the 2008 recession. Demand will not return to pre-crisis highs any time soon, although we expect an increase by 2015 as industrial production recovers. We see very slow annual growth beyond 2015 as the UK continues to shift to a service-based economy and energy efficiency measures and technological changes take hold.
- We anticipate 20GW of generating capacity in Britain will close by the end of 2016 due to environmental requirements, age and challenging economics for older gas-fired generation. Assuming the carbon price floor is implemented as planned, an additional 4GW of coal plants will retire by 2020 as they are affected by the carbon price floor and impending Industrial Emission Directive.
- However, we expect that the large swath of retirements will be offset by the 30GW of capacity due to come online by 2016 – around two-thirds of which is renewables. Life extensions for most of Britain's nuclear fleet will further offset plant closures.
- Beyond 2017, we expect new capacity to primarily be low-carbon as large amounts of wind and solar are added each year. We take a conservative view on expensive (nuclear) and immature (CCS and marine) technologies and see limited build levels through 2030.
- Unabated coal faces the most challenging future of existing generation technologies. In particular, the rising carbon price floor will tighten the noose around the neck of coal generators – pushing them to the margin and reducing the profitability they currently enjoy.
- Although we predict the supply and demand balance will tighten following plant retirements mid-decade, capacity margins discounted for the intermittency of renewables should remain at a comfortable level through 2020. This suggests that the planned capacity mechanism could be an unnecessary intervention as the market remains well supplied this decade.

1. FORECASTING POWER DEMAND

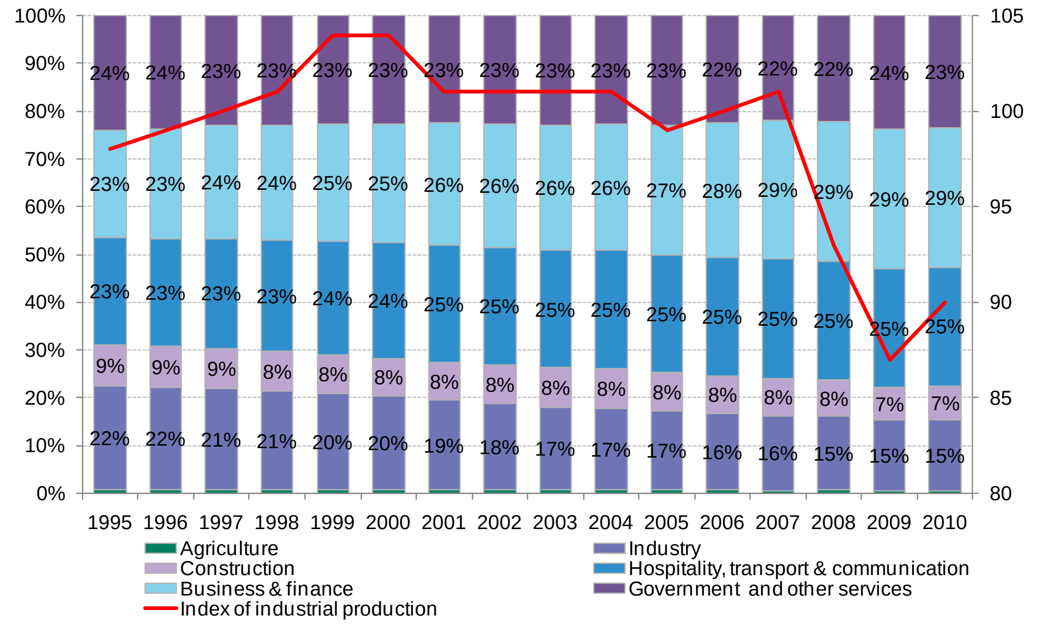
The first step in determining the need for new power generation capacity is to estimate future power demand. This needs to take into account historical trends as well as expected changes in the structure of the British economy, level of economic output and the way electricity is consumed.

In this analysis we forecast power demand in Britain using a multi-variable regression-based model run over the last 10 years. This relates power consumption to the following influencing factors: gross domestic product, index of industrial production, domestic power prices, heating degree days, cooling degree days, solar insolation and population. The model shows that of all these variables, industrial production has the greatest influence on power demand – its impact on the forecast is roughly three times stronger than that of both GDP and heating degree days. This is mostly because of the strong correlation between electricity demand and industrial output during the recession following the financial crisis in 2008.

The fall in industrial output had a significant effect on power demand during the 2008-09 recession

As well as the acute impact of industrial output on power demand during periods of economic volatility, the gradual de-industrialisation of the UK economy will also have longer-term effects on power demand. Figure 1 shows the contribution to UK national output (GDP) from different sectors of the economy between 1995 and 2010. The share of GDP from the industrial sector has declined from 22% to 15% over this period, while that of business and finance has increased from 23% to 25%. As industry is more electricity-intensive than business and finance, this trend, if it continues, will lead to a gradual weakening of power demand from the non-domestic part of the economy in the long run.

Figure 1: Structure of UK economy



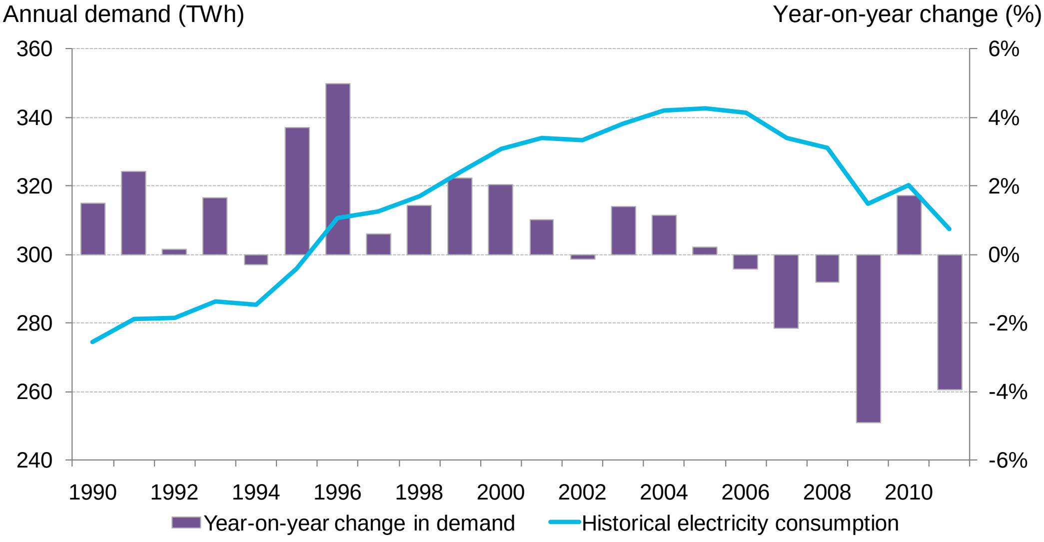
Source: Bloomberg New Energy Finance, Office of National Statistics

Figure 2 shows the trend in power demand in Britain from 1990 to 2010. After 15 years of consistent growth, demand peaked in 2005 driven by a combination of strong economic output and a particularly cold winter. Since then power consumption has fallen every year, except in 2009-10, with the recession playing a crucial rule in hindering any recovery in demand. The banking crisis kicked off in 2008 and the first signs of the ensuing recession appeared as the UK economy shrank by 7% between 2008 and 2009 and industrial production collapsed by 13% in 18 months.

Changes in electricity consumption over this period were highly influenced by industrial production; the fall in industrial output alone resulted in a 4.4% reduction in power demand between 2008 and 2009. After accounting for the contraction in GDP and other factors including small changes in power prices and the weather, power consumption in Britain declined by 4.9% between 2008 and 2009.

An extremely cold Q4 in 2010 (that December was 5°C colder than normal) and a small recovery in industrial output then caused 2010 power demand to recover 1.7%. This however was a short-term effect, with weather accounting for more than twice the variation in demand than industrial production. In 2011, UK GDP remained flat and the index of industrial production suffered another small drop after its temporary 2010 rally; power demand fell by another 4%.

Figure 2: Power demand, Great Britain



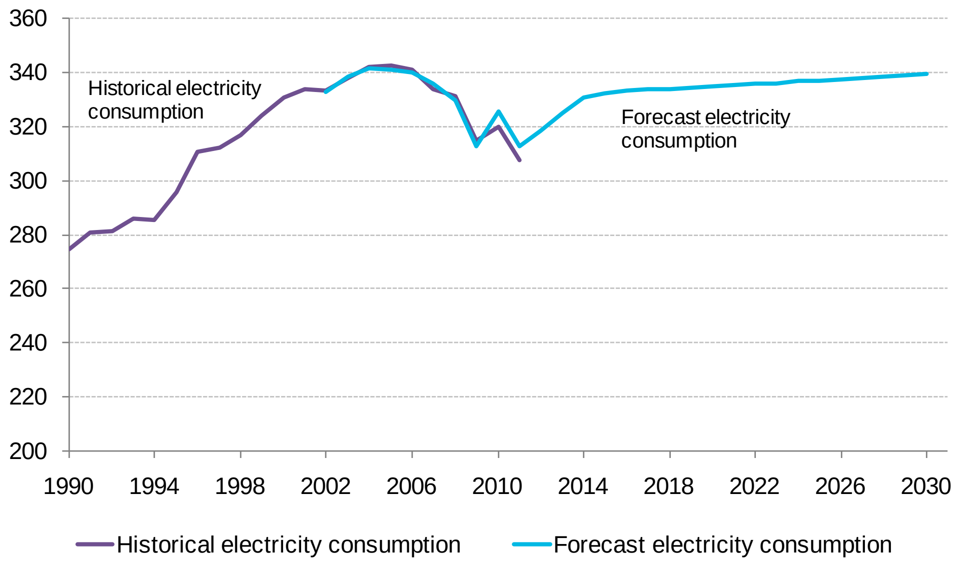
Source: Bloomberg New Energy Finance, DECC, National Grid

On average, power demand will depend on the state of the underlying economy, industrial output and use of technology rather than short-term weather patterns. Consequently, our forecast (which uses average heating and cooling degree day data) follows historical data in projecting another drop in demand for 2011, before starting a period of demand recovery in 2012 (Figure 3).

Beyond 2012, our central forecast projects that the economy will regain some of the ground lost during the recession but will only see sluggish growth thereafter.

Beyond 2012, our central forecast projects that the economy will regain some of the ground lost during the recession but will only see sluggish growth thereafter. Following a year of stagnation in 2012, we forecast 2% real GDP growth in 2013, followed by 2.5% for the three years up to 2016. Factories which were operating below full capacity or mothballed will see activity return as world trade picks up and the index of industrial production claws back 10 of the 13 lost percentage points by the end of 2014.

Figure 3: Annual power demand forecast, Great Britain (TWh)



Source: Bloomberg New Energy Finance, DECC, National Grid

After 2016, we see real GDP growing at the long-term average of 2.3%. However, industrial output will increase by only 0.2% on average as the UK continues its long-term trend away from heavy manufacturing – the UK index of industrial production has not seen significant sustained growth since the early 1990s. We also expect rising power prices, the emergence of new technologies and new energy efficiency policies to further dampen power demand growth, shaving 10% off demand in 2015 and 18% by 2030. The final result is a minimal level of annual demand growth – just 0.1% per annum through 2030.

Although the adoption of electric vehicles will increase power demand, our analysis suggests the impact will be muted. In our central projection of future electric vehicle penetration, UK power demand is expected to increase by no more than 1% by 2025. The most significant impact of electric vehicles on the UK power market will be in the form of ancillary services, such as fast reserve or frequency response.[1]

2. CAPACITY RETIREMENTS

Power plant operators may decide to close facilities for a variety of reasons including age, regulatory requirements and a lack of profitability. A high level of retirements over the coming years could increase the need for new build, despite weak power demand. We outline our views on retirements through 2030 below.

2.1. Retirements (2012-16)

We expect 20GW of generating capacity in Britain to close by the end of 2016

In total we expect 20GW of generating capacity in Britain to close by the end of 2016 (Figure 4). 11GW of this will come from coal and oil plants which have opted out of the Large Combustion Plants Directive (LCPD – European regulations covering emissions of sulphur dioxide, nitrogen oxide and dust) and are limited in the hours they can operate by 31 December 2015. We expect 3.5GW of coal to retire before 2015 as plants run through their LCPD hours, are subject to the full auctioning of carbon allowances and are hit by the UK's carbon price floor. We expect RWE, which has converted its 1GW coal plant at Tilbury to biomass, to relicense the plant to run beyond 2015.

In terms of nuclear power, all of Britain's fleet with the exception of Sizewell B is due to retire by the end of 2023. However, given the concerns over the 'capacity crunch' due to the 11GW of retirements discussed above, we believe nuclear plants will be granted life extensions. Although there are safety concerns for granting life extensions, we assume that expected retirements will be postponed by five years on average in line with previous practices. However, we conservatively assume that Hinkley Point B and Hunterston B will close as scheduled in 2016 given that they already received five-year life extensions in 2007.

Flexibility is becoming increasingly valuable due to the greater penetration of intermittent renewables in the system and the potential for future capacity payments

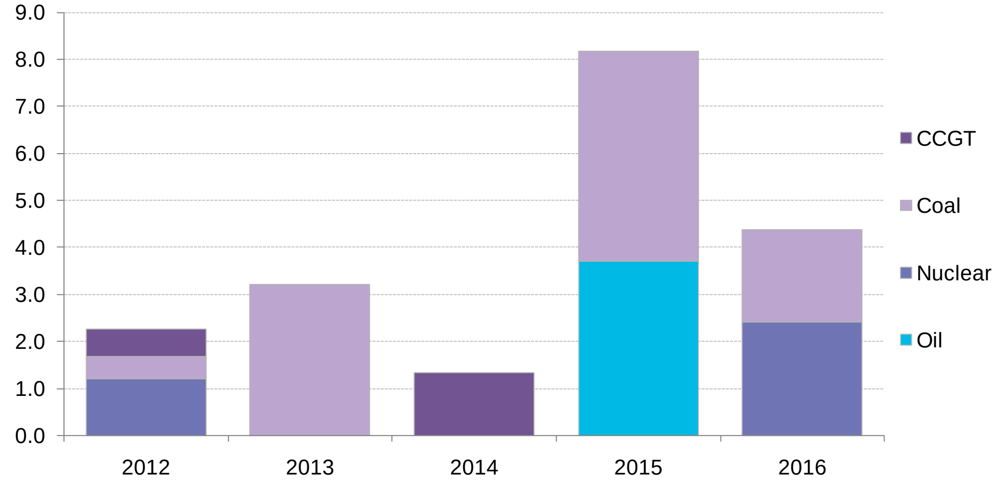
While the retirements mentioned above are widely expected, there is significant uncertainty around which other plants will close. For operators, the decision is one of optionality: is it worth continuing to pay transmission charges and other fixed costs in order to retain the ability to generate power? At the moment, low spark spreads do not justify retaining much of the older gas plants online. This has led Centrica to announce the closure of its Barry and King's Lynn plants.

However, flexibility is becoming increasingly valuable due to the greater penetration of intermittent renewables in the system and the potential for future capacity payments. We therefore believe that some of the older gas plants (approximately 2GW) will close by 2015 but expect more generators to opt for mothballing or running these plants in open-cycle mode to maintain their

1 Subscribers of the Bloomberg New Energy Finance European Power Service can read, Will electric vehicles cause a pile-up in the power reserve markets?, 23 January 2012 for more details.

option value. We are already seeing this trend, with recent announcements by Centrica, E.ON and SSE.[2]

Figure 4: Retirements 2012-16, Great Britain (GW)



Source: Bloomberg New Energy Finance

2.2. Retirements (2017-30)

In the period through 2020, 3.4GW of nuclear plants are scheduled to close. However, as mentioned above and confirmed recently by nuclear plant operator EDF, these plants will seek life extensions. Assuming additions of five years, these retirements will be postponed to 2023-28, at which point we expect new nuclear projects to be generating power.

Another looming European policy, the Industrial Emission Directive (IED), threatens the 11 other coal plants in Great Britain and some older gas plants.

Another looming European policy, the Industrial Emission Directive (IED), threatens the 11 other coal plants in Great Britain and some older gas plants. Facilities will once again be able to opt out of the directive and operate for a limited number of hours (17,500) between 2016 and 2023 rather than install 'best available technology' for SO_2, NO_x and particulates abatement. Coal plants operating beyond 2016 will have already installed flue gas desulphurisation equipment to lower SO_2 emissions and are therefore likely to face limited costs in this requirement. However, NO_x reduction can be expensive – Drax Power estimates it would cost the 4GW coal plant (the most modern of its type in Great Britain) GBP 200m (USD 315m) to comply with the requirements.

Older plants, already burdened with an escalating carbon price floor (see Section 5) and pricing impacts due to a higher penetration of renewables are unlikely to justify this investment. We therefore assume that 4GW of coal closes in 2017-19 and a further 4GW closes by 2023.

While the IED had the potential to result in a significantly higher level of retirements – potentially most of Britain's coal and older gas fleet – three factors could mitigate the size of retirements:

- The IED has a provision which allows less stringent pollution requirements for plants which run less than 1,500 hours per year. As coal and some gas plants already face a challenging outlook beyond 2016, many could opt to run limited hours – perhaps running only during the months of December, January and February when prices are highest. Such plants might also benefit from additional revenue by providing ancillary services to the grid which could cover fixed costs.
- Secondly, plants are already considering altering their operations beyond 2020 given the impending directive. Drax is the clearest example with plans to predominantly fire biomass.

2 Subscribers of the Bloomberg New Energy Finance European Power Service can read, UK CCGTs' search for profitability, 01 February 2012 for more details.

The 2GW Eggborough Power also recently announced that it is considering conversion to increase its biomass capabilities. Existing coal plants therefore might convert to biomass (and receive subsidies) in order to remain online.

- Finally, the rising carbon price floor has the potential to induce greater take-up of carbon capture and storage (CCS). Given that operators have already incurred sunk costs through capital and transmission investments, plants could undertake upgrades and install CCS technology. We assume 3.8GW of coal plant will do so by 2030.

3. NEW GENERATION CAPACITY

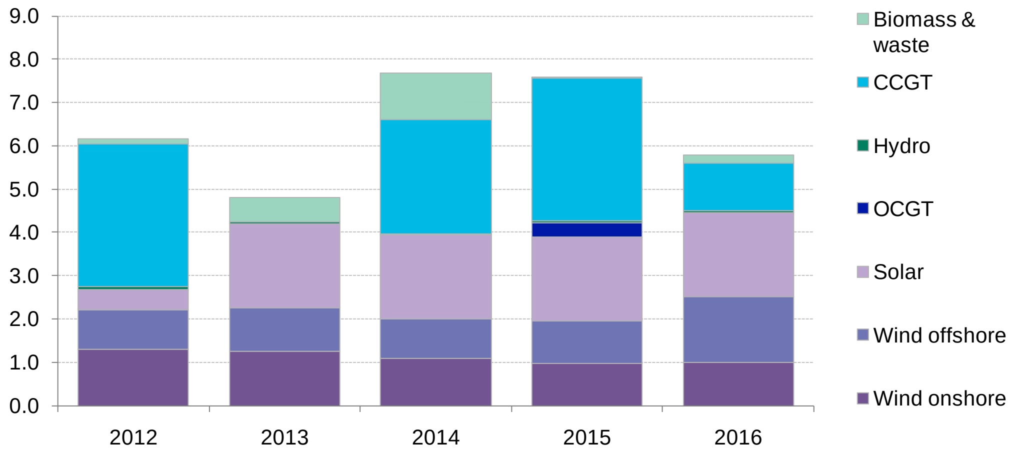
A large pipeline of new power plants coming online will help minimise the need to replace plants which close. Again, we divide this section into two parts. The first covers 2012 through 2016, a period in which we have some foresight over what will be built due to our knowledge of projects which are already under construction or are at various stages of planning. This foresight decreases beyond 2016. We therefore rely on modelling new build in 2017-30 by taking into account the relative costs of technologies and policies (such as renewables/nuclear targets and security of supply requirements).

We expect some 30GW of new capacity to be developed by the end of 2016. Around two-thirds of this will come from renewables with the remainder from gas turbines.

3.1. New build (2012-16)

We expect some 30GW of new capacity to be developed by the end of 2016 (Figure 5). Around two-thirds of this will come from renewables with the remainder from gas turbines. However, capacity additions will not fully offset the 20GW of thermal plant we expect to close in this period. This is because thermal plants can be called on to meet peak demand whereas most renewables (biomass and pumped storage excluded) are subject to the vagaries of the weather.

Figure 5: New build power capacity, Great Britain, 2012-16 (GW)



Source: Bloomberg New Energy Finance

- *Biomass*: there is currently a flurry of excitement around biomass in Great Britain given changes in subsidies and the potential for coal plants to escape a death sentence imposed by the LCPD by converting to biomass. In our analysis we take into account coal-to-biomass conversions which have been agreed (such as E.ON's Ironbridge plant) but take a conservative view with regard to other conversions in which final investment decisions have not been made (such as Drax and Rugeley) and do not include those in our forecasts. After accounting for plant conversions and the handful of dedicated biomass projects being planned, we see 2GW of additional biomass capacity by 2016.
- *Gas*: the UK is in the midst of its second dash for gas having already built 4.5GW of CCGTs since 2010 with a further two large projects (RWE's 2GW Pembroke and EDF's 1.3GW West Burton) due online in 2012. These projects were planned and financed prior to the recession

and in anticipation of a supply crunch mid-decade. However, there remains a large pipeline of projects which have received consent but await investment decisions. We discount these projects based on their stage of planning and foresee Great Britain building a total of 11GW of new gas plants in 2012-16.

- *Nuclear*: no new nuclear plants will be built before 2016 given current plans and the long lead times required for constructing new nuclear capacity.
- *Onshore wind*: we estimate 1,300MW of new onshore wind capacity will be installed in 2012 as several large projects come online (such as Clyde and Whitelee extension) and developers look to build wind farms before a reduction in subsidies from April 2013. In total we forecast 5.6GW of new onshore wind capacity will be added to the system by 2016.
- *Offshore wind*: attractive subsidies through the UK Renewables Obligation continue to drive investment in offshore wind with several large projects due online over the next few years. We see 900MW of offshore wind capacity coming online in 2012 and a total of 5.3GW installed in 2012-16.
- *Solar PV*: we also expect an average of 1.6GW of solar PV to be added each year in spite of the government's recent announcement on reducing the domestic feed-in tariffs. This is largely due to the continuing decline in module prices, improvements in installation efficiency and more sophisticated financing packages. Our forecast follows a government announcement on 9 February 2012 that the UK will target 22GW of solar capacity by 2020. This is an extremely ambitious target given the current solar PV capacity of 1.1GW. However, it is clear that solar PV can be rapidly deployed when sufficient incentives are in place (Germany for example installed 3GW last December).

Our central assumption is that no new unabated coal plants will be built due to strong public opposition and the emission performance standard. This is a component of the proposed electricity market reforms which would impose emission limits on new fossil fuel plants.[3] We also include capacity additions from hydro, marine and landfill gas in our forecasts, but these remain small in scale.

3.2. Long term (2017-30)

Beyond 2016, our analysis of expected new power generation capacity takes as its starting point policy-driven capacity additions and expected upgrades. For the time being, we take a conservative view on the build of expensive (nuclear) and immature technologies (marine). Specifically:

Total non-nuclear thermal build is minimal given low demand, large amounts of additional low-carbon capacity being added in the 2020s and legacy thermal capacity which can provide peaking capabilities.

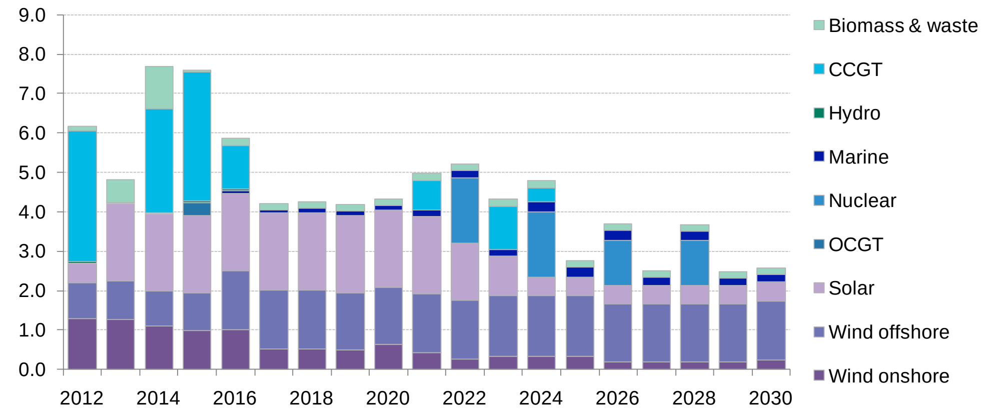
- *Biomass*: we expect that the scramble to build biomass is predominantly short term. Indigenous supply is limited and biomass is increasingly subject to sustainability requirements as generators look to source supplies from abroad. If there is a significant increase in large-scale coal conversions (similar to 750MW Tilbury), then there is potential for biomass costs to rise considerably. We assume an additional 500MW is built over 2017-20 and an additional 1.7GW installed in the 2020s.
- *Coal and gas*: we see 2GW of highly efficient CCGTs built in 2021-24 to replace coal retirements under the IED. We also assume a large coal plant (1.8GW) with CCS will be built around 2025 as the carbon price makes the economics viable. However, total non-nuclear thermal build is minimal given low demand, large amounts of additional low-carbon capacity being added in the 2020s and legacy thermal capacity which can provide peaking capabilities.
- *Marine*: marine technology has high potential in Great Britain and is currently being targeted as an important technology in the future as its subsidy increases from 2013. However, it

3 Subscribers can read, UK Electricity Market Reform, 9 July 2011 for more details.

remains the most expensive renewable technology and has yet to be proven on a large scale. We assume only 500MW is installed by 2020 and 2.7GW by 2030.

- *Nuclear*: the coalition government supports the development of new nuclear power in Great Britain and has identified eight potential sites for future plants by 2025. Although an indicative timeline suggests the first plant could be operational by 2018, we take a conservative view that this will not occur until 2022. This follows France's experience with building the first European pressurised reactor (EPR) which is due to begin operations four years behind schedule and €3bn over budget (as currently projected). Furthermore, there is still uncertainty over the nuclear subsidy (including details on the low carbon feed-in tariff) and public opposition (protestors are preparing to blockade the entrance to the Hinkley Point Plant in March). We therefore assume that 5.5GW of nuclear built is built in 2022-28.
- *Solar*: solar PV is expected to capture an increasing share of new build as costs continue to decline. Our central forecast is solar capacity reaching 17GW in 2020 and 25GW in 2030. This is around the current level of solar PV in Germany.
- *Wind*: we expect 1.5GW of onshore and 4.5GW of offshore wind capacity will be developed between 2017 and 2020. Beyond 2020 we assume Britain continues to deploy 1.5GW of offshore wind per year on average given the quality of the resource and declines in technology costs. After 2020 most of the onshore wind capacity additions are likely to come from the repowering of existing sites, effectively adding 3.2GW to the already installed capacity in 2020 of 14GW.

Figure 6: New build power capacity 2017 - 2030, Great Britain (GW)



Source: Bloomberg New Energy Finance

Beyond the directly supported technologies outlined above, the carbon price floor will also drive some changes to the thermal technologies, particularly after 2020 when the price starts to rise considerably. Our analysis suggests the price floor will make it attractive to fit coal capacity with CCS technology in the 2020s, resulting in 3.8GW of coal with CCS by 2030. We also model around 2.5GW of CCGT upgrades as older gas plants increase their efficiency.

4. CAPACITY EVOLUTION

Gas will play a leading role in Britain's energy future, acting as the key thermal resource while the country decarbonises.

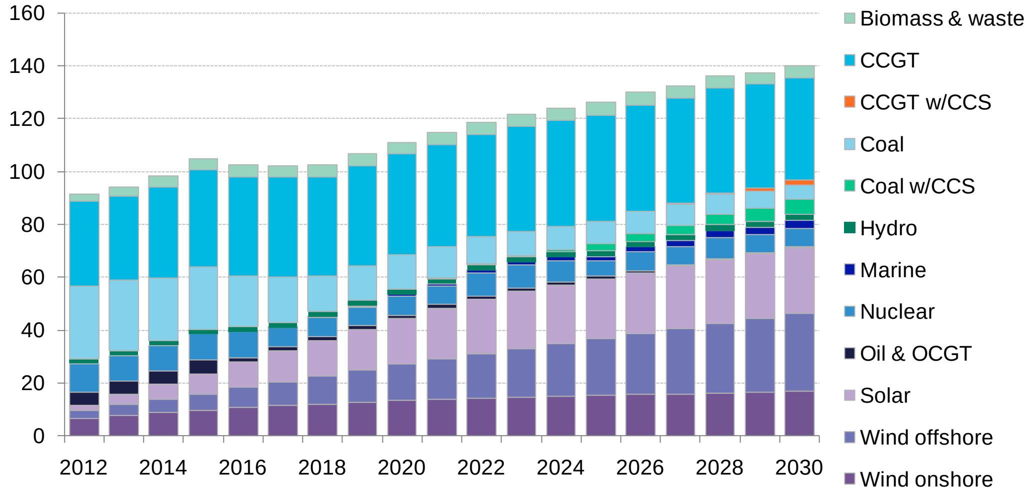
The net effect of the above capacity additions and retirements is shown in Figure 7. This illustrates that thermal capacity will decline from 83% of totalled installed capacity at the end of 2012 to 54% in 2020 and 42% in 2030.

Gas will play a leading role in Britain's energy future, acting as the key thermal resource while the country decarbonises. The CCGTs built this decade will provide the flexibility needed to manage a high penetration of renewable on the grid. Coal will register the sharpest decline in capacity as plants are subject to the LCPD and IED, and face mounting pressure from a rising carbon price floor.

Nuclear capacity roughly halves by 2030 but the size of the decline is mitigated due to life extensions of the existing fleet and new build in the 2020s.

Meanwhile total installed capacity for renewable energy increases from 17% in 2012 to 46% in 2020 and 58% in 2030. Within the renewable sector, offshore wind will overtake onshore wind as the largest source of renewable capacity after 2020. There will be an increase in the use of biomass to generate power though much of this will be burnt at existing coal fired stations through co-firing. However, the ultimate potential of biomass will be limited by the availability of resources to be delivered at scale and the subsidy it receives.

Figure 7: Installed capacity, Great Britain (GW)



Source: Bloomberg New Energy Finance

5. THE BIG COAL SQUEEZE

The generation mix only shows half the story. What matters for power prices and carbon emissions is which plants are running and how much of the time. These in turn depend on the prevailing fossil fuels, carbon prices and the availability of natural resources (wind, solar, biomass, rainfall and tidal currents).

Unabated coal faces grim prospects for being scheduled as plants are hit by the full auctioning of carbon permits and the carbon price floor.

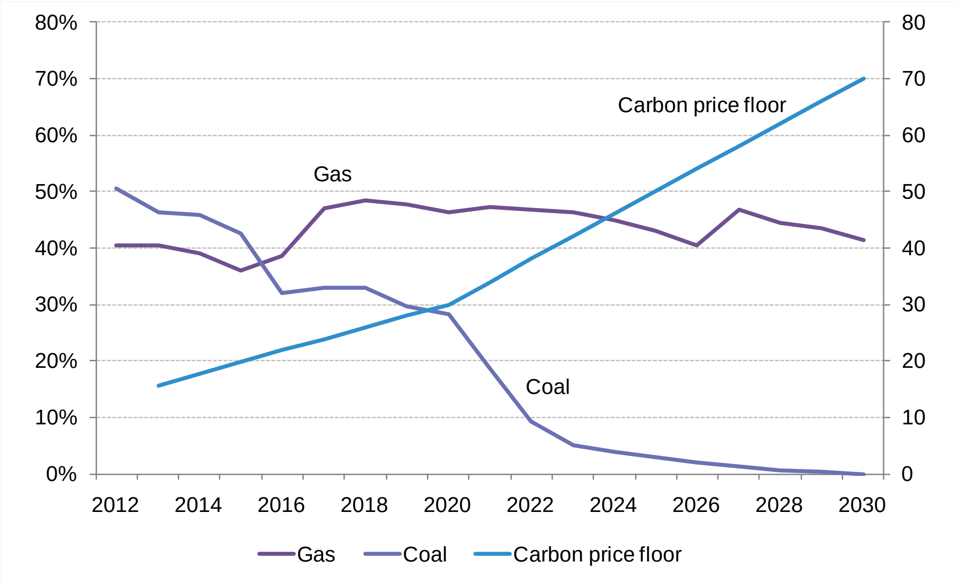
The UK carbon price floor in particular (which is set to reach GBP 30/tonne in 2020, excluding inflation) will have a profound effect on the scheduling of the UK generation fleet. Our modelling suggests load factors for conventional coal plants without CCS will fall from 60% today to below 10% from 2022 (Figure 8) as they are pushed to margin once carbon prices are included in the cost of operation. However, CCGTs and plants fitted with CCS gain at coal's expense as they increasingly run to supply baseload power.

These effects on generation output are shown in Figure 9 and Figure 10. These differ from power demand shown in Figure 3 as this is net of electricity consumed at power stations and transmission losses. Under our base case, the total generation from renewables reaches around 26% in 2020. This is slightly below the government's pathway of c.30%. However, the co-firing of biomass at coal plants could raise this figure so that the UK comes closer to reaching its target (this will depend on the subsidy for 'enhanced co-firing'). Although renewables account for 46% of installed capacity in 2020, the lower load factors on these technologies reduce their share of generated power to 26%.

Output from coal plants decreases significantly from 38% in 2012 to 17% as a percentage of total generation in 2020. Output collapses over the following few years as plants close under the IED or operate for only a limited number of hours as they provide peaking capacity.

It is not until 2025 – when CCS becomes viable – that coal generation begins to rise again. CCGT capacity output expands significantly reaching 46% of output in 2020, up from 34% in 2012. CCGT output then declines slightly to 36% of total output by 2030 as renewables continue to expand and coal with CCS runs preferentially in the merit order.

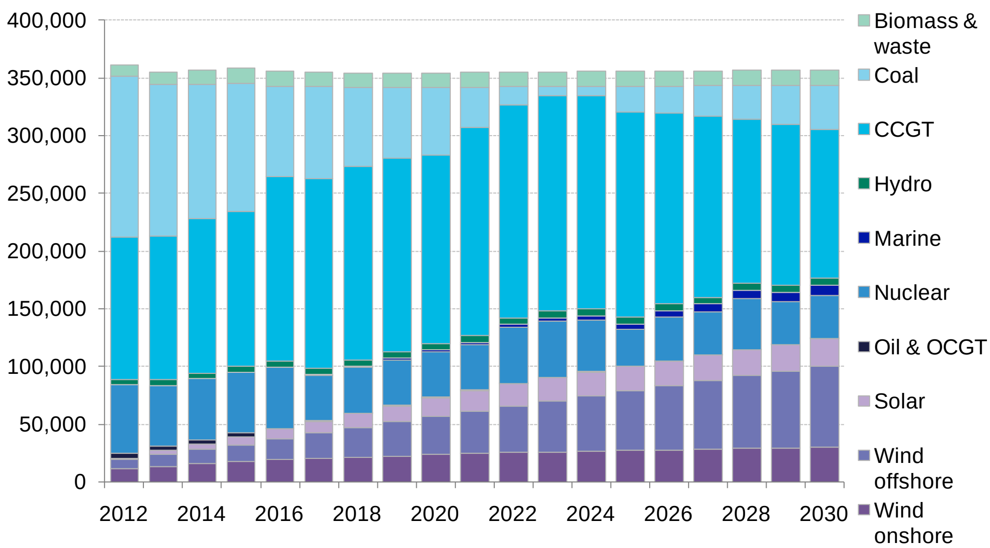
Figure 8: Load factors of coal and gas in Great Britain



Source: Bloomberg New Energy Finance. Note: Excludes coal or gas with CCS. Carbon price floor is shown in 2009 prices (inflation excluded).

Total generation remains fairly flat through 2030. This is due to power demand which is increasing slowly and a greater dependence on imports from continental Europe. This occurs as the carbon price floor increases electricity prices relative to those on the continent.

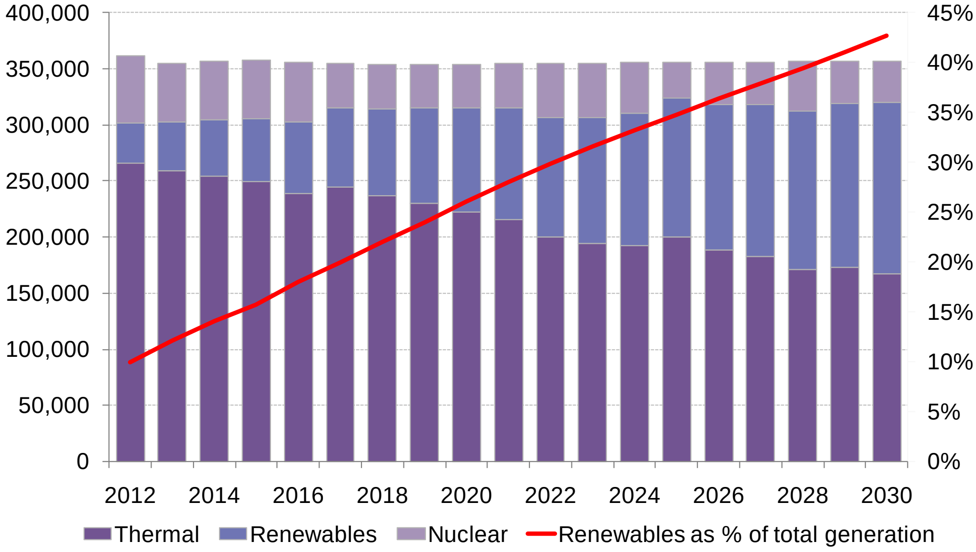
Figure 9: Generation by technology, Great Britain (MWh)



Source: Bloomberg New Energy Finance

Figure 10: Thermal – Renewables split, Great Britain

Generation (MWh)



Source: Bloomberg New Energy Finance

6. PUTTING THE PIECES TOGETHER

The result from the above analysis is that we project around 20GW of new capacity (net of retirements) will be added between 2012 and 2020, which will far outstrip the growth in peak demand. However, much of this new capacity will be intermittent and therefore of limited use in meeting peak demand (which in Great Britain occurs on a winter evening). We therefore show capacity margins expressed in terms of 'de-rated' and 'fully dispatchable' capacity.

Table 1: De-rating factors

Technology	Capacity credit
Biomass	90%
Coal	90%
Gas	90%
Nuclear	75%
Hydro	70%
Marine – Wave	30%
Marine – Tidal	13%
Oil	95%
Pumped storage	100%
Interconnector	95%
Solar	0%
Wind	10%

Source: Bloomberg New Energy Finance, DECC, National Grid

De-rated capacity margins reflect the amount of capacity the system operator can expect to rely on at peak times (Table 1). For dispatchable margins, we look at only plants which can be called on to produce electricity (thermal, biomass and some hydro).

In evaluating capacity margins, there is no widely agreed standard – there is an economic trade-off between how much consumers are willing to pay to avoid blackouts (value of lost load) and the cost of keeping excess capacity available despite running infrequently. However, in consultation documents DECC has used 10% as a threshold in its modelling of capacity mechanisms.[4] We use this as the baseline from which we evaluate security of supply (Figure 11).

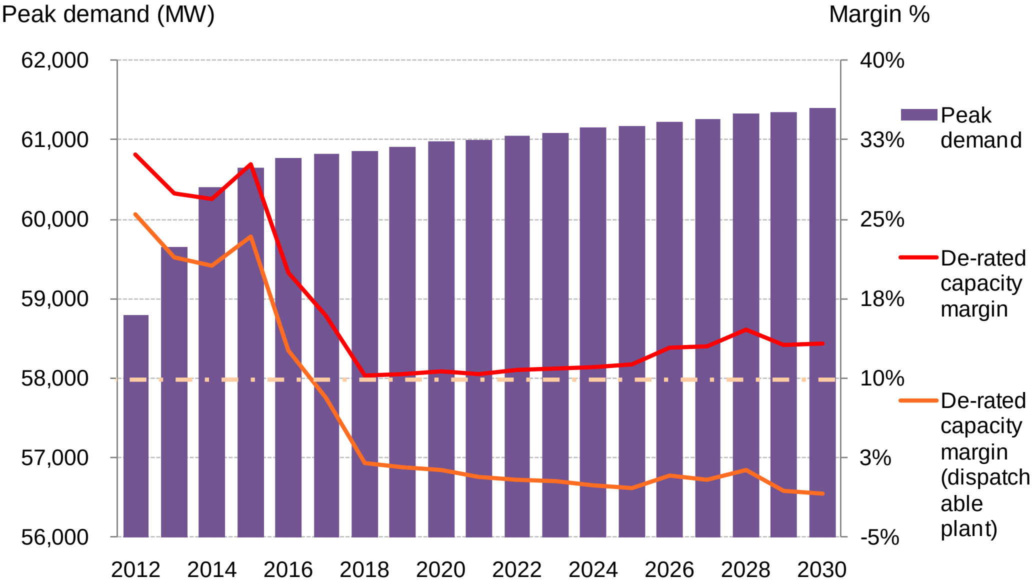
Our results highlight the following key points:

- For the next three years the GB power system will have more than enough capacity, operating in excess of a 25% de-rated capacity margin. Even the fully dispatchable capacity margin will be in the 20-25% range.
- The flurry of retirements in 2015 and 2016 will then see the system tightening, with de-rated capacity margins stabilising in the 10-15% range. Retirements after 2016 are effectively offset by more wind capacity being added to the system, even after applying a conservative credit of 10% to this capacity.
- Fully dispatchable capacity margins however fall to 0% in 2022. While this appears disconcerting, this is acceptable as renewables penetration will be high and diffuse with some level of renewables output available. Indeed, by 2022 we expect over 14GW of onshore wind

4 According to DECC's technical update (December 2011), if de-rated margins fell to five percent, the result would be an average lost load of around 8GWh in a year.

and 17GW of offshore wind deployed across the whole of Great Britain. As wind output tends to be correlated with seasonal demand in the UK, it is highly unlikely that the whole of Great Britain will experience a wind drought at a time of peak demand.

Figure 11: Capacity margins, Great Britain



Source: Bloomberg New Energy Finance. Note: De-rated margins are discounted to reflect ability of capacity to meet peak demand. Margins include interconnections and pumped storage.

Our analysis suggests that the planned capacity mechanism could be an unnecessary intervention as the market remains well supplied this decade.

Is a capacity market necessary?

To ensure adequate supplies of electricity, the UK intends to establish a capacity market as part of its electricity market reform. It is still unknown what level of reliability will be targeted (the minimum capacity margin) or how much capacity National Grid will contract for via auction.[5] However, our analysis suggests that the planned capacity mechanism could be an unnecessary intervention as the market remains well supplied this decade.

The current 'dash for gas' in the UK could be its last.

Beyond 2020 the picture is less clear as uncertainty over technology costs, power demand and plant retirements is magnified. The power system will require not only a sufficient supply of electricity but will also need increasingly flexible capabilities to balance demand as intermittent resources become the predominant form of capacity. The large fleet of existing gas and coal plants could provide this flexibility and peaking capabilities. However, these plants will need to receive adequate remuneration (especially as they might only operate occasionally). These plants can provide low-cost capacity along with demand-side response. This means that the current 'dash for gas' in the UK could be its last as there is little need for additional carbon-emitting thermal capacity beyond what is being built this decade.

7. WHERE COULD WE BE WRONG?

As with any modelling exercise, our forecast is only as strong as the assumptions behind it. Due to the large number of variables inherent in forecasting capacity, there is a number of areas in which we could be wrong. We set out a non-exhaustive list of key risks to our analysis below:

- *Power demand*: we assume weak but positive power demand growth in the UK through 2030. Power demand could in fact be negative due to a continued decline in industrial production

5 Subscribers can read, Security of supply in Great Britain by scalpel or hatchet?, 15 April 2011 and DECC gift wraps a capacity market for UK power, 16 December 2011 for more details on the UK's capacity market proposals.

and greater energy efficiency improvements. This would lead to additional closures and less new build. Conversely, a power demand recovery would result in lower capacity margins with greater new-build requirements. Changes in peak demand would also impact our security of supply analysis.

- *Fossil fuel prices*: changes in fossil fuel prices affect the merit order. A sharp decline in natural gas prices due to exploitation of the Bowland Shale, for example, would increase the profitability of gas plants which might be scheduled more often.
- *Technology costs:* we use an economic model which builds capacity when it is needed based on the cheapest available technologies (along with various constraints). Shifts in technology costs will alter which technologies are built. This is especially relevant for the immature technologies (ie, marine and CCS) for which there is little cost data available and the technologies have yet to be proven on a large scale. The future cost trajectories for these technologies could have significant consequences as shown by the impact of rapidly declining solar PV module prices.
- *Carbon price floor:* the carbon price floor is a unilateral measure by the UK and levied by HM Treasury. As a political instrument, it is subject to change and could be reduced or eliminated if the gap between the price floor and European carbon prices continues to widen. If UK carbon prices diverge from the price floor, the merit order and levelised cost of technologies (especially CCS) will shift.
- *Policy and regulation*: the UK power sector benefits from low regulatory risk compared with some of its peers. The sector however is certainly subject to politics. A change in nuclear policy, for example, might prevent life extensions or new build by excluding nuclear power from subsidies (ie, the low carbon feed-in tariff). Furthermore, an increasing number of decisions relating to energy are taken at a European level. Changes in EU policy relating to renewables, carbon and energy efficiency will impact our forecasts. Finally, the ongoing question of Scottish independence could throw a spanner in the works for renewables plans as uncertainty hinders investment in Scotland.
- *Transmission*: we assume that sufficient transmission will be in place to connect additional capacity to the grid. This follows plans to invest in transmission which will relieve current bottlenecks such as the 2GW Scotland-Wales linkage being built by Iberdola for 2016. However, a lack of progress on these investments would jeopardise the scale of capacity which can be added in Great Britain.

ABOUT US

SUBSCRIPTION DETAILS

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