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Issue 178 / November 2008

Power UK

3 *Generation*
ESBI takes Carrington stake and unveils British expansion plans
Welsh Power is placed up for sale
Intergen plans Spalding expansion
Drax unveils 900-MW biomass plan

6 *Nuclear*
Output plummets at BE
NDA sets out land disposal details
BE takes next step towards new build
NDA wants Oldbury life extension

8 *Renewables*
Vattenfall continues shopping for renewables
Green light for 300-MW biomass plant
Credit crunch and supply threaten wind plans

13 *Environment*
Carbon policy risk and investment
CO2 emissions increase at E.ON
RWE challenges CCS shortlist
UK recession would reduce demand for EU Allowances

18 *Politics*
UK to raise green feed-in tariff cap to 5 MW
Climate Change Bill approved

21 *Scotland*
Plant problems and FGD delays hit SSE

24 *Ireland*

24 *Trading Arrangements*

25 *Transmission*
The implications of intermittency
Grid seeks to boost border trades

27 *Supply*
Independent suppliers go under
First Utility to lower prices

29 *Prices*
Prices fall with recession fears

29 *News in brief*

30 *Viewpoint*
Melting markets, melting ice caps by Dr Thomas Schneider

32 *The Power UK interview*
Mark Daeche, chief executive, First Utility

36 *Events*

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TRANSMISSION

The implications of intermittency

The targets for renewable energy in Britain and Ireland resulting from the European Union's 20% target for 2020, with a target of 15% of final energy demand from renewables, require a seismic shift in the generation mix. Under optimistic assumptions for transport and heat sectors, the UK will require over 30% electricity generation from renewables, while less success meeting renewable heat and transport targets could mean 45% generation from wind. The investment costs of these changes are significant but well documented – somewhere in the region of £60-70 billion. What is less well documented – or indeed understood – is the suite of changes to system operation, patterns of despatch and even to the market rules themselves which will be required to achieve this revolution. In the following article **James Cox*** sets out the issues.

Within the energy markets, there are many euphemisms, but the one that has been used most frequently in reference to the 2020 targets is 'challenging'.

At a recent event, attended by many of the major players in the GB market, Poyry conducted a survey of views of the evolution of the market in order to meet the 2020 targets. 69% of participants believed that the GB market design (i.e. Betta) would be 'significantly different' by 2020. In particular, half of attendees thought that capacity payments would be a likely feature in the future.

At first blush, investing in the electricity industry should not require a new market framework – after all does not the current one permit and encourage new investment? So what has driven this view that the market structure needs to change so radically?

Most of all, it is the combination of two factors that will alter the electricity markets to require this new market design: large volumes of intermittent or variable generation (most notably wind), combined with large volumes of baseload generation, such as nuclear, biomass and carbon capture and storage (CCS).

Individually, these two changes may not cause significant change – after all, historically most new build generation is aimed at baseload, dropping to mid-merit or peaking as it gets older. But in a market where mid-merit and peaking generation is required to offset the variability of wind generation a significant new build program of baseload generation may exacerbate the difficulties the system faces.

What is the best new investment?

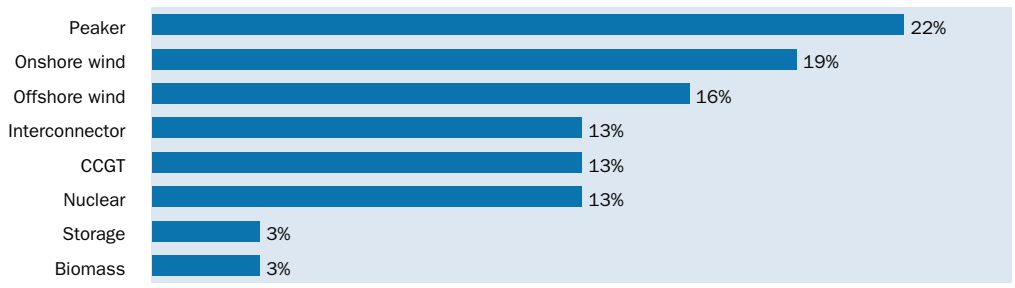
There are probably six major technologies we may see deployed in the next 15 years – combined cycle gas turbine (CCGT), nuclear, wind, tidal, carbon capture and storage (CCS (probably coal)) and biomass.

Of these, all apart from CCGTs are baseload (or price insensitive technologies). In the case of nuclear, wind and tidal, this is because high capital costs combine with low variable costs.

But in the case of biomass, it is less about variable costs of generation, and more the opportunity cost of Renewables Obligation Certificates (ROCs) – not generating one MWh means not only the loss of the revenue from the electricity price, but also the associated ROC value.

For CCS, it is not yet clear how the technology may work, as variable costs will be higher than conventional coal due to the extra costs of capturing the carbon. It is likely that CCS will operate at baseload despite relatively high

Figure 1 – What new generation plant would you build for 2018?



Source: Poyry

variable costs (driven by the coal price and the capture costs) due to regeneration of the amine in the capture process that means shutting down is difficult.

When we asked our survey participants what they would invest in for 2018 if they had £200 million, a balanced view of new entry emerges (*see Figure 1*). Surprisingly, given the existing market rules, recent investment history and present plans, peaking generation is the most popular, followed by onshore and offshore wind – the combination of all three perhaps being regarded as well hedged by our voters.

Equal numbers would build CCGT, nuclear and interconnection, the latter choice probably being influenced by the high flows seen recently on the recently commissioned NorNed. Whatever our participants' choice, the majority of new investment will be in wind. There is no doubt that wind generation increases during the important demand periods, with National Grid assuming in its Winter Outlook Report, a mean load factor of 35% for wind generation during the winter compared to 27% across the year.

But associated with this is the variability. In the same report National Grid commented that wind variability has been from zero to 90% load factors during the crucial part of winter when demand is highest, and wind generation operated at an 8% load factor during the 2007/08 demand peak.

What are the implications?

The impact of high levels of wind and baseload generation on existing plant could be quite significant.

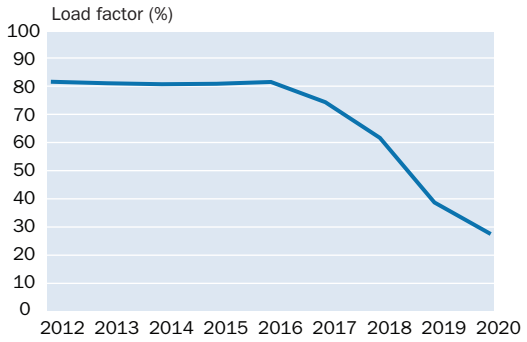
Analysis suggests that load factors of coal plant could drop below 30% and CCGTs to 20% with 30 GW of wind on the system. Equally importantly could be the operational profile of these plant – if they are required to cycle more frequently than currently this will lead to higher costs, associated with increased outages, maintenance costs, along with higher emissions. This was the major concern of the majority in our survey who thought that a capacity mechanism would be necessary.

With or without a capacity mechanism, we may see much more volatile prices. This applies not only when there is low wind generation and consequent high prices, but when there is very high wind generation, which could lead to periods of low or negative prices, as generators bid down to stay on the system to gather their ROCs.

Given the locational nature of the new wind generation, largely in the north of the country and above all in Scotland, it is possible to envisage a scenario where the value of energy in Scotland is zero owing to high wind speeds, but is positive in England, with constraints on the North-South transmission.

This in turn has implications for market design and whether locational pricing should be implemented.

Figure 2 – Load factor of FGD coal plant in a 30GW wind scenario



Source: Pöyry Energy Consulting analysis

Locational pricing is becoming an important feature of market design across Europe, with the zonal Italian market and the proposed market coupling arrangements for France, Belgium, Netherlands, Germany and Luxembourg following the Nord Pool zonal market example.

Wind curtailment may also be an issue but not solely due to higher wind than demand. Instead, it is likely that the requirements to provide system reserve, which will increase as wind penetration increases, mean that increased amounts of thermal plant have to be kept on the system which may displace wind. The thermal plant reserve is not just to provide spinning reserve for unforeseen events and inaccurate forecasting but keeping plant part-loaded to ramp up for known decreases in wind generation.

Proponents of distributed generation would argue that the large untapped resource for system balancing is the demand side. And there is no doubt that demand management offers huge potential – if there were 10 million electric cars on the roads, this represents 300GWh of stored energy or 7 hours of GB demand. But, in our survey, less than 10% of participants thought that the 'flexibility gap' would be addressed in a significant way by demand side management while 50% thought that CCGT and peaker technologies together offered a much more effective solution.

A question of timing

Fundamentally, this came down to a question of timing – almost all participants agreed that the demand side can offer significant scope to manage intermittent generation, but none thought this could be deployed in a timescale to help manage the 2020 issue. None of these issues are in any way insurmountable but recognising them and understanding the impacts will make mitigation and management much more effective.

And the final question we asked? What will the Brent price be on 1 January 2009? The spread of answers was between $50/bbl and $120/bbl – roll on the New Year!

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