Response to Electricity Market Reform Consultation

[redacted]

10 March 2011

1. Emissions Performance Standards (EPS)

1.1 Comments

The 'preferred' proposals for an EPS are fatally flawed because:

a) they would give a very high risk of carbon lock-in for the UK fossil generation fleet and consequent inability for the UK to meet its carbon targets;

b) they appear to be inconsistent with EU and UK regulations on Carbon Capture Readiness;

c) they make a future hiatus in fossil fuel plant construction almost inevitable; and

d) this design for an EPS makes the only reasonable path for widespread introduction of CCS to a large proportion of UK fossil-fired power plant capacity, through retrofitting CCS to individual plants in the existing fleet at the time of CCS deployment, difficult or impossible.

The proposed EPS design principles are summarised in Box 8 of the consultation document as:

• *application to individual power stations;*
• *setting an annual limit on the total amount of CO_2 permitted per unit of installed capacity;*
• *application to new power stations only, and with an ongoing principle of grandfathering, i.e. the level of the EPS on the date of consent of a new power station will apply for the economic life of the installation;*
• *consistency with a CCS Demonstration Programme covering the full range of approaches to carbon capture.*

a) High risk of carbon lock-in

Problem (a) arises because under these proposed arrangements all existing plants and all future new plants pending a change in EPS regulations (that would be difficult to implement – see (c) below) could not be required to achieve emissions that are any lower than those of an unabated gas plant. Virtually all new plants that are envisaged at present are gas plants. These proposed arrangements, therefore, represent no significant change to business as usual now. Importantly, they would also effectively exempt nearly the entire UK fossil fleet from being required to reduce emissions using CCS for the foreseeable future. If it is an economic advantage, then plants permitted with initial EPS levels outlined in the consultation document could and will be operated without such modifications as would trigger 'new plant' rules virtually indefinitely. This expectation applies to both natural gas plants and coal plants. The problem is even more acute because it is the timing of consent that determines the EPS level (or effective exemption from an EPS for natural gas plants). It can be expected that utilities will 'bank' as many consents as possible, at relatively minimal costs, before any further change takes place.

b) Inconsistency with CCR regulations

Problem (b) arises because the proposed EPS principles guarantee that capture ready (CCR) new gas plants and capture ready components of new coal plants will not have to have CCS fitted to them during the life of the plant, for the reasons discussed above. This is entirely inconsistent with the aims of making the plant CCR and could possibly lead to a judicial review being sought. Related to this, a grandfathered EPS, as proposed, would also guarantee that no-one could reasonably take the process of making new power plants capture ready seriously.

c) Future hiatus in fossil fuel plant construction

Problem (c) arises because it is inevitable that utilities will seek to consent as many years as possible worth of new plants before an EPS is introduced (or with a favourable EPS that would be 'grandfathered' in place). They can then be expected to delay consenting and building further plants, even if it transpires they are needed, for an extended period, if they would be at a significant commercial disadvantage to all BAU-for-gas plants that have been consented before a more stringent EPS is introduced.

d) Making widespread use of CCS difficult or impossible

An important option for significantly reducing CO_2 emissions from the UK fossil fuel fleet is to increase the proportion of CCS capacity in the system by retrofitting individual existing plants. This measure may be complemented by some new-build plants with CCS, but in order to achieve an absolute reduction in total CO_2 emissions it is necessary to tackle CO_2 emissions from the existing fleet. As noted above, it should not be assumed that future new build plants can be relied on to significantly reduce running hours, and hence CO_2 emissions, of fossil power plants constructed before a more stringent EPS is introduced.

In all cases, after CCS has been demonstrated at commercial scale, each site where CCS is used should have as much CO_2 captured as is reasonably possible (so emissions levels at 100gCO_2/kWh or lower). As already noted, the present proposals would severely handicap the ability to have CCS retrofitted to existing plants, which is often likely to be the lowest cost way to cut emissions using CCS. They are also strongly at variance with the type of EPS that <u>would</u> achieve the desirable emission reduction trajectory using CCS. This is a limit on overall fossil fuel CO_2 per kWh of electricity generated by an appropriately selected group of plants, with 'full' CCS applied on the necessary number of individual plants and using the cheapest opportunities first.

1.2 Recommendations

The stated policy objective for an EPS at present is:

• *to establish an emissions performance standard that will prevent coal-fired power stations being built unless they are equipped with sufficient carbon capture and storage (CCS) to meet the emissions performance standard.*

(i) Thus logically an EPS should be applied to new coal plants only. Having the proposed regulations apply to gas plants as well is effectively <u>exempting</u> these gas plants from any EPS.

(ii) The EPS should also not be expressed simply as a gCO_2/kWh (or tCO_2 emitted per year, based on average gCO_2/kWh) limit. Whether it is 600 gCO_2/kWh or 450 gCO_2/kWh, there is always a strong likelihood that it could (and in, at least, some cases will be) achieved at coal-fired power plants by cofiring biomass and/or possibly also cofiring some natural gas rather than by fitting CCS. As the recent biomass firing proposals by Drax Power, RWE Tilbury and elsewhere show, 100% biomass firing of large units is considered feasible. Firing at around 20% biomass (600 gCO_2/kWh) or 40% (450 gCO_2/kWh) is, therefore, also entirely technically possible with direct injection of biomass into the boiler.

(iii) If the regulation is designed to encourage CCS deployment to meet the EPS it must, therefore, be framed so as to explicitly require sufficient CCS to achieve a given level of emissions when firing only coal (and any minor amounts of other fuel required for start-up and flame support purposes). Consideration should also be given to whether regulations should address how CCS is operated, regardless of the fuel being burned at any particular time (i.e. not just installation).

(iv) To avoid carbon-lock in and the prospect of substantial amounts of coal capacity operating without CCS until perhaps 2050 is it also essential that a coal-only EPS is not grandfathered for any extended period. It could reasonably be fixed for 5-10 years of operation, however, to give time for CCS development. In this case, the emission level can be set at 600 gCO_2/kWh without any long-term risk (such a risk would be reduced only marginally by a grandfathered EPS set at 450 gCO_2/kWh).

2. Feed-in Tariffs

2.1 Comments

There appears to be a systematic tendency in the consultation document to aim for a uniform support mechanism for all low carbon technologies. While this may seem a 'tidy' approach there are fundamental differences between the generating technologies (see Figure 1) which cannot be ignored or altered. Of particular concern is that:

a) renewables and nuclear power have mainly fixed costs;

b) CCS has a significant fuel cost element in the overall cost of generation.

There is a very significant risk that the objectives of EMR will not be realised if CCS is not supported in an appropriate way. A failure to give financial terms for CCS which do not match in their <u>effect</u> the terms for renewables and nuclear is likely to lead to higher costs for the consumer and a much higher risk of failing to meet carbon targets, or if fossil fuel generation is curtailed, of failing to achieve continuous supply of electricity. Terms for CCS which are similar to those for other, non-fossil, low-carbon generation technologies will not achieve similar effects.

We therefore concur with Qu. 4 " Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?" without significant reservations for renewables and nuclear, but have major reservations for its application to CCS.

The fundamental and unavoidable differences that the inherent characteristics of CCS impose in required support mechanisms are identified in the Redpoint assessment (Electricity Market Reform Analysis of policy options). The modifications that Redpoint suggest, while generally appearing reasonable, are so extensive that it is:

a) arguably unreasonable, as DECC do in the consultation document, to call the effective CCS support mechanism by the name of the 'equivalent' renewables and nuclear mechanisms; and

b) reasonable to be concerned that, since the CCS-specific modifications do not appear to be identified by DECC themselves in the consultation document, then DECC may not consider they are important and may not implement them, or implement them fully, in the final EMR regulations.

Examples of the renewables/nuclear support mechanism and the Redpoint classification of the equivalent modified CCS support mechanism are as follows (actual Redpoint documents quotes):

Renewables/Nuclear mechanism	**CCS mechanism**
Premium Payments	*Premium Payments* *The costs of Premium Payments would be paid for by consumers through some form of consumer levy (or through an obligation on suppliers).*
Fixed Payments, or feed-in tariffs	*For plant with higher and varying short-run costs such as CCS plant and biomass, the Fixed Payments would need to take a different form, incorporating a utilisation element and an availability element. The utilisation element would be designed to cover the SRMC of the plant and would be paid when the plant operates (ie, when the electricity price is higher than the SRMC of the plant). This could be achieved through a contract price indexed to a basket of fuel and carbon prices, taking into account plant efficiency and operating costs. (This component of the payment would clearly then vary with fuel prices, and <u>the term Fixed Payments would be something of a misnomer in this respect</u>.) The availability element would be designed to cover the fixed and capital costs of the plant, and paid regardless of whether the plant operates, as long as it is technically available to do so. The combination of utilisation and availability elements would yield a stable earnings stream for the generator.*
Contracts for Difference	*The Contracts for Difference concept is more complex for plant that have significant fuel input costs such as CCS and biomass. Because the input costs vary (based on fuel and carbon prices), a two-way CfD against the electricity price does not stabilise earnings in the same way as for nuclear and most renewables. Also it is possible that electricity prices may fall below short-run costs on occasions and the plant would choose not to run.* *In this case the CfD concept becomes more like a tolling agreement – the central agency pays the generator a tolling fee for use of the plant. Effectively the generator is swapping the infra-marginal spread (the difference between the electricity price and its SRMC) for a fixed tolling fee. In terms of financial instruments this is equivalent to the generator selling a one-way CfD on the spread between the electricity price and its short-run costs (defined by some form of indexation formula) and receiving a premium in return. If the spread is positive (and the plant runs) the generator pays out the difference between the electricity price and the fuel indexation formula. Hence, to minimise its risk the generator is incentivised to sell its power and buy its fuel / carbon close to the respective indices. The premium that it receives would be designed to cover the fixed and capital costs of the plant, and is equivalent to the concept of the availability fee under Fixed Payments.* *As under the two-way CfD, these premia would differ by technology and could be set by Government or established via a competitive tender.*

It is also apparent that in many cases the support required for CCS is dependent on fossil fuel prices in a way that nuclear and renewable support are not. This leads to a misleading assessment of support levels for CCS as shown in the Redpoint document; they will in fact vary and be lower or higher depending on actual fuel prices.

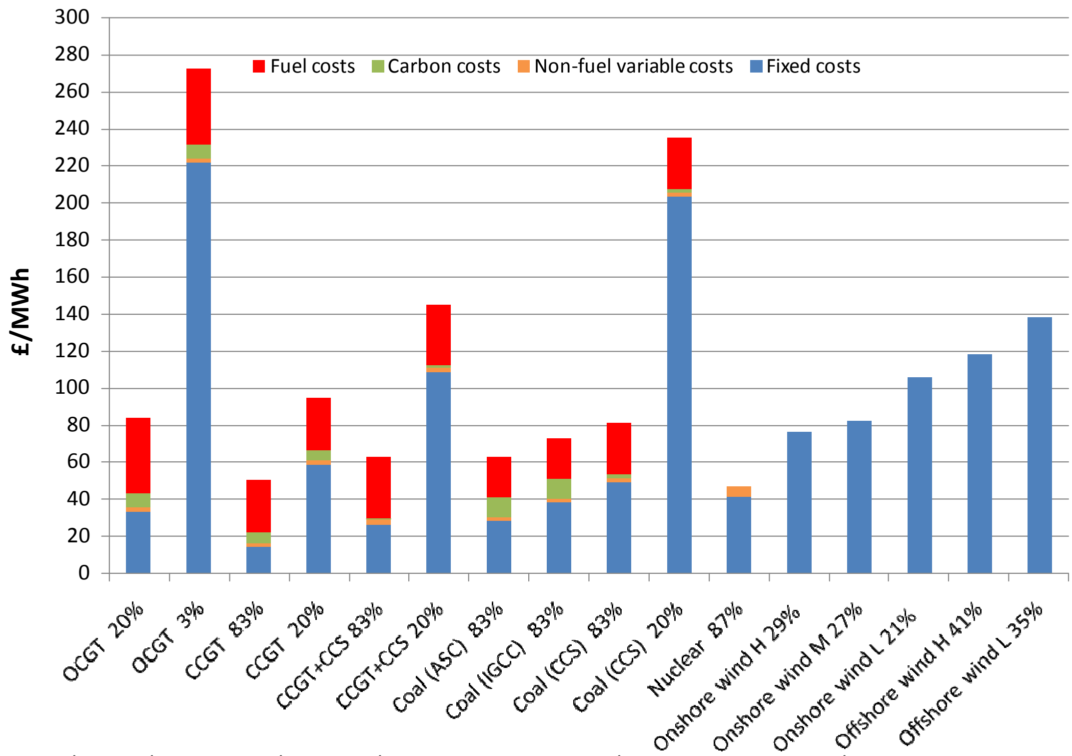
2.2 Recommendations

The use of the same names for renewables/nuclear and CCS support mechanisms is both misleading and dangerous.

Different names should be used for CCS support mechanisms and their cost levels should be assessed and shown for a range of fuel prices, not just for central fuel price values. The overall cost of electricity supplied to the consumer and who pays for this (i.e. consumers or taxpayers) also needs to be assessed, not just the apparent monetary level of the support instrument.

This would lead to much simpler definitions for CCS support mechanisms, which are therefore more likely to be implemented properly in regulations and to achieve the desired overall effects.

Both the FIT and CfD versions of the Redpoint support mechanisms for CCS in the table above appear reasonably likely to be successful, provided they are implemented with the full range of proposed modifications, but we would also advocate serious consideration of Premium Payments or a Premium FIT (which appears similar in many respects to both of the above). The principles involved in this mechanism are illustrated in Box 1 overleaf.



Based on *Redpoint: Decarbonising the GB power sector: evaluating investment pathways, generation patterns and emissions through to 2030, A Report to the Committee on Climate Change, September 2009.*
2008 capital costs, assumed £15/tCO_2 carbon price, gas price £15/MWh_{th}, coal price £10/MWh_{th}. 10% interest rate

Figure 1 <u>Illustrative</u> Cost Breakdown for UK Generation Options

Box **1** Paying for CCS- but not for FOAK plants. which need special support

Principle is to pay for delivery of low carbon electricity, with sufficient confidence in the revenue for the plant to allow financing at reasonable cost

Plant has to be able to compete with unabated natural gas combined cycle as an alternative investment (and potentially coal plants, but currently less relevant)

Need to allow for variation in fuel price, <u>which market electricity prices will do</u>
-so use a Premium Feed in Tariff (which roughly equates to additional fixed costs)

But CCS projects cannot run if excessive amounts of wind and nuclear are also available
- so the Premium Feed in Tariff has to be guaranteed for a minimum number of hours per year (e.g. 7000 hrs or 80% load factor), provided the plant is available to operate

Electricity price has to cover fuel cost and other variable operating costs for CCS plant
- electricity price is roughly equal to (fuel costs +carbon costs) for unabated gas
- a floor on carbon price will make this part of the revenue stream more certain
- needs to be high enough to make sure it is worth running existing CCS plants

Illustrative electricity cost breakdown