Response to DECC Consultation on Electricity Market Reform

[redacted]

Sussex Energy Group, SPRU, University of Sussex

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Summary

This response to the consultation on Electricity Market Reform (EMR) puts forward some principles that we have used to evaluate the proposals, our views on the four elements of the proposed package, and some crucial considerations for policy implementation.

Whilst we agree that the status quo is not an option, the reforms should avoid excessive policy complexity. Policy interactions should be analysed carefully (within the EMR package and with other instruments). The reforms should ensure adequate competition to promote efficiency, new entrants and protect consumers, and should promote low carbon innovation.

With respect to the four elements of the package, we are least convinced about the carbon price floor. This measure is likely to be redundant since it will make little difference to carbon emissions covered by the EU ETS. It risks providing windfall gains to existing low carbon generation (e.g. nuclear plants). It would also give rise to policy interactions (particularly with the proposed 'feed in tariffs') which have not been analysed sufficiently.

The emissions performance standard would also have little effect as presently proposed. Through section 36 powers, the Secretary of State can already refuse permission for new unabated fossil fuel plants. If the EPS is seen as an essential part of the EMR package, we argue that it should be more ambitious (i.e. with a lower limit on emissions). It should also apply to existing plants from a pre-specified date (e.g. 2025).

The capacity mechanism proposed may be required at some point in future, but we are not convinced that it is required now. There are significant planned investments in the pipeline already (albeit mostly for gas-fired plant). Furthermore, the new system of contracts should lead to a greater level of investment over the medium term. Taken together, these drivers will compensate for planned plant closures. We agree that a capacity mechanism should be targeted, but this may lead to gaming by generators wishing to take advantage of it.

We strongly support the implementation of long-term contracts for low carbon generation. Given the need for investor certainty and the need for some competition, we think that the premium feed-in tariff is the best option for now. We urge caution with respect to auctions. Whilst auctions to determine contract prices are desirable, they will be impractical in many cases where there may be too few bidders (e.g. for nuclear, offshore wind and CCS).

The consultation pays insufficient attention to the implementation of EMR. We suggest that contracts should be awarded by an arms-length government body in tranches that synchronise with the UK's five-yearly budget periods. This approach provides opportunities for learning and adjustment, and will help to guard against the risks that the EMR will usher in excessive centralised planning. More thought is needed to ensure that EMR includes smaller players in the contract system, minimises transaction costs, and is flexible enough to include contracts for demand-side investment. Finally, the implications of a possible move to radically different electricity systems with smarter grids reinforces the need for a flexible policy framework that can be changed over time.

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[1] We would like to thank [redacted] and members of the Sussex Energy Group steering board for their contributions to the thinking behind this response. The views expressed here are ours alone. [redacted]

About the Sussex Energy Group

The Sussex Energy Group undertakes academically rigorous, inter-disciplinary research that engages with policy-makers and practitioners. The aim of our research is to identify ways of achieving the transition to sustainable, low carbon energy systems whilst addressing other important policy objectives such as energy security. We are a group of 15 social scientists working on energy policy from a multidisciplinary perspective. We are funded from a diverse range of sources, primarily UK Research Councils, Government Departments and the European Commission. Through the Group, the University of Sussex is a core partner of the Tyndall Centre for Climate Change Research. The Group is also part of the UK Energy Research Centre.

Introduction: Our approach to the consultation

We welcome this major review of the electricity market. In particular we welcome the focus on the question of how to provide effective and efficient incentives for low-carbon investment. Alongside this, the consultation rightly recognises the urgency of transforming the GB electricity system towards a close-to-zero carbon emitter by 2030, and at the same time the need to avoid any unnecessary increases in electricity costs to consumers. We have reservations about the scope of the review. It focuses too narrowly on supply-side issues and it pays too little attention to critical governance questions that need to be resolved at the same time as the technical issues that are covered so extensively in the consultation. The consultation also pays little explicit attention to the proposed 4th budget from the Committee on Climate Change (for 2023-27) which we believe should provide a key context for any reforms that are implemented. In this response, we first set out some general principles and tensions which have informed our comments on the consultation.

First, there is an issue of complexity. While the principle of simplicity is important in the design of public policy, we do not accept the argument that the only thing required to provide an incentive for low carbon investment is a high enough carbon tax or some other form of carbon pricing. There are two reasons why this would not be effective. First it is widely acknowledged that the level of the carbon price would in these circumstances have to be so high that it is politically implausible. Second, a universal economic instrument of this kind would not ensure investment in the technologies required to keep the UK on a reducing pathway of emissions whilst maintaining acceptable levels of electricity system reliability. For example, electricity supply technologies as diverse as wind power, nuclear power and CCS are at different stages of development with different rationales, costs and risks associated with them. A singular instrument cannot deal with this diversity of attributes and would tend to induce significant investment only in technologies that were relatively cheap at the outset. Carbon pricing, practiced alone, would not be sufficient to develop and deploy the diverse range of technologies that the government acknowledges to be vital to the low carbon future. So there would be a limited impact on innovation (see below).

Second, part of the complexity in the consultation proposals is due to the fact that they aim to achieve two quite distinct policy objectives. Three of the proposals - on carbon floor prices, feed-in tariffs and an emissions performance standard - are squarely aimed at the urgent need to decarbonise the electricity supply system. The other proposal, for capacity mechanisms, is directed towards ensuring supply security, both in the immediate operational sense, and in the longer term sense of ensuring adequate generating capacity to meet peak demand. We argue below that it is unnecessary to implement capacity mechanism proposals at the present time, and advocate their postponement until the point at which they may become necessary. Given the inevitability of unintended and unwanted policy interactions, we argue that it would be better to leave these out of the present mix of proposals.

However, policy design should still be as simple and transparent as possible and in this context the high level of complexity of the EMR package merits serious consideration – particularly since there are other pre-existing policies in play including the EU ETS, the climate change levy (CCL), the renewables obligation (RO) and (at least in planning) the Green Investment Bank. It is therefore not clear why all four elements of the package are required to achieve the Government's goals. The proposals include a large number of instruments proposed for a (mostly) similar purpose, and therefore some may be redundant (Q26 and Q29). We examine some of the detailed issues arising from this point later in our response.

Third, it is important that any reforms pay attention to competition issues. There are serious questions to be asked about the current extent of competition within the UK electricity market – both in generation (where the great bulk of electricity is traded bilaterally under contract and not through wholesale markets) and retail (where Ofgem and others have raised concerns). Now that we would like incumbents to deliver a large amount of investment in low carbon power generation, and to do so in the UK rather than in other countries, there is a balancing act for government. On one hand, there is a need to preserve (and perhaps enhance) competitive pressures in the market so that investments are efficient, consumers are not fleeced, and new entrants can come in. The desirability of investment from new entrants stems both from the size of the investments needed, which might be beyond the plausible scope of the incumbent 'big 6' utilities, and also because it would inject further competitive pressure into the market. On the other hand, too much investment risk, which can be a consequence of some models of competition, might jeopardise investment – especially of the capital intensive type that characterises all low-carbon electricity investment.

The fourth key issue is innovation – in developing, demonstrating and deploying new low carbon technologies on the supply and demand side. There is mixed evidence on the impact of competition on innovation (Lockwood and Lent 2010) – but a lack of competition risks stifling innovation and locking us in to current technologies (or incremental variants of them). This means that enhancing competition will generally be a desirable but that it is important to test the extent to which particular kinds of competitive structures do not lead to excessive risks for potential investors who may then be less likely to innovate.

Fifth, there is the question of the overall rationale for this particular package of proposals. There are three generic types of low carbon supply technology – renewable technologies, fossil plants with CCS and nuclear power. As the consultation notes, demand-side measures are also very important. Renewables already have support from the RO and feed-in tariffs. The RO arguably needs reform to be more effective. There are demonstrations confirmed or planned to help CCS technologies through to commercialisation. We also have the carbon price (albeit with a currently weak signal) from the EU ETS. There are schemes in place or planned for energy efficiency. Though again, it is not clear that they are, or will be, effective enough. The conspicuously absent option from this list is nuclear power. If a major purpose of EMR is to subsidise nuclear power without appearing to do so, then it would be better and more transparent to simply propose specific mechanisms to support this option. A debate could then be had about the desirability and cost-effectiveness of such proposals.

In our specific comments below, we have linked our response where possible to the specific questions in the consultation document (with the relevant question number in brackets). However there are many consultation questions, and we have not found it possible to reply to them all or to develop a coherent argument that precisely follows the order of questions asked. We have assessed each of the four main elements of the EMR 'package' in turn – starting with the Treasury-based consultation issue of carbon price support. We then conclude by highlighting three sets of issues that we believe are important to consider when implementing the reforms.

The carbon price floor

In our view, the carbon price floor will increase abatement costs for the UK and the EU, provide windfall profits to existing low carbon generators (especially nuclear) and deliver no additional emission reductions at least until 2020 and possibly not beyond. We therefore see no rationale for its inclusion within the EMR and recommend that it be dropped. The following explains our reasoning.

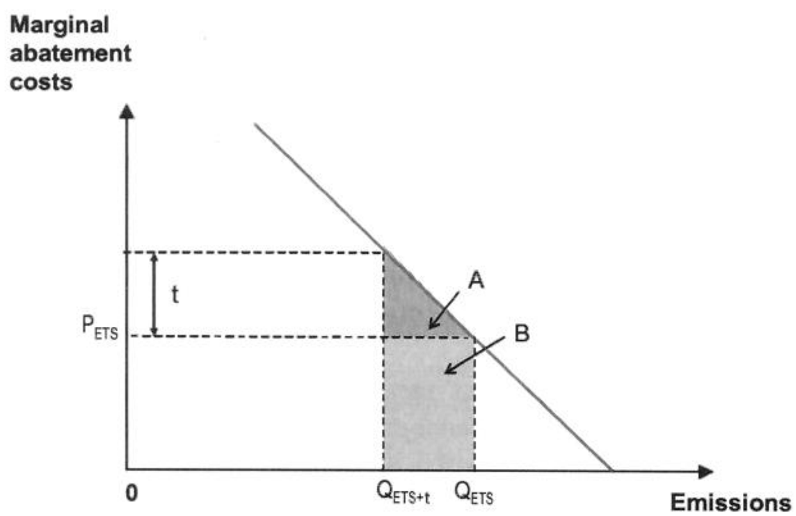
Interactions between policies have been overlooked

In work conducted for the European Commission in the early part of this decade, SEG showed how the interactions between different climate policy instruments can be complex and lead to both unintended and unwanted outcomes (Sorrell 2003b; Sorrell 2003a; Sorrell, Boemare et al. 2003). Since that time, the UK policy mix has grown in complexity and now includes, amongst others, the EUETS, the Climate Change Levy (CCL), the Climate Change Agreements (CCAs), the Carbon Reduction Commitment (CRC), the Renewables Obligation (RO) and the Carbon Emission Reduction Target (CERT). The EMR proposals add further complexity to this increasingly crowded policy mix. While the consultation document gives some attention to the interactions between existing and proposed policies, many important points are missed. In particular, the implications of the proposed carbon price floor are inadequately explored.

A defining feature of a cap-and-trade scheme such as the EU ETS is that (assuming adequate enforcement and full compliance) there is certainty that total emissions will be less than or equal to the aggregate cap. A second feature is that, assuming competitive operation of the allowance market; the scheme should allow the emissions target to be met at least cost - with marginal abatement costs being equalised across sources and equal to the allowance price. These features have important implications for the interaction of the EU ETS with other policies (Sorrell and Sijm 2003). Specifically, such policies will achieve no additional emission reductions and will increase the overall costs of meeting the emissions cap. This result applies to instruments that directly affect CO_2 emissions from EU ETS participants, such as a tax on fuel use, as well as those that indirectly affect those emissions, such as a tax on electricity consumption.

The proposed carbon price floor directly affects EU ETS participants by taxing the fuel used by electricity generators. As a consequence, the generators are likely to reduce emissions further than they would under the EU ETS alone, which means that they are likely to either sell more allowances or purchase fewer allowances. The implications of this are illustrated in a stylised form in Figure 1. In the absence of the tax, the marginal abatement costs faced by GB generators is equal to the EU ETS allowance price (P_{ETS}) which is initially assumed to be fixed. The tax (t) encourages GB generators to reduce their emissions further from Q_{ETS} to Q_{ETS+t}, increasing their marginal abatement costs from P_{ETS} to (P_{ETS}+t) and leading them to spend an additional amount equal to area A+B on emission abatement. This additional expenditure will only be partly compensated by the revenue from increased allowance sales (or the cost savings from reduced allowance purchases), represented by the area B. Hence, the generators will find their total abatement costs increased by area A, leading to higher costs for the UK as a whole. These additional costs will be passed backwards to suppliers of capital, fuel and other inputs and forwards to electricity consumers. In practice, most of the additional cost burden is likely to be borne by electricity consumers.

Figure 1, The carbon price floor raises the overall compliance costs for GB generators



Importantly, the aggregate emissions from EU ETS participants will not have changed. This is because other EU ETS participants can be expected to purchase and use any 'freed-up' allowances to cover either increases in emissions or reduced emissions abatement. Alternatively, the allowances may be banked and used in subsequent trading periods, but they will still ultimately be used to cover emissions. Hence, the taxation of fuel use by GB generators leads to no additional emission reductions - since the reduced emissions from the GB generating sector are merely compensated for by increased emissions elsewhere.

Figure 1 assumes that the carbon price floor has no impact on EU ETS allowance prices, but in practice the additional abatement by GB generators is likely to lower the allowance price. For example, Fankhauser et al (2011) estimate that a €10/tCO_2 tax on UK participants in the EU ETS may reduce the 2010 allowance price by around 5% (0.7€). This will make it cheaper for EU ETS participants that are net buyers of allowances to comply with their targets, while at the same time reducing the revenues of participants that are net sellers of allowances. However, the overall abatement costs for EU ETS participants will have increased and UK electricity consumers will effectively be subsidising abatement in other Member States.[2]

[2] As Bohringer et a have shown, there are some restrictive circumstances in which the UK could benefit from the introduction of the tax (Böhringer, Koschel et al. 2008). These are a) the UK is a net importer of allowances before and after implementing the tax; b) it has relatively flat marginal abatement costs in the sectors affected by the tax; and c) the tax induces a sufficiently large reduction in allowance prices that the lower cost of allowance

The above argument is valid for the period to 2020 - the end of EU ETS Phase 3. Beyond Phase 3, it is expected that the EU ETS cap will be tightened and/or the policy framework modified. Hence, the effect of the carbon price floor on emissions after 2020 will depend upon whether and how it influences the EU-wide policy mix after that date, including in particular the stringency of any post-2020 EU ETS cap. For example, if the tax accelerates the decarbonisation of the GB generating sector, GB emissions will be lower in 2020 than would otherwise be the case. In these circumstances, lower and declining domestic emissions may help the UK in negotiating a more stringent EU-wide cap. The probability of such an outcome may be increased if other Member States introduce comparable domestic policies that reduce EU allowance prices further, thereby assisting overall EU compliance in encouraging the adoption of more ambitious emission targets. However, not only does this argument rest upon highly speculative scenarios regarding EU-wide policy developments after 2020, it also assumes that the carbon price floor accelerates the decarbonisation of the GB generating sector relative to what would have occurred in its absence. The following section argues that it will not.

Existing and proposed policies make the carbon price floor redundant

Chapter 3, paragraph 16 of the consultation document states that:

> "The [carbon price floor] could form an important part of a package to reduce carbon emissions from the electricity sector, by: firstly encouraging more investment in low carbon generation and secondly encouraging a switch in dispatch decisions of existing plant from high carbon lower carbon ones (i.e. coal to gas switching).... On its own, the mechanism would not be able to encourage the investment needed in renewable generation to meet the EU 2020 target, because additional support is needed reflecting the higher cost of renewables."

We will take these arguments in reverse order. First, a carbon price would incentivise sufficient investment in renewable generation if the carbon price was high enough. But since the consultation document fails to model a 'carbon price floor only' scenario, the size and distribution of the associated costs remain unclear. We anticipate, however, that these will be high.

Second, we agree that the carbon price floor will modify short-term dispatch decisions and therefore reduce emissions from the GB electricity sector. However, as argued above, this will not reduce EU or global carbon emissions and hence will have no direct environmental benefits – although it will raise costs for the UK and for the EU as a whole. This crucial point appears to be largely overlooked in the consultation document. In the absence of any global emission reductions, the benefits of reducing carbon emissions from GB generators deserve more justification. One important argument that could be used in justification is that the UK should implement additional emissions reductions as an expression of political leadership.

Third, we disagree that a carbon price floor is necessary to encourage more investment in low carbon generation. The EMR consultation investigates various types of revenue support for low carbon generation in combination with the carbon price floor but does not investigate their operation in the absence of a carbon price floor. As a result, it fails to acknowledge that

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imports (due to both lower allowance prices and fewer allowance imports) more than compensates for the increased cost of abatement. In practice, this combination of circumstances appears unlikely.

the preferred Contract for Difference (CfD) option makes the carbon price floor redundant. As noted in Chapter 3, paragraph 53:

> "Under a CfD the support level is dynamic. It changes in response to the average wholesale electricity price, so that the combined revenues from electricity sales and support under the CfD equal the strike price in the CfD. In practice, this means that the government could change its target price through the carbon price support mechanism without affecting the overall returns made by lower carbon generators."

In other words, a lower (or higher) carbon price leads to a higher (or lower) payment under the CfD but leaves the sum of the two, and hence the revenues to low carbon generators, unchanged. So, low carbon generators can receive adequate revenues without a carbon price floor.[3] Hence, from the perspective of incentivising investment in low carbon generation, the carbon price floor may be abandoned.

From a public spending perspective, the impacts of abandoning it may not be so straightforward. It is unclear in the consultation how the payments for CfDs or premium FITs will work. However, if they are classed as public spending whilst the carbon price floor is not, there will be a greater impact on the public budget if CfDs alone are implemented.

The carbon price floor would lead to unwanted outcomes

Abandonment of the carbon price floor would lead to different outcomes in terms of the size and distribution of revenues and costs, but without detailed modelling of the relevant scenarios, the precise differences cannot be established. Nevertheless, some general points may be made.

First, while the CfDs only benefit new low carbon plant, the carbon price floor will affect all generators whose revenues depend in whole or in part on the wholesale price. In particular, the floor price will deliver substantial 'windfall' profits to nuclear generators, since these will obtain higher revenues but not face any increase in costs. For the highest price floor proposed (£40/tCO_2 in 2020), WWF and Greenpeace estimate total windfall profits of £3.43bn over the period to 2026[4]. The existence, size of and justification for these profits is not discussed in the consultation document, but one of the reasons cited for rejecting a 'premium FIT' is that it would "....enable [existing generators] to earn more than an economic return on their investment, unfairly, at the expense of the consumer" (p107). The carbon price floor creates comparable problems that could be easily avoided by simply using CfDs.

Second, the floor price will discourage the use of existing coal fired generation that is not fitted with CCS. As indicated above, this will lower emissions from the GB generating sector but not from the EU as a whole, so this is therefore of questionable value. One possible consequence would be to bring forward the date of retirement of such plant which could have implications for security of supply. Again, this problem could be avoided by using CfDs or premium FITs alone.

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[3] In practice, the level of the CfD will be calculated relative to 'average' wholesale electricity prices over some period, while the impact of the carbon price floor on wholesale prices will vary on an hourly basis, depending upon the carbon intensity of the marginal plant on the system (commonly CCGTs). The overall returns to low carbon generators may not, therefore, be entirely independent of the level of the carbon price floor, and it is possible that the existence of a floor price will reduce the level and predictability of these returns.

[4] 'Energy bills to rise as nuclear gets £3.43bn for doing nothing' WWF and Greenpeace press release, 14th February 2011.

Third, the carbon price floor adds further complexity to the policy mix while failing to price carbon consistently between sectors and fuels. In particular, oil products continue to be taxed differently from other fossil fuels for historical reasons that lack any economic justification. Also, many consumers in the public, commercial and industrial sectors will effectively face triple regulation of their carbon emissions – directly through the CCL on electricity use and indirectly through the impact on electricity prices of both the carbon price floor and EUETS allowance price. The economic impact on downstream consumers may be expected to become an increasing concern.

Fourth, the carbon price floor introduces some additional political risk. Investors may discount a carbon price floor in investment appraisal since it does not have the certainty of a contract[5]. As demonstrated by the CCL and road duty escalator, the government may vary a tax in response to economic incentives or political lobbying. So even if it were otherwise functional, a carbon price floor, may be a less effective way of reducing investment risk.

Finally, the existence and level of the carbon price floor will influence the distributional impact of the policy mix (Q29), but the consultation document provides insufficient information on either what this will be or which option is preferred. The carbon price floor will raise prices for electricity consumers, but its ultimate economic burden will depend upon how the revenues are recycled – which is not specified. The economic burden of the CfD or premium FIT will depend upon whether they are financed through a levy on electricity consumers or through general taxation or borrowing (and if so, which forms of taxation/borrowing). If a levy is chosen, the impact on electricity prices may be largely independent of the level of the carbon price floor – since a lower floor price must be compensated by a higher levy - and vice versa. Conversely, if general taxation is chosen, electricity prices will vary with the carbon price floor, with increases (or reductions) in that price being compensated for by reductions (or increases) in government subsidies for low carbon generation. These in turn will be funded through reductions (or increases) in general taxation or government borrowing or changes to other forms of public expenditure. There will be macroeconomic and distributional arguments regarding the relative merits of different options, but these are independent of the impact of EMR on investment, security of supply and carbon emissions. Hence, since the carbon price floor adds nothing to the objectives of the EMR and creates some perverse outcomes (e.g. increased abatement costs, windfall profits to nuclear, possible threats to security of supply) the case for its introduction must rest entirely on these broader macroeconomic and fiscal arguments. In our view, this case has not been made.

Alternatives not considered

We acknowledge the economic rationale for raising and stabilising the carbon price (Roberts and Spence 1976; Wood and Jotzo 2011), but argue that the proposed method leads to perverse outcomes. We suggest, therefore that the following options be considered as alternatives:

- The first-best option would be to tighten the Phase 3 EU ETS cap. This would occur if the EU agreed to a 30% reduction in emissions by 2020, rather than a 20% reduction. At

[5] In discussions of the EMR proposals that we have been involved in, potential investors have often stated that it is likely that they would discount a carbon price floor.

present, the prospects for this seem remote, but it is welcome that the UK is lobbying within the EU to negotiate such a reduction.

- An alternative would be to introduce a reserve price in the Phase 3 allowance auctions (Hepburn, Grubb et al. 2006) – i.e. a minimum price at which allowances would be sold. Any unsold allowances should be cancelled, thereby reducing the supply of allowances, tightening the cap, lowering emissions and raising the EU-wide carbon price. Implementing a reserve price in isolation would not create a price floor for UK generators, since they could purchase cheaper allowances from other EU ETS participants, either in the UK or other Member States. However, if several Member States introduced reserve prices, the cumulative effect could be substantial and would increase over time as a greater proportion of Phase 3 allowances were auctioned. This option would raise UK and EU compliance costs, but unlike the carbon price floor, this would lead to actual emission reductions during Phase 3 and raise the likelihood of agreeing tougher targets after 2020.

Emissions Performance Standard (EPS)

If all the other measures proposed in the consultation document work well an EPS at the level currently proposed must also be considered redundant (Q13). The government's preferred option (a limit of 600g/kWh for new plants only) would allow all forms of new generation apart from unabated coal. In practice, given existing requirements on CCS, the likelihood of rising carbon prices and other regulatory risks, investment in unabated coal seems unlikely even in the absence of an EPS. Also, Section 36 of the 1989 Electricity Act already gives the Secretary of State powers to refuse construction of any plant with a capacity >50MW. More importantly, a weak EPS that is inconsistent with the UK's carbon targets signals a lack of political commitment to tackling climate change, and hence could be counter-productive. The EPS also adds further complexity to the policy mix and introduces additional regulatory risks since investors may anticipate the standards being tightened in the future. This could be justified if the standard was expected to deliver additional emission reductions, but at the level currently proposed this seems unlikely. Hence, the EPS should either be dropped altogether or made significantly more stringent.

The proposed 600g/kWh standard is designed to allow CCS to be demonstrated on 25% of the capacity of new, 1600MW coal-fired power stations. The consultation paper argues that a tighter standard would effectively rule out CCS demonstration as it would require more than 300 MW to be abated - a costly option that would discourage investors and achieve little additional learning. But this approach gives the impression of the tail wagging the dog – why should the requirements of the demonstration plants dictate emission limits for all plant for the foreseeable future? A better approach would be to apply the 600g/kWh limit to demonstration plants and impose a tighter limit for subsequent plants.

The, consultation paper also rationalises the EPS as a 'regulatory backstop' to prevent investment in high emission plant. But despite acknowledging that "… over the longer term the UK will need gas plant to be equipped with CCS" (p74), it sees no need to tighten this backstop because: "…other reform measures will provide an effective means to decarbonise the electricity sector." (p74) This argument lacks consistency: if a backstop is needed now, surely it will be even more necessary after 2020 when emission targets are more difficult to meet and the associated costs are higher.

The arguments for grandfathering also lack clarity (Q14). While the principle is endorsed, it only applies to: ".... the period of time investors would expect to see a return on their capital investment" (p73). The aim is assure investors that their plant: "... will not be subject to a tighter level during their economic life" (p74). But it is not clear whether 'economic life' is the same as the "period of time investors would expect to see a return on their capital investment" (p73) , nor is it clear how long these periods would be for different types of plant. As a result, new gas-fired plant may still need to retrofit CCS, restrict operating hours or close, but the point at which this will be required remains unclear.

The arguments made above regarding the environmental impact of the carbon price floor also apply to the EPS. In the period to 2020, the EPS will not deliver any additional environmental benefits since the avoided emissions (if any) will simply lead to surplus allowances that are used by other participants in EU ETS. The EPS can only reduce emissions beyond 2020 if it accelerates the decarbonisation of the GB generating sector - which seems unlikely if it remains at 600g/kWh. Hence, if the government insists on retaining the EPS, there are good reasons for making a more stringent. But since this runs the risk of increasing overall costs and introducing perverse incentives, it would need to be very carefully designed.

Investors will need clear, long-term signals regarding the scope and stringency of the EPS, together with confidence that the regulations will not be arbitrarily revised. The initial and announced future level of the EPS needs to be informed by the Committee on Climate Change's recommendation that the carbon intensity of the power sector should be reduced to around 50gCO_2/kWh by 2030 (Committee on Climate Change 2010) – a significantly more ambitious target than the 100gCO_2/kWh analysed in the EMR. This leaves even less room for unabated fossil plant after 2025 than suggested in the Redpoint modelling. The scope and stringency of the EPS should therefore be increased over time, but the number of 'milestones' should be minimised and signalled clearly in advance. In addition, the same EPS rate should be applied to all generation technologies. Implementing too many intermediate adjustments and different rates for different technologies would risk micro-managing the power sector, and constraining the flexibility of investors to make efficient decisions.

The implications of various options for increasing the scope and stringency of the EPS need to be investigated through detailed analysis. We suggest an initial EPS for any new coal plant that is not hosting CCS demonstrations of around 300g CO_2/kWh, with the EPS being extended to new gas-fired plant no earlier than 2020 and to existing fossil fuel plant around 2025 (Q13, Q14 and Q15). The level of the EPS by that time should be consistent with the expected load factors from unabated fossil plant in a scenario that delivers an average carbon intensity of 50gCO_2/kWh by 2030. The announced extension of the EPS to existing plant should prevent a 'dash for gas' in the latter part of this decade, while at the same time neither inhibiting the investments currently going ahead or those anticipated over the next couple of years. However, we emphasise that the final choice needs to be based upon detailed analysis.

Capacity mechanism

All the other mechanisms in this consultation are designed to accelerate progress towards a de-carbonised electricity system. Proposals for a capacity mechanism are instead intended to ensure better operational and long-term system security. Given that there is no immediate capacity problem and there is potential for policy instruments to interact with each other, often in unintended and unwanted ways, we argue that it would be desirable to postpone the introduction of capacity mechanisms until they are manifestly more necessary (Q19 and Q20).

At present, operational problems seem manageable and there is adequate gas-fired capacity consented or currently under construction to avert any capacity shortage problem for now. .

Nevertheless we comment briefly on the proposals that Government makes. The proposal to make the capacity payment rather specific (targeted rather than available to all generation) seems broadly right (Q22). A universal mechanism would cause a much more fundamental change to the market, for questionable benefits. But a targeted mechanism leads to questions about how decisions will be made about eligibility of plants to receive it. This could lead to gaming behaviour by generators in order to meet the criteria for eligibility – and could end up reducing its effectiveness. The consultation notes the potential for this 'slippery slope' (p94) but discounts it – in our view rather too easily. It is also worth noting that the Government's implicit assumption in the consultation is that to meet peaks in demand, new plant – operating for very limited peak periods – might be constructed. The example quoted is open-cycle gas turbines. While this of course is a possibility, it is historically true that peak demands have almost always been met by old, high running cost plant shortly before its retirement. A capacity mechanism powerful enough to provide incentives for construction of new plant entirely for peaking purposes would almost certainly have to be expensive.

But the key issue here is one of timescale. At the moment, the need for a capacity payment does not appear to be very strong since there is enough capacity being built (particularly new gas plants). But in future, there may be a need for some attention to incentives for new plant that is expected to be run at a low load factors. Seen in this light, the capacity payment may not be required until further down the line and we recommend that it be dropped from the current round of proposals.

Long-term contracts

This set of proposals – designed directly (and hopefully powerfully) to give rise to high levels of investment in low-carbon generating capacity - is by some distance the most important in the consultation. We have argued above that none of the other three proposals is entirely necessary in the forms they are proposed - either for security or, more important, securing investment in low carbon capacity. But we are strongly of the view that introducing effective long-term contracts for low carbon generation is an essential step in de-carbonising electricity generation.

The primary need is for a high level of investor confidence that low-carbon investment has a reasonable prospect of a fair return – while at the same time, from a Government and consumer perspective, avoiding unnecessary windfall gains or inefficiencies. The consultation offers three possible ways forward which are all described as 'feed-in tariffs' rather than as contracts (which would have been a more accurate description). A 'premium' tariff would involve a fixed premium price over the wholesale price of electricity. A fixed feed-in tariff, would be entirely independent of current market prices. Contracts for difference would involve generators being paid the difference between a strike price and the current wholesale price if the strike price were the higher of the two, and paying back the difference if the wholesale price exceeded the strike price.

In terms of economic theory, and on the assumption of competitive market behaviour and adequate market liquidity, there would be clear advantages to contracts for difference (CfDs) on orthodox efficiency and incentive grounds. For these reasons, this is the Government's preferred option. But the problem is how to determine the strike price that would provide the basis for this CfD system. The wholesale market is far from transparent and based on bilateral trading – spot trading is very limited, there are very limited forward and futures markets and therefore there is little or no indication of a basis for determining a strike price. Without addressing these issues, a system of CfDs (or indeed the alternative forms of contract proposed) risks a situation that compounds this lack of transparency.

The Government's answer to this limitation is to propose auctions (Q31), possibly to determine different strike prices according to particular technologies. But in the absence of effective competition – especially in the nuclear case where the overhead costs of getting in to a position to bid are very high and there is presently only one credible bidder – auctions might give inefficient signals, or government may have to resort to the less transparent and less politically credible process of negotiation with interested parties. While limited competition might result in prices at auction that are higher than needed, experience also shows that in more competitive conditions prices may be too low – while this is good in the short term for consumers it is harmful to the development of low carbon capacity. The history of the NFFO for renewables shows what happens when bidders bid too low, and cannot subsequently make their projects work financially even though they have a contract at a guaranteed price (Mitchell 2000).

Given that negotiation is most likely in the nuclear case, because of the restricted field of competitors to engage in an auction, the political problems could be severe. The new system will clearly offer a subsidy to nuclear power (as it will to other low carbon technologies). However, Government's attempt to avoid making this explicit in the nuclear case would be compounded if the main area for negotiation were with the nuclear sector (primarily EDF). This would raise suspicions of sweetheart deals. As the consultation document notes (p113), similar risks may arise with respect to auctions for offshore wind. We are therefore of the view that auctions may only be practical and desirable for a limited subset of low carbon technologies in which sufficient competition is likely and barriers to entry are not excessive. Even if these two conditions are met, the lessons from the NFFO indicate that auctions in practice may not be as desirable as they may appear to be in theory (Q31).

There are also significant issues in the case of CCS. It is not clear how the contracts will interact with the funding mechanism for the CCS demonstration programme. The first demonstration ('Demo 1') is going to be part funded by up to £1bn of up-front support from government. The competition to build this plant is now down to just one potential bidder. This is a difficult situation for the government which once again illustrates the problem that arises when too few bidders are willing to take part in a competitive bidding process. Funding for demonstrations 2-4 will be different. In our view, the government is correct to propose an output based funding mechanism for these demonstrations (Department of Energy and Climate Change 2010). This will provide a better incentive for CCS demonstrations to minimise costs and maximise operational effectiveness (von Stechow, Watson et al. 2011). What is more problematic is the uncertainty created by the EMR process – and the decision to keep open the final form of funding for demos 2-4 while the EMR consultation takes place.

This critique of CfDs in particular and auctions in general does not mean that the other two options for contracts are free of problems. In both cases there is a need to determine the extent of subsidy to be offered, technology by technology, but the problem is somewhat less than in the case of the CfD, because in the latter case a view has to be taken of the future wholesale market prices as well as the degree of subsidy. In these other two cases only the subsidy needs to be pre-determined. In terms of a preference between the premium and fixed tariff, the advantage of the premium tariff is that it retains greater efficiency incentives from the wholesale market price signal that a fixed tariff would not provide.

This premium feed in tariff advantage could erode over time. It would still rely on the wholesale electricity prices to deliver some revenue to low-carbon investors that have contracts. It would therefore be important to set the premium at a level that is not too high so that the wholesale price signal continues to matter to investors. This wholesale price is currently influenced by the marginal cost of fossil fuel. However, the aim is to move away from a system dominated by the short term costs of fossil fuels, which would then (if successful) have a knock-on effect on wholesale prices. This could then lead to a situation in which a greater proportion of generator revenue would come from the premium feed-in tariff, and the importance of the wholesale price could decline.

Based on this discussion, our view is that premium feed-in tariff is the best way ahead because it balances the need for investor certainty and reward with the need to retain competitive pressures (Q4). It should be based on output (Q11). If implemented, the premium feed-in tariff would need to be reviewed after a few years. This will draw on experience and information generated, with the expectation that sooner or later the prices paid to low carbon generators will need to be determined much more closely by the costs of those technologies, rather than (in part) by the vagaries of fossil fuel costs in electricity generation. We make further comments on the need for review below.

Implementation issues

Whilst we recognise that every consultation exercise and reform process needs to be bounded in scope, there are a number of critical issues that are not addressed adequately in the EMR consultation (Q30). In this final section of our response, we highlight three of these: first, the institutional implications of EMR; second, the inclusion of smaller-scale investments in low carbon generation and the demand side; and third, the need for policy flexibility as the electricity system undergoes radical change.

Institutional implications of EMR

The institutional implications of EMR are discussed relatively briefly in chapter 6 of the consultation document. These implications could be far reaching, and therefore require some careful thought. In our view, it is important that the analysis of these implications is conducted now so that institutional questions do not derail or un-necessarily delay the implementation of new policies.

As the consultation document notes, some of the proposals will lead to a much more 'hands on' role for government. For example, the consultation argues that the use of auctions to set levels of support within long-term contracts 'would require Government to determine what share of the electricity mix should be low-carbon and may require Government to have a view on the breakdown of technologies within the low-carbon mix' (p115). Even if auctions are not used (see our earlier scepticism on the practicality of auctions), it will be hard for government to avoid questions about the 'right share' of the electricity mix – both for low carbon options in general and for particular options within this.

Given the likelihood that Ministers will become involved in decisions about the 'right mix' of supply technologies and energy efficiency measures, it is important that some principles for implementation of the reforms are established. As noted earlier, we believe that by far the most important element of the EMR proposals are the proposed long-term contracts for low carbon generation (and possibly energy demand reduction). We favour the premium feed-in tariff over the CfD option for these contracts. With respect to the institutional arrangements for the implementation of these contracts (Q32), our suggestions are as follows:

- Contracts could be administered by an arms-length public body with a remit to maximise transparency so that new entrants (large and small) are able to negotiate contracts without incurring excessive transaction costs;
- Guidance could be provided to this body by Ministers about the desirable volume and mix of contracts to be awarded, and the associated price premiums payable (including any 'degression' in prices over time);
- This guidance should be consistent with the UK's five-yearly carbon budgets and advice from the Committee on Climate Change on future budgets;
- The guidance should include some level of technological specificity (e.g. how much wind, marine renewables, CCS), but should avoid specifying particular variants of particular technologies (e.g. how much of particular types of CCS to be deployed). This will guard against micro-management and will preserve some level of technological competition;
- The guidance should be provided for time limited 'tranches' of contracts that are designed to synchronise with the need to meet the UK's five-yearly carbon budgets. This limit on time horizons will avoid the need to forecast the desirable supply mix too far into the future (always a hazardous pursuit);
- This limited time horizon would also allow a crucial process of evaluation and review (for example of contract price levels) to be built into the arms-length body's activities.

Smaller-scale investors and the demand side.

As noted above, transparency and low transaction costs in the contracting process are very important. This is particularly the case for smaller generators that might wish to take advantage of the contract system, whether they are private firms, community groups or Local Authorities. There is a need to learn lessons from previous institutional and market reforms such as NETA, and their initial failure to take full account of the particular barriers faced by small-scale generators.

The current uncertainty over feed-in tariffs for small-scale renewables provides a clear illustration of the need to think ahead when implementing EMR. If at some future date a decision is made to reduce or discontinue feed-in tariffs for sub-5MW projects, the implementation of EMR needs to be flexible enough so that smaller generators are not excluded. The process of negotiating premium feed-in tariff contracts therefore needs to be simple and clear – and designed to be appropriate for generators of a variety of sizes (Q9).

Similarly, the contracts system also needs to be flexible enough to include demand side actions. The consultation document discusses in some detail the need for demand side actions, both in contributing to electricity system operation and through investment in energy saving measures. However, it is not clear that enough thought has been given to the latter of these potential contributions from the demand side. One possibility is that long term contracts would be available for demand–side investments as well as low carbon supply side investments. Such a possibility should not be excluded from the implementation process.

This leads on to a third, related consideration. As the consultation document notes, there is now a prospect that the IT revolution will radically change our energy system in the future through a combination of smarter meters and appliances, smarter grids, the integration of heat and transport (e.g. electric vehicles) and electricity storage. These are exciting possibilities, but the EMR proposals largely assume a 'business as usual' approach to system development – i.e. large-scale investments in electricity supply capacity to meet demand. There is little thought within the consultation proposals of how these technological possibilities could fundamentally change the relationship between supply and demand. This could call for a more integrated approach to investment and operation which includes supply, demand and networks together. The consultation briefly discussed a 'Regulated Asset Base' model which could be one way to provide appropriate rewards to firms that invest in and operate integrated systems. As the consultation notes (p66), the use of a RAB model would risk a loss of efficiency and competitive pressures. However, further thinking is clearly needed about an appropriate policy framework that could guard against an unnecessarily rigid separation of electricity supply and demand.

Radical change and policy flexibility

The previous discussion has highlighted the possibility of radical electricity system change in the medium to long term. Of course, the reduction in emissions required to meet UK policy targets already implies a radical level of change. The possibilities offered by smart grids, and the prospect of the 'electrification' of heat and transport, simply add to this. But the pathway from where we are now to radically different electricity futures is important too – and needs to strike a difficult balance between flexibility and certainty (Scrase and MacKerron 2009).

As noted earlier, it is hazardous for governments to try to predetermine a detailed pathway for the UK electricity system a long way into the future. Such planning has been tried before in the UK and abroad, and often fails to predict basic parameters such as future electricity demand growth accurately.

It will be important that individual contracts are designed to provide enough certainty to investors over the required timescales. But this does not mean that all aspects of the policy framework can be (or should be) set in stone for many years to come. We therefore suggest an iterative approach to electricity system development which builds in opportunities for policy learning. Such learning could lead to the adjustment of specific incentives (e.g. feed in tariff levels) and/or changes to the wider policy framework (e.g. the need for a capacity payment mechanism). A clear mechanism and timetable for such learning should therefore be built into the implementation of the EMR proposals.

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