Consultation by DECC on Electricity Market Reform

Response by Renewable Energy Systems Group (RES)

RES is one of the world's leading independent renewable energy project developers with operations across Europe, North America and Asia-Pacific. RES has been at the forefront of wind energy development since the 1970s and has developed and/or built more than 5GW of wind energy capacity worldwide, including projects in the UK, Ireland, France, Scandinavia and the United States. We also have a large additional portfolio under construction and in development. RES built its first wind farm in Cornwall in 1992 and since then has built more than 560MW in the UK and Ireland. RES is headquartered in the UK, and is an example of a strong, sustainable British company. We have over 920 employees worldwide and nearly 400 in the UK.

The focus of RES is onshore wind but we have a rapidly growing interest in offshore wind, having developed Centrica's Inner Dowsing and Lincs offshore projects. We are jointly developing their Round 3 project in the Irish Sea. We also have two biomass projects under development and a range of smaller, onsite renewable energy technology companies. Our broad technology base, independent status and international reach means we are well-positioned to comment on the proposals.

We welcome the opportunity to provide comment on the Electricity Market Reform (EMR) consultation. The structure of the support scheme and wider electricity market is of great important to RES as it has a direct impact on our income. Our international experience enables us to compare the current GB market and the Project Discovery proposals with markets and support schemes elsewhere.

The EMR consultation will have a fundamental impact on RES's business in future. Whilst we consider that the RO remains fit for purpose, we recognise there is strong political will to replace it. We are keen to ensure that any new mechanism introduced is workable and will deliver the Government's objectives of securing greater investment in renewables. Whilst we accept that both the Government's preferred Contracts for Difference (CfD) option and second Premium FIT option can be made to work; implementing the CfD will require significant and substantive changes to the whole electricity market.

Headline Comments

1. In the current circumstances a Premium FIT is preferable to a CfD. We do not consider that the market structures needed to make a CfD work can be put in place in the timescales needed.
2. For both the Premium FIT and CfD a fully liquid market is important for the proposals to work efficiently. If a CfD is pursued then a liquid market is an essential pre-condition and reform of the wholesale market should be addressed as a matter of urgency.
3. It is necessary to maintain an obligation, requirement or other incentive on suppliers to contract for renewable electricity until the market is sufficiently liquid for generators to finance projects by selling directly to the market without a PPA. Without such an incentive, we expect suppliers to claim a higher portion of the available rent and consumers will be worse off.
4. If a CfD mechanism is pursued it is vital the CfD references half hourly prices to avoid basis risk.
5. It is not necessary or appropriate for the Government to take on long-term electricity price risk as would be the case under the CfD as proposed, whereby CfD payments would increase if wholesale prices fell.

6. Auctions must not be used to determine support levels; they do not lead to sustainable prices, they create unacceptable development risk, and there is limited competition in important low carbon sectors.
7. New projects should not be forced onto the new system before 2017. Support under the RO must remain a credible and financeable option for new projects until 2017.
8. A one-size-fits-all approach is not appropriate given the very varied characteristics of low carbon technologies. We agree that nuclear will be an important element of the future generation mix and accept the need to facilitate investment. However, it should not be at the expense of lower cost low carbon technologies such as onshore wind.
9. It is necessary to properly consider how best to implement the EMR proposals in the devolved administrations. This appears to have been overlooked in the analysis to date. The market implications in Northern Ireland are particularly significant.
10. Ambitious long-term targets for renewables, currently lacking in the proposals, are required to enable a supply chain to become established in the UK.

We have fundamental concerns over the economic analysis which supported the consultation. We consider that the flaws in the analysis overstate the benefits of a CfD and overestimate the potential difficulties with a Premium FIT. The analysis ignores crucial factors, such as the current structure of the electricity market and the impact of contractual structures. Many of the results are based on arbitrary, unjustified and value-based assumptions. For example the expectation that a 1% reduction in revenue uncertainty leads to a 1% increase in the amount of debt that can be raised is not and cannot be justified in any meaningful way, yet it underpins the whole analysis. Our concerns with the Redpoint analysis are set out in more detail in Annex C.

What further details are needed as a priority?

In order to provide clarification for investment decisions in the near term it is important that the Government moves quickly to minimise uncertainty. Particular points of clarification needed include;

- Confirmation of the type of low carbon support mechanisms to be pursued (a Premium FIT) along with concise details on how the chosen support mechanism will work within the electricity market and any changes to the wholesale electricity market that will be implemented to ensure the support scheme works efficiently.
- Confirmation as to the level of the Carbon Price Floor and how it will interact with imported electricity and in the SEM in Northern Ireland over the longer term.
- Confirmation on proposed changes to the balance mechanism and market liquidity.
- Confirmation that support levels will be set by independent analysis, the process for establishing support and the expectations of wholesale electricity revenues the Government anticipates renewable generators to realise.
- Details on how the arrangements will work within the devolved administrations, in NI in particular which has a different electricity market.
- Full details of the transition arrangements, in particular confirmation from Government that support under the RO will remain a credible and financeable option for new renewable generators becoming eligible until 2017.

- If a CfD structure is pursued then the Government must publish the contractual structures expected and a detailed analysis of the market implications, followed by a further consultation opportunity.

The Government's proposals, as they currently stand, do not allow sufficient time to debate. This gives rise to a significant risk of a badly designed and poorly implemented market change. We ask the Government to give us clear and detailed guidance of the preferred option, an opportunity for further consultation on that option and sufficient time to work towards a full and effective implementation.

RES's Preferred Structure

RES believes that a Premium FIT, based on the support needed to bridge the gap between each technology's levelised costs and the expected wholesale electricity price given the carbon floor price, is the most appropriate structure to deliver the required increase in renewable energy efficiently whilst creating minimal uncertainty while the reforms are being implemented implementation.

We believe that;

- The support levels should be determined by independent analysis of technology costs, not auctions.
- The Government should work towards a fully liquid market such that generators would not need a Power Purchase Agreement (PPA) with a supplier to access the market and financiers have confidence to lend to projects without a PPA.
- Until liquidity is achieved it will be necessary to impose an obligation on suppliers to contract with independent renewable generators. One option is that the cost of supporting low carbon technology should be allocated to utilities according to their share of brown power generation.
- The level of premium should be reduced if low carbon generators' revenues reach a certain threshold for a prolonged period. This would prevent low carbon generators from receiving additional support if the electricity price made that support unnecessary.
- It is necessary for renewable generators to have access to the wholesale market as this would ensure stable power prices over the transition and would enable the lower marginal costs of low carbon generation to reduce wholesale prices as their penetration increased.

The Government's Preferred Structure

If the Government is to pursue a CfD based mechanism, we believe that it will take a significant amount of time, research and reform to establish the market environment in which it can work effectively. If a CfD is introduced it is important that;

- The CfD mechanism must not be over-simplified. The CfD involves complex interactions between the market, traders, supplier and generators. The current analysis does not review these interactions and there are currently no clear contractual structures envisaged.
- Basis risk must be avoided; the CfD must reference half hourly prices. If there is a difference between the PPA reference price and the CfD reference price then there will be potential for basis risk which will undermine the confidence investors have in the CfD strike price. It also creates an opportunity to game the market.

- The CfD must be set as close to gate closure as possible. This will minimise the production risk. Without this, significant price exposures will remain for either the generator, trader or PPA provider.
- Whilst the financial community requires a PPA for financing purposes, an obligation must remain on suppliers. Without such an incentive, PPA providers will inevitably claim a higher portion of the available rent, leaving consumers paying unnecessary levels of support.
- The impact on market liquidity and trading must be understood. The reference period at which the CfDs are struck will focus liquidity in certain trading periods. The Government needs to assess the full impact on liquidity in other trading periods and potential for gaming between periods.
- There must be priority dispatch for low carbon generation.

Further detail on the conditions necessary for a CfD to work are set out in Annex B.

Current Market Arrangements

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

We agree that the high capital cost and low operating costs associated with low carbon generation present unique challenges that the current market arrangements do not adequately address. Within an undefined market the investment choice for the foreseeable future is likely to remain with Combined Cycle Gas Turbines (CCGTs). For renewable generators this has been addressed effectively through the RO which has successfully brought about onshore wind and biomass, and has made the UK the market leader in offshore wind. A similar mechanism may be required to support nuclear and Carbon Capture and Storage (CCS) generation.

The consultation treats all low carbon generating technologies as similar. Whilst it is true that they tend to have high capital costs and low marginal costs the scale of the various technologies creates very different problems. Nuclear in particular faces specific problems due to its scale, cost and lifecycle. A one-size-fits-all approach, across all low carbon generation, would have to work for nuclear as well as renewables. A support mechanism which works for nuclear would not necessarily work for renewables and it would be unreasonable to create a 'low carbon' support which disadvantaged renewables to meet political pressures to avoid being seen to directly subsidise nuclear generation.

Similarly the consultation identifies finance requirements of low carbon generation as a constraint. As an independent generator with onshore wind assets, we have not found the availability of 3rd party financing to be a constraining factor. We accept, however, that finance may be a concern in sectors that have a significant construction risk (offshore wind, nuclear and CCS generation). However the Government proposals do not address this. Revenue risk is a relatively small barrier and with nuclear and CCS specifically it can be overcome effectively by operating as a baseload generator in a well-established liquid trading market.

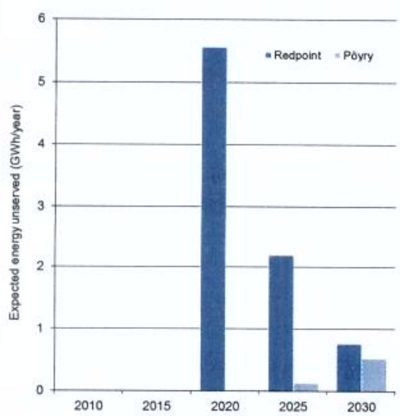
Even with a renewable obligation on suppliers, one of the most important barriers to independent developers entering the market is the lack of liquidity in the wholesale market. The consultation assumes that Ofgem's liquidity review will address this problem. We do not consider this likely given that the initial focus of the review was on the retail not the wholesale markets. It is deeply concerning that the EMR consultation appears to overlook the actual wholesale electricity market. A correctly structured and functioning wholesale market is vital to delivering decarbonisation and security of supply in a cost-effective manner.

Finally, we do not consider that the current proposals will deliver the objective of affordability to consumers. The current bi-lateral market creates substantial scope for inefficiencies. In particular the dependence of many independent generators on PPAs from suppliers coupled by the lack of competition in the market enables suppliers to apply margins which do not reflect the costs incurred. As vertically integrated utilities own a decreasing proportion of the generation capacity the potential for PPA based route to market increases. The potential for suppliers to extract margins therefore also increases.

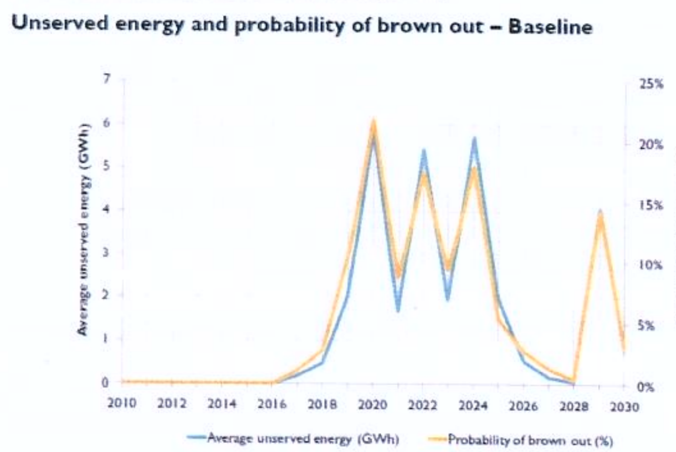
2. **Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?**

We disagree with the emphasis that has been placed on security of electricity supply. This appears to be an important motivating factor for pressing ahead with change at the earliest opportunity but we are concerned that the Government is responding to a hypothetical problem rather than an actual problem. Alternative research by Poyry suggests that unserved energy is not expected to be an issue until 2025 (and then at relatively low levels). This contrasts to the dramatic peak in 2018 suggested by Redpoint.

Estimates of Unserved Energy by Poyry and Redpoint



Poyry Chart



Redpoint Chart

As this appears to be an important motivational factor for the Government's haste, we would request less emphasis is placed on unserved energy and time is dedicated to a more considered approach to market reform.

Options for Decarbonisation

Feed-in Tariffs

3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

No, we fundamentally do not agree with the Government's assessment of the pros and cons of each of the FIT models. The analysis supporting the proposals is fundamentally flawed and creates misleading conclusions. Details of our concerns over the Redpoint analysis are set out in Annex C.

The reductions in hurdle rates expected to result from the reduction in revenue risk are not realistic in particular;

- The results are based on arbitrary investment betas.
- The calculation does not take account of the higher returns required on the remaining equity in a project.
- There is no empirical basis for assuming that a percentage change in revenue risk correlates to percentage increase in debt and this leads us to question how the reductions in hurdle rates outlined on page 56 of the consultation can be achieved.
- The hurdle rate for nuclear is reduced from 13.2% to 11.2% (pg 56). We do not understand the basis for these figures. The starting point of 13.2% is contrary to the Mott Macdonald report cited earlier in the consultation document. Additionally we do we understand the reduction to 11.2% as nuclear is a high capital cost baseload generator and the greatest risks are therefore related to construction costs and time, which are not addressed by the EMR. The benefits therefore appear over-stated.

Given that under a CfD, generators would retain short-term market risk, whereas under a fixed FIT this would be removed, it is not clear how the reductions in hurdle rates achieved from CfDs is the same as those achieved through the fixed FIT.

Furthermore, the analysis ignores many factors vital to the success of the proposals including:

- The structure of the electricity market and the ability of generators to realise value in the market. For example the CfD does not take account of the discounts applied within PPAs or how these discounts will increase if the obligation on suppliers is removed. If this were taken into consideration then we would expect the increase in the PPA discount to outweigh any savings for the consumer and make the whole system less economically inefficient.
- The analysis assumes perfect liquidity in the wholesale market. In reality it is not possible for generators to trade out position in the market close to real time.
- The Premium FIT analysis assumes that investors can only factor in carbon price increases for a maximum for five years. When carbon prices rise for longer than this as a result of the carbon floor price, a double benefit is achieved. Overall the analysis substantially overstates the benefits in terms of investment cost reduction resulting from the CfD and underestimates the benefits of a Premium FIT.

- The CfD appears to be modelled on a different basis to the Premium FIT (which is paid for on availability rather than production). This could distort the results.

- The analysis assumes that there are no hiatus impacts from the introduction of the proposals.

4. **Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?**

We do not agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff. We do not consider that the wider wholesale market structure is suitable to ensure that a CfD can operate effectively or will be reformed by the time a CfD would take effect.

CfDs do not fit with the current market structure

We do not consider it realistic to expect a sufficiently liquid market, whereby generators will not require PPAs, to be developed in the timescales required to make a CfD work efficiently. Both Ofgem's liquidity review and the EMR documents have not placed importance on the wholesale market structure to date.

The current lack of liquidity means that many generators are reliant upon PPAs to access the market. The PPA based structure of the market is likely to mean either that generators will not have revenue certainty, a key requirement for the expected reductions in hurdle rates, or that the support will be unnecessarily high as suppliers will only pass on a portion of the value to generators.

Under a CfD there is a large potential for basis risk

We do not agree that revenue certainty under a CfD is assured as it is currently proposed. Under the proposed structure, generators would remain exposed to balancing risk as an absolute minimum. Unless the CfD is calculated on the same basis as low carbon electricity is ultimately valued (i.e. half hourly) then generators will be exposed to basis risk in addition to balancing risk (this is explained in more detail in Annex A).

Poyry has modelled the likely differences between wind generation weighted average prices and day ahead, week ahead, month ahead and year ahead prices. This represents the expected loss of value a wind generator would realise if a CfD was based on the various different time periods. It is only under half-hourly prices that basis risk is avoided. As can be seen it is not the case that as the time period increases the difference becomes greater; monthly price differentials are greater than annual prices. There is a 6-7% difference between weekly and half-hourly prices. This rises to an 11% difference between monthly and half-hourly, but falls to 8-9% for annual prices. This switch occurs as the price impact on an annual basis is partly offset due to wind having higher output in winter when prices are higher. It should be noted that the figures do not include balancing risk and are based on outturn prices. Any systematic difference between a month ahead and average monthly (ex post) prices would add to the basis risk potential.

It is vital that the CfD strike price references half-hourly prices, as that is the only time period which avoids generators being exposed to basis risk as well as balancing risk.

<u>Poyry forecasts of wind revenue capture discounts relative to baseload prices</u>

Capture prices (real €/MWh)	Hourly contract (GWA price)	Daily TWA contract	Weekly TWA contract	Monthly TWA contract	Annual TWA contract
2010	53.6	53.3	53.3	53.5	53.0
2015	51.1	51.3	51.7	52.3	51.4
2020	55.4	56.2	58.9	61.0	60.2
2025	70.1	71.0	74.5	77.3	76.2
2030	83.9	85.2	90.0	93.9	92.3
		daily TWA price x daily gen.	weekly TWA price x weekly gen.	monthly TWA price x monthly gen.	annual TWA price x annual gen.
Difference from hourly contract (GWA)					
2010	0%	1%	1%	0%	1%
2015	0%	0%	-1%	-2%	-1%
2020	0%	-1%	-6%	-9%	-8%
2025	0%	-1%	-6%	-9%	-8%
2030	0%	-2%	-7%	-11%	-9%

Wind revenue on market

CfD reference price

Incorporating Basis Risk into PPAs

Annex B sets out in more detail our views on what would be needed for a CfD to work. It sets out five possible structures of CfD and the contractual arrangements that might be necessary.

If any time period apart from half-hourly was chosen as the CfD reference point then in order to maintain revenues to generators, this price impact will need to be included within the suppliers' PPA discounts and would have to be incorporated into the CFD strike price (option 2 in Annex B). Under such a structure there would, however, be little incentive for suppliers to minimise their price discounts and such a structure would incentivise inefficiencies.

It is reasonable to assume, given the level and range of uncertainties in the market coupled with their historic behaviour, that suppliers will be risk-averse. They are likely to factor in the worst case for the price impact. Therefore any gains that arise from market improvement (demand side management, storage, interconnections or improved forecasting) which result in lower price discounts arising than had been assumed when setting the discount in the PPA, will directly benefit the supplier rather than being passed onto the consumer.

Restructuring the market so that it provides the liquidity necessary to remove the need for PPAs (option 5 in Annex B) and therefore the potential for uncompetitive PPA discounts is likely to be far more cost-effective.

A two-way CfD as proposed is unproven as a support mechanism

We also question whether a two-way CfD as proposed has been successfully implemented before. We are not aware of a two-way CfD model being used elsewhere and the Government's case studies appear to be examples of how problematic the policy can be. The fact that such a support structure is unproven will create uncertainty amongst financiers, especially in the early years. The sliding premium scheme in the Netherlands was a one-way contract for difference. Generators were not required to pay money back to the Government if the electricity price exceeded the reference. Whilst a two-way CfD could be made to work, the risk of unintended consequences of the system are far greater than under a Premium FIT. At recent European conferences the RO has been set out as an example of good practice by other Member States, as it combines support with a market mechanism. The RO has established the UK as a leading market for offshore wind development and we should not undermine this.

Revenue uncertainty can help balance other downside project risks

We are not aware of substantial concern within industry over revenue uncertainty and are not aware of companies requiring revenue certainty. We seek certainty over the support mechanism and market arrangements, but are confident that we are able to cope with the current level of uncertainty over revenues. Removing revenue uncertainty is not necessarily a positive outcome.

Most of the risks we face as a developer and owner of renewable energy projects are downside risks. That is, there is a greater chance of the risks (usually costs) being worse than our central case. For example, it is unlikely grid costs, operating costs, or business rates are going to decrease significantly, although they may increase significantly. Electricity revenues allow potential for some upside. The potential for electricity prices to be higher than forecast balances out the downside risks. Removing the upside potential from a project leaves it characterised by downside risks. The risk associated with that project therefore increases which would usually require a higher hurdle rate to compensate. This is counter to the general premise of the proposals. As a general principle, those investing in the electricity market are generally the best placed to accept and manage electricity market risk.

5. **What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?**

We do not believe it is beneficial or appropriate to transfer substantial amounts of risk from generators to suppliers or the Government, and ultimately the consumer. There is a cost attached to exposure to such risks but the cost can be minimised by the ability to hedge or mitigate the risk. This is an important component of a liquid and actively traded electricity market, and promoting liquidity will encourage traders that are in a position to manage such risks. The Government and consumers are not well placed to hedge or mitigate such risks, so they are not the most appropriate parties to bear such risk.

There is an implication in the document that a CfD represents a one-way bet for the Government and that electricity prices will rise. As a result signing CfDs which are potentially lower price than the wholesale price is considered a minimal risk. We do not agree with this. Whilst we consider it likely that gas and carbon prices will lead to increases in the wholesale power price, we do not consider this to be a certainty. By not fully considering the implications, or potential costs, of the transfer of gas and carbon price risk from generators to Government and consumers the proposals skate over a key risk with the EMR proposals.

We think that long-term electricity price risk is overstated and that it is appropriate for generators to remain exposed to electricity price risk. Generators are well placed to deal with those risks, certainly better placed than Government, and the opportunity of 'upside' is an important driver for investment.

The inability or unwillingness of some investors to accept carbon price risk appears to be a key driver of the choice of a CfD rather than a Premium FIT. As a low carbon generator our expectations for carbon price and fuel prices are an important component of our investment decision and we do not ask for the consumer to underwrite them.

6. **What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?**

Removing the price element on renewable generation is likely to restrict improvements from improved forecasting, market developments and operational improvements.

Improved forecasting techniques and effective market risk management techniques are the main potential consequence of price signals on low carbon generators. Wind forecasting is currently an area of significant entrepreneurial activity. This could be undermined if the price signal no longer incentivises accurate forecasting.

Similarly the German electricity market experienced a significant number of negative prices during 2009. However, during 2010 these negative prices were almost non-existent due to more effective market behaviour. Whilst there may be limitations on behavioural improvements, there is a risk that excessive regulations imposed at this point will suppress the entrepreneurial responses necessary to bring about the low carbon economy.

Operational improvements include operational efficiency that could be achieved by nuclear stations. In Germany there is evidence of existing stations load-following once exposed to price signals and being able to cycle up and down by up to 50%. The consultation assumes that nuclear is inflexible so these benefits are not expected to be realised under the proposed CfD structure.

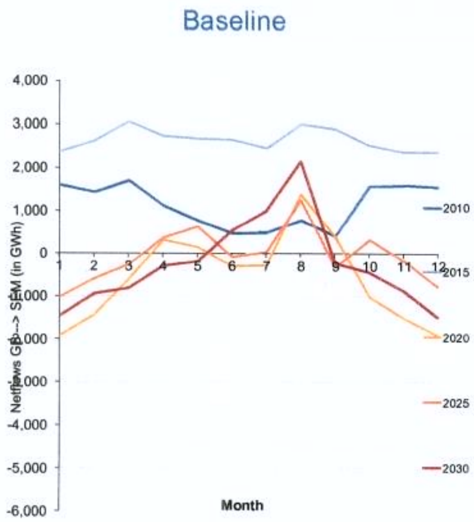
Similarly operational improvements could arise from aggregation, where many wind farms are combined for balancing purposes, reducing the overall balancing cost relative to each wind farm acting as an individual unit.

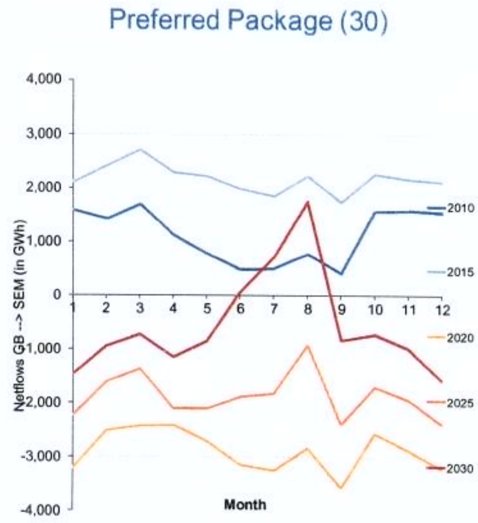
Impact on interconnection flows

Northern Ireland is part of the Single Electricity Market (SEM). It operates as a mandatory pool across the Republic of Ireland and Northern Ireland. Changes which are introduced across the UK will therefore impact the SEM. To date there has been minimal consideration of SEM and NI specific issues. There is potential for the EMR to have a considerable impact on the operation of the SEM. In particular the carbon floor price is likely to have a considerable impact on interconnector flows between the SEM and the GB market.

Poyry has modelled the impact of the EMR and found that interconnector flows are substantially affected by the EMR proposals. As can be seen in the charts below, under a non-EMR scenario (Baseline in the charts below) it is expected that there will be a mix of net flows on the interconnector each month. With the EMR proposals (Preferred Package in the charts below) interconnector flows become much more heavily skewed towards imports to the GB market from the SEM. Constant flows in one direction will severely reduce the benefits of the interconnectors, as it will remove much of the flexibility they were intended to deliver.

Comparison of Net Interconnector Flows between the SEM and GB Markets





Source: Poyry Energy Consulting

7. Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

No, we do not agree with the Government's assessment of the impact of the cost of capital.

The impact of different models of FIT are completely hypothetical and appear to have no empirical basis. Currently as an independent generator we are able to secure more attractive financing terms than are available in many countries that are supported by a FIT. The attractiveness of the financing terms are driven primarily by the market having confidence in the Government's support for renewables. This attracts new and competitive players to the market and with them new debt structures.

Separate to the economic justification outlined in the analysis, the huge regulatory uncertainty that the proposals create is likely to increase the risk associated with projects in the near term and potentially in the longer term. This would increase the cost of capital for those investments. This regulatory uncertainty has not been considered in the analysis and as a result has not been taken into account in the consideration of the costs and benefits of the various proposals.

We consider that the extent of the reduction in hurdle rate possible from increasing the amount of debt has been overstated. The impact of increased returns required on the hurdle rate has not been considered nor has the impact on equity significantly reducing or negating the increased debt impact.

By removing the potential for upside on the electricity price a CfD can negatively impact the risk balance for an individual project. Most uncertainties faced by a project are downside risk. Wholesale price uncertainty includes a certain amount of upside risk, i.e there is a very low probability but high potential for prices to increase above forecast levels. This helps balance out the downside risks within a project. By removing the upside potential a project's risk profile would shift towards downside risk. A project characterised by mostly downside risk would be subject to higher hurdle rates than a more balanced portfolio of uncertainties.

8. What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and the existing investor base?

The Government's proposals will have an adverse impact on the availability of finance to the low-carbon electricity sector. The investment community needs clarity of Government objectives, support mechanisms and contracts more than revenue certainty. The CfD will be a highly complex mechanism, far more complicated than the consultation document suggests, which will not provide revenue clarity or contractual clarity. The implementation and transitional difficulties are already leading to a financing hiatus; the more complex the system that replaces the RO the greater the likelihood of a prolonged investment hiatus.

We agree that there is a need to attract greater amounts of post-construction finance into the low carbon sector. However, it will still be necessary for developers to take on development and construction risk, as these stages in a project's life are subject to far greater risks than the post-construction phase. In addition, development and construction of offshore wind will become more risky as projects are developed further offshore. It is vital to ensure that the development and construction of projects can attract finance as well as the post-construction phase. The availability of development and construction financing will not be improved by the CfD.

The CfD as proposed will not lead to revenue certainty for generators due to the potential for basis risk and, in the current market, for suppliers to overprice this basis risk in PPA discounts. As a result we do not consider that financing will become more readily available.

In addition the current proposals, and in particular the proposals to auction the support mechanism, will undermine the case for development of assets. Current development costs for a single onshore wind farm are around £1.3m and this increases to £2.3m if the cost of unsuccessful sites are taken into consideration. For offshore wind, the development costs are many times higher, at around £75m. These risks and expenditures need to be recognised if development is going to continue.

We believe that a Premium FIT, whilst still requiring reform of the wholesale market and an obligation on suppliers to contract, can be implemented more easily than a CfD based FIT. The mechanism is closer to the current system and Premium FITs are relatively well established in other markets. Their simpler and proven structure would enable financiers to have confidence in them more quickly.

9. What impact do you think the different models of FITs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

We would expect vertically integrated utilities (VIUs) to be able to secure more benefits from the CfD or premium FIT than independent players. Due to the lack of competition and liquidity in the current market, independent generators are required to enter into PPAs which cede material value to the dominant VIUs. The VIUs do not face this loss of value and so are able to realise the full value available. Under a fixed FIT, because there is no need for a PPA, the full value could be realised by generators.

A market, or support structure, in which independent generators are dependent upon a contract with suppliers, will continue to undermine generators' position in the market. If it is the Government's intention to have institutional investors owning generation assets, it will be vital that there is a viable position in the market for independent generators. If the market cannot be easily accessed by independent generators then the capacity owned by the infrastructure funds will not be able to thrive in the market and will not be an attractive investment prospect. To enable new entrants into the market it is necessary for the wholesale market to be made much more liquid and competitive.

The RO was instrumental in securing access for independent generators. However, even with a legislated obligation, the VIUs did not offer full value for ROCs (typically 5-10% is retained), so one can readily surmise that without any form of obligation, access for independents will be extremely constrained without significant market reform.

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Greater liquidity in the wholesale market is fundamental to the effective and efficient operation of a CfD or Premium FIT scheme. We are very concerned that the EMR has not addressed the market liquidity issue in sufficient detail and has passed responsibility to Ofgem. This presents a significant risk of introducing a system with scope for substantial inefficiencies and unnecessary costs built into it. Ultimately it should be possible for new low carbon projects to raise finance without a long term PPA from a VIU.

It is very important that the CfD references half-hourly prices to prevent basis risk under a CfD [see Annex A for further justification of the need for half-hourly reference prices]. If the CfD was based on daily, weekly, monthly or annual prices there would be potential for the market value captured by wind generators to be lower than the market price reference of the CfD. As a result generators would not achieve revenue certainty from the CfD. It would be important that all low carbon generators supported by a CfD trade into that market.

11. Should the FIT be paid on availability or output?

We believe that a FIT should be paid primarily on output. It is possible that paying some support for availability would avoid incentives to bid negative prices into the market. Whilst this would avoid unnecessarily high payments from consumers under a CfD, it remains to be seen whether this would outweigh the benefit of strong price signals arising from output-based support. Further modelling would be needed to determine the optimal split between availability and output-based support.

Emissions Performance Standards

12. Do you agree with the Government's assessment of the impact of an emission performance standard on the decarbonisation of the electricity sector and on security of supply risk?

We agree that coal stations should be required to reduce their emissions if they are to play a role in the generation mix in future, given the current definitions we do not consider the levels proposed (600g CO_2/kWh and 450g CO_2/kWh) in the EPS to be sufficiently tight to impose a constraint. These limits appear to be predicated on coal continuing to operate as a baseload generator and it would not require substantial reductions in load factor to enable new unabated coal stations to adhere to the limits.

The Government should clarify that the calculation of the annual emissions of a plant running baseload is at 80% load factor rather than 100%. The emissions levels permitted on the expectation of 100% operation could be achieved through minor reductions in operating patterns.

The EPS must not be seen as an alternative to the requirement to demonstrate CCS as part of the consenting process. It should strengthen it, rather than replace it. Furthermore we do not agree with the suggestion in the consultation that CCS coal will be flexible capacity; our expectation is that the economics of CCS coal will require it to have very high load factors.

13. Which option do you consider most appropriate for the level of the EPS? What considerations should the Government take into account in designing derogations for projects forming part of the UK or EU demonstration programme?

Without clarity on the method of calculation it is impossible to say what the most appropriate level is for the EPS. As it is currently stated we do not expect it to be a binding constraint at either level and therefore consider 450g CO2/kWh to be the most appropriate level for the EPS.

14. Do you agree that the EPS should be aimed at new plant, and 'grandfathered' at the point of consent? How should the Government determine the economic life of a power station for the purposes of grandfathering?

We agree that the EPS level should be grandfathered at the point of consent. For a coal station the economic life should be 20 years. After that point it would be reasonable to impose tighter EPS controls as the load factor of a plant more than 20 years old would be expected to be lower, so meeting the requirement from reduced operating hours would be possible. We agree that it should only apply to new plant and life extensions and upgrades.

15. Do you agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions or upgrades? How could the Government implement such an approach in practice?

We agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions. The definition of significant life extensions could be based on a set range of upgrades, or replacement of certain parts.

16. Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

We agree with the approach.

17. How should biomass be treated for the purposes of meeting the EPS? What additional considerations should the Government take into account?

Biomass should be 'zero rated' under the EPS, with minimal reporting requirements to avoid unnecessary administrative burden. Biomass co-firing should also be zero rated but co-firing should not be supported separately as the carbon price support and EPS requirements are likely to create sufficient incentive for co-firing economic without support.

18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

Exemptions to the EPS should only be made in the event of short-term security of supply events and any emissions in excess of the EPS levels should be recovered the following year.

Options for Market Efficiency and Security of Supply

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

We believe that the focus on capacity rather than flexibility is misplaced. Ensuring sufficient flexible capacity is delivered removes the need for a specific capacity margin to be achieved. Focussing on flexibility should also enable the demand side to more easily offer services to the market. This is likely to reduce the cost of ensuring security of supply.

We consider that a capacity mechanism that was targeted, with payments separate to the market price, would provide the optimal solution. We would prefer to see a capacity mechanism which reduces imbalance volatility. Balancing risk is likely to be a residual risk that a CfD will not address. It is therefore important for it to be minimised if possible. Although reducing balancing mechanism volatility would distort imbalance prices, this would, in itself bring benefits in terms of imbalance risk reduction.

A mechanism which led to capacity that was rarely used, such as would occur under a capacity of last resort, with potential for bids to be priced at the value of lost load, would not be good value. It would be preferable for a mechanism to provide flexible capacity that was used relatively frequently.

20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

We are strongly supportive of a separate capacity mechanism. In particular a capacity mechanism which led to reduced imbalance price volatility would bring benefits in other areas of the market.

In the consultation document the Government alludes to Ofgem's proposal for centralisation of variable renewable generators within the balancing mechanism. This form of aggregation could have a significant and beneficial impact on the balancing exposure of renewables and other generators. It should be explored as a more central part of any proposal and considered alongside any improvements to liquidity.

21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

A targeted mechanism, under which flexible plant bid in its short-run marginal costs to the balancing mechanism, could create less volatility in balancing prices. Whilst this would distort the market we believe that the benefits it would bring in terms of reduced imbalance risks would justify such a move.

22. Do you agree with Government's preference for a the design of a capacity mechanism:
• a central body holding the responsibility

We believe that it would be preferable to have a central body with responsibility rather than a devolved responsibility on suppliers or the market in general. However their remit should also take into consideration the flexibility of plant (or demand) that is available to the system.

• volume based, not price based

We agree that it would be preferable for the mechanism to be based on volume.

• a targeted mechanism, rather than market-wide

We agree that it would be preferable to have a targeted rather than market wide mechanism.

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

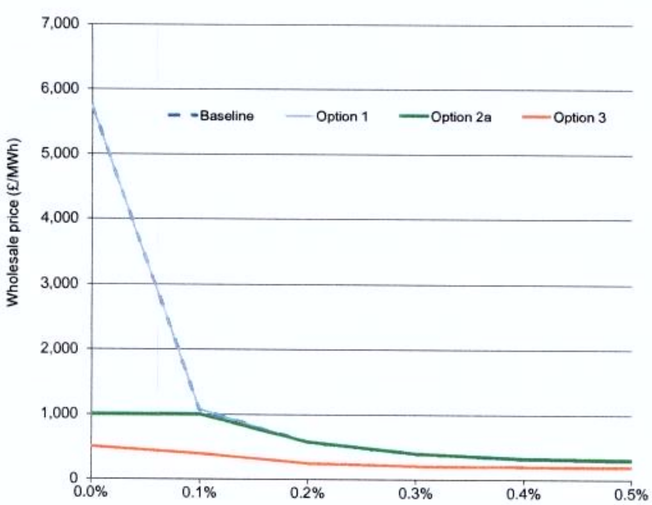
We support the proposed approach of a targeted capacity payments mechanism. Our preferred option would be for a targeted capacity mechanism which led to flexible plant being used relatively frequently. Modelling by Poyry suggests that such a mechanism would reduce price volatility, which would reduce the extent of wind revenue cannibalisation. The proposed mechanism would lead to a relatively high level of price distortion, as it would reduce price spikes. We do not believe that an approach which seeks to avoid price distortions above all else is reasonable. Whilst the dampening of price spikes constitutes distortion, it brings benefit as well. Reduced price spikes means less volatile prices and, as a result, less severe wind revenue cannibalisation.

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:
• Last-resort dispatch; or
• Economic dispatch.

An economic dispatch model would be preferable to a last-resort model. Paying for capacity which was only used in exceptional circumstances would not be good value to the consumer and if it was required to recover its full capital costs during the hours that it was running then it would also lead to more volatile prices in the balancing mechanism.

Whilst economic dispatch may introduce a greater level of distortion into the market this mainly occurs at times of very high prices and a very short proportion of the year. It is our expectation that economic dispatch based on short-run marginal costs (Option 2a in the chart below) will reduce overall volatility within the market and have a generally beneficial impact.

Estimated Maximum Wholesale Prices under the EMR



Option 1: Value of Lost Load, last resort

Option 2a: Economic dispatch based on short run marginal cost (includes capital cost recovery)

Option 3: Economic dispatch based on long run marginal costs

Source: Poyry Energy Consulting

25. Do you think there should be a locational element to capacity pricing?

No, we do not consider that a locational element of capacity pricing should be introduced.

Such a mechanism would be highly complex and would send distorting signals to the market and could deter from making longer-term investment decisions in upgrading the grid in favour of a short-term capacity fix.

Analysis of Packages

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

The question is misleading as the Government's preferred package is stated as package 3, which includes a CfD and not a Premium FIT.

We agree that a package of different measures is needed. Given the range of different objectives for the electricity market, it is not reasonable to expect one individual policy or mechanism to deliver it all on its own. We do not, however, consider the current analysis to be sufficiently rigorous to allow us to support a particular package of proposals. There are many potential unintended consequences, and the details of how each proposal will work and the market environment into which they will be imposed are currently undefined.

As outlined above (and elaborated on in Annex B) we have considered a number of different ways in which a CfD could be implemented. In order for a CfD to operate efficiently, avoiding unnecessary costs to the consumer, it is vital to have a highly liquid market, with generators having direct access to that market, without a need for a PPA with a supplier. Such substantial changes to the wholesale market arrangements are not currently being considered by DECC and we do not consider the necessary market conditions will be in place, in the timescales required, to enable a CfD to work effectively.

We believe a package comprising a Premium FIT for low carbon generation, carbon price support, EPS and flexibility mechanism would be preferable the Government's preferred package. However we need to see more robust analysis, particularly with regard to market liquidity. In particular we are concerned that a 'one-size-fits-all' approach to renewable support may be inappropriate and damaging.

In the absence of a liquid market it would be necessary to have a strong obligation or incentive on suppliers to contract with renewable generators. At present, when there is a strong incentive for suppliers to contract for renewable energy; suppliers retain a proportion of the market and support value in return for entering into contracts with renewable generators. There is a substantial risk that once the obligation on suppliers is removed, as would be the case under the proposals, that the discounts applied in PPAs would increase.

RES currently sees discount levels around three times higher in the UK than in Nordpool, the highly liquid Scandinavian market. We believe that other, smaller, generators face larger discounts than us. Any discount above the actual price of risks exposed or costs incurred under such a scheme represents unnecessary costs. The consumer would be paying higher than necessary strike price, or Premium FIT to cover suppliers' unjustified discounts. We do not consider that consumers will be prepared to pay for supplier discounts in the long term, and that further market reform will be needed in future.

Any market arrangements which do not address the problem of the lack of liquidity and the ability of the VIUs to extract value as a result of their market power are not sustainable in the longer term. It is therefore vital that these issues are addressed at the outset.

Finally, we would expect that any potentially beneficial packages could be completely undermined by the use of auctions. We do not consider, under any plausible circumstances, that auctions could successfully be used to determine the level of support provided.

27. What are your views on the alternative package that Government has described?

We consider that the alternative package, with a Premium FIT as opposed to the CfD based FIT, is a more workable and simple solution. Premium FITs are simple and well understood by financiers. The level of support is transparent. More detail on our views of a premium FIT and the conditions needed to ensure it works efficiently are set out on page 3 of this response.

With a premium FIT it would still be necessary to ensure liquidity in the market in the longer term to ensure an economically efficient outcome in the long term. However, because a Premium FIT is more similar to the current mechanism and simpler to implement, much of the uncertainty and hiatus likely with a CfD could be avoided.

28. Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

We are very concerned that the level of analysis has not been sufficiently detailed to fully assess the wider impacts on the electricity system given the significance of the changes proposed. It is difficult to identify or anticipate the wider impacts that may occur without robust analysis involving many parties and analysts. In addition, a full set of proposals that include proposals for liquidity and contractual details should be made available for full industry discussion.

29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

We would expect the carbon price support to increase the wholesale electricity price. This would reduce the size of the premium required under a Premium FIT or, under a CfD, reduce the level of the top-up payments needed.

The proposed changes to the cashout regime would make balancing prices sharper, but this could be at least partly offset by the choice of capacity mechanism.

Implementation Issues

30. What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

There is significant implementation risk for the Government's preferred package relative to a Premium FIT. The main implementation risk of a CfD is that the wholesale market is not made sufficiently liquid and generators remain reliant on suppliers' PPAs to access the market. Combined with the proposed removal of the obligation on suppliers, this would lead to increased PPA discounts. The impact of this would be that the increased discounts are incorporated into the CfD strike price and that the cost to consumers will be higher than it needs to be. Such an economically inefficient outcome will not be sustainable in the longer term and will require further reform at a later date.

Given the scale of the changes required for the Government's preferred package, there is a very significant risk of non-delivery. If there is uncertainty surrounding the Government's ability to deliver these fundamental reforms effectively then this will have a detrimental impact on both the development and the financial community which could jeopardise investment in both and the provision of broader support services.

There is a significant risk that if support levels are determined by auctions, the prices derived in the auctions would not be sustainable. This could lead to a collapse in renewable deployment, as witnessed in the successive NFFO rounds in the 1990s. In the last NFFO auction round, only 5% of the capacity contracted was built. Whilst the NFFO auctions appeared very successful at reducing prices, it was at the expense of deployment. It is not clear how any auction process could work for emerging technologies or nuclear.

The final risk is that the scale of changes proposed in the EMR creates potential for existing contracts to be renegotiated or terminated. Whilst the current availability of details are insufficient to effectively assess this risk, the loss of the obligation on suppliers and the carbon floor price both have potential to constitute material changes to the market and could trigger reviews. The Government should be very careful to ensure any changes are implemented so as to minimise the risk of force majeure.

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?
• Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?

Auctions and tenders cannot deliver sustainable competitive prices. We are absolutely opposed to auctions as a means of setting support levels. As witnessed in the successive NFFO auctions in the 1990s, auctions can drive down prices, but the race to the bottom leads to prices falling to unsustainably low levels with full recovery of development costs (including unsuccessful projects) unlikely to be realised.

The two auctions cited in the consultation documents largely failed. Bids into the auctions in the Netherlands were higher than expected, which resulted in less capacity being awarded contracts. The scheme has since been abandoned for offshore wind. The scheme in Denmark had only one bidder. This is also not considered a successful scheme.

The timing of auctions is very difficult. An auction early in the development process is likely to have poor cost or energy yield information, so there is a risk that bids are too high or too low to account for unexpected cost changes arising later in the development. Alternatively, if auctions are held post consent, it creates substantial development risk.

Development spend (prior to construction) can be up to £75m for a large offshore wind project. Developers will not commit such substantial amounts of money if there is a risk that the fully consented project might not secure support, or if there is uncertainty over the level of support it would receive. In addition post-consent auctions, whilst having more accurate cost information, are likely to treat development costs as sunk costs (for that individual project as well as others in the portfolio which fall away), and not reflect these costs in the auction bid. If bids do not reflect development spend the prices derived will be unsustainable as future development costs will not be covered.

It is not reasonable to introduce auctions for offshore wind projects that have already signed up to delivery conditions for their seabed lease.

We see no credible way that support levels for new nuclear stations could be set by auctions. The low number of participants in the auctions would make it impossible to secure sufficient competition in the auctions. Given the Government's obvious need for new low carbon capacity to be built, the threat of not accepting unreasonably high bids is not credible.

- **Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?**

<u>Auctions/tenders should not be used</u>.
We do not expect auctions or tenders to be workable under any circumstances, whether they are technology neutral or technology specific. If they are technology specific there is a risk that there would be too few bidders to secure any meaningful level of competition. There are only three consortia of nuclear developers. The published estimates of when the new nuclear stations will be operational suggests there would be minimal competition between different developers. As a result it is not reasonable to expect that an auction with only one or two potential bidders, in which all participants would know the number of other potential bidders, would deliver competitive prices.

If auctions are multi-technology, bids would have to reflect a multitude of technology specific issues. It is unlikely that the price realised could be meaningful for many of the technologies included. Both arrangements are too substantially flawed to work in practice.

The level of support must be defined by fully evidenced, independent analysis which is open to scrutiny and consultation by market participants.

- **How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?**

To be clear, this question only becomes relevant if the Government is committed to implementing auctions and we do not, under any circumstances, consider auctions to be viable.

We agree that it is important that levels of support reflect each technology's costs. If the level of support is set independently by analysis through independent consultants then the structure of the contract is determined primarily by public perception and whether it is politically acceptable to present nuclear as being directly subsidised or not.