We have given more detail on our preferred solution, along with a critique of DECC's proposals and further potential solutions in our answers to the specific questions below.

Please could you provide a summary of your experiences with the PPA market over the past three years? Specific areas for which detailed information would be particularly helpful are set out in the Annex.
The market has recently been affected by regulatory uncertainty, including the unknown outcome of EMR and increasing imbalance risk, which is likely to have resulted in some potential buyers requiring higher discounts when buying PPAs. However, this has not prevented a number of new providers entering the PPA market during this period, demonstrating that there remains an appetite to provide PPAs. We have heard in public forums that some independent generators have found fewer potential providers for PPAs. The increased risks for providers, and the consequential impact this may have had on the risks carried on balance sheets and so ability to offer PPAs, may help to explain why this has occurred. This highlights the danger of imposing a short-term regulatory solution on the market.
Have you seen significant changes to the PPA market over the past three years, and if so, what do you think has driven this? If you have asked PPA providers for explanations of why changes have occurred, what reasons have been provided?
There have been no major changes in the structure of the PPA market itself in the past three years, though the drivers on players in that market may have changed as described above. Over the slightly longer term, since the financial crisis the treatment of PPAs by funders and credit rating agencies has started to change. In particular, the onerous credit terms that PPA providers are now typically required to accept in order for developers to attract funding has placed further risk on potential providers. PPA providers will have assessed the wider balance sheet and credit rating implications of these changes and this may have reduced the number of potential providers in the market place while discounts are at their current level. It is worth noting that as CfDs provide certainty of income per MWh generated, so long as a generator can achieve the market reference price, our expectation is that banks will not require the same level of credit terms from PPA providers as under the Renewables Obligation (RO).
How does the GB market for PPAs compare to other international markets? If you operate in other markets, how do PPA structures and terms differ? If terms differ what are the drivers behind the differences?
The UK PPA market is different from that in other markets where E.ON has a major presence and so we do not provide PPAs in the same manner in other European markets as in the UK. Accordingly we are not able to compare these markets on a like for like basis. However, we do operate in many European markets and are able to provide some comparison of the drivers

from the perspective of a renewable generator and a trading business.

The major driver for the differences in the sale of renewable electricity between different European markets is due to the differences in renewable support mechanisms. For example, in the German market support is delivered as a feed in tariff, so that transmission companies are obliged to buy renewable electricity at a set price – effectively a PPA and subsidy in one. The cost of this is then passed to suppliers and hence customers via a pre-set charge.

One major difference, even in markets where support is provided via a form of obligation (e.g. Sweden) or Contract for Difference (e.g. Denmark) is the potential cost of imbalance. Imbalance costs are driven by unexpected deviations from the expected level of generation and supply and, as the result of a statistical distribution, are dependent on the size of the power system and correlations in supply and demand disturbances within that system. With the UK both geographically smaller and with a smaller and less interconnected power system than continental Europe, the difficulty of balancing the UK system is always likely to be larger and so the risks around (even if not current costs of) imbalance will always be greater in the UK.

Despite the lower risk, imbalance costs have been specifically considered in setting support levels in Denmark, Spain and Belgium (and a separate premium is paid to wind installations in Denmark to cover these costs). In Italy, renewable generators are excluded from paying for imbalance (though this is under review). We believe it would be advantageous if the UK government were to also consider in more detail these costs in the support levels offered to intermittent forms of renewable generation.

The combination of factors considered above means that selling the output of renewable, and particularly wind, plant will be lower risk in many other European markets. This will both lower the need for PPAs from the perspective of some generators and lower the risk in taking a PPA from the perspective of a provider.

What are the factors preventing or encouraging participation in the GB market? How (and why) do you expect these to change over time?

The factors which affect participation include the size of the market, regulatory and market certainty, and how contracts are treated by accountants (e.g. potentially as a derivative) and credit rating agencies. As explained in our introduction, the level of risk in the market is a key determinant of how attractive that market is for a given level of expected profit.

The GB market has frequently been and is currently subject to significant regulatory and political uncertainty. This creates an environment in which the scale of commercial risks being taken within a contract cannot be fully understood. In particular, for a buyer of PPAs, the level of risk associated with that purchase will be significantly dependent on the total level of wind generation on the electricity system. Increasing levels of wind generation on the system depress power prices and increase likely imbalance costs (at least for wind) during periods when it is windy. As a result, the level of risk in purchasing a PPA is increased by the political uncertainty around the future of our electricity system.

That said, the risks around market price for the generator should be removed by the introduction of the CfD mechanism (see our answer to the later question). However, the risks around balancing will remain.

Considering balancing further, the cost of imbalance is also subject to more specific risks, both regulatory and technological. Technological risk is unavoidable and will arise in any situation where the cost of a specific service is expected to rise; innovators and entrepreneurs will always look for new solutions to tackle a growing problem. The regulatory risk is, in principle, avoidable, but it is currently seen as very significant. As an example of this, the rules which determine imbalance costs have been subject to repeated interventions:

2001 – 3 changes (Adjuster for Option Fees; De minimis tagging; CADL tagging)
2003 – NIV tagging
2005 – Removal of emergency instruction from calculation
2006 – 2 changes (PAR of 100MWh; PAR of 500MWh)
2009 – System flagging and replacement prices.
2012 – Electricity Balancing Significant Code Review

Even the regulatory philosophy of imbalance costs is not clear, with recent changes targeting more volatile penal payments, whereas this consultation implies reduced risk for renewables which suggests smearing of costs. Market participants see this current uncertainty (and expect it to continue whatever decisions are taken in the near future) and will seek to incorporate this within their forecast of the future cost of imbalance, even if they can account for technological risk.

Operating in such uncertainty, participation in long term agreements which require transfer of these costs is always likely to be more limited than would otherwise be the case. Significant risk premiums will be required in order for any PPA provider to whom the risk would be transferred to sign that PPA.

Do you expect the EMR package to change the PPA terms that you might offer/receive and if so how do you believe they will change? What do you think is the primary driver for these changes?

Yes, we would expect generators to need very significant change in the terms of PPAs for renewable projects as a result of EMR and the introduction of CfDs.

PPA terms that have typically been offered under the existing RO regime include:

- offering power price certainty to independent generators in the form of floor type arrangements within the contract;
- a price for green certificates covering the ROC (including Recycled Benefit) and Levy Exemption Certificates (LECs);
- managing imbalance exposure for generators including the provision of a range of services from the day-ahead stage to gate closure and settlement.

Many of these services will still be desired by independent generators under EMR, particular around the management of imbalance risk. However, the replacement of the RO with Contracts for Difference (CfDs) means that there will no longer be a market for new long term ROCs. Most significantly, generators will no longer want to achieve price certainty on the power price. Instead, generators without their own trading business will want a guarantee of achieving the Market Reference Price for associated with their CfD.

Offering access to the Market Reference Price (MRP) through a market access agreement of some form (e.g. as an agent) is relatively easy for a sophisticated trading business. The cost of this access will vary depending on the MRP chosen and, if the reference price is hard to achieve, costs will rise. However, so long as the MRP is set through a clearing price day-ahead auction such as the one conducted by N2EX, we would expect the cost of access itself to be relatively low. Taken alone, this would be likely to increase competition for provision of access to market. However, risks around the imbalance cost will remain and (as discussed above) are likely to grow.

One of the concerns raised by independent generators has been the need to find a buyer for their product under EMR, therefore needing a PPA. However, provided the MRP is set through a day-ahead clearing price auction, any generator placing an unpriced offer into that market will receive the clearing price of the auction and would be guaranteed to sell its product without the need for a PPA. As CfD generators' income is set by the sum of the energy and difference payment, all CfD generators will become price takers in the auction and could choose to give their energy away without any financial impact. Through this mechanism, the market (or the system operator on shorter timescales) will effectively be obligated to take whatever generators produce or constrain it off – paying the appropriate price. We can understand that independent generators without a trading business may still need to secure a contract for access to market, but do not believe that this must be in the form of a PPA.

Aside from the direct implications of EMR, there is additional uncertainty around imbalance created by the proposed Significant Code Review (SCR) into electricity balancing and the long history of intervention in these mechanisms. The current intervention into gas balancing regulations will also have, as yet unknown, consequences for the electricity market. Strengthening of market signals for generators being out of balance may be the right outcome from a holistic energy policy perspective, but it will further increase risk for providers of PPAs. This will either be priced into the contract or, if the risk becomes too great, may result in some potential market participants choosing not to enter (or even to leave) the market. Should this happen, the discount which has to be paid by a generator to secure a PPA is likely to increase further.

Even given the general high level of regulatory risk, the uncertainty due to EMR and the heightened uncertainty due to the SCR are transitory. Accordingly, there should be no read across from the PPA market seen today to what might emerge once EMR is operational and the market is more certain of its future. Any pre-emptive action risks stifling potential market solutions that may emerge.

What has been the determining factor in selecting a preferred PPA and PPA provider?
Striking a balance between risk and reward. Where risks cannot be adequately understood or managed, offering a PPA cannot be justified commercially.

Have you seen a change in investment returns as a result of the changing nature of PPA terms and can you provide an example, how this has been calculated? Do you expect the EMR package to change investment returns, and if so what is the driver for this?
Since the first PPAs signed alongside the introduction of the RO, as a provider we have seen the value to us of PPAs fall over time. This has reflected the greater competition brought about by the increased certainty and knowledge gained over that period. More recently, the credit terms independent developers have required from PPA providers have become more onerous since the financial crises began in 2007. In particular, we have seen greater demands for floor prices on the power price offered under a PPA; offering such terms would significantly increase the level of risk which we would have to manage. Together with decreasing reward, this has made the provision of PPAs less commercially attractive.

Options to achieve the Government's objective

What are your views (costs, benefits and risks) on the potential options discussed in this call for evidence that may be necessary to achieve the Governments objectives?
Looking at the specific proposals made by government in the Call for Evidence: **Market-led initiatives** Given the bespoke nature of PPAs and the differences in risk between different technologies and projects, reaching a transparent menu of costs and/or contractual terms is unlikely to be simple to achieve. Both parties to the PPA will have different requirements in terms of the mechanics and underlying commercial risk sharing and these must be matched for each individual case. The fundamental problem appears to be one of small scale generators seeking to shift their own risks on to the balance sheet of today's large suppliers and an unwillingness to pay the cost of doing so (possibly due to a lack of realisation of the resulting cost to those suppliers). Providing the kind of certainty these generators are seeking involves a risk transfer, the price of this must be left to negotiation. It is not appropriate for government to intervene to distort the price paid for these risks, unless it is willing to underwrite that risk fully through a government backed entity. The power market will take the power produced by the least cost producer. As CfD generators

could give their power away at auction (if this sets the MRP) without impacting the total income received, true PPAs do not appear to be a real requirement.

Competition Measures
The measures outlined by DECC are short-term market actions taken by Ofgem and we are not clear that any can be effective:

- It is unclear how improving liquidity would directly aid the PPA market, given that liquidity in forward markets is unlikely to ever approach the duration necessary for a PPA – some 10 to 15 years.
- Cash-out reform could indeed lower the balancing risk in coming years; however, this is likely to come at the cost of dampening the efficiency of the wholesale market and would be likely to come at a net cost to customers. Furthermore, the frequency and degree of change we have seen in balancing rules in the past means that PPA providers would not be able to entirely discount this risk even were it to reduce temporarily. However, it is possible that some minor changes might be found which would reduce the renewable risk without damaging efficiency.
- We are not clear what realistic steps could be taken to encourage independent aggregators into the market which would not also aid the provision of PPAs at lower cost by existing participants.

Though some regulatory change might be beneficial for PPA availability, the very fact that such regulatory interventions are relatively common in the UK market highlights the very regulatory risks which add to the cost of any fixed price PPA (whether power price or imbalance price).

If Government believes that an independent aggregator will be beneficial to achieving its objectives, it should establish such a company and a mechanism for transferring costs to the suppliers of the day based on their market share – to include all suppliers.

Regulatory Measures
As discussed in our introduction, we do not believe that an obligation on suppliers would be either effective or justifiable given the scale of the problem and its impact on those suppliers. Furthermore, we do not believe that it is sensible to target one subset of suppliers that happen, in 2012, to be part of large companies with both generation and supply businesses. In order to fund investments in renewables, contracts would need to have durations of greater than ten years (from an investment decision, through construction and operation); on such timescales it is probable that at least some of today's large suppliers will have changed ownership, shrunk or both and hence be even more inappropriate as the counterparty to a PPA. Any such treatment would be unfair discrimination in favour of other suppliers, who could conceivably become larger in scale or financial strength during the duration of any PPA.

Even if an obligation were proposed, it is not clear how it could work. If suppliers were obligated on the basis of market share, how would this be measured, and how could contacts be allocated on an efficient basis? Furthermore, how would a fair price for the power purchased be agreed when there may well not be a price point acceptable to both parties?

If, despite these issues, some form of obligation to provide PPAs to generators was introduced, it would be important that it only involved the off-take of physical power. Any other form of trading would lead to regulation requirements under the European Market Infrastructure Regulation (EMIR) and Markets in Financial Instruments Directive (MiFID).

The formation of a government or customer backed purchaser for PPAs could be feasible, though there are a number of factors which would need to be addressed:

- In order for such a purchaser to have any value it would need to offer prices not obtainable in the market (contrary to the suggestion of a higher than market cost in the Call for Evidence).
- If prices are offered to one potential generator they would need to be offered to all in order to avoid distorting the market
- If good prices are offered to all generators then such a purchaser is likely to become the purchaser of electricity from all renewable generators (possibly including that of large utilities), not just a "purchaser of last resort" for some small independent generators.

What are your views of the potential for market distortions and possible impact on the wider market?

The Electricity Third Package Directive[4] requires, by Article 3, that Member States shall not discriminate between electricity undertakings as regards either rights or obligations. Whilst Article 3(2) enables public service obligations to be imposed upon electricity undertakings, it also makes clear that any such obligation should be non-discriminatory. Any obligation that falls on only a segment of the supply market would be likely to be discriminatory within Article 3 of the Electricity Third Package Directive as well as under the general common law duty of fairness/EU non-discrimination duty. In addition, any such obligation that was only applicable to a certain category of generators ("independent renewable generators") and only incumbent upon a certain group of suppliers ("obligation on large suppliers") would be likely significantly to distort competition by favouring certain undertakings and therefore could also to raise State Aid concerns.

If any obligation were placed only on larger "Vertically Integrated Utilities" (however defined) the market will be distorted in favour of the other players in the market and this would raise issues of compatibility with EU law, as described above. For suppliers, this distortion would be additional to the exemption provided to smaller suppliers under ECO arrangements and create an incentive for suppliers to remain small, whilst increasing the inequity and discrimination between smaller and larger suppliers. This would in turn raise costs for all customers (for those of large suppliers through a need to pay for a disproportionate share of socialised costs, for those of small suppliers because of the inability of their supplier to gain economies of scale through growth). Contrary to arrangements such as that for ECO, an obligation to purchase a true PPA would be an obligation based on a company's size today but would last over a decade. This could continue to distort the market against today's larger suppliers even in a future where one or more had become smaller than a new entrant or small supplier of today (for comparison,

[4] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

until 2002 one of the largest UK supply businesses was TXU Energi, a business which failed, going into administration partly as a result of long-term contracts).

Any action taken to lower or smear imbalance costs in favour of small or intermittent generators is a market distortion, and would be inconsistent with the principle that any company that is not in balance with its contracted position is penalised accordingly. Removal of the market signals to balance will lessen the incentive for renewable generators to accurately forecast and (where possible) balance their own plant. Removing these signals would increase the amount of balancing necessary and so the system cost. Due to these higher costs, customers would end up paying more, both for their own contribution to imbalance and for the increase in smeared balancing costs due to the poor incentives for renewable plant.

Can you identify and explain any other viable options (voluntary, competition based, regulatory or otherwise) that should be considered?

Socialisation of renewable cost risks
The magnitude of the imbalance risk facing potential PPA providers may over time lead to a reassessment of the degree of interest in this market from traditional players. Cash-out reform may or may not help to reduce this risk but, in a high wind penetration world, the financial risk may still be high. Given that independent generators will not want to keep this risk, either this risk is provided to multiple PPA providers through the operation of a competitive market, or a body is created specifically to take and manage this risk. However, this approach does raise a number of issues that would need to be considered including how socialisation would be performed, how it would be funded, and how it would operate in the broader electricity market. In resolving these issues, it is important that incentives to forecast renewable output and sell it through the wholesale market are retained.

Change of law terms
The CfD contracts should have sufficiently strong change of law terms, covering all regulatory and political interventions which could potentially raise costs, and particularly balancing costs, for renewable generators. Such an approach would transfer some risk to the customer, but only the political and regulatory risk which is unmanageable for generators. By transferring this risk, the risk to be managed by independent generators is significantly reduced.

Combined with the CfD (and consequent move from a fixed to floating price element in PPAs) this approach should allow for PPAs to be negotiated at smaller discounts than today. With the residual balancing risk (due to technological change and generation mix uncertainty) there will still be a need for a significant risk premium in PPAs, but this should be of a more manageable level than it might be otherwise.

Our preferred approach
Overall E.ON would favour this last approach of minimising regulatory risk via strong change of law terms in the CfD and then reflecting any residual risk in subsidy (e.g. strike price) levels. It has the merit of removing from the market the risk that the market cannot manage and leaving the risk that it can manage.

If the explicit compensation for PPA costs required within subsidy under this approach is not acceptable to DECC (which may require a rise above subsidies available today if such costs rise), we see no effective way of doing so without socialising the risks which may increase the cost of PPAs. To preserve efficient dispatch for all plant within the wider electricity market, any socialisation of risk would need to be designed in such a way as to preserve the incentives on a renewable plant to forecast its output to the best of its ability and to then sell it through the market.

For independent Renewable Developers

How many counterparties have issued responses to your PPA tenders and has this number changed? If this number has changed, what has the trend been over this period?
Generically, what proportion of these responses have been from utilities and what proportion from independent aggregators/non-utilities? Have you seen new PPA providers enter into the market in this period?
Typically, what length PPAs have been offered to you in responses and if this has changed how has it changed
Broadly, what are the sizes of discount factors that have been included in these responses and if these have changed how have they changed?
Have floor price levels and conditions changed and if so, how have they changed?
Has the nature of risk allocation relating to imbalance, change of law and collateral changed and if so, how has it changed?
Have financiers become more or less risk averse and if their risk appetite has changed how has this impacted the terms PPA terms they are requesting to secure project finance?

For PPA providers

Have you seen an increase in the number of requests that you have received for the provision of PPAs?
No.

Have you have been able to respond to a larger or smaller proportion of the PPA requests for tender? If your ability to offer PPAs has increased or decreased over this period what have been the drivers (commercial or otherwise) for this change?
Given changes in the market place, the ability of commercial companies to underwrite PPA risks has fallen. The desire of customers is for increasingly short term links to the wholesale market, and the level of customer churn means that suppliers do not have long term income against which to offset the risks of writing fixed price PPAs. Since the financial crisis of 2008, energy companies, like many global entities, have sought to de-leverage themselves and as such taking on large fixed price exposures forms a less attractive activity.
Have the terms that you have been able to offer in response to PPA tenders changed, and if so how have they changed? What are the drivers for this?
Over the last 18 months E.ON have no longer been able to offer PPAs which include all of the features desired by most developers and at prices acceptable to the market. In particular, the liabilities we would have taken on by offering the floor prices on the power price which developers desired were not justified by the reward available to us. This change has been driven by a combination of the increased risk we perceive and the increased demands of developers (and their funders) for price certainty since the financial crisis.
Have you been able to win more or fewer PPA tenders based on the terms you have offered?
Our offers of PPAs without a floor price have been less attractive to developers and this has reduced the number of PPAs we have been able to agree in the last year.
How do you think EMR and the CfD will influence the terms that you are able to offer in response to PPA tenders?
Taken aside from other regulatory or market changes, EMR should make offering PPAs more attractive as we would only need to match the MRP rather than offer a floor price or fixed price for energy price. This could create a more liquid PPA market, provided that the threat of market intervention is also lifted.