Shell Response to the Department of Energy and Climate Change Consultation on Electricity Market Reform

Summary

1. Shell supports the UK's carbon emission targets and agrees with the Government's objectives for securing early and substantial emission reductions from the UK electricity sector, while ensuring that electricity supply is secure and affordable. We agree time is short and stronger market instruments are needed as investment incentives. However, the risk of implementing a number of different interventions in the market is over-complexity, with the possibility that the measures work in contrary directions and/or drive unexpected outcomes. We suggest keeping the package as simple as possible. Focussing on energy efficiency and demand-side measures is also essential to meeting the carbon targets successfully. We also stress the importance of achieving these objectives at least cost in order to preserve the UK's competitiveness.

2. In that context, Shell welcomes the UK Government's focus on strengthening the carbon price signal. But we believe the best approach is to strengthen the EU ETS in a multilateral way. We recommend that the Government urgently pursues two actions on the ETS with the EU and other Member States:
    - A balanced reduction of available credits from Phase III of the ETS.
    - Early action on Phase IV, including the announcement of a reserve price on auctions.

3. Action within the EU ETS would be much preferable to a UK only approach as it would avoid the adverse consequences of unilateral action, i.e. carbon leakage, undermining the EU ETS, and higher than necessary energy prices in the UK impacting economic competitiveness. A robust carbon price within the EU ETS and targeted subsidy support for pre-commercial technologies would be able to drive the change needed to meet the UK's long-term emission targets.

4. However, we recognise the UK's need for action on a timetable earlier than might be pursued through the ETS. Therefore, if the CCL is to be reformed to strengthen the carbon price signal, it should be done to establish a CO_2 price floor so that the downside risk to major front-end investment in low carbon technology is reduced. We believe it would be a policy error to design the carbon price support mechanism to try to set the marginal cost of CO_2 mitigation.

5. The proposed contract for difference (CfD) or feed-in tariff (FIT) should not be a long term instrument but used as "launch aid" for pre-commercial technologies at demonstration phase. The main such technologies are new nuclear, offshore wind and CCS. The reliability and cost of all these technologies must be properly appraised and proven before subsidies for large scale deployment are applied. So if used, FITs and CfDs should be a transition mechanism only, with the long term signals set by the EU ETS. Open-ended subsidies for nuclear, wind and CCS should not be implemented.

6. Of the low-carbon mechanisms proposed we believe that a CfD would be the more efficient way for Government to meet its goals. The alternative of a premium FIT for renewables and nuclear would expose these generators to much greater electricity price risk, which could lead to a delay

in the investment decisions or higher costs. The design of a CfD should include the following elements:

- Flexibility should be designed into the CfD process to respond to cost and technology developments and to allow the wholesale market to continue to deliver generating capacity;
- CfDs should be time-limited and regardless of when the CfDs are written, the electricity and carbon markets should be the sole support to all technologies no later than 2030; and
- The specific structure for a CfD for CCS must be designed carefully to take account of the difference in the nature of the technology compared to nuclear and renewables, in particular the fuel price risk.

7. For CCS, Shell strongly supports the implementation of the UK Government's four-project demonstration programme, but greater clarity is required on the funding for this programme and the mechanisms proposed to support low-carbon technology.

8. Given the other instruments in the package, we see no added benefit of an Emission Performance Standard (EPS) and do not support its implementation. It would not be needed to drive emission reductions, nor does it offer an incentive to invest in low-carbon generation. It has been suggested that an EPS should be designed in such a way that it will become more stringent over time, to indicate an eventual desired limit on the building of unabated gas-fired capacity. An explicit signal along these lines, before CCS is commercially available, risks creating greater uncertainty and would potentially further deter investment in gas generation, with potential negative impacts on security of supply and system costs.

9. Should all the market reforms be implemented as proposed then there will be a need for flexible generation plant to deal with the increased intermittency. Under the envisaged market structure it is unlikely that flexible peaking plant will be sufficiently remunerated given the increase in low marginal cost plant in the mix, limiting the hours available for flexible plant to recoup their costs. Some form of capacity mechanism that offers appropriate incentives to maintain capacity on the system to ensure security of electricity supply is therefore likely to be needed. We believe that a targeted capacity mechanism should be designed:
   - so as not to interfere with the wholesale market signals that lead to economic dispatch;
   - to reward plant that meet certain criteria such as flexibility and low carbon intensity; and
   - to reflect locational factors in order to encourage the optimal investment in both generation and transmission.

10. Shell supports the need to strengthen the incentives for low-carbon investment. But we believe that Government must take account of the risk that substantial support to nuclear and offshore wind may reduce the attractiveness of, and thus crowd out, investment in gas-fired generation. Gas is an immediately available and affordable energy solution, and its contribution to emissions reduction is increasingly widely recognised:
    - Gas replacing old coal is the fastest, biggest and surest way for the UK to reduce CO_2 emissions in the next 10 years. We estimate the reductions in terms of hundreds of millions of tonnes and up to 20% of UK power sector emissions by 2050.

- Gas puts least stress on the physical and financial system. On a levelised cost basis CCGTs are currently half as expensive as offshore wind and the estimated cost of gas+CCS is 60% that of Round 3 offshore wind costs on a First of a Kind basis, and 80% on an Nth of a Kind Basis[1].
- Pursuing the most cost effective pathway is critical for increasing the probability of successfully meeting emission reduction targets and maintaining UK employment and economic competitiveness. A UK study by Redpoint for the UK Energy Networks Association[2] found that pathways with ongoing gas use could lead to potential savings to Great Britain of almost £700bn over the 2010 to 2050 period on a Net Present Value (NPV) basis – around £20,000 per household or £10,000 per person. Similarly, a European Gas Advocacy Forum[3] study for the EU, supported by McKinsey, shows that compared to the pathway with 60% renewables[4] in the energy mix by 2050, the pathway with a stronger gas component would reduce investment costs by €400-450 bln in the period to 2030, and still meet the EU's 2020 and 2050 emission reduction targets.
- Concerns that reliance on gas for power generation will lock-in another generation of fossil fuel emissions are misplaced. With CCS, gas can remain an important low carbon energy source for the long-term, and economic analysis has shown that gas-CCS plants are competitive compared with coal-CCS, nuclear and offshore wind. Even if gas prices more than doubled from today's levels, according to the Mott MacDonald report, gas-CCS would still be cheaper than offshore wind (gas prices would have to be higher than $19/MMBtu for gas-CCS to be more expensive than offshore wind).
- It is also wrong to assume that if gas prices remain indexed to oil, they will closely track oil prices. The structure of gas contracts tends to limit gas prices when oil prices are high. For example, when oil prices averaged $130/barrel in summer of 2008, the gas price did not exceed the equivalent of $90/barrel.

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[1] Mott MacDonald (June 2010). "UK Electricity Generation Cost Update".

2 Redpoint (2010) – 'Gas future scenarios project'. http://energynetworks.squarespace.com/storage/ena_publications/ena_gas_future_scenarios_report.pdf

[3] The European Gas Advocacy Forum (EGAF) is an industry group including Centrica, E.ON Ruhrgas, Eni, Gazprom Export, GDF SUEZ, Qatar Petroleum, Shell and Statoil.

4 European Climate Foundation (ECF): 'Roadmap 2050 – A practical guide to a prosperous, low-carbon Europe'. http://www.roadmap2050.eu/

Introduction

Shell welcomes the opportunity to respond to the Department of Energy and Climate Change's (DECC) consultation on Electricity Market Reform. We recognise these reforms are a significant change from the way that the current UK electricity market operates. We would welcome further engagement on the more detailed design and implementation of a number of the proposed instruments that have not been covered in depth in the consultation. For example, the institutional arrangements required to implement some of these measures have not been discussed in any length in the consultation and we would therefore welcome further clarity on what is being proposed. A lack of detail on some of the proposals has also meant that we could not fully determine the impact on our business and provide comments to all the questions. This response should also be read in conjunction with our response to the HMT consultation on carbon price support. Our response below reiterates the key points made in the executive summary and responds to some of the specific questions raised in DECC's consultation.

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?

Shell supports the UK's carbon emission targets and agrees with the Government's objectives for securing early and substantial emission reductions from the UK electricity sector as well as ensuring that electricity supply is secure and affordable. We agree time is short and stronger market instruments are needed as investment incentives to meet the low-carbon targets. The primary way of strengthening market mechanisms to deliver the low-carbon targets is through strengthening the carbon price and offering targeted support to new low-carbon technologies in the development and early deployment phases. We welcome the fact that Government is considering proposals in these two areas and have provided detailed comments on the carbon price support consultation to the Treasury.

It should be recognised that there is a need for investment in the development of a variety of low-carbon technologies to ensure continued diversity of the UK generation mix. Targeted subsidies of limited duration should be used to support RD&D to improve the reliability and costs of pre-commercial technologies (including new nuclear, offshore wind and CCS), but should stop short of supporting large scale deployment. Feed-in tariffs or a contract for difference mechanism should be provided only as a transition mechanism to support pre-commercial technologies through their demonstration and early deployment phases. The eventual transition to reliance on only the electricity and carbon markets once these technologies mature should also be made clear at the outset.

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

The current market arrangements reward flexible and peaking plant through price signals in the wholesale and balancing markets. In future, there will be a need to provide capacity both to respond to short-term peaks in demand (tea-time peaks) and the reduction in electricity output from renewable generation, which in the case of wind, often coincides with periods of high electricity demand. For example, on the three coldest days around the 20th December last year when average temperatures were well below zero in the UK, wind was only producing 3% of its metered, installed capacity. Significant level of back-up generation is required to respond to this generation gap, which may otherwise be running at low load factors. Given the increased reliance on low and zero short-run marginal cost electricity envisaged in the future generation mix, the existing price signals that remunerate peaking plant may be dampened. In addition, the implementation of some of the proposed measures in this consultation could lead to either:

- the early closure of existing flexible plant (as a result of an EPS), or
- low-carbon capacity being contracted off-market (depending on the type of FIT implemented).

These effects would further limit the incentives to provide flexible and sufficient back-up capacity. Alongside the implementation of low-carbon measures therefore there also needs to be some support for flexible, back-up generation as the proposed measures may reduce the market signals to provide enough security of supply. The role of increased interconnection as a means of providing further flexibility and the role of demand-side response should also be carefully considered in this context as they also have a role to play in mitigating the impacts of the greater intermittency on the system.

Feed-in-Tariffs

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

A robust CO_2 price within the EU ETS system, combined with targeted subsidies for immature low-carbon technologies is the best way to drive transformational change at best value. These subsidies should be aimed at specific demonstration projects and early deployments. They should not support the deployment of pre-commercial technologies on a large scale, as this pre-judges the outcome of competition among the immature technologies and would not represent good value for money.

Among the alternative support mechanisms proposed, a fixed CfD against a wholesale electricity market price would be most effective in incentivising investment in renewables and new nuclear with their relatively high capital costs and low operating costs. However, this would shift exposure to electricity price risk and renewables volume risk to the CfD counterparty (either taxpayers or consumers). These risk exposures can be managed in part by limiting the length of the CfD (eg to 15 years). In addition, flexibility should be designed into the CfD process to respond to cost and technology developments. The terms of the CfDs should change over time to reflect these developments, and regardless of when the CfDs are written, the electricity and carbon markets should be the sole support to all technologies no later than 2030. At the same time, the electricity market must continue to deliver generating capacity – likely to be principally through CCGTs - to ensure supply security, and this may require a capacity mechanism. The alternative of a premium FIT for renewables and nuclear would expose these generators to much greater electricity price risk, which could lead to delay in the investment decisions or higher costs to the CfD counterparty.

CfDs should also be made available for CCS projects. But because electricity prices typically reflect the relatively high operating costs of fossil fuel generators (fuel and carbon costs), the CfDs should be designed to compensate the generator just for the additional operating and capital costs associated with CCS. This targeting of support can be achieved by writing CfDs on the difference between the electricity price and an index of operating costs (fuel and carbon costs) (ie, a tolling CfD). This approach would produce a stable earnings stream to compensate the generators for the additional capital and operating costs of CCS, without distorting the central role of the electricity market. The main risk exposure of the CfD counterparty (taxpayers or consumers) would be the volume risk of fossil fuel generators with CCS. As with the fixed CfDs for renewables and nuclear, the tolling CfDs for CCS should be limited in length (eg 15 years) and the terms of the CfDs should be allowed to change over time to reflect developments in costs and technology. Moreover, electricity and carbon markets should provide the sole support for CCS not later than 2030.

The main alternative to the fixed CfDs (renewables and nuclear) and tolling CfDs (CCS) would be a form of premium FIT. However, this mechanism would expose investments in the targeted technologies to greater electricity price or "spark-spread" risk, which could lead to delays in investment decisions or higher costs to taxpayers or consumers.

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?

If the CfDs are carefully designed as a transition mechanism along the lines described above, generators would still be exposed to the long-run electricity and carbon price risks. Given the long-lived nature of these investments, they are likely to still be in operation after the transitional supports end and a significant proportion of their revenues streams would therefore depend on these markets. This is likely to lead to more robust long-term decisions for investments that benefit from the support mechanisms. Moreover, it should be emphasised that while the fixed CfDs for renewables and nuclear would transfer significant electricity price risk to the CfD counterparty, the tolling CfDs for CCS would leave this risk with the fossil fuel generators that can more efficiently bear this risk.

We urge government to consider carefully which technologies should be eligible for CfDs based on their stage of maturity. We suggest that the CfDs should be (1) available to all low-carbon technologies (all decarbonisation methods with a carbon emission intensity below a certain level should qualify); (2) cover pre-commercial stage technologies only; and (3) be time-limited, with long-term support to low-carbon technologies that are commercial being provided through the electricity and carbon markets.

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?

Fixed CfDs for renewables and nuclear would not materially affect operating decisions in the electricity system because their short-run marginal costs (SRMC) are likely to be below both the CfD strike price and electricity price. Tolling CfDs for CCS would create an incentive for these generators to bid somewhat more aggressively in the wholesale market than they would under a hypothetical lump-sum transfer because their subsidy is dependent on generation volume. This would be most likely to displace the unabated fossil fuel generation in the mix against which CCS generation would most closely compete against.

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

If implemented, the FIT should be paid on output. If it were based on availability, the incentive for the efficient location of renewables would be dulled, along with incentives for improving plant performance and efficiency and for cost management for all supported investments. If it is necessary to implement an instrument to provide security of supply, this should be separate from any low-carbon mechanism.

Emission 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?

An EPS combined with a robust carbon price and FITs would be redundant in driving incremental emissions reductions. It should not be needed to drive emission reductions, nor does it offer an incentive to invest in low-carbon generation. We recognise the need to ensure that no new unabated coal fired power stations are built, but consider that the measures already in place will achieve this aim. We do not therefore support the implementation of an EPS.

We believe in general, an EPS should only be implemented with the following three key features:

- it approximates the emission reductions that would occur under the EU ETS with a robust CO_2 price (ie that are least cost);
- it treats existing and potential new facilities equitably; and
- it should not prescribe premature application of specific and particularly new and undemonstrated technologies.

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?

While we do not support the implementation of an EPS, we consider Option 2 (a $450gCO_2/KW$ with derogations for CCS demo plants) to be the most appropriate level. In designing derogations for projects forming part of the UK or EU demonstration programme the Government should consider the need for technologies to be tested both technically and economically in the demonstration phase (at demonstration scale) before moving to deployment scales. Thus, derogations may be appropriate.

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?

An EPS should treat all existing plants in the same way and not discriminate between new plants and existing ones, in order to maintain the incentive for investment in new capacity. If an EPS is only applied to new plants, there will be an incentive to run older more inefficient plants first rather than investing in new ones. If implemented in the UK, new plants should be 'grandfathered' at the point of consent only if Option 2 is implemented. Economic life could be defined as the life-time of a plant over which the plant does not require significant extensions or upgrades to be made (eg replacement of turbines).

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?

Yes. If an EPS is applied to all existing plants then there will be no need to have special provisions for plants undergoing significant life extensions or upgrades. The equipment of a plant which may not be replaced without losing the status of existing plant, needs to be carefully defined and be consistent with, where practical, similar definitions in other environmental legislation.

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

There are suggestions that the EPS should be designed in such a way that it will become more stringent over time, to indicate an eventual desired limit on the building of unabated gas-fired capacity. An explicit signal along these lines, before CCS is commercially available, risks creating greater uncertainty and would potentially further deter investment in gas generation.

Any review of the EPS should be very closely tied into the development of CCS technology. Implementing a more stringent EPS before CCS becomes commercially available could have significant impacts on investment in CCGTs, with negative cost and security of supply implications. Using gas in the power sector creates strong optionality for future reductions, through the application of CCS, as well as making a significant contribution to immediate emission reductions. Frequently resetting targets will undermine certainty for investments and could lead to a hiatus in investment before every review. Therefore, we propose setting longer term targets that are only reviewed when there are significant developments in technology.

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

Biomass in power generation should not be treated differently from its treatment in any other sector (eg biomass for biofuels in transport). Sustainability criteria should be applied as are being developed for biofuels under the Renewable Energy Directive. Not all biomass has the same GHG savings so it should be differentiated by type of biomass and source, with reporting as for biofuels.

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

No. Exceptions to the EPS do not provide regulatory certainty for long-term generation investments. If this measure is to be implemented, the criteria should be clear, determined upfront and made transparent.

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?

Should the full package of market reforms be implemented as proposed, then there will be a need for flexible generation plant to deal with the increased intermittency and lower flexibility of the generation. Under the envisaged market structure it is unlikely that flexible peaking plant will be sufficiently remunerated. Therefore there is a need to consider implementing some form of capacity mechanism that offers appropriate incentives to maintain capacity on the system to ensure security of electricity supply.

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

The capacity mechanism should be designed so as not to interfere with the wholesale market signals that lead to economic dispatch. As well as providing remuneration for generation capacity being available, it will be important to ensure the supply of fuels in circumstances where this is required, given the costs associated with maintaining the fuel supply flexibility. Commercial arrangements between generator and fuel supplier (eg via netback) should ensure that both the asset and the fuel are readily available should there be a need to dispatch, but this may require monitoring to ensure that adequate contingencies are put in place by the market. This should bring about a more integrated supply chain for capacity, with shared risks and incentives for multiple partners to deliver the desired outcome.

Existing and new CCGTs should be eligible for the capacity mechanism. If an EPS is implemented, for consistency across measures, no plant that does not meet the EPS should qualify for capacity payments. Lower-carbon options, eg CCGT + CCS also have the potential to operate flexibly and counter the problem of intermittency. It is therefore important to invest in demonstrations to test CCS plant flexibility and investigate the potential for deployment in a 2020-2050 time frame.

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

It will stabilise prices, by providing peaking in times of tight demand.

22. Do you agree with Government's preference for the design of a capacity mechanism:

- **a central body holding the responsibility;**
- **volume based, not price based; and**
- **a targeted mechanism, rather than market-wide.**

If capacity payments are to be implemented, it is important that this instrument does not weaken the effectiveness of the other policy instruments being proposed. Since the analysis shows that a market-wide capacity mechanism would be met entirely through existing plants that no longer chose to close under new EU environmental legislation, the targeted capacity mechanism would achieve a better environmental outcome. This is a material consideration given the envisaged scale of renewables. If a targeted mechanism is adopted, it would have to be centrally administered and should aim to achieve a volume target for reserve capacity.

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?

The extent to which these technologies are incentivised will ultimately depend on how they are rewarded under the capacity mechanism. The role of smart grids in demand side management should also be considered and taken forward.

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

Economic dispatch, as this will use available capacity more efficiently and reduce the costs of maintaining reserve capacity.

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

Yes. If implemented, capacity pricing should reflect locational factors. This will allow clearer investment decisions to be taken with actual costs factored into the economics, and drive optimum levels of investment in transmission and generation. It is likely that this would lead to more generation being built closer to demand centres and it could ease congestion points on the transmission system. Ultimately, locational pricing, going all the way through to the customer level, will best deliver market signals and drive the optimal outcome of demand and supply.

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?

Ideally for simplicity, efficiency and a least-cost solution, a robust carbon price within the EU ETS and targeted subsidy support for pre-commercial technologies would to drive the change needed.

Shell's first preference for a robust carbon price would be for no additional price support to be put in place, but rather to ensure that the EU ETS functions effectively. To secure the right level of investment in low carbon technology for the medium and long-term, we would propose that the Commission undertakes a balanced withdrawal of credits from Phase III and introduces an allowance reserve price for Phase IV. These features would signal to investors that future unexpected shortfalls in emissions would be used in part to step up emission reductions and at the same time reduce uncertainty in long-run investments associated with the CO_2 price. This intervention is needed now because most large-scale investments being considered today will only see a Phase IV carbon price in terms of operating costs, given the timeline for investment decisions and implementation.

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?

The risk of implementing a number of different interventions in the market is over-complexity, with the possibility that the measures work in contrary directions and/or drive unexpected outcomes. We suggest keeping the package as simple as possible. There is also a risk of contradiction or duplication with other measures being taken forward in other contexts such as the Review of Ofgem and Ofgem's Project Transmit that is looking at transmission pricing. A further risk is that complex and numerous interventions reduce liquidity. Competition in the electricity market drives down costs and encourages innovation and should therefore be encouraged in any package of reforms.

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?

See answers below.

- **Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?**
  In the longer-term, competitive tenders will be the most efficient and transparent way of determining the level of support and/or the different price indices to be used in the low-carbon support mechanisms.
- **Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?**
  Eventually, there should be a level playing-field between all low-carbon technologies, to encourage participation, innovation and drive to reduce the costs of abatement. Auctions could therefore be implemented longer-term. We do recognise however than in the short-term, given the differences in the costs structure of low-carbon technologies, a more tailored approach to individual technologies may be more appropriate.
- **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?**
  See the responses to questions 4-6 above for our suggestions on how CfDs may vary according to the different risks faced by different technologies.
- **Should prices be set for individual projects or for technologies?** Generally by technology, but allow a methodology for projects to apply for a differentiated price line if sufficiently different.
- **Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one particular technology? Are there other ways to mitigate against this risk?** An auction system would probably be the best way to ensure that low-carbon support is set at the right level and eventually erodes with technology maturity, given enough competition and liquidity. Systematically however, the government needs to ensure the criteria for qualifying technologies are met, eg pre-commercial, below a certain carbon threshold etc.

32. What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

We note DECC's current review of Ofgem. In that context, any subsequent changes to Ofgem's role, functions or powers should be consistent with the requirements of:

- any reforms to the electricity market - in particular, it is important that once policy has been set by government, the regulator is charged with its implementation; and
- the 3rd EU Energy Package (Article 39 of DIRECTIVE 2009/73/EC sets out the requirement for the designation and independence of national regulatory authorities).

Additionally, Ofgem's Project Transmit should be cognisant of the potentially wider reforms to the electricity market. We consider that it would be unhelpful if decisions regarding transmission pricing approaches inadvertently limited policy options elsewhere.

33. Do you have view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

See answer to Q31. Longer-term, the auctioning method will probably be the best design to minimise market distortion, but careful attention should be paid to detailed design elements.

34. Do you agree with the Government's assessment of the risks of delays to planned investments while the preferred package is implemented?

Uncertainty around the detailed implementation of the low carbon support mechanisms and the capacity mechanism could lead to a hiatus in investment.

35. Do you agree with the principles underpinning the transition of the Renewables Obligation into the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investments?

We do not agree that the RO should be vintaged at 2017. The RO should no longer apply to new projects at the point that CfDs are available.

36. We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition to introduce the new feed-in tariff for low carbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:

- **All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;**
- **All new renewable electricity capacity accrediting after the introduction of the low-carbon support mechanism but before 1 April 2017 should have a choice between accrediting under the RO or the new mechanism.**

As suggested above the accreditation period under the RO should end when the CfDs are implemented so 2013-2014. If both systems run in parallel then this could lead to delays in investment as developers will wait to decide which mechanism will offer them higher returns.

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