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MGT Power Response to the Department of Energy and Climate Change to the Consultation on Electricity Market Reform, December 2010

Executive Summary

- MGT Power understands the need to further incentivise investment in new capacity for the generation of low carbon electricity, and broadly supports the effort to do so

- We are very concerned that uncertainty caused by the EMR process will cause further delay to (and possibly cancellation of) renewable electricity generation projects waiting to enter construction today. To prevent this from happening, it is crucial that firm decisions are made on the transition of the RO as soon as possible, and definitely no later than the current ROC banding review timescale, ie Autumn 2011

- Investors and lenders are becoming more focused on, and concerned about, the headroom mechanism for calculating RO levels, given the increased sensitivity to these calculations for RO accredited plants going forward into the future. We strongly urge DECC to do away with this additional risk and complexity and move to a fixed ROC price, indexed to RPI

- We urge DECC to grandfather all RO biomass bands requiring capital investment. DECC should recognise the difference in capital investment of co-firing between co-milling and direct injection. We recommend coal units burning biomass be identified as co-milling, direct injection or full conversion, with each technology banded on its own merits and the later two grandfathered in a way that reflects the underlying capital cost. In a similar way, energy crops should be grandfathered due to their associated need for investment.

- The CFD structure proposed by DECC for EMR is an appropriate mechanism for managing risk/reward in long term power price movements for low carbon investments. However it is not an appropriate mechanism for managing short term output variability risk, and these objectives must not be confused. To do so would remove all incentive to manage and predict variability of generation and to use plant flexibility where possible for the benefit of the system, leading to an unacceptably high balancing cost to the system. We urge DECC to use annual power price indexation if CFDs are implemented under EMR.

About MGT Power

MGT Power is an independent company founded in 2007 to develop large scale biomass power generation and global renewable fuel supply chains. Our two main investors are both London based financial fund managers. MGT is actively developing two biomass projects, each 295 MW, in the North East of England. The two projects combined will be capable of meeting about 5% of the Government's legally binding 2020 renewable energy targets. As two of the largest and most efficient biomass plants in the world they will deliver over 91% CO_2 savings versus the EU comparator, consuming only sustainable biomass.

Tees REP

The Tees Renewable Energy Plant is fully permitted, and about £6 million has been invested in development so far to take the project close to the point where an investment decision is ready to be made. The construction investment decision has been delayed on two occasions by new regulatory issues concerning the Renewables Obligation (grandfathering of biomass in 2009 and the RO banding review in 2010), and is now expected to be made in late 2011 or early 2012. The plant is expected to represent a capital investment of between £600 and £650 million.

Tyne REP

The Tyne Renewable Energy Plant is designed to be a sister project to the Tees REP, reducing both development and operational costs which can be shared across the two sites, as well as benefiting from the experience and learning opportunities of the Tees REP. The development of the Tyne REP was put on hold in late 2009 due to severe regulatory uncertainty, including the introduction and subsequent reform of the Independent Planning Commission and its associated National Policy Statements as well the same grandfathering and RO banding issues which have delayed the Tees REP. The board of MGT power is due to decide on the future of the Tyne REP project by the end of March, with cancellation a likely outcome.

General Remarks

MGT Power understands and supports the Government's desire to incentivise more low carbon generation in the UK. Without doubt the UK needs significant investment in power capacity, and, while we are normally in favour of pure market based solutions, we feel that on a national level there is too much strategic risk in allowing the UK to become ever more dependent on volatile global gas supplies. We also support the effort to tackle climate change.

Since MGT Power's value and current focus is heavily skewed towards the Tees REP project, our response is clearly biased towards consideration of the RO transition arrangements. However, as a biomass development company, with the full intention of continuing both to develop projects and supply renewable fuel we have a large stake in the new arrangements and have attempted to address some of the broader questions. MGT Power's resources are limited in comparison to most other industry players, however we are a member of both the Association of Electricity Producers and Renewable Energy Association, and in some cases we have chosen to echo their comments where we are in complete agreement. These are marked.

Our full response to the consultation is attached as Appendix 1.

Renewables Obligation Transition Risks

In order to prevent further regulatory delay we strongly urge the Department of Energy and Climate Change to ensure that full clarity over the Renewables Obligation transition arrangements is provided in the strongest possible terms by the autumn of 2011 at the latest.

We cannot stress enough that investor patience has been stretched to breaking point by serial regulatory uncertainty including changes to planning regulations, the 2009 Energy Review, grandfathering of biomass and the ROC banding review. It is highly unlikely that investors will continue to participate in the development of low carbon generation if yet another regulatory shock is allowed to further impede progress.

In addition to the uncertainty created, the EMR consultation has thrown up two very important questions which have been highlighted to us as potential issues by financing parties with whom we are in discussion, which could prevent or severely delay financial close for projects wishing to enter construction well before the activation of the EMR arrangements. We urge DECC to address these as robustly as possible given the potentially disastrous UK-wide impact of a further investment hiatus:

1. Potential for competitive disadvantage

To some extent the biomass industry already has to live with the risk of competitive disadvantage, since biomass generation is now grandfathered and therefore future projects could receive a more competitive ROC band. However there is a big difference between known risks within a stable and well understood framework, and the risk of competing with a new and currently unknown regulatory structure.

The change to the EMR system may or may not create a much broader and less predictable spread of incentives than the change between RO bands. For example if market power prices were to fall significantly this would commercially disadvantage an RO plant against a plant in possession of a CFD, since one way of managing fuel price risk is to manage "spreads" (i.e. the difference between power and fuel which tends to be less volatile than fuel or power alone).

This is creating concern for those finance parties considering financing projects under the RO transition. In order to prevent a freeze on financing, we strongly recommend that this risk is mitigated by allowing plant accrediting into the RO between 2013 and 2017 a one-off option to switch into the prevailing EMR mechanism.

For the sake of fairness and investor confidence (although this suggestion has no direct consequences for MGT Power) we suggest that existing RO accredited plant should also be given the opportunity to migrate to the new system, probably on the basis of a once-only limited decision window.

2. Increased importance of the "headroom calculation"

Biomass investors and lenders are already very uncomfortable with the headroom mechanism for two reasons:

a. Regulatory interference. Investors and financers do not trust governmental bodies to make good decisions where judgement is required. This is not a reflection on the competence of the individuals but merely a recognition that decisions are subject to a host of competing interests with no visibility or predictability of outcome.

b. The "wind effect". Due to the high proportion of wind within the RO, and the variability of the wind resource, the supply of ROCs can be very unpredictable. Wind generators benefit from the fact that in windy years higher output will offset lower ROC recycle prices, but biomass (and other technologies such as landfill gas) see the opposing dis-benefit from this effect.

Arguably investors are already exposed to these headroom concerns now, however:

i) "Calculation B", the headroom calculation will go from being used sometimes, to always, and (we assume) there will be no "hard floor" to RO levels as there is now

ii) The proportion of ROCs generated by wind is likely to increase steeply, because:

   a. We expect non-wind ROC levels to decrease due to the closure of non-LCPD co-firing plants; non-grandfathered co-firing plants leaving the RO to enter the EMR; and landfill gas gradually fading away as old sites deplete and new sites enter EMR.

   b. As new offshore wind sites commission and become accredited they will earn 2 ROCs per MWh, therefore dominating even more in terms of ROCs than MWhs.

   As the proportion of ROCs generated by highly unpredictable wind increases, so does the unpredictability of the recycle value, and potentially the buy-out price could suffer as well if suppliers are forced to use banking to manage ROC supply/demand.

One outcome so far has been over-compensation to generators, i.e. Ofgem has tended to err on the side of generator comfort, and has set headroom higher than necessary. While on the surface this is a good thing for generators, quality investors are not looking for occasional windfall gains; we would far rather see predictability over cash flows and we view over-compensation as a potentially dangerous trend leading eventually to a consumer backlash.

All of this can be mitigated, and over-compensation can be prevented, by moving to a fixed ROC price with ROCs purchased by a central body. We do not see any other practical way of managing the transition period of the RO in a fair and stable way such that investors and financiers can make good investment decisions in the period between now and the activation of EMR.

We caution DECC however that we do not expect the large integrated suppliers to support these arguments. For one they are able to finance projects on balance sheet which works to their advantage when dealing with regulatory risk. More importantly however, the current RO structure represents to them a very significant shareholder windfall. Due to low levels of competitive pressure, the typical discount on a medium to long term PPA is at least 10% per ROC, equating to a windfall of somewhere between £10 and £20 million per annum for a supplier externally purchasing 3 million ROCs per year.

Conversely, MGT Power must declare its own interest of approximately £10 to £13 million of annual income for the Tees REP alone, which would no longer be needlessly lost to a supplier's shareholders. In itself, this would represent a powerful boost to the financing of the Tees REP.

We are aware that the issue of stability of existing PPAs is one that concerns DECC and could prevent it from following the best practise solution of fixing ROC prices now to remove uncertainty. If DECC is unwilling to tackle the PPA issue, we suggest that each generator should be given the option once per year to remain within the headroom calculation or to transition to a fixed ROC payment, with all generators transitioning by 2027 at the latest. Generators could then transition gradually as each PPA expires. We note however, that a proper structuring of legislation to govern PPA transition would be a cleaner and more rigorous solution.

Non-Grandfathered Technologies

We note that DECC is re-considering grandfathering those technologies that are not currently grandfathered under the RO.

We believe that the purpose of grandfathering is to provide a predictable minimum level of cash flow for a defined period of time in order that capital-intensive investments can be made at a reasonably low cost of capital. The incentivisation of capital investments under the RO is a factor of two things – banding levels and grandfathering length, together these must be enough to pay a return on capital expenditure and account for any higher operational or fuel costs. There is no reason why capital expenditure should be amortised over 20 years, other than it tends to deliver the lowest cost of capital, and spreads the cost for consumers; a shorter grandfathering period could be allowed, but would instead require a higher ROC band to deliver the same given amount of capacity.

Generation relying on volatile renewable fuel prices is often considered less suitable for grandfathering. Changes in future fuel prices may give the government cause to adjust ROC banding in order to continue to incentivise projects to be built, but this may allow those future projects to out-compete grandfathered projects for fuel on an open market cannibalising existing investments. Therefore, the argument goes, it is better not to grandfather technologies with a high ratio of fuel cost to capital investment. We do not agree with this approach, although the issue is complicated. However, for the sake of flexibility, we agree that technologies with very low upfront capex (i.e. co-firing with co-milling) should not be grandfathered, since they will be delivered in any case if the ROC band is high enough.

We consider the biomass technologies below:

1. Co-firing via co-milling (i.e. the biomass is co-mingled with coal prior to the coal mills). This technology requires so little investment that we agree there is no point in grandfathering it. The generator is able to switch between biomass and coal, and therefore only the RO or a premium FIT is appropriate to incentivise this technology. A CFD would be highly inappropriate because it would incentivise the generator to burn more biomass at times of low power prices and coal at times of high power prices. This does not make sense and amounts to regulatory arbitrage. We therefore recommend that co-firing via co-milling remains within the RO for as long as the RO continues to exist, but is NOT grandfathered.

2. Co-firing via direct injection (biomass is milled in dedicated mills and injected into the coal boiler at some point after the coal mills). In this case a significant investment is required, albeit less in relation to cash-flow than most other technologies. Still, since capital is required, we believe co-firing via direct injection should be grandfathered, albeit at a lower ROC band than dedicated biomass. Since the generator still retains the ability to switch between coal and biomass, they should remain in the RO indefinitely for the same reasons as point 1, and should not have the flexibility to choose a CFD structure in the future.

3. Conversion of coal to biomass (coal boilers are retro-fitted to burn 90% biomass or more with no option to switch back to coal). Significant investment is required in this case, probably more than for direct injection but still less than dedicated biomass. Again, grandfathering should apply, probably at a band intermediate between direct injection and new dedicated biomass. Because the generator does not have the flexibility to switch between coal and biomass (10% fossil fuel may only be used for specific technical reasons), projects starting now should have the ability to migrate to a CFD if they prefer.

4. Energy crops. Energy crops require a capital investment for planting and machinery. However because grandfathering applies to the power asset and not the fuel producing assets, this is a complicated issue. We suggest that generators that are grandfathered for ordinary biomass would also be grandfathered for use of energy crops. This will allow those generators to go out and offer firm priced long term contracts with farmers and land owners to plant with confidence. We recognise that the solution would not address energy crops for co-milling applications, however introducing energy crops via coal mills has proven technically challenging in any event.

5. Bio-liquids. We believe the rational for not grandfathering bio-liquids is due to volatility in liquid fuel prices, with assets potentially stranded if fuel prices increase in the future. We do not agree with this approach. Generators should find ways to secure supplies and manage fuel price risk. If generators are unable to do so and are unwilling to take the price risk commercially then we see no reason why society should do so instead. Bio-liquids projects should be grandfathered.

As a general point we would note that the Government's rational from 2002 until now for artificially limiting co-firing and coal conversions in order to benefit other types of renewable electricity generation has surely now disappeared. The sheer volume of renewable energy that has to be delivered to meet legally binding targets is such that the financial impact to society of rationing lower cost solutions in favour of higher cost technologies (such as deep offshore wind and solar photovoltaics) should no longer be justified, especially given the current economically challenging environment. Experience and countless academic studies have shown that vast amounts of sustainable biomass fuel will become available as market demand develops, at costs far lower than alternative domestic sources of renewable electricity. It is in everyone's interests (even those of a competing developer such as MGT power) to see a robust and liquid market develop in biomass fuels; incentivising conversion of coal generation to biomass, in addition to dedicated new biomass plant, is the lowest cost way to achieve that goal.

Contracts for Difference

MGT Power supports the use of Contracts for Difference (CFDs). Without doubt they will reduce the cost of capital in construction of low carbon energy plants, especially those with low fuel costs such as wind and nuclear.

There is a broad expectation that the price of fossil fuels, and therefore UK power prices, will rise in the future as global supply struggles to keep pace with rapidly increasing demand, particularly from developing countries. A CFD structure will prevent overcompensation of supported generation in the event of rising power prices whereas a premium FIT will not, something which in our view lends additional stability and future proofing to the proposal.

<u>CFDs for Biomass</u>

In the case of biomass, the use of CFDs is more complex as they remove the ability to manage spreads (the difference between fuel cost and power income) which are usually less volatile than fuel price alone. It will be challenging to manage biomass price risk alone without any positive exposure to global energy price trends.

One option is to use the spread between a fuel and power index for the reference price of the CFD. The problems with the fuel indexation approach are:

1. UK biomass plants use a multitude of different fuels, each with their own pricing dynamics

2. Even the best biomass index that has been developed so far (APX-Endex for wood pellets) has some way to go before becoming a trusted reference price in the industry

We suggest an approach which would be to mandate all UK biomass plants to report actual delivered prices and volumes for their fuel to a central UK body on a highly confidential basis. This body would then report 3 annual indices based on broad fuel sectors (we suggest: waste derived fuels; domestic agricultural products including energy crops; and international biomass commodities) which would reflect the annual average change in the delivered price per unit of energy (GJ) rather than an absolute price level. This would then be included in the reference price of the CFDs. We are aware of similar confidential price reporting agencies operating successfully in other segments of the biomass industry and we are confident that a suitable system is easy to implement.

This approach would still incentivise each generator to buy fuel as cheaply as possible because they would each keep the savings from beating the market average, or take the penalty from doing worse.

In order to ensure critical mass for each index, it would be necessary to include existing biomass generators and co-firers in the mandatory reporting. This could be done without the need to transition existing generators to CFDs.

We would suggest that each new generator would have a one off chance to nominate which of the three fuel indices it was exposed to or to nominate no fuel index exposure if they prefer to manage their own fuel price risk.

MGT Power would be pleased to discuss this approach further with DECC. Clearly considerable thought would need to be put into the design of any such scheme.

<u>CFD Power Indexation</u>

CFDs should be used to hedge long term movements in power prices NOT to manage short term variability risk. Hence annual power price indexation should be used as the reference price.

Short term variability risk must sit with generators otherwise genuine incentives to manage and predict variability are removed, which will inevitably lead to higher system costs. <u>These risks are already managed by generators</u>, a CFD mechanism does not change that, but instead provides a different sort of benefit by reducing long term power price risk.

Biomass plants in particular are able to offer flexibility to the system, for instance by turning down at times of very low or negative power prices. The optimum CFD index to ensure this benefit is not lost to the system is annual indexation; even quarterly indexation removes seasonal effects. This works as follows:

Example (annual CFD indexation):

In this example the annual power price for reference purposes is £70/MWh and the CFD strike is £100/MWh. The marginal running cost (i.e. mainly fuel cost) is also £70/MWh. The generator sells his power forward a year ahead as annual baseload at the annual reference price of £70/MWh.

The generator will continue to generate as much power as possible in order to benefit from a CFD payment of £30/MWh (power and fuel net off to zero).

However (during a mild, windy day) the daily power price falls to £35/MWh, and the generator then chooses to buy back his power instead of generating. The generators' cash flow will then look like this:

- Annual baseload power sale income = + £70/MWh
- Short term power buy-back = - £35/MWh
- Fuel cost and CFD payment = 0 (not running)
- Net income = £35/MWh (more money!)

In other words a biomass generator will turn down its output at a given (likely positive) power price, adding flexibility to the system.

However if the CFD is indexed to the daily power price the opposite is true:

Example (daily CFD indexation):

In this example the power price for reference purposes is the daily price and the CFD strike is £100/MWh. The marginal running cost (i.e. mainly fuel cost) is £70/MWh. The generator sells his power each day in order to match the CFD reference and eliminate risk.

Whatever the daily power price is, if the generator runs, he will receive a £30/MWh profit.

However, if the daily power price is negative £100/MWh (a very mild, bright, windy day), the generator may consider choosing not to run. If so, his net cash flow will look like this:

- Power sales income = 0 (the generator simply chose not to sell his power at negative £100/MWh)
- Fuel cost and CFD cost = 0 (not running)
- Net income = 0

In other words the generator will never chose to turn down voluntarily due to fluctuations in daily power prices, no matter how low they go, as he will get nothing and lose his £30/MWh income. There is no flexibility.

We are aware that wind generators would prefer to see shorter term indexation of the CFD power reference price; this is understandable as it would remove far more risk from their business model.

However at some level market and operational incentives must be left with the generator. The variability of wind energy DOES impose a cost on the system and biomass energy DOES provide valuable flexibility.

If these operational factors are completely eradicated via artificially narrow CFD indexation, the cost of EMR to consumers will ultimately be much higher because generators will no longer care about the (positive or negative) impact their generation will have on the overall system. We do not believe this can be justified to consumers, therefore DECC must choose annual power reference price indexation.

We look forward to further discussion of these very complex matters with DECC in due course

Yours Faithfully

[redacted]

<u>Appendix 1</u>

MGT Power Response to the EMR Consultation Questions

<u>Current Market Arrangements</u>

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 do not believe that under any circumstances £200 billion of new investment will come forward by 2020. Investors simply do not have the appetite for such huge capital sums, especially in the UK. Only a handful of energy/utility companies have the appetite and potential to invest more than a few billion pounds in the UK in that timeframe, and we believe only one single energy company can or will invest more than £10 billion; pure financial investors have been scared by the frequency and complexity of regulatory change, and growth in this sector will likely be slow. This is MGT Power's experience, having spent 3 years discussing a £600m investment with a very wide range of different potential investors and lenders.

We believe £100 billion of investment is a realistic aim, and that DECC should bear this in mind when setting policy.

Ways must be found of extending the life of existing assets while reducing carbon emissions. Those new low carbon assets which are built should focus strongly on the most cost effective and least capital intensive projects.

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

Not answered.

<u>Feed-in Tariffs</u>

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

Yes, we believe that CFDs will reduce the cost of capital of new investments (lowering the cost to consumer), attract more capital (but not £200bn by 2020), and prevent over-compensation.

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

Yes, see above.

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?

The first advantage is that, as long as investors believe in the mechanism, more "incentivised" generation will be built than would otherwise be the case.

The second advantage is that consumers will see a higher level of price stability than would otherwise be the case if the UK power system was allowed to continue towards ever greater dependence on global LNG.

The third advantage is that global carbon emissions will be lower than they otherwise would have been.

The first disadvantage is that less non-incentivised generation will be built, because investors will fear the lack of a level playing field.

The second disadvantage is that the mechanism introduces the risk of over-delivery of power capacity, by removing self-correcting long term price signals. Potentially an unnecessary and damaging expense to the UK economy, although our view is that low availability of investment capital will prevent this anyway.

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?

It is vital to set out a clear understanding of what we are trying to achieve. There is a very important distinction between long term price signals and short term price signals.

The incentive packages will have the effect of encouraging more low carbon generation to be built and less fossil fuel generation to be built and some fossil plant to shut earlier than would otherwise be the case, even if low carbon generation is more expensive than fossil generation. It will also tend to cause low carbon generation to run in merit before existing fossil generation, even if it is less economic to do so. This we believe is what the government intends.

Short term price signals however are about optimising existing plant on the system and properly incentivising generators to predict and control their output and react appropriately to system conditions. We do not believe the government ever intended for these incentives to be removed, even though it would make life a lot easier for wind generation.

Therefore the government should rely on annual reference prices for CfDs.

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?

Broadly yes, although the extent to which the cost of capital will be reduced has likely been somewhat overestimated.

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 main factor for availability of finance will be stability of the regulatory regime. This message was delivered as strongly as possible by the industry in 2001 during planning for the Renewables Obligation, and yet major changes to that scheme were made every single year without exception and now even more fundamental change will be wrought.

Given our current starting point, it could take up to 5 years of very stable operation of the EMR environment before independent financial investment in UK low carbon generation is able to grow significantly from existing levels – perhaps less if investor returns are increased. However, we do expect that some UK/European energy utilities will increase investments in low carbon technologies, particularly nuclear, if the returns are high and stable enough.

CFDs will enable higher leverage of power project debt and independent investment than premium FITs; this is because in order to finance a project with exposure to long term price prices, a long term PPA with a floor price must be obtained from a credit worthy counterparty. PPA's currently available in the power market contain extremely low floor prices for electricity, which are then used by banks to size loans. Some technologies (those with predictable output) may no longer need a long term PPA if they have a CFD; likely to result in an additional 5% to 7% of revenues of saved PPA cost for independent generators, very significant indeed, and a highly desirable outcome as this cash was "dead weight" - windfall profit to shareholders of large energy companies. It can instead be used either to save cost for consumers or to increase returns for investors; the later option increasing the level of overall investment.

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?

Independent generators with predictable output (biomass, nuclear, CCS and some hydro) will benefit far more from CFDs than premium FITs because a CFD will remove the requirement for a long term PPA in order to achieve financing. This will lower the cost of capital in two important ways, firstly by providing a much higher level of predictability of cash flows and secondly by removing the very high cost of the long term PPA.

Independent generators with variable output (wind, tidal, wave, solar and some hydro) will still benefit more from a CfD than a premium FIT, however the effect will be less than for predictable/flexible generation. This is because independent variable generators will still need a long term PPA with a power offtaker in order to guarantee the "discount" between the baseload power price and the lower value of the variable output. As is currently the case, we don't doubt that high credit rated energy companies will extract a swingeing cost for signing such contracts; competition in this market is very poor indeed. However, since there will be less risk over the long term base value of power, we still expect that variable generation will derive a lower overall cost of capital.

CfDs remove a sizable barrier to entry for independent generators, and therefore may be considered negative by some integrated energy utilities. However we ultimately believe that those companies wishing to pursue nuclear will most likely value the predictability of revenue more highly than the loss of competitive advantage and that therefore CfDs will find broad support among the industry.

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?

We strongly believe that an annual power price index should be used. We would recommend that the government carries out a competitive process to determine which annual index should be preferred.

To incentivise a high level of biomass generation, some biomass price indexation is desirable, and MGT has provided some suggestions for how this could work.

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

In order to avoid a very unstable state of misaligned incentives, it is absolutely essential that FITs are paid on output and not availability.

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?

Not answered

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?

Not answered

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?

Not answered

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?

No. Such a move would prevent existing plant from upgrading, instead forcing it to close, adding even further cost to the system for no benefit.

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

Not answered

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

If an EPS is introduced, biomass generation should be treated as zero carbon emission, as is currently the case in the EU ETS.

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

We support the following comment by the AEP: The need to consider exceptions to the EPS at this stage suggests that the Government is uncertain about the effects of the mechanism on security of supply. That uncertainty may arise from the introduction of an emission limit before the capabilities of CCS technology have been proven at commercial scale. If an EPS is introduced, the scope of any exceptions should be set out clearly in advance, together with the procedure for implementing them, as they have the potential to affect operating decisions and competition in the wholesale market.

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 reserve judgement until further detail is available about the design of such a mechanism and greater clarity about which plant would be affected among existing plant and/or plant yet to be commissioned.

In addition we would seek to understand how the capacity mechanism would interact with the FIT where back-up generation is provided using renewable fuels.

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

Ultimately we believe the market should deliver reserve capacity, efforts should be made to encourage demand response.

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

Not answered

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.

Not answered

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?

It very much depends upon how a capacity mechanism is to be applied and is therefore difficult to assess at this time

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

- Last-resort dispatch; or
- Economic dispatch.

Neither

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

Not answered

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?

Regulatory stability is everything, we urge simplicity. History shows the higher the complexity, the harder it is for regulators to resist constantly changing important variables, with a highly negative impact on investment.

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

Not answered

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?

The key risk is that the FIT mechanism will deliver too much non-despatchable plant in the absence of proper market signals to curtail runaway investment in nuclear and wind.

Once again we must stress that required investment in UK power just to keep the lights on let alone to deliver against carbon reduction targets is already extremely challenging. Over-investment in non-despatchable generation will displace investment in despatchable plant, leading to oversupply of power during times of low demand and high wind, and undersupply at times of high demand and low wind, seriously endangering UK energy security. Therefore we urge DECC to consider how it might go about rationing the premium incentivisation of non-despatchable generation. We suggest a reasonable starting point would be to limit combined wind and nuclear FITs to a maximum of 120% of lowest system demand.

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

AEP response: The implications for the Renewables Obligation of the transition to a new support mechanism for renewables, including the proposal in the EMR consultation to fix the price of a Renewables Obligation Certificate, will need to be carefully considered. The tensions between the carbon floor price and the EU ETS are also an issue. Finally, it is paramount that the industry has certainty on grandfathering options and the length of time that 'interventions' are to be applied.

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?

It is essential to investors of live projects that transition arrangements for the RO are made as soon as reasonably possible, and in any event no later than autumn 2011.

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

- 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?
- Are there other models government should consider?
- Should prices be set for individual projects or for technologies?
- Do you think there is sufficient competition amongst potential developers / sites to run effective auctions?
- 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?

We fully support the response of the AEP: The Association recognises the need to ensure that the most cost-effective support is implemented and therefore appreciates the desirability of some form of price discovery when setting levels of support. However, we consider that an administered price should be used and that there should be open access to support for all developers. This would be far preferable to the use of auctions. Auctions present a major barrier to investment because they provide no guarantee that a project will be able to secure a CfD.

The issues that would need to be addressed for an auctioning process to work effectively are listed below and it does not appear that these could be successfully overcome at this stage.

- It would be difficult to accommodate project planning as there can be no assurance that a project would necessarily obtain support under an auctioning process.
- Different auctioning rounds are likely to lead to a stop-start approach to development, which could lead to bottlenecks in supply chains and planning systems.
- Projects would face significant upfront costs to participate in an auction, which could discourage some companies from participating.
- The difficulty of ensuring that all necessary consents, especially planning permission and grid connection, could be obtained alongside financial support under the new mechanism.
- Nuclear and offshore wind will be large projects with single developers on pre-determined sites and are therefore unlikely to be suitable for auctioning, whereas onshore renewable energy projects are likely to be smaller, leading to greater competition and potentially more speculative bidding.
- Based on the experience of the RO, it will be necessary to band the support mechanism, setting different levels of support for different technologies, in order to incentivise the deployment of a wide range of technologies. Separate auctions are therefore likely to be required for each technology. This would, in effect, allow the government to determine the fuel mix.
- Winning an auction would not necessarily lead to the building of plant. Some winning bidders may find it uneconomic to build, while others may see

winning as the start of a protracted negotiation period to address issues not covered in the bid, delaying construction. It would be difficult for the government to impose penalties for non-development of a winning project given the range of factors that are outside of a project developer's control.

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

Not answered

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?

Not answered

Renewables – Maintaining investor confidence

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

The RO is a mechanism that is well-understood by investors. A change to the support mechanism for renewables at this stage introduces the risk of a hiatus in deployment which could jeopardise the UK's chances of meeting its 2020 renewable energy targets. This will need to be carefully managed.

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?

The principles of the transition must be to protect existing RO investments and prevent a hiatus in renewables deployment.

It is critical that investors in renewable energy projects receive clarity about the future operation of the RO on the same timescale as the current RO banding review, i.e. by Autumn 2011. Many projects, representing several billion pounds of investment, have been put on hold while awaiting the outcome of that banding review. If these projects do not have sufficient visibility of and confidence in the RO arrangements after 2017 to form a reasonable view of future revenue and cash flows by the time the banding review is concluded, there could be a further hiatus in investment, with very serious repercussions for both existing development projects and the government's legally binding renewable energy targets.

We would welcome clarity on the following issues in the forthcoming White Paper:

- What is the closing date for accreditation of projects within the RO and what qualification criteria will be adopted?

- Will the RO remain as a supplier obligation or will a government agency take over responsibility for buying the certificates?
- If the RO remains as a supplier obligation:
    - What will be the future method of calculating the size of the obligation?
- If a government agency takes over the purchasing of the certificates:
    - What will the price be or how will it be determined?
    - What will the interval of purchase be?
    - Which body will be responsible for purchasing the certificates?
- What grandfathering arrangements, if any, will be put in place for bioliquids, co-firing and energy crops?
    - If no grandfathering is to be put in place for these technologies, what will be the process and timing for determining future banding levels?

For existing projects accredited for the RO, DECC must clarify any future rules concerning refurbishment or replacement of plant – whether this support will be provided under the RO or the new mechanism – and, similarly, how additional capacity will be treated.

36. We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition is 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 outlined above, we consider it essential to preventing an investment hiatus that generators accrediting between 2013 and 2017 be given the opportunity to chose between the RO and FIT.

37. Some technologies are not currently grandfathered under the RO. If the Government chooses not to grandfather some or all of these technologies, should we:

- Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?
- Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?
- Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?

Some existing technologies should be grandfathered. Some are not suitable for CFD FITs (please see letter response above). Non grandfathered generation remaining within the RO should be subject to 4 yearly banding reviews. We strongly object to the concept of "early review", it is a perfect example of what we mean by wilful destruction of investor confidence.

38. Which option for calculating the Obligation post 2017 do you favour?

- Continue using both target and headroom
- Use Calculation B (Headroom) only from 2017
- Fix the price of a ROC for existing and new generation

Fix the price of a ROC as explained above. For non-wind projects, we consider this the only viable way forward.