Details of Respondents

Macquarie Infrastructure and Real Assets (Europe) Limited (MIRAEL) is a division of Macquarie Group Limited, an Australian Stock Exchange-listed financial services organisation. MIRAEL is the manager of a number of European focused infrastructure funds which have been raised from institutional investors including international pension funds and insurance companies. The funds invest in infrastructure assets which provide essential services to communities and attract a secure and stable cash-flow allowing the payment of regular yields to investors. Investments to date include airports, toll roads, utilities, telecoms broadcast towers and renewable energy assets.

MIRAEL manages the Macquarie European Infrastructure Funds 1, 2 and 3 (MEIF 1, 2 and 3). Within these funds MIRAEL manages in excess of €7 billion of committed equity. The funds invest across the EU and EU accession countries and have made a number of investments in the renewable/clean energy arena, a key target sector for the funds. Investments have been made across a range of technologies including biomass, landfill gas, wind, solar and waste-to-energy in the UK, France, Spain, Sweden and Germany with differing low-carbon support mechanisms.

In the UK, MEIF 1 owns 100% of Energy Power Resources Limited ("EPRL"), a renewable energy company which owns and operates five biomass power stations (113MWs in total), two wind-farm joint ventures (16 MW in total). EPRL is the UK's largest independent renewable energy generator from power stations dedicated to the combustion of biomass.

EPRL has a long history of development and operation of biomass power projects, and associated biomass fuel procurement. EPRL's five operating plants commissioned between 1992 and 2001 initially under the Non Fossil Fuel Obligation (NFFO) regime with power now sold under Renewables Obligation power purchase arrangements. In addition, EPRL is at the early stages of developing a new 40MW biomass fuelled power station, which was submitted for planning approval in November 2010.

MEIF 1 also owns 100% of CLP, a dedicated landfill gas to power company, operating from 26 sites across the UK providing around 65MWs of renewable generation capacity.

MIRAEL also manages investments in other significant UK based infrastructure assets including Thames Water, Wales & West Utilities, Arqiva and Airwave.

Infrastructure funds managed by MIRAEL are designed to hold assets for a longer period of time than traditional private equity models. MIRAEL management takes a long term view of the investments it manages with a key focus on ensuring operational excellence and customer service. Based on this outlook, key areas of interest to MIRAEL management include: consistent government policy and regulation; and stability of cash-flows. Potential investment areas are judged against competing demands for equity capital across a range of infrastructure and geographic areas as outlined above. Therefore, the regulatory environment underpinning any investment is a significant determinant on the viability of investments as well as the returns that will be demanded for investing equity into that area.

Summary Response

The consultation document represents a very good and comprehensive analysis of the challenges faced by the electricity industry in the coming decades and the potential mechanisms available to facilitate meeting the objectives of low-carbon affordable electricity and security of supply between now and 2050.

We are supportive of the generic proposals for carbon price support, capacity payments and an Emission Performance Standard. We agree that these proposals need to be combined with a low-carbon generation support scheme.

Additionally, the recognition of the need for a transition plan which includes the honouring of previous commitments and maintaining investor confidence is vital, in terms of avoiding an investment hiatus due to uncertainty and perceived risk.

With that in mind it is worth noting that there are two specific issues which need to be addressed in terms of transition:

(i) Whilst it is proposed that new projects will be able to opt for either RO or the agreed FIT between April 2013 and March 2017, it is unclear how this would be achieved, given that qualification for the FIT may be achieved through some form of auction or tendering process. This is particularly relevant for a project which misses the March 2017 date, could no longer get RO accreditation but was unsuccessful in an auction process. Our preference is to avoid auction or tender processes in any event; and

(ii) The issue of NFFO contracts which end post March 2017 is not addressed in the consultation. Prior to this consultation the expectation was that these would be supported under the RO regime until 2027.

Given the recognition of the importance of an effective transition and the intention to honour previous commitments, we are sure that these two specific circumstances can be addressed satisfactorily through the process. As a suggestion, perhaps a grace period for RO final accreditation could be agreed (of, say, two years for projects pre-accredited before April 2017), this combined with avoiding an auction or tendering process would largely remove this issue. In addition, all operating NFFO contracts could be terminated and projects switched to the RO regime at some point prior to April 2017, this would have the benefit of both certainty and a potential saving in associated administration costs.

One further point in this regard, the 2011 ROO consultation detailed the issue of appropriate support mechanism for RO projects with extended operation lives beyond 2027 or 20 years through significant refurbishment and/or capital investment. We are supportive of such support (and extended support for biomass projects generally due to ongoing fuel costs) and this should be considered in light of the proposed switch to a FIT regime.

In terms of low-carbon generation revenue support, our fundamental question is what drives the need to switch from the current RO regime to feed-in tariffs. Whilst the RO regime did not lead to new capacity between 2002 and 2009, this was generally due to the support level being set at too low a level and not reflecting the relative costs and risks of different technologies. This was addressed with the introduction of banding from 1st April 2009, from which point a number of new projects were announced and significant interest stimulated. This progress was later stifled when DECC announced that the banded support levels were not grandfathered. This issue has subsequently been addressed.

On this basis we believe that the current banded RO scheme is acceptable and with appropriate banding reviews has the potential and flexibility to deliver the required investment in low-carbon generating capacity. Further, it is also now well understood by the investment community and does not require a transition period, and in terms of support levels provides investors with the two key elements: understanding of future value and certainty. Whilst projects remain exposed to wholesale price movements, this is an element of risk that is, at least, understood and would be mitigated partially by the carbon price support mechanism. In terms of cost of capital the RO scheme probably does not achieve the lowest cost of capital given the exposure to wholesale prices which impacts the cost and volume of debt and equity. We understand that DECC and the Government generally wishes to move away from the RO as a matter of policy and in light of this, the balance of this response focuses on the proposals for its replacements, namely feed-in tariffs.

As a significant investor of equity into renewable energy assets across a range of European regimes, MIRAEL has evaluated and invested in many different regulatory regimes similar to those being discussed in the consultation document so is well placed to comment on the impact of those regimes on investment attractiveness. In general terms the following areas are the key considerations with respect to investment attractiveness for infrastructure equity:

- Stability of Government policy e.g. how stable is Government and do different parties have widely differing views on the policy;
- Stability of regulatory regime e.g. how often does the regime change, how sustainable is the regime in terms of delivery against any stated Government targets, how does the cost of the regime compare to other schemes across Europe;
- Volatility of pricing under the regulatory regime (and therefore certainty of income) e.g. fixed feed-in tariffs versus tariff subject to green certificate and wholesale price volatility;
- Complexity of the framework. The more complex the framework the less likely it is that investors will get comfortable that their understanding is sufficient to take the risk of investing capital into projects; and
- Protection for investments already made under the regulatory framework. If the Government does not show a commitment to protect existing investments when it determines that regulatory change is essential, then this will be an unattractive area to place long-term investment capital.

We do believe that the introduction of a feed-in tariff has the potential to increase the pool of capital available to the low carbon generation sector and to reduce the cost of capital demanded by investors if well designed and meeting the principles set out above.

In terms of the three potential FIT regimes put forward in the consultation document our views on how they would impact decision making in terms of the equity that we invest are set out below.

Fixed feed-in tariffs are a clear favourite with infrastructure equity and would open up the maximum quantum of equity to the sector. They are also associated with lower costs of capital in general. We understand the Government's concern that a fixed FIT is somewhat disassociated with wholesale electricity prices and the carbon support being proposed within that area. As such the two schemes do not naturally sit together in a complimentary fashion.

We understand the theoretical assessment of the benefits of a FIT with a CFD. If it provides long term price certainty this should decrease cost of capital and increase the pool of capital available. In addition, it has a compatibility with the carbon price changes proposed in that increased wholesale electricity prices would automatically reduce the cost of support for generators. Further, the Government hopes to encourage optimal behaviour in responding to short term electricity pricing signals.

We have some concerns that in practice this scheme has a number of issues which may reduce its effectiveness. These include:

- Complexity/Income Volatility – whilst in theory straightforward, in practice there are a lot of issues around the chosen index and basis risk for the generator and understanding how this may impact on risk to income. The scheme has not been seen in any other market in Europe and so is an unknown to financiers and equity investors, increasing the risk around transition.

- In practice we think the scheme is likely to lead to independent generators seeking to negotiate power purchase agreements that remove the basis risk and thereby offer Generators a fixed price with no exposure to short-term electricity price changes (note this is what has happened in many cases with respect to the RO regime in order to remove wholesale price risk to enable capital to be made available).

- For this regime to work it would be vital that liquidity in the market increases dramatically to enable generators to effectively manage the risks of short-term price exposures. Whilst we accept that this is being reviewed, it is not clear at this stage that this could be successfully achieved, meaning that independent generators would have a potentially major exposure.

- Based upon our discussions with DECC on 25th February, it appeared to be suggested that the FIT with CfD mechanism would protect against (i) excessive support costs from a HMT perspective; and (ii) over delivery; whilst also providing clear market signals to generate compared to a Premium FIT. We do not believe that this is the case. In the event of wholesale prices being very low or even negative, under a CfD mechanism this will lead to a higher CfD payment, the trigger for deployment and generation will not be the wholesale market (reference) price but the actual feed-in tariff itself. Generators will be encouraged to invest and generate whatever the wholesale price. This is not the case with a Premium FIT.

Where the generator takes some element of price risk and fixes the energy price, it is unlikely that this would be set on a sculpted half hourly basis. For example, assuming that a four or six rate tariff PPA was agreed, in periods of high demand and high half hourly prices it is likely that a generator would face a relative financial disincentive to generate as the CfD payment (being the difference between the set fixed level and the chosen index) would be reduced. Where actual half hourly prices are low (i.e. during periods of low demand), CfD payments would be greater and the generator's total revenue would be higher, see table below:

Table 1: Example of FIT with CfD

Long term tariff level £110 with implied support of £60 per MWh and brown price of £50 per MWh
Four rate tariff PPA with weighted average of £50 per MWh

Summer peak	£60
Summer off-peak	£35
Winter peak	£80
Winter off-peak	£45

	High Demand/Price Winter peak	Low Demand/Price Summer off-peak
FIT agreed tariff	£110	£110
Actual average price	£100	£25
CfD Support	£10	£85
PPA price	£80	£35
Generator revenue	**£90**	**£120**

In our opinion, the FIT with CfD will either result in the generator fixing total revenue through a PPA (leading effectively to a Fixed FIT) or there will be high levels of price risk and potentially a disincentive to generate when actual demand and prices are highest and the market signals will become distorted. This is particularly relevant for biomass, which can be dispatched and the fuel costs per MWh are fixed.

A Premium FIT would work as the easiest transition from the current scheme which is somewhat like a Premium FIT with a little more volatility (around both ROC and wholesale electricity prices). This has some attractions as it could be introduced in a fashion which may limit the likelihood of investor uncertainty causing a significant hiatus on investment in the sector. The exposure to wholesale electricity price is, however, likely to cause higher costs of capital and will in some cases mean that pools of equity are unavailable. It also has the risk that high wholesale prices in the future could lead to excessive costs for customers. We believe that this situation could be improved by introducing a Premium FIT with a cap and floor mechanism. This is the approach used in Spain for the wind sector which has seen a significant build of capacity under the regime. The advantage of this type of Premium FIT is that the downside protection would help to increase debt capacity and reduce cost of capital for investments. The upside cap would stop excessive costs for customers where wholesale prices rise significantly. The linkage to wholesale electricity prices would be complimentary to the carbon price support proposals.

The cap and floor would need to be fixed prices with an appropriate indexation. The indexation would need to be carefully considered but for wind and solar type investments would make most sense being an inflation related index. For biomass it would be preferable if an index could be found with some linkage to ongoing biomass fuel costs.

On balance, for the reasons set out above, we believe that an indexed Premium FIT which incorporates an indexed cap and collar mechanism is the best option of the three FIT models, as price signals are retained and the generator is able to choose the appropriate PPA structure for its risk profile. As the Premium FIT model is closely aligned to the current Renewables Obligation regime, if set at the correct level it would stimulate deployment (subject to avoiding an auction/tender process) and would be clear to investors.

To summarise, balancing the requirements of access to and costs of capital, cost to consumers and transition risks, we rank the FIT schemes as follows:

1. Premium FIT with cap and collar
2. Fixed FIT
3. FIT with CfD
4. Premium FIT

Whichever feed-in tariff mechanism is selected, the access to the market and the process of awarding a FIT to a project need to be considered.

A FIT regime introduces significant additional development risk under an auction or tendering process, with the potential that either too few projects will be brought forward or a number of speculative projects which will then fail to materialise. This differs from the current RO regime, where projects can be fully developed and brought to financial close in anticipation of a known regime and revenue structure and a view on future revenue streams. Fewer projects are likely to be fully developed and ready for financial close prior to entering an auction or tender process due to uncertainty over future revenue and the upfront costs involved prior to entering a process over which the participant has limited influence or control. As such we are strongly against an auction based system for determining pricing for any of the proposed schemes. We understand the theoretical arguments around optimum price determination. However, in our experience this has been tried on a number of occasions in the sector around Europe and the experience has generally been rather poor, including the NFFO scheme used in the UK prior to the RO.

For independent generators, access to the market is a significant potential impediment to allowing them to successfully develop projects. The current system is heavily weighted in favour of the large six suppliers to get bankable long-term access to market and pricing for projects. However, the obligation on Suppliers to obtain ROC's has, we believe, encouraged the large suppliers to play an active role in the market so that at least projects do have access to place their capacity in the market. (We acknowledge that the buyout option for Suppliers means it is not truly an obligation. However, in terms of PR we believe there have been strong incentives for Suppliers to attempt to contract capacity in the market).

In the new proposals a significant advantage of a fixed FIT is presumably it would be based around a Government backed off-taker which would ensure that renewable generation from independents was not disadvantaged (the credit quality of a Government based off-taker would again reduce cost of capital). For a Premium FIT or FIT with CFD we have some concerns that independent generators will have some trouble accessing the market given lower incentives for Suppliers to look to contract smaller independent generators for the wholesale element of their remuneration. This could result in a the market ultimately being either restricted to the integrated utility players or to higher costs for consumers as suppliers extract a quasi monopoly rent to allow independents to access the market. We believe that consideration should be given to a body selling all renewable generation into the wholesale market with privileged access to the market for low carbon generation.

With either the Fixed FIT or FIT with CfD, appropriate indexation will need to be proposed and it is likely that different indexation is appropriate to wind compared to say biomass where the ongoing operating and fuel costs are significantly higher. Simple RPI or CPI indexation may be appropriate for the Premium FIT where overall revenue is linked to the wholesale electricity price although our preference would be for any such scheme to include an indexed cap and collar mechanism, the former to protect the Government and the latter to provide a floor to encourage investment.

It is also unclear from the consultation document how biomass co-firing will be supported. Assuming post 2017 accredited co-firing projects are awarded a FIT, it is important that dedicated biomass projects are supported on an equitable basis (which may not be the same FIT regime). Under a Fixed FIT or FIT with CfD (subject to indexation used), co-firing will be over-supported compared to dedicated biomass assuming wholesale electricity prices increase above the indexation used, as co-firers will get access to that price and equivalent reduction in fossil fuel prices for limited investment. This can be best accommodated by adopting a Premium FIT under which co-firers and dedicated biomass projects will be competing for similar fuels but will have similar revenue streams, allowing for reduced co-firing support as under the banded RO.

Clarity required in the White Paper

In addition to clarifying the transition details from the consultation, the following clarity is required:

- Which feed-in tariff is to be adopted
- How the tariff will be set
- How the tariff will be accessed (auction, tender or other process)
- How long tariffs will be available until reviewed
- If FIT with CfD is to be adopted, what reference index to be used
- Obligation of suppliers to contract with renewable generators, how will this be achieved under either the FIT with CfD or Premium FIT schemes

Detailed Response

Current Market Arrangements

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

We agree with the Government's assessment that changes to the market and new additional mechanisms are required to support the requirements of security of supply, decarbonisation, and deployment of renewable generation whilst balancing affordability.

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

Yes.

Options for Decarbonisation

Feed-in Tariffs

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

As a significant investor of equity into renewable energy assets across a range of European regimes, MIRAEL has evaluated and invested in many different regulatory regimes similar to those being discussed in the consultation document so is well placed to comment on the impact of those regimes on investment attractiveness. In general terms the following areas are the key considerations with respect to investment attractiveness for infrastructure equity:

- Stability of Government policy e.g. how stable is Government and do different parties have widely differing views on the policy;
- Stability of regulatory regime e.g. how often does the regime change, how sustainable is the regime in terms of delivery against any stated Government targets, how does the cost of the regime compare to other schemes across Europe;
- Volatility of pricing under the regulatory regime (and therefore certainty of income) e.g. fixed feed-in tariffs versus tariff subject to green certificate and wholesale price volatility;
- Complexity of the framework. The more complex the framework the less likely it is that investors will get comfortable that their understanding is sufficient to take the risk of investing capital into projects; and
- Protection for investments already made under the regulatory framework. If the Government does not show a commitment to protect existing investments when it determines that regulatory change is essential, then this will be an unattractive area to place long-term investment capital.

It should be noted that given that MIRAEL has invested equity into the current UK renewables regime, that there is a good degree of comfort with the existing model for investment. The regime is considerably more complicated than many other schemes across Europe and has been subject to a number of regulatory changes over the years. Whilst neither of those are desirable characteristics, the approach the Government has taken to these changes, in being careful to ensure existing investment is not disadvantaged (and have listened and responded when proposed changes which would be detrimental have been put forward) and the fact that changes have been incremental and understandable in the context of meeting the UK's climate targets has ensured that investors have retained faith in the current system.

In terms of ensuring the Government's objectives of cost-effectiveness are met this involves setting a level of support that is sufficient to ensure projects are built to meet de-carbonisation targets but that are not set at excessive levels offering an unbalanced risk-reward outcome. The required levels of support will depend upon the style of the framework since this will have an impact on the returns required to attract capital into the market. In general we would make the following remarks around the different proposed frameworks including the current regime.

The requirement to change to a FIT model assumes that there are issues with the current Renewables Obligation regime. We believe, following the introduction of banding, that the current RO scheme with appropriate banding reviews has the potential and flexibility to deliver the required investment in low-carbon generating capacity. It is also well understood by the investment community and does not require a transition and in terms of support levels provides investors with the two key elements: support level and a reasonable degree of certainty. Whilst projects remain exposed to wholesale price movements, this is an element of risk that is, at least, understood and would be mitigated partially by the carbon price support mechanism. In terms of cost of capital, the RO scheme probably does not achieve the lowest cost of capital given the exposure to wholesale prices which impacts the cost and volume of debt and equity.

We believe that the introduction of a feed-in tariff has the potential to increase the pool of capital available to the low carbon generation sector and to reduce the cost of capital demanded by investors, if it is well designed and meets the considerations set out above. In terms of the three potential FIT regimes put forward in the consultation document our views on how they would impact decision making in terms of the equity that we invest are set out below.

Fixed FIT

Fixed feed-in tariffs are a clear favourite with infrastructure equity and would open up the maximum quantum of equity to the sector. They are also associated with lower costs of capital in general. We understand the Government's concern that a fixed FIT is somewhat disassociated with wholesale electricity prices and the carbon support being proposed within that area. As such the two schemes do not naturally sit together in a complimentary fashion.

Premium FIT

A Premium FIT would work as the easiest transition from the current scheme which is somewhat like a Premium FIT with a little more volatility (around both ROC and wholesale electricity prices). This has some attractions as it could be introduced in a fashion which may limit the likelihood of investor uncertainty causing a significant hiatus on investment in the sector. The exposure to wholesale electricity price is, however, likely to cause higher costs of capital and will in some cases mean that pools of equity are unavailable. It also has the risk that high wholesale prices in the future could lead to excessive costs for customers. We believe that this situation could be improved by introducing a Premium FIT with a cap and floor mechanism. This is the approach used in Spain for the wind sector which has seen a significant build of capacity under the regime. The advantage of this type of Premium FIT is that the downside protection would help to increase debt capacity and reduce cost of capital for investments. The upside cap would stop excessive costs for customers where wholesale prices rise significantly. The linkage to wholesale electricity prices would be complimentary to the carbon price support proposals.

The cap and floor would need to be fixed prices with an appropriate indexation. The indexation would need to be carefully considered but for wind and solar type investments would make most sense being an inflation related index. For biomass it would be preferable if an index could be found with some linkage to ongoing biomass fuel costs.

FIT with CFD

We understand the theoretical assessment of the benefits of a FIT with a CFD. If it provides long term price certainty this should decrease cost of capital and increase the pool of capital available. In addition, it has a compatibility with the carbon price changes proposed in that increased wholesale electricity prices would automatically reduce the cost of support for generators. Further, the Government hopes to encourage optimal behaviour in responding to short term electricity pricing signals.

We have some concerns that in practice this scheme has a number of issues which may reduce its effectiveness. These include:

- Complexity/Income Volatility – whilst in theory straightforward, in practice there are a lot of issues around the chosen index and basis risk for the generator and understanding how this may impact on risk to income. The scheme has not been seen in any other market in Europe and so is an unknown to financiers and equity investors, increasing the risk around transition.

- In practice we think the scheme is likely to lead to independent generators seeking to negotiate power purchase agreements that remove the basis risk and thereby offer Generators a fixed price with no exposure to short-term electricity price changes (note this is what has happened in many cases with respect to the RO regime in order to remove wholesale price risk to enable capital to be made available).

- For this regime to work it would be vital that liquidity in the market increases dramatically to enable generators to effectively manage the risks of short-term price exposures. Whilst we accept that this is being reviewed, it is not clear at this stage that this could be successfully achieved, meaning that independent generators would have a potentially major exposure.

- Based upon our discussions with DECC on 25th February, it appeared to be suggested that the FIT with CfD mechanism would protect against (i) excessive support costs from a HMT perspective; and (ii) over delivery; whilst also providing clear market signals to generate compared to a Premium FIT. We do not believe that this is the case. In the event of wholesale prices being very low or even negative, under a CfD mechanism this will lead to a higher CfD payment, the trigger for deployment and generation will not be the wholesale market (reference) price but the actual feed-in tariff itself. Generators will be encouraged to invest and generate whatever the wholesale price. This is not the case with a Premium FIT.

In addition to the comments on the individual proposals we have some general comments on aspects that could impact any scheme.

A FIT regime introduces significant additional development risk under an auction or tendering process, with the potential that either too few projects will be brought forward or a number of speculative projects which will then fail to materialise. This differs from the current RO regime, where projects can be fully developed and brought to financial close in anticipation of a known regime and revenue structure and a view on future revenue streams. Fewer projects are likely to be fully developed and ready for financial close prior to entering an auction or tender process due to uncertainty over future revenue and the upfront costs involved prior to entering a process over which the participant has limited influence or control. As such we are strongly against an auction based system for determining pricing for any of the proposed schemes. We understand the theoretical arguments around optimum price determination. However, in our experience this has been tried on a number of occasions in the sector around Europe and the experience has generally been rather poor, including the NFFO scheme used in the UK prior to the RO.

For independent generators, access to the market is a significant potential impediment to allowing them to successfully develop projects. The current system is heavily weighted in favour of the large six suppliers to get bankable long-term access to market and pricing for projects. However, the obligation on Suppliers to obtain ROC's has, we believe, encouraged the large suppliers to play an active role in the market so that at least projects do have access to place their capacity in the market. (We acknowledge that the buyout option for Suppliers means it is not truly an obligation. However, in terms of PR we believe there have been strong incentives for Suppliers to attempt to contract capacity in the market).

In the new proposals a significant advantage of a fixed FIT is presumably it would be based around a Government backed off-taker which would ensure that renewable generation from independents was not disadvantaged (the credit quality of a Government backed off-taker would again reduce cost of capital). For a Premium FIT or FIT with CFD we have some concerns that independent generators will have some trouble accessing the market given lower incentives for Suppliers to look to contract smaller independent generators for the wholesale element of their remuneration. This could result in a the market ultimately being either restricted to the integrated utility players or to higher costs for consumers as suppliers extract a quasi monopoly rent to allow independents to access the market. We believe that consideration should be given to a body selling all renewable generation into the wholesale market with privileged access to the market for low carbon generation.

To summarise, balancing the requirements of access to and costs of capital, cost to consumers and transition risks, we rank the FIT schemes as follows:

1. Premium FIT with cap and collar
2. Fixed FIT
3. FIT with CfD
4. Premium FIT

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

For the reasons set out under question 3 we do not agree with the preferred policy of introducing a FIT with CfD, our preference would be for a Premium FIT including an indexed cap and a collar mechanism in order to protect against unexpected fluctuations in the wholesale market price.

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?

Revenue stability is viewed positively by equity investors and those providing debt funding, so transferring long-term electricity price risk to the Government should encourage investment and deployment of renewable generation assets. However, in our experience, the certainty of the support regime is of equal importance as equity and debt providers understand the drivers of electricity price and have become more comfortable with this degree of risk.

As detailed above, we do not believe that the FIT with CfD model transfers electricity price risk to the Government in all cases. Generators are left with significant price risk as the CfD settlement is derived from the difference between the agreed tariff and the market price which can be volatile. This can be mitigated through a PPA which mirrors the market price used in the CfD but this then becomes a Fixed FIT where generators are rewarded for generation at the same level whatever the wholesale market price, and thereby the link to the market is lost, although generators will be left with a compromise between balancing risk and power price discount.

We believe that some exposure and link to the electricity market is sensible as generation is financially rewarded when it is most needed and (biomass) fuel and operating costs and electricity prices are linked to economic activity.

This could be achieved by a Premium FIT with cap and collar mechanism, but needs to be balanced against the uncertainties of changing the support mechanism at this point given the recent and current uncertainties elsewhere across Europe (e.g. Grandfathering, PV feed in tariffs and Spanish PV tariffs).

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?

See above.

As an example, under the RO scheme, EPRL's five biomass power stations and CLP's landfill sites are encouraged to generate during the higher priced winter months. Annual outages are scheduled for the summer when power prices are typically lower. This would not necessarily be the case under the Fixed or CfD FIT proposals, though in practice outages are easier to do during summer months when there are more hours of daylight.

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?

We agree with the theory underpinning the Government's assessment of the different models. However, we believe that residual electricity price risk for generators under the FIT with CfD is greater than the Government assumes (for the reasons stated above) and therefore the cost of capital and overall costs to society are likely to be understated. In addition the complexity introduces a level of uncertainty that will take some time for the investment community to understand and get comfortable with. This may introduce a hiatus in investment. As modelled in theory, we would argue that the FIT with CfD is little different to a Fixed FIT and therefore has the same disadvantages.

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 impact will depend upon the level of support afforded under each of the models. It is difficult to comment further on the abstract models without understanding the specific values being ascribed to each. However, anything which takes out commodity price risk will increase the amount of institutional capital available (if it works and is not too complex). For example, some pension funds would currently not invest in the UK system due to exposure to electricity price risk. If this is largely eliminated, a much larger pool of capital would become available. Existing investors in the space such as MIRAEL would be likely to make more capital available in similar circumstances to those described above.

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?

The impact of FITs on different types of generators will depend largely upon the implicit support levels and the relative appetite for risk.

Under a Fixed FIT there will be limited relationship with Suppliers; this will presumably be administered by a central body, in the same way that NFPA operates under the NFFO regime (it is assumed that the Fixed FIT price will incorporate LECs). Consideration will need to be given to the treatment of Generator Use of System charges/credits under such a scheme. A Premium FIT scheme will require a PPA with a supplier (covering output, LECs and Generator Use of System charges/credits) equivalent to those in place under the RO scheme. A FIT with CfD will require a PPA with a supplier (covering output, LECs and Generator Use of System charges/credits) but to mitigate electricity price risk the generator may require the electricity price to mirror the market. However, there is some uncertainty over whether the parties' conflicting goals (the supplier wanting greatest output in periods of highest demand and wholesale prices, whilst the generator will be ambivalent as the revenue per MWh is effectively fixed to the CfD strike price) can be accommodated in such a regime.

Note our earlier discussion on this area. For investors prepared to take short-term pricing risk we believe there is a reasonably competitive market for power purchase agreements. However, for projects needing long term bankable contracts it is wholly reliant on the large six suppliers in the UK. In our experience this does not make for significant competition in terms although the ROC system has at least ensured that a route to market is generally available. A Premium FIT and FIT with CFD system has the disadvantage that independent generators are only selling wholesale power to the Supplier. Given that often these projects will be relatively small there will be limited incentive for Suppliers to engage in negotiations without very large discounts which means that the premium paid on top of wholesale electricity will need to be larger increasing costs to consumers at the expense of increased profitability for the large Suppliers.

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

Greater wholesale market liquidity is required in the FIT with CfD regime where the generator is unable to contract under a PPA on a basis which mirrors the CfD mechanism. With a fixed price PPA structure under a FIT with CfD regime, greater wholesale market liquidity will reduce (but not eliminate) exposure to price volatility. Without some form of institutional solution which ensures independent generators have a route to market greater liquidity in the wholesale market is an absolute must, otherwise it is likely that independent generators will not play a significant role in the market.

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

In general we believe a FIT should be paid on output as an availability based system would tend to risk gaming from generators and need far greater administrative oversight.

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?

Yes.

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?

We consider option 2 (limit equivalent to 450gCO_2/kWh) to be appropriate. This provides a strong signal on the need for decarbonisation whilst providing for the principle of exceptions in the event of energy shortfalls and derogations for projects forming part of the UK's demonstration programme.

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

We agree that the EPS should be targeted at new plants and grandfathered at the point of consent in order to provide certainty for investors. At this stage we would suggest that grandfathering should be set as a minimum period based upon a station's expected operating life determined by experience.

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?

The principle of extending the EPS to cover existing plant which is extended or upgraded is fair. As a minimum, given that a grandfathering period will be set for new plant, this period could be used to set a date after which existing plant have to comply with the currently existing EPS level. This does not directly answer the question of extensions and upgrades but would provide a finite life for existing stations not provided with an EPS level.

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

Yes.

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

We agree that the emissions from co-firing of biomass should be differentiated in assessing EPS compliance but we do not believe that the differentiation should take the form of zero-rating biomass. It should also be noted that co-firing of biomass is, and will continue to be, supported through co-fired ROCs and the planned carbon price support mechanism so any scheme should take this into account and ensure that co-firing is not over-supported in terms of financial regime or EPS compared to dedicated biomass plants.

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

Whilst in theory we do not agree (as the market should ensure that this does not arise), in practice, exceptions should be allowed.

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 agree with the assessment of introducing a capacity mechanism.

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

Yes.

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

A successful capacity mechanism (in whatever form) will lead to greater capacity margin and therefore should reduce both wholesale prices and market volatility.

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.

Yes.

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?

A targeted capacity mechanism should be able to incentivise demand-side response.

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

Our preference would be for a targeted capacity mechanism based upon last-resort dispatch in order to minimise market distortion.

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

On balance we do not believe that capacity pricing should differentiate by location. Given that use of system charges for generators and high use demand customers (already implemented through CDCM and to be implemented through EDCM on 1st April 2012) are intended to send cost signals based upon network constraints, we believe that further cost signals are unnecessary and could lead to double payments or costs, and risks further market distortion.

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?

We agree that a package of options is required to meet the objectives of ensuring the supply of reliable, low-carbon and affordable electricity. We also agree broadly with the proposed elements of support; however we believe that FIT with CfD is not the optimum mechanism (subject of course to the chosen level), it does not fit with a carbon price support mechanism (see below) and we suggest that a Premium FIT scheme with indexed cap and collars would be preferable.

A renewable energy generator operating under a Fixed FIT or FIT with CfD will not benefit from carbon support mechanism, except to the extent that it is incorporated into the FIT as there is no link to the wholesale electricity market.

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

See above.

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?

Not that we are aware.

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

The consultation document details the principal interactions. One impact not considered specifically is that of the carbon price support mechanism and the demand for biomass for co-firing, which could be further encouraged by the EPS. Whilst this is generally positive, the risk of co-firing being over-supported needs to be managed and an increase in co-firing will lead to an increase in the cost of biomass fuel which will have an adverse impact upon dedicated biomass generators. Whilst biomass generators may benefit from higher wholesale electricity prices (based upon carbon price support), it is likely that much of this will be offset by higher biomass fuel cost.

Whilst each round of FIT will be able to take account of biomass costs, existing biomass generators (under RO and previous FIT schemes) will be disadvantaged and penalised. The same is true under the existing banded RO regime on the basis that existing biomass generating plant is grandfathered. This is of concern given the significant proportion of operating costs represented by biomass fuel.

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 principal implementation risks are setting the carbon price support level, capacity mechanism and FIT CfD strike price in order to meet the policy objectives whilst guarding against unnecessarily high returns. The biggest risk of these is setting the CfD strike price; this will need to be different for each technology and such strike price will need to include consideration of the Government's assessment of the technologies of which it wishes to encourage deployment. This would be the same key risk across all of the potential FIT options.

In our opinion, the other key implementation risk with respect to the proposed package is the risk that its complexity and bias towards large integrated players will lead to a hiatus in project development from independent developers and a hiatus in debt financing availability whilst the scheme is properly understood and the risks fully considered. The major project finance banks operate across the world and therefore will place capital where the risks are best and most easily understood. There is a risk that a completely new type of scheme leads to, at best, a hiatus and at worst the allocation of scarce capital to other renewable markets across the world.

The CfD strike price can either be set by the Government or through auction/tender. The Government has to date set support levels through the RO scheme and reflected on the relative costs and risks of different technologies when the RO was banded from April 2009. This method would pose least implementation risk. The consultation document notes the risks associated with an auction based approach and we believe that these significantly out-weigh the potential benefits of price discovery.

The implementation risks are broadly the same for each package under consideration. However, we note the risk of increasing competition and costs of biomass fuel linked to the carbon price which are unlikely to be offset by increasing electricity price and revenue under a Fixed FIT or FIT with CfD regime with simple indexation.

The implementation risks of setting the CfD strike price (or any other FIT scheme) could be removed by leaving the existing RO scheme in place.

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 believe that an administratively determined support level, based upon research and cost data is preferable to the risks of an auction or tender process. Whilst an auction can allow price discovery it requires an efficient process with a number of participants. It also increases development risk, by increasing upfront development costs with no guarantee of a successful tender at the end of the process and this would restrict competition.

There is also a significant risk of projects which are successful in the auction/tender process but which success is due in part to costs having been understated or risks not being fully understood, ultimately not being commissioned.

Whatever process is used for price setting, it must be technology specific in order to allow a broad range of technologies to be deployed and to mitigate the risk of dependence on a single technology. Prices could be set for individual projects (although this could lead to increased ongoing administrative costs) but this is unlikely to work for those using common biomass fuels as it would distort competition for such fuel.

An auction could assist in preventing FITs from incentivising an unsustainable level of deployment of one particular technology. This could also be achieved when setting the support level through an administrative process.

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

The consultation document details the many institutional arrangements which will need to be developed under the various packages under consideration and we have nothing further to add in this regard.

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?

There are two potential unintended consequences which need to be addressed specifically in terms of transition:

(i) Whilst it is proposed that new projects will be able to opt for either RO or the agreed FIT between April 2013 and March 2017, it is unclear how this would be achieved, given that qualification for the FIT may be achieved through some form of auction or tendering process. This is particularly relevant for a project which misses the March 2017 date, could no longer get RO accreditation but failed in an auction process. Our preference is to avoid auction or tender processes in any event; and

(ii) The issue of NFFO contracts which end post March 2017 is not addressed in the consultation. Prior to this consultation the expectation was that these would be supported under the RO regime until 2027.

Given the recognition of the importance of an effective transition and the intention to honour previous commitments, we are sure that these two specific circumstances can be positively addressed through the process. As a suggestion, perhaps a grace period for RO final accreditation could be agreed (of, say, two years for projects pre-accredited before April 2017). In addition, all operating NFFO contracts could be terminated and projects switched to the RO regime at some point prior to April 2017, this would have the benefit of both certainty and a potential saving in associated administration costs.

One further point in this regard, the 2011 ROO consultation detailed the issue of appropriate support mechanism for RO projects with extended operation lives beyond 2027 or 20 years through significant refurbishment and/or capital investment. We are supportive of such support (and extended support for biomass projects generally due to ongoing fuel costs) and this should be considered in light of the proposed switch to a FIT regime.

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

We agree that with any change in regime (be it a change in RO banding or support mechanism) may lead to a lack of clarity and could will give rise to a delay in investment and this is adequately addressed in the consultation document. However, the document does not consider that the relative complexity of the options will potentially have a significant impact on whether delays occur. In our opinion, the current preferred package (including FIT with CfD) has much greater risks, in this regard, than other FIT proposals.

See answer to question 33 on two identified transition risks which need to be specifically addressed.

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 agree with maintaining the RO regime through to 31st March 2017. There is a risk that schemes anticipating RO accreditation and being developed on that basis but which have not been successful in a FIT tender/auction process could miss this deadline. We would suggest a grace period post 31st March 2017 for final RO accreditation.

Alternatively, the RO scheme could be maintained and not replaced by a FIT regime.

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.

Both options are acceptable although the second option would lead to greatest deployment.

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?

Our suggestion is to undertake the scheduled RO banding reviews.

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

Provided that the level is equivalent to expectations (to protect existing investors) and is in line with the comparative FIT, fixing the price of a ROC (incorporating some value for the recycle element) would be our preferred option and would remove one of the complications of having two regimes co-existing and would save some administrative costs.

However, this would potentially have implications for existing long term power purchase agreements that could result in termination for change in law which may have implications for the financing of these projects. Therefore, consideration should be given to this factor whereby a continuing obligation on suppliers in line with the current way the scheme works might ultimately allow all agreements to continue until their natural end. There is also an implication on whether, without a continuing obligation, independent generators would find a route to market (see earlier responses).

We are strongly of the opinion that existing generators should be given the option to opt-into any new scheme which the Government implements. As a principle of safeguarding existing investments, it is important that where significant new changes are proposed to the market, existing generators have the right to participate in that new regime at their option. We would propose that this right could be given to generators at the implementation of the new scheme and also when long-term power purchase agreements have terminated. As the Government has identified, changes it is making to the market to encourage wind and nuclear power may lead to a collapse in wholesale electricity prices. If that is the case, generators under the RO regime may be forced to close prematurely with significant losses for investors. To guard against this outcome it would be fair and reasonable for existing generators to have a right to access the new market (though that right should clearly end at the same point as RO qualification would end).