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10 March 2011

DECC Consultation on Electricity Market Reform, December 2010:
A Response by Drax Power Limited

Summary of Key Points

- **Drax agrees that the current market will not deliver the Government's key policy objectives on security of supply, the decarbonisation of electricity generation and affordability to end consumers.**

- **These objectives are best achieved by maintaining adequate generation capacity margins and plant flexibility, incentivising appropriate cost-effective investment in low carbon generation technologies, and promoting greater wholesale market liquidity.**

- **The Emissions Performance Standard (EPS) is an unnecessary layer of additional legislation which could be counter-productive and should be dropped.**

- **We have serious reservations about the carbon price support proposal. If it is introduced it must be set at, or very close to, the EUA price and introduced on a timeline that fits with the support requirements of new nuclear generation. If not, it will distort the GB and EU electricity markets and provide significant, costly and unnecessary windfall profits, mainly for existing nuclear generation, but also for existing renewable and gas generators.**

- **A broad Capacity Mechanism and a Contract for Difference (CfD) Feed-in Tariff (FIT) for low carbon generation have, together, the potential to help achieve these objectives, provided they are designed and implemented appropriately.**

- **A Capacity Mechanism is required to maintain security of supply - particularly with increased deployment of intermittent and inflexible generation capacity over the next decade and beyond. However, DECC's proposed Targeted Capacity Mechanism (TCM) is not appropriate and a wider capacity mechanism should be developed which:**
  - **does not focus narrowly and exclusively on meeting extreme peak demand;**
  - **recognises the critical importance of flexibility in maintaining security of supply in real time;**
  - **ensures there are adequate returns for making both new and existing capacity available to the market, thereby avoiding early and inefficient closure of existing plant; and**
  - **incentivises the provision of enhanced flexibility from both new and existing generators.**

- **Drax and other members of the Independent Generators' Group commissioned Oxera to review DECC's proposed Targeted Capacity Mechanism (TCM) and**

suggest an alternative which better meets the above criteria. Their report has been submitted separately to DECC but the Executive Summary is attached (Annex 2). The key point on the TCM is that it would create market distortions and deter investment in required capacity by influencing peak prices. Oxera also suggest a possible wider alternative.

- **Drax believes a wider capacity mechanism is essential, but the precise design of that needs further discussion.**

- **The CfD FIT approach is the most appropriate and cost-effective mechanism to incentivise investment in new low carbon generation. If designed correctly it will reduce regulatory uncertainty for investors, increasing their confidence to invest. It will also lower the cost to end consumers and in particular ensure any potential excess revenues from high market prices are returned to end consumers.**

- **The key suggested features of a possible CfD FIT regime are set out in Annex 1, but in summary:**

  - **scheme payments to (and from) low carbon generators should be administered by an independent body, with payments made from a levy on customers collected by all licensed suppliers in accordance with a new licence condition or statutory instrument;**
  - **the Independent FIT Administrator (IFA) would periodically (eg. every 6 months) review the FIT Levy Rate to be charged by all suppliers (p/MWh supplied) and adjust it if necessary;**
  - **the CfD strike price should be:**
    - **banded by technology,**
    - **fixed for 20 years with appropriate indexation, which may incorporate fuel costs for biomass and CCS,**
    - **paid (for all technologies) by reference to a single, liquid, transparent traded index – Drax recommends a Week Ahead index,**
    - **set, initially at least, through a cost-based banding review process rather than auctions;**
  - **eligibility for CfD contracts should be based on a “2 Gate” process with contracts offered on receipt of planning consent, and confirmed at Financial Close (or equivalent). This will eliminate the current issue under the RO which has stifled investment;**
  - **transition between the RO and the new FIT regime must not disadvantage any investors in RO schemes and needs to avoid any investment hiatus:**
    - **there should be a period of parallel running prior to 2017 during which developers of new projects can choose either scheme,**
    - **all schemes accredited under the RO should be given a one-off opportunity to switch to the FIT prior to 2017,**
    - **all RO support levels should be grandfathered for their remaining supported period beyond 2017,**
    - **RO Headroom should be fixed at say 10% from 2017 until 2027 and then ROC levels fixed thereafter to the RO end date of 2037,**
    - **sustainability requirements for biomass should be grandfathered at either the point of accreditation under the RO, or on granting of a CfD contract under the FIT, to minimise investment risk;**

  - **DECC should consider offering smaller, embedded low carbon generators (eg. <10MW) a full, fixed FIT.**

About Drax

Drax is predominantly an independent power generation business responsible for meeting some 7-8% of the UK's electricity demand. The Company also owns Haven Power, an electricity supplier serving the needs of business customers.

Drax is the owner and operator of the 4000MW Drax Power Station in North Yorkshire, which is the largest, cleanest, most efficient and most flexible coal-fired power station in the UK. As such, Drax is committed to playing its part in reducing its carbon footprint and that of UK power generation. To this end, in summer 2010 the largest biomass co-firing facility in the world was commissioned at the power station.

With the capability to produce 12.5% of the station's output from sustainable biomass – equivalent to the output of over 700 2MW wind turbines – Drax is by some distance the largest renewable generating facility in the UK. In 2010, Drax produced around 7% of the UK's renewable power, more than twice that of the next largest facility. In addition, we are more than two-thirds of the way through the largest steam turbine modernisation programme in UK history. Together these two initiatives will reduce our emissions of carbon dioxide (CO_2) by over three and a half million tonnes a year, which represents a reduction of over 17% compared to 2006 levels.

Drax is pleased to have the opportunity to participate in the EMR consultation. As a key provider of flexible generation and system support services to the System Operator and a very significant investor in renewable electricity generation from biomass, Drax believes it is well placed to comment.

Introduction

This DECC EMR consultation is part of a package of proposals developed by the Government to put in place a framework to facilitate the £200bn+ investment needed to ensure we can meet our binding 2020 carbon emissions and renewables targets, and put the UK on a sustainable and credible path to its longer-term commitment to reduce carbon emissions by 80% by 2050. As such it needs to be considered alongside the proposals for carbon price support put forward by HM Treasury in December 2010.

Drax supports the need for changes to the current market arrangements in order to deliver the Government's key climate change, decarbonisation and renewables targets while maintaining secure energy supplies and minimising the cost to UK consumers. These objectives are best achieved by putting in place a stable, enduring, credible and efficient framework to incentivise investment in low carbon generation; introduce a new market mechanism to ensure there is adequate generation plant margin and sufficient flexible capacity to complement and support the increasing volumes of intermittent wind and inflexible nuclear generation on the system; and promoting greater liquidity, competition and tenure of contracts within the electricity wholesale market.

We do not believe any of the packages of proposals put forward by DECC fully meets these design criteria for the reasons outlined below.

Incentives for Peak and Flexible Capacity

Significant generation investment is needed to meet future peak demand and flexibility requirements, despite relatively low forecast demand growth over the medium-term. Up to 20GW of intermittent wind capacity is expected to be connected to the system by 2020, with the closure of around 18GW of fossil plant and 7GW of nuclear plant expected to occur over the same period. In addition, the availability of existing flexible plant is also expected to reduce over the next decade, as such plant has to comply with increasingly stringent environmental legislation. However, the need for flexible plant will actually increase because:

- typically, demand increases by up to 50% on a winter morning between the hours of 5am and 9am. This will not change and may actually increase; and
- by 2020, the extreme hour-to-hour changes in demand net of wind output could be as much as 17GW[1], which is a significant increase from the maximum variation of 5GW in 2009.

In these circumstances, there is a need for market mechanisms to recognise the critical importance of flexibility in maintaining security of supply in real time. This is best done by ensuring there are adequate returns for making all flexible capacity available to the market, thereby avoiding early closure of existing flexible plant. In addition, provision of medium-term signals for investment in existing and new flexible plant and demand side measures is required, which would ensure the most efficient investment prevails, lowering the cost to end consumers. Neither of these is provided by the current energy-only market arrangements and it is therefore clear that a capacity mechanism of some kind is required.

In order to deliver efficient investment in flexible capacity and demand response, the capacity mechanism must provide signals to the market that allow both new and existing plant to compete both to meet peak demand, but also for the provision of flexibility and system support services. DECC's preferred approach to a capacity mechanism, the Targeted Capacity Mechanism (TCM), does not provide existing plant with the appropriate signals to deliver security of supply services. The proposal could force existing flexible thermal capacity to close prematurely, when such plant may well represent the most efficient investment option to provide peak demand and flexibility services.

DECC's preferred solution focuses too narrowly and exclusively on meeting extreme peak demand scenarios (such as winter peak requirement), and fails to address the looming issue of flexibility in low demand periods. Given the increasing volumes of intermittent wind and inflexible baseload nuclear generation capacity coming on stream over the next decade, it is essential that the capacity mechanism addresses both seasonal capacity demand extremes and hour-to-hour flexibility requirements. The technical characteristics of certain plant (e.g. the ability to quickly increase or decrease output) makes them more suitable for providing flexibility services than others. This needs to be reflected in the capacity mechanism.

In addition, the capacity mechanism options suggested in the EMR consultation are the two extreme solutions, i.e. a highly targeted approach that is limited to a very small volume of Open Cycle Gas Turbine (OCGT) plant and an all inclusive (i.e. all plant) approach based upon a fixed capacity payment value. Whilst the consultation document critiques the difference in cost between the two approaches, it fails to recognise that there is the potential to develop models that fit between the two extremes. Such models could deliver greater security of supply at an acceptable cost to the consumer, based upon a market approach that promotes competition in order to provide the most cost effective solution. There is also scope for greater involvement of demand side response as a flexibility provider.

Drax believes it is inappropriate and inefficient to build a capacity mechanism around a prediction today of what may be required at some distance into the future from an assumed type of plant, for example OCGT plant that typically runs for only around 30 minutes on a few occasions per year.

Rather than the narrow TCM approach, Drax advocates a broader capacity mechanism that is available to all types of plant and demand measures capable of providing reliable flexibility services. It should be underpinned by clear investment signals either set by a central body or

[1] Green, R., (2010) "Are the British Electricity Trading and Transmission Arrangements Future-proof?", Utilities Policy

by a market mechanism. Competition should provide the most efficient and cost effective solution to both extreme peak demand and hour-to-hour variation in intermittent generation output. Existing Government and EU policy objectives will ensure that flexible plant is incentivised to decarbonise, in order to continue to be competitive and remain connected to the system.

A well designed capacity mechanism would also ensure that the value of both capacity and energy is transparent to all investors in the market, promoting a competitive and efficient wholesale market in which to invest.

In order to inform its views on this, Drax and other members of the Independent Generators' Group commissioned Oxera to review DECC's proposed Targeted Capacity Mechanism (TCM) and suggest an alternative proposal which better meets the above criteria. Their report has been submitted separately to DECC, although the Executive Summary is attached to this response (Annex 2).

The key points made in the report are that the TCM would create market distortions and deter investment in required flexible capacity by influencing peak prices. One possible better alternative suggested by Oxera would be a market-wide revenue mechanism based on an ex-ante annual assessment of system flexibility requirements with the revenue raised used to reward all available flexible generation and demand within any given period. We believe this should be considered as one possible alternative solution, although Drax believes there is a need for wider industry debate on this issue before any conclusions can be drawn as to the most appropriate design.

Incentives for Low Carbon Investment

Drax agrees with DECC that the CfD FIT approach is the most appropriate and cost-effective mechanism to incentivise investment in new low carbon generation. If designed correctly it will reduce regulatory uncertainty for investors, increasing their confidence to invest. It will also lower the cost to end consumers and in particular ensure any potential excess revenues from higher than expected market prices are returned to end consumers.

Attached as a separate Annex 1 is Drax's view of how a CfD FIT could actually work in practice. The key features of this are set out in the Summary of Key Points above.

Effectively managing the transition from the RO to the new FIT regime will be important to ensure there is no investment hiatus and that any investors in RO schemes are not disadvantaged. DECC will therefore need to agree the details of this as early as possible.

Drax would support a period of parallel running of at least 2 years prior to 2017 during which time developers of any new renewable projects can choose to be supported under either scheme. In addition, all schemes already accredited under the RO should be given a one-off opportunity to switch to the FIT prior to 2017. This would reduce the overall costs of the support required since the FIT should be less risky for investors, whilst not forcing any RO schemes to switch to the FIT. In both cases, the choice will have to be notified at the latest in the June prior to entry into the FIT to ensure that there are no unanticipated effects on the RO.

On RO support levels after 2017, these should ideally be grandfathered for their remaining supported period beyond 2017. RO Headroom should be fixed at say 10% from 2017 until 2027 and then ROC levels fixed thereafter to the RO end date of 2037. This would minimise any disruption to existing PPA contracts, whilst at the same time effectively maintaining the value of the RO for projects choosing to remain in that scheme.

On sustainability, mandatory sustainability requirements for biomass should be grandfathered at either the point of accreditation under the RO, or on granting of a CfD contract under the FIT, to minimise investment risk.

The carbon price support mechanism has also been put forward by Government as a mechanism to incentivise low carbon investment. As set out in Drax's separate response to HM Treasury's Consultation (the Executive Summary of which is attached as Annex 3), we have serious reservations about this proposal. We firmly believe that such a mechanism will have no real impact on new build low carbon investment because the 'bankability' of the proposed mechanism is uncertain. It will not therefore be as effective as a direct support mechanism such as a CFD FiT mechanism. This is for two main reasons:

- Indirect price signal : the carbon floor is an indirect and inefficient forward price signal for investment in low carbon generation. This is because it will only impact the wholesale electricity price when fossil fuel plant are the marginal generators in the system and thus setting electricity prices. Whereas this is expected to be the predominantly the case in the near term, in the medium to long term there will be extended periods where low carbon generation is the pricing plant on the system. The carbon floor will not influence the wholesale price of electricity in those periods; and
- Political Risk : since the level of carbon uplift is not grandfathered, and as it is a tax, it will always be subject to change. Indeed, successive Governments may well take different views of the purpose of the tax and the rate and/or trajectory it should be set at. This will be increasingly likely the further out of line UK prices (and hence competitiveness) get from prices in the rest of the EU-27.

If carbon price support is introduced it must be set at, or very close to, the EUA price and introduced on a timeline that fits with the support requirements of new nuclear generation – ie. 2018 and beyond. If not, it will distort the GB and EU electricity markets and provide significant, costly and unnecessary windfall profits of between £4-9bn, mainly for existing nuclear generation, but also for existing renewable and gas generators.

Emissions Performance Standard (EPS) for Carbon

The EPS is apparently designed to prevent any new unabated coal plant being built in the UK. There are other very effective mechanisms in place that could do exactly that without introducing new legislation, for example, the planning system. It is also unnecessary alongside the existing EU-ETS, the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED). These directives provide the framework for the agreed European-wide emissions standards (including CO_2) for electricity generation plant.

EPS is therefore an unnecessary layer of additional legislation. Creating legislation that is not actually required is inconsistent with the Government's Better Regulation Principles. It will also create regulatory risk and uncertainty for investors over the fact it may at some time in the future be tightened, or extended to cover, for example existing coal plant, or gas plant. A UK specific EPS should not therefore be implemented and the proposal dropped.

Wholesale Market Liquidity

A liquid, competitive wholesale market is fundamental to promoting efficient investment by both independent incumbents and new entrants. Except in the very short-term, the current market has inadequate liquidity, competition and tenure of contracts. Inadequate levels of medium-term liquidity continue to have a detrimental effect on the development of efficient market price signals, which diminishes investor confidence in the GB wholesale electricity market. This has the potential to jeopardise future security of supply, increasing consumer costs and damaging the wider economy and needs to be addressed.

Drax is disappointed that DECC decided not to address market liquidity issues as part of the EMR work-stream. It is essential that DECC ensures that its EMR package does not make liquidity matters any worse, At the same time DECC must continue to place pressure on Ofgem to act quickly to address the liquidity issues that independent market participants, from both the generation and supply sides of the market, currently experience. If the regulator fails to address such concerns speedily and effectively, DECC must consider direct intervention to:

- find a solution that deals with the fundamental market structure issues that lead to low levels of liquidity in the GB wholesale electricity market;
- improve market price signals by ensuring that there is a meaningful increase in generation and demand volumes traded via the wholesale market;
- promote a market in which the value of capacity (thereby investment in capacity) is visible to all participants;
- promote greater competition to lower the costs and barriers faced by new entrants; and
- ensure that plant is dispatched in an economic and efficient manner, determined by an open and competitive wholesale market.

Drax considers that a (possibly time-limited) requirement for the six major vertically integrated players to trade a proportion of their future requirements transparently through the wholesale market would be a useful and potentially effective initiative. For example, on a rolling basis, they could be obliged to trade a minimum of perhaps 5% of their expected generation and supply requirements for year 5, 10% for year 4, 15% for year 3, 20% for year 2 and 25% for the year ahead. This would not be an onerous requirement on them, but would create liquidity further out on the forward curve, which may stimulate more active trading.

Consultation Process and European Implications

The EMR Consultation is a key strand of the Government's overall package of market reform proposals which also includes the carbon price support measure. Hence we are concerned that we were not able to consider these separate but inter-related elements of the package together. Indeed, we note that the EMR analysis and the options presented by DECC all assume that the Treasury's carbon price support proposals are implemented.

In addition, a number of issues of incompatability and / or inconsistency with various European regulations have been raised during the EMR / CPS consultation processes – particularly on the Carbon Price Support mechanism. These include:

(i) the harmonisation requirements of the Emissions Trading Directive and the anticipated proposal to amend the Energy Taxation Directive;
(ii) potential granting of State aid, particularly through windfall benefits to existing generators, which would be unlawful without clearance from the European Commission;
(iii) the EU principles of proportionality and non-distortion of competition;
(iv) the prohibition on discriminatory internal taxation in Article 110(2) of the Treaty on the Functioning of the European Union; and
(v) the Third Energy Package requirements on tendering for new capacity.

It will clearly be important for investor and market confidence to ensure that the overall EMR package of proposals are robust and implemented in a manner that minimises the risk of any substantive infringement of European law. We therefore urge the Government to engage with the European Commission and clarify these matters urgently.

DECC Electricity Market Reform: Response to Specific Consultation Questions

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?***

Drax agrees with the Government's assessment that the current market will not support the required investment. Drax continues to support a bilaterally traded competitive wholesale market since such markets provide least cost solutions, delivering the greatest benefit to consumers and investors. However, the current market design is not equipped to deliver the required level of low-carbon investment.

Government must ensure that new investment incentives, such as the proposed FIT mechanism, promote greater investor certainty. The support mechanism must deliver as much of the full value of the incentive as possible to investors, continue to promote a competitive wholesale market and minimise the cost to consumers. The proposed CfD FIT approach would deliver this.

Drax agrees that action is required now in order to meet the Government's 2020 targets. It is crucial that clarity over the Government's chosen reform package is delivered swiftly.

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

Drax agrees that there is an increasing risk to security of supply over the next decade and beyond. A high volume of flexible fossil fuel capacity will disconnect over the next decade, with newly connecting low-carbon capacity (other than dedicated biomass and co-firing plant) being intermittent wind or inflexible nuclear.

Analysis from Oxera[2] and others demonstrates that whilst overall system demand may remain relatively unchanged, as wind capacity increases there will be a substantial increase in system demand variation hour-to-hour. In particular, increasing intermittent wind deployment could increase within-hour demand variation to 17GW by 2020 and 25GW by 2030.

It is therefore essential that the Government's EMR package provides a mechanism to incentivise availability of flexible capacity to meet these demand requirements. There must be signals to invest in existing plant to meet environmental legislation and provide reliable, flexible capacity. There must also be signals to invest in new efficient, flexible thermal plant to avoid a capacity shortfall.

The chosen mechanism to deliver security of supply must allow the *market* to determine which investment is made to provide the required level of security. This will provide greater investor certainty whilst delivering security of supply at the least cost to the consumer.

Drax agrees that action is required now in order to meet the flexibility requirement over the next decade.

[2] Oxera (2011), 'GB capacity mechanism design: Meeting future flexibility requirements to secure a low-carbon transition', page 6, prepared for the Independent Generators' Group, March 9th 2011

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)?

Drax agrees that a CfD FIT would be the most appropriate model. A CfD FIT approach would ensure:

- the cost of delivering renewable investment is minimised;
- consumers are protected against windfall profits;
- market liquidity is protected and potentially enhanced;
- market distortions are minimised; and
- there is a potential for the cash-flows for low carbon generators to be greatly improved and stabilised.

A Premium FIT approach would fall short of addressing the following issues:

- generators are still exposed to the volatility of power prices, thereby no greater protection of investment return;
- a larger subsidy is required to cover volatility of power price, meaning a higher cost to the consumer; and
- potential for generator windfalls at the cost of the consumer during high price periods.

A Fixed FIT approach would be the least desirable, as it would:

- fix generator revenue streams by completely remove generators from the market, thereby reducing market liquidity;
- provide no signal for economic plant dispatch, meaning a higher cost to consumers;
- render the power price unable to signal that delivered volume is not required; and
- not expose generators to the consequences of their actions (i.e. their failure to deliver contracted volume).

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

Drax agrees that a CfD based approach would provide the most appropriate low carbon support mechanism. A CfD FIT will provide revenue certainty for investors whilst protecting market liquidity and minimising the cost to consumers.

The final model should ensure improved cash-flow timescales for investors, certainty of support longevity (grandfathering) and be administered by a central body (to avoid market power).

The CfD FIT model should use a Week Ahead market index to set the support payment value, as the Week Ahead product already has strong liquidity. A Week Ahead market index also makes managing the risk of output variation much easier for an off-taker, as the price differential between Week Ahead and real time are much closer and better correlated than, for example, Month Ahead or annual prices and real time.

Concerns have been raised by small developers of their ability to contract with parties to off-take power under a CfD FIT or Premium FIT scheme; these parties are likely to be small onshore wind developers. As such, Drax suggests that small developers (<10MW capacity) could be removed from the CfD FIT scheme and provided with a Fixed FIT. It is highly unlikely that the removal of such small plant from the traded market would have a significant detrimental effect on market liquidity.

A more detailed possible CfD FIT model design with supporting analysis can be found in Annex 1 to this document.

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?***

Reform should ensure the market remains attractive to new and existing investors by:

a) ensuring the mechanism provides revenue certainty that financiers view as (and require to be) 'bankable';
b) ensuring the mechanism allows investors to achieve an efficient capital structure and lower borrowing costs; and
c) removing the market power held by large vertically integrated companies under the RO, creating a level playing field (thereby improving competition).

Removing longer-term electricity price risk under a CfD FIT approach would increase revenue certainty without the requirement for an investor to necessarily enter a long-term PPA (although that choice would still be available). This is particularly advantageous in a market with low levels of longer-term liquidity.

A key risk to market participants is where reform diminishes wholesale market liquidity and price signals, as it would under a Fixed FIT approach.

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?***

The final FIT mechanism will be aimed at renewable and low-carbon generation investment. It must be noted that there are other types of generator that are not supported by the CfD FIT (i.e. traditional thermal plant). Such plant requires a fully functioning market to underpin the investment in new and existing flexible thermal generation that will be required to provide the flexibility and system support to complement intermittent wind and inflexible nuclear generation.

Market price signals ensure optimal investment decisions and economic dispatch, minimising costs to consumers. Such signals ensure that:

- the correct level of capacity is built to meet demand (avoiding under- / over-capacity);
- the most cost effective plant is built (most competitive);
- the most efficient plant is utilised first (economic dispatch and market competition driving down costs);
- generators are incentivised to meet contracted positions (imbalance cost); and
- investment in plant continues over the long-term (increasing efficiency, thereby promoting competitiveness and minimising costs).

The preferred CfD FIT approach aims to preserve market price signals by ensuring that all generators remain "within the market". The model preserves market liquidity, preserves economic dispatch signals and ensures that generators (or their agents) receive feedback from their actions (e.g. imbalance). In addition, the model removes potential windfall generator profits due to higher than expected market prices, which would otherwise create market price distortion and increase costs to consumers.

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?***

Drax agrees that all of the FIT mechanisms would remove a degree of risk from investors, and hence reduce the cost of capital, for the following reasons:

- There would no longer be a requirement to trade certificates;
- Generators would be dealing direct with a central body with a good credit rating;
- potential for much improved cash-flow timescales; and
- potential to avoid consumer subsidies being held inefficiently in supplier bank accounts for many months.

The preferred CfD FIT approach has the added benefit of effectively removing longer-term market price risk from generators. However, this is just one of the risks faced by investors, and the overall cost of capital will reflect other issues including political and regulatory risk, planning, construction etc. Thus, while there will be a reduction, we are not convinced it will be as large as DECC assumes. Ensuring that investors can achieve a more attractive average cost of capital will encourage investment from existing players and new entrants at a lower overall cost.

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?***

All three FIT models have advantages over the existing regime as large domestic suppliers are:

- Not obliged to purchase ROCs under the RO (ability to pay the buy-out price); and
- Not obliged to purchase power under the RO (although they are in a powerful position to negotiate large discounts).

The CfD FIT and Fixed FIT models provide much greater protection against market prices (revenue certainty), which is bankable. The transfer of risk reduces the cost of capital to all types of investor (whether independent or vertically integrated), ensuring new investors are not disadvantaged.

The CfD FIT approach has the added benefit of preserving liquidity in the wholesale electricity market. This is essential if investment in existing and new flexible thermal generation is to be encouraged to address security of supply concerns.

A more detailed possible CfD FIT model design with supporting analysis can be found in Annex 1 to this document.

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?***

Each of the FIT models improves competition when compared to the RO. FITs remove investors' reliance on the 6 large vertically integrated domestic suppliers to off-take power, ROCs and LECs, which currently enable them to secure excessively large discounts on purchases of ROCs, LECs and power.

A CfD FIT approach ensures that independent renewable and low-carbon generators achieve greater revenue certainty whilst protecting wholesale market liquidity. Wholesale market liquidity is important for market price formation that encourages investment in new and existing flexible thermal plant by independent generators and new entrants.

To better accommodate investment in plant with variable fuel costs, the Strike Price should be fixed for 20 years with appropriate indexation, which would be determined by the *type* of low carbon technology:

- Those with significant fuel costs (e.g. CCS, biomass) could have some indexation to their fuel prices. This would increase Government and investor confidence that the support will be sufficient to incentivise the technology, whilst protecting consumers against over-payments if fuel prices were lower than expected;
- Those without variable fuel costs would be indexed to a time value inflator (e.g. RPI for wind, solar).

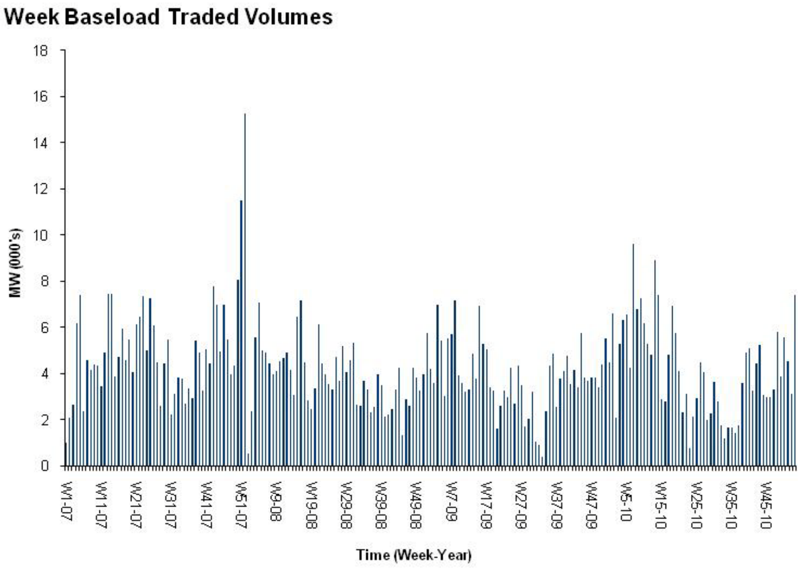
With a CfD FIT, renewable investors that want the option of entering into longer-term PPAs / off-take agreements are no longer reliant on the six dominant domestic suppliers. The FIT creates a direct revenue stream, as no certificate trading is required via a middleman. In addition, many more market participants can act as off-takers / aggregators, including suppliers, generators (both vertically integrated and independent) and banks.

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?

Short-term liquidity is sufficient to support a CfD-based FIT. It is longer-term liquidity in the wholesale market that provides the greatest barrier to investors, i.e. the ability to hedge investment. The CfD FIT approach largely removes this risk for low-carbon investment.

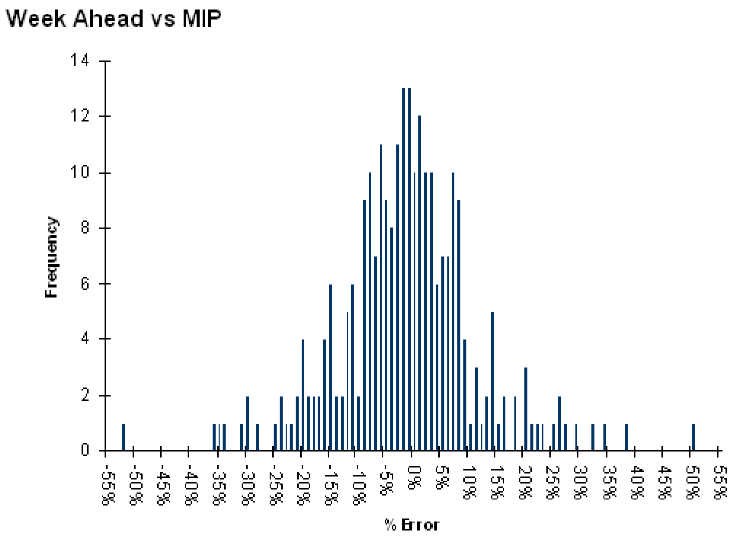
The model should use a Week Ahead market index to set the support payment value (ie. The CdF Strike Price), as the Week Ahead product already has strong liquidity; see Figure 1 below.

Figure 1: Week Ahead liquidity observed in the GB wholesale market



A Week Ahead market index also makes managing the risk of output variation much easier for an off-taker, as the price differential between Week Ahead and real time are much closer (compared to Month Ahead and real time); see Figure 2 below.

Figure 2: Margin of error between Week Ahead and out-turn prices



Once the CfD FIT is established, we would expect liquidity in the Week Ahead Index to improve even more as generators and their agents seek to manage and hedge their exposure to week ahead prices. This would then potentially attract financial and other players into the market offering financial hedging products against this index. So we may well see a developing longer-term CfD market.

A potential CfD FIT model design with supporting analysis can be found in Annex 1 to this document.

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

The FIT should be paid on output. Remuneration should be based upon the project's contribution to meeting the Government's decarbonisation targets; the incentive is for renewable and low-carbon plant to run first, not to build and stand idle.

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?

No. The EPS is an unnecessary layer of additional legislation alongside the existing EU ETS, the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED). These directives provide the framework for the agreed European-wide emissions standards (including CO_2) for electricity generation plant. A UK specific EPS should not, therefore, be implemented as it will create regulatory risk and uncertainty for investors.

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?

The EPS is an unnecessary layer of additional legislation which should not be implemented as it will create regulatory risk and uncertainty for investors. However, should the Government decide to implement an EPS, a standard of $600gCO_2/kWh$ at baseload equivalent output should be adopted. Any EPS should be grandfathered at the point of building consent in order to avoid investment risk. Any proposal should be designed to ensure it does not undermine investment in emissions abatement for existing plant.

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?*

The EPS is an unnecessary layer of additional legislation which should not be implemented as it will create regulatory risk and uncertainty for investors.

However, should the Government decide to implement an EPS, the standard should be aimed solely at new plant. Aiming an EPS at existing plant will force early closure causing potential security of supply concerns without encouraging investment in carbon abatement. Any EPS should be set and grandfathered at the point of building consent in order to avoid investment risk. The economic life of a power station will depend upon the individual technology used and the time required to repay the investment. The economic life may be individual to the technology or the site, particularly for new and unproven technologies.

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. Extending the EPS to upgrades for existing plant will force early closure causing potential security of supply concerns without encouraging investment in carbon abatement.

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

Yes. The ability to review any EPS when the effectiveness of CCS is better understood means that the Government would not be forced to set specific CCS emissions criteria now.

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

Drax agrees that emissions from biomass should be zero rated as it is a renewable technology. Biomass is treated as carbon neutral under the European Commission's EU Emissions Trading System (EU ETS) and the same treatment should apply for any EPS. Including biomass under the EPS will reduce the incentive for new and existing coal plant to build a proportion of co-firing into its design and remove all incentives for investment in dedicated biomass plant. It is important that the Government develops an overall market that encourages the use of biomass, eventually moving to a system that incentivises the use of biomass with CCS for plants with over 300MW net output, rather than the reverse.

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

No. There should be no exemptions in the event of energy shortfalls, as this will undermine the incentive to invest in carbon abatement. The market and the associated support mechanisms must provide adequate investment signals for capacity and flexibility from new and existing generation and demand to ensure security of supply.

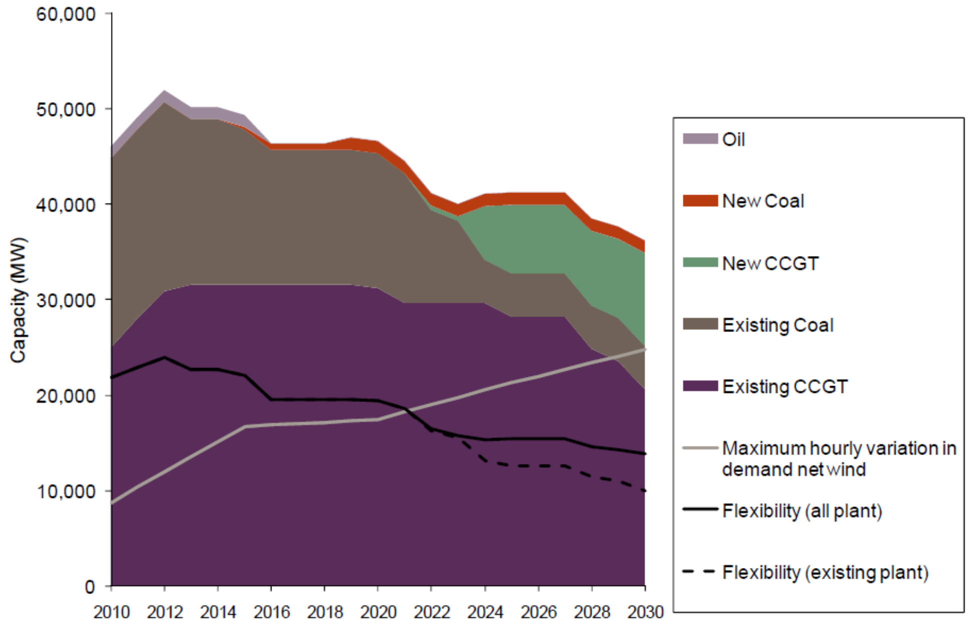
Options for Market Efficiency and Security of Supply

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

It is clear that significant investment is required to meet future peak demand and flexibility requirements. It is essential that the system is able to cope with the scheduled closure of around 18GW of flexible plant and 7GW of nuclear plant by 2020[3]. In addition, the system must contend with up to 20GW of intermittent wind capacity connected to the system by 2020[4]. This is only sustainable if the correct incentives are developed to ensure an adequate level of flexible plant is connected and available.

Analysis by Oxera[5] demonstrates that system flexibility is likely to decline over time due to a reduction in thermal capacity despite some investment in new plant, whilst flexibility requirements are expected to increase as a result of increasing wind capacity. This is illustrated in Figure 3 below.

Figure 3: Supply and demand for hourly flexibility



Source: Oxera Analysis, March 2011

When designed correctly, capacity mechanisms ensure adequate returns for making flexible capacity available to the market. This avoids forced early closure of existing plant and provides medium-term investment signals for both existing and new flexible plant. It is essential that the capacity mechanism rewards both availability and the provision of flexibility.

[3] Redpoint (2010), 'Electricity Market Reform: Analysis of policy options', page 25, prepared for DECC, December 2010
[4] Oxera (2011), 'GB capacity mechanism design: Meeting future flexibility requirements to secure a low-carbon transition', page 4, prepared for the Independent Generators' Group, March 9th 2011
[5] See Footnote 3.

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

Drax agrees that a capacity mechanism is required and should be implemented alongside a CfD FIT mechanism. The incentivised growth of intermittent and inflexible generation increases the risk of:

a) an increased hour-to-hour variation in delivered output from intermittent capacity;
b) an increased volume of connected plant that is unable to respond to hour-to-hour variation in delivered output (i.e. inflexible low-carbon capacity);
c) greatly reduced load factors for thermal plant fulfilling a "flexibility" role;
d) the market being unable to reflect the value of flexibility in the power price; and
e) the early closure of flexible plant where costs cannot be covered over a limited number of running hours.

A well designed capacity mechanism would ensure that the value of both medium-term capacity and short-term energy requirements are signalled to investors. Such signals must be transparent to all investors and continue to promote a competitive and efficient wholesale electricity market.

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

A Targeted Capacity Mechanism (TCM) would distort market price formation, which would deter investment in both new and existing flexible capacity. It is inappropriate and inefficient to build a capacity mechanism around a prediction today of what may be required some time in the future from an assumed type of plant (e.g. OCGT); competition should determine the most efficient investment option.

Traditional "last resort" peaking plant in the UK has been OCGT, running on a few occasions per year against a background of nuclear, coal and gas fired generation. It should be noted that the future generation mix will be dominated by intermittent wind, inflexible nuclear, CCS and gas powered plant and that completely different solutions may be appropriate.

The TCM approach focuses purely on extreme peak demand requirement, neglecting the importance of flexibility in operating the system in real time and maintaining security of supply. This approach could lead to a vicious circle where centrally determined actions depress market price signals for plant that must make a return over an increasingly limited number of running hours. Such plant may be forced to close prematurely and further action will be required by the central body to contract more capacity, thus the cycle begins.

Drax and other members of the Independent Generators' Group commissioned Oxera to review DECC's proposed TCM. The report identifies some key issues with the TCM and suggests a possible alternative mechanism that better meets DECC's objectives and the capacity needs of the transmission system. Drax believes a wider capacity mechanism is essential, but the precise design of that needs further discussion.

The Oxera report has been submitted separately to DECC by the Independent Generators' Group, although the Executive Summary is attached as Annex 2 to this document.

22. ***Do you agree with Government's preference for a 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.***

Central body

Yes. The capacity mechanism should be a centrally administered scheme. The use of a central body avoids parties with "obligations" holding market power (as experienced under the RO).

Volume based

Yes. The central body should set the volume required. The price could be set either by market participants in a competitive process (allowing for the efficiencies of a market based approach) or by a calculated price based upon the cost of the marginal plant. It is reasonable to expect that the capacity price could reduce to zero if there is an over capacity.

Targeted Mechanism

No. The mechanism should not focus narrowly on meeting extreme peak demand. The mechanism must recognise the wider importance of flexibility in maintaining security of supply, particularly with the increased deployment of intermittent and inflexible generation capacity over the next decade and beyond.

The aim of the capacity mechanisms is to ensure an adequate return for making both new and existing capacity available to the market. The mechanism must incentivise the provision of flexibility services from much needed new investment, whilst avoiding early and inefficient closure of existing plant.

Further thoughts

The capacity mechanism should be wider and open to a range of plant types and demand response, providing a competitive solution to both peak demand and flexibility requirements. This approach would ensure investment in the most cost effective solution, lowering the cost to consumers.

Drax and other members of the Independent Generators' Group commissioned Oxera to review DECC's proposed Targeted Capacity Mechanism. The report identifies a possible alternative mechanism that better meets DECC's objectives and the capacity needs of the transmission system. Drax believes a wider capacity mechanism is essential, but the precise design of that needs further discussion.

The Oxera report has been submitted separately to DECC by the Independent Generators' Group, although the Executive Summary is attached as Annex 2 to this document.

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?***

Drax and other members of the Independent Generators' Group commissioned Oxera to review DECC's proposed Targeted Capacity Mechanism. The report identifies a possible alternative mechanism that better meets DECC's objectives and the capacity needs of the transmission system that we believe warrants further discussion and development. The alternative mechanism also incorporates Demand Side Response as an important player in the wider capacity mechanism. Drax believes a wider capacity mechanism is essential, but the precise design of that needs further discussion.

The Oxera report has been submitted separately to DECC by the Independent Generators' Group, although the Executive Summary is attached as Annex 2 to this document.

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

Drax supports a wider capacity mechanism to that set out in the consultation document. Under any capacity mechanism, economic dispatch should prevail and all plant should continue to form a part of the traded market.

Holding capacity outside of the traded market and centrally dispatching it during peak demand periods would effectively cap efficient market price signals, increasing the risk that generators may not be able to achieve revenues that are sufficient to cover their costs. This could lead to premature plant closure and may diminish investment signals for new capacity.

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

No. The mechanism should be location neutral and based upon the availability of flexible generation and demand across the whole GB system. Locational issues, to the extent that they may arise, should be dealt with by appropriate reinforcement of the Grid and / or the BETTA constraint management process.

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 do not support any of DECC's packages. However, of the ones put forward DECC's preferred package (Package 3) is the least damaging.

Drax agrees with the proposal for a CfD FIT; a proposed model with supporting analysis can be found in Annex 1 to this document. Drax also agrees with the requirement for a capacity mechanism, although the final approach must be much wider than that proposed by DECC; an Executive Summary on analysis performed by Oxera (commissioned by the Independent Generators' Group) regarding the requirements of a capacity mechanism can be found in Annex 2 to this document.

Drax has serious concerns with proposals for a Carbon Price Support, as it provides no real incentive signals for low-carbon generation, it distorts competition between GB and EU Member States, and will only serve to provide costly and unnecessary windfall profits to existing nuclear and renewable generators. The primary support mechanism for low-carbon generation should be the proposed CfD FIT mechanism. In addition, Drax disagrees with the proposed EPS, as the proposal is an additional and unnecessary layer of legislation which should be dropped.

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

We do not support any of DECC's packages. However, Package 3 would better achieve:

- adequate investment returns for renewable / low-carbon plant;
- appropriate signals for investment in flexible thermal plant, both new and existing;
- a level playing field for all market participants; and
- minimal market distortion by maintaining liquidity in the wholesale market and ensuring economic dispatch.

However, the proposed CfD FIT and capacity payment mechanisms (particularly the latter) require further work to ensure that they will be effective. These mechanisms are addressed in Annex 1 and Annex 2 (respectively) to this document.

Drax does not support proposals for a Carbon Price Support or an Emissions Performance Standard.

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?

If the Carbon Price Support is set at a premium to the EUA price, it will have many adverse effects on electricity markets and UK competitiveness. It may place plant located in GB at a competitive disadvantage to those located in mainland Europe. This could lead to investment being redirected to other Member States, with GB becoming more reliant upon imports of electricity in order to meet national demand.

In addition there will be an upward pressure on the European Gas prices as UK dependence on this fuel increases. This creates further security of supply concerns regarding input fuel.

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

The Carbon Price Support (CPS) is unnecessary, particularly as the CfD FIT mechanism is the primary mechanism for incentivising investment in low-carbon generation. It is an economically inefficient tool that aims to indirectly support specific technologies whilst simultaneously distorting the wholesale market. The CfD FIT provides the incentive to invest in renewable / low-carbon plant. Those investments that are meant to benefit from the Carbon Price Support are immune to the effect of uplifted power prices under a CfD FIT. In addition, Drax does not believe that a Carbon Price Support would be "bankable", unlike a CfD FIT.

There are further conflicts with mechanisms that fall outside of the Government's proposed reforms. A conflict would exist between the Carbon Price Support and the existing EU ETS. The CPS is a unilateral measure taken by the UK Government on a European-wide market. The cost of carbon should continue to be determined by the market-wide EU ETS cap, not by unilateral Member State intervention. There may also be issues of State Aid in the CPS, which the Government should clear with the European Commission. As a relatively closed system, reducing the UK's demand for EUAs within the EU ETS will simply lead to a lower carbon price and higher consumption on the continent. This effect could negate the UK's objectives to further cut CO_2.

There could be an additional conflict between the EPS and both the LCPD and the IED. These European directives have been put in place to tackle issues surrounding plant emissions; the EPS is an unnecessary additional layer of legislation.

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 implementation approach must take into account:

- the complexity of the current market arrangements and the nature of term industry contracts;
- commitments already made to investors, i.e. levels of support offered under the RO;
- differing types of plant may require support at differing points in time, e.g. new nuclear capacity will not be delivered until 2020; and
- the timing of the generation capacity that Government policy is seeking to incentivise.

The issues identified above apply to each of the potential packages for reform. The implementation approach must provide certainty of longevity and allow sufficient time for the relevant industry codes to be modified.

Drax supports a transitional approach that ensures:

- urgent fundamental market reform occurs sooner rather than later;
- policy takes effect in line with investment timescales; and
- transitional arrangements are put in place where contracts and commitments currently exist.

Working with industry stakeholders should ensure a smooth transition.

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?***

The FIT support levels should continue to be set by banding until at least 2017. Moving to auctions / tenders in such short implementation timescales adds an unnecessary additional complication during the transition period. Banding FIT support until at least 2017 will mean that the CfD FIT and RO options have similar arrangements whilst the run in parallel during the transition period.

It may be more appropriate for subsequent rounds (i.e. beyond 2017) to incorporate auctions / tenders for certain technologies. This would provide more time to develop a coherent approach to FIT auctions / tenders, assessing which technologies to apply it to, the awarding of planning permission, the securing of grid connections and offshore auction rounds (for wind).

Eligibility for CfD contracts should be based on a “2 Gate” process. Contracts should be offered on receipt of planning consent (Gate 1) and confirmed at Financial Close or equivalent (Gate 2). The period of time between Gate 1 and Gate 2 could be time limited; the length of time should allow projects sufficient certainty to progress and complete financing discussions.

This approach would eliminate the issue currently experienced by developers under the RO, where technologies with long build times are uncertain of the final level of support they will receive. This issue has significantly stifled investment to date.

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

Attached at Annex 1 is a possible model of how a CfD FIT regime may work, including the institutional arrangements. Minimal changes would be required to the current institutional arrangements. A CfD FIT “Independent FIT Administrator” would be required to administer the scheme, although the majority of the work could be performed by an existing industry code administrator. National Grid is currently able to provide demand and capacity data; Elexon is currently able to process operational data, cash-flow and settlement; Ofgem currently has powers to monitor the market.

However, it will be important to provide careful guidance to such parties when performing their specified role. These parties should efficiently and professionally administer arrangements and processes in accordance with their terms of reference. They should not interfere with the fundamental workings of the market. Market fundamentals and economic dispatch should prevail, based upon efficient market price formation.

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?*

The market should be disrupted as little as possible. A CfD FIT approach ensures market liquidity is maintained, all types of generation continue to contribute to price formation and generator windfalls are avoided. This is achieved by ensuring renewable / low carbon generators remain a part of the wider power market.

It is essential that a capacity mechanism is introduced and that it is not narrowly targeted. This will reward the availability and flexibility of non-subsidised, thermal generation in meeting the system’s security of supply requirements. Distortion to competition and market price formation should be avoided.

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

Whilst investment may be delayed (in the immediate short-term), reform is required now to ensure delivery of the investment required to meet the Government’s targets. The Government must move swiftly to identify its final (enduring) package and to inform the market of the intended way forward.

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?*

Yes. Drax agrees with the principles. Honouring the grandfathering of support, the RO remaining open during the transition period (i.e. to 2017), accelerating the RO Banding Review and reviewing those technologies that are not grandfathered, all appear to be reasonable actions. In addition, existing RO accredited projects should also have a single option to transfer from the existing RO to the new FIT arrangements prior to 2017. This would reduce the costs to consumers, whilst ensuring that investors in the existing RO were not forced out of that scheme.

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

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

Drax would support a period of parallel running of at least 2 years prior to 2017 during which time developers of any new renewable projects can choose to be supported under either scheme. In addition, all schemes already accredited under the RO should be given a one-off opportunity to switch to the FIT prior to 2017. This would reduce the overall cost of supporting such schemes and the FIT should pose less risk for investors than the existing RO arrangements. In both cases, the choice will have to be notified at the latest in the June prior to entry into the FIT to ensure that there are no unanticipated effects on the RO.

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?***

All technologies should have grandfathered support in order to promote investor certainty. In addition, all existing projects, and those with significant upgrade potential, should have a single time limited option to transfer from the existing RO to the new arrangements.

If technologies are left without grandfathered support, it will be essential to undertake scheduled banding reviews to maintain investor confidence. Intervals of six to eight years would be an appropriate timeframe.

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***

The RO must continue to function alongside the CfD FIT mechanism post-2017. RO payments must be protected and grandfathered support must continue for all schemes registered under the RO in 2017.

The headroom must be maintained to encourage ROC trading, i.e. to prevent the ROC market from collapse. This could be achieved by applying a fixed headroom percentage of 10% from 2017 until 2027, with ROC levels being fixed thereafter to the RO end date in 2037.

Annex 1: A Possible CfD FIT Model

The CfD FIT approach is the most appropriate and cost-effective mechanism to incentivise investment in new low carbon generation. If designed correctly it will reduce regulatory uncertainty for investors, increasing their confidence to invest. It will also lower the cost to end consumers and in particular ensure any potential excess revenues from higher than expected market prices are returned to end consumers.

If designed and implemented appropriately, a CfD approach to FITs would ensure:

- the cost of delivering the required renewable investment is minimised;
- consumers are protected against windfall generator profits;
- wholesale market liquidity is protected and potentially enhanced;
- market distortions are minimised; and
- low carbon generator cash-flows are greatly improved.

A Premium FIT approach would fall short against the criteria above primarily because:

- low carbon generators are still exposed to the volatility of power prices, thereby providing no greater protection of investment returns than the RO;
- a larger subsidy is required to cover volatility of power price, meaning a higher cost to the consumer; and
- potential for generator windfalls at the cost of the consumer during higher than expected price periods.

A Fixed FIT approach would be the least desirable, as it would:

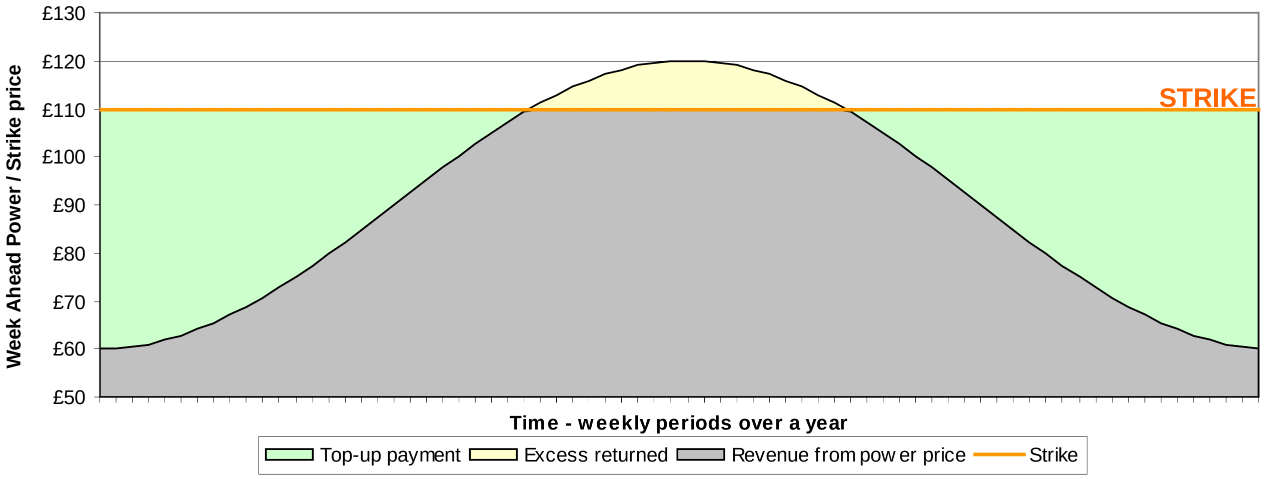
- fix generator revenue streams by completely removing low carbon generation volumes from the market wholesale market, thereby increasingly reducing market liquidity;
- provide no signal at all for economic plant dispatch, meaning a higher cost to consumers;
- render the power price unable to signal that delivered volume is not required; and
- not expose generators (or their agents) to the consequences of their actions (i.e. their failure to deliver contracted volume).

Overall CfD FIT Structure

The basic structure is a financial contract for difference (CfD) against the forward power price. CfDs are well established and widely traded financial instruments that dominate trading and hedging activities in world-wide commodity markets. A CfD provides a high degree of revenue certainty for low carbon investors whilst minimising the cost to consumers and at the same time maintaining wholesale market liquidity.

It would be a two-way CfD (ie. both parties to the contract can make and receive payments) which provides substantial benefit to both sides of the contract. The low carbon generator is protected against market price collapse, which increases investor confidence and so reduces funding costs. The consumer is protected against generator windfalls if market prices out-turn higher than expected, reducing the cost to consumer. This will also make the scheme more sustainable to potential political / regulatory interventions in the future.

Figure A1.1: Variation in CfD net settlement price in response to changes in power index price.



- If Market Price Index is below the Strike Price for the given period, the renewable generator *receives* the Net Settlement Price from the central body (levied from consumers);
- If Market Price Index is above the Strike Price, the renewable generator *pays* the difference (excess) to the central body (mitigating the levy from consumers).

The model also aims to ensure improved cash-flow timescales for investors, certainty of support over investment timescales (grandfathering) and be administered by a central body (to avoid market power).

CfD FIT Structure

There are three main elements to the CfD FIT: the Strike Price, the Market Index Price and the Net Settlement Price.

<u>Strike Price</u>

The Strike Price in the CfD contract is set at the total price the generator is deemed to require per MWh delivered in order to invest. It would be banded by technology to reflect the different costs / risks of the various low carbon technologies. It could be set via a cost based review process in a similar way to the RO or it could be set via an auction process. To try and introduce auctions early in the transition to the new regime, would be an unnecessary and potentially counter-productive step. We therefore recommend that, at least initially, it is done via a centrally administered cost-based process as with the RO. However, once the new FIT scheme is well established, then it may be appropriate to consider auctions for certain technologies at a later stage.

The Strike Price would be fixed for 20 years with appropriate indexation, which would be determined by the *type* of low carbon technology:

- Those with significant fuel costs (eg. CCS, biomass) could have some indexation to their fuel prices. This would increase the Government and investor confidence that the support will be sufficient to incentivise the technology, whilst protecting consumers against over-payments if fuel prices were lower than expected;
- Those without variable fuel costs would be indexed to time value inflator (e.g. RPI for wind, solar).

Market Index Price

The Market Index Price against which the financial difference payments are made needs to be a recognised, published index that is based upon a liquid, traded forward market product. This is the value the generator is expected to achieve per MWh in the wholesale traded market. The Market Index Price is technology neutral (i.e. exactly the same index is used for all plant). We recommend that a Week-Ahead Index is chosen (see later section).

Net Settlement Price

The Net Settlement Price is the top-up payment required (by either party) to fill the gap between the Market Price Index and the Strike Price (i.e. the subsidy payment). This is calculated and published ahead of each settlement / Strike Price period. For example, if the Week Ahead Index is £60/MWh for the next week, and a low carbon generator has a CfD FIT contract with a Strike Price of £110/MWh, the generator would receive £50/MWh for all generation produced in the week in question (see figure A1.1 for illustration). The generator would also receive the income from sales of its physical output during the week, which could be via a PPA, or through sales in the wholesale market either itself, or via an aggregator.

CfD Term Sheet

The CfD contractual and administrative terms would comprise two main elements. The first is an agreement between the low carbon generator and the Independent FIT Administrator (IFA). This would be an industry standard agreement that could have similar terms to those found under ISDAs. It would contain similar settlement terms to those used for BSUoS and could form a part of an existing industry code.

The second element would be an obligation on all licensed suppliers to recover a FIT Levy from their customers, akin to the way the Climate Change Levy (CCL) is managed at present. This obligation could be established either by a Licence condition or through secondary legislation. The value recovered through the Levy would be paid by suppliers into an account held by the IFA, from which it would make (and receive) the CfD difference payments to low carbon generators.

Figure A1.2: Cash-flows between the central body and the renewable generator

Subsidy Collection and Payment

Generator payments are delivered closer to generation timescales than under the existing RO arrangements. This would improve investor cash-flow and reduce supplier default risk by ensuring the value collected from customers does not sit in suppliers' bank accounts for lengthy periods of time.

Suppliers are obligated (via a Licence condition or secondary legislation) to recover the FIT Levy from consumers:

- Step 1: Levy is charged as a fixed charge p / MWh invoiced:
  - IFA calculates and sets the Levy for suppliers;
  - Levy is adjusted, but only as necessary, at a maximum frequency of every six months, in order to provide suppliers with tariff transparency / stability;
- Step 2: Levy collected from consumers through their bills by suppliers:
  - Works in a similar way to the current CCL processes;
  - Collected from consumers over each billing cycle per kWh invoiced;
- Step 3: Levy is paid into a central account held by the IFA:
  - Suppliers transfer invoiced amounts every three months, minimising supplier default risk;
- Step 4: Low carbon generators receive CfD payments from IFA every three months.

The IFA should also have an obligation to review the Levy rate every 6 months and adjust it as necessary in accordance with the following principles in order to smooth recovery shortfalls and excesses:

- minimise disruption to suppliers and the competitive supply market;
- smooth cash-flows to low carbon generators; and
- ensure efficient operation of the system, e.g. not to create / maintain an excessive cash reserve.

The FIT Levy rate would be reviewed by the IFA for the period in question based upon a forecast of low carbon generation, an assessment of forward Week Ahead prices and any accumulated or consumed funds. In times of unexpectedly high renewable generation / lower than expected prices: the Net Settlement Price (subsidy payment) to generators would be scaled back; recovery from consumers would be scaled up in later periods to recover the shortfall; and generators would be made whole as the shortfall is recovered.

Central Body: Independent FIT Administrator (IFA)

The chosen IFA should possess a good credit rating; have a good knowledge of market indexes, cost structures and settlement calculation processes; must be able to handle revenue collection / distribution; and have the ability to ring-fence arrangements to minimise risk exposure.

This role could be provided by an existing industry code administrator. For example, Elexon currently provides a cost recovery service to the industry for BSUoS which is calculated and charged on a Settlement Period basis. All suppliers and generators have an existing contractual relationship via the BSC and the systems and settlement procedures are already in place.

Qualification for the CfD FIT

Eligibility for CfD contracts should be based on a “2 Gate” process. Contracts at the agreed CfD Strike price should be offered on receipt of planning consent (Gate 1). Contracts would be signed at Financial Close or equivalent (Gate 2). The period of time between Gate 1 and Gate 2 could be time limited, with the contract offer lapsing if Gate 2 was missed; the length of time should allow projects sufficient certainty to progress and complete financing discussions. 2 years might be an appropriate period.

This approach would eliminate the issue currently experienced by developers under the RO, where technologies with long build times, like large scale biomass, are uncertain of the final level of support they will receive. This issue has significantly stifled investment to date.

Small Developers

Concerns have been raised by small renewable developers over their ability to contract with parties to off-take power under a CfD FIT or Premium FIT scheme. These schemes will all be embedded in the distribution networks and unlikely to ever trade their power on the wholesale market As such, Drax suggests that small developers (perhaps <10MW capacity) could be removed from the CfD FIT scheme and instead be offered a Full Fixed FIT. It is highly unlikely that the removal of such small plant from the traded market would have a significant detrimental effect on market liquidity.

Comparison of CfD FIT and the Renewables Obligation (RO)

Table A1.1 provides a summary of the similarities and differences between the current RO arrangements and the proposed CfD FIT mechanism.

Table A1.1: Comparison between the existing RO and the proposed CfD FIT arrangements

Comparison of Arrangements	RO	CFD FIT
Support Level		
Technology specific support levels	✓	✓
Periodic Banding Review	✓	✓
Banding based on study of technology project costs	✓	✓
Technology specific grace period to provide certainty	Required	Required
Subsidy arrangements grandfathered	✓	✓
Effectively a guaranteed investor return	✗	✓
Subsidy Payments		
Subsidy paid per MWh delivered	✓	✓
Subsidy Payment fixed regardless of market power price	✓	✗
Subsidy Payment calculated using Market Index Price ahead of delivery period	✗	✓
Power Sales		
Generator may trade power via wholesale electricity market	✓	✓
Generator may put a PPA / off-take agreement in place	✓	✓
Standard power settlement arrangements	✓	✓
Subsidy Collection		
Supplier collects the subsidy value from customers' via bills	✓	✓
Delay until generator receives Subsidy Payment	18 Months	3 Months

Market Index Price Rationale

The objective of a CfD-based FIT is to deliver a stable income to all types of low-carbon generator at the lowest cost to the consumer. Liquidity is a key factor to ensuring a reliable market index; sufficient liquidity exists within the short-term market to support a CfD-based FIT.

Drax has undertaken analysis to determine the most suitable forward market index, including analysis on the correlation between Month Ahead and Week Ahead products against real time prices. A Week Ahead index appears the most appropriate due to this product having a good level of liquidity and a close correlation to out-turn prices. There would be a greater level of market volatility risk using a Month Ahead index. A Week Ahead index provides greater certainty of capacity availability, weather variation and, thereby, power price.

On this basis, this model uses a Market Index Price based upon a Week Ahead market index.

Week Ahead Index

The analysis showed that the margin for error (difference) between the closing Week Ahead trade price and Elexon's Market Index Price (MIP) (close to real time price) is concentrated at the centre (around zero). Figure A1.2 demonstrates that off-takers are able to manage the variation of prices between Week Ahead and real time prices (e.g. generators, suppliers and banks).

Week Ahead Liquidity

Setting a market index and managing the risk of output variation is much easier for an off-taker in a liquid market. Figure A1.3 demonstrates strong liquidity in the Week Ahead traded product. This is a strong basis on which to set a reliable Market Index Price.

Figure A1.3: Margin of error between Week Ahead and out-turn prices

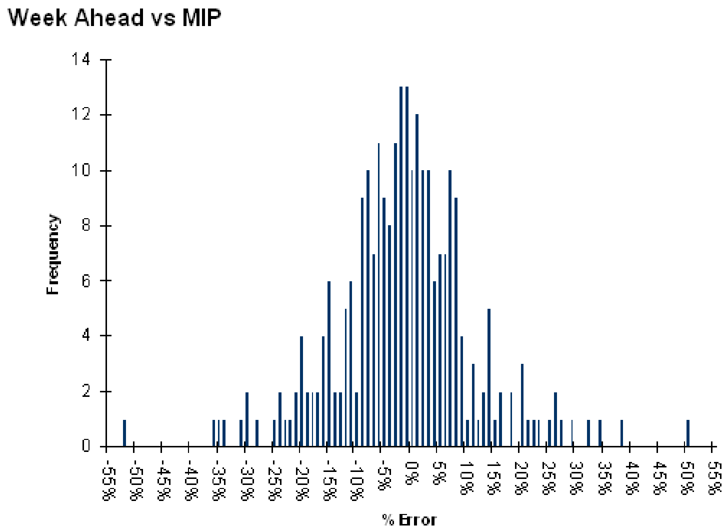
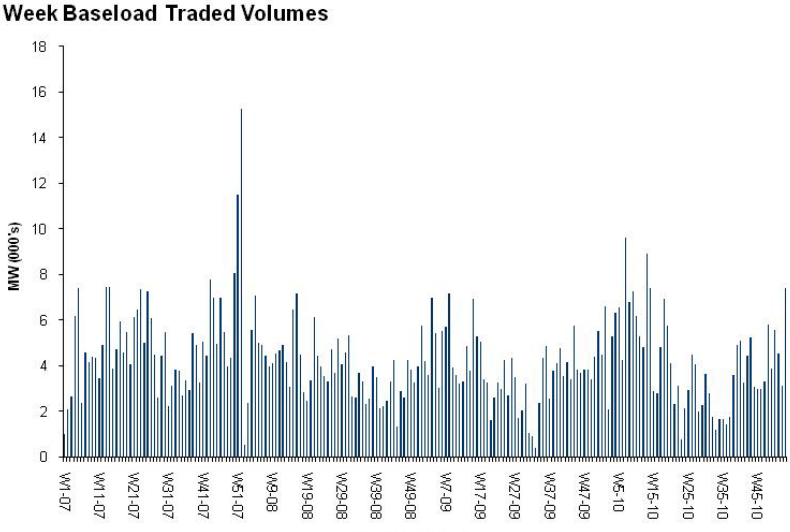


Figure A1.4: Week



GB capacity mechanism design

Meeting future flexibility requirements to secure a low-carbon transition

Executive summary

Prepared for members of the Independent Generators Group

March 9th 2011

The Independent Generators Group (IGG) is made up of the largest independent generators in the UK, comprising 20% of capacity and 20% of generation**. Member companies include ConocoPhillips European Power Ltd, DONG Energy Power (UK) Ltd, Drax Group plc, Eggborough Power Ltd, ESBI, InterGen, and International Power plc.**

Note **that DONG Energy and ESBI fully endorse the Oxera analysis of the issue but** ***do not*** **support the solution proposed.**

Executive summary

This report, prepared for members of the Independent Generators Group (IGG), provides an analysis of DECC's preferred approach to the introduction of a capacity mechanism in the GB electricity market. It examines the appropriateness of narrowly targeting capacity payments to certain reserve capacity in order to meet a centrally determined target capacity margin.[6]

The report provides an initial assessment of the change in system conditions, and the accompanying risks that may be caused by increased wind generation alongside the expansion of nuclear and carbon capture and storage (CCS) projects in the GB electricity market.

In particular, analysis is presented to examine the extent to which system 'flexibility requirements' are likely to change over time. That is, the hourly and daily changes in demand net wind, as well as the economic incentives that may be present in order for existing and potential flexible capacity to be available to meet this requirement—a challenge that is distinct from the need to provide a capacity margin above system peak demand.[7]

The analysis provides a starting point with which to undertake an initial assessment of whether DECC's preferred targeted capacity mechanism (TCM) might alleviate or exacerbate these risks, and the scope for potential price distortions and the impact that this may have on investment incentives.

The report then sets out some initial considerations on an alternative mechanism that could be better equipped to address the flexibility challenge posed by the possibility of early retirement of existing flexible plant, and weakened investment incentives that may otherwise deter investment in sufficient new flexible capacity to deliver longer-term security of supply.

Flexibility requirements

With regard to system flexibility requirements, the key findings of the analysis are that:

– changes in the generation mix could increase GB flexibility requirements, which are governed by short-term variations in demand net wind, and as such, are different to the traditional need to meet system peak demand;

– flexibility can be provided by flexible generation and demand-side response (DSR), with short-term responsiveness on the generation side governed by the difference in plant's maximum and stable export limits, with further constraints determined by plant ramp rates and whether the plant are already synchronised;

– a 'flexibility gap'—defined in this report as the situation in which short-term responsiveness from flexible capacity could be insufficient to meet hourly demand-net-wind variations—could emerge by around 2020, regardless of whether system capacity is sufficient to meet peak demand.

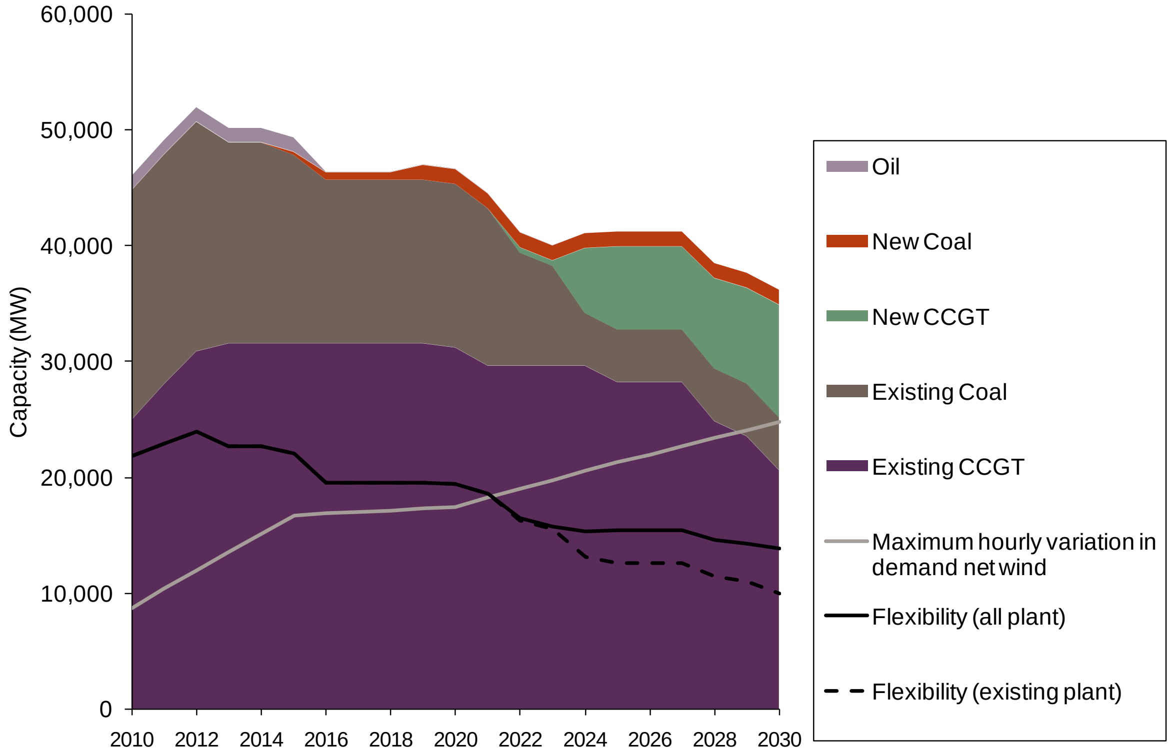
Figure 1 below shows a projection of total de-rated capacity for flexible thermal plant, and the supply and demand of hourly flexibility (or responsiveness). The analysis is based on commodity price assumptions reflective of current forward prices, and investment in new CCGTs based on

[6] Department of Energy and Climate Change (2010), 'Electricity Market Reform. Consultation Document', December.
[7] Flexibility requirements are likely to include the ability to meet hour-to-hour variations as well as increased variation in daily peaks and toughs of demand net wind. The analysis in this report focuses on the ability to respond to hourly variations.

current price dynamics and revenue expectations that assume perfect foresight and efficient dispatch.

The figure highlights the increase in system flexibility requirements over time, and the decrease in the supply of flexibility (measured as the difference between plant's maximum and stable export limits) alongside the decrease in total flexible capacity.

Figure 1 Supply and demand for hourly flexibility



Note: Retirement profiles of existing plant and investment in new plant are based on efficient dispatch and existing price dynamics that reflect the historical relationship between price levels and capacity margins, and absent possible price distortions. Capacity is de-rated to reflect average availability. Capacity figures exclude nuclear and CCS, which are deemed to be inflexible (both due to technical restrictions and because they are likely to operate at high load factors and to have limited scope to provide additional output). It also excludes pumped storage, which cannot be drawn on frequently once depleted, and is often used to provide shorter-term (sub-hourly) response.
Source: IEML, and Oxera analysis.

Increased wind penetration is also likely to exacerbate the total peak-to-trough changes in demand net wind over the duration of a typical day. The analysis in this report suggests that the maximum simulated daily range of demand-net-wind levels could increase by around 40% compared with 2009.

Flexibility investment incentives

With regard to flexibility investment incentives, the key findings of the analysis are that:

- absent intervention, there might be insufficient incentive to invest in adequate flexibility. This is because thermal plant could be required to rely increasingly on short-term revenues that encompass increased risks that may not be hedged, and are subject to the threat of distortions from 'out-of-market' actions;
  - specific risks include the ability to capture short-term price spikes caused by wind variations, and the increased risk to plant performance from more frequent output variations;

– these risks could be larger for non-integrated and non-portfolio players—uncertainty over future operating conditions could reduce the scope to contract forward and sell power sufficiently far in advance at attractive terms, as well as hedge price risk.[8]

DECC's preferred TCM does not attempt to mitigate these risks, and may exacerbate the risk of price distortions. Out-of-market actions (or even the potential for such actions) by the operator of capacity contracted under the proposed TCM, can directly affect price and volume expectations for balancing and ancillary services. In particular:

– they may reduce balancing volumes procured through the market, and hence expectations of balancing mechanism prices;
– there may also be a reduction in other reserve contracts and ancillary service requirements, leading to reduced price expectations for contracts outside the proposed mechanism.

The Electricity Market Reform (EMR) consultation recognises that potential distortions could arise through the effect of dispatch of the targeted capacity on peak prices, and that these distortions, along with the risk that an increasing proportion of capacity may need to be contracted under the proposed mechanism, 'could undermine the mechanism's ability to ensure secure supplies of energy'.[9]

DECC's proposed TCM is similar to the Swedish model, which makes use of peak load reserves. There is evidence from regulators and academic studies that potential price distortions remain a risk under this model and that peak load tendering should generally be avoided.[10]

An alternative flexibility mechanism

A broader-based mechanism, designed to reward flexible capacity, could provide the necessary investment incentives and mitigate the increasing market risks faced by providers of flexibility. Basic, technology-neutral eligibility criteria could be defined, and plant receiving FITs could be deemed ineligible to avoid over-rewarding low-carbon capacity.

In the EMR consultation DECC states that it would assess the effectiveness of the market reform options along four broad principles:

– cost-effectiveness;
– durability and flexibility;
– practicality;
– coherence.

In this context, an appropriate flexibility mechanism might be expected to:

– mitigate the increased risks faced by flexible plant as wind penetration increases;
– minimise entry barriers that could accompany a non-market-based and discretionary mechanism such as the TCM;
– provide the greatest signals to invest as the flexibility requirements from intermittency increase;

[8] Hart (1988) describes how the firm as an institution can be thought of as arising from the incompleteness of contracts and the need to allocate residual control rights. See Hart, O. (1988), 'Incomplete contracts and the theory of the firm', *Journal of Law, Economics and Organization*, **4**(1), spring.
[9] Department of Energy and Climate Change (2010), op. cit., p. 94. The EMR consultation recognises that the potential effects on peak prices and the 'slippery slope' effect could undermine the performance of the proposed TCM.
[10] See, for example, Svenska Kraftnät (2002), 'Effektförsörjning på den öppna elmarknaden, Utredningsrapport', January 10th. Johansson, T. and Nilsson, M. (2010), 'Signs of stress II: The customer strikes back', April 9th. Nord Pool Spot (2010), 'Handling of the peak load reserves in the spot market', October 1st. Botterud, A. and Doorman, G. (2008), 'Generation Investment and Capacity Adequacy in Electricity Markets', International Association for Energy Economics. Energy Markets Inspectorate (2006), 'Price Formation and Competition in the Swedish Electricity Market', report 2006:13. NordREG (2009), 'Peak Load Arrangements, Assessment of Nordel Guidelines', report 2/2009. NordREG (2010), 'Assessment of Nordel's revised Guidelines for transitional peak load arrangements', March.

- accommodate increased DSR, and spur innovation and increasing participation from the demand side.

Based on the initial considerations in this report, a fixed revenue mechanism might be able to strike an appropriate balance between creating the right investment signals for providers of flexibility while minimising complexity and the risk of gaming. Such a mechanism could be implemented as follows.

- An annual flexibility requirement (in GW) could be calculated based on wind penetration and expected variations in output, inflexible demand variations, and a security standard (eg, a requirement to meet three standard deviations (or 99.7%) or expected hourly variations in demand net wind).

- A total annual revenue amount could be determined based on system flexibility requirements and the costs of the marginal provider of flexibility.

- The revenue pot could be split between different time periods, based on a combination of anticipated flexibility requirements and ex post demand and wind outturn (so that greatest revenues are available when flexibility requirements are highest).

- All flexible generation and demand participants available within a given period could be eligible to receive a share of the revenue available in that period.

The advantages of such a mechanism are that:

- a degree of stability could be introduced into the flexibility payments through tailoring the revenue split between a fixed element and one related to ex post system conditions;
- the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions could help promote longer-term investment signals;
- short-term signals could be generated to create the incentive for flexible generation and demand to be available through the ex post revenue allocation.

The potential drawbacks of such an approach are the administrative costs of annual forecasting and operation of the scheme. This would be likely to be a feature of any broad-based mechanism, but could be smaller for mechanisms that are relatively less complex.

A useful area for further analysis would be to consider the timeframe over which flexibility requirements should be defined.

Next steps

This report provides an initial analysis of the potential flexibility gap facing the GB electricity system, and the risks that are likely to be faced by owners of existing flexible capacity and developers of new plant. The provision of future flexibility has been assessed based on existing price dynamics.

Useful further work would be to refine the estimates of future GB flexibility requirements, based on a more detailed analysis of flexible plant operating capabilities, and the manner in which prices may respond to a potential flexibility shortfall and the implications of this for plant returns. This would also facilitate a full cost–benefit analysis of alternative flexibility mechanisms.

Annex 3: Carbon price floor: Drax Response to Treasury Consultation

11 February 2011

Response by Drax Power to HM Treasury's Consultation on '*Carbon price floor: support and certainty for low carbon investment*', December 2010

Executive Summary

Drax has some major reservations about this policy proposal. We believe this will distort the competitive market, and deliver detrimental unintended consequences. In particular, it will:

- **lead to very significant windfall profits to existing nuclear and renewable generators, estimated to run into several £billions;**
- **distort electricity market competition both within the UK and between the UK and other EU markets;**
- **have no real effect on overall CO_2 emissions since any reduction in the UK's emissions will simply result in higher emissions in the rest of the EU;**
- **have no real impact on new build renewable investment, which will be much more effectively incentivised by either the ROC mechanism or a CFD FiT mechanism;**
- **cause critical marginal and flexible UK coal-fired plant to close earlier than replacement new low carbon plant can be constructed, adversely affecting security of supply; and**
- **result in higher UK power prices which will reduce the competitiveness of UK industry and exacerbate fuel poverty issues in the residential sector.**

All these impacts will all have an adverse effect on UK consumers and all are avoidable. They could, and should, all be significantly mitigated by ensuring that the carbon price floor closely tracks the market price of EUAs.

About Drax

Drax is predominantly an independent power generation business responsible for meeting some 7-8% of the UK's electricity demand. The Company also owns Haven Power, a small electricity supplier serving the needs of business customers.

Drax is the owner and operator of the 4000MW Drax Power Station in North Yorkshire, which is the largest, cleanest, most efficient and most flexible coal-fired power station in the UK. As such, Drax is committed to playing its part in reducing its carbon footprint and that of UK power generation. To this end, in summer 2010 the largest biomass co-firing facility in the world was commissioned at the power station.

With the capability to produce 12.5% of the station's output from sustainable biomass – equivalent to the output of over 700 2MW wind turbines – Drax is by some distance the largest renewable generator in the UK. In 2010, Drax produced over 6% of the UK's renewable power, more than twice that of the next largest renewable generating plant. In addition, we are more than two-thirds of the way through the largest steam turbine modernisation programme in UK history. Together these two initiatives will reduce our emissions of carbon dioxide (CO_2) by over three and a half million tonnes a year, which represents a reduction of over 17% compared to 2006 levels.

Drax is pleased to have the opportunity to participate in the carbon price support consultation. As a key provider of flexible generation and system support services to the

System Operator and a very significant investor in renewable electricity generation from biomass, Drax believes it is well placed to comment.

Introduction

This consultation is part of a package of proposals developed by the Government to put in place a framework to facilitate the £200bn + investment needed to ensure we can meet our binding 2020 carbon emissions and renewables targets, and put the UK on a sustainable and credible path to its longer-term commitment to reduce carbon emissions by 80% by 2050. As such it needs to be considered alongside the rest of the Electricity Market Reform (EMR) proposals put forward by DECC in December 2010.

Drax agrees with the Government that the current EU-ETS mechanism has not stimulated as much investment in low-carbon technology as might have been expected. However, we question whether addressing this by unilaterally introducing a carbon price floor in the UK is the best way forward. Any substantial difference between the implicit price of CO_2 in the UK and in the rest of the EU cannot really be sustainable. That in itself will create uncertainty and reduce the 'bankability' of the floor price for UK low carbon investments. We would instead urge the Government to rely on the current Renewables Obligation, and on the new low-carbon Feed in Tariff (FiT) mechanism proposed under the EMR to stimulate such investments. In the meantime we should work hard with our EU partners to improve the current EU-ETS.

Windfall Profits

The stated purpose of the carbon price floor is to stimulate new low carbon (primarily new nuclear) investment. However, when introduced it will impact the electricity prices paid to all generators. This will provide substantial and unnecessary windfall profits for existing nuclear and renewables generation. We estimate this could be between £4-9bn depending on the assumptions used. It will also provide windfall profits to existing gas generators when coal is the marginal plant on the system. This should be addressed to ensure that UK consumers do not pay any more than is absolutely necessary to meet our climate change targets.

Distorting EU trade

Any substantial difference between UK and EU carbon prices would raise potential questions about the degree to which the carbon price floor may affect trade in energy between Member States – whether over interconnectors, or in the case of Ireland, as part of the SEM. A higher power price in the GB market will provide incentives for greater imports into GB over interconnectors, and thus dependence on foreign producers. This will put GB plant at a competitive disadvantage and would lead to lower load factors, or even closure, of existing marginal GB peaking / mid-merit generation capacity with direct impact on GB employment and higher costs for consumers.

Effect on overall EU Emissions

- Any benefit this unilateral UK proposal may have in lowering UK emissions will be offset by a corresponding increase in overall emissions in the rest of the EU-27. This is because the EU-ETS scheme applies an overall cap on total EU emissions allowances. A reduction in UK use of EU ETS certificates will simply mean the rest of the EU will use more EU ETS certificates.

Low Carbon Investment Signals

The ‘bankability’ of the proposed mechanism to support new build low carbon investments is uncertain and will not be as effective as a direct support mechanism like the existing ROC mechanism or a CFD FiT mechanism as proposed in the EMR. This is for two main reasons:

- Indirect price signal : the carbon floor is an indirect and inefficient forward price signal for investment in low carbon generation. This is because it will only impact the wholesale electricity price when fossil fuel plant are the marginal generators in the system and thus setting electricity prices. Whereas this is expected to be the predominantly the case in the near term, in the medium to long term there will be extended periods where low carbon generation is the pricing plant on the system. The carbon floor will not influence the wholesale price of electricity in those periods.
- Political Risk : since the level of carbon uplift is not grandfathered, and as it is a tax, it will always be subject to change. Indeed, successive Governments may well take different views of the purpose of the tax and the rate and/or trajectory it should be set at. This will be increasingly likely the further out of line UK prices (and hence competitiveness) get from prices in the rest of the EU-27.

Effect on Existing Marginal Coal-fired plant

Over 40% of installed generation capacity in the UK is coal and oil generation plant and low efficiency gas generation plant. The resultant cost increase from the introduction of a carbon price floor at a significant premium to the EUA price could jeopardise the viability of marginal fossil fuel generation plant. Such generators are already facing key investment decisions for compliance with the Industrial Emissions Directive in 2016 against a background of current unsustainably low generation margins in the wholesale market. There is a real risk that, if a carbon floor is introduced, there will be premature closure of generation capacity and cessation of the provision of the flexible services provided by such plant, Premature closure should be of major concern because the plant would close too quickly to permit the commissioning of the low carbon generation plant which is needed to replace it. This would lead to security of supply issues.

Consultation Process

The Carbon Price Floor is a key strand of the Government’s overall EMR package proposals. Hence we are disappointed that we were not given more time to consider this consultation response alongside the other elements of the package. Indeed, it was surprising that HM Treasury were not able to accommodate a normal 12 week consultation period for such an important issue.