DECC's Electricity Market Reform (EMR) Consultation

Submission by International Power plc

10 March 2011

(I) About International Power plc

International Power plc (IPR) welcomes the opportunity to contribute to DECC's consultation process on Electricity Market Reform.

International Power plc is a leading independent power generation company with active interests in closely linked businesses such as LNG terminals and water desalination. Following the combination with GDF SUEZ Energy Europe and International, International Power plc has strong positions in all of its major regional markets (Latin America, North America, the Middle East, Turkey and Africa, UK-Europe, Asia and Australia). In total, it has 66 GW gross capacity in operation and committed projects for a further 22 GW gross new capacity.

In the UK-Europe region, International Power plc has 13.2 GW capacity in operation and a further 1.3 GW under construction. This includes over 7.3 GW of plant in the UK market made up of a mixed portfolio of conventional plant – coal, gas, CHP, a small diesel plant, and the UK's foremost pumped-storage facility. Several of these assets are owned and operated in partnership with Mitsui & Co. Ltd. IPR's assets represent just under 9% of the UK's installed capacity, making IPR the country's largest independent power producer.

IPR in the UK-Europe region operates about 1100 MW of wind power. The company is keen to develop its renewable portfolio further and is developing a range of projects in the UK as part of this strategy. The company also has a significant Industrial and Commercial retail supply business, and a gas supply business in the UK.

(II) Summary of Response

Current Market Arrangements

- The current market framework has served the UK economy very well over the last decade or so, focusing primarily on delivering a competitive market and the best deal for consumers. More recently Government has placed more emphasis on encouraging investment from low carbon sources as it strives to meet its climate change commitments. Government also recognises the need to retain a robust energy market is also essential to encourage investment.

- The EMR proposals place considerable emphasis on decarbonisation but the security of supply challenge does not receive sufficient consideration. This is not just a "peak capacity" issue, but also one of the system's inherent ability to cope with wind intermittency on a large scale. Existing plant including thermal plant will still be needed to manage this intermittency. Understanding and anticipating these challenges is critical to market design and essential to the *facilitation* of the low carbon transition.

- IPR believes that a more balanced, holistic, and detailed assessment of market reforms is required to deliver a largely decarbonised sector and at the same time ensure Security of Supply and provide consumers with affordable electricity.

Options for Decarbonisation

Carbon Price Support

- Although the Carbon Price Support mechanism is covered in HMT's recent Consultation it is important it is considered here because of potential interaction with EMR initiatives described in DECC's Consultation document.

- There needs to be greater clarity on what is meant by 'certainty' and 'support' for the carbon price. If the purpose of a Carbon Price Support Mechanism is to insure against a collapse in the carbon market, the level should be set close to the European Commission's price projections for Phase 3 and beyond.

- It is widely accepted that investment in low carbon technologies will be incentivised by the Feed-in Tariff mechanism and not via the Carbon Floor Support mechanism. Nonetheless the latter needs to dovetail efficiently with other elements of market reform.

- A carbon price floor will deliver very substantial unwarranted 'windfall profits' for existing nuclear and renewables generation, paid for by consumers. Depending on assumptions this could amount to between £4 and £8.5 billion for the period 2013 to 2030.

- Overall, we would recommend a low trajectory for the price floor and, because of the impact on consumers, a start date that is consistent with the commencement of operation of new nuclear plant

- It should also be recognised that the chosen trajectory can have a direct impact on the phasing of closure decisions relating to existing thermal plant. This has a direct impact on security of supply, and could, if not effectively combined with the overall EMR package, conflict with the need for adequate system flexibility highlighted above

Feed-In Tariffs

- We agree with DECC that the "Full FiT" model would not be consistent with the maintenance of a viable wholesale market. Diverting significant physical volumes away from the wholesale market would impact on liquidity, undermine pricing signals, and distort balancing activity.

- Of the remaining two alternative models we support the introduction of Premium FiTs. This would deliver improvements over the current ROC regime in moving administration to a central agency, allowing all participants to capture the full value of the low carbon credit. Furthermore they will provide increased certainty to developers and investors.

- Crucially, the Premium FiT model minimises any potential impact on the wholesale market, reduces the incentive to bid negatively and has the potential to interact effectively with the Carbon Price Floor initiative.

- Although Contracts for Difference (CfD) FiTs may provide additional certainty to low carbon investors, this benefit is outweighed by a number of negative factors the most important of which is that it could have a highly detrimental impact on the operation of the wholesale market, undermining price formation and investor confidence.

- A Contract for Difference mechanism would be complex, not least because there is no 'one size FiTs all' which means a number of variants may be required, adding further bureaucracy.

Emission Performance Standards

- In light of existing and new emission reduction regulation, IPR believes Emission Performance Standards are an unnecessary additional regulation.

Options for Market efficiency and Security of Supply

- We do not support DECC's preferred approach for a narrow, targeted capacity mechanism via additional reserve contracts with the system operator. This is a wholly inadequate response to some very significant security of supply challenges that will develop over the next decade and beyond.

- Whilst the current energy-only market has delivered significant investment over the last 20 years, it was not designed with these increasing levels of subsidies and intermittency in mind. There will be a fundamental shift in the relationship between capacity and energy across the energy system, with a very significant tranche of capacity operating flexibly at very low load factors, but critical to delivering on security of supply objectives, and to supporting the integration of wind capacity.

- In this context, a narrow, targeted approach, effectively capping wholesale prices for plant not eligible for targeted payments, actually *accelerates* security of supply concerns rather than fixing them. *For these reasons, IPR would prefer to maintain the current energy-only market design, over the introduction of a narrow, targeted approach.*

- A better option however, would be to develop a broader mechanism aimed at incentivising the provision of flexible capacity to the market. It has the potential to address increasing market risks faced by flexible plant by providing some revenue certainty to this important section of the market, and to ensure that the system maintains sufficient capability to keep pace with increasing flexibility requirements.

- We would expect capacity to be eligible via a set of 'basic' flexibility criteria. These criteria would be technology neutral, and therefore open to demand-side capacity, storage technologies, as well as thermal and peaking plant; we would not envisage plant covered by a FiT arrangement to be eligible.

- We anticipate implementation being required in the second half of this decade, driven by a growing demand for flexibility, alongside a loss of flexible capacity by the end of 2015 enforced by the Large Combustion Plant Directive.

- Given the likely time needed to develop such a mechanism by 2015, a joint Government/industry project to design and develop sufficient detail to allow implementation should commence this year.

Analysis of Packages

- We recommend a different emphasis on the package of reforms to that initially preferred by DECC - Low carbon incentives should be provided primarily via a Premium FiT mechanism while security of supply challenges will need to be covered via a market-wide, technology neutral, flexibility mechanism.

- Since low carbon generation will be incentivized through the FiT mechanism the role of the Carbon Price Support mechanism should be to ensure against collapse of the carbon price in the market- a low trajectory as close to market projection as possible is sufficient to achieve this. IPR believes the Emission Performance Standards is an unnecessary regulation.

- Initiatives designed to encourage market liquidity should be progressed ahead of EMR implementation, and market viability/liquidity should remain a key delivery criteria.

- IPR therefore supports a revised package of measures that we believe supports government objectives more fully than the preferred options identified in the EMR consultation and addresses impending, complex security of supply challenges. Crucially, the package maintains the viability of the energy market at the core of the arrangements, and as such continues to promote competition, retains investor confidence, and encourages a healthy independent sector.

Implementation Issues

- More work is needed in a number of important areas to ensure implementation delivers on all three DECC objectives for the electricity system – Decarbonisation, Security of Supply, and Affordability.

- The EMR offers a number of "off-market" interventions and subsidies, rather than any proposed change to the mechanics of market operation. Such interventions can have a very significant and real impact on market prices, trading patterns, liquidity, dispatch, and the allocation of risks amongst market participants. The combined effect of an increasing range of interventions around a market, can ultimately lead to a situation whereby that market is undermined and is unable to operate freely and effectively. This can have a negative impact on the interests of customers.

- The interaction of the EMR proposals with the Carbon Price Floor must be considered. All of these elements have a potentially major impact on the wholesale market – the carbon price floor cannot be perceived as an independent taxation decision.

(III) Answers to 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?

1. As noted in the consultation document, the current electricity market has functioned well since privatization and brought about 30GW of new investment. Its limitations in supporting massive investment in low carbon generation are not a "failure" of the market, rather, it is a reflection of changing priorities. The current market was designed primarily to drive down wholesale costs to the benefit of customers, supplemented by a specific renewable subsidy scheme (the Renewables Obligation) and latterly incorporating the costs associated with the EU wide Emissions Trading Scheme.

2. It cannot therefore be expected to deliver on the ambitious domestic long term carbon reduction goals now agreed in the UK, or indeed binding EU targets on renewables. New low carbon generation needed to meet these environmental targets will have to be subsidised (absent any EU wide political agreement to tighten caps under the EU ETS). It is correct therefore for the Government to recognize that without additional measures, the current market arrangements will not deliver on these overriding low carbon objectives.

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

3. In Chapter 2 of the consultation document, DECC sets out its rationale for reform and highlights the range of challenges faced by companies considering investment in flexible plant, against a background of increased low carbon capacity. Whilst this is a promising start, of DECC's three objectives for the electricity system (Security of Supply, Decarbonisation and Affordability), the EMR proposals themselves are clearly geared towards achieving Decarbonisation1 and do not sufficiently address the associated security of supply challenges.

4. We note the speech Charles Hendry gave recently to the NOF Energy Conference on 2nd March where the Energy Minister said:

   "We need to get away from the idea that the Government has to choose between energy security, low carbon or affordable prices. And instead we have to recognise that the key to

[1] This conclusion is reinforced by the binding assumption in all of the supporting analysis that EU Renewables targets and UK Carbon budgets will be met – irrespective of cost.

affordability is energy security. In the modern age, security and low carbon go hand-in-hand....

My ambition is to take the issue of energy security off the agenda completely. It is to put in place a structure that will make the UK one of the most attractive places for investors."

5. Whilst progress towards a decarbonised system can be consistent with energy security at a macro level (e.g. reducing the reliance on imports of fossil fuels) we do need to recognise that it will bring about a new, more challenging operational environment for the market and the system operator. In particular, security of supply becomes not just a problem of securing "peak capacity" issue, but also one of securing the system's inherent ability to cope with wind intermittency on a large scale. Understanding and anticipating these challenges is critical to market design and essential to the facilitation of the low carbon transition. This important work is not adequately covered and, therefore, in our view the Government assessment is incomplete.

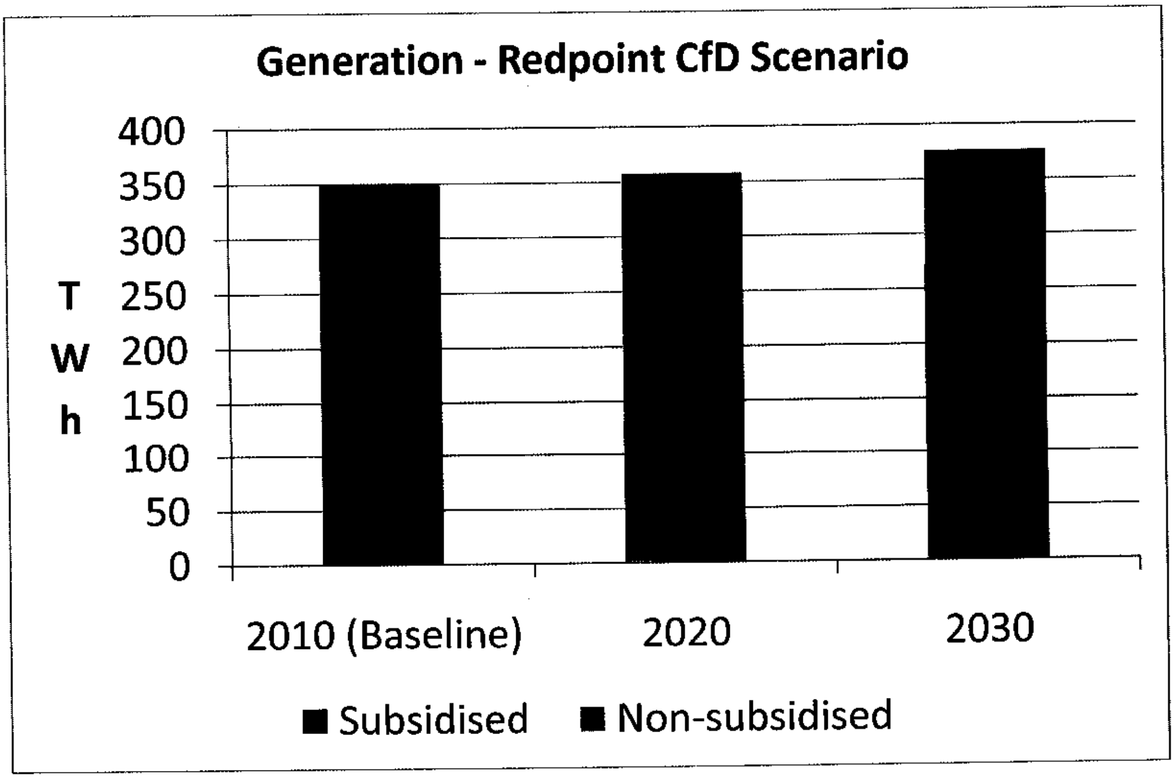
Options for Decarbonisation

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

6. We agree that both Fixed FiTs, and the regulated asset base model, should be ruled out for the reasons stated in the consultation. We do not support the Low Carbon Obligation as it would further exacerbate the dominant position of the 'big 6' vertically integrated companies. We have therefore limited our assessment to the pros and cons of CfD and Premium FiTs. We have provided a summary on our assessment of these two alternatives in Appendix 1.

7. DECC's support for the CfD FiT model rests primarily on it having a lower cost to consumers compared to the Premium FiT. Under Q7 we list the limitations of Redpoint's analysis; below we have focussed on a more qualitative assessment of the drawbacks of a CfD FiT compared to a Premium FiT. These have not been fully recognised in the consultation document:

- **Indifference to the level of wholesale prices** – the low carbon generator will always be topped up to the CfD strike price and so will be indifferent to price when it generates. Its only incentive will be to try and beat the index price. Table 13 of Redpoint's analysis as depicted in the graph below shows that by 2030, over 70% of the market volumes could be subsidized via a CfD FiT.



Under these circumstances it is not credible to assume that the wholesale market is unaffected. Plant in receipt of top-up payments will not face the same commercial risks and imperatives as those faced in the residual wholesale market. This can be damaging to the market, and to investor confidence. Under a Premium FiT, whilst the same percentage of generation receives a subsidy, all generation would still be fully and equitably exposed to the wholesale price.

- **Impact on Liquidity** – over and above the generic impacts on market behaviour, there are significant risks that the detailed implementation of a CfD model can distort trading activity and impact on liquidity patterns. For instance, without any obvious price index under BETTA, the chosen reference price(s) for CfD FiTs will inevitably lead to a concentration of trading activity at times when the index is fixed. This is likely to lead to a reduction in liquidity at other times, particularly in the forward markets. Further, and allied to the first point, indifference to price levels may discourage operators from trading more actively to manage price risk, leading to lower churn levels.

- **Additional Complexity** – a "one size FiTs all" reference price will not be suitable for all types of low carbon generation; please see response to Q10 for further detail. Therefore, whilst the CfD FiT conceptually appears simple, in reality it will be far more complex to implement and administer than a Premium FiT approach.

- **Incompatibility with EU legislation** – there is an EU initiative to have an integrated energy market in place by 2014. To ensure revenue stability, the CfD FiT design will have to be robust to a change in the index price and possibly a change in the market mechanism. This is further complexity that will be difficult to reflect contractually (a Premium FiT would of course apply independently to the market price.) Further, we understand that the European Commission is planning to review the potential for EU-wide harmonisation of renewables/low carbon support mechanisms in order to reduce regional distortions. A unilateral UK decision at this stage to introduce a radical overhaul to the Renewables Obligation is inherently risky given the potential for these plans to be unwound in the medium term.

- **Inconsistency with the carbon floor price** - the carbon floor price becomes redundant as a mechanism to incentivise low carbon generation where a CfD FiT regime is in place - the FiT price level can on its own reflect the degree of subsidy needed.

- **Greater occurrence of negative prices** – under a CfD FiT, the low carbon generator will be indifferent to the extent and frequency of negative prices. Under a Premium FiT, pricing negatively will result in price cannibilisation[2] – the low carbon generator will eat into all its revenues (low carbon or otherwise). This provides a useful incentive to avoid behaviour that would drive prices negative.

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

8. No. Under Q3 above we have listed the many drawbacks of the CfD FiT compared to the Premium FiT. Our judgement is that these drawbacks outweigh the potential benefits associated with the CfD model of FiT. In particular, we strongly believe that the potential impact on the wholesale market of widespread CfD FiT implementation has been underestimated by DECC.

9. The complexities of implementation become particularly apparent as the concept is developed into practical design alternatives. For instance, how would the reference price be set? A single reference price will not suit all types of low carbon generation. An intermittent generator will require an index set close to real time to align with generation certainty, a nuclear generator will prefer a baseload index. Further detail on the selection of price indices is provided under Q10.

[2] Price cannibalisation will occur in the wider wholesale market regardless of whether a Premium or CfD FiT is adopted simply due to a large amount of subsidised generation with very low marginal costs. This price cannibalisation is already being observed in the Spanish, German and Benedelux markets. Over and above this, a Premium FiT would provide a specific incentive on low carbon generators to avoid negative pricing.

10. IPR recommends a Premium FiT for the following reasons:

- it preserves exposure of low carbon generators to wholesale prices; i.e. it keeps the market whole and discourages negative pricing and hence provides a robust market to establish the efficient dispatch of plant;
- it is (relatively) simple to design and administer;
- it aligns with the current ROC mechanism which is well understood.
- it would deliver improvements over the current ROC regime in moving administration to a central agency allowing non-suppliers to capture the full value of the support mechanism for the project term. This would increase revenue certainty for developers and investors;
- it works alongside a carbon floor price and allows the support level to be explicit; and
- it is robust to EU initiatives to establish a single energy market.

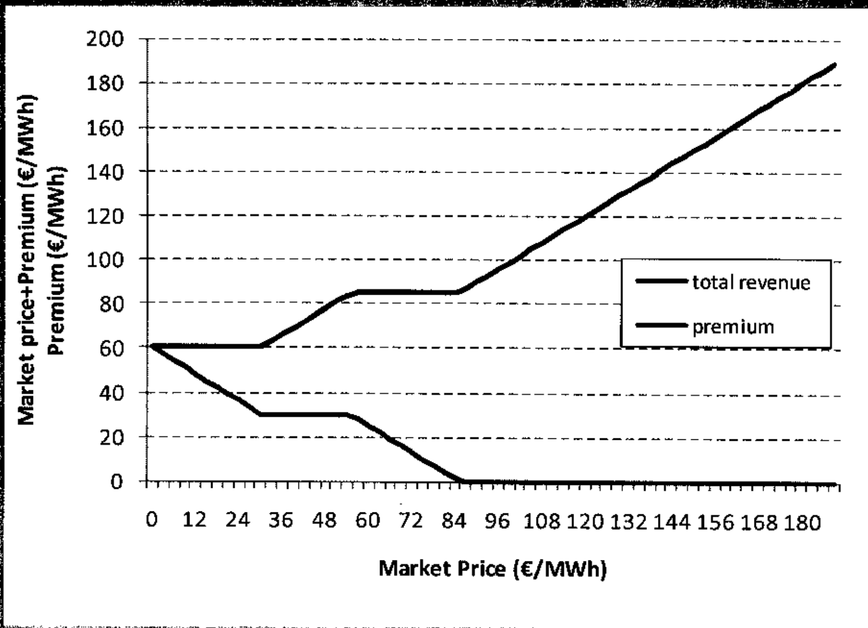
11. We recognize that DECC has highlighted some concerns with regard to the Premium FIT. In particular the risk of windfalls should wholesale prices rise from the starting point of the contract. (Equally, however there is the risk that wholesale price could fall.).

12. If the 'windfall" issue remains an overriding concern for DECC then to mitigate these risks for both the operator and the customer, the Premium FiT could have a cap and collar applied - further information on this "variable Premium FiT" which has been adopted in the Spanish electricity market is described below.

Variable Premium FiT

In the Variable Premium Feed in Tariff, the premium paid to the generator varies as a function of the market price; cap and floor thresholds are introduced to limit extreme situations. The presence of a floor price de-risks the project, giving some certainty to future revenues from sales. At the same time the cap limits the cost of the policy to the consumer, which is not forced to continue subsidising a technology when market conditions no longer require it.

The premium paid reduces in a graduated way until the electricity price reaches a certain level at which point it decreases to zero and the producer only receives the market price.



[illegible] Crucially though, between the cap and collar price levels, this model preserves the viability of the wholesale market [illegible]

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?

13. Advantages of transferring risk to Government

- Revenue certainty for the generator – the generator will be able to achieve the full value of the support level reducing the cost of capital required.
- Reduced consumer cost - the lower cost of capital may result in lower costs to consumers compared to the current ROC mechanism3

14. Disadvantages of transferring risk to Government

- **Regulatory uncertainty** - Political risks will increase with extra reliance on government support schemes. Governments typically change the detailed rules (for example as they have done regularly under the Renewables Obligation) and tend only to have a relatively short time horizon on their policies. Given investments will be made on assets with a life expectancy of 40 years, this lack of long term stability does not engender investment confidence. Government would need to ensure stability of the support mechanism within and across successive Governments. This could be achieved through legal contracts or legislation.
- **Over/under supply** - There is a risk that the Government sets the subsidy level incorrectly resulting in either a failure to meet it targets or over provision of low carbon generation increasing consumers' costs. Oversupply will increase the problems that will be encountered in managing intermittency.
- **Dilution of long term price risk** – The indifference of low carbon generators to wholesale price under CFD FiTs is a major flaw associated with this option. This is covered further in our response to Q3.

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?

15. An efficient market is fundamental to delivering the priorities of "Affordability" and "Security of Supply". The proposed package limits market efficiency.

16. Robust signals from efficient price formation and price discovery are fundamental to the functioning of the market. A robust electricity market price (along with the relevant fuel costs) enables a generator to optimise the real-time despatch of plant, perform hedging decisions and formulate suitable outage plans. This is necessary to meeting demand at the lowest cost (benefiting consumers) and inefficient signals will limit the achievement of this aim. In the long term robust price formation is an essential feature of a suitable investment environment, and, therefore, maintaining security of supply.

17. The proposed CfD FiT renders a large volume of the market indifferent to the wholesale price and negatively impacts liquidity (see Q3); this can only limit the efficient functioning of

[3] although additional risks may appear elsewhere in the market as a result of unintended consequences

the market. The effects of increasing levels of generation "outside" the market should not be underestimated.

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?

18. We agree with the relative ranking which reflects the increased risk arising from reduced revenue certainty as one moves from a fixed FiT to a Premium FiT. Beyond this, DECC should be cautious in placing too much reliance on the NPV net welfare calculations.

19. Table 12 of Redpoint's analysis shows that under a Premium FiT, the net welfare NPV cost over the period 2010 -2030 is £3bn more than under a CfD FiT. Redpoint's analysis uses some apparently precise cost of capital calculations to determine the impacts of the different FiT models suggesting that a high degree of rigour has been applied to the analysis.

20. In reality, the various WACCs are based on estimated input assumptions; a small change to these assumptions could markedly change the benefit and hence the conclusion. This does not engender much confidence in the accuracy of the net benefits. For onshore wind projects, for example, we estimate that the introduction of CfD FiT would reduce the Weighted Average Cost of Capital (WACC) by between 0.5-1.0%. This compares to the Redpoint assessment of a 1% difference and would reduce the cost differential of a CfD FiT vs Premium FiT.

21. Furthermore, given the £200bn of investment required in generation and infrastructure, Redpoint's estimated £3bn difference over 20 years is not significant. DECC should therefore be cautious in placing too much emphasis on the Redpoint analysis and should give greater weighting to the unintended consequences of a CfD FiT as we have described under Q3 and Q4.

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?

22. Although CfD FiTs (and of course Full FiTs) have the potential to reduce project risks and therefore attract more interest from investors, we do not anticipate any significant variations across the different FIT models:

- Offtake contracts are just one of a range of risks that need to be managed. Planning, grid connection and construction issues remain significant and common to all projects
- Investors are likely to be wary of a radical overhaul of incentive arrangements. The RO regime has provided valuable stability and understanding. Moving too far away from this model risks losing confidence and creating an investment hiatus.

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?

23. Without further detail in the proposals, it is difficult to provide any comprehensive comment.

24. From the perspective of an indepedent low carbon developer all of the options are likely to be positive. Currently, independent developers are subject to negotiations and ultimately arranging Power Purchase Agreements (PPAs) with electricity suppliers for their output. The way the RO is structured as a supplier obligation forces this model to exist and this results in somewhat of a captive market for renewable generation. This has tended to lower the value of their output because contracts are negotiated at a discount rate to the full value of the RO, typically 5-7.5%.

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?

Importance of liquidity

25. Levels of liquidity, particularly in the medium to long term are of concern currently. This arises because there is little imperative to trade amongst the 'big 6' vertically integrated companies. Improved liquidity is therefore important now and in the future for all FiT options, not just a CfD FiT.

26. In its assessment, DECC has given little attention to the impact that the preferred FiT model will have on liquidity. A CfD FiT needs a liquid index or indices to facilitate the sale and purchase of power, provide investor confidence and prevent gaming opportunities. With over 70% of the market potentially in receipt of the FiT by 2030, careful design is essential to prevent a CfD index being further detrimental to broader market liquidity. Thermal generators, and in particular, independent thermal generators, will still need to be able to efficiently trade in and out of positions along the curve and not just at discrete points that suit the timing of trading of low carbon generation. The indices must be designed with the whole market in mind.

Index design

27. As noted under Q4, a single reference price will not suit all types of low carbon generation. A wind generator requires a reference price set close to real time so that it can have confidence in the level of output it is trading and minimize exposure to imbalance cashout. This is likely to imply an index based on a combination of day-ahead and within-day prices. Any mechanism must however provide a requirement to trade the renewable output. An

ex- post index must be avoided as a renewable generator can then always spill and will have certainty of always achieving the strike price. It would have no reason to trade its output.

28. However, the closer to real time the index is set, the greater the risk of price cannibalisation simply because short term prices will fall dramatically when there is a high degree of wind generation which the market will not have anticipated in advance. To avoid this price cannibalisation, a forward baseload price as suggested below for nuclear would need to be adopted but wind generation would have no certainty in output in the longer term. What wind needs and what the market would want as an index for wind generation are therefore at odds.

29. Nuclear generation is more consistent with a longer term, possibly annual baseload reference price. Forward markets are already relatively thin. With 34% of generation coming from renewable sources by 2030[4], a prompt-based index CfD FiT for renewable generation is likely to further bias trading activity into the short term. To prevent any market distortion or even gaming opportunities, a nuclear based index will need to be carefully designed so that it aggregates trading volumes over a suitable period of time.

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

30. This question is being asked due to concerns over negative prices. This is an issue that would arise particularly under a CfD FiT - please refer to the response to Q2.

31. On a more practical level, if paid on an availability basis, assumptions would have to be made on the likely load factor in order to set the FiT at the correct level. The load factor will vary dependent on the location requiring location specific availability FiTs. If location is ignored, an availability-based FiT would create of winners and losers in the level of support. IPR does not consider an availability-based FiT to be workable.

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?

32. IPR agrees with the need to limit the construction of new unabated coal fired power stations. However IPR does not consider that an EPS is necessary in addition to the incentives already in place: the EUETS, the requirements of the Environment Agency for Carbon Capture Readiness and the limitations of the Industrial Emissions Directive. The introduction of an EPS simply amounts to unnecessary 'double regulation'.

[4] Redpoint Analysis of Policy Options Table 13

33. IPR considers that many of the regulatory difficulties addressed in the consultation, e.g. uncertainty, grandfathering, review, treatment of biomass and exceptions to the EPS in the event of long-term or short-term energy shortfalls can be avoided simply by not implementing an EPS.

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?

34. If an EPS is to be set for new power stations, since CCS is still unproven technology, of the two options IPR would prefer to see Option 1 introduced in the first instance to provide maximum technical flexibility to support the development of CCS.

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?

35. IPR agrees that any EPS should be aimed at new plant only and that the conditions applied at consent should not change post consent. Grandfathering should apply for the life of the power station regardless of whether it operates beyond a standard 'economic life'. IPR considers this an important measure to ensure that the regulatory certainty at the point of investment decision is not undermined by the creation of a stranded asset. IPR would prefer to see power stations close because of market pressures rather than by retrospective direct regulation. If the EUETS functions in a proper manner, then unabated coal fired plant would either close or run very rarely but provide security of supply back up, due to the cost of carbon.

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?

36. IPR considers that such an eventuality is unlikely to arise. The LCPD and the IED will ensure that tranches of power stations will close in 2016 and 2023 respectively. If any of these plants want to return to service, they will have to meet the Environment Agency's New Plant Standards including CCR in order to be permitted. Any other plant remaining open will be faced with market pressures including the price of carbon and application of BAT by the Environment Agency. For these reasons IPR considers that it is practically not necessary to extend the EPS to existing plant under any circumstances.

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

37. If an EPS must be introduced then a programme of reviews will be required. The proposed review mechanism seems reasonable.

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

38. Electricity generation from biomass is still a developing market and is considered to be beneficial on the road to a low carbon economy. Biomass needs the same regulatory certainty for sound investment decisions to be made as any other form of generation. Biomass plants should not be required to install CCS.

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

39. We do not agree with this principle. Any exceptions have the potential to both undermine market processes, and the role of the EPS as a "regulatory backstop". There is already sufficient flexibility built into the proposed EPS, and additional exceptions would add complexity and be unhelpful.

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?

40. We agree that DECC has come to the correct conclusion that despite other potential reforms to the market arrangements to enhance security of supply, a capacity mechanism is indeed necessary.

41. If the current energy-only market was retained and the low carbon targets were to be met, prices would need to respond to ensure supply and demand balanced. With Redpoint anticipating 102GW of generating capacity by 2030 and 35GW of this coming from intermittent wind sources, this would be expected to result in significant price volatility, including large spikes in short term prices during low wind conditions.

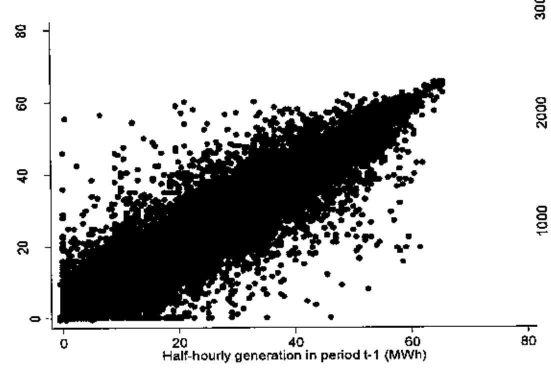
42. Whilst these market conditions are potentially attractive for flexible peaking plant, the absence of revenue certainty to support investment means that it is unlikely that new peaking generation would be built in sufficient quantities.

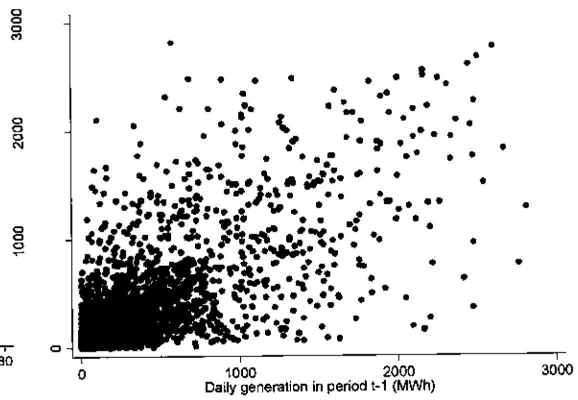
43. These investment risks will not be limited to what we have traditionally labelled as peaking plant. We estimate there will be a further 20GW of thermal generation operating at load factors of less than 10%. There is a question mark therefore over whether sufficient existing plant will remain open to provide much needed flexibility.

44. The increased amount of supported low carbon generation and the uncertainty over when wind will be generating will reduce the scope for this plant to contract in the forward market. This increases risk, placing more emphasis on the level of infrequent and uncertain price spikes to deliver a return on investment.

45. Further uncertainty exists in relation to the confidence of operators to capture value in a price spike driven environment:

- Regulators and politicians, supported by consumers, may well be tempted to implement price caps.
- Generators will not have perfect foresight of wind conditions, even in the very short term. The two graphs below serve to highlight the difficulty in predicting prices spikes. They compare wind output over consecutive half-hours and consecutive days. Although wind output is highly correlated over consecutive half-hours, there is still potential for significant variations in output from half-hour to half-hour. When comparing wind output over consecutive days, the degree of correlation falls with the extent of variability increasing substantially.





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Note: Analysis based on Maximum Export Limit of wind plant during 2008 to 2009 obtained from BM Reports
Source: Oxera analysis of historical wind output.

46. Based on the above, we do not consider that an energy only market will reliably remunerate the amount of fossil generation needed to ensure security of supply. A capacity mechanism is therefore essential in providing this 'missing money'5 and protecting security of supplies.

[5] In an energy-only electricity market, generators earn all of their revenues through the sale of electricity through the wholesale market (including markets for forward and spot power, as well as balancing services), and no additional mechanisms (eg, capacity payments) are used to cover generators' costs (including financing costs or capital charges). Price spikes therefore provide a signal of the need for more generation capacity and thereby incentivise new market entry. If high prices during peak hours are not realised due to interventions by system

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

47. DECC is right to recognise that the market faces some new and significant security of supply challenges in the coming decades, as a result of the intermittent nature of our wind resources. This increases the demand for system flexibility, and for backup capacity running at lower load factors.

48. We therefore agree with Government that a capacity mechanism will be required in response to these major structural changes. However we do not agree with the Government's preferred option. The so-called "targeted" approach has some significant drawbacks which mean that this is not a sustainable alternative. It is likely to undermine security of supplies, rather than improve security. More details on this are provided in response to the following questions.

49. Unless these ideas are developed into a broader mechanism to reward flexible capacity, then it would be preferable to retain the energy only market model.

50. Improvements to the current market (cashout calculations, procurement of balancing services and actions to improve liquidity) also have some merit. In particular, we would draw DECC's attention to the importance of liquidity to the full range of market reform scenarios. Liquidity is an underlying measure of the health of the wholesale market and having confidence in adequate levels of liquidity is an essential precursor for potential new entrants. Independents in particular rely on the wholesale market to deliver revenues, and associated investment. We note that DECC has referenced the work Ofgem is currently undertaking to look at potential options to improve liquidity. We would urge DECC and Ofgem to expedite this work. It is a very real issue now, and measures can and should be implemented in advance of any market reform proposals.

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

51. As proposed, the targeted mechanism is little different to a long term STOR contract. Like STOR contracts, it will effectively cap energy prices at the peak reducing potential revenues and the viability of plant not under contract.

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operators or regulatory authorities, generators may earn revenues that are insufficient to cover their costs. This phenomenon is commonly referred to as the missing money problem.

52. This effect is visible currently – when the system is under stress, STOR capacity offered into the balancing mechanism at predetermined, fixed offer prices can provide this cap to wholesale prices. Over time the market has learnt to factor in the impact of these STOR contracts, and a working balance has been struck between the role of the market and that of the system operator. It is not perfect, but "customer practice" has evolved over time to reach a pragmatic equilibrium.

53. The targeted mechanism implies that significantly more volume could be allocated into long term STOR contracts magnifying the potential impacts on prices in the wholesale market (and threatening to undermine the STOR product itself6). Because of the growing volume of low load factor plant, compared with the current market, energy prices will need to reflect an increased capacity element in order to fixed costs to be reliably recovered. With plant held under contract effectively able to run "in merit" at a fixed offer price (presumably close to short run marginal cost), the gap between this effective cap, and the "true" all-in energy price required will widen considerably, enhancing the 'missing money' problem.

54. In theory, as suggested by DECC, cashout prices could be modified to mitigate this 'missing money' issue. The cashout mechanism design would have to ensure that prices did spike sufficiently and at appropriate times. This in itself is not a simple task; industry has already devoted considerable time to considering ways of better reflecting the cost of reserve holding in cashout prices and so far has not come up with a solution that the regulator has been willing to adopt. This is without having to also consider the unpredictability of wind in the mechanism design.

55. There are also other consequences of this type of cashout reform. Penalties for going short would potentially increase, perhaps significantly. Increasing balancing risks in this way is unlikely to be consistent with other policy objectives. In particular, for physical events that cannot be prevented (e.g. a sudden plant trip or fall in wind speeds) companies can be exposed to imbalance prices that could, in the extreme, result in disproportionate financial damage to a generator. Smaller, independent generators in particular are at greatest risk in these circumstances. This is one of the key reasons why Ofgem has on balance rejected past proposals to, for instance, calculate cashout prices based on marginal actions in the balancing mechanism.

[6] Capacity should not be confused with Reserve. National Grid seeks to contract STOR against an overall Short Term Operating Reserve requirement in order to hedge its costs of managing short term system security. It already anticipates increases to this STOR requirement as wind penetration increases; however its role does not extend to paying for "generic" capacity to ensure longer term matching of supply and demand. A change to these arrangements encroach on the viability of the wholesale market.

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

A central body holding the responsibility

56. We agree that a central body should have responsibility for deciding on the level of capacity and its procurement:

- It is more transparent, and therefore more accessible for independents and new entrants
- It provides a level playing field for all market participants, counteracting some of the advantages enjoyed by the main vertically-integrated players
- It can be designed more robustly to avoid any gaming opportunities
- Placing such an obligation on suppliers would not sit well with retail competition

Volume based, not price based

57. We are not convinced by DECC's arguments for a volume based system over a price-based approach, although we believe that this design feature does not need to be 'hardwired' at this stage. Alternatives are available, such as the Capacity Payment under Ireland's Single Electricity Market, where a hybrid solution is employed that refers to both quantity and price.

Targeted mechanism rather than market wide

58. IPR does not support a targeted mechanism for the reasons give below:

- **The 'Slippery slope'** – DECC envisages the targeted mechanism applying to perhaps 5GW of generation by 2030 to ensure a de-rated 10% capacity margin. DECC anticipates that by 2030, 102GW of generation will be required to meet demand. Below this 5GW we estimate there will be a further 20GW of generation running at less than a 10% load factor.

  In order to remain profitable, this plant will have to able to predict and capture price spikes in a world where these spikes will be driven by the degree of wind generation rather than the level of consumption. That there is 20GW of generation competing in this sector of the market will for the bulk of the time push these peak prices down below profitable levels. Whilst this is good for the consumer in the short term, it is not sustainable. It will lead to plant closure exacerbating security of supply issues or, alternatively, the need for more targeted payments. Ultimately this leads to a situation where all capacity might in fact be covered by a "targeted" payment, but on an opaque case by case basis rather than a market determined basis. This scenario also precludes the ongoing viability of the energy market – it effectively collapses, resulting in a "central buyer" model by the back door.

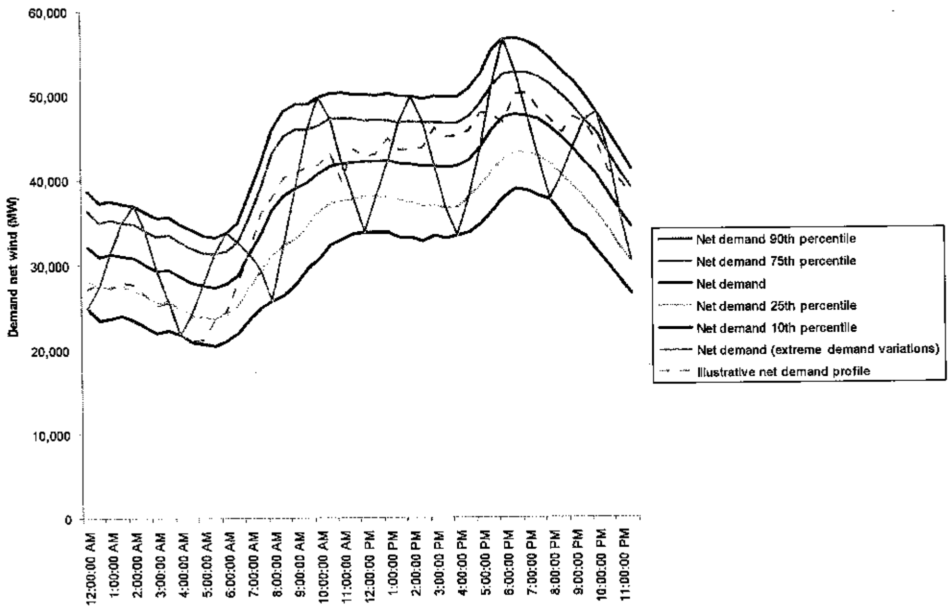
- **Increased risks for independent generators vs big 6** – with the ability to make profits along the value chain, under a targeted mechanism, the 'big 6' will be able to sustain periods of low prices for longer than independent generators. Ultimately, this will reduce competition in the generation sector.

- **Failure to address the need for flexible generation** – DECC's analysis and conclusion that a targeted mechanism for 5GW of capacity is preferable, focuses only on the capacity needed to meet peak demand. It ignores the short term, hour to hour fluctuations in demand net of wind that are expected, as well as the increasing daily swings that need to be met by flexible sources of generation or demand.

- **Not robust to higher demand growth assumptions** –The consultation has assumed that demand and demand shape remain unchanged through to 2030 yet Government anticipates a high growth in electricity consumption arising from the electrification of heat and transport. These changes have not been reflected in the capacity gap analysis. This suggests that there is a significant risk that the capacity and flexibility challenges are potentially greater than presented. A narrow, targeted approach is unlikely to be an adequate response in these circumstances.

59. The Independent Generators Group (IGG), of which IPR is a member, has commissioned Oxera to examine the suitability of the proposed targeted approach. In its report[7] Oxera looks in more detail at these drawbacks and concludes that an alternative model is required. The Executive Summary of the report is attached to our submission as Appendix 2. The expected need for flexibility is illustrated in the chart below, taken from this report.

Demand net wind distributions, winter 2020



[7] Oxera: "GB Capacity Mechanism Design – Meeting future flexibility requirements to secure the low carbon transition"

60. Oxera's analysis highlights the extent of flexibility requirements by 2020, showing:
    - large potential variations in net demand across a day, including considerable volatility; and
    - large hour-to-hour variations in net demand, with maximum hourly changes of up to 17GW by 2020, 25 GW by 2030.

61. To cope with this variability, a large volume of fossil generation will have to operate with greater flexibility; an increased number of starts which leads to increased maintenance costs and an increased requirement to operate at stable export limit, reducing efficiency

62. In its analysis, DECC does not consider the full extent and impact of these critical changes in the market, brought about by the other elements of market reform in relation to low carbon incentives. The conclusions drawn are therefore overly simplistic. Moreover, our assessment is that the introduction of a targeted mechanism will only serve to accelerate the increase in market risks to the bulk of the plant that is required to meet the flexibility swings, and could therefore bring forward security of supply issues rather than resolve them.

Requirement for a broader-based mechanism, rewarding flexibility

63. It is generally recognised that the demand for flexibility will increase dramatically in the coming decades in order to reliably compensate for the inherent inflexibility and variability of low carbon sources of generation in all timescales. It makes sense therefore to base a capacity mechanism design on the provision of this critical commodity. IPR's strong preference is for a broader capacity mechanism aimed at incentivising the provision of flexible capacity to the market:

- It has the potential to address the increasing market risks faced by flexible plant by providing some revenue certainty to this important section of the market, and to ensure that the system maintains sufficient capability to keep pace with increasing flexibility requirements.
- We would expect capacity to be eligible via a set of 'basic' flexibility criteria. This would broadly preserve the current role of the system operator in procuring reserve and response, and preserve the important role of the energy market in efficiently despatching flexibility when it is required. These criteria would be technology neutral, and therefore open to demand-side capacity, storage technologies, as well as thermal and peaking plant.
- We would not envisage megawatts covered by a FiT arrangement to be eligible, even if it met the agreed flexibility criteria. Capacity support is already provided via the tariff, and its primary role is in maximising the generation of low carbon energy. A low carbon generator could however elect to forego its low carbon subsidy and instead receive the flexibility payment for any element of low carbon generation that met the flexibility criteria.

64. We anticipate implementation being required in the second half of this decade, driven by a growing demand for flexibility, alongside a loss of flexible capacity by the end of 2015 enforced by the Large Combustion Plant Directive.

65. In its report to the IGG, Oxera has developed some more detail to illustrate how a potential alternative mechanism might be designed to address the issues highlighted. Further work and analysis is clearly required to identify the most suitable approach. We recommend that a joint government/industry programme is commenced this year to establish an agreed model.

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?

Demand side response

66. A broader capacity mechanism, based on rewarding flexibility, should incorporate demand side response, but this must be on a fair and transparent basis.

67. IPR GdF Suez is the second largest retail supplier to C&I customers in the U.S.. Below we provide lessons we have learned from operating in this market that DECC should consider in developing a capacity mechanism that incorporates demand response:

- **Competitive Prices require similar Capacity Products** - it is not possible to yield good competitive market price formation in a clearing price market where products of lesser value (e.g., limited hours of access) are permitted to displace products of greater value (e.g., more extensive hours of access or services valuable to system operation). Such a design would either under compensate the higher valued product or over compensate the lesser valued product and may lead to a suboptimal mix of resources. Capacity market designs with the same payments to all resources regardless of type have led to an excessive amount of demand reduction bidding into the market and contributed to an apparent capacity over supply, depressing prices and discouraging new investment. This has been a significant issue in the PJM market, where over time rule changes have been required to tighten up demand response requirements.
- **Equity is important** – a demand reduction provider limited to a few hours per year may avoid the need for a new peaking plant, but that customer still requires load service for the balance of the year. Therefore there needs to be a distinction between different capacity products.
- **Demand response cannot play all roles** – many loads willing to provide demand response may only be willing to do so on an infrequent basis whereas generation capacity is expected to be there year round. In addition, customer curtailments usually result in demand being turned off. They are rarely subject to partial curtailment so cannot provide flexibility.

Energy efficiency

68. It might be possible to reward energy efficiency schemes under a broad capacity mechanism, although this would not be so consistent with the overriding need for flexibility (where demand response can play a key role). In any case it would be difficult to identify accurately the energy efficiency that arises in response to a capacity signal rather than any demand savings that would have occurred through other areas of wider market reform such as higher wholesale prices arising through the carbon floor price or the Green Deal.

69. Interconnectors or generation arriving through an interconnector should not receive a targeted capacity payment as there is no way of linking that generation back to source.

70. It would also be inappropriate to pay the interconnector owner under a broader capacity payment as the interconnector owner is already receiving a capacity payment through the auction of interconnector capacity. The justification for interconnectors therefore remains unchanged, and based on the arbitrage value between the respective markets.

Storage

71. Storage technologies are capable of providing some of the much needed flexibility to the market, and therefore making a significant contribution to system security. As with all low load factor plant, investment in storage against a volatile energy-only market is challenging (even in the current market), and eligibility for a capacity based payment has the potential to provide some valuable revenue certainty. It should therefore support investment in new storage capacity and supplement potential value available from arbitrage against increasingly volatile energy prices.

72. Storage plant can also typically provide services at the very fast end of the flexibility spectrum (e.g. fast reserve, dynamic frequency response). Whilst it might be possible to design a capacity mechanism to differentially value these additional capabilities, this would undermine the role of the system operator in procuring an appropriate range of ancillary services. In a sense these are already "targeted" contracts aimed at securing supplies in a finer resolution than that achieved by the market.

73. In summary, a broad technology neutral flexibility mechanism would clearly include storage plant and, together with the growing demand for reserve and response services, provide a fillip for investment.

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

Last-resort dispatch; or

Economic dispatch.

74. IPR does not support a targeted capacity mechanism for the reasons given in the responses to Q21 and Q22. If however, DECC continues to believe that a targeted mechanism is appropriate, a last resort dispatch mechanism would be preferable as it will be the option least damaging to the functioning of the wholesale market.

75. We do however have a number of concerns as to how a last resort mechanism would work in practice. Whilst DECC has advocated the Swedish Peak Load Reserve (PLR) market as a model for GB, we understand that the Swedish mechanism was only ever intended to be a temporary solution to ensuring demand is met. Whilst it has been extended and is still in use, the Swedish regulator has argued that PLR should be phased out from 2011/12 and removed by 2019/20. The Nordic regulators group, the Nordic TSO and the Nord Pool Spot (the market operator) all believe that this out of market intervention leads to market distortions. Such a strong and unanimous opinion borne from experience should not be ignored; it is surprising that DECC has put forward this solution. These market distortions would equally apply to the targeted mechanism proposed by DECC.

76. Furthermore, it is difficult to imagine last resort plant not being used if it is available and the regulator, System Operator or Government perceives there to be a risk to security of supply or has concerns that wholesale prices have risen to uncomfortable levels and could be capped through the use of last resort plant. In using this plant prematurely, the functioning of the energy market will be entirely undermined. Rules would have to be clearly and unambiguously defined to ensure that last resort plant is used truly as a last resort.

77. There is also a real risk that plant that is called upon to run extremely infrequently may well fail and therefore not be able to ensure security of supply. The consumer will not gain much comfort if non delivery penalties are applied to last resort plant but only after the lights have gone out. To guard against this, the SO would have to contract for more plant than necessary.

78. Despite the limitations listed above, IPR still believes that a last resort mechanism is preferable to a targeted mechanism with economic dispatch, because it has a marginally reduced impact on the functioning of the energy market.

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

79. No. This isn't necessary. The GB system is not sufficiently large or constrained to warrant the additional complexities that would arise. If demand is higher in a constrained geographical area then the plant will be called to run more often as happens now. In the long run, the higher potential load factors will be factored into investment decisions.

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?

80. No, IPR recommends a different package of reforms to that initially preferred by DECC:

- Low carbon incentives should be provided via a Premium FiT system, in conjunction with the Government's planned carbon price floor.
- Security of supply challenges will need to be covered via a market-wide, technology neutral flexibility mechanism.
- Initiatives designed to encourage market liquidity should be progressed ahead of EMR implementation, and market viability/liquidity should remain a key delivery criteria.
- IPR therefore supports a revised package of measures that we believe:
  - supports government objectives more fully than the preferred options identified in the EMR consultation
  - addresses impending, complex security of supply challenges
  - maintains the viability of the energy market at the core of the arrangements
  - better manages the interactions between the various elements into one coherent package
  - better promotes competition, investor confidence, and a healthy independent sector

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

81. DECC's alternative package (Package 2) with a universal capacity mechanism is preferred by IPR to Package 3 (DECC's preferred option) as it would ensure all generation is exposed to wholesale prices and in doing so, this keeps the market whole. We still do not see the need however for an emissions performance standard.

82. One of DECC's justifications for rejecting package 2 is that in the event the carbon floor price is increased, wholesale prices will increase but the Premium level will stay the same resulting in infra marginal rents. Whilst we agree that the Premium FiT level should not have to play catch up with the carbon price floor or the wholesale price, the carbon price should be used to provide future price certainty on the EU ETS price and not provide support to low carbon generation. Furthermore, a FiT such as the variable Premium FiT adopted recently in Spain could be use to provide a cap and collar on low carbon revenues whilst still providing an incentive to trade.

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?

83. As recognized by DECC, liquidity is an issue that needs to be addressed. This is particularly important if a CfD is adopted. For the time being, liquidity remedies have been parked by Ofgem pending the outcome of the EMR consultation. As highlighted above, there should be no reason to delay action on liquidity – it is an issue that needs addressing under current market arrangements that can help support EMR objectives.

84. It should be recognised that whilst EMR has the potential to help manage risks for developers (and perhaps increase risks for other market participants through less direct market impacts) it does not resolve the very significant practical hurdles that need to be overcome to ensure low carbon capacity delivery. Planning consent, reactor design approval, construction delays arising from constrained supplies and resources and grid access all need to come together.

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

85. Coherence of the proposed package is clearly recognised as an important criterion. However, the preferred package (3) does not appear to be internally consistent. The planned implementation of a CfD FiT system would ensure that the carbon price floor mechanism becomes redundant as a way of incentivising low carbon generation. This is a key failing of this package. Package 2 is more coherent in this regard.

86. Furthermore, it should be recognised that the chosen trajectory of the carbon floor price can have a direct impact on the phasing of closure decisions relating to existing thermal plant. This in turn has a direct impact on security of supply, and could, if not effectively combined with the overall EMR package, conflict with the need for adequate system flexibility. Conflicting signals are unhelpful.

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?

87. IPR views the main implementation risks as follows:

- Government sets the FiT support level incorrectly and either fails to meet its low carbon targets or overshoots them, depressing wholesale prices to unsustainable levels. This would apply to all types of FiT.

- In the light of EU aims to introduce an integrated energy market by 2014, any EMR proposals and mechanisms subsequently introduced may need to be altered to ensure compliance. This would apply particularly to package 3 as a CfD FIT would be less robust to a further change to the market framework.

- None of the packages removes risk entirely and will not guarantee that the low carbon targets are met.

- Package 3 glosses over how a CfD FiT will work in 2030 the absence of a liquid wholesale market where low carbon dominates the generation mix. This needs to be addressed before a CfD FiT is adopted, not after.

- Government varies the carbon support level in response to changing wholesale prices to mask the level of subsidy being paid to low carbon generation. This would detrimental to investment in existing or future thermal generation.

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?

88. IPR does not believe auctions or tenders can work from a practical point of view. The auction can take place either on a speculative basis or close to the point of financial close of a project. If Government seeks tenders or holds auctions with the aim that those successful will then go on to build a low carbon generation source, this will result in 'winners curse' or put another way "MWs are tendered and kWs get built" as happened under the NFFO.

89. On the other hand, the developer could take on this risk of putting together all the aspects of the project (e.g. site purchase, planning consent, grid access) before the tender/auction but would then be incurring considerable cost upfront with no certainty of success in the tender/auction. This option would also result in far less competition as only projects that were sufficiently advanced could take part and would employ a higher cost of capital to reflect the increased risk.

90. For new nuclear, it is difficult to see how a tender or auction could work other than as an initial stage in a negotiated process given the lack of competition. The support level should however be set on a technology basis.

91. IPR believes that the only approach to setting a feed in tariff is to administer the price on a technology specific basis at a similar degree of granularity to the banding levels under the RO. This way, low carbon developers will know up front the support level to be paid, and the implementation risks are reduced by mirroring some of the widely accepted RO type processes.

92. Constructions costs and wholesale prices will vary over time. Like the RO, the support level will have to be reassessed periodically and could be used as a way of capping consumers' exposure. To retain revenue certainty, it will be important to retain the RO grandfathering principles.

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

93. **FiTs** – a government body will be required to assess the appropriate level of support required for different technologies. Support levels will need to be independently audited to ensure the consumer receives value for money for the low carbon generation.

94. **Carbon price support** – a government body will be needed to determine the level of support, adhere to predefined rules on when and how the support level can be changed. The body will have to take account of the interaction between the support level and expected forward wholesale electricity prices.

95. **Consumer bills** – the costs of delivering these reforms should be explicit on consumer bills

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?

96. We have covered these issues in earlier answers. We agree that there are a number of serious unintended consequences associated with these initiatives, and have suggested a number of alternatives to address them.

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

97. Yes. This is inevitable. But the package of reforms should not be rushed through in a desire to minimise these delays.

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?

98. As with the RO, grandfathering should be a fundamental principle under any FiT regime to ensure stable returns for investors.

99. There should be a statement from the minister to confirm this.

100. Commercially related delays under the RO have traditionally been seen where there is uncertainty around the RO banding reviews. Developers are unsure whether to move early or wait in hope for improved terms.

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 lowcarbon 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.

101. In the case where the FiT is introduced before the closure of the RO, there should be a choice available to investors. This reduces the regulatory risk for projects already under consideration. Not having a choice may render some marginal projects uneconomic and therefore they may not be progressed.

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?

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?

102. Either of option b or c as these gives better certainty.

[redacted]

[redacted]

Appendix 1- Assessment of CfD FiT vs Premium FiT

CfD FIT	Premium FIT
Pros	
Offers certainty to investors and de-risks investments	Offers "bankable" certainty to investors
May result in lower overall consumer costs compared to the current ROC mechanism	Minimises impact on viability of wholesale market: maintains liquidity and competition
	Maintains the efficient despatch of plant
	Improvement over existing ROC regime
	Forms coherent set of policies with Carbon Floor Price
	Compatible with EU initiatives
	Administratively simple
Cons	
Negatively impacts "market viability" and therefore efficient despatch of plant and security of supply	Risk of windfalls should prices rise (this can be mitigated with caps/collars)
Reduces market liquidity and impacts trading patterns	Relies on Government to establish "correct" Premium level to both encourage sufficient investment and minimises over all costs
Renders Carbon Floor Price redundant	Risks that oversupply increases consumer costs
Complex implementation issues including index design	
Incompatible with EU legislation	
Greater occurrence of negative prices	
Relies on Government to establish "correct" CfD level to both encourage sufficient investment and minimise overall costs	
Risks that oversupply increases consumer costs	

Appendix 2

Executive Summary of Oxera report prepared for IGG members:

"GB capacity mechanism design: Meeting future flexibility requirements to secure a low-carbon transition"

Oxera

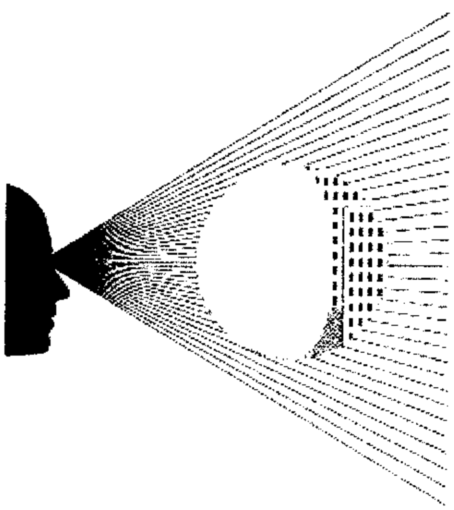
GB capacity mechanism design

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.[8]

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.[9]

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—

[8] Department of Energy and Climate Change (2010), 'Electricity Market Reform. Consultation Document', December.

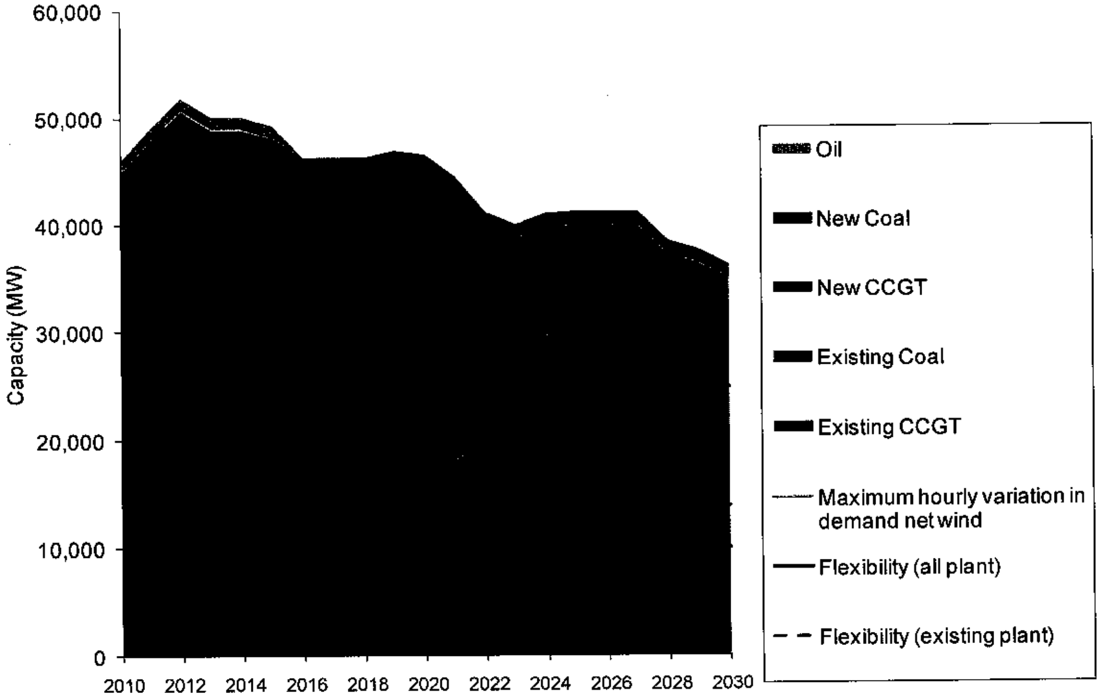
[9] Flexibility requirements are likely to include the ability to meet hour-to-hour variations as well as increased variation in daily peaks and toughs of demand net wind. The analysis in this report focuses on the ability to respond to hourly variations.

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 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.[10]

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'.[11]

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.[12]

[10] 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.

[11] 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.

[12] 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.

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;
- 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.