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UK Electricity Market Reform:

The draft Energy Bill

June 2012

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Contents

Introduction

On May 22nd the Secretary of State for Energy and Climate Change announced the publication of a draft Energy Bill (the **Energy Bill**), for pre-legislative Parliamentary scrutiny by the Energy and Climate Change Committee. The draft bill contains provisions which are intended to put in place the foundations of the Electricity Market Reform (**EMR**) contemplated in the White Paper of July last year – "Planning our electricity future: A White Paper for secure, affordable and low-carbon electricity" (the **White Paper**). These provisions relate to:

– ***Contracts for differences*** (**CfD**) – the long-term contracts contemplated in the White Paper which are to provide stable and predictable incentives for investors in low-carbon generation.

– ***Investment Instruments*** – a welcome addition since the White Paper, being long-term instruments which will give investors more certainty around the future terms of their support, thereby enabling final investment decisions to be taken in advance of the CfD regime being finalised and in force. This is a material development to mitigate the risk of an investment hiatus given the delay in finalising the detail of the CfDs.

– ***Capacity Market*** – the Energy Bill provides for the introduction of a Capacity Market to incentivise the availability of sufficient reliable capacity.

– ***Conflicts of Interest/Contingency Arrangements*** – it is envisaged that National Grid will play a key administrative role in relation to CfDs and the Capacity Market. This approach potentially gives rise to conflicts of interest which the Energy Bill contains mechanisms to manage.

– ***Renewables Transition*** – following introduction of the CfD regime, the Renewables Obligation (**RO**) will (subject to grace periods) be closed to new generation from 31 March 2017. From 2027 a "Fixed Renewables Obligation Certificates" regime will apply and the draft bill contains enabling provisions for this.

– ***Emissions Performance Standard*** (**EPS**) – to be set as an annual limit at an equivalent of 450g CO_2/kWh to reinforce the requirement that no new baseload coal-fired power stations are built, but not to interfere with necessary short-term investment in gas.

The reforms all contemplate intervention by the Government in the functioning of the wholesale market for power in the UK. Such intervention has been justified in earlier consultations and the White Paper by reference to there being a market-failure in delivering investment in the types of asset the Government wishes to see developed to deliver a decarbonised and energy secure future. There is no surprise that a free market does not invest in a policy choice which necessitates investment in more expensive low-carbon technologies. As we said in our commentary on the White Paper[1], the key question therefore remains:

Will the proposed reforms produce a regime that is better suited to attracting the type of capital in the amounts necessary to meet the Government's aims of security of supply, decarbonisation and affordability?

1. Available at www.allenovery.com/UK-Electricity-Market-Reform

We still believe that this could be the case when compared to a "do nothing" case. However, the lack of progress on all of the important detail within the framework, which has been clear to market participants since the White Paper, is now very concerning given the timetable proposed and developments around the world. Of particular concern is:

– Does the Energy Bill represent true progress or just necessary process? As regards EMR there are very few definite arrangements set out in the Energy Bill itself. It is essentially enabling, and the detail will not be definitive until secondary legislation and first delivery plan are available around the end of next year (a diagramatic timetable is set out below). (Although many "emerging proposals" are set out in the documents accompanying the Energy Bill.) Almost the only hard points are a multi-partite quasi-statutory form of CfD and long-term grandfathering for a 450g/kWh EPS; and the Government acknowledges the first of these may change. We believe that the CfD structure could beneficially be simplified, and it is positive that the Government is evidently continuing to listen and consult on these difficult issues. However, the absence of hard decisions risks a significant investment hiatus. This may be compounded by a loss of integration as areas move at different speeds. Arrangements for the capacity market appear to be lagging and a strategy to facilitate investment in gas generation is now to be announced in the Autumn.

– Renewable generation projects which are scheduled to complete by 31 March 2017, but which may be delayed, face a particular dilemma as the grace period for RO eligibility is only available for limited reasons such as a delay in grid connection or radar installation. The impact of the loss of the RO as a result of other events of delay is not likely to be a liability which generators will be able to recover from their contractors. Therefore the ability to opt for the RO is presumably effectively closed off at a much earlier point than March 2017. This situation is currently compounded by the concerns of renewable generators as to their ability to access power purchase agreements on reasonable terms if outside the RO.

– The fixing of part of a supposed market structure (through investment instruments) before the detail and therefore the implications of the consultation around the UK gas strategy is known and CfD Regulations are finalised. While it is very important that progress towards nuclear new build can continue, bespoke arrangements with individually negotiated prices may challenge the Government's commitment not to subsidise nuclear energy (even if Carbon Capture and Storage (**CCS**) projects are also eligible for investment instruments). Flexibility is desirable, but there is a risk that an opaque process will not visibly deliver value for money.

– Will there really be enough competition between technology types to ensure that all technologies have matured to allow a move to technology neutral auctions by the 2020s? Even if this is possible, how will the Government ensure that the pre-allocated sites for new build nuclear power and offshore wind farms are not "land-banked", rendering such competition ineffective?

– The practicality of the proposed CfD allocation process. It appears that projects must be about to reach "Financial Close" before application for a CfD can be made. While certainty of support levels may now be brought forward relative to the RO process, unless there are transparent acceptance criteria (including as to availability of allocations within volume limits) such a level of cost-incurrence prior to allocation may not be supportable. We also question, for example, how construction arrangements and finance can be finalised before a commissioning window is approved. A semi-annual application window could also strain processes and resources.

– While timely delivery of low-carbon generation is crucial, the proposed regime of penalties for delays in achieving commissioning on schedule will need to be carefully calibrated, given the challenges facing significant areas of low-carbon technology and potentially difficult risk allocation debates. We agree that the lessons of NFFO must be applied and holders of CfDs must be incentivised to progress developments; we are not sure the balance is yet right.

– The allocation process seems likely to bring challenges for phased projects, particularly where an initial phase will incur additional costs (such as offshore transmission lines), from which later phases could benefit.

– This process also brings into sharper focus the financial limits for CfD allocation that will exist. Recent experience in Continental Europe and indeed UK solar is not altogether reassuring.

– While there are helpful developments of thinking in relation to reference prices, identification of these now seems to rely on matters not directly within DECC's control. The preferred reference price for intermittent generation relies on the future implementation of market coupling arrangements and that for baseload is dependent on the outcome of Ofgem's ongoing liquidity review.

– Somewhat oddly, references to one-way CfDs have resurfaced and the statutory provisions contemplate alternative payment obligations to those based on the difference between a strike price and a reference price.

– Proposed collateral arrangements for generators could well increase barriers to entry and eat up debt capacity, with adverse affordability implications.

– It is helpful that the Government now seems to accept that protection for at least some change of law should be included in a CfD, though there is not yet any clarity as to the scope of this (and it might be more reassuring if such a provision had been included in the (non-exhaustive) statutory list of provisions that may be included in a CfD).

– The swirling head-winds of austerity mean that the real cost to the consumer and to UK industry of the decarbonisation/energy security agenda must be taken into account over all relevant time-horizons. As commentators increasingly compare the European approach to the likely emissions reduction path and re-industrialisation of the US based on the availability and price of unconventional hydro-carbons, real policy questions are now being asked of UK and European politicians. The role of gas in the energy mix will continue to be hotly debated, particularly as politicians shift the justification more towards energy security and away from decarbonisation so that higher bills can be described as a necessity and not as a voluntarily assumed responsibility[2]. We expect that this debate will be significantly affected by the extent to which the US Department of Energy will grant export permits for hydro-carbons (some will be required in order to ensure that the resources are exploited at all but the extent of this will be crucial in any energy security debate).

– The debate around the UK Gas strategy and its implications for the Capacity Market, the role of the quintennial strategic energy review laid down by Government and the change in law/change in policy protection to be provided by the CfDs will be fascinating to watch – will there be a back-ending and/or extension in the timetable towards the substantial decarbonisation of the power sector by the 2030s? Given that there are suggestions in the documentation published with the Energy Bill that "flexibility" in meeting carbon budgets will be needed in order to minimise costs to the economy, this seems to us to be a clear indication of the direction of travel in this debate. This will have implications for the robustness of the change in law/policy protection that investors will seek through the CfDs.

A separate dimension to this is the growing disparity in the price of carbon between the UK and the rest of the EU. A weakening Euro and soft EU ETS mean that the carbon price support rate "top up", to achieve the Government's rising target trajectory for the (Sterling) price of carbon in the UK, were doubled in the last Budget. The Government has already committed £250 million to energy-intensive industries to offset the effects of carbon price rises. Such circularity hardly demonstrates coherence and in 2014 progress towards 2020 renewables goals will be reviewed with a view to aligning the UK's carbon budget with the actual EU trajectory.

In addition to provisions that implement matters referred to in the White Paper, the Energy Bill also:

– Makes provision to "tidy-up" the structure of the regulation of civil nuclear power in the UK by putting the Office of Nuclear Regulation (**ONR**) onto a statutory footing as the body to regulate the safety and security of nuclear power plants in the UK.

– Corrects an over-sight in the law relating to the transmission of electricity which allows developers of wind-farms who also develop the associated offshore transmission assets under the "generator-build"

2. Indeed, a subtle shift in language used in the documents which accompany the Energy Bill indicates this is already underway.

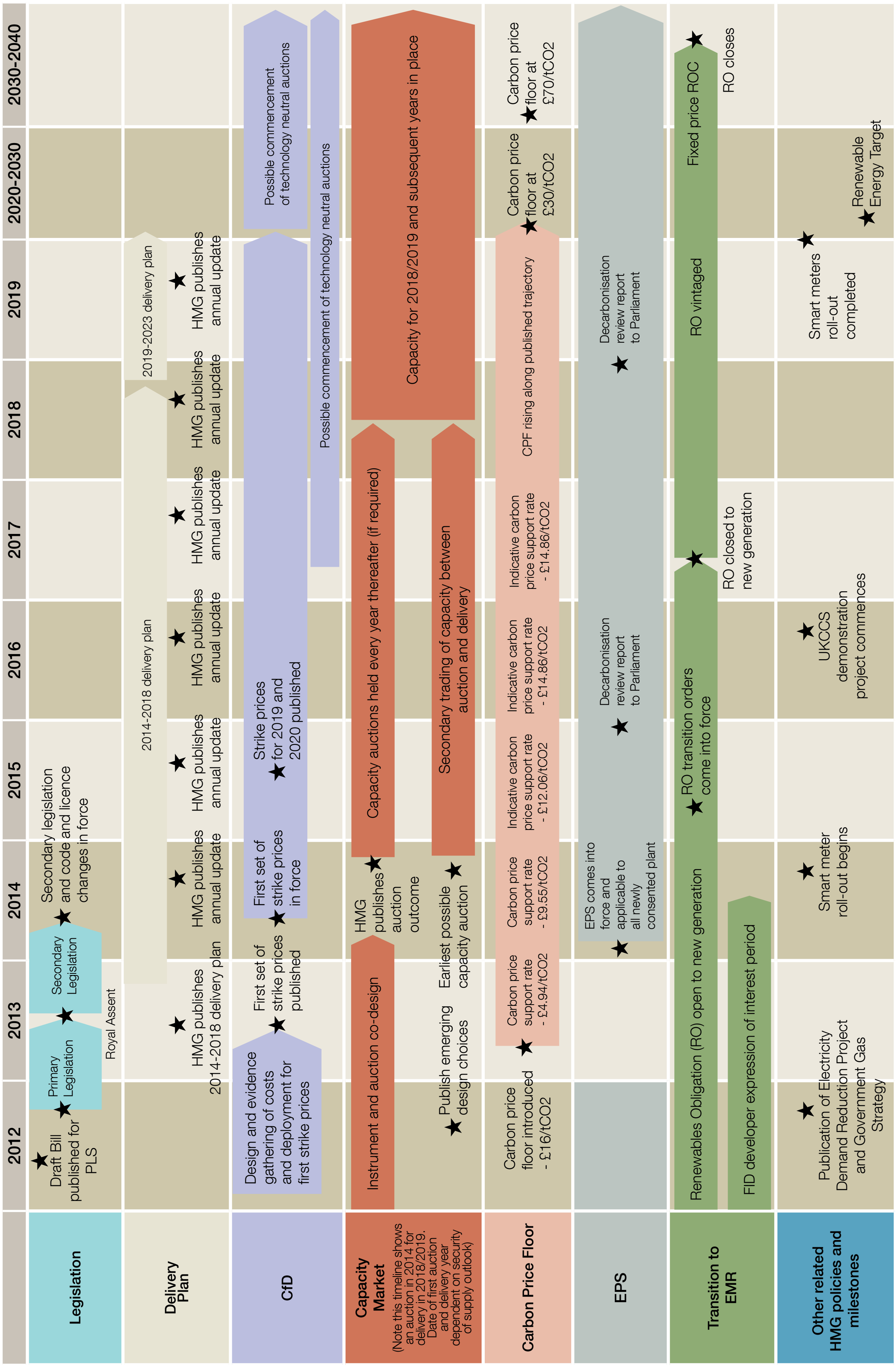
option to transmit electricity through such assets during testing and commissioning, which applies to the period before a completion notice is given (what this entails is not yet clear) and for a further period of up to one year until the date of sale of the transmission assets to an offshore transmission owner (**OFTO**). It will be important to understand the point at which the completion notice is given, since a period of one year from, for example, the date that substantial power begins to be transmitted, may not be sufficient to protect developers given past experience of construction issues on existing projects and the risk of delays in the tender process. If the developer was forced to stop generating because of delays in the OFTO transfer process this would represent a significant additional development risk.

– Makes provision to enable the sale of the Government Pipeline and Storage System (**GPSS**). This has previously been anticipated to be of particular interest to financial investors seeking an exposure to a quasi-regulated return on capital deployed within an asset where further capital expenditure (and therefore future investment) is required. It has also been thought that such a structure would deliver maximum sales receipts to the public purse. However, the enabling provisions do not specify that the GPSS will be transferred with the benefit of a regulated return on capital, presumably because of the customer profile of the GPSS. An element of regulated return could still however be introduced, at least in relation to the Ministry of Defence's (**MoD**) usage requirements, if a leasing structure rather than an absolute transfer is used. The lease could then be used as a vehicle to underpin returns to investors (in return for an upside share for the Government) against an agreed business mirroring in many respects the structure of the CfDs which sit at the heart of EMR.

In the remainder of this briefing, we provide you with a brief synopsis of the various aspects of the Energy Bill referred to above, a discussion of some of the more interesting issues which remain outstanding, more detailed summaries of the proposals and finally a summary table of the impact of the Energy Bill for different types of generation.

We hope that this briefing provides you with much of what you need to know. Please do get in touch with any of us or your usual Allen & Overy contact if there are further matters you wish to discuss.

Should you wish to consult the underlying documentation, the Energy Bill and the other documents published with it (together with our earlier briefings) are available at: www.allenovery.com/UK-Electricity-Market-Reform.


2012
2013
2014
2015
2016
2017
2018
2019
2020-2030
2030-2040
Legislation
Draft Bill published for PLS
Primary Legislation
Royal Assent
Secondary Legislation
Secondary legislation and code and licence changes in force
Delivery Plan
HMG publishes 2014-2018 delivery plan
2014-2018 delivery plan
HMG publishes annual update
HMG publishes annual update
HMG publishes annual update
HMG publishes annual update
HMG publishes annual update
HMG publishes annual update
2019-2023 delivery plan
CfD
Design and evidence gathering of costs and deployment for first strike prices
First set of strike prices published
First set of strike prices in force
Strike prices for 2019 and 2020 published
Possible commencement of technology neutral auctions
Possible commencement of technology neutral auctions
Capacity Market
(Note this timeline shows an auction in 2014 for delivery in 2018/2019. Date of first auction and delivery year dependent on security of supply outlook)
Instrument and auction co-design
Publish emerging design choices
HMG publishes auction outcome
Earliest possible capacity auction
Capacity auctions held every year thereafter (if required)
Secondary trading of capacity between auction and delivery
Capacity for 2018/2019 and subsequent years in place
Carbon Price Floor
Carbon price floor introduced - £16/tCO2
Carbon price support rate - £4.94/tCO2
Carbon price support rate - £9.55/tCO2
Indicative carbon price support rate - £12.06/tCO2
Indicative carbon price support rate - £14.86/tCO2
Indicative carbon price support rate - £14.86/tCO2
CPF rising along published trajectory
Carbon price floor at £30/tCO2
Carbon price floor at £70/tCO2
EPS
EPS comes into force and applicable to all newly consented plant
Decarbonisation review report to Parliament
Decarbonisation review report to Parliament
Transition to EMR
Renewables Obligation (RO) open to new generation
FID developer expression of interest period
RO transition orders come into force
RO closed to new generation
RO vintaged
Fixed price ROC
RO closes
Other related HMG policies and milestones
Publication of Electricity Demand Reduction Project and Government Gas Strategy
Smart meter roll-out begins
UKCCS demonstration project commences
Smart meters roll-out completed
Renewable Energy Target

Synopsis

Overview

The Energy Bill contemplates five principal changes:

– The introduction of the framework for Electricity Market Reform;

– The introduction of a Strategy and Policy Statement to improve regulatory certainty by ensuring that the Government and Ofgem are aligned at a strategic level;

– Creating the Office of Nuclear Regulation;

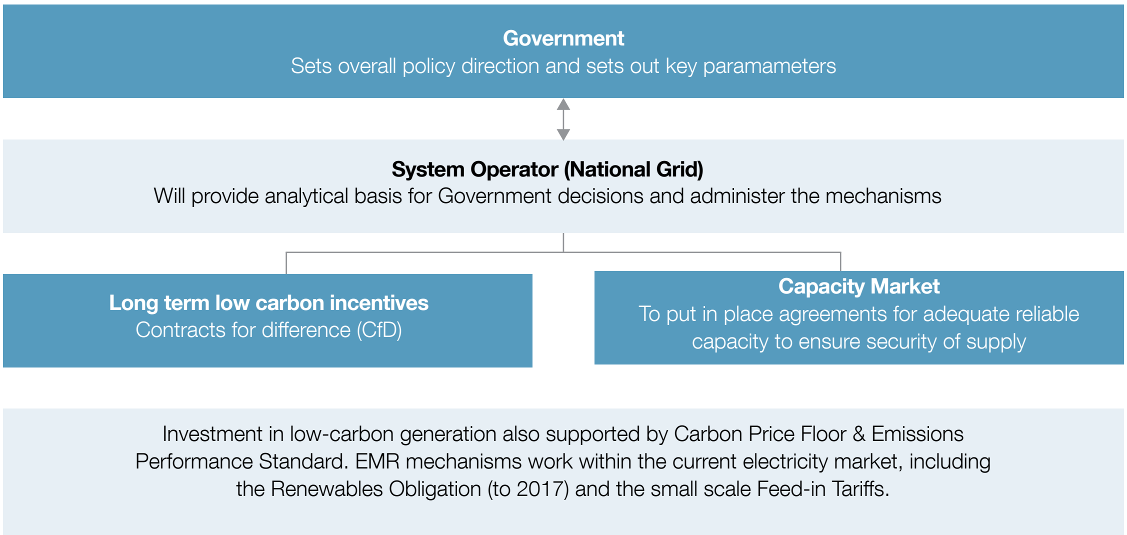
– Enabling the sale of the Government Pipeline and Storage System; and

– A correction to current law to ensure that offshore wind generators constructing transmission assets do not breach the law when testing/commissioning such assets which applies to the period before a completion notice is given (what this entails is not yet clear) and for a further period of up to one year until a sale of such assets to an OFTO.

EMR is designed to secure the investment needed to deliver a diverse low carbon technology mix. While the Government has a long-term vision of low carbon generators competing fairly under a robust and stable carbon price, the different stages of development of low carbon technologies mean that significant, if diminishing, market intervention is required for a generation. The various interlocking parts of Electricity Market Reform are therefore anticipated to run in four stages:

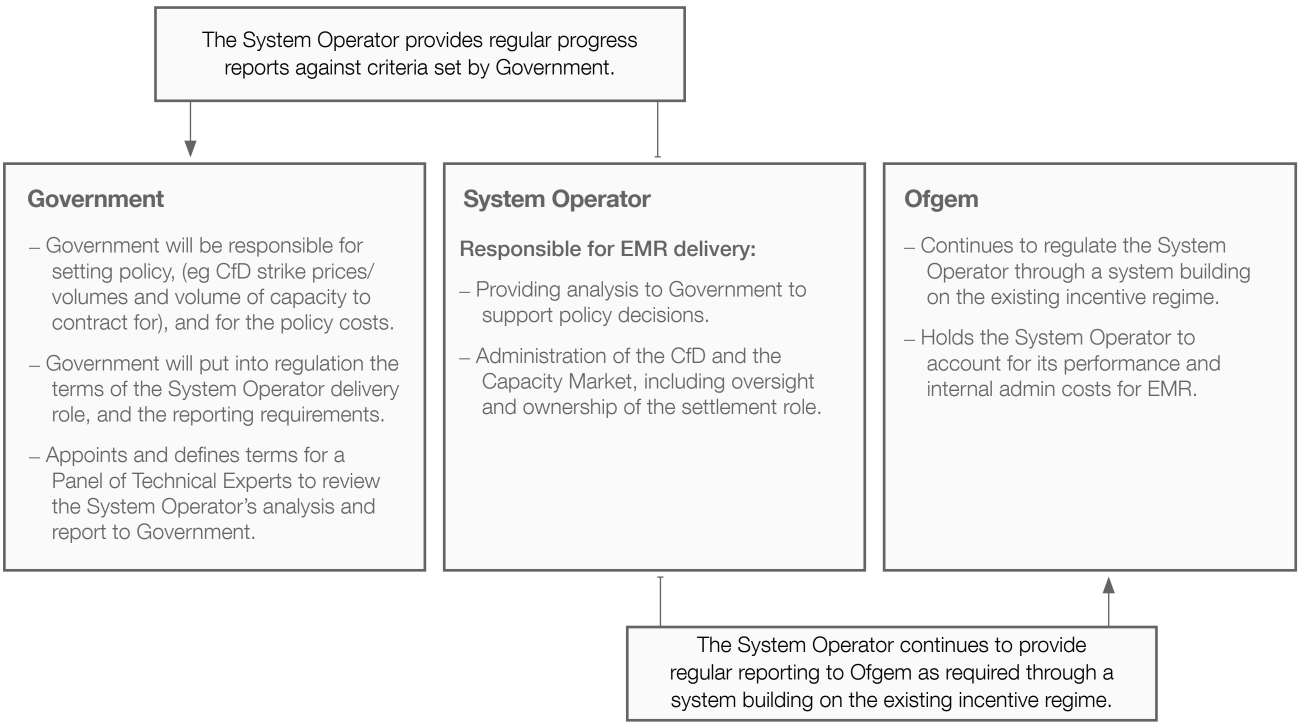
Stage 1 To 2017	**Stage 2 2017 – 2020s**	**Stage 3 2020s**	**Stage 4 late 2020s/beyond**
Current arrangements (RO) alongside new contracts for difference with prices set administratively. Capacity auctions could be initiated depending on the supply outlook.	Technologies mature (but at different rates) and some are able to enter competitive, technology-specific auctions. The Capacity Market could be fully operational if initiated.	All technologies have matured to move to technology-neutral auctions. Demand side response, and additional storage and interconnection, will play an increasingly large role in managing supply and demand.	Technologies are mature enough and the carbon price is high and sustainable enough to allow all generators to compete without intervention.
Capacity auctions run if needed			

Within this staged approach, it is envisaged that the various reform instruments will interact and be administered as follows:



The role of the System Operator in administering the CfDs and Capacity Agreements within both a new Capacity Market and the wider wholesale market is critical. A clear allocation of roles and responsibilities between the Government, the System Operator and Ofgem is therefore more than an administrative nicety – it is essential to the practical utility of the new arrangements. Unfortunately, this detail is not currently available and will not be available until the relevant secondary legislation is available in 2013-2014. The Energy Bill does include the following high-level overview of the interaction between the Government, the System Operator and Ofgem. The detailed implementation of this will need to include procedures and mitigants for any potential conflicts of interest which arise as a result of the System Operator's role in the delivery of EMR.

An overview of the roles and responsibilities within the Institutional Framework.



In addition, since our last briefing there have been developments in relation to a gas strategy in UK power, liquidity in the UK wholesale electricity market and the Carbon Price Floor (**CPF**).

Electricity Market Reform

Structure of Part 1 of the Energy Bill – Electricity Market Reform

- Chapter 1 – Contracts for Difference
- Chapter 2 – Investment Instruments
- Chapter 3 – Capacity Mechanism
- Chapter 4 – Conflicts of Interest
- Chapter 5 – Contingency Arrangements
- Chapter 6 – Renewables Obligation: Transitional Arrangements
- Chapter 7 – Emissions Performance Standard
- Chapter 8 – Strategy and Policy Statement

(a) Contracts for Differences

Structure of Part 1 of the Energy Bill – Electricity Market Reform

- Powers for Ministers to establish CfD regulations, including provisions for:
  - eligibility,
  - CfD terms (such as duration), and
  - the level of low-carbon support provided through CfDs (the “strike prices”);
- Powers for the System Operator and Secretary of State to issue CfDs;
- Powers to set maximum costs and targets relating to CfDs; and
- Powers to make changes to license conditions to enable the System Operator to carry out its functions in relation to delivering CfDs.

It is expected that the terms of the CfDs will be largely standardised across technologies but that in the short term variations may be required to reflect differences in generation profile (e.g. intermittent versus baseload) and risk profile (e.g. early stage Carbon Capture and Storage (**CCS**) projects). Any such variations must represent value for money and maintain a level playing field so as to be consistent with the state aid approach taken by the Government. CfDs (and investment instruments – as to which see below) will also need to reflect the statements of the Minister in relation to what is and is not a subsidy in the context of new build nuclear plant[3].

3. Written Ministerial Statement on energy policy 18 October 2010. See page 16 of our commentary on the White Paper.

It is clear that disagreements remain between industry and the Government as to how the CfDs should be implemented. The Government is no doubt constrained by its approach to state aid in the context of the structure of the CfDs and industry is no doubt concerned that the proposed model is simply more complicated than is necessary (and is therefore unattractive to themselves and importantly future passive financial investors) but the lack of progress here is very worrying. There is simply no point implementing EMR unless industry is satisfied as there are no other entities that can act as architect engineers of the huge programme of investment that is required in the fields of CCS, nuclear and offshore wind to deliver the Government's policy objectives.

In this regard, much has been written and said of the importance of a clear allocation of change in policy risk. It seems from the documentation that this will be delivered through a grandfathering of the CfDs. It is not currently clear to us how this will be achieved in practice in a "statutory contract" model and it will be interesting to see how this evolves. It also seems that protection may be being offered solely in relation to changes in policy and not wider change in law. This will be a disappointment to some investors and may mean that strike prices are higher than they need to be. It will also lead to a difficult debate as to where policy meets law and which policies affect which types of generation. There is significant (and difficult) detail around the definition of change in policy/law and it is disappointing that no obvious progress has been made in relation to this crucial issue.

(b) Investment Instruments

There is a very welcome acknowledgement that with the lack of detail that is available as to the CfDs an investment hiatus is probable for the early projects. The Energy Bill therefore allows the Secretary of State to issue "investment instruments" in advance of the implementation of CfDs so as to give comfort to investors in taking final investment decisions.

(c) Capacity Market

The Energy Bill includes:

- powers for the Secretary of State to design and introduce a Capacity Market; and
- powers to confer functions on National Grid to enable delivery of the Capacity Market.

The Capacity Market is intended to be the means by which the Government ensures that future blackouts do not occur as a result of the policy choice to invest in intermittent and inflexible generation.

The proposed Capacity Market will run on the basis of an auction looking ahead for a number of years. Winners in the auction will enter into capacity agreements (it is not explicit with whom) committing to provide electricity when needed and paying penalties if they fail. It will be open to both generation and demand side capacity providers. The costs of the Capacity Market will be shared between electricity suppliers (and therefore indirectly socialised to consumers through electricity bills).

There will be no obligation to run the Capacity Market; it is contemplated that it will only operate if needed.

The Government does not expect to have completed its work on designing the Capacity Market until March 2013. The formal consultation on the Capacity Market will not therefore take place until after the first quarter of 2013.

(d) Conflicts of Interest and contingency arrangements

The Energy Bill includes:

- powers for the System Operator to administer CfD and Capacity Market mechanisms;
- reserve powers to deal with potential conflicts of interest within National Grid, if needed; and
- contingency arrangements including powers to transfer delivery functions, if needed.

The current design of EMR envisages that National Grid, as the System Operator, will play a key role in administering the CfDs and the Capacity Market. There are acknowledged synergies from this approach but without the detail of the arrangements it is impossible to conclude that conflicts of interest cannot emerge which would affect delivery.

The Energy Bill includes powers to enable the Secretary of State to manage potential conflicts of interest of National Grid. The powers also include the ability to require appropriate business or legal separation. The Energy Bill also contains contingency arrangements to give the Secretary of State power to transfer the EMR delivery functions away from National Grid if considered necessary.

(e) Renewable transition

Whilst the investment instruments are targeted at preventing an investment hiatus for new plant that will clearly come through under the CfD regime, an alternative hiatus mitigant is required for plant which are to be brought through under the RO scheme.

This is achieved by a phased changeover. The RO will remain available open to new generation until 31 March 2017 allowing new renewable generation that comes online between 2014 (when the CfDs start) and 2017 to choose between the CfD and the RO. After this time the RO will be closed to new entrants and "vintaged".

Some flexibility around the 2017 date is contemplated for plant whose completion is delayed by reasons outside of their control (such as delays in grid connection or planned radar installation).

The Energy Bill provides for powers to fix the price of RO certificates issued under the scheme from 2027 to 2037.

(f) Emissions Performance Standard

Powers in the Energy Bill includes:

– duty on power stations not to exceed annual CO2 emissions limit;

– powers for the exemption for publicly funded CCS projects;

– powers to bring additional plant into the regime, specifically where an existing plant replaces a boiler or where a 'gasification' plant is associated with two or more generating stations; and

– powers for monitoring and enforcing the limit.

The EPS is one of the backstops which supports the delivery of EMR; in particular it seeks to ensure that no new coal fired power stations will be built unless they are equipped with CCS technology.

It will be a legal requirement on power stations not to exceed an emissions limit which has been initially set at 450g/kWh for all new fossil fuel plant. An exemption is available for new plant that form part of the UK's CCS commercialisation programme or which benefit from European funding for commercial scale CCS.

There will be a grandfathering for new plant brought through under the 450g/kWh limit through to 2045.

The exemptions and grandfathering referred to above are essential to join the EPS into the aspects of EMR which are focused on the development of CCS within a CfD and the development of gas plant incentivised by the Capacity Market.

Strategy and Policy Statement – Aligning Government and Ofgem

There is a sense that the roles of the Government and Ofgem have become confused and that Ofgem's role has become much more complicated compared to the 1980s when it was introduced as the economic regulator. This has led to regulatory uncertainty. With increased Government intervention in the wholesale power market to deliver its desired policy goals this blurring and confusion becomes ever more dangerous. The Energy Bill therefore sets out a structure that contemplates a closer and clearer alignment as to strategy between Government and Ofgem (as the economic regulator) but without infringing the EU law requirement for Ofgem to be independent.

This is envisaged to be delivered by introducing a requirement for the Government to produce a new statutory document – a Strategy and Policy Statement. This will set out the Government's strategic priorities for energy policy, describe the roles and responsibilities of the Government, Ofgem and potentially other relevant persons and define policy outcomes that the Government considers Ofgem to have a particularly important role in delivering.

Ofgem and the Secretary of State will be obliged to act in the manner best calculated to further the delivery of these policy outcomes subject to ensuring the fulfilment of Ofgem's principal objective to protect the interests of existing and potential consumers. It is recognised that Ofgem may not be in complete control of delivering any particular policy outcome. In such circumstances Ofgem must define its role and contribution to delivering the relevant policy objective as clearly as possible.

The Energy Bill includes:

- a power to designate a Strategy and Policy Statement;
- a duty to review a Strategy and Policy Statement every five years;
- a power to review it before the end of five years in certain circumstances, for example, following a Parliamentary election;
- duties on the Secretary of State and Ofgem in relation to the content of a Strategy and Policy Statement, for example, Ofgem to have regard to the strategic priorities section; and
- reporting requirements on Ofgem related to a Strategy and Policy Statement.

The duration of any Strategy and Policy Statement is not anticipated to exceed the lifetime of a Parliament. This is much shorter than the gestation period of a major energy project and woefully short in comparison to the investment horizon of such projects. The arrangements around the Strategy and Policy Statements is therefore to be welcomed provided that it forms the basis on which the Government clearly and unambiguously accepts change in policy risk in the CfDs (including its practical application through the work of the economic regulator and others) and is not a substitute for, or a justification for seeking to water down, such acceptance.

Office of Nuclear Regulation

The Energy Bill provides for the consolidation of the current nuclear regulator, the ONR, onto a statutory footing. The intention is that this will allow the ONR to retain the best of current practice whilst also creating a modern nuclear regulator based on the key regulatory principles of transparency, accountability, proportionality and consistency.

This aspect of the Energy Bill really completes the consolidation of the nuclear regulatory framework in the UK which has been underway for a number of years.

Importantly, the Energy Bill will ensure that the ONR has the financial flexibility to meet its business needs on a sustainable basis. Financial resources and a commitment to transparency are some of the most important aspects so that the ONR can clearly demonstrate its effective independence from those bodies and organisations concerned with the promotion of nuclear power.

Government Pipeline and Storage System

The Energy Bill facilitates a sale by the Government of the GPSS so as to:

– raise a capital receipt for the Government;

– enable increased private sector investment in the GPSS to increase the resilience of the system; and

– allow commercial development of the GPSS.

OFTOs

The Energy Bill includes an amendment to the OFTO licensing regime intended to clarify that a developer who exercises the generator build option under the enduring regime (which was an option introduced in response to developer representations during consultation) before transferring assets to an OFTO is not in breach of the prohibition on participating in the transmission of electricity without a licence during the commissioning of those assets. However, the restriction of this exemption to the period before a completion notice is given and for a further period of up to one year until a sale of such assets to an OFTO means that there could still be significant risk to a developer in the event of delays in the completion of the OFTO transfer process, depending on the stage at which a completion notice is given.

Carbon Price Floor

The Carbon Price Floor was introduced in the 2011 Budget with carbon price support rates at levels equivalent to £4.94 per tonne of CO_2 (tCO_2) for 2013-14.

The 2012 Budget has raised these to the equivalent of £9.55/tCO_2 for 2014-15, in line with the policy of increasing the tax inclusive price of carbon to £30/tCO_2 (2009 prices) by 2020.

Liquidity

Independent generation developers often rely on long-term Power Purchase Agreements (**PPAs**) to secure the finance they need. It has become increasingly difficult for such developers to attract offers of bankable PPAs. The Government believes that a competitive market should provide bankable routes to market for independent generation projects and wants to see a stronger, more competitive PPA market that can underpin investment.

The Government wants to ensure that the extent and nature of issues in the current market – and likely developments in the future PPA market – are fully understood and, if necessary, will bring forward proposals to ensure that independent developers have a viable route to market. The Department of Energy and Climate Change (**DECC**) will publish a Call for Evidence, which will include initial options to address the issues, in June 2012, in order to ensure that the evidence base is fully developed. The Call for Evidence will seek to understand any barriers to a competitive PPA market in the current arrangements and in the future when EMR measures are implemented. It will also set out and seek views on options to address the barriers. DECC will respond to the Call for Evidence in the Autumn before the Energy Bill is introduced to Parliament.

Liquidity is essential not only to promote a competitive market and bring down costs, but also to enable efficient functioning of EMR mechanisms. A liquid market is important to ensure that CfD strike prices are established on the basis of an efficient competitive market and to provide robust and realisable reference prices. Poor liquidity in the GB wholesale electricity market is also an important barrier to entry to independent electricity generators and suppliers.

There have been, in recent months, significant improvements in liquidity in the day ahead trading markets. In addition, Ofgem has recently closed a proposal to require the large vertically integrated UK electricity companies to sell 25% of their generation output in a range of key products in the forward market.

Gas Strategy

The Government increasingly recognises that gas will continue to play an important role in the electricity sector, providing flexibility to support intermittent or inflexible low-carbon generation, meeting a significant element of demand and enhancing security of supply.

The Secretary of State has recently stated “Gas will continue to play a vital role in the low-carbon economy. Modern gas-fired power stations are relatively quick to build and twice as clean as many of the coal plant they’re replacing”.[4]

DECC will publish a strategy on the role of gas in the electricity market in Autumn 2012.

Gas is recognised as a potentially important element in the Capacity Market, and the grandfathering of current EPS limits to 2045 is intended to provide long-term comfort to investors in current and new gas plant.

Electricity Market Reform

The draft Energy Bill provides disappointingly little detail in relation to EMR. It consists primarily of high-level enabling provisions, with the operative provisions to be contained in subsequent statutory instruments.

However, a number of consultations are anticipated, which do indicate that the Government is continuing to engage with stakeholders.

Alongside the Energy Bill, the Government has published an explanatory Electricity Market Reform Policy Overview document (including a draft Operational Framework for CfDs). A final operational framework (including a firm decision on the CfD design and which is expected to give visibility on the CfD terms) is to be published in the Autumn. The draft is nevertheless helpful in understanding some of the detail of the Government’s thinking.

4. Ministerial statement 17 March 2012.

Electricity Market Reform (Part 1 Energy Bill)

(a) Contracts for Difference (Chapter 1)

The CfD is intended to provide developers of eligible low carbon generation with a long-term instrument that provides for a stable revenue stream, enabling investment in low carbon. The scheme will be administered by the operator of the national electricity transmission system (National Grid Electricity Transmission PLC (**NGET**)) who will initially allocate CfDs in line with agreed objectives set by the Government. In the longer term it is expected allocation will be determined by a competitive process. The Secretary of State will also have a power to allocate CfDs to individual projects, for example where the generic terms are not suited and will have to be individually negotiated.

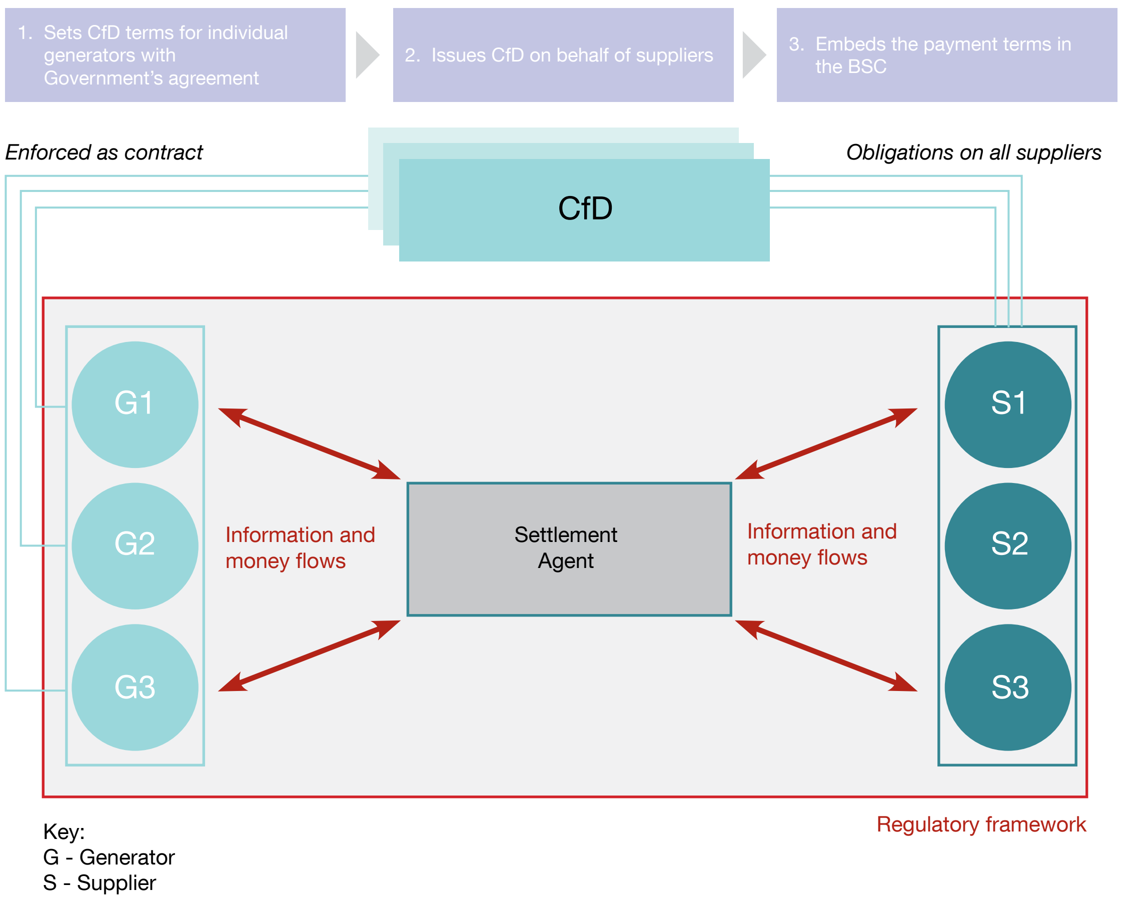
In most cases the mechanism will work by setting a strike price in the CfD which will (for CfDs in the initial stage) be at the level administratively determined to be necessary to support the particular technologies supported by the scheme. Generators will sell their generation into the market and will generally be paid (in addition to the revenue raised by the sale of such electricity) the difference between the strike price and a reference price. The reference price is a price which attempts to reflect the wholesale electricity price and implicitly should reflect the price the generator can realise.

When the reference price is above the specified agreed strike price, payments will be made by the generator to the licensed suppliers. This is aimed at ensuring that consumers are protected from paying generators where the wholesale electricity price would still be sufficient to support the generator.

There will however potentially be variations on this "two-way" CfD model in order to support different types of generation whilst still retaining sensible incentives to generate. It is unclear in what circumstances the Government would contemplate moving to a one-way CfD, as this would seem to lose part of the coherence between CfDs and the Carbon Price Floor.

The Energy Bill envisages CfD payments to generators will be made by all licensed suppliers, who will be party to each instrument issued, where the reference price is below an agreed strike price (or where a fixed payment is due to be made under a one-way CfD). The following diagram shows how this system might look.

National Grid as the CfD Delivery Body:



DECC has stated that the CfD legal framework and payment model outlined in the draft Operational Framework and the Energy Bill reflects the Government's current preferred option. However, DECC has also stated that it recognises that industry has strong concerns about this model and has suggested alternatives using a single counterparty. The Government states that it is seriously considering these concerns and the alternatives and it is expected that there will be further detailed consideration given to these questions as part of the pre-legislative scrutiny process. A final decision on the framework and payment model will be made by the Autumn. (See "C. Legal Framework and Payment Model" below.)

The Energy Bill sets out the Secretary of State's power to make, by statutory instrument, regulations (**CfD Regulations**) to give effect to the CfD policy aimed at decarbonising UK electricity generation. The Energy Bill provides that a statutory instrument containing CfD Regulation is subject to annulment by a resolution of either House of Parliament or otherwise will become effective after 40 days.

CfD Regulations will set out the terms that can be included in CfDs. These terms will include provisions ensuring that the generator receives a stabilised revenue for low carbon electricity produced for the duration of the CfD. The provision allows the level of support to be set at a specific level (the strike price) for different technologies, and payments to or from generators to be calculated based on the difference between this and a deemed level of market support (the reference price).

The Secretary of State and the System Operator may issue CfDs in accordance with provisions set out in the CfD Regulations. Most projects will receive CfDs issued by the System Operator in accordance with the terms set out in the CfD Regulations. Where flexibility is needed to vary the terms for particular projects, the Secretary of State will be able to issue the CfDs.

CfD Regulations will define the meaning of "generators" (determining eligibility of generation projects for the CfD scheme) and the Energy Bill sets out some characteristics which may in particular be defined.

The Energy Bill sets out a non-exhaustive list of the type of terms, such as duration and payment calculations, which may be included in a CfD. These terms will be set out in the CfD Regulations. These terms may include a requirement for the parties to a CfD to enter into agreements with a third party; the settlement of disputes; and the termination, amendment and assignment of CfDs.
Change of law provisions are not specifically mentioned in the Energy Bill, but are referenced in the draft Operational Framework. (See "B. CfD Terms" below.)

The Energy Bill provisions allow for the different processes which may be used to set the strike price:

– Administrative price setting – e.g. consultative process leading to a stated price for each technology or a negotiated process with specific generation assets; and/or

– Competitive price setting – e.g. an auction or tender process.

Strike prices may be set by the Secretary of State or by a person designated by him, such as the System Operator.

The Energy Bill enables the Secretary of State to make (subject to Parliamentary approval) an order setting out a limit on the cost of the scheme, alongside specific targets for the System Operator in issuing CfDs.

The Secretary of State may also set specific targets relating to the amount of CfDs issued in respect of:

– type of generation technologies;

– size of generation capacity; and

– location of generation.

The Secretary of State may modify transmission licences, the standard conditions of such licences and documents maintained in accordance with conditions of such licences (such as industry codes). The powers will be used to confer functions upon the System Operator to enable it to administer the CfD scheme. It will also be used to make provision about settlement of payment obligations under CfDs.

The Energy Bill sets out the overall objectives to which the Secretary of State must have regard when setting up the CfD scheme and later modifying it. The Secretary of State must take account of the need to meet climate change and renewables targets, alongside the impact the policy will have on security of supply and the cost to consumers. However, of itself the Energy Bill gives almost no detail in relation to CfDs. Almost the only concrete provision is that the CfDs will be multi-partite, with all suppliers from time to time being counterparties, but even this is stated to be under review. The proposed Energy Bill is therefore more process than progress, and there is little in its terms on which investors can base decisions.

However, the draft Operational Framework, published alongside the Energy Bill, provides further details on current Government thinking on the approach to CfDs. These are summarised in the table below, divided into the following sections:

A. Price setting and allocation
B. CfD terms
C. Legal framework and payment model

Further detail and analysis of these areas follows below.

Feature	Description	Emerging DECC proposal
A. Price setting and allocation		
Administrative price setting	How strike prices will be set for different technologies.	Renewables: similar to RO banding review process. CCS: initially through the CCS Commercialisation Programme competition in conjunction with the FID Enabling process. Nuclear: initially on a project by project basis, through the FID Enabling process.
Competitive price setting	When and how strike prices will be set using a competitive process.	Move to competition as soon as market conditions allow; this could be 2017 for certain renewable technologies.
Eligibility	Which technologies will be eligible for support under the CfD regime.	Minded that new low-carbon technology plants that are not eligible for the small-scale FIT will be eligible for a CfD.
Allocation	How developers can apply for a CfD before the move to a fully competitive process.	Renewables: through allocation rounds run every six months. CCS: initially through the CCS Commercialisation Programme or the FID Enabling process. Nuclear: initially through the FID Enabling process.
Managing financial exposure	Ensuring costs of CfDs remain affordable.	Minded to instruct the System Operator to remain within an agreed budget when issuing CfDs. Considering whether further controls are required for particular technologies.
B. CfD terms		
Pre-commissioning	The arrangements for monitoring the development of plant after CfD award.	Minded to place obligations on developers to build within agreed timescales, with proportionate penalties to incentivise compliance.
Reference Price	The market price for electricity that is referenced in the CfD for the purpose of calculating CfD payments.	Intermittent: Hourly Day Ahead Auction Price for the GB Zone (as established under North West European Market Coupling). Baseload: Year Ahead, price source to be determined.

Feature	Description	Emerging DECC proposal
CfD Volume	The definition of the volume of electricity for the purpose of calculating CfD payments, and the resulting metering requirements.	Minded to pay the CfD on the basis of metered output unless the price in the reference market is negative, in which case to pay on a measure of availability.
Allocation of supplier payments	How suppliers' payment obligations / entitlements are calculated.	Minded to base suppliers' payment obligations on market share (as defined by 'supplier cap take').
Settlement	Process and timing for invoicing and administering CfD payments.	Minded to base processes on Balancing and Settlement Code processes. Minded that settlement periods will be monthly or possibly shorter.
CfD Length	The length of the CfD from the payment start date as defined in section C.	Initial view that CfD length for renewables should be 15 years. 10 years (subject to negotiations) for early stage CCS project(s) supported under CCS Commercialisation Programme. Nuclear and long-term CCS-equipped plant to be determined.
Inflation indexation	Arrangements for adjusting the CfD strike price in line with inflation.	Minded to choose CPI as a standardised and established inflation measure that is familiar to international institutional investors.
Fuel Price indexation	Arrangements for adjusting the CfD in order that payments reflect a generator's input fuel costs.	Minded not to link the CfD strike price to fuel costs for biomass. For the first CCS project(s), minded that the CfD should provide indexation needed to hedge against long term fuel price variability.
Credit and Collateral	The requirements on generators and suppliers to provide credit / collateral.	Minded to place a collateral requirement based on an estimate of likely settlement amounts
Amendment of the reference price and other CfD parameters	The arrangements for amending CfD parameters in response to changes which might impact the validity of the indices used.	Minded to include an 'independent expert' role in the CfD framework to manage any review of CfD parameters and determine any amendments required.
Change in Law	Arrangements for adjusting the CfD in response to relevant changes (e.g. regulatory) that materially affect the value of the CfD to either party.	Minded in principle that the CfD should contain change in law provisions, the form and scope of which remain to be determined. Further detail will be set out in the autumn.
Dispute Resolution	Procedures for resolving any disputes arising under the CfD.	The Government will seek further legal advice in this area before engaging with stakeholders later in the year.
C. Legal Framework and Payment Model		
Legal status of the CfD	The arrangements for promoting investor certainty.	The Energy Bill outlines that the CfD will be an instrument created by statute that sets out obligations on suppliers and generators. However, the Government is considering industry concerns around whether a conventional contractual model would be preferable.

A Price setting and allocation

Price setting

The level of support for low-carbon generation will be set according to a series of principles, foremost amongst which is the need to deliver decarbonisation whilst minimising costs to consumers. The Government's position remains that the best way to do this in the long term is through competitive price setting, but until market conditions can support such processes, prices for all low-carbon technologies will be set administratively or through negotiation.

Stage 1 (to 2017) – for renewable technologies the initial process will be similar to that used for the most recent Renewables Obligation banding review, giving visibility of prices for a five-year period to enable planning. Strike prices for early stage CCS projects (including those supported under the UK CCS Commercialisation Programme) and nuclear projects will be determined through cost, risk and price discovery processes and negotiation.

Stage 2 (2017-2020s) – as technologies and the market begin to mature, the Government intends to begin to move to a competitive price discovery for specific technologies. For renewable technologies deploying after 2020 it is expected this may begin as soon as 2017.

Stage 3 (2020s) – technologies and the market have matured sufficiently for the Government to move to technology-neutral competitive price setting.

Stage 4 (late 2020s and beyond) – CfDs no longer needed, as market sufficient to drive competition.

Initially strike prices for different technologies will be set administratively at policy-determined levels. For most projects, strike prices will be set by the Government and published in a delivery plan (which will be informed by evidence and analysis from the System Operator). Strike prices for some projects, for example early stage CCS projects (including those supported under the UK CCS Commercialisation Programme where there will be case-by-case negotiation), new nuclear projects and also some renewable projects, could be determined through a bespoke process that involves cost, risk and price discovery processes and negotiation – for example through the Final Investment Decision (**FID**) Enabling Project. The Government envisages a process similar to the most recent ROC banding review (though we hope it is not so protracted!) and DECC will be using much of the same data to ensure consistency.

The Government intends to move to a competitive price discovering process (involving tenders or auctions) as soon as practicable (though there will be no hard deadline for this transition). When the allocation processes progress to auctions, the key decisions will be volumes and timing for the auctions. The decisions on volume and timing will be published by the Government in five-year delivery plans and annual updates.

For nuclear generation the major issue will be whether there are enough competitors to allow competitive price discovery. This is likely to be exacerbated by the fact that there are limited sites, all of which have differing characteristics, the sites are not freely transferable, and the timescales for building nuclear generation mean it is unlikely that projects will be competing for the same allocation windows (see below). The Government will continue to consider the feasibility and desirability of introducing a competitive element for nuclear projects, and with a view to doing so as soon as appropriate.

Therefore the nuclear CfD strike price will for now be determined by negotiation with developers on a project by project basis. This may strain the Government's commitment to no subsidy for nuclear, and also has state aid implications.

We query whether similar issues will become apparent for offshore wind given that Round 3 allocation has already happened.

There is already a competitive element in the setting of the support level for early stage CCS projects bidding into the CCS Commercialisation Programme, as this will be determined as part of the Programme competition in conjunction with FID enabling processes. Beyond the Commercialisation Programme, DECC expects the strike price to be the key factor in deciding which CCS projects to support, before competition with other technologies with similar generation characteristics is introduced.

The Government will publish the first five-year delivery plan in late 2013, containing an outlook to 2030 to provide visibility and transparency in advance of the introduction of the CfD mechanisms. A draft delivery plan, containing indicated prices, will be published in mid 2013.

The first delivery plan will set out the following information and decisions for the 2014-2018 delivery period:

– **the security of electricity supply outlook**, based on Ofgem's 2013 capacity assessment, and a decision on whether a capacity auction will be required in 2014 and, if so, the volume of capacity to contract for;

– **policy decisions on the CfD including strike prices for renewable technologies** and an indication of timing for a move to auctions for certain technologies;

– **the process and timing** for any decisions that might be necessary within the 2014-2018 delivery period, for example the timings, period and process for setting future strike prices and for the introduction of auctions.

In addition to the five-yearly delivery plan, the Government will publish annual updates from 2014 onwards, which will set out:

– a summary of delivery information from the System Operator, for instance the number and type of CfDs allocated;

– once the Capacity Market has been initiated the annual update is expected to contain the volume of capacity contracted in the previous year's auction, the updated security of electricity supply outlook and the volume required for the upcoming auction;

– CfD policy decisions, for example, if necessary, forward strike price revisions or extensions of the administratively set strike prices beyond the delivery period (see below); and

– potentially any other ad-hoc decisions that might be required, for example changes to the operational details in delivering the CfD or Capacity Market (such as auction rules).

The Government intends to consult on the underpinning data for the first set of CfD strike prices for renewables as part of the draft delivery plan in 2013 and will announce prices in the second half of 2013 when it publishes the 2014-2018 delivery plan.

Date	Activity
Before Summer recess 2012	RO Banding Review decision published with underlying data.
Summer 2012	Government commissions the System Operator to review RO Banding data and gather any additional evidence, including data to cover pricing period beyond 2017.
Late Summer 2012	The System Operator carries out the review of costs (appointing consultants if required) and issuing call for evidence.
Summer/Autumn 2012	System Operator carries out analysis to identify differences between RO Banding assumptions and CfD strike price assumptions, e.g. including cost of capital.
Summer/Autumn 2012	Industry provides cost data to the System Operator responding to call for evidence. System Operator uses data to generate indicative strike prices.
Early 2013	System Operator carries out further analysis, including on impacts of different strike prices on Government objectives, reviewed by Panel of Technical Experts.
By mid 2013	The Secretary of State considers the System Operator's analysis and carries out consultation on data and underpinning analysis with draft delivery plan.
By late 2013	Government makes final decision on strike prices, following appropriate consultation with Devolved Administrations, and publishes as part of the delivery plan consultation.
Early 2014	Government introduces and consults on secondary legislation on the broader CfD regime and strike prices.
Mid 2014 (TBC)	Start of CfD regime: strike prices in force.

In order to provide investors – especially as regards technologies with longer build times – with sufficient visibility, the Government would expect strike prices for 2019 and 2020 to be published in mid to late 2015 in the annual update to the delivery plan.

The allocation process is designed to balance certainty to developers about their ability to obtain CfDs, and allowing the Government to manage the costs of the regime. The Government's intention is that specified new low-carbon technology plants (which are not eligible for the small-scale FIT) will be eligible for the CfD scheme.

In the period before auctions or tenders are used to award CfDs, most renewables projects will secure their CfDs through participating in allocation rounds. The design of the allocation process will both support the delivery of the 2020 Renewables Target and enable the Government to manage levels of deployment appropriately to ensure the cost effectiveness and durability of the CfD.

It is expected that CCS, nuclear and some renewable projects will seek to obtain investment instruments through the CCS Commercialisation Programme or the FID Enabling process (see "Investment Instruments" below). The process for other low carbon technologies to secure CfDs beyond the FID Enabling process is still under consideration, and further details will be published in the Autumn.

Please also see the section on "Transitional Arrangements" below.

The price setting process described above will result in strike prices being set for each year from 2014-2018. These prices are likely to differ by technology and by year, so that a project allocated a CfD in 2017 may receive a different strike price than if it had been allocated a CfD in 2016.

The Government proposes to allow developers to apply for a CfD immediately before "Financial Close". Consequently, a project which secures a CfD will have certainty about the revenue it will receive at a point earlier than it would do if supported under the Renewables Obligation (where the trigger point is generally commissioning).

While "Financial Close" is not yet defined, for project financed plant the Government envisages that it will be the point at which the banks or equivalent organisations commit to financing the project, subject only to the award of the CfD. (DECC describe this point as the loan agreement is ready for signature, but it would seem that further work will be necessary to integrate the application/award process with raising project finance. Not giving clarity of allocation until a loan agreement is ready seems unlikely to be feasible.)

For on-balance sheet funded projects, Financial Close will be less easy to evidence precisely. The Government is currently considering whether it will be necessary to set specific criteria for equity plant of each technology type. In any event developers are likely to have to provide proof of substantive commitment of resource to the project, e.g. board papers approving expenditure.

All projects as part of their milestones (see "B. CfD terms – Pre-commissioning" below) will be required to provide evidence of contracts, e.g. for turbines and construction works within a given time period after Financial Close.

The proposal is that the System Operator will run allocation rounds every six months e.g. April and October. Each round is expected to take about three months, with the application window open for a month, the System Operator carrying out an assessment of applications against criteria and then awarding CfDs to successful projects by the award date marking the end of the allocation round.

Once the allocation window closes, the System Operator will allocate CfDs and agree timescales for commissioning. At this point, developers who are successful will have a CfD with a fixed strike price, subject to commissioning within an agreed target commissioning period.

The earlier confirmation of the level of the strike price (compared with RO projects) is helpful (particularly for larger projects), though the windows will introduce some transaction management challenges and we can foresee growing complexity around what constitutes "Financial Close".

Strike prices will be set administratively for most renewables projects. The Government aims to avoid disrupting developers and supply chains, which might occur if published strike prices were rapidly revisited or if the supply of CfDs were suddenly curtailed. The Government has given visibility of the level of deployment ambition for renewables projects in the Renewables Roadmap[5] and hopes that developers have the confidence to deliver against such renewables targets, while the Government is able to protect consumers by retaining appropriate control over the costs of decarbonisation. The Government is minded to instruct the System Operator to only issue CfDs for low-carbon generation up to the value of the amount set out in the Levy Control Framework[6]. The same principle will also apply when the Secretary of State is issuing any investment instruments in relation to projects that require final investment decisions in advance of EMR implementation, or issuing any CfDs after the CfD regulations come into force.

5. Further detail is in the A&O bulletin on the White Paper at www.allenovery.com/UK-Electricity-Market-Reform

6. For each Spending Review period the Treasury sets out, as part of the public spending framework, a control framework for DECC levy-funded spending.

As with current provisions for 'emergency review' under the Renewables Obligation, the process for setting CfD strike prices beyond 2018 can be used to review prices for technologies where unexpected cost changes or rates of deployment have occurred. The Government affirms its commitment to the principle of grandfathering commitments, and on this basis any process would not alter strike prices of CfDs already issued, which would remain fixed (barring any adjustments within the terms of the CfD, e.g. for inflation).

The Government is considering whether further controls on aggregate cost should be included – either volume targets for each technology or price setting (with or without additional controls such as pre-accreditation or less forward certainty on available strike prices). A decision on which mechanism is most appropriate will be made prior to issuing the final CfD Operational Framework in Autumn 2012.

While low carbon generation cannot be exempt from the age of austerity, the potential for constraints in "over-deployment" scenarios will need to be considered by developers.

B. CfD Terms

In principle, the CfD should be largely standardised across technologies. This is intended to provide a stable basis for investment, and make it easier to compare costs of different technologies during the envisaged move to technology-neutral auctions in the longer term.

In the short term, however, variation in CfDs may be needed for some technologies – within intermittent (i.e. generation that is inherently variable and dependent on primary power sources outside the control of generators, e.g. wind, wave and solar) and baseload (i.e. generation that generally operates continuously to serve the minimum electricity demand over a given period of time) classes – in recognition of their different risk profiles (for example early stage CCS projects, due to their demonstration status), to ensure they come forward at a reasonable cost. The Government has stated that any variations agreed will have to represent value for money and maintain a level playing field in line with the Government's approach to securing state aid clearance. The Government will going forward review the requirement for a specific CfD for flexible plant.

The Government supports the principle of 'grandfathering' CfDs to provide investor certainty, and so intends that a CfD cannot be changed retrospectively once issued, other than under pre-agreed circumstances.

Pre-commissioning

The Government believes that the CfD should contain pre-commissioning terms which place obligations on developers to encourage projects being built to agreed timescales. The Government also proposes that proportionate penalties should be available to incentivise compliance with these obligations.

Developers would be obliged to provide the System Operator with a schedule of construction milestones as part of a CfD application.

Whilst developers clearly have incentives to deliver on time, imposed on them by their financing agreements and build contracts, mandating precise project delivery dates is unlikely to be achievable. The Government is therefore minded to allow projects to commission within a defined 'target commissioning window' time period before or after their target commissioning date without facing any penalties under the CfD.

In order to encourage developers to provide as accurate a forecast of their target commissioning date as possible, projects that commission ahead of their specified target commissioning window will be able to operate commercially and sell their power, but will not receive or make CfD payments until the start of that target commissioning window. After that point they will receive or make payments under the CfD as normal.

The Government proposes that a penalty may be triggered by failure to commission by the end of a target commissioning window. The penalty imposed would be a reduction in the agreed term of the CfD commensurate with the length of any delay beyond the window. (However, the Government is still considering alternative and possibly additional options. These might include a reduction in the agreed CfD strike price, or (similar to the arrangements for the Danish offshore wind tender) imposition of financial penalties for delay or abandonment, with developers required to provide collateral to cover those penalties.)

The Payment Start Date for a CfD will be the date on which the project passes the Commissioning Acceptance Tests, unless this occurs before the beginning of the Target Commissioning Window. On such occasions the Payment Start Date will be the start of the Target Commissioning Window.

Commissioning Acceptance Tests will be stipulated in the issued CfD. For the purpose of the CfD, it is suggested that these tests include:

– completion of Commissioning Acceptance Tests required under the Grid Code or by a relevant Distribution Network Operator; and
– (possibly) any further tests that may be required to establish that the plant meets the specifications for which the CfD was awarded as set out by the System Operator in the allocation rounds or through the FID Enabling process or CCS competition.

Further consideration will need to be given to arrangements to apply in relation to projects which commission in phases.

There will be interesting questions around risk allocation for such delays and also whether there will be force majeure-type exceptions to these penalties.

In relation to early stage CCS projects, the Government has acknowledged the need to ensure that the arrangements for Commissioning Acceptance Tests and any associated penalties take account of, and are appropriate given the additional period of testing expected to be required for, CCS-equipped plants. One can foresee that other categories of generators may also seek such a relaxation unless commissioning windows are generously wide.

Reference prices

CfD payments will be based on the difference between the reference price and the strike price. In Great Britain, electricity can be bought and sold on different trading platforms, in different volumes and at different periods of time before it is actually delivered. Any reference price is likely therefore to be only a representation of the actual market price achievable by a generator, although the two can be the same. It will be used to calculate CfD payments to be made to or received from low-carbon generators.

Intermittent generation

For intermittent generation, the EMR White Paper stated a preference that the day ahead market should be the market segment from which the reference price is drawn. More specifically, the White Paper suggested that the Reference Price for intermittent CfDs would:

– reflect a basket of exchange-based (e.g. APX, N2Ex) and OTC price indices, with an 'independent expert' appointed to review and change the weights in the basket as and when required; and

– be expressed as a baseload day ahead price (as opposed to hourly day ahead prices) in part because the available OTC indices (such as LEBA) adopt this product definition.

A number of developments have caused DECC to change its position in the light of concerns with the original proposal:

– the planned implementation of Market Coupling arrangements for the North Western Europe (**NWE**) region in late 2012/early 2013;

– the creation of a 'GB Hub' for day ahead trading to support this initiative; and

– the significant growth in exchange-based day ahead trading in the GB market.

For Great Britain to participate effectively in NWE Market Coupling, a single 'GB Price Zone' will need to be created, which will contain the orders of the Great Britain power exchanges (currently APX and N2Ex). National Grid is in the process of establishing a 'GB Hub' which will pool the bids and offers from the power exchanges and, as part of the wider NWE coupling arrangements, calculate a single 'GB Zone Price' for each hour. To enable this, the power exchanges will need to offer compatible day ahead auction products and participate in the NWE Market Coupling auction processes. The Market Coupling arrangements for the NWE region are currently scheduled for implementation in early 2013 and, unless delayed, would therefore be in place in time for CfDs.

There has also been significant growth in the volumes of electricity traded through exchanges, specifically through day ahead auctions. Exchange based day ahead trading has increased by more than 500% since the EMR White Paper, and presently represents around 20% of GB generation. There are a number of factors which may help solidify this recent growth in such trading, including:

– continued domestic regulatory pressures to ensure a liquid wholesale market (see "Liquidity" below);

– European regulations which increase the cost of bilateral trading;

– the need for market participants to trade through these exchanges if they wish to access the interconnectors and the NWE market; and

– the possibility of a 'virtuous cycle' of liquidity generation as a clear day ahead price reference emerges (reinforced by increasing volumes from intermittent CfD generation).

The Government is therefore now minded that the reference price for the intermittent CfD should be the hourly day ahead GB Price Zone which it believes is likely to provide the most credible, robust and enduring index. In addition, it will significantly increase revenue certainty and stability for intermittent generators, who are able to trade the reference price (i.e. removing basis risk (though not forecasting and offtake risk)) by participating in either the APX or N2Ex day ahead auction, and will be far better able to capture an hourly price than a baseload price, as they will be able to trade more in line with their forecast output. There is however a risk that smaller generators will in many cases not be able to participate directly in either exchange (see "Liquidity" below). Clearly there are risks in this choice as the GB Price Zone does not yet exist. Should market coupling arrangements not be implemented as planned, a likely fallback option would be to apply a (volume weighted) average of the hourly prices from each day ahead auction conducted by the GB power exchanges (currently APX and N2Ex). This would introduce some basis risk but at current levels of liquidity DECC believes it would still represent a robust CfD reference price. Moreover, as an hourly price it would be preferable, for an intermittent generator, to the previously envisaged baseload alternative. This could also be a likely fallback option should market coupling arrangements be delayed, possibly as an interim measure to enable market participants to become familiar with the new (market coupling) arrangements.

Baseload generation

For baseload generation, the EMR White Paper set out the preference that the year ahead market should be the market segment from which the reference price is drawn. The Government remains minded to use the year ahead market.

Ofgem's most recent consultation on enhancing liquidity in the wholesale electricity market (see "Liquidity" below) highlights a lack of liquidity in 'products further along the curve, such as those beyond a month out'. The consultation proposes 'focusing on the development and delivery of a Mandatory Auction selling key longer-dated products'.

This would involve regular auctions with a requirement on obligated parties to sell specific products, 'with sufficient volume in each product to potentially meet demand and produce robust prices'. The Mandatory Auction therefore seems be a strong candidate for the reference price source for the baseload CfD.

In the absence of a Mandatory Auction, the Government remains minded that the reference price would be calculated as the average of the Summer & Winter EFA baseload contracts calculated each business day in the year (April-March) for the following year's delivery based on OTC, Market Assessments and Exchange Transactions.

CfD volume

Payments under the CfD could either be based on output, a measure of availability, or a mixture of both. Paying on output is the obvious approach as there is a clear link between the low-carbon support and the low-carbon electricity. However supporting low-carbon generation based solely on output leads to dispatch distortions as, to enable it to access support, this plant will generate even when the electricity price it receives is lower than its running costs.

The Government proposes generally to pay on metered output:

- it is simpler as there is a clear and direct link between the low-carbon output and the low-carbon support;
- there is no risk of paying when the plant is not available and not generating; and
- analysis demonstrates that the distortions to the merit order are likely to be limited.

Paying intermittent plant on firm volume would have meant that generators would have to pay back the difference between the reference price and the strike price when the former is higher. However, as intermittent plant cannot control their output, they would not know whether they would be generating (and thus earning the market price) in such a scenario. As a result, this would represent a significant and unknown risk for intermittent plant. In addition, when the reference price is high, it is more likely that at least some intermittent CfD plant will not be generating (as higher prices are likely to be caused by the more expensive fossil fuel plant coming onto the system due to unmet demand from intermittent plant). Paying on firm volume is not a practical solution for intermittent plant. Paying on metered output will require further work to be done on payment in circumstances where CfD plant is constrained off by the System Operator.

Additionally, in the future with a high penetration of low marginal cost plant such as wind and nuclear, it is quite likely that there will be periods when the electricity generated by wind and nuclear will be greater than demand. In this scenario prices could turn negative, meaning that there is plant on the system that is prepared to pay someone to take their electricity. Generators are prepared to pay someone to take their power either because they want to access support for low-carbon generation, or because their costs of turning off or down are significant, or both. Studies indicate that negative prices will become increasingly likely as the amount of intermittent generation on the grid increases. These negative prices would present a significant challenge to the System Operator in balancing the system.

Negative prices could also result in large CfD payments (though not net revenues for low-carbon generators) should the reference price be highly negative, as the CfD plant would always be topped up to the strike price, no matter how low the reference price was.

To address potential negative prices, the Government proposes to pay CfD supported plant based on metered output (as stated above) unless the reference price drops below zero, in which case generators would be paid on availability. This is for the following reasons:

– it makes it easier for the System Operator to balance the system and reduces distortion in the balancing mechanism (resulting from intermittent plant requiring higher prices to turn off in order to offset foregone CfD revenues);
– it provides a clear and transparent set of criteria for paying the CfD should the reference price be negative; and
– it limits the scale of the CfD payments, making it more predictable for generators, suppliers and the Government. It also reduces the strike price as generators know they will be paid even if prices are negative. The strike price would otherwise be higher to cover this risk.

The CfD availability payment would be fixed at the strike price (i.e. the top-up to the strike price as if the reference price were zero). CfD plant would then have an incentive to stop generating once the reference price (day-ahead in the case of intermittent and year-ahead in the case of baseload) dropped below zero.

The impact of paying on availability if the reference price is negative is different for intermittent and baseload CfD plant because of the different reference prices used.

DECC analysis is that a negative day-ahead reference price for intermittent is likely under a base case set of assumptions. Therefore, under the proposed approach intermittent plant has an incentive to turn off if supply is greater than demand, as it would be paid more if it shut down and received availability payments. It will be necessary for such an ability to withhold generation to be accommodated in any long-term offtake arrangements, but this may be achievable since the market (though not necessarily the PPA counterparty) is obviously long on power at such time.

For intermittent plant there is also an obvious challenge in measuring availability appropriately.

The baseload CfD, however, uses a year-ahead reference price which would only turn negative under the most extreme scenario. If the day-ahead electricity price were negative, baseload plant would not necessarily turn off; this plant would have an incentive to turn off only when the electricity price is lower than its marginal costs minus the top up it receives. However modelling demonstrates that even with a high take up of mid merit plant (biomass and CCS equipped plant), this plant would have turned off by the time the price is negative.

It is likely, however, that less flexible nuclear plant would still be running, even when prices are negative, given the costs they incur to turn down or off. This CfD design still provides nuclear with an incentive to turn off, should prices go negative. This approach is therefore a driver to develop flexibility.

Allocation of supplier payments

Under the proposed structure, all licensed electricity suppliers are collectively responsible for meeting payment obligations arising under a CfD. As such there is a need to ensure that this obligation is distributed proportionally across licensed electricity suppliers.

In principle, the Government feels that this proportion should reflect the relevant licensed supplier's gross demand for electricity in that period. In relation to this, there is an established industry approach to measuring gross supplier demand for electricity (Supplier Cap Take as defined in the Balancing and Settlement Code (BSC)). Whilst the Government will continue to discuss possible metrics with stakeholders, the emerging view is that this represents the most likely metric for calculating the obligation on each licensed supplier in each CfD settlement period.

Settlement

The EMR White Paper indicated a monthly settlement period following established industry processes akin to the BSC. The Government is now investigating options for shortening this period in order to reduce the collateral and credit requirements on electricity suppliers. However, there are also benefits to longer settlement periods, in reducing administrative burdens and credit risk on smaller, independent generators and suppliers in particular.

However, it is also important that basis risk is not thereby introduced between the price and settlement terms achieved by a generator through market facing trading operations and those applying under the CfD.

As regards invoicing, payment and reconciliation schedules for CfDs, the Government is minded these will follow existing BSC processes.

CfD length

For renewable technologies, DECC's initial analysis points to a CfD length of 15 years. It regards a CfD length of 15 years as representing an effective balance between enabling a range of projects to secure debt finance and achieve required returns to equity, and minimising the costs of consumer support.

DECC analysis shows broadly similar results for dedicated biomass and for biomass conversion, although for the latter decisions on CfD length will also be affected by the maximum operational life of the converted plant. Analysis for other renewable technologies (including for example wave and tidal) has not yet been carried out.

The Government has yet to form a firm view on the optimal CfD length for nuclear plants, but in principle would expect a CfD length of no less than 15 years. In part due to the possible scale of these investments and the potential operational life of the plant, the Government considers that it is prudent to form a view following the Final Investment Decision Enabling process. This may include a decision as to whether to establish a standard CfD length for nuclear as a technology, or alternatively vary CfD length by project.

In relation to early stage CCS projects, DECC may allow for different CfD lengths for different projects, for example distinguishing between a retrofit to an existing plant and a new build thermal plant with CCS. In addition, the terms on which such projects are likely to be financed will become clearer as the CCS Commercialisation Programme competition progresses and this will inform the Government's view on CfD length. Subject to the outcome of the competition, the initial view is that CfD length for projects supported under the Commercialisation Programme should be 10 years.

The term of a CfD is from the Payment Start Date referenced under "Pre-commissioning" above. Note also the possibility of reduction of the term for a delay in commissioning.

Inflation indexation

The EMR White Paper indicated that the Government was minded to adjust the CfD strike price for inflation. This remains the proposed position, on the basis that it is likely to represent a more efficient allocation of risk between investors and consumers.

If a generator's inflatable costs are not indexed, then the CfD strike price would presumably be higher and reflect the risk premium associated with uncertainty over future inflation. However, indexing variable costs to an appropriate price index removes the inflation risk from the generator and hence the risk premium. HM Treasury guidance has indicated that indexing these costs is therefore likely to provide value for money.

The Government is still considering what proportion of the strike price should be indexed, or similarly what proportion of the index the strike price could be adjusted for.

The Government is minded to link the strike price to a general inflation index such as CPI or, possibly, RPI (or CPI-X).

Fuel price indexation

Fuel price indexation is an issue for fuelled low-carbon generation such as biomass and CCS Projects, where operating costs mean that stability of gross revenues alone may not be sufficient to bring forward investment. For biomass, the lack of a single, established biomass price index and the diversity of feedstocks would make it extremely difficult to calculate a single price to index against. On this basis the Government proposes not to link the CfD strike price to fuel costs for biomass, and considers that this risk is best managed by biomass generators and taken into account in the calculation of the (administered) CfD strike price.

For CCS projects selected through the Commercialisation Programme competition, the Government is minded that the CfD should provide for some indexation as a hedge against long-term fuel price variability. The Government will continue to consider the best arrangements for supporting commercial CCS over the longer term, taking into account the experience of the CCS Commercialisation Programme.

Credit and collateral

The CfD scheme effectively involves regular but variable payments flowing between generators and suppliers in both directions. Credit risk to generators, for example, arises from losses as a result of supplier default that are not covered by the collateral lodged by that supplier, or 'unsecured' losses. This risk is driven by both the amount of collateral held and the time it takes for the payment flows to resume in the event of a supplier default.

The potentially large credit risks to all CfD participants resulting from late payment or non-payment would if unmitigated significantly increase financing costs, or may even prevent financing of projects. In order to manage this risk effectively, collateral requirements will be placed on both participating generators and suppliers.

While DECC will continue discussions on the nature of the collateral requirement, the Government's current view is that a collateral requirement based on an estimate of likely settlement amounts of a CfD party due in a given trading period (possibly subject to a cap) could apply. A similar mechanism in the BSC has limited unsecured losses to 0.12% of turnover, despite a number of major parties going into liquidation. Collateral (held as either cash or letters of credit) is likely to be set at a level that covers the total liabilities of a party at any one point in time, as it is currently under the BSC. The level of the collateral held is affected by how often the payments are settled (e.g. daily or monthly settlement) and how far in arrears the payments are made (see "Settlement" above).

We believe that to increase affordability and reduce barriers to entry it would be desirable to eliminate (or, if not eliminate, reduce) the need for collateral/credit support from suppliers and generators. From a generator's perspective, it will eat up any available limited recourse debt, possibly require recourse to the parent company balance sheet and possibly constrain or increase the cost at which financial investors will invest if balance sheet exposure is required.

Amendment of the reference price and other CfD parameters

Given the longevity of the CfD, it is necessary to ensure that the appropriate contract terms can be adjusted in response to certain market and regulatory changes as agreed within the contract terms. The Government is considering establishing an independent expert function in order to, for example, review the validity of reference prices or resolve disputes that may arise from time to time during the contract period of the CfD.

Change in law

The Government has emphasised that the CfD would be the vehicle under which the Government assumes, on a legally enforceable basis, policy risk. The Government's thinking is that:

– in case of a change in law, the CfD should be capable of being amended as necessary to enable ongoing performance of the asset and compliance with the obligations in the CfD. The occurrence of a change in law is not expected to provide the parties with a right to suspend performance or terminate the CfD;

– in the case of a qualifying change in law, the Government is further minded that the CfD should be adjusted so as to preserve the overall balance of risk and reward between the parties. The parties to the CfD would be expected to take all reasonable steps to mitigate any adverse effects of a change in law.

Over the Summer DECC will develop proposals on:

– the scope of change in law protection in the CfD and what should constitute a 'qualifying change in law';

– the mechanisms for:

  – notification of a change in law;

  – assessment of whether the change in law is a qualifying change in law;

  – negotiation of the impact of a change in law – resolution of any disputes arising under the change in law provision including the mechanism for challenge (see also "Dispute Resolution" below);

– the approach to risk sharing, including the use of materiality thresholds; and

– the approach to administering compensation payments.

These proposals will be informed by protection previously provided to private sector investors as well as provisions of private sector contracts. The Government now recognises (as we have repeatedly emphasised) that this is an extremely important issue for investors and has stated that it plans to share these proposals for discussion with market participants at the earliest possible opportunity, and welcomes views.

It will be interesting to receive the perspective of the suppliers, as it appears it is they (rather than the Government directly) who are being invited to assume, in the first instance, policy risk through the CfD. Might this affect their views of Ofgem's proposals and investigations relating to both the wholesale and the consumer markets?

Dispute resolution

Over the course of a CfD disputes are likely to arise, from time to time, between a generator and supplier(s) with respect to the terms of that CfD. Those disputes could relate to matters of interpretation of the CfD; defaults (actual or alleged) under the CfD; and amendments to the CfD to deal with, for example, changes to price indices or change in law. The disputes may affect one or more suppliers party to the CfD, and may be specific to one particular CfD or of general application to a number of CfDs.

The multi-partite nature of the current CfD proposal design means that efficient dispute resolution procedures will be much more complex than in the case of ordinary bilateral contracts where the number of parties are limited.

It may not be attractive for an independent generator to be suing every supplier. Some generators will themselves be suppliers (or affiliates of suppliers). Co-ordination among all suppliers will be extremely cumbersome unless Ofgem or NGET can have a co-ordinating role.

The Government states that it is seeking further legal advice in a range of areas around this to enable it to share proposals for discussion with market participants at the earliest possible opportunity, and welcomes views. (Note also "Amendment of the reference price and other CfD parameters" above).

C. Legal Framework and Payment Model

The draft Energy Bill outlines that a CfD will be an instrument that sets out obligations on a generator and all suppliers. DECC's aim is to provide investors with a level of certainty about the legal status of the CfD that is equivalent to a conventional contract with a counterparty who has a strong credit rating. As with a conventional contract the CfD would be crystallised when it is issued; that is, the obligations would come into force and stand separate from the underlying legislation. The intent is that even if the regulations setting out the CfD scheme were subsequently amended, the CfDs issued beforehand would remain as initially agreed and that a CfD cannot be changed except in accordance with its own terms.

DECC has stated that the CfD legal framework and payment model outlined in the draft Operational Framework and the Energy Bill reflects the Government's current preferred option. DECC has also stated that it recognises that industry has strong concerns about this model particularly around whether it can provide an adequate framework to support planned levels of investment, or whether a model which is broadly similar to a conventional bilateral contract with a single counterparty would be preferable. Government analysis shows that the model as set out in this section could work, but recognises that this approach would be novel and that concerns from industry persist. The Government states that it is seriously considering these concerns and the alternatives and it is expected that there will be further detailed consideration given to these questions as part of the pre-legislative scrutiny process. A final decision on the framework and payment model will be made by the Autumn.

The model which DECC has most fully developed and which is provided for in the draft Energy Bill is one in which the CfD is an instrument created by statute, which sets out obligations on a number of parties. On one side is the generator, who has applied for a CfD. On the other side are all licensed suppliers, who will have obligations imposed upon them. The principal obligation on suppliers is that they are obliged to make payments on the basis of the difference between a reference price and a strike price. Other obligations, such as to provide relevant data and enter into agreements with administration bodies, facilitate the running of the CfD regime. In addition, for some large, baseload low-carbon generation, the CfD may need to contain obligations on the generator to provide a specified level of service over a particular timeframe, to ensure that public policy aims can be met. The Government needs a greater level of certainty about decisions and timing of new capacity for very large projects than it does for smaller projects which come in larger numbers.

Whilst the generic terms of the CfD will be set out in regulations, each project will be issued with a specific CfD by the System Operator. Once a CfD has been issued it will effectively require suppliers to meet their share of the obligations to the generator as set out under the CfD terms (or receive payments should the market price for electricity be higher than the CfD strike price). Each supplier's share of the obligations will be determined by their market share, defined by metered use. This will result in costs of CfDs being passed through to consumers. Payments under the CfD will be administered by a settlement agent (probably Elexon as the Balancing and Settlement Code Company).

The Government is minded to use arrangements similar to, and potentially integrated with, the BSC as the mechanism through which to bill and settle the payments for the CfD.

Utilising the mechanisms like those under the BSC should reduce the amount of unsecured losses which may arise from a company entering administration; however, there will still be a risk of unsecured losses and the larger risk of a big energy supplier becoming insolvent. Under the proposed legal framework each supplier is a counterparty to each CfD. There are a number of systems that are intended to further protect CfD payments:

– Supplier of last resort (**SOLR**) - The SOLR process may facilitate the flow of CfD payments from consumers to generators in the event of supplier default. This process allows Ofgem to revoke the failed supplier's licence and appoint another supplier to take on its customers. If this has the effect that such other supplier would be responsible for increased obligations under CfDs in replacement of the defaulting supplier it would clearly be helpful going forward, the position of accrued losses may be less clear.

– Energy Supply Company Administration Regime - The Energy Act 2011 provided for an energy supply company administration scheme which, in the event of a large supplier becoming insolvent, enables arrangements to be put in place to ensure customers continue to be supplied with gas and electricity, pending the company in difficulty being either rescued, sold or its customers are transferred to other suppliers.

– Processes within the BSC for recovering unsecured losses - In the BSC any unsecured losses are spread evenly across all generators and suppliers. DECC suggest that processes could be put in place for the CfD element of the Code whereby any unsecured losses are recovered from suppliers only (instead of being spread across all parties); this would minimise this risk for generators.

The Energy Act 2011 provided the broad framework for energy supply company administration. The Government is due to consult on secondary legislation in Summer 2012 to complete implementation. The energy supply company administration regime is expected to be fully implemented by Spring 2013.

Should a large supplier fall into financial difficulty, the energy supply company administration regime will allow the Secretary of State or Ofgem to apply to the court for an energy supply company administration order. The court may make the order and appoint an energy administrator if the company meets the statutory tests for insolvency. The objective of the energy administrator would be to continue to supply customers as cost-effectively as possible until the company is either rescued, sold or its customers are transferred to other suppliers. The Government may provide financial support to the company in energy supply company administration, so that it can continue to operate normally. The energy administrator, as an agent of the company, would be required to comply with all the company's statutory and licence obligations, including making balancing and CfD payments.

The Energy Act also includes provisions to require the company to repay any financial support received from the Government. However, it is possible that the company may not be in a position to repay some of the funding. Therefore the Energy Act also empowers the Secretary of State to amend gas and electricity licences to introduce a cost recovery mechanism, so that any shortfall in the repayment of funding is socialised. The Government plans to consult on the proposed licence modifications and cost recovery mechanism in Summer 2012. At present the envisaged cost recovery mechanism is similar to that already in place for Energy Administration – the special administration regime for energy network and distribution companies.

An important consideration is whether the CfD is defined as a financial instrument (or derivative) for the purposes of accounting treatment, notwithstanding the fact it amounts to a set of statutory obligations. If it were treated as a derivative, it would be treated differently to the RO with a potential mark-to-market impact on generators and supplier PALs. If this were the case the lifetime cost of the CfD would be counted on both supplier and generator balance sheets and may be subject to FSA regulation.

We are told the Government has sought advice from the major accounting firms on this issue – given that the obligation is linked to market share, it is not a long-term liability as the obligation would fall away if a supplier exited the industry. Although it is not possible to provide a definitive view, it is therefore possible that CfD costs could be seen as a 'production' cost rather than a long-term liability (as it would be if the supplier itself signed a CfD). This is how the Government presumes obligations under the RO would be treated on supplier balance sheets.

Going forward it will also be important to keep under consideration any possibility of application of the EU EMIR and REMIT regimes.

The development of and support for new large scale low carbon generation in the UK seeks to deliver the policy goals of decarbonisation and energy security. To achieve these goals conditions must exist that facilitate a programmatic development approach for nuclear and offshore wind. Given the restricted market for funding sources for the construction phase of these types of development, it is likely that utilities will need to bear the brunt of development costs at least for the foreseeable future. This is not generally considered sustainable for the European utilities (given funding demands elsewhere and the need to defend investment grade ratings) and therefore they wish to be able to refinance these development costs through a combination of equity sales to new investors and/or limited recourse debt.

To us the key purpose of altering the revenue structure through EMR is to attract capital. There are many risks for new investors to understand and one should therefore aim to have as simple and predictable a revenue story as possible consistent with the delivery and operational risks that investors in new build low carbon generation are expected to bear. We are concerned that these principles have not obviously been met with the proposed legal framework and that this could threaten the required programmatic development. Examples include:

– Statutory contracts have not been used to any great extent in the UK. The absence of history may be of concern to financial investors.

– Precedents for the "statutory contract" model appear to us to be relevant to "fall back" situations where for reasons of public policy it is important for individuals to be protected and, for one reason or another, they are without or unable to agree the terms of a contract that they are entitled to expect. It is not obvious to us that this is an appropriate starting point for a contract that underpins the UK Government's policies of decarbonisation and energy security.

– The proposed statutory contract is in fact much more complicated than the suggested precedents – being multi-party and, it appears, split between a contract document, primary and secondary legislation, licence conditions and an industry code. This complexity will cause financial investors some concern particularly if there are other available investment opportunities which are more simple to understand and give an acceptable risk/reward profile. There is nothing in principle that prevents a "statutory contract" model being adopted; however, it would in our view be preferable if this contract was documented in one place pursuant to clear primary legislation.

– It has been DECC's view that the statutory contract should be entrenched and not capable of amendment without the consent of the generator (and presumably all of the suppliers). In our view, this may not be constitutionally possible. It would be possible for the risk of "change" to be reallocated in any backstop agreement between a generator and the Government although, taken to extremes, one would look for an independent governing law and dispute resolution forum to avoid analogies with Greek debt and collective action clauses. Precedent in the UK is of course against asking for such independence in relation to governing law and dispute resolution.

– Treatment of disputes which may arise between generators and suppliers is significantly more complex under the statutory contract. For example, if elements of the protection against qualifying change in law (see above) are included in the statutory contract there could be a dispute as to whether a qualifying change in law has arisen and who should do what to whom as a result. It is not clear to us how this would work in a multi-party contract world. Would NGET litigate with the generator(s) and then impose the solution on suppliers(s) or (even worse) would NGET litigate with the supplier(s) and then impose the solution on the generator(s)?

– Notwithstanding the various mitigants, it means the risk of unsecured losses may still fall on generators and/or suppliers who are not in control of the collateral requirements to mitigate this risk. This is not obviously equivalent to a bilateral contract. We also have a concern over whether this structure could introduce systemic risk on suppliers and generators if they are each forced to socialise the cost of another's failure through a smearing of unsecured losses from the CfDs.

– The agreement of stabilisation/economic balance provisions, clear allocation of change in policy/law risk, clear allocation on the risk of performance/status of third parties independent from the Government (e.g. NGET and Elexon) and agreement on the terms of legislation will therefore be important. This would need to be reflected in any investment instrument. A simple scheme and therefore a simple yet comprehensive investment instrument is therefore key for a number of different reasons.

– Some change of law protection is to be included within the payment structure of the CfD, ultimately socialising their cost with consumers. However, investors seeking Energy Charter Treaty protection may look for a separate contract between a generator and the Government.

(b) Investment Instrument (Chapter 2)

The Government now recognises that the continuing lack of certainty as to changes to the market proposed under EMR is leading to investment decisions being delayed. It is looking to enable early investment decisions, including those required ahead of EMR implementation, to progress the timetable wherever possible. Following the EMR Technical Update at the end of last year, the FID Enabling Project was established to take forward this work.

The Energy Bill contains provisions aimed at addressing the hiatus in investment in low carbon electricity generation which the Government acknowledges is likely to extend until the CfD regime is implemented through the CfD Regulations. These provisions (i) will enable the Secretary of State to issue "investment instruments" after the enactment of the Energy Bill (but prior to the CfD Regulation taking effect) which will be binding and are expected to take an analogous form to CfDs and (ii) will also impose a duty on the Secretary of State to issue, once the Energy Bill is passed, any investment instruments that he has laid in draft before Parliament during the passage of the Bill (thereby providing an accelerated commitment).

The Energy Bill provides that (as with CfDs) the effect of an investment instrument is to impose obligations on all electricity suppliers and on the electricity generator to whom it is issued. Therefore, an investment instrument cannot impose obligations on any other persons. However, electricity suppliers is defined to cover not only those persons who hold a supply licence at the time the investment instrument is issued but also any other person who becomes a supply licence holder after that time. Therefore, a person will become a party to and be bound by a pre-existing investment instrument when they become a licensed supplier.

The definition of "electricity generator" for the purpose of an investment instrument covers not simply someone who is directly involved in the generation of electricity. For example, it will be possible to issue an investment instrument to someone intending to establish, operate or participate in the operation of a new or altered electricity generation station or who has a freehold or leasehold in such facilities.

While the Secretary of State may include within an investment instrument an obligation for the parties to make payments to each other based on the difference between a strike price and a market reference price, investment instruments may include provisions for payments to be made on a different basis. While a similar provision is included in relation to CfDs, this seems on its face to be extremely wide ranging; while prospectively helpful in bringing forth early investment, it would seem that there could be some risk of challenge here.

In more detail, if:

(i) the Secretary of State has laid a draft investment instrument before Parliament during the passage of the Energy Bill – i.e. between its introduction and enactment;

(ii) the draft was accompanied with a statement to the effect that the Secretary of State is (i) laying the draft instrument in anticipation of commencement of this clause and that he (ii) considers that issuing the instrument would encourage low carbon electricity generation, (iii) *considers that unless the draft is laid there is a significant risk that the low carbon electricity generation (i.e. that which reduces greenhouse gases) to which the instrument relates will not occur or be significantly delayed* and (iv) considers that issuing the instrument would be appropriate having regard to: the need to ensure security of supply in Great Britain; likely costs to consumers and two duties under the Climate Change Act 2008 relating to the 2050 carbon target, and carbon budgeting;

(iii) before the draft was laid the electricity generator to whom the instrument would be issued has consented to the laying of the draft and that licensed electricity suppliers have been consulted on it by the Secretary of State; and

(iv) the Secretary of State is of the opinion that issuing the instrument would give rise to unlawful state aid,

the Secretary of State <u>must</u> (once the Energy Bill is passed) issue such investment instrument.

Additionally, once the Energy Bill has been passed but prior to the CfD Regulations permitting the Secretary of State to issue CfDs (subject to a longstop date of 31 December 2015), the Secretary of State may also issue investment instruments. The criteria in these circumstances are similar to those for pre-enactment investment instruments (but the laying of the instrument does not need to be pre-enactment and there is no requirement to certify that there is a risk of delay).

In relation to the consultation process for investment instruments, the Secretary of State must not disclose without consent what he regards as commercially sensitive information. While we understand that this is a difficult area, this does seem to result in a potentially very opaque process.

The Secretary of State is given powers to make modifications relating to transmission licences issued under section 6 of the Electricity Act 1989 (in contrast with CfDs there is also power to modify generation and supply licences) to confer functions upon the System Operator in connection with investment instruments (for example to enable it to take on a role to administer them) or to make provision about settlement of payment obligations under investment instruments.

The Secretary of State may by statutory instrument make regulations and make further provisions about or in connection with investment instruments. This specifically includes conferring functions on the Gas and Electricity Markets Authority (or any other body) in connection with investment instruments to monitor and collate information relating to the implementation of investment instruments. It would be possible to provide for a body (other than NGET) to administer the settlement of payments under investment instruments. Such a statutory instrument may be annulled by a resolution of either House of Parliament or otherwise will become effective at the end of a 40-day period.

From the outline of possible terms of investment instruments it appears to be contemplated that these will be broadly similar to CfDs (though this does not seem to be required). However, we note that axiomatically the CfD Regulations may not have been finalised and therefore query how investors will get comfortable as to the operation of such instruments (though we presume the investment instrument would give certainty as to key terms such as strike price and tenor where a CfD format is adopted).

A developer relying on investment instruments laid during the passage of the Energy Bill will, of course, be taking the risk that the relevant provision is enacted.

Generators have already expressed concerns that this arrangement may be vulnerable to a state aid challenge. DECC has stated it is working to understand and overcome any state aid issues. See "EU Aspects" below.

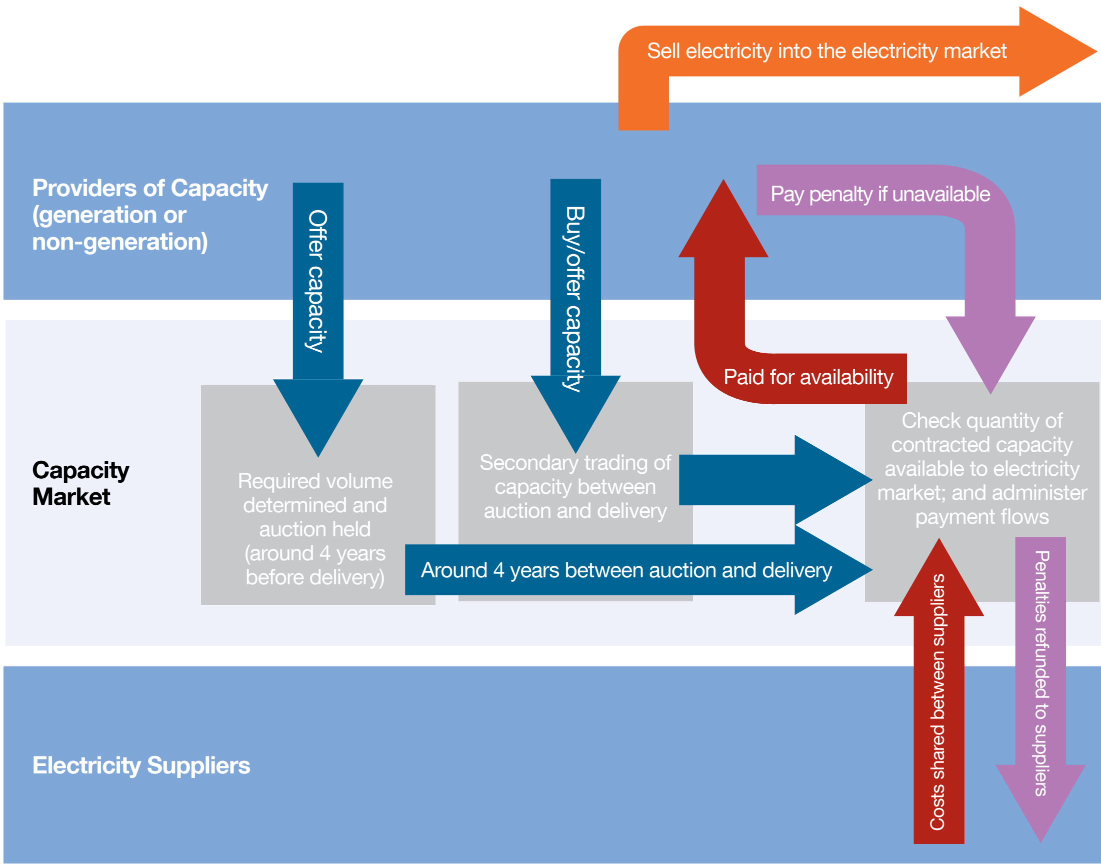
Given that nuclear generation would seem to be a prime candidate for such bespoke investment instruments, the Government will also need to tread carefully to respect its commitment to no public subsidiary for new nuclear (in the sense of arrangements where similar support is not made available more widely to other types of generation). It may help that these arrangements will also be available for CCS.

(c) Capacity Mechanism (Chapter 3)

The Capacity Mechanism remains subject to significant further detailed design development, in particular in relation to the length of the contracts that will be available for new plant and the structure of the penalty regime for non-delivery.

The Government recognises that this may create a disincentive to make investment decisions on new plant until the Capacity Mechanism is settled, which is not expected to be until later in 2013 although the Government intends to publish its design choices on matters of most significance to investors at the end of 2012. It has also indicated that plants which begin construction between May 2012 and the first auction may be treated on the same basis as new plant, to ensure there is no disincentive for plants to be built before a Capacity Mechanism is introduced. Nevertheless, there will still inevitably be a disincentive to build until the treatment of new plant is clear.

The proposed length of contract of one year for existing plant would not be likely to be sufficient to enable new plant to be built in reliance on that contract and we imagine that new plant would be looking for around a 15 year contract.



The structure of the penalties for non-delivery and whether there will be a cap on that liability will be of importance in determining the attractiveness of participation in the Capacity Mechanism. Concern has also been expressed in impact assessments that there could be a risk of double liability under the penalty regime and under any contracts entered into to support the delivery of that capacity by secondary trading depending on how the penalty regime is structured. In the latest paper, Government has moved away from the suggestion of a pure market mechanism and is looking to combine market based incentives (such as basing penalties on the price in a reference market) with physical checks to ensure capacity is in place. The Government intends to develop the penalty regime in conjunction with Ofgem's further work on cash-out pricing.

The structure of the auction and whether this will result in a price based on "pay as bid" or on a "descending clock" or some other mechanism had not yet been decided and again, this will influence the attractiveness of participation in the Capacity Mechanism.

It has been decided that responsibility for the payments will be shared between electricity suppliers, but whether this will take place through multi-party arrangements or though an intermediary based structure has not been settled. The latest paper suggests that the liability of suppliers to make payments could be based on a supplier's peak load in the delivery year which would incentivise suppliers to offer different payment terms to customers to encourage demand reduction in peak periods. There are also provisions that would enable smaller suppliers to be exempted from the payment arrangements if considered appropriate. Penalty payments received from capacity providers would be returned to suppliers.

The risk that capacity agreements may be awarded to providers who are subsequently unable to deliver capacity when needed (or cover any penalty payments incurred) is recognised. In addition to the penalty regime it is expected that some evidence of the physical backing of the capacity will be required to pre-qualify to participate and that there will also be requirements for the provision of financial support. However, the details of these have not yet been settled.

The intention is demand side capacity should participate in the Capacity Mechanism on a full and fair basis but it is acknowledged that further work is required to set and verify reliable baselines for non-generation technologies and that there may need to be separate pre-qualification criteria for demand side participants.

The Government is minded to prevent plant that receives an administratively set CfD from participating in the Capacity Mechanism, as it thinks the administratively set CfD should provide a sufficient incentive for those plants. It does, however, note that in the future when the strike price for CfDs is determined through technology neutral auctions, the treatment of CfD funded plants in the Capacity Market may need to be revisited for investors signing CfDs after that point. The question of whether plants in receipt of RO support will be able to participate in the Capacity Mechanism has not yet been decided.

It is confirmed that the Capacity Mechanism will be in addition to the Short-Term Operating Reserve market (**STOR**), but the interaction of the Capacity Mechanism with the procurement of balancing services has not been fully resolved.

Further details of the interaction of the Government with the Devolved Administrations has been given and as previously stated the Capacity Mechanism will not apply to Northern Ireland as there is a separate capacity mechanism as part of the all Ireland single market. However, the Government does recognise that power from interconnectors may participate in the Capacity Mechanism and that it needs to develop the pre-qualification criteria which would apply to the participation of that capacity. The criteria for interconnector participation will also need to be compliant with EU law.

The impact assessment recognises that the Capacity Mechanism is a significant intervention in the market and has potential for gaming and unintended consequences and so the detailed design of the Capacity Mechanism requires further analysis and consultation.

The Energy Bill contains enabling provisions allowing the Secretary of State to make regulations for the purposes of the Capacity Mechanism (the first set of which regulations will require an affirmative resolution of each House of Parliament).

(d) Conflicts of Interest (Chapter 4)

The current design of Electricity Market Reform envisages that National Grid, as the System Operator, will play a key role in administering the CfDs and the Capacity Market. There are acknowledged synergies from this approach, but the Government together with Ofgem is still analysing whether this will give rise to conflicts of interest which need to be managed and this work is due to report at the end of 2012.

The Energy Bill includes powers to enable the Secretary of State to manage potential conflicts of interest of National Grid if this is considered to be necessary. Those powers include the ability by order to separate the activity of system operation (which would include EMR functions) from the activity of transmission by making these distinct, licensable activities. The order may provide a prohibition on the same person holding both types of licence. The powers also include the ability to require appropriate business separation which could include limiting the control or influence which a parent company or other subsidiary could exercise over system operation functions, requiring functions to be carried out at separate locations and on separate IT systems, providing for separate accounts and requiring information separation. The powers also include the ability to modify licence conditions.

(e) Contingency Arrangements (Chapter 5)

In addition to the conflict of interest measures in relation to National Grid discussed above, the Energy Bill gives the Secretary of State power to transfer the EMR delivery functions away from National Grid if an energy administration order is in force in relation to it, if the Secretary of State considers this necessary or desirable as a result of a change of ownership of it, if the Secretary of State considers it is not carrying out its EMR functions in an efficient and effective manner or the Secretary of State considers this necessary or desirable to further the purposes of the Contracts for Differences or the Capacity Market.

These powers also enable the Secretary of State to further transfer the EMR delivery functions if the relevant conditions are met in relation to that transferee, either to another person or back to National Grid.

Chapter 5 also introduces Schedule 1 which confers a power on the Secretary of State to designate a transfer scheme to transfer designated property, rights and liabilities from the old delivery body to the new one.

(f) Transitional Arrangements (Chapter 6)

The Energy Bill includes provisions enabling the Secretary of State to make a certificate purchase order to establish the Fixed ROC mechanism. The certificate purchase order will require affirmative resolution of each House of Parliament.

As described in the December Technical Update, the Fixed ROC is to be based on a supplier levy model where the purchasing body (which the Energy Bill identifies should be the Authority or the Secretary of State) will buy the ROCs at a fixed price and levy suppliers to recoup the cost of the ROCs. Importantly, generators should be able to sell the Fixed ROCs to a third person such as a supplier or aggregator who would then sell the Fixed ROCs to the purchasing institution, as well as being able to sell to the purchasing institution directly. This flexibility will fit more easily with the existing structures of power purchase agreements which provide for generators to deliver ROCs and other renewable benefits to the offtaker.

The Fixed ROC will apply from 1 April 2027 to 31 March 2037. It is proposed that the price should be fixed as the buy-out price plus 10% headroom indexed on the same basis as the current buy-out price.

Transitional Arrangements

Generation already accredited at the introduction of the CfD (expected April 2014) – will remain within the RO and will not have the option to switch. (Note that the FiT CfD is not expected to be introduced in Northern Ireland earlier than 2016.)

Generation commissioning between the introduction of the CfD and 31 March 2017 – will have a one-off choice between the RO and the CfD. (Additional capacity of more than 5MW that is added during this period will also have the benefit of this choice in respect of that additional capacity. Additional capacity of less than 5MW will be able to opt for the CfD unless it is eligible for the small-scale feed-in-tariff.)

RO will be closed to new generation on 31 March 2017 – thereafter new generation will only be eligible for the CfD. (Additional capacity of more than 5MW that is added after 31 March 2017 will be eligible for the CfD. Additional capacity of less than 5MW will be eligible for the CfD unless it is eligible for the small-scale feed-in-tariff.)

The **"vintaged" RO from 1 April 2017** will:

– be calculated on the basis of expected generation plus 10% headroom until 31 March 2027;

– be based on "Fixed ROC" (proposed as the buy-out price plus 10% headroom) indexed on the same basis as the current buy-out price from 1 April 2027 to 31 March 2037; and

– likely grandfather technologies at the RO support level applicable on 31 March 2017.

There will be a **grace period** for accreditation in the RO for generation which was scheduled to complete by 31 March 2017, but is delayed by a delay in grid connection instigated by the transmission or distribution operator, or a delay in the planned installation of radar necessary to satisfy planning conditions for wind generation projects. However, generators benefiting from the grace period will remain subject to the 2037 end date of the RO and therefore would not receive the full 20 year support period.

The '**Fixed ROC**' is to be based on a supplier levy model where the purchasing body (the Authority or the Secretary of State) will buy the ROCs at a fixed price and levy suppliers to recoup the cost of the ROCs. Importantly generators should be able to sell the Fixed ROCs to a third person such as a supplier or aggregator who would then sell the Fixed ROCs to the purchasing institution, as well as being able to sell to the purchasing institution directly. This flexibility will fit more easily with the existing structures of power purchase agreements which provide for generators to deliver ROCs and other renewable benefits to the offtaker.

Offshore wind generators with split phases will:

– be able to register all of the remaining turbines representing the consented capacity of the generating station under the RO on or before 31 March 2017, but the 20 year support period will begin from the point of registration; and

– be able to participate in the CfD for any remaining turbines that will not be registered under the RO by 31 March 2017 (with metered output readings being pro-rated as necessary).

Non-Fossil Fuel Obligation (NFFO) generation developed between the introduction of the CfD and 31 March 2017 will be required to accredit under whichever scheme provides the best return for the Non-Fossil Purchasing Agency (**NFPA**), and if developed after 31 March 2017 will be eligible to participate in the CfD (subject to sterilisation on the same basis as sterilisation from the RO).

(g) Emissions Performance Standard (Chapter 7)

The Emissions Performance Standard will impose an "emissions limit duty" on the operators of new fossil-fuel power stations and associated CCS plant. The duty obliges such plant not to emit more than a specified amount of CO_2 in each year of their operation, thereby reinforcing the existing policy (set out in national policy statements designated under the Planning Act 2008) that no new coal-fuelled plant should be built unless equipped with CCS.

Unlike most of the other EMR provisions, key details are proposed to be included in the Energy Bill as primary legislation, rather than subsequent statutory instruments. The EPS will be an annual limit, equivalent to 450g of CO_2 per kilowatt hour of electricity for a plant operating at baseload. This is below the level expected of new coal plant when operating unabated, which is nearly 800g/kWh. It is, however, above the level of modern combined cycle gas-fired power stations, which operate at below 400g/kWh. Provision is made to except (or a case-by-case basis) from the requirements of the EPS, plant which form part of the UK's CCS Programme or benefit from European Union funding or a CfD or investment instrument for commercial scale CCS. Provision is also made to apply the emissions limit duty with or without modification in a range of non-standard scenarios.

The limit is based on the individual plant's installed generating capacity, a statutory rate of emissions and a load factor of 85%, and the provisions place a duty on operators not to exceed this limit in any one year.

The statutory limit is to be set at 450g/kWh until 2045. The duty is applicable to fossil fuel plant of at least 50MWe that are built pursuant to a relevant consent made on or after the date the EPS provisions come into force.

The regime covers plant which use fossil fuel but is not intended to cover generating stations which only make incidental use of fossil fuel for safety, start-up or stabilisation purposes (such as biomass plants): provision is therefore made (in subsection (6)(c)) for emissions from such use of fossil fuel to be disregarded for the purposes of the EPS. The regime does, however, cover generating stations using fuel produced from a CCS plant, and the associated CCS plant itself. Further provision may be made in regulations as to what constitutes associated CCS plant for these purposes, but it is intended that the regime will cover Integrated Gasification Combined Cycle (**IGCC**) plant as well as gasification plant producing, for example, hydrogen from fossil fuels as a fuel for a generating station which is not built as part of the generating station. In such a case, while the power station itself would have no CO_2 emissions, the emissions limit duty would ensure that the CCS plant supplying fuel to the generating station would have to apply CCS to the CO_2 that would otherwise be emitted as a by-product of the manufacture of non-CO_2 emitting fuel.

This Secretary of State may except plant from the annual CO_2 emissions limit where a project demonstrating CCS is being carried out at the plant and it is being supported by public funding or through CfDs.

There is also power to exclude emissions associated with the supply of heat to customers from CHP plants.

Significant upgrades or life extensions of existing plant (other than to comply with EU law, retrofitting CCS or conversion works to facilitate the use of biomass) would also be subject to the EPS. So for example replacing a boiler or upgrading to supercritical technology could force an existing plant down a CCS route.

The EPS is set at 450g/kWh until 2045. The Government will however review the EPS on a regular basis pursuant to the reporting requisites under the 2010 Energy Act. If it were to be deemed that changes for future plant (for example were sufficient new gas generation to be in place to maintain security of supply as older fossil fuel plant close), then changes could be introduced but prior to 2045 this would require primary legislation.

The Government had in the EMR White Paper announced that the EPS would be subject to a principle of grandfathering. In March it was announced that this would extend to 2045. The threshold has now been hard wired to that date in primary legislation.

The Government now expressly acknowledges the importance of investment in new gas plant during the transition to low carbon. This in turn means giving comfort to such investors that the EPS will not be used to curtail the operation life of such plant. The compatibility of this time frame with the Government's objective of substantially decarbonising UK generation by the 2030s (which in itself represents a potential slippage of a decade compared with the Committee on Climate Change recommendation of 2030) is less apparent.

Please see also "Gas Strategy" below.

(h) Strategy and Policy Statement (Chapter 8)

As part of the governance measures for EMR, the Energy Bill 2012 provides for the designation of a "Strategy and Policy Statement" to set out the strategic priorities in formulating energy policy, the particular outcomes to be achieved as a result of the implementation of that policy and the roles and responsibilities of the Secretary of State, the Authority and other persons in implementing that policy.

The Authority must then have regard to the strategic priorities set out in the Strategy and Policy Statement when carrying out regulatory functions.

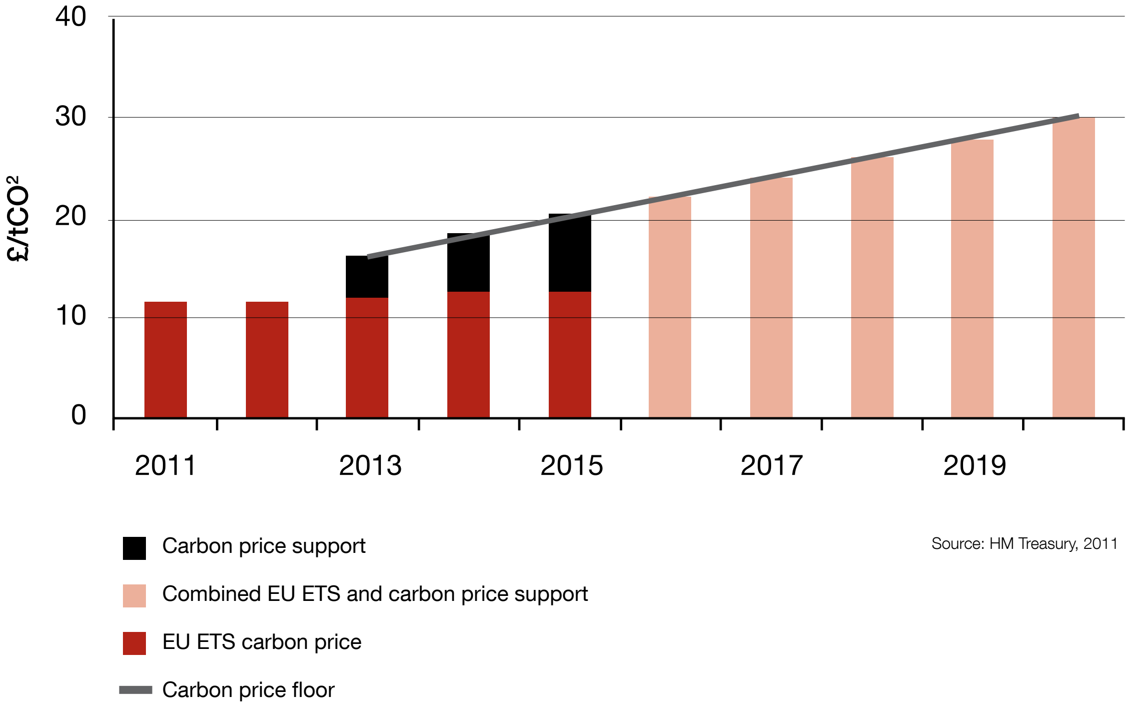
The Strategy and Policy Statement can only come into effect if specified procedural consultation processes, including consultation with the Devolved Administrations, have been followed and each House of Parliament has passed a resolution approving the statement.

The Strategy and Policy Statement must be reviewed every five years and may be reviewed at other times if an election has taken place, the Authority gives notice that the policy outcomes in the statement are not realistically achievable, a significant change in energy policy has occurred or Parliamentary approval was not given following the last review.

Carbon Price Floor

The Carbon Price Floor complements the other elements of EMR, but being a tax is administered by the Treasury and is therefore outside the scope of the Energy Bill.

Carbon price floor illustration (in real 2009 prices and calendar years)



Source: HM Treasury, 2011

The Government announced in the 2012 budget the 2014-15 rates for Carbon Price Support. A depreciating Euro and substantial over-supply of EU allowances has reduced the Sterling equivalent of the EU ETS carbon price compared with earlier expectations.

The 2014-15 Carbon Price Support figures have consequently increased from the estimate for such period in the 2011 Budget of an equivalent of £7.28 per tonne of carbon dioxide to £9.55/tCO_2. This figure is intended to maintain the UK's commitment to a sustainable and gradual increase in the tax-inclusive price of UK carbon to £30 per tonne (2009 prices) by 2020.

The above also demonstrates the growing divergence between UK and EU carbon prices. It seems plausible that there will be increasing tensions between affordability and decarbonisation objectives. The Chancellor's 2011 Autumn Statement included a £250m package for energy intensive industries to mitigate the effects of EU and EMR policies (including the carbon price floor). Last year the Chancellor stated that "We're going to cut our carbon emissions no slower but also no faster than our fellow countries in Europe". This position seems difficult to reconcile with the growing differences in carbon prices. The Government has also announced that in 2014 it would review progress toward 2020 goals and if the UK's domestic commitments were found to place it on a different trajectory than the EU ETS trajectory agreed by the EU, the UK would revise upwards its carbon budget to align it with the actual EU trajectory.

Indicative carbon price support rates for 2015/16 and 2016/17 were also announced in the 2012 Budget and these are equivalent to £12.06/tCO_2 and £14.86/tCO_2 respectively.

From 1 April 2013 (as addressed in our March 2011 update) good quality Combined Heat and Power (CHP) will be exempt from the carbon price support rates (subject to state aid approval). However, CHP will lose its Levy Exemption Certificates for energy supplied indirectly to the consumer. The CHP association have highlighted that this may lead to the closure of some CHP plants.

Generators, and any connected persons, with a combined generation capacity of two megawatts or lower will not be liable to the carbon price support rates of the Climate Change Levy.

Liquidity

As set out in our March 2011 update, successful implementation of the CfD will require a liquid wholesale energy market to ensure a robust pricing structure. The direct downstream control that the Big 6 maintain over both the generation and supply of UK energy may affect the liquidity of the energy market and consequently must be considered in the implementation of the CfD.

There has been a significant growth in the volumes of electricity traded through exchanges over the past year. In particular SSE, E.oN and Scottish Power are committed to trading large volumes (in the case of SSE all of their supply and demand) in the day ahead markets. Exchange based day-ahead trading has increased from around 1TWh to 5-6 times that and now represents something like 20% of UK generation.

In February 2012 Ofgem published a consultation (which closed last month) on its Retail Market Review, expressing concern that, despite improvement throughout 2011, the current UK energy market structure is still not providing sufficient access to the range of traded products required by independent electricity generators and suppliers, nor an adequate pricing mechanism for those products. A range of traded products is essential to enable independents to hedge against the risk of future movements in wholesale energy prices and, despite the Big 6 implementing a number of bilateral trading initiatives, growth in these areas has been limited.

Highlighting these two objectives as key to the implementation of the EMR, Ofgem has renewed its commitment to implement a Mandatory Auction (**MA**) mechanism. Alterative mechanisms previously considered such as Mandatory Market Making (**MMM**), Self-Supply Restriction (**SSR**) or Direct Trading Obligation (**DTO**) do not as effectively address Ofgem's two key concerns.

	Liquidity objectives		
	Improves availability of forward products	**Supports development of robust reference prices**	**Effective near-term market (met by market developments at present)**
MA			
MMM (March proposal)			
Large-scale MMM			
SSR			
DTO			

The MA as described in the consultation would require the Big 6 to sell (rather than simply make available) 25% of their annual generation (equivalent to 50TWh or more than 40% of UK household electricity demand) outside of their immediate downstream supply chains. This is a substantial increase from the 10%-20% estimate provided in 2011 and reflects the renewed commitment to creating a wholesale market large enough to facilitate the changes to be adopted under the EMR.

The supply will be focused on a wide range of trading products on a monthly basis. The Big 6 will also be required to comply with rules on buy-side participation in the auction process, ensuring they cannot simply buy the amount they sell (therefore ensuring a market surplus) and to buy and sell only at prices that reflect market prices.

Ofgem has suggested that appropriate mechanisms should mean it would not need to be involved in the regulation of prices; however it is currently considering its role in providing the best platform to underpin the MA. The two options currently being considered are: (a) a single service provider tendered via Ofgem, or (b) a single or multiple platform tendered via the participants themselves.

Design Aspect	Key features	Rationale
Participation	– Big 6 obligated to sell defined products in each auction – Non-obligated parties can take part on the buy or the sell side	– It is appropriate that those companies with a significant position in both the generation and supply markets are responsible for discharging the obligation to improve those markets – Vertically integrated companies have a reason for buying and selling power, meaning they can manage the risks of holding the obligation through participation on the buy side of the auction
Products	– Our indicative list includes products from front month to season +5 – Volumes each month would be sufficient to provide a 'one stop shop' for products needed for hedging	– Our indicative product list aims to provide a one-stop shop with a range of hedging products needed by market participants – It is informed by submissions received from a range of independent generators and suppliers (see appendix four). However, we will be keen to hear views from stakeholders on the appropriate products to be supported by the auction – Requiring the sale of products in this list will also generate robust reference prices along the curve
Volume	– Volume sold is equivalent to 25% of Big 6's generated output (around 50TWh based on 2011 data)	– 25% is sufficient to improve availability of products that support hedging – 25% is also enough volume to make sure that sufficient trading in each product takes place in each auction to provide a robust reference price – Greater volumes could impose disproportionate costs on market participants, which could be passed on to consumers
Governance	– Ofgem-led governance arrangement based on clear principles – No regulation of reserve prices – Two alternative approaches for platform selection	– The MA must be robust, trusted by market participants and capable of achieving our liquidity objectives. Consequently there must be clear principles governing its operation – However, it must also align with what works best in the market and be flexible enough to respond to market developments. Ofgem will therefore not be involved in the day-to-day running of the auction (eg through the setting of a reserve price)
Safeguards	– Big 6 subject to rules governing buy-side participation in the auction	– Buy-side rules are necessary to ensure that all parties are able to benefit from trading in the auction – The rules will also ensure that the price discovered by the auction is reflective of market fundamentals

Work by Ofgem and industry to improve liquidity will play an important part in increasing competition and trading options. However, there are some projects that will not be directly helped by these measures, in particular independent wind and other intermittent renewable technologies that currently rely on long-term PPAs, for their route to market and risk management. PPA terms vary, but typically the off-taker agrees to buy power at a discount to the prevailing wholesale price. The discount reflects the risks that the off-taker will manage on behalf of the generator, but the overall discount may be affected by the level of competition amongst PPA providers. Reliance on PPAs reflects, in part, the scale of some generators' projects; including limited in-house trading capacity and the difficulties that individual wind projects face in managing their imbalance risks. An important reason why independent generation projects rely on PPAs is that these projects rely on non-recourse project finance to part-fund the investment, which given the long length of financing typically requires the offtake and other risks to be entirely managed through a long-term PPA with a creditworthy counterparty. Whilst other routes to markets are theoretically available, in the majority of cases financiers will require a PPA.

There is reducing appetite amongst utilities to offer long-term fixed price PPAs. However, generators are not expected to seek fixed price PPAs under the CfD regime, as it is the reference price (or a fixed discount thereto) they wish to capture.

Developers have suggested that the move from the RO to CfD is likely to undermine their ability to secure PPAs because suppliers will no longer be under an obligation to source renewable electricity. Whilst the removal of the obligation is likely to be one of many factors influencing supplier attitudes to structuring PPAs, the Government argues that in time a competitive market should provide bankable routes to market for independent generation projects. The Government believes suppliers and independent aggregators will continue to offer PPAs as there will still be commercial opportunities in doing so:

- the large vertically integrated companies and independent aggregators can manage imbalance risk more efficiently than an independent generator;
- the main electricity suppliers are short on power overall;
- there is an incentive to offer PPAs linked to the reference price to hedge price risk arising from suppliers' obligations to pay the CfD top-up payment in proportion to their market share; and
- possibilities for cash-out reform (such as a pre-gate closure balancing market) could reduce the costs of managing imbalance risk in the longer term (though equally there is expected to be a "sharpening" which would disadvantage intermittent generation).

The Government believes that alongside the development of a more liquid and competitive market the CfD offers the potential for PPAs to be simpler, more transparent and potentially offer better terms, mainly due to the simplification of risk management under the CfD.

However, it may take time for this market to develop, and DECC believes that more evidence is needed to ensure that the extent and nature of the issues in the current, and likely developments in the future, PPA market are fully understood.

The Government will seek with investors, independent generation developers, potential PPA providers and Ofgem fully to develop the evidence base, including:

– evidence of the issues related to the current PPA market including the levels of competition, discounts and risk transfer;

– evidence of the impact that changing conditions in the PPA market are having on investment decisions, the level of return and the required levels of debt and equity;

– views on the likely development of the PPA market in the transitional period from the RO to CfDs, and then under the CfD only from 2017;

– evidence of the barriers to a competitive market; and

– options, including market-led solutions, that may be available to remove or reduce those barriers and to ensure a competitive and efficient PPA market.

As part of this process the Government will issue a Call for Evidence in June 2012 to examine the issues outlined above, setting out understanding of the issues, the evidence that is needed to move forward, and outlining initial options that may address market concerns.

Gas Strategy

The Government envisages a phased approach to low carbon generation, recognising that gas generation will continue to play a critical role, in the short and medium terms, as a reliable and flexible electricity source to meet core demands now and balancing demands in the future. The Government's Introduction to the Energy Bill specifically recognises (at paragraph 73) that investment in new gas generation will be needed to ensure security of supply.

Clearly, investors will need to be convinced that such plant will be economic over its working life. The Government's plan for de-carbonising the electricity sector as a stepping stone to 2050 targets appears to be slipping beyond the timetable proposed by the Climate Change Committee, and long-term grandfathering of the EPS also suggests a longer horizon for unabated gas. The role of the capacity mechanism will however be crucial in a future where much generation has low marginal costs (and change in law protection).

Of course, there is also the possibility that unconventional gas means that the projection of gas prices being dragged up by rising oil prices is pessimistic (though this does underpin arguments for eventual relative savings through these reforms).

A strategy on the role of gas in the electricity market is to be published in Autumn 2012. We hope that this will not be too late to inform the design choice for the Capacity Mechanism. The stated focus of the gas strategy is on ensuring security of supply by setting out any necessary Government interventions needed to address barriers to investment in gas generation.

The Government will also be publishing a document in Summer 2012 focusing on the challenges around balancing and system flexibility as the UK decarbonises electricity use.

EU Aspects

As we commented in our review of the White Paper, the proposed EMR raises a number of European legal issues, not least the compatibility of the CPF and the CfDs with the European state aid rules. Even if the Government contends that the proposed measures are intended to promote longer term security of supply, de-carbonisation and affordability, and are as such intended as 'corrections to market failures', this will not necessarily lead to Commission acquiescence. Obtaining state aid clearance for the proposals is likely to be challenging.

Indeed a number of major energy companies have raised concerns as to the state aid hurdles facing the implementation of the proposed market reforms and have indicated their unwillingness to commit to investment until clearance has been obtained. The Commission has also received a complaint from Energy Fair, the anti-nuclear pressure group, citing the CPF, the CfD and the Capacity Market as illegal state aids.

The Draft Bill – State Aid Issues Acknowledged

The summary that precedes the Energy Bill itself makes several references to the need to obtain state aid clearance. The areas where the Government acknowledges where state aid clearance will need to be considered going forward include:

(a) exploring options for reducing the impact of electricity costs arising as a result of electricity market reform policies and potentially costly environmental legislation, including with respect to FIT with CfDs;

(b) varying CfDs for different technologies. Although the CfD will be largely standardised across technologies, the Government accepts that variations will be needed for intermittent and baseload generators in recognition of their different risk profiles;

(c) considering the issue of investment instruments on terms and conditions as the Secretary of State considers appropriate in advance of the implementation of CfDs. This is reflected in the Energy Bill legislation at section 15(6) which provides that the Secretary of State may not issue an investment instrument if such an issue would constitute a grant of state aid. This is further confirmed in the explanatory notes to section 15. The preferred option is to issue investment instruments before EMR is fully implemented, but again with price and contract terms conditional on any necessary state aid approvals being granted; and

(d) considering the provision of a flexible mechanism to review the strike price after the award of a CfD to CCS projects and in the price setting process more generally.

The summary document also acknowledges that DECC are already working closely with the European Commission on the interaction of EMR with the wider EU legal framework, and to ensure that EMR policies are consistent with European secondary legislation, as well as the Treaty rules on state aid.

Commentary

The publication of the Energy Bill coincides with the EU Commissioner for Competition's announcement on 8 May 2012 of a major overhaul of EU state aid policy – the so-called State Aid Modernisation Plan, also known as **SAM**. The Commission's plans to reform state aid control could have an impact on how it assesses the proposed EMR reforms for compatibility with the EU Treaty rules. Although the SAM primarily focuses on the implementation of Articles 107 and 108 of the Treaty of the Functioning of the European Union (**TFEU**), it is highly likely that this policy will also apply to any form of support to the nuclear sector even though nuclear energy falls under the ambit of the Euratom Treaty. That Treaty does not contain any specific provisions on state aid and the Commission's policy has been to assess the compatibility of any aid to the nuclear sector under the TFEU legal framework, albeit bearing in mind the broader goals of the Euratom Treaty to foster nuclear power as an important component of security of supply policies. Earlier decisions on aid to the nuclear sector suggest that the Commission accepts that Member States have little alternative but to provide some level of support for nuclear power, and are effectively faced with the choice of funding that support either through tax revenue or passing it on to energy consumers.

While the Commission may accept the necessity of state aid to promote nuclear investment, it must still be convinced that the aid is proportionate to the objectives pursued and is not distortive of inter-state trade. This is where the proposed SAM could bite.

(a) Definitional issues

A likely bone of contention will be whether all of the ERM proposals fall within the ambit of the European state aid regime. The Treasury appears adamant that the CPF, to be implemented through the imposition of the Climate Change Levy on fossil fuels, does not amount to state aid but is rather a taxation instrument, the introduction of which falls within the exercise of its sovereign powers and which will not lead to a selective advantage for any particular producer or supplier. In other words, this measure would not meet the crucial 'selectivity' test – a state measure must confer a selective economic advantage on particular products or sectors. Clearance for the CPF is not therefore included in the list above. But this approach is not without difficulty. The Commission (supported by the European courts) has been quick to find that environmental taxes or levies create selective advantages and constitute state aid if the benefits of the tax or levy are not intrinsic to its objectives. The CPF was expressly introduced to support new low-carbon investment, but raising wholesale prices also benefits existing renewable and fossil fuel plant. Further, once CfDs are introduced, any new low-carbon generator will, as a result of the CfD, be deprived of the benefit of future increases in the CPF.

The regulatory regime for the Capacity Market has still to be worked out in sufficient detail to determine whether it could be considered as compensation for the performance of a public service obligation. Provided a number of essentially procedural conditions are satisfied, such compensation can escape classification as state aid, and, as such, notification to and subsequent clearance by the Commission. There remains some uncertainty as to whether CfD generators will be eligible to participate in the Capacity

Market, if activated, and if so on what basis. In particular it is unclear if baseload nuclear plant could be included within the Capacity Market mechanisms.

The administration of the proposed strike price also raises definitional issues and in particular whether this instrument will involve state resources – another crucial component of the definition of state aid in Article 107 of the TFEU. Again, the Commission takes a broad view of this concept, and indeed the Treaty itself refers to 'state resources in any form whatsoever'. The strike price mechanism is based on an administrative approach to price setting and if revenues are channelled through and apportioned in a manner mandated by a government, then past precedent confirms that 'state resources' are involved, even if the energy customer is paying the bill.

The roll-out of the SAM is unlikely to solve all the definitional problems that pervade European state aid law but the Commission is determined to provide greater clarification on the notion of aid. Whether it would be inclined to use the complex ERM proposals as a test case here remains to be seen, and of course it is for the European courts and not the Commission to have the final word on matters of definition.

(b) Commission policy alignment

Importantly, the SAM also promises to align Commission principles on compatible aid assessment and to place greater emphasis on determining the incentive effect of a proposed state aid measure, avoiding the wasteful use of public money and ensuring a more systematic assessment of the negative effects of state aid on the internal market. The new approach will be applied to the assessment of its Environmental Aid Guidelines (**EAG**) – up for renewal at the end of 2013 but with consultation on proposed reforms beginning early 2012. To date, the Commission has taken a somewhat benign attitude to aid to renewable energy (which does not include nuclear energy) and has cleared most national support measures as necessary to meet the '20-20-20' target of ensuring 20% of renewable energy generation in the national fuel mix by 2020. However, the SAM indicates that Commission scrutiny of renewable support measures will intensify and that it will demand a more exacting case to be made out in favour of longer term support. This may lead it to question the efficiency of the proposed CfD mechanism and to require the Government to demonstrate that fewer interventionist measures or alternatives are not able to meet the stated policy objectives. Further, the impact of the EMR on the wider European energy market will remain firmly within the Commission's sights.

Conclusion

Although the SAM will not be fully rolled out until late 2013 and the current version of the EAG will not be updated and amended before that date, the announcement and subsequent implementation of the Commission's reform plans will undoubtedly add a further element of uncertainty for would-be investors in the UK energy market. Although the Government is committed to long-term policy stability, it cannot offer a protection against subsequent changes of law where this is mandated by EU law. EU state aid law and policy is likely to cast a long shadow over the viability of EMR.

Government Pipeline and Storage System (Part 3 Energy Bill)

The Government Pipeline and Storage System (**GPSS**) consists of around 2,500 kilometres of cross-country pipelines of differing diameters, together with storage depots, associated pumping stations, receipt and delivery facilities and other ancillary equipment. The system receives, stores, transports and delivers light oil petroleum products for military and civil users.

In peacetime, the military use amounts to only around 10% of the current throughput and 30% of the storage capacity of the system. It distributes 40% of aviation fuel within the United Kingdom.

The powers under which the system was constructed and under which rights were acquired in relation to it were many and varied. Elements of the system were constructed on or under what was, or remains, publicly owned or acquired land. Much of the system, however, was constructed on or under private land. Some elements of the system were constructed on or under private land under statutory powers. Other elements were built by agreement with the landowner at the time.

Part 3 of the Energy Bill effectively sets up the basis on which the GPSS can be privatised so as to:

– Raise a capital receipt for the Government;

– Enable increased private sector investment in the GPSS to increase the resilience of the system; and

– Allow commercial development of the GPSS.

If privatisation occurs, the MOD will contract with the buyer to meet its ongoing requirements and will also seek to protect the interests of other customers during negotiations.

In broad terms, the Energy Bill seeks to achieve this by:

– ***Defining the GPSS.***

– ***Defining the rights of the Secretary of State in relation to the GPSS:***

  – The Secretary of State may maintain and use the GPSS, or any part of it, for any purpose for which it is suitable.

  – The Secretary of State may inspect or survey the GPSS or any land on or under which it is situated and may remove, replace or renew the GPSS or any part of it. If the system, or any part of it, is removed or abandoned, he may restore the land.

  – For the purpose of exercising the rights described above, the Secretary of State may enter any land on or under which the GPSS is situated or any land held with that land ("the system land").

  – If the owner or occupier of the system land is entitled to exercise a right to pass over other land ("the access land"), the Secretary of State may exercise a corresponding right of access over that land for the purpose of accessing the system land.

– Except in an emergency, the above rights may be exercised only at a reasonable time and with the consent of the occupier of the land or under the authority of a warrant. The rights do not include a right to enter dwellings.

– ***Requiring the registration of those rights:***

– The rights referred to above (and the transfer rights referred to below) are not subject to any enactment requiring the registration or recording of interests in, charges over or other obligations affecting the land but they bind any person who is at any time the owner or occupier of the land.

– However, in England and Wales such rights are local land charges and it will be the duty of the Secretary of State to apply for their registration. In Scotland the rights may be registered in the Land Register of Scotland or recorded in the Register of Sasines.

– ***Requiring that compensation be payable in respect of the creation of new rights or the exercise of rights:***

– The Secretary of State must pay compensation to a person who proves that the value of a relevant interest in the land to which that person is entitled is depreciated by the creation of the rights referred to above (and the transfer rights referred to below). Such compensation being equal to the amount of the depreciation.

– If a person proves loss by reason of damage to, or disturbance in the enjoyment of, any land or certain property as a result of the exercise of the rights referred to above, the person on whose behalf the right was exercised must pay compensation in respect of that loss.

– ***Allowing for the GPSS and the rights referred to above to be transferred:***

– The Secretary of State may sell, lease or transfer the GPSS and any right or liability relating to the GPSS system, or any part of it, subject to such conditions, if any, as he considers appropriate.

– This includes the statutory rights granted to the Secretary of State and referred to above.

– ***Providing for the modified application of the Pipe-lines Act 1962 (c.58) to the GPSS.***

The GPSS is currently managed by the Oil and Pipelines Agency (a statutory corporation set up for the purposes of exercising and performing functions assigned to it by the Oil and Pipelines Act 1985 (c.62). The Energy Bill therefore provides that the Secretary of State may, by order, repeal the Oil and Pipelines Act 1985 and dissolve the Oil and Pipelines Agency. It also provides that if the Agency is dissolved, the Secretary of State may, by order, make a scheme for the transfer to the Secretary of State of property, rights and liabilities (a transfer scheme). The terms of such a transfer scheme may be wide-ranging and in particular may:

– provide for the transfer of property, rights and liabilities that could otherwise not be transferred;

– provide for the transfer of property acquired after the making of the scheme; or

– make consequential, supplementary, incidental or transitional provisions such as:

– to create rights or impose liabilities in relation to property or rights transferred;

– to provide for shared ownership or use of property.

Interestingly, the Energy Bill does not contemplate the need for a further transfer scheme in the event of a privatisation of the GPSS. At first read, it is therefore difficult to see how the benefit of the detail of any particular transfer scheme can be transferred to the private sector as part of any privatisation. This will no doubt be something that is considered as part of current scrutiny of the Energy Bill.

As with so much of the Energy Bill, the real interest for investors will come later when the details of the structure and terms of any privatisation become known. In the current market, infrastructure sale prices are highest for assets with a regulated or quasi-regulated return on capital. Given that the first reason for the sale is given as producing a capital receipt for the Government, it is interesting that the Energy Bill does not set up the framework for such a regulated return (even if only in respect of the MOD usage requirements). It will be interesting to see how this develops and how the customers of the GPSS (for example Heathrow) seek to protect their interests during any privatisation process.

Offshore Transmission (Part 4 Energy Bill)

The Energy Bill includes an amendment to the OFTO licensing regime intended to clarify that a developer who exercises the generator build option under the enduring regime (which was an option introduced in response to developer representations during consultation) before transferring assets to an OFTO is not in breach of the prohibition on participating in the transmission of electricity without a licence during the commissioning of those assets. The four conditions for the new exception to apply are that:

(1) the transmission takes place over an offshore transmission system or any transmission assets in relation to that system;

(2) the transmission takes place during a commissioning period, which is the period before the completion notice is given and during the period of one year after that notice;

(3) a tender exercise has been or is being held for the granting of an offshore transmission licence in respect of that system and the transmission assets have not yet been transferred to the successful bidder; and

(4) the developer in relation to the tender exercise is the person who constructed and installed the transmission assets (or on whose behalf those assets were constructed and installed) and is the operator of a generating station generating electricity transmitted over that offshore transmission system.

At the moment, a similar situation under the transitional regime (where developers are building and commissioning the transmission assets as part of the original wind farm development) is dealt with by the commencement of the regulatory regime in relation to 132kV assets conveying electricity from offshore being restricted to assets from the point of transfer to an OFTO. (Ofgem has also made statements that, prior to completion of commissioning, it does not consider that a licence is required, principally because the transmission assets would not have been proven as a transmission system.)

In due course, however, the Government intends to commence the regulatory regime in full rather than on the current partial basis, at which point the amendment introduced by the Energy Bill will be an important protection to developers. Nevertheless, the restriction in the Energy Bill exemption to one year after the completion notice may present difficulties for developers, depending on the stage at which the completion notice is given. Previous OFTO projects have experienced a number of construction difficulties, including with grid code compliance issues, and it will need to be checked whether the completion notice is intended to correspond to interim operation following initial commissioning tests or to final operational status after full grid code compliance tests.

Notably the restriction may not sufficiently protect all of the transitional projects. Ofgem has stated that it is continuing to consider how existing transitional projects should be treated, with a view to recognising their transitional nature whilst also ensuring they are transferred as soon as is reasonably practicable.

Although not part of the Energy Bill, it is worth noting some of the effects of the Electricity and Gas (Internal Markets) Regulations 2011 which are now in force in relation to the implementation of the EU Third Package on the OFTO businesses. A number of new OFTOs have been submitting applications under those Regulations for certification for compliance with the ownership unbundling requirements of the Third Package. Last month the EU Commission issued an opinion which set out that, as the transmission systems of the OFTOs were not in place on 3 September 2009, the only unbundling option provided for those operators under the Electricity Directive is the full ownership unbundling option, and that Ofgem needs to undertake further analysis in relation to whether the requirements of the Electricity Directive are satisfied in relation to those OFTOs.

ANNEX 1: *Quick Reference Guide to the Proposals*

Contract for Difference (CfD)

Updated Proposal

Contracts for Difference for low-carbon generators calculated on the basis of the difference between a strike price and a reference price.

Different contract structures will be used for different generation types:

– intermittent (e.g. wind, wave, solar)

– baseload (e.g. nuclear, some biomass, some CCS)

– (if required) flexible

Reference price for intermittent generation to be hourly day ahead auction price for the GB Price Zone (to be established under NWE Market Coupling).

Reference price for baseload to be year ahead, with the price source to be determined in light of Mandatory Auction developments.

The Government plans to exclude plants in receipt of an administratively set CfD from the Capacity Market to avoid overcompensation of low carbon plants.

The Government minded to introduce 'independent expert' role within the CfD framework – this expert would be mandated to ensure that the derivation of the price and volume variables applied in the settlement of the CfD remain valid over time.

CfD expected to be available from April 2014.

Generation not already accredited when the FiT CfD is introduced will have a choice between FiT CfD and RO until 31 March 2017 (subject to certain grace periods).

Strike prices will initially be administratively set. 2014-2018 strike prices for renewables to be confirmed in first delivery plan by end 2013.

Strike prices will be partially inflation-indexed.

Aim to move from administrative price processes to more competitive forms of price discovery such as auctions or tenders when the wider conditions in the market will support their successful deployment, envisaging technology-specific auctions for contracts towards the end of the decade and greater competition between technologies towards and into the early 2020s.

For early stage CCS projects (including those supported under the CCS Commercialisation Programme) and nuclear, the level of the strike price is expected to be determined through a process of negotiation between developers and DECC.

The Government proposes to pay CfD supported plant based on output unless the reference price drops below zero, in which case it would be paid on availability.

Initial view that CfD length for renewables should be 15 years, with 10-year length for certain CCS projects, leaving the time scale for nuclear and long-term CCS-equipped plant to be determined.

Multi-partite arrangement between low-carbon generators and all suppliers (subject to review).

As yet unpublished secondary legislation to set out full workings of CfD.

The Government is to conduct a review assessment in 2016, but is committed to grandfathering and no retrospective change.

Objectives

To improve long-term revenue certainty for low-carbon generation.

To achieve cost-efficient low-carbon investment.

To retain normal commercial incentives to sell electricity in a way that best reflects the plant's operational mode.

To mitigate the potential for windfall profits/excessive rents and the risk of gaming and contract manipulation.

To avoid arrangements which favour a particular corporate structure.

Outstanding Issues

Detailed design of the CfD, including clarifications to length of contract, frequency of payments, conditions of contract, terms for credit and collateral, indexation mechanisms, payment mechanisms due in Autumn 2012.

Confirmation of proposed legal framework (nature of contract; multi-partite/bilateral).

Reviewing RO banding costs and assessing what further data gathering is required to support CfD price discovery.

If Ofgem's measures are not enough to sufficiently improve wholesale electricity market liquidity, the Government will work with industry and Ofgem to consider what further action is necessary.

The Government plans to issue a call for evidence in June 2012 in relation to availability of power purchase agreements for renewable generators to set out an understanding of the issues, the evidence that is needed to move forward, and to outline initial options that may address market concerns.

Interaction with Capacity Mechanism – the Government will consider including an element of payment for capacity within the CfD.

Confirm details of how availability will be measured when prices are negative. Develop policy on how CfD-supported plant is paid following instruction to adjust its output for operational reasons.

Proposals around managing financial exposure under CfDs to be developed.

Term	Description	Emerging Proposal
Reference Price	The market price for electricity that is referenced in the CfD for the purpose of calculating CfD payments.	Intermittent: Hourly Day Ahead Auction Price for the GB Zone (as established under North West European Market Coupling). Baseload: Year Ahead, price source to be determined.
CfD Volume	The definition of the volume of electricity for the purpose of calculating CfD payments, and the resulting metering requirements.	Minded to pay the CfD on the basis of metered output unless the price in the reference market is negative, in which case to pay on a measure of availability.
Allocation of supplier payments	How suppliers' payment obligations/entitlements are calculated.	Minded to base suppliers' payment obligations on market share, as defined by 'supplier cap take'.
Settlement	Process and timing for invoicing and administering CfD payments.	Minded to base processes on Balancing and Settlement Code processes. Minded that settlement periods will be at most one month.
CfD Length	The length of the CfD from the payment start date as defined in section C.	Initial view that CfD length for renewables should be 15 years. 10 years (subject to negotiations) for early stage CCS project(s) supported under CCS Commercialisation Programme. Nuclear and long-term CCS-equipped plant to be determined.
Inflation indexation	Arrangements for adjusting the CfD strike price in line with inflation.	Minded to choose CPI as a standardised and established inflation measure that is familiar to international institutional investors.
Fuel Price indexation	Arrangements for adjusting the CfD in order that payments reflect a generator's input fuel costs.	Minded not to link the CfD strike price to fuel costs for biomass. For the first CCS project(s), minded that the CfD should provide indexation needed to hedge against long-term fuel price variability.
Credit and Collateral	The requirements on generators and suppliers to provide credit/collateral.	Minded to place a collateral requirement based on an estimate of likely settlement amounts due in a given trading (settlement) period.
Amendment of the reference price and other CfD parameters	The arrangements for amending CfD parameters (such as the reference price or other variable definitions) in response to changes in trading arrangements which change or render variable definitions invalid, or changes in market liquidity or trading platforms which might impact the validity of the indices used to calculate the reference price.	Minded to include an 'independent expert' role in the CfD framework to manage any review of CfD parameters and determine any amendments required.
Change in Law	Arrangements for adjusting the CfD in response to relevant changes (e.g. regulatory) that materially affect the value of the CfD to either party.	Minded in principle that the CfD should contain change in law provisions, the form and scope of which remain to be determined. Further details will be set out in the Autumn.
Dispute Resolution	Procedures for resolving any disputes arising under the CfD.	The Government will seek further legal advice in this area before engaging with stakeholders later in the year.

Carbon Price Support

Updated Proposal

The Government has removed the exemptions from the Climate Change Levy (**CCL**) for fossil fuels used to generate electricity and tax these at rates to take account of their average carbon content (which will be different to the main Climate Change Levy rates). The Government has also reduced the amount of fuel duty that can be reclaimed when oil is used to generate electricity.

The changes will apply from 1 April 2013, but anti-avoidance provisions are in effect.

Rates from 1 April 2013 to 31 March 2014 are equivalent to £4.94/tCO_2.

Rates from 1 April 2014 (equivalent to £9.55/tCO_2) and indicative rates from 1 April 2015 (equivalent to £12.06/tCO_2) and 1 April 2016 (equivalent to $14.86/t$CO_2$) were published in the 2012 Budget.

Future rates will be announced at subsequent Budgets, depending on the prevailing carbon price. These rates will be set two years in advance to allow generators time to plan hedging strategies, with indicative rates published for two further years.

Since the initial consultation, the Government has proposed a change to the treatment of Combined Heat and Power (**CHP**) to give the heat output of good quality CHP an exemption on the carbon price support levy, subject to state aid approval. However, it also proposed to remove from CHP the benefit of Levy Exemption Certificates (LECs) for electricity supplied indirectly to a consumer. Exemption certificates relating to generation made before 1 April 2013 may continue to be used until 31 March 2018.

The Government will implement a partial relief for fossil fuels used in CCS plants. If a power station is capturing and storing a quarter of the CO_2 it produces, then it will be given relief on a quarter of its input fuel.

Following consultation, coal with a calorific value of more than 15 gigajoules per tonne will be the only taxable solid fuel.

Generators, and any connection persons, that have a combined generation capacity of 2 megawatts or lower will not be liable to the carbon price support rates of the CCL.

All generators liable to pay the CPS rates of CCL must register with HM Revenue and Customs and must account for, declare and pay the CPS rates of CCL.

Objectives

To encourage additional investment in low carbon generation by providing greater support and certainty to the carbon price.

To 'top-up' for electricity generation the effective carbon price resulting from EU ETS. The Government is targeting a price for carbon (inclusive of EU ETS) of £30/tCO_2 in 2020, rising to £70/tCO_2 in 2030 (real 2009 prices).

Requires less public expenditure as funded by the tax system.

Aligned with the 'polluter pays' principle.

Outstanding Issues

Obtain state aid approval for reliefs for CHP.

Monitoring the interaction for Northern Ireland generators with the island of Ireland Single Electricity Market.

Emission Performance Standard (EPS)

Updated Proposal

The main provisions of the EPS are set out in the Energy Bill and this also provides powers for the Secretary of State to make further regulations in relation to the scope of the EPS and its enforcement.

The EPS sets an annual regulatory limit on carbon dioxide attributable to the use of fossil fuel emitted by individual fossil fuel plant. (The meaning of attributable to the use of fossil fuel is to be further defined by regulations, but this is understood to be the basis for the 'zero rating' of emissions from biomass fuel referred to in the previous papers.)

In general the EPS limit will only apply to fossil fuel plant constructed pursuant to a relevant consent for development granted after the applicable section of the Energy Bill comes into force, which is expected to be Q1 2014.

The Secretary of State does, however, have the power to make regulations to apply the EPS limit to existing plant which replaces its main boiler or installs an additional main boiler (including the power to make different provision, in relation to different parts of the plant). There are also some suggestions that regulations could apply the EPS to existing plant in other situations, but this is still unclear.

The EPS limit is set at a level equivalent to 450g CO_2/kWh at 85% load factor calculated on the plant's installed electrical capacity. This limit is fixed in the primary legislation for the period up until and including 2044. (The Government calculates that this is below the level expected of new coal plant when operating unabated, which is nearly 800g/kWh, but above the level of modern combined cycle gas-fired power stations which operate at below 400g/kWh. It also assesses this as meaning that typical advanced supercritical coal-fired power stations subject to this requirement would need to abate their emissions by 40% compared to what they could otherwise emit.)

The definition of relevant consent means that the EPS should not apply to plant of less than 50MW declared net capacity.

The reference to "fossil fuel plant" includes any associated CCS plant. There is also provision to address separate CCS plant supplying fuel to more than one generating station.

However, the Secretary of State may, by order, provide an exemption for CCS demonstration plants which may include plants for commercial-scale CCS projects benefiting from public funding, from EU funding or from a CfD or Investment Instrument. The Secretary of State must publish the policy for making such orders.

Provision is made for the regulations to be issued by the Secretary of State to disregard the use of fossil fuel used for ancillary plant, for safety purposes or in an emergency.

The regulations to be issued by the Secretary of State may also provide that emissions attributable to the supply of heat from combined heat and power plant are not attributable to the use of fossil fuel. The accompanying EMR Overview Document Annex D says it is the intention that the regulator would use the Qualifying Heat Output (**QHO**) detailed on the relevant year's Good Quality CHP (**CHPQA**) certificate and apply a discount of the QHO multiplied by the emission intensity of a 90% efficient gas boiler. Under this approach, plant which does not hold a CHPQA certificate would not be able to discount its emissions.

The definition of fossil fuel is coal, lignite, peat, natural gas, crude liquid petroleum, bitumen and any substance produced directly or indirectly from them for use as a fuel. The explanatory notes state that this definition is not intended to capture waste, which includes materials manufactured from fossil fuel sources if they have not been produced for use as a fuel. This should mean that the EPS does not apply to Energy from Waste plant.

The enforcement regulations may contain provisions requiring enforcing authorities to comply with directions given by the Secretary of State. It is expressly contemplated that this may include directions to treat the emissions limit as modified or suspended for a specified period. This appears to be the mechanism intended to implement the previous suggestion to allow coal plant under tightly defined circumstances to turn off their CCS equipment at times of exceptional demand, but the scope of this is currently unclear.

The EPS will be subject to regular reviews, as part of the process of three-yearly reports on decarbonisation under the Energy Act 2010. The accompanying EMR Overview Document Annex D says that if it were deemed that changes were necessary for future plants not already consented, for example to apply the emissions limit to new gas plant, these changes would be consulted on and introduced through primary legislation.

The accompanying EMR Overview Document Annex D also states that (in addition to the replacement of a main boiler which is already referred to in the Energy Bill) it is the Government's intention that upgrading a plant to supercritical technology would trigger the application of the EPS to existing plant and that this will be provided for in secondary legislation. Nevertheless, it states that it is intended that if a plant needs to carry out other major works such as installation of CCS or equipment needed to meet European environmental standards (such as equipment to reduce nitrous oxide or other emissions as required by the Industrial Emissions Directive), it should not be caught by the EPS. Conversion works to facilitate the use of biomass would also seem to fall within this category of other major works and so to be intended not to be caught by the EPS, which is consistent with what the White Paper suggested.

Objectives

To prevent unabated new build coal plant whilst allowing for demonstration of all CCS technologies.

To complement the regulatory carbon capture ready requirements.

Outstanding Issues

The provisions of the regulations and the policy for issuing orders, including the following:

– The detailed calculations for determining which emissions are attributable to the use of fossil fuel.

– The terms on which the EPS could be applied to existing plant (other than for replacement of a main boiler).

– The terms of the exception for heat from combined heat and power plant.

– Shaping the scope of the additional flexibility to deviate from the EPS to maintain energy security.

– The details of the enforcement regime.

Capacity Mechanism

Updated Proposal

Further analysis and consultation will be carried out on the detailed design of the Capacity Mechanism.

The Energy Bill contains enabling provisions allowing the Secretary of State to make regulations for the purposes of the Capacity Mechanism (the first set of which regulations will require an affirmative resolution of each House of Parliament).

The current proposals for the high-level design of the Capacity Mechanism are set out in Annex C to the EMR Overview Document published alongside the Energy Bill and are as follows:

– Trigger – The structure of the Capacity Mechanism would be put in place as early as possible and a decision on whether to trigger the mechanism would be made annually by Ministers.

– Volume of Capacity - Ministers would decide the total amount of capacity needed to ensure security of supply based on forecasts of future peak demand. The Capacity Market will not specifically contract for flexibility.

– Competitive Auction – Capacity as determined by Ministers will be contracted through a competitive central auction, run by the System Operator, carried out around four to five years ahead of the delivery year in question (although this period could be shorter for the first auction if required).

– Further Auction – There could be a secondary auction closer to the delivery year (i) of some of the originally projected required capacity held back from the primary auction to enable it to be auctioned later or (ii) for additional capacity if the most recent supply projections suggest additional capacity will be needed.

– Capacity Agreements – Providers successful in the auction will enter into capacity agreements, committing to provide electricity when needed in the delivery year (in return for a steady capacity payment) or face penalties, the terms of which would include:

  – Pricing – A number of design options are being considered, including "pay as bid" and "descending clock" approaches;

  – Payment Terms – Payment is to be made in the delivery year;

  – Length – A one year contact is being considered for existing capacity, with longer contracts for new capacity;

  – Limits – Possible restrictions on the amount of capacity providers can offer are yet to be determined;

  – Financial support - The financial support required is yet to be determined;

  – Physical backing – The extent of the evidence required for physical backing is yet to be determined.

– Secondary Trading – Capacity agreements would be able to be traded on the secondary market between the initial issuing of capacity agreements through the primary auction and the point of delivery. Any party taking on a capacity agreement through secondary trading would need to demonstrate that they could meet the pre-qualification criteria set out for the primary auction.

– Pre-qualification Requirements – Specific, tailored pre-qualification criteria may be required for different types of capacity such as GB-based generation, interconnected (overseas) capacity and non-generation technologies such as Demand Side Response.

– Delivery Penalties – It is proposed to combine market-based incentives (ie basing penalties on the price in a reference market) with physical checks to ensure capacity is in place.

– Payments – The costs of capacity payments will be shared between electricity suppliers in the delivery year. This could be on the basis of a supplier's peak load in order to provide incentives for suppliers to reduce (and offer their customers price terms to incentivise them to reduce) their share of peak load. Penalty payments received from capacity providers will be returned to suppliers.

The Government is minded to prevent plant that receives an administratively set CfD from participating in the Capacity Mechanism. In the future, when the strike price for CfDs is determined through technology-neutral auctions, the treatment of CfD-funded plants in the Capacity Market may need to be revisited for investors signing CfDs after that point.

Plants which begin construction between May 2012 and the first auction (as well as substantial refurbishment of existing plant) may be treated on the same basis as new plant, to ensure there is no disincentive for plants to be built before a Capacity Mechanism is introduced.

The Capacity Mechanism is intended to be in addition to the existing STOR.

The proposed Capacity Mechanism would apply across Great Britain only because the single electricity market for the island of Ireland already uses a capacity mechanism.

Objectives

To provide an insurance policy against the possibility of future blackouts, for example during periods of low wind and high demand.

The objective of the detailed design work is to design a Capacity Mechanism which:

– enables the provision of adequate reliable capacity in the GB electricity market at minimum cost to consumers;

– minimises unintended consequences and risks, and supports delivery of wider Government objectives; and

– can be implemented to deliver a capacity auction as early as 2014 if required.

Outstanding Issues

Whether RO-funded plants should be eligible to participate in the Capacity Mechanism.

How interconnected capacity will participate in the Capacity Mechanism.

How to set and verify reliable baselines for non-generation technologies.

Penalty model.

Whether penalties should be capped, and if so how.

Interaction with Ofgem's work on cash-out.

Whether the payment structure is multi-party or intermediary based.

Interaction with the procurement of balancing services.

ANNEX 2: *Particular Impacts on generation types*

Type	Electricity Market Reform
Oil	See general discussion above.
Gas	See general discussion above. The Government indicates that the EPS, although set to 2044 at a level that only affects coal, could be tightened in the future (respecting the principle of grandfathering) to a level which could affect future gas plant consented after the date of the change.
Coal	The EPS, designed to prevent new build of unabated coal fired plant, set at an annual limit equivalent to 450g CO2/kWh (at 85% load factor), with provision for an exception for plant in the UK CCS Demonstration Programme or benefiting from European funding for commercial scale CCS or a CfD or Investment Instrument. The EPS will also apply to existing plant which undergoes a significant life extension or upgrade which is currently drafted to refer to replacement of a main boiler (but is intended to exclude upgrades undertaken to comply with EU law, the retrofit of CCS or works undertaken to facilitate the use of biomass). The limit applies to emissions attributable to the use of fossil fuel which should effectively 'zero rate' the emissions from biomass fuel when calculating plant carbon dioxide emissions.
CCS	CCS will be a low carbon technology eligible for a CfD. The Government's initial view is that the CfD length for projects supported under the CCS Commercialisation Programme should be 10 years. It may be appropriate to allow different CfD lengths for different projects, for example distinguishing between a retrofit and a new build. Strike prices for early stage CCS projects will be determined through cost, risk and price discovery processes and negotiation. Different prices may be set for different projects. The Government is also considering providing flexibility to review the strike price at the end of construction and again following a limited period of further testing. For CCS projects selected through the Commercialisation Programme competition, the Government is also minded that the CfD should provide some indexation as a hedge against long-term fuel price variability. The precise arrangements for this indexation are still under consideration, including whether to adjust the strike price or the reference price and the choice of price source. The Government will continue to consider the best arrangements for supporting commercial CCS over the longer term. The EPS contains powers to grant specific exemptions for plant forming part of the UK's CCS Demonstration Programme or benefiting from European funding for commercial-scale CCS projects or a CfD or Investment Instrument. The Government has stated its intention to build additional flexibilities into the EPS to enable coal power stations to temporarily turn off their CCS equipment without being penalised under the EPS in order to supply additional electricity in times of need. The draft Energy Bill contains the ability to make regulations which contain provisions requiring enforcing authorities to comply with directions given by the Secretary of State, which may include directions to treat the emissions limit as modified or suspended for a specified period.
Biomass	The Government intends to 'zero-rate' the emissions from biomass fuel when calculating carbon dioxide emissions for the EPS, which is dealt with by restricting the limit to emissions attributable to the use of fossil fuel. The Government remains minded not to link the CfD strike price to fuel costs for biomass. The lack of a single, established biomass price index and the diversity of feedstocks would make it extremely difficult to calculate a single price to index against and the Government considers that this risk is best managed by generators and taken into account in the calculation of the (administered) CfD strike price. For biomass CfDs, additional tests are likely to be required, for example to verify that the sustainability and carbon content of the fuel used by a biomass plant is in accordance with the basis on which the developer was awarded the CfD.

Carbon Price Support	Other
Reduction in ability to reclaim fuel duty. Rates from 1 April 2013 and 1 April 2014 have been published, as well as indicative rates for 1 April 2015 and 1 April 2016.	
Introduction of charge on gas used to produce electricity. Rates from 1 April 2013 and 1 April 2014 have been published, as well as indicative rates for 1 April 2015 and 1 April 2016. Anti-avoidance provisions in effect from 23 March 2011 with additional anti-forestalling provisions introduced in 2012 Budget.	
Introduction of charge on coal used to produce electricity. Rates from 1 April 2013 and 1 April 2014 have been published, as well as indicative rates for 1 April 2015 and 1 April 2016. Anti-avoidance provisions introduced with effect from 23 March 2011 with additional anti-forestalling provisions introduced in 2012 Budget.	
The Finance Bill 2012 provides for a partial relief for fossil fuels used in CCS plants to reflect the proportion of carbon dioxide captured and disposed of by way of permanent storage. There is a provision for carbon dioxide captured by a generating station which leaks before it is permanently stored not to affect the station's carbon capture percentage where the leak did not occur within the grounds of the station or on any other land under the control of, or from any pipeline, facility or installation maintained by, the operator of the station or a person connected to the operator.	The 2011 Budget announced that the Government will not proceed with the CCS levy, but will instead fund CCS demonstration projects from general taxation.
	Sustainability criteria will need to be met from April 2013. The Government launched the UK Bioenergy Strategy on 26 April 2012.

Type	Electricity Market Reform
CHP	The EPS regulations may provide that emissions attributable to the supply of heat from CHP plant are not attributable to the use of fossil fuel. The proposal is to apply a discount of the Qualifying Heat Output multiplied by the emission intensity of a 90% efficient gas boiler. Under this approach, plant which does not hold a CHPQA certificate would not be able to discount its emissions. The Government recognises that large-scale fossil fuel CHP plants that export electricity to the grid will face challenges following the removal of their exemption from the Climate Change Levy. The evidence for future support for fossil fuel CHP is currently being assessed, by considering the barriers and market failures facing fossil fuel CHP, and appropriate policy options for addressing these, including through EMR. The Government will continue to work with industry, including the Distributed Energy Contact Group and the CHP Association (CHPA), as thinking is developed on this issue.
Waste	The definition of fossil fuel for the purposes of the EPS is coal, lignite, peat, natural gas, crude liquid petroleum, bitumen and any substance produced directly or indirectly from them for use as a fuel. The Government states that this definition is not intended to capture waste which includes materials manufactured from fossil fuel sources if they have not been produced for use as a fuel. This should mean that the EPS does not apply to EfW plant.
Renewables Generally	RO will remain open for projects accredited by 31 March 2017. There will be some limited grace periods for generation which was due to accredit on or before 31 March 2017 but was delayed through no fault of its own, by either a change in grid connection date instigated by the transmission or distribution operator, or a delay in the agreed installation of radar, but this generation will remain subject to the 31 March 2037 end date for the RO. Generation not already accredited when CfD is introduced, which is expected to be April 2014 for Great Britain but not earlier than 2016 for Northern Ireland, will have a choice between RO and CfD until 31 March 2017. The Government's initial view is that the CfD length for renewables should be 15 years and the CfD should be awarded through allocation rounds run every six months. In terms of setting the strike price, the Government's proposal is that: Stage 1 (to 2017) – the initial process will be similar to that used for the most recent RO Banding Review, giving visibility of prices for a five-year period to enable planning. Stage 2 (2017-2020s) – as technologies and the market begin to mature, the Government intends to begin to move to a competitive price discovery for specific technologies. For renewable technologies deploying after 2020, it is expected this may begin as soon as 2017. In the initial Stage, the Secretary of State will make a decision on the strike prices. It is proposed that five years of strike prices for renewables will be published in the delivery plan in late 2013 (i.e. from the start of the CfD regime in 2014 until 2018). Earlier visibility will be provided through indicative prices in the draft delivery plan, published in mid 2013, to allow developers to prepare their investment plans accordingly. Much of the same data used in the RO Banding Review will be used to ensure consistency between the two schemes, but adjustments will be made, where appropriate, to reflect the different nature of the CfD mechanism, for example adjusting analysis to account for the lower cost of capital available under the CfD. The proposal for the reference price for intermittent generation is the Hourly Day Ahead Auction Price for the GB Zone (as established under NWE Market Coupling). For baseload, the proposal is Year Ahead, price source to be determined. The Government is minded to pay under the CfD on the basis of metered output unless the price in the reference market is negative, in which case to pay on a measure of availability. Risk of greater exposure to higher cash-out prices for intermittent generation.

Carbon Price Support	Other
The Finance Bill 2012 provides for the Treasury to make regulations to exempt supplies of gas and coal to CHP stations for the part of the supply not referable to the production of electricity, subject to state aid approval. Removal of the exemption from CCL on indirect supplies of electricity made by CHP generators will come into effect from 1 April 2013.	The Government aims to publish a response to the RO Banding Review by Spring 2012 and legislate in Summer 2012. In the October 2011 consultation, the Government stated that it proposes to end the RO CHP uplift for new stations accredited on or after 1 April 2015. New accreditations or additional capacity added between 1 April 2013 and 31 March 2015 would have a choice between power-only RO bands plus the Renewable Heat Incentive (RHI) or the RO CHP band. From 1 April 2015, new accreditations and new additional capacity will not be eligible for the CHP uplift, but may receive support for their electricity output from the RO and for their heat output from the RHI. Any technologies or energy sources currently eligible to receive the CHP uplift which are not eligible for the RHI on 1 April 2015 will remain eligible to apply to receive the CHP uplift until 2017. The Government is proposing to reduce support for energy from waste (EfW) with CHP. The Government proposes setting RO support at 0.5 ROCs for new accreditations (and additional capacity added) in the banding review period. The Government also proposes that any EfW with CHP accredited under the RO would continue to be ineligible for support under the RHI. Existing and new EfW with CHP plant which choose not to accredit under the RO may be eligible to receive support from the RHI.
	Waste, landfill gas or sewage gas will not need to meet sustainability criteria and will not need to report on sustainability. In the October 2011 consultation on the RO Banding Review, the Government proposed that a new advanced ACT band would cover electricity generated by an internal combustion engine from a gaseous or liquid fuel produced from waste or biomass by means of gasification or pyrolysis. It would also cover electricity generated by an internal combustion engine from a liquid fuel produced from syngas. See CHP above for EfW plant with CHP.
	The Government aims to publish a response to the RO Banding Review consultation by Spring 2012 and legislate in Summer 2012. Changes to take effect from 1 April 2013 for most technologies and 2014 for offshore wind. For onshore wind, the Government proposes to set the band at 0.9 ROCs/MWh for new accreditations and additional capacity added in the banding review period. The National Planning Policy Framework was published on 27 March 2012, condensing the framework and holding a central presumption in favour of sustainable development. On 2 August 2011, the Government published an updated Memorandum of Understanding on Wind Turbines and Aviation Radar Mitigation issues, shifting the focus from research to deployment of the solutions identified in the Aviation Plan.

Type	Electricity Market Reform
Offshore Wind	See also Renewables Generally above. Generating stations accredited under the RO will be able to register some or all of their remaining unregistered turbines that constitute the consented capacity of the generating station under the RO by 31 March 2017 in order to receive support under the RO mechanism for those turbines. The 20-year support period will begin from the date of registration. Generating stations accredited under the RO will be able to sign a CfD for any turbines that are not registered under the RO on 1 April 2017.
Nuclear	See general discussion above. For nuclear projects, the level of the strike price will be determined through an administrative price-setting process until the conditions are in place to move to competitive forms of price discovery. To begin with, this process will involve negotiation with developers on a project-by-project basis. The Government has yet to form a firm view on the optimal CfD length for nuclear plants, and considers that it is prudent to form a view following the Financial Investment Decision Enabling process. This may include a decision as to whether to establish a standard CfD length for nuclear as a technology, or alternatively vary CfD length by project. The proposal for the reference price for baseload generation is Year Ahead, price source to be determined.
Interconnectors/ "Supergrid"	The Government's preference is for UK-wide strike prices, but in the event that relevant differences in market conditions require it, CfD strike prices in Northern Ireland may be slightly different to those in the rest of Great Britain to reflect those differences. The Government envisages that the Capacity Mechanism could allow non-GB generation (for example a generator based in France) to participate.

Carbon Price Support	Other
	The RO Banding Review for offshore wind is to take effect from 1 April 2014. Under the RO Banding Review, the Government proposed to set the band for offshore wind at 2 ROCs/MWh for new accreditations (and additional capacity added) in 2014/15. The Government proposes to bring support levels down to 1.9 ROCs for generating stations accrediting (and additional capacity added) during 2015/16, and to 1.8 ROCs for generating stations accrediting (and additional capacity added) during 2016/17. The Government also stated that it intended to maintain its policy of allowing phasing for offshore wind-generating stations so that the relevant band applicable at the time of accreditation of the generating station shall apply to all subsequent phases of turbines forming part of the capacity of the generating station as accredited. Each phase will be eligible for a maximum of 20 years support, subject to registration of the phase before 1 April 2017 and the 2037 end date of the RO. A Ministerial Statement in July 2011 partly addressed concerns about the ability to terminate Crown Estate leases for oil and gas development by confirming existing policy that termination should not occur without appropriate compensation. The Government had committed to working with offshore oil and gas industries to set out guidance on how to resolve conflicts before the end of 2011 but no guidance has yet been announced.
	The draft Energy Bill contains provisions to create the Office of Nuclear Regulation as a statutory body.
There will be no change to the tax treatment of imported electricity in line with EU excise and energy tax directives. Electricity exported from the UK will continue to be exempt from CCL, but fossil fuels used to generate electricity which is then exported will be liable to tax. Likely to result in increased incentive for importing electricity and reduced incentive to export electricity. The Government will monitor the impact of the Carbon Price Support in Northern Ireland, recognising the interaction with the island of Ireland Single Energy Market.	Ofgem are currently inviting stakeholder views on their preliminary conclusions and their progress to date in developing a GB regulated investment regime. The ISLES project is assessing the feasibility of creating an offshore interconnected transmission network. Ofgem launched a consultation on Integrated Transmission Planning and Regulation (ITPR) in March 2012 to consider what is needed with respect to system planning to deliver the future integrated transmission system onshore, offshore and cross-border.

ANNEX 3: *Proposed Timetable*

Initiative	Current Position	Next Steps
Carbon Price Support Mechanism	Main provisions introduced in the 2011 Finance Act. Finance Bill 2012 awaiting committee stage. Draft secondary legislation published.	Finalise Finance Bill 2012. Finalise secondary legislation. Obtain state aid approval for CHP exemption.
Electricity Market Reform (EMR)	Draft Energy Bill published on 22 May 2012 for consultation and enquiry by Commons Energy and Climate Change Committee.	Aim to publish the Operational Framework, giving full details of how CfDs will work, in Autumn 2012. Aim to publish bill in Autumn 2012 and to have legislation in place by Summer 2013. Secondary legislation to be issued for consultation. State aid issues to be discussed with EU Commission. Energy design choices for the Capacity Mechanism (including the preferred penalty regime) to be published at the end of 2012, with design completed by March 2013 and formal consultation on the detailed design later in 2013.
Liquidity Review	Ofgem issued a further consultation on 22 February 2012, which closed on 8 May 2012.	Ofgem anticipates publishing its favoured proposals in Summer 2012 followed by a statutory consultation in Autumn 2012.
Impact of EMR on RO	The draft Energy Bill 2012 enables the Secretary of State to make a certificate purchase order for the Fixed ROC mechanism.	See also EMR above. The Government will consult in early 2013 on draft regulations to enable the time limited one-off choice between the RO and the CfD. The regulations will be laid as secondary legislation before Parliament in early 2014 and are likely to come into force on 1 April 2014. The Government will consult further on the Fixed ROC proposals in Q3 2014. The Government intends to lay the Fixed ROC regulations as secondary legislation in Parliament in Q1 2015, to come into force in Q2 2015.
Banding Review	DECC consultation on the banding review was issued on 20 October 2011 and closed on 12 January 2012.	Government response to consultation expected in Spring 2012.
Green Investment Bank (GIB)	The Government committed in the 2011 Budget to fund the GIB with £3bn over the period to 2015. The GIB was incorporated in May 2012 as a public company called UK Green Investment Bank plc, but does not yet have approvals to become operational. BIS's UK Green Investments team (UKGI) will make direct investments before the GIB is operational. £80m has been committed to the small-scale waste infrastructure sector. A further £100m has been made available for the non-domestic energy efficiency sector.	State aid approval expected at end of 2012. Finalise legislation.
Gas Strategy	On 2 May 2012 DECC launched a call for evidence to inform gas generation strategy, open until 28 June 2012.	DECC to publish a strategy on the role of gas in the electricity market in Autumn 2012.

	Proposed Method of Implementation	Expected Implementation Date
	2011 Finance Act and 2012 Finance Bill plus secondary legislation.	1 April 2013.
	Draft Energy Bill 2012 and various secondary legislation. State aid approvals to be checked.	CfDs to be available from mid 2014 (but in Northern Ireland not earlier than 2016). EPS intended to apply to any new fossil fuel plant granted development consent after Q1 2014. Capacity Mechanism could have first auction as early as Autumn 2014 for a delivery year of Winter 2018-19 (or as early as Winter 2015-16 if necessary).
	Licence Modification.	Late 2012.
	Energy Bill 2012. Secondary legislation.	Accreditation under RO to be available until 31 March 2017. RO to continue until 2037 but from 1 April 2017 will not be open to new accreditation and will be 'vintaged'. Fixed ROC to apply from 1 April 2027 to 31 March 2037, when RO will close.
	Regulations in Summer 2012.	New bands to be brought into force 1 April 2013 but April 2014 for offshore wind.
	Enterprise and Regulatory Reform Bill.	The GIB will evolve over three phases: – From 2012 to state aid approval, the Government will make direct state aid compliant investments until these investments can be transferred to the GIB. – Establishment of the GIB as a standalone operating institution following state aid approval (expected Autumn 2012). – From 2015 the GIB will be given full borrowing powers, subject to public sector debt falling as a percentage of GDP and further state aid approval being granted.

Key contacts

Key contacts

If you require further information on any of the matters raised in this document, please contact any of the following:

Gareth Price
Global Co-Head of Energy
Tel +44 (0)20 3088 2740
gareth.price@allenovery.com

Sheila Connell
Partner – Energy
Tel +44 (0)20 3088 3303
sheila.connell@allenovery.com

Chris Andrew
Partner – Energy
Tel +44 (0)20 3088 2684
chris.andrew@allenovery.com

Mark Walker
Partner – Energy
Tel +44 (0)20 3088 3316
mark.walker@allenovery.com

Mark Friend
Partner – Competition and Regulatory
Tel +44 (0)20 3088 2440
mark.friend@allenovery.com

Prof Dr Leigh Hancher
is of Counsel in the Amsterdam Office
Tel +31 20 674 1122
leigh.hancher@allenovery.com

FOR MORE INFORMATION, PLEASE CONTACT:

London

Allen & Overy LLP
One Bishops Square
London
E1 6AD
United Kingdom

Tel +44 20 3088 0000
Fax +44 20 3088 0088

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