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UK Electricity Market Reform:

EMR Update - Capacity Market and Strike Prices

July 2013

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Contents

Introduction

On 27 June 2013, DECC published a further series of documents in relation to Electricity Market Reform. These documents include strike prices for many (but not all) relevant technologies, policy statements in relation to certain of the "hot topics" arising out of the previously published heads of terms for the Contract for Differences and important emerging detail on the design of the capacity market.

We now look set to have a market for power which is fragmented along technological lines, for example:

(1) Gas refurbishment/conversion to OCGT/new build on the basis of a capacity market.

(2) Wind and large scale solar on the basis of the rump of the RO schemes or generic CfDs.

(3) Small scale solar on the basis of a feed in tariff.

(4) CCS on the basis of a centralised support programme and bespoke CfD.

(5) The support for dedicated biomass without CHP remains unclear.

(6) Biomass with CHP and biomass conversion on the basis of the rump of the RO schemes or generic CfDs.

(7) Nuclear on the basis of a bespoke CfD.

But the intervention to encourage investment now goes beyond reforming the revenue side of the power market and extends to the funding side of the market with the well publicised support from the UK Green Investment Bank plc (in both a debt and equity capacity) and from Infrastructure UK in the form of debt guarantees for both new build and secondary market transactions. Many market participants are now concerned that the layers of intervention could produce unintended and unanticipated market distortions which may require further and deeper intervention to correct. This could become an endless loop. For example, if the capacity market operates to reduce wholesale market prices in relevant markets then the Levy Control Framework (**LCF**) will be used up more quickly, blunting the effort to invest in low carbon, CfD-supported generation. If the capacity market does not reduce wholesale market prices then are price takers in the capacity market being over-rewarded? Perhaps this is intentional if the shift towards gas as a shoulder fuel through to 2030 (as highlighted in our previous bulletin) is now a committed direction of travel as part of a reweighting of the trilemma towards security of supply and affordability and away from decarbonisation (at least in the very short term).

It is therefore no surprise that European authorities are taking a keen interest in power market developments (not just in the UK) as the type of market interventions contemplated in the UK and elsewhere have the ability to impede the development of a single European market for energy. The guidance to be issued later this year by the EC in relation to capacity markets and support for renewables (which will be followed by new State aid guidelines for low carbon technologies) and any shift in the position that security of supply (the prime driver of capacity markets) is a national rather than an EU issue, all have the ability to disrupt the UK plans. No doubt Ofgem's Future Trading Arrangements forum will also have an influence on how and when the wholesale market is re-established as the driver for investments in place of increased national intervention.

This all serves to emphasise the importance of protection for investors against "change" which, as you will see from this bulletin, remains a work in progress in the terms of the Contract for Differences and appears entirely lacking in the design of the UK capacity market. The duration of the generic contracts for difference and Capacity Agreements also potentially leave investors in relevant technologies without change protection (beyond wholesale price exposure) for significant parts of the useful life of the relevant assets. It is to be seen whether this will be an impediment to deployment or whether it in fact increases the levelised cost to the consumer by forcing a faster rate of amortisation of investment than the useful life of the relevant assets requires.

The Energy Bill is continuing its Parliamentary passage, but it merely sets out a framework for EMR. With the publication of the detailed design of the capacity market and of draft renewables strike prices, the commercial parameters which will shape the evolution of the UK electricity market are becoming clearer.

The capacity market seems to be a potentially expensive way of bringing forward the additional capacity required to maintain security of supply in the new market. However if, notwithstanding ever-increasing levels of intervention, a market-based approach is sought, and the risks of perverse incentives and of yet further delays through aggravating State aid concerns are to be avoided, there seem few good options. Much seems to depend on whether capacity market payments, funded through the suppliers and ultimately the consumer, are materially offset by consequently lower wholesale prices.

Subsequent to these publications, DECC has made its contribution to the debate on the EU 2030 framework for climate and energy policies. While ambitious carbon reduction policies continue to be supported (particularly in the context of a global comprehensive agreement), the UK opposes a 2030 renewable energy target on efficiency grounds. This is also further circumstantial evidence of a revision of the role of gas as referred to above.

While the first capacity auctions will run in 2014, this will be for delivery of capacity in 2018/2019 (although earlier capacity contributions may be enabled through demand side reduction or response measures). This will not alleviate the Ofgem-anticipated accelerated tightening of capacity margins in the interim, and we question how much potential new build capacity will be in a position to participate in the first auction. (Indeed we feel there may be further work to do aligning the development and auction cycles to allow new build capacity fully to participate.) Ofgem's consultation on additional balancing services (and in particular Demand Side Balancing Reserve) for the mid-decade narrowing of capacity margins is therefore highly relevant to the debate on capacity market design. We would also note that some further thought on incentivising 'clustering' of capacity additions into one auction year may have significant affordability benefits. (Similarly a longer term contract for new capacity should have a collateral benefit of reducing the auction prices paid to other plant.)

We also suspect that changes may be needed for the trading modalities of the gas market to be aligned with the requirements of a capacity market independent generator looking to generate in periods of system stress under the current capacity market design.

While progress is being made, there remain a number of features of the capacity market where greater visibility is required:

– The legal form of Capacity Agreements seems ambiguous. It is to be hoped that lessons from the challenge of producing a robust CfD which avoids unnecessary complexity and has the certainty of a private contract, will not be ignored.

– There appears to be no reference to "change" protection being included in a Capacity Agreement.

– The approach to calculating de-rated capacity seems not to be settled. We are concerned that this reflects continuing tension between the roles of the capacity market in providing security of supply and a degree of back-up to intermittent generation.

– We believe that further explanation of choosing between types of capacity and the corresponding terms of Capacity Agreements, would be helpful in demonstrating that the arrangements are efficient in terms of levelised costs.

The draft strike prices for renewable CfDs have been published for consultation, together with the LCF envelope out to 2021. DECC intends the strike prices to be consistent with Renewables Obligation (**RO**) levels of support (taking into account that for renewables CfDs will generally last 15 years rather than the 20 years of the RO and the lower cost of capital EMR is intended to promote); however even on the basis of reducing technology costs, it is not clear the deployment ambition of the Renewables Roadmap is being maintained.

There is also increasing clarity on certain terms of the CfD and the Supplier Obligation which underpins payments thereunder. DECC has responded to some concerns, but we believe there is further work to be done to provide the levels of change protection promised at the outset of EMR and to ensure that low carbon generators can look through to the aggregate credit of the suppliers (and thus the consumer). For example, while the capacity market funding obligations of suppliers are apparently to be mutualised, there is no requirement (but rather an option) for this to be the case for the Supplier Obligation in relation to CfDs.

In relation to other aspects of EMR we have asked the base question:

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?

Looking at this question in the context of the capacity market it is too early to say. Much more detail will be required to determine this. At this stage, all one can really say is that the risk profile of an investment in a capacity market supported investment (whether generation or demand side reduction/response) appears very different to that of a CfD supported investment. Is this because different types of investor are desired?

As the announcements last week are really an interim measure, the majority of the items noted as "Work in Progress" in our previous bulletin remain outstanding – although progress is being made across the various expert groups. Copies of this bulletin together with our previous publications on EMR and the various underlying documents are available at: http://www.allenovery.com/UK-Electricity-Market-Reform.

Finally, it seems clear that, in the new normal, Ofgem's role in policing licence conditions such as the potential 'Secure and Promote' and the 'Market Abuse' conditions will be crucial. Intervention produces rules and rules require a policeman.

Please do get in touch with any of us or your usual Allen & Overy contact if there are further matters you wish to discuss.

Energy Bill Update

The Energy Bill completed its first journey through the House of Commons on 4 June 2013. It is now at the Committee Stage in the House of Lords, during which every clause of the Bill has to be agreed to and votes on amendments can take place. The Government remains committed to completing the Parliamentary process this year.

Various amendments have been made to the Bill since it was first introduced into the House of Commons on 30 November 2012. These include changes to the capacity market regime, including the power of the Secretary of State to make capacity market rules, and changes to the rules on the CfD Counterparty, such as restrictions on the ability of the Secretary of State to designate more than one CfD Counterparty.

There was keen debate, during the Third Reading of the Bill in the House of Commons, on the issue of the setting of a decarbonisation target for the power generation sector. As anticipated in our December 2012 EMR bulletin on The Energy Bill, the Government introduced an amendment into the original form of the Energy Bill to include a power to set (in secondary legislation) a decarbonisation target range for the power sector for 2030, subject to the proviso that this power could not be exercised until after the fifth Carbon Budget (covering the period 2028-2032) had been set in 2016.

A further amendment was proposed which would have required the Secretary of State to set a 2030 decarbonisation target by 1 April 2014 with the aim of providing increased certainty for investors in renewables and low-carbon energy. One of the main arguments in support of this further amendment was that it would provide clarity for investors on the direction of energy policy in the future. The government has so far resisted this further amendment on the grounds that the over-arching carbon budgets already provide investors with sufficient certainty. During the Third Reading in the House of Commons, this amendment was narrowly rejected. It has now been re-tabled in the Committee Stage of the House of Lords, together with yet another alternative amendment requiring a target to be set by 31 December 2016. In addition, a further alternative amendment has been proposed to provide that the earliest year in relation to which a decarbonisation target may be set is 2020, rather than 2030, and that thereafter the target may be set at five year intervals. It remains to be seen whether an amendment is approved in the House of Lords and, if it is, in what form. It should be noted that any amendment voted for by the House of Lords must return to the House of Commons to be approved.

The discussion around a decarbonisation target of course plays into questions of affordability, security of supply, decarbonisation and industrial competitiveness. These issues were clearly to the fore in the Government's Gas Generation Strategy published in December 2012. DECC notes that the amount of gas capacity we will need to call on at times of peak demand will remain high, with potentially significant amounts of new gas generating capacity required by 2030. The following table from the Gas Generation Strategy demonstrates the expected impact on new gas generation of alternative decarbonisation trajectories and emphasises how setting a statutory decarbonisation target could cut across answering such questions in a flexible way which responds to changing circumstances. The lack of such a requirement does, however, emphasise the need for some comfort around "change" for investors. An alternative approach could be to provide for appropriate protection in the CfD and Capacity Agreement together with greater visibility on the future LCF levels and full information on what proportion is left (assuming that all potential CfDs then under discussion are entered into).

	100gCo2/KWh	200gCo2/KWh	50gCo2/KWh
New CCGT Capacity, GW (2012-2030)	26	37	19
Total CCGT Capacity, GW (2030)	37	49	31
CCGT Generation, TWh (2030); % of total generation	89 22%	181 45%	41 10%
Average CCGT load factor (2030)	27%	43%	15%

Source: DECC Analysis, 2012

Amendments introduced by the Government continue to show some willingness to seek to address concerns raised in relation to the Bill. The Energy Bill now requires the Secretary of State to provide that suppliers must make payments to a CfD Counterparty so that the counterparty can, in turn, make payments to generators under CfD contracts. (This is referred to as the "Supplier Obligation".) Following the Committee Stage in the House of Commons, an amendment to the Supplier Obligation was included to require there to be a duty on a CfD Counterparty in relation to the collection of these sums from suppliers, seeking to reduce the risk that a CfD Counterparty, protected by "pay-when-paid" provisions as against generators, does not exercise its rights against suppliers.

There have also been amendments introduced in relation to, inter alia, the circumstances in which there could be multiple CfD Counterparties and the structuring of the Supplier Obligation (see "CfD Update – CfD Counterparty/SO" below).

In relation to the capacity market, the amendments to the Energy Bill include the ability for the Secretary of State to make capacity market rules (as well as the Secretary of State having the power to make regulations), but those rules must be laid as a draft before Parliament before being made. Electricity capacity regulations may also make provisions to confer on the Gas and Electricity Markets Authority the power to make capacity market rules, which would need to be laid before Parliament once made.

Other amendments are to include provisions for special treatment for electricity demand reduction, in contemplation of a pilot scheme.

The provisions of the Energy Bill concerning the role of the settlement body now include wording to facilitate its role in relation to calculating amounts owed, but no longer include the suggestion that a Capacity Agreement may create direct payment obligations between electricity suppliers and capacity providers.

The Energy Bill remains, insofar as it relates to EMR, essentially an enabling framework – a mannequin on which (hopefully attractive) clothes may be presented. EMR will be implemented through regulations. Please see ("Next Steps") below in relation to the process in this regard.

Next Steps

While the draft CfD strike prices for most types of renewables have now been announced (see "CfD Update" below), DECC have confirmed they will still publish the draft EMR Delivery Plan for consultation in the second half of July. This will include information on the methodology and analysis behind the draft CfD strike prices, as well as the proposed draft reliability standard which will inform the level of capacity to contract through the capacity market (please see "Capacity Market Update" below). The policy on whether and how dedicated biomass which is not CHP will be supported under CfDs will also be confirmed as part of the draft EMR Delivery Plan. (We note that such capacity is prospectively subject to the "supplier cap" under the RO.)

There will be a ten-week consultation (including in respect of the draft strike prices) which will begin following the publication of the draft EMR Delivery Plan. DECC have announced that they will engage with stakeholders through a number of workshops to be held over the summer during the consultation period – details of which are to be published on DECC's website. These interactive sessions are designed to explain the way DECC have arrived at their proposed strike prices in more detail and provide an opportunity for stakeholders to ask questions before finalising any written responses they may wish to make to the consultation.

Final strike prices will be set in December 2013 (subject to State aid approval and Royal Assent of the Energy Bill). DECC will also confirm the level of the reliability standard for the capacity market at this point (as part of the first EMR Delivery Plan). Please see Annex 1 for details of areas of further work in relation to the capacity market.

Later this month, alongside the draft EMR Delivery Plan, DECC also intend to publish a consultation on the transition arrangements from the RO to CfDs. This would be expected to clarify how DECC is responding to requests by certain renewable energy investors to bring forward the Fixed ROC mechanism.

DECC state that they will publish further detail on the CfD contract terms in early August, including drafting for all the key contract terms which go to the value of the CfD contract. DECC intend to engage with interested stakeholders on the detailed drafting of the CfD contract, with two events in August to seek views. The final contract drafting will be published in December alongside the final strike prices, and implemented through regulations laid before Parliament in 2014. Government has emphasised that for renewables there will be no scope to vary or negotiate the standard terms of the applicable CfD. At least, by implication therefore, the terms of the CfD will not be final for other technologies.

At the same time as publishing the draft CfD terms, DECC will set out more detail on the allocation of CfDs, and the Government response to the call for evidence on the CfD Supplier Obligation.

DECC will consult on the secondary legislation for the implementation of EMR (including the capacity market, the Supplier Obligation and related amendments to industry codes and licences) from October this year.

Overall DECC regards the EMR programme as on track to be implemented in 2014, with the first CfDs under the generic regime expected to be signed in the second half of 2014 following implementation of the secondary legislation, and the first capacity auction in 2014 (for capacity in 2018/2019).

The above are subject to State aid approval. The Government has advised it is in discussion with the European Commission to secure this. Please see further "State aid Update" below.

Capacity Market Update

Ofgem 2013 Capacity Assessment

On 27 June 2013, Ofgem published its 2013 Capacity Assessments, prompting a short spate of apocalyptic media headlines.

Ofgem's report shows that over the past year the supply side outlook has deteriorated (albeit there has been a significant fall in demand). More than 2GW of installed capacity has been withdrawn with further withdrawals expected, while continuing uncertainty limits investment in conventional generators.

The new reference scenario shows capacity margins decreasing faster than expected last year. Small reductions in margins for these levels would result in a significant increase in the risks to security of supply. The probability of a large shortfall in 2015/2016 requiring the controlled disconnection of customers is estimated by Ofgem as increasing from around 1 in 47 years in Winter 2013/2014 to 1 in 12 years in 2015/2016 (and to around 1 in 4 years if demand reductions fail to materialise).

The following charts summarise Ofgem's view of capacity margins and loss of load expectation (**LOLE**).

Fig. 1 – De-rated capacity margins

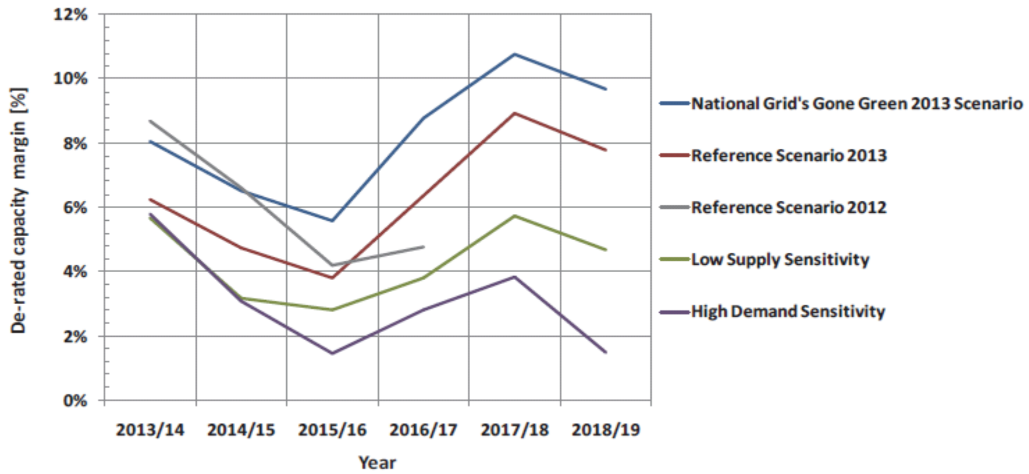
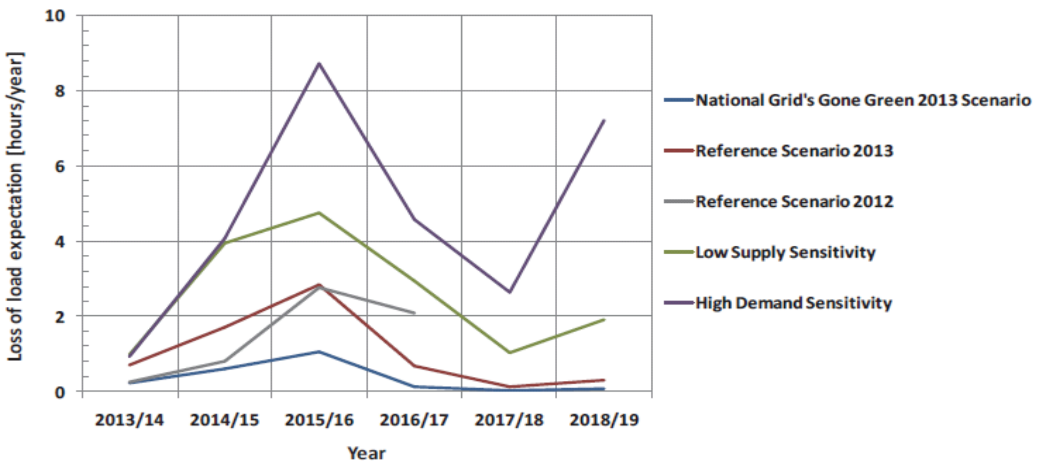


Fig. 2 – Loss of load expectation



Source: Ofgem

Concurrently, Ofgem published an open letter on 27 June 2013, and National Grid (**NGET**) launched an informal consultation on the potential requirement for new balancing services by NGET to support the uncertain mid-decade security supply outlook. These are Demand Side Balancing Reserve (**DSBR**) and Supplemental Balancing Reserve (**SBR**), and are aimed at providing additional reserves to bolster security of supply prior to taking emergency actions. These are separate from the capacity market as described below.

The two mechanisms are intended to have minimal impact on the efficient operation of the electricity market while providing additional safeguards that could be deployed if capacity margins become a concern. The proposed new balancing services would be subject to Ofgem approval, and only procured if there is a requirement and economic justification to do so. The consultation is open to responses until Friday 26 July 2013, and both DSBR and SBR are hoped to hold tenders in 2013/14 for services to be provided in Winter 2014/15 and 2015/16.

DSBR is designed to incentivise reduction in demand by users at peak times (on non-holiday weekdays November-February), increase grid contributions from embedded generation and bolster the provision of DSR services ahead of their participation in the capacity market. The aim is to facilitate much wider participation by the demand side than before. The DSBR is made up of two products, both of which are aimed at anyone who is able to establish a demand reduction capability at a site with half-hourly settlement metering, with a utilisation price ranging from £500/MWh to £15000/MWh (subject to the value of lost load) and which are not BM units subject to the requirement under the Grid Code to submit Physical Notifications. Providers would need to be able to respond within two hours of instruction.

Under Product One providers are incentivised by a set up payment followed by additional utilisation payments. The service would be called upon in order of economic precedence with other balancing services, and hence used relatively infrequently. Product Two works in exactly the same way but there is no set up payment, and thus providers only receive payment when delivery is actually called.

The SBR is aimed at medium sized generators and larger demand reducers, it is designed for plant that would not otherwise participate in the wholesale energy market arrangements (i.e. would otherwise be mothballed or decommissioned). Irrespective of utilisation price, this mechanism would only be used as an absolute last resort, in an emergency situation after all other balancing services had been exhausted. Providers would be paid a capability fee, utilisation fee and warming costs if necessary. All SBR participants would need to be available to respond whenever required by NGET and would face non delivery charges if unable to respond. Plant providing Supplemental Balancing Reserve would be prohibited from participating in the markets for energy and balancing services and would not be permitted to generate or demand reduce other than in accordance with such NGET despatch instructions.

In addition to the above consultation Ofgem had previously launched the Electricity Balancing Significant Code Review (**EBSCR**) of the electricity cash-out arrangements, which is still ongoing although final policy decisions are due in early 2014. It is anticipated that implementation will occur from early 2015. The interaction of the capacity market penalty regime and this Significant Code Review is to be kept under review.

Whilst it might be expected that narrowing margins would encourage the market to maximise the availability of plant by, for instance, delaying plant closure and bringing mothballed generation plant back into service, the reasons that have motivated the Government's EMR and Ofgem's EBSCR give cause for concern that this may not happen to the extent required.

Capacity Market – Background

Two documents have recently been published by DECC providing updates to the capacity market design and structure, namely, the Detailed Design Proposals and capacity market Strawman, v.11 (the **Strawman**). (The latter is a working document that provides a technical description of how the proposed GB capacity market might work in practice; it is not a description of agreed Government policy.)

The proposals set out in the Detailed Design Proposals are to form the basis for the development of detailed implementing secondary legislation. The proposals and draft legislation to implement them will be consulted on in October with the aim that, subject to State aid clearance, legislation can be in force by this time next year, to enable the first capacity auction to be run in 2014. The first delivery year for the capacity market is to be Winter 2018/2019.

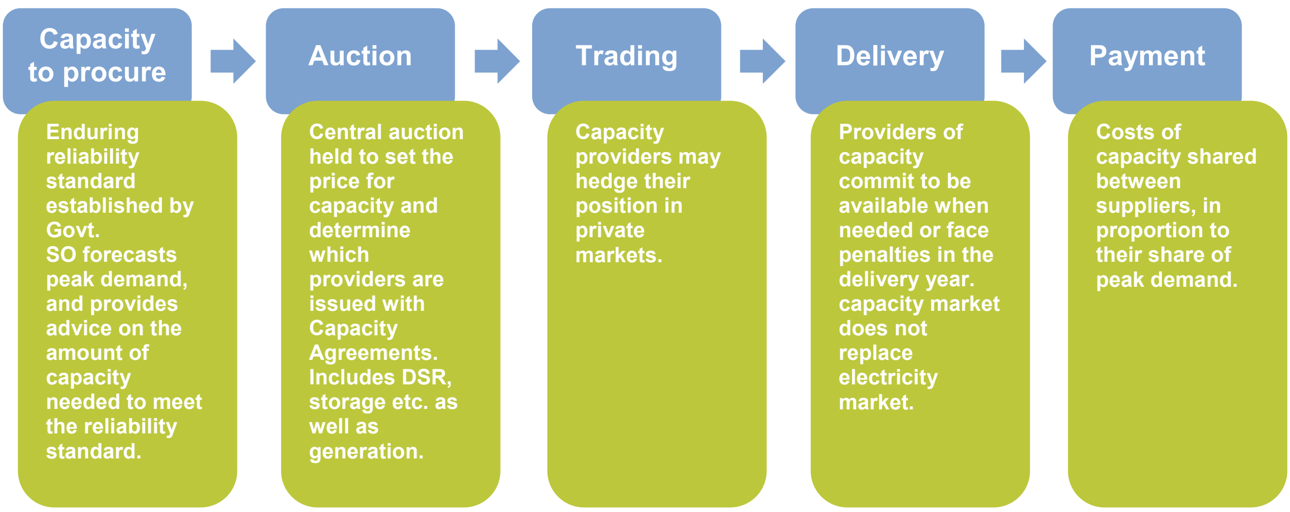
However, there is the prospect of auctions for an earlier delivery period specifically for Demand Side Response (**DSR**) (see "Treatment of DSR" below).

The proposals published by DECC are designed to encourage investors by providing certainty through awarding longer Capacity Agreements to new builds and allowing them (within an elevated cap) to set their own bid price (which is likely to result in new builds exerting control over the eventual auction price). In order to provide additional comfort to those looking to invest now, plant that commence construction between May 2012 and the first capacity auction will have the benefit of being treated as 'new' in the auction.

Summary

The principles for the capacity market previously announced and discussed in our December 2012 briefing have not significantly changed, but further detail has been added. The new publications describe the working of the capacity market in five key operational stages as outlined below.

Fig. 3 – Stages of capacity market Operation



Volume of Capacity

In order to enable calculations of the volume of capacity to be procured, the Government intend the Secretary of State to set an enduring 'Reliability Standard' to provide an indication of the desired level of security of supply, taking into account the likely costs of providing that level of supply. The reliability standard (expressed in terms of LOLE) is designed to increase long term investor certainty and minimise the risk of large variations in available capacity at auction (and thus overinflated bids) from one year to the next. The amount of capacity available for Capacity Agreements in an auction is the total capacity required minus capacity on the system that is not able to participate in the capacity market (e.g. those ineligible to participate or opting out). The Government has also published details of their intention to set out the enduring methodology for determining a demand curve and the auction price cap. The demand curve will be determined each year allows a trade-off between reliability and cost and is intended to provide a method to reduce gaming and reduce opportunities for participants to push up the price through market power (see below).

Fig. 4 – Illustrative demand curve

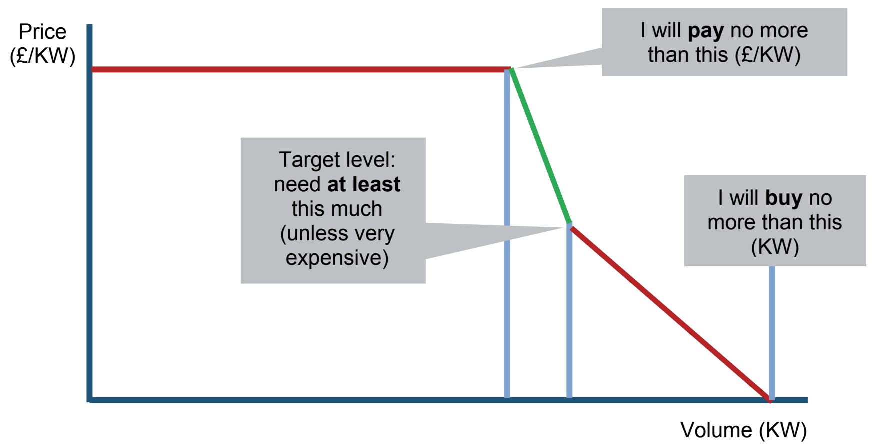
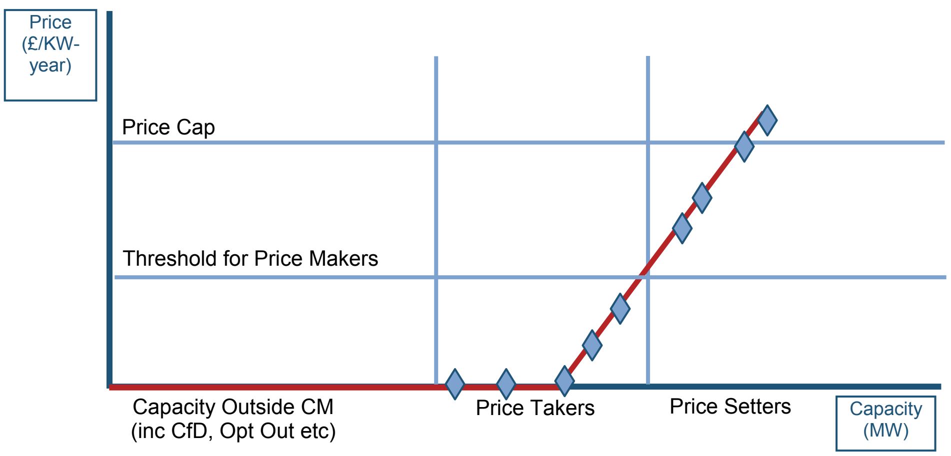


Fig. 5 – Illustrative supply curve



Eligibility

The capacity market has been designed to be technology neutral, and all types of capacity are able to participate with some limited exceptions discussed below.

In these latest publications, the Government retains the position that plant receiving a CfD will be prevented from participating in the capacity market, although there is an indication this may be limited to the period where the levels of support for the CfD are set administratively. The recent design proposals also confirm that neither RO nor FiT supported renewables will be able to participate in the capacity market; however a question still remains over whether renewable CHP in receipt of the RHI will be eligible to participate in the capacity market.

Specific issues affect co-firing biomass plant – such a plant may at the pre-qualification stage run as a standard co-firing biomass and take on capacity obligations but must have ceased co- firing before the delivery year in order to receive capacity payments. If a plant cannot demonstrate this to the System Operator (**SO**), and does in fact receive RO or CfD payments it will not receive capacity payments and its Capacity Agreement will be terminated. Similarly, if a coal plant takes on capacity obligations but subsequently chooses to co-fire biomass and as a result receives RO or CfD support, it must inform the SO prior to the delivery year, at which point the Capacity Agreement will be terminated. See Annex 2 for a further review of the impacts on each individual industry sector.

The Government remains keen to allow interconnected capacity to participate in the capacity market to increase efficiency and competition, but achieving this whilst maintaining the integrity of the GB capacity market and compatibility with the European internal energy market rules are a barrier at present. As a result it has been decided that interconnected capacity will not be eligible to participate in the first proposed capacity market auction in 2014 but the Government is committed to find a solution to allow this in future auctions.

A 2MW de-minimis threshold applies to small scale generators (although if combined with other small generators they may participate in aggregate), but DSR and small scale capacity will undergo a two stage transitional period to facilitate participation. See further "Treatment of DSR" below.

To address concerns over providers entering the capacity market without sufficient capacity to participate, during pre-qualification (see section "Description of Options for Generators" below) a provider must demonstrate it is eligible to participate. An existing plant must: submit its de-rated capacity, pass a credit check, prove it has previously generated on the system up to its bid level and hold a valid Transmission Entry Capacity. New plant must: submit its de-rated capacity, pass a credit check, produce evidence of a valid Development Control Order and submit plausible construction milestones. In addition, to avoid the risk of providers with Capacity Agreements subsequently being unable to deliver, the SO will have the ability to carry out spot testing on providers who have failed to demonstrate their ability to deliver the level of capacity specified in their Capacity Agreement. Capacity payments will be withheld from any plant which fails a spot test until the plant passes a subsequent test.

Auction and Agreements

The structure of the auction has been clarified. Following a mandatory pre-qualification process, eligible potential capacity providers will be allowed to opt in or out and, subject to certain restrictions, specify if they wish to participate as price 'makers' or price 'takers'. The auction itself will be conducted by way of a reducing clock format, in order to offer greater price discovery for capacity providers. Government suggests that any increased risk of collusion under this approach will be mitigated through measures to enforce competition – such as through the use of the demand curve and the requirement for existing plant (which are not to be the subject of significant refurbishment) to enter the capacity market as price takers. As previously, the proposal is "pay as clear" for both new and existing plant, so that every successful provider (whether a price maker or a price taker) would be paid the clearing price set by the most expensive successful provider that bid into the auction. As explained further below, it seems likely that new plant, as price makers, will set the level of the auction price.

Those plant entitled to be price makers are new plant and plant undertaking a significant refurbishment (and in certain limited circumstances other existing plant) as well as demand side response. Plant which is not entitled to be a price maker can participate as a price taker. Price makers may bid up to the overall auction 'cap' which is set at a multiple of the cost of new entry (**CONE**). Below the cap is a threshold, price takers may freely bid up to this pre-determined threshold. The threshold is not intended to be a perfect reflection of the costs faced by existing plant, rather it is intended to be set at a level such that the majority of existing plant should be willing to participate in the capacity market without being price makers.

Plant which are successful in the auction will be awarded a Capacity Agreement issued by the SO, committing them to provide electricity when needed in the delivery year (in return for a steady payment) and penalising them if they fail to deliver energy at times of system stress (see "Payments and Penalties" below). It is not clear whether the Capacity Agreement will take the form of a conventional bilateral contract or an instrument created by statute. An instrument created by statute would be novel and is likely to raise concerns with investors (see "Nature of a Capacity Agreement" below).

The proposed length of contract remains essentially as previously published; one year for an existing plant and between one and ten years for a new plant.[1] It remains to be seen whether a ten-year term would be sufficient for a new plant to be built by new investors in reliance on the Capacity Agreement. (There also seems to be value for money issues if a shorter term pushes up auction prices.) Existing plant which are due to undergo significant refurbishment could be eligible for a longer term Capacity Agreement[2] but must submit board approved documentary evidence of the investment plans for that refurbishment, which must be of a significant nature (long term maintenance does not qualify as refurbishment). The refurbishment must be completed between the date of the auction and start of the relevant delivery year, however, there is no discussion as to the consequences of failure to meet the refurbishment deadline and impact on any Capacity Agreement in place, although it might be expected that similar principles to those applicable to late new build may be extended to refurbishing plant.

Treatment of DSR

It is intended that DSR, including embedded generation, will participate in the auction process but it will be supported by transitional arrangements to develop the capability of the sector. A multiple stage DSR programme will focus on temporary load shifting, temporary load reduction, behind-the-meter generation and small scale generation and storage linked to a consumption account. Both existing and new DSR are classified as price makers and able to bid up to the overall auction price cap (see above).

It is envisaged that DSR will participate in one year-ahead auctions (due to the difficulty of this technology committing at the 4 years-ahead auction) but in advance of the first full year, transitional arrangements will be put in place with the aim of increasing the total volume of DSR on the system and to ensure DSR capabilities are fully exploited.

Prior to the first year-ahead auction (scheduled for late 2017), specific DSR auctions will be run in 2015 and 2016, each for delivery one year ahead. The timing of these will be reviewed in light of Ofgem's decisions on additional balancing services as referred to earlier (see "Ofgem 2013 Capacity Assessment" above). It remains to be seen if this early introduction of DSR auction goes any way to alleviating any potential mid-decade issues occurring before the capacity market is fully introduced. In 2017, the first year-ahead auction for the capacity market would be run and DSR support would move to a further transitional stage, based on developments identified from the preparatory auctions. Eventually the DSR regime will be refined into an enduring regime.

Payments and Penalties

Under a Capacity Agreement a provider is obliged to generate during system stress periods during the delivery year. (Note that there is no offtake imbedded within a Capacity Agreement – delivery is putting power onto the system: this could be under a PPA or by "spilling".)

A "Capacity Market Warning" is delivered 4 hours in advance of an anticipated stress event. Providers who fail to deliver in response to this warning will be required to pay a penalty based on the value of the lost load and subject to an aggregate cap for a delivery year of a multiple of cost of new entry. Capacity obligations will be load-following which means that providers are only obliged to deliver the percentage of their obligation that is proportional to the percentage of relevant demand at the time of system stress. Providers who deliver more than their obligation will be paid for their excess delivery at the inverse of the penalty rate provided that they notify the amount they will deliver to the SO before gate closure or react to specific SO instructions.

1 It is thought new plant have the option to request a contract with a term between one and ten years, however the Government are still considering the term limits for new (as well as for refurbishing) plant. It is currently thought a term of up to ten years is appropriate for new plant, however DECC will consult formally on the length of contract and whether it would be feasible and desirable to run an auction process which would require new entrants to bid on the basis of a contract of around 10 years and one that is significantly longer. This would enable the SO to choose the length of contract based on price comparison. For ease of reference throughout the rest of this document we shall refer to ten years, notwithstanding the fact this is under consultation.

2 See previous footnote above: it is thought that refurbishing plant will be offered a contract with a term of up to 3 years, although the Government publications are conflicting and there is also a suggestion such plant may have the option to choose a contract with a term between 1-5 years, but this is still under consultation. For ease of reference throughout the rest of this document we shall refer to three years, notwithstanding the fact this is under consultation.

Payments to capacity providers will be made by a settlement agent (expected to be Elexon) and the costs of the settlement agent recovered from suppliers according to their forecast total peak demand, which will later be reconciled based on actual demand (when meter data is available). Similarly, penalties recovered from capacity providers for non-delivery will be split between suppliers pro-rata according to their forecast peak demand. Changes will again be reconciled based on actual demand when metered data will be available. Suppliers will be required to post collateral (sufficient to cover payment obligations for one month) to cover defaults. The Strawman says that once a supplier's collateral has been exhausted any residual outstanding amount will be mutualised across the remaining supplier base to ensure the settlement agency is always in a position to pay capacity providers. Prompt mutualisation will be important to prevent liquidity issues arising for generators who are dependent on prompt payment. Capacity providers will not be required to lodge any collateral against potential penalty payments, but penalties will be deducted from future capacity payments. Any defaulted penalty amounts outstanding at the end of the delivery year will be mutualised across suppliers.

The structure of the penalties for non-delivery and the level of the cap on that liability have been outlined in more detail in the new DECC documents (see *Penalties – Quick Guide* reference box below for more information on penalties).

There are not expected to be any force majeure events or relief for gas supply emergencies. However, capacity market penalties will not apply in the limited circumstances where there is an unmet demand or voltage reduction as a result of a failure or deficiency in the transmission or distribution system.

Penalties – Quick Guide

- Providers who fail to meet their delivery obligation in times of system stress face penalties[3].
- The SO must submit a Capacity Market Warning to providers which is a 4 hour notice for plant to fulfil their Capacity Agreement obligations. If the SO fails to issue 4 hour warning, no penalties may be issued.
- New and existing plant face the same level of penalty.
- There are very limited force majeure scenarios, no exceptions are available for gas supply emergencies, only in times of transmission/distribution system constraint are no penalties applied.
- The level of penalty is subject to an annual cap (calculated as a multiple of CONE x MW of Capacity Agreements held). Rules to create a 'soft cap' will ensure providers always have an incentive to deliver in times of system stress.
- The penalty cap is aggregated across a portfolio. Portfolio providers are therefore afforded less monetary protection in relation to an individual plant that fails to respond as they are unlikely to ever reach their portfolio cap, but have greater opportunity to avoid the application of the penalty as they can net across other plant in the portfolio.
- Spot tests may be carried out where a provider has failed to demonstrate its ability to deliver the level of capacity specified in their Capacity Agreement. Capacity payments will be withheld from any plant which fails a spot test until the plant passes a subsequent test.

Secondary Auction

In order to enable providers to manage their risk of exposure to penalties, at any time from a year ahead of the start of the delivery year and throughout the delivery year, providers may (with SO consent) physically trade their Capacity Agreement obligations if there is additional unencumbered pre-qualified capacity to take their place. A transferee provider must be eligible to participate in this secondary trading, i.e. if a plant has opted out of the capacity market, it will no longer be eligible, however, there are conflicting suggestions as to whether a plant who opted to retire but could remain open with the benefit of a Capacity Agreement would be eligible (see further "Specific issues for Existing Plant" below). The purpose of the limited time window for secondary trading is to prevent parties who fail to build new plant on time from profiting from higher prices in the year ahead auction.

In addition, providers may also manage their risk at any point in time through private financial hedging, in this scenario they would remain liable for any penalties and must settle as normal but would recoup costs from their financial trading partner. The Government is looking into whether it may have a role in establishing a trading platform.

[3] The System stress definition refers to issuance of a demand control instruction– which historically has been a rare occurrence (there was one in 2008, one in 2012) and will include voltage reductions.

Locational issues and review

The GB capacity market will operate as a single zone. However, the SO is asked to design its IT systems to allow for the possibility that the GB electricity market splits as a result of the EU Target Model, or interconnection with non-GB capacity zonal auctions. As previously stated, the capacity market will not apply to Northern Ireland as there is a separate capacity market as part of the all-Ireland single electricity market.

It is confirmed that the capacity market will be in addition to the Short-Term Operating Reserve market (**STOR**). All eligible capacity will be free to participate in both the capacity market and balancing services markets.

The need for the capacity market will be reviewed every five years. At present, the Government believes there is a need for the mechanism for at least the next ten years and potentially longer. It remains to be seen the length of time that the GB market will require this level of support; it is dependant upon factors such as development of the underlying national and European electricity markets particularly levels of market liquidity, an active demand side and the effect of more interconnection.

Description of Options for Generators

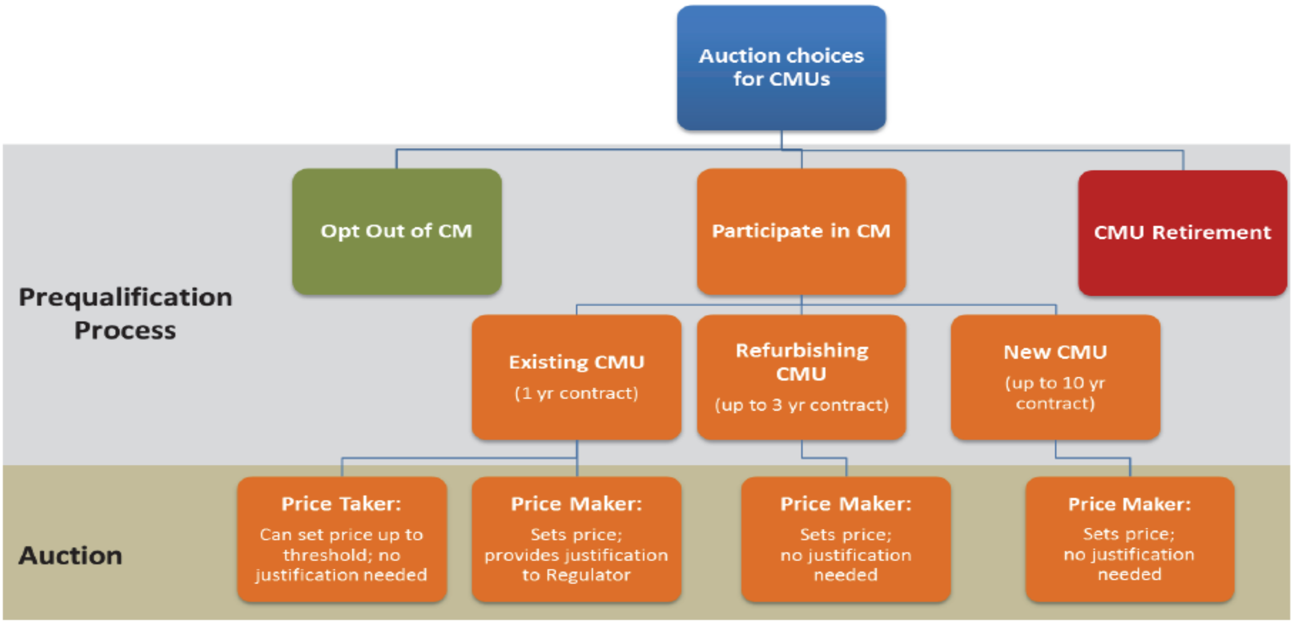
Pre-qualification

All licenced generation that is eligible to participate in the capacity market must first participate in a compulsory 'pre-qualification' process in order to determine the eligibility and bidding status of potential capacity providers. It is likely there will be an auction instrument to bind bidders to the pre-qualification and auction rules.

The amount of capacity ascribed to each capacity market resource reflects that which they are realistically able to produce known as 'de-rated' volume. The de-rated volume for each capacity provider is set administratively by the system operator as part of the pre-qualification process. A provider's de-rated eligibility takes into account forced outage probabilities, scheduled outage durations and fuel availability and is thereby intended to avoid the risk of providers "gaming" capacity volumes. (See further "Issues for Further Consideration – De-Rated Capacity below")

In the pre-qualification process, all prospective providers must state whether they will provide capacity and how they wish to participate. The three main options are: to opt out; to participate; or to retire (see figure 6 below). Plant that opt out of the capacity market do not receive capacity payments, hold any obligations or face any penalties and are not eligible for any payment for over-delivery (they may also not trade in the secondary market). The option however remains for such plant to opt back in for subsequent auctions (including the year ahead auction for the same delivery year). Plant that opt out are de-rated by the SO to determine the capacity to net-off in the capacity auction. Plant that declare they are due to close can retire from the capacity market process entirely but will be assumed not to provide any capacity in the relevant delivery year. If in fact the plant remains open, it may not participate in the year-ahead auction for the same delivery year, and may be subject to regulatory investigation.

Fig. 6 – Summary of routes to auction for eligible providers



For those plant that participate in the competitive auction process, the procedure is slightly different for existing, new or to-be refurbished plant.

Existing Plant

An existing plant may participate as a price taker or in some cases as a price maker. It will by default be considered a price taker and may offer an auction price up to a set threshold (lower than the auction cap). In such circumstances it may not exit until the price has fallen below its offer, but if successful in the auction it will be offered a one year Capacity Agreement at the auction clearing price. If existing plant wishes to offer a price exceeding the set threshold, they must request price maker status and provide to Ofgem a written 'Price Maker Memorandum and Certificate' approved by their board of directors evidencing net going forwards costs[4]. It remains to be seen how much influence Ofgem will exercise over the admission of existing plant to price maker status through this design feature. Existing plant requesting price maker status who are unsuccessful in the auction but continue to operate may face regulatory investigation, during which the Price Maker Memorandum and Certificate could be used as evidence.

Refurbishment

An existing plant that is due to undergo substantial refurbishment could be eligible for a longer term Capacity Agreement if it submits a Refurbishment Plan and Certificate to the SO outlining the proposed work and quantifying the investment (which must be 'material', i.e. exceeding a proportion of the value of the refurbished plant). Refurbishment must be more than mere routine long term maintenance; for example conversion of OCGT to CCGT or boiler replacement qualifies as refurbishment. If the capacity provider is able to demonstrate to the SO[5] that the criteria are satisfied, a plant due for refurbishment may take part as a price maker without providing further evidence or justification. Refurbishment must be completed between the date of the auction and start of the relevant delivery year. There is currently no discussion as to the consequences of failure to meet the refurbishment deadline and impact on any Capacity Agreement in place, although it might be expected that similar principles to those applicable to late new build (see below) may be extended to refurbishing plant.

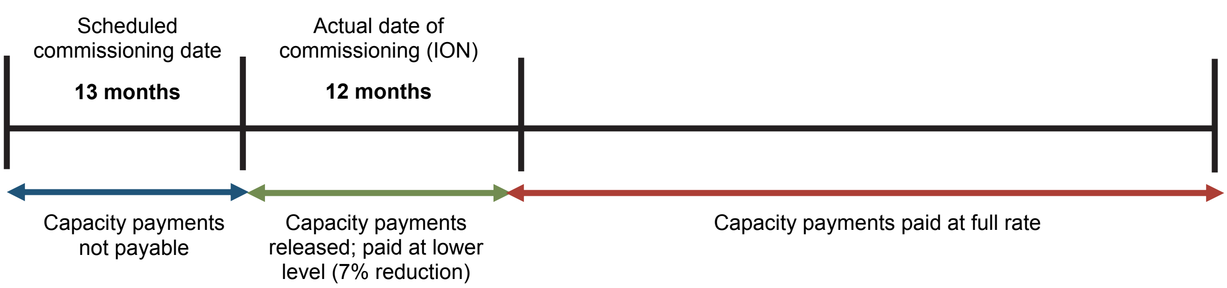
New Entrants

New entrants may participate as price makers and may choose the term of their Capacity Agreement of up to ten years without justification. A plant may use existing infrastructure (grid connection, pipelines and up to [50]%[6] of [new] [7] equipment) and still qualify as new. The longer contract duration is designed to enable new entrants to secure cheaper finance and thus reduce overall costs. DECC are aware that the flip side to this is that the contracts for new plant will lock in capacity payments for a significant period and as such will carefully consider these factors in the consultation for the optimal length of new plant contracts. However, it appears that in the auction the term of a prospective Capacity Agreement will not be taken into account (see "Issues for Further Consideration – No account taken of term of capacity agreement within auction" below).

New plant have strong incentives to build on time and are required to demonstrate Substantive Financial Commitment within a year of the contract being awarded, failure to do so results in termination of the contract and (possibly) a termination payment fee.[8]

Capacity payments are not payable until new plant reaches Interim Operational Notification (**ION)** but new plant are not subject to testing or penalties until they reach this milestone. Capacity payments are reduced by 1% for each month a project is delayed by more than 6 months beyond its scheduled commissioning date (as detailed in the Capacity Agreement) but this reduction is only applied for the first 12 months following the commencement of operation when payment is due. See figure 7 below. (Reductions are applied pro-rata in relation to partial operation of a plant.)

Fig. 7 – Example time frame of new plant delayed by 13 months



4 The Government is yet to publish any detail on how this term will be defined and how such 'net going forward costs' will be calculated.
5 It is currently expected that this body will be the SO.
6 This number is not yet fixed in the DECC publications.
7 We note that the Strawman refers to [50]% new equipment, however we assume this should refer to existing equipment.
8 Whether a termination fee will be payable in these circumstances is to be confirmed.

If the Longstop Date (18 months after scheduled commissioning) is not achieved, the Capacity Agreement will terminate and a termination fee at a level to be determined would be payable by the provider. The Longstop Date is met if 90% of the contracted volume is operational by that date. If only 50-90% is operational, a further extension of 6 months is applied but failure to achieve the 90% target by the end of such period will result in a reduced level of actual contracted operational volume. If less than 50% of capacity is operational at the 18 month Longstop Date the Capacity Agreement is terminated and a termination fee at a level to be determined is applied.

Fig. 8 – Summary of Options for Different Plant

Plant	Available Term	Price Maker/ Price Taker	Submissions To Be Made
New	Up to 10 years[9]	Price Maker	Must demonstrate evidence of Substantive Financial Commitment within a year of contract being awarded. There are penalties for delay, specific milestones apply to avoid reduced payments /termination.
Existing	1 year only	Price Taker or request to be Price Maker	To request to be a Price Maker and therefore bid above the Price Taker threshold, existing plant must provide to Ofgem a written, Board-approved 'Price Maker Memorandum and Certificate' evidencing net going forwards costs
Refurbishment Due	Up to 3 years[10]	Price Maker	Must evidence the refurbishment plans and investment by a Board-approved Refurbishment Plan and Certificate to the SO justifying the suitably significant refurbishment (more than mere long term maintenance required)

Auction Process

Participation in the auction itself is voluntary, and will be run in multiple rounds on the basis of a "descending clock" whereby parties indicate the quantum of the obligations they wish to provide at the announced price. The price is lowered progressively in rounds until a clearing price is found where the offers equal the willingness to pay. The number of rounds and the size of the decrement in each round will be determined by the SO. It is anticipated that the auction would be completed in approximately one working week. DECC have acknowledged the risk of industry collusion and aim to combat this with anti-competitive avoidance measures including the demand curve and restrictions to participation as price takers.

We discuss the latest proposals below, first by reference to existing plant, then by reference to new plant and finally by reference to more general issues for further consideration.

9 As previously described these term lengths are under consultation.
10 As previously described these term lengths are under consultation.

Specific Issues for Existing Plant

Existing licensed generation capacity which is eligible to participate in the capacity market is required to go through a mandatory pre-qualification process (which takes place some[11] months ahead of the auction) to state whether it will run in the delivery year and how it intends to participate in the capacity auction. The available scenarios are set out below. The main scenarios are summarised in a diagram in the Strawman, a copy of which is included in figure 6 above.

Opt out

A generator may state in the pre-qualification process, even if it has not stated that it intends to close its plant (see below), that it wishes to opt out of participating in the capacity market.

In that case, the plant will not be eligible to receive the capacity payment or be subject to the penalties for failure or the payment for over-delivery in respect of the relevant delivery year. It will still be able to opt in at a later date, including in the year ahead auction for the same delivery year. Although it appears it would not be able to acquire capacity obligations by secondary trading for that delivery year.

This opted-out capacity would be taken into account by the SO as a deduction in establishing the level of capacity required to be procured from the auction. It is not clear what protection the system then has if this plant, which has been assumed would run, chooses in fact not to do so in the delivery year. Although if electricity prices are sufficiently high at times of system stress that would act as an incentive for the plant to run. (Though this assumes they had fuel availability as, for example, if the system stress is caused or contributed to by a gas supply problem then we would anticipate that interruptibility conditions in non-firm supply contracts could be triggered.) This lack of control over plant which opts out seems to be one reason why existing plant which does opt in is intended to receive a capacity payment, so as to encourage existing generators to opt into the capacity market.

Retirement

A generator that intends to be closed in the delivery year may opt out of the capacity market on account of impending closure.

The difference between this and the situation discussed above of opting out while stating that the plant is not intending to close, is that this opted-out plant will not be eligible to participate in the year ahead auction for the same delivery year (or, according to the Strawman, in the auctions for the two subsequent delivery years) and will automatically be subject to regulatory investigation if it stays open in the delivery year. The Detailed Design Proposals state that existing plant that had intended to retire may look to pick up a Capacity Agreement in the secondary market, but the Strawman states that plant that declared it was retiring will not be eligible to acquire capacity obligations by secondary trading. (Interestingly, in the Strawman, there is a provision for the SO to verify and accept previously de-mothballed capacity for secondary trading, so it appears from the Strawman that a plant which had already been mothballed may be in a better position than plant which has not yet mothballed in this respect – will this prompt "pre-emptive" further mothballing?)

This type of opted-out capacity will not be taken into account by the SO as a deduction from the level of capacity required to be procured from the auction. Given the restrictions on a plant which has opted-out by reason of retirement, there does not seem to be an incentive on a generator to opt out by reason of intended retirement rather than opting out and stating that it intends not to close which would leave it more flexibility for a later stage. It seems more likely that plant which might or might not close in the delivery year would choose to opt out and state that it was not intending to close, rather than opt out by reason of intending to close, at least at the four year ahead auction stage. This may make the position of procuring the right amount of capacity in the auction more difficult as the system operator could be assuming some plant would run, which when it comes to the delivery year decides not to do so.

Coal plant expecting to reach its emissions limits in the delivery year might seem an obvious candidate to opt out for reasons of retirement, although the mechanisms discussed above mean that it would be penalised if it did opt out on this basis and was then actually in a position to continue to run.

[11] In the Detailed Design Proposals this is stated to be seven months ahead, but in some parts of the Strawman it is stated to be four months ahead with a possible shorter period for the 2014 auction.

Refurbishment

A generator that intends to refurbish its generating plant may choose to participate in the capacity market auction as a price maker and seek a capacity agreement for up to three years (and the Strawman indicates that up to five years has been under consideration and has not yet been ruled out).

Only more significant refurbishments such as conversion of CCGT to OCGT, boiler replacement or supercritical technology conversion will be eligible for this purpose. The pre-qualification process will involve a generator wishing to participate on this basis submitting a board-approved business plan and board certificate demonstrating that the planned capital expenditure is material. The materiality threshold will be set by reference to the value of the plant once refurbished, although it is unclear how the value will be assessed. (In many measures of value a Capacity Agreement would confer additional value which would make this circular. If value is assessed by reference to equipment price, it is not clear this would create the right incentives for vendor owned plant.) This method of assessing materiality may also not sufficiently address the situation of large plants who have a significant existing value, but may be able to provide additional capacity cost-effectively. It is not clear whether parts of plant may be regarded separately for eligibility to take into account the process of upgrading some units and not others.

A refurbishment will be affected by many similar issues to those which affect new plant (see section "Specific Issues for New Plant" below) particularly in relation to the timing of investment decisions and construction completion. However, although it is stated that new plant that had commissioned early would be able to participate in secondary trading, it is not clear whether refurbished plant will have the same position as new plant in this respect.

Note that as discussed below, a plant may qualify as a new plant rather than a refurbishment, even if it reuses existing infrastructure including, up to [50]%[12] new equipment.

In order to secure a Capacity Agreement for the refurbishment in the first place the generator will, of course, have to be successful in the auction with other price makers. The most likely competitor is new build plant who will have the opportunity for a longer contract over which to amortise their capital costs. Given that the Government has said that the auction will be based on price against the annual demand curve and will proceed mechanistically without Ministerial intervention once the auction is in process, it seems possible that the auction may be forced to accept a new entrant with a longer contract rather than a refurbishment with a shorter contract even though the capacity shortfall was only expected to last for a relatively short period (before, for example, new nuclear generation came on line) as the new entrant price (amortised over a longer period) might be lower than the refurbishment price in that year, although it would in the long run be more expensive as the payment would continue for a greater number of years.

A plant which is unsuccessful in securing a Capacity Agreement in the auction will be eligible to take on capacity obligations in the secondary market. It does not appear that the restriction on operating that applies to existing plants, which request price maker status but which do not succeed in the auction, would apply to plants which were seeking a capacity agreement for refurbishment; but this needs to be confirmed.

Price Maker

An existing plant which is not seeking a Capacity Agreement for refurbishment may apply to participate in the capacity market as a price maker (rather than the more usual classification of price taker). In order to be accepted to do this it needs to provide justification that it faces "net going forward costs" (accompanied by a board certificate). It is not clear what is the term "net going forward costs" is intended to encompass. However if the price maker existing plant is unsuccessful in the auction then there is a statement in the Strawman that if it continues to operate in the delivery year it will automatically be subject to investigation by Ofgem (although it is not clear from the statements on secondary trading whether it would be excluded from participating in the secondary market). See also the discussion of licence obligations in "Issues for Further Consideration" below. Given that existing plant in any event allowed to participate in the auction as a price taker (see below) and if successful it receives the price at which the auction clears, more detail of the term "net going forward costs" is needed to establish whether an existing plant would wish to seek price maker status given that this can have negative consequences. One possibility is that this is intended to be a protection against negative spark spread.

12 This number is not yet fixed in the DECC publications.

Price Taker

All other existing plant which are eligible for the Capacity Market will be able to participate in the auction as a price taker and will be entitled to bid into the auction up to a defined threshold. The Strawman suggests that this threshold will be set at the lesser of [50%] of net CONE or 70% of the last clearing price set by new entry in the four-year ahead auction (adjusted for inflation). A price taker is not entitled to exit the auction until the price has fallen below its offer. The relatively low threshold for price takers means that the existing plant may be more likely to be successful in the capacity auction and would then receive a one year contract for the price at which the auction cleared.

This means that existing capacity that may have been intending to operate anyway will be paid extra to remain on the system, which may be a more expensive route for consumers than was actually needed to maintain the capacity margin. Government suggests that if generators are receiving the capacity payments then wholesale electricity prices should be able to reduce by a corresponding amount. This would clearly assist affordability objectives, but has not been reconciled with earlier, marginal cost-driven, methodologies. It would also introduce a further dynamic for those not in receipt of a CfD (including ROC projects). In support of its approach, Government states that treating new and existing plant differently would create regulatory risk and it wants to incentivise existing plant to make capacity available. The Government also states that allowing even existing plant that have sunk all their investment costs but have material net go forward costs, to bid up to a threshold level is appropriate because those participants may be exposed to a risk of paying penalties greater than the total capacity payments they receive.

As noted below, there is no force majeure protection proposed for a technical failure of the plant or for a problem with the gas network, so the penalty (see "Payment and Penalties" above) on a generator participating in the capacity market if it fails to deliver when required at a time of system stress could be a significant cost to it.

Specific Issues for New Plant

New entrants (defined to include plant that began construction from May 2012) will have to register for the pre-qualification stage at least 4 months ahead of the primary auction. As part of the pre-qualification process, new entrants will have to submit plausible construction milestones to achieve commissioning onto the GB system. If the new entrant is successful in the auction process, the Capacity Agreement issued by the SO will set out the key project milestones and the corresponding dates at which such milestones must be achieved. Consequences of the provider failing to achieve operational status within 6 months of the scheduled commissioning date are set out below.

New entrants therefore have about one year to prepare for the first 4-year ahead auction in 2014 (for the delivery of capacity in the Winter of 2018/2019). New entrants will therefore need to act fast to secure a contract in the first 4-year ahead auction. Will prospective new entrants be prepared to spend the time and money needed to have all its investment arrangements (including construction and financing) sorted within this time frame in order to know what to bid in the auction? Alternatively, will prospective new entrants wait for the second 4-year ahead auction, which will give them more time to finalise their investment arrangements and also allow prospective new entrants to see how other participants behave/react in the first auction? We also query whether the presumably lower costs (at least on a levelised basis) of returning mothballed plant to operation means that new entrants will wait until after this has occurred before spending the time and costs involved in finalising investment arrangements as to be able to participate in an auction.

New entrants will have to demonstrate that they have made a significant financial commitment to their project within a year of being awarded the Capacity Agreement. Failure to provide sufficient evidence will result in the termination of the Capacity Agreement and possibly the application of a termination fee. Projects that fail to achieve operational status within 6 months of their scheduled commissioning date will have their capacity payments reduced (by 1% per month for every month they are delayed over 6 months) for the first 12 months following the commencement of operation. Projects delayed beyond a long-stop date of 18 months after the scheduled commissioning date will have their Capacity Agreement terminated and become liable to pay a termination fee of a level to be determined, but would be eligible to participate in future auctions. The long-stop date is met if 90% of the contracted volume is operational. If only 50-90% is operational, a further extension of 6 months is applied but failure to achieve the 90% target by the end of such period will result in a reduced level of actual contracted operational volume. If less than 50% of capacity is operational at the 18 month long-stop date, the Capacity Agreement will be terminated and a termination fee of a level to be determined is applied.

New entrants will be price makers able to set their own bid price (up to the auction price cap) and to select a contract term up to 10 years.[13]

Implications for timing of investment arrangements

If the new build involves a construction process of significant length and it is not a process which the generator would consider cost-effective absent a capacity payment, then the generator would presumably not wish to wait until the year ahead auction, but would instead wish to secure a contract in the four year ahead auction. This means that the generator would need to have all its investment arrangements finalised four to five years ahead of when construction is to be completed, in order to know what it can bid into the auction. This is more difficult for plant which requires project financing than for balance sheet financed projects, so the currently proposed structure is likely to disadvantage independently financed power projects. The way the penalty regime allows portfolio players to offset shortfall on one capacity market plant against another, also disadvantages independently financed power projects compared to portfolio players. A financier is unlikely to hold pricing open for a prolonged period of time and similarly construction contractors will be unwilling to hold pricing open for a prolonged period of time. This means that, particularly for an independently financed project (and in relation to construction costs even for other projects) it is likely that a generator would want to start construction soon after the four year ahead auction, rather than waiting until closer to the delivery period. This seems to run the risk of a new plant commissioning before its entitlement to a capacity payment arises. Again, this may cause increased challenges for an independently financed power project.

In relation to a plant that completes earlier than expected to, the Strawman provides that new plant that commission early would be able to participate in secondary trading, although it states that plant that has taken on capacity obligations will not be eligible to take on additional capacity obligations (presumably this just refers to the delivery year in question and not earlier delivery years).

It may be helpful if the capacity market design were to clearly allow a plant which expects to commission before the commencement of its capacity payments to bid as a price maker for a one year contract in the year ahead auction for years before their first projected delivery year and so start receiving revenue earlier.

Issues for Further Consideration

Gas Market

Gas remains the “shoulder” fuel that can fill the gap left as older coal and nuclear plant close (and can subsequently perform as standby generation (i.e. capacity) in respect of new nuclear (which has large single loss load characteristics) and wind (which has intermittent characteristics) when they subsequently come on line) while playing an important role in meeting the 2050 decarbonisation target without compromising energy security and affordability.

The capacity market is the primary intervention to support the construction of new build gas generation in Great Britain. However, it is not clear that the National Transmission System for gas is designed to provide the within day flexibility that will be needed to meet the demand of a fleet of back-up gas generators all starting up at the same time to cover gaps in intermittent renewable output, or the tripping of a large nuclear plant or to cover a system peak. This is exacerbated by a lack of underground gas storage capacity.

The absence of an hourly traded gas market also raises concerns as to whether sufficient gas can be supplied at short notice. It is also likely that current gas contracting arrangements will need to change. Long term gas contracts with significant take-or-pay obligations will not be appropriate for standby generators that do not know how often they will be called upon to generate (we assume that capacity payments will not be allowed to be so large as to cover such take-or-pay payments!). However, it is unclear that there is a market for long-term intermittent gas supply and any short term arrangement may expose generators to significant gas price volatility, which will be very difficult to forecast and therefore price for the purposes of the capacity market auctions. It seems clear that if more investment were made in gas exploration (including of shale gas resources), short term storage and seasonal storage combined with counter-seasonal LNG imports a smoothing out of gas prices could be achieved, which could assist the operation of the capacity market.

[13] DECC intends to consult formally on the length of contract available. See footnote 3.

CCGTs

It is unclear that CCGTs (the most efficient form of gas generation and with the lowest emissions) will be able to respond within the required 4-hour period unless CCGTs are kept warm and ready to run, which is inefficient. Query whether this will lead to the less efficient OCGT technology (with its higher emissions, lower construction costs and higher operating costs) becoming the default new build option used within the capacity market? This is likely to depend (at least to some extent) on whether stress events tend to appear "out of the blue" or can be reasonably anticipated in advance – perhaps because of movements in the balancing market (although the SO may choose to issue a Capacity Market Warning first, as the cheaper option in the case of the general system (i.e. non-locational) system stress) or because there is not enough gas generation available to support intermittent wind generation during high pressure weather systems. Given the penalties are calculated in relation to each half-hour settlement period, generators may be more relaxed about this requirement if they are able to respond shortly after 4 hours and believe that Capacity Market Warnings will be rare. Although, given Ofgem's estimates in its Electricity Capacity Assessment Report 2013 of the increased probability of a large shortfall requiring the controlled disconnection of customers, generators are perhaps unlikely to take this view.

In relation to existing plant, will every plant that needs to carry out work in order to respond to the 4-hour Capacity Market Warning (issued by the SO in advance of any anticipated stress event) seek a refurbishment Capacity Agreement (such as for the conversion of CCGT to OCGT) and, if so, what will this mean for the pricing dynamics of the first auction?

De-rated Capacity

A plant will only be entitled to participate in the auction in respect of its "de-rated" capacity. This is intended to correspond with the amount of reliable capacity that can be ascribed to that corresponding potential capacity market resource. The process for determining the de-rated capacity is yet to be established but is expected to involve de-rating from the 'nameplate' capacity by taking account of forced outage probabilities, scheduled outage durations, and fuel (e.g. gas, wind) availability. The de-rated capacity is to be determined by the SO, but the capacity provider will be entitled to appeal.

It will be interesting to see if the process adopted is similar to that used for technology bands under the NFFO contracts. If the process ascribes an average de-rating factor, however, this may not necessarily correspond to the reliable capacity at a time of system stress, for example in the case of intermittent technologies. It is also not clear if the same de-rating test will be applied for assessing the contribution of capacity which is not eligible for participation in the capacity market. As this will include intermittent renewables (whether ROC or CfD – supported), the issue is particularly acute, and important here, since this will have a potentially very significant impact on the capacity requirement.

If the de-rated capacity is lower than the plant's actual capability this would leave it some headroom in relation to achieving the required level to avoid a penalty when called upon to deliver.

It appears that a capacity provider would be required to bid its entire de-rated capacity into the auction.

Government is considering whether a plant's de-rated capacity would be revised if it fails a spot test.

Nature of a Capacity Agreement

It is not clear whether the Capacity Agreement will take the form of a conventional bilateral contract or an instrument created by statute. An instrument created by statute would be novel and is likely to raise concerns with investors.

Paragraph 84 of the Strawman makes it clear that the contractual architecture remains under development. Avid followers of EMR will no doubt recall that this was an early feature of the CfD. Clearly, the aims of simplicity and predictability need to be focussed on so as to ensure that the final architecture enables capital to be invested into capacity projects at least cost. To the extent that the final architecture were to include elements of a "statutory" contract (and this has not been ruled out from the documentation provided so far) the points we raised in relation to the early design of the CfD would be relevant:

- Statutory contracts have not been used to any great extent in the UK. The absence of history may be of concern to 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 security of supply.

– Any statutory contract would be complicated, being split between a contract document, primary and secondary legislation, licence conditions and an industry code. Such complexity could cause 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 is hard to see how any change in law protection could be meaningfully included in any "statutory contract".

No account taken of term of Capacity Agreement within auction

As mentioned above in relation to refurbished plant, auctions will be based on price against the annual demand curve and will proceed mechanistically without Ministerial intervention once the auction is in process. This means that no account is taken of whether a provider is bidding for a 1-year, 3-year or 10-year Capacity Agreement. This may give an advantage to new build plant, which can expect to amortise costs over 10 years (as opposed to refurbished plant) which can only amortise over 3 years and may be one of a number of reasons why refurbished plant seeks to qualify as new build by way of limiting use of existing equipment. Minimising the annual cost of the Price Makers which set the auction price of course minimises payments to Price Takers participating in that auction.

It is also not clear to us that the SO should be indifferent to which of these achieves a Capacity Agreement (though new plant or refurbished plant may become a Price Taker once its initial Capacity Agreement has expired).

We note that providers may reuse existing infrastructure (including grid connection, pipelines and up to [50]% [new][14] equipment) and still qualify as new entrants. No guidance is given as to how to calculate the percentage of equipment used. If based on value, then query how this is calculated in relation to vendor owned equipment.

Preferential treatment of DSR

It is worth noting that under the proposed capacity market, DSR appears to receive preferential treatment in some respects.

As previously described, preparatory DSR auctions will be introduced prior to the main capacity auction and run in 2015 and 2016 with a view to increasing the total volume of DSR on the system and ensuring its capabilities are fully exploited. These early auctions may go some way to relieve any potential mid-decade constraint issues. It is envisaged that the year-ahead auctions, whilst useful for refining the level of capacity for which Capacity Agreements are issued, are focussed on facilitating the participation of DSR. Under the enduring regime, as DSR is fully integrated into the capacity market it will have two distinct options to pre-qualify. DSR capacity must demonstrate either:

– That capacity can be despatched in a test or through evidence from previous successful despatch; or

– By submission of a credible business plan (and accompany meter identification numbers) and posting a bid bond (which shall be returned to the provider following a successful test after the auction or in the alternative if the provider fails to win a Capacity Agreement).

  DSR capacity will be considered akin to new plant in respect of its ability to participate as a price maker. DSR capacity can therefore bid any price into the auction up to the auction price cap, which will be compared against other bids to establish the clearing price.

Embedded Generation

One relative beneficiary of the capacity market proposals is embedded generation, which is included within DSR. Both existing and new DSR are classified as price makers and are able to bid up to the overall auction price cap. In addition, it is proposed that the costs of capacity payments are recovered from licensed suppliers at the time of GB system peak total annual demand determined in the same manner as for the existing "TRIAD" methodology used by NGET when determining Transmission Network Use of System charges. This should mean that increased benefits accrue to embedded generators for "TRIAD" avoidance.

[14] We note that the Strawman refers to [50]% new equipment, however we assume this should refer to existing equipment.

Trading and Imbalance

Capacity providers will be eligible to provide the full range of balancing services to the SO[15] and to make offers into the balancing mechanism without losing capacity market payments or facing capacity market penalties. (In recognition of this, a capacity provider's obligation is adjusted to take account of reduction in output instructed by the SO as a consequence of Bid-Offer Acceptances, a BMU Specific Trade or through the delivery of balancing services (e.g. mandatory frequency response) that sees an automatic fall in the output of the unit as a consequence of delivering that service.)

Possible issues include:

(1) Where a Capacity Market Warning has been issued but no actual stress event occurs, what is to prevent providers making excessively low bids to reduce generation into the balancing mechanism (or seeking to charge excessive amounts for interim trip devices on plant)? Licensed generators would obviously have to take into account standard licence condition 20 (Transmission Constraint Licence Condition) which prohibits a generator from obtaining an excessive benefit from electricity generation in relation to a Transmission Constraint Period. However, the terms of any fuel supply contract may mean that it is not possible to avoid costs in the short-term, such that a low bid is cost reflective.

(2) If a plant which is subject to a Capacity Agreement trips on or shortly after a Capacity Market Warning, there are a number of potentially complex interactions:

   (a) The capacity provider will be penalised for its decreased output relative to its pre-warning status during the four hour notice period.

   (b) Assuming a stress event (defined as any settlement periods in which either voltage control or controlled load shedding are experienced at any point on the system for 15 minutes or longer) occurs and is ongoing, after four hours' notice via the Capacity Market Warning, a capacity provider that fails to meet its obligations will be penalised based on the amount of its load-following obligations and value of lost load (**VoLL**) minus the "System Buy Price" (i.e. the "cash out" imbalance charge under the Balancing and Settlement Code) for each half hourly settlement period in which there was system stress. (A capacity provider's performance will, however, be assessed at a portfolio level so that output from other plants in its portfolio can be used to offset a shortfall at the plant that tripped. The performance of a plant not participating as part of a wider portfolio structure will be assessed on a standalone basis. There are not expected to be any exceptions, e.g. for force majeure or gas supply emergencies. However, where there is unmet demand or voltage reductions because of failures or deficiencies in the transmission or distribution systems, capacity market penalties will not apply. A capacity provider's cumulative penalty exposure in a delivery year will be capped at twice CONE multiplied by their volume (MW) of Capacity Agreements held. Rules to create a "soft cap" will ensure providers always have an incentive to deliver in times of system stress.)

   (c) The capacity provider will be liable to "cash out" imbalance charges at the System Buy Price under the Balancing and Settlement Code for at least 1½ hours after which it should be able to adjust its Final Physical Notification to zero (and assuming that it is similarly able to adjust any bilateral net contracted position). Note that the penalty under the Capacity Agreement is reduced by its System Buy Price (see (b) above), therefore netting this out and avoiding a double penalty.

   (d) The capacity provider will also be liable for any non-delivery penalties under any relevant balancing services contract.

   (e) In respect of any Bid-Offer Acceptances the capacity provider will be liable for non-delivery charges. However, the capacity provider's exposure in relation to future settlement periods for which gate closure has not occurred can be avoided by reducing the maximum export limit to reflect the outage.

   (f) Although capacity providers can physically trade their obligations where there is additional unencumbered pre-qualified capacity that can take their place, secondary trading is clearly not designed to cover short-term trips. It is also unclear how much of this unencumbed pre-qualified capacity will be available.

15 It is intended that the bulk of balancing services procurement would take place after the year-ahead capacity auction to limit any over procurement. DECC consider that where there is a competitive market for balancing services it is likely the market price for that service will be reduced to reflect capacity payments.

(g) Providers can also hedge their position financially. However, without a physical hedge, this will only ever reduce (rather than eliminate) exposure. It is also unclear whether there will be much of a market for this kind of speculative trade. Insurance (see below) may be a more appropriate mitigant in these circumstances although it is likely to be difficult to obtain and even if obtainable expensive and subject to significant deductibles.

(3) Where a plant is able to over-deliver against its load following obligations at times of system stress, it will be paid for its excess volume at the inverse of the penalty rate provided that it holds a Capacity Agreement and has notified the amount that it will deliver to the SO before gate closure or reacts to a specific SO instruction. It is likely that an over-delivering plant will be uncontracted, at least in respect of the excess quantity, and will therefore "spill" and receive the "cash out" System Sell Price (as defined in the Balancing and Settlement Code).

We therefore query whether a peak shaving plant that needs a capacity payment (because it would not expect to run otherwise) would ever forward contract for the sale of its power when it does not know when or if it will be called upon to delivery. Whereas, there is likely to be a market for such power produced by embedded plant (as part of "TRIAD" avoidance), there is unlikely to be much appetite for such power produced by a transmission connected plant.

Lack of gas emergency relief

The concerns in relation to the current "capacity market fitness for purpose" of the gas infrastructure, balancing and contracting arrangements (see "Gas Market" above) are further exacerbated by the expectation that a generator will not be relieved of its load following obligations for gas emergencies. Therefore, any problem with the gas network that coincides with a time of system stress will result in a significant cost to a generator participating in the capacity market, in the form of a penalty for non-delivery. This may be expected to lead to a greater focus on back-up fuels such as liquefied petroleum gas or distillate fuel oil, requiring delivery and storage infrastructure. However, use of liquid fuels in a gas-fired plant can be expected to lead to poorer performance, increased emissions and increased maintenance costs (e.g. due to the increased risk of damage to turbine blades) and may therefore be restricted under any long-term service agreement with the turbine manufacturer.

Insurance

Capacity penalties are unlikely to be easily insurable since fines and penalties are typical policy exclusions and premiums to add this cover back (even if it were available) would be likely to be very high.

Licence Obligations

There are several places in the Detailed Design Proposals and the Strawman which contemplate that Ofgem's use of the regulatory powers of the Gas and Electricity Markets Authority (the **Authority**) would operate as a control on certain types of behaviour by capacity market participants. It is not clear, however, that the Authority's powers are presently framed in a way that gives Ofgem the ability to effectively perform that role (even taking into account licence conditions such as the "Transmission Constraint Licence Condition").

It will therefore be important to see whether (in addition to the auction rules currently contemplated) further licence conditions, regulations or capacity market rules are developed to assist Ofgem in performing its roles in relation to the capacity market. Section 31 of the Energy Bill contains a power to modify licence conditions for the purposes of the introduction of the capacity market. Section 30 of the Energy Bill provides that electricity capacity regulations or capacity market rules may include provision that the requirements of those rules or regulations may be enforced as if they were relevant requirements for the purposes of section 25 Electricity Act 1989 (see below). If there are relevant licence conditions or requirements, the following enforcement provisions are available:

– Where the Authority is satisfied that a licensee is contravening or is likely to contravene any relevant licence condition or other relevant requirement, it may under section 25 Electricity Act 1989 secure compliance by means of an enforcement order. An order may be provisional or final.

– If a licensee does not comply with the order, compliance can be enforced by the courts as provided for in section 27 Electricity Act 1989. Under Schedule 2 of a generation licence the Authority may also revoke the licence if the failure to comply with the order is not rectified to the satisfaction of the Authority, or any financial penalty is not paid, within three months after the Authority has given notice of such failure to the licensee.

- The obligation to comply with a final or provisional order is a duty owed to any person who may be affected by a contravention of that order and, under section 27(5) Electricity Act 1989, any breach of that duty which causes that person to sustain loss or damage shall be actionable at the suit of that person, but in those proceedings it shall be a defence for the regulated person to prove that he took all reasonable steps and exercised all due diligence to avoid contravening the order.
- Breach of a licence condition can also attract fines of such amount as is reasonable in all the circumstances of the case up to a maximum of 10% of the licensee's annual turnover in the year preceding the date on which the Authority gives notice of its proposal to impose a penalty. (Section 27A Electricity Act 1989 and Electricity and Gas (Determination of Turnover for Penalties) Order 2002.)

In addition, the Authority has powers under the Competition Act 1998 (concurrently with the Office of Fair Trading) to deal with certain breaches of competition law which relate to commercial activities connected with the electricity market, including breaches of the prohibitions on agreements between undertakings which aim to prevent, restrict or distort competition, or conduct which amounts to abuse of a dominant position. Where the Authority has reasonable grounds to suspect that competition law is being breached it has powers to instigate an investigation and, following conclusion that a breach has occurred, it can issue directions to bring the breach to an end and impose financial penalties for breaches committed intentionally or negligently (up to 10% of an undertaking's turnover).

CfD Update

Draft CfD Strike Prices for Renewables

Government has just published the draft CfD strike prices for most renewables technologies. These are set out below. DECC will be consulting on these as part of the consultation on the draft EMR Delivery Plan scheduled to be published later this month.

The strike prices for key technologies come down over time reflecting assumed declines in technology costs. (Note the figures are expressed in 2012 prices and are therefore indexed, presumably to CPI given the announced policy approach on CfDs – see below.) DECC has stated that these strike prices are set to be consistent with the RO levels of support (though adjusted down as the CfD is designed to protect the investor against additional risks and lower the cost of capital). The conversion from the level of support under the RO into a CfD price apparently takes into account a number of elements. These include: the current projections for wholesale prices; the level of support being for 15 years as opposed to 20 years (except in certain cases such as biomass conversion – see below); the indexation to the Consumer Price Index (as opposed to the Retail Price Index); power purchase agreement terms; the effective tax rate of an average developer; and the lower cost of capital assumed as a result of the increased price certainty afforded by the CfD.

The publication for consultation of draft strike prices is a clear milestone towards an end to the current hiatus in reaching final investment designs for new generation. While the reduced term of the support has been taken into account, a 15-year agreement necessarily requires accelerated amortisation, and developers will doubtless be doing their own calculations.

Projected wholesale prices are also stated to have been taken into account. It will be interesting to learn how much impact the capacity market has been assured to have on these.

The shorter term means that the protection against change which is contained within a CfD (see "Policy on CfD Terms" below) will cover correspondingly less of the economic life of renewables plant.

The final CfD renewables strike prices will, once finalised, also be applicable to Investment Contracts with renewables generators. Nuclear and CCS continue to be developed on a bilateral basis and there is as yet no visibility on these strike prices.

A Panel of Technical Experts was appointed to scrutinise NGET's analysis which informed these draft strike prices and its report will be published in July, alongside consultation on the draft EMR Delivery Plan (which will set out more detailed information on the draft strike prices). The Panel was appointed in February 2013. Since then, the Panel has been working alongside NGET and reporting informally to DECC throughout the analytical process to enable them to scrutinise the analysis.

Note that there are 14 published strike prices, in contrast to the 35 RO support bands for renewables. In some cases, Government are offering one strike price to cover two or more support bands under the RO, as Government are moving away from having more than one support level for a single technology. In addition, strike prices are not to be offered for certain RO technologies at the present time, for example due to sustainability reasons.

Government policy of whether and how dedicated biomass will be supported under CfDs will be confirmed within the draft EMR Delivery Plan (see "Next Steps" above).

DRAFT STRIKE PRICES FOR RENEWABLE TECHNOLOGIES						
Renewable Technology	Draft Strike prices (£/MWh) (2012 prices)					Potential 2020 Deployment (GW)
	2014/15	2015/16	2016/17	2017/18	2018/19	
Advanced Conversion Technologies[1] (with or without CHP)	155	155	150	140	135	***c.* 0.3**
Anaerobic Digestion (with or without CHP)	145	145	145	140	135	***c.* 0.2**
Biomass Conversion	105	105	105	105	105	**1.2 – 4**
Dedicated Biomass (with CHP)[2]	120	120	120	120	120	***c.* 0.3**
Energy from Waste (with CHP)	90	90	90	90	90	***c.* 0.5**
Geothermal (with or without CHP)[3]	125	120	120	120	120	**< 0.1**
"Small" Hydro	95	95	95	95	95	***c.* 1.7**
Landfill Gas	65	65	65	65	65	***c.* 0.9**
Offshore Wind	155	155	150	140	135	**8 – 16**
Onshore Wind	100	100	100	95	95	**9 – 12**
Sewage Gas	85	85	85	85	85	***c.* 0.2**
Large Solar Photo-Voltaic	125	125	120	115	110	**2.4 – 3.2**
Tidal Stream[4]	305	305	305	305	305	***c.* 0.1**
Wave[5]	305	305	305	305	305	

1 Standard and advanced gasification and pyrolysis, including advanced bioliquids.

2 The draft strike price is based on the assumption that Dedicated Biomass CHP generators can apply for the current (1p/kWh) RHI large biomass tariff. Revised RHI tariffs were consulted on in September 2012 and a Government response is pending. DECC may adjust the Dedicated Biomass CHP strike price once RHI tariffs have been confirmed.

3 The proposed strike prices for geothermal have been set with the aim of giving equivalent returns from investment as could be accrued under the RO. The Government has commissioned an external report on the potential of geothermal power in the UK – due to conclude in July – and its findings will be incorporated in setting the final strike prices.

4 The strike price for Tidal Stream is intended for the first 30 MW capacity of any project. For higher capacity projects, support for the additional MW will be set at the offshore wind strike price.

5 The strike price for Wave is intended for the first 30 MW capacity of any project. For higher capacity projects, support for the additional MW will be set at the offshore wind strike price.

There is no published strike price for tidal range or larger hydro projects. Instead, given the lack of cost data available, DECC will consider how best to price CfDs and the appropriate length of contracts for tidal range and larger hydro projects on a case by case basis.

Combined Heat and Power (**CHP**) projects will also receive support and revenue for the heat element of their generation, therefore overall for a given technology they will receive greater support than non-CHP generators. The draft strike prices for CHP plant are based on the assumption that CHP generators can apply for the current tariff under the Renewable Heat Incentive (**RHI**). Revised RHI tariffs were consulted on in September 2012 and a Government response is pending. DECC have stated they may adjust the CHP strike prices once RHI tariffs have been confirmed.

Energy from waste without CHP will not be supported under CfDs. (This is consistent with the position under the RO.)

Further detail will be published in July, as part of consultation on the draft EMR Delivery Plan (see "Next Steps" above). This will be followed by a ten-week consultation period.

The potential 2020 development scenarios included in the table above are stated to be dependent on industry cost reductions over time. DECC says the figures are not to be regarded as Government forecasts. The figures do not include deployment supported under the small-scale Feed-In Tariff.

DECC states that the deployments are broadly consistent with deployment scenarios presented in the Government's Renewables Roadmap and reflect new cost assumptions and the growth figures announced at Budget 2013. We set out below the potential deployment described in the latest Renewable Energy Roadmap, where this is broken down by renewable technology, alongside the Government's figures from last month.

Renewable Technology	Potential 2020 Deployment Sensitivities in Delivering UK Investment paper 2013	Potential Deployment as stated in UK Renewable Energy Roadmap 2012
Offshore Wind	8 - 16 GW	18 GW
Onshore Wind	9 - 12 GW	13 GW
Solar PV	2.4 - 3.2 GW (refers to 'large solar PV' only)	7 – 20 GW
Biomass	1.5 – 4.3 GW (biomass conversion and dedicated biomass (with CHP))	6+ GW (total biomass capacity (including biomass co-firing and conversion))

It seems to us that, notwithstanding some potential differences in methodologies, there is a suggestion that the deployment ambition may have declined, for wind capacity at least. A mid-range position of 12GW for offshore wind would necessarily exclude a number of Round 3 projects.

It may also be a consequence (or potentially a driver) of the settlement on the LCF – issues around this are set out below.

LCF and Allocation Update

DECC has now set out the LCF (**LCF**) annual limits for low carbon generation (including CfDs, the RO and the small scale feed in tariff) out to 2020/21 as follows:

LCF – Upper Limits on Spend (£bn) (2011/12 prices)[16]						
2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
£3.3	£4.3	£4.9	£5.6	£6.45	£7.0	£7.6

The figure of £7.6bn (2011/12 prices) for 2021 had been announced earlier this year, but in due course it became apparent that this was for that year in isolation, rather than a medium-term framework. The position for intervening years has now been agreed with HMT.

This framework now gives clearer visibility on the medium term commitment to funding CfDs, and the limits thereof. It is also considered to be important because it shows to investors that EMR has been properly costed. This is thought to reduce policy risk.

However, we note that calculations of the availability of LCF headroom are critically dependant on both the technology mix (and thus applicable strike prices) and the forecast level of reference prices.

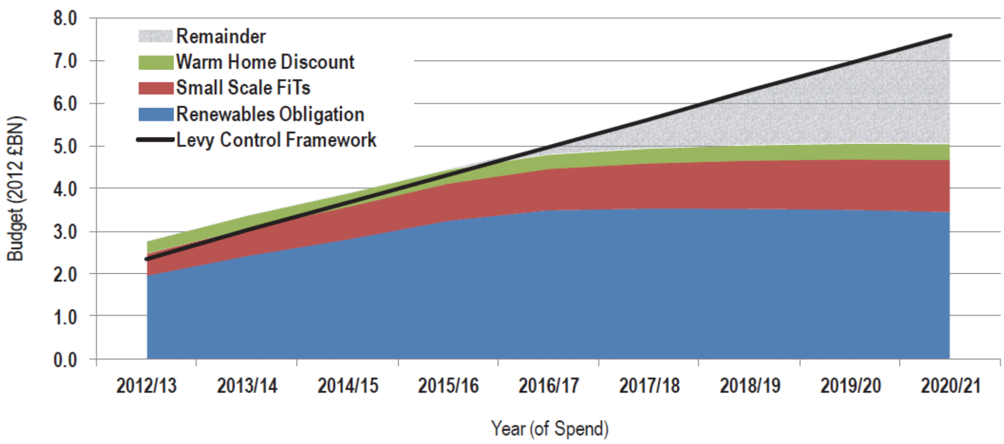
In relation to the latter, one could take the view that the LCF acts as a hedge for the consumer/Treasury. If wholesale prices are higher than expected there is more CfD capacity in the LCF; if they are lower (e.g. due to the capacity market or unconventional gas exerting downward pressure) CfD issuance is constrained.

However, it is also important to be aware that other elements of EMR will also be impacting the level of wholesale prices. In particular the Carbon Price Floor will, on its present trajectory, exert significant upward pressure on prices (while fossil fuel is the price setter). If there were to be a change in approach (see "Carbon Price Floor Update" below) this may have a considerable impact on CfD capacity.

In addition DECC has stated that the capacity market will dampen wholesale electricity prices (see "Capacity Market Update" above). A reconciliation of this with previous analyses based on marginal cost pricing has not been provided, but if it were not to be correct there would clearly be significant affordability issues. The extent of any such dampening will again be important for LCF headroom.

Notwithstanding the above, there already seem to be numerous competing claims on the LCF.

The analysis below was prepared by GL Garrad Hassan. While it pre-dates the announcement of the interim LCF amounts, they do not seem materially at odds with the assumed trajectory. Other consultations have come to similar conclusions.



Source: GL Garrad Hassan

16 Control totals for the Levy Control Framework will be set in nominal terms at the relevant Spending Review.

The above does not take into account Hinkley Point C (albeit it is not clear that difference payments in relation to this will start within the relevant time scale, and if not whether it would still require an allocation from existing limits) or other Investment Contracts. It appears that there will be an LCF sub-limit for Investment Contracts, but this has not yet been determined (see "Investment Contracts Update" below).

This work at the least raises the spectre of moving from "first-come-first-served" allocation to allocation rounds (and technology pots or sub-limits?) in an accelerated process. (Please see our December 2012 bulletin on The Energy Bill http://www.allenovery.com/UK-Electricity-Market-Reform for further detail on allocation rounds.)

DECC has previously suggested that the trigger point for allocation rounds could be if 50% of the allocation budget for an individual year is used. While much detail remains under discussion this would seem inevitably to lead to less certainty for investors and ever-deeper involvement of Government in technology if not project, choice.

Policy on CfD Terms

Last month DECC announced its policy approach to a number of the key contractual terms for CfDs. These are set out below together with our comments on the policy decisions.

Please see Allen & Overy's bulletin of December 2012 on The Energy Bill (http://www.allenovery.com/UK-Electricity-Market-Reform) for further details of the issues around these CfD related topics and which supplement the below commentary.

Draft contract terms for the key terms going to value of the CfD are to be published in August with the final contract drafting to be published in December.

CfD Term	DECC Policy Decision	Commentary
Contract term: Length of the contract from point project is commissioned (i.e. starts generating).	**Contract length standardised, but flexibility to adapt to technology requirements** Renewables projects (under the 'standard' allocation mechanism) – 15 years of payments. Biomass conversion – all contracts cease to pay in 2027 (regardless of start date), consistent with the approach under the RO and reflecting the transitional nature of the technology. Flexibility for the Secretary of State to adjust contract term for projects where technology justifies a different duration (e.g. nuclear, CCS, tidal range and potentially large hydro projects).	Note that the payment period will be reduced if commissioning and the fulfilment of the other conditions necessary for the Start Date to occur is delayed beyond the Target Commissioning Window (as this may be extended for Force Majeure and delays caused by the failure of the transmission and distribution system owner, as the case may be, to carry our agreed connection of reinforcement works) This is consistent with the position set out in the CfD Operational Framework. The flexibility for the Secretary of State to adjust contract terms for technology specific issues is constrained by the written Ministerial Statement of October 2010 in relation to subsidy and nuclear power. The application of such flexibility will no doubt be part of the State aid considerations for such CfDs however. It will be interesting to see whether the 15 year term (in the context of the published strike prices) is sufficient to attract investors to renewables projects, particularly offshore wind, in the volumes required to deliver the desired new capacity. It is important to remember that the CfD provides more than just a mitigant to wholesale price exposure – it is also an important mitigant for change in law/policy risk. Given that Ofgem have already established a forum to consider what the future market will look like after EMR, this may be a concern for investors as it will be unclear whether exposure to the wholesale price after expiry of the CfD will be a sufficient mitigant for accepting such "change" risk.
Inflation indexation: How strike prices are adjusted for inflation.	**Index-linked payments** Strike price fully indexed 100% to Consumer Price Index (CPI) throughout entire term.	The Government believes that this approach will facilitate investment by opening up the sector to new capital flows from a wider pool of investors (including those seeing index-limited exposure). It also believes that it represents a more efficient risk allocation between consumers and investors as investors will not have to price inflation risk into their strike price decisions.

CfD Term	DECC Policy Decision	Commentary
		We query the value for money of this standardised approach for the following reasons: – whilst some investors do seek inflation protection on their equity returns this is not a universal requirement from new pools of capital; – inflation linked debt (which could be enabled by this structure) is not always the most desirable – it depends on market conditions at the time; and – the underlying cost base of many "fuelled" renewables plant does not obviously correlate to CPI (particularly biomass, CCS and nuclear) so that investors will still need to take a view on their inflation risk in the strike price; and – renewables plant will only have a significant exposure in its operational cost base to CPI if it borrows inflation linked debt to fund or refinance its construction and development costs; and – the corporate inflation linked debt market is small in comparison to the sovereign linked debt market. It is unclear to us whether "linker" investors will be prepared to debt fund an EMR based project during construction (absent an IUK guarantee or other credit support). Will IUK-supported debt rather than index-linked gilts be the new normal for index-linked debt investors?
Reference prices: The difference payments are based on the difference between the reference price (a measure of the electricity market price) and the strike price.	**Payments based on a reliable measure of the market price** Intermittent technologies (e.g. wind) – hourly day-ahead price. Baseload technologies (e.g. nuclear) – season-ahead price, moving to year-ahead price when conditions allow.	The selection of the reference price is important as the "capturability" of this price is a key determinant of the return that investors in a CfD-supported project will obtain. The proposed selections, if they drive disproportionate trading volumes into the relevant markets, may also operate to unacceptably reduce liquidity at other points on the forward curve absent mitigating action. The Government has, in the Energy Bill, reserved for itself a right to make changes to electricity supply licences, conditions and related industry codes, to facilitate investment in electricity generation by promoting the availability of power purchase agreements. If independent generators are to be encouraged (which must be the intention given the explicit desire to attract new pools of capital) it may be important that this power is used to ensure that PPAs that capture the relevant reference price, and not just the availability of PPAs that leave basis risk with CfD generators, are available. Interestingly therefore, do the selection of these reference prices make it more likely that Government will need to exercise its powers in the Energy Bill in relation to the availability of PPAs and wholesale electricity market liquidity. If so, this is one of the best examples of intervention begetting more intervention. The flag that the baseload reference price could change to year ahead also raises the spectre flagged in the last operational framework that an independent expert could alter the reference price from time to

CfD Term	DECC Policy Decision	Commentary
		time to reflect changing circumstances. It will be interesting to see how this has evolved when more detail on the CfD terms is available later this month.
Refinancing gain: Whether to include any arrangements to recover higher returns from project refinancing.	**Developers free to recycle capital, consumers protected by price-setting process** No refinancing clause in the generic CfD contract. Bilaterally negotiated CfDs for large projects may have different approaches, including possible refinancing clauses.	It is unclear to us why a distinction on this issue could be drawn between technologies which are both within an administrative price setting but who are differentiated by the need for a bilaterally negotiated CfD. Having said that, we remain of the view that refinancing/recycling gain share provisions should only be required as part of an "invest-to-reinvest" arrangement so as to assure programmatic development.
Change in law and other adjustments: Protections given to developers against certain changes in law.	**Developers protected against changes in law that target a project, technology or the CfD** Compensation available for material and unforeseeable changes in law that uniquely target specific technologies, individual projects or CfD holders as a group. Protection also covers political decisions to shut down a generator, and general changes in law that have discriminatory effects without objective justification. Protection extends to such changes in law that limit a generator's ability to either deliver its output or to receive appropriate payment. Compensation will adjust strike prices to reflect 100% of operating costs, a proportion of capital costs (tapering over time) and for lost revenues, over the term of the CfD. Protection against certain changes in network charges, relating to the costs of the balancing system and transmission losses.	Power projects in the UK have generally been developed against the principle that the "owner" of the wholesale price "owns" the risk of change in law/code/regulation etc. Changes in tax of general application and foreseeable changes of law at the date of contracting have been the typical base exceptions to this approach. Whilst a little simplistic (and there are as many detailed variations on this which change between technologies and vintages of developments) there is a logic here as, in a deep liquid and transparent market, a change in underlying costs caused by a change in law will, to the appropriate degree, find its way through to the wholesale price and then onto the consumer. The electorate generally (assuming that they are all consumers of power) bears the cost consequences of a change effected by their elected representatives (or the responsible persons selected by their elected representatives). It is therefore disappointing to continue to see a reference to "certain changes in law", "material…changes", "specific" changes and "discriminatory" changes as, if this position is maintained, the "gaps" in protection from the perspective of an independent generator will need to be plugged either by additional change provisions in the market facing PPAs contemplated above or by risk pricing in the strike price. Both of these threaten value for money and delivery from new sources of capital. Notwithstanding the above, in certain respects it would appear that DECC's thinking has evolved since the publication of the CfD Heads of Terms at the end of last year alongside the introduction of the Energy Bill into Parliament. At that point, even if the change of law did meet all stated criteria, protection was only offered for net cost increases and not for losses in revenue. This was a major concern and: it appears that this has now been recognised. However, it still appears that compensation is through adjustments to the strike price and therefore relies on continued generation (and in the case of capital costs, a source of funding).

CfD Term	DECC Policy Decision	Commentary
		It is also unclear to us why it is objectionable for the consumer (rather than the investors in EMR projects) to bear the cost risk of changes in law – they are after all the people to whom the lawmakers/regulators/monopolistic SOs etc. are ultimately responsible. Finally, the EMR system (for example the credit strength of the CfD Counterparty and in relation to nuclear certain laws which implement certain treaties) rely on certain laws not changing. Changing these laws may not produce a cost or revenue consequence but may radically alter the risk profile of the relevant investment. It is possible that the reference opposite to protection for changes in law that limit a generator's ability to receive appropriate payment addresses this, though it is not immediately obvious how this will be integrated with the CfD structure and "pay-when-paid" provisions. It would be positive if DECC are grappling with this issue as we do believe investors will require comfort here. The reference to "tapering" protection for "capital" changes is interesting and we await further detail on this.
Capacity adjustment: Amount by which a developer can reduce the project capacity (with and without penalty) between applying for a CfD and commencement of payment.	**Developers provided with flexibility to vary their plans** Developers may vary capacity to a certain limited degree above or below their original proposal, without penalty. Developers will be able to exercise part of this flexibility before and part after construction. Further flexibility provided to reduce capacity delivered beyond this level, but with a reduction to the strike price, to encourage accurate planning and prevent overallocation of the available budget for CfDs.	The possibility of additional flexibility but with an incentivised arrangement outside a band is very welcome.
Conditions precedent etc.: Parameters to ensure project delivery	**Developer flexibility to deliver within a 'commissioning window'** Payments commence once specified standards are met relating to connection, metering, capacity instalment, and contract payment/collateral requirements. Satisfaction of conditions precedent outside of the target commissioning window leads to a reduction in the contract's payment term. Failure to satisfy by the long stop date could lead to termination.	These provisions seem to be broadly acceptable provided that the Target Commissioning Window is wide enough and there is appropriate force majeure protection.
Force Majeure: Criteria for when flexibility will be allowed on a developer's contractual obligations.	**Protection against events outside of the control of the developer** Force Majeure will allow relief for circumstances beyond a developer's control (which will include a 'reasonable and prudent operator test'). Additional flexibility where connection delays are caused by network operator.	The application of the RPO test will need to be carefully crafted.

CfD Term	DECC Policy Decision	Commentary
Dispute resolution: Mechanism for resolving contractual disputes.	**Clear process to resolve disputes in a timely manner, including with binding arbitration** Developer and CfD Counterparty will seek to agree informal resolution of disputes, but with access to external, legally binding determination of disputes. Government has no contractual right to impose settlements.	This seems consistent with the previously understood position.
Termination: Circumstances when contract can be terminated.	**A proportionate approach to contract enforcement** Includes material breaches of contract by generators – such as, non-payment, fraud and non-delivery of capacity (subject to Force Majeure or delay to grid connection). Measures that encourage generators to move back into compliance with the contract e.g. 'remediation plans' and payment suspension.	The direction of travel away from "loan agreement" style drafting to a more "commercial contract" style approach is very welcome. The reference to non-delivery of capacity is interesting and does not obviously reflect provisions in the version of the CfD Heads of Terms released last year. The acceptability of this will no doubt be related to the availability of appropriate arrangements if there is insufficient PPA liquidity.
Metering arrangements: How low-carbon electricity generation is recorded for the purposes of billing.	**Arrangements to support a wide-range of project types, using existing processes where possible** Loss adjusted net metered energy. Making use of existing settlement arrangements, where possible. Arrangements will be developed for transmission, distribution and private wire generation.	This seems consistent with the previously understood position.

CfD Counterparty/Supplier Obligation

Multiple CfD Counterparties

Amendments to the Energy Bill by the Secretary of State include further clarification on the circumstances in which there could be more than one CfD Counterparty. Section 7(5) of the Energy Bill now provides that the Secretary of State may exercise its power to designate a CfD Counterparty so that more than one designation has effect but only if he considers it necessary for the purposes of ensuring that:

(a) liabilities under a CfD are met;

(b) arrangements entered into for purposes connected to a CfD continue to operate; or

(c) directions given to a CfD Counterparty continue to have effect.

On one hand this may be a step in the right direction as there can now only be multiple CfD Counterparties if the Secretary of State considers it necessary (a high bar) for the purposes described above- essentially to promote/ preserve the CfD arrangements. Some comfort may also be taken from the new Section 15(3) of the Energy Bill which stipulates that the Regulations must include such provision as the Secretary of State considers necessary to ensure that a CfD Counterparty can meet its liabilities under any CfD to which it is a party. Arguably it would be hard to deliberately strand generators who have contracted with one CfD Counterparty as a result of this language.

However, it is not apparent that this amendment entirely addresses the concerns relating to the possibility of multiple CfD Counterparties (those concerns being the risk of ghettoisation, stranding and/or discriminatory treatment of generators who have entered CfDs with one CfD Counterparty). It is fundamental that Government cannot use the bankruptcy – remoteness of a CfD Counterparty as a "firewall" to prevent the effective operation of key protections in the bilateral CfDs. A single CfD Counterparty, whose performance is necessarily pivotal to the UK electricity market, significantly raises the stakes in relation to Government interventions.

Limb (a), which we understand to be intended to cover a situation where a CfD Counterparty becomes insolvent and thus there needs to be a second CfD Counterparty to take over the obligations of the first CfD Counterparty under its CfDs, is understandable. However, it is not clear to us exactly what scenarios or risks limbs (b) and (c) are seeking to cover and thus, given their broad drafting, they have the potential to undermine the comfort that can be obtained from the new form Section 7(5). The drafting of all three limbs also leaves something to be desired given that the limited recourse provisions of the CfD mean that the CfD Counterparty will have no "liabilities" in respect of difference payments to the extent it is not in receipt of relevant funds.

Principally, we fail to see why additional CfD Counterparties are needed in any circumstances other than a failure of a CfD Counterparty to meet its statutory obligation to collect sums from suppliers and/or a failure to meet its liabilities. Even in such circumstances, the legislation would ideally provide that all extant CfDs should be transferred to, and all new CfDs entered into with, the new CfD Counterparty – a point that is not yet reflected in the Energy Bill.

The Supplier Obligation

It is equally fundamental that the CfD Counterparty cannot favour specific generators or classes of generators in shortfall circumstances. There is also a new provision that when making regulations as to the apportionments of a shortfall in regulations as to the Supplier Obligation amounts received by a CfD Counterparty, the Secretary of State "must have regard to the principle that sums should be apportioned in proportion to amounts that are owed" (Section 12(3)). We are not persuaded that, of itself, such language necessarily excludes "cherry picking".

In addition to the new requirements for a duty on a CfD Counterparty in relation to the collection of the Supplier Obligation referenced in "Energy Bill Update" above, it is provided that overdue amounts of the Supplier Obligation are recoverable as a civil debt. We note however that (notwithstanding precedents in relation to Smart Hubs) mutualisation of the Supplier Obligation amongst suppliers remain optional.

As mentioned above, a further new provision states that regulations must include such provision as the Secretary of State considers necessary to ensure that a CfD Counterparty can meet its liabilities under any CfD to which it is a party. While the principle seems laudable, there remains devil in the detail, for example it does not have a timing element (and could arguably be totally obviated by pay-when-paid). Conversely if this was a reliable solution, certain other provisions would seem redundant.

Timing concerns may also arise as regards the detail of the mechanics of the SO. Clearly there is complexity in allocating CfD payment to suppliers in "real time"; however, absent extensive, and expensive, liquidity/collateral arrangements, passing the risk of timing mismatches through to generators via the CfD pay-when-paid provisions will surely be unacceptable to investors unless conservative provision for all the impacts of this has been made in the draft strike prices.

Whether this Supplier Obligation is fixed or variable is a keen design question which really resolves down to who is best placed to establish and manage at least cost the liquidity buffer (whether on a funded or unfunded basis) which will be necessary to cover deviators from the actual sums due under the CfDs for those anticipated from time to time.

Investment Contracts Update

In our EMR bulletins in June and December 2012, we welcomed the addition to the Energy Bill of a mechanism to give investors more certainty around the future terms of support and thus to mitigate against the investment hiatus that has been evident while EMR is further developed and fully implemented. Unfortunately, the progress to date and trajectory set out in DECC's updates on the FID Enabling process for renewables in March and June of this year have perhaps cast a shadow over the ability of Investment Contracts (formerly investment instruments) to provide that certainty on a timetable that will be of practical benefit to potential renewable generators.

In Update 1[17], DECC restated its objective of enabling developers of renewable energy projects to take critical investment decisions directly impacting on time to commissioning which would otherwise be delayed by the uncertainty of transition to the CfD regime. However, this objective was expressly tempered by an acknowledgment that this needs to be met in a way that supports rather than undermines the delivery and sustainability of EMR, including as to price setting and contract terms.

Therefore, perhaps as a recognition that to base Investment Contracts on a CfD regime that is not sufficiently developed will not provide the required comfort to investors and to reflect State aid problems with the proposed Investment Contract regime, Update 1 laid out DECC's plans for a two stage approach to the application and allocation of Investment Contracts, buying time for the further development of the CfD regime. Phase 1 therefore requires developers to apply for a confirmation that their project meets certain minimum eligibility criteria[18] and information on the development of strike prices, investment contract allocation and contract terms, which may, on request by the applicant, be documented in a non-contractual, non-legally binding and without prejudice, relatively standard form, "Status Letter" from DECC. Phase 2 requires applicants who have passed the Phase 1 requirements to apply for an Investment Contract.

Update 2[19] has built upon this two stage process, fleshing out the bones of Phase 2 in particular. Notably, it has confirmed that passing Phase 1 is a pre-requisite for applying for an Investment Contract in Phase 2 and therefore, as the deadline for applying for Phase 1 was 1st July 2013, if a renewables generator has not already submitted its interest in the Investment Contract process to DECC, it is probably now too late.

In summary, under Phase 2, applicants are required to reconfirm their responses to the Phase 1 criteria, flagging any material changes in circumstances. The applications are then evaluated against a set of eight criteria which are split into two categories:

(a) deliverability (both technical and financial) – intended to ensure that Investment Contracts are truly bringing forward investment that would otherwise be delayed; and

(b) industry development – intended to ensure that a project will support the creation of a developed supply chain and thus the long term growth and economic viability of industries associated with renewable electricity generation.

The eight criteria are given various weightings and, in the case of the deliverability criteria, certain minimum thresholds. Projects will be assessed and scored against all criteria in order to establish an overall score and has achieved a minimum thresholds. Projects that do not meet the minimum thresholds will be rejected, and projects that do meet the minimum thresholds will be "qualifying projects" and sent a draft Investment Contract. It appears from DECC's materials that the overall score and assessment on the criteria without minimum thresholds will be used in the

17 Final Investment Decision Enabling for Renewables- Update 1: Invitation to participate. 14 March 2013

18 These criteria are: (a) that the project is for a type of renewable electricity generation which is currently eligible to receive support under the RO; and (b) that the developer is able to demonstrate to the satisfaction of DECC that: (i) there are credible plans in place to progress the project in order to start generating electricity within the period 2014/15 – 2018/19; (ii) without an Investment Contract there is a significant risk that electricity generation to which it relates will not occur or will be significantly delayed; (iii) the project is not already accredited under the RO; (iv) the project has an expected nameplate capacity of 50MW or greater, or in the case of an offshore project, 100MW or greater, and (v) the project is located in the UK.

19 Final Investment Decision Enabling for Renewables- Update 2: Investment Contract allocation. 27 June 2013

event that there is a need to select between two applications in any affordability down-selection process (in relation to which see further below).

Applicants who receive a draft Investment Contract will have a period of time to consider the draft Investment Contract, obtain internal approvals and submit a binding application for the Investment Contract to DECC. DECC state that they do not expect to enter into substantive or detailed negotiations with applicants on the terms of individual Investment Contracts and that instead the opportunity for renewables generators to influence the terms of the Investment Contract will be over the summer of 2013 as the final form of CfD is progressed. The extent of industry participation in the CfD development process has been good to date and perhaps gives hope that the form of CfD published in December is more likely to be in a form and substance broadly acceptable to generators. However, this stance from DECC just goes to show that one cannot underestimate the importance of generators getting involved in the EMR debate as soon as possible while they still have a chance to affect the outcome. Where mark ups to the form of draft Investment Contract are suggested by applicants that do not materially alter the commercial substance of the agreement or the allocation of risk, DECC have reserved their ability to accept or reject such mark ups, whether to disclose such mark ups to other applicants, and whether to apply any proposed amendments to one Investment Contract or to all Investment Contracts on a collective basis.

Once binding applications are provided, DECC will carry out an affordability assessment and, where required due to budgetary constraints (in relation to which see further below), select those Investment Contracts which the Secretary of State will enter into and lay before Parliament in accordance with the requirements of the Energy Bill.

The most important aspect of Update 2 is the statement of so called "Investment Contract Dependencies" and the revised timetable for the application and allocation of Investment Contracts resulting therefrom. DECC has stated that entry into the first Investment Contracts is dependent upon the following:

– *Finalisation of the LCF* – as summarised under "CfD Update – LCF and Allocation Update" above, the annual profile for the LCF from 2014/15 through 2020/21 has been published, but DECC are waiting to determine if there will be any additional EMR budget constraints or constraints specific to FID Enabling that will determine the total level of funding available for FID Enabling in any individual year. It is not entirely clear what these constraints might be nor when they will be resolved[20].

– *Finalisation of the standard form CfD* - DECC state that development of the Investment Contract will be dependent on the development of all relevant terms of the standard form CfD. Precisely what is meant by "all relevant terms" is not entirely clear. The final form of CfD contract is not now expected until December 2013 and DECC's revised timetable would imply that it is this final form on which Investment Contracts will be based.

  However, there are inconsistent statements in Update 2 that suggest the full terms of the CfD will not have been wholly finalised by the time the first Investment Contracts are issued (in particular, elements such as metering, payment mechanics and collateral requirements) and that mechanisms may be included in Investment Contracts for their terms to be modified to reflect the final positions reached on such areas under the CfD. It seems strange to suggest that the "final form" CfD will not have reached a landing on matters as fundamental as payment mechanics and collateral requirements, however the fact that Investment Contacts would need to be flexible enough to accommodate shifts in the final CfD regime has always been a necessary evil of the concept of an early CfD. Indeed, even if the terms of the CfD are relatively final, the underlying legislative framework will not be fully implemented, and Update 2 highlights again the key areas of difference there will be between the Investment Contract and enduring CfD regimes as a result, including the conditions precedent to effectiveness of the payment obligations under Investment Contracts, and the fact that, at least initially, the counterparty to Investment Contracts will be the Secretary of State. This all serves to reinforce the point that a key issue will be the conditions to modification of the Investment Contract (and indeed ultimate transfer of the Investment Contract to a CfD Counterparty/ investment contract counterparty). A generator will want comfort that the elements of the CfD framework being incorporated into their Investment Contract, or to which they are being transferred, are acceptable- a slightly different type of change in law risk to that generally discussed in relation to EMR.

– *Publication of the EMR Delivery Plan* – As noted above, a draft form of Delivery Plan will be published later this month with further detail on the draft strike prices that were announced on 27 June 2013. A final form Delivery Plan with final strike prices is planned for December 2013 and DECC now expects the strike prices in Investment Contracts to be those strike prices published in December.

20 Although it is suggested this will be by December 2013.

The revised timetable is set out below, with the expected date for the first Investment Contracts now being March 2014. Learning the lessons of Update 1, there are also a number of disclaimers that the dates are subject to change and dependent on the timetable for EMR generally[21], along with a statement that the earliest date for the commencement of payments under Investment Contracts is to be determined pending development of the relevant policies, functions, systems and bodies including the timetable for settlement.

The delay in Investment Contracts being available and the uncertainties in the timetable means the instrument designed to create certainty for developers itself lacks certainty and does not provide generators with a reliable basis on which investment decisions can be made- extending the investment hiatus for another 8 months. The particular statement noted above also suggests that even after the entry into an Investment Contract, the conditions precedent to the effectiveness of the payment obligations thereunder may be more extensive than just enactment of the Energy Bill and State aid approval as was suggested in the Operational Framework and Energy Bill. At the time generators are entering Investment Contracts there will be little visibility on how and, more importantly, when issues such as settlement will be resolved, and given that such resolution will necessarily require the involvement and approval of third parties such as NGET, the value of the Investment Contract in terms of certainty is further undermined. Given that the first CfDs are still expected to be entered into in the second half of 2014, the utility of Investment Contracts for renewables may perhaps be debateable.

We note that the two updates on FID Enabling for Renewables from DECC have not extended to CCS, new nuclear and other non qualifying projects – developers have instead been instructed to approach DECC separately. It is therefore unclear what the timetable is for the development of Investment Contracts in these fields and the extent to which this process will be as transparent as that apparently envisaged for renewables.

Update 2 also provides no further update on the State aid challenges facing Investment Contracts or progress with the European Commission. There is a reminder to potential applicants that Investment Contracts will be conditional on the Energy Bill receiving Royal Assent and State aid approvals being obtained, and a warning that generators need to understand the risk that these conditions bring. Please see "State aid Update" below for further discussion of these issues.

INVESTMENT CONTRACT TIMETABLE	
Indicative date	**Milestone and activity**
27 June 2013	DECC issues this document (Final Investment Decision Enabling for Renewables: Update 2: Investment Contract Allocation)
July 2013	DECC publishes the draft EMR Delivery Plan
August 2013	DECC publishes drafts of the key CfD clauses
12.00 BST (midday) 6 September 2013	Deadline for application for Phase 2 - allocation of an Investment Contract
November 2013	Applicants for allocation of an Investment Contract in Phase 2 notified whether their projects have satisfied the minimum threshold evaluation criteria and (if so) requested to confirm in writing to DECC within 10 working days their interest in remaining in the FID Enabling for Renewables process
December 2013	DECC publishes the final EMR Delivery Plan and standard form CfD
December 2013	DECC sends Investment Contracts to applicants whose projects meet the minimum threshold evaluation criteria
February/March 2014	Applicants make binding applications for Investment Contracts
Following receipt of binding applications for Investment Contracts	Assessment of affordability against LCF settlement levels and affordability constraints DECC completes any necessary down-selection process
March 2014	The Secretary of State enters into Investment Contracts with successful applicants. Investment Contracts are laid before Parliament (subject to Parliamentary timetable)

21 The 6th September 2013 deadline for initial Phase 2 applications is the only date expressly stated to not be provisional or subject to change.

State Aid Update

The Government has indicated that it continues to work with the European Commission on the interaction of EMR with the wider EU legal framework, to ensure that EMR policies are consistent with European secondary legislation, as well as the Treaty rules on State aid.

Without State aid clearance from the European Commission, the CfDs cannot deliver investor stability. State aid is expressly a generator risk in the Heads of Terms for the renewables CfD (and it would appear under an Investment Contract given that comfort that was given in the draft Bill was deleted in the version presented to Parliament).

Risk for Generators

The proposed CfD Heads of Terms provide that if the Commission (or other Competent Authority) decide that any State aid granted or paid in relation to the CfD Agreement must be recovered then the Generator shall repay or procure repayment of the relevant sums.

Recovery is obligatory if the Commission finds aid to be illegal and incompatible, unless the Commission finds that there are exceptional circumstances which may justify waiving the recovery obligation. However, this is rarely the case.

It is sufficient for the Commission to determine in general terms the amounts to be recovered – it does not have to provide a precise calculation. We note that it is envisaged that the CfD will allow the United Kingdom to request information and then forward it to the Commission in order to consider the amounts of State aid (if any) involved. Presently the Commission does not have powers to request market parties to provide information to it; it must request the Member State alleged to have granted aid to supply the requisite information. The Commission has proposed that new powers to request information directly from market players should be included in revised legislation now under consideration in the Council.

It is not open to a Member State to offer any form of indemnity or compensatory damages if the original aid is recovered from a contract party, as that would in effect be equivalent to restoring the aid.

Definitional Issues

Given that CfDs will have a Government backed company as counter-party and will be funded by levies imposed on suppliers, it is difficult to conclude that the CfD is not a State aid measure (funded directly or indirectly through State resources) within the meaning of the Treaty. The strike price mechanism is based (at least initially) on an administrative approach to price setting and as the levy revenues are channelled through and apportioned by a State-controlled company, then past precedent confirms that 'State resources' are involved, even if the final energy customer is eventually paying the bill.

The Commission will therefore in all probability need to declare the CfD system to be compatible State aid under Article 107(3)(c) and in line with its revised EEAG (see below) for it to form the basis for investment. As explained below a guiding principle now under consideration for the planned EEAG is technological neutrality. The proposed allocation and administrative strike price arrangements as set out in the Energy Bill can probably not aspire to this goal. However, as explained below, the Commission is considering that deviations may be acceptable.

CfDs as Compatible State Aid?

As we have previously indicated, the Commission's ongoing plans to reform State aid control could have an impact on how it assesses the Energy Bill and the further roll-out of EMR for compatibility with the EU Treaty rules. The so-called State aid Modernisation (**SAM**) exercise primarily focuses on the implementation of Articles 107 and 108 of the Treaty of the Functioning of the European Union (**TFEU**).

In the summer of 2012 the Commission opened a consultation on the review of its Environmental Aid Guidelines (**EAG**), last revised in 2008, with a view to adapting them to the objective of ensuring a transition to a low carbon economy.

This consultation process is still ongoing. On 11 March 2013, the Commission (DG COMP) issued a Consultation Paper on the planned reforms to be incorporated into a new set of Energy and Environmental Aid Guidelines (**EEAG**) for the period 2014 to 2020. This latter Paper acknowledges the "*wish of some Member States to widen support for specific renewable technologies to other low-carbon energy sources including nuclear*". The Paper indicates only that this warrants "*an in-depth discussion in order to analyse whether market failures justify intervention and whether it is possible to establish ex ante rules in the framework of Guidelines while ensuring cost transparency and the internalisation of external costs*".

The Paper also indicates that the Commission favours tender and auction mechanisms to identify the most cost efficient technologies and further that instruments of support should be digressive over time.

A separate European level consultation process is also underway in relation to capacity markets and generation adequacy. The DG COMP Paper of March 2013 notes that system stability and generation adequacy may justify deviations from the principle of technological neutrality – which is one of the main principles to be applied in the new EEAG. However, if a Member State shows excessive import dependency or the outcome of the application of the principle of technological neutrality contradicts other policy objectives such as sustainability, deviations may be permitted.

While the Commission may accept the necessity of State aid to promote the transition to a low carbon economy 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 SAM exercise and the revised EEAG could have an impact on national policy: the Commission (supported by the Council) proposes to take a tougher approach to assessing aid for renewables generally, and to ensure that the level of support diminishes over time and that the support scheme itself will expire automatically once the underlying market failures justifying support are corrected[22].

Capacity Markets: National or European?

The Government appears to still be considering how the planned capacity market will interact with the EU State aid rules.

While the Government acknowledges that there are a number of potential benefits of enabling capacity located outside the GB market but connected to GB via interconnectors to participate directly in the capacity market, direct participation of interconnected capacity in the capacity market is seen as unworkable, given the challenges to allowing interconnected capacity to participate on equal terms – in particular in ensuring that interconnected plant actually deliver energy to the GB market at times of system stress. The interconnected capacity would also have to demonstrate that it is not receiving a capacity payment from another EU Member State, that it meets the pre-qualification criteria for the GB capacity market, and that it has delivered energy when needed[23].

A related issue is whether interconnection capacity would have to demonstrate that it was available for the GB market by booking physical transmission rights. As GB interconnectors have not yet moved to full market coupling and still run explicit auctions, this option is still feasible. However in accordance with EU policy, market coupling should be in place by late 2014 so that a requirement to demonstrate physical transmission rights, or requirements to meet pre-qualification criteria and to provide p ability to deliver is likely to be seen as a barrier to trade, outlawed by Article 34 of the Treaty. It is unlikely that the Commission will share the Government's view that it is 'not appropriate for interconnectors to participate directly in a capacity market as interconnectors are primarily transmission infrastructure and therefore do not directly provide capacity".

22 See the Council Conclusions on Renewable Energy, 3 December 2012.
23 Annex C: capacity market Design and Implementation Update 21.

The Commission (DG Energy) opened a consultation on capacity market mechanisms – and the need for a blue-print for an EU-wide capacity market – on 15 November 2012. The Commission observed that several EU Member States had introduced capacity markets in various ways. The introduction of different capacity markets could lead to a distortion of competition in the generation market. According to the Commission's consultation paper incompatible or poorly designed capacity markets risk distorting trading, production and investment decisions. If capacity markets become more common in the internal market the potentially distortionary effects will become greater, which undermines the internal electricity market. Therefore the Commission is of the opinion that a coherent approach on capacity markets should be developed to ensure market interventions to deliver on clearly defined security of supply purposes, and ensuring that measures comply with the requirements of both energy policy and competition policy. On the basis of the consultation process the Commission decided to provide a guidance document with respect to capacity markets, which means that capacity markets will not be regulated on an EU-wide basis. This guidance document will be issued in July 2013. The Secretary of State should take this guidance document into account if capacity market rules will be made on the basis of Chapter 3 of the new Energy Bill.

Capacity mechanisms are also relevant from a State aid perspective. As indicated above in its March Paper 2013 with respect to the reform of the EEAG, the Commission (DG COMP) considers that if capacity markets are to be found necessary, then the tendering of the capacity in an open, transparent and technology-neutral manner should be required.

Future Commission Policy Alignment

The State aid Modernisation exercise 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. This approach is to be applied to the review of its Environmental Aid Guidelines (**EAG**) – up for renewal at the end of 2013 – and now to extend to Energy and Environmental aid, and to the revision of the so-called General Block Exemption Regulation (**GBER**), also scheduled for late 2013.

All in all, the SAM process indicates that Commission scrutiny of low-carbon support measures generally will intensify and that it will demand a more exacting economic case to be made out in favour of longer term support. This may require the UK Government to demonstrate clearly that EMR does indeed 'maintain a market-based approach while addressing market failures' and is designed 'to meet the investment challenge and deliver this at lowest cost' and it must convince the Commission that less interventionist measures or alternatives are not able to meet the stated policy objectives.

Further, the impact of the Energy Bill on the wider European energy market - and in particular the impact of plans for and access to capacity markets and access to balancing markets will remain firmly within the Commission's sights as the Commission strives to maintain its own vision - as recently re-stated in its Communication 'Making the Internal Energy Market Work' of 15 November 2012 - that a well-interconnected, competitive and open European energy market is the best means to deliver a secure and affordable low-carbon energy future[24]. It is no surprise that the Commission views enhanced interconnection as the better alternative to a system of national fragmented and heavily subsidised capacity markets.

24 Com (2012) 663 final, 15.11.2012 available on DG Energy's website.

Conclusion

The European Commission has an almost exclusive competence to declare State aid to be compatible with the EU Treaty. Although the SAM will not be fully implemented until late 2013 and the current version of the EAG will not be updated and amended before that date, the roll out of the Commission's State aid reform plans will continue to cast some uncertainty over the legality of a number of provisions of the Energy Bill, and once drafted, the implementing secondary legislation. Although the Government is committed to long term policy stability, it cannot offer a protection against subsequent changes in this area of the law where this is mandated by EU law. The draft CfD Heads of Terms in fact acknowledge this, as discussed in the section on CfDs above. Generators must therefore bear the risk that the Commission can recover aid from them. It is not possible for the Government to indemnify them against this risk.

State aid control remains a highly politicised arena and the Government may well succeed in convincing the Commission of its laudable, longer term aims so that EMR can be rolled out broadly as planned.

The enforcement of EU law on freedom of movement as well as the internal energy market legislation is an entirely different matter. Although the Commission can and does launch infringement actions against Member States for failure to observe their obligations, individuals – consumers, NGOs, industry – can rely on their rights under this body of law to challenge national law that does not correctly implement European requirements. It is perhaps in acknowledgement of this risk that the Government has indicted that non-UK based generators may under certain conditions, qualify for CfDs (see "Trading Renewable Energy Internationally" below). Similarly, it has been considering whether there could be certain conditions under which interconnection capacity be admitted into the planned capacity market.

Carbon Price Floor Update

Carbon Price Support Rates

The Government has announced the 2015-16 rates for Carbon Price Support in the 2013 Budget. The substantial over-supply of the EU Emission Trading Scheme allowances has reduced the Sterling equivalent of the forecast EU ETS carbon price compared with earlier expectations. The Carbon Price Support figure has consequently increased for 2015-16 from the indicative threat of £12.06/tCO_2 to a confirmed rate of £18.08/tCO2 (2013/14 rate is £4.94/tCO_2; the 2014/15 rate is £9.55/t CO_2). The Government has also announced the indicative rates for 2016-17 and 2017-18 in the 2013 Budget and these are equivalent to £21.20/tCO_2 (revised from £14.86/tCO2) and £24.62/tCO_2).

The steep rise in the Carbon Price Support rates has been driven primarily by the increasing divergence of the UK Government's desired trajectory and a flat-lining EU ETS.

While a limited form of "backloading" has just been passed by the European Parliament (see text box below), at least giving hope that the decline of the EU ETS may not necessarily be terminal, we continue to have difficulty reconciling the divergences with the Chancellor's statement that we're going to cut our carbon emissions no slower but also no faster than our fellow countries in Europe. Further, the 4th Carbon Budget remains subject to upward revision next year if the UK's domestic commitments place it on a different emissions trajectory to that of the EU. As can be seen from the table on page 4 above, gas generation and capacity are highly sensitive to target carbon levels. An upward revision in the 4th Carbon Budget would be compatible with a more important role for gas generation.

We note that at the end of March the European Commission published for consultation a Green Paper on "A 2030 framework for climate and energy Policies" (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2013:0169:FIN:EN:PDF). This states:

> "*This framework for 2030 must be sufficiently ambitious to ensure that the EU is on track to meet longer term climate objectives. But it must also reflect a number of important changes that have taken place since the original framework was agreed in 2008/9:*
>
> – *the consequences of the on-going economic crisis;*
> – *the budgetary problems of Member States and businesses who have difficulty mobilising funds for long term investments;*
> – *developments on EU and global energy markets, including in relation to renewables, unconventional gas and oil, and nuclear;*
> – *concerns of households about the affordability of energy and of businesses with respect of competitiveness;*
> – *and the varying levels of commitment and ambition of international partners in reducing GHG emissions.*"

The UK Government formally responded to the Commission Green Paper at the beginning of this month. While supporting an ambitious greenhouse gas reduction target for 2030 (40% reduction on 1990 levels with a possibility to move to a 50% reduction in the context of a global comprehensive agreement on climate change), the UK does not believe that there should be a renewable energy target or mandatory energy efficiency target as these may not represent the most cost-effective pathway to achieving emissions reductions on terms.

This appears to be leaving the door open for a reconfiguration of the UK power market which, while still low(er) carbon,does not see the replacement of coal and previous generation nuclear plant as by renewables.

The Government remains aware of competitiveness issues and (subject to State aid restrictions) is seeking to protect electricity intensive industries from the costs of both the Carbon Price Floor and the CfD. (BIS announced a further consultation on this on 4 July 2013.) Leaving aside the questionable rationale of exempting those whom one might have thought should be the principal target of these arrangements, we note that this pushes a yet heavier burden on to retail consumers.

Emissions Allowances for stationary plants are to be auctioned as of 2013; the procedure, timing and other matters in relation to the auctioning of the EUA are regulated through the Auctioning Regulation of the Commission (Regulation (EU) No. 1030/2010) (the **Auctioning Regulation**). Due to the weak economic climate, the demand for the EUAs have been less than original expected at the time of introducing the Auctioning Regulation. Between 2008 and 2011, EUAs and emission credits for 8.7 billion tonnes of CO2 emissions were acquired, while only 7.8 billion tonnes of CO2 was created, resulting in a surplus of about 900 million EUAs. This has two implications. First, the prices of the EUAs have fallen considerably and continue to fall. From a price of about EUR30 per tonne of CO2 in 2008, the price had fallen to about EUR5 per tonne of CO2 by the beginning of 2013. Second, these surplus EUAs may be utilised at a later date when the economy improves, which may affect the EU's emissions reduction targets.

Therefore, in order to control the price of the EUAs and strengthen the EU ETS before other structural reforms are introduced at a later stage, the Commission sought to amend the timetable for auctioning the EUAs under the Auctioning Regulation to temporarily delay the issue of a part of the volume of EUAs ('backloading') for the period 2013 to 2015. To this end, the Commission sought to amend the ETS Directive (Directive 2003/87/EC) and the Auctioning Regulation. The ETS Directive was sought to be amended 'for the purposes of legal certainty' to confer on the Commission the power to adapt the timetable for each period 'so as to ensure an orderly functioning of the market'. The Auctioning Regulation was sought to be amended to allow for backloading a part of the volume of EUAs for the period 2013 to 2015, and additional auctioning of the backloaded EUAs in the period 2019 to 2020. However, at a plenary vote on 16 April 2013, 344 members of the European Parliament (MEPs) voted against the amendments, with 315 MEPs voting for it, and six abstaining.

The European Parliament's Environment Committee has proposed redrafted amendments to the ETS Directive and the Auctioning Regulation. The amendments stipulate that a maximum of 900 million EUAs can be withheld, and that the backloading can be applied only once and only in the period 2013-2020. The EUAs shall be withheld only after it has been assessed and established by the Commission that the backloading would not have a significant detrimental impact on sectors categorised as being exposed to carbon leakage risk. These amendments were passed in a plenary vote on 3 July 2013, with 344 MEPs voting in favour of it and 311 voting against.

Enhanced Wholesale Market Liquidity

Introduction

It is central to EMR that generators are able to capture the applicable reference price without an excessive discount. We believe that independent generators reliant on bank finance will need to obtain PPAs.

The Energy Bill contains potentially draconian powers for the Secretary of State.

It would permit the modification of electricity supply licences, conditions and related industry codes for the purpose of facilitating investment in electricity generation by promoting the availability of power purchase agreements.

It is specifically contemplated that such powers may impose obligations as to the terms of PPAs and the circumstances or manner in which suppliers offer to purchase electricity.

There are similar provisions in relation to promoting liquidity and new entry.

In parallel with this Ofgem proposes to intervene in the wholesale electricity market through introducing a 'Secure and Promote' condition to certain electricity generators' licenses.

Background to 'Secure and Promote' Licence Condition

Notwithstanding recent improvements, particularly in the near-term markets, Ofgem remains concerned at the poor liquidity in the wholesale electricity market.

Given the effect such poor liquidity has, and is expected to have, on, among other things, the functioning of the market and competition, and therefore:

(a) establishing the reference price necessary for the operation of CfDs; and

(b) Ofgem's objective of protecting the interests of present and future electricity consumers,

Ofgem has set out its proposal for intervention in the wholesale electricity market. Ofgem's intervention is proposed to be by means of a new 'secure and promote' condition to be added to certain electricity generators' licences. Ofgem has chosen *not* to pursue mechanisms involving: separation of vertically integrated suppliers and generators; mandatory auctions of specific products; or an obligation to trade a minimum volume, as means of improving liquidity.

Ofgem's proposals are set out in a consultation entitled "Wholesale power market liquidity: final proposals for a 'secure and promote' licence condition". Responses to the consultation are required by 9 August 2013. Following this consultation Ofgem will decide whether to launch a statutory consultation on implementing the 'secure and promote' licence condition in Autumn 2013. It is anticipated that a formal direction to amend licences would be made before the end of 2013 with the new licence condition coming into effect in in the first quarter of 2014.

Liquidity Objectives and Licence Conditions

Ofgem believes that poor availability of products and price signals can deter firms from trading in the market, which then further reduces the availability of products and prices; further, that the market therefore becomes locked in a low-liquidity equilibrium, and that there may be insufficient incentives for individual firms to break free from this equilibrium. It believes an external shock – such as a regulatory intervention – can set liquidity on an upward path; and that as firms become confident that products will be available at robust prices, they will increase their participation in the market, further improving liquidity.

Ofgem has identified three key characteristics of the wholesale electricity market that it believes need support for the functioning of a liquid, competitive market. A summary of Ofgem's proposals in relation to each of those three characteristics is set out below:

	Characteristic	Proposed intervention under S&P	Licensees subject to obligation
1	Availability of products that support hedging	**Supplier Market Access Rules** – Rules to ensure small suppliers can access the wholesale market products they need	Centrica, Drax Power, E.ON UK, EDF Energy, GDF Suez, RWE Npower, ScottishPower, SSE
2	Robust reference prices along the curve	**Market Making Obligation** – Licensees must post bid and offer prices in the market, supporting price discovery and ensuring regular opportunities to trade	Centrica, E.ON UK, EDF Energy, RWE Npower, ScottishPower, SSE
3	Effective near-term market	**Reporting requirements** – Monitoring of near-term to ensure it remains liquid. Market intervention only if necessary	Centrica, Drax Power, E.ON UK, EDF Energy, GDF Suez, RWE Npower, ScottishPower, SSE

The details of the 'Secure and Promote' obligation are proposed to be set out in three schedules to the licence condition: schedule A for the Supplier Market Access rules, schedule B for the Market Making obligation and schedule C, which sets out the reporting requirements for the licensees. It is intended that modifications to those schedules would follow the standard statutory process, including consultation phases and opportunities for appeal. The 'Secure and Promote' licence condition would be subject to the normal enforcement processes applicable to generation and supply licences, set out in Ofgem's Enforcement Guidelines on complaints and investigations.

Ofgem acknowledge that over time, the characteristics of market participants may change such that the list of licensees should change. It has indicated that it will keep the list of generators to which the licence condition applies under review. It notes that any amendments to the list of 'Secure and Promote' licensees would need to be justified in relation either to the effectiveness of the obligation or the fair treatment of different parties within the market.

As noted above, the Energy Bill contains backstop powers to enable the Government to act to promote liquidity in the event that Ofgem's liquidity project does not fully meet the Government's objectives. Ofgem's liquidity project remains the primary vehicle for achieving improvements to liquidity. Ofgem has noted that it is working closely with DECC to align its work on liquidity and minimise uncertainty for market participants.

Supplier Market Access Rules

Ofgem wishes to ensure that all market participants can successfully gain access to the wholesale market products that they need to compete effectively.

The rules seek to ensure that negotiating trading agreements with small suppliers is not treated as a low priority and that credit and collateral are subject to fair and transparent terms. It is also intended that smaller market participants are able to access the hedging products that they require.

The proposed rules provide for detailed requirements for: the negotiation of trading agreements; the determination of credit and collateral terms; smaller clip sizes; the range of traded products; and fair and transparent pricing.

Market Making Obligation

Ofgem wishes to ensure that the wholesale market delivers the necessary forward market products that generators and suppliers need to manage their businesses and compete effectively.

Ofgem has indicated that it particularly welcomes feedback in relation to the Market Making Obligation, but has confirmed its view that market making is the intervention most likely to improve liquidity and reference prices along the curve. However, due to the interactions with European financial regulation, it proposes that licensees will be able to nominate a third party to undertake market making on their behalf if they choose. Its starting point is that market making would be delivered through licence obligations. Although, some stakeholders have suggested that an industry tender process may be preferable. Ofgem believes there are practical challenges to an industry tendered approach. However, if stakeholders are able to propose a credible, practical plan for the timely implementation of market making through an industry tender process, Ofgem has indicated that it will consider it as an alternative to the market making obligation. We note that the maximum trade size a licensee is compelled to offer is 10MW, it therefore seems unlikely that this would ensure a route to market for larger generators.

The Market Making Obligation seeks to:

(a) provide regular opportunities to trade for all market participants, enabling them to meet their wholesale market needs and compete more effectively;

(b) enable the development of a series of robust prices along the curve, which can inform a range of commercial decisions, including prices offered to customers, investment in new generation and the scheduling of plant maintenance. It is expected that this will facilitate competition in both the generation and supply markets and will support security of consumers' supplies; and

(c) encourage competition between incumbent players in the market (particularly the domestic supply market), by increasing the scope for firms to compete to identify the best hedging strategy in order to provide the best possible price offer to their customers.

Proposals for the detailed rules are set out below:

<table>
<tr><th colspan="2">Market Making Obligation – detailed rules</th></tr>
<tr><td>B1 – Nominating a third party</td><td>Licensee may nominate a third party to undertake their obligation on the same basis set out in this licence condition (unless otherwise specified). The licensee must not nominate any party delivering more than one other licensee's obligation. The third party must be set up to trade with a minimum of 10 generation and/or supply licensees.</td></tr>
<tr><td>B2 – Platform</td><td>The licensee is required to market make on any GB wholesale electricity market trading platform which can be accessed by a significant number (e.g. 10) of generation and/or supply licensees</td></tr>
<tr><td>B3 – Products</td><td>The licensee must post bids and offer prices in the following products:
Baseload: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3, Season+4
Peak: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3.</td></tr>
<tr><td>B4 – Availability</td><td>For each of the listed products the licensee must post prices within the bid-offer spread limits specified for more than 50 per cent of the market opening time in any given calendar month.
If a third party meets the obligation of two firms: the third party must post prices within the bid-offer spread limits specified for more than 80 per cent of the market opening time in any given calendar month.</td></tr>
<tr><td>B5 – Bid-offer spreads</td><td>When market making, the licensee must maintain a spread between their bid and offer price narrower than:
<table>
<tr><th colspan="2">Baseload</th><th colspan="2">Peak</th></tr>
<tr><td>Month+1
Month+2
Quarter+1
Season+3
Season+2</td><td>0.3%</td><td>Month+1
Month+2
Quarter+1
Season+1
Season+2</td><td>0.7%</td></tr>
<tr><td>Season+3
Season+4</td><td>0.5%</td><td>Season+3</td><td>1%</td></tr>
</table></td></tr>
<tr><td>B6 – Obligation to trade</td><td>Providing normal prerequisites are in place (e.g. a GTMA and credit agreement), if requested, the licensee must trade at posted prices.</td></tr>
<tr><td>B7 – Trade size</td><td>At any particular posted bid or offer price, licensee must be willing to trade in clip sizes of 5MW. The maximum trade size the licensee must execute is 10MW, although they may trade larger volumes if they wish.
If a third party is nominated to meet the obligation of two licensees: the maximum trade size multiplies accordingly.</td></tr>
</table>

Near-term Markets

Ofgem does not presently propose to intervene in near-term markets, the expected costs exceeding the benefits of intervention. Ofgem is satisfied that a number of developments in the market (developments including market coupling and the bringing together of the two day-ahead auction platforms in Great Britain through the virtual 'GB Hub' in 2013; and the incentive on CfD generators to trade in order to capture the CfD reference price) should help to ensure that the volumes seen on day-ahead auction platforms remain regardless of regulatory intervention. Ofgem has indicated that it will continue to monitor this part of the market and will be prepared to intervene if necessary. The proposed reporting requirements licence condition reflects this position.

Wholesale Liquidity

It is possible that the choices of reference prices for CfDs will tend to stress the liquidity curve; perhaps the Market Making Obligation can counteract this.

Notwithstanding all the above and the "big stick" the Secretary of State is being granted under the Energy Bill, the question remains whether the arrangements will give sufficient confidence to both debt and equity investors that the markets will be such that, in conjunction with a CfD, they will provide low carbon generators with the stable revenues, insulated from wholesale price risk, which are intended to be the centrepiece of EMU.

A further consideration is whether these licensing conditions provide a firmer basis for new entrants on the supply side of the market, notwithstanding the potential headwinds from the aspects of EMR such as collateral and mutualisation of suppliers' funding obligations.

Trading Renewable Electricity Internationally

Background

The Government is looking at how to enable industry to export renewable electricity out of the UK, as well as enabling it to be imported from qualifying generators. In April 2012, DECC issued a Call for Evidence on Renewable Energy Trading (the **Call for Evidence**). In June 2013 DECC published a summary of the responses that it received (the **Summary**), while indicating that it intends to set out a clear policy position at the end of 2013.[25]. This:

– recognises that importing electricity could be an attractive opportunity with much potential;

– confirms that Government is minded to take up some level of physical trading so long as it can be made to work; and

– outlines the further actions it is taking in order to overcome barriers to trade in renewable energy.

Final decisions will be announced at the end of the year.

Renewables Energy Directive

The Renewables Energy Directive (the **Directive**) includes provisions setting out "flexibility mechanisms" designed to allow Member States to partially[26] fulfil their renewables generation targets in, or with, other countries. Although DECC remains confident that the 2020 renewable energy target could be met through domestic action alone, it has indicated that flexibility mechanisms will be considered if proposals demonstrate cost savings compared with an alternative, wholly-domestic approach.

DECC also believes that renewable energy trading represents an opportunity for the UK to capture energy from wind and marine resources for export to regions that lack such advantage and that this potential supply could be very significant.

The three flexibility mechanisms are described in the Call for Evidence:

(a) Statistical transfers (Article 6): whereby one Member State with an expected surplus of renewable energy can trade it statistically to another Member State. This form of trade may take place without any accompanying physical flows of energy, i.e. only the 'renewable value' of the energy is transferred.

(b) Joint projects (Articles 7 – 10): whereby a new offshore or onshore renewable energy project in one Member State can be co-financed by another Member State and the 'renewable value' of the energy can be shared between the two. This form of trade between Member States may take place with or without any accompanying physical flows of energy, but if there was no physical flow then it would likely take the form of a statistical transfer. Joint projects for renewable electricity can also occur between a Member State and a third country (including Crown Dependencies), but only if the energy produced in the third country is imported into the EU.

(c) Joint support schemes (Article 11): whereby two or more Member States agree to cooperate on all or part of their support schemes for developing renewable energy and share out the renewable value by agreement between them.

The Directive does not set out a detailed framework by which these mechanisms will operate.

25 https://www.gov.uk/government/publications/response-to-call-for-evidence-on-renewable-energy-trading
26 The flexibility mechanisms cannot be used to meet the 10 per cent. renewable transport sub-target.

Response to Call for Evidence on Renewable Energy Trading

(a) Statistical Transfers

DECC has said that the majority of responses to the Call for Evidence opposed the use of this mechanism, some strongly, either because they felt it was an undesirable option, or because it was unfeasible. Common objections are understood to be its uncertainty, inability to confer lasting benefit, and impact on investor confidence. Questions were also apparently raised about the impact of any large statistical transfers on the operation of the non-UK state's electricity market. Fewer submissions are understood to have felt that such transfers may have a role, but that they might carry higher risk, or perhaps that transfers could be used to 'fine tune' a deployment path. On the other hand, there appears to have been a minority view that it could be a helpful 'first step', with divergent views about the role of the private sector in such a mechanism. Although open to the full range of options for meeting the 2020 target, in the light of the current uncertainties about feasibility and cost, Government has stated that it does not believe that it is possible to make plans for engaging in statistical transfer at this stage.

(b) Joint Projects

These were considered largely in the context of physical flows of energy. DECC has said that it is clear from the submissions received that there is strong interest in joint trading projects across a range of developers in different geographies, many with much experience and expertise.

The current development of renewables projects in the Republic of Ireland, and the wider economic benefits that may flow from connecting to generation close to UK territory has already lead to a programme of work with the Irish Government to tackle some of the issues and barriers to projects raised in submissions (although it is emphasised this should not be taken as an endorsement exclusively of that one country). A number of possible scenarios are apparently being explored: for example, collaboration between the UK and the Republic of Ireland on a 'first phase' of international trading for the purpose of meeting the 2020 target, which would also serve as a vehicle for resolving a series of barriers to wider market and system integration with Europe. It is thought the outcome of this work could help accelerate the 'All Islands Approach'[27] and contribute to further integration of EU electricity markets as renewables penetration increases. Government discussions with the EU Commission indicate it remains strongly supportive of Member States' use of flexibility mechanisms. However, more generally, the Government's final preferred policy position is being refined.

(c) Joint Support Schemes

DECC has indicated that it does not believe that it is appropriate, at this stage, to develop Joint Support Schemes. There is a concern that UK consumers should only fund, through taxation and/or levies on energy bills, schemes over which the Government retains control.

Future Developments

DECC expects to focus on physical trading over the coming months and in particular policy, technical, and regulatory barriers. DECC anticipates principal work streams to comprise, amongst other things:

(a) Drafting of an Intergovernmental Agreement with the Republic of Ireland, including discussion with the EU Commission as to how such an agreement would work in practice. The UK has entered into a period of negotiation with the Irish Government on the precise content of this document, which will need to include provisions to mutually bind each party in a way that allows trading to go ahead at lowest risk and cost.

(b) Development of the UK Government's approach to support mechanisms. This includes the mechanism's structure, how any support level might be set, and how it could be allocated. For example, the powers in the Energy Bill currently proceeding through Parliament allow the Secretary of State to enter into bilateral negotiation with international projects should he choose to do so. DECC is considering this now, but does not expect to develop a clearer view until after summer 2013.

(c) The treatment of transmission assets. There are a range of regulatory and policy questions about how any wire should be treated, and DECC is working with the regulator and others to devise an approach for projects seeking to export power for 2020.

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27 This refers to the UK, Irish Republic, Channel Islands and the Isle of Man working together to exploit major renewable resources and better co-ordinate interconnectivity. Also see: www.britishirishcouncil.org/sites/default/files/file%20attachments/20110620%20Energy%20Grid%20BIC%20Summit%20Discussion%20Paper%20-%20AIA.pdf

GIB and IUK

UK Green Investment Bank plc

The Chief Secretary to the Treasury's announcements on 27 June 2013 also included further news in relation to the funding of UK Green Investment Bank plc (**GIB**). Since its launch in November 2013, GIB has committed £635million of the £3billion initially allocated to it across all of its priority sectors, and has entered into a memorandum of understanding with Abu Dhabi's state backed renewable energy company, Masdar to explore opportunities to jointly invest in green infrastructure projects in the UK over the next seven years.

GIB's investments to date have been made in the context of the State aid approvals obtained by the Department of Business Innovation & Skills for the initial funding of the bank, which, as we highlighted in our EMR bulletin in December 2012, require GIB's investments to be in accordance with the market economy investor principle. What has become clearer over the last 9 months is the significance of other limitations in that State aid approval, notably the requirement that GIB operate under an "additionality" principle pursuant to which GIB will only participate in transactions where projects have been unable to obtain sufficient funding at a reasonable market rate. The tension between the obligation to invest on terms on which a market investor would invest on one hand, and the obligation to invest where others are not prepared to invest on the other, is axiomatic and perhaps acts as a break to the bank's ability to fulfil its mission of accelerating investment in the UK's transition to a green economy as it walks the tightrope of complying with both requirements.

However, there has been relatively strong cross party support for GIB and the work that it has been doing – many being surprised at the fact the bank is up and running and investing so quickly. This was rewarded by the announcement from the Chief Secretary to the Treasury, Danny Alexander, that the Government has allocated a further £800million to the bank in the year 2015/2016, up to £500 million of which can be borrowed from the National Loans Fund (the permission to borrow therefore coming a year earlier than the revised expectation in the Chancellor's December 2012 Autumn Statement). As we noted in December, the allocation of the additional funds and the power to borrow will require further approval from the European Commission, however it is a sign that the government sees a role for GIB going forward and emphasises the intended trajectory of GIB eventually being funded in full from sources other than the UK Government.

Infrastructure UK

The issue earlier this year of £7.5m of notes by Drax Power guaranteed by HM Treasury in connection with the biomass conversion of three units of Drax power station, was the first transaction under the new UK Government Infrastructure Guarantee scheme since the announcement of its launch in July 2012. Since then Infrastructure UK has become increasingly fundamental to thinking about long-term financing for major new generation projects.

In conjunction with the recent DECC announcement, HM Treasury announced that it had pre-qualified Hinkley Point C for a UK Government Infrastructure Guarantee of up to £10 billion.

Devolution

DECC will be seeking to agree a Memorandum of Understanding on how the UK Government and Devolved Administrations will work together on EMR on an ongoing basis.

DECC is considering a separate strike price for renewables projects located on Scottish islands (where these have clearly distinct characteristics to typical mainland projects). There will be a consultation on this issue in the summer. DECC anticipates that a differential strike price will be set for these projects in the final Delivery Plan in December.

DECC will continue to work with Department of Enterprise, Trade and Investment in Northern Ireland on their decision on applying strike prices in Northern Ireland. The capacity market will not apply in Northern Ireland and Investment Contracts relating to generation in Northern Ireland will require the consent of the Department of Enterprise, Trade and Investment (although it is not anticipated that CfDs will be offered in Northern Ireland until 2016).

ANNEX 1: Quick reference guide to the capacity market

Current Position

The current proposals for the high-level design of the capacity market as set out in the Detailed Design Proposals and capacity market Strawman v11. published in June 2013 are as follows:

- ***Trigger*** – Government is minded to run the first auction in 2014 for delivery of capacity in Winter 2018/19. The plan is now to implement transitional arrangements for DSR in advance of first full delivery year in order to develop the capability of the sector[28].
- ***Volume of Capacity*** – Ministers are to decide the total amount of capacity needed. This is to be calculated by reference to: (i) an enduring reliability standard established in the EMR Delivery Plan[29] to indicate the acceptable level of security of supply and (ii) a demand curve providing an auction price cap and the ability to reduce opportunities for participants to exercise market power.
- ***Pre-qualification process*** – A mandatory pre-qualification process for all eligible generators will allow providers to opt in or opt out of the capacity market and request to set the bid price as price makers or participate only as price takers. It is also used to confirm each providers eligibility status and de-rated capacity prior to the auction.
- ***Competitive Auction*** – Capacity, as determined by Ministers, will be contracted through a competitive central auction in a reducing clock format, run by the SO, carried out four years ahead of the delivery year in question.
- ***Further Auction*** – A further year ahead auction will be held in the year immediately prior to the delivery year. DSR (which will find it difficult to participate in an auction four years before delivery) is expected to participate in the year ahead auction and will be subject to earlier transitional arrangements for years before the first year ahead auction.
- ***Eligibility*** – Capacity receiving CfD support will not be eligible to participate in the capacity market, at least while CfD prices are set administratively. A decision has been made that neither RO not FiT supported capacity will be eligible either until the RO/FiT has expired, although it remains to be seen if CHP benefiting from the RHI will be able to participate. The Government is keen to find a way for interconnected capacity to participate in the capacity market to increase efficiency and competition. Currently, however, due to the complexity of energy trading arrangements between markets it is not possible for interconnected capacity to participate in the first capacity market.
- ***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) and will be penalised if they fail to deliver energy at times of system stress.
- ***Pricing*** – Government favours a "pay as clear" approach for both new and existing plant, so that every successful provider is paid the clearing price set by the most expensive successful provider that bid into the auction. New plant are likely to bid as ‘price makers’, existing plant will default to participation as ‘price takers’ and only be allowed to bid up to a set threshold unless they can justify that they face ‘net going forward costs’ and are accepted as a price maker. Plant due for significant refurbishment may enter as a price maker subject to sufficient evidence of the proposed refurbishment and satisfaction of a materiality threshold.
- ***Payment Model*** – A government owned settlement body (currently proposed to be Elexon) will be responsible for payment flows. The settlement agent model would be underpinned by collateral provided by suppliers and payment defaults will be mutualised, so that the settlement agent is always in a position to pay capacity providers.

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28 Permanent reductions in electricity demand (EDR) could also participate. Government has amended the Energy Bill to enable this and is considering whether to pilot the approach before final decisions on EDR are made.

29 To be established in December 2013 following consultation in July 2013.

- ***Length*** – A one year contact is proposed for existing capacity, with new capacity eligible to choose a contract between one and ten years (without consideration being given to plant being required to offer a longer period to the SO as an alternate). Plant that begin construction between May 2012 and the first capacity auction will have the option of being treated as 'new', to ensure there is no disincentive for plant to be built before a capacity market is introduced. Refurbished plant are eligible for contracts between one and three years (with consideration being given for up to five years).
- ***Delivery*** – Plant that are awarded a Capacity Agreement will be penalised if they fail to deliver energy at times of system stress. Capacity obligations will be load following which means that providers are only obliged to deliver the percentage of their obligation that is proportional to the percentage of relevant demand at the time of system stress. A Capacity Market Warning is delivered 4 hours in advance of an anticipated stress event.
- ***Financial support*** – Suppliers must provide collateral to cover defaults equivalent to one month's payment obligations in the event of default. There is no requirement for collateral to be posted by generators.
- ***Secondary Trading*** – Capacity Agreements would be able to be traded on the secondary market at any time from a year ahead of the delivery year. Sufficient notice must be given to, and consent obtained from the SO who will assess the party's eligibility and pre-qualification to participate. Plant that has taken on obligations, opted out or declared they would be retiring will not be eligible to take an additional obligations by secondary trading.
- ***Portfolio providers*** – A providers' performance is assessed at a portfolio level which enables portfolio operators to net across plant. However, the penalty cap applies to portfolios as a whole.
- ***Locational issues*** – The proposed capacity market is still intended to apply across Great Britain only, because the single electricity market for the island of Ireland already uses a capacity market and it is not yet possible to include interconnectors. The possible need to switch to zonal auctioning in the future is acknowledged and will be taken into account if and when it is needed on the basis of non GB capacity being eligible for the capacity market.

Further Work

Issues around the capacity market on which Government continue to work and are yet to be finalised include:

- Potential solutions for participation of interconnectors in future auctions;
- Ability of renewable CHP capacity receiving support through the RHI to participate in the capacity market;
- The possible need for a zonal auctions is not thought to occur in the initial years of the capacity market but SO will need to future proof its IT System to cater for this;
- State aid discussions with European Commission;
- Consideration of potential pilot for EDR;
- Consultation on Capacity Agreement lengths; and
- Determination of the price taker threshold and auction price cap.

ANNEX 2: Capacity market impacts on generation types

Table of Generation Types

Type	Treatment in the Capacity Market
Oil	No special treatment.
Gas	The capacity market is likely to have the greatest impact on gas generation, one of the capacity market's primary aims is to ensure medium term electricity supply as old plant close and support gas fired generators as they face difficult market conditions. The capacity market should provide comfort to investors in new gas plant.
Coal	The capacity market is designed to be technology neutral, and as such will benefit coal plant too. However, coal plant that participate in the capacity market but subsequently choose to co-fire biomass and as a result receive RO or CfD support will be under a duty to inform the SO prior to the delivery year, at which point the Capacity Agreement will be terminated and they will thereafter be ineligible to take on capacity obligations. If a plant enters the pre-qualification stage as a standard co-firing biomass plant and takes on capacity obligations, in order to receive its capacity payments, it must demonstrate to the SO prior to the delivery year that it has ceased co-firing biomass.
CCS	Where CCS is a beneficiary of CfD support it will be ineligible to participate in the capacity market (at least while levels of support for CfDs are set administratively). This is regardless of whether the capacity runs in unabated mode at certain times during a delivery year and will include circumstances where capacity is increased temporarily to respond to peaks in demand. ** CCS capacity not in receipt of a CfD, or unabated units within a partly abated power station, will be eligible to participate in the capacity market.
Biomass	See above for approach to coal plant that switch to or from biomass co-firing. As a beneficiary of CfD/RO support biomass will be ineligible to participate in the capacity market (at least while levels of support for CfDs are set administratively).**
CHP	CHP is eligible to participate in the capacity market, however, the Government is yet to confirm if CHP that is in receipt of support through the RHI will be eligible to participate in the capacity market.
Waste	See CHP above for EfW with CHP.
Renewables Generally	As a beneficiary of CfD/RO support most low carbon renewable technologies will be ineligible to participate in the capacity market (at least while levels of support for CfDs are set administratively).**
Offshore Wind	As a beneficiary of CfD/ RO support offshore wind will be ineligible to participate in the capacity market (at least while levels of support for CfDs are set administratively).**
Nuclear	As the capacity market is technology neutral, existing nuclear (not in receipt of CfD support) will be eligible to participate. As a beneficiary of CfD support new nuclear will be ineligible to participate in the capacity market (at least while levels of support for CfDs are set administratively).
Interconnectors/ "Supergrid"	As described above, due to the complexities of the interaction with the European market it will not be possible for non GB interconnections to participate in the first capacity market auction. Going forwards, the Government is committed to work on a solution to this and exploit the benefits of interconnected capacity participating in the GB capacity market.

** Technology benefitting from RO/FiT support will be eligible to enter the capacity market once their RO or FIT support has expired provided they meet all other eligibility criteria (such as minimum size). However, with the exception of biomass co-firing plant, RO-accredited plant will not be eligible to terminate their 20-year term of RO support early in order to bid in to the capacity market.

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