



Department  
of Energy &  
Climate Change

# Electricity Market Reform: Consultation on proposals for implementation Government Response

June 2014

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# 1. Introduction

## Consultation overview

1. The Electricity Market Reform (EMR) programme is promoting investment in secure, low carbon electricity generation, while improving affordability for consumers. EMR will primarily be implemented through the Energy Act 2013 and secondary legislation.
2. In October 2013 the Government published the consultation *Electricity Market Reform: Consultation on proposals for implementation*<sup>1</sup>. This sought views on the proposals for implementing the key mechanisms for reforming the electricity market - Contracts for Difference (CFDs) and the Capacity Market - as well as their institutional and delivery arrangements. The consultation was published alongside a package of draft secondary legislation designed to help illustrate the proposals.
3. In November 2013 the Government published an addendum to the consultation<sup>2</sup>, the *Supply Chain Plan Consultation*, which set out proposals for implementing the key eligibility criteria of a supply chain plan for larger projects taking part in the allocation process for a CFD. Analysis of the consultation questions in the November 2013 addendum and final policy positions are included in this Government Response.
4. The EMR implementation consultation closed on 24 December 2013. During the consultation period a total of five workshops were held on the CFD and Capacity Market proposals in London, and in each of the Devolved Administrations. The Government also continued to engage with stakeholders during this time through the existing EMR Expert Groups, industry workshops, other industry fora and meetings set up by EMR policy teams.
5. In total 123 responses were received to the EMR implementation consultation. Responses were received from a wide range of stakeholders, including energy suppliers, generators, consumer bodies, the renewables industry and EMR Delivery Partners. We

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<sup>1</sup> See <https://www.gov.uk/government/consultations/proposals-for-implementation-of-electricity-market-reform>

<sup>2</sup>In December 2013 a further addendum, *Electricity Market Reform: Consultation on Regulations for Contracts for Difference (Standard Terms and Modifications)*, was published. This publication built on the information published in the implementation consultation document and set out the Government's intended policy positions for four areas of the CFD regime. The feedback provided as part of this consultation informed the final regulations. Analysis of the consultation questions and final policy positions are included in a separate Government Response. This is available at <https://www.gov.uk/government/consultations/consultation-on-regulations-for-contracts-for-difference-standard-terms-and-modifications>.

would like to thank all those who took the time to engage with the consultation by attending a stakeholder event or submitting a response. A full list of respondents is included in Annex A.

6. The publication of this document and the laying of the implementing legislation in Parliament represent the completion of the design phase of the new reforms. The Government is working closely with our delivery partners to implement these reforms, with the first CFDs under the enduring regime<sup>3</sup> expected to be allocated in Great Britain by the end of 2014; and the first capacity auction expected to be run by the end of 2014, for delivery of capacity in winter 2018/19, subject to Parliamentary process and State Aid approval.
7. Published alongside this document is *Implementing Electricity Market Reform*<sup>4</sup>, which details the final decisions on the new arrangements, following the proposals set out in the consultation document. *Implementing Electricity Market Reform* is a guidance document designed to offer a comprehensive picture of the EMR programme in a single document and is intended to be a useful resource for industry and other stakeholders. For each question or set of questions, this Government Response signposts to the relevant sections of *Implementing Electricity Market Reform*.
8. The final decisions taken as a result of this consultation have been reflected in the implementing secondary legislation and supporting documentation<sup>5</sup>. However, some of the aspects of EMR were outside the scope of this consultation and subject to separate consultation and decision-making processes, for example the CFD strike prices, EMR Delivery Plan, approach to CFD budget allocation and standard terms of the CFD<sup>6</sup>.

## Electricity Market Reform

9. The reformed market will incentivise up to £100 billion of the further investment in electricity infrastructure which is required up to 2020 in order to ensure future security of supply, and in a way which meets the UK's legally binding decarbonisation and renewables targets. This is through two new mechanisms:
  - **Contracts for Difference** (CFDs), to incentivise low carbon generation; and
  - The **Capacity Market**, to incentivise development of reliable capacity to ensure security of supply.
10. The mechanisms must achieve the objectives above in a way which minimises costs to consumers, and DECC's latest analysis suggests household electricity bills will on average be £41 (or 6 per cent) lower per year over the period 2014-30 under the

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<sup>3</sup> In April 2014 Investment Contracts (an early form of CFDs ahead of the start of the enduring regime) were awarded to eight projects under the Final Investment Decision (FID) Enabling for Renewables process.

<sup>4</sup> See <https://www.gov.uk/government/publications/implementing-electricity-market-reform-emr>

<sup>5</sup> The Capacity Market Rules and the Allocation Framework.

<sup>6</sup> Full details of these consultations can be found on the [www.gov.uk](http://www.gov.uk) website.

reformed arrangements compared to meeting the Government's objectives with existing policy instruments<sup>7</sup>. For businesses, bills are expected to be 7-8 per cent lower.

11. The Government's commitment to implement these reforms and transform the UK's electricity system to ensure that the future electricity supply is secure, low carbon and affordable was announced in 2010 with further detail on the intended reforms set out in a 2011 White Paper<sup>8</sup>. In the period following this significant progress has been made on developing the proposals, and in December 2013 the proposals became law as the Energy Bill received Royal Assent to become the Energy Act 2013.
12. Publication of *Electricity Market Reform: Consultation on proposals for implementation* and the associated draft secondary legislation represented a major milestone for the EMR programme, and since then CFD strike prices for renewable technologies and an updated version of the CFD contract have been published. As set out in paragraph 6, the design phase of EMR is now complete and delivery is expected this year.
13. Investment is already being unlocked as a result of these reforms. In April 2014 Investment Contracts (an early form of CFDs) were awarded to eight projects under the Final Investment Decision (FID) Enabling for Renewables process. These projects could add a further 4.5GW of electricity to the UK's generation mix, providing up to £12 billion of private sector investment by 2020, and supporting 8,500 jobs<sup>9</sup>.

## Analysis of consultation responses

14. For every consultation question set out in the October 2013 consultation and supply chain addendum we have set out the question in this document along with a summary of responses received<sup>10</sup> and details of the decisions taken.
15. All responses received as part of the October 2013 consultation and supply chain addendum have been considered in developing final policy positions in the areas covered, and we have sought to ensure stakeholder concerns have been addressed in the final design, where this has been appropriate. Given the volume of responses

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<sup>7</sup>Based on an illustrative carbon emissions intensity of 100gCO<sub>2</sub>/kWh for the power sector in 2030, analysis based on average emission levels of both 50gCO<sub>2</sub>/kWh and 200gCO<sub>2</sub>/kWh in 2030 are available as part of the EMR impact assessment:

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/288463/final\\_delivery\\_plan\\_ia.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/288463/final_delivery_plan_ia.pdf)

This figure does not include EMR administrative costs, a summary of which can be found in the Supplier Obligation IA, available at: <https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform>. Estimates provided in the Supplier Obligation IA suggest that EMR administrative costs up to 2020 are relatively small; average annual cost of between 30 and 40 pence per year for households from 2015 to 2020. Further information on energy prices and bills is available at: <https://www.gov.uk/government/publications/estimated-impacts-of-energy-and-climate-change-policies-on-energy-prices-and-bills>.

<sup>8</sup> *Planning our electric future: a white paper for secure, affordable and low-carbon energy*. See <https://www.gov.uk/government/publications/planning-our-electric-future-a-white-paper-for-secure-affordable-and-low-carbon-energy>

<sup>9</sup> All figures are estimates based on information from industry on the eight projects awarded contracts and compiled by DECC.

<sup>10</sup> Where the summaries of responses include a breakdown of views (for example 'the majority' or 'half of respondents') this refers to the responses to that question only, and is not in relation to the total 123 consultation responses received.

## Introduction

received not all views received are reflected in the summaries of responses set out in this document. These summaries are intended to provide a representative overview of the feedback received and to explain why final decisions were taken.

16. The analysis in this document also takes into account feedback received during the consultation workshops<sup>11</sup>, and similarly this feedback has been considered in coming to final policy decisions.

## Next steps

17. The decisions taken in light of this consultation are reflected in the implementing secondary legislation, which includes Statutory Instruments (SIs) as well as the CFD Allocation Framework and Capacity Market Rules. The implementing secondary legislation has been laid in Parliament alongside the publication of this document, and is expected to come into force by the start of August. The secondary legislation coming into force will enable the process for issuing the first CFDs under the enduring regime, and the first capacity auctions to start later this year.

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<sup>11</sup> The slides from the consultation workshops can be found on the *Engaging with DECC on Electricity Market Reform* webpage on the [www.gov.uk](http://www.gov.uk) website. See: <https://www.gov.uk/government/publications/engaging-with-decc-on-electricity-market-reform>



# 1. Implementing Contracts for Difference – questions and responses

## Investment Contracts

Consultation question		36 responses
CFD1	Do you agree with the approach outlined in section 3.2.1.2 of the consultation document to treat Investment Contracts as CFDs once they have been transferred to the CFD Counterparty in order to allow the CFD Counterparty to administer and fund these contracts in the same way as CFDs?	
See <i>Implementing Electricity Market Reform</i> section: 1.4.2.3		

### Summary of responses

All respondents were broadly supportive of the approach to treat Investment Contracts as CFDs once transferred to the CFD Counterparty<sup>12</sup>.

Some respondents raised concerns about the potential impact of any delays to State Aid approval, and questioned what mitigating options would be introduced in the event of such delays.

It was also suggested that awarding Investment Contracts to the projects progressing in the FID Enabling for Renewables process which had not yet secured planning consent could potentially lead to a lack of parity between Investment Contracts and CFDs, since planning consent is one of the eligibility criteria under the CFD allocation process.

### Decisions taken since consultation

The Government intends to transfer Investment Contracts to the CFD Counterparty. Where Investment Contracts are transferred to the CFD Counterparty they will be treated as CFDs for the purposes of the regulations concerning the supplier obligation<sup>13</sup> and will therefore will be funded as CFDs from contributions made by electricity suppliers.

A State Aid conditions precedent has been included in Investment Contracts, making clear that the contract is conditional upon the receipt of State Aid approval, which reflects concerns raised by some respondents. If this condition precedent is not fulfilled, the generator is entitled to terminate the Investment Contract within a specified termination period in the contract. Similarly, if there is a delay beyond this termination period in receiving State Aid, the generator is also entitled to a day for day deferral in their Milestone Delivery Date and initial day of the Target

<sup>12</sup> The Low Carbon Contracts Company Limited (LCCC) will be designated as a CFD Counterparty and is intended to be the only CFD Counterparty for the foreseeable future. For ease of comparison with the consultation document, the majority of references to the LCCC remain as the 'CFD Counterparty'. This also applies to the Electricity Settlements Company, the incorporated name for the Capacity Market Settlement Body.

<sup>13</sup> Further details of the supplier obligation are described at questions CFD10-CFD53.

Commissioning Window. If State Aid approval is not obtained by a longstop date in 2017, the contract can be terminated by the CFD Counterparty.

In response to the point raised regarding lack of parity between Investment Contracts and CFDs, the planning and consents requirements for qualification under Phase 2 of the FID Enabling for Renewables process varied between technologies as set out in Level 3 Criterion 1.1.3 (in Update 2)<sup>14</sup>.

Under the generic CFD, due diligence is not undertaken on projects and so the contract needs to include parameters (such as planning consent) to help ensure the deliverability of projects.

### CFD budget

Consultation question		49 responses
CFD2	Do you agree that Government should be able to increase the budget allocation to the EMR Delivery Body without further consultation, but should be restricted from reducing this for applicants within an allocation round?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.2.2.4		

### Summary of responses

The vast majority of respondents were supportive of this approach. However, some respondents expressed concern with the knock-on impact increasing the budget may have on the budgets for subsequent delivery years, or on suppliers' costs and consequently consumers' bills. Some responses also suggested that to maintain investor confidence the Government should be prevented from reducing the budget in a set timeframe prior to (in addition to within) an allocation round.

Respondents also highlighted the need for a robust process and transparency when making any changes to the budget.

### Decisions taken since consultation

After issuing a Budget Notice ahead of the opening of an allocation round (which must be issued no later than 10 working days before the first date applications may be made in the application round), the Secretary of State can revise the budget by issuing a Budget Revision Notice. A Budget Revision Notice can increase or decrease the budget if it is issued at least 10 working days before the first date that applications may be submitted in the allocation round. After that point, in light of the consultation responses, we have provided first that budgets can only be increased and, secondly, that maxima and minima may only be increased if the overall budget is increased by at least the same amount.

We note that some stakeholders called for a longer timeframe prior to the opening date for applications in which the budget cannot be reduced. However, this would not be practical given the interdependency of the CFD and RO budgets under the LCF. CFD budget allocation is

<sup>14</sup> See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/209367/2013\\_-\\_06\\_-\\_27\\_FiDe\\_Update\\_2\\_Master\\_Draft\\_2\\_.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/209367/2013_-_06_-_27_FiDe_Update_2_Master_Draft_2_.pdf)

informed by the setting of the RO obligation for the next financial year which is confirmed annually at the end of each September. To fix the budget significantly in advance of applications being made in an allocation round would mean making imprudent budgetary decisions that do not fully take into account the likely RO spend.

The Delivery Body must inform DECC of the total value of applications before proceeding to the allocation process, (i.e. the process that determines which of the qualifying applicants will be offered a CFD, a process which may include a form of auction). The Secretary of State would then have five working days to decide whether to increase the budget before the allocation process commences. It is envisaged that for the first allocation round this would be before applicants are invited to submit sealed bids.

The Government notes concerns from stakeholders that an increase to the budget in one round may reduce available budget in subsequent years; this will be one of the factors which the Secretary of State will consider if and when a decision to increase the budget needs to be made.

Consultation question		54 responses
CFD3	Do you have any comments on the use of minima and/or maxima budgets, the case for technology-specific and general auctions, and how they might best support value for money and the management of the CFD budget (within the LCF)?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.2.2.2		

### Summary of responses

The vast majority of the responses focused on the use of minima and maxima; with over a third of respondents expressing support for minima and maxima, and a further quarter for minima (with no mention of maxima). Many of these responses indicated the conditions in which they believed minima or maxima should apply, and/or the groups of technologies which they should be applicable to. Many respondents stressed the need for transparency on the rationale for the application of minima or maxima budgets.

Fewer respondents provided views on auctions. There were mixed views on the introduction of auctions; several responses rejected auctions outright whilst those responses which supported technology-specific auctions favoured auctioning for less established technologies. A small number of respondents also commented, with mixed views, on the auction mechanics e.g. pay-as-clear vs. pay-as-bid.

Several responses called for early visibility of the auction design and Allocation Framework.

## Decisions taken since consultation

In January 2014 the Government published *Electricity Market Reform: Allocation of Contracts for Difference - Consultation on Competitive Allocation*<sup>15</sup> which set out the approach to competitive allocation under Contracts for Difference. This consultation was launched as part of efforts to give stakeholders more information on the circumstances in which a competitive allocation would take place. In the Government response to that consultation (May 2014), we confirmed our intention to move to a competitive process for all low carbon technologies as soon as practicable in order to reduce costs of decarbonisation for consumers.

The Government will divide the CFD budget between a grouping of more established technologies and a grouping of less established technologies, and, for the first allocation round, run allocations (concurrently) for each group. Competitive allocation of CFDs has the potential to improve value for money, whilst supporting new entry and innovation.

The Government launched a further consultation in May 2014<sup>16</sup>. This proposed a single 100MW minimum allocation for wave and tidal stream projects and that no other minima or maxima would be introduced within the first Delivery Plan period<sup>17</sup>. The 100MW minimum would apply across all years until the end of the Delivery Plan period, and would apply across both the RO and CFDs. The consultation also considers the allocation approach for onshore wind projects on the Scottish islands and for biomass conversion projects. This consultation closed on 10 June 2014 and we plan to confirm the policy position in July 2014.

We have undertaken extensive stakeholder engagement to develop the design of the CFD auction under competitive allocation, including through collaborative development in autumn 2013, and more recent CFD Expert Group sessions. We have also used responses to publications in August 2013, and the October 2013 EMR consultation, as well as the January 2014 consultation on competitive allocation to further shape the design.

On 8 April 2014 the Government published a summary of the allocation process alongside a draft of the Allocation Framework<sup>18</sup>. The summary document describes the allocation process, in particular the intended interaction between what will become (when approved by Parliament) the Contracts for Difference (Allocation) Regulations 2014 and the Allocation Framework<sup>19</sup>. The draft Allocation Framework sets out, amongst other things, the detail of the application process, for example, the eligibility and qualification assessment process, detailed auction rules and the valuation formula – matters which are required by the Contracts for Difference (Allocation) Regulations 2014.

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<sup>15</sup> See <https://www.gov.uk/government/consultations/electricity-market-reform-further-consultation-on-allocation-of-contracts-for-difference>

<sup>16</sup> See <https://www.gov.uk/government/consultations/electricity-market-reform-allocation-of-contracts-for-difference>

<sup>17</sup> Delivery Plans will be published every five years; the first Delivery Plan period will run from 2014/15 to 2018/19.

<sup>18</sup> See <https://www.gov.uk/government/publications/electricity-market-reform-contracts-for-difference>

<sup>19</sup> Only the Contracts for Difference (Allocation) Regulations 2014 are subject to a parliamentary process. The Allocation Framework is not but is dependent on the Regulations being approved by Parliament.

## Eligibility criteria

Consultation question		44 responses
CFD4	Do you agree with the proposed eligibility criteria set out at Annex D of the consultation document? Do you have any further comments that should be taken into account in finalising these eligibility criteria (you may wish to refer to the August Allocation Methodology document)?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.3.		

### Summary of responses

The majority of respondents agreed with the eligibility criteria as set out in Annex D to the EMR implementation consultation document, however a number of respondents had concerns in specific areas or requested additional detail on the criteria. These included:

- **Grid connection offer/acceptance:** Approximately a quarter of respondents asked for greater flexibility on the requirement for grid connection offer acceptance, suggesting that an offer should suffice given the costs associated with securing a signed agreement. One respondent suggested that this requirement could prove a barrier for smaller or community funded projects that would find it difficult to meet the costs of a connection agreement.
- **Overplanting<sup>20</sup>:** Some respondents requested clarity on whether the capacity and location of projects can differ from what is stated in the consent and grid connection to account for adopting an overplanting strategy.
- **Biomass CHP:** Respondents flagged that the current CHPQA Standard and Guidance Note 44 only refer to the RO and need to reference CFDs; and should also include the relevant consents and permits for Scotland.
- **Biomass conversion:** It was suggested by one respondent that biomass eligibility criteria should include specific legally binding wood sourcing requirements.
- **Supply chain plan:** The supply chain process was challenged by a number of respondents, who questioned its benefit and/or raised concerns over its potential to delay the process of CFD allocation.
- **Bid bonds:** Three respondents objected to use of bid bonds as a penalty for non-delivery.
- **Other technologies:** Comments included that eligibility should be extended to include low carbon hydrogen and fuel cells; that phasing policy<sup>21</sup> should be extended to other

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<sup>20</sup> Overplanting is where installed capacity exceeds the grid connection capacity.

technologies; and some respondents requested bespoke criteria and timelines for unproven/nascent technologies.

### Decisions taken since consultation

- **Grid connection offer/acceptance:** The policy intent is that applicants who connect directly to the grid will hold a grid connection agreement; applicants connecting indirectly (private networks), will hold an agreement with the operator of the private network that permits connection to the grid; and applicants not connecting to the grid will have to declare that no connection is applicable at the time of application. These requirements are specified in the Allocation Framework and Allocation Regulations as well as section 2.2.3.1 of *Implementing Electricity Market Reform*.
- **Overplanting:** We are not proposing to make specific provision for ‘overplanting’. However, the Allocation Framework will specify that applicants will only be required to demonstrate that their projects have a grid connection agreement for capacity equal or greater than 75 per cent of the initial capacity estimate, at the point of application. In practice this will allow certain projects to ‘overplant’ capacity, whilst also ensuring that the commissioned capacity cannot exceed the maximum contract capacity.
- **Biomass CHP:** In line with requirements for other technologies, there will be no requirement for an eligibility check that a plant is biomass CHP. Reference to the Guidance Note 44 will be solely within the CFD contract (and administered by the CFD Counterparty) for determining the output of the plant for calculating CFD payments. As indicated by consultees, revisions will be required to CHPQA Guidance Note 44 to reference its use for CFD payments. It is expected that a revised CHPQA Guidance Note 44 will be published by the end of September 2014.
- **Biomass conversion:** The Government does not agree that applicants in respect of biomass conversions should have a requirement placed on them not to source domestic wood. Analysis published by DECC on use of UK wood for biomass conversions and CHP shows that electricity generators interested in conversions intend to source material from abroad as the UK supply chain is poorly developed and of insufficient size to meet their needs. This information has been published at: [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/246006/UK\\_wood\\_and\\_biomass.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/246006/UK_wood_and_biomass.pdf). This analysis will be repeated on a yearly basis.
- **Supply chain plan:** As detailed in the *Allocation Methodology for Renewable Generation*<sup>22</sup>, the Government is keen to ensure that renewable investment supports the development of sustainable supply chains and increases the scope for competition between providers in order to lower costs to consumers. Therefore, any CFD applicant

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<sup>21</sup> Large offshore wind projects are likely to be built in a series of stages. The CFD has been designed to accommodate this approach to construction.

<sup>22</sup> See

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/226976/Allocation\\_Methodology\\_-\\_MASTER\\_-\\_6\\_Aug\\_v\\_FINAL.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/226976/Allocation_Methodology_-_MASTER_-_6_Aug_v_FINAL.pdf)

with a project capacity of 300MW or more will be required to provide the Secretary of State with a supply chain plan, setting out how their project and procurement strategy will support the development of a diverse, robust supply chain and support innovation and the development of skills.

Regarding delays to the process, the Government has now removed the 90 day approval timeframe. The timetable is set out in the *Supply Chain Plan Draft Guidance*<sup>23</sup> which includes the window for submission of the plans in order to ensure that the assessment will be completed within 30 working days, although borderline cases may take longer. The Electricity Market Reform (General) Regulations will require the Secretary of State to assess plans as soon as reasonably practicable. In addition, the draft Electricity Market Reform (General) Regulations 2014 now include a power to allow the Secretary of State to suspend the supply chain requirement for the first allocation round if it is not possible to assess all supply chain plan applications before the last date on which CFD applications can be made for the first allocation round.

- **Bid bonds:** Bid bonds were initially discussed as part of the auction design as a way to incentivise developers to commission. However, the Government’s position remains that bid bonds will not be required as part of the CFD allocation process.
- **Other technologies:** Technology eligibility was consulted on and finalised in the *Allocation Methodology for Renewable Generation* publication (August 2013) and therefore was out of the scope of this consultation.

There are a number of technologies which currently receive support under the Renewables Obligation, for which we are not currently setting a strike price or offering the option of bespoke negotiations. These technologies are biomass co-firing, dedicated biomass (using solid and gaseous biomass), standard bioliquids and geopressure. Detailed reasons for this position are set out in the *Allocation Methodology for Renewable Generation* document.

As set out in the *Allocation Methodology for Renewable Generation*, only offshore wind will be considered as phased projects. This aligns with and builds on the existing RO structure which allows offshore wind projects to structure their projects in a way that recognises that they deploy over a number of years, whilst maintaining a level of protection for both the Government and consumers against risks of non-delivery, late delivery and gaming that phased projects may otherwise introduce.

Consultation question		13 responses
CFD5	Do you have any further comments that should be taken into account in finalising eligibility criteria for Northern Ireland?	

<sup>23</sup> See <https://www.gov.uk/government/publications/supply-chain-guidance>

See *Implementing Electricity Market Reform* section: 1.5.1

### Summary of responses

The majority of respondents commented that NI eligibility requirements should be aligned or comparable to the GB equivalent, or that no additional criteria should be applied. Further comments included that NI eligibility requirements should take into account the differences in regulatory and market frameworks and associated timelines, including NI's commitment to 40 per cent renewable electricity generation by 2020, and the convention that developers cannot make an application for grid connection before a project has received planning consent.

### Decisions taken since consultation

The Government's policy aim is to ensure that the eligibility criteria act as a filter that identifies those projects likely to progress to commissioning. However, we recognise that there will be differences to NI planning systems, regulatory and legislative frameworks, amongst others, and these differences will be reflected as we continue to develop the NI CFD policy.

Consultation question		26 responses
CFD6	<p>Do you agree with the eligibility criteria for dedicated biomass CHP and the decision to offer the strike price for Qualifying Power Output only?</p> <p>Do you agree with the proposed five year safeguard measure?</p> <p>Do you agree with the use of Guidance Note 44?</p> <p>Do you agree with the approach to Energy from Waste CHP?</p>	
See <i>Implementing Electricity Market Reform</i> section: Annex A		

Do you agree with the eligibility criteria for dedicated biomass CHP and the decision to offer the strike price for Qualifying Power Output only?

### Summary of responses

Just under half of respondents agreed with the eligibility criteria for dedicated biomass CHP and the decision to offer the strike price for Qualifying Power Output only. Reasons for disagreement included that the criteria is not suitable for biomass CHP as the risk of losing a heat contract and hence losing CFD support would make financing impossible to secure; the ineligibility of dedicated biomass with no CHP should be revised; and that the five year safeguard should be extended to other technologies e.g. Energy from Waste CHP or power stations that were previously fossil fuel generating.

### Decisions taken since consultation

We recognise that the proposed approach may represent a risk for biomass CHP investors relative to arrangements under the RO. However, the strike price has been set – and the CFD contract designed – with the specific intention of bringing forward biomass CHP projects. The approach suggested by some consultees of providing support on Total Power Output would risk paying for electricity-only dedicated biomass, which is not the intended policy outcome. This



runs counter to Government policy which is not to provide new support for electricity-only, new-build dedicated biomass.

In addition, support for CHP must be compatible with Energy Efficiency Directive (EED) Article 14<sup>24</sup>, which requires support for CHP to be subject to the electricity produced originating from high-efficiency cogeneration and the heat being effectively used to achieve primary energy savings. Some consultees argued that plant which were designed as CHP, but subsequently lost their heat load and operated as power only plant, met the EED requirements and could still be considered eligible for CFD support as biomass CHP. We consider that while there are circumstances in which compliance with this requirement can be based on plant design, e.g. in the case of a grant to a plant which is not yet operational, the EED does require actual operational performance to be taken into account in assessing eligibility for ongoing support.

Another approach suggested was to implement a lower, dedicated biomass (electricity-only) strike price for plant which had commissioned as biomass CHP and subsequently lost their heat load. However, it is difficult to envisage how a lower level would be both sufficient to bring forward investment and low enough to avoid encouraging biomass (electricity-only) projects in respect of which there never was any intention of operating as CHP on an on-going basis. We therefore intend to maintain the position set out in the consultation document that the CFD will only support Qualifying Power Output.

Do you agree with the proposed five year safeguard measure?

### **Summary of responses**

The vast majority of respondents who commented on the safeguard measure (just under half of all respondents) welcomed the approach, but several suggested that the safeguard period would need to be increased to be effective. One respondent felt that there should be no safeguard at all, in line with other technologies. Another respondent proposed that the safeguard should also apply to Energy from Waste with CHP.

A small number of respondents suggested that the safeguard provision would be of greater value if it was a floating period that could be triggered at any point during the CFD contract.

### **Decisions taken since consultation**

Providing support solely for Qualifying Power Output means that a CHP project losing its heat customers loses CFD support even if it continues to generate renewable electricity. This risk applies uniquely to CHP. Consultation feedback confirms that some safeguard measure to address this risk is essential in order to secure investment in biomass CHP, in line with our objectives. In our view a longer safeguard period would not be consistent with a strike price intended for stations that are good quality CHP in normal operation. In addition, the EED requires the primary energy savings to be determined under normal conditions of use. However, moving to a 'floating' five year safeguard, which can be used at any point during the CFD lifetime (with the five years not necessarily being consecutive) is consistent with providing

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<sup>24</sup> See [http://ec.europa.eu/energy/efficiency/eed/eed\\_en.htm](http://ec.europa.eu/energy/efficiency/eed/eed_en.htm)

support for plant whose normal operation is as CHP and significantly increases the security offered by the safeguard.

We therefore intend to implement - for the CFD only - a floating five year safeguard for dedicated biomass CHP. This will be implemented within an updated CHPQA Guidance Note 44. We will keep the safeguard provision under review if evidence emerges that it is not proving effective in bringing forward investment and if credible alternative approaches that would provide greater investment certainty are identified.

We do not believe that a safeguard is required for Energy from Waste CHP as continued operation in power-only mode remains economically viable in the absence of CFD support due to payment of gate fees for waste.

#### Do you agree with the use of Guidance Note 44?

##### **Summary of responses**

Of the respondents commenting on the use of Guidance Note 44, the majority were in agreement. One suggested that the timelines for certification should be extended as the details of individual heat customers will not be finalised at the time of making a CFD application. Therefore certification should be obtained prior to the commencement of support/close of the Target Commissioning Window. The other respondent suggested that eligibility requirements for biomass CHP be tightened to require it to meet an overall efficiency of 70 per cent.

##### **Decisions taken since consultation**

After considering the suggestion to extend the timeline for certification, and in line with requirements for other technologies, the Delivery Body will not check CHPQA certificates at application. CHPQA certificates will be verified by the CFD Counterparty through the CFD contract and reference to the Guidance Note 44 will be solely within the contract.

In order to remain an eligible generating station and receive CFD payments, successful CFD projects must meet CHPQA Guidance Note 44 certification requirements which are central to ensuring that support is given only to good quality CHP with clear heat off takers, in line with our objectives. The Government Response on the review of qualification criteria for renewable CHP<sup>25</sup> set out our views on efficiency requirements for biomass CHP and why we did not believe a 70 per cent overall efficiency requirement to be appropriate.

#### Do you agree with the approach to Energy from Waste CHP?

##### **Summary of responses**

With the exception of the above proposal by one respondent to extend the safeguard provision to Energy from Waste CHP, all respondents agreed with the proposed approach.

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<sup>25</sup> See

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/211917/D13\\_813935\\_CHPQA\\_Consultation\\_Government\\_Response.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/211917/D13_813935_CHPQA_Consultation_Government_Response.pdf)

## Decisions taken since consultation

The policy will remain as that set out in the consultation document.

## Allocation process

Consultation question		39 responses
CFD7	Do you agree that the proposed split between regulations and the CFD Allocation Technical Framework <sup>26</sup> is the best way to implement the policy, whilst retaining the necessary flexibility?	
See <i>Implementing Electricity Market Reform</i> section: 2.1.1		

## Summary of responses

The majority of respondents agreed with the proposed split between the regulations and the Allocation Framework. A number of respondents said that any changes to the Allocation Framework should be subject to consultation, and others indicated that they would want to see further details of the split before commenting further.

A small number of respondents were opposed to the Allocation Framework on the grounds that it creates too much uncertainty, and suggested that all policy should instead be set out in the regulations.

## Decisions taken since consultation

The consultation document set out the proposed split between the Contracts for Difference (Allocation) Regulations and Allocation Framework. The main changes to the proposals set out in the consultation document are:

- References to First Come First Served (FCFS) have been removed. This is because contracts will be allocated on the basis of allocation rounds and the period of First Come First Served will no longer apply (see response to CFD8).
- Frequency of allocation rounds are not specified in the regulations. The regulations specify the process for formally announcing allocation rounds and budgets and the notice periods that apply.
- The Allocation Framework will not include budget information. This will all be included in a Budget Notice that must be published at least ten working days before an allocation round opens for applications.
- Regulations provide that an Allocation Framework cannot be revised less than ten working days before the opening date for applications for the allocation round to which the framework applies.

The first version of the Allocation Framework reflects policy positions that have benefitted from extensive engagement with stakeholders. Whilst there is no legal requirement to consult on changes to the Allocation Framework, the Government intends to give notice of any changes

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<sup>26</sup> To note that the Allocation Technical Framework is now known as the Allocation Framework. The change is for presentational reasons and not because of any change in the detail that will be contained in it.

that it intends to make and will consider whether – and in what form – engagement with stakeholders on any proposed changes might be appropriate. This approach ensures that minor changes can be made in a timely way, whilst also allowing for engagement with stakeholders where this is appropriate.

Consultation question		45 responses
CFD8	Do you have any further comments on any aspects of the design of the allocation process set out in this section (you may wish to refer back to the detail of the allocation process set out in the August 2013 Allocation Methodology)?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.3		

### Summary of responses

A range of comments were received on the allocation process, including:

- Respondents sought greater clarity and visibility on the CFD budget and allocation process. Over a quarter of comments received stated that further detail was needed to adequately assess the process or to provide investor confidence. A number of respondents wanted clarity on how unallocated budget or the allocation system would work in the event that a project is not awarded a CFD due to budget constraints.
- Clarity on the appeals or challenge process – some respondents wanted a clearer process route to challenge the outcome of the allocation process and wanted to know how under the current system a successful appeal would impact on the overall allocation.
- Supply chain plans – some respondents reiterated their concerns with the requirement to submit a supply chain plan and its potential for delays and/or the need for further detail and guidance.
- Clarity on the transition from First Come First Served to auctions. Some respondents raised concerns over the lack of certainty over how long First Come First Served will apply, and others objected to the trigger to switch to auction once 50 per cent of the budget has been allocated.
- First Come First Served vs auction: A few respondents suggested that the allocation process should move immediately to auction (one suggested for mature technologies at least), or criticised First Come First Served on the grounds that it would result in a rush of projects coming forward. Conversely a small number of respondents suggested that an auction process should not be adopted at all.
- A number of respondents put forward arguments for different types of auction design, including descending clock and pay-as-bid or pay-as-clear.

## Decisions taken since consultation

The Government recognises the need for clarity on the CFD allocation process and this year has sought to develop policy positions – in consultation with stakeholders – and share these with industry as soon as practicable:

- We published our high level position on CFD auction design via an open letter<sup>27</sup> on 12 February 2014. This confirmed that the allocation approach would adopt a sealed-bid model for the first allocation round and set out the rationale behind this.
- In February 2014 the Government published a consultation on CFD allocation, which confirmed that contracts will be allocated on the basis of allocation rounds and the period of First Come First Served will no longer apply. It also confirmed that there will be constrained allocation (competition) for at least those technologies deemed ‘established’ from the commencement of allocation.
- The CFD Allocation Framework was published in draft on 8 April and set out the rules for the allocation process, including the workings of a sealed bid, cleared price auction. An advanced draft of the Allocation Framework<sup>28</sup> will be published to coincide with the laying in Parliament of EMR regulations.
- A stakeholder workshop was held on 9 April, which explained the draft Allocation Framework, and set out the auction process in detail<sup>29</sup>.
- In May 2014 a further consultation was published which confirmed our position on a move to competition for established technologies, and sought views on the treatment of individual technologies, including detailed proposals for the application of technology specific minima or maxima and an update on the LCF timeline (see CFD3).
- We have also set out more information on the process of eligibility appeals at recent stakeholder events<sup>30</sup>, and have also reflected this with additional provisions in the regulations.

It is intended that an indicative CFD budget will be published in July to give stakeholders an idea of what the budget might be three months ahead of the first CFD allocation round.

On concerns relating to the supply chain, please see the answer to CFD56 – the Government has now removed the 90 day approval time for supply chain plans and the regulations will require the Secretary of State to assess plans as soon as practicable after a supply chain

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<sup>27</sup>

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/279414/Policy\\_Letter\\_CFD\\_allocation\\_Auction\\_format.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/279414/Policy_Letter_CFD_allocation_Auction_format.pdf)

<sup>28</sup> The final version of the Allocation Framework will be published nearer to the commencement of the first allocation round.

<sup>29</sup>

See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/302725/af\\_event\\_9\\_april\\_slides.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/302725/af_event_9_april_slides.pdf)

<sup>30</sup> Slides from the stakeholder events are available at <https://www.gov.uk/government/publications/electricity-market-reform-contracts-for-difference>

application is received. The Government has produced guidance<sup>31</sup> which sets out the process for submitting and assessing supply chain plans. In addition, the draft Electricity Market Reform (General) Regulations now include a power to allow the Secretary of State to suspend the supply chain requirement for the first allocation round if it is not possible to assess all supply chain plan applications before the last date on which CFD applications can be made for the first allocation round.

### Contract management

Consultation question		46 responses
CFD9	Do you have views on any aspect of the proposals set out in this section?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.4		

### Summary of responses

The majority of respondents were supportive of the proposals on contract mechanics, including the proposal to use a coversheet coupled with standard CFD terms and conditions to accommodate potential variations to CFD contracts.

Respondents were also generally supportive of revisions to the contract when needed, subject to these being clearly communicated to industry and consulted upon. Some respondents questioned under what circumstances a review of the standard terms would be triggered, and a number requested further clarity on the ‘minor’ and ‘necessary’ criteria.

The majority of respondents with concerns focused on the pre-commissioning contract management incentives to deliver, largely the proposed timings (raised by approximately a quarter of respondents overall). A number suggested that the longstop date (LSD) should be extended to two years after the Target Commissioning Window (TCW), and similarly it was suggested that the Substantial Financial Commitment Milestone (SFC) should be extended to two years following application – particularly for offshore wind. A small number of respondents also stated that the introduction of TCWs and LSDs with penalties would increase risk and therefore costs.

The announcements on contract capacity adjustment made in the *Investing in renewable technologies – CFD contract terms and strike prices document* (December 2013)<sup>32</sup> were welcomed, however it was suggested that the Government should consider a de minimis criterion before the capacity adjustment provisions apply with greater flexibility below this.

### Decisions taken since consultation

With a finite budget to support projects, the CFD regime is structured in such a way that it requires a significant degree of certainty as to the capacity and timings of the generation it supports. Consequently, developers are expected to gauge accurately the capacity they can

<sup>31</sup> See <https://www.gov.uk/government/publications/supply-chain-guidance>

<sup>32</sup> See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/263937/Final\\_Document\\_-\\_Investing\\_in\\_renewable\\_technologies\\_-\\_CFD\\_contract\\_terms\\_and\\_strike\\_prices\\_UPDATED\\_6\\_DEC.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/263937/Final_Document_-_Investing_in_renewable_technologies_-_CFD_contract_terms_and_strike_prices_UPDATED_6_DEC.pdf)

provide in a given timeframe, and then deliver this capacity in a timely way (albeit with a number of contractual flexibilities).

There is a balance to be struck between giving developers more time than required to bring their capacity online (resulting in less efficient use of the LCF budget) on the one hand, and setting deadlines that make project timescales more challenging (thereby increasing risk and cost).

However, taking advantage of the full TCW and the period running up to the LSD, projects benefit from a significant degree of flexibility (even before Force Majeure and other contractual flexibilities are considered); with most technologies still receiving support after commissioning up to two years later than the date the developer initially nominated. These dates were set in consultation with stakeholders, and reflect advice from engineering consultants on the timescales required for each technology. Therefore, we consider that reasonably well-run projects should still be able to deliver within these flexibilities and existing timeframes.

Having considered the issues put forward on the timing of the Milestone Delivery Date (MDD), we have retained a 12 month timeline for all technologies, including offshore wind. This maintains a consistent and established policy for all technologies, one which has been visible to industry and EMR Expert Groups since summer 2013. Though we acknowledge that this position may be more challenging for certain technologies, we do not believe that it prevents projects being brought forward. We also consider that any extra burden specific to offshore wind projects is manageable and acceptable, and that it is important to ensure that developers of all technologies only apply for a CFD when they are sufficiently close to entering a substantial financial commitment (and thus are confident that they can meet the MDD requirements within a year).

Further, the robustness of the current milestones, which are based upon substantive evidence of commitment to the project, is required for the CFD Counterparty to accurately ensure the commitment of projects progressing through the development stages of the contract. Any decrease in the evidentiary burden would increase risk to the CFD budget.

The proposals to enable 'necessary' modifications of 'minor' effect were the subject of their own consultation<sup>33</sup>, conducted from 19 December until 7 February. On 23 April the Department published a formal Government Response to that consultation. The response set out our intent to closely define both concepts through regulation.

With regard to concerns raised by a small number of respondents over bespoke coversheets, the Government will need to ensure CCS CFD contracts in particular are structured to enable some of the flexibilities that will be required for early stage CCS projects.

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<sup>33</sup> See <https://www.gov.uk/government/consultations/consultation-on-regulations-for-contracts-for-difference-standard-terms-and-modifications>

## The CFD supplier obligation

### Introduction

The following questions (CFD10-CFD53) relate to the supplier obligation, which will fund CFD payments to generators.

In the October 2013 consultation document we set out proposals for a supplier obligation with the following features:

- a unit cost fixed rate levy set on an annual basis;
- an annual reserve fund to cover the risk that payments to CFD generators are higher than forecast or electricity demand is lower than forecast, and to cope with timing differences between payments in from suppliers and out to generators;
- annual reconciliation to ‘true up’ supplier payments to their underlying liabilities for CFD payments.

This fixed rate levy was proposed following a call for evidence where suppliers, particularly smaller suppliers, expressed concerns, about a variable rate levy and their ability to manage the daily volatility and uncertainty in CFD payments<sup>34</sup>.

Respondents to the October consultation raised several concerns with the proposals for an annual unit cost fixed rate levy that went beyond the specific questions asked in the consultation document. These comments are summarised in the section below on overarching levy design, together with a summary of the decisions taken in response to these general comments. The subsequent sections cover the responses to the specific consultation questions that were asked.

### Overarching levy design

#### Summary of responses

The key concerns raised by respondents were that the requirement for a reserve fund and annual reconciliation resulted in a levy that was effectively not ‘truly fixed’, as suppliers would still be exposed to actual CFD payments via the year end reconciliation process. In addition, the reserve fund was an inefficient way of managing payment risk that would be particularly hard for smaller suppliers to deal with because they would be required to make potentially large lump sum payments.

Different views were expressed on what would be the optimal design. Three large energy suppliers expressed a preference for a variable rate levy, whilst the remaining large suppliers and most smaller suppliers preferred a fully fixed £/MWh levy (incorporating a reserve fund into the £/MWh rate if required), where any surplus at year end would be ‘rolled over’ and used to reduce the levy rate in the following year (a ‘rollover levy’). Several suppliers also argued that the CFD Counterparty should be able to access working capital from HM Government to

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<sup>34</sup> See <https://www.gov.uk/government/consultations/contracts-for-difference-CFD-supplier-obligation-call-for-evidence>



manage in-year differences between payments collected from suppliers and payments owed to CFD generators, rather than collecting a reserve fund from suppliers.

Following the consultation, the Government has continued to engage with suppliers and other stakeholders on how these concerns can be mitigated. This has included considering what concerns can be addressed if it is not possible to implement a 'rollover levy' or enable the CFD Counterparty to access working capital. Of those suppliers whose first preference was for a rollover levy, two larger suppliers and two smaller suppliers indicated that they would prefer a variable rate levy if rollover or working capital was not possible. The remaining suppliers indicated that they would still prefer a unit cost fixed rate levy, but suggested that the reserve fund should be sized to cover a shorter period of time and collected more frequently, as this would reduce the total amount needed to be held by the CFD Counterparty.

These discussions also covered the question of the appropriate market share to use for calculating suppliers' CFD liabilities, particularly if the levy period was shortened from the original annual proposal. The majority of suppliers expressed a view that liability for CFD payments should be calculated on the basis of daily market share on the day that the CFD generation took place, as this would improve the degree to which the supplier obligation provided a hedge against wholesale prices for suppliers.

During the consultation period the Government also commissioned further analytical work from Baringa Partners to get a better understanding of potential variability in CFD payments, and the implications of this variation for reserve fund requirements. This work has informed our consideration of consultation responses, and the results are published in a report alongside this Government Response<sup>35</sup>.

### **Decisions taken since consultation**

Several suggestions were made in the consultation for changes to the overarching levy design, and our assessment of these is set out below.

**Rollover levy.** We recognise that there would be some advantages to suppliers if the CFD Counterparty could use surplus funds raised from suppliers in one year to reduce the levy rate in the following year. In particular, this might give suppliers greater certainty over the supplier obligation costs for the upcoming year, as they would not face any lump sum reconciliation payments at year end. However, it would represent a fundamental change to the nature of the supplier obligation, because it would break the link between CFD payments and suppliers' liabilities in-year. Under a rollover levy, suppliers would not ultimately be liable for their share of underlying CFD payments, and would instead be liable for paying the levy rate set by the CFD Counterparty before the start of the levy year. The amount collected through the levy rate in one year would never precisely match payments to CFD generators, resulting in a mismatch between the CFD Counterparty's income and expenditure. This would mean that the supplier obligation would no longer be fiscally neutral and could have an adverse impact on public sector finances. A rollover levy would therefore not be consistent with Government policy.

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<sup>35</sup> See <https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform>

**Working capital.** We recognise that there might be benefits to suppliers if the CFD Counterparty were able to access working capital instead of collecting a reserve fund from suppliers. However, working capital would have a negative impact on public sector finances, whether provided from taxpayers’ funds or through the financial markets, as it would impact on fiscal aggregates – in particular increasing public sector net debt – and potentially put taxpayer funds at risk.

The Government has therefore decided not to provide working capital to the CFD Counterparty from taxpayer funds. Our proposals in response to the consultation do, however, focus on reducing the amount of excess suppliers’ capital that is held by the CFD Counterparty at any time to reduce the impacts on suppliers.

**Variable rate levy.** In deciding not to implement a rollover levy or provide working capital, we also considered whether we should revert back to a variable rate levy, as preferred by some suppliers. A variable rate levy offers some benefits over a unit cost fixed levy as it reduces the costs associated with the CFD Counterparty holding reserve funds collected from suppliers (although suppliers may need to hold their own internal reserve funds to manage CFD payment volatility). However, concerns remain about the potential impact of daily payment volatility under a variable rate levy on smaller suppliers, some of whom indicated (after the consultation) that they would prefer a unit cost fixed levy over a variable one for this reason. We have therefore decided not to revert to a variable rate levy.

We do, however, recognise the concerns over the size of the reserve fund and lump sum payments that suppliers would have to make under the annual unit cost fixed levy as proposed. We have therefore decided to reduce the size and impact of the reserve fund by setting it and the unit cost rate on a quarterly rather than an annual basis. This would mean suppliers pay a quarterly lump sum into a reserve fund to cover CFD payment uncertainty in the following quarter only. Suppliers’ reserve and unit cost rate payments will also be reconciled against their liability for actual CFD payments on a quarterly basis. We estimate that this option will reduce the size of the reserve fund collected compared to an annual reserve fund by around 70 per cent on average for the period 2015-2020, and halve the cost to suppliers of financing the reserve fund held per year on average over 2015-2020 compared to an annual reserve fund. The costs to suppliers of financing the reserve fund are likely to be reduced by an average of £13m to £20m over the same period. The table below indicates the latest estimated impact on bills of the annual unit cost fixed rate levy compared to the new proposal of a quarterly levy.

Option	Annual average bill impact (2014 – 2020)
Unit cost fixed levy with annual reconciliation	£0.80 - £1.60
Unit cost fixed levy with quarterly reconciliation	£0.60 - £1.40

We have also decided to amend the way that individual suppliers’ liabilities for CFD payments are calculated. Suppliers’ liability for daily CFD generation payments will be calculated

according to their market share on the day of CFD generation that the payments refer to. This should improve the degree to which the supplier obligation represents a ‘hedge’ against wholesale market prices for a supplier, which should reduce suppliers’ overall uncertainty regarding its supplier obligation liabilities. Suppliers’ liability for exceptional CFD payments that are not related to generation on a particular day (such as one off compensation payments to a generator, or termination payments received from a generator) will be calculated according to their average market share over the levy period (i.e. quarter) in which the non-difference payment arose.

We recognise that there remain conflicting views on the appropriate design of the supplier obligation mechanism, so we will keep this under review after implementation of the reformed market.

Further details on how the quarterly unit cost fixed mechanism will operate are set out in the *Implementing Electricity Market Reform* document.

Comments on the specific policy questions set out in the consultation document are detailed below.

### The levy formula

Consultation question		27 responses
CFD10	Do you have any comments on the proposed formula to calculate the supplier obligation?	
See <i>Implementing Electricity Market Reform</i> section: 2.3 (overview)		

*Note that in this and subsequent sections, where respondents made comments about the overarching design of the supplier obligation mechanism these are covered in the section above.*

### Summary of responses

The majority of respondents who commented specifically on the formula were content with the proposal. Some respondents felt that it was not possible to give a full assessment of the formula without further information, including detail on how the exemption for energy intensive industries (EIs) would be calculated, and the proposals for in-year levy adjustments.

### Decisions taken since consultation

We have revised the formula for the supplier obligation in light of the changes to the policy set out above, and this is reflected in the Contracts for Difference (Electricity Supplier Obligations) Regulations 2014.

The supplier obligation formula should be considered on its own as we are still considering how the EII exemption will be implemented. The Government consulted on the eligibility for the EII exemption in August 2013<sup>36</sup>.

The Government is reviewing the eligibility for the EII exemption in response to the revised Energy & Environmental Aid guidelines (EEAG) which were published in April 2014 and will publish a separate consultation on eligibility. A further consultation on implementation, including draft regulations and a full impact assessment will be published alongside this consultation. This consultation will also include details of when the EII exemption will come into force.

### Notification and information provision

Consultation questions		
CFD11	Do you have any comments on what would be an appropriate minimum notification of the unit cost rate, bearing in mind that notification earlier than three months will be less accurate?	26 responses
CFD12	Are there any other items of information that suppliers need in order to manage CFD payments?	23 responses
CFD19	Do you have any comments on the timings outlined for notification of the amount of money required for the reserve fund?	24 responses
See <i>Implementing Electricity Market Reform</i> section: 2.3 (overview)		

### Summary of responses

The majority of respondents considered that three months' notice of the unit cost rate and reserve fund could be insufficient, yet recognised that an earlier notification period would impact on accuracy. Many respondents therefore indicated that three months' notice would be acceptable if regular forecasts of the unit cost rate and reserve fund were also supplied in advance (suggestions ranged from one to three years in advance). These forecasts could then be adjusted as new data became available. Similarly, several noted that three months would be acceptable provided suppliers were able to have sight of both the inputs and models that the CFD Counterparty will use to calculate the unit cost rate. Alternative proposals included a period of four, six or twelve months' notice, with respondents noting the former would align the notification period with the Renewables Obligation.

Almost all respondents to CFD12 called for transparency and the publication of as much information as possible. This included forecast strike prices, generation output, reference prices and demand data, and it was suggested it would be beneficial to publish this on a rolling basis. A number of respondents emphasised that early availability of information on any liabilities accruing in the reserve fund was essential, as it would allow suppliers to assess whether additional funds were likely to be required. It was also suggested that the methodology used to calculate the levy and all the input data should be made public as soon as it is available,

<sup>36</sup> See <https://www.gov.uk/government/consultations/electricity-market-reform-contracts-for-difference-costs-exemption-eligibility>

possibly via the CFD Counterparty's website. One respondent suggested that on-going provision of information on methodology and inputs should be a requirement under the regulations.

Some smaller generators and suppliers highlighted that whilst access to such information was important in managing risk, some smaller organisations will have less resource to review it. These respondents therefore requested a concise summary of the information to ensure a level-playing field with bigger, more well-resourced organisations.

### **Decisions taken since consultation – CFD11, CFD12 & CFD19**

We consider that providing three months' notice to suppliers of the interim rate and reserve fund strikes the right balance between accuracy and providing suppliers with sufficient time to raise funds and/or adjust tariffs. A longer notice period would require a larger reserve fund, and increase the chance that the CFD Counterparty would have to adjust the interim rate or reserve fund within a levy period. Therefore, we have decided to retain the requirement that the CFD Counterparty sets the interim rate and reserve fund three months before the start of the levy period to which they apply.

We agree with respondents to the consultation that it is important that the CFD Counterparty provides advance forecasts of expected CFD payments. The Contracts for Difference (Electricity Supplier Obligations) Regulations will require the CFD Counterparty to keep suppliers informed of their past and potential future liabilities under the supplier obligation. We intend that the CFD Counterparty will forecast the interim rate and the reserve fund on a quarterly basis for at least the three quarters following the quarter for which the levy rate and reserve fund have been determined – i.e. for a period of 15 months in total (since the levy rate and reserve fund are set three months in advance). The CFD Counterparty will also have the flexibility to provide longer term forecasts if it deems it necessary and practical to do so.

We also agree that it is important that the CFD Counterparty's forecasting is as transparent as is reasonably practical, to provide stakeholders with confidence that the CFD Counterparty has undertaken a robust process in determining the interim rate and reserve fund and to provide information that will enable stakeholders to perform their own modelling if desired. The CFD Counterparty is in the process of tendering for a forecasting model which will include a 'transparency tool' to help suppliers understand the basis for the forecasts and provide access to the underlying data, and is also forming an industry group to help with the design of the model. Additionally, the Framework Document<sup>37</sup> governing the relationship between the shareholder (the Secretary of State) and the CFD Counterparty will set out the shareholder's intention that the CFD Counterparty will be as open as is reasonably possible in the way that it manages the supplier obligation and operational cost levy arrangements, subject to considerations of cost, practicality, and proprietary or commercially sensitive information.

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<sup>37</sup> See section 2.4.1.4 of *Implementing Electricity Market Reform*.

## Impact on liquidity

Consultation question		24 responses
CFD13	What are your views on the impact of a unit cost fixed rate levy on the incentives for suppliers to trade in the reference market and consequently wholesale market liquidity?	
See <i>Implementing Electricity Market Reform</i> section: 2.3 (overview)		

### Summary of responses

Responses were mixed, with some respondents suggesting that while it affected the timing of cash flows and costs of financing, the design option would have little impact on liquidity; and others considering that the fixed rate levy (in contrast to the variable rate levy) will remove the incentive to hedge/trade within the market to help manage the volatility of CFD payments and therefore reduce liquidity.

### Decisions taken since consultation

After some consideration we judge that, as suppliers are ultimately liable for the exact CFD payments, there is still some incentive to hedge against CFD costs under a fixed rate levy which should improve liquidity in the markets that set the CFD reference prices. Since both a unit cost fixed and a variable rate levy should have some beneficial impact on liquidity, we do not consider that this is a critical factor in determining the design of the supplier obligation mechanism. However, we have decided to base the calculation of suppliers' liability for CFD generation payments on their daily market share on the day the generation took place, which should increase incentives on suppliers to trade in the reference market.

## Reconciliation

Consultation question		
CFD14	Do you agree with the described approach to levy reconciliation? If not, why and what alternatives can you suggest?	26 responses
CFD15	Do you have any comments on how frequently the levy should be reconciled?	25 responses
CFD20	Do you have any comments on the frequency of reserve fund reconciliation?	25 responses
See <i>Implementing Electricity Market Reform</i> section: 2.3.6		

### Summary of responses

The majority of stakeholders responding to CFD14 considered that levy reconciliation at year end undermines the benefits of a fixed rate, and called for reconciliations to be made through adjustments to future rates (the 'rollover levy' described earlier).

Nevertheless, several stakeholders believe that the approach to levy reconciliation set out in the consultation document is reasonable. Additional suggestions included that it would be

beneficial to impose a cap on suppliers' potential liability during annual levy reconciliation to allow for unpredicted costs to be carried into the future; and that reconciliations should be aligned with Balancing and Settlement Code (BSC) runs. One respondent also said that while they supported the approach they would prefer a solution which did not include the 28 month dispute run (although in responses to question CFD21 another respondent stated that it was important to include the possibility of reconciling after 28 months where the BSC had done so).

Notwithstanding respondents' support for reconciliations to be made through adjustments to the following year's rate as raised in answers to CFD14, in response to CFD15, most stakeholders agree that the levy should be reconciled in accordance with BSC timescales (usually over a 14 month timetable, although it can be up to 28 months where there has been a dispute). Some respondents showed support for reconciliation to take place with larger amounts only, with smaller amounts carried over to the following year to reduce the administrative burden. Several respondents also took the view that reconciliation should take place on a quarterly basis, or more frequently if practical.

On the reserve fund (CFD20), several respondents reiterated the view put forward in answers to previous questions that rolling over under- and over-payment into the following year would remove the need for reconciliation. Some stated that if reserve fund reconciliation were to go ahead, then annual reconciliation would be sensible, but quarterly would be preferable. Others called for reconciliations to be as frequent as monthly.

Some respondents noted that sizing the reserve fund conservatively should avoid the need for multiple reconciliations within the course of the year, or large adjustments (although some respondents to CFD16 argued against this due to the potential costs to consumers). Several also noted that infrequent reconciliation would be cumbersome for suppliers and supported calls for rolling over under- and over-payment into the following year.

### **Decisions taken since consultation – CFD14, CFD15 & CFD20**

As described above, the Government has decided that reconciliation of suppliers' interim payments (the interim rate and the reserve fund) against their underlying liabilities for CFD payments should take place on a quarterly rather than an annual basis. This will reduce the size of the reserve fund required, and therefore the opportunity costs of the funds provided by suppliers to the CFD Counterparty.

We have also decided to retain the proposals to reconcile suppliers' daily interim rate payments as supply data is adjusted through BSC reconciliation runs. However, this daily 'data reconciliation' of interim rate payments will cease once interim rate payments have been reconciled against underlying CFD payments ('levy reconciliation') through the quarterly process described above. Any adjustments to supply or generation data relating to a previous quarter will be reflected in the following quarterly reconciliation process.

Suppliers will remain liable for all data reconciliation and levy reconciliation payments after exiting the market. If they have defaulted or no longer exist, then outstanding debts are mutualised across suppliers.

More details on reconciliation processes are set out in the *Implementing Electricity Market Reform* document.

## Reserve fund

Consultation question		30 responses
CFD16	What are your views on the approach to sizing the reserve fund?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.4		

### Summary of responses

Most respondents stated that they appreciated the difficulty in sizing the reserve fund, noting the trade-off between a fund that is large enough to enable the CFD Counterparty to meet uncertain CFD payments without needing in-period adjustments to the interim rate, and a fund that is over-sized leading to excessive sums of money being held in reserve, which might be particularly difficult for small suppliers. There was widespread support for a review mechanism to ensure that reserve funds do not accumulate, and support for the reserve fund to be held in an account where interest will accrue to each party that has lodged funds.

Some respondents noted that a fully variable levy would render a reserve fund unnecessary, and a number of respondents voiced their opposition to the proposal to set the reserve fund at “conservative” level, due to costs and impact on consumers.

### Decisions taken since consultation

The Government has considered its approach carefully and decided that reducing the period that the reserve fund covers from annual to quarterly would significantly reduce the amount of money required and therefore the likelihood that the CFD Counterparty will hold excessive funds. It is expected that the average annual reserve fund collected over the period 2015 – 2020 is reduced from £340m under an annual fixed unit cost levy to £101m under a quarterly fixed unit cost levy. Moving from annual reconciliation of reserve fund payments to quarterly reconciliation reduces the estimated annual financing costs associated with a reserve fund from £24m - £36m to £11m - £16m averaged over 2015 – 2020.

However, it is also important for investor confidence in the CFD regime that the CFD Counterparty has sufficient funds to be able to meet payments to generators. The Contracts for Difference (Electricity Supplier Obligations) Regulations therefore specify that the reserve fund should be sized at a level which the CFD Counterparty determines is necessary for there to be a 19 in 20 probability of it being able to make all payments likely to be due under CFDs in the relevant levy period.

Consultation question		29 responses
CFD17	Do you have any comments on how to fund the reserve fund? What funding options will ensure the CFD Counterparty has sufficient funds to cope with unexpected events and smooth payments?	



See *Implementing Electricity Market Reform* section: 2.3.4

### Summary of responses

There was widespread support from stakeholders for the CFD Counterparty to be able to borrow, either from Government or from the financial markets. Stakeholders believed that these options would be cost effective and would lower barriers to entry in the market.

There was also some support for funding the reserve fund through letters of credit, or a mixture of letters of credit and cash to avoid frequent drawdown of letters.

Several stakeholders also expressed concern at having a reserve fund funded by an annual lump sum cash payment at the start of the funding year, as this would have a significant impact on suppliers. Instead these respondents expressed a preference for making payments to the reserve fund on a more regular basis such as quarterly or monthly.

### Decisions taken since consultation

As set out above, the Government has decided against allowing the CFD Counterparty to access working capital. We have considered whether suppliers should be able to fund reserve fund payments from letters of credit, but we do not judge that this will provide sufficient liquidity to the CFD Counterparty to ensure that it can make payments to generators when due.

However, we understand the impact that funding the reserve fund on an annual basis will have on suppliers, and to minimise that the Government has therefore decided that the reserve fund will be funded on a quarterly basis.

Consultation question		28 responses
CFD18	Do you have any comments on the approach to determining market share for payment of the reserve fund?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.4		

### Summary of responses

Suppliers were mostly consistent in their view that it is inappropriate to use one month's market share data to determine a whole year's liability for the reserve fund, as suppliers have different seasonal profiles of energy consumption and it will fail to reflect changes in market share that happen over the course of the year. There was widespread support for a quarterly calculation to accommodate movements in market share.

Some stakeholders also commented that participants should be able to challenge the forecast market share calculation and should have full visibility of how the market share has been derived for each supplier.

Some respondents also commented that using Supplier Volume Allocation and Central Volume Allocation metered sites is an appropriate methodology for determining market share as this is

consistent with Ofgem’s guidance on determining market share under the Renewables Obligation.

**Decisions taken since consultation**

The move to a quarterly unit cost levy and reserve fund means that the CFD Counterparty will no longer be relying on one months’ data to size a year’s worth of reserve fund. Under a quarterly fixed rate, we judge that it is appropriate to use the market share for the last 30 days to calculate the lump sum for each supplier for the forthcoming quarter. As the quarters change and the calculation is re-run, this will pick up changing market share. Furthermore, the quarterly levy reconciliation process means that suppliers’ interim payments will be trued up against their share of CFD payments on a more regular basis.

To clarify, the market share calculation is not forecast. Instead it based on the most recent 30 days of SF (Initial Volume Allocation Run) data which is available. Suppliers are able to dispute the market share calculation by following the supplier obligation dispute procedures.

**Settlement**

<b>Consultation question</b>		30 responses
CFD21	Do you have any comments on the reduced settlement timescale?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.1		

**Summary of responses**

The majority of consultation responses were supportive of the reduced settlement timescale brought about by daily settlement and issuing of invoices seven working days after the settlement day. Many of these cited the fact that these timescales would reduce the amount of collateral to be provided.

Those respondents who raised concerns about the length of the settlement timescale were largely concerned with how it might affect small generators. Primarily these respondents were concerned about the administrative costs of daily settlement and the fact that for small generators operating with a Power Purchase Agreement (PPA), settlement of the PPA will be monthly rather than daily. Some respondents specifically noted that they would welcome the ability to outsource settlement to another organisation, such as a PPA provider.

Some respondents also commented that the shorter timescales and the use of Interim Information (II) rather than Initial Settlement (SF) data may lead to more settlement disputes. This issue is covered in more detail in question CFD22.

**Decisions taken since consultation**

We have considered the concerns raised by a small number of respondents about daily settlement for generators. On points made regarding outsourcing, although the CFD Counterparty would be settling daily, the generator could be settled on a different timeframe such as monthly, in line with their PPA. Clause 73 of the *Update on Terms for the Contract for*

*Difference*<sup>38</sup> (December 2013) allows generators to assign the benefits of their CFD to another organisation such as their PPA provider if they so choose with the permission of the CFD Counterparty.

Where a generator chose to do this, the provider would handle billing statements and would be expected to make and receive the payments due under the CFD. These payments would then be passed on to the generator in line with the agreements that the generator has made with that provider. The generator would continue to be responsible for the payments and so where the PPA provider failed to make payments, the generator would continue to be responsible. We have discussed the potential role for PPA providers in settlement with both generators and PPA providers and understand that this is a service which the market is likely to offer.

Given the fact that the majority of respondents supported daily settlement and the fact that market mechanisms should develop to offer an alternative to those generators who may find daily settlement more difficult, we will retain daily settlement for the supplier obligation and for CFD difference payments.

Two respondents were concerned about the impact of daily settlement on small suppliers, suggesting that suppliers should be able to make payments using direct debit and additionally raised concerns about making payments on non-working days. Where we refer to daily settlement, we mean the fact that billing periods for the supplier obligation and for CFD difference periods are one day but invoices and billing statements and all payments will be made only on working days. Suppliers and generators will not be expected to process invoices or billing statement or make or receive payments on non-working days.

Consultation question		27 responses
CFD22	Do you have any comments on the use of the BSC's Interim Information Run for the first supplier obligation invoice?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.1		

### Summary of responses

The majority of respondents were broadly supportive of the use of the BSC's Interim Information Volume Allocation (II) Run, particularly in light of the reduced collateral. However, some respondents expressed concern with the proposed approach, commenting that the use of II will result in inaccuracies and could see small suppliers having to make larger up-front payments (exacerbated for suppliers with large numbers of non-half hourly meters).

One respondent commented that few existing payment processes use II data and another sought clarity as to how non-BSC data will be integrated within the II run. However, the terms for non-BSC generators (Private Wire Network Generators) are under development and are not dealt with in this consultation.

<sup>38</sup> See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/267735/EMR - Update on Terms for the Contract for Difference v8.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267735/EMR_-_Update_on_Terms_for_the_Contract_for_Difference_v8.pdf)

### Decisions taken since consultation

The use of the Interim Information (II) Volume Allocation Run data is one of the key ways in which we have proposed reducing the settlement timescale and thus reducing the amount of collateral required from suppliers. The II run is available 11 working days earlier than the Initial Settlement (SF) Volume Allocation Run on which BSC settlement begins, and so use of II means that invoices can be sent 11 working days earlier. The result is that collateral that suppliers are asked to post is 15 days smaller (11 working days plus weekends) than if invoices were based on the SF run.

Information from ELEXON suggests that for Supplier Volume Allocation registered generation and demand, the percentage of total volume of electricity settled on actuals was not substantially higher for the SF compared to the II run although there is a significant difference between half hourly and non-half hourly meters. In addition, once SF run data is available, the CFD Counterparty will carry out a reconciliation to ensure that the most recent BSC data is used for supplier obligation settlement. Given the support for the use of the II run and the significant savings in the amount of collateral to be provided, the Government considers that the use of the II run for the first supplier obligation invoice is appropriate.

Consultation questions		
CFD23	Do you have any comments on how the minimum required collateral should be calculated?	27 responses
CFD26	Do you have any comments on the amount of time necessary to size collateral requirements?	16 responses
See <i>Implementing Electricity Market Reform</i> section: 2.3.8		

### Summary of responses

The majority of respondents were supportive of the proposal to post 21 calendar days of collateral. However, some respondents caveated their support. Comments included that the timeframe would be suitable if collateral was provided through a letter of credit but would need to be reviewed if Parent Company Guarantees (PGCs) were considered acceptable forms of collateral as they may take longer to access. There was also a general concern about how bank holidays would be dealt with during the 21 calendar day period and the interactions with temporary spikes in the collateral requirement.

Several generators sought clarification on the collateral approach for generators in their response to this question.

A small number of respondents suggested that collateral should only be posted if a supplier has a history of late payments.

## Decisions taken since consultation – CFD23 & CFD26

Collateral for generators is governed by the Contract for Difference rather than the supplier obligation, and detail was provided in the *Update on Terms for the Contract for Difference*<sup>39</sup> document, published December 2013.

To reduce the cost of providing collateral, the 21 calendar day collateral cover period does not include bank holidays. Where the 21 calendar day collateral cover period falls over a bank holiday, the collateral requirement will increase by the number of bank holiday days only in that period. Suppliers will be notified of this by the Settlement Services Provider.

Consistent with the rolling 21 calendar days calculation for collateral, suppliers who experience a temporary spike in supply will be required to increase their collateral to ensure that they meet the minimum requirements. Where a supplier finds themselves over-collateralised, they will be able to request a refund of collateral held with the CFD Counterparty, as long as after the reduction they still satisfy their minimum collateral requirements.

We are therefore retaining the approaches which were outlined in the consultation document.

One respondent wished to see the analysis produced by ELEXON Ltd on the potential to use recent II run data for the BSC credit calculations. This analysis is available at [http://www.elexon.co.uk/wp-content/uploads/2012/04/ISG137\\_09\\_Removing\\_GCDC\\_and\\_CALF\\_from\\_Credit\\_calculation.pdf](http://www.elexon.co.uk/wp-content/uploads/2012/04/ISG137_09_Removing_GCDC_and_CALF_from_Credit_calculation.pdf).

The suggestion of allowing PCGs as acceptable collateral is addressed at CFD28.

Consultation question		35 responses
CFD24	Do you have any comment on how many working days will be sufficient to make payments to the CFD Counterparty, given the fact that longer payment periods would increase collateral requirements?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.1		

### Summary of responses

Overall, a slight majority felt that the proposed five working day period was sufficient.

For suppliers, the majority of respondents felt that the five working day period proposed was achievable and welcomed the fact that it would reduce the amount of collateral that suppliers were required to post. Respondents considered that the length of payment period is not a considerable problem for suppliers given the regularity of invoices for the supplier obligation. This was also supported by the fact that all licensed suppliers would already be accustomed to the shorter three working day payment period required under the BSC.

<sup>39</sup> See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/267735/EMR\\_-\\_Update\\_on\\_Terms\\_for\\_the\\_Contract\\_for\\_Difference\\_v8.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267735/EMR_-_Update_on_Terms_for_the_Contract_for_Difference_v8.pdf)

There was concern from some generators that it could be challenging, particularly for smaller generators, to make payments within this time. A five working day payment period for generators was thought to be a particular concern when the payment was relatively unusual i.e. where a short-term price fluctuation moved the reference price above the strike price. Where payment requirements are relatively infrequent, respondents said there is a greater relative burden to put in place systems to approve and make payments within a relatively short time period.

Of those who requested a longer payment period, 30 calendar days/one month was the most common suggestion.

### Decisions taken since consultation

In line with the majority of consultation responses received, we will retain a five working day payment period for supplier obligation interim levy payments.

In response to the concerns from generators that it could be challenging to make payments in the proposed timescales, we have increased the payment period to 10 working days for generators. Due to the payment periods required for BACS payments and the impact of non-working days on payments to and from the CFD Counterparty, increasing the payment period beyond 10 working days would have a negative impact on the CFD Counterparty's cash flow as it would be required to start payments to other generators for the settlement day in question before having received payments from generators. We therefore rejected a payment period longer than 10 working days.

Consultation question		36 responses
CFD25	Do you have a view on whether the settlement process (including lengths of billing period, invoicing period and payment period) should be the same for suppliers and generators, as currently proposed?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.1		

### Summary of responses

Responses to this question were split as to whether the settlement process should be the same for generators and suppliers. Those that supported identical processes did so on the grounds of simplicity and consistency.

Of the responses against, the majority of these were from generators who echoed some of the points put forward in the answer to CFD24, including that the arrangements are burdensome for smaller generators. Some considered that the differences between the obligations on suppliers and generators meant that different processes and timeframes would be appropriate. Several generators also made the case that a mirrored approach would undermine aspirations for a diverse generator community, with the complexity of daily settlement acting as a barrier to entry.

### Decisions taken since consultation

All licensed suppliers subject to the supplier obligation are already parties to the BSC and so would already be accustomed to the daily settlement and short payment periods as required by the BSC.

Amongst CFD generators, there will be a mixture of generators who are parties to the BSC and those, smaller generators who are not parties to the BSC and would not otherwise be required to deliver to these timescales. Furthermore, the collateral requirements on suppliers mean that there are clear benefits for suppliers in shorter settlement processes which would be less of a consideration for generators given the different collateral requirements under the CFD. Due to these differences we have decided that it is not essential for the settlement process for generators to mirror that for suppliers and so each process has been considered on its own merits.

### Collateral

Consultation question		20 responses
CFD27	Do you have any comments on the length of the late payment rectification period [for collateral]?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.8		

### Summary of responses

Responses to this question were mixed, with some who thought two working days was an adequate period and those who thought it should be extended.

Of the responses which stated the period should be longer, there was not agreement on the length of the period needed, with alternative suggestions ranging from three to 10 working days. Reasons for the extension included that administrative issues could lead to unnecessary termination in such a short period; that letters of credit would take longer to renegotiate; and that smaller parties were likely to be disproportionately affected due to resource or system limitations.

Some respondents asked why, compared to the BSC, a simpler collateral requirement should translate into a longer late payment rectification period; and whether collateral would be used immediately on non-payment being identified.

### Decisions taken since consultation

The Government has considered the views of respondents who requested a longer late payment rectification period against the need to ensure that the supplier obligation payment model is not exposed to undue risk of non-payment. If a supplier was allowed 10 working days to increase minimum collateral levels, the CFD Counterparty would be exposed to the risk of an uncollateralised supplier default for that period. We have, therefore, decided to retain the existing collateral rectification period of two working days. Under the proposed collateral approach, the CFD Counterparty (via the Settlement Services Provider) will notify suppliers daily of their collateral levels, giving early warning for suppliers to increase or extend existing

letters of credit or post additional cash collateral to satisfy their minimum collateral requirement. The two working day collateral rectification period is also longer than collateral rectification period under the BSC.

If, at any point during the late payment rectification period, it becomes clear to the CFD Counterparty that the non-paying supplier is in financial distress the CFD Counterparty will have discretion to draw on that supplier's collateral before the two working days have elapsed. Should an invoice remain unpaid on the day after the payment rectification period expires, and the defaulting supplier's collateral has not yet been called, the CFD Counterparty may call the collateral. The CFD Counterparty will also issue a notification to the defaulting supplier to notify them that their collateral has been called due to non-payment.

Since the consultation document was published, the Government has further considered the timing for the posting of collateral by suppliers. The consultation document outlined that suppliers would be required to lodge 21 days collateral 10 working days prior to the commencement of the supplier obligation on 1 April 2015.

Further consideration has highlighted that the approach proposed in the consultation document required suppliers to lodge collateral as security against non-payment at least 22 working days before their first interim payment for the supplier obligation would fall due. This is because a supplier's first interim payment is not due until 12 working days after the first settlement day, with the CFD Counterparty's subsequent payment to CFD generators due 28 calendar days after the first settlement day.

The Government recognises that collateral has a cost to suppliers and that implementing the approach outlined in the consultation document would mean that the CFD Counterparty would be holding supplier's collateral long before payments were due to be made to CFD generators. Because of this timing, the Government has revised the approach to collateral so that suppliers are not required to lodge collateral with the CFD Counterparty prior to the start of the supplier obligation. Existing suppliers will instead be required to provide at least 21 calendar days collateral by the end of the first day of the supplier obligation regime. The minimum credit cover for new market entrants, who begin supplying after the start of the supplier obligation regime, will increase daily from the first day of supply until they have posted collateral of 21 calendar days.

In assessing the cost of collateral to suppliers, the Government also understands that certainty of payment is important to CFD generators. The change in the timing for the posting of collateral does not affect when the CFD Counterparty can draw on a defaulting supplier's collateral. Irrespective of whether collateral is lodged before or on the first settlement day, the first opportunity which the CFD Counterparty can draw on collateral for non-payment of an interim payment is 12 working days after the settlement day. If there was a situation where a supplier had defaulted on their interim payment and had not posted collateral with the CFD Counterparty, the supplier's default amount could be mutualised across all non-defaulting suppliers. The mutualisation process should ensure that in the event of non-payment, the CFD Counterparty has enough funds to make payment to CFD generators when they fall due.



Consultation question		27 responses
CFD28	Do you have any comments on the form of collateral, such as cash or a letter of credit as proposed?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.8		

### Summary of responses

Over a third of respondents supported the proposed forms of collateral (cash or letters of credit and very few expressed disagreement. The majority of respondents either suggested alternatives or provided (varied) comments on collateral.

Almost all respondent proposing an alternative suggested Parent Company Guarantees (PCGs) (and to a lesser degree, Qualified Guarantees), favoured as a result of their lower costs. One respondent also proposed using insurance bonds.

Some responses also emphasised the importance of the guarantor’s credit rating or creditworthiness when using letters of credit, and others noted that the ability to access letters of credit varies between small and large organisations – with smaller more likely to use cash instead, which can reduce their available working capital.

### Decisions taken since consultation

In formulating its policy on collateral requirements the Government has carefully considered requests from respondents to include PCGs as an acceptable form of collateral. Our current approach to collateral is that suppliers will be able to provide collateral either in cash or in the form of a letter of credit. This is because in order to provide the CFD Counterparty with the required funding cover in the event of a supplier defaulting on its daily supplier obligation payments, collateral must be sufficiently liquid to allow drawdown on the collateral within a day of the default occurring.

The need for liquidity arises due to the fact that suppliers will make daily supplier obligation payments to the CFD Counterparty. Where a supplier defaults on its daily payments, collateral may need to be called immediately if there is evidence that the supplier is insolvent. The immediate calling of collateral will help ensure that payments to generators are made without interruption. In order to achieve this, the CFD Counterparty must be able to have swift access to liquid funds. Cash and letters of credit provide the required level of liquidity. Where collateral is in the form of a letter of credit, the CFD Counterparty must also have confidence in the credit strength of the issuer.

Compared to letters of credit and cash, PCGs would take the CFD Counterparty longer to access. This delay may mean that payment defaults need to be mutualised across all non-defaulting suppliers sooner than were the collateral able to be drawn down within day.

We have set the minimum credit rating of letters of credit at a level that provides payment certainty whilst being mindful of the costs to suppliers associated with providing letters of credit.

Any potential “widening of the net” of appropriate collateral instruments to would need to consider whether the need for liquidity and an appropriate/consistent credit rating is achieved.

We have assessed PCGs against the above requirements. Due to the inherent constraints around liquidity and monitoring the consistency in minimum credit ratings for PCGs, they have not been included as an approved collateral instrument.

Consultation question		24 responses
CFD29	Do you have any comments on the proposed credit rating requirements for letters of credit?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

While there was some support for the proposed credit rating requirements, several respondents raised concerns over the feasibility of the proposals, specifically whether there were sufficient eligible banks following the cross-industry decline in credit ratings in recent years.

Respondents suggested that the minimum rating requirements could lead to exposure being concentrated in only a few institutions. There was also concern that any future reduction in credit ratings across the board could result in all or a significant number of suppliers no longer meeting the credit rating requirement; and that it would over-restrict available sources of funding. Those that proposed an alternative suggested lowering the minimum credit rating requirement, aside from one which suggested using three rating agencies and requiring the issuing institution to meet minimum criteria of two of the three agencies.

Other respondents commented some financial institutions do not have credit ratings (either because they are too small, or choose not to) and queried what would happen in cases where an institution met the minimum requirement under one rating agency but not the other. Respondents also suggested that letters of credit should also be accepted from issuers that meet the equivalent minimum credit rating requirement from Fitch Ratings (the draft regulations specified Standard and Poor’s and Moody’s only).

Some respondents noted there is inconsistency between the proposal to allow 10 working days from the day of a bank’s credit rating downgrade to replace a letter of credit, and the draft regulations, which state that the letters of credit cease to be collateral eight working days after the downgrade.

### Decisions taken since consultation

Having considered the issues raised, the Government has amended the supplier obligation regulations to also allow letters of credit from issuers which meet the equivalent minimum credit rating requirement from Fitch Ratings so that available sources of funding are not unnecessarily restricted.

To further ensure that available sources of funding are not unnecessarily restricted, the regulations also outline that the minimum rating requirement should reflect the issuer’s short-term rating due to the fact that letters of credit are shorter-term instruments. The minimum short-term rating requirements are A-1 with Standard and Poor’s, or P-1 with Moody’s or F-1 with Fitch Ratings.

Some respondents raised queries around how a split credit rating would be accommodated. In the event of a split credit rating of a letter of credit issuer (i.e. either Standards and Poor’s, or Moody’s or Fitch lowers its rating whilst the others maintains their rating) the highest rating will apply.

The supplier obligations regulations clarify that in the event that a letter of credit is issued by an institution whose credit rating is downgraded to below the minimum rating, that letter of credit will cease to be considered an appropriate letter of credit from the tenth working day after the institution is downgraded.

<b>Consultation question</b>		13 responses
CFD30	Do you have any comments on the process for monitoring and enforcing credit requirements?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

Respondents were broadly supportive of the proposed process for monitoring and enforcing credit requirements. However several considered that the CFD Counterparty should be monitoring collateral requirements regularly and issuing warnings to suppliers of any additional cover requirements or issues.

Additional comments included that the 10 working day period for providing an alternative letter of credit (if the issuing bank is downgraded) is too long given that the collateral is sized to 21 calendar days. Other respondents were concerned that paying outstanding amounts may not be sufficient as there is no consistency with the 21 calendar day collateral period calculation, which may already require additional credit. Respondents also stated that there should be flexibility not to enforce additional collateral requirements to allow for temporary spikes in supply.

### Decisions taken since consultation

The Government agrees that if collateral is regularly monitored and credit breaches reported, other market participants will be more aware of when the CFD Counterparty is enforcing credit requirements. This will allow suppliers to plan for any remote risk of mutualisation payments. The following monitoring and enforcement process will be adopted:

1. During the two day collateral rectification period: A private notice will be sent to the relevant supplier informing the supplier that the notice may be published on the CFD Counterparty’s website if collateral level not restored.

2. After the two working day collateral rectification period: Where collateral levels are not restored within the required period (two working days later), an internal validation process will take place, and the CFD Counterparty may issue the supplier a default notice which may also be published on its website.
3. Where collateral levels are restored, the notice will remain on the CFD Counterparty’s website for five working days but will be updated to say this breach has been rectified.
4. The notice for that specific breach will be removed after five working days.

In response to concerns regarding the 10 working day period for providing an alternative letter of credit, we consider that this provides suppliers with enough time to make alternative arrangements without jeopardising the payment certainty for generators. In the event of non-payment, the CFD Counterparty can still draw on the collateral provided for by the letter of credit during this period.

To clarify, in addition to paying outstanding amounts, suppliers may also need to post additional collateral as either cash or letters of credit to meet their minimum collateral requirements.

The regulations outline that the 21 calendar days collateral requirement applies at all times after a supplier makes a supply. This means that in the event that a supplier experiences a temporary spike in supply, their minimum collateral requirement would also increase.

Consultation question		25 responses
CFD31	Do you have any comments on the approach to sharing of collateral across the Contracts for Difference and Capacity Mechanisms schemes, and between suppliers and generators? What alternatives would you propose and how would this mitigate the risk of non-payment by the CFD Counterparty?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

**Summary of responses**

Responses were mixed in terms of the sharing of collateral between schemes, and between suppliers and generators. Approximately a third of respondents explicitly mentioned being opposed to the sharing of collateral, and of those a small number stated that full collateral should be posted, and a small number said that while they were against sharing, netting off when within the same legal entity should be permitted. The reasons given against sharing were largely complexity and/or uncertainty, but also that it would not lead to a reduction in credit cover and because the proposals for calculating market shares for the CFD supplier obligation and the Capacity Market supplier obligation are different.

Approximately a third of respondents were in favour of sharing collateral, and of these, a small number specifically mentioned that it should be only within the same legal entity.

Other responses and alternative suggestions included opposition to the CFD Counterparty holding collateral; that suppliers and generators should be allowed to choose the arrangements

that they find most easy to manage; and that rather than sharing collateral across these two schemes in isolation, industry needs to review all the collateral arrangements across all schemes and industry contracts as a whole.

### **Decisions taken since consultation**

The draft supplier obligation regulations did not explicitly allow for collateral sharing across the Contracts for Difference and the Capacity Market schemes. Sharing collateral across the schemes, depending on how it was implemented, could mean that suppliers would post a reduced amount of collateral to cover payment obligations across both the Contracts for Difference and the Capacity Market schemes. Under this approach, where a payment default occurs under one scheme, the collateral will be drawn from the shared account to cover the non-payment.

We have considered this approach and have concluded that the sharing of collateral is not a viable option. The Capacity Market Settlement Body (Electricity Settlements Company<sup>40</sup>) and the CFD Counterparty (Low Carbon Contracts Company) need to be kept legally separate from each other to provide confidence in the Contracts for Difference and Capacity Market regimes, which are separate schemes with separate rights for generators to expect and pursue payment. The payment flows, liabilities and assets of each entity need to be identifiable and separate from each other.

We do, however, recognise that collateral has a cost to all suppliers so we have kept the reduced collateral requirement of 21 calendar days. Compared to the collateral requirements proposed in the November 2012 publication, the proposal of a 21 calendar day collateral period results in a reduction of the collateral period of almost one month.

We have also removed the requirement for a separate insolvency reserve fund, which is separately addressed at CFD 33.

Some respondents outlined opposition to the CFD Counterparty holding collateral, with some suggesting that suppliers and generators should be able to choose the arrangements they find the most easy to manage. We consider that a standardised and robust approach to collateral is important as it ensures payment certainty for generators. Allowing suppliers and generators to choose the arrangements they find most easy to manage, or not requiring collateral at all could affect the payment certainty of payments to generators. As noted above, we do recognise the cost of collateral and have retained the proposed 21 calendar days collateral cover.

We understand that the industry's credit and collateral arrangements have been cited by suppliers as a key barrier to entry and growth. The Government has commissioned research to map the existing and emerging credit and collateral arrangements in the gas and electricity and wholesale and retail markets. This work also assesses the impact of the arrangements on

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<sup>40</sup> The Electricity Settlements Company (ESC) will be designated as a Capacity Market Settlement Body and is intended to be the only Capacity Market Settlement Body for the foreseeable future. For ease of comparison with the consultation document, the majority of references to the ESC remain as the 'Settlement Body'. This also applies to the Low Carbon Contracts Company Limited (LCCC), the incorporated name for the CFD Counterparty.

different market participants and considers options for reducing the burden of existing credit and collateral arrangements that are imposed by the Government, a regulator or industry code.

However, because the requirements for CFDs had not been finalised at the time the research was commissioned, the credit and collateral arrangements for CFDs are not considered in the second phase of the work that considers options for reducing the burden of credit and collateral on industry participants. We expect the credit and collateral report to be published shortly.

We will continue to monitor the collateral arrangements for CFDs.

Consultation question		12 responses
CFD32	Do you have any questions or comments on regulations 14 (Collateral) and 15 (Calculation of a suppliers' collateral requirement)?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

On regulation 14, some respondents requested clarification on how cash or letters of credit would be held; and some respondents raised queries relating to the banks supplying the letters of credit (regarding credit ratings and on the eligibility of foreign banks).

### Decisions taken since consultation

Letters of credit will be accepted by the CFD Counterparty on terms which the CFD Counterparty considers are appropriate. Cash collateral will be deposited in a Government Banking Service account.

On the treatment of letters of credit from international banks, the regulations confirm that the CFD Counterparty will accept letters of credit from all banks which meet the minimum credit rating specified in the regulations, and which are on terms considered appropriate by the CFD Counterparty.

### Insolvency reserve fund

Consultation questions		
CFD33	Do you have any comments on the concept of an insolvency reserve fund; if not what alternatives would you recommend to manage the associated risk?	31 responses
CFD34	Do you have any comments on how to size the insolvency reserve fund?	25 responses
CFD35	Do you have any comments on the most appropriate means of funding the insolvency reserve fund?	21 responses
CFD36	Do you have any comments on the minimum credit requirements for letters of credit used to fund the insolvency reserve fund?	25 responses

CFD37	Do you have any comments on the length of notice period given to a non-defaulting supplier to replace a letter of credit with cash before it is called by the CFD Counterparty?	18 responses
CFD38	Do you have any questions or comments on regulations 16 (Insolvency reserve collateral), 17 (Calculation of a supplier's insolvency reserve requirement) and 18 (Repayment of insolvency reserve collateral)?	15 responses
CFD43	Do you any questions or comments on regulation 16 (Insolvency reserve collateral)?	11 responses
See <i>Implementing Electricity Market Reform</i> section: 2.3.4		

### Summary of responses

Responses to these questions were split in their support for an insolvency reserve fund (IRF), with a slight majority against the fund. Respondents in favour tended not to be suppliers. These respondents consider that an IRF would add security and stability, and would reduce the risk of generators being exposed to the costs of a failed supplier. Those respondents against tended to be suppliers, who cited concerns about the cost, which would ultimately fall on consumers; the size of the fund, which they were concerned was oversized given that mutualisation or an enduring solution like the Energy Supply Company Administration (ESCA) scheme or Supplier of Last Resort (SoLR) process could commence; that the fund ties up capital, yet supplier insolvency is a rare event; that it is not typical across the market; and that the burden falls disproportionately on suppliers.

Alternative suggestions to manage risk included that any payments after collateral had been used could be met through the mutualisation process, or that a smaller fund could be created with a quicker route to mutualisation. It was also suggested that the risk could be managed through an insurance product; generators could manage the risk of supplier default; or the CFD Counterparty could borrow from capital markets to manage within-year shortfalls.

On CFD34, some respondents focused on the proposal to base the sizing on the three largest small suppliers, suggesting that this static approach would not accommodate future changes in the market (e.g. new entrants, mergers), or that it incorrectly assumes there is a lower risk of default from larger suppliers. Several respondents felt that the proposed sizing of the fund was too conservative, with most of these focusing on the 38 calendar day timescale which they considered excessive. A few respondents commented that SoLR arrangements would take effect well within this window. Alternative suggestions included 10, 15 and 30 calendar days.

The majority of respondents felt that the proposed 24 hour period to replace a letter of credit with cash under either collateral or the IRF was too short (CFD37), with some suggesting meeting this deadline would be particularly challenging over weekends, or for a smaller supplier. One respondent noted that this would also mean suppliers would hold additional cash, increasing costs to consumers. Alternative suggestions included three and 10 working days.

Additional comments on the IRF in response to question CFD38 included:

- Clarification on how low the IRF and collateral requirement would need to go before triggering the mutualisation process.
- Clarification on when the insolvency reserve fund would need topping up.
- Using supplier market share across November only was inappropriate; any supplier with a residential bias in its portfolio would be over contributing when compared to an industrial/commercial supplier.

There were few substantive comments on draft regulation 16 in addition to the points raised in answers to previous questions. One respondent stated that they would advocate a more relaxed requirement for debt ranking associated with parties who issue a letter of credit. It was also raised that the timescales for notifying and reporting payment default appeared harsh, with calendar days as the trigger for the early warning and the formal report for non-payment occurring after a further five working days proposed as an alternative.

### **Decisions taken since consultation – CFD33-38 & CFD43**

Having considered the current structure of the supplier obligation backstops against the interests of suppliers, consumers and generators, the Government has decided to remove the IRF from the structure of the supplier obligation backstops. Instead, the potential temporary gap between the exhaustion of a defaulting supplier's collateral and the receipt of mutualisation payments will be covered by the reserve fund so that the CFD Counterparty continues to be able to make payments to generators in the event of collateral being exhausted.

When sizing the reserve fund, the CFD Counterparty will have regard to the risk of supplier default on interim rate payments, reserve fund payments and reconciliation payments. This flexible approach will allow the CFD Counterparty to determine how much should be set aside to cover insolvency, based on the likelihood of payment default based on the current market conditions, the reserve fund balance, and the speed with which the CFD Counterparty could mutualise any default. We anticipate that the amount included in the reserve fund to cover the risk of insolvency will be small because:

- For the majority of each quarter the CFD Counterparty is expected to have a cash surplus, as it will be collecting a lump sum reserve payment at the start of each quarter intended to cover all but exceptional levels of CFD payments in each quarter.
- The CFD Counterparty will be able to adjust the interim rate levy or require an additional reserve fund amount by providing suppliers with 30 days' notice, enabling it to quickly respond if an unexpected event leaves it at risk of being short of funds to pay generators.
- The CFD Counterparty may commence mutualising any payment default approximately seven calendar days before the defaulting supplier's collateral is exhausted (based on its calculations of when collateral will be exhausted) and would therefore start receiving mutualisation payments 10 days after initiating mutualisation (plus two days payment rectification period), so the 'mutualisation gap' is likely to be four working days at most.



- The SoLR or ESCA schemes can be implemented rapidly in the event of supplier insolvency.

The revised approach leads to an anticipated reduction in the amount which suppliers would have to post to cover insolvency from an estimated annual average of £14m - £21m as provided in the October 2013 Impact Assessment<sup>41</sup> to a central estimated annual average of £1m in the June 2014 Impact Assessment<sup>42</sup>. This results in an estimated annual average financing cost reduction from £1m as assessed in the October 2013 Impact Assessment to £0.07m - £0.1m in the June 2014 Impact Assessment. Savings from this revised approach will have direct benefits for smaller suppliers who were concerned about the overall cost of the supplier obligation backstops.

## Mutualisation

Consultation question		25 responses
CFD39	Do you have any comments on the concept of mutualisation? What alternative mechanism would you propose to ensure the insolvency reserve fund remains adequately funded?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

The large majority of respondents were supportive of the concept of mutualisation.

Additional points raised were that support for mutualisation was contingent on there being robust processes to deal with insolvency; and that it was not clear what would happen to the mutualisation process if an Energy Supply Company Administration (ESCA) order is made. Some respondents also requested clarification on whether the mutualisation payments will follow the existing reconciliation settlement process or whether it will be a one-off payment. Some respondents also reiterated their support for HMT-backed solutions.

### Decisions taken since consultation

In line with consultation responses, the CFD Counterparty can mutualise defaults on supplier obligation payments when it determines the defaulting supplier's collateral will be exhausted.

Respondents requested clarification about the mutualisation process. In the event of non-payment by a supplier, the CFD Counterparty will determine whether to mutualise the unpaid amount across all other non-defaulting suppliers. If amounts are later recovered from the defaulting supplier, this would be repaid to the suppliers who participated in the mutualisation process. Mutualisation can continue for as long as a supplier continues to default on its payments, but we would expect that this would not be a long period of time because, if the non-

<sup>41</sup> See <https://www.gov.uk/government/consultations/proposals-for-implementation-of-electricity-market-reform>

<sup>42</sup> See <https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform>

payment is a result of insolvency, the need for mutualisation should be resolved through the SoLR or ESCA processes.

The SoLR process allows Ofgem to take all reasonable steps within its available powers to secure continuity of supply for all customers in the event of a supplier failure. The current regulatory regime gives Ofgem discretion as to when it revokes a licence, and how it selects and appoints a SoLR. Ofgem can revoke a supplier’s licence in not less than 24 hours in certain circumstances<sup>43</sup>. In the unlikely event that a SoLR is not appointed before the defaulting supplier’s collateral is exhausted, the CFD Counterparty may continue mutualising non-payments until the SoLR is appointed and is making supplier obligation payments (with the reserve fund funding the temporary gap between the exhaustion of collateral and receipt of mutualisation payments). The SoLR will be due to make supplier obligation payments (in line with the supplier obligation settlement process) from the first day that it starts supplying electricity to the customers of the failed supplier.

If a large supplier became insolvent, and it was not feasible to appoint a SoLR, then the Secretary of State, or Ofgem with the Secretary of State’s consent, may apply to the court for an energy supply company administration order. An energy administrator is then appointed by the court to run the company until it is either rescued, sold or its customers transferred to other suppliers. In running the company the energy administrator must comply with all licence conditions, and will be responsible for ensuring that debts that have arisen in relation to licence conditions prior to the company entering energy supply company administration are paid.

Consultation question		25 responses
CFD40	Do you have any comments on whether suppliers should pay towards mutualisation in proportion to their market share?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

The large majority of respondents supported an approach where suppliers’ payments towards mutualisation are in proportion to their market share, in line with the consultation document. However a number stressed the need for clarity on when and how the market share was calculated, and the importance of a robust methodology.

Some respondents made suggestions relating to the calculation, including that it should be based on market share on the day of default, or that bi-annual or quarterly snapshots should be taken to reflect changing market conditions. It was also suggested payment should only be sought from suppliers with at least one per cent market share to avoid the smallest suppliers having to meet calls for large payments.

<sup>43</sup> See page 7, “Licence revocation” – taken from “Supplier of Last Resort – Revised Guidance”, <https://www.ofgem.gov.uk/ofgem-publications/59624/solrrevisedguidance-december2008.pdf>

Some suppliers considered the proposed approach did not reflect circumstances where a supplier’s market share was rapidly increasing or declining.

### Decisions taken since consultation

Having considered the concerns listed above relating to the calculation of market share we have revised the approach for mutualisation. In the instance where a supplier defaults on their interim rate payment, mutualisation amounts owed by non-defaulting suppliers will be calculated on the basis of their market share (as a proportion of the total amount of electricity supplied by non-defaulting suppliers) on the day to which the payment default relates. In the case of defaults on other payments (e.g. reserve fund or reconciliation payments), non-defaulting suppliers’ mutualisation payments will be calculated according to their market share for the most recent 30 calendar days for which the BSC has carried out an Initial Volume Allocation Run (as a proportion of total electricity supplied during this period by non-defaulting suppliers).

Consultation question		20 responses
CFD41	Do you have any comments on whether there should be a minimum threshold for an outstanding debt before mutualisation begins? If so what threshold amount would you propose and how would this operate to ensure that the risk balance to the CFD Counterparty remains the same?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

There was a mixed response to whether there should be a minimum threshold before mutualisation begins. Of those who did not feel that it was necessary to apply a threshold, the reasons given were the low likelihood of mutualisation taking place, and that it would avoid multiple small debts depleting the insolvency reserve fund.

Of those respondents who thought that there should be a threshold, the thresholds amounts suggested were £50,000, £500,000 and half or less of the liabilities associated with the CFD Counterparty’s 28 day working capital.

### Decisions taken since consultation

The Government has decided not to introduce a minimum threshold for mutualisation. If a minimum threshold was applied before payments are mutualised, smaller amounts would have to be saved up for larger mutualisation events. Given that mutualisation is expected to be infrequent and will only occur if outstanding payments outstrip collateral, it is not clear that imposing a minimum threshold outweighs the greater risk of the CFD Counterparty being unable to meet generator payments.

In relation to the costs associated with the mutualisation process, the processing costs to the CFD Counterparty and suppliers are expected to be the same irrespective of the size of the mutualisation event.

Consultation question		18 responses
CFD42	Do you have any comments on the use of recovered funds?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.9		

### Summary of responses

The vast majority of respondents agreed with the proposed use of recovered funds<sup>44</sup>, which was to distribute the funds according to the proportion to which parties contributed to a mutualisation event within five days of the funds being recovered. One respondent suggested that if the repayment was less than £50,000 it would administratively more efficient to credit the amount to suppliers' backstop funds. Another respondent stated that if the amount was returned by crediting against future payments then interest should be added. Two respondents questioned the five day payment period for the CFD Counterparty to make payments to non-defaulting suppliers, suggesting it should be shorter.

### Decisions taken since consultation

The Government has decided not to amend the approach which was proposed in the consultation document. Recovered funds will not be credited against future payment liabilities (although they may be set-off against determined liabilities). Non-defaulting suppliers who contributed to a mutualisation event will receive a proportion of any interest which is recovered from the defaulting supplier.

The five working days for redistribution allows the CFD Counterparty to calculate the distribution to all non-defaulting suppliers and to make those payments. In addition it is also consistent with the payment timeframes for suppliers to make payments to the CFD Counterparty.

### Arrangements for dealing with non-payment

Consultation questions		
CFD44	Do you have any comments on the proposed timescales for notifying and reporting payment default to Ofgem?	21 responses
CFD48	Do you have any comments on the proposal that the notification of a payment or credit default by a supplier should be published on the CFD Counterparty's website?	21 responses
See <i>Implementing Electricity Market Reform</i> section: 2.3.10		

The majority of respondents agreed with the proposed timescales, however some thought that seven calendar days before a payment default is notified and reported to Ofgem is too short. One respondent thought that the timescale was too long, suggesting that Ofgem should be notified immediately in order to take action and prevent mutualisation costs accruing. It was

<sup>44</sup> Recovered funds are funds which have been recovered from defaulting suppliers following a mutualisation event.

also suggested that working rather than calendar days should be counted when considering the timeframes for notification and reporting.

There was strong feedback from stakeholders throughout the consultation period that the timescale for notifying and reporting should not be aligned to those under the Balancing and Settlement Code (BSC). Stakeholders considered that the BSC timescales for notification and reporting were not suitable for the purpose of the supplier obligation.

The Government also raised in the consultation document that it was considering whether the notification of payment default should be published on the CFD Counterparty’s website. Consultation responses received on this matter suggest that there is clear support for such a measure.

Many respondents stressed the importance of adequate checks before publication, highlighting the reputational damage and potential negative knock-on effects on third parties dealing with the affected supplier. Similarly some asked for clarification on the procedure if a supplier is disputing the notification.

**Decisions taken since consultation – CFD44 & CFD48**

The Government considers that the timing for notifying and reporting non-payment strikes the right balance between the interests of suppliers and generators. The two working day rectification period ensures that there is sufficient time for suppliers to rectify any non-payment before the CFD Counterparty notifies Ofgem of the default. In addition to any monitoring and investigation by Ofgem, the CFD Counterparty may, taking into account of the circumstances, seek to secure non-payment through the civil courts.

The Government has decided that payment or collateral default by a supplier may be published by the CFD Counterparty. The Government is aware that it is important that a robust assurance process is in place to ensure that when payment default information is published it is current and correct. To this end, suppliers will receive a private notice of non-payment and will have a two working day rectification period before the default is published.

<b>Consultation question</b>		15 responses
CFD45	Do you have any comment on the approach to the enforcement of debts through the courts by the CFD Counterparty?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.10		

**Summary of responses**

The majority of respondents supported the proposed approach to give the CFD Counterparty discretion over whether to pursue debt through the courts, with many of these stressing the importance of taking a proportionate approach and ensuring a proper cost-benefit analysis of likely success is taken before a decision is taken.

Some respondents commented on the funding of legal action, and requested clarity on how the additional costs would be met.

### Decisions taken since consultation

The Government has decided that the decision on whether the CFD Counterparty should enforce a payment default through the courts should follow the approach set out in the consultation document. The CFD Counterparty will determine whether to enforce a payment default through the courts based on the relevant facts of the matter.

Costs which are incurred in enforcing a debt through the courts will be covered by the operational cost levy.

Consultation question		6 responses
CFD46	Do you have any questions or comments on regulation 19 (Enforcement of requirements)?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.10		

### Summary of responses

There were few substantive comments on regulation 19 in addition to the points raised in answers to previous questions. One respondent suggested that a tougher approach should be taken to non-payment to limit financial losses, for example by revoking supplier licences in extreme cases. Another respondent commented that it was important that payments to generators are not affected should one of the large suppliers become insolvent, and requested assurance that there would be protections in place.

### Decisions taken since consultation

Any amounts due under the regulations are enforceable as 'relevant requirements' for the purposes of section 25 of the Electricity Act 1989. In the event of a payment default, the CFD Counterparty will notify details of the default to Ofgem. Ofgem will consider the report and relevant circumstances and could lead to a revocation of the defaulting supplier's licence and the appointment of a Supplier of Last Resort (SoLR) following non-compliance.

We consider that the approach to backstops, including the posting of collateral and mutualisation offers sufficient protection to generators. The posting of collateral and mutualisation has been historically successful in the context of the Balancing and Settlement Code (BSC). The Government's analysis on the BSC's collateral requirement has shown that holding collateral reduces the overall level of unsecured losses.

### Disputes and enforcement

Consultation question		13 responses
CFD47	Do you have any comment on proposed timescales within which suppliers must raise a dispute the CFD Counterparty for notifying and reporting payment default to	

	Ofgem?
See <i>Implementing Electricity Market Reform</i> section: 2.3.11	

### Summary of responses

The majority of respondents were in favour of the proposed 28 calendar days timescale. Some respondents also suggested that the process should be aligned with other industry arrangements, for example Balancing and Settlement Code (BSC) dispute procedures. Alternative suggestions included that the timescale should be extended to 56 calendar days; that it should be shortened, with disputes raised immediately; and that it would be more effective to have a specific disputes process without the need to bring a judicial review challenge.

One respondent also suggested that calculations made by the CFD Counterparty should also be covered by the dispute process.

### Decisions taken since consultation

The Government will implement the approach on timing for disputes which was outlined in the consultation document as it provides sufficient time for suppliers to raise a dispute and for the CFD Counterparty to respond. This approach does not affect the existing BSC Trading Dispute procedures. Calculations made by the CFD Counterparty will be covered by the dispute process outlined in the consultation document.

Consultation question		10 responses
CFD49	Do you have any questions or comments on regulation 20 (Disputes)?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.11		

### Summary of responses

There were few substantive comments on regulation 20, other than those raised in response to previous questions. Additional points included:

- Further clarity was requested on the procedure for generators to dispute generation data used by the CFD Counterparty.
- It was raised whether there needs to be another dispute mechanism, other than judicial review, so that disputes can be resolved quickly and clearly with minimal administrative costs.

### Decisions taken since consultation

We have carefully considered the dispute mechanisms and in particular the mechanisms which apply to the different types of disputes.

The metered supply data for a particular day will be the basis for the amount which the CFD Counterparty invoices an individual supplier. Suppliers who wish to dispute the metered supply data which is the basis for an invoiced amount are able to do so according to the Trading

Dispute Processes which are outlined in the Balancing and Settlement Code. The CFD Counterparty will not make a determination on disputes on metered supply data.

For disputes on determinations by the CFD Counterparty, suppliers are able to raise a dispute with the CFD Counterparty within 28 calendar days of the disputed event. The CFD Counterparty will have 28 calendar days to make a determination and respond to the supplier. In making a determination, the CFD Counterparty will have to have regard to all the facts regarding the disputed event. If suppliers are not satisfied with the CFD Counterparty’s response, they are able to seek judicial review.

The processes for generator disputes are outlined in the CFD contract<sup>45</sup>.

### Operational costs

Consultation question		23 responses
CFD50	Do you have any comments on what would be acceptable to use as the basis for calculating suppliers’ share of operational costs?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.13 & 2.3.14		

### Summary of responses

The majority of stakeholders responding to this question agreed that suppliers’ share of operational costs should be based on their market share.

A few respondents suggested that costs should be shared with generators, on the grounds that this was more equitable and would provide incentive for generators to consider the cost impact of any changes to contracts they requested. A small number of respondents thought that costs should be met through general taxation rather than through suppliers.

On the estimated £15m annual operating costs, a small number of stakeholders commented that there should be transparency over how these costs are calculated, and assurance processes in place to ensure value for money for consumers is being achieved.

### Decisions taken since consultation

Suppliers’ share of the CFD Counterparty’s operational costs will be calculated using a fixed levy rate (£/MWh of electricity supplied) which will be set in the Contracts for Difference (Electricity Supplier Obligations) Regulations in advance of each operational cost levy period, following a public consultation. It was originally proposed that the billing would be based on Interim Information (II) Run data with reconciliation up to the Initial Settlement (SF) run, but it has now been decided that using the SF run (which is available 16 working days after settlement) will be sufficient. As SF data will be used as final supply data, suppliers’ share of operational costs will be partly based on a mixture of profiled and metered data. However, compared to what will be collected from suppliers under the supplier obligation for CFDs, the

<sup>45</sup> See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/305539/CFD\\_agreement.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/305539/CFD_agreement.pdf)



CFD Counterparty’s operational costs will be small, and therefore we believe there is not the same need to reconcile data for 14 months (and potentially up to 28 months).

We highlighted in the Operational Framework published in November 2012<sup>46</sup> that we were considering levying the operational costs on suppliers as we recognised that these costs will ultimately be passed through to consumers, for instance through higher strike prices (if levied on generators). We took the relevant power to levy these costs on suppliers in the Energy Act 2013.

Transparency and scrutiny of the CFD Counterparty’s operational costs will be achieved through the annual consultation on the operational cost levies and the publication of the company’s audited annual accounts. Ultimately the operational costs of the Electricity Settlements Company and Low Carbon Contracts Company will also be subject to the approval of Parliament, as the operational levies are amended in regulations annually.

A further consultation on operational costs was published in March 2014. Most stakeholders responding to this consultation supported that the CFD Counterparty’s operational costs should be calculated using a fixed levy rate (£/MWh of electricity supplied) in order to mirror the supplier obligation levy.

Further details can be found in the Government response to the March 2014 operational costs consultation<sup>47</sup>, published alongside this document.

Consultation question		23 responses
CFD51	Taking into account the constraints that arise from the need to set the rate in legislation, do you have any views on the proposed timetable for both 2014/15 budget and enduring regime? For example, does the timetable give enough notice to suppliers of the levy rate that will apply?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.14		

### Summary of responses

Stakeholders commenting on the proposed timetable indicated that they wanted as much notice as possible of the levy rate; most suggested a minimum of three months’ notice whilst a small number proposed 6-12 months’ notice.

There were some concerns raised on the proposed timetable for 2014/15, including that there has been no opportunity to build the costs into customer bills.

<sup>46</sup> See [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/65635/7077-electricity-market-reform-annex-a.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65635/7077-electricity-market-reform-annex-a.pdf)

<sup>47</sup> See <https://www.gov.uk/government/consultations/consultation-on-the-emr-operational-cost-levies>

### Decisions taken since consultation

Consultation responses confirmed that suppliers want a minimum of three months' notice and that an earlier indication of the rate would be helpful. We consulted on the levy rate for 2014/15 in March 2014 but will not be collecting the payment until March 2015 (see response to CFD52), therefore providing 9 months' notice to suppliers of the first operational costs levy.

We expect to consult on the levy for 2015/16 in autumn 2014 in order to provide interested parties early sight of expected costs and the levy rate, and an opportunity to scrutinise and challenge the proposed costs and levy rate. The Contracts for Difference (Electricity Supplier Obligations) Regulations to make the operational cost levy rate are affirmative. Any change to the rate will also be consulted on then taken through Parliament. This process will therefore give suppliers notice of future rate changes.

Consultation question		22 responses
CFD52	With regard to operational cost payments that are accrued between July and December 2014, do you have any comments on the proposed payment period and frequency for recovering these payments (i.e. in instalments payable by the end of each month from January to March)? Do you have any other preference e.g. lump sum payment for the accrued amount?	
See <i>Implementing Electricity Market Reform</i> section: 2.3.15		

### Summary of responses

Responses to the consultation indicated a preference for levy payments to be spread out across the year in the enduring regime and an acceptance of some form of lump sum payment(s) in 2014/15. On the latter, a slight majority were in favour of monthly instalments. Some respondents supported the single lump sum payment in 2014/15 on the grounds of simplicity, while others – mainly smaller suppliers or generators – were opposed as it would impact on cash flow.

### Decisions taken since consultation

In order to ensure that systems are ready to process payments, the operational cost levy to be charged for the period 1 August 2014 to 31 March 2015 will be collected in one instalment, after the SF data run is available for 31 March 2015.

### Implementing the payment model

Consultation question		23 responses
CFD53	Do you have views on any aspect of the proposals set out in this section 3.4?	
See <i>Implementing Electricity Market Reform</i> section: 2.4		

### Summary of responses

A range of comments were made in relation to the proposals for implementing the payment model. These included:

- Requests for clarity on which decisions the Secretary of State can instruct the CFD Counterparty on, and a sense that these should be reserved for very few matters of a strategic nature, to ensure the independence of the CFD Counterparty.
- Timing – some respondents said that the CFD Counterparty should be operational by the time agreements are signed and need to start being implemented. Under current timings, some respondents thought that some projects may be eligible for payments before the CFD Counterparty is fully operational.
- Location of the CFD Counterparty – some respondents suggested the CFD Counterparty should be based outside London to minimise costs.
- A number of respondents welcomed the decision to designate ELEXON as CFD Settlement Services Provider due to their experience in BSC settlement.

Some consumer groups provided detailed responses to this question, arguing that the Government should stipulate (via modifications to secondary legislation or licence conditions) how suppliers translate levy costs and end of year reconciliation payback payments into tariff charges, to ensure these are being passed on to consumers fairly.

### **Decisions taken since consultation**

The CFD Counterparty is being set up to be operationally independent on a day-to-day basis and it will operate under an independent board. The CFD Counterparty will exercise its judgement in the areas where it has discretion. The Government will produce a Framework Document which forms part of the governance documentation of the company. This will set out further detail on its relationship with the Secretary of State and details of the parameters within which the CFD Counterparty is working, specifying where decisions require shareholder consent. These will be broken down into the following main areas:

- Varying a CFD/Investment Contract beyond its terms, which would alter the intended balance of risk and reward;
- Entering into commitments outside of the CFD/Investment Contract management process with financial or policy impacts for DECC;
- Approval of the annual budget and business plan; name and location change; and investment and borrowing restrictions.

The Government has entered into a number of Investment Contracts this spring. The process for applying for the first CFD contracts will commence later in 2014 when the CFD scheme goes live. Generation under CFDs and Investment Contracts will first become eligible for difference payments from April 2015. Having a common start date enables all industry participants to plan for payment and will give certainty that payments will not be requested under the CFDs before this date. April will give potential generators, licensed suppliers and the CFD Counterparty and Settlement Services Provider sufficient time to prepare and test their billing and payment systems to allow a smooth introduction for CFD difference payments. This was reflected in the *Update on terms for the Contract for Difference*<sup>48</sup> (December 2013). The CFD Counterparty will

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<sup>48</sup> See <https://www.gov.uk/government/publications/electricity-market-reform-contracts-for-difference>

be operational from the point that it is designated under the Energy Act 2013 when the designation order is made in August 2014.

On the location of the CFD Counterparty, as we outlined in the consultation document, current Government policy is that no new leases should be signed when there is existing Government estate available, to avoid new charges to the taxpayer. We undertook an assessment of existing Government estate that would meet the company’s space requirements, ensuring that there are also the appropriate skills available in these locations. The decision was taken to locate the CFD Counterparty in London<sup>49</sup> to enable close working with DECC and ELEXON Ltd (its designated Settlement Services Provider) during the final stages of set up and operation, to ensure that the CFD Counterparty is operational on time and implementation progresses smoothly. However, as set out in the consultation document we will review that decision once the company has been operational for three years in order to decide whether to locate it outside London and South East within five years of operation.

One respondent commented on the proposed method by which the Settlement Services Provider would communicate with suppliers and generators. A subsidiary of ELEXON, as Settlement Services Provider, carried out a consultation on this issue in February and March. More information is available at [http://www.elexon.co.uk/wp-content/uploads/2014/02/Consultation-on-potential-mechanisms-for-parties-to-exchange-data-with-the-EMR-Settlement-System\\_v1-0.pdf](http://www.elexon.co.uk/wp-content/uploads/2014/02/Consultation-on-potential-mechanisms-for-parties-to-exchange-data-with-the-EMR-Settlement-System_v1-0.pdf).

### Devolved Administrations

Consultation question		11 responses
CFD54	Given the different planning and grid connection regime in Northern Ireland, we would welcome views from Northern Ireland generators as to which point in the grid connection process in NI is most appropriate to sign a CFD.	
See <i>Implementing Electricity Market Reform</i> section: 1.5.1		

### Summary of responses

Detailed responses were received from a small number of stakeholders, with many of emphasising that as much as possible there should be consistency with the regime in GB, and that NI projects should not be disadvantaged.

A number raised concerns over the uncertainty of grid connection in NI, particularly as the System Operator for Northern Ireland (SONI) was shortly due to consult on grid connection and ownership. Respondents indicated that there are difficulties aligning the timing of project consent and grid connection in NI which would impact on CFD allocation, suggesting that the Government should adopt a more flexible approach for NI projects, or allow CFDs to be signed at grid offer acceptance stage. Respondents also cited the ‘cluster approach’ as a source of uncertainty, as securing regulatory approval and connection costs was dependent on other

<sup>49</sup> See section 2.4.1.5 of *Implementing Electricity Market Reform* for more on the set up and location of the Low Carbon Contracts Company (the CFD Counterparty).

projects within the cluster. This could be exacerbated under the CFD regime if some projects are awarded CFDs and others not.

### Decisions taken since consultation

As set out in the summary of CFD5, we recognise that there will be differences to NI planning systems, regulatory and legislative frameworks, amongst others, and these differences will be reflected as we continue to develop the NI CFD policy.

Consultation question		14 responses
CFD55	Are there any other issues in the allocation criteria that need to be amended for NI generators?	
See <i>Implementing Electricity Market Reform</i> section: 1.5.1		

### Summary of responses

Most responses to this question focused on the impact that the late start date for the CFD regime in Northern Ireland would have on the available budget, suggesting that there would be little budget left for NI projects, or that they would be disadvantaged if a constrained allocation process commenced by that point. One respondent asked for clarity within the Allocation Framework on how the different strike prices for NI should be treated in the event of constrained allocation.

Some respondents also mentioned that offshore wind projects in NI were subject to different constraints than in GB. For example, there is direct liability for an increased share of connection assets, and that tenders for offshore energy development zones were completed 36 months after the most recent tenders for GB offshore capacity.

### Decisions taken since consultation

Final decisions on the allocation criteria for NI generators have not yet been taken. The Government will continue to work closely with colleagues in Northern Ireland to design a CFD implementation programme in Northern Ireland that starts from April 2017.

The comments provided by stakeholders in response to this question have been helpful in identifying NI-specific issues and are being considered as final policy is developed. The Government intends to provide an update on the NI CFD by the end of the year.

## Supply Chain Plan Consultation questions

The following questions CFD56-60 were set out in a separate document, *Supply Chain Plan Consultation: Addendum to Electricity Market Reform: Consultation on Proposals for Implementation*<sup>50</sup>.

Consultation question		36 responses
CFD56	What impact, in terms of benefits and costs, do you think the supply chain plan assessment will have?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.3.2		

### Summary of responses

Most responses were supportive of the supply chain plan policy, recognising a large number of potential benefits. These benefits included reducing costs through widening the supply chain and increasing competition; better project management due to the increased visibility of the procurement process and the publication of post build reports; and long-term economic benefits through strengthening the supply chain and increasing investment in skills.

Some responses also stated concerns about the process which they felt may, if unmitigated, outweigh potential benefits. The main concern highlighted was the potential delay the proposal would have on applying for a CFD – particularly if the assessment process extended past 30 working days, or if additional information was required. Respondents therefore requested clarity in the guidance on how the assessment criteria could be successfully met and how the Government would achieve the 30 working day assessment deadline.

### Decisions taken since consultation

The Government has removed the 90 day approval time as industry felt it introduced a maximum time limit which was unhelpful given the tight timetable in year 1 of the Contract for Difference. The timetable is set out in the guidance document<sup>51</sup> to demonstrate that the Government will endeavour to assess the plans within 30 working days although borderline cases may take longer. The Electricity Market Reform (General) Regulations will require the Secretary of State to assess plans as soon as practicable after a supply chain application is received by the Secretary of State.

Consultation question		28 responses
CFD57	What additional steps could Government consider to deliver our objectives? If applicable, you may wish to draw on your experience of the FID Enabling for	

<sup>50</sup>

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/260732/supply\\_chain\\_consultation.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/260732/supply_chain_consultation.pdf)

<sup>51</sup> The Supply Chain Plan guidance sets out the process for submitting and assessing supply chain plans. See <https://www.gov.uk/government/publications/supply-chain-guidance>

Renewables process.
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See <i>Implementing Electricity Market Reform</i> section: 2.2.3.2
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### Summary of responses

There was a wide variety of suggestions with no conclusive trends. Comments included that supply chains should be assessed throughout the lifecycle of a project (particularly for less established technologies, such as offshore wind; that plans should include more explicit references to UK content or delivering local economic benefit; and that the criteria should be clear not to rule out 'alliancing' approaches to procurement, which can bring cost savings via co-operation in the supply chain. A small number of respondents also suggested that individual plans should be aggregated and used to develop an overall supply chain plan for the UK.

### Decisions taken since consultation

The Government considered all the various responses and has amended the policy to ensure it is clear that a project could contract via alliancing frameworks and meet the criteria set out in the guidance. It will ensure that the individual plans are used to develop an overall joined-up approach to the supply chain.

Consultation question		29 responses
CFD58	Should the supply chain plan assessment process take into account the development stage of the project? If so, how could this best be reflected and measured in the supply chain plans to be submitted e.g. considering any procurement commitments that are in place, status of construction etc?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.3.2		

### Summary of responses

The majority of respondents agreed that the development stage of a project should be taken into account in the assessment of the supply chain plans, given that a number of key project decisions will have already been made at the time a plan is submitted. However, a small number noted that many projects will not reach final investment decision (FID) stage until they are awarded a CFD, and therefore supply chain plans are unlikely to reflect major procurement decisions or significant binding commitments at the point of submission.

A small number of responses suggested that the assessment process should take into account financial and contractual commitments made up to the point that the final detail of the policy is published (in summer 2014), not just the policy announcement stage, and that the provision should also apply to the supplier pre-qualification process that is undertaken prior to the contract award.

### Decisions taken since consultation

In line with respondents' views, the assessment process will take into account the development stage of the project and will consider which key project decisions were made before the announcement of the policy (November 2013).

Consultation question		31 responses
CFD59	Do you have any views on whether the three main criteria of innovation, competition and skills should be weighted and whether the sub-criteria should be scored evenly?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.3.2		

### Summary of responses

The majority of respondents supported equal weighting for the three main criteria and the sub-criteria. Of those that supported differentiated weightings, there was no consensus about the right way to achieve this. A small number of responses supported the Government's suggestion that competition should be given a higher weighting but similar numbers that thought the same of the 'skills' criteria, and others suggested that skills should have a lower weighting. A number of responses requested further detail on the sub-criteria and criteria before finalising comments.

Two responses suggested that the Government consider health and safety and sustainability or the carbon footprint of a project as additional or alternative criteria due to the potential benefit to UK companies.

### Decisions taken since consultation

For the supply chain plan assessment process the Government noted that most respondents requested that the criteria (skills, innovation and competition) and sub-criteria should be weighted evenly and has decided to follow this proposal. This is to avoid complexity with the scoring of the plans. Similarly to minimise administrative burden and ensure simplicity additional criteria will not be added to those proposed on the consultation document.

Consultation question		32 responses
CFD60	Do you have any other comments or suggestions for the assessment criteria or scoring process that you think would support the aims of EMR to drive down the cost of low carbon generation (by promoting innovation, skills and open and competitive supply chains)?	
See <i>Implementing Electricity Market Reform</i> section: 2.2.3.2		

### Summary of responses

There was a wide variety of suggestions on how to improve the assessment and scoring process and the main themes were clarity and transparency. The key concern (across all the answers) was that the assessment process did not delay the application for a CFD. To avoid



this risk, respondents wanted a clear and unambiguous process with enough time to develop responses properly or the ability to submit a draft response to discuss any issues early.

Respondents also stated that the criteria should not be too subjective, and that there should be clarity about how a plan might be rejected, to avoid any misinterpretation. Several respondents were therefore keen to be involved in the development of the guidance, criteria and assessment process or asked for further consultation on these. There were also a number of requests to strengthen and clarify the requirement on the post build report and for implementation to be monitored.

Separately, responses also raised issues such as how to treat projects that had more than one CFD application, and the necessity of thinking about skills and the supply chain across the industry rather than on a project by project basis.

### **Decisions taken since consultation**

The Government noted the responses and has discussed the policy further with relevant stakeholders from the developer and supply chain community. The guidance document will set out a clear process such that the assessment process will not delay the application for a CFD in year 1. The guidance will also set out when a post-build report will be required.

## 2. Capacity Market detailed design proposals – questions and responses

### Amount to auction

Consultation question		29 responses
CM01	What are your views on the proposed delivery year (1 October to 30 September)?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.1.5		

### Summary of responses

Overall, a slight majority were content with the proposed delivery year, noting that it is aligned to the period where the greatest need for capacity begins, as well as to the seasonal contracting window.

Around a third of respondents felt the delivery year should be changed to April – March, to align with Transmission Network Use of System (TNUoS) charges, the RO scheme year, and the timetable for paying other business rates. They favoured this timing on the grounds that this could reduce expensive/complex system changes, and in particular the need for participants to budget for more than one year of system capacity Transmission Export Capacity (TEC) when calculating their bid price.

A few respondents suggested 6/18 month ‘transitional’ delivery years to allow an October start before changing to April-March.

### Decisions taken since consultation

Each delivery year will run from 1 October to 30 September. The majority of respondents were in favour of this approach and the Government feels that the alternative suggestions, including the introduction of transitional delivery years, would add unnecessary complexity to the process.

Consultation question		30 responses
CM02	What are your views on the proposed approach for setting the amount to contract in each Capacity Market auction?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.1		

### Summary of responses

The majority of respondents agreed with the proposed approach of basing the amount of capacity to contract on an enduring reliability standard expressed as a Loss of Load Expectation (LOLE). However, of these, most requested more transparency and robustness in the analytical process and in the governance arrangements (e.g. the relationships between the Secretary of

State, the Delivery Body, Ofgem and industry) and made a number of suggestions for improvement. These included that the information provided to the Panel of Technical Experts and the Panel's views should be published; that National Grid's draft Capacity Adequacy Assessment should be open for comments by wider industry stakeholders; and that further information should be provided on the process that the Secretary of State will adopt in setting the reliability standard.

### Decisions taken since consultation

The amount to auction will be determined by an annual security of supply analysis on the amount of capacity required to meet a reliability standard carried out by National Grid. It will be scrutinised by the Panel of Technical Experts.

A capacity demand curve will be determined annually by the Government, in advance of capacity auctions. The demand curve will:

- set a target level of capacity to auction;
- enable the trade-off between cost and reliability to be automatically determined at auction; and
- set a cap on the maximum price that can be set at auction.

As confirmed by the Government in the EMR Delivery Plan published in December 2013<sup>52</sup>, an enduring reliability standard will guide the amount of capacity obligations to be let by the auction. The Delivery Plan confirmed that the reliability standard for the GB electricity market is a LOLE of 3 hours per year.

The Secretary of State will determine an estimate of the target capacity to contract in the four-year ahead (T-4) and one-year ahead (T-1) capacity auctions, in order to meet the reliability standard in the relevant delivery year, with the T-1 estimate particularly informed by the prospects for demand side response (DSR).

The Government recognises the need for a transparent and robust process. This estimate will be based on independent annual analysis and advice from National Grid in its role as EMR Delivery Body on the electricity supply and demand outlook over the period. The Delivery Body will consult with stakeholders as part of the Future Energy Scenarios process. An independent Panel of Technical Experts has been appointed to scrutinise the analysis carried out by the Delivery Body, including on the amount of capacity to contract.

Consultation question		38 responses
CM03	Do you think the proposed value for net-CONE (£29/kW per year) and the proposed auction price cap (1.5 * net-CONE) are appropriate for the first auction? If not, do you think that the proposal for a transitional price cap of around £75/kW is appropriate to allow for a wider range of projects to set the price in the first auction(s)?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.1.2 and 3.2.1.2		

<sup>52</sup> See <https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan>

## Summary of responses

The majority of respondents argued that the proposed level of net Cost of New Entry (CONE) - and therefore proposed auction price cap - is too low. Respondents were more comfortable with a transitional price cap of around £75/kW, although some suggested much higher price cap (e.g. £100-125/kW).

Stakeholders also highlighted that it was important for the price cap to be based on a reasonable estimate of net CONE, in order to manage public perceptions (it was suggested that there would be reputational risks - for the Government and Capacity Market participants - associated with auctions continuously clearing above publicly available net-CONE estimates) and to facilitate market participants' understanding. Many respondents disagreed with the Parsons Brinckerhoff (PB) estimates of CONE and wanted more clarity on the assumptions used.

Amongst consumer organisations, there was strong support for a lower price cap. Respondents noted international comparisons (capacity auctions in the US) and the fact that prolonging the life of existing plant and demand side response (DSR) can be cheaper than building new plant.

## Decisions taken since consultation

The Government intends to increase the level of net-CONE in the auction to £49. This change reflects the majority of consultation responses which argued it was unlikely that open cycle gas turbines (OCGTs) could be built in time to participate in the first auction. £49kW was the estimate of the clearing price for a 2018/19 capacity auction in the March 2014 EMR Impact Assessment<sup>53</sup>. It represents the expected bid of a combined cycle gas turbine (CCGT) after allowing for the revenues which our modelling suggests would be earned in the energy market. In practice our analysis suggests this change will make little difference to the cost of the Capacity Market, but increasing the estimate of net-CONE reduces the risk that we buy too little capacity.

In light of support from respondents, the Government intends to administratively set a price cap of £75/kW per year for the first T-4 auction (expected to be held in December 2014 for the 2018-19 delivery year). The price cap is necessary to protect consumers from unforeseen problems with the auction, such as a lack of competition or abuse of market power. This price cap has been calibrated to allow participation from a wider range of projects/technologies and encourage competition.

Consultation question		33 responses
CM04	Do you think that the price of new entrant bids in the auction should inform the net-CONE set in subsequent auctions?	

<sup>53</sup> See

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/288463/final\\_delivery\\_plan\\_ia.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/288463/final_delivery_plan_ia.pdf)

See *Implementing Electricity Market Reform* section: 3.2.1.3

### Summary of responses

The majority of respondents agreed that the price of new entrant bids in the first auction should inform net-CONE in the subsequent auctions. However, many provided caveats or additional comments, for example referring to points made in answer to CM02, requesting that DECC disclose the methodology used, or that it should only apply if a sufficient amount of new entrants come forward. Some respondents stressed that there are other variables that impact on the value of net-CONE (for example, technology changes, new emissions legislation, planning policy and changes in the energy market).

Several large energy providers disagreed with this approach, stating that CONE should be based on a robust ex-ante assessment of the potential costs of new entry. This assessment should take place periodically and be based on a transparent methodology.

### Decisions taken since consultation

Net-CONE will be determined from the cost of a new build combined cycle gas turbine (CCGT) plant (i.e. gross-CONE) minus expected electricity market and ancillary services revenue. It will be revised, if necessary, for each subsequent auction - for instance based on new engineering cost estimates for new build and on information gained in previous auctions. Methodologies are as set out in the EMR Delivery Plan which will be reviewed every five years.

The £75/kW price cap will be at 2012 price levels and bids for the late 2014 auction will need to reflect price levels in the base year (2012). The capacity price will then be adjusted to account for changes in the Consumer Price Index (CPI) at the start of each delivery year. This will apply to all capacity providers including existing plants with one-year capacity agreements.

Consultation question		28 responses
CM05	What are your views on the proposed approach to indexing capacity payments and penalties?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.1.3 (box text)		

### Summary of responses

The majority of respondents supported the proposed approach, with some suggesting that it would be helpful if worked examples were included in National Grid's Auction Guidelines.

One respondent requested that payments are indexed from the auction year onwards, on the grounds that this would remove inflation risk from the participants and allow generators to offer lower prices. As suppliers fix the bulk of their sales volumes at shorter timescales, the reduced inflation risk would have the likely overall impact of reducing costs to consumers.

Other stakeholders suggested that for investment in power stations it would be more appropriate to index capacity payments to a basket of indices (for example Association for the

British Electrotechnical Industry (BEAMA) indices or the Producer Price Index), as these are known by industry and better reflect the nature of power station costs.

### Decisions taken since consultation

The auction price cap has been stated as £75/kW p.a. (at 2012 price levels) for the first auction. Rather than adjust the £75 cap by estimated inflation between 2012 and the start of the delivery year, all capacity prices for capacity obligations awarded in a T-4 auction will be indexed from a base year (for the first auction prices will be at 2012 levels) to the start of the delivery year. This replaces the earlier intent where only capacity agreements of longer than one year would be indexed. For longer term capacity agreements this would be continued for the start of each subsequent delivery year

Consultation question		14 responses
CM06	Do you have any further comments on aspects of the design described in this sub-section?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.1		

### Summary of responses

The majority of respondents' comments related to wanting greater transparency and information on the auction parameters, including more robust methodologies, transparent reporting and appropriate governance arrangements. A small number of respondents also said that they wanted to see more information on the design of various aspects of the Capacity Market.

Other feedback included a request to set up collaborative sessions to discuss core design issues with stakeholders and further comments regarding the auction price cap. One respondent also suggested that the overall level of capacity in the supply side curve should be based on participants' selected de-rating, as pre-determined averages by technology could lead to under procurement.

### Decisions taken since consultation

The Government's decisions on the design of the auction are explained in response to the questions above, and elsewhere in this document – for example in response to CM12, which sets out the Government's position on de-rating.

The Government has continued to regularly engage with industry representatives on the design of the Capacity Market.

Consultation question		15 responses
CM07	Do you have any comments on Parts 2 and 3, and Chapters 1 and 2 in Part 4 of the regulations for implementing proposals for setting the amount of capacity to auction?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.1		

## Summary of responses

Responses were broadly positive, with some detailed and varied comments raised. These included:

- **Capacity year:** It was suggested that ‘capacity year’ should be defined according to a transmission charging year (1 April to 31 March) in order to align with other industry measures.
- **Electricity capacity report:** A small number of respondents suggested that the report should include a series of potential stress scenarios; others said that the Secretary of State should publish directions and assumptions given to the Delivery Body each year.
- **Auction:** Some responses noted the problem of the uncertainty regarding the amount of capacity that may be bid into the auction. One stated that the Secretary of State should, as early as possible, announce if an auction will be held and what the parameters will be, and another asked for details of prequalified CMUs to be published ahead of the auction to ensure a level playing field for large and small participants.
- **DSR:** One respondent made a number of points: splitting the auctions into T-1 and T-4 could make the Capacity Market untenable for DSR, and will remove the benefits of pay-as-clear auctions; the requirement for all expenditure to be incurred within 24 months is likely to be impossible for DSR, and conflicts with efficient project finance; and DECC should employ DSR providers to determine the capacity that could become available for T-1.

## Decisions taken since consultation

The Government has considered these points in coming to final decisions and has set these out in other sections of this document. For example, decisions on auction year and amount to auction are set out in CM01 and CM02, and decisions on DSR are set out in the section covering questions CM43-CM52.

With regard to the electricity capacity report, as set out in the consultation document, additional assurance on the robustness of the advice from National Grid will be provided via the independent Panel of Technical Experts, who will comment on the assumptions to be used in the analysis, scrutinise the modelling approach and review the models chosen for the analysis.

## Eligibility and pre-qualification

Consultation question		39 responses
CM08	Do you think the proposed limitations on eligibility for participating in the Capacity Market are appropriate? For example, do they give rise to particular issues for any technology type?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2		

## **Summary of responses**

A slight majority of respondents were supportive of the proposed limitations on eligibility. The eligibility criterion most frequently commented on by respondents was the exclusion of capacity already in receipt of support, for example through the RO or CFD. Some expressed strong support for this, while others thought that all capacity should participate on equal terms and therefore not be excluded on this basis. A number supported the proposal but thought that capacity receiving support under the RO was an exception and should be eligible.

Respondents also suggested that there should be greater clarity on the rules for moving in and out of eligibility. One respondent suggested that the Government should review how the Energy Company Obligation (ECO) brokerage scheme can link to the Capacity Market to ensure the energy efficiency industry can compete for funding.

## **Decisions taken since consultation**

The Capacity Market will be a technology-neutral mechanism in which all types of capacity can participate, except for the following types:

### *Low Carbon Capacity*

As set out in the consultation document, capacity receiving support through the Renewables Obligation (RO), Contracts for Difference (CFDs), small-scale Feed in Tariffs (FIT), Renewable Heat Incentive (RHI), New Entrants Reserve 300 (NER300), or UK Carbon Capture and Storage Commercialisation Programme will not be eligible for the Capacity Market. Having considered responses, it remains the Government's view that these exclusions are necessary to avoid any risk of double payment, and will have a minimal impact on future low carbon investment, as the levels of support offered for low carbon investment through other schemes should be not be affected by the introduction of a Capacity Market.

### *Long-term STOR*

In addition to the exclusions to eligibility set out in the October consultation document, the Government has decided that capacity subject to an existing long-term (LT) contract to provide Short-Term Operating Reserve (STOR) may only participate in the Capacity Market where it irrevocably commits to the termination of the STOR contract if successful in the capacity auction and ahead of the relevant delivery year.

The original proposal to include all balancing services capacity, including STOR capacity, in the Capacity Market was taken to avoid any conflict with National Grid's deployment of balancing services, to make the Capacity Market compatible with existing frameworks and to recognise the genuine security of supply contribution of this capacity. Under such circumstances a provider's capacity obligation will be adjusted to take account of their balancing services delivery. This is desirable where the availability and utilisation prices for future annual STOR auctions are reset annually and competitive forces ensure providers can take account of their Capacity Market revenue streams when pricing their STOR bids – so that their total revenue remains broadly constant.

Relatively late in the policy development process DECC discovered that a small population of providers held existing LT STOR contracts which overlapped multiple Capacity Market delivery



years through to 2025. For this group there appeared to be a risk that capacity payments would constitute an overpayment which would represent poor value for consumers. This only became apparent as the consultation responses were being considered and technical analysis was being carried out to simulate the supply that is expected to come forward in the early years of the Capacity Market. As such the timescales did not permit this issue to be raised in the *EMR Implementation Proposals 2013* consultation.

The risk of overpayment arises because the LT STOR contracts in question were entered into in 2010 when the Capacity Market was in the very early stages of development, and it would therefore be reasonable to assume that the value ascribed to future Capacity Market revenues at that time would have been severely discounted, if any value were ascribed at all. Unlike contracts awarded in annual STOR auctions, providers holding LT STOR contracts are unable to re-price their STOR bids to reflect their Capacity Market revenues.

Government considers it would be overpayment to allow LT STOR providers to receive capacity payments in addition to their STOR availability payments, STOR utilisation payments and energy market revenue. This is because the projected STOR revenue, potentially with some uncertain energy market revenue, was of sufficient quantum over the 15-year period of the STOR contract to recover their fixed costs and prove the business case for the LT STOR plant to be built. Modelling suggested that failing to exclude providers holding LT STOR contracts from the Capacity Market would lead to significant overpayment to these providers, with the costs borne by consumers.

In contrast, payments for annual STOR products are set on a year-ahead basis and the Capacity Market is likely to dampen the prices offered in the annual STOR market as parties will have already secured the payment through the Capacity Market they need to remain open. It should be noted that this is in addition to the competitive dampening of prices as a result of market forces between the annual and LT STOR auctions.

To gather evidence from affected providers, DECC approached National Grid for the identities of the relevant LT STOR providers, which National Grid subsequently provided after gaining release approval from the STOR providers concerned.

DECC wrote to the six affected STOR providers on 3 March 2014 requesting their views on the exclusion proposal by 14 March 2014. During this period a dedicated meeting was organised (13 March) to discuss the issue in detail. Representations were received from the attendees at the meeting and via formal written responses.

These representations focused on the proposal being unduly discriminatory to LT STOR capacity (which are subject to increasing competitive forces in the STOR market), questioning why the identity of a counterparty to a private contract with the generator should be of relevance to the generator's Capacity Market eligibility and the impact of the Capacity Market's introduction on the frequency with which STOR capacity would be despatched by National Grid. Additional concerns were raised around the potential depression of energy prices and resultant reduction in revenue for capacity outside of the Capacity Market, the unintended consequences of providers cancelling their STOR contracts, the Capacity Market's introduction encouraging

older plant into the STOR market (increasing competition and undercutting long-term prices) and the impact on the volume to be auctioned in the capacity auction.

The Government acknowledges and has considered the representations made by the affected STOR providers. It considers, however, that the LT STOR providers are in a different situation to other balancing service providers, given that they entered into contracts spanning capacity delivery years prior to any plans to introduce the Capacity Market. The Government also considers that private contractual arrangements between National Grid and LT STOR providers are of legitimate interest for public policy making, unlike other contractual or Power Purchase Agreement (PPA) arrangements, given that the terms of National Grid's Transmission Licence enable them to recover the costs associated with balancing the system from generators and suppliers via their Balancing Services Use of System charges. Suppliers and generators are obliged to pay this charge as a condition of their connection agreement with National Grid. Competition and the relative utilisation of capacity on long-term and annual STOR contracts is a matter of normal market risk and regulatory risk which providers have to manage their exposure to. It is not considered a matter for the Capacity Market to address.

In December 2010 the Government published initial proposals for a targeted capacity mechanism design to provide the right investment signals to secure system balancing in the latter part of this decade and into the 2020s. This was accompanied by details of modelling which indicated that, in the absence of a capacity mechanism-type intervention, de-rated capacity margins would reduce in the latter part of the decade from circa 20% to below 10%. Confirmation of the Capacity Mechanism's market-wide design was published in December 2011, and final confirmation of the decision to invoke the Capacity Market in 2018 was published in June 2013. This level of detail had not, however, been published at the time the counterparties to the LT STOR contracts were undertaking their investment appraisals for their STOR tender bids and before the 15-year STOR contracts were awarded in August and October 2010. As such there would have been significant uncertainty about potential Capacity Market revenue at the time of such investment appraisals, meaning that little value could have been credibly ascribed to capacity payments by the LT STOR counterparties at that time. The Government therefore maintains that any valuation of potential Capacity Market revenue in such circumstances must be an under valuation and to allow such parties to participate in the Capacity Market, whilst receiving STOR payments which take no realistic account of capacity revenue, would result in over payment. This is especially pertinent given there is no mechanism for LT STOR providers to adjust their STOR prices commensurately with any capacity payments.

Given the concerns raised by LT STOR providers about the potential depression of energy prices and resultant reduction in revenue for capacity outside of the Capacity Market, the Government has decided to allow LT STOR capacity to participate in the Capacity Market if they choose, on condition they make an irrevocable declaration, in respect of a Capacity Market Unit, to allow their STOR contracts to be terminated ahead of the relevant capacity market delivery year if awarded a capacity agreement. National Grid has confirmed to STOR providers that they would be willing to accept an offer to terminate a long-term STOR contract without prejudice in the event that a provider holding such a contract wished to participate in the Capacity Market and was successful in the auction. LT STOR capacity which is not subject to

such a declaration will be ineligible to participate in the Capacity Market. Applicants will be required to declare in their Capacity Market applications whether their CMU benefits from a STOR exclusion at the time of the application and a system of random spot checks will be implemented as part of an agreed fraud prevention and audit strategy to ensure that such declarations are accurate.

In response to LT STOR providers' concerns that the impact of the Capacity Market's introduction on the frequency in which STOR capacity would be despatched by National Grid, the Government considers that the Capacity Market will not have a causal link with the frequency with which STOR capacity is deployed, given the very intricate relationship between the capacity margin levels, the introduction of the Capacity Market, contribution of intermittent renewables, levels of synchronized reserves and STOR deployment. Government also does not consider this proposal will impact on the volume of capacity to be auctioned in the capacity auction, given such STOR capacity should be available during the peak-demand STOR availability windows.

Consultation question		28 responses
CM09	Are you aware of any solutions that might permit interconnected capacity to participate within the Capacity Market that would meet the Government's criteria as set out in this document?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2.7		

### Summary of responses

Most respondents were broadly supportive of including interconnected capacity in the Capacity Market and the Government's commitment to finding a solution to the issue. The importance of interconnectors to security of supply was underlined by many respondents. However, there were a small proportion of respondents were unsupportive or believed that a solution is unworkable,

There were some recurring concerns and comments relating to complexity of a solution, including that the approach should be capable of integrating with a wider EU approaches; the difficulty of enforcing delivery obligations and associated penalties; and that an EU wide solution must recognise the difference between GB/Ireland-Europe interconnection and between Member States in continental Europe, where there is often higher levels of interconnection.

Suggestions for solutions to allow interconnected capacity to participate were wide-ranging, including National Grid participating in the auctions to acquire capacity that it could schedule as necessary; interconnector capacity holders participating in the auctions; offering new products across the interconnector that are not currently provided for or excluded by network codes; and hybrid options with the interconnector owner acting as an agent for generating capacity in the foreign market.

### Decisions taken since consultation

Interconnected capacity will not be able to participate in the 2014 capacity auction. However, the Government acknowledges the benefits that interconnected capacity can provide in relation to security of supply and notes the importance of recognising this value through the Capacity Market.

For this reason, the Government is working to enable interconnected capacity to participate in the Capacity Market from the second auction in 2015. This will mean overcoming challenges such as not being able to guarantee the direction of energy flows, which is further complicated by differences in the reliability standard between interconnected markets, by difficulties in de-rating foreign capacity and in enforcing penalties.

The Government is looking at all policy options and has noted the points raised by respondents. We recognise that equal treatment of interconnected capacity may not necessarily mean the same treatment as GB capacity providers, and any solution will need to preserve the integrity of the internal energy market, respect the Target Model and accommodate the new market and network codes. It will also need to take into account the extent to which the UK can rely on interconnected capacity to deliver energy during a stress event and, finally, the need to ensure value for money for GB consumers.

The Government is doing additional policy thinking to develop final proposals which will be consulted upon in autumn, in order to amend the Capacity Market secondary legislation in Q1 2015, in time for interconnected capacity to participate in the 2015 capacity auction. The Government continues to engage with a wide range of stakeholders and welcomes further suggestions on this issue.

It is also important to note that Ofgem is progressing work on the regulatory framework for new electricity interconnection through a cap and floor model in relation to the proposed Nemo interconnector and through the Integrated Transmission Planning and Regulation (ITPR) project. Depending on the outcome of this work, it is possible that there could be interaction between a future GB regulatory framework for interconnection and a policy design to enable interconnected capacity to participate in the Capacity Market. The Government is working with Ofgem to consider the issues associated with any such interaction and, should they arise, Ofgem will aim to discuss them in future publications.

Consultation question		27 responses
CM10	What are your views on the approach to pre-qualification, including the submission criteria, time allowed for the process and the deadlines industry will be required to meet?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2.8 and 3.7.2		

### Summary of responses

Overall the majority of responses considered that the pre-qualification process was too complex and needed to be simplified.

Respondents noted that the timelines were short for the first auction and urged the Government to ensure that these timelines did not slip. Some respondents believed that National Grid should populate the pre-qualification submission using information already held to minimise the administrative burden on applicants. Additional comments included that the definition of a CMU needs to be clarified as this will affect the pre-qualification process; that five working days is not enough time to appeal against eligibility and that draft rule 3.3.3 (which set out circumstances in which an application could not be made for a CMU) should be rewritten.

### Decisions taken since consultation

The Government has designed the pre-qualification process and timetable to ensure that auctions can be run successfully and that all participants can deliver the capacity they have committed to in response to stress events. In light of consultation responses, and other engagement with industry, the Government has sought to simplify the pre-qualification process, whilst ensuring that it is robust and continues to meet these objectives. This has included work with industry on the content of the draft Capacity Market Rules and regulations, especially in relation to the definition of a CMU. Generating units will now be able to be combined as one CMU where they are within the same trading unit (excluding base trading units), or if not applicable then behind the same boundary point, across separate sites but with a connection capacity of between 2 and 50 MWs or where there are ten or less hydro generating units registered in the BSC as a single balancing mechanism unit.

Government has acknowledged representation regarding the requirement to demonstrate Transmission Entry Capacity (TEC) in respect of the 2014 auction. Transmission connected units will be able to declare they do not have TEC at the point of pre-qualification, but that they will have obtained it by 18 months ahead of the relevant delivery year. This commitment will be backed by collateral lodged before the auction, and units failing to demonstrate TEC by the 18 month deadline will have their agreements terminated and their collateral drawn down.

The Government has also decided to extend the deadline by which relevant planning permission has to be demonstrated in regards to the 2014 capacity auction. Applicants will now have until 15 working days before the auction to provide copies of the relevant certification – failure to do so by this deadline will result in not being considered as pre-qualified for the auction. This will provide a few extra weeks for plants currently undergoing the planning process to obtain the relevant clearances.

Consultation question		17 responses
CM11	Are you aware of other ownership/legal structure arrangements that should be accommodated in the definition of applicants able to register for pre-qualification? If so please provide details.	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2.8 and 3.7.2		

**Summary of responses**

Approximately a third of respondents said they were unaware of any additional arrangements which should be included in the definition. Other respondents made a number of comments in relation to the ownership/legal structure arrangements, including that some organisations fall within the definition of mandatory CMU, but not the ownership and legal structure rules as set out in the draft Capacity Market Rules; that companies should be allowed to decide which corporate entity registers and is responsible for each CMU; and that it was unclear why the definition of Permitted Person is restricted to UK limited liability companies, as this may lead to discrimination claims and unduly restrict participation.

One respondent did not agree with the proposal that penalty caps should be determined at portfolio level, suggesting that this goes beyond the usual liability structure of commercial arrangements, and another said it was difficult to understand the precise definitions of ownership set out in the consultation document.

**Decisions taken since consultation**

The Government believes that is important that all participants in the Capacity Market have a legal status that means they can compete on an equal basis. The Government has reviewed and removed the ‘Permitted Person’ rule to instead require all applicants at pre-qualification to submit legal opinion confirming that the applicant is:

- (a) Duly formed and validly existing under the laws of the jurisdiction of its formation; and
- (b) Has the power to enter into capacity agreements and to perform capacity obligations.

The Government’s view is that this approach will not unnecessarily restrict participation in the Capacity Market.

We have continued to engage with industry on the content of the draft Capacity Market Rules and regulations.

The decisions regarding penalty caps are set out in response to question CM35 below.

Consultation question		35 responses
CM12	<p>Do you think the proposed methodology for de-rating capacity, and the proposed range, is robust?</p> <p>What are your views on the proposals for the auction to credit units at the fuel-type average availability level, rather than the unit’s selected de-rating figure?</p>	
<p>See <i>Implementing Electricity Market Reform</i> section: 3.2.2.8 and 3.7.2</p>		

**Summary of responses**

Almost half of respondents believed that plant operators are best placed to determine the de-rated capacity. Many responses also raised concerns with a ‘one-size-fits-all’ approach and DSR, electricity storage and CHP were specifically mentioned as having distinct features and therefore not suited to the proposed methodology. Some respondents said that it was difficult to

make a judgement without seeing figures or examples, and others raised questions over the process for managing disputes, with support for a robust appeals process.

Other comments included that the approach should be simplified; that the proposals were sufficient provided there was flexibility for participants to adjust their deemed de-rating to better reflect individual circumstances; and that users should be able to select a range which is greater than the average.

### Decisions taken since consultation

As proposed in the consultation, the de-rating factors for each generating technology class will be calculated and published each year by the Delivery Body. However following feedback from stakeholders, three options will be available to Capacity Market applicants to determine their 'connection capacity' in their pre-qualification application, to which the centrally determined de-rating factors are applied. They will be required to select from their unit's Connection Entry Capacity (and distribution equivalent), the mean of their three highest generation outputs demonstrated within the previous 24 months or their unit's Connection Entry Capacity pro-rated according to the level of site's Transmission Entry Capacity (TEC).

The processes for dispute resolution are discussed in CM14, below.

Consultation question		23 responses
CM13	Do you think the level and type of collateral requirements for new build plants are appropriate?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.3.6 (box text)		

### Summary of responses

While around a quarter of respondents were content with the level and type of collateral requirements for new build plants, the majority of stakeholders raised concerns with the proposals – suggesting that they were too onerous or the level of collateral too high. These included concerns relating to the impact that the aggregated collateral requirements across the EMR programme would have on new builds; that having to meet milestones would cause problems in negotiations between projects and contractors; and that the construction plan requirement needed further consideration.

Additional suggestions included that collateral for new plants should only be due within 28 days after a successful auction; that five working days was not long enough to finalise any collateral arrangement and that insurance bonds should also be permitted as an acceptable type of collateral.

### Decisions taken since consultation

If new plants do not build on time it could mean that consumers potentially face higher prices and other providers could bear a higher risk of penalties. The Government has confirmed, therefore, that collateral sufficient to cover 100 per cent of a plant's potential exposure to termination fees will be required in the form of either cash or letters of credit. We consider this a

reasonable level to ensure plants under construction have strong incentives to build on time. The Government has also decided to apply the collateral requirement from the 2014 capacity auction onwards. The Government has, however, reduced the level of termination fee one, which effectively sets the level of collateral for new plants, to £5,000/MW in order to reduce potential barriers to entry whilst retaining the aforementioned delivery incentives.

The rules for new build plants are discussed at CM22 below. Decisions in relation to delivery are set out in response to questions CM33-CM42.

Consultation question		18 responses
CM14	Do you have any comments on the proposed process for dealing with pre-qualification disputes?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2.9		

### Summary of responses

The majority of respondents were happy with the three tier approach for dealing with pre-qualification disputes. However, most expressed concerns about the timings of each stage, in particular the proposed five days for appealing National Grid’s decision, which respondents did not believe was long enough. Concerns were also expressed about the lack of a deadline for the appeals process to finish, which would cause uncertainty if there was a large amount of disputes outstanding when the auction takes place.

### Decisions taken since consultation

In the light of responses to the consultation and continuing engagement with industry, the Government has streamlined and simplified the appeals process. The Government has decided to:

- Reduce the number of types of Delivery Body reviewable decisions in regulation 68 of the Electricity Capacity Regulations (previously in section 12.2 of the Capacity Market Rules) to only include: pre-qualification decisions, updates of Capacity Market Register, amendments to capacity agreement notices, and termination notices.
- Introduce additional requirements in the Electricity Capacity Regulations regarding the information to be provided by participants in an application to the Delivery Body for reconsideration of a decision. The regulations also restrict the evidence that can be submitted to Ofgem so that it only includes what was submitted to the Delivery Body before the reconsidered decision was made or needs to show what evidence was before the Delivery Body when the reconsidered decision was made. This will benefit both capacity providers when submitting their application, and Ofgem in that it will not consider new evidence that has not been already considered by the Delivery Body.
- Not include in regulations a specific timeframe for Ofgem to resolve any Tier 2 disputes. Instead, an indicative non-legally binding timeline will be set out in the forthcoming Ofgem guidance on disputes for Capacity Market applicants. This will ensure participants



have an understanding of the timeframe by which Ofgem will seek to determine Tier 2 disputes.

Consultation question		16 responses
CM15	Do you have any further comments on aspects of the design described in this sub-section?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2		

### Summary of responses

There was a wide mix of additional comments relating to design simplification, detail provided prior to the first auction, the CMU definition, monitoring of ownership of capacity providers, termination fees and CHP. One respondent provided a detailed response to this question on why the Capacity Market was suboptimal to the UK economy.

### Decisions taken since consultation

The points raised in response to this question have been taken into account in finalising the design decisions relating to eligibility and pre-qualification. The decisions were taken to help aid simplification, and also took into account engagement with industry and wider consultation feedback.

Consultation question		17 responses
CM16	Do you have any comments on Chapter 3 of Part 4 and Parts 6 and 9 of the regulations and Chapters 2, 3, 4, 10 and 12 of the Capacity Market Rules for implementing proposals for eligibility and pre-qualification?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.2		

### Summary of responses

Respondents indicated that they believed that the proposed process for pre-qualification and eligibility was too cumbersome and complex, and that the requirements should be minimised. In particular, there were extensive comments on Chapter 3 of the Rules, with respondents asking for clearer definitions in the regulations and rules relating to these sections (e.g. the definition of a 'generating CMU' is not well-aligned with the BMU definition and should be revised). Respondents were also keen to see clearer criteria on what constitutes new build capacity relating to capacity operational pre-July 2014.

There were also concerns over how narrowly disputes are defined in the regulations and the time limit of five working days. Some respondents requested further detail and guidance on how the rule change process will work.

### Decisions taken since consultation

The Government has continued to engage with industry and has made changes to the rules and regulations in order to ensure that the eligibility criteria and processes are fair, robust and

workable. These changes are set out in the answer to CM14, above. The Government has engaged with industry on the definition of a Capacity Market Unit<sup>54</sup>.

### Auction frequency, format and agreement lengths

Consultation question		29 responses
CM17	<p>What are your views on the proposal for price takers and price makers?</p> <p>What is the lowest price taker threshold that should enable the most existing plant to participate in the auction without needing to qualify as a price maker?</p>	
See <i>Implementing Electricity Market Reform</i> section: 3.2.3.5		

#### Summary of responses

The majority of respondents expressed a view that the price maker/taker distinction was unnecessary and undesirable, or raised concerns with the proposals. They noted that it was unnecessary as the auction would be competitive and that there were already legal restrictions against anti-competitive behaviour; and that any price taker threshold would be arbitrary – as costs differ widely between plants, and as there is limited liquidity on the forward market it is difficult to see what parties should bid in to cover the risk of future price changes.

Respondents noted that this requirement created an onerous administrative burden – particularly if the threshold was set low. One respondent noted it could be reduced if boards can sign one statement for all plants in their portfolio intending to bid above the threshold, with an annex setting out evidence for each such CMU.

In terms of what was considered an appropriate threshold, almost all respondents thought that £14.50 was too low and would lead to a much higher proportion of plants than 25 per cent choosing to be price makers. Respondents said that the threshold needed to reflect the true range of costs, e.g. existing plants will have maintenance cycles and will discount future capacity revenues as they are uncertain, TNUoS charges cut across Capacity Market delivery years and carbon prices are uncertain.

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<sup>54</sup> Generating units (defined with reference to: providing electricity, being capable of independent control, net output measured by half hourly meter(s), capacity in excess of 2MW) may participate individually as a CMU or aggregate with other eligible generating units under the following conditions: (i) the units all form part of the same Trading Unit (i.e. power station); or (ii) where all the units are connected to the system at the same Boundary Point (BSC term) - i.e. the same site, but where the Trading Unit concept does not apply; or (iii) where the aggregate capacity of all the units is between the minimum (2MW) threshold and 50MW (effectively embedded generation spread across several sites; thresholds included to prevent aggregation of larger generation capacity across sites) or iv) where ten or less hydro generating units registered as a single balancing mechanism unit under the BSC.

DSR CMUs are defined with reference to a commitment to reduce demand, by the DSR provider being (i) a DSR customer; (ii) owning the DSR customer; or (iii) having contractual DSR control over the DSR customer. Such commitment should cause the DSR customer to reduce the import of electricity (as measured by half hourly meters) and/or export electricity generated by on-site generating units which are owned by the DSR customer. In addition, each component should be connected to a half hourly meter and the provider's total DSR capacity should be between 2MW and 50MW.

Many respondents supported defining the threshold according to CONE, but preferred a higher level – reiterating view that the proposed net-CONE was too low. Some respondents thought that a threshold of £25-30 was adequate, while others thought that it needed to be £40-50. Some respondents also noted a particular need for a higher threshold in the first auction as parties will seek to recover several years' losses.

### Decisions taken since consultation

While the Government notes stakeholders' concerns regarding the introduction of the price maker/taker distinction, the Government considers that the approach is necessary to mitigate the potential abuse of market power, and intends to set the price taker/price maker threshold at 50 per cent of net CONE for the late 2014 auction. In order to make the auction process simpler, the price taker threshold will be rounded to the nearest end of round price.

In response to concerns that too high a proportion of plant will choose to be price makers, the Government has decided that existing resources will default to price taker status unless a memorandum is lodged with the Authority justifying the need for price maker status. New resources and DSR will default to price maker status.

Consultation questions		
CM18	<p>Do you agree that that the relevant considerations to be taken into account when setting the capacity agreement length for new plant are the extent to which:</p> <ul style="list-style-type: none"> <li>• Long-term capacity agreements can reduce financing costs;</li> <li>• investors in new plant value capacity prices beyond the term of their capacity agreement;</li> <li>• long-term capacity agreements risk locking in volumes of capacity which is not needed;</li> <li>• long-term capacity agreements risk locking in high prices;</li> <li>• long-term capacity agreements impact the ability of existing plant on one year contracts to compete?</li> </ul> <p>Are there other considerations which should or must be taken into account?</p>	31 responses
CM19	<p>What do you consider to be the appropriate maximum agreement lengths for new, refurbishing and existing capacity?</p>	33 responses
CM20	<p>Do you think financial thresholds are appropriate for distinguishing between new and refurbishing plants?</p> <p>Do you think the proposed levels of the thresholds are appropriate?</p> <p>Do you have any views on the type of refurbishments likely to require a longer term agreement? What scale of investment would these plants be making?</p>	25 responses
<p>See <i>Implementing Electricity Market Reform</i> section: 3.2.3.</p>		

## Summary of responses

Approximately half of respondents indicated they agreed with the proposed considerations (CM18). Few explicitly disagreed and instead most of the remaining respondents focused on suggesting other considerations and their thoughts on agreement lengths.

Independent generators generally expressed a preference for longer capacity agreements – pointing out that 15 years was the likely *minimum* level to attract project finance to the auction (with longer agreements enabling a lower price), that it is consistent with the CFD, and that attracting independents would increase competition and therefore lower consumer costs in the long run.

Other respondents expressed a view that longer agreements could lock consumers into capacity they do not need and could squeeze out existing plant. Many of these respondents felt 10 years struck an appropriate balance. Some offered alternative proposals e.g. having separate auctions for short and long-term contracts.

There was a wide range of views expressed on capacity agreement lengths (CM19). Some respondents preferred allowing all plant to be eligible on the same terms; others preferred having shorter contracts for all or favoured the use of “price duration curves” to enable agreements of different lengths to be compared on a more nuanced basis. However, most thought that a 10 year agreement for new capacity was appropriate – alongside a refurbishment category of three to five years. Independent generators repeated calls set out in CM18 for 15 year agreements; however a sizeable minority of such respondents also thought that having everyone on short-term contracts would be better to avoid locking consumers in.

On CM20, respondents reiterated their opposition to discriminatory treatment against existing and refurbishing plant, arguing that financial thresholds were inevitably arbitrary.

Many respondents worried that use of financial thresholds would incentivise inefficient capital expenditure to qualify for long-term agreements. However a sizeable minority of respondents thought that the use of financial thresholds was a legitimate simplifying measure and was unlikely to have perverse incentives to increase spend. Alternative proposals mentioned include defining new plant according to use of a new site, a new environmental permit or Section 36 Consent, and defining refurbishing plant by life extension of a plant or its major items, or procuring a major plant item (possibly in addition to a financial threshold).

Most respondents did not provide their own view of appropriate thresholds. Some suggested DECC’s proposed levels were appropriate. A few suggested the threshold for refurbishment was too high – with one respondent saying it should be £80/KW, and that this should include expenditure incurred in the year *before* the auction.

## Decisions taken since consultation - CM18 – CM20

If successful at the auction, an existing generation unit or a DSR unit will be awarded a one-year capacity agreement at the clearing price. Longer-term agreements will be available for refurbishing plants and new build generators (including storage). The Government intends to set

the thresholds for qualifying as refurbishing/new plants at the levels set out in the consultation document (£125/kW for refurbishing, and £250/kW for new). The thresholds will be calculated on the basis of expenditure per kW of de-rated capacity. The thresholds are set to ensure that plants undertaking routine maintenance (as opposed to significant refurbishment) are not eligible for longer term agreements, and that existing plants will only be eligible for longer-term agreements if spending as much capital as it could cost to build a new plant.

In response to feedback and engagement, the Government has decided that new plants will be able to access capacity agreements of up to a maximum of 15 years. This will allow investors to spread the capital costs over a longer period, providing greater revenue certainty and enabling lower bids in the auction. It should also enable a more efficient debt structure to be put in place and allow refinancing within the agreement term which again should result in lower prices and wider participation. Plants undertaking significant refurbishment will be able to access capacity agreements of up to a maximum of three years.

Although in the first auction the Government will express no preference for agreement lengths of different durations, the Government will retain powers to set price duration curves in the future and to vary the maximum permissible length of capacity agreements in light of evidence from the first and subsequent auctions.

Consultation question		34 responses
CM21	Is a 'price only' (i.e. selected on price alone, irrespective of the length of agreement) or a dual auction comparing bids for around 10 and 25 years more appropriate? If the latter, how should the preference be established?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.3		

### Summary of responses

The majority of respondents believed that the auction should be 'price only', with very few stating support for a dual auction. Most respondents thought that an auction that assessed bids on agreement length as well as price would add complexity to the auction, or thought that there was a lack of clarity over how it would operate. Some respondents stated that if dual auctions were to be adopted it would be important to set out the assessment criteria clearly to potential applicants.

### Decisions taken since consultation

In light of feedback from respondents, the auction will operate on a 'price only' basis. This corresponds to a 'fixed prices' auction format under which the Government does not set minimum or maximum targets for how much of each agreement length it seeks to buy. Capacity is procured on price-alone basis, so that only the least-cost capacity is selected, irrespective of the duration of the capacity agreements offered to successful participants<sup>55</sup>.

<sup>55</sup> Except that in the event of a tiebreaker, where the shorter term would be selected.

Under a fixed-prices auction format, the Government will set out the price spreads that define the difference in price for a given agreement length and which would render the Government indifferent between various agreement lengths and a single-year offer. The Government intends to *implicitly* set **price spreads of zero for the 2014 auction**, so that capacity will be effectively selected on price basis only. However, the Government will retain powers to *explicitly* set price duration curves in the future.

The auction will be ‘pay-as-clear’ – so all participants will receive the clearing price set by the marginal bidder. It will follow a descending clock format, in which the price offered is gradually reduced until the minimum price is reached at which the supply of capacity offered by bidders is equal to the volume of capacity required.

The capacity auction will be mechanistically run. The first capacity auction will be allowed to run for up to four days, with approximately four rounds per day. This should ensure that the **price decrements** remain small (e.g. £5/kW) and that parties have more time to consider their bids in light of the outcome of the previous round. The decrements will be rounded and will be approximately equally sized. The price schedule will be announced prior to the auction as part of the auction guidelines published by the Delivery Body.

For each delivery year, an auction will be held four years ahead of delivery, supplemented by a further auction one year ahead of delivery to enable the participation of DSR and provide an opportunity to refine the level of capacity for which capacity agreements are issued. National Grid will have the capability to run zonal auctions if necessary to manage constraints but no such zones will be created unless approved by Ofgem and the necessary amendments to the rules are made.

Consultation questions		
CM22	Do you think the additional rules proposed for prospective capacity providers that must build or refurbish their plant between the auction and delivery year are appropriate?	23 responses
CM23	Do you agree with the concept of termination fees being applied to new build plants that are not operational for their delivery year? Would it be more appropriate to make such plant liable for penalties in any system stress events?	25 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.3.6 (box text)		

### Summary of responses

Just under half of respondent either supported the proposals or indicated that they agreed with the principle and/or recognised the need for rules to ensure providers deliver (with the majority of these falling into the latter two categories). However, the majority of respondents made suggestions for improvements to the rules or raised concerns with specific proposals, with some noting that the proposals may have the effect of increasing cost rather than encouraging delivery. Many noted that the monitoring of project progress, combined with the commercial pressure to earn revenues, provides adequate incentive to complete on time.

Concerns commonly raised were that the 50 per cent expenditure test at 12 months for new build is inappropriate and impractical, and that the 24 month completion requirement for refurbishing projects was inefficient and problematic. Some noted that refurbishing work may take longer than two years or may need to be staggered across different units. Many highlighted that the current rules will act as a disincentive to investment in refurbishing plant.

On CM23, views were split between (i) support for termination fees to new build plants; (ii) the view that penalties for stress events should apply (with the ability to trade out obligations if the plant is not ready); and (iii) the view that the loss of revenue and the commercial pressure to complete on time is an adequate incentive.

Some large energy suppliers considered that new and existing capacity should be treated equally, with penalties for non-delivery at stress events. This is also linked to an ability to trade out of obligations ahead of the delivery year - hence secondary trading is seen as vital.

Generators were also divided - some preferring termination fees against an open ended liability, with others preferring a stress event penalty, linked with trading.

### **Decisions taken since consultation – CM22 & CM23**

#### *Additional rules for new plants*

Recognising these points the Government has worked with the industry EMR Expert Group to simplify the requirements in this area. Prospective generators will be subject to a series of additional checks and incentives to ensure they will be ready to deliver in the relevant delivery year. In recognition of the fact that prospective plants will have already incurred sizeable development and consenting costs to get to the stage where they can demonstrate such requirements, the following, simplified, requirements will apply:

<b>Parameter</b>	<b>Proposed requirements</b>
Financial Commitment Milestone	18 months after the auction, prospective units will need to demonstrate: (i) that they have spent at least 10 per cent of the total project costs (independently verified); <u>or</u> (ii) relevant project commitments - such as board commitment to undertake project and financial close, director's certificate of sufficient financial resources and contractual robustness – with supporting evidence, evidence of an Engineering, Procurement and Construction (EPC) contract or of an agreement to supply major components representing at least 20 per cent of total project costs, again independently verified.
Substantial Completion Milestone ('longstop date')	Any new capacity failing to have operational at least 50 per cent of the amount specified in its capacity agreement by 12 months after the start of the first relevant delivery year will have a six month cure period applied before its obligation is terminated, and be subject

	to a termination fee.
Termination fee	For failing Financial Commitment Milestone: £5,000/MW per capacity obligation (e.g. £2.5m for a 500MW unit). For failing longstop date milestone: £25,000/MW per capacity obligation (£12.5m for a 500MW unit).

There will be provisions to allow the Secretary of State a 60 day discretionary period for deciding whether to rescind the termination of a capacity agreement. Decisions on credit cover for terminations fees are covered in the response to CM13.

#### *Additional rules for refurbishing plants*

Plant undertaking significant refurbishment which are successful in securing a three year capacity agreement will also be subject to the financial commitment milestone (as defined above) and to the longstop date milestone (starting from the beginning of the delivery year, i.e. the point onwards from which they receive capacity payments).

In light of consultation feedback, refurbishing plants will not be required to have completed their refurbishment two years after the relevant auction, as proposed in the consultation document. The implications of failing the longstop date will remain as per the consultation document, i.e. their capacity agreement term will be reduced to one year; they will have their de-rated capacity for the delivery year adjusted to their pre-refurbishment level, and they will be restricted to bidding for annual capacity agreements for the following two years.

<b>Consultation questions</b>		
CM24	Under what circumstances would it be appropriate to cancel holding an auction or to reject its results?	23 responses
CM25	Should the Capacity Market create requirements for participants to bid fairly and to not engage in collusion or market manipulation? Do you have any comments on the proposed definitions of collusion and market manipulation in the Capacity Market Rules? Do you think that participants should have to sign up to a Certificate of Ethical Conduct in order to sign up to the auction? Do you think there are any potential gaps in existing competition powers that need to be addressed to ensure that Ofgem can ensure competition in the Capacity Market?	28 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.3.3		

#### **Summary of responses**

Respondents shared concerns over the Secretary of State's discretion to cancel auctions, including that they may base such a decision on the price being unexpectedly high, rather than there being material evidence of gaming. Respondents wanted greater clarity on the circumstances in which an auction could be rejected (noting the broad categories – IT failure,



competition and breach of rules – were appropriate), as well as what happens if it is rejected (with respondents preferring the auction delayed).

Most respondents thought it was inappropriate to cancel the auction if insufficient capacity came forward – noting this was a signal of scarcity, rather than lack of competition. Respondents thought it was important that a high enough price cap is set in the auction so that it would definitely clear.

Many respondents thought it unnecessary to put obligations on parties to act competitively as such obligations already exist in competition law – noting this would add to administrative burden. Respondents said it is only appropriate to mandate parties bid fairly if the Government is willing to define fair bidding and to set out how this will be enforced.

Respondents approved of the definition of market manipulation – noting it was consistent with EU regulation No 1227/2011 on wholesale energy market integrity and transparency (REMIT). Respondents considered that a Certificate of Ethical Conduct must only reflect existing requirements in competition law and should avoid defining “ethical” behaviour more widely.

#### **Decisions taken since consultation – CM24 & CM25**

Prospective CMUs which have successfully pre-qualified must confirm 10 working days prior to auction whether they are participating in the auction. CMUs must also confirm whether they intend to participate as price makers or takers if they are existing plants (if price makers, they must also provide justification for why they need the higher price); and their choice of contract length if new/refurbishing plants. Two working days later, the Delivery Body will send the Secretary of State the list of confirmed participants and their status<sup>56</sup>.

On the basis of this information, and taking account of any advice from the Delivery Body, the Secretary of State will assess whether the auction is likely to be sufficiently liquid and competitive - and would thus represent fair value for consumers - and will decide whether the auction should proceed. If the Secretary of State does not act, then the auction will proceed.

Following consultation, the Government has decided to retain the requirement for participants to certify that they have complied with relevant legislation and not engaged in market manipulation. A pro-forma will be added as an annex to the rules which the applicant can sign to discharge this requirement. This pro forma will be referred to as a ‘Certificate of Conduct.’

There will be no changes to the definitions of ‘collusion’ or ‘market manipulation’ and Ofgem will not have additional powers to enforce the rules on auction conduct.

<b>Consultation question</b>		<b>22 responses</b>
CM26	What are your views on which party should act as auction monitor and what should be the scope of their role?	

<sup>56</sup> This list will also be published, however it will omit whether existing plants are participating as price makers or takers.

See *Implementing Electricity Market Reform* section: 3.2.3.3

### Summary of responses

The majority of respondents said that the auction monitor should be an independent body; with additional comments including that the monitor should be efficient, have experience in auctions and should be subject to regular review. Of the few suggesting an existing party, ideas included Ofgem, the independent Panel of Technical Experts or a voting body consisting of representatives from DECC, National Grid and Ofgem.

On scope, comments included that their role should be limited to reporting any irregularities in the auction process that could materially alter the auction outcome; and ensure that auction has been run fairly, equitably, transparently, and generally in accordance with the capacity market rules.

Again some respondents noted the importance of the scope of the auction monitor's role being subject to regular review, and others noted its role should be tightly and clearly defined. Concerns were also raised with what they considered to be the wide scope of powers given to the auction monitor under the Capacity Market Rules.

### Decisions taken since consultation

The auction will be monitored by an auction monitor, who will assess whether the auctioneer conducted the auction in accordance with the rules. The auction monitor, will be a third party, appointed by the Delivery Body, but will directly report to the Secretary of State. The identity, contact details and duration of the appointment of the auction monitor must be published on the Delivery Body's website. After receiving the auction monitor's report, the Secretary of State will have seven working days to annul the auction. If the Secretary of State does not annul the auction within this time the provisional results (which will be published five days after the auction) will stand.

The Government notes respondents' concerns on the powers of the auction monitor and ensuring its role is tightly defined. The scope of the role is set out in the Capacity Market Rules. The Government has decided to narrow the auction monitor's role and it will now be only to assess whether the Delivery Body conducted the auction in accordance with the rules.

Consultation question		24 responses
CM27	Do you agree that the Government should introduce a guarantee to auction 50 per cent of the capacity initially set aside for the year ahead auction?  Could DSR capacity compete without the guarantee?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.3.1		

### Summary of responses

A very slight majority of respondents were in favour of introducing a guarantee to auction 50 per cent of the capacity initially set aside for the year ahead auction. Respondents in favour of the

guarantee cited the need for investor certainty to drive participation in the T-1 auction and the benefits of supporting DSR generally. The majority of support was caveated, for example with keeping the effectiveness, necessity and cost of the guarantee under review over time and not ring fencing it exclusively for DSR. Those opposing the guarantee pointed to the cost to consumers of procuring additional capacity; unfairly advantaging DSR; potential issues for State Aid clearance and distortions to the T-4 auction.

There was a small number of comments on whether DSR could compete without the guarantee, with respondents providing mixed views.

### Decisions taken since consultation

Because it will be difficult for nascent technologies, such as DSR capacity, to participate in the four-year ahead auction, the Government confirms its intention that the target volume of capacity a one-year ahead auction will be at least 50 per cent of the capacity that was reserved for it at the four-year ahead stage<sup>57</sup>. Capacity will be procured on a price-alone basis, so that only the least-cost capacity is selected, irrespective of the duration of the capacity agreements offered to successful participants<sup>58</sup>.

Consultation questions		
CM28	Do you have any further comments on aspects of the design described in this sub-section?	9 responses
CM29	Do you have any comments on Part 3 and chapters 1, 2, 3 and 4 in Part 4 the regulations and Chapters 4, 5, 6 and 7 and Schedule 1 of the Capacity Market Rules for implementing proposals for auction format and frequency?	15 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.3		

### Summary of responses

Responses to these questions were mixed, with respondents repeating many points raised in the answers to previous questions. For example, some respondents repeated concerns relating to the Secretary of State's power to delay or reschedule the auction, with one respondent particularly concerned that this provides no assurance that there will be a Capacity Market from one year to the next and therefore does not give providers certainty to invest. There was general agreement that the Secretary of State should immediately publish a detailed explanation for any delay or reschedule to the auction.

Some respondents noted that they required further information on the auction guidelines in order to comment properly on the design; and requested that the Government engage with industry on the design as it is finalised.

<sup>57</sup> The target amount is the amount of capacity that the Delivery Body will procure if the auction clearing price is equal to net-CONE, with the demand curve and price cap allowing for more or less capacity to be procured according to the price.

<sup>58</sup> Except that in the event of a tiebreaker, where the shorter term would be selected.

Some detailed and mixed comments were provided on the regulations and rules. For example, one respondent made a general comment that further work is required on the auction frequency, format and agreement length.

### Decisions taken since consultation CM28 & CM29

The points raised in response to CM28 and CM29 have been considered in developing final policy on the auction frequency, format and agreement lengths. Decisions on auction cancellation are at CM24 and CM25 and decisions on auction frequency, format and agreements lengths are at CM17 and CM21 and CM18-CM20.

For reasons of transparency, the Government has decided that the following information regarding participation in the auction will be published:

- Following pre-qualification:
  - Which CMUs qualified for the auction and at what de-rating, and whether as existing, new or refurbishing plant – but not whether they qualified as price maker or taker;
  - Which CMUs have opted out and how much capacity will be deducted from the demand curve;
  - Which CMUs said they will be retiring/unavailable (this capacity will not be deducted from the demand curve).
- During the auction:
  - How much spare capacity there is at the conclusion of each auction round.
- After the auction:
  - How much spare capacity there was in each round (unrounded) – but not the price at which individual units exited;
  - Which CMUs received capacity agreements and what obligation they have taken on.

### Secondary market

Consultation questions		
CM30	<p>Do you have any comments on the proposed provisions for secondary trading of capacity? Are there any better approaches?</p> <p>Do you consider there are additional measures or design changes that the Government can take to facilitate a liquid hedging market around penalties for under-delivery?</p>	30 responses
CM31	Do you have any further comments on aspects of the design described in this sub-section?	9 responses
CM32	Do you have any comments on Chapters 7 and 9 of the Capacity Market Rules for implementing proposals for secondary trading?	16 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.4		

## Summary of responses

The majority of respondents considered secondary trading to be important in order to ensure the successful implementation of the Capacity Market – particularly for managing their penalty risk during expected outages. While a minority of respondents were content with the proposed incentives for trading, most respondents had concerns around the ability of a liquid secondary market to develop. Respondents cited the requirement for revenue neutrality and the restrictions on physical trading as likely causes of market failure. Some respondents also referred to poor liquidity in the wholesale market and the fact that Government is not providing a central trading platform or mandating that portfolio players trade on this platform. Many respondents also indicated that applying the cap on liabilities at portfolio level is not helpful for secondary trading.

Respondents provided a number of suggestions for improving incentives for secondary trading. Some respondents indicated it would be sufficient for Government to provide a “firm” rate of payments for over-delivery. Many respondents also suggested removing restrictions on physical trading, or making provision for parties to be able to allocate their physical over-delivery to another unit, or allowing parties windows for taking maintenance. Some respondents also said that the Government should provide a platform for trading and mandate that parties trade on this. A few respondents indicated that, given that a liquid secondary market was unlikely to develop quickly, having a lower level of penalty and a lower cap were the most important ways to make penalty risk manageable for investors.

On CM32, the majority of respondents agreed that more work is required on secondary trading, suggesting that the proposals in Chapter 9 would severely limit the ability to trade physically. In particular respondents considered that the penalty regime was too onerous for secondary trading to be profitable; and there was not parity between penalties and over-delivery payments.

Several responses agreed that the capacity register detailing which CMUs have tradable capacity should be publicly available to facilitate physical trading.

## Decisions taken since consultation – CM30 - CM32

Capacity providers will be able to transfer their capacity obligations between Capacity Market Units and to a certain limited number of other parties. Trading is an important tool for investors to be able to manage the risks associated with holding a capacity obligation<sup>59</sup>.

The Government believes that there is no necessity for it to intervene and create an organised market for onward transfer of capacity obligations.

Following feedback and discussion with the industry EMR Expert Group, the Government has reviewed the design of the penalty regime to ensure that it delivers its objectives and does not create unmanageable risks or discourage secondary trading – see CM33-CM39 for the decisions on penalties and testing.

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<sup>59</sup> For example, volume reallocation trading takes place after a system stress event and, as such, is a very effective method for parties to manage the risk of penalties.

In light of respondent feedback, the Government has reviewed the proposals for secondary trading with the aim to enhance participants’ ability to trade. Three forms of secondary trading are anticipated and the main characteristics and differences are summarised in the table below. To note: Provisions relating to Obligation Trading are not set out in the current draft of the Capacity Market Regulations – it is intended that these will be introduced via a subsequent amendment to the regulations.

**Table 2.1: Capacity Market secondary trading arrangements**

	<b>Financial Trading</b>	<b>Volume Reallocation</b>	<b>Obligation Trading</b>
Eligibility	Parties can trade with whomever they choose (e.g. each other or insurers)	Parties can reallocate excess output to another CMU	Parties can only move obligations to pre-qualified resources to the limit of their de-rated capacity and which do not have obligations (i.e. empty vessels).
Payment for holding capacity obligation	Unaffected	Unaffected	Payment goes directly to whoever holds the obligation.
Timing	As privately negotiated.	Volume reallocation can only happen ex post in 11 to 19 working days following months in which there have been stress events.	Obligation trading can take place following the T-1 auction up to near real time.
Size of trading blocks	As privately negotiated.	No restrictions on size.	Minimum trading blocks to be determined
<b>Examples</b>			
Agreement	For a fixed fee, A agrees to pay B an amount if B becomes liable for a penalty	Agreement made after stress event.	B transfers the capacity obligation to A. B has no obligation. A has the same obligation B once held
B under-delivers; A over-delivers	B is penalised, but receives a private payment from A. A is eligible for over-delivery payments in	A nominates surplus to B (so A has no surplus and hence receives no over-delivery payments); B receives surplus when off-	B has no obligation. A receives over-delivery payments.

	the ordinary course.	sets and B has no liability.	
A and B under-deliver	A and B are penalised. B receives a private payment from A.	Neither A nor B have excess output to reallocate. Both must look for another party to reallocate volume with, or face a penalty.	B has no obligation. A is penalised.

## Delivery

Consultation questions		
CM33	Do you agree that liability for penalties should be conditional on the issue of a Capacity Market warning? If so, is the proposed four-hour period appropriate?	30 responses
CM34	Do you think the proposed penalties applicable for non-delivery both more than and less than four hours after a Capacity Market warning are appropriate?	33 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.5.1 (box text)		

### Summary of responses

All respondents agreed that the liability for penalties should be conditional upon the issue of a Capacity Market warning, and almost all agreed with the proposed four hour timescale. However, several responses requested a longer notification period (between 4 to 12 hours) to recognise the ramp up times for coal and combined cycle gas turbine (CCGT) plant and to avoid potential distortions on the Short-Term Operating Reserve (STOR) market. A very small number suggested that the four hours should be reduced.

On the penalties applicable to non-delivery (CM34), approximately a third of respondents were supportive of the proposed approach, with the rest raising concerns about the impact of penalties or with certain details of the proposals. A number of respondents suggested that penalties should be applied to non-delivery more than four hours after a Capacity Market warning only. Several responses also highlighted that the proposals may create a perverse incentive for participants to submit unrealistically low physical notifications (PNs) until shortly before gate closure, and the unequal exposure of generating and non-generating plant (with a greater risk to higher merit order plant).

Several responses stated that the proposed penalty levels are excessive and present a barrier to debt financed plant, suggesting that ideally penalty exposure should be predictable, capped and within the control of the operator. Some responses suggested that the proposed level of penalties would not represent value for money for consumers as the risk would be priced into auction bids. Others questioned the interaction with reformed, marginal single cash out price. A couple of responses also suggested that the penalty rate should be fixed in legislation to

provide certainty to participants. Several respondents stated that all Capacity Market participants should face the same penalty exposure.

### Decisions taken since consultation – CM33 & CM34

In light of support from respondents, the Government confirms that liability for penalties should be conditional on the issue of a Capacity Market warning, and almost all agreed with the proposed four hour timescale.

In response to the points raised by stakeholders the Government has reviewed the design of the Capacity Market penalty and testing regime to ensure that it delivers its objectives without creating unmanageable risks which could discourage participation and increase costs to consumers.

#### Penalty rate

- The penalty rate (£/MWh) for an obligation will be set at 1/24th of the relevant auction clearing price, adjusted for inflation. Under this approach all providers failing to deliver their obligations at times of stress will reach their monthly caps in circa four hours (depending on the profiling of the month’s revenue) – irrespective of their auction vintage and clearing price. Whilst providers of different auction vintages may be exposed to different per MWh incentives in any specific settlement period, they will have the same proportional exposure relative to their annual payments and monthly cap. This is likely to make it easier for the market to engage in secondary trading.
- Applicants will not select a de-rating figure from within a centrally determined range (as this was originally proposed to enable applicants to determine their risk exposure in the context of annual penalty caps in excess of annual capacity revenue).
- In line with feedback from stakeholders, capacity obligations, and therefore penalty liabilities, will not be imposed in the four hour period following the publication of a capacity warning.

Consultation questions		
CM35	Do you think that a penalty cap of between 101 – 150 per cent of a unit’s annual capacity payments achieves an appropriate balance of consumer value for money, delivery incentives and investability?	32 responses
CM36	Do you agree with the proposal that penalty caps should be determined at the portfolio level? If so, do you agree with the approach for determining portfolio structure?	27 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.5.4		

### Summary of responses

A small majority of respondents stated that the proposed 101-150 per cent penalty cap was too high and would discourage auction participation, especially from project financed new builds, and that it would inflate auction bids.



Alternative figures proposed by respondents ranged from <50 per cent to >150 per cent, with 100 per cent being a frequently quoted figure to balance risk and reward. However several responses stated that failing providers should not profit from their capacity payments (i.e. upside only), with one stating the annual cap should be at least 150 per cent of the unit's capacity payments.

Several responses suggested spreading out penalty payments over several months to avoid the need for plants to accrue large amounts of capital (where penalised without having received any Capacity Market revenue). The Offshore Transmission Owners (OFTO) regime's approach of spreading penalties over several years was cited by several responses as a potential model.

The majority of respondents disagreed with the proposal to cap penalty liabilities at the portfolio level (CM36); on the grounds this would create administrative and legal complexity, the impact on trading and difficulties determining portfolio structure. Several responses highlighted that the portfolio approach may discourage investment in joint venture arrangements, whilst several highlighted the inconsistency between assessing performance at a unit level, but capping at a portfolio level (suggested that portfolio caps could work if performance was assessed at this level).

Capping liabilities at the CMU level was the preferred approach by the majority of respondents, citing a beneficial impact on secondary trading and maintaining the focus on individual unit performance. It was also suggested that applicants could be provided with a choice of unit or portfolio cap (and which units would be included in such a cap).

### Decisions taken since consultation – CM35 & CM36

The penalty regime must act as an incentive for participants to deliver capacity or reduce demand when needed, and avoid creating a situation where providers price more risk into their bids such that it could deter new entrants from participating in the Capacity Market.

In light of consultation responses, the Government has made changes to the penalty cap in order to strike the right balance:

- Penalties will be capped at 200 per cent of a provider's monthly capacity revenues. This means that, given the weighting of monthly payments according to system demand, providers *may* be exposed to a penalty liability of up to c.20 per cent of their annual revenue in any one month.
- Penalties will be also subject to an overarching annual cap of 100 per cent of annual revenues.
- Penalty caps will not apply at portfolio level but at CMU level.

Consultation question		31 responses
CM37	Do you think that the proposal to apply different penalty rates to units depending on their balancing mechanism status is appropriate and offers value for money to consumers?	

See *Implementing Electricity Market Reform* section: 3.2.5.3

**Summary of responses**

A small majority of responses disagreed with the proposal, primarily on the grounds of asymmetries (and therefore complexity) between over-delivery and penalty payments, inequity between generation and DSR capacity (resulting in potentially lower participation of DSR in the auction) and impact on secondary trading liquidity. Additional concerns were raised about the equality of opportunity costs and penalty exposure, and the fact that all participants would be subject to imbalance price signals, either directly or indirectly through a consumption account and the price which demand pays their supplier.

**Decisions taken since consultation**

Having considered the points raised by stakeholders, we have decided to remove the distinction between the penalty rates for units based on their balancing mechanism status. All capacity market units will therefore be subject to the same penalty rate as described in the response to questions CM33 and CM34.

Capacity providers who are successful in the auction will receive predictable capacity payments in return for their promise to deliver energy at times of system stress, and will face penalties proportional to any deficit and over-delivery rewards for surplus.

Consultation question		30 responses
CM38	Do you think that over-delivery payments are an important design feature for providing efficient despatch incentives and facilitating secondary trading?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.5.5		

**Summary of responses**

The majority of responses were broadly supportive of the introduction of over-delivery payments, although there were varying views on whether they would facilitate secondary trading. While some respondents felt they were a vital feature in supporting secondary trading, others argued that they would hinder secondary trading, on the grounds it reduces incentives for generators to take on secondary obligations due to the additional risk of penalties and lack of certainty. A number of respondents also noted that over-delivery payments should mirror the penalty rate.

The interaction between the de-rating approach was raised by several respondents, stating that over-delivery is highly likely, and that revenue neutrality should be achieved over a period longer than a month.

**Decisions taken since consultation**

Over-delivery payments have been retained, and will be funded from penalty payments received (otherwise there is a risk of an unfunded liability if there is net over-delivery throughout the delivery year). Over-delivery payments will be calculated and paid out at the end of the year, at

the lower of the penalty rate or the total penalty revenue divided by the total over-delivery volume. Calculating over-delivery payments at the end of the year – instead of after each month which included a stress event, as previously proposed – increases the likelihood that the penalty revenue received over the year is shared between those providers that have over-delivered in a more equitable manner.

Consultation question		30 responses
CM39	What are your views on the proposals for identifying and spot testing participants' ability to deliver when needed?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.5.6		

### Summary of responses

Whilst the requirement for a testing regime was questioned by some respondents, especially in light of REMIT and transparency regulation, most respondents agreed with the demonstration and testing proposal. Some modifications were suggested, including having 24 hours advance notification, rather than the six hours proposed; and one rather than three satisfactory performance days. Concerns were also raised by some respondents about the interaction with secondary trading and delivery of Balancing Service contracts, with some questioning whether they would still be subject to spot testing if they had traded out of an obligation.

### Decisions taken since consultation

The revised penalty regime will be complemented by a strengthened testing regime to ensure capacity providers have sufficient incentives to deliver. As set out in the consultation, generators will be required to nominate (ex-post) any three settlement periods, on separate days between October to April, in which they have delivered at least their de-rated capacity. DSR/storage providers will have to nominate a maximum of six periods in advance, in which they must demonstrate a prescribed demand reduction on three occasions unless they are using performance in a Capacity Market stress event to demonstrate delivery.

Providers unable to nominate three periods where they have demonstrated their capacity by the end of April will forfeit further capacity payments until they can demonstrate their capacity on three occasions of their selection after this point. Obligations will be discharged by the provider retrospectively nominating settlement periods in which they have performed to the requisite level, rather than being spot tested by the Delivery Body.

Those providers which have not demonstrated capacity by the end of the year will be required to repay all net capacity revenues received across the year, and providers holding enduring capacity agreements will forfeit payments for future delivery years until they demonstrate their capacity as above.

In addition, providers completely failing to deliver during the course of stress events in two months or more will have their testing requirements doubled as a consequence. This would mean that those failing to deliver in two month's stress events and on six occasions over winter

would forfeit their payments until they could demonstrate six times over the summer. Those failing to achieve the six occasions will have to repay net payments received over the year.

Consultation question		27 responses
CM40	Do you think the proposed treatment of 'force majeure' events is appropriate and offers value for money to consumers?	
See <i>Implementing Electricity Market Reform</i> section: 3.2.5.2		

### Summary of responses

The majority of responses were broadly supportive of the proposed treatment; however most of these requested the inclusion of gas supply interruptions or emergencies and delays in providing gas transmission connections. Some respondents called for a further extension of force majeure events, to include any circumstances that are beyond a capacity provider's control, such as a national emergency, extreme Acts of God or a situation where a generator is prevented from generating by Government action.

Some respondents considered that expanding force majeure events would provide greater value for money for consumers, as the alternative would be for potential providers to price the risk into auction bids.

### Decisions taken since consultation

The proposals set out in the consultation document with regard to force majeure and maintenance windows will be retained. This is to avoid weakening delivery incentives and increasing the costs for end consumers. This is consistent with the Balancing and Settlement Code's treatment of contingencies. With regards to the specific stakeholder concerns about gas deficiency emergencies, it is proposed that existing mechanisms, for example Post Emergency Claims (PEC) procedure, will provide stakeholders with suitable compensatory routes.

Consultation questions		
CM41	Do you have any further comments on aspects of the design described in this sub-section?	15 responses
CM42	Do you have any comments on Chapters 7, 9, 11, 13 and 14 of the Capacity Market Rules for implementing the proposed obligations and penalties?	19 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2.5		

### Summary of responses

On CM41, many stakeholders reiterated comments made in answers to previous questions. Comments included that obliging providers to combine into one portfolio may limit participation; that reducing payments in the event of a failure of a spot test is unduly harsh; that the penalty

cap is too high; and that there needs to be further consideration of the Capacity Market's interaction with the gas market.

Responses to CM42 also suggested that further work is required, stating that the current proposals will limit secondary trading and the penalty regime is too harsh. Some responses felt that both the cap and the rate of penalties need to be reviewed to balance the need for reliable performance against the ability for stand-alone plant to secure finance and investment with manageable risk. Two responses raised questions around over-delivery payments being funded by penalty payments.

Several responses were concerned with the monitoring of capacity auctions and providers and associated funding arrangements, with particular concerns expressed on the wide ranging powers given to the Delivery Body to monitor capacity auctions and providers.

Responses also highlighted the need for clarification of obligations during a Capacity Market warning and system stress event as well as the need for the Capacity Market Rules to allow for notice of load following obligations.

### **Decisions taken since consultation – CM41 & CM42**

The responses to questions CM41 and CM42 cover subjects addressed in the responses to CM33-CM40, above.

In addition, and following discussion with the industry EMR Expert Group, the Government has decided that amendments will be made to the algebra of the balancing service contract capacity credit which gives effect to the agreed principle that resources can simultaneously participate in the Capacity Market and provide balancing services, and that an exception should be granted to resources that are unable to perform due to a deficiency in the transmission system. These changes will avoid double counting in the determination in the Capacity Market obligations and will better take into account instructions issued by the Delivery Body.

Specific provision has also now been made in the rules to recognise that delivery of an obligation by a storage unit can be by generating electricity and reducing demand.

### **Specific procedures for DSR participation**

<b>Consultation questions</b>		
CM43	Do you agree that the specific rules for DSR (i.e. the proposals on bid bonds, eligibility, baselining, metering) are justified and provide DSR with a reasonable opportunity to participate? Are any other features needed (and if so why?)	30 responses
CM44	Is the proposed level of the bid bond (£4,420/MW) for prospective DSR appropriate to sufficiently incentivise delivery without presenting an unacceptable barrier to entry?	24 responses
CM45	What do you think of the proposal that failure to deliver the total capacity awarded in the auction should result in the forfeit of the total bid bond? Does this provide a comparable incentive for	27 responses

	prospective DSR to deliver when compared to the incentives for new generation to deliver?	
CM46	Do you have any further comments on aspects of the design described in this section?	15 responses
CM47	Do you have any comments on Chapters 3, 4 and 5 in Part 4 of the regulations and Chapters 3, 4 and 10 of the Capacity Rules on the eligibility and pre-qualification arrangements for DSR?	14 responses
See <i>Implementing Electricity Market Reform</i> section: 3.3		

### Summary of responses

The majority of responses were broadly positive regarding the specific rules for DSR, albeit with some recurring reservations. All respondents who mentioned the penalty regime rejected the proposed VOLL/VOLL-cash out split.

Respondents generally felt the participation of DSR should be encouraged but not unduly advantaged, although inevitably views differed on where that line was drawn. DSR providers in particular advocated a level playing field for all resources by allowing DSR to take on limited obligations.

Greater clarity on the baseline methodology was requested, with some respondents suggesting a range of baseline options and the removal of the year old data from the baseline. Some respondents suggested a range of de-rating factors would be needed for DSR, although the extent to which various DSR resources varied in practice was not evidenced. Opinions were divided on the suitability of existing metering within the market, with some respondents concerned about onerous new metering requirements and others concerned about unreliable metering being used in settlement.

Respondents were also divided on the long-term participation of DSR with some respondents claiming that DSR could not operate in the Capacity Market as currently envisaged (with a range of suggestions to enable DSR) and others arguing that DSR must participate on the same terms as other resources.

On CM44, the majority of responses supported the inclusion of a bid bond for DSR on principle, and felt that the level was appropriate. A number of respondents recommended keeping the level under review or increasing it slowly from 10 per cent rather than moving straight to 100 per cent.

Some DSR providers felt that bid bonds represented a barrier to the new entry of DSR; however others, including suppliers and generators, were strongly in support of ensuring the correct incentives were in place on all providers. A few respondents went further to suggest that the bid bond did not include all the costs faced by new generation and did not require sufficient information provision (such as delivery milestones), therefore unfairly advantaging DSR and increasing risks to security of supply.

The majority of respondents felt that return of the bid bond on a pro rata basis (CM45) was more reasonable than a total loss for any under-delivery and would better incentivise new players to enter the market. Variations on this included reaching a threshold level before the pro rata was applied and making exceptions for force majeure in project delivery. However, there were arguments supporting the position set out in the consultation document, including the assertion that DSR is already providing less surety than generation and pro-rating the bid bond widens this gap undesirably.

There were no consistent themes in responses to CM46 and CM47. Some respondents raised concerns about the restrictive nature of not allowing exceptions for Triad delivery in the Capacity Market, and another sought clarity on which balancing services will be permitted (e.g. schemes run by the DNOs as well as National Grid's).

Echoing earlier responses, some respondents questioned the provision of a single de-rating factor for DSR and recommended further investigation and collaboration over the methodology. Respondents raising concerns about the comparability of the Demand Side Balancing Reserve (DSBR) and the Capacity Market in incentivising reliable capacity, suggesting that DSBR would adversely affect DSR's de-rating if included in the methodology.

Some responses highlighted that the market knows little about DSR and suggested a working group to consider how data is fed into the market before and during a system stress event. There was a general request for further work on DSR participation in the Capacity Market, and for clearer drafting and calculations in the regulations and rules.

#### **Decisions taken since consultation - CM43-CM47**

Demand side response (DSR) and storage have the potential to offer capacity that is reliable and which provides an effective alternative to investing in generation infrastructure.

The Government has taken the decision to allow DSR and storage to participate in capacity auctions from their launch in 2014. The pre-qualification process for DSR and storage in advance of capacity auctions being held will remain as set out in the consultation document. DSR and storage will be de-rated by the Delivery Body during pre-qualification, in line with other capacity providers. Tests to ensure that DSR providers will be able to deliver capacity when needed will be triggered as set out in the consultation. Dependent on the pre-qualification route, the Delivery Body will check control systems, despatch processes, that a relationship exists between the provider and the resource that will reduce demand, and that a reduction occurs at the time of the test.

#### *Metering and baselining*

The non-Central Meter Registration Service capacity provider will be required to declare during pre-qualification how metering will be carried out following one of the pathways set out in the consultation document, although the additional BMU option has been removed. Providers shall ensure the metering of their units provides the Settlement Services Provider with the necessary data to assess their delivery. If no metering data is provided, the unit will be deemed to have failed to deliver during the event or test. Provision has been made for missing data in settlement periods forming the baseline.

The baseline methodology is largely the same, although data from a year ago has been removed and we have distinguished between working days and non-working days. It is important that consumption of electricity during a system stress event is compared to consumption at other, similar times to determine whether a DSR provider has delivered its obligation.

#### *Collateral*

Credit cover will be required (a bid bond) and the amount is **now set at £5,000/MW and aligned with generation**. In line with consultation responses, the bid bond will now be returned pro rata to delivery (as opposed to the DSR provider losing their full bid bond if they fail to deliver) if the proven capacity is 90 per cent or above the capacity obligation. The Government can confirm that credit requirements will apply in respect of the capacity auction in late 2014.

In addition, credit cover requirements have been simplified for DSR by reducing the number of acceptable types of credit cover set out in the consultation document to the following two: cash and letters of credit. This will also be the case for collateral posted by prospective generators.

The Government has engaged with stakeholders throughout the development of these proposals and will monitor the success of DSR's participation in the Capacity Market to ensure the rules and regulations are working effectively.

#### DSR transitional arrangements

Consultation question		28 responses
CM48	Do you agree with the necessity of transitional arrangements to help build the capability of the DSR sector?	
See <i>Implementing Electricity Market Reform</i> section: 3.3.2		

#### Summary of responses

The vast majority of responses agreed with the principle of supporting DSR through transitional arrangements. Additional comments included that the transitional arrangements should be time limited from the outset, and that it was important to ensure the arrangements are needed and result in benefits to consumers.

#### Decisions taken since consultation

The Government has decided that transitional arrangements will be needed. Details are set out in the response to questions CM49-CM52, below.

Consultation questions		
CM49	What are your views on the proposed transitional arrangements and do you think they will prove effective i.e. over 2 time limited stages and with the parameters set out?	21 responses



CM50	Do you agree that the level of the bid bond should be reduced by 90 per cent for prospective DSR during the transition period?	19 responses
CM51	Do you have any further comments on aspects of the design described in this section?	11 responses
CM52	Do you have any comments on Chapter 5 in Part 4 of the regulations and Chapter 10 of the Capacity Market Rules on the transitional arrangements?	10 responses
See <i>Implementing Electricity Market Reform</i> section: 3.3.2		

## Summary of responses

The majority of respondents were supportive of the transitional arrangements (CM49). A number of respondents provided comments on the timings, with some arguing for open ended arrangements pending further information on how DSR responds, and others arguing for a timetable to be set out to provide certainty to the rest of the market.

On CM50, almost all respondents agreed with the proposal regarding the bid bond and the level set. Opinions differed slightly on the effectiveness of such a low bond citing concerns about consumer costs, and on whether there should be a gradual increase after stage 1 or whether DSR must then move to a bond that mirrored generation.

There were few responses to CM51 and CM52, and no themes emerged. Respondents commented on the interaction between Demand Side Balancing Reserve (DSBR) and transitional arrangements, noting the differences in payment structure and questioning DSBR's potential effectiveness as a first stage for DSR. Additional comments included support for a larger DSR programme with further research and more options for DSR's participation in the long-term, and that that there would need to be a rebalancing of the risk/reward profile between providers and aggregators.

Several responses agreed that DSR should be able to participate in both the transitional and four-year ahead auctions, with some arguing that the first transitional delivery year should be 2015/16. Questions were raised around how information will flow to the Settlement Agent<sup>60</sup> in simulated stress events, and permitting the inclusion of sub 50MW Central Meter Registration Service CMUs. A small number of respondents also called for DECC to consult on the detailed rules e.g. auction rules, despatch rules etc.

## Decisions taken since consultation – CM49 – CM52

In light of the strong support the Government will proceed with transitional arrangements for DSR. However, in response to feedback some adjustments have been made to the DSR transitional arrangements and the main Capacity Market to simplify and align processes. The adjustments are:

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<sup>60</sup> This role is now referred to as the Settlement Services Provider. ELEXON Ltd will establish a subsidiary company within ELEXON Ltd itself to deliver EMR settlement services.

- Changing the design of the transitional arrangements time banded and load following<sup>61</sup> sub-auctions to procure both products in one auction;
- Aligning the transitional arrangements and Capacity Market in-year testing requirements;
- Introducing a maximum size for an aggregated CMU of 50MW and removing the size limit on CMU components.
- Aligning the penalty arrangements for the DSR transitional arrangements and the main Capacity Market
- As set out above:
  - Splitting the verification checks into two stages: capacity output and metering set up;
  - Returning the bid bond pro rata to delivery if the proven capacity is 90 per cent or above the capacity obligation;
  - Adjustments to the baseline methodology for DSR.<sup>62</sup>

### Payment model: calculating charges and payments

Consultation questions		
CM53	Do you have any comments on the charges being calculated for the purposes of Capacity Market settlement?	19 responses
CM54	Given the Government’s objective to link the costs of the Capacity Market with the drivers of those costs, and the desire to facilitate demand side participation in the Capacity Market, are you aware of an alternative to the peak charging methodology that might better meet those objectives?	21 responses
See <i>Implementing Electricity Market Reform</i> section: 3.4		

#### Summary of response

Over half of respondents were against the proposals relating to charges (CM53). Of those against, a number focused on the peak charging methodology, suggesting that customers would be paying for capacity to be available across the year (not just peak) and so the charge should reflect this. Some respondents felt that customers might be incentivised to move between suppliers with lower forecast Triad, then move prior to reconciliation – which would be anti-competitive.

Respondents also commented that peak is harder to forecast (and will become more so), which increases risk to suppliers and so increases the cost passed on to consumers. There was a call for charges to be clear and transparent, with several respondents proposing a fixed-unit charge.

<sup>61</sup> Time banded product: Providers are only obliged to respond to stress events over winter daily peak times. Load following product: Providers are obliged to respond to stress events throughout the delivery year as they would in the Capacity Market.

<sup>62</sup> Please note there will be terminology changes in the updated regulations and Capacity Market Rules, for example the ‘Customer Demand Response (CDR)’ term is now defined as ‘DSR’.

Of the respondents who supported the proposed approach, some commented that it would help incentivise DSR at times of high demand and so drive down the amount of capacity needed. It was also suggested that the Settlement Body could maintain and publish an 'index' of Capacity Market charges over time to aid public understanding/trust.

Respondents echoed similar points in answers to CM54. Alternatives to the peak charging methodology included having costs allocated based on a share of supplier volume or based on market share across the year; adopting a fixed rate approach (in line with the CFD); using monthly data from the previous month to calculate the following month's obligation (based on total volume, not at peak); and for a 4pm – 7pm charge.

### **Decisions taken since consultation – CM53 & CM54**

In response to consultation feedback, the supplier charge methodology will now see suppliers' charges initially based on the suppliers' forecast market share between 4pm and 7pm on weekdays over the period from the start of November to the end of February in the delivery year (the same period from which the Triads are taken), and subsequently reconciled when data becomes available, enabling the calculation of actual market shares for those periods.

This combines elements of several alternative approaches proposed, and will retain a clear association with times of high demand in order to incentivise demand reduction (and potentially time-of-use tariffs), while removing the specific association with the Triad peaks and the potentially increased cost risk this creates for suppliers. Suppliers will need to forecast their share of demand, but not predict the Triad periods and their demand at those specific settlement periods. We believe that this will reduce the variability between forecast and actual charges and, therefore, reduce the risk identified by suppliers. The form of the outputs from this method should align with those of the peak charging approach (i.e. a forecast market share, and resultant charges, updated when actual data is available from the end of February).

Supplier charging will use net demand, i.e. the total demand for which a supplier is responsible (including any directly connected demand) with the output of any embedded generation the supplier is responsible for netted off. The minimum value of net demand will be zero.

This new charging methodology is intended to address feedback that:

- With the previous method the suppliers' liability for Capacity Market charges would vary from that initially calculated and there was a risk that their final Capacity Market charge being significantly higher than the initial charge.
- The charging methodology should be predictable to suppliers (to reduce the cost of managing risk, which would be passed to consumers), transparent (so customers can understand the charge) and cost reflective in its allocation of Capacity Market costs to consumers;
- It is particularly difficult for suppliers to accurately estimate their share of demand over the Triad periods
- Suppliers already try to reduce demand over the Triad periods and the proposed approach won't have any material additional impact;

- The proposed methodology discriminates against suppliers with a greater proportion of domestic, rather than industrial, customers because industrial customers are able to respond to incentives to reduce demand over Triad periods; and
- Since suppliers will pass the charge to consumers, the proposed methodology discriminates against customers of suppliers with a relatively high proportion of domestic customers (and therefore domestic customers’ funding of the Capacity Market could be disproportionately high compared with industrial customers).

The alternative proposal of using a fixed unit charge has been discounted due to the difficulties – noted by some respondents – associated with establishing and funding a buffer fund to address any resulting discrepancies between funds received and funds owed. . Considering the relative certainty of Capacity Market payment flows (compared to the more variable nature of CfD payment flows for example) it is not considered desirable or necessary to create such a fund. This approach would also completely remove the demand reduction incentive, which is an important policy objective. Charging suppliers according to average annual market share has also been ruled out as it would dull existing incentives for suppliers to offer time of use tariffs and for reducing energy use at times of high demand.

The interest rate for late payments invoices relating to capacity market charges has been confirmed as five per cent over the Bank of England base rate in alignment with Contracts for Difference.

References to supplier charging methodology have been removed from draft regulations and will be added back in via further regulations, a draft of which is intended to be laid before Parliament in summer 2014.

Consultation question		22 responses
CM55	Do you believe that any contribution from DSR CMUs should be excluded from suppliers’ market share calculations, and if so what is the best method of doing this?	
See <i>Implementing Electricity Market Reform</i> section: 3.3.2.2		

**Summary of responses**

Respondents were split in their views, with a small majority believing that DSR CMUs should not be excluded from suppliers’ market share calculations.

Of those suggesting that DSR CMUs should not be excluded, reasons included complexity/practical difficulties; that it would remove the opportunity for the supplier to choose the most cost effective option between paying the recharge of Capacity Market costs or using DSR to avoid the costs (which could reduce cost effectiveness for consumers).

**Decisions taken since consultation**

The contribution of DSR CMUs will be included in suppliers’ market share calculations. Government acknowledges the concerns around ‘double benefits’ accruing due to reduction in

supplier metered demand achieved through DSR CMUs (leading to benefits accruing to both the DSR provider directly through the Capacity Market and to the supplier through lower funding charges). However, under the revised charging approach based on market share over winter (November to February) weekdays between 4pm and 7pm (as set out above) the potential double benefit is mitigated because DSR CMUs would need to contribute to demand reduction over peak hours across the whole of winter in order to reduce supplier metered demand (not just reduce demand in a few specific potential Triad peak periods).

Consultation question		10 responses
CM56	Do you have any comments on Chapters 5, 6 and 7 of the payment regulations covering calculating charges and payments?	
See <i>Implementing Electricity Market Reform</i> section: 3.4.2		

### Summary of responses

Comments included that further work is required on the payment regulations, and that they must be consistent with the rules. There were concerns that the regulations do not appear to refer to a redistribution of costs based on actual Triad demand, and it was also suggested that - in line with the arrangement for CFDs - it would be more efficient for the Settlement Agent to release payments to capacity providers. Additionally it was suggested that more than three days is needed for capacity providers to validate invoices in respect of penalties (with 14 days suggested); and three months seems too close to the start of the capacity year to calculate the monthly supplier charge.

### Decisions taken since consultation

See response to CM53, above.

### Payment model: Data systems and data collection

Consultation question		
CM57	Do you have any comments on the data to be collected for the purposes of Capacity Market settlement (including whether all appropriate data flows been captured accurately)?	17 responses
CM58	Do you have any comments on Chapter 4 of the payment regulations on the provision of data?	8 responses
See <i>Implementing Electricity Market Reform</i> section: 3.4.3		

### Summary of respondents

Approximately a third of responses to CM57 indicated they were comfortable with the data to be collected and believed that using existing mechanisms or processes (e.g BSC data flows) is the most reasonable approach. Others noted that it is important that the rules do not conflict with any existing requirements on parties, and that all data should be compliant to the BSC half hourly standards for all participating CMUs.

Some stakeholders emphasised the importance that data provided by non-BSC parties are from meters that meet the same accuracy standards as BSC-compliant meters. In addition, a small number of respondents suggested that steps should be taken to ensure that suppliers' forecasts of demand are correct, for example it was suggested data supplied should be subject to independent auditing to avoid any errors and to mitigate potential gaming. There was also some concern about the time required to implement changes to systems to manage new payment flows.

Responses referred to allocation and expressed that this should be based on overall market share (or forecast annual demand) rather than Triad shares.

The majority of responses to CM57 suggested that more work needs to be done on the payment regulations to ensure they represent a workable arrangement. Various detailed comments were provided highlighting potential corrections to the data units set out in regulations. Additionally some respondents wanted more detail on how calculations will be made.

#### **Decisions taken since consultation – CM56 & CM57**

Comments relating to peak demand have been addressed in the answers to CM53 & CM54 above. There are no substantive policy changes in relation to these questions, but where necessary minor corrections have been made to ensure that the correct data units are captured in order to allow the Capacity Market settlement process to function as intended. In addition, data provisions have been removed from the regulations and placed in the Capacity Market Rules (Chapter 14). The only exception to this is the requirement on electricity suppliers to provide a forecast of the net demand in order to establish their share of the capacity market charge – this provision will be in the forthcoming Electricity Capacity (Supplier Payment) Regulations.

A small number of respondents expressed a need to incentivise suppliers to provide accurate data regarding their forecast share of demand, and/or to audit this data for accuracy. It was felt that this was required in order to avoid intentional underestimating by suppliers so that they are able reduce their initial share of the Capacity Market charge until actual demand data is available. However, there was no clear consensus on how this might be achieved and suggestions of an independent audit were deemed potentially excessive. As such no further provisions of this nature have been added. However, this will be an area for future review following the initial DSR transitional auctions if experience demonstrates that such intentional underestimating by suppliers is occurring.

A separate piece of work is underway to create the new metering configuration options for non-BSC data. These will be developed over the summer and full provisions will be introduced in early 2015. Some changes are already in train, for example, for the Half Hourly Data Aggregator (HHDA) option the consequential amendments to the BSC and other codes are being made so that systems will be ready to go live in early 2015. This should give providers time to implement the metering solution before the first transitional arrangement auction. Following industry

feedback, the metering configuration solutions are use of current half hourly meters (the 'HHDA option'); bespoke metering; and balancing services metering.

### Payment model: invoicing, banking and payment 1

Consultation questions		
CM59	Do you have any comments on the settlement timetable?	22 responses
CM60	Do you have any views on the proposal to delay payment of penalties and over-delivery payments pending the outcome of any disputes?	18 responses
CM61	Do you think sufficient time is allowed for payments to be made once invoiced, given the fact that a forecast of monthly costs will have been provided in advance of the delivery year as part of the credit cover process?	19 responses
CM62	Do you have any comments on the differences between payment timings proposed within the Capacity Market and those proposed for CFDs?	15 responses
CM63	Do you have any comments on Chapters 6 and 7 of the payment regulations regarding invoicing, banking and payment?	10 responses
See <i>Implementing Electricity Market Reform</i> section: 3.4.4		

### Summary of responses

Respondents were split on the settlement timetable (CM59), with a slight majority considering that it was too long, arguing that a shorter settlement period would improve cash flow and collateral arrangements. Some suggested it would be preferable to base the Capacity Market charge on a fixed price level across the relevant delivery year.

Other points raised included that typical timetables elsewhere in the energy market are closer to 15 to 20 days following receipt of payments from suppliers; that as suppliers are obliged to pay within five working days after the start of the month it seems reasonable for generators to be paid within ten working days after the end of the month; and that the Government/industry standard payment terms of 30 days should be adopted.

On CM60, just under half of respondents were content with the proposed approach, however most respondents raised concerns with potential delays.

The vast majority of responses agreed that the proposed timings were sufficient, and few additional comments were made (CM61).

On CM62, the majority of respondents either stated that they believed the timings were appropriate and recognised that there were practical reasons for the differences between the two mechanisms, or stated a preference for having the timings aligned between Capacity Market and CFD settlement but again recognised there were practical reasons for the

differences. The main concern raised was the proposed length of time it will take capacity providers to be paid compared to CFD generators.

In line with previous responses, stakeholders indicated in response to CM63 that some further work was required on the regulations. Comments included:

- Clarification was required on whether transactions under EMR are deemed to be taxable supplies for VAT and if so, for the regulations to set out that the Settlement Body will be responsible for issuing VAT invoices.
- That the monthly settlement timetable will place significant cash constraints on small suppliers in the form of credit cover/collateral payments.
- That the names of non-payers in default under the CFD supplier obligation are excluded from the non-payment register, at least until the resolution of any disputes.

### **Decisions taken since consultation – CM59–CM63**

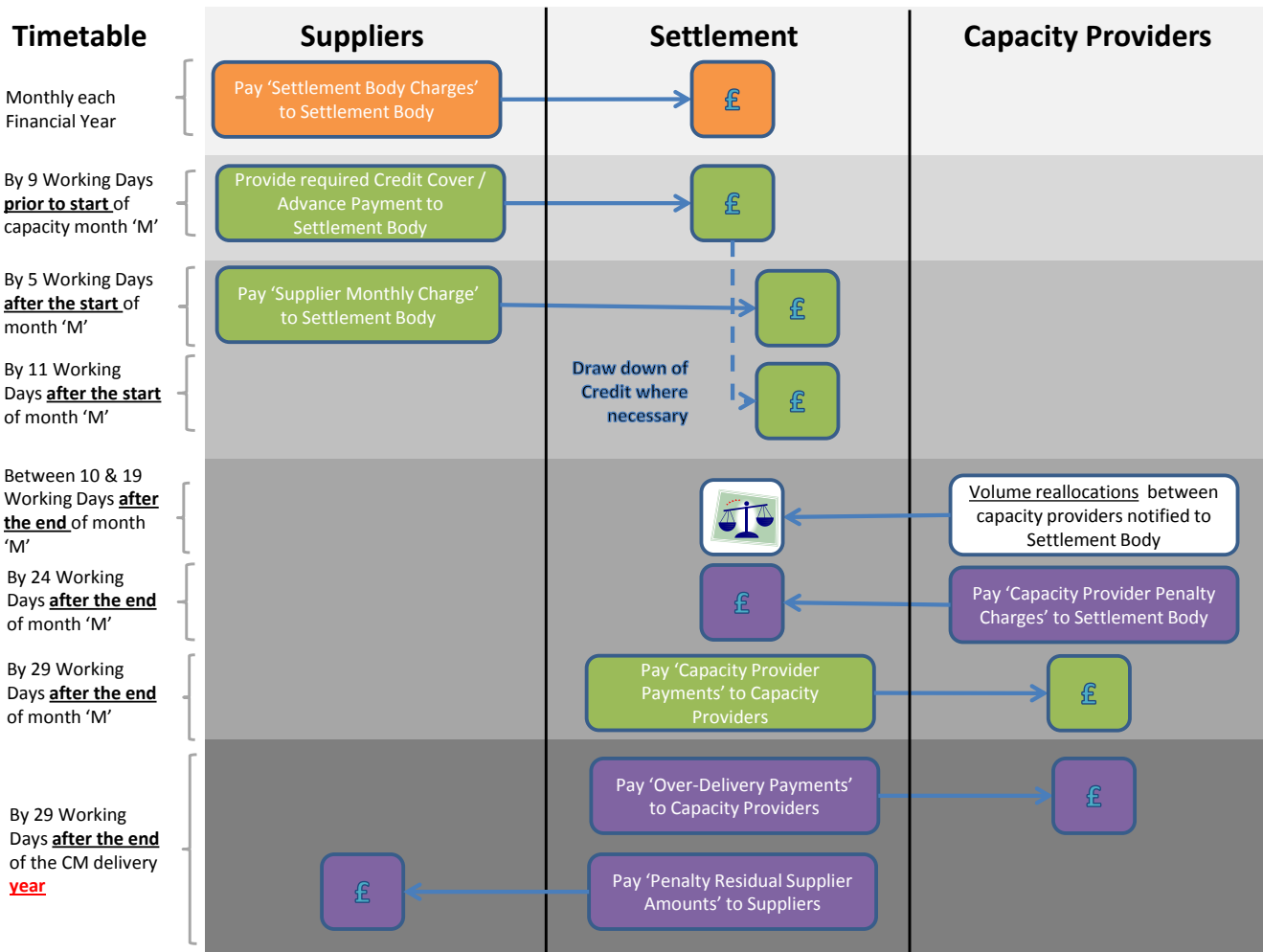
Transitional arrangements for the collection of the settlement costs levy will be set out in the regulations to enable costs to be collected in the first year as the necessary systems for doing so are still being developed. The enduring settlement cost levy has been decoupled from the principal Capacity Market supplier charge timetable, and has been aligned to the financial year as it will share operational functions with the CFD Counterparty, the costs of which will be accounted for according to financial years. This enduring settlement cost levy will be set out in forthcoming regulations.

The timetable must now take account of volume reallocations taking place following a stress event.

In response to stakeholder concerns about the length of time before payments to capacity providers are made, these have been brought forward to 29 working days after the end of the month. This cannot be brought forward any earlier as payments must occur after any penalties have been collected following the completion of volume reallocation.

The settlement timetable is summarised below:





As addressed previously, the payment of over-delivery payments will be carried out at the end of the capacity year in question, but otherwise there is no policy change relating to delaying payments in order to resolve disputes. Any payment changes resulting from disputes will be captured by the reconciliation process carried out by the Settlement Services Provider, which will be able to carry out a reconciliation run as late as 28 months if necessary, reflecting BSC processes.

Regarding VAT, the levy raised by the Settlement Body in accordance with the relevant regulation is expected to be outside the scope of VAT and so there is no requirement for the Settlement Body to issue VAT invoices. Further, it is suppliers who are obligated to pay the levy, not their customers, and therefore the levy does not appear to meet the criteria for disbursements as per paragraph 25.1 of PN 700 (The VAT guide). Therefore, to the extent it is passed on and forms part of the consideration for the supply, it is liable to VAT, whether or not it is separately itemised on the invoice issued by the supplier.

**Payment model: invoicing, banking and payment 2**

Consultation questions		
CM64	Do you have any comments on the size of credit cover being requested?	20 responses
CM65	Do you agree with the form of credit cover being cash or a letter	20 responses

	of credit, if not what alternatives would you recommend?	
CM66	Noting that suppliers' credit cover amounts are based upon suppliers' own demand forecasts do you feel additional checks or controls on such forecasts are required?	17 responses
See <i>Implementing Electricity Market Reform</i> section: 3.4.4.2 and 3.4.4.3		

### Summary of responses

Nearly all of respondents believed the credit cover requirements (CM64) were too high. Respondents considered that the amount of collateral that suppliers have to post should be minimal, particularly given the impact on smaller suppliers. It was also emphasised that the continued increase of credit cover and collateral requirements contribute to uncertainty and could impact on competition.

On CM65, some respondents agreed that the provision of cash or a letter of credit would be acceptable, and that a minimum credit rating level of A- (Standard & Poor's) and A3 (Moody's) is appropriate. However, a number of additional questions were raised; for example, what would happen where a letter of credit issuer has a split credit rating. Some respondents noted that banks' credit ratings had been significantly downgraded in recent years and therefore the proposed levels may no longer be appropriate.

The most commonly cited alternative form of credit cover that was recommended was Parent Company Guarantees (PCGs), on the ground that they are lower cost.

On CM66, Respondents were split on whether or not additional checks on forecasts were needed. Some respondents felt that there was a case for the Settlement Body to check credit cover amounts in case inaccurate/under-forecasts led to insufficient credit being posted – particularly considering volatility of market shares following tariff price revisions and April/Oct contract rounds for non-domestic customers. Several respondents suggested that if market shares are based on forecasts these should be provided by the Settlement Agent based on historic data.

### Decisions taken since consultation – CM64 – CM66

The Government has decided to retain the amounts of collateral as set out in the consultation document, including the 10 per cent headroom. The Government considers this necessary in order to ensure that the Capacity Market payment model remains sufficiently secure – in the absence of any further securitisation - by reducing the likelihood that remaining suppliers have insufficient credit cover in the event that a supplier's payments are mutualised. In addition, the Settlement Body<sup>63</sup> (Electricity Settlements Company) will be required to publish default notices on its website as an early warning mechanism.

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<sup>63</sup> The Electricity Settlements Company (ESC) will be designated as a Capacity Market Settlement Body and is intended to be the only Capacity Market Settlement Body for the foreseeable future. For ease of comparison with the consultation document, the majority of references to the ESC remain as the 'Settlement Body'. This also applies to the Low Carbon Contracts Company Limited (LCCC), the incorporated name for the CFD Counterparty.

As set out in the answer to CFD28, due to the inherent constraints around liquidity and the consistency in minimum credit ratings applicable to PCGs, they have not been included as an appropriate collateral instrument.

With regards to the point about a split credit rating, the approach is the same as set out in CFD29: in the event of a split credit rating of an letter of credit issuer (i.e. either S&P, or Moody's lowers its rating whilst the others maintains their rating) the approach will be that the highest rating will apply.

<b>Consultation question</b>		16 responses
CM67	Do you feel the current credit cover default provisions are appropriate?	
See <i>Implementing Electricity Market Reform</i> section: 3.4.4.3		

### Summary of responses

A slight majority of respondents considered the proposals to be appropriate. Comments were wide ranging and included that the three days to provide credit cover were more reasonable than the one day currently allowed under BSC arrangements; that the proposals were too onerous, creating administrative burdens for other suppliers; that partial mutualisation was preferred; and that any shortfall under £50,000 should not be subject to mutualisation as this would be administratively inefficient.

### Decisions taken since consultation

Provisions in the Electricity Capacity Regulations (for Capacity Providers) and the forthcoming Regulations (for suppliers) for the non-payment and credit default register remain as set out in the consultation document. For clarification, credit will not be required to cover the Capacity Market settlement cost levy.

<b>Consultation question</b>		8 responses
CM68	Do you have any comments on Chapters 5 and 8 of the payment regulations with regards collateral requirements?	
See <i>Implementing Electricity Market Reform</i> section: 2.4.4.2 - 4		

### Summary of responses

Comments included that the arrangements need to be reviewed to ensure that processes can continue to operate in the event that one of the Capacity Market delivery bodies were to get into financial difficulties; that more detail was required on how the Settlement Agent calculates a supplier's market share; and one respondent disagreed with the requirement that the Settlement Body or Agent should be responsible for monitoring that credit is valid and sufficient, arguing that only suppliers can ensure credit is in place.

### Decisions taken since consultation

The collateral arrangements set out in the regulations to be laid before Parliament will be designed to ensure that they Capacity Market can continue to operate at all times that it is necessary.

### Payment model: settlement disputes

Consultation question		
CM69	Do you have any comments on the process for the review of Capacity Market settlement disputes? Should there be specific provision for enforcement of obligations on the Settlement Body?	17 responses
CM70	Do you have any comments on Chapter 10 of the payment regulations on settlement dispute resolution?	9 responses
See <i>Implementing Electricity Market Reform</i> section: 3.4.5		

### Summary of responses

Several respondents considered that the disputes process should align to existing BSC procedures. Comments included that further clarity is needed on the link between dispute resolution, via other codes, and the resolution of Capacity Market disputes; that a process is needed whereby additional Capacity Market data provided by the Delivery Body can be disputed; and that there should be an appeals process via Ofgem before judicial review.

On the regulations, concerns were raised that an embedded generator, who is not a BSC party, would need to go through their supplier in order to dispute metered data. This was viewed as an additional burden and could be avoided if the principle is established that the recipient of the information is able to dispute the information without the need for a third party. Additionally it was argued that the regulations should be clear on how any re-settlement required outside of a capacity year will be managed.

### Decisions taken since consultation – CM69 & CM70

The disputes process on settlement remains the same as set out in the consultation document. However, the process has been simplified to place all obligations to the Settlement Body (incorporated name - Electricity Settlements Company). It is envisaged that the Settlement Body will contract out some of its functions to a Settlement Services Provider (EMR Settlement Ltd) but it will remain accountable for the performance of the functions conferred on it by regulations, and in particular, for the determination of outcomes of disputes, apart from in the case of metered supply data. Those who wish to dispute the metered supply data are able to do so according to the Trading Dispute Processes which are outlined in the Balancing and Settlement Code. The Settlement Body will not make a determination on disputes on metered supply data.

For all other disputes, such as calculation disputes or disputes on the implementation of processes, suppliers are able to raise a dispute with the Settlement Body within 28 calendar

days of the disputed event. The Settlement Body will have 28 calendar days to make a determination and respond to the supplier. The Settlement Body make appoint an independent person to consider and report on a disputed matter in order to inform its determination. In making a determination, the Settlement Body will have to have regard to all the facts regarding the disputed event. If suppliers are not satisfied with the Settlement Body's response, they will be able to seek judicial review.

### Payment model: reconciliation

Consultation question		
CM71	Do you have any comments on the timing or the approach to reconciliation? Should this be more or less frequent?	16 responses
CM72	Do you have any comments on Chapter 11 of the payment regulations on reconciliation?	9 responses
See <i>Implementing Electricity Market Reform</i> section: 3.4.6		

### Summary of responses

Approximately half of respondents stated that they were content with the approach to reconciliation, with many emphasising support for an approach which aligns with the BSC. Several respondents said that reconciliation should follow the current ELEXON reconciliation process; that the 29 days after month end is not achievable; and that adjustments to market share using actual data may create cash flow problems for suppliers if there are material differences between estimates and actuals.

On the regulations, some suggested that the proposals are not workable; and that reconciliation, particularly ad-hoc reconciliation runs, will introduce additional uncertainties for small suppliers.

One respondent argued that it will be more efficient to have a clear settlement timetable related to the availability of data from BSC reconciliation settlement runs.

### Decisions taken since consultation - CM71 & CM72

In response to stakeholder feedback, the forthcoming Capacity Market (Supplier Payment) Regulations will be amended to require the Settlement Body to publish a settlement timetable setting out when settlement runs will occur to give more clarity to suppliers. The Settlement Body will also be able to carry out further settlement runs, which will be aligned with the timing of existing BSC settlement runs. The Settlement Services Provider, acting for the Settlement Body will, if necessary, be able to carry out reconciliations up to 28 months following a calculation being made in order to take account of any disputes that may arise.

### Payment model: governance

Consultation question		13 responses
CM73	Do you have any comments on the proposed governance arrangements for the	

	Capacity Market Settlement Body and Settlement Agent <sup>64</sup> ?
See <i>Implementing Electricity Market Reform</i> section: 3.5.1.4	

**Summary of responses**

A few respondents were concerned about the complexity of the governance arrangements, and requested further clarity on oversight of Settlement Agent’s duties. There was support for the Settlement Body as a private company owned by the Government, and with ELEXON as the Settlement Agent, which is similar to (but financially separate from) the CFD Counterparty. One response queried the need for a separate board for the Settlement Body and CFD Counterparty.

One respondent expressed concern over a lack of detail regarding governance arrangements, and stated that parties need confidence that rules/processes cannot be changed without consultation/appropriate checks and balances. Additionally, they argued that routes of appeal of regulatory decisions were needed, so that judicial review was not the only option.

One comment was that the Settlement Agent should not be named in regulations, and noted a possible discrepancy with the provision that Secretary of State must terminate the SA’s appointment, whereas the Settlement Agent’s contract is with the Settlement Body – which will also presumably have termination provisions.

**Decisions taken since consultation**

DECC’s function as shareholder is to ensure that the Settlement Body’s functions do not change and that the rules and processes which govern it will be subject to the appropriate levels of scrutiny. The company’s operations will be totally transparent. Whilst the boards of the Settlement Body and the CFD Counterparty will be different, they will be composed of the same people.

Consultation question		7 responses
CM74	Do you have any comments on the methods through which the costs of the Settlement Body and its agent will be controlled and levied?	
See <i>Implementing Electricity Market Reform</i> section: 3.4.4.1		

**Summary of responses**

No concerns were raised with the proposals. It was suggested that the Settlement Body could be funded by the Government. One respondent also commented that clarity is needed on how the Settlement Body and CFD Counterparty costs will be allocated, and another requested that annual forecasts and budgets should be subject to consultation.

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<sup>64</sup> This role is now referred to as the Settlement Services Provider. ELEXON Ltd will establish a subsidiary company within ELEXON Ltd itself to deliver EMR settlement services.

## Decisions taken since consultation

The *CFD Counterparty and Electricity Settlements Company operational costs 2014/15*<sup>65</sup> consultation (March 2014) on the operational costs of the CFD Counterparty and the Electricity Settlements Company outlines the model we have adopted for levy funding both companies. The CFD Counterparty will be funded by a £pMwH levy and the Electricity Settlements Company's levy will be calculated by dividing its operational cost forecasts amongst Capacity Market participants based on their annualised market share of peak demand.

Consultation question		9 responses
CM75	Do you have any further comments on any aspects of Capacity Market settlement not covered in your responses to previous questions?	
See <i>Implementing Electricity Market Reform</i> section: 3.4		

## Summary of responses

Respondents provided general comments on complexity (and need to use existing processes where possible), the need to minimise costs (including by minimising collateral requirements), and reducing barriers for small suppliers. One respondent sought confirmation on whether Ofgem will regulate how Capacity Market monies are collected from customers. There was a comment that an ability to adjust prices for material changes in transmission, distribution, or losses costs, as are allowed under CFDs, would be helpful.

## Decisions taken since consultation

In order to minimise the operational costs of the two companies, it is intended that the Settlement Body - the Electricity Settlements Company - will pay the CFD Counterparty at cost for the use of shared facilities, back-office functions and the use of staff required by the Electricity Settlements Company for its corporate functions and activities in 2014/15, including developing the settlement systems. The Electricity Settlements Company will handle the posting of credit cover, but the company has the ability to contract the Settlement Service Provider to do so.

## Institutions and governance

Consultation questions		
CM76	Do you have any comments on the proposed institutional and governance arrangements for the Capacity Market? In particular that Ofgem will be responsible for amending the Capacity Market Rules, and the process for changing the rules and regulations.	26 responses
CM77	Do you think it would be preferable for the Electricity Capacity	23 responses

<sup>65</sup> See

[https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/298354/CFD\\_Counterparty\\_and\\_Electricity\\_Settlements\\_Company\\_operational\\_costs.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/298354/CFD_Counterparty_and_Electricity_Settlements_Company_operational_costs.pdf)

	Regulations to set objectives for the Capacity Market Rules? Such objectives may allow Ofgem to more easily assess the merits of a proposed change to the rules. If so what do you think these objectives should be?	
See <i>Implementing Electricity Market Reform</i> section: 3.5		

### Summary of responses

There was concern about the lack of detailed process for changes to the Capacity Market Rules, and concern about the scope of Ofgem’s powers (specifically that Ofgem can amend the rules as well as being responsible for dispute resolution). Many responses requested a code panel arrangement, similar to the BSC or CUSC, which would be appropriate for the raising, assessment and determination of proposed changes. Others said that there should be a bespoke appeals route.

In response to CM77, the majority of respondents thought it preferable for the regulations to set objectives for the rules. The suggested objectives included:

- Maintain the Capacity Market Rules with minimum change to achieve the reliability standard;
- Propose or support industry amendments which maximise participation in the Capacity Market, such that there is always an excess of participation over the target procurement in any auction;
- Maintain the commercial bargain inherent in capacity agreements and reject changes which do not;
- Maintain penalty levels commensurate with loss of profitability of capacity agreements, rather than loss of cost coverage;
- Promote improved efficiency of the arrangements;
- Ensure the Capacity Market is non-discriminatory;
- Ensure the arrangements do not introduce conflicts of interest between the Delivery Body and Capacity Market activities;
- To stimulate and maintain competition in the Capacity Market;
- Provide the lowest cost option to the end consumer;
- Provide medium to long-term security of supply;
- Ensure non-BSC generators and DSR providers are not adversely or disproportionately impacted by rule changes.

### Decisions taken since consultation – CM76 & CM77

The Government will develop the Capacity Market Rules, but Ofgem will take ownership of the rules the day after the result of the first auction is published. The Government’s intention is that Ofgem will thereafter be primarily responsible for amending the rules, although legally the Secretary of State will retain a residual power under section 34 of the Act to make further rules or amendments.

The rules include technical rules and procedures such as pre-qualification and capacity auctions, and provision about the contents of capacity agreements and obligations of capacity



agreement holders. The Government believes that this puts in place appropriate controls for the Government and Ofgem to keep budgetary control and to enable changes to the market to be made in a timely and coherent manner.

Ofgem may amend, add to and revoke provisions in the Capacity Market Rules and this could mean that Ofgem can expand or reduce the scope of the rules in future. However, Ofgem will do this in accordance with objectives set out in the regulations. In order that the rules can be adapted in response to learning from industry, there will be a duty on Ofgem to consider any proposal for a rule change that it receives. Industry, delivery partners and the public will be able to suggest changes to the rules though they will not be able to block a change to the rules. If parties wish to challenge a change made to the rules this will be by way of a judicial review. There will be a requirement for Ofgem to consult on all changes it decides to make. Ofgem will have discretion on how long the consultation should be in light of the extent of the change.

Ofgem will publish guidance for industry on the process it intends to use to amend the rules. This guidance could, for example, standardise the processes for minor, normal and major rule changes.

### Nature of a capacity agreement

Consultation question		
CM78	Do you have any comments on the draft capacity agreement notice template?	10 responses
CM79	<p>Do you have any comments on the nature of a capacity agreement?</p> <p>The proposed capacity agreement will create statutory rights and obligations which can be enforced by Ofgem – so capacity agreements should serve the same ends as private law contracts. Capacity agreements will be funded by a full credit strength Settlement Body as described in Section 4.4. This regime has desirable parallels and consistency with the existing Balancing Mechanism.</p> <p>Are there any other features or attributes that ought to be incorporated to ensure the regime is investable (including for lenders)?</p>	17 responses
See <i>Implementing Electricity Market Reform</i> section: 3.6.2		

### Summary of responses

There were a small number of mixed comments on the draft capacity agreement notice template (CM78), with respondents noting issues of confidentiality; governance of the Capacity Market Register and transparency of confidential information; and ensuring all parties are bound by the Capacity Market Rules. It was also suggested that it was more appropriate to describe the document as a set of statutory rights and obligations, rather than an agreement.

On the nature of a capacity agreement (CM79), the majority of respondents noted that the agreement was not a private law contract and considered the proposed mechanism to be too complex and that it would increase risk perception. The lack of governance structures was a key issue, including the lack of enforceability against the Delivery Body or Settlement Body, and the need to take action directly against Ofgem. Additionally the ability of Secretary of State and particularly Ofgem to make commercial changes was a major concern.

In terms of specific features or attributes which ought to be incorporated, comments included that the 'pay when paid' principle creates an additional bankability issue, there should be greater force majeure protections, and that there should be provisions for capacity providers to terminate the agreement in certain circumstances, e.g. if not fully paid.

### **Decisions taken since consultation - CM78 & CM79**

The Capacity Market will be established via legislation and the Government can confirm that capacity agreements will not be in the form of a private law contract. While respondents' views were noted, the Capacity Market is intended to provide partial revenue certainty in recognition of poor market conditions facing many generators, but is not an investment contract. Nevertheless, the Government has sought to ensure the regulations and Capacity Market Rules provide the clarity required.

Alongside capacity agreements there will be the Capacity Market Register, which will be publically accessible for reasons of transparency. Exceptions to this are a plant's status in the auction as either a price maker or price taker, or details of exit bids for pre-qualified plants which were not successful in the auction.

The capacity agreement notice will state that the holder has the rights and obligations pursuant to the regulations and rules. It will be issued by National Grid in respect of each successful CMU, within 20 working days of the auction result.

The entry in the Capacity Market Register is the definitive document and, in the event of conflict, the Capacity Market Register would take precedence over the capacity agreement notice. The duration of the capacity agreement, the clearing price applicable for that duration and the de-rated capacity of the CMU (unless the de-rated capacity figure is otherwise changed under the rules) would not change by virtue of any change in the legislation.

Should the entire Capacity Market be withdrawn at a future point, all existing capacity agreements will continue to their expiry date, including any longer-term agreements with prospective new build units. If a CMU subsequently participates in a renewable support scheme, or is supported under a CFD, it must request cancellation of its capacity agreement and withdraw from the Capacity Market prior to the one-year ahead auction for the relevant delivery year. If it fails to do so in time, it must trade its capacity agreement for the full delivery year.

In response to concerns regarding the lack of governance structures and risks relating to any changes to the capacity agreements, the Government has specifically introduced provisions so that the key terms are grandfathered which (subject to any express change in the regulations to

the contrary) will preserve the key obligations and liabilities of a capacity provider notwithstanding a future rule change. The Government has also agreed, with Ofgem, key objectives which must be followed in considering any future rule change. The grandfathering of key terms and the inclusion of objectives for future rule change is a positive response to the industry concerns and should alleviate concerns as to the “bankability” of capacity agreement and the change control/governance issues raised. These key terms to be grandfathered are:

- agreement length;
- capacity price and entitlement to payment (still subject to the principles of the payment model);
- capacity obligation and de-rating figure;
- completion milestones and termination fees applicable; and
- maximum liability for penalties: i.e. monthly and annual caps (while penalty rates may change).
- DSR’s baseline methodology.

Consultation question		20 responses
CM80	Do you consider the test of financial commitment which applies to new build or refurbishing CMUs to be appropriate?	
See <i>Implementing Electricity Market Reform</i> section: 3.6.2.7		

### Summary of responses

While there was some support for a milestone test, the view from the large majority of respondents (including most of those who support the concept of a milestone test) was that the 12 month test of 50 per cent of planned expenditure was inappropriate, or will not work in practice.

Several suggested an alternative of demonstrating a substantive commitment (e.g. FID or financing in place) while some suggested cases should be considered on an individual basis. Others also suggested that the commercial pressures to complete on time are sufficient incentive. A number repeated concerns that the 24 month period to complete a refurbishing project is inappropriate.

### Decisions taken since consultation

In response to concerns from stakeholders, the financial commitment test proposed at consultation stage will be replaced with a revised financial commitment test which mirrors a similar requirement in the CFD contract. The revised Capacity Market financial commitment test requires new and refurbishing plants to demonstrate spend of 10 per cent of the anticipated total project costs (or alternatively demonstrate that Energy Performance Certificate (EPC) contracts and financial resources are in place) by 18 months after the auction results.

Recognising the concern regarding the 24 month completion period for refurbishing plant, the timescale has been extended such that a refurbishing plant will now have to reach completion by the start of the delivery year.

<b>Consultation questions</b>		
CM81	<p>Do you consider the proposed provisions relating to termination of a capacity agreement to be appropriate and a proportionate balance between ensuring that capacity is delivered and affording appropriate safeguards to investors?</p> <p>Do you consider the timescales and appeal process relating to termination to be appropriate?</p>	21 responses
CM82	Do you consider the sanctions other than termination for failure or delay of new or refurbishing capacity to achieve substantial completion to be appropriate?	21 responses
See <i>Implementing Electricity Market Reform</i> section: 3.6.2.7		

### **Summary of responses**

Responses to CM81 were mixed. Some respondents agreed with the termination provisions on principle, but suggested additional rights to remedy any breach. Others considered a liability for stress event penalties combined with an ability to trade obligations, or the commercial pressure to complete and earn revenue to be adequate incentives to deliver.

Additional comments included that the 50 per cent substantial completion test was seen as arbitrary; termination fee two is too high and creates an unnecessary risk and cost; and on demand side response, failure to prove part of the capacity should not lead to termination of the whole - there should be a pro-rata forfeit of the bid bond.

On the appeals process, respondents called for greater clarity. It was suggested that the general right of appeal to the Court of Appeal is extended to cover all disputes under the Capacity Market Rules/regulations, not only pre-qualification decisions.

Responses were similarly mixed to CM82. Many supported the proposals, while others suggested the proposals were too onerous and created a disincentive for new investment, particularly the provisions associated with the failure to achieve substantial completion.

### **Decisions taken since consultation – CM81 & CM82**

In light of responses, the policy in respect of termination and appeals has been revised to provide clearer cure periods, clearer provisions and timescales relating to appeals via National Grid and Ofgem, including an appeal route to the High Court and the ability for a provider to make representation to the Secretary of State to extend or withdraw a termination notice.

- The Financial Commitment Milestone has been revised from 12 months to 18 months after the auction.
- Milestone is 10 per cent of total project cost or financing/EPC contract in place (as noted above).

- The minimum completion test is still set at 50 per cent. However, this is now to be achieved by 12 months after the start of the delivery year (rather than 18 months as previously set out), but with an automatic cure period of a further 6 months before a termination notice is issued (120 working days).
- A 60 working day “firebreak” period still applies for any termination (including that above after the 120 working day cure period) but there is now provision for representation to the Secretary of State to extend this for a further 60 working days or to request withdrawal of the termination notice.
- Failure to secure a metering test certificate will result in termination
- Separately, a provider can request a reconsideration by National Grid and subsequently appeal to Ofgem and the High Court as to National Grid’s determination about the existence of a factual ground for termination.

Consultation question		15 responses
CM83	Do you consider the enforceability of payments due to, or from, a capacity provider to be sufficiently robust under the proposed structure?	
See <i>Implementing Electricity Market Reform</i> section: 3.6.2.7 and 3.4		

### Summary of responses

Approximately a third of respondents agreed that the payment model was sufficiently robust. Of those who disagreed, comments raised included concerns with the "pay when paid" principle; concern over whether the Settlement Body is incentivised to properly carry out its duties (as it is not liable to pay unless paid by the suppliers); and how payments can be enforced against the Settlement Body. Several respondents called for greater clarity as to enforceability and/or called for a private law contract.

### Decisions taken since consultation

The concerns raised in these responses and other decisions on the payment model are set out in the responses to CM53-79

### Ensuring the Capacity Market meets its objectives

Consultation question		
CM84	Has the Government got the right balance between ensuring investors have sufficient certainty to bring forward the investment in capacity we need, and ensuring consumers’ interests are protected?	29 responses
CM85	Can the proposed design of the Capacity Market be simplified without sacrificing the ability for the mechanism to deliver the Government’s objectives?	23 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2		

## Summary of responses

On CM84, nearly all respondents argued that the design of the Capacity Market did not achieve a balance between investor certainty and consumer interests. The most frequently raised concerns related to complexity; that the penalties were too high, which dis-incentivised investment or added costs to the consumer; the need for liquid secondary trading; price caps and price taker thresholds; change in law issues and force majeure protection; and the thresholds and terms for refurbishing plant against new plant.

In terms of the design (CM85), there was broad agreement that there is scope to simplify the design of the Capacity Market and a range of specific suggestions were received.

Whilst there was general consensus on some areas to focus on, particularly simplifying pre-qualification, the anti-gaming measures and the penalties regime, there was little consensus on the actions needed to simplify the design, e.g. some responses proposed increasing the price taker threshold, other responses proposed scrapping the price taker threshold.

Responses focused on the following aspects of the Capacity Market's design:

- **Eligibility:** with some responses suggesting that the refurbished plant category should be scrapped, others that existing plant should be able to choose an agreement of up to three years and that the financial thresholds on existing plant should be scrapped.
- **Pre-qualification:** with a large number of responses highlighting that there is significant scope for reducing administrative burdens and streamlining the pre-qualification process. Responses also focused on the price taker proposal (e.g. increasing the threshold or scrapping it) and whether plant should be able to set their own de-rating.
- **Gaming:** There was general agreement that the additional anti-gaming measures in the design should be removed as they do not add anything beyond anti-gaming legislation already in existence.
- **Secondary trading:** There was no general consensus on how to simplify this, with responses highlighting that there should be fewer restrictions on secondary trading and the system should be based on physical obligation trades.
- **Penalties and over-delivery payments:** A large number of responses thought that the penalty regime should be simplified, with a consensus that penalties before the 4 hour warning and the portfolio cap should be scrapped. Some respondents thought that the penalty charge should be simplified with a £/MWh rate used rather than a complicated formula. Others focused on the need for over-delivery payments to be simplified or scrapped.

## Summary of responses

Many of the points raised in this question have been addressed in the answers to other previous questions. In response to concerns expressed about the complexity of the Capacity Market, we would highlight that simplification was a key aim behind many of the decisions taken which are outlined in this document.

As a result, the Government believes that this final design of the Capacity Market is necessary to deliver the objective of securing electricity supply, at the least cost to consumers. The design also ensures that the Capacity Market can be exited from, when the time is right.

Consultation question		
CM86	Do you agree that the Capacity Market design appropriately mitigates against the risk of gaming in the auction?	23 responses
CM87	Is there more that could be done to ensure the proposed design supports the delivery of wider Government objectives such as the development of the internal energy market?	20 responses
See <i>Implementing Electricity Market Reform</i> section: 3.2		

### Summary of responses

The vast majority of respondents said that the proposed design had gone too far in attempting to mitigate gaming risks, and as a result the design is overly complex and created unnecessary administrative burden and regulatory risk for participants. Comments included that the price cap and the administrative de-rating would prevent competitive price discovery, while the Certificate for Ethical Conduct and the price maker justification created unnecessary complexity, administrative burden and regulatory risk if not accompanied by clear guidance and enforcement.

Most respondents thought that competition already mitigated gaming risks and that many of the mitigating measures will put off new entrants and would therefore have the effect of making the market less competitive.

On developing the design to support wider Government objectives (CM87), approximately half of respondents called for the inclusion of interconnected capacity. Additional comments included that the Capacity Market should be time limited, that more should be done to encourage active DSR participation; and also to promote competition.

### Decisions taken since consultation – CM86 & CM87

The Government has decided to retain those parts of the Capacity Market design that mitigate the risk of gaming, in order to protect consumers and other market participants. As outlined in response to question CM85, the Government has sought to simplify the design, whilst ensuring that it can achieve its objectives. The Government will keep the position under review, as outlined in response to question CM88.

Consultation question		24 responses
CM88	Do you have any comments on the proposed five-yearly review process?	
See <i>Implementing Electricity Market Reform</i> section: 5.6		

### Summary of responses

Most respondents to the consultation agreed that five-yearly reviews was a sensible approach and that more frequent reviews of the regulations could lead to uncertainties in the market.

Approximately a quarter of respondents argued that the Capacity Market should be reviewed sooner given the rapidly changing energy landscape (a three, rather than five, year process; and a review each year for the first four years were suggested).

### Decisions taken since consultation

In line with consultation feedback, the statutory requirements for reviews of the Capacity Market remain annual for an operational review by Ofgem and five-yearly for a holistic review of the regulations by the Secretary of State and of the rules by Ofgem. It has been confirmed with Ofgem that the annual operational reviews will be delivered six months following the latest of the auctions in any capacity year.

Consultation question		19 responses
CM89	Should there be sanctions to cover the event of a party providing false or misleading information in response to a request from the Government or Ofgem for the purposes of reviewing the Capacity Market? If so what should these sanctions be?	
See <i>Implementing Electricity Market Reform</i> section: n/a		

### Summary of responses

Responses on this issue were mixed. Several did not believe that there should be sanctions with one urging the Government and Ofgem to refrain from industry intervention and instead to concentrate on facilitating broad and open competition in the Capacity Market, as this would drive better outcomes for consumers.

Approximately a third of respondents were in support of sanctions, with suggestions including sanctions of up to 10 per cent of annual turnover, and banning parties from participating in future auctions. A further third felt that existing UK law is sufficient to cover for these instances.

### Decisions taken since consultation

Ofgem will retain the ability to request information from any of the Capacity Market's administrative parties, electricity suppliers or the owners of a CMU for the purposes of reviewing the Capacity Market or for amending the Capacity Market Rules respectively. Information will be protected as set out in the regulations.

After considering the arguments put forward from respondents, the Government is satisfied that existing UK law is sufficient in the event of any party providing false or misleading information in response to a request from the Government or Ofgem. Therefore, no new sanctions will be introduced.

### Consultation questions



CM90	Do you have any comments on the proposed provisions for the protection of information in Part 7 of the regulations?	10 responses
CM91	Do you have any comments on Parts 7 and 12 of the regulations?	9 responses
See <i>Implementing Electricity Market Reform</i> section 3.5.1.6		

### Summary of responses

Responses to these questions focused on the importance of protecting confidential information, and how this needs to be balanced with the requirement to publish information in a timely manner – for both transparency and enable the auction to function effectively.

Some respondents had specific recommendations for tightening the legislation, including that Part 7 should be tightened and that information obtained under it should be ineligible for distribution to any non-Government body; and that Regulation 36 should be narrowed to a review of whether the applicant has complied with obligations.

Other respondents raised concerns about Regulation 38, namely that the list of exceptions is too wide in scope and allows for retrospective changes. More specifically, Regulation 38(2)(b)(i) and (ii) can be changed without consent. It was also suggested that Government should publish the de-rated capacity, nature and ownership of all pre-qualified and opted-out capacity.

### Decisions taken since consultation – CM90 & CM91

The Government has continued to engage with industry on the drafting of the detailed rules and regulations. The provisions in the draft regulations for the protection and use of information are consistent with best practice and relevant legislation. Legal provisions for the use of confidential information will be appropriate to the circumstances and limited to that which is necessary for the proper functioning of the Capacity Market.

### 3. Ensuring effective and transparent delivery of EMR – questions and answers

#### Enduring Delivery Plan process

Consultation question		30 responses
DP01	Do you agree the proposals here achieve the right balance between providing certainty to industry protection of commercial information and providing the right degree of flexibility to the System Operator (EMR Delivery Body) and Government?	
See <i>Implementing Electricity Market Reform</i> section: 5.1 – 5.4		

#### Summary of responses

Most stakeholders felt that the proposals achieved a reasonable balance between operational flexibility and providing industry with sufficient assurance about the use of commercial information. However, some concerns were raised about the requirement for developers to provide information to the System Operator, particularly highly commercially sensitive information such as build, capital and operational costs. Ensuring the responsible and professional use of information was also emphasised, particularly the confidentiality and anonymity of sources.

#### Decisions taken since consultation

The Government agrees it is paramount that CFD generators have confidence in the way commercially sensitive information is handled. The powers in the Energy Act 2013 Section 19(2)(f) and Section 45 enable us to ensure that sensitive data is treated appropriately and to make modifications to National Grid Electricity Transmission’s (NGET) Transmission Licence to address potential conflicts of interest.

Prior to EMR secondary legislation coming into effect, the Government has a legally binding confidentiality agreement in place with NGET. At conferral of functions, modifications to NGET’s Transmission Licence will ensure that commercially sensitive information is handled and protected appropriately. This modification and its effects are set out in the answer to DP05, below.

Consultation question		31 responses
DP02	Do you agree that it is appropriate for the System Operator to have access to relevant information from CFD generators in order for it to fulfil its analytical and advisory functions as EMR Delivery Body?	
See <i>Implementing Electricity Market Reform</i> section: 5.2.4		

## Summary of responses

The majority of responses were broadly supportive of the need for the System Operator to have access to the information required to fulfil its analytical and advisory role. However, a number of respondents caveated this position and/or raised concerns with the nature and handling of the information:

- The administrative burden: Respondents highlighted that requests needed to be reasonable and should not place undue burden on generators.
- Some respondents were concerned about the sharing of commercially sensitive information, and asked that the Government provide a clear explanation of the information required and how it will be used.
- Similarly some respondents raised concerns with about the risk of commercially sensitive data being released via Freedom of Information requests, and said they would welcome clarity on the Government's approach to redaction and information handling in such cases. It was also suggested that this could be addressed if a third party or dedicated handling facility within the System Operator was set up to anonymise and aggregate commercially sensitive information before being used for analysis.

Stakeholders welcomed the role of the independent Panel of Technical Experts in scrutinising the analysis undertaken by the Delivery Body and supported greater scrutiny by Ofgem of the outcomes delivered through the Delivery Body.

## Decisions taken since consultation

The Secretary of State will make requests to the Delivery Body for analysis and advice. The provision of timely and relevant cost data will facilitate more accurate analysis and enable the reforms to offer the best possible value for money to consumers.

The Delivery Body will seek information which is relevant to the request made of it from the CFD Counterparty in the first instance. If the information is not provided by the CFD Counterparty, only then will the Delivery Body require CFD generators to provide information.

This approach ensures the Delivery Body can obtain all the information it requires in order to provide advice and analysis commissioned in relation to CFD strike prices. It provides for the lowest administrative burden as the information will only be sought from those who are likely to have the information the Delivery Body needs. In most cases we expect that the CFD Counterparty will be able to provide the relevant information (as it is already collecting most of the information from generators under CFDs) and therefore information will only be sought from generators where the CFD Counterparty is unable to provide relevant information.

Freedom of Information and Environmental Information Regulations requests are dealt with on an individual basis. The exemptions provided for in these regulations ensure a proper balance is achieved between the right to know, the right to personal privacy and the delivery of effective Government.

<b>Consultation question</b>	29 responses
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DP03	Do you agree that it is appropriate for National Grid to require cost information from CFD generators to provide cost information to the System Operator in order for it to deliver its role as EMR Delivery Body and to enable the Secretary of State to take informed decisions which will impact on the affordability and “bankability” of CFD strike prices?
See <i>Implementing Electricity Market Reform</i> section: 5.2.4	

**Summary of responses**

Responses were mixed on whether it was reasonable to request cost information for National Grid. Some stakeholders were supportive, citing the need for full cost transparency to protect consumers. However other respondents felt that such information was too commercially sensitive and were in favour of continuing with the process used previously to assess costs. Some of these respondents also questioned the value and necessity of obtaining such information.

Other points raised include that operational activities and costs will vary considerably between organisations, will be portfolio dependent, and will change depending on the point of the project lifecycle. Therefore any subsequent changes to operational data should not be used to penalise companies at a later date.

**Decisions taken since consultation**

The Government agrees that it is important that any updated analysis provided by the EMR Delivery Body reflects new information from the market. The provision of timely and relevant cost data will provide greater certainty the Delivery Body has the right tools it needs to perform the commissioned analysis. Provision of this data will facilitate more accurate analysis and enable the reforms to offer the best possible value for money to consumers. The Government acknowledges that the Delivery Body will still need to run a call for evidence.

The CFD Counterparty is able to transfer commercially sensitive information to the Delivery Body for use in its analysis. In particular the licence modifications referred to in DP05 require NGET to set up a Data Handling Team to handle, anonymise and aggregate particularly sensitive EMR information. We believe the measures described in response to DP01 and DP02 address concerns about the Delivery Body’s handling of sensitive commercial data and reducing the administrative burden.

**Liability shield**

Consultation question	22 responses
DP04	<p>Do stakeholders have any views on whether the principled approach should be the preferred approach? Or do stakeholders feel there is merit in adopting the approach whereby the liability shield is applied to all of National Grid’s EMR Delivery Body functions?</p> <p>Do stakeholders feel that there are other good reasons for supporting the principled approach or the approach whereby the liability shield is applied to all of National Grid’s EMR Delivery Body functions? Please provide reasons for your views.</p>

### **Summary of responses**

The majority of respondents supported the adoption of the principled approach (determining whether or not the liability shield should be applied guided by a set of high level principles, on a function by function basis). Reasons given for this mainly focused on ensuring that National Grid was sufficiently incentivised to manage risk and deliver the EMR functions in an economic and efficient manner.

Respondents favouring the alternative approach - the application of a complete blanket shield to all of National Grid's Delivery Body functions - did so on the grounds that National Grid's risk profile should not be impacted as a consequence of it being appointed as the EMR Delivery Body; one respondent suggested that there was no need for a liability shield and instead clear licence conditions should specify the services that the System Operator will deliver. Another respondent also made an alternative suggestion, that National Grid should be compensated according to the risk they are willing to take on and receive no additional special protections.

Additional comments made included that National Grid should take responsibility if exercising discretion; and that the application of a liability shield should not protect it from complaints, nor deny people other forms of redress against its decisions.

### **Decisions taken since consultation**

In response to stakeholders' views, further work was undertaken on the principled approach however, this proved problematic to apply in practice due to difficulties in specific application to the detailed EMR functions. Consequently, a third approach was developed and the Government has decided to shield all of National Grid's EMR delivery functions, with specific exclusions to deal with the concerns of stakeholders.

Those exclusions include:

- where National Grid has acted in bad faith;
- breached the Human Rights Act 1998; or
- is in breach of an enforcement order made by Ofgem under its powers in the Electricity Act 1989.

To ensure that the shield does not have the effect of diluting incentives for good performance by National Grid and to address stakeholders specific concerns (in particular, concerns about maintaining the confidentiality of EMR information), the Government has gone beyond these minimum exemptions to also include exemptions where National Grid has acted criminally, has breached confidentiality, or is in breach of contract.

The application of the liability shield will not protect National Grid from complaints, nor deny people other forms of redress against its decisions. For example, both the Capacity Market and CFD functions will have appeals processes to help resolve issues arising between National Grid and others affected by the exercise of its EMR Delivery Body functions. It is important to note

therefore that the shield, where applied, will only protect National Grid (or its directors, employees, officers or agents) from liability in damages.

### Modifications to National Grid’s licence to implement mitigation measures to manage Conflicts of Interest

Consultation question		19 responses
DP05	<p>How effectively will the licence modifications achieve the mitigation proposals set out above?</p> <p>Please explain your answer, providing evidence where you can.</p> <p>Are there any unintended consequences you can foresee from these modifications?</p>	
See <i>Implementing Electricity Market Reform</i> section: 5.5		

#### Summary of responses

The points made by stakeholders in response to this question were mixed. In general, supporters were in favour of measures to manage any conflicts of interest, with some requesting an independent scrutiny process, or a separate route for industry to raise potential conflicts.

Although some respondents did not think there were significant synergies between the EMR Delivery Body role and the System Operator role, others noted that there were which would provide benefits, in particular by improving balancing services activities. Other comments included that it was important arrangements did not impact on the ability to utilise shared services across National Grid’s functions and therefore drive up costs; that there should be some form of annual review; and some requested further detail on the reporting requirements which are to be put in place.

#### Decisions taken since consultation

Following consultation, we have considered the measures and how they may be strengthened where possible to take into account concerns expressed by stakeholders. It has been decided that the licence modification to NGET’s Transmission Licence will include:

- An overarching requirement that National Grid carry out the EMR functions conferred on it having regard to stated objectives which are in brief:
  - the efficient and effective carrying on of EMR functions;
  - compliance with the principles of best regulatory practice; and
  - to act to ensure that none of National Grid’s businesses or associated businesses are either unfairly advantaged or allowed to unduly influence the exercise of EMR functions;
- A requirement to establish a physically separate data handling team to handle, anonymise and aggregate certain delivery plan data when received;
- A requirement to establish and maintain a physically separate team to carry out EMR administrative functions;
- Non-disclosure agreements to be signed by all staff working in both teams above.

- Restrictions on sensitive EMR information being passed outside of the System Operator business or to one of National Grid’s competitive businesses (such as offshore or interconnection);
- Restrictions on movements of staff in and out of the EMR data handling and EMR administration teams;
- A compliance officer to be appointed to be responsible for providing and overseeing a compliance statement approved by Ofgem;
- A requirement for a single responsible director who reports to the board to sign an annual declaration of compliance; and an independent audit may be commissioned at Ofgem’s direction to review the practices procedures and systems implemented to comply with this licence condition, assess their appropriateness and report on National Grid’s compliance with its requirements.
- An obligation to establish and maintain legal, managerial, employee, physical and information separation between National Grid and relevant competitive businesses (with limited exceptions to allow certain staff to carry out shared services and “de minimis” services)
- A prohibition on National Grid employees engaged in EMR functions from engaging in “de minimis” services provided to certain National Grid owned competitive businesses.

On the last two points, we do not believe that a total prohibition on National Grid carrying out “de minimis” services to its relevant competitive businesses (as it does at present) is justified. This is because we are satisfied that, given the clear understanding we now have of the role of the Delivery Body and the extensive measures taken to ensure separation of EMR staff and information from the rest of National Grid as listed above, we are confident that the risk of conflicts occurring between National Grid’s EMR Delivery Body role and the rest of its business activities has been minimised. This is because cumulatively these measures should:

- Create separate teams within the System Operator for certain EMR functions such as data handling, CFD allocation and running the Capacity Market auctions in accommodation effective in restricting access by other personnel;
- Restrict EMR information leaving the System Operator;
- Prevent the identification of the source of data used by analysts within the System Operator who are carrying out EMR Delivery Plan analysis where this relates to commercially-sensitive information;
- Ensure senior accountability to ensure the impartiality of the analysis;
- Ensure separation measures are in place between National Grid’s System Operator-Transmission Owner business and certain other competitive businesses owned by National Grid; and
- Provide for independent scrutiny of National Grid’s compliance systems and their implementation.

## Annex A – List of consultation respondents

AB Sugar	Energy Norway
ABB	Energy Pool
Air Products	Energy UK
Alstom	Environmental Services Association
Association of UK Coal Importers (Coallmp)	ESB
ATCO Power Generation Ltd	Estover Energy Ltd.
Banks Group	European Federation of Energy Traders
BMT Group	European Forest Resources Group
Bonaprene Products Ltd	Eyemouth Harbour Trust
BT	Fergusson Group Ltd (FGL)
Carlton Power	First Flight Wind
Centrica	First Utility
Chemical Industries Association	Forth Energy
Clydeport	Freightliner Heavy Haul Limited
Combined Heat and Power Association	Gaelectric
Consumer Futures	GDF SUEZ Energy UK-Europe
Cornwall Energy	GE Power Conversion
DONG Energy	Global Energy Advisory
Drax	Gazprom Marketing & Trading Ltd
E.ON	Good Energy
Ecotricity Group Ltd	Graham M. Phillips
EDF Energy	Green Frog Power
EDP Renewables	Hargreaves Services Plc
EEF	Haven Power Ltd
Eggborough Power Ltd	Helius Energy plc
EirGrid	Highlands and Islands Enterprise
ElectraLink	Horizon Nuclear Power Wylfa
Electricity Storage Network	Industrial and Commercial Shippers and Suppliers (ICoSS) group
Element Power	Infinis
ELEXON Ltd	InterGen
Energia	Kier Minerals Ltd
Energie-Nederland	



Macquarie Infrastructure and Real Assets (Europe) Ltd.	States of Jersey, States of Guernsey, Chief Pleas of Sark and the States of Alderney
Mainstream Renewable Power	Statkraft
Miller Argent	Statnett
Mutual Energy	Statoil UK
National Grid	TGC Renewables
Navitus Bay Wind Park	The Carbon Capture & Storage Association
New Earth Solutions	The Concrete Centre
Northern Ireland Renewables Industry Group (NIRIG)	The Confederation of UK Coal Producers (CoalPro)
Opus Energy	The Co-operative Energy
Ovo Energy	The Crown Estate
PeakGen Power Ltd	The Isle of Man Government's Department of Economic Development
Peel Energy	Tidal Lagoon Power
Power NI	UK Demand Response Association
Powersite Ltd	UK Green Investment Bank
PWR Consultants Limited	UK HFCA
Quarry Battery Company Ltd	UK Power Reserve Ltd
Renewable Energy Association (REA)	Vattenfall
Regen SW	Velocita
Renewable Energy Systems Limited (RES)	Vestas Wind Systems
RenewableUK	Viridor
RenewableUK & Scottish Renewables	VPI Immingham
Repsol Nuevas Energias UK Limited	Waste2Tricity Limited
RWE npower	Waters Wye Associates (on behalf of small STOR providers, Peak Gen Power & Welsh Power Group)
Scottish Enterprise	Welsh Power Group Limited
ScottishPower	Which?
Scottish Renewables	Wood Panel Industries Federation
Seajacks	
Sembcorp UK Utilities Limited	
Siemens	
Smart Energy Demand Coalition	
SmartestEnergy	
SmartGrid GB	
SSE	
Stag Energy	



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