Title: Electricity Market Reform – Capacity Market [update: October 2013]	**Impact Assessment (IA)**
	Date: 24/10/2013
IA No: DECC0151	**Stage:** Final
	Source of intervention: Domestic
Lead department or agency: DECC	**Type of measure:** Primary legislation
	Contact for enquiries: Anthony Tricot Anthony.Tricot@decc.gsi.gov.uk

Summary: Intervention and Options

RPC: N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, Two-Out?**	**Measure qualifies as**
£0.2bn	£4.8bn		No	Tax and Spend

What is the problem under consideration? Why is government intervention necessary?

Over the next twenty years our electricity generation mix will move away from fossil fuel generation and towards more intermittent and less flexible generation – around a fifth of capacity available in 2011 has to close over this decade. There is a significant risk that the market will no longer deliver an adequate level of security of supply as it has done historically, principally because potential revenues in the energy-only market may no longer incentivise sufficient investment in capacity. This is the 'missing money' problem and may be caused by:

1. The electricity price not reflecting the true cost of system balancing actions when there is scarcity
2. The lack of a liquid forward market to build capacity on the basis of expected scarcity rents. This can be due to investor concerns that the Government/Regulator would not let parties earn "scarcity rents".

There are additional market failures due to barriers to entry and from reliability being a quasi-public good. A Capacity Market reinforces energy market signals to ensure there will be sufficient capacity to meet demand.

What are the policy objectives and the intended effects?

The high level objectives of a Capacity Market are:

- **Security of Supply**: to incentivise sufficient investment in capacity to ensure security of electricity supply;
- **Cost-effectiveness**: to implement changes at minimum cost to consumers
- **Avoid unintended consequences**: to minimise design risks and complement the decarbonisation agenda
- **Timing**: Capacity Market can be implemented in time for a first auction in 2014

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

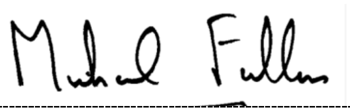
This Impact Assessment (IA) updates the previous IA published in May 2013, in which the lead policy option to mitigate risks to electricity security of supply was identified as a Capacity Market – in which an auction is run annually to determine the level of support needed to ensure sufficient reliable capacity is made available.

This IA has been updated to present Cost Benefit Analysis (CBA) and price and bill impacts as a result of updated assumptions, including technology costs and electricity demand at the time the analysis was undertaken. The Annexes to this IA set out the analysis supporting the detailed policy choices that have been made around the design of the Capacity Market, including on auction design, penalty regime, agreement lengths, and who is eligible to participate in the mechanism. In addition to analysis based on a carbon emissions intensity of 100gCO2/kWh for the power sector in 2030, consistent with previous Capacity Market impact assessments – includes analysis based on an average emission level of both 50gCO2/kWh and 200gCO2/kWh in 2030.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** See Section 10

Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** No	**< 20** No	**Small** No	**Medium** No	**Large** No
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:** +46 $MtCO_2$	**Non-traded:** 0	

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister:  Date: 24/10/2013

Summary: Analysis & Evidence

Lead Policy Option

Description: Administrative Capacity Market

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2012	Time Period Years 19	Net Benefit (Present Value (PV)) (£m)		
			Low: -348	High: 1,170	Best Estimate: 183

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	N/A	6	N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	143		64	**1107**

Description and scale of key monetised costs by 'main affected groups'

1. **Energy system costs**: These include costs from building additional capacity and the associated impacts on fuel and carbon costs. The impact on energy system costs have a lifetime PV of £0.8billion. Distributional analysis shows that this cost is largely borne by consumers through electricity bills.
2. **Business administrative costs** are estimated to be £16m per year, with a PV to 2030 of £231 million.
3. **Institutional costs** for a central deliverer to procure capacity for the Capacity Market – estimated to be £13 million to set up and £2 million to run annually, with a discounted PV of £32m in the base case. Institutional costs are lower in the transition period.

Other key non-monetised costs by 'main affected groups'

The cost of the Capacity Market could differ from the modelled effects according to:

- Whether the capacity auction is illiquid;
- The degree to which the Capacity Market can bring down investment financing costs for new plant
- Whether generators take account of the potential scarcity rents when setting a price in the CM
- Whether the optimal level of capacity is contracted for

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	N/A	6	N/A	**759**
High	N/A		N/A	**2,276**
Best Estimate	0		103	**1,290**

Description and scale of key monetised benefits by 'main affected groups'

A Capacity Market incentivises additional capacity which reduces the likelihood of blackouts and voltage reductions. This reduction in energy unserved is valued at £1,290 million. However a small change to assumptions around demand or value of lost load can significantly increase expected benefits.

Other key non-monetised benefits by 'main affected groups'

A Capacity Market has a number of significant non-monetised benefits (discussed further in Section 7):

- a Capacity Market provides a more predictable revenue stream for capacity providers which can lower financing costs for new capital; and
- a Capacity Market has potential to reduce gaming opportunities in the energy market by increasing penalties on generators that are unavailable at times of system stress.

Key assumptions/sensitivities/risks Discount rate (%) 3.5

The first capacity auction is run in 2014, with a delivery year of 2018/19. In the capacity auction generators bid in the true cost of providing additional capacity (modelled as the level of support they need in addition to electricity market rent to provide capacity). Providers are entitled to keep any scarcity rents they earn in the energy market. Energy prices are assumed to rise up to £6,000/MWh at times of lost load. We have assumed a VoLL of £17,000/MWh. In the High Net Benefit Scenario we assume a £30,000 VoLL, and in the Low Net Benefit Scenario we assume a £10,000/MWh VoLL. In line with previous IAs for the Capacity Market (and EMR) a decarbonisation trajectory of 100gCO_2/kWh in 2030 is assumed. The EMR package modelled includes a low-carbon instrument (the CfD) and a Capacity Market, combined with an Emissions Performance Standard (EPS). The analysis includes existing policies such as the Renewables Obligation (RO) and support for early-stage CCS projects.

BUSINESS ASSESSMENT

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: 6,255	**Benefits: 11,063**	**Net: 4,808**	No	N/A

Evidence Base (for summary sheets)

Contents

1 Background

1.1 This IA provides an update to analysis of the impact of the Capacity Market. It supports the consultation on the secondary legislation setting out the detailed rules for the mechanism, and this IA provides the analytical justification for the detailed design choices made.

1.2 Previous IAs for the Capacity Market – primarily December 2011,[1] November 2012,[2] and May 2013[3] – have analysed the policy options that would best deliver our security of supply objective. The key conclusions from these previous impact assessments are:

- A Capacity Market is the preferred instrument to mitigate security of supply risks compared to alternatives, including a strategic reserve and doing nothing.[4]
- An Administrative Capacity Market is the preferred form of the capacity market compared with a reliability option.[5]

1.3 This IA presents updated energy modelling analysis and price & bill impact analysis for an Administrative Capacity Market. The results of the updated analysis are consistent with estimates published in the July 2013 IA for the Draft Delivery Plan.

1.4 The Annexes of this IA also provide the economic assessment for the detailed design choices that have been made in designing the mechanism. These include rules for the auction, penalty regime, secondary trading and payment model.

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf
[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf
[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/197911/capacity_market_ia.pdf
This IA was originally published in January 2013, but was republished in May 2013 alongside the publication of the Energy Bill.
[4] This decision was first presented in the December 2011 Technical Update to EMR (http://www.decc.gov.uk/assets/decc/11/consultation/cap-mech/3883-capacity-mechanism-consultation-impact-assessment.pdf).
[5] An Administrative Capacity Market is one in which capacity providers receive a payment for offering capacity which is available when needed, but are able to keep their energy market revenues. Under a Reliability Market, capacity providers receive a payment for offering capacity which is available when needed, but are required to pay back any scarcity rents earned in the energy market.

Modelling changes since May 2013

1.5 From the last Capacity Market IA in May 2013 until the IA accompanying the Draft Delivery Plan in July 2013,[6] a number of modelling changes were made:

i. A bespoke module was introduced into the Dynamic Dispatch Model (DDM) to model the value to society of unserved energy. This provided a more granular and more sophisticated analysis of the frequency and duration of periods with unserved energy. This modelling approach was designed to be closer to the Ofgem capacity assessment and was procured in collaboration with National Grid to ensure this was the case. The new approach showed higher estimates of unserved energy which, when combined with the increase in VOLL from £10,000 to £17,000/MWh, meant there was a large increase in the expected benefits of the capacity market from reducing unserved energy. This was the key driver of the increase in the NPV relative to the previous analysis (by over £2bn to 2030).

ii. These increased benefits are offset to some extent by the inclusion of system costs (amounting to just over £1bn up to 2030), which was an additional feature not previously accounted for in EMR modelling.

1.6 The effect of these changes was to increase the estimated benefit of the Capacity Market from increased reliability of electricity supply, leading to an overall benefit of £0.2bn from a previous estimated net cost of -£0.6bn.

1.7 Following the Draft Delivery Plan, further refinements were made to the DDM to better reflect the final design of the Capacity Market, for instance targeting a Loss of Load Expectation of 3 hours per year and incorporating a demand curve for the auction.

1.8 The latest modelling also makes a number of changes to reflect the security of supply context: It uses the latest demand figures from the Updated Energy Projection and the assumptions about plant retirement have been updated to be consistent with Ofgem's 2013 capacity assessment. The modelling also has updated build constraints for new gas plant, and assumes a greater security of supply contribution from demand side response (DSR) and interconnection.

1.9 The value of the changes in the NPV estimates between May 2013 and this update is shown in the table below.

1.10 The finding in this Impact Assessment of a £0.2bn net benefit from a Capacity Market is broadly consistent with the findings of the Impact Assessment for the Draft Delivery Plan in July (which showed a £0.1bn net benefit).

Figure 1: Change in Net Welfare (NPV) – Capacity Market, comparison of July 2013 (Draft Delivery Plan) and latest figures (emissions intensity in 2030 = 100gCO_2/kWh)

	NPV, £bn (2012-2030, real 2012 prices)		
	May 2013	**July 2013**	**October 2013**
Capacity market	-0.6	0.1	0.2

Source: DECC modelling

[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225981/emr_delivery_plan_ia.pdf

1.11 Modelling shows an increase in the average annual domestic electricity bill of £13 in 2016 to 2030 (in 2012 prices). This is equivalent to a 2% average increase in domestic bills. The table below shows the impact of a Capacity Market on the bills of different groups – domestic consumers, non-domestic consumers and energy-intensive industries (EIIs).

Figure 2: Electricity Bill Impacts

Bills in 2012 prices	**Typical bill without CM**	**Change with CM (%)**
Domestic, (£)[7]		
2011-2015	567	0.0%
2016-2020	593	0.5%
2021-2025	618	2.2%
2026-2030	694	3.0%
Non Domestic (£000) [8]		
2011-2015	1,100	0.0%
2016-2020	1,300	0.5%
2021-2025	1,400	3.7%
2026-2030	1,500	4.1%
Energy Intensive Industry, (£000) [9]		
2011-2015	7,900	0.0%
2016-2020	10,300	0.7%
2021-2025	11,800	4.2%
2026-2030	12,400	4.7%

Source: DECC modelling

[7] Results for the household sector are based on a representative average electricity demand level for households, derived from historical total domestic consumption, and is set at 4.5MWh of electricity before policies.
[8] Non-Domestic users are based on the consumption of a medium-sized fuel user in industry, with an electricity usage of 11,000 MWh, and includes the effects of the CRC. Percentage impacts on the bill are expected to be the same for non-CRC users.
[9] For the energy-intensive industry sector, illustrative users consume (before policies) 100,000MWh of electricity.

2 Overview

2.1 The Government has taken powers in the Energy Bill to run a Capacity Market and is now consulting on the secondary legislation that sets out the detailed rules for how the Capacity Market will function. The Capacity Market will incentivise sufficient reliable capacity (both supply and demand side) to ensure a secure electricity supply, even at times of peak demand.

2.2 This impact assessment (IA) presents an appraisal of the lead option for mitigating security of supply risks in the GB electricity market – a Capacity Market. The analysis presented in this IA is based on a standardised set of assumptions, including technology costs and electricity demand at the time the analysis was undertaken. These assumptions are set out in more detail in Annex G.

2.3 The objective of the Capacity Market is to ensure that an adequate level of security of electricity supply is delivered in a way that is cost-effective and complementary to decarbonisation policies. Over the coming years, the UK electricity market will undergo profound changes. Around a fifth of capacity available in 2011 has to close this decade and we will see a significant rise in intermittent and less flexible generation to support our climate change objectives. We also expect overall demand for electricity to increase in the long term as a result of the electrification of our transport and heating systems.

2.4 If the existing energy market worked perfectly, this would not be a problem as investors would bring forward capacity on the basis of the high prices they could earn at times of scarcity. However, imperfections in the market could mean that the market fails to bring forward sufficient capacity. Electricity prices do not currently reflect the value of scarcity due to how imbalance ("cash out") prices in the balancing mechanism are calculated. Moreover even if cash out were reformed to perfectly reflect the value of scarcity, industry may not feel able to invest if they are concerned that the Government/Regulator would intervene to prevent parties earning "scarcity rents".

2.5 A Capacity Market is an appropriate way to mitigate the risk of voltage reductions ("brownouts") and controlled load shedding ("blackouts") due to the energy market not bringing forward the economically optimal amount of capacity. It does this by enabling the System Operator to decide the level of capacity it judges is appropriate and then contracting for this capacity through an auction four years ahead. This ensures there is sufficient reliable capacity to meet demand, for example during winter anti-cyclonic conditions when demand is high and wind generation is low for a number of days.

2.6 DECC's latest energy system modelling supports Ofgem's assessment[10] and the analysis in the Electricity Market Reform White Paper[11] that capacity margins are likely to tighten in the years ahead. DECC's analysis suggests that a failure to intervene could lead to a significant increase in risks in the 2020s as the level of intermittency is greater and as a number of existing plants retire. However modelling is inevitably uncertain given the wide potential ranges for factors such as demand, weather conditions, the reliability of plant, and changes to the cash out regime. We recognise as a result that it is plausible that this assessment is likely to underestimate the benefits of a Capacity Market.

2.7 The Government will run the first auction in 2014, for delivery of capacity in the year beginning in the winter of 2018/19, subject to state aid approval.

[10] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx
[11] http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx

2.8 Our base case analysis shows that a Capacity Market is expected to have a net benefit of £200m relative to a scenario where the energy price is able to rise to £6,000/MWh but not to the full value of customers' value of lost load (estimated at £17,000/MWh). However the benefits of a Capacity Market could be greater if it succeeds in reducing the risk for investing in new capacity by giving investors a steady capacity payment to uncertain scarcity rents in the energy market.

2.9 However the security of supply outlook is uncertain as it is difficult to predict capacity margins with precision or to estimate the security of supply impacts from tighter margins. Small changes in assumptions can lead to significant changes in outcomes. The overall conclusion from the analysis is therefore that a Capacity Market is a sensible precaution against the risk of market failures in the energy market leading to inadequate levels of security of supply.

2.10 The Capacity Market is assessed with quantitative and qualitative analysis. The quantitative analysis (Section 6) shows that this option leads to an increase in consumer bills (around £13 per year for an average domestic household in the period in which a Capacity Market is bringing on additional capacity).

2.11 The qualitative analysis (Section 7) looks at wider impacts. In particular it considers how well this option fits within the existing market structure, noting challenges around compatibility with the Single Market and how well the mechanism design mitigates gaming risks, while Section 8 concludes.

2.12 The Annexes gives details around our modelling approach as well as setting out the analysis underpinning some of the more detailed design issues that have been considered, namely:

i) The choice of auction format;
ii) The timeline for procuring capacity;
iii) The choice of agreement length;
iv) The parameters of the demand curve;
v) Eligibility rules for participation in the CM; and
vi) The level of penalties and when they are applied;
vii) Introduction of DSR transitional arrangements

3 Objectives

3.1 As set out in the previous Impact Assessment, the high level objectives of a Capacity Market are:

i) Security of Supply**:** to incentivise sufficient investment in generation and non-generation capacity to ensure security of electricity supplies.

ii) Cost-effectiveness**:** to implement changes at minimum cost to consumers.

iii) Avoid unintended consequences**:** to minimise design risks and ensure compatibility with other energy market policies, including decarbonising the power sector.

iv) Deliverable for 2014 auction date**:** Given the risks to security of supply as plants retire over this decade and the potential for an investment hiatus until a Capacity Market is implemented, the Government will run the first auction in 2014; it is therefore important that the chosen Capacity Market can be implemented in time for a first auction in 2014.

4 Rationale for Intervention

Introduction

4.1 Electricity markets are different to other markets in a number of ways, two of which are particularly significant: capacity investment decisions are very large and infrequent; and there is currently a lack of a responsive demand side as consumers do not choose the level of reliability of supply they are willing to pay for (as load shedding occurs at times of scarcity on a geographic basis rather than according to suppliers and as domestic consumers do not respond to real time changes in the price of electricity). Smart Meters, which are expected to be rolled out by 2019, should help to enable a more responsive demand side but it is anticipated that it would take time for a real-time responsive market to evolve.

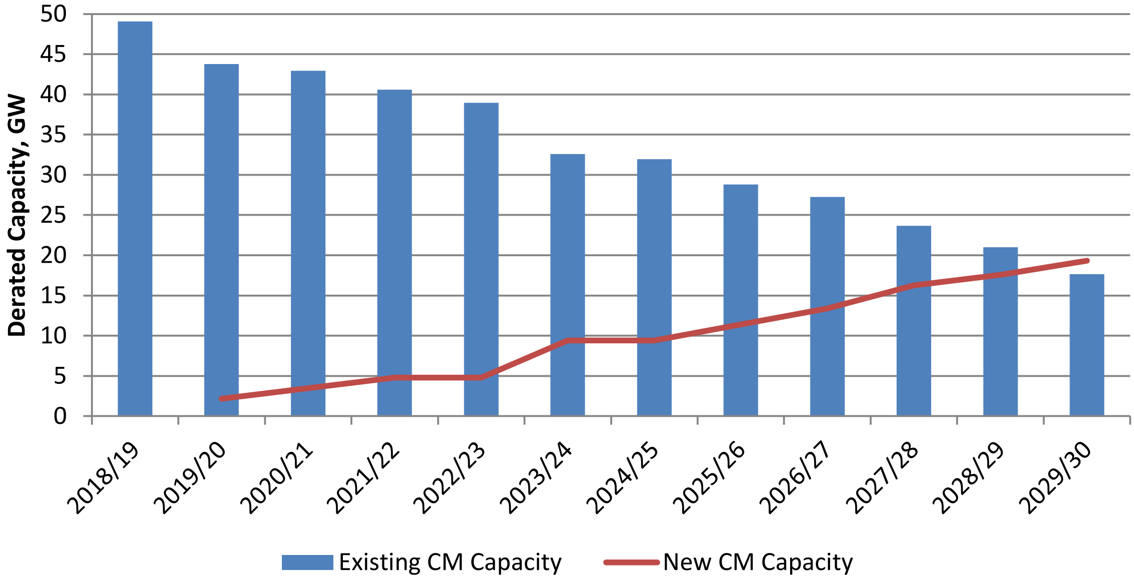
4.2 In the absence of a flexible demand side, an energy-only market may fail to deliver security of supply either:

i. if the electricity price fails to sufficiently reward capacity for being available at times of scarcity; or
ii. if the market fails to invest on the basis of expected scarcity rents.

4.3 These conditions would tend to lead to under-investment in capacity and its reliability.

4.4 While the market has historically delivered sufficient investment in capacity, the market may fail to bring forward sufficient capacity in the future as a fifth of existing generating capacity has to close this decade and as the power system decarbonises: The decarbonisation of the power sector means that thermal plants can expect to run at lower load factors in future and so need to recover a greater proportion of their fixed costs through scarcity rents at times of stress. This increases risks for investment in thermal capacity exactly at a time when the UK needs significant investment in new gas build to replace the existing ageing fleet. So while there have always been risks that an energy-only market would fail to invest sufficiently in new capacity, these risks have become now significantly more material and so necessitate intervention to ensure security of supply.

Figure 3: Amount of existing capacity that needs to be replaced through the CM



Source: DECC modelling

4.5 The market may also fail to provide incentive for capacity built to be sufficiently reliable, flexible and available when needed. A Capacity Market mitigates against the risk that an energy-only market fails to deliver sufficient incentives for reliable and flexible capacity.

Market failures in the energy market

4.6 In the Electricity Market Reform White Paper, we set out the potential market and regulatory failures in the current market that could prevent these signals from being realised.

4.7 The principal market failure is that **reliability is a quasi-public good**: It is non-excludable in the sense that customers cannot choose their desired level of reliability, since the System Operator cannot selectively disconnect customers. Therefore it can be expected that reliability will not be adequately provided by the market.

4.8 In theory this problem is addressed in an energy-only market by allowing prices to rise to a level reflecting the average value of lost load (i.e. the price at which consumers would no longer be willing to pay for energy) and allowing generators to receive scarcity rents.

4.9 As the power sector decarbonises and new thermal capacity expects to run at lower load factors, the investment case for such plant would become riskier and more dependent on scarcity rents. However if real-time energy prices were able to reflect the value of scarcity then the market could develop trading solutions to deal with such risk. For example, suppliers could insure themselves against the risk of price spikes by paying for an option (a firm fixed payment) to capacity providers who in return would forego scarcity rents should they occur. This should lead to investment in the socially optimal level of capacity.

4.10 However in reality an energy-only market may fail to send the correct market signals to ensure optimal security of supply and to enable investors to obtain project finance for building new capacity. This is commonly referred to as the problem of ‘**missing money**’, where the incentives to invest are reduced, due to the three reasons below:

i. Current wholesale energy prices do not rise high enough to reflect the value of additional capacity at time of scarcity. This is due to the charges to generators who are out of balance in the Balancing Mechanism (“cash out”) not reflecting the full costs of balancing actions taken by the System Operator (such as use of reserve capacity or customer disconnections).

ii. Stress events are unlikely to occur frequently: With decarbonisation investors face uncertainty about running hours and so will be increasingly reliant on recovering fixed costs through infrequent and uncertain scarcity rents.

iii. At times when the wholesale energy market prices peak to high levels, investors are concerned that the Government/regulator will act on a perceived abuse of market power, for example through the introduction of a price cap.

4.11 The third problem is exacerbated if there are significant **barriers to entry**, effectively restricting the number of participants in the wholesale electricity market. As margins become tighter and prices more volatile in the future, market participants may have more opportunities to withhold supply to drive up prices – particularly so as demand is inelastic in response to short-term shocks and so there are potentially significant gains from withholding at times of scarcity. This could result in a greater likelihood of gaming in the energy market and difficulties in differentiating such gaming from legitimate prices, which would increase the risk that the Government may want to intervene in the wholesale market to cap prices.

4.12 This has not previously been a significant concern as prices historically have not risen above £938/MWh[12] as a result of excess capacity on the system depressing wholesale market prices. The excess capacity arose due to a number of factors that no longer hold: Most of this capacity was built prior to the introduction of an energy-only market in 2001; the decline in gas prices in the 1990s under the "dash for gas" made it profitable to invest in new gas plant in this period while there was still sufficient coal capacity; and the financial crisis in 2008 and the subsequent fall in rate of economic growth significantly supressed demand for electricity. In the future, analysis suggests that prices could need to rise to up to £10,000/MWh (or even higher) for short periods to allow flexible plant to recover investment. Investors are concerned that Government or the regulator would intervene if this were to happen. The perception of this regulatory risk could increase 'missing money' and under-investment.

Does the current electricity market sufficiently value capacity?

4.13 The current electricity market may fail to provide sufficient incentives for investment in new capacity or for existing capacity to be flexible, reliable and available when needed.

4.14 This is due in part to the determination of imbalance prices ("cash out") failing to reflect the value of capacity at times of scarcity.[13] The main cash out price is the closest thing to a real-time price in the GB market but has historically failed to reflect scarcity for a number of reasons: the use of reserve capacity is not priced appropriately into cash out, the SO's actions are averaged when priced into cash out, the cost of customer disconnections and voltage reductions are not priced at all into cash out, and there is no real-time market into which parties can sell energy and receive the clearing price.

4.15 Historically the highest cash out prices have risen to is £938/MWh, although it should be noted that this may also be due to excess capacity on the system. If prices could only go to around £1,000/MWh in scarcity events it would imply that the current price is far from cost-reflective: A £1,000/MWh price during a controlled load shedding is equivalent to around 70 pence per hour per domestic household - which is likely to be significantly less than the amount consumers would be willing to accept to avoid being disconnected (estimated at around £12).[14]

[12] System buy price on 5th January 2009, settlement period 35. Balancing Mechanism Reporting System (BMRS), http://bmreports.com/

[13] For example, if there is an unexpected decrease in supply (for example because of a plant failure), the System Operator will be required to correct the potential imbalance by procuring additional supply – the price paid for this additional supply is known as the 'cash out' price.

[14] Based on estimate of average household peak demand of 0.7 kWh.
Energy Saving Trust report, "Powering the nation: Household electricity-using habits revealed" (2012)

4.16 Ofgem is currently carrying out an Energy Balancing Significant Code Review, and has recently published a draft policy decision[15] to reform cash out to rise to £6,000/MWh at times of stress and to have a single marginal price and to better price in the System Operator's use of reserve. This will go some way to addressing the missing money that is currently present in the energy market. This should mean that providers will have less need to recover their fixed costs through the CM, and the price in the CM auction should be lower than it would be without the cash out reform.

4.17 However, this price is still considerably lower than VoLL (£17,000/MWh) and so may not be sufficient in providing optimal incentives for investment.

4.18 Even if cash out were reformed to allow prices to spike to levels which reflect the full cost of energy in scarce periods there are still significant concerns around the ability of an energy-only market to deliver sufficient levels of investment in capacity. This concern about "missing money" will become increasingly significant as the power sector decarbonises and gas plants runs at lower load factors – recovering a higher proportion of their fixed costs through scarcity rents.

4.19 If the market worked perfectly, this would not be a problem as operators of flexible capacity would have sufficient confidence that prices would spike to such an extent that would enable them to cover their costs. However, industry may not feel able to invest if they cannot attain finance on the basis of uncertain scarcity rents or if they do not have confidence that the regulated market will be allowed to operate in an unconstrained way. As such, the level of flexible capacity required may not come forward, potentially resulting in controlled load shedding/voltage control and an increase in wholesale prices and consumer bills at times of high demand and low wind.

Contribution of Interconnection

4.20 Interconnection to other electricity markets can contribute to GB security of supply by allowing other markets to supply energy at times of stress and so reducing the need to build domestic backup plant.

4.21 However the extent of the contribution made depends on the degree of correlation between stress events in GB and abroad: Where stress events are increasingly associated with temperature and weather affecting wind output, and where wind output is highly correlated across neighbouring European markets, then the contribution of interconnection might be limited.

4.22 Nevertheless, analysis for DECC by Poyry suggests that, if we assume an efficient market, we can expect to be importing some energy through interconnectors at times of stress – equivalent, on average, to 57% of the total transmission capacity of the interconnectors. This factor helps to compare interconnected capacity with GB generating capacity – showing, for a given reliability standard, how much demand in the GB capacity market can be lowered relative to a situation with no interconnection.

4.23 However we recognise there are currently two key barriers to the efficient operation of interconnectors between GB's electricity market and other Northern European markets that mean a more cautious view of interconnection is justified in the short term:

[15] https://www.ofgem.gov.uk/ofgem-publications/82294/ebscrdraftdecision.pdf

4.24 The first is that interconnector flows do not always reflect price differences between markets. Where interconnector flows are determined through ‘explicit’ auctioning of interconnector capacity, the flows do not reflect forward price differentials between markets as well as where interconnector capacity is allocated *implicitly* according to differentials in forward prices. Analysis by the European Commission notes evidence relating to several interconnectors where explicit auctions have led to power flows frequently moving in the wrong direction (that is, from the higher-price side of the inter-connector to the lower-price side).[16]

4.25 The second is that spot prices for electricity in the GB Market do not reflect the value of capacity at times of system stress as well as other interconnected markets, meaning that, even where capacity is scarcer in GB than neighbouring markets, the GB spot price may be lower. For instance, cash out prices in GB during the system stress event on 11 February 2012[17] only rose to £268/MWh, whereas prices in France rose to their price cap of €3000/MWh in the following week.

4.26 Market reforms currently being implemented by Ofgem should ensure more efficient dispatch for interconnector capacity in the future. Ofgem’s proposal for cash out reform will ensure that the GB energy price is able to more fully reflect the value of energy imports at times of stress. And the introduction of day ahead market coupling to the GB market will ensure that in the future interconnector capacity is allocated through implicit auctions, as already occurs with a portion of the capacity of the GB-Netherlands interconnector (BritNed), and so mean that interconnector flows will better reflect day ahead price signals. Over a longer horizon we would hope that reforms would ensure interconnector flows match price signals closer to real time to ensure that interconnector capacity is able to respond to events that aren’t foreseen at the day ahead stage (as may increasingly be the case for stress events as we move to a more intermittent system in the future).

4.27 In the modelling in this Impact Assessment we have assumed interconnector capacity does not contribute to security of supply in the first delivery year due to the market failures in paragraph 4.23 above; however the contribution of interconnectors to security of supply increases thereafter due to correction of the market failures increasing the reliability of interconnection as well as additional capacity being built, with the derating factor for interconnected capacity rising to 57% by 2025, in line with Poyry analysis of interconnector capacity derating in an efficient energy market. We have additionally assumed 3GW of new interconnector capacity is brought on to Belgium, Norway and France. It should be noted however that this is a modelling assumption and should not be interpreted as DECC’s prediction for future interconnection or support for particular projects in preference for others.

4.28 It is possible that further interconnector capacity will be built: for example, Poyry analysis[18] modelled a “high interconnection” scenario for DECC in which interconnection provided a derated capacity value of 7GW.

[16] “From Regional Markets to a Single European Market” (2010), http://ec.europa.eu/energy/gas_electricity/studies/doc/2010_gas_electricity_markets.pdf

[17] http://www.nationalgrid.com/NR/rdonlyres/AD95408D-7FFF-4CAB-8EC1-D861AF0D2327/51852/04_Sat_11_Feb_2012.pdf

[18] “Impact of EMR on Interconnector Flows”, December 2012, Poyry https://www.gov.uk/government/consultations/proposals-for-implementation-of-electricity-market-reform

4.29 However the Capacity Market remains vital for GB to attract sufficient investment in GB capacity to maintain security of supply. Even in a high interconnection scenario, modelling suggests the GB market would still need to bring on 21GW of new gas plant between 2018 and 2030. The CM and promoting investment in IC are therefore both necessary and complementary measures to meet the capacity adequacy challenge facing GB over the coming decades.

Exit Criteria for the Capacity Market

4.30 This IA identifies a number of market failures present in the energy-only market that justify the introduction of a Capacity Market. However, as noted, an energy-only market can under certain conditions provide sufficient incentives for investment in capacity – even in a decarbonised power system where thermal plant runs at very low load factors. The Capacity Market is intended to be a transitional measure that will complement measures to strengthen energy market incentives for investment and so allow exit from the mechanism. However it is expected that the Capacity Market will be in place for at least ten years and further for as long as additional capacity remuneration is needed to ensure security of supply.

4.31 Analysis suggests remuneration through the Capacity Market would become less necessary in future at the point that two current features of the energy market (lack of an liquidity and an active demand side) had been adequately addressed:

4.32 Development of greater demand side response**:** The lack of an active demand side in the energy market leads to greater price volatility (as prices in a competitive market jump from the short run marginal cost of the peaking plant to VoLL) and potential for abuse of market power for parties withholding generation at times of stress. So the development of a sufficiently active demand side response in the energy market would help to enable a return to an energy-only market.

4.33 However it may take a long time for a fully active demand side response to develop. In particular it would require greater infrastructure for DSR (such that households are able to turn down load in response to real-time price signals) and it would require that demand is sufficiently responsive (for instance such that it would be rare for prices to rise above £1,000/MWh even in the event of scarcity).

4.34 Improvements to liquidity: Reform of balancing arrangements could help to mitigate concerns around “missing money” in the energy market. However, it is unlikely that cash-out reform would have a large impact in the short term, but is more likely to affect investment decisions in the medium to longer term as the price signals work through the system.

4.35 In theory, as this happens, prices should reduce towards zero in the capacity auction. However this will only happen if investors are able to invest on the basis of uncertain scarcity rents. The move to a single marginal spot price for energy (and possibly a balancing market) could help create a robust reference price around which people could trade financial options (as occurs in Australia and America and as used to happen in GB under the pool). This would involve suppliers paying a steady payment to generators in exchange for a financial hedge against price spikes in the spot market. A liquid options market could enable suppliers and generators to hedge the risk of volatile prices and so help investors build new plant on the basis of uncertain scarcity rents.

4.36 Investment in Interconnection: A greater degree of interconnection could also help to reduce the role of the Capacity Market in future. Interconnection can help with security of supply in a number of ways:

i. It reduces the overall level of investment needed in GB capacity to the extent that interconnected capacity provides ;

ii. It can increase diversity of supply by connecting GB to markets with different plant and technology mixes.

4.37 Given the scale of investment in new capacity needed it is unlikely that greater interconnection alone would enable an exit from the capacity market. However coupled with more effective energy price signals and/or greater DSR, further investment in interconnection should reduce the level of support needed in the Capacity Market to achieve security of supply.

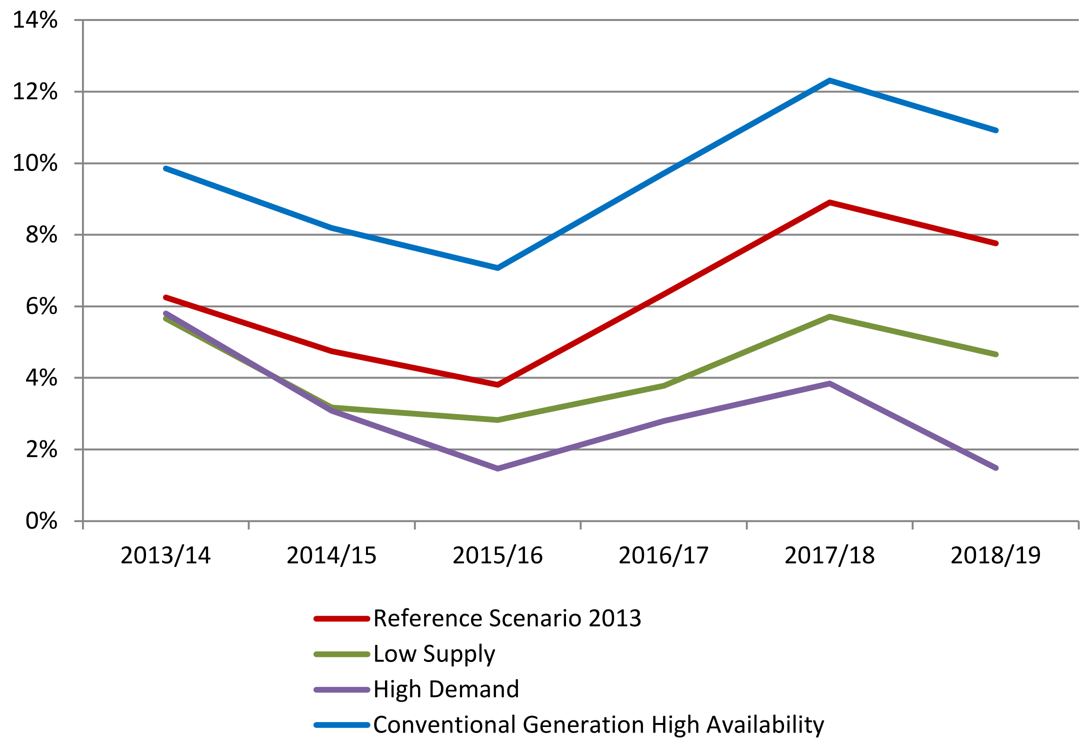
Security of Supply Outlook

4.38 We have looked at security of supply risks both in the short term, particularly 2015/16, by when the Large Combustion Plant Directive will have prompted a number of existing coal plants to retire, as well as the longer term security of supply outlook out to 2030 as the power sector decarbonises. The key factors that affect the security of supply outlook are expectations for peak demand, the contribution of interconnection to security of supply, the level of nuclear life extensions, and expectations for new build decisions and mothballed plants.

4.39 Ofgem produced its annual Electricity Capacity Assessment Report in June 2013, as part of its statutory obligation to review security of electricity supply.[19] The report suggests that the risks to electricity security of supply, in the absence of any additional policy interventions, increase faster towards the middle of the decade than expected in Ofgem's first assessment, published in October 2012. Beyond 2015/16, the risks to electricity security of supply are then expected to decrease primarily due to the impact of falling demand, although the report notes that there is uncertainty over the projected reductions in demand. According to the Reference Scenario, presented in Ofgem's report, de-rated capacity margins are expected to fall from their anticipated level of around 6% this winter to around 4% in 2015/16, before recovering to around 8% by 2018/19.[20]

[19] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013
[20] Ofgem defines the de-rated capacity margin in the Electricity Capacity Assessment as the excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that can in principle be accessible in reasonable operational timelines, i.e. it is not decommissioned or offline due to maintenance or forced outage.

Figure 4: Ofgem estimates of de-rated capacity margins



Source: Ofgem (June 2013)

4.40 Given the significant uncertainties around the evolution of both demand and supply, Ofgem has also developed a number of sensitivities. A full list of these and the assumptions which underpin them can be found in their report. The derated capacity margins that Ofgem forecast in 2015/16 are similar to the levels experienced in 2005/6. While this was a tight year for National Grid to manage, there were no customer disconnections. We recognise however that the generation mix in 2005/06 is not the same as the mix in 2015/16, implying different risks to security of supply.

DECC's energy system modelling

DECC's modelling of the energy system is based on DECC's in-house Dynamic Dispatch Model (DDM). This analysis is consistent with the Energy and Emissions Projections published on 17 September 2013 and the technology cost, fossil fuel price assumptions underlying it.

The EMR package modelled includes a low-carbon instrument (the CfD) and a Capacity Market, combined with an Emissions Performance Standard (EPS). The analysis includes existing policies such as the Renewables Obligation (RO) and support for early-stage CCS projects. This IA makes some detailed assumptions about the implementation of these policies, in particular that the 2020 renewables target is met through domestic deployment, that there are two early stage CCS projects.

The modelling makes assumptions about the trajectory for power sector decarbonisation beyond 2020. A decarbonisation trajectory of 100gCO_2/kWh in 2030 is used in the modelling in this Impact Assessment to ensure consistency with previous IAs on capacity mechanisms. Further details on the modelling assumptions are set out in Annex G.

DECC made a number of changes to DDM inputs for this Impact Assessment:

- The model has been updated to account for the use of a demand curve and loss of load expectation in the auction.
- The modelled price cap is now £6,000/MWh to be consistent with Ofgem's draft policy decision on cash out, and assumes a VoLL of £17,000/MWh for calculating the cost to consumers of power cuts.
- The model assumes 3GW of additional interconnector capacity is built, and that the derating factor for interconnector capacity rises linearly from zero in the first CM delivery year up to 57% in 2025.
- We assume 2GW additional DSR capacity becomes available by 2025. This is based on analysis of the experience of DSR in the Pennsylvania Jersey and Maryland (PJM) capacity market in the US since the introduction of forward capacity auctions there[21].
- The build constraints on new gas build have been revised: It is now assumed that up to 3GW of new OCGTs can be built in a given year. However the costs of new OCGT build now rise after 1.5 GW of new OCGT are built. The cost assumptions are consistent with Parsons Brinckerhoff estimates of central and high capital expenditure involved in new build.[22] This is consistent with the average rate of new gas build under the "dash for gas" in the 1990s.

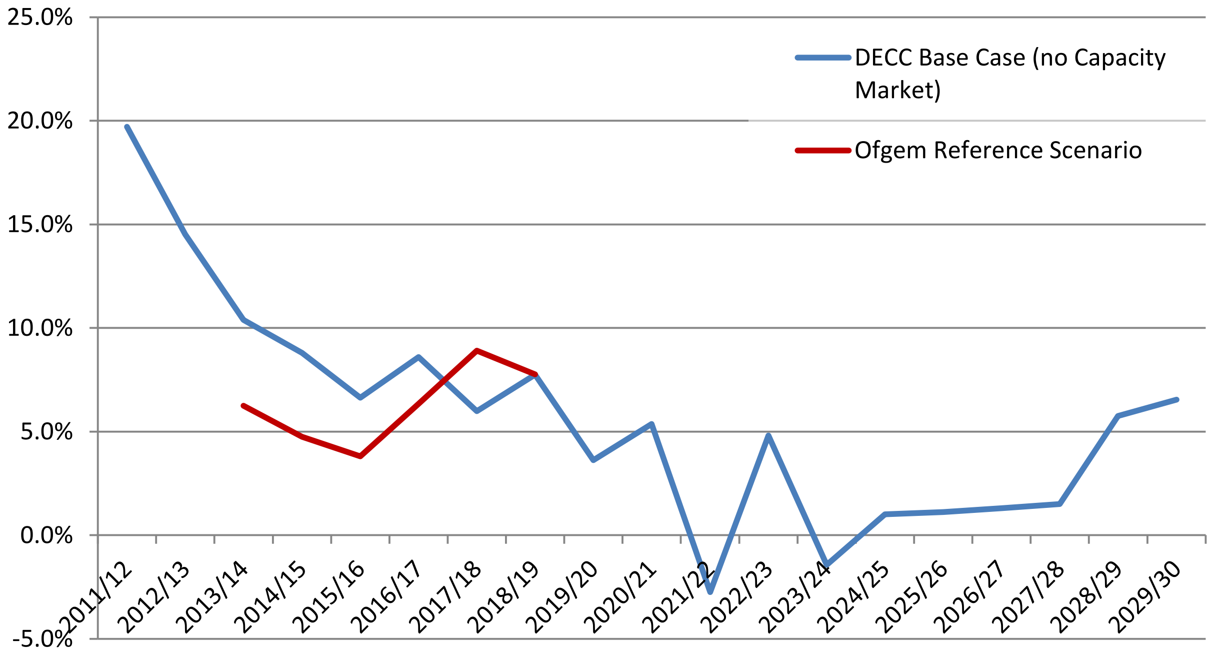
[21] PJM has led to around 12GW of DSR capacity being contracted. This could be equivalent to around 4GW of DSR in the GB market (which is a third of the size of PJM). However there is already estimated to be around 2GW of DSR capacity – incentivised through TRIAD - that is already accounted for in the peak load profiles. We have therefore assumed that the level of DSR in GB grows gradually from 2GW in the first delivery year to 4GW in 2024/25.

[22] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223634/2013_Update_of_Non-Renewable_Technologies_FINAL.pdf

4.41 We have modelled security of supply out to 2030 if no Capacity Market is introduced under the 'DECC base case' scenario. This is in line with DECC's published projections of annual demand and fossil fuel prices[23] and assumes that other parts of EMR are introduced from 2016/17, including the FiT-CfD to bring on investment in low-carbon capacity, and that cash-out is reformed to be able to rise to £6,000/MWh at times of stress. Consistent with previous publications, the targeted level of decarbonisation in the power sector is around 100gCO_2/kWh in 2030.

4.42 We compare these runs in the chart below with the base case scenario in Ofgem's Electricity Capacity Assessment out to 2018/19.

Figure 5: Long-term estimates of de-rated capacity margins



Source: Ofgem, DECC analysis

4.43 In our latest analysis using the DDM, de-rated margins in the base case continue on a downward trend, as it has been doing in the past few years, and continue to remain dangerously low in the 2020s. This is largely attributed to the retirement of a significant proportion of conventional thermal plant capacity between now and 2023, and an insufficient amount of reliable base-load generation brought forward to replace this capacity. De-rated margins do not fall to uncomfortably low levels (sustained below 5%) until the early 2020s so long as we are not exporting at times of system peak.

4.44 The de-rated capacity margin in Ofgem's Electricity Capacity Assessment for 2015/16 is lower than DECC's projections.[24] A large part of the reason for this is the treatment of interconnectors. Both Ofgem and DECC assume exports to Ireland at times of winter peak of around 0.75GW, but Ofgem treats the interconnection with the Continent at float, (i.e. neither importing nor exporting) while DECC assumes 0.75GW of imports from the Continent.

[23] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx
[24] Detail on the differences between the Ofgem and DECC short-term security of supply outlook are contained in the Government's response to Ofgem's Electricity Capacity Assessment. This is found in Annex A of the Statutory Security of Supply Report 2013, published October 2013.

4.45 DECC's assumptions on net imports reflect historic patterns of interconnector flows. However, it is difficult to predict future patterns of interconnector flows because capacity margins have been wide for the past six years, Ofgem's reforms of cash out will increase incentives for interconnectors to flow into GB at times of stress, and the rules governing interconnector flows are currently being revised to ensure interconnector flows more closely reflect price differentials in the day-ahead market ("market coupling").[25]

4.46 Ofgem provides a range of sensitivities for interconnectors. For example the Ofgem analysis shows that if we assume that we are *importing* through our interconnectors with France and the Netherlands at times of winter peak then, even if we are exporting fully to Ireland, de-rated margins in 2015/16 would be around 9%.

4.47 We believe that interconnectors make a positive contribution to security of supply at times of system stress. However, the contribution of interconnectors to security of supply would be further strengthened if cash-out were reformed so GB prices better reflected scarcity as this would help ensure the interconnector flows in the economically efficient direction at times of scarcity in GB.

4.48 Both the projections from DECC and Ofgem of tightening capacity margins imply an increased likelihood of controlled load shedding and voltage reductions in the future. This is illustrated below for 2015/16 for DECC's base case and Ofgem's reference scenario and high demand scenario. The relationship between capacity margins and estimates of the probability of lost load are inferred from Ofgem's Electricity Capacity Assessment for the DECC base case.

Figure 6: Probability of load shedding under different scenarios[26]

	De-rated capacity margin in winter 2015/16 (%)	**Likelihood of some customer disconnections[27]**
DECC base case	6.6	~1 in 50 years
Ofgem reference scenario	3.8	1 in 12 years
Ofgem high demand	1.5	1 in 4 years

Source: DECC modelling

4.49 However, long-term projections of capacity margins are highly uncertain because of the difficulties in anticipating, for example, the level of electricity demand, wind patterns, generator reliability and the contribution of interconnectors in periods of system stress. Moreover, the relationship between loss of load expectation and de-rated capacity margin is not linear.

4.50 The decision to invest in generation capacity in the DECC model is based on the simplifying assumption that investors have perfect foresight of energy demand five years ahead. The consequence of this assumption is that investors can gauge precisely peak demand and build just enough capacity to meet it in most circumstances. But if peak demand is uncertain, the economically efficient capacity margin is likely to be greater than that under perfect foresight because there is an increased likelihood of energy scarcity and the associated jump in energy price to its scarcity value. Therefore, a perfect energy-only market would be likely to bring forward a higher capacity margin than that forecast by the DECC model without a Capacity Market.

[25] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52007PC0528:EN:NOT
[26] We have inferred the risks to security of supply in the DECC analysis using the relationship between Capacity Margins and risk measures, contained in Ofgem's Electricity Capacity Assessment. Note that this is therefore not a modelled output from the DECC model. We note that the relationship between the capacity margin and the risk measures is not one-for-one as it depends on the exact generation mix. Therefore the estimates of risk in the DECC scenario is illustrative.
[27] The likelihood of some customer disconnections gives the probability of some customers facing disconnection after the system operator has made full use of the mitigating measures available to it, including requesting emergency services from Britain's interconnectors. Industrial customers would be disconnected before household.

4.51 The key points to take away from looking at the range of modelling we have undertaken is that:

a) Risks to electricity security of supply are increasing faster towards the middle of the decade than previously forecast, underlining the credible risk of a capacity problem in the medium-term;

b) However, the further into the future we try to assess future levels of capacity, the less certainty we have about the outcome.

5 Options Appraisal

5.1 The previous Impact Assessment published alongside the Energy Bill in November 2012[28] set out the evidence for the choice of a Capacity Market as the lead policy option to mitigate risks to electricity security of supply. A summary of the evidence informing that decision is presented here, but detailed analysis of other potential options is not included.

Basecase

5.2 The baseline against which we are comparing the options for the Capacity Market assumes that a number of policy options that form part of the Electricity Market Reform package have been implemented, including the FiT CfD, Emissions Performance Standard and Carbon Price Floor. It also assumes reform to the cash-out regime so that the scarcity value of electricity reflects the Value of Lost Load (VoLL).

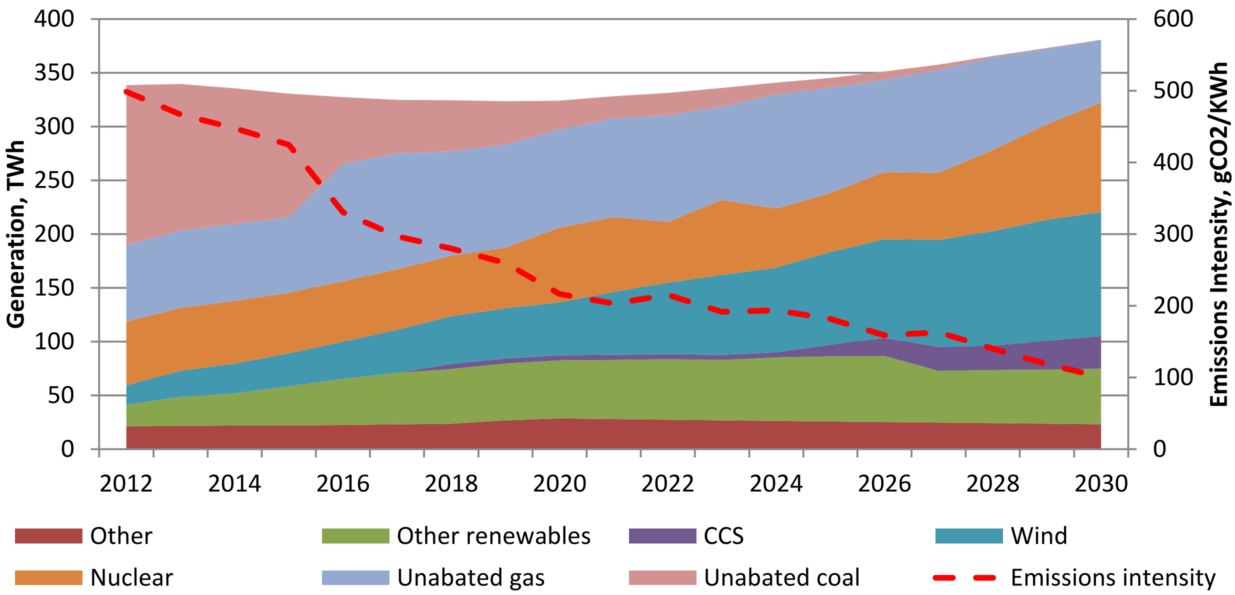
5.3 The basecase also has a number of important characteristics:

i. <u>Decarbonisation</u>: As for previous IAs, **t**he basecase assumes that the power sector decarbonises to an average level of 100gCO_2/kWh in 2030. This entails a significant increase in intermittent and less flexible generation (predominantly wind and nuclear), as shown in Figure 7 below.[29]

ii. <u>Retirement of existing plant</u>**:** Around a fifth of capacity available in 2011 is expected to close over this decade.

iii. <u>Missing Money</u>**:** We have assumed a wholesale market where prices can rise to a value of £6,000/MWh when there is scarce capacity. This is consistent with Ofgem's draft policy decision to price in involuntary load shedding at £6,000/MWh from 2018.

Figure 7: Type and carbon intensity of electricity generation in the basecase



Source: DECC modelling

[28] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf

[29] Analysis for the Carbon Plan suggests that cost-effective pathways to 2050 include decarbonising the power sector to around 100g CO_2/kWh in 2030. The Government will take a decision on a decarbonisation target for the power sector once the CCC has provided advice on the 5th carbon budget.

Capacity Market

5.4 A Capacity Market pays capacity providers for capacity, which is defined as delivering energy when needed. Capacity providers offer capacity into the Capacity Market and, if successful in the auction, receive a capacity payment. They may also be eligible for long-term contracts if they are new plant. At times of system scarcity, when the System Operator is forced to issue load-shedding due to insufficient capacity, any capacity providers that were not generating will be fined an administratively-set penalty.

5.5 The detail of how the Capacity Market will work is set out in the Consultation. However the high level features of the mechanism are summarised in the box below:

Features of a Capacity Market:

1. **Amount of capacity**: Ministers decide the amount of capacity for which agreements are to be auctioned based on analysis from the System Operator on the amount needed to meet an enduring reliability standard
2. **Eligibility and auction:** The CM will be technology neutral and all existing and new forms of capacity (including demand side) will be eligible to participate, except for capacity receiving support through low-carbon support schemes such as the Renewables Obligation and FiT CfD. Providers will offer capacity in a pre-qualification process run by the system operators. Pre-qualified capacity will then enter competitive central pay as clear auctions, also run by the System Operator. Successful bidders will be awarded 'capacity agreements.' Existing plants will have access to one year contracts, refurbishing plant to three year contracts, and new plant to ten year contracts.
3. **Secondary market:** Participants will be able to hedge their position through secondary trading.
4. **Delivery:** Capacity providers will receive payment for capacity in the delivery year. In return they will be obliged to deliver energy in periods of system stress and will be financially penalised (following the publication of a CM warning) if they do not deliver in stress periods.
5. **Payment:** The costs of capacity agreements will be met by suppliers based on their market share at times of peak demand.

Option assessment

5.6 A Capacity Market is appraised based on both qualitative and quantitative analysis. The quantitative analysis (in Section 6) shows that a Capacity Market has a net benefit where there is missing money.

5.7 However the quantitative estimate does not take into account a number of significant factors. The qualitative assessment provides a more comprehensive assessment of the options.

6 Quantitative options assessment

6.1 The value for money assessment of the Capacity Market were assessed quantitatively in the following ways:

i. Energy system impact
ii. Institutional impacts
iii. Impacts on businesses

6.2 In addition to the value for money assessment, we have quantified the potential impacts of a Capacity Market on security of supply and on energy bills.

Auction Modelling

The auction format for the Capacity Market is pay-as-clear, where each party taking on an agreement is paid the clearing price in the auction – set at the price of the most expensive unit accepted. This auction format should lead to the lowest costs for consumers. The rationale and analysis of this choice of auction format is set out in Annex A.

We have assumed in the modelling that under a pay-as-clear auction parties bid in their true cost. However we recognise that there are gaming risks whereby parties may attempt to exercise market power to raise the clearing price. However we think the risk of overpaying in the auction has been largely mitigated through the detailed design choices:

i. The auction is held four years out to allow sufficient time for new entrants to build capacity if successful in the auction
ii. A sloping demand curve will be set for the auction so that less capacity is bought if the price is very high
iii. A price cap in the auction will provide protection against the risk of an uncompetitive auction delivering a high price
iv. The capacity value of plants in the auction will be administratively determined, and where a plant chooses to "opt out" of the auction the demand in the auction will be lowered. This prevents existing plants from withholding capacity to drive up the price
v. Existing plant will be assumed to be a "price-taker" by default. This means they will only be able to bid in up to a low level. Alternatively they can act as a price maker if they provide a Board-approved justification for why they need a higher price, and this can be used as evidence by Ofgem as part of an investigation into breach of licence.

Further analysis of gaming risks is set out in Section 7 and policy design choices to mitigate gaming risks is explained in further detail in Annexes A-D. The Gaming Study undertaken by independent consultants Charles River Associates provides further validation of this approach.

Energy system modelling

6.3 Energy system modelling of the electricity market provides a view of the costs and benefits of a Capacity Market, although there are significant caveats associated with the results. The methodology for the modelling is set out further in Annex G. The modelling shows a net benefit of £0.4bn over the period 2012 – 2030[30] compared to the counterfactual of an energy-only market.

What capacity margin have we targeted in the modelling?

- Government has proposed a reliability standard for the Capacity Market of 3 hours loss of load expectation (LOLE) per year. This means that we would expect on average three hours per year in which there supply is insufficient to meet demand, forcing the System Operator to enact involuntary load shedding – leading to voltage reductions ("brownouts") and possibly customer disconnections ("blackouts").
- A LOLE of 3 hours per year is equivalent to a derated capacity margin of around 4%.
- However the level of capacity required is subject to significant uncertainty up to four years out. Given that the relationship between capacity margins and LOLE is asymmetric – i.e. LOLE increases faster as the capacity margin falls towards zero. So to procure a LOLE of 3 hours per year, a target capacity margin of around 8% is needed prior to the four-year ahead auction.
- This target then informs the demand curve – with the capacity auction buying up to 1.5GWs above or below the target depending on how far the capacity price is from Net CONE (estimated at £30 in the DDM).
- Modelling in the DDM assumes investors have perfect certainty about demand up to five years out – so concludes that that 8% capacity margin targeted is an overestimate of the capacity needed. This means that the DDM may overestimate the costs of the Capacity Market as it assumes an inefficiently high capacity margin is sought.

6.4 The costs modelled include the capital costs of the additional capacity incentivised by the Capacity Market, as well as the fuel and carbon costs associated with the additional capacity. The security of supply benefits modelled are reductions in unserved energy. This is mostly from reductions in involuntary energy unserved – i.e. lower blackouts and forced voltage reductions.

6.5 Benefits modelled come from reduced levels of forced outages. These are modelled below assuming a value of lost load (VoLL) of £17,000/MWh. The average household uses about 0.7KWh at times of peak demand[31], so a £17,000/MWh assumption of VoLL implies that the average domestic household would pay around £12 to avoid being disconnected for an hour. Uncertainty around the VoLL is considered further in the sensitivity analysis.

[30] These estimates exclude the administrative costs of the Capacity Market, which are considered later in this section. The costs and benefits have been discounted to present values. Note that all costs occur between 2023 and 2030 because that is when a Capacity Mechanism would be triggered under the scenario.
[31] Energy Saving Trust report, "Powering the nation: Household electricity-using habits revealed" (2012)

6.6 Figure 8 below shows the results of energy system modelling in terms of the impact of the Capacity Market relative to the base case and how this breaks down into its various components. This does not capture the wider monetised costs – the administrative burden on companies created by new regulation and the institutional costs to delivery bodies of running the mechanism. These are included in the Net Present Value Assessment in Figure 16.

Figure 8: Energy system costs and benefits (excluding admin costs)

Energy System Costs and Benefits of a Capacity Market 2012-2030	**£m (2012 prices)**
Carbon cost savings[32]	-854
Generation cost savings[33]	-176
Capital cost savings[34]	1415
System cost savings[35]	-1184
Interconnection cost savings[36]	-44
Unpriced carbon savings (appraisal value)	0
Energy System Cost Savings	**-843**
Energy System Benefits (Reduction in unserved energy[37])	**1,290**
Change in Consumer Surplus	-10,385
Change in Producer Surplus	10,315
Change in environmental tax revenue	517
Change in non-internalised social costs of carbon [38]	0
Change in Net Welfare	**447**

Source: DECC modelling

6.7 The result that a Capacity Market has a net benefit in the modelling is driven by the assumption of missing money – i.e. that the energy-only market would fail to bring forward sufficient investment in capacity as prices would not be able to rise to the value of lost load and investors would fail to invest on the basis of uncertain and infrequent scarcity rents.

[32] The total carbon emissions for a year are multiplied by the appraisal value in that year to determine the total carbon costs for that year. An increase in carbon cost, other things remaining constant, leads to a decrease in net welfare.
[33] These are the sum of variable and fixed operating cost savings. The carbon component of the variable operating costs is removed – the EUA price is accounted for in the carbon costs, and the carbon price floor cost is a transfer between producers and the Exchequer so appears in the surplus calculations but not in the net welfare. An increase in generation costs leads to a decrease in net welfare.
[34] All new build is included (plants built by the model, and pipeline plants). Construction costs are annuitized over the economic lifetime of the plant, based on the hurdle rate. An increase in capital costs leads to a decrease in net welfare.
[35] These are the sum of the costs savings from building and operating the electricity system (TNUoS and BSUoS costs). These costs are calculated by National Grid models, based on DDM outputs. An increase in system costs leads to a reduction in net welfare.
[36] This measures the cost savings from electricity imported via the interconnectors net of the value of exports. If imports are greater or wholesale prices are higher than the cost of imported electricity is increased, scored as a reduction in net welfare.
[37] The estimation of Expected Unserved Energy takes plant outage probabilities, technology mix, demand and historical wind data and uses stochastic modelling to estimate a probability distribution of energy unserved. The mean unserved energy is valued at VOLL (defined by the user, assumed to be £17,000/MWh). An increase in unserved energy leads to a decrease in net welfare.
[38] 'Change in non-internalised social costs of carbon' values the impact on UK society of changes in greenhouse gas emissions, less the value of a European Union Allowance (EUA). The EUA value is subtracted from this item in the distributional analysis as the value of the EUA is reflected elsewhere in the 'Change in producer surplus' line.

6.8 The modelling shows the Capacity Market leading to a reduction in capital costs and an increase in generation. This is because in the modelling the Capacity Market brings on less investment in new CCGT build than an energy-only market, though a higher capacity margin overall (with the additional capacity coming from OCGT – which has lower capital costs but higher generating costs). The modelling result for what technology is brought forward by the Capacity Market is sensitive to a range of assumptions, such as the degree to which CCGTs can charge a markup in the energy market as well as the capital costs for new OCGT build.[39] However while there is uncertainty around the mix of plant that will come forward through the Capacity Market, the mechanism design should ensure that the market has optimal incentives to bring forward an efficient plant mix.

6.9 VoLL is particularly hard to estimate as it includes both the private costs to individuals from blackouts (which differs significantly between consumers and at different times of the year) and the wider social costs of blackouts, such as harm to Britain's reputation as a positive environment for investment. Studies indicating a plausible range of between £10,000 and £30,000/MWh,[40] equivalent to a range of £7-£21 cost of disconnection per hour for an average household. The assumption of VoLL can have a significant impact on the size of total benefits and can affect whether a Capacity Market has a net cost or benefit.[41] The size of benefits under different assumptions about VoLL is illustrated below:

Figure 9: Sensitivity analysis around energy system benefits from a Capacity Market

NPV 2012-2030, £m (2012 prices)	**£10,000 VoLL**	**£17,000 VoLL**	**£30,000 VoLL**
Benefits from reduction in unserved energy	759	1,290	2,276

Source: DECC modelling

6.10 Modelling is likely to understate the benefits of a Capacity Market as it assumes an unrealistically perfect market where investors have perfect certainty of demand when choosing whether to build a new plant. However the range in benefits if you change the assumption of VoLL illustrates that the impact of a Capacity Market is much more beneficial if there is a significant "missing money" problem in the market and if that problem leads to the market failing to bring forward sufficient capacity.

6.11 We have also considered the impact of the Capacity Market against a counterfactual where the power sector decarbonises on an alternative trajectory, shown in figure 10 below.

Figure 10: NPV of Administrative Capacity Market under different decarbonisation scenarios

NPV 2012-2030, £bn (2012 prices)	**Decarbonisation target in 2030 (gCO_2/kWh)**		
	50	**100**	**200**
Capacity Market	1.9	0.2	-0.7

Source: DECC modelling

6.12 Analysis suggests that if the power sector decarbonises to 200gCO2/kWh in 2030 there is a net impact of -£0.7bn from an Administrative Capacity Market. Under a 50gCO2/kWh scenario, this impact changes to +£1.9bn.

[39] Under previous analysis (November 2012 CM Impact Assessment) using OCGT capital costs based on smaller-scale aero-derivative generators, the modelling resulted in new gas build being predominantly from CCGTs rather than OCGTs.
[40] Oxera report "What is the optimal level of electricity supply security", (2005)
[41] DECC is commissioning further analysis to strengthen evidence about the Value of Lost Load, which will report later in 2013

6.13 This suggests that the faster the pace of decarbonisation, the greater the net benefit of the Capacity Market – as decarbonisation leads to thermal plant running less and so exacerbates the impact of the “missing money” market failure in an energy-only market. This is consistent with the results in the May 2013 IA.

6.14 It should be noted that even under a 200g scenario the Capacity Market has an important role to play in mitigating the risk that an energy-only market could lead to underinvestment in capacity. This is because there is a significant need for investment in new thermal capacity due to volume of capacity that needs to retire over the next decade and because, even under a 200g scenario, new gas plant will still be running at lower load factors than has historically been the case. A Capacity Market in this scenario ensures that sufficient capacity is brought forward to ensure security of supply and helps to reduce risk for investment in new capacity, potentially reducing the financing costs for new build and attracting a wider range of investors to the market.

Administrative costs to Business

6.15 A Capacity Market is likely to create an administrative burden for businesses as they start participating in a new market. This has been estimated based on the assumption that companies participating in capacity auctions will require one or two members of full time staff, costing around £50,000 each and that the number of businesses affected is estimated to be between 77 and 277.[42] In the base case we have assumed the mid-way point in the estimated cost range (i.e. £13m per year) to be the best estimate of the administrative burden of a Capacity Market. This cost is incurred every year from 2013, i.e. a year before the assumed first auction in 2014, but in the first five years (i.e. 2013-17) it is assumed that costs are double as the mechanism is implemented. Given a 2014 first auction date, the present value of this cost is now estimated as £231m.

Institutional costs

6.16 The institutional costs associated with delivering a Capacity Market are estimated to be around £13m to set up (to cover one off costs such as IT systems) and £2m per year to run (recruitment, building preparation, implementation, facilities, and maintaining IT systems). This implies a discounted cost to 2030 of £32m.

Distributional impacts

6.17 The energy system modelling shows a transfer from consumers to producers in the basecase, with consumers paying through their energy bills for capacity payments and with many generators receiving significant infra-marginal rents[43] for their plant. The cost to consumers of capacity payments is only partly offset through lower prices in the wholesale electricity market. The reason in practice we would not expect the dampened wholesale price to fully offset the cost of the capacity payments is that a Capacity Market is compensating for the effect of 'missing money' and so an increase in overall payment could be required to incentivise new capacity to come forward (see Section 4 for a fuller explanation of 'missing money'). However if a stable capacity payment can bring down the financing costs for new capital, then a Capacity Market could have a lower impact or even reduce bills for consumers.

6.18 Modelling shows an increase in the average annual domestic electricity bill of £13 in the base case in 2016-2030. This is equivalent to a 2% average increase in domestic bills. A Capacity Market is not expected to have a significant impact on bills until then, as it is not bringing on new capacity. The table below shows the impact of a Capacity Market on the bills of different groups – domestic consumers, non-domestic consumers and energy-intensive industries (EIIs). Figure 12 illustrates the changes in domestic consumer electricity bills each year in the base case.

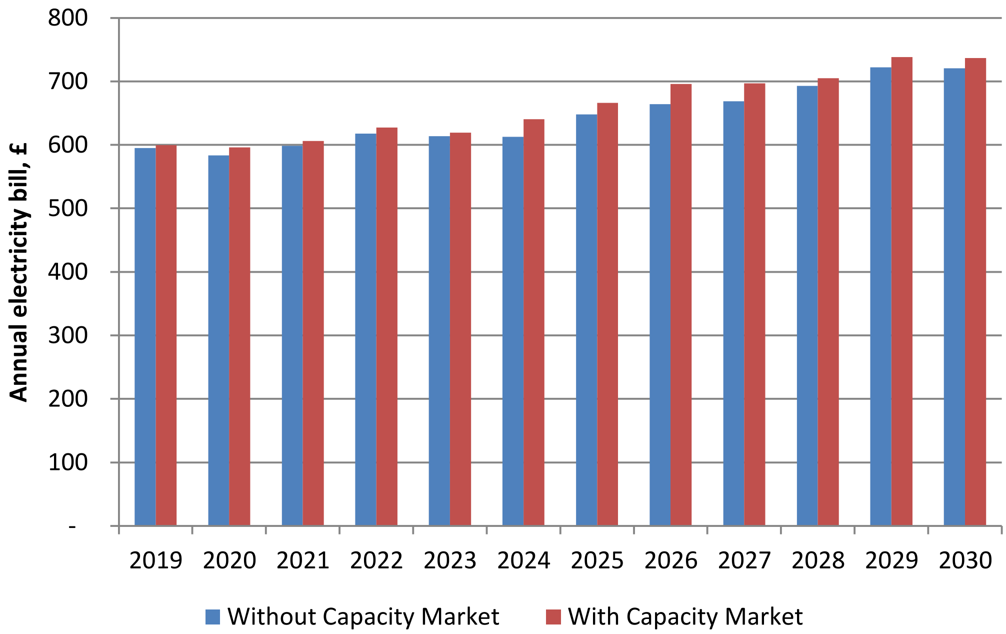
[42] The lower figure comes from 5.11 in DUKES and is the number of major power producers. The upper figure represents the current number of Balancing and Settlement Code parties.
[43] I.e. they are paid the clearing price in the auction rather than the price they bid.

Figure 11: Electricity Bill Impacts

Bills in 2012 prices	**Typical bill without CM**	**Change with CM (%)**
Domestic, (£)[44]		
2011-2015	567	0.0%
2016-2020	593	0.5%
2021-2025	618	2.2%
2026-2030	694	3.0%
Non Domestic (£000) [45]		
2011-2015	1,100	0.0%
2016-2020	1,300	0.5%
2021-2025	1,400	3.7%
2026-2030	1,500	4.1%
Energy Intensive Industry, (£000) [46]		
2011-2015	7,900	0.0%
2016-2020	10,300	0.7%
2021-2025	11,800	4.2%
2026-2030	12,400	4.7%

Source: DECC modelling

Figure 12: Change in Domestic Electricity Bills in the Base Case



Source: DECC modelling

[44] Results for the household sector are based on a representative average electricity demand level for households, derived from historical total domestic consumption, and is set at 4.5MWh of electricity before policies.
[45] Non-Domestic users are based on the consumption of a medium-sized fuel user in industry, with an electricity usage of 11,000 MWh, and includes the effects of the CRC. Percentage impacts on the bill are expected to be the same for non-CRC users.
[46] For the energy-intensive industry sector, illustrative users consume (before policies) 100,000MWh of electricity.

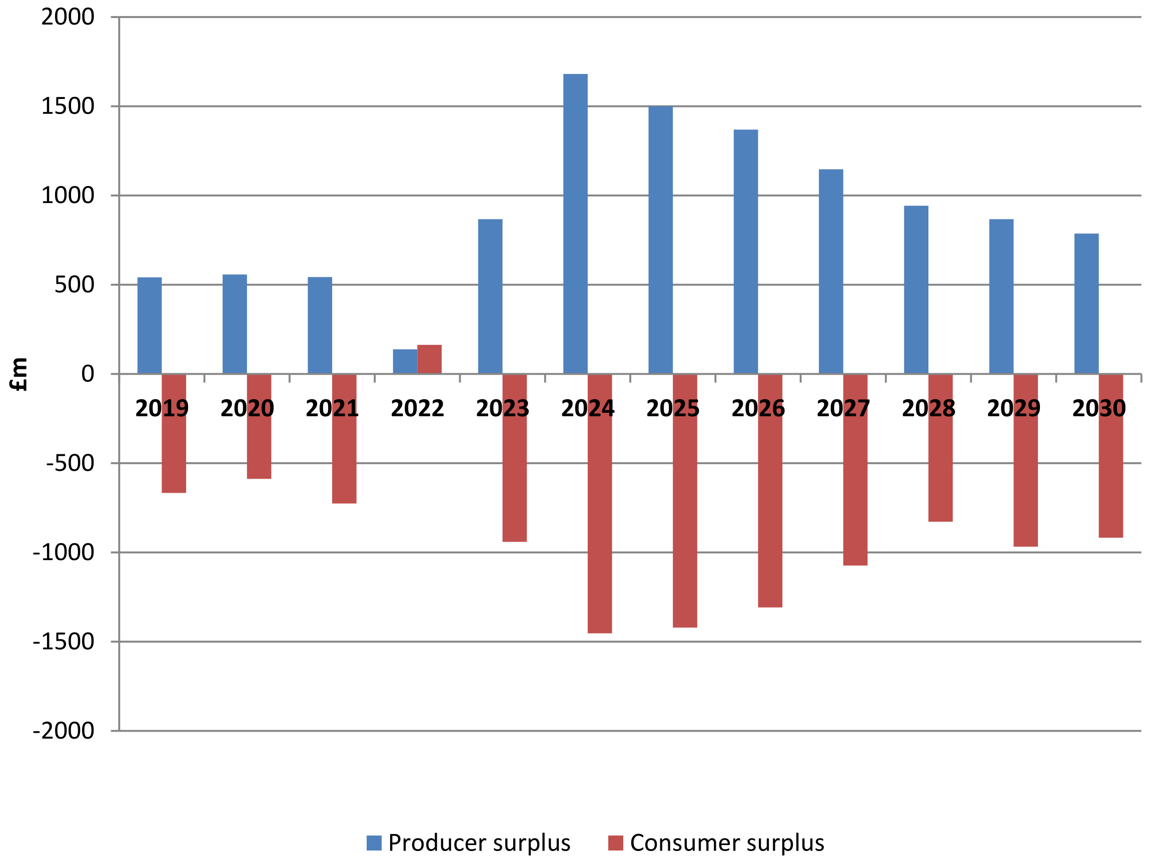
6.19 There are a range of other factors that could significantly affect the economic impact of a Capacity Market which are not reflected in the modelling. These include:

i. The degree to which providing a stable capacity payment reduces risks for investment in new capacity and therefore brings the financing costs down.
ii. The degree of liquidity/competition in the capacity auction.
iii. Whether the electricity market is reformed so that prices can rise to reflect scarcity, and whether investors will value potential "scarcity rents" when pricing into the Capacity Market
iv. Whether a central determination of the "optimal" level of capacity needed four years ahead is more or less successful than the market estimating how much additional capacity is needed.

6.20 Given these uncertainties, figures should therefore be treated with caution. However the Capacity Market has been designed to reduce the impact on bills by ensuring a competitive outcome in the auction and ensuring that only the economically efficient level of capacity should be procured.

6.21 As well as the impact on consumers of electricity there is also an impact on the generation companies which produce electricity. Figure 13 shows the producer surplus resulting from the introduction of a Capacity Market. The Capacity Market increases producer surplus because it compensates generators for the "missing money" in the existing energy-only market and therefore provides some infra-marginal rents for existing capacity[47].

Figure 13: Change in producer and consumer surplus as a result of a Capacity Market



Source: DECC modelling

[47] i.e. capacity that would have been present without a capacity payment

Size of capacity revenues

6.22 The tables below shows the gross capacity revenues associated with a Capacity Market as well as the modelled prices:

Figure 14: Prices in the Capacity Market, £/KW year

(2012 prices)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capacity Prices (£/KW)	16	21	20	21	23	58	31	34	31	29	30	30

Figure 15: Gross capacity revenues through a Capacity Market, £m

(2012 prices)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capacity Payments (£m)	900	1,100	1,000	1,000	1,100	2,600	1,600	1,700	1,600	1,600	1,600	1,600

6.23 Capacity prices differ from the central estimate of Net CONE for a number of reasons:

i. Sunk costs: In some years additional capacity is not needed and the price is set by existing plant, which tends to set a lower price than new plant.

ii. Ancillary service payments: Plants are assumed to receive some rewards for ancillary services offered (£10/KW for CCGT and £15/KW for OCGT). It is recognised that there is significant uncertainty around these estimates – for instance whether they impose an opportunity cost on generators (i.e. they forego the opportunity to make energy market rents) or whether they are for services not valued through the energy market (such as for mitigating locational constraints or providing very flexible generation).

iii. Build constraints: It is assumed that it is only possible to build 3 OCGTs in a given year at the central estimated cost of new entry. Beyond that the costs of projects will increase – for instance as investments are made on more expensive sites. Furthermore the model constrains build of OCGT at 6 plants, with further build having to come from CCGTs, which can be significantly more expensive (though also have low running costs). The relaxed OCGT build constraints are in line with build of new gas plant under the “dash for gas”, and the increased costs of OCGT as more plants are built are based on high capital cost estimates provided by Parsons Brinckerhoff.[48]

6.24 Under a Capacity Market the gross capacity revenues that go to providers of capacity are modelled to be up to between £900m and £2.6bn per annum. It should be noted however that projections of the capacity revenues are highly uncertain and are sensitive to assumptions around how competitive the auction is, the cost of new entry, and whether investors value scarcity rents when choosing how to price into the capacity auction. In theory as cash out is fully reformed and the market learns to invest on the basis of scarcity rents the capacity price should tend towards zero under a Capacity Market.

[48] https://www.gov.uk/government/publications/parsons-brinkerhoff-electricity-generation-model-2013-update-of-non-renewable-technologies

Net Present Value assessment

6.25 Modelling suggests that the Capacity Market has a net benefit in the basecase. This is because an energy-only market with missing money leads to an inadequate level of investment in new capacity, resulting in a significant level of lost load. The benefit of greater reliability presented by the Capacity Market outweighs the cost of the additional capacity as well as the administrative costs on participants and the institutional costs of delivering the Capacity Market.

Figure 16: Net present value of an Administrative Capacity Market

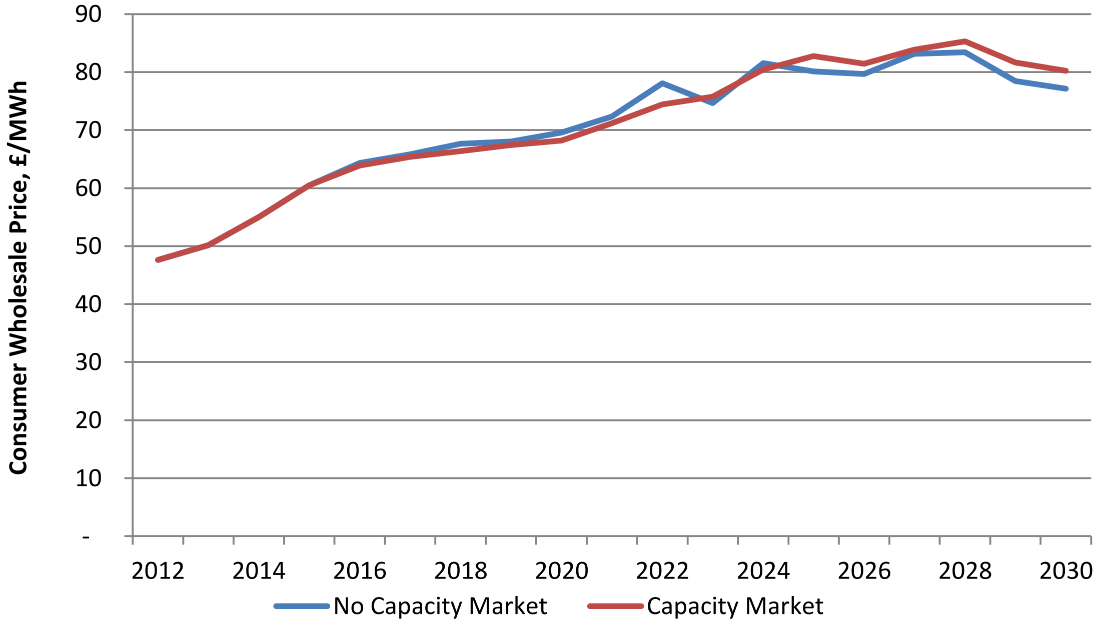
Costs, benefits	**£m, 2012-2030**
Energy system costs	843
Institutional costs	32
Administrative costs	231
Total costs	**1107**
Total benefits	**1,290**
Change to consumer surplus (energy system)	-10,385
Change to producer surplus (energy system)	10,315
Change to environmental tax revenue	517
Change to non-internalised social costs of carbon	0
Change in Net Welfare	**183**

Source: DECC modelling

Impact on wholesale market

6.26 Modelling shows that the Capacity Market leads to an increase in wholesale prices in some years but a decrease in wholesale prices in other years. This is shown by figure 17 below.

Figure 17: Wholesale electricity prices, £/MWh



Source: DECC modelling

6.27 The DDM finds that the additional capacity brought on by the Capacity Market is from OCGT plants, and that the Capacity Market brings on less new CCGT than would be the case under an energy only market. OCGT has higher short run marginal costs than CCGT and so will run less and set a higher electricity price when they do run. The result that the Capacity Market brings on OCGT rather than CCGT and so does not dampen wholesale prices is sensitive to a range of assumptions, particularly around the capital costs of OCGTs and the degree to which tighter margins under an energy-only market would give generators greater market power and so enable them to demand higher prices in the wholesale market.

6.28 However there is uncertainty around the impact of the Capacity Market on wholesale prices and the analysis is sensitive to a number of other results, such as the degree to which an energy-only market would bring on adequate capacity margins, the technology mix of the capacity brought on by a Capacity Market, and how generators would price in an energy-only market with tighter capacity margins. For instance, if the Capacity Market brought on more CCGTs rather than OCGTs then a downward effect on wholesale prices would be expected as this new plant would push other less efficient plant down the merit order. Moreover, there is uncertainty around the degree to which an energy-only market would bring on sufficient new capacity or how generators might affect their pricing strategy in the wholesale market if margins tightened significantly. Experience from the Californian energy crisis in 2001 provides some instructive lessons about wholesale prices in a market with tight capacity margins: While the underlying causes of this event[49] may not be the case in the UK, this event showed that where an energy only market leads to underinvestment in new capacity then wholesale electricity prices can increase markedly as generators become more able to exercise market power in the wholesale market.[50] So the introduction of a GB Capacity Market provides a hedge against the risk of high wholesale prices caused by tight capacity margins.

6.29 Nevertheless we expect that in reality the effect of the Capacity Market on wholesale prices will be limited: The Capacity Market does not impose any caps or restrictions on pricing in the energy market (unlike the Irish energy market (the SEM), where participants are required to bid in to the energy market at their short run marginal cost), and participants will only seek to recover through the Capacity Market the proportion of their fixed costs that they cannot earn through selling their energy in the energy market.

Conclusions from quantitative modelling

6.30 Quantitative modelling provides useful insights into the overall impact of the Capacity Market, namely the value of the greater reliability it provides and the cost of the additional capacity.

6.31 However the results are sensitive to a number of assumptions made – such as the Value of Lost Load, or to investors' ability to invest on the basis of infrequent and uncertain scarcity rents.

6.32 There are also limitations to the DDM's ability to perfectly reflect how investment decisions would occur in reality: The modelling does not capture the full range of uncertainty over future demand and so may overestimate the costs of the Capacity Market.

[49] An investment hiatus caused by perceived regulatory risk and a retail price freeze leading to poor liquidity in the wholesale market
[50] De Vries, 2004, "Securing the public interest in electricity generation markets", http://www.nextgenerationinfrastructures.eu/download.php?field=document&itemID=449557

6.33 Moreover the model is unable to capture the impact of differences in the detail design of the mechanism – for instance around measures to mitigate gaming in the auction, or the effect of the penalty regime of dispatch decisions. These factors are considered further in the Qualitative Assessment, and the explanations for particular design choices are set out in the Annexes to this IA.

7 Qualitative options assessment

7.1 There are a number of limitations to using energy system modelling to assess the impact of a Capacity Market. This section considers the additional non-quantifiable risks associated with introducing a Capacity Market relative to the basecase – particularly the potential for gaming, and implication for the single market.

7.2 Further qualitative analysis is set out in the annexes assessing the detailed design choices that have informed the final design of the Capacity Market that we are consulting on. These design choices include:

i. The choice of auction format;
ii. The timeline for procuring capacity;
iii. The choice of agreement length;
iv. The parameters of the demand curve;
v. Eligibility rules for participation in the CM;
vi. The level of penalties and when they are applied; and
vii. Introduction of DSR transitional arrangements

7.3 DECC regularly seeks to improve its modelling capabilities and has undertaken a number of changes to the model to reflect the final policy design – for instance incorporating a demand curve as part of the auction simulation. However the degree of nuance involved in the policy design choices listed above mean that it in practice at this stage these are mainly assessed qualitatively.

Gaming risk

7.4 One of the principal risks identified in previous Impact Assessments from a Capacity Market is that of gaming: Capacity Markets are significant interventions in the market, adding complexity to the market and so creating potential for unintended consequences and for market participants to exploit arrangements to be able to earn undue profits.

7.5 Two particular high level gaming risks are around the auction design and penalty regime, which are included here. However, this is not an exhaustive list:

Auction Design

7.6 Existing plant in the auction are likely to have significantly lower capacity bids than new build as existing plant will not need to recover its fixed costs. Moreover demand in the capacity auction is price inelastic as parties have a high aversion to load shedding if insufficient capacity is procured. These two factors combine to mean that capacity prices could vary significantly whether new build sets the price in a given year. This creates incentives for auction participants with a sizeable portfolio of generators to withhold some of their capacity from the auction – either by keeping some plant outside of the auction or by offering it into the auction at a high price – in order to drive the price up to the cost of new entry. However given the scale of new investment needed – with modelling showing the auction bringing on new entrants in every year after the first auction – incumbent players should have limited incentive to withhold capacity.

Penalty regime

7.7 Parties seeking to manipulate the rules to receive undue profits may attempt to overstate the value of their capacity. This can occur in a few different ways;

i. By overstating the reliability of a plant prior to the auction: Significant uncertainty and asymmetric information exists about the capacity value of providers between the System Operator and the providers themselves. Providers have incentive to overstate the reliability of their capacity at the auction to receive higher payments, and the risk of penalties for underdelivery may be an insufficient deterrent to this action as stress events will be infrequent and as liabilities in the mechanism are capped.

ii. By appearing to overdeliver capacity in stress events: Providers with obligations might have incentive to artificially create or prolong a stress event in order to receive overdelivery payments, or (in the case of Demand Side Response) they might have incentive to manipulate the baseline against which they are assessed so they appear to have delivered more energy than is the case.

Mitigation of risks in design

7.8 The Capacity Market has always sought to mitigate such potential for gaming in its design – and has built in a number of policy design features specifically to mitigate the risks identified above. These mitigation measures include:

i. Holding auctions four years out to allow for new entrants to compete against existing plant.

ii. Administratively determining the capacity value of participants – to prevent providers from understating the capacity value of their plants to withhold capacity from the auction, or overstating the value to receive undue capacity payments. This is complemented by a system of physical checking and spot tests to ensure capacity is able to deliver.

iii. Reducing demand in the auction where existing plant chooses to “opt out” of participation. This means that plant will not be able to game the auction by withholding plant.

iv. Existing plants will be required to act as price takers in the auction unless they are able to justify a need to set the price above a low threshold.

v. The level of supply in each auction round and the identity of particular bidders will be concealed to mitigate risk of collusion.

vi. The demand curve will ensure the capacity price is less sensitive to the volume of capacity offered into the auction and so reduce incentives for participants to withhold capacity from the auction

vii. There will be provisions to cancel or postpone the auction if it is undersubscribed.

viii. There is a strong penalty regime for providers that fail to delivery energy when needed.

ix. There will be a system of periodic reviews to consider whether the rules are fit for purpose once the mechanism is in place.

Independent Gaming Study

7.9 In addition, DECC appointed Charles River Associates (CRA) to undertake an independent review of the gaming risks associated with the Capacity Market design.[51] This concluded that "the proposed Capacity Market design is internally consistent, comparable to designs of other established Capacity Markets, and its design provides substantive mitigation against the principal gaming risks that can arise. However, no procurement process is immune from such risk and inevitably there will be areas where problems could arise."

7.10 CRA identified a number of further risks and proposed mitigation measures – most of which have now been reflected in the mechanism design. The key findings of this report were that:

i. As a result of the mechanism design, there are strong incentives for existing plants to participate in the auction rather than to withhold – particularly as demand in the auction is lowered where plant opts out, and plants that claim they will have retired but fail to do so will be barred from participation in subsequent auctions and could be investigated by Ofgem for abuse of market.

ii. The penalty regime is strong which by itself would have the potential to incentivise games to benefit from over-delivery payments (which are the analogue of penalties). However, the risk of this occurring is small as actions to withhold energy at times of stress would be observable and already prohibited under the provisions of REMIT, and so the potential for enforcement by the Regulator should have a deterrent effect.

iii. The most significant area of concern about gaming risk comes from difficulties demonstrating the additionality of Demand Side Response (DSR), as DSR providers could manipulate the baseline (i.e. increasing demand when they expect a stress event) to make a reduction in load appear more significant. While there are mitigation measures built into the mechanism design, CRA recognised that a system of monitoring was crucial to identify gaming actions and to adapt penalty regime in future where necessary.

7.11 A more detailed list of recommendations from the report and how the Government has responded to the recommendations is set out in DECC's paper to the Expert Group.[52]

Gaming risks in the Basecase

7.12 While the risk of gaming and unintended consequences must be considered as part of the assessment of the introduction of a Capacity Market, it is also important to recognise that there are gaming risks to having an energy-only market which are potentially more significant.

[51] "Capacity Market Gaming and Consistency Assessment", September 2013, CRA https://www.gov.uk/government/consultations/proposals-for-implementation-of-electricity-market-reform
[52] Update on Gaming Mitigation", Meeting paper for DECC Expert Group 11 September 2013 https://www.gov.uk/government/policy-advisory-groups/capacity-market-emr-expert-group#meeting-papers

7.13 An energy-only market is likely to lead to under-investment in capacity due to the market failures identified in Section 4. However as margins tighten in the electricity wholesale market, particularly at times of stress, generators become able to withhold supply from the market in order to drive up price. If this happens it may be hard to distinguish between anti-competitive gaming and legitimate pricing behaviour whereby generators recover their fixed costs. However experience from the Californian energy crisis in 2000 and 2001[53] demonstrates that a lack of investment in generation capacity can undermine the competitiveness of the market, as generating companies withheld supply in order to drive prices above their competitive levels when margins became slim. And given the time it takes to build new plants, once the market reaches a point at which margins are slim generators can continue to exercise market power for a protracted period of time in absence of regulatory intervention.

7.14 A Capacity Market reduces gaming risk in the energy market in a number of ways.

i. The Capacity Market ensures a sufficient capacity margin to limit market power for generators in the wholesale market.

ii. A Capacity Market means energy prices need not be allowed to rise all the way to the Value of Lost Load (£17,000/MWh) at times of stress and can be capped at a lower level without compromising generation adequacy – which further mitigates incentives to withhold energy at times of stress.

iii. Finally, a Capacity Market ensures capacity remuneration is set in a more competitive, transparent and well-regulated process. Because this market is held four years out and not under stress conditions it can build in the mitigations enumerated in this section to limit gaming risk: For instance unlike in the energy market, the Capacity Market features a demand curve, a price cap, obligations on existing plant to act as price-takers, the threat of new entry, and an arrangement that sees demand lowered where existing plant "opt out" of offering capacity into the auction.

7.15 Thus the overall impact of a Capacity Market should be to reduce gaming risk relative to an energy-only market.

Conclusions from qualitative analysis

7.16 A Capacity Market acts to mitigate potentially significant risks to security of supply associated with the market failing to invest sufficiently in reliable capacity. However it is a significant and complex intervention which inevitably has some risk of unintended consequences – particularly around competition in the auction and correctly estimating the value of capacity offered by particular providers. However while some risk is unavoidable, the mechanism design builds in a number of measures to mitigate these risks wherever possible and builds on from experiences of other capacity markets in the world, particularly PJM and ISO-New England in the US.

[53] De Vries, 2004, "Securing the public interest in electricity generation markets", http://www.nextgenerationinfrastructures.eu/download.php?field=document&itemID=449557

7.17 The risk of gaming in the Capacity Market must also be considered against the gaming risks associated with not intervening in the market: An energy-only market is likely to deliver a tighter capacity margin in the future, and this creates greater opportunities for parties to withhold energy from the market to drive the price up to VoLL. This risk may be greater than the threat of parties withholding in the capacity auction as there wouldn't be the same safeguards in place to protect consumers – i.e. the use of a demand curve, restrictions on bidding behaviour by existing plant, and minimum competition requirements in the capacity auction do not hold in the energy market at times of stress.

8 Conclusion

8.1 The energy system modelling for this Impact Assessment reinforces the analysis provided by Ofgem's 2013 Electricity Capacity Assessment and by previous Impact Assessments: that capacity margins are going to tighten over this decade; that the scale of the investment challenge over the medium term is considerable, and that there is uncertainty over the ability of the energy-only market to provide sufficient incentives for investment.

8.2 The case for a Capacity Market is therefore ultimately a judgement on the balance of risks around intervening in the market or trusting cash out reforms and the market to deliver. A Capacity Market serves to mitigate the risk that an energy-only market does not provide sufficient capacity, either due to investors being unable to get project finance for new capacity on the basis of uncertain and infrequent scarcity rents. The modelling in this IA shows that a Capacity Market has a positive impact on society as a result of mitigating market failures and ensuring an efficient level of investment in capacity. Given the limited impact of the measure to consumer bills and the potentially large cost from blackouts if the market fails to deliver sufficient capacity there is a strong case for introducing a Capacity Market.

8.3 There is no design of Capacity Market that is without risk, and the Annexes set out the range of detailed design choices that have been made and the trade-offs associated with each such choice. In particular the mechanism has been designed with a strong focus on designing a competitive auction process to enable efficient price discovery. It has also been recognised that it is important that the Capacity Market act as a complement to reforms to the energy market (such as cash out reform, measures to promote liquidity, and the introduction of Smart Meters), and that the necessity and design of the mechanism are kept under regular review as the mechanism is implemented and as the energy market evolves.

9 Other Impacts

Impact on small firms

9.1 In terms of additional regulatory or administrative burdens, a Capacity Market will primarily impact on electricity generators in the sector, which are mostly classed as large businesses. However some capacity providers may be small or medium-sized. These will be negatively impacted by additional administrative costs associated with participating in the capacity market. However these negative impacts should be mitigated from having a more secure and predictable funding. If designed well, the overall effect of a Capacity Market may be to reduce barriers to entry.

9.2 Electricity suppliers will also be impacted by a Capacity Market, in that they will be charged the costs of a Capacity Market and will need to recover the costs from consumers. The design of Capacity Market should minimise any adverse impacts on the financial flows of suppliers but the additional administrative requirements are likely to have a greater impact on small and medium suppliers.

UK Competitiveness

9.3 A Capacity Market has the potential to increase energy bills, which could negatively affect UK competitiveness. However this cost needs to be considered against the significant harm to UK competitiveness that could arise if the energy-only market failed to deliver security of supply objectives, leading to blackouts and which could have a damaging impact on the UK's reputation.

Implications for One-In, Two-Out

9.4 Based on the latest HMT advice, the Capacity Market options are to be treated as tax and spend measures, so would be out of scope for One-In, Two-Out (OITO).[54]

Equality impact

9.5 It is not envisaged that the Electricity Market Reform Capacity Market options will impact on measures of equality as set out in the Statutory Equality Duties Guidance. Specifically options would not have different impacts on people of different racial groups, disabled people, men and women, including transsexual men and women. There are also no foreseen adverse impacts of the options on human rights and on the justice system. We will keep a watching brief on this but we are confident that any issues can be addressed at the design stage without adverse impact on either human rights, or on the effectiveness of the mechanism.

Impact on Business

9.6 Businesses would be affected in a number of ways by a Capacity Market. The key quantified impacts are:

i. The benefit to businesses of reduced energy unserved[55]
ii. The change in **producer surplus** that capacity providers face as a result of the Capacity Market (by receiving capacity payments but also receiving less revenues in the electricity market due to a dampened wholesale price)

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[54] http://www.bis.gov.uk/reducing-regulation

[55] Calculated on the basis that 58% of electricity consumed is by non-domestic consumers and therefore around 58% of the benefit of reduced energy unserved will be experienced by businesses (DUKES 2013, Chapter 5). We have assumed that businesses have the same VoLL on average as consumers (£17,000/MWh). Whilst SMEs will generally have a higher VoLL, large industrial users will typically have a lower VoLL.

iii. The **administrative costs** on electricity companies associated with participating in a Capacity Market

iv. The impact on business from facing higher energy bills as a result of the Capacity Market.[56]

9.7 A Capacity Market is modelled as having a positive impact on businesses, as the benefits of reduced energy unserved and rents accrued by providers in capacity auctions outweigh the increased costs to businesses from higher energy bills. However this benefit is principally received by generators, largely at the expense of business in general, as reductions in energy unserved is smaller than the increase in bill costs.

Figure 18: Impacts of a Capacity Market on Business

Impact on business, 2012-2030	**£m**
Administrative costs	231
Cost to business of increased energy bills	6,023
Total costs	**6,255**
Reduction in energy unserved	748
Producer surplus to capacity providers	10,315
Total benefits	**11,063**
Net impact on business	**4,808**

Source: DECC modelling

[56] Calculated on the basis that 58% of electricity consumed is by non-domestic consumers and therefore businesses would face an equivalent proportion of the impact on consumer surplus identified in the energy system modelling.

10 Post-Implementation Review

10.1 The Department of Energy and Climate Change has committed to regular reviews of the Capacity Market. This will be a five-yearly review of the mechanism to be published alongside the Delivery Plan. The objectives of the review will be as set out in primary legislation – i.e. the report will:

i. set out the objectives of the provisions of each Chapter subject to review
ii. assess the extent to which those objectives have been achieved, and
iii. assess whether those objectives remain appropriate and, if so, the extent to which those objectives could be achieved in a way that imposes less regulation.

10.2 This review will involve a public consultation to invite views. The outcome of the review will be published as well as laid before Parliament.

10.3 In addition to the five-yearly reviews there is potential for further informal or ad-hoc reviews to be held.

Annex A: Auction Format

1. The auction format chosen for the Capacity Market is a descending-clock, pay-as-clear auction in which all successful suppliers are paid the last-accepted bid. This Annex sets out the analysis that underpins these design choices and the alternative options considered:

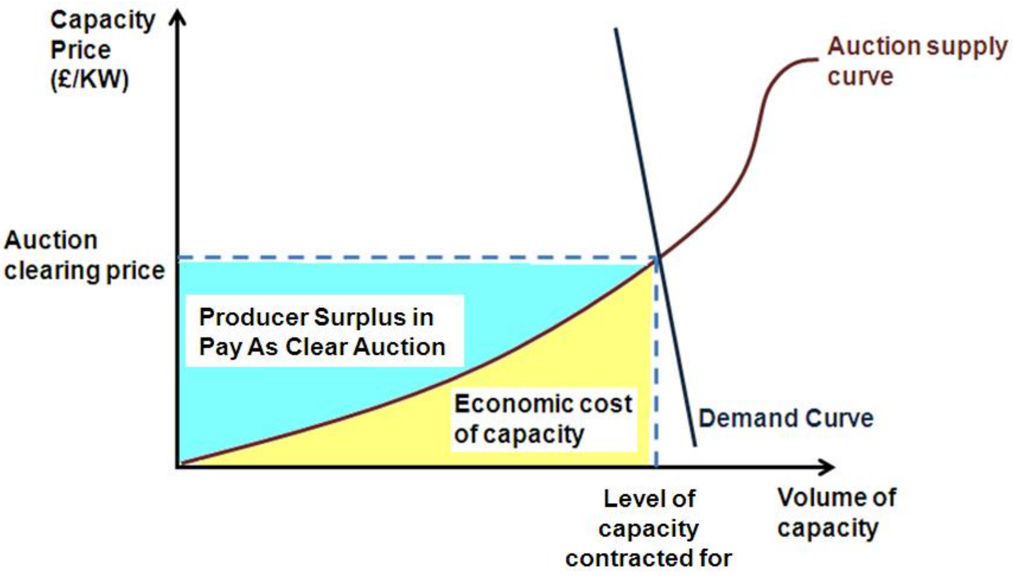
   i. Pay-as-clear versus Pay-as-bid
   ii. Descending clock versus Sealed-bid
   iii. Last-accepted bid versus first-rejected bid

Pay-as-Clear versus Pay-as-Bid

2. Wholesale electricity markets are commonly organised around a spot energy market, Forward contracts tend to constitute the majority of wholesale electricity trading, the prices of which are a reflection of the spot price. Suppliers submit bids and the market is cleared at the price that balances supply and demand. Under a pay-as-clear auction all parties are paid the market clearing price set by the most marginal bid into the auction.

3. By contrast a pay-as-bid auction pays each successful bidder the price it bids. In a pay-as-bid auction the price paid to a supplier is based on the actual bids made by that supplier. Pay-as-bid auctions are thus commonly referred to as discriminatory auctions because they pay successful bidders different prices based on their specific price bid. Pay-as-bid auctions are sometimes promoted as a way to reduce the cost to suppliers, resulting in lower consumer prices for electricity, as described by Giulio and Rahman.[57] However to the extent that parties are able to exercise market power then it is likely to produce the opposite result – strategic bidding by suppliers, inefficiency in plant dispatch and capacity investment, and ultimately a higher average price as described by Tierney.[58]

Figure 19: Pay-as-clear auction



[57] Federico, Giulio, and David Rahman. "Bidding in an electricity pay-as-bid auction." *Journal of Regulatory Economics* 24.2 (2003): 175-211. Available at: http://www.nuff.ox.ac.uk/economics/papers/2001/w5/federico-rahmansept2001.pdf

[58] Tierney et al, "Pay-as-Bid Vs Uniform Pricing," Fortnightly Magazine, March 2008

4. The key motivation for a pay-as-clear auction is that it provides suppliers with stronger incentives to bid their true economic cost of providing capacity. In a setting where there is no uncertainty about the clearing price, a pay-as-bid auction creates incentives for shadow-pricing the marginal bid and ensuring they are successful. Even though in a pay-as-clear auction some suppliers are being paid more than the economic cost of capacity, this effect is mitigated by greater incentives to bid at true economic cost[59]. In this way, the auction identifies the most economic suppliers of capacity and pays the lowest single-price that attracts enough supply to meet demand.

5. Under a pay-as-clear auction, each supplier receives a *uniform* market-clearing price, set at the offer price of the most expensive resource chosen to provide supply i.e. the marginal auction offering.

6. In a pay-as-bid auction, a plant will seek to cover its fixed and variable costs. If the cost of production (e.g. due to increase in fuel price) for one technology (e.g. CCGT or onshore wind) increases, and the price offered by this technology increases as a consequence, there will be no incentive for investment in the relatively cheaper technology (say nuclear plants or PV) as they will still only look to cover fixed and variable costs. Under pay-as-clear auctioning, where a uniform price is offered, more investment will occur where it is more economically efficient to do so (in this example, nuclear power plants or PV). This case is put forward (this case, along with further nuances, is put forward by Cramton and Stoft[60]. Artificial transaction costs appear in the spot market between seller offers and buyer bids exist to discourage its use, which has been a feature of the UK market in recent years[61]. These sunk costs are avoided through uniform prices offered in a pay-as-clear as prices paid are exactly equal to though received.

7. Alongside economic efficiency, pay-as-clear auctions have a number of advantages over pay-as-bid auctions in this context:

    i. Fairness: In markets it is seen as a fair outcome for parties to be paid the same price for provision of a homogenous product. In the Capacity Market the homogenous product is the provision of available capacity at times of system stress, and is designed to be a technology neutral product. In this way new and existing plant, as well as DSR and storage, can compete openly against each other in the auction. The pay-as-clear auction pays each supplier the same price. In contrast, the pay-as-bid auction pays different parties different prices for providing the same service. This may be viewed as unfair. In a PAB auction, artificial transaction costs appear in the spot market between seller offers and buyer bids exist to discourage its use, which has been a feature of the UK market in recent years[62]. These sunk costs are avoided through uniform prices as prices paid are exactly equal to those received.

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[59] Academic studies reaching this conclusion include Alfred E. Kahn, Peter Cramton, Robert H. Porter, and Richard D. Tabors, "Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond," *Electricity Journal*, 70-79, July 2001

[60] Cramton, Peter, and Steven Stoft. "Why we need to stick with uniform-price auctions in electricity markets." *The Electricity Journal* 20.1 (2007): 26-37.

[61] Ibid.

[62] Cramton, Peter, and Steven Stoft. "Why we need to stick with uniform-price auctions in electricity markets." *The Electricity Journal* 20.1 (2007): 26-37.

ii. Competition: Pay-as-bid auctions introduce a “guessing game” for suppliers. Those suppliers best able to predict the clearing price will be able to bid the most aggressively and thereby reap the largest profits. Often, this gives an advantage to large portfolio players who have better information to forecast the clearing price, and indeed can take actions to impact the clearing price in significant ways. In contrast, small independents are at a disadvantage, since they are apt to have fewer resources to estimate the clearing price and less ability to impact the clearing price. The exercise of market power by a large participant in a pay-as-bid auction tends to reinforce market concentration. By contrast, in a pay-as-clear auction, the exercise of market power by large participants tends to be self-correcting. Smaller suppliers are able to free-ride on the exercise of market power by large suppliers. Thus, the exercise of market power with pay-as-bid pricing, because it favours larger bidders, will tend to encourage consolidation and discourage entry; whereas the exercise of market power with uniform pricing encourages entry and reduces concentration. As a result, the market may evolve to more competitive structures under uniform pricing[63]. This action makes room for smaller participants and thereby encourages entry in the long-term, which helps to mitigate incentives for large participants to withhold. There remains a risk of collusion in a pay-as-clear auction, although this is likely to be a small risk given that there are significant legal penalties.

iii. Long-term price signals*:* Paying the clearing price can create the right long-term signals for the market to innovate and develop cheaper technologies so as to capture later rents in the capacity market. A market that pays a single price provides incentives for everyone to try to provide capacity at less than this price. Over time this puts downward pressure on the price and therefore tends to achieve the lowest long-term sustainable price.

8. However there are still risks associated with running a pay-as-clear auction for capacity. The main risk is the exercise of market power to achieve a high price. This incentive may be greatest in years in which no new build is required. Existing resources are apt to have much lower going forward costs than new capacity, and therefore the competitive clearing price may be quite low in these years. To avoid this low price, large existing players may bid a much higher price.

9. This risk should be largely mitigated through the other measures in the mechanism design to ensure competition in the auction – such as use of a downward sloping demand curve, minimum competition requirements for holding the auction, and price-taker requirements for existing plant. These are detailed in Annexes B and C.

Descending Clock versus Sealed Bid

10. The proposed format is a descending-clock auction with pay-as-clear pricing. This involves the auctioneer announcing a high price at the beginning of the auction and providers indicating that they are willing to supply capacity at that price, and then

[63] Cramton, Peter, and Steven Stoft. "Why we need to stick with uniform-price auctions in electricity markets." *The Electricity Journal* 20.1 (2007): 26-37.

repeated rounds at lower prices until the auction discovers the lowest price at which demand equals supply.

11. This option is an alternative to a sealed bid auction, whereby providers each state the minimum price at which they are willing to provide capacity and the auctioneer identifies the marginal bid (i.e. the most expensive bid accepted) and sets that as the clearing price.

12. The descending clock format has several potential advantages over a sealed-bid format.

13. One benefit is reduced uncertainty about common cost elements that may be revealed in the bidding process. This reduction of uncertainty enables bidders to bid more aggressively without fear of the winner's curse (winning at a price that is too low) because new entrants know they can withdraw their bid once they see a significant number of other bidders withdraw from the auction. This reduction of uncertainty can both increase revenues and improve efficiency.[64]

14. A second benefit is improved price competition. Bidders often bid more aggressively in dynamic auctions for various behavioural reasons. For example, dropping out of the auction is an admission of "inferiority"—that the supplier has higher costs than a competitor.[65]

15. In a descending price auction, allows bidders to condition future bids based on the results of previous bids and the bidding behaviour of other bidders, allows the bidder to revisit its reserve price, resulting in a more efficient process[66].

16. It is recognised that there are disadvantages to descending clock auction relative to sealed-bid: It could be more administratively onerous for parties to participate in a descending clock auction as it takes place over a longer time period. Moreover the price-discovery afforded by descending clock auctions can also be used by parties to collude (explicitly or tacitly), driving up prices.

17. However the risks of descending clock auctions can largely be mitigated through mechanism design: Auction participants can be allowed to put in proxy-bids so that they don't have to be present for the whole auction process. And the risk of collusion is largely mitigated by a licence obligation on auction participants not to collude or share information and the ability of Ofgem to investigate and ultimately impose strong penalties on offending parties. Tacit collusion is also mitigated through the conduct of the auction, such as the size of the bid decrements and the information policy. In addition, auctions will generally be expected to last only a day in order to limit opportunities for collusion between participants – although there is contingency for the auction to last up to a week if need be (for instance if there is a system fault or if in future zonal auctions are introduced, increasing the number of rounds that needs to be held)

Last-accepted bid versus first-rejected bid

18. A further significant policy decision is whether to set the clearing price at the price of the first rejected bid or the last accepted bid. The first rejected bid provides further incentives for parties that are aware that they are the marginal plant to bid in their true cost rather

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[64] Milgrom, Paul and Robert J. Weber (1982), "A Theory of Auctions and Competitive Bidding," *Econometrica*, 50, 1089-1122.

[65] Peter Cramton, "Ascending Auctions," *European Economic Review* 42:3-5 (1998) 745-756.

[66] Maurer, Luiz and Barrosa, Luiz, *Electricity Auctions: An Overview of Efficient Practices*, World Bank Publications, 2011.

than to bid up to cost of the least-cost plant that will be rejected. However in practice it is likely that setting the price at the last accepted bid is likely to reduce costs for consumers – as there is likely to be some uncertainty around the price of the marginal plant and so it would be difficult for incumbents to game the auction by bidding up to the price of the lowest-cost plant to be rejected. This is the most common pricing rule in pay-as-clear auctions.

Conclusion

19. Based on the analysis we see a number of advantages to a pay-as-clear auction format to ensure the market delivers the efficient long-term price signals for competition and innovation. In the long run this should lead to lower costs for consumers, particularly as the pay-as-bid auction creates perverse incentives for providers to overstate their costs and skews the market in favour of large portfolio players. However we recognise the risk of overpayment under a pay-as-clear auction if existing plant are able to drive the price up to the cost of new entry in years when no new build is needed – and so we have put in place a range of measures to mitigate this gaming risk (set out in Annexes B – D).

20. Similarly a descending clock auction is preferred as it enables greater price discovery and so should further reduce risk for the market to invest in capacity.

21. The choice of auction format – pay-as-clear with descending clock - is consistent with the principal capacity markets in the United States – including PJM and ISO-New England.

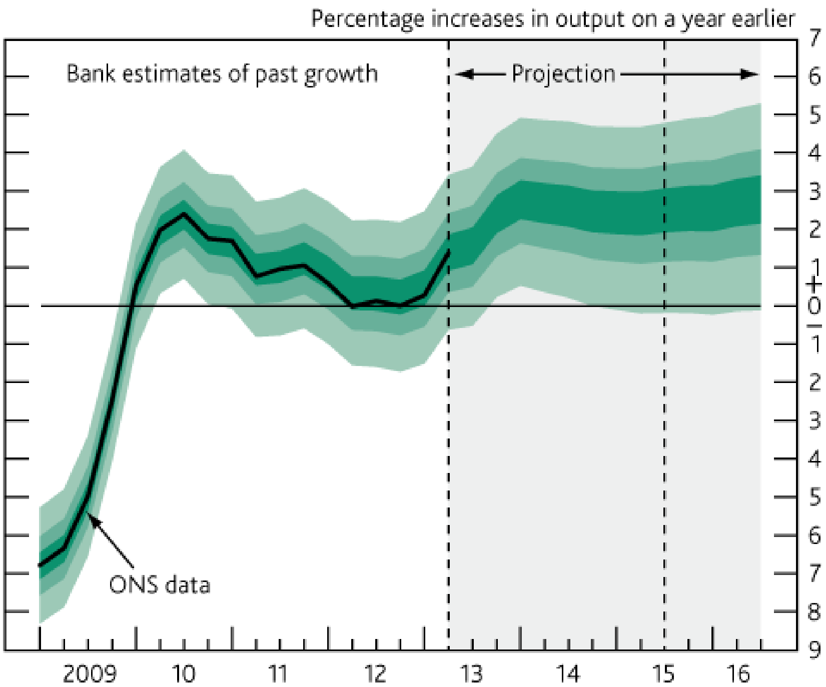
Annex B: Timeline for procuring capacity

1. The principal capacity auction is to be held four years ahead of the delivery year, with a supplementary auction held a year ahead of delivery year. The split between volume of capacity to contract at the year ahead will be determined on the basis of an assessment of how much DSR is expected to come forward. This annex considers the issues around the choice of a four-year ahead auction and why this was chosen over a single year-ahead auction.

Efficient risk allocation

2. In running an auction four years out it is necessary to assess the need for capacity in the delivery year – and there is likely to be significant uncertainty around this assessment. Uncertainty around the volume to procure four years out comes from both demand (e.g. economic growth and the effectiveness of energy efficiency programmes) and supply (e.g. the expected commissioning date for a new nuclear plant or the degree of investment in new renewable capacity).
3. Procuring capacity through a single year-ahead auction would clearly carry less risk in terms of contracting the right volume of capacity as there is much greater certainty as the delivery year approaches.

Figure 20: Fan Chart with GDP Growth Projections



Source: Bank of England[67]

4. However the suitability of contracting closer to real time carries alternative risks. It is not possible to build new thermal capacity at the year-ahead stage (although it may be possible to incentivise new DSR or some existing plant that would otherwise retire to stay open). The length of time taken to build new plants is illustrated in the diagram below:

[67] August 2013, Bank of England Inflation Report, http://www.bankofengland.co.uk/publications/pages/inflationreport/irfanch.aspx

Figure 21: Lead times for new build (number of years)

	Predevelopment Period (Years)	Construction Period (Years)
CCGT	2.3	2.5
OCGT (large scale)	1.8	1.8
OCGT (aeroderivative)	2.1	1.9
Nuclear	5	6
Gas - CCGT with post combustion CCS – FOAK	5.0	4.5
Coal - ASC with CCS - FOAK	6	5.5
Coal - IGCC with CCS - FOAK	5.3	5
Pumped Storage	5	4.5

Source: Parsons Brinckerhoff[68]

5. Depending on a year-ahead auction in years when new build may be needed would therefore impose a higher level of risk on investors than having a four year ahead auction: With a one year ahead auction, the market would have to estimate the need for new plant four years ahead and invest in new capacity needed so it will be able to participate in the year-ahead auction. This is similar to how investment is funded in an energy-only market, where there is limited liquidity in forward markets beyond a year ahead.

6. An advantage of procuring capacity close to the delivery year is that it would incentivise the market to bring forward types of capacity that can be built as quickly as possible – as they face the least risk of not being needed by the time of the auction.

7. However a year ahead auction is likely to be a less efficient allocation of risk than contracting new capacity four years out: The market is as likely to correctly estimate capacity needs four years out as the Government is. But the main advantage to procurement four years ahead of the delivery year is that it mitigates the coordination problem with leaving the market to decide which power plants to build. For instance it may be that there is market consensus that only one or two new gas plants will be needed in four years' time: If there is no central auction four years ahead then investors deciding whether to build must first make a judgement about whether other investors will do the same. This can lead to potential overinvestment or underinvestment where investors fail to guess correctly the actions of other market players. Investors may publicise that they have made final investment decisions to deter other investors from building new plant – however they may have perverse incentives to make such declarations even when they have not yet made a final investment decision. Four year-ahead auctions provide a mechanism for coordinating which investors will build the additional capacity that is needed.

8. There is also additional risk for the market around how the price will be set in the auction: In a four-year ahead auction new build offers will price into the market based on the cost of new entry – i.e. the level of payment at which it is profitable for the plant to be built. However in a year-ahead auction the capex and pre-development costs of the new build will have already been sunk, so if there is any risk that the investor may not receive a contract in the auction then they might bid below their cost of new entry to ensure they get at least some revenue to cover fixed costs.

[68] For all technologies apart from storage: https://www.gov.uk/government/publications/parsons-brinkerhoff-electricity-generation-model-2013-update-of-renewable-technologies
For Storage: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65712/6884-electricity-gen-cost-model-2012-update.pdf

Technology neutrality

9. An important principle in the design of the Capacity Market is technology-neutrality: The Capacity Market has been designed to create the same incentives that would be present in an efficient-energy only market, and one such incentive would be for the market to select the efficient mix of plant in response to price signals.

10. However it is recognised that the choice of how far out to hold the auction has potential to affect the likely mix of plant that comes forward. In particular year-ahead auctions favour existing plant and DSR, four year ahead auctions might favour gas plant but disadvantage DSR (which may struggle to commit four years ahead – for example an aggregator may not know how many customers it will have) and storage or new nuclear (which may take longer than four years to build).

11. Modelling of the energy system suggests that significant new gas build (particularly OCGT) is needed – although this projection could be less if interconnection or DSR delivered more than expected or if an innovative new technology came forward to replace OCGT as the marginal plant.

12. The choice to have two auctions – four years-ahead and year-ahead – enables both gas and DSR to participate effectively in the auction. The decision of how much capacity to procure at the year-ahead stage is clearly likely to be influential to the technology mix that the Capacity Market will bring forward. However with each additional auction there should be greater certainty about the volume of DSR that can participate cost-effectively against thermal plant, and Government can learn if past estimates were too high or too low based on whether the year-ahead auction cleared at a price greater than or less than the four year-ahead auction.

13. It is recognised that having auctions further out than four years would help to bring forward technologies such as storage that take longer to build. However the further out that auctions are held the greater the uncertainty for the Government in estimating the volume of capacity needed to deliver the reliability standard. Given that modelling shows new build is predominantly needed from new gas build, which can be built within 3-4 years, holding the auction 4 years out achieves an appropriate balance between giving certainty about capacity prices to investors and giving Government greater certainty about the volume of capacity needed.

Competition in the auction

14. The main advantage of having the principal auction four years ahead is that it allows new build to obtain a capacity price before committing to building plant. To participate in a year-ahead auction, by contrast, a new build would have to take a greater risk that the price in that auction would be high enough to cover the plant’s fixed costs. Moreover the plant would be worried about setting the price in that auction at the true cost of new entry as the plant has already been built by that time so if the plant were unsuccessful in that auction it would remain operational but not receive any capacity payments.

15. A further benefit to having forward auctions is that it allows new build to compete against existing plant in the auction, providing an incentive to existing economic plant to not offer capacity above the cost of new entry. New build would replace existing plants if existing plants were to bid above the cost of new entry. In this way the market is contestable – although there is residual risk of gaming by existing plant up to the cost of new entry

(which is why a range of other mitigation measures – such as obligations on existing plant to act as price takers - have been put in place). Experience from the Californian energy crisis in 2001 shows that where an energy-only market has underinvested in capacity, existing generators gain significant market power and so can increase prices for several years until new capacity has been brought to market.

16. Segmenting the market into two auctions carries some risk: It means that existing plant or DSR may be able to set a high price in the year ahead auction if they know there is insufficient capacity and no threat of competition from new plant. Moreover the ability to offer the capacity of existing plant into the year-ahead auction makes it more profitable to withhold capacity from the four-year auction in an attempt to drive the price up to the cost of new entry.

17. However these risks can largely be mitigated through policy design: Where existing plant withholds from the principal auction, the demand in that auction will be reduced accordingly to avoid potential for gaming. Moreover there are gaming-mitigation measures in the year-ahead auction, including use of a demand curve and price cap as well as rules for existing plant to be price-takers unless providing justification.

18. Thus while there is some risk to having a supplementary year-ahead auction given the lack of new build able to participate, this risk is limited and outweighed by the advantages – namely enabling DSR to participate effectively alongside conventional capacity, and allowing the Government to adjust the volume to procure at the year-ahead stage as it has greater certainty about the level of capacity required.

Annex C: Choice of Agreement Length

1. The Capacity Market will offer one year contracts to existing plant, and longer term agreements to new plant (depending upon its level of capital expenditure). It will also offer plant undertaking significant refurbishment an agreement term between 1 year and the term offered to new plant. Multi-year agreements for new build plant should facilitate a more efficient allocation of risk, resulting in lower capacity prices for the consumer.
2. However, determining the optimal agreement length for new plant involves complex trade-offs. This annex sets out those trade-offs, and explains why, on the basis of current evidence, DECC considers one possibility to be to offer 10 year agreements to all new plant. However, it also highlights uncertainties around how well the market can invest on the basis of capacity payments beyond the agreement length and hence that longer agreements may be desirable to avoid investors seeking to recover all capital costs over a shorter term.
3. DECC is inviting views as part of the Consultation on the issues of optimal contract length and whether the auction should assess offers on the basis of agreement duration as well as price. A final position on agreement lengths will be set out alongside the Summary of Responses to the Consultation in 2014.
4. This Annex also considers the proposed approach for defining “new” and “refurbishing” plant.

Theory on contract length

5. Perceptions on contract length are likely to differ between buyers and sellers. Buyers typically want the potential cost advantages of a longer contract length but do not want significant volume risk (contracting capacity which is not required) or price risk (where they are locked into a more expensive contract than the current market would provide). By contrast sellers favour greater and longer revenue certainty.

Buyer’s Perspective

6. In this instance, from the perspective of the ‘buyer’ (i.e. the consumer in this case), the risk exists that the capacity is not needed in the future. Figure 3 demonstrates that we are facing an increasing capacity requirement within the horizon on which we are broadly confident i.e. to 2030. This capacity requirement does not necessarily have to be met by new gas build – with greater energy efficiency, DSR, and interconnection as substitutes. However the scale of new capacity required suggests that volume risk is not an immediate material consideration for offering long term contracts to new build, though clearly the longer the time horizon the more uncertainty exists around this conclusion.
7. Price risk is more concerning as we assess that, despite countervailing pressures including rising demand as a result of the large scale electrification of heat and transport, long term, the capacity market price is more likely to fall than to rise because:-
    i. Energy market revenues are likely to increase as the impacts of Ofgem’s cash out reforms feed through into strong energy market signals which in turn should lead to investors requiring lower remuneration in the Capacity Market;
    ii. New cheaper CM technologies (such as Demand Side Response) might come forward that replace OCGT as the marginal resource at auction; and

iii. The experience of forward capacity prices in the PJM Capacity Market (one of the major US markets) is an instructive example: the volume of DSR significantly expanded after five years of the mechanism being in place, with prices regularly falling to below the Cost of New Entry of a generating plant as Demand Side Response sets the price in the auction. This shows that there is a significant risk that prices could decline with the development of innovative technologies such as DSR. This is an 'up-side' risk- i.e. a potential benefit - to consumers which they cannot appreciate if they have already locked in to buying capacity at a higher price.

Seller's Perspective

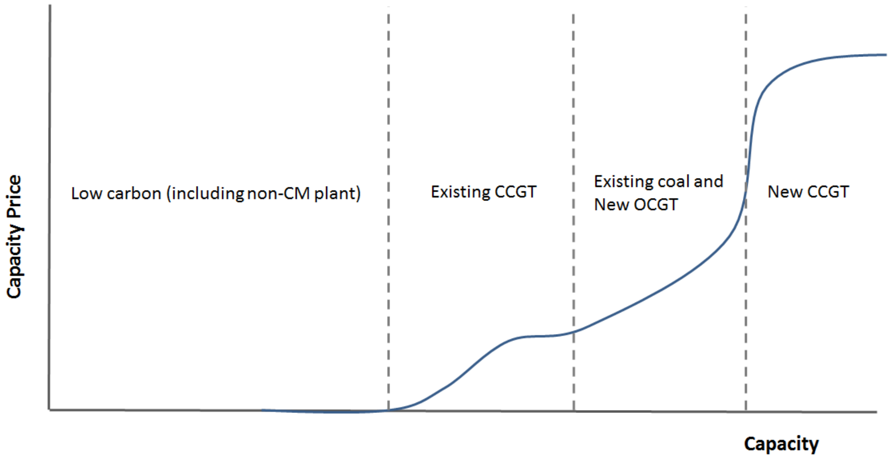
8. Long term agreements reduce risk for investors and so reduce the price at which they may be willing to offer capacity into the auction. However, in theory, investors are best placed to hold the risk of future changes in capacity prices – as they will reflect this in their bid and this will lead to the Capacity Market procuring the optimal mix of plant – for instance with new plant getting contracts in years when investors expect a high value for capacity in future years, and existing plant or DSR winning in years when investors expect capacity values will fall in future years.
9. Nevertheless, long-term agreements can reduce the risk of investment in capacity to a level that makes it attractive for project finance, and so can bring in a wider range of investors. Maximising the pool of investors is important particularly in the current climate where incumbent energy utilities, who would finance investments on the basis of equity and so would be better able to take on risk of price changes beyond the agreement length, are capital constrained and so limited in the extent to which they can provide the investment in capacity needed.
10. While there is limited evidence about the risk appetite of banks to provide finance for capacity investments, stakeholder engagement has suggested the following points:
    i. The regulatory changes arising from Basel III has caused banks to be generally unwilling to lend for a period longer than 7 to 9 years; – or if achievable would be linked with more stringent conditions

    ii. Banks would lend to power projects but would demand a strong sponsor and a strong off-taker

    iii. Agreement length is just one of a number of features of Capacity Market design that is important to banks in terms of willingness to lend.
11. This indicates that a capacity agreement length of circa 10 years is not in itself a barrier for lenders and that offering agreements with longer durations would not necessarily mean more attractive financing terms. However, the lack of any certainty in the project 'tail' may be an issue for equity investors depending on their view of the energy revenues achievable, or would impact the ability to attract refinancing of the debt part way through initial tenors, and hence will impact the pricing of a capacity tariff.
12. An important principle for the capacity auction is that new and existing plant should be able to compete against each other on fair terms.

13. Providing long term agreements to new plant provides an advantage to existing plant as investors are protected against potential future reductions in the capacity price. If this advantage were material enough it could lead to the market over-investing in new plant relative to existing plant. The stylised supply curve below illustrates, on the basis of DDM modelling, how existing coal and new OCGT plant could both be marginal in the auction.

Figure 22: An illustrative capacity auction supply curve



14. The risk of distorting the playing field is limited for ten year agreements: in the medium term (i.e. out to 2030), we expect the Capacity Market to be a rising market in which new build continually sets the clearing price in the auction. This means that retaining a price only auction is a justified and valid simplification that does not distort the market in favour of long term build. However, the longer the term of the contract the more this simplification will be challenged. Over the long term we expect a larger uptake of DSR as well as increased energy market incentives for investment to reduce the need for remuneration through the Capacity Market so capacity prices are more likely to fall than to rise over time. This means that allowing long term contracts over a period in which there is a likelihood that Capacity Market prices could fall risks disadvantaging existing plant in favour of new build.

15. This has been a major consideration in the design of US Capacity Markets: for instance a move to longer agreements in PJM was rejected by the US regulatory authority (FERC) on the grounds that this was discriminatory against existing plant and that PJM had succeeded to attract investment in new capacity on the basis of single-year agreements.

Defining new and existing plants

16. To offer longer term agreements to new build, it is important to be able to define what a new build is, to ensure that existing plant undertaking routine cyclical maintenance is not able to qualify as new. However this definition can be less clear-cut than first appears, as new plants can make use of existing infrastructure – sites, transmission connections, and parts – and particular definitions of new can therefore run the risk of perversely incentivising investors to not make efficient and conservative use of existing resources.

17. For this reason, the definition of new build has been set on a technology neutral basis according to the level of capital expenditure involved in a project – i.e. that an investor has to spend broadly the same amount as if building a new plant from scratch. This avoids technical definitions (e.g. new turbine, greenfield site, or new TEC connection) that could cause parties to not make efficient use of existing resources.

18. The threshold proposed is that new build must involve capital expenditure of at least £250/KW. As can be seen from the table below, this is the lower range of estimates of capital expenditure for OCGT plant – which is itself the least capital intensive form of generating capacity – which is low enough to ensure that the threshold does not cause inefficient spend but that it is still high enough to avoid existing plant undertaking more modest forms of refurbishment from being able to attain long term contracts.

Figure 23: cost of building new gas plant and fitting SCR equipment, £/kW

	Low	Central	High
Net Power Output (MW)	561	565	608
Pre-licencing costs, Technical and design (£/KW)	16	19	25
EPC cost (excluding interest during construction) (£/KW)	218	274	330
Infrastructure cost (£/KW)	12	16	18
Total (£/KW)	**247**	**309**	**373**

Source: PB Power[69]

19. It is recognised that some existing plant may need to spend significant amounts of capital on refurbishments in order to keep that plant open. We consider that longer term contracts should be offered to such plant; however, only plant undertaking the most extensive refurbishments should qualify. On the basis of data received from published reports[70], industry and internal estimates of refurbishment costs, DECC consider that a threshold of £125/KW will allow the most expensive refurbishments to qualify, whilst not allowing plant undertaking more routine refurbishments to access long term contracts. It is currently proposed that plant making refurbishments above the threshold of £125/kW would be offered agreements of up to 3 years and that if a refurbishment exceeds the £250kW threshold for new plant, it would qualify for the same term as available to a new plant.

20. This threshold is based on the lower end of estimates of the cost of fitting Selective Catalytic Reductions (SCR) on coal plant (which reduces their emissions and allows them to stay open longer under the Industrial Emissions Directive). The refurbishment threshold has been set according to the cost of SCR as this is clearly an exceptional form of investment for existing plant and so sets the bar sufficiently high so as to mitigate the risk that existing plant is able to qualify as refurbishing plant for undertaking routine cyclical maintenance. However DECC has invited industry views and evidence on how this threshold should be set as part of the Consultation.

Conclusion

21. The issue of a contract length is a complex one and we have set out a number of considerations to inform its selection. DECC has proposed that an agreement term of 10 years for new build strikes an appropriate balance between reducing financing risk (given views that banks, who are least willing to hold price risk, are not willing to lend for over ten years) and avoiding distorting the playing field between new and existing plant (given that both existing capacity and new build are likely to be needed over the medium term).

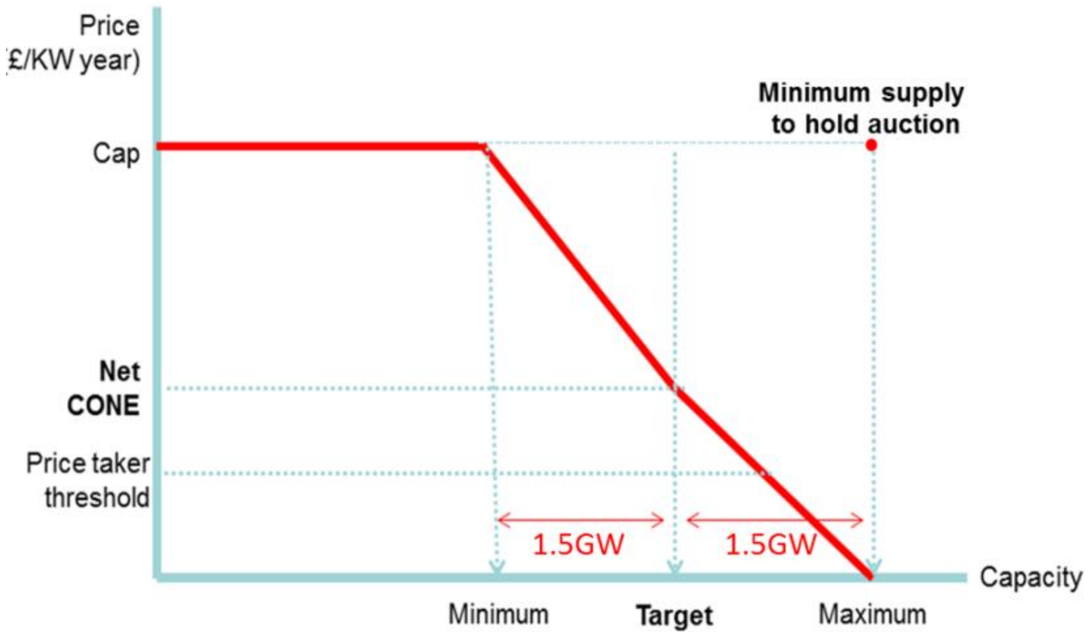
[69] Electricity Generation Cost Model – 2013 Update of non-renewable technologies, PB Power
[70] For example, Updated Impact Assessment of the Industrial Emissions Directive (IED): Large Combustion Plants, AMEC September 2012

Annex D: Parameters of the Demand Curve

Parameters for the Auction

1. The Capacity Market detailed design proposals set out how the particular auction parameters determine the functioning of the auction – particularly through the demand curve (illustrated below).

Figure 24: Illustrative Demand Curve



2. These parameters are:

   i. Net Cost of New Entry (Net CONE): This is the central administrative estimate of the level of capacity payment needed to incentivise sufficient new build. This sets the price at which the Government is willing to buy the target volume of capacity - with more bought if the capacity price is lower and less bought if the capacity price is higher than Net CONE.

   ii. Price Cap: This sets the maximum price at which we are willing to procure capacity. This needs to take account of the uncertainty involved in the estimate of Net CONE.

   iii. Range around Target: This sets the slope of the demand curve by defining how much more or less than the target volume of capacity will be procures if the clearing price differs from Net CONE.

   iv. Price Taker Threshold: This establishes the maximum price that existing plants can offer capacity into the auction for without providing a Board-approved justification for their offer.

   v. Minimum supply to hold the auction: This sets the minimum requirements for competition that need to be met in order to hold the auction.

3. This Annex sets out how these parameters will be set and how we have estimated these parameters for the first auction.

Existing parameters

4. A number of other key parameters for the functioning of the Capacity Market have already been outlined in the Government's Draft Delivery Plan[71]:

5. Gross CONE: This is the total cost of capacity for the marginal plant. In steady state, we consider that large scale OCGTs are most likely to be the marginal plant in capacity auctions, and have therefore used the cost of such an OCGT to estimate Gross CONE. Using assumptions of a 7.5% hurdle rate and 25 year payback period gives a Gross CONE estimate of £47/KW/year.

6. VoLL: The Government and Ofgem undertook a joint study of the value customers put to avoiding power cuts – and estimated this as £17,000/MWh on average.[72]

7. Reliability Standard: This defines the economically efficient level of reliability at 3 hours of lost load per year. This is calculated by dividing gross CONE by VoLL to give the number of hours in which the marginal plant would be able recover its fixed costs in an efficient energy only market (where the price goes to VoLL at times of lost load).

Net CONE

8. Net CONE is by estimating the value of energy market rent[73] for the marginal plant and subtracting this from Gross CONE.

9. If the marginal plant is a peaking plant (i.e. large or small scale OCGT), it is reasonable to assume that it will almost never run – i.e. only run in the three hours per year indicated in the reliability standard in which there is expected to be load shedding.

10. Ofgem has announced its intention to reform balancing arrangements so that from 2018 cash out goes to at least £6/KWh when there is load shedding.[74] One approach to estimating energy market revenue is therefore to assume that the marginal plant would earn this level of revenue for three hours per year, adding up to £18/KW. It can then be assumed that this revenue is pure rent: while there may be some fuel costs, these costs will be negligible relative to the size of the energy rent.[75]

11. We have used this methodology to estimate Net CONE: subtracting £18/KW from £47/KW to get £29/KW.

Price Cap

12. There is uncertainty around the estimate of Net CONE. Setting a price cap too low may therefore foreclose buying the efficient level of capacity, or lead to auctions being postponed as Government is forced to re-estimate Net CONE. However there are conversely risks around setting the price cap too high in that it reduces Government's ability to exert cost control and as it potentially allows for greater gaming risk in the auction.

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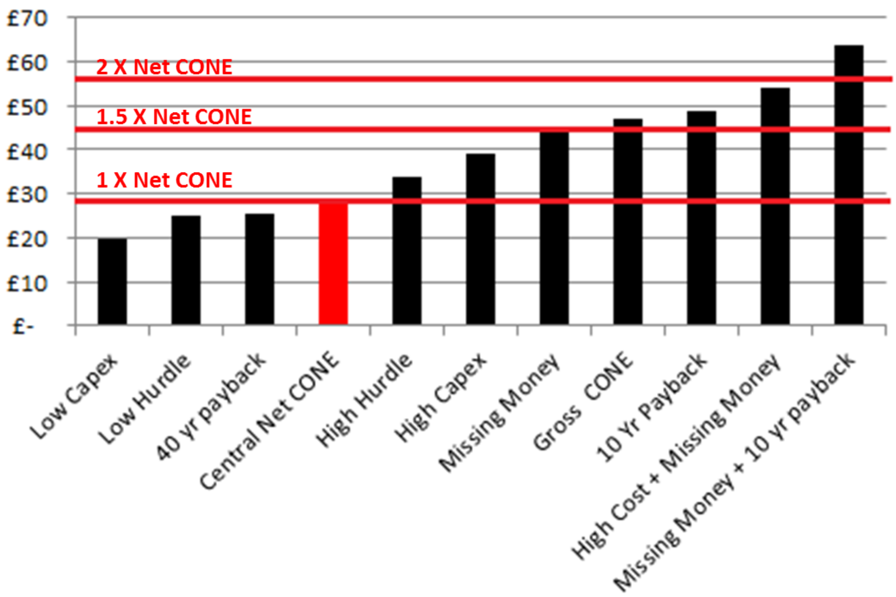
[71] https://econsultation.decc.gov.uk/emr/draft-emr-delivery-plan
[72] This is for domestic users and SMEs during winter peak. Industrial and Commercial users are excluded from this average calculation as it is assumed that they are able to provide DSR if they have a lower value of lost load than other users.
[73] I.e. energy market revenue net of short run marginal costs such as fuel and running costs.
[74] This is a draft policy decision subject to consultation and is not expected to be finalised until Spring 2014.

13. It is therefore desirable to set the price cap at a multiple of Net CONE – with the size of the multiple recognising the degree of uncertainty around the estimate. The factors that principally influence Net CONE are:

i. Hurdle rates for financing new build
ii. The payback period
iii. The capital cost estimates
iv. The degree of energy market revenue assumed
v. The choice of marginal technology

14. The graph below illustrates the impact of the assumptions on hurdle rates, payback period and the sensitivities around capital cost estimates.

Figure 25: Sensitivities around Net CONE



15. This analysis suggests that if investors make individual assumptions that are more conservative than DECC's (e.g. that they will earn at least £1000/MWh three hours a year (the "Missing Money" scenario), or if they have high hurdle rates (9%), or high capital costs) then they will still be able to bid in at less than the 1.5 X Net CONE cap. However under a combination of more conservative assumptions then a higher price cap is warranted.

16. DECC has two proposals for setting the price cap that it is considering as part of the Consultation.

17. The first proposal is to set a cap at 150% of Net CONE (£44/KW) to allow for uncertainty around the £29/KW central estimate of Net CONE. The second is to allow for a higher price cap of £72/KW to incentivise a wider range of participants to come forward to the auction.

18. Initial feedback from industry stakeholders has indicated that the £29/KW estimate of Net CONE may be optimistic, at least in the short term, for the following reasons:

i. Technology of Marginal Plant: Large scale OCGT may not be the marginal plant for the first capacity auction. No such OCGTs are currently consented to be built, whereas CCGT and small scale OCGT which are likely to have higher costs – have consent.

ii. Payback period: The methodology assumes a 25 year payback period for new build. In practice risk-averse financiers may put more limited value on payments beyond the 10 year agreement length as these are more uncertain.

iii. Scarcity Rents: The methodology assumes generators value the revenue from three hours lost load per year. However stress events are not evenly distributed – there may be many years without any hours of lost load – and investors may not be able to invest on the basis of uncertain and infrequent scarcity rents. Investors might also fear that Government will overprocure capacity leading to a lower LOLE than set out in the reliability standard (3 hours per year). The methodology also assumes that generators can earn the cash out price for their generation. This may be difficult in practice because the Balancing Mechanism (BM) is currently arranged on a pay-as-bid basis, so generators can only earn the cash out price if they bid it before gate closure.

iv. Risk Premium: The methodology assumes parties do not bid in a risk premium over their Net Going Forward Cost – on the basis that parties are as likely to receive overdelivery payments as pay penalties for non-delivery, and as we expect a secondary market to develop for parties wishing to hedge their penalty exposure. However some participants, particularly independents without a portfolio mitigating their performance risk, may seek to bid in a risk premium – particularly until a liquid secondary market develops.

19. In order to reflect these uncertainties in our estimate of transitional Net CONE, we considered potential costs of new OCGT under more conservative assumptions, as well as the potential Net CONE for CCGT. This analysis suggests that Net CONE in the short term under more conservative scenarios could be closer to £60/KW:

i. OCGT: The net cost for large-scale OCGT is £62/KW year assuming a 10 year payback period, no scarcity rents, and a higher risk premium.[76]

ii. CCGT: The DDM forecasts CCGT bidding in to the first auction at £60/KW year. This is based on a 7.5% hurdle rate, 25 year payback period, and a £10/KW year ancillary service payment.

20. DECC is therefore considering the option for the price cap in the first auction to be set at around £75/KW. This is a 125% multiple of the Net CONE estimated for CCGT.

21. Given the uncertainty in administratively setting Net CONE, DECC also proposes to make use of information learned in running the first auction to set Net CONE for subsequent auctions, and that the cap would then be set as a multiple of Net CONE. We would expect however that over time Net CONE would tend downwards toward the £29/KW estimate, as parties begin to value scarcity rents more once cash out reform is implemented, as new large-scale OCGT projects compete, and as parties have more experience assessing the risks associated with participation in the Capacity Market (i.e. that Government procures the right amount of capacity, that a secondary market develops, and that prices remain stable in subsequent capacity auctions).

[76] 9% hurdle rate, rather than 7.5% previously, to reflect the risk premium for penalties. This is within the 6-9 % range suggested by Oxera for gas financing costs. It also assumes a combined ancillary service payment and energy market rent of £10/KW year.

Price Taker Threshold:

22. Another important measure to mitigate gaming risk in the auction is to require existing plants to offer capacity below a low threshold or else be prepared to provide a justification (authorised by the company's board) for why the higher offer price is required.

23. This justification can subsequently be used by Ofgem as evidence in an investigation.

24. This measure is needed as most existing plant will have costs that are lower than new entry and so may seek to exercise market power to set a high price in years where new entry is not needed. However it is also recognised that some plants will reasonably need to demand a high price in the auction – for instance if they are old plants in need of significant maintenance costs. The price taker threshold therefore needs to balance the administrative burden of requiring existing plant to submit a business case in order to bid above the threshold, with the risk of gaming if existing plant are able to price high without good justification.

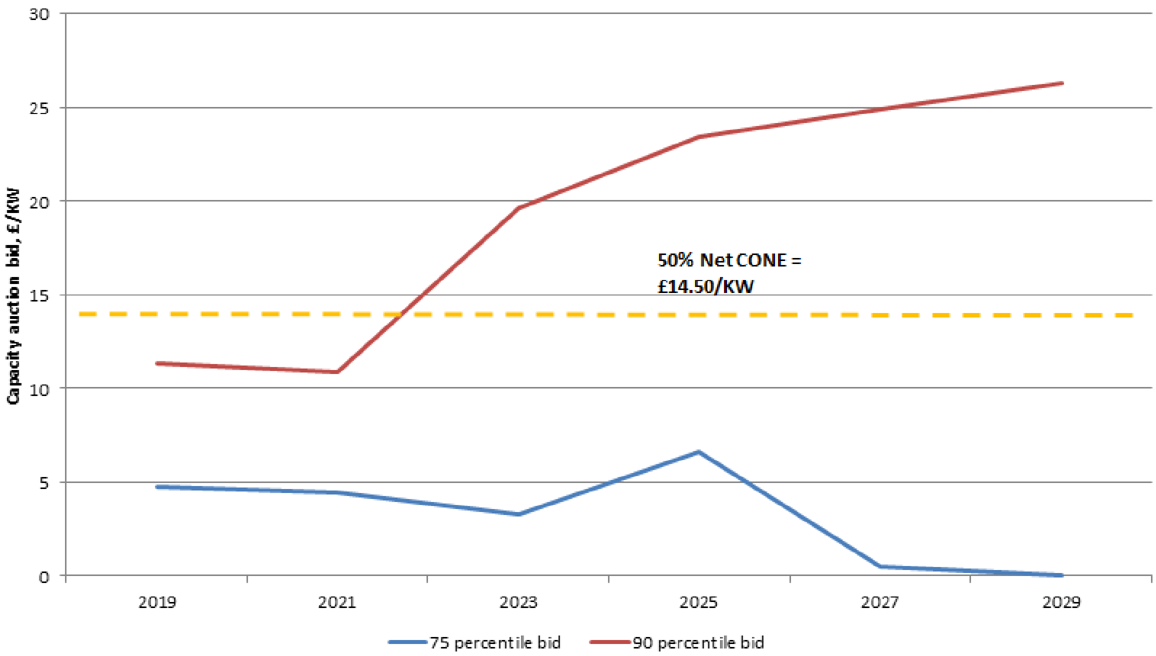
25. The existing proposal is to set the threshold at the *lesser* of:

    i. 70% of the lowest clearing price set in the preceding auction by new plant; and
    ii. 50% of Net CONE

26. The first constraint is only likely to bind if Net CONE has been significantly overestimated. In all other cases it is likely that the second constraint will be the binding constraint.

27. Setting the threshold at 50% of Net CONE is based on modelling using DECC's dispatch model to look at how existing plant will participate in the capacity auction. The chart shows modelling of the distribution of how existing plants may bid in the capacity auction.

Figure 26: Net going forward costs for existing plant



Source: DECC DDM modelling

28. This indicates that over 75% of plant should generally not need to bid more than £5/kW year into the auction (though bids are higher in one year). Moreover in the first two auctions over 90% of plant should not need to bid in more than £12/KW year into the auctions, though over time the cost of the most expensive existing plants becomes increasingly marginal against the cost of new entry.

29. In practice there is uncertainty to the level of support that existing plants would require. For instance:

    i. Plants may bid higher if they seek additional payment to compensate for additional risk they are taking on by holding capacity payments;

    ii. Plants may seek lower if they think that there are likely to be ‘scarcity rents’ due to prices rising to VoLL at times of stress; and

    iii. Plants that are currently making losses in the energy market may seek a higher level of payment in the first auction in 2014 to justify staying open until the first delivery year in 2018/19.

30. However while there is uncertainty around how plants need to bid into each auction, a threshold of 50% of Net CONE (£14.50) should strike an appropriate balance between preventing existing plant from pricing high into the auction while ensuring that only a small fraction of existing plants should need to qualify as price makers.

31. The price taker threshold can be reviewed prior to further auctions if evidence from the auction suggests it should be lower or higher or if Net CONE is changed. DECC is also currently inviting views as part of the Consultation on how much existing plants will need to bid into the auction to support our existing evidence base.

32. Below the price taker threshold, competition between existing generators should still provide some downward pressure on bidding behaviour – with existing plants incentivised to bid in close to their marginal cost if they think that the auction is sufficiently competitive. Allowing existing plants to set the price up to the price taker threshold equal to a fraction of CONE is consistent with the practice in other major capacity markets, including in PJM and ISO-New England.

Minimum competition for holding the auction

33. A further gaming mitigation measure is to mandate that a minimum degree of competition must be present in the auction for it to be held.

34. The proposed rule is that the volume of capacity in the first round of the auction must exceed the target plus 1.5GWs of capacity. This ensures that there is sufficiently more supply than demand so that there can be confidence the result reflect genuine price discovery rather than parties exercising market power. This measure is technology neutral – i.e. it does not assess whether the volume come from new entrants or existing plant, or the portfolio mix of the participants – but it is considered to be an adequate and simple proxy for the level of competition in the auction.

35. This measure also ensures that auctions will automatically be delayed where there has been a significant problem in the prequalification process – for instance if parties are appealing their derating factor – or if Net CONE has been significantly underestimated such that it is not sufficiently attractive for new build to participate.

36. No minimum volume rule is proposed for the year-ahead auction. This is because no new build is able to come forward in this auction so if there is a significant shortfall then it may be efficient to buy whatever capacity is available. The threat of gaming risk in this auction is lower as the volume of capacity to be procured in this auction is much smaller than in the four year ahead auction. Moreover capacity in the year ahead auction will principally be provided by DSR, who will tend to have smaller capacity portfolios than the typical participants in the four year ahead auction.

Annex E: Eligibility Rules for Participation in the CM

Rationale for Market Wide Mechanism

1. The Capacity Market is intended to be a market-wide and technology neutral mechanism.
2. The rationale for this approach was set out in the 2011 Impact Assessment that considered a more targeted form of intervention ("Strategic Reserve") which only paid for additional capacity to be used in exceptional circumstances[77]. This analysis concluded that there were strong advantages to having a market-wide mechanism, particularly one that included existing plant as well as new:
   i. Missing money: In the energy market all plant are able to sell their energy at the same price – and so all plant face the same "missing money" due to energy prices not adequately rewarding capacity at times of stress.

   ii. Making use of existing capacity: Any decision to exclude existing plant forces Government to have to assess the volume of existing capacity that will stay open without support. Moreover since the Capacity Market has potential to dampen wholesale prices it also risks prompting existing plant to close prematurely. By contrast a market-wide mechanism is technology neutral – letting new and existing plant compete against each other so the most economic plant wins. This means that a market-wide mechanism can be more cost-effective as it avoids over- or under-procuring new capacity and ensures economic existing plant is kept open.

   iii. Avoid regulatory risk: If the Capacity Market reduces wholesale prices then it may reduce the degree to which existing generators can recover their fixed costs. This creates two potential regulatory risks: The first is that it may prompt investors to demand a higher return on new build as they perceive a greater regulatory risk around the Government not letting investors realise the value of their plants over the long run. The second risk is that a number of existing plants could threaten to close if they do not become eligible for payment – leading to a "slippery slope" to paying everyone a capacity payment without having a structured competitive procurement process to ensure value for consumers.
3. However two categories of capacity have been excluded from participation in the Capacity Market. These are plant receiving low-carbon support as well as interconnected capacity. This Annex sets out the rationale for these exclusions.

Exclusion of plant receiving low carbon support

4. Low carbon plant receiving support will be excluded from the Capacity Market to avoid any risk of overpayment.[78]
5. The rationale for this is that the level of support through each mechanism has been set at the minimum level of support that can bring forward sufficient investment in low carbon

[77] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf
[78] Although they will be eligible to participate in the Capacity Market once they cease receiving low carbon support, such as on expiry of the CfD or RO contract.

capacity. Providing additional support through the Capacity Market creates potential for overpayment or overinvestment in particular technology types. However if low carbon technologies choose not to receive support through these mechanisms then they will remain eligible to receive support through the Capacity Market.

6. There are however significant differences between support mechanisms:

    i. Contracts for Difference (CFD): The CfD rewards plants on the basis of their energy generation. However the strike price for the contract for difference will be set to incentivise sufficient investment in capacity. It would be possible to include CfD-supported plant and avoid overpayment if the CfD strike prices were set at a lower level to reflect the value of capacity payments. However this would then introduce a new uncertainty into the setting of CfD strike prices, increasing the risk of making incentives either insufficient or overly generous. In future, once CfD strike prices are set through auctions (rather than through an administrative process), it may be possible to allow new CfD plant to participate in the Capacity Market.

    ii. Small Scale Feed In Tariffs (FITs): This mechanism supports embedded low carbon generation (such as solar panel installations) by providing a fixed price for generation that does not vary with the market price. This level of support clearly has no interaction with the Capacity Market and so participation in the Capacity Market would constitute overpayment relative to the levels of support that were originally intended through the FIT.

    iii. Renewable Obligation (RO) plant: Plant receiving support through the RO are exposed to changes in the wholesale price. Nevertheless, current strike prices have been set taking account of the impact of the Capacity Market on capacity margins. While some existing plant may be slightly negatively affected if the Capacity Market reduces wholesale prices, this impact is likely to be small and far lower than the windfall that existing RO-plant received through the introduction of the Carbon Price Floor (the impact of which was not anticipated in previous banding reviews). This emphasises an important principle in setting RO support – which is that support levels are not amended retrospectively, so it would not be appropriate to provide existing RO plant with capacity payments.

    iv. Renewable Heat Incentive (RHI): Renewable combined heat and power (CHP) projects are eligible for RHI payments for their heat generation and for RO payments for their electricity generation. These levels of support have been set to not need additional support. It would therefore be inappropriate for this capacity to additionally be eligible for CM capacity payments.

7. The decision of how much capacity to procure in the Capacity Market needs to take account of capacity excluded from the mechanism. It is recognised that exclusion of the above groups of capacity introduces additional uncertainty in the decision of how much capacity to procure – as it is necessary to estimate how much capacity will come through these alternative mechanisms. However this is judged to be an acceptable trade-off to avoid overpaying for low carbon technologies seeking support through multiple schemes.

Exclusion of Interconnected Capacity

8. In theory it would be desirable for overseas capacity to be able to participate in the Capacity Market. This would enable greater competition in the auction and ensure that the mechanism does not introduce any distortions to investment signals – e.g. as to where in Europe capacity should be situated or to how much interconnection should be built between GB and other markets.

9. However there are also significant practical difficulties to allowing for the inclusion of interconnected capacity in to the Capacity Market. These include:

    i. Verification: It would be necessary to have cooperation between System Operators so that the physical capacity of plant situated outside of GB can be verified, as well as their delivery of energy at times of stress. Assessing whether parties overseas have delivered energy at times of stress may be complex as they will be participating in a different energy market – for instance they may be constrained off due to local constraints.

    ii. Additionality: It would be difficult to assess the appropriate derating of interconnected plant where their contribution is significantly limited by the transmission constraints between them and the GB market and where interconnectors may be flowing out of GB as well as in at times of stress.

    iii. Eligibility: We have excluded from the CM plant already in receipt of particular types of support to avoid the risk of overpayment. However different markets in Europe may each have their own set of support schemes and there will be complexity in assessing whether capacity overseas would be overpaid if they received capacity payments in GB.

    iv. Compatibility with the Target Model: It is the objective of the Target Model to ensure that interconnector flows are determined implicitly by price differentials between the markets, rather than explicitly through procurement of physical transmission rights over the interconnector. This means that it is not possible to identify whether any particular plant has directly contributed to interconnector flows. Because of this it would be impossible to impose a CM penalty on a non-GB generator if it had delivered in its home market, but the interconnector from that market to GB was not delivering energy (and hence its capacity) to GB. Because of this it is difficult to see how the treatment of non-GB plant could be equitable with GB plant given that when a plant delivers in GB it clearly always primarily delivers its energy (and capacity) onto the GB system.

10. While the Capacity Market will be introduced without foreign plant being able to participate, we are continuing to work with industry and other member states to find a suitable proposal for including interconnected capacity in future that addresses the issues above.

Annex F: Rules for Applying Penalties

1. Previous analysis – in Annex A of the Capacity Market IA issued in November 2012[79] – addressed the decision to set penalties for capacity providers that fail to deliver energy at times of stress. This analysis focuses on two key elements in relation to penalties – the level of VOLL and the imposition of a penalty cap.

Rationale for having penalties

2. The penalty regime in the Capacity serves two main purposes:

   i. Performance Incentives: The Capacity Market gives providers a stable payment but reclaims this money in the event that providers fail to deliver energy at times of system stress. In an efficient energy-only market, prices would rise to VoLL at times of stress, providing generators with a powerful incentive to be available at those times and to invest in the reliability of their plant. An important principle of the Capacity Market design has been that the incentives created should, wherever possible, mirror the incentives that would exist in an efficient energy-only market.

   ii. Adjusting of capacity value: The presence of sharp penalties for failure to deliver energy at times of system stress provides an incentive for participants in the auction not to offer unreliable capacity into the auction. This ensures that the mechanism procures the plant mix that is best value for consumers (rather than plants that are least cost in the auction but have little ability to deliver energy when needed). In practice the capacity value of plants will be administratively determined (within bands) and there will be some degree of uncertainty when setting the derating for each plant – with deratings overestimated for some plant and set too low for others. The penalty regime – with rewards for overdelivery and penalties for underdelivery – should ensure that over time the overall levels of payment for each plant match the value of the capacity that plant offers.

Design of the penalty regime

3. The penalty regime aims to reintroduce the incentives not present in the market due to "missing money". Missing money principally occurs at times of lost load when the price in a perfectly efficient energy-only market should rise to VoLL (estimated in GB to be £17,000/MWh). In practice this is significantly above past prices (which have not been seen to rise above £1000/MWh) and future proposals for cash out reform (which will introduce a £6000/MWh scarcity price signal).[80]

4. The level of missing money is therefore estimated as VoLL minus the prevailing cash out price. If cash out in future rises to £6,000/MWh then the level of missing money at times of stress is £11,000/MWh.

5. However there is a trade-off between having penalties that reflect the full degree of missing money and reducing risk for investment in new capacity. In an energy-only market it is necessary for scarcity signals to fully reflect VoLL in order to ensure there are

[79] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf
[80] See section 4.14 of this IA for further detail.

sufficient incentives for investment in new capacity. However by having a separate capacity payment the introduction of a Capacity Market allows for investment to be remunerated in a way that is less risky for investors – mitigating the significance of performance risk. This is achieved in two ways:

i. Cap on liabilities: Unlike in an energy-only market, liabilities in the Capacity Market will be capped in proportion to their capacity payment.

ii. Lower level of VoLL: It is assessed that incentives do not need to reflect the full VoLL as performance incentives will still be very strong if lower, and as a lower penalty rate still enables payment to unreliable plant to be reclaimed. The lower level of VoLL will be determined through the use of a scaling 'z' factor in the penalty rate.

Nature of cap on liabilities

6. The cap on liabilities has been designed with two important features:

   i. Soft cap: The cap has been designed so that once plants have hit their liability cap they can still "roll back" their penalties in subsequent events. This ensures that plants always retain strong incentives to delivery.

   ii. Portfolio definition: The cap applies at a portfolio level. Large portfolio players are therefore unlikely to benefit from the cap as their portfolio provides them with a hedge against liabilities (as at least some plants are likely to deliver in a large portfolio), whereas independent players – who need the cap most to attract project finance – gain most from it as it provides a hedge against individual plant performance risk.

Level of liability cap and 'Z' factor

7. In an energy-only market, capacity would have to be available and generating at times of lost load to earn the market revenues equivalent to the missing money. Hence, the annual penalty cap level should at least be 100% of annual capacity payments to mimic energy-only market incentives,.
8. In addition, we are consulting on setting the annual penalty cap above 101% to minimize the risk of gaming in the CM, as it prevents CM participants (existing capacity) that never intended to perform in the CM from taking a gamble with the expectation of receiving capacity payments without facing significant loses. This should ensure value for money to consumers.
9. We are also consulting on the level of 'Z' (which determines the rate at which the penalty cap is reached) such that the CM penalty rate lies within the £1,000-£3,000 MWh range. If as a result of Ofgem's EBSCR proposal cash-out prices of £6,000/MWh in times of system stress the energy market has strong performance incentives, then the CM penalty rate would represent a top-up to the cash-out price. Whilst the objective of the penalty rate is to reduce the amount of capacity payments and penalize CM participants that do not perform as required by providing levels of reliability below their de-rating factors, topping up the cash out price signal with a higher penalty rate (greater than

£3,000/MWh) would, however, provide minimal benefit in terms of performance incentives (as a £6,000/MWh signal is already sufficiently high).

10. It is proposed that the optimal combination of penalty rate and penalty cap is a high cap (greater than 101%) and a lower penalty rate (£1,000 to £3,000/MWh), which provides consumer value for money and reduces the penalty risk exposure for participants, especially in combination with the other design features of the mechanism (e.g. load following obligations, secondary trading and the Capacity Market Warning). Alternative combinations, such as a low cap and a high penalty rate or a high cap and a high penalty rate, have been discounted on the grounds of gaming risk, poor value for money or barrier to entry concerns. In calibrating the annual penalty cap and the penalty rate level however, careful consideration will have to be given to ensure that the penalty regime does not block efficient entry in the capacity market to ensure that capacity auction prices remain competitive.

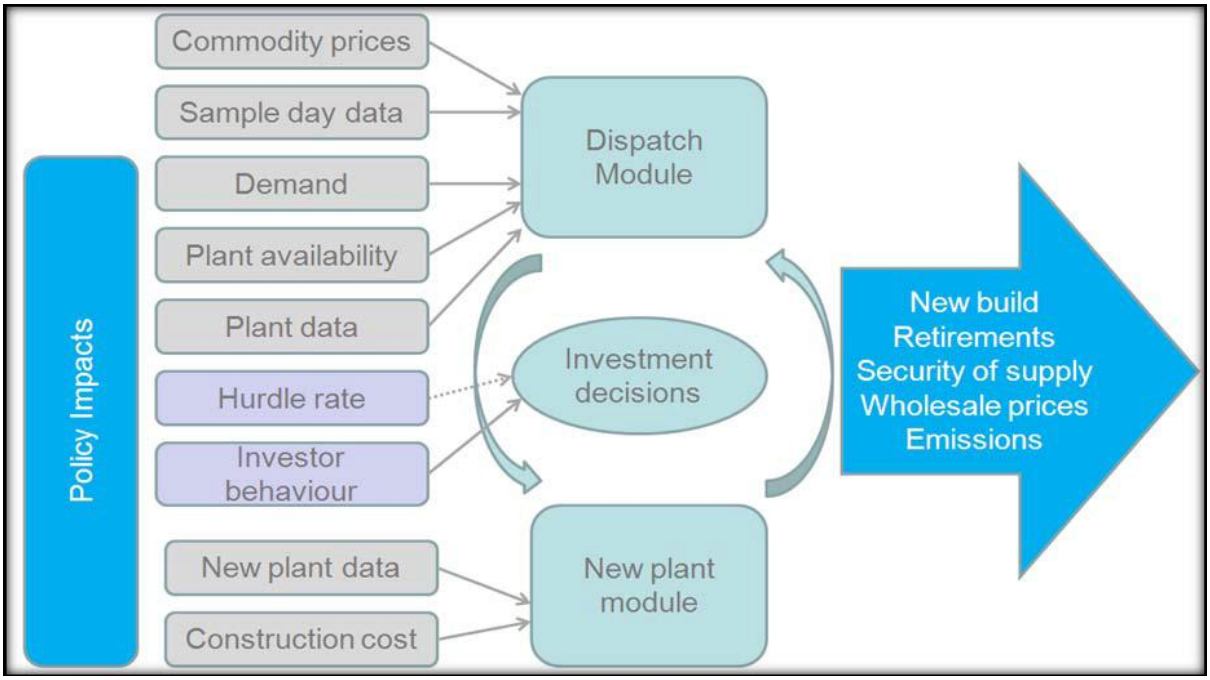
Annex G: Energy System Modelling

1. The Dynamic Dispatch Model (DDM) is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from construction through to decommissioning. The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of supply and carbon emissions, and also outputs comprehensive and consistent Cost-Benefit Analysis results.

Overview

2. The DDM is an electricity supply model, which allows the impact of policies on the investment and dispatch decisions to be analysed. Figure 27 illustrates the structure of the model.

Figure 27: Structure of the Dynamic Dispatch Model (DDM)



The purpose of the model is to allow DECC to compare the impact of different policy decisions on capacity, costs, prices, security of supply and carbon emissions in the GB power generation market.

Dispatch Decisions

3. Economic, energy and climate policy, generation and demand assumptions are external inputs to the model. The model runs on sample days, including demand load curves for both business and non-business days, including seasonal impacts and are variable by assumptions on domestic and non-domestic sectors and smart meter usage. Also, there are 3 levels of wind load factor data applied to the sample days to reflect the intermittency of on- and offshore wind. The generation data includes outage rates,

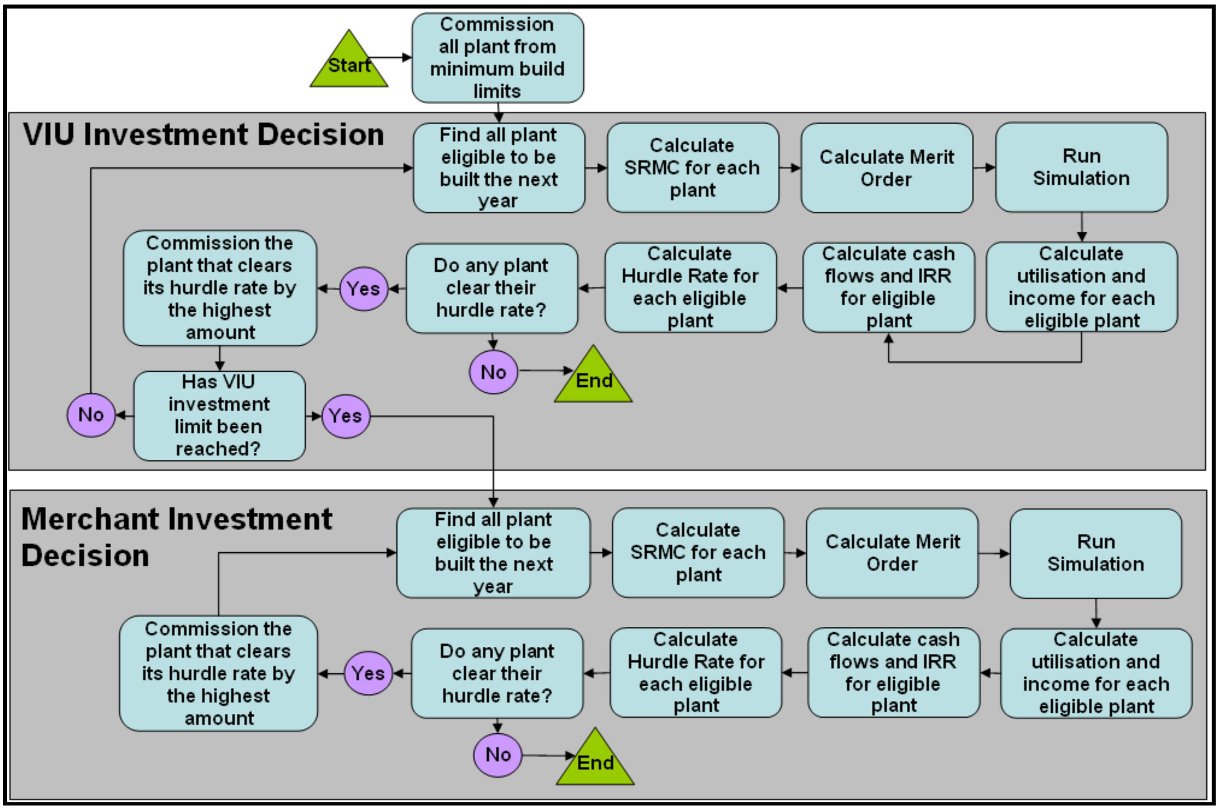
efficiencies and emissions, and also planned outages and probabilities of unplanned outages.

4. The Short Run Marginal Cost (SRMC) for each plant is calculated which enables the calculation of the generation merit order. Demand for each day is then calculated taking wind profiles into account and interconnector flows, pumped storage, autogeneration and wind generation. Once the required reserve is calculated the system SRMC is calculated by matching the demand against the merit order and taking the SRMC of the marginal plant to meet demand. The wholesale price is equal to the system marginal price plus the mark up. The mark up is derived from historic data and reflects the increase of system marginal price above marginal costs at times of reduced capacity margins. Plant income and utilisation are calculated and carbon emissions, unserved energy, and policy costs are reported.

Investment Decisions

5. The model requires input assumptions of the costs and characteristics of all generation types, and has the capability to consider any number of technologies. In investment decision making the model considers an example plant of each technology and estimates revenue and costs in order to calculate an IRR. This is then compared to a user specified technology specific hurdle rate and the plant that clears the hurdle rate by the most is commissioned. This is then repeated allowing for the impact of plants built in previous iterations until no plant achieves the required return or another limit is reached. The model is also able to consider investment decisions of both Vertically Integrated Utilities (VIUs) and merchant investors, see figure 28. Limitations can be entered into the model such as minimum and maximum build rates per technology, per year, and cumulative limits.

Figure 28: Investment decisions in the DDM



Policy Tools

6. The model is able to consider many different policy instruments, including potential new policies as well as existing ones. Policies are implemented by making adjustments to plant cashflows which either encourage or discourage technology types from being built in future and impact on their dispatch decisions. The policy modelling has been designed flexibly and policies can be applied to all technologies or specific ones, only new plants or include existing plants and be varied over time and duration. Policies can be financed through Government spending/taxation or charged to consumers.

Outputs

7. The model can be run in both deterministic and stochastic modes – this enables analysis to be carried out with different levels of randomness, allowing for more realistic treatment of uncertainty to be incorporated into the model outputs and better understanding of investment behaviour. The model outputs many metrics on the electricity market and individual plant that enables the policy impacts to be interpreted. Using these outputs a Cost Benefit Analysis is carried out on the model run including a distributional analysis.

8. The DDM therefore enables analysis to be carried out on policy impacts in different future scenarios, allowing DECC to consider and compare the estimated impacts of different potential policies on the electricity market.

Peer Review

9. The model was peer reviewed by external independent academics to ensure the model is fit for the purpose of policy development. Professors David Newbery and Daniel Ralph of the University of Cambridge undertook a peer review to ensure the model met DECC's specification and delivered robust results. The DDM was deemed an impressive model with attractive features and good transparency. For the Peer Review report see 'Assessment of LCP's Dynamic Dispatch Model for DECC' (http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/5427-ddm-peer-review.pdf).

Levy Control Framework

10. On 23 November 2011, the Government agreed a Levy Control Framework (LCF) to 2020, which is set at a total of £7.6bn (in real, 2012 prices).[81] This will help diversify our energy mix by increasing the amount of electricity coming from renewables (from 11% today to around 30% by 2020), as well as supporting new nuclear power and carbon capture and storage commercialisation. It also helps to provide certainty to investors across a range of generation technologies and protection to consumers.

Scenario-based analysis

11. The baseline for DDM analysis represents a plausible outcome of Electricity Market Reforms, characterised by a diversified supply mix[82] and an assumed carbon emissions intensity of 100gCO_2/kWh in 2030, which is an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments.

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[81] http://www.decc.gov.uk/en/content/cms/news/pn12_0146/pn12_0146.aspx

[82] Diversification reflects (in part) the objective of support for the development of a portfolio of low-carbon generation technologies, in order to reduce the technology risks associated with the decarbonisation objective for the power sector

12. Dispatch modelling is sensitive to a number of such assumptions (e.g. around inputs, methodology), which influence the capacity and generation mix realised under different scenarios. This outcome therefore represents a specific state of the world and is not intended to be a prediction or forecast about what the future is expected to be.

13. Given the considerable uncertainty over how the electricity sector will develop to 2030, we are also developing different sets of assumptions to represent other potential future scenarios, which can then be modelled using DDM analysis. These scenarios reflect possible futures in which one low-carbon generation technology (nuclear, CCS, renewables) is deployed more heavily than the others. These recognise that there will be changes that we cannot predict in the supply chain, planning and grid constraints on deployment, technology costs and wider impacts of different technologies. Nevertheless, these scenarios include many common assumptions such as the modelling of EMR policies, fossil fuel prices, demand and the decarbonisation of the power sector to 100gCO_2/kWh by 2030.

Input assumptions

Fossil fuel price assumptions

DECC's fossil fuel price assumptions are used in the DDM as set out below to 2030. Details can be found at https://www.gov.uk/government/publications/fossil-fuel-price-projections-2013

2012 prices	Oil			Gas			Coal		
	$/bbl			p/therm			$/tonne		
	Low	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**
2012	112	112	112	60	60	60	92	92	92
2013	93	108	122	53	62	72	85	90	94
2014	92	109	126	51	65	86	86	96	105
2015	91	110	129	48	68	89	87	102	110
2016	89	112	132	46	69	91	88	106	116
2017	88	113	136	44	71	93	88	109	121
2018	87	114	140	41	72	96	89	113	126
2019	86	116	143	41	72	98	90	117	131
2020	84	117	147	41	72	101	91	120	136
2021	83	119	151	41	72	103	91	120	142
2022	82	120	155	41	72	103	91	120	147
2023	81	122	159	41	72	103	91	120	152
2024	80	123	163	41	72	103	91	120	157
2025	79	125	168	41	72	103	91	120	162
2026	78	126	172	41	72	103	91	120	162
2027	77	128	177	41	72	103	91	120	162
2028	76	129	181	41	72	103	91	120	162
2029	75	131	186	41	72	103	91	120	162
2030	74	132	191	41	72	103	91	120	162

Carbon Prices

The DDM uses DECC's appraisal values for carbon, as set out below.

DECC appraisal values for greenhouse gas emissions impacts in the traded sector, 2012 £/tonne of CO2e

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central	6	3	4	4	4	4	4	4	5	12	19	26	33	40	47	54	61	68	75

In addition to this the Carbon Price Floor is included in the model following the trajectory set out in the government's response to the consultation on the Carbon Price Floor:
http://www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf

Carbon Price Floor, 2012 £/tonne of CO2e

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7	12	19	23	25	28	30	32	36	41	45	49	53	58	62	66	70	75

Technology Assumptions

Cost and technical data for new plant is taken from DECC's Electricity Generation Costs 2013 report for all renewable and non-renewable

technologies. Details can be found at:

https://www.gov.uk/government/publications/electricity-generation-costs

Modelling Assumptions

14. A range of assumptions were made for the effects of the different policy instruments to be modelled. These are published on DECC's website.[83]

15. **Decarbonisation**: the indicative target used is 100gCO_2/kWh in 2030, which is consistent with modelling for previous capacity mechanism Impact Assessments.

16. **Renewables uptake**: Consistent with the lead scenario of the Renewable Energy Strategy, it is assumed that around 105TWh of GB electricity demand is met by renewable generation by 2020.

17. **Carbon prices**: These are assumed from 2013 to follow the Carbon Price Floor levels announced in Budget 2011.[84] The carbon price is set to £7/tCO_2 in 2013 rising to £32/tCO_2 in 2020.

18. **Fuel prices**: fuel price assumptions are based on DECC's Updated Energy and Emissions Projections (UEP) Central Price case.[85]

19. **Demand**: demand assumptions are based on results of the UEP Central scenario for total electricity supply.[86]

20. **Capital costs**: Capital cost assumptions for non-renewable new build have been provided by PB Power's 2012 electricity generation cost model and capital cost assumptions for renewable new build are from the 2012 Study Report by Arup. Both are listed on the DECC website.[87] Capital cost assumptions have also been taken from DECC's Electricity Generation Costs 2013 report.[88]

21. **Hurdle rates**: Hurdle rates are based on assumptions by Oxera (2011) and Arup (2011) and are informed by market data points.[89]

22. **Investor foresight**: Investor foresight of demand, the carbon price and the wholesale price is assumed to be 5 years, in line with the assumptions made in the Electricity Market Reform White Paper. Investors have foresight of support levels for the length of the contract.

23. **Transition/timing**: In the model capacity auctions begin from 2014 with a first delivery year of 2018/19. All new low-carbon capacity that comes on from 2016 onwards is assumed to be through the CfD, rather than the RO.

Limitations of the modelling

24. There are important limitations to the modelling. Two significant ones from a security of supply perspective are:

    - It assumes perfect foresight of demand. This means that the model finds that the economically efficient capacity level is close to zero. In practice demand is uncertain and the risks to building too little are greater than the risks of building too much, so the economically efficient capacity level is higher in reality.
    - It doesn't model the effects of plants needing to be warm In order to operate. As a result it may underestimate the likelihood of scarcity events or prices rising above marginal cost when margins are wide. It also fails to reflect the effect of cash out reform on the degree of plant warming or on the market incentives to invest in plant faster ramp-up times.

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[83] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_dispatch/gen_dispatch.aspx
[84] http://www.hm-treasury.gov.uk/consult_carbon_price_support.htm
[85] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx
[86] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx
[87] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_costs/gen_costs.aspx
[88] https://www.gov.uk/government/publications/electricity-generation-costs
[89] The minimum rate or return needed for investors to be willing to make a particular investment

Capacity Market

25. To capture the effect of capacity contracts, both the contract allocation process (auction) and the effect on the wholesale electricity market have been modelled.

26. The auction process is modelled by a ‘stack’ of the capacity offered into the auction. For simplicity we have assumed that all existing and potential new generators are bidding in their de-rated capacity to the auction. However low-carbon plant in receipt of payment through the RO and CfD is not eligible for capacity payments.

27. The bid prices for each generator are calculated based on the required additional revenue to extend the plant lifetime or build a new plant.

28. In each year, the auction ‘stack’ requires as inputs the volumes of capacity offered by each generator or new project and the prices at which this capacity is offered. Each generator offers at a price which makes their generation or project profitable, de-rated by the standard capacity credits in the Electricity Market Reform modelling. From this ‘stack’, the auction clearing price for each year is calculated, along with which plant receive the reliability contracts.

29. The key parameters for a modelled Capacity Market[90] are:

- The volumes of capacity procured by the central buyer are sufficient to deliver 3 hours lost load per year. This is open to all eligible capacity and there is no differentiation based on flexibility.
- CfD and RO-funded plant as well as interconnected capacity are assumed to not receive capacity payments, although their capacity credit is taken into account when setting the level of capacity to contract for. Interconnection is assumed to have a derating factor up to 57% by 2025, implying imports of up to 3GW of generation at times of system stress.
- Contract length: 1 year contracts for existing plant and ten-year contracts for new plant.
- Once a generator has physically closed it cannot re-enter the auction in a later year –i.e. the possibility of mothballing capacity has not been considered.
- Generators offer their de-rated capacity factors into the auction.
- Plant that have signed a multi-year reliability contract bid in at zero, while they are being paid the contracted level.
- All plant operating under the Limited Lifetime Opt-out (LLO) mechanism must close in 2023.

[90] Note that these parameters have been formulated for modelling purposes, and do not reflect latest developments in terms of policy design for the Capacity Mechanism. More detailed design (and updated analysis) will be set out in due course.