Title: Electricity Market Reform – Capacity Market **IA No:** DECC0103 **Lead department or agency:** DECC	**Impact Assessment (IA)** **Date:** 27/11/2012 **Stage:** Final **Source of intervention:** Domestic **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, One-Out?**	**Measure qualifies as**
£-1.7bn	-£289m		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 looks at the optimal form of Capacity Market and assesses three options:

1. **Business As Usual** (BAU): Electricity Market Reform is implemented without a capacity mechanism.
2. **Administrative Capacity Market**: A market-wide mechanism is introduced to ensure sufficient capacity is brought forward. Generators face administratively-set penalties if not delivering energy when needed.
3. **Reliability Market**: A market-wide financial capacity mechanism is introduced, buying insurance against price spikes for consumers. This gives generators a market-based incentive to be available when needed.

Option 2 (Administrative Capacity Market) is the favoured option as it ensures security of supply objectives are met without being an undue intervention in the market.

This Impact Assessment follows a previous Impact Assessment published in December 2011 which favoured a Capacity Market over a targeted Strategic Reserve on the basis that a market-wide solution is needed to address enduring problems with an energy-only market that mean it could fail to bring on sufficient new capacity.

The analysis presented in this IA is based on an agreed set of assumptions, including technology costs and electricity demand at the time the analysis was undertaken, but with no affordability constraint. This set of assumptions is set out in Annex C. It has not been possible to reflect the very recent decision on the levy control framework or the OBR growth figures to be published alongside the Autumn Statement. However, as outlined in this IA, we believe the EMR framework and policy suite (including the Capacity Market) are robust to various states of the world as reflected in the range of scenarios included in this IA.

In addition, in the Energy Bill the Government will take a power to set a decarbonisation target range for the power sector in secondary legislation. The power will provide for flexibility in the setting or reviewing of the range by consideration of wider economic factors. The decision to set a target range for carbon emissions in 2030 should be taken when the Committee on Climate Change has provided advice on the 5th Carbon Budget which will cover the corresponding period (2028 – 2033), and once the Government has set that budget. The power will not be exercised until the Government has set the 5th Carbon Budget.

The analysis presented in the Capacity Market Impact Assessment uses $100gCO_2/kWh$ as an illustrative level of decarbonisation in the power sector, consistent with previously published Capacity Market Impact Assessments. To reflect the decision to take a power to set a decarbonisation range (and the decision on the levy control framework) we will be updating the analysis early in the New Year to consider the impact of a Capacity Market if the power sector decarbonised to an average emissions level of $200gCO_2/kWh$ in 2030. In addition, the update will include sensitivity analysis of a $50gCO_2/kWh$ emissions intensity level.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** See Section 9

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:** **22 $MtCO_2$**	**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: 27/11/2012

Summary: Analysis & Evidence

Policy Option 1

Description: Business As Usual: No Capacity Market is introduced. Other parts of Electricity Market Reform (EMR) are introduced, including the Contract for Difference to incentivises investment in low carbon capacity.

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2010	Time Period Years 19	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate:

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				

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

This option is the baseline against which other options are compared so there are no costs or benefits.

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

In the BAU case the intermittency of electricity generation increases as up to a quarter of generating capacity in 2020 comes from wind and as around a fifth of capacity available in 2011 has to close this decade.

Ofgem estimates de-rated capacity margins falling to 4% by winter 2015/16. In most years the System Operator should be able manage system stress events through voltage reductions with minimal impacts on consumers. However with tightened margins the risk of customer disconnections will rise to 1 in 12 years in Ofgem's base case. Risks could be more severe under some Ofgem scenarios.

Under DECC de-rated modelling, capacity margins are expected to tighten over this decade and to fall below 10% by 2022. The risk of some customer disconnections could rise to 1 in every 4 years from 2024.

In addition, in the BAU case, wholesale prices can rise to very high levels at times of scarcity leading to transfers between consumers and producers. As capacity margins tighten prices are likely to increase for consumers.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				

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

n/a

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

n/a

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

Prices in the wholesale energy market are assumed in the base case to rise to £10,000/MWh when there is lost load (equivalent to around £7 per hour for a typical domestic household). More significant security of supply risks could materialise if arrangements for cash out are not sufficiently reformed to allow prices in the electricity market to reflect scarcity. In this case the market could fail to bring forward sufficient capacity, particularly in the 2020s as the power sector decarbonises, and the market may fail to bring forward the right type of capacity (i.e. that is sufficiently reliable and flexible); generators may have insufficient incentives to be available when needed; and GB could be exporting to Europe at times of scarcity if GB prices failed to sufficiently reflect scarcity here. A decarbonisation trajectory of 100gCO_2/kWh in 2030 is assumed.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: n/a	**Benefits: n/a**	**Net: n/a**	No	N/A

Summary: Analysis & Evidence

Policy Option 2

Description: Administrative Capacity Market

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2010	Time Period Years 19	Net Benefit (Present Value (PV)) (£m)		
			Low: -2087	High: 4,218	Best Estimate: -1,738

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	48	6	177	**2,079**
High	268		236	**2,610**
Best Estimate	158		177	**2,079**

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 £1.5billion. Distributional analysis shows that this cost is largely borne by consumers through electricity bills.
2. **Business administrative costs** are estimated to be £14m per year, with a PV to 2030 of £240 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 £30m 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 Administrative 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	0	6	16	**170**
High	0		621	**6828**
Best Estimate	0		33	**340**

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

An Administrative Capacity Market incentivises additional capacity which reduces the likelihood of blackouts and voltage reductions. This reduction in energy unserved is valued at £340 million in the base case. 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'

An Administrative Capacity Market has a number of significant non-monetised benefits (discussed further in Section 6):

- an Administrative Capacity Market mitigates against the risk that an energy-only market fails to bring forward sufficient investment in capacity as a result of 'missing money';
- an Administrative Capacity Market provides a more predictable revenue stream for capacity providers which can lower financing costs for new capital; and
- an Administrative 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

We have assumed the first auction is run in 2014, with a delivery year of 2018/19.
In the Administrative Capacity Market, capacity providers are entitled to keep any scarcity rents they earn in the energy market. 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 revenue to provide capacity).
Valuations of the costs of blackouts and brownouts (value of lost load) are highly uncertain. For the purposes of modelling, we have used a value of £10,000/MWh (equivalent to around £7 per hour for typical domestic household). In the High Net Benefit Scenario we assume a £30,000 VoLL and model a stress test including higher demand, delays to low carbon investment and a £500/MWh price cap. A decarbonisation trajectory of 100gCO_2/kWh in 2030 is assumed.

BUSINESS ASSESSMENT (Option 2)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: 2,903	Benefits: 2,614	Net: -289	No	N/A

Summary: Analysis & Evidence

Policy Option 3

Description: Reliability Market

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2010	Time Period Years 19	Net Benefit (Present Value (PV)) (£m)		
			Low: -3,385	High: 3,352	Best Estimate: -2,820

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	816	6	202	**3,161**
High	1420		257	**3,555**
Best Estimate	1118		202	**3,161**

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

Modelled costs are the same as under an Administrative Capacity Market but there are additional Option Trading costs:

1. **Energy system costs**: The impact on energy system costs have a lifetime PV of £1.8billion.
2. **Business administrative costs** are estimated to be £14m per year, with a PV to 2030 of £240 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 £30m in the base case. Institutional costs are lower in the transition period.
4. **Option trading costs**: these are the costs to the market from reliability options prompting a change in how the market trades energy. The cost is £1.1bn PV and is based on previous cost estimates of moving to NETA.

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

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

- Whether the capacity auction is competitive/liquid;
- The degree to which a Reliability Market can bring down investment financing costs
- 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	0	6	16	**170**
High	0		621	**6828**
Best Estimate	0		33	**340**

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

A Reliability Market incentivises additional capacity which reduces the likelihood of blackouts and voltage reductions. This reduction in energy unserved is valued at £340 million in the base case. However a small change to assumptions around demand or delays to low carbon significantly increase expected benefits.

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

A Reliability Market has a number of significant non-monetised benefits (discussed further in Section 6):

- a Reliability Market mitigates against the risk that an energy-only market fails to bring forward sufficient investment in capacity as a result of 'missing money';
- a Reliability Market provides a more predictable revenue stream for capacity providers which can lower financing costs for new capital; and
- a Reliability Market has the potential to reduce gaming opportunities in the energy market by capping generators' revenues so they don't stand to gain from driving the price above the strike price..

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

We have assumed the first auction is run in 2014, with a delivery year of 2018/19.

In a Reliability Market providers have to pay back the difference between the short term wholesale market price and the agreed strike price when prices exceed the strike price (£500/MWh). Generators bid in the true level of support they need in addition to electricity market revenue to provide capacity.

Valuations of the costs of supply disruption (i.e. the value of lost load) are highly uncertain. For the purposes of modelling, we have used a value of £10,000/MWh (equivalent to around £7 per hour for typical domestic household). In the High Net Benefit Scenario we assume a £30,000 VoLL and model a stress test including higher demand, delays to low carbon investment and a £500/MWh price cap. A decarbonisation trajectory of $100gCO_2/kWh$ in 2030 is assumed.

BUSINESS ASSESSMENT (Option 3)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: 3,985	**Benefits: 2,614**	**Net: -1,371**	No	N/A

Evidence Base (for summary sheets)

Contents

1 Introduction

1.1 The Government will take powers in the Energy Bill to run a Capacity Market. The Capacity Market, if required, will incentivise sufficient reliable capacity (both supply and demand side) to ensure a secure electricity supply even at times of peak demand.

1.2 This impact assessment (IA) presents an appraisal of the options for a Capacity Market to be introduced in the GB electricity market. The analysis presented in this IA is based on an agreed set of assumptions, including technology costs and electricity demand at the time the analysis was undertaken, but with no affordability constraint. This set of assumptions is set out in Annex C. It has not been possible to reflect the very recent decision on the levy control framework or the OBR growth figures to be published alongside the Autumn Statement. However, as outlined in this IA, we believe the Capacity Market is robust to various states of the world.

1.3 In addition, in the Energy Bill the Government will take a power to set a decarbonisation target range for the power sector in secondary legislation. The power will provide for flexibility in the setting or reviewing of the range by consideration of wider economic factors. The decision to set a target range for carbon emissions in 2030 should be taken when the Committee on Climate Change has provided advice on the 5th Carbon Budget which will cover the corresponding period (2028 – 2033), and once the Government has set that budget. The power will not be exercised until the Government has set the 5th Carbon Budget.

1.4 The analysis presented in this Impact Assessment uses 100gCO_2/kWh in 2030 as an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments.

1.5 To reflect the decision to take a power to set a decarbonisation range (and the decision on the levy control framework) we will be updating the analysis early in the New Year to consider the impact of a Capacity Market if the power sector decarbonised to an average emissions level of 200gCO_2/kWh in 2030. In addition, the update will include sensitivity analysis of a 50gCO_2/kWh emissions intensity level.

1.6 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.

1.7 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".

1.8 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.

1.9 DECC’s latest energy system modelling supports Ofgem’s assessment[1] and the analysis in the Electricity Market Reform White Paper[2] 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.

1.10 The Government is minded to run the first auction in 2014, for delivery of capacity in the year beginning in the winter of 2018/19. A final decision will be taken subject to evidence of need. This will be informed by updated advice from Ofgem and National Grid which will consider economic growth, recent investment decisions, the role of interconnection and energy efficiency, as well as consideration of the outcome of the review of the 4th Carbon Budget.

1.11 The Government will provide further analysis on the evidence of need for a capacity auction, including in its first delivery plan. This will be published by the end of 2013 (subject to Royal Assent) and will be informed by evidence and analysis including Ofgem’s statutory Electricity Capacity Assessments for 2012 and 2013 and analysis provided by National Grid as the delivery body for EMR.

1.12 Our base case analysis shows that a Capacity Market is expected to have a net cost of £1.7bn relative to a scenario of an efficient energy market – i.e. where the energy price is reformed to reflect consumer’s value of lost load and where the market is able to invest on the basis of scarcity rents. However as this assumes a perfectly efficient energy market it necessarily concludes that a Capacity Market has a net cost.

1.13 In practice the energy market does not work perfectly. We are concerned that the market may fail to deliver an adequate level of reliable capacity due to imperfections in the current cash out arrangements and due to investor concerns about the riskiness of investing in capacity that may have low load factors and be reliant on recovering fixed costs through scarcity rents. This may result in a lack of liquid forward markets for investors to attain project finance.

1.14 A Capacity Market could have a significant net benefit given that an energy-only market could fail to bring on an adequate level of capacity. Our modelling suggests that if prices were not able to rise sufficiently to reflect consumers’ aversion to being disconnected a Capacity Market could have a net benefit of up to £4.2bn in our stress test.

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

1.15 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.

1.16 The leading options for a Capacity Market (a Reliability Market and an Administrative Capacity Market), are assessed with quantitative and qualitative analysis. The quantitative analysis (Section 5) shows that both options lead to a small increase in consumer bills (around £14 per year for an average domestic household in the period in which a Capacity Market is bringing on additional capacity), though the impacts are less in the stress test. However an Administrative Capacity Market has lower initial costs than a Reliability Market, as a Reliability Market creates significant additional exposure to a volatile real-time price, potentially prompting parties to trade financial options around this market.

1.17 The qualitative analysis (Section 6) looks at those wider impacts and provides a more robust and comprehensive assessment of the options. In particular it considers how well both options fit within the existing market structure, noting challenges around compatibility with the Single Market and interactions with the cash out regime. Section 7 concludes that, based on all the analysis, an Administrative Capacity Market is more likely than a Reliability Market to deliver security of supply objectives at least cost to consumers and is more likely to be deliverable in time for a potential first auction in 2014.

1.18 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 penalty regime for an Administrative Capacity Market; and
ii) The auction format

2 Objectives

2.1 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 is currently minded to 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, if needed.

3 Rationale for Intervention

Introduction

3.1 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 supplier 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.

3.2 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.

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

3.4 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 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

3.5 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:

3.6 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.

3.7 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.

3.8 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.

3.9 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 two reasons below:

i. Current wholesale energy prices cannot 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 voltage reduction).
ii. 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.

3.10 The latter regulatory risk 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. This has not previously been a significant concern as prices historically have not risen above £938/MWh[3] as a result of excess capacity on the system depressing wholesale market prices. 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?

3.11 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. This is due in large part to the determination of imbalance prices ("cash out") failing to reflect the value of capacity at times of scarcity.[4] Cash out prices may fail to reflect scarcity for a number of reasons:

i. Cash out is not currently set according to the marginal cost of electricity, but rather the average cost of the 500MW of most expensive energy balancing actions.
ii. When there is insufficient supply to meet demand, leading to load being shed, cash out is not set at the Value of Lost Load (VoLL)[5]

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

[4] 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.

[5] This value is hard to determine as it varies over time and between persons. The December 2011 Impact Assessment noted a range of estimates between £5,000/MWh and £30,000/ MWh, with a £10,000/MWh value of lost load assumed in the quantitative modelling.

iii. Balancing services (such as Short Term Operating Reserve) are not properly priced into the cash out price. The System Operator procures reserve capacity through STOR to address short-term balancing issues, but when called upon this is then priced insufficiently high and so disincentivises the market from bringing forward sufficient capacity at times of scarcity.

3.12 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 pay to avoid being disconnected.

3.13 The failure of cash out prices to sufficiently reflect scarcity can have a number of negative implications for security of supply. These are:

i. *Risks from interconnection*: Interconnector flows with Europe should reflect price differentials between the connected markets. However if the GB price cannot rise sufficiently to reflect scarcity (and if the price in interconnected markets can better reflect scarcity) then it is likely that GB could be exporting at times of system stress. This could limit the benefits of greater interconnection and of progress towards a single market as it means interconnection could be a liability at times of system stress.

ii. *Lack of resource adequacy*: The lack of “scarcity rents” in the energy market for those available at times of system stress means the market may not provide sufficient signals for investment in additional capacity, especially because gas plants will run less often as we decarbonise the economy.

iii. *Incentives for capacity to be reliable*: The lack of “scarcity rents” fails to give appropriate incentives for the market to bring forward capacity that is reliable (this is likely to be a mix of plants, some baseload and some flexible) and to ensure that this plant has strong incentives to be available at times of system stress.

3.14 A more responsive cash out price could also create additional risk for market participants because suppliers and generators who fail to meet their contracted position are required to pay for the replacement supply at the cash out price. It might also have a particularly negative impact on smaller players and renewables that struggle to accurately predict their position ahead of gate closure.[6] Benefits to security of supply from cash out reform will have to be balanced against these costs, although it may be possible to mitigate some of the adverse effects through a single cash out price, balancing market, or renewables aggregator.

3.15 In August 2012 Ofgem launched a Significant Code Review of electricity balancing (including cash out). The Significant Code Review is a process which enables Ofgem to propose and implement changes to cash out. DECC supports Ofgem in reviewing whether the current balancing arrangements best deliver security of supply and cost-effectiveness for consumers.

[6] This effect could be partly mitigated through a single cash out price, which would reduce the incentive for parties to balance their positions ahead of gate closure, although this could make energy balancing post-gate closure more difficult and unpredictable for the System Operator.

Ofgem's Significant Code Review of Electricity Balancing

In August 2012 Ofgem launched a Significant Code Review of electricity balancing (including cash out). The Significant Code Review is a process which enables Ofgem to propose and implement changes to cash out. Ofgem's initial consultation sets out a wide range of policy options to address their concerns listed below:

- cash-out prices may not fully reflect scarcity at times of system stress
- cash-out prices may not provide the right incentives for demand side response (DSR)
- cash-out prices suffer from a lack of transparency and predictability
- dual cash-out prices have a large spread, resulting in imbalance risk and hampering the formation of reference prices
- participants are not incentivised to provide accurate physical notifications
- reconciliation cashflows are large and opaque, potentially causing inefficient allocation of costs to participants.

Longer term risks: missing money for reliable plant

3.16 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.

3.17 Over the next twenty years, our electricity generation mix will move away from flexible fossil fuel generation and towards more intermittent and less flexible generation, such as wind and nuclear. This change will put pressure on the energy-only market's ability to ensure sufficient flexible capacity to meet peak demand. Remuneration for such flexible capacity will be increasingly uncertain as more and more low marginal cost plant enters the market and pushes more flexible (but higher marginal cost) plant up the merit order.[7] Without intervention, this would mean flexible plant running less frequently and therefore increasingly relying on the very peaky prices that can occur at times of high demand and system stress in order to recoup their costs.

3.18 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 do not have confidence that the regulated market will be allowed to operate in an unconstrained way. For instance they may fear the intervention of the Regulator if the electricity price goes too high. Alternatively if scarcity rents do occur it could prompt Government to intervene and cap prices or put a windfall tax on generators if industry is perceived to be making 'excessive profits'. 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.

3.19 Even if investors do expect sufficient scarcity rents to justify investment, it may become increasingly difficult for them to get project finance. A fixed capacity payment could prove cost effective for consumers if it helps to bring down the financing costs for new capital. The impact of a Capacity Market on project finance for new gas plant is explored further in Section 5.

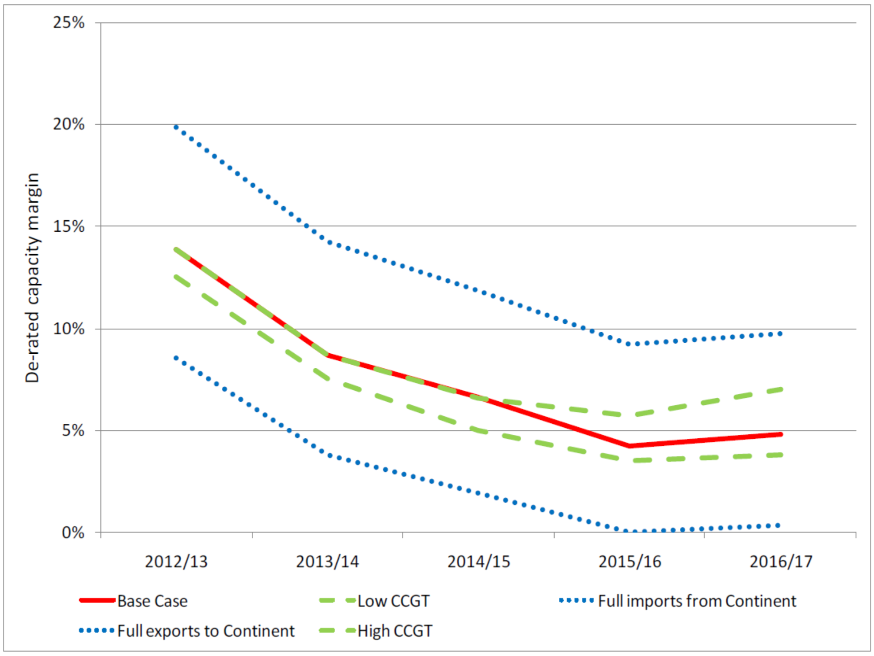
[7] The order in which different generation technologies are dispatched based on their short run marginal cost.

Security of Supply Outlook

3.20 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.

3.21 Ofgem has recently produced its first Electricity Capacity Assessment as part of its statutory obligation to review security of electricity supply. This assessment indicates that de-rated capacity margins[8] will tighten significantly from their current levels of around 14% to around 4% by 2015/16 in their base case scenario, though they estimate a range of outcomes depending on assumptions such as the contribution of interconnection and investment decisions to security of supply.

Figure 1: Ofgem estimates of de-rated capacity margins



3.22 The levels 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.

[8] 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.

DECC's energy system modelling

DECC's modelling of the energy system based on DECC's in-house Dynamic Dispatch Model (DDM). This analysis is consistent with the Energy and Emissions Projections published on 15 October 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. The IA includes 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 the previous two Impact Assessments on capacity mechanisms. We also include an indicative $200gCO_2$/kWh sensitivity, and will provide an update on $200gCO_2$/kWh and include a $50gCO_2$/kWh sensitivity in the New Year. Further detail about the modelling assumptions are set out in Annex C.

3.23 We have modelled security of supply out to 2030 if no Capacity Market is introduced under two scenarios:

i. **DECC base case**: This is in line with DECC's published projections of annual demand and fossil fuel prices;[9] It 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 fully cost-reflective. It also assumes that investors have certainty of demand up to five years out.

ii. **DECC stress test**: This is a plausible but more problematic scenario. This differs from the DECC base case in assuming higher levels of electricity demand based on National Grid's demand assumptions in their "Gone Green" scenario, that electricity prices are not able to rise above £500/MWh, and that there are delays to the deployment of low carbon capacity.[10] Demand in this scenario is assumed not just to be higher on average but to have a peakier profile than that assumed in the DECC base case, with one day a year when demand is one third higher than the average level of demand that year.[11] Consistent with previous publications, the power sector decarbonises to around $100gCO_2$/kWh in 2030.

[9] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx

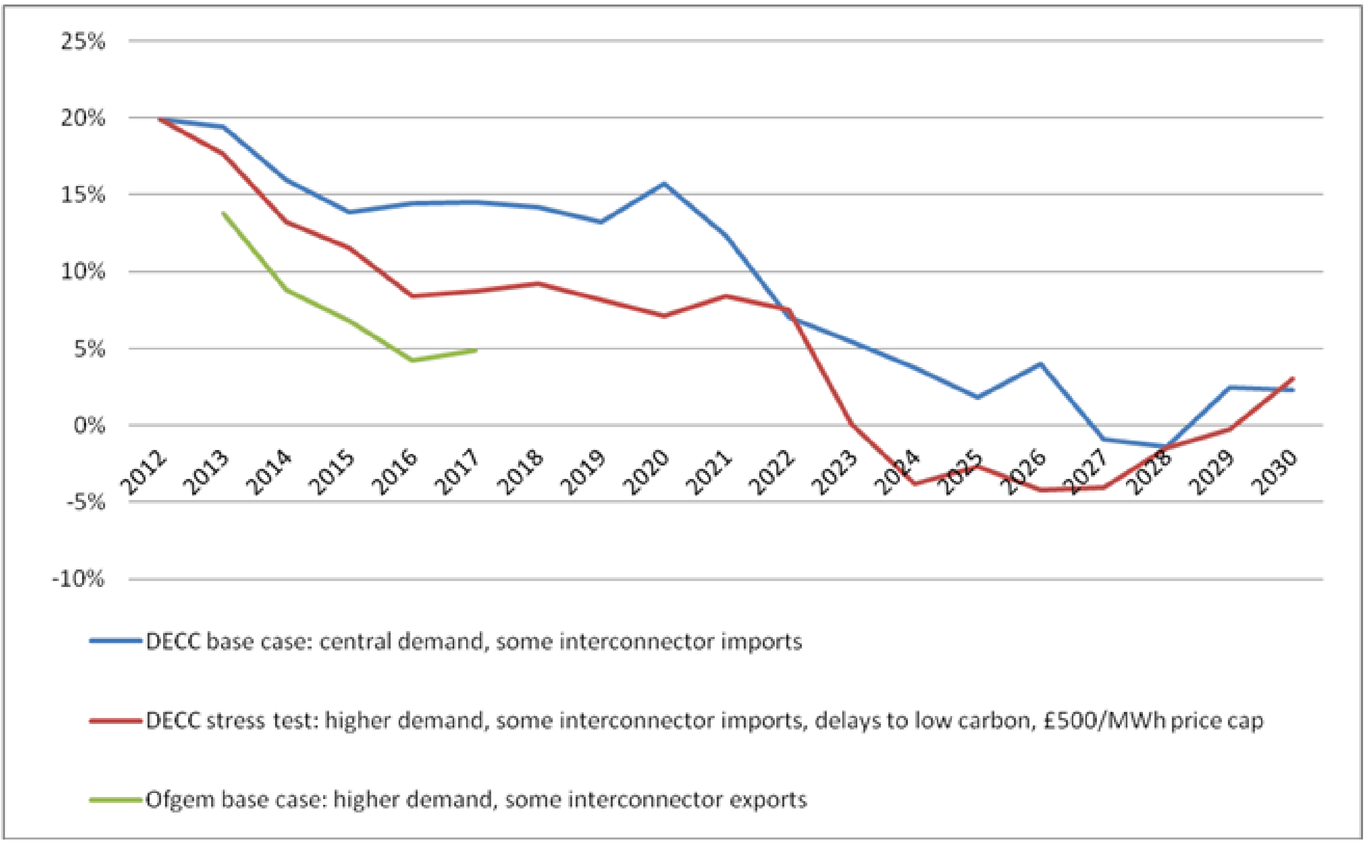
[10] The stress test includes a number of assumptions which will impact negatively on security of supply. Note that these assumptions are not in themselves implausible, but taken together, our judgement is that this represents a pessimistic appraisal of security of supply in the absence of a Capacity Mechanism. Key assumptions include:

- Demand following National Grid's assumed profile from their Gone Green scenario, rather than DECC UEP projections. In DECC's demand assumptions there is a large fall in electricity demand to 2020, whereas National Grid estimates a small rise. This is the most important difference in this scenario compared to the central scenario between now and 2020.
- A 2 year unexpected delay to the nuclear program meaning that the first new nuclear plant can only be built in 2021 rather than 2019.
- A moderate level of missing money, so that the maximum price in the wholesale electricity market would be £500/MWh rather than the £10,000/MWh price that is assumed in the base case.
- That biomass meets a lower proportion of our renewables targets than in the base case.
- An unexpected delay to 2GW of R3 offshore wind in 2021-22.

[11] Capacity Margins are lower in this scenario than in the base case in part because no additional capacity is brought on to be available on this extra high demand day given a £500/MWh price cap.

3.24 We compare these runs in the chart below with the base case scenario in Ofgem's Electricity Capacity Assessment out to 2016/17.

Figure 2: Ofgem and DECC estimates of de-rated capacity margins



3.25 In the Impact Assessment which accompanied the 2011 Technical Update, we projected that de-rated margins would be around 11% in 2016 in our base case, although they could fall to slightly below 10% in a stress test which had higher demand.

3.26 Since this analysis, demand has been more similar to the 2011 DECC base case than the 2011 DECC stress test. However, this analysis assumed that interconnectors were partly importing at times of system peak. If we had assumed that interconnectors would be exporting at times of system peak then de-rated margins in the scenario would have been slightly closer to Ofgem's by 2016.

3.27 In our current analysis using the DDM, de-rated margins in the base case do not dip below 10% until after 2020. This is partly explained by DECCs projection of electricity demand over the period, which is lower than previous projections. If we use National Grid's assumptions of demand (which were also used by Ofgem), then margins fall to below 10% in 2016. However under either assumption about demand, de-rated margins do not fall to uncomfortably low levels until the 2020s so long as we are not exporting at times of system peak.

3.28 The de-rated capacity margin in Ofgem's Electricity Capacity Assessment for 2015/16 is lower than DECC's projections (both the base case and stress test). A large part of the reason for this is the treatment of interconnectors. Both Ofgem and DECC assume exports to Ireland at times of system peak of around 1GW, but Ofgem treats the interconnection with the Continent at float, (i.e. neither importing nor exporting) while DECC assumes 2.5GW of imports from the Continent.

3.29 DECC's assumptions on net imports reflect historic patterns of interconnector flows. However it should be noted that it is difficult to predict future patterns of interconnector flows because capacity margins have been wide for the past six years and the rules governing interconnector flows are currently being revised.[12]

3.30 Ofgem provides a range of scenarios 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 system peak then, even if we are exporting fully to Ireland, de-rated margins in 2015/16 would be around 9%.

3.31 We believe that interconnectors make a positive contribution to security of supply at times of system stress. The contribution of interconnectors to security of supply would be further strengthened however 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.

3.32 DECC's projections of tightening capacity margins imply an increased likelihood of controlled load shedding and voltage reductions in the future, though the risks are still lower than Ofgem's assessment. This is illustrated below for 2015/16 for DECC's base case and stress test and Ofgem's base case 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.

Figure 3: Probability of load shedding under different scenarios[13]

	De-rated capacity margin in winter 2015/16 (%)	Likelihood of some customer disconnections[14]
DECC base case	14.4	~>1 in 3000 years (0%)
DECC stress test	8.4	~1 in 50 years (2%)
Ofgem base case	4.2	1 in 12 years (8%)
Ofgem high demand	0.3	1 in 2 years (50%)

3.33 It should be noted however that 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 loss of load probability is highly uncertain for a given de-rated capacity margin.

3.34 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.

[12] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52007PC0528:EN:NOT
[13] 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 scenarios are illustrative.
[14] 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.

3.35 The key points to take away from looking at the range of modelling we have undertaken is that (a) there remains a credible risk of a capacity problem in the medium-term; however (b) the further into the future we try to assess future levels of capacity, the less certainty we have about the outcome.

Conclusions about rationale and timing for intervention

3.36 The case for a Capacity Market comes down to a judgement about balancing the risks of imperfections in the energy market leading to insufficient incentives to build enough capacity versus the risks from intervention in the market. Given the potential market failures, including lack of certainty about the impact of energy market reforms such as cash out, there is a strong rationale for introducing a Capacity Market to reduce the risk of power cuts occurring, particularly with more intermittent and inflexible generation.

3.37 The Government is minded to initiate auctions from 2014, for delivery of capacity in the year beginning in the winter of 2018/19.[15] A final decision will be taken subject to evidence of need, and will be informed by updated advice from Ofgem and National Grid which will consider economic growth, recent investment decisions, the role of interconnection and energy efficiency, as well as consideration of the outcome of the review of the 4th Carbon Budget.

3.38 This means that a Capacity Market may not be able to address the security of supply risks identified by Ofgem until then, although the Government is also minded to run pilot auctions for delivery of demand side and storage from 2015-18 to provide additional capacity during this period. DECC will also continue to monitor the security of supply outlook and will respond to an earlier problem if necessary.

[15] A 2018/19 first delivery date ensures a four year lead time for capacity auctions so that the threat of new entry gives parties an incentive to offer capacity at the true cost level.

4 Options Appraisal

4.1 We have analysed the three options which are set out below:

i) **Business As Usual (BAU)**: The electricity market framework incorporates the other measures under Electricity Market Reform but does not include any form of Capacity Market.
ii) **Administrative Capacity Market:** Capacity providers receive a payment for offering capacity which is available when needed but are able to keep their energy market revenues
iii) **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.

4.2 The BAU is the baseline against which we are comparing the two options for a Capacity Market. It 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 Standards and Carbon Price Floor.

4.3 Both the Administrative Capacity Market and the Reliability Market are market-wide volume-setting mechanisms that have a number of common features as set out below:

Features of a Capacity Market:

- a forecast of future peak demand will be made, four years ahead of the delivery year;
- the net amount of capacity needed to ensure security of supply (which is likely to be determined through an enduring reliability standard) will be contracted through a competitive central auction;
- Generation and non-generation approaches will be able to participate in the capacity auction. All generation plants, including existing plants, will be eligible to participate in this auction, with some exceptions (e.g. low carbon plants receiving the FiT CfD);
- providers of capacity successful in the auction will enter into capacity agreements, committing to provide electricity when needed in the delivery year/s (in return for steady capacity payments) or face financial penalties; and
- the costs of the capacity payments will be shared between electricity suppliers in the delivery year.

4.4 The previous Impact Assessment published in December 2011 considered a Strategic Reserve as well as a Capacity Market and concluded that a market-wide solution was needed to address enduring problems with an energy-only market that mean it could fail to bring on sufficient new capacity. This remains our conclusion.

Strategic Reserve:

A Strategic Reserve is a targeted capacity mechanism. The System Operator tenders for capacity to be part of the Strategic Reserve, The capacity is then kept outside the market and only deployed at times of scarcity, i.e. when there would be blackouts or brownouts in absence of the reserve being deployed. This energy would be priced into the market at a high level, potentially VoLL, to avoid the mechanism dampening prices and reducing incentives for investment in capacity through the energy market.

A Strategic Reserve was expected in the 2011 Impact Assessment to have a net present value of -£1.1bn. However although the modelled impact was more positive than a Capacity Market (and remains so in this year's analysis), the Strategic Reserve option was rejected on qualitative grounds:

A Strategic Reserve has the advantages of being a small intervention in the market and of having a smaller impact on bills (by not paying inframarginal rents (i.e. more than they bid) to providers in a capacity auction).

However it does not address the "missing money" problem, in that energy prices are not currently cost-reflective at times of scarcity and due to investor concerns about the riskiness of investing in capacity that is reliant on recovering fixed costs through scarcity rents. The latter problem in particular is seen as an enduring problem with energy-only markets and which will become more significant as the power sector decarbonises and as flexible capacity expects to run less frequently.

A Strategic Reserve could even exacerbate the "missing money" problem if investors fear that the Government would come under pressure to deploy the Strategic Reserve at times when there are high prices but no scarcity. If a Strategic Reserve deterred investment it is likely that the Government would come under pressure to expand the Strategic Reserve, creating a "slippery slope" towards a market-wide mechanism.

The Capacity Market was therefore assessed to be the best mechanism to ensure security of supply as it addresses the underlying market failure. This remains our view in light of further analysis.

Option 1: Business As Usual

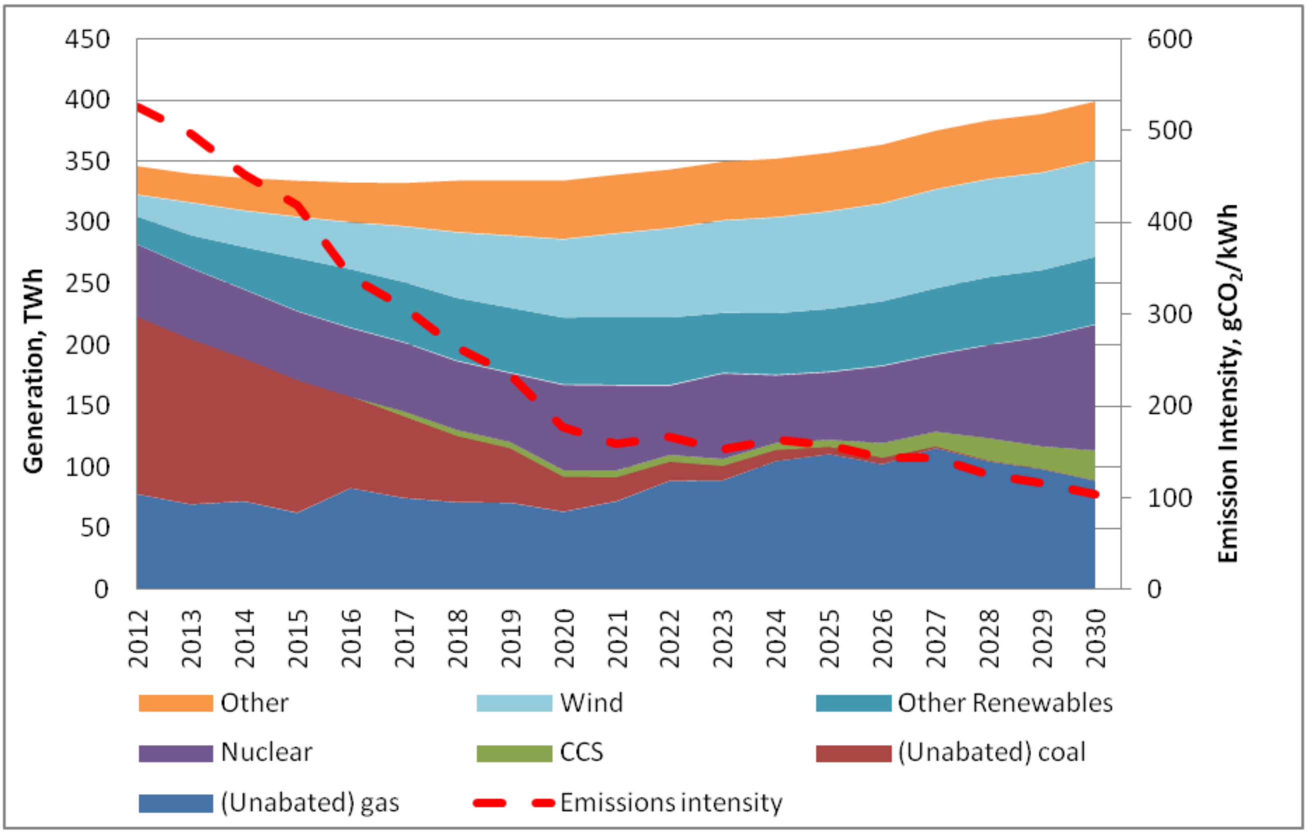
4.5 The BAU is the baseline against which we are comparing the options for the Capacity Market. It assumes that a number of policy options that form part of the Electricity Market Reform package have been implemented, including the FiT CfD, Emissions Performance Standard and Carbon Price Floor. It also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

4.6 A number of significant changes are expected to occur in this option even in absence of further policy interventions:

- **Decarbonisation:** The BAU modelled in the latest energy system modelling runs assume that the power sector decarbonises so that the average plant emits at most 100gCO_2/kWh in 2030, to be consistent with previous Impact Assessments on capacity mechanisms. This entails a significant increase in intermittent and less flexible generation (predominantly wind and nuclear).[16]

[16] 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 Committee on Climate Change (CCC) has recommended decarbonising the power sector to 50

Figure 4: Type and carbon intensity of electricity generation in the base case:



- **Retirement of existing plant:** Around a fifth of capacity available in 2011 is set to close over this decade.
- **Missing Money:** In setting out the rationale for a Capacity Market, we have argued that there is potentially missing money, and that prices may not rise to the value of lost load. However, for the purposes of modelling of the BAU we have assumed a wholesale market where prices can rise to a value of lost load of £10,000/MWh when there is scarce capacity. In one sense, this assumes that the cash out process is reformed so as to make the cash out price in the balancing mechanism fully cost reflective. However a £500/MWh price cap is modelled in the stress test to illustrate the effect of market failure if cash out is not sufficiently reformed or if investors fail to take value scarcity rents when making investment decisions.

4.7 Given uncertainty about the BAU case (in particular around demand, cash out reform and the trajectory for decarbonisation) we have modelled the impact of a Capacity Market against two separate counterfactuals:

i. **DECC base case:** This assumes the energy market is reformed and functions efficiently, and DECC's published central projections of demand and fossil fuel price are known with certainty by investors up to five years ahead;[17]

ii. **DECC stress test:** This assumes demand in line with National Grid's "Gone Green" projections (which is both higher on average and has a peakier profile), a £500/MWh wholesale price cap and delays to the delivery of low carbon plant. The assumptions behind the stress test are explained further in Section 3.

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gCO_2/kWh by 2030. A 200 gCO_2/kWh trajectory is also considered in the sensitivity analysis. 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.

[17] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

Option 2: Administrative Capacity Market

4.8 An Administrative 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.

Option 3: Reliability Market

4.9 Under a Reliability Market, parties with a reliability contract have an obligation to pay the difference between the real-time price (i.e. cash out price) and an agreed strike price when there is system scarcity and the real-time price exceeds the strike price. This ensures that parties have a market-based penalty to be available when needed and also that parties' energy-market revenues are capped at the strike price. Reliability Options do not however act as a cap on prices – they merely insure consumers against the risk of price spikes and allow generators to receive a steady payment in exchange for foregoing the possibility of scarcity rents.

How the options have been assessed

4.10 The options for a Capacity Market are appraised based on both qualitative and quantitative analysis. The quantitative analysis (in Section 5) shows that either form of Capacity Market has a slight net cost in the base case where there is no "missing money" problem, although there could be a significant net benefit under a stress test where the market fails to bring forward adequate levels of investment and where consumers have a high value of lost load that market prices fail to reflect.

4.11 However the quantitative estimates do not take into account a number of significant factors and make a number of simplifying assumptions to be able to model the effect of different forms of Capacity Market. The qualitative assessment provides a more robust and comprehensive assessment of the options. This shows that the Administrative Capacity Market is a less risky intervention than a Reliability Market as it does not depend on cash out being reformed and is less likely to lead to changes in how parties sell energy forward (or require retrospective changes to existing trading contracts). However it also notes that both forms of Capacity Market carry policy risk and that there are a number of advantages to Reliability Options that mean that, depending on the way the energy market develops, this may become a more desirable form of Capacity Market in the future if cash out is reformed.

5 Quantitative options assessment

5.1 The value for money assessment of the two Capacity Market options have been assessed quantitatively in the following ways:

i) Energy system impact
ii) Transaction costs
iii) Institutional impacts
iv) Impacts on businesses

5.2 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 design

Although no final decision has been made on the format of capacity auctions, both options for a Capacity Market are modelled on the basis of a pay-as-clear auction. This is because alternatives to a pay-as-clear auction create strong incentives for parties to bid up to the expected marginal cost in the auction and so it is simpler to model the cost of a Capacity Market under a pay-as-clear auction format (also known as a 'marginal bid auction').

We have assumed 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. We think the risk of overpaying in the auction can be mitigated through a number of potential measures:

i. Differentiating between price-makers and price-takers: Existing plant could be assumed to be a "price-taker" unless they request otherwise. Existing plant that wishes to be a price-maker could be required to submit information that justifies the level of capacity payment that has been demanded in its bid. This information could be open to investigation/ enforcement, if there were potential market power concerns. If a plant were found to have abused its market power it could then lose its licence and the parent company could be fined up to 10% of annual turnover. Similarly if the offer were *not* accepted in the auction and if the plant stayed open despite not having received the price it had said it needed then the Regulator could look at whether the plant had attempted to exercise market power.
ii. A sloping demand curve could be set for the auction so that less capacity is bought if the price is very high
iii. A cap in the auction could be set reflecting the cost of new entry

We recognise further work needs to be undertaken to assess the gaming risks and ensure these risks are mitigated through the auction design. Further analysis on the advantages and disadvantages of a pay-as-clear auction format are set out in Annex B.

Energy system modelling

5.3 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 C. The modelling shows a net cost of £1.5bn over the period 2010 – 2030[18] compared to the BAU in the base case (which assumes no "missing money" problem"). However it shows a significant net benefit under the stress test where there is a market failure ("missing money") combined with higher assumptions about peak demand.

5.4 The impacts for both an Administrative Capacity Market and a Reliability Market are identical in the energy system modelling as the model fails to take account of the effect of different penalty regimes on how plants bid into the capacity market, and as the model doesn't forecast prices going above £500/MWh (the strike price in the Reliability Market) if a 10% de-rated capacity margin is delivered.[19] However even with a 10% de-rated capacity margin we expect that prices could occasionally rise above £500/MWh (particularly if cash out is reformed) and therefore that generators could expect a higher price for participating in a Reliability Market than an Administrative Capacity Market, particularly if cash out is reformed. This is considered further in Section 6.

Why have we assumed 10% as an appropriate capacity margin in the modelling?

- In our modelling we assume a 10% de-rated capacity margin as the specified policy objective for the Capacity Market.
- To estimate a derating factor it is necessary to estimate the likelihood that providers will be generating up to their nameplate capacity (i.e. theoretical maximum) at times of peak demand.
- We have used 10% as a proxy for an appropriate capacity margin. This is approximately equivalent to the margin used in the pool (the electricity trading arrangements prior to 2001) which targeted a nameplate capacity margin of 23%.
- In practice, we expect to use a reliability standard to set the amount of capacity required in the Capacity Market. This will be based on the economically efficient level of capacity and will weigh up the value of reliability against the costs of additional capacity. The reliability standard should bring on the same level of capacity as an energy-only market would if prices were fully able to reflect scarcity and investors could invest on the basis of scarcity rents. The capacity margin resulting from this assessment may be higher or lower than 10%.
- Modelling in this Impact Assessment suggests that the optimal de-rated capacity margin is less than 10%. However, the model does not reflect the full range of uncertainty over future demand and is therefore likely to under-estimate the economically efficient capacity margin for the reasons set out in paragraph 3.34.

[18] 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 2024 and 2030 because that is when a Capacity Mechanism would be triggered under the scenario.

[19] In the Case this is because the market brings forward sufficient capacity to avoid price spikes above this level. In the Stress Test, the assumption of missing money means that the price cannot rise above the strike price in the Reliability Market even when there is scarcity.

5.5 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.

5.6 Benefits modelled come from reduced levels of forced outages. These are modelled below assuming a value of lost load (VoLL) of £10,000/MWh. The average household uses about 0.7KWh at times of peak demand[20], so a £10,000/MWh assumption of VoLL implies that the average domestic household would pay around £7 to avoid being disconnected for an hour. Uncertainty around the VoLL is considered further in the sensitivity analysis.

5.7 The table below shows the results of energy system modelling in terms of the change in net welfare from a Capacity Market relative to the BAU counterfactual and how this breaks down into its various components. Two BAU scenarios are modelled, a base case (assuming an energy market with cost-reflective prices and DECC central demand assumptions) and a stress test (assuming missing money, a higher and peakier demand profile, and delays to low carbon deployment):

Figure 5: Energy system costs and benefits

Energy System Costs and Benefits of a Capacity Market 2012-2030, £m (2012 prices)	**Base Case (£10,000 VoLL)**	**Stress Test (£10,000 VoLL)**
Carbon costs	392	454
Generation costs	755	1,098
Capital costs	682	1,099
Interconnection costs[21]	-20	-132
Total Costs	**1,809**	**2,518**
Total Benefits (Reduction in unserved energy)	**340**	**2,276**
Change in Consumer Surplus	-4,294	-50
Change in Producer Surplus	2,614	-462
Change in environmental tax revenue	478	570
Change in non-internalised social costs of carbon[22]	-266	-301
Change in Net Welfare	**-1,468**	**-242**

5.8 The result that a Capacity Market has a net cost in the modelling is driven by **two key** assumptions, namely that:

i. Modelling of the BAU base case assumes that there is no “missing money” and that energy prices rise to the VoLL if load is shed. This means that energy-only market in BAU delivers the “economically efficient” capacity margin albeit based on assumption ii. below.

[20] Energy Saving Trust report, “Powering the nation: Household electricity-using habits revealed” (2012)
[21] Negative interconnection cost figures show a reduction in interconnected energy consumed.
[22] ‘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.

ii. The assumption that investors have certainty about demand up to five years ahead when deciding whether to build capacity.

5.9 These two assumptions mean that modelling is likely to understate the benefits of a Capacity Market as it assumes an unrealistic energy-only market where prices can reflect scarcity and where investors have perfect certainty of demand when choosing whether to build a new plant. Any scenario which included a Capacity Market would necessarily show a negative NPV against the base case because there is no market failure leading to underinvestment in capacity. However the Capacity Market is intended to mitigate the risk of market failure – particularly from missing money – and so the modelling in the base case underestimates the potential benefits from the Capacity Market. The sensitivity analysis shown around the size of the benefits illustrates that the introduction of a Capacity Market could have a significant net benefit if there are energy market imperfections or failures that mean the market brings forward a suboptimal level of capacity, particularly if consumers have a high value of lost load. The Capacity Market therefore serves to mitigate the security of supply risks associated with those market imperfections or failures.

5.10 The differences between the modelling in the base case and stress test are primarily driven by two factors:

i. **Missing money**: Prices are assumed in the stress test to not be able to rise above £500/MWh, yet consumers are assumed to have a VoLL that is significant higher. Modelling of this market failure means that the market fails to bring forward the efficient level of capacity.

ii. **Demand profile**: The stress test assumes demand follows a peakier profile than in DECC's base case – i.e. it assumes that there is one day a year when demand is a third higher than average. This means that the "efficient" level of unserved energy is higher because it is expensive to maintain additional capacity just to service the occasional days when demand is very high. In the stress test no additional capacity is built to be available on this extra high demand day because it is not profitable to do so if prices cannot rise above £500/MWh when there is scarcity.

5.11 These two factors in combination mean that a Capacity Market can have a positive impact if there is "missing money," depending on the profile of demand and the assumption about consumers' VoLL because it drives the likelihood of lost load down towards the socially optimal level.

5.12 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 £5,000 and £30,000/MWh,[23] equivalent to a range of £3.50 - £21 cost of disconnection to 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. The size of benefits under different assumptions about VoLL is illustrated below:

[23] Oxera report "What is the optimal level of electricity supply security", (2005)

Figure 6: Sensitivity analysis around energy system benefits from a Capacity Market

Energy System Benefits of a Capacity Market, 2012-2030 £m (2012 prices)	**£5,000 VoLL**	**£10,000 VoLL**	**£30,000 VoLL**
Base Case	170	340	1020
Stress Test	1,138	2,276	6,828

5.13 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.

Transaction Costs (Reliability Market)

5.14 A significant cost to the implementation of a Reliability Market comes from the additional risk it places on parties that sell energy forward. By requiring generators to pay the difference between the reference price and strike price in a real-time market, it would create significant basis risk for generators who sell their energy forward as they would be paid according to the forward price but have a liability to pay the real-time price. For generators to hedge this risk they would likely either cover their position by purchasing financial options when they sell energy forward or they would sell energy into the real time market and buy financial products to hedge price risk up to that point. The introduction of Reliability Options could also precipitate retrospective changes to existing trading agreements as parties may look to renegotiate the terms of contracts.

5.15 The transition to purchasing financial products is potentially costly, particularly in the implementation phase until appropriate liquid markets emerge. The cost of this transition may be comparable to the cost of transitioning from the pool to NETA (current bilateral trading arrangement) in 2001, where parties moved from trading financial options and started selling energy forward bilaterally. Under a Reliability Market, parties could move back towards trading financial options and this could therefore have a similar cost to the transition to NETA, particularly as there is no obviously appropriate reference price in the GB market and so it may be difficult for liquid options markets to emerge. Even if parties choose not to trade options around the reference price, a Reliability Market would impose extra risk on generators, who would factor this into their bid.

5.16 The cost of transitioning to NETA was estimated at the time[24] to cost (in today's prices) £675m to set up and then £41m per year from then on. The setup costs of transitioning to NETA included:

[24] July 1999, "The New Electricity Trading Arrangements", Annex 12

Figure 7: Setup costs of transition to NETA

Type of Cost	£m (2012 prices)
Financial realignment	283
New trading systems	136
Legal costs	14
Cost of renegotiating contracts	136
Other costs	86
Total cost to participants	**654**
Central setup cost	20
Total setup cost	**675**

5.17 This IA has assumed the same level of setup and annual costs for a Reliability Market as a result of creating a change to trading arrangements, implying a £1.1bn PV to 2030 from increasing transaction costs. A range is assumed of £0.9-1.3bn (i.e. 20% above or below the central estimate) to reflect uncertainty in the cost estimates.

5.18 It should be noted however that a number of these costs arise in the Business As Usual scenario if cash out is reformed in particular ways and if the market evolves on its own to trade reliability options.

Administrative costs to Business

5.19 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 number of businesses affected is estimated to be between 80 and 239.[25] In the base case we have assumed the mid-way point in the estimated cost range (i.e. £15m 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 £240m, with a range of £65-415m.

Institutional costs

5.20 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 £41m.

[25] 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.

Distributional impacts

5.21 The energy system modelling shows a transfer from consumers to producers in the base case, with consumers paying through their energy bills for capacity payments and with many generators receiving significant inframarginal rents[26] 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 3 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.

5.22 Modelling shows an increase in the average annual domestic electricity bill of £14 in the base case in 2024-2030 (the years in which the Capacity Market is bringing on additional capacity). This is equivalent to a 2.1% 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.

5.23 Under the stress test, a Capacity Market has a smaller effect on bills (a £9 increase between 2023-2030, the years in which the Capacity Market is bringing on additional capacity in this scenario). The bill impact is smaller as capacity margins are tighter without a Capacity Market in the stress test than in the base case, so a Capacity Market has a more significant effect in dampening the wholesale price. The increase in consumer bills in the stress test is approximately equal to the benefit to consumers of reduced load shedding if you assume consumers have a value of lost load of £10,000/MWh. The benefit to consumers of reduced load shedding far outweighs the extra cost to consumers however if you assume that consumers have a value of lost load of £30,000/MWh (as is assumed in the 'High Net Benefit' scenario).

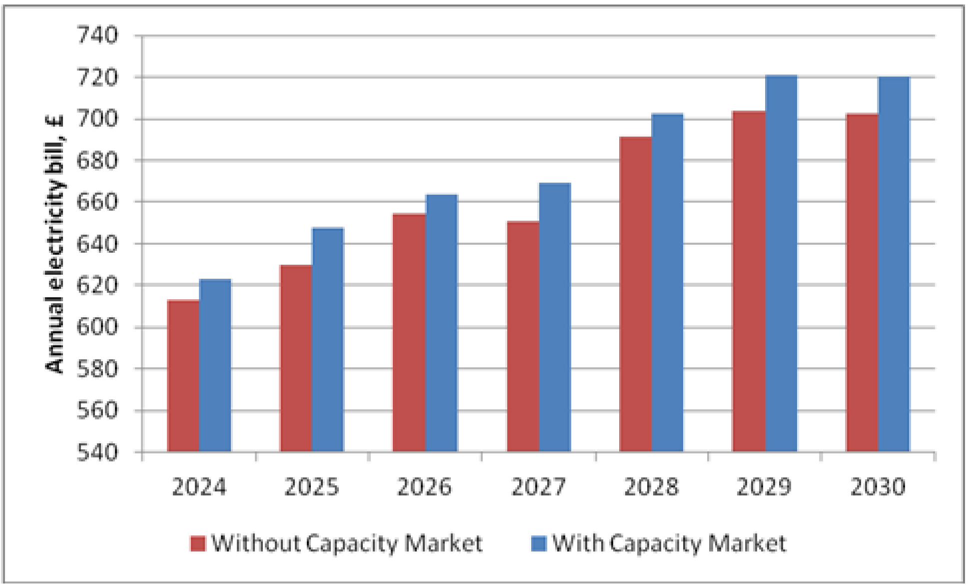
5.24 The table below shows the impact of a Capacity Market on the bills of different groups – domestic consumers, non-domestic consumers and energy intensive industries (EIIs). Figure 8 illustrates the changes in domestic consumer electricity bills each year in the base case.

[26] I.e. they are paid the clearing price in the auction rather than the price they bid.

Figure 8: Consumer Electricity Bill Impacts

Consumer bills in 2012 prices	Typical bill for the Business As Usual		Change in Typical bill % as a result of a Capacity Market	
	Base Case	**Stress Test**	**Base Case**	**Stress Test**
Domestic, (£)[27]				
2011-2015	580	581	0.0%	0.0%
2016-2020	611	618	0.0%	-0.5%
2021-2025	606	620	0.7%	0.6%
2026-2030	676	694	2.1%	1.2%
Non Domestic (£000)[28]				
2011-2015	1,100	1,200	0.0%	0.0%
2016-2020	1,400	1,400	-0.1%	-0.9%
2021-2025	1,500	1,500	0.9%	1.1%
2026-2030	1,500	1,500	3.1%	2.7%
Energy Intensive Industry, (£000)[29]				
2011-2015	8,300	8,400	0.0%	0.0%
2016-2020	10,800	11,100	-0.2%	-1.0%
2021-2025	11,900	12,100	1.0%	1.3%
2026-2030	12,300	12,500	3.5%	3.1%

Figure 9: Change in Domestic Electricity Bills in the Base Case



[27] 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.
[28] 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.
[29] For the energy intensive industry sector, illustrative users consume (before policies) 100,000MWh of electricity.

5.25 However it should be noted that there is significant uncertainty around modelling the impact of a Capacity Market on bills. The precise impact forecast is heavily dependent on a number of variables, in particular how much capacity would have been in the counterfactual (i.e. if the Capacity Market had not been implemented) and how high prices go as capacity margins tighten. Previous modelling which assumed higher prices when margins are tight suggested that the Capacity Market could lead to a reduction in bills (-£33/year per average domestic household).[30]

5.26 A Capacity Market is only intended to bring forward the same level of capacity as an energy-only market would if it worked efficiently. In theory, a perfectly functioning energy market should already provide sufficient incentives for investment in new capacity by allowing generators to sell energy for high prices at times of scarcity. If this were the case, we would expect the price in the capacity auction to fall to zero and for a Capacity Market to have no impact on prices and bills.

5.27 However the energy system modelling predicts a positive impact of a Capacity Market on bills even in the base case (which assumes a perfectly efficient energy market). This is because the modelling assumes that the "efficient" de-rated capacity margin approaches zero over time. This is largely due to limitations of the modelling as it assumes generators have perfect certainty of demand and other factors up to five years ahead, whereas in practice demand is uncertain and the efficient outcome is for the market to bring forward spare capacity given the potential for scarcity rents when margins are tight. In practice we think that a 10% capacity margin is likely to be closer to the efficient level, and therefore that the impact of a Capacity Market on bills would be minimal if cash out were reformed and if the market developed to value scarcity rents in the energy market.

5.28 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:

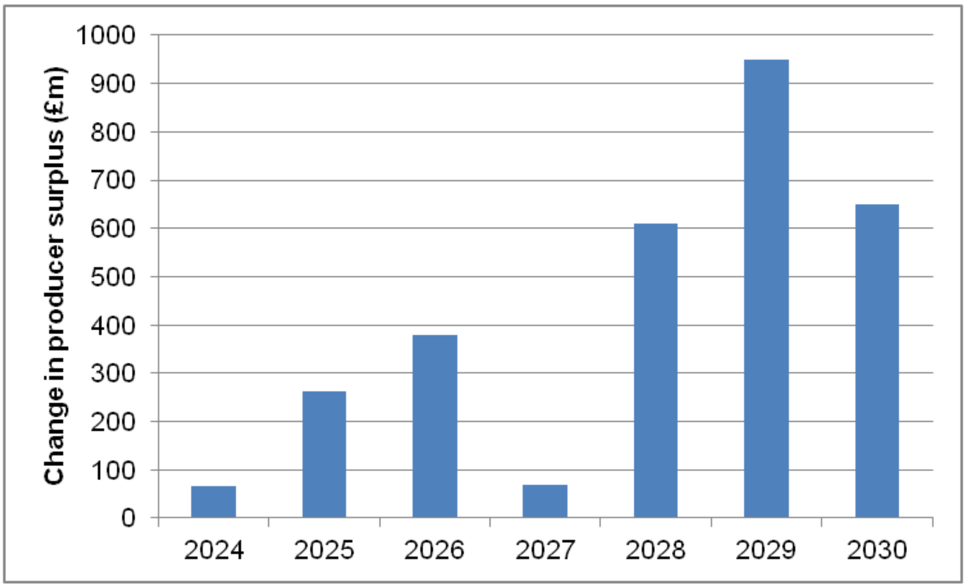
i. The degree to which providing a stable capacity payment reduces risks for investment in new capacity and therefore brings the financing costs down.
ii. the degree of liquidity/competition in the capacity auction.
iii. Whether the electricity market is reformed so that prices can rise to reflect scarcity, 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.

5.29 Given these uncertainties, figures should therefore be treated with caution, However there remains strong reason to think that the overall effect of a Capacity Market on bills is likely to be small.

5.30 As well as the impact on consumers of electricity there is also an impact on the generation companies which produce electricity. Figure 10 shows the producer surplus that results 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 inframarginal rents for existing capacity[31] (only partly offset by dampened wholesale prices).

[30] This was based on dispatch modelling for DECC by Redpoint. DECC's DDM modelling is comparable to the modelling by Redpoint, except that the DECC modelling uses updates DECC's latest projections of demand and fossil fuel prices as well as different assumptions about price mark-ups at times as margins tighten.
[31] i.e. capacity that would have been present without a capacity payment

Figure 10: Change in producer surplus as a result of a Capacity Market



Size of capacity revenues

5.31 The table below shows the gross capacity revenues associated with a Capacity Market under the base case and stress test.

Figure 11: Gross capacity revenues through a Capacity Market, £m

(2012 prices)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Base case	0	0	0	0	127	1,042	1,043	1,422	2,230	2,478	1,724
Stress test	0	0	0	1,026	1,248	1,603	1,377	2,023	2,337	2,192	1,760

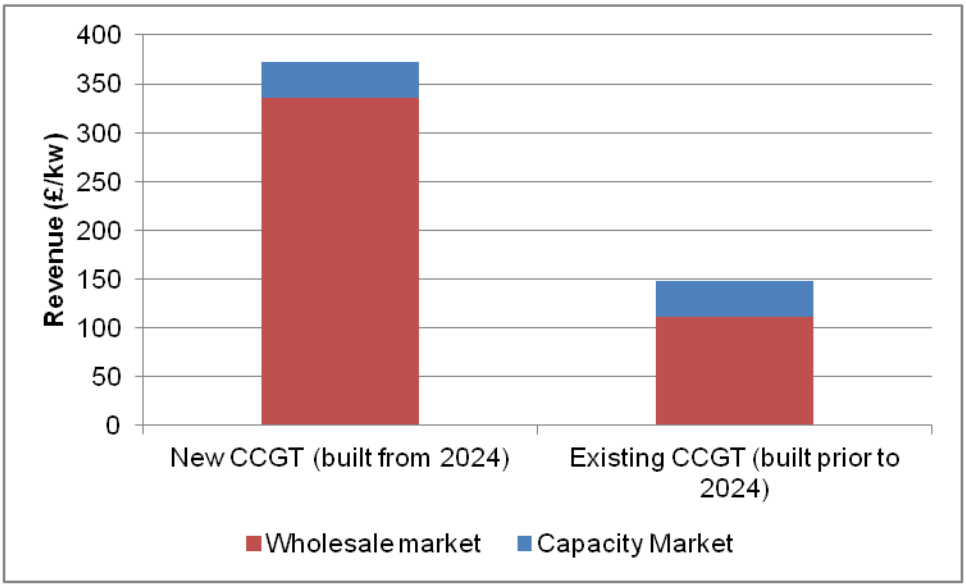
5.32 Under a Capacity Market the gross capacity revenues that go to providers of capacity are modelled to be up to £2.5bn per annum. The size of the capacity payment is likely to increase over time as the power system decarbonises and as new plants expect to run for decreasing amounts of time. The size of capacity payments is projected to be the same for both an Administrative Capacity Market and a Reliability Market as no scarcity rents are projected above the £500/MWh strike price in the reliability option.

5.33 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, whether the electricity market is reformed so that prices better reflect scarcity, as well as whether investors value scarcity rents when choosing how to price into the capacity auction. In theory if cash out is fully reformed then the capacity auction should clear at zero under an Administrative Capacity Market, though not necessarily under a Reliability Market (as generators would not be willing to voluntarily forego the opportunity to earn scarcity rents without compensation).

Impact on plant economics

5.34 A Capacity Market changes the way participating generation plant receives revenues. Once a Capacity Market has been implemented plant will receive two revenue streams, one from a Capacity Market and one from an Energy Market. The energy system modelling provides an indication of what the revenues might be for certain types of Combined Cycle Gas Turbine (CCGT) plant. It assesses how much revenue a new CCGT plant from 2024 receives from selling its energy as well as how large the capacity payment needs to be in any given year to secure a minimum 10% de-rated capacity margin. The chart below compares the different forms of revenue for all new CCGT built after 2024 (when the model shows the Capacity Market bringing on additional capacity) and CCGT built up to that point. Capacity payments account for a more significant part of an existing plant's revenue because the existing plant is older and so less efficient than new plant, and therefore likely to be generating less of the time. For both types of plant however the capacity payment is expected to remain a small part of the overall revenue generated by a CCGT plant.

Figure 12: Average annual revenues for a CCGT plant 2024 – 2030 in the base case



Net Present Value assessment

5.35 Modelling suggests both options for a Capacity Market are equivalent in terms of costs and benefits, apart from the additional cost of option trading under a Reliability Market due to it placing increased risk on generators that choose to sell energy forward. Both options are modelled to have a net cost in the base case. However the modelling doesn't take full account of imperfections in the energy market. This means it may overestimate the costs of a Capacity Market (as an energy only market would be likely to procure a higher capacity margin than if it did not have perfect foresight of demand five years out as assumed in the modelling) and it may underestimate the benefits of a Capacity Market if it corrects for market failure (i.e. if there is missing money that leads to underinvestment in capacity).

Figure 13: Net present value of a Capacity Market

Net Present Value of a Capacity Market 2012 to 2030, £m (2012 prices)	Administrative Capacity Market	Reliability Market
Energy system costs	1809	1809
Cost of option trading	0	1082
Institutional costs	30	30
Administrative costs to business	240	240
Total Costs	**2079**	**3161**
Total Benefits (energy system)	**340**	**340**
Change to consumer surplus (energy system) [32]	-4,294	-4,294
Change to producer surplus (energy system)	2,614	2,614
Change in environmental tax revenue	478	478
Change in non-internalised social costs of carbon	-266	-266
Change in Net Welfare	**-1,738**	**-2,820**

Sensitivity Analysis

5.36 The central estimates of NPV make a number of assumptions about the extent and costs incurred through a Capacity Market. Sensitivity analysis helps illustrate the impact of an Administrative Capacity Market or Reliability Market under alternative plausible assumptions.

5.37 In the base case we have assumed DECC's central demand projections and that prices in the current market can rise to VoLL (which is assumed to be £10,000/MWh).

5.38 The stress test has made a number of modelling assumptions, particularly that there is a £500/MWh price cap (reflecting missing money in the current market), as well as higher demand and delays to new nuclear build. These changes mean that an Administrative Capacity Market or a Reliability Market has a higher net benefit as capacity margins are much tighter in their absence.

5.39 Further differences in the modelling come from assumptions about:

i. Estimate of Value of Lost Load used: £10,000/MWh in the central case, £5,000 - £30,000/MWh in the sensitivities.
ii. The size of the administrative burden of a Capacity Market, with the range reflecting the number of businesses affected.
iii. The cost of transitioning to a Reliability Market is assumed in the sensitivities to be either 20% less or more than the cost of transitioning from the pool to NETA in the central case (£1.1bn).

5.40 The assumptions around the different scenarios are summarised in Figure 14:

[32] Consumer and producer surplus are based on energy system costs and benefits only; they exclude cost of options trading, administrative costs and business and institutional costs as it is not clear whether these costs will fall on producers or consumers.

Figure 14: Scenarios for sensitivity analysis

Low estimate of net benefit	Best estimate of net benefit	High estimate of net benefit
DECC base case assumptions used in energy system modelling. Price cap of £10,000/MWh but VoLL estimated at £5,000/MWh. High estimate of institutional costs and administrative costs on business.	DECC base case assumptions used in energy system modelling. Price cap and VoLL estimated at £10,000/MWh. Central estimate of institutional costs and administrative costs on business.	Stress test modelling used, assumes £500/MWh price cap, two year delay on first new nuclear build and National Grid demand estimates. VoLL estimated at £30,000/MWh. Low estimate of institutional costs and administrative costs on business.
Estimate of cost of option trading in a Reliability Market 20% higher than cost of transitioning to NETA.	Estimate of cost of option trading in a Reliability Market equal to cost of transitioning to NETA.	Estimate of cost of option trading in a Reliability Market 20% lower than cost of transitioning to NETA.

5.41 The results of the sensitivity analysis are shown below:

Figure 15: Sensitivity analysis on impact of a Capacity Market

Sensitivity Analysis of NPV 2012-2030, £m (2012 prices)	Administrative Capacity Market	Reliability Market
Best estimate of net benefit	-1,738	-2,820
High estimate of net benefit	4,218	3,352
Low estimate of net benefit	-2,087	-3,385

5.42 The sensitivity analysis shows that it is difficult to estimate the impact of a Capacity Market with precision and that a Capacity Market could have a significant net benefit under certain circumstances. The difference between the central case (showing a £1.7bn net cost) and the high net benefit scenario (showing a £4.2bn net benefit) is driven by a combination of greater missing money in the stress test coupled with a peakier demand profile which means that the energy-only market could fail to deliver the economically efficient level of capacity.

5.43 We have also considered the impact of the Capacity Market against a counterfactual where the power sector decarbonises on an alternative trajectory. Indicative analysis suggests that if the power sector decarbonises to 200 gCO_2/kWh in 2030 there is a net impact of -£2.3bn from an Administrative Capacity Market and -£3.4bn from a Reliability Market. This analysis will be updated, along with a 50 gCO_2/kWh sensitivity, in the New Year.

Conclusions from quantitative modelling

5.44 As discussed, there are very significant caveats around the energy system modelling of the different options, particularly related to the assumption of missing money in the modelling and that it does not capture the full range of uncertainty over future demand.

5.45 The quantitative modelling therefore tells us that if we think that there are no problems of 'missing money' then a Capacity Market could have a small net cost to society and lead to a small increase in bills for consumers.

5.46 However, as set out in Section 4, there is reason to think that an energy-only market will not deliver the efficient level of capacity, particularly due to market failures arising from the determination of cash out prices and due to investor concerns about the riskiness of investing in capacity that is reliant on recovering fixed costs through scarcity rents. The quantitative modelling tells us that the costs from inaction are potentially much more significant in the event of market failure (i.e. if cash out is not sufficiently reformed so that prices can reflect scarcity), particularly if this market failure is combined with high and peaky demand. In this event a Capacity Market could have a potential net benefit to society – potentially a large benefit if consumers have a high aversion to blackouts. The Capacity Market therefore serves to mitigate the security of supply risks associated with these market imperfections or failures.

5.47 However there are also significant limitations to quantitative modelling of the impact of a Capacity Market. A Capacity Market is a significant intervention in the market and as such carries a risk of unintended consequences. For instance the implementation of a Capacity Market could lead to overpayment if the capacity auction is not sufficiently competitive or if there is "gaming" of the market. Ultimately the economic case for a Capacity Market must consider qualitatively the impacts of the intervention. These impacts are explored in Section 6.

6 Qualitative options assessment

6.1 As explained above there are significant caveats around the energy system modelling of an Administrative Capacity Market and Reliability Market. In practice the costs and benefits of the various options are likely to differ due to a number of factors not captured by the economic modelling. This section therefore provides a qualitative assessment of the options to complement the quantitative analysis in Section 5.

6.2 The options for a Capacity Market have been assessed according to the four objectives for the policy set out in section 2, namely:

i. **Benefit:** the extent to which the mechanism delivers security of supply objectives
ii. **Cost:** whether the mechanism has minimal impact on consumer bills
iii. **Risk:** whether the mechanism fits with existing market arrangements
iv. **Timing:** whether it is possible to deliver the mechanism in time for a potential first auction in 2014

Security of supply benefits

6.3 Both options for Capacity Market try to ensure that capacity will be there when needed in two ways:

- By use of "spot checks" for plant that is not regularly generating at the level of capacity it has claimed it is able to provide at; and
- By creating a financial penalty for plant that is unavailable at times of scarcity

6.4 Plants already face a financial incentive to be available at times of scarcity – if they have sold forward they are liable to pay the cash out price, and if they have not sold forward then they face an "opportunity cost" in that they forego the opportunity to sell their energy into the market for a high price.

6.5 An Administrative Capacity Market potentially places additional penalties on generators that fail to deliver energy at times of scarcity. The penalty is an administratively set level at times of voltage reductions and controlled load shedding, though this could "net off" the prevailing cash out price so that there is no "double penalty" for providers that are unavailable.

6.6 By contrast, the incentive in the Reliability Market is the energy market price. Providers are liable to pay the cash out price regardless of whether they have sold forward, so they are incentivised to buy financial options to hedge their risk if they know their plant will be unavailable. They are also incentivised to buy financial options to hedge their risk if they are selling forward to avoid having to pay out a high cash out price if they are available and not selling their energy for the real-time price.

6.7 If the energy market price were able to perfectly reflect scarcity, the Reliability Market would provide the optimal incentive for generators to be available when needed. So if cash out is fully reformed then both options for a Capacity Market have strong market-based incentives for plant to be available when needed (although the two options might differ in expected cost – as considered below).

6.8 However existing arrangements for cash out mean that signals in the existing energy market may currently be insufficient to give providers incentive to be available when needed. This means that the Administrative Capacity Market has stronger benefits in terms of security of supply than the Reliability Market as it provides stronger incentives and so, in absence of effective cash out reform, reduces gaming risk. It should also be noted that both options reduce the risks of gaming in the energy market: When margins are tight there are increased opportunities for parties to withhold generation to drive up prices. This is because both demand and supply are highly insensitive to price over very short timescales (for instance until spare plant has had time to warm up) and so in theory prices could quickly be driven from £50/MWh to £10,000/MWh when unexpected scarcity events occur.

Costs to consumers

6.9 Quantitative estimates of the impacts of a Capacity Market are made in Section 5. Modelling is unable to reflect the difference in energy system impacts between an Administrative Capacity Market and a Reliability Market. However a Reliability Market is estimated to have a worse net impact on society as it is also expected to have an additional cost of £1.1bn associated with changes to the manner in which generators are likely to sell energy.

6.10 There are a number of potentially significant factors that affect the costs of the different mechanisms that cannot be reflected in the modelling:

- <u>Effect on investment costs:</u> If a Capacity Market brings down the financing costs for new capital it could potentially lower consumer bills and improve the NPV of the Capacity Market. This effect could be significant as financing costs are a significant part of the costs of investments in new capacity – particularly as investments in capacity are large, infrequent and have long lead-in times.

- <u>Competition in auctions</u>: Modelling has assumed that auctions are perfectly competitive. In practice the marginal plant in the auction may be able to push up the clearing price if the auction is not sufficiently competitive. This would not affect the NPV of the Capacity Market (as any overpayment would constitute a transfer from consumers to generators) but it would increase consumer bills.

- <u>Effect of Missing Money</u>: Modelling assumes that generators are able to value scarcity rents when deciding how to price into the Capacity Market. The security of supply benefits of a Capacity Market are linked to the extent that the market fails to value scarcity rents, as if the market fails to allow prices to rise sufficiently at times of scarcity, or if investors fail to invest on the basis of scarcity rents, then not enough capacity will be brought forward and there will be a greater likelihood of power cuts.

  Under an Administrative Capacity Market (though not under a Reliability Market) generators are allowed to keep their scarcity rents in the energy market. If they do not take these into account when pricing into the capacity market, there may be overpayment if cash out is reformed. The table below illustrates the size of this potential overpayment, assuming investors don't value scarcity rents above £1,000/MWh. It shows that the more cash out is reformed, and the tighter the reliability standard set in the Capacity Market, the greater the potential for overpayment if generators do not take account of scarcity rents when pricing into the capacity market.

Figure 16: Potential annual overpayment of an Administrative Capacity Market

Potential overpayment in an Administrative Capacity Market if there is “missing money” above £1,000/MWh	Loss of Load Expectation: **3hr/yr** (as in France)	Loss of Load Expectation: **5h/yr** (as in N Ireland)	Loss of Load Expectation: **8h/yr** (as in Ireland)
£1,500/MWh price cap	£0.1bn	£0.1bn	£0.2bn
£5,000/MWh price cap	£0.3bn	£0.4bn	£0.7bn
£10,000/MWh price cap	£1.5bn	£2.5bn	£4.0bn

- Effect of overprocurement: If more capacity is procured through a Capacity Market than is efficient this would increase costs for consumers and lead to the policy having a lower NPV. In practice predicting demand four years out is already subject to significant uncertainty and the market currently bears that risk. Under a Capacity Market there would be a central determination of the level of capacity to contract for. If the decision maker is risk averse there may be perverse incentives to overestimate the level of demand (or to underestimate the contribution of interconnection) when setting the level of capacity to contract for. However this could be mitigated in a number of ways:

  i. by Government setting out an enduring reliability standard and then setting out clear rules for how the level of capacity to contract for in any given year should be determined;
  ii. by use of an Expert Independent Panel to review the technical analysis underpinning the assessment of the level of capacity that should be contracted for; and
  iii. by selling back unneeded capacity in the market.

- Effect on single market: It may be easier to facilitate interconnected plant participating in a Reliability Market than in an Administrative Capacity Market. This is because the product in a Reliability Market is fundamentally a financial one (providing insurance against price spikes) and so may not require the same level of verification that capacity provided is physically contributing to GB security of supply.

Risks

6.11 There are a number of risks to the successful delivery of a Capacity Market.

- Administrative Capacity Market: There remains risk around ensuring the design of an Administrative Capacity Market that strengthens existing market signals for plant to be flexible, reliable and available when needed but also fits in with the existing market structure. The introduction of a Capacity Market is a significant intervention in the market and is therefore likely to have some degree of unintended consequences, for instance in changing the role of reserve in ensuring system balancing.

- Reliability Market: A Reliability Market has similar risks to an Administrative Capacity Market but also has additional risks as it does not fit as easily with the GB market. This is because in the GB market parties trade energy forward. If generators held reliability options then they would have an unhedged risk if they sold forward.[33] They could mitigate this by buying financial options around the real time price or by selling a greater proportion of their energy into the real-time market. This development could impose significant transaction costs if a liquid options market failed to develop around the real time price. The lack of a real-time reference price is a further risk: cash out may not currently provide sufficiently strong signals for plant to be reliable and a liquid options market may fail to develop as the balancing mechanism is currently a quasi-market with cash out determined through complex administrative procedures.

Conclusion

6.12 An Administrative Capacity Market is more likely than a Reliability Market to ensure security of supply in absence of certainty about the outcome of cash out reform. This is because the Administrative Capacity Market provides strong additional incentives for plant to be reliable, flexible and available when needed. It is also more likely to be cost-effective as it involves less change to existing trading arrangements and does not create risks for generators that are difficult to mitigate in absence of a liquid options market.

6.13 However if cash out is reformed in particular ways a Reliability Market could prove a more cost-effective mechanism if investors did not sufficiently value scarcity rents. This is because there is potential for overpayment in an Administrative Capacity Market if cash out is reformed and investors do not value scarcity rents, and the savings to consumers from introducing reliability options could outweigh the potential costs to generators from trading energy in a different manner. If cash out is reformed, a Reliability Market could reduce risk for suppliers (who are insured against price spikes) as well as for generators (who no longer need to value scarcity rents as part of their investment case) and so should in theory reduce costs overall for consumers.

6.14 Therefore if cash out were fully reformed and yet prices in the capacity market failed to fall to zero then there might be a case for amending the Capacity Market design and introducing a one-way CfD into the capacity contract (i.e. transitioning to a Reliability Market).

[33] For instance if they sold forward for £100/MWh but the price eventually rose to £10,000/MWh, that generator would have to pay out £9,500/MWh even though he delivered energy when needed and even though he never made any scarcity rents when selling the energy. In theory, the forward price includes a premium reflecting the risk of price spikes and so over the long run the generator should not be out of pocket for having sold forward. However in practice this type of liability puts significant risk on the parties' balance sheets, particularly for small players.

Figure 17: Summary assessment of Capacity Markets

Criteria Assessment	Administrative Capacity Market	Reliability Market	Explanation
Benefit	↑	↔	ACM provides strong incentives for plant to be reliable, flexible and available when needed; Reliability Market dependent on cash out reform to provide appropriately sharp incentives.
Cost	↔	↔	Both mechanisms may lead to a small increase in bills. Reliability Market may lead to higher capacity payments but could be more efficient in the long-term, if cash out is reformed in particular ways.
Risk	↔	↔	Reliability Market has greater risk due to significant change to existing arrangements.
Timing	↔	↓	Delivering either option for a 2014 auction is challenging but the delivery risks to a Reliability Market are greater.

7 Conclusion

7.1 The energy system modelling for this Impact Assessment reinforces the conclusions drawn in the Impact Assessment for the Technical Update last year: that capacity margins are going to tighten over this decade; that there is considerable uncertainty in modelling the electricity sector over the medium term; and that our assessment of the timing and severity of the future capacity problem is sensitive to a range of assumptions which are subject to change.

7.2 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 electricity prices being unable to reflect scarcity or due to a lack of liquid forward markets meaning investors cannot get project finance for new capacity on the basis of expected scarcity rents. 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 initiating a Capacity Market.

7.3 There is no design of Capacity Market that is without risk, and there are advantages and disadvantages to each of the options considered in this Impact Assessment.

- An Administrative Capacity Market provides strong signals for plant to be reliable, flexible and available when needed (even if cash out isn't further reformed). It also doesn't create significant change to existing trading arrangements and so is more likely to be deliverable for a potential first auction in 2014. However there is a risk of overpayment if cash out is reformed and if investors do not learn to value scarcity rents when pricing into the capacity market. We will mitigate this by considering transitioning to reliability options if cash out were fully reformed. We will also undertake further work assessing gaming risks and how these might best be addressed through policy design.

- A Reliability Market addresses the long term 'missing money' problem in a cost effective way by insuring consumers against price spikes, mitigating gaming risks, and therefore reducing the risk that Government will intervene in the market to prevent scarcity rents. However a Reliability Market is dependent on cash out reform to provide appropriate signals to the market to bring forward the right mix of capacity. There is also significant risk that the market would fail to bring forward liquid options markets for generators to hedge risks around the real time price. Liquid options markets may be necessary for generators to continue to sell their energy forward without taking on significant basis risk, where they would have to pay back significant scarcity rents that they are not receiving as a result of trading forward. If participating in this mechanism were seen to significantly increase risk for generators then participants will price high into the capacity auction and the ultimately mean that the mechanism is not cost-effective for consumers.

7.4 On balance an Administrative Capacity Market is assessed to be the best mechanism as it is most likely to deliver security of supply objectives, has less delivery risk, is not dependent on cash out reform, and is likely to have modest cost relative to the cost of inaction if the market fails to bring forward sufficient capacity. However, if cash out were fully reformed and if the capacity auction price failed to fall to zero, there could be a case for considering whether it would be appropriate to transition to a Reliability Market.

8 Other Impacts

Impact on small firms

8.1 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.

8.2 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

8.3 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, One-Out

8.4 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, One-Out (OIOO).[34]

Equality impact

8.5 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

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

i. 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)
ii. The **administrative costs** on electricity companies associated with participating in a Capacity Market
iii. The impact on business from facing higher energy bills as a result of the Capacity Market.[35]

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

8.7 A Capacity Market is modelled as having a small negative impact on businesses as rents accrued by providers in capacity auctions are narrowly outweighed by increased costs to businesses from higher energy bills. However a Capacity Market insures against security of supply risks that could have a much more significant effect on businesses in GB.

Figure 18: Impacts of a Capacity Market on Business

Impacts of a Capacity Market on Business 2012-2030, £m (2012 prices)	**Administrative Capacity Market**	**Reliability Market**
Administrative costs	240	240
Cost of option trading	0	1,082
Cost to business of increased energy bills	2,663	2,663
Total costs	**2,903**	**3,985**
Total benefits (producer surplus to providers)	**2,614**	**2,614**
Net impact on business	**-289**	**-1,371**

[35] Calculated assuming that around 62% 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.

9 Post Implementation Review

9.1 The Department of Energy and Climate Change has committed to a statutory review of the Capacity Market within the Energy Bill. The exact nature of the review policy will be determined as the detailed policy design develops. The date of the review will depend on the timing of the first capacity auction process.

9.2 It would seem appropriate to have regular reviews subsequently to assess the effectiveness of the mechanism and to address significant changes in the environment in terms of decarbonisation and security of electricity supply. The Delivery Plan process also serves to monitor the outcomes of the auction, with the System Operator reporting against the reliability standard to Government on an annual basis.

9.3 At this stage it is too early to put in place a detailed Post Implementation Review. The department intends to register a full Post Implementation Review and to confirm in detail how the Capacity Market will be reviewed when it publishes draft secondary legislation to implement Electricity Market Reform.

Annex A: Penalty Regime

1. The penalty regime for a Capacity Market is a key design feature as it effectively defines the product that is being bought. This Annex sets out the rationale for the specific penalty regime chosen for the Administrative Capacity Market.

Penalty regime options considered

2. Two forms of penalty regime were considered for an Administrative Capacity Market:

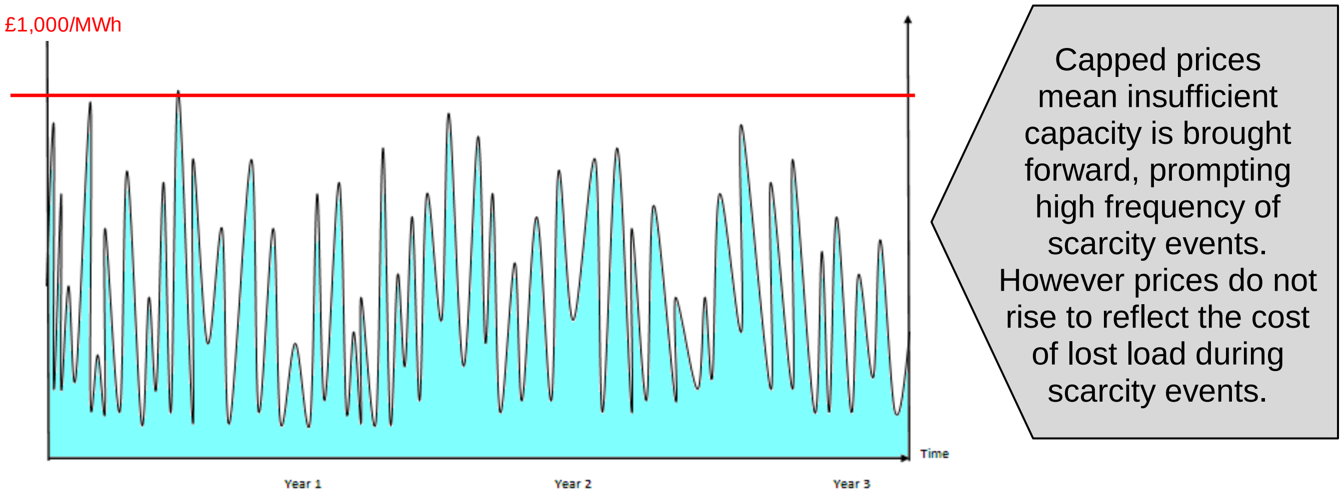
   ii. Declared Availability: Under this model providers' capacity payment is pro-rated according to how many settlement periods they declared themselves available for at four hours ahead of real time. There are "spot checks" to identify providers trying to exploit the potential gaming opportunities of the mechanism by falsely declaring themselves available: Where there is a high risk that a particular provider is gaming (determined with reference to whether or not they were generating in previous periods of narrow margins), that provider will have to demonstrate to the System Operator that they are capable of generating the level of capacity they had offered into the auction. Providers which fail these "spot checks" will face an administrative penalty, potentially capped at twice the annual payment level.

   iii. Delivered Energy: This is the preferred form of Administrative Capacity Market and the variant assumed in the Impact Assessment. Capacity providers pay back their upfront capacity payments if they were not delivering at times of scarcity (i.e. when there were blackouts or brownouts). A potential form of penalty is for providers who were not delivering in scarcity events to face an administrative penalty reflecting consumers' value of lost load minus the prevailing cash out price. Total penalties could be capped at twice the annual payment level. Providers additionally have to demonstrate they are capable of generating at the level of capacity they have offered on a certain number of occasions a year in order to provide additional delivery assurance given the estimated low frequency of scarcity events.

Rationale for options

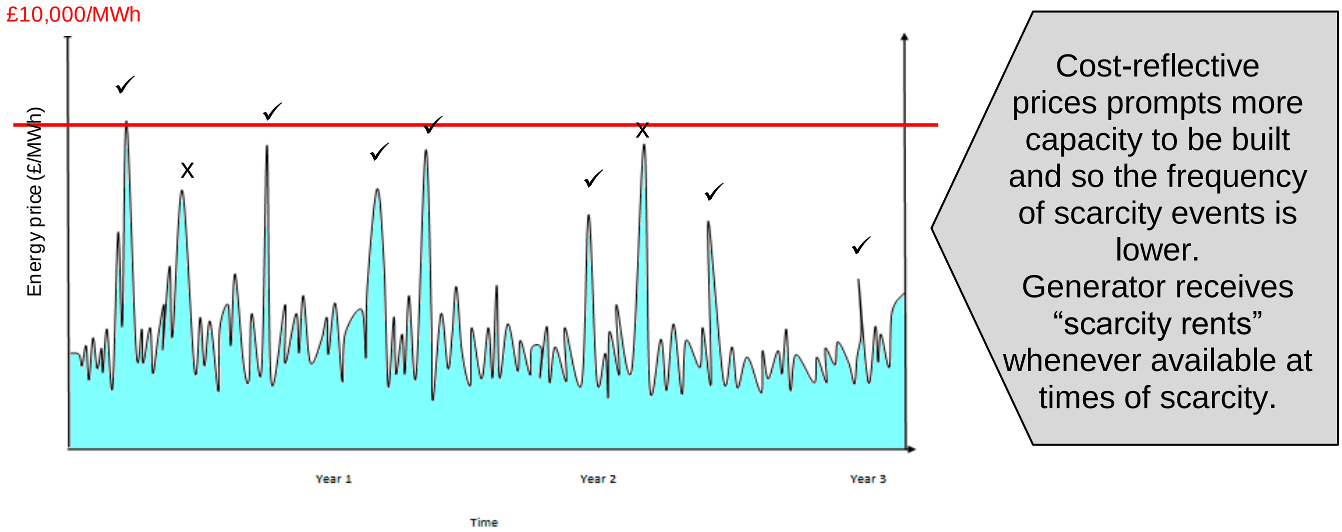
3. It is projected that the current energy-only market arrangements will fail to bring forward sufficient capacity in the long term due to generators' concerns over their ability to access suitably high prices in periods of system scarcity to cover their investment costs (the aforementioned 'missing money' issue), directly leading to an increasing volume of scarcity events each year – as shown below in Figure 19.

Figure 19: Prices in energy-only market with capped prices



4. Under a hypothetically reformed energy-only market, where cash out prices could rise to reflect the value of scarcity, only those generators delivering in times of scarcity (indicated by a tick in Figure 20 below) would be able to access the higher scarcity rents. The market would incentivise an economically efficient level of capacity, with the result that scarcity events would occur at a lower frequency than that projected for an un-reformed energy-only market.

Figure 20: Revenue in energy-only market with fully cost-reflective prices

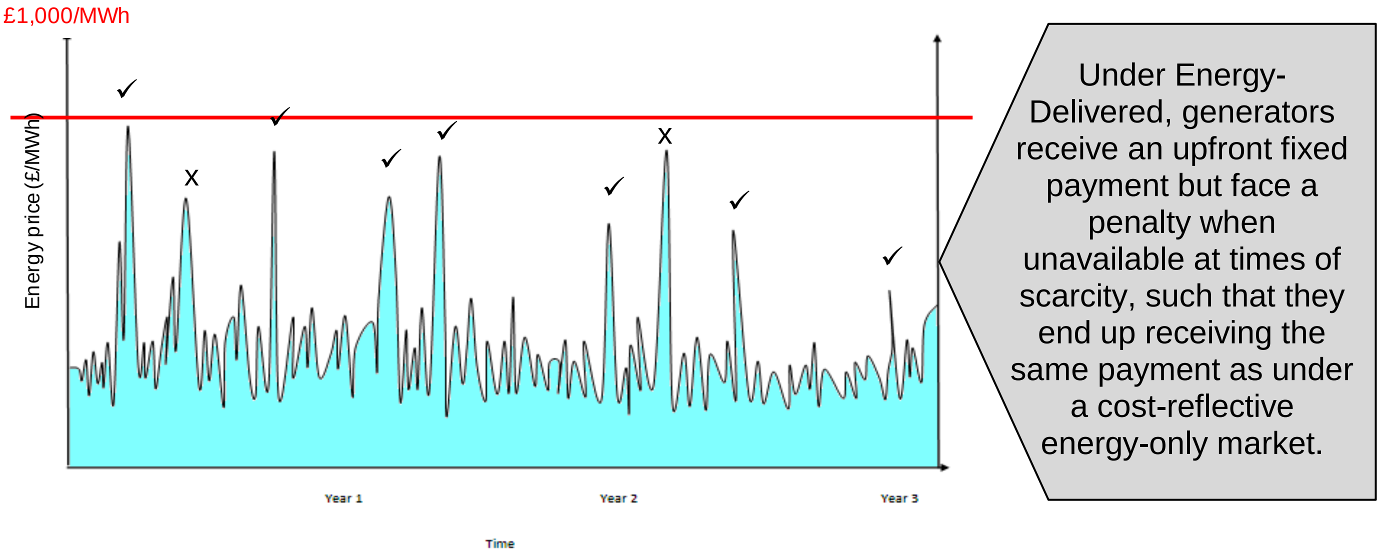


5. In the “Declared Availability” model, generators will receive a fixed payment for capacity. This should reflect the “missing money” that exists in the energy-only market without scarcity rents. The payment however does not vary significantly according to whether the provider is available at times of scarcity.[36] Moreover they are paid according to availability four hours out, rather than in real time (which is when it is known with certainty whether there is scarcity). Thus providers are remunerated on a much more stable basis than in an efficient energy-only market.

[36] If the provider is available 99% of the time, but not the 1% of the time when there is a scarcity event, it will receive 99% of the full capacity payment.

6. In the proposed “Delivered Energy” model capacity payments will be paid upfront to providers to replace the ‘missing money’ component of the current energy-only market. Providers will be required to return a proportion of these upfront payments for each scarcity event they are not delivering. The total revenue and delivery incentives of the “Delivered Energy” model will therefore reflect the incentives of an energy-only market with a cost-reflective price. This has the result that scarcity events are still likely to occur but at a similarly low level to the reformed energy-only market scenario in Figure 20.

Figure 21: Energy-market revenue under Delivered Energy model



Assessment of options

7. The “Declared Availability” model leaves market signals to determine when generators should run. Penalties will not be applied to providers failing to deliver at times of scarcity; such providers will however, face subsequent “spot tests” which they must pass or face administrative penalties. The logic for this model is that providers that fail to be available at times of scarcity either already face “cash out” as a penalty or lose the opportunity cost to be sell their energy for a high price.

8. However if “missing money” in the energy market means that insufficient capacity would get built in an energy-only market, it also means that the market may fail to provide signals for plant brought forward in a Capacity Market to be reliable when needed. Thus there is a risk that investors would bring forward whatever capacity is cheapest and meets the testing regime, regardless of whether it is sufficiently reliable under scarcity conditions. The interaction with Ofgem’s cash out reforms is therefore crucial for this model to provide appropriate signals to bring forward the right type of capacity and for capacity to be reliable under scarcity conditions.

9. The “Declared Availability” model has a number of advantages over the “Delivered Energy” model, as it is relatively straightforward to implement and therefore has a lower risk of unintended consequences for the wider market in the short-term. However it increases the risk that capacity will not be delivering when needed and by paying for availability rather than the delivery of energy it is more vulnerable to gaming.

10. The “Delivered Energy” model is intended to mimic the incentives of an efficient energy-only market (i.e. where the electricity price is fully cost-reflective): Providers receive an

upfront capacity payment instead of needing to wait for scarcity rents in the energy market but only keep this payment when delivering at times of scarcity, as would happen in an efficient energy-only market.

11. The Delivered Energy model puts greater risk on capacity providers and so could lead to higher capacity payments than a "Declared Availability" model. However overall it should ultimately prove better value for consumers as it is more likely that it would deliver the security of supply objectives of the mechanism. Allocating risks to capacity providers ensures that there is the appropriate incentive for plants to deliver when needed, to build an overall plant mix that is sufficiently flexible[37], and to invest in the reliability of the plant.

12. The "Delivered Energy" model could lead to existing plants running warm a greater proportion of the time as participants respond to the sharper incentives. This could lead to additional costs as well as carbon emissions, and over time may see plant with different characteristics being built (for instance to avoid the need for expensive warming) than would otherwise occur without such incentives. However, such a model will only incentivise plants to run warm where economically efficient to do so (plants will not incur costs greater than the incentive itself), whereas the current energy only market may fail to do so as it may not sufficiently reward plants that are available on occasions of system stress.

Conclusions

13. The "Delivered Energy" model avoids the inefficiencies and gaming risks of the "Declared Availability" model by targeting the delivery of energy to those periods when needed. Whilst the model does increase risk for providers and has a greater level of design complexity than the "Declared Availability" model (due to the specification of technical parameters such as definition of delivery and scarcity events), it should be less susceptible to gaming and provide stronger assurance that capacity will be delivering when needed – thus directly reducing the risk of scarcity events.

[37] This is not to say all plant needs to be flexible, rather the correct incentives for an efficient plant mix with some baseload, some flexible, etc.

Annex B: Auction Design

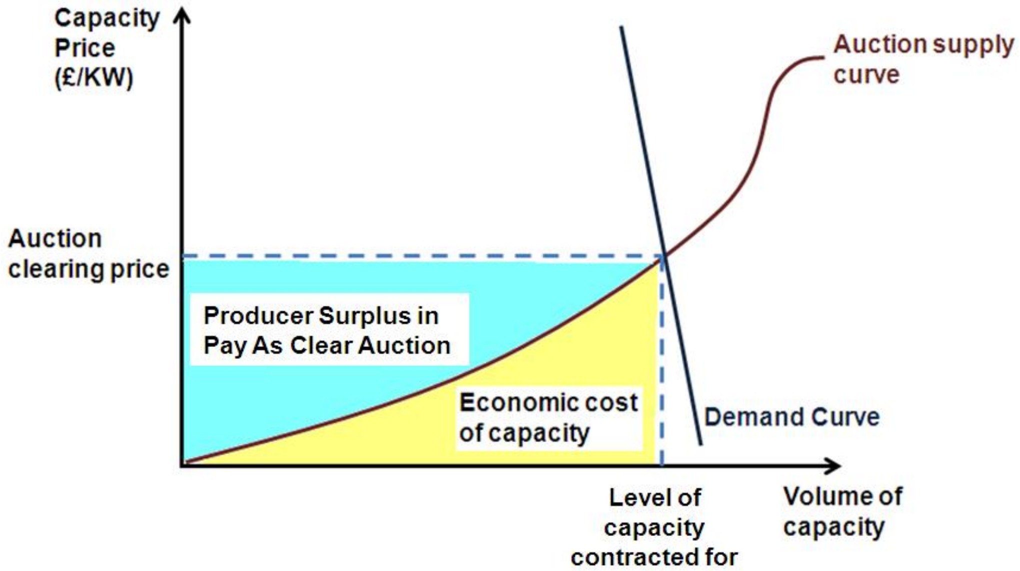
1. The Impact Assessment has assumed for modelling purposes that a Capacity Market uses a pay-as-clear auction, also known as a 'marginal bid' auction, where all plant bid in their true capacity cost. No decision for auction format has yet been made and a number of options are currently under consideration. This Annex sets out the impact of these options:

    i. Pay-as-clear
    ii. Pay-as-bid
    iii. Pay-as-bid; mandate that existing plant bid their true cost

Pay as Clear Auction

2. Under a pay-as-clear auction all parties are paid the clearing price set by the most expensive successful provider that bid into the auction. This initially appears to deliver poor value for money for consumers because, even if the auction is perfectly competitive and all parties offer their capacity at true cost level, parties are paid more than the price they said they would be willing to provide capacity for. The size of the producer surplus awarded in a pay-as-clear auction is illustrated below:

Figure 22: Pay as clear auction



3. There are two potential reasons to think that a pay-as-clear auction format is appropriate:

    i. *Fairness*: There is an argument that in markets, parties should be paid the same price for the same product. This argument is strong in the case of markets with homogenous goods. An Administrative Capacity Market that creates strong incentives for plant to be reliable could be seen as such a market as it prevents unreliable capacity from claiming the same level of payment as more reliable capacity. However some parties may be overpaid if given the clearing price, particularly if the auction is not competitive and where parties may be able to increase the marginal bid. The risks around gaming and the potential mitigation measures are further explored in Section 6 of the IA.

ii. *Cost-effectiveness*: It can be argued that while pay-as-clear auctions pay many generators more than their bid price, this format of auction is still more cost effective than the alternatives. This argument is assessed below in the context of the alternative options for auction design.

Pay as Bid Auction

4. Under a pay-as-bid auction existing plant no longer have incentive to bid their true cost level, even if the auction is competitive, because they know they are not the marginal plant and so will still get a capacity contract if they bid high.
5. At first glance, it would appear that this form of auction leads to, at worst, the same level of payment as in a pay-as-clear auction because parties will bid in the marginal price if they know what it is (and could well bid lower if they don't know the marginal price and if they are risk averse).
6. However in practice there are a number of reasons to think that pay-as-bid auction could lead to higher costs for consumers than a pay-as-clear auction:

   i. *Economic inefficiency:* Providers could bid high if they underestimated the cost of the marginal plant. This could mean that economically inefficient decisions e.g. to build new plant are made rather than pay existing plant to stay open.

   ii. *Price discovery:* In a pay-as-clear auction (particularly a descending clock auction) parties learn how other parties value the opportunity of building a new plant. Given uncertainty investors face when deciding whether to build capacity (given the cost, lead-in-time, and market/regulatory risk), this kind of "price discovery" can be helpful to the market and lower investors perceived risk and therefore to price lower. It also reduces the risk of "winners' curse".

   iii. *Competition:* Pay-as-bid auctions introduce a guessing game for existing plant, where the parties that can best guess the marginal price make the most profits. This gives an advantage to large portfolio players who have better information to forecast the level of the highest acceptable bid and disadvantages independents. A reduction in competition in the market can ultimately lead to consumers paying more as a result of a pay-as-bid auction. Under a pay-as-clear auction, the withholding of capacity by large participants to raise the clearing price makes room for smaller participants, which will tend to encourage entry in the long-term.

   iv. *Long term signals:* Paying the market 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 sets a single price incentivises everyone to try to provide capacity at less than this price - over time this puts downward pressure on the price and therefore achieves the lowest long-term sustainable price.

Pay-as-bid - mandating that existing plant bid their true cost

7. To minimise the amount of producer surplus that goes to capacity providers in the auction it is therefore necessary not just to have a pay-as-bid auction but also to mandate that existing plant only bid in their true cost level – i.e. the minimum payment for which they are just willing to stay open or to build plant. Otherwise a pay-as-bid

auction creates a game of “guess the clearing price” – a game which big portfolio players are best placed to win.

8. However there are significant practical disadvantages to regulating what price a party may offer into the auction for:

    i. *Uncertainty*: It is very difficult to establish what is the true cost for a plant to stay open as there are significant information asymmetries between Government and individual investors. In absence of knowing what a true cost level, Government will occasionally have to “call the bluff” of a provider that has bid high into the CM and provided weak justification for why it needs this high payment. This is necessary to deter other parties from similarly attempting to bid above their true cost level. This could lead to existing plant retiring and being replaced by new plant that needs a higher price than the existing plant was requesting.
    ii. *Regulatory risk*: Forcing parties to provide analysis setting out why they need a particular level of payment is administratively burdensome. A greater concern for investors is that they don’t know whether they will be able to continue being able to offer into the auction of whether the regulator will tell them they are pricing too high. This creates an incentive to bid high in initial years as investors do not know what capacity payment they might get in future years. Ultimately the degree of interventionism in this option could mean that Britain is seen as a less promising environment for investment (because Government is seen to arbitrarily intervene to stop parties from earning “too much” money) and so parties require higher payments to participate in this market. Once a higher price is set in the auction by new plant it creates greater headroom for existing plant to stay open, thereby leading to a situation whereby everyone is now being paid a high price.
    iii. *Long term signals*: As with a simple pay-as-bid auction, this option may blunt incentives for the market to drive ingenuity and innovation as new technologies cannot see what potential earnings they might make if they can undercut the clearing price in the auction.

Conclusion

9. 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 signals for competition and innovation. In the long run we think this is likely to lead to lower costs for consumers, particularly as expecting parties to bid their true cost level in a pay-as-bid auction is difficult to enforce and can create regulatory risk and give an advantage to large portfolio players who are better able to guess the clearing price.

10. However we recognise the risk of overpayment under a pay-as-clear auction, particularly if incumbents are able to drive up the clearing price in years when there is no new capacity being brought forward. We are continuing to look at measures to mitigate these risks, for instance by requiring incumbents wishing to set the price to justify their bid level.

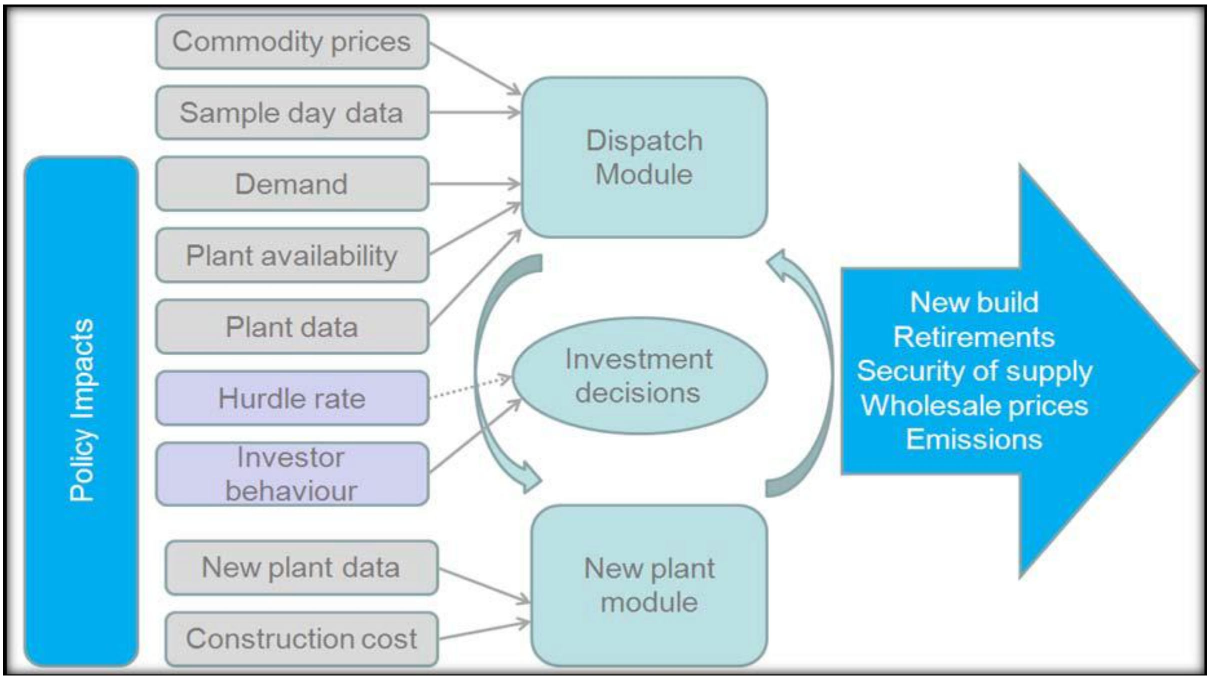
Annex C: Energy System Modelling

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 1 illustrates the structure of the model.

Figure 1: 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,

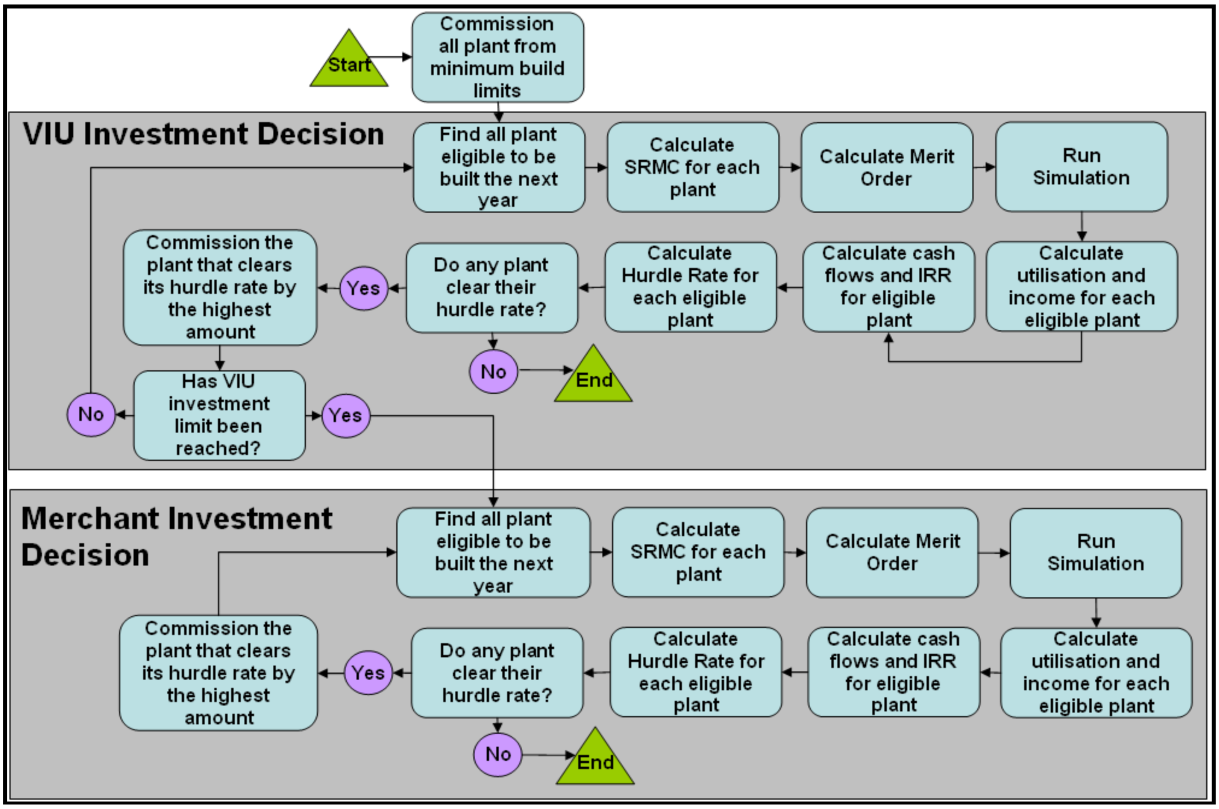
efficiencies and emissions, and also planned outages and probabilities of unplanned outages.

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 2. Limitations can be entered into the model such as minimum and maximum build rates per technology, per year, and cumulative limits.

Figure 2. 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).

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 http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx

2012 prices	Oil			Gas			Coal		
	$/bbl			p/therm			$/tonne		
	Low	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**
2011	115	115	115	58	58	58	124	124	124
2012	105	115	125	54	63	72	97	102	107
2013	103	116	128	51	70	87	94	110	121
2014	102	117	131	49	76	89	92	116	134
2015	**100**	**118**	**134**	**47**	**77**	**91**	**89**	**117**	**139**
2016	99	119	137	45	78	93	86	117	144
2017	97	120	140	43	75	95	84	118	149
2018	96	121	144	41	72	98	81	119	154
2019	95	122	147	41	72	100	79	119	159
2020	**93**	**124**	**151**	**41**	**72**	**102**	**76**	**120**	**164**
2021	92	125	154	41	72	103	76	120	167
2022	90	126	158	41	72	103	76	120	171
2023	89	127	162	41	72	103	76	120	174
2024	88	128	165	41	72	103	76	120	177
2025	**86**	**129**	**169**	**41**	**72**	**103**	**76**	**120**	**181**
2026	85	130	173	41	72	103	76	120	182
2027	84	131	177	41	72	103	76	120	184
2028	83	133	181	41	72	103	76	120	186
2029	81	134	186	41	72	103	76	120	187
2030	**80**	**135**	**190**	**41**	**72**	**103**	**76**	**120**	**189**

Carbon Prices

The DDM uses DECC's projected carbon price for the traded sector as well as the appraisal values of carbon, as set out below.

Projected EU-ETS carbon price for the traded sector, 2012 £/tonne of CO_2e

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central	6	6	6	6	7	7	8	8	9	9	9	10	10	10	11	11	11	12	12

DECC appraisal values for greenhouse gas emissions impacts in the traded sector, 2012 £/tonne of CO_2e

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central	6	6	6	6	7	7	8	8	9	15	22	29	35	42	49	56	62	69	76

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 CO_2e

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
10	14	20	24	26	28	30	32	37	41	45	50	54	58	63	67	71	76

Technology Assumptions

Cost and technical data for new plant is taken from the 2012 PB Power study (for non-renewable technologies) and the Renewables Obligation Banding Review for renewable technologies. Details can be found at:
http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_costs/gen_costs.aspx

Hurdle Rate Reductions by Technology Type under FiT CfDs

	Reductions under FiT CfDs
Onshore Wind	-0.5%
Offshore Wind (R1/R2)	-1.1%
Offshore Wind (R3)	-1.2%
Biomass (Large and Small)	0%
Biomass CHP	0%
Nuclear	-0.8%

Modelling Assumptions

10. A range of assumptions were made for the effects of the different policy instruments to be modelled. These are published on DECC's website.[38]

11. All options, including the base case, were set to achieve the same level of decarbonisation and level of renewables deployment in order to make them comparable.

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

13. **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.

14. **Carbon prices**: These are assumed from 2013 to follow the Carbon Price Floor levels announced in Budget 2011.[39] In accordance with Budget, the carbon price is set to £16/tCO_2 in 2013 rising on a linear trajectory to £30/tCO_2 in 2020.

15. **Fuel prices**: fuel price assumptions are based on DECC's Updated Energy and Emissions Projections (UEP) October 2012 Central Price case.[40]

16. **Demand**: demand assumptions are based on provisional results of the published UEP October 2012 Central scenario for total electricity supply.[41] The stress test uses the "Gone Green" demand forecast in the National Grid Future Energy Scenarios.[42]

17. **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.[43]

18. **Hurdle rates**: Hurdle rates are based on assumptions by Oxera (2011) and Arup (2011) and are informed by market data points.[44]

19. **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.

20. **Transition/timing**: In the model capacity auctions are triggered once de-rated margins are set to fall below 10%. All new low-carbon capacity that comes on from 2016 onwards is assumed to be through the CfD, rather than the RO.

[38] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_dispatch/gen_dispatch.aspx
[39] http://www.hm-treasury.gov.uk/consult_carbon_price_support.htm
[40] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx
[41] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx
[42] http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/47855/DevelopmentofEnergyScenariosTBE2011.pdf
[43] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_costs/gen_costs.aspx
[44] The minimum rate or return needed for investors to be willing to make a particular investment

Limitations of the modelling

21. 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.

Capacity Market

22. To capture the effect of capacity contracts, both the contract allocation process (auction) and the effect on the wholesale electricity market have been modelled.
23. 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 or CfD are not eligible for capacity payments.
24. The bid prices for each generator are calculated based on the required additional revenue to extend the plant lifetime or build a new plant.
25. 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.
26. The key parameters for a Capacity Market are:

    - The volume of contracts bought by the central buyer are peak demand plus 10%. 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 40% derating factor, implying imports of 1.5GW 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.
    - Investors have full confidence that the policy will maintain de-rated capacity margins at a minimum of ten per cent.
    - 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.