UPDATE ON CM AUCTION PARAMETERS

Section 1: Scope

1. This paper provides updates on a number CM auction parameters:
   i. Net Cost of New Entry (Net CONE)
   ii. Auction Price Cap
   iii. Price Taker Threshold
   iv. New/Existing/Refurbishment Definition
   v. Net Going Forward Cost
   vi. Volume to Contract

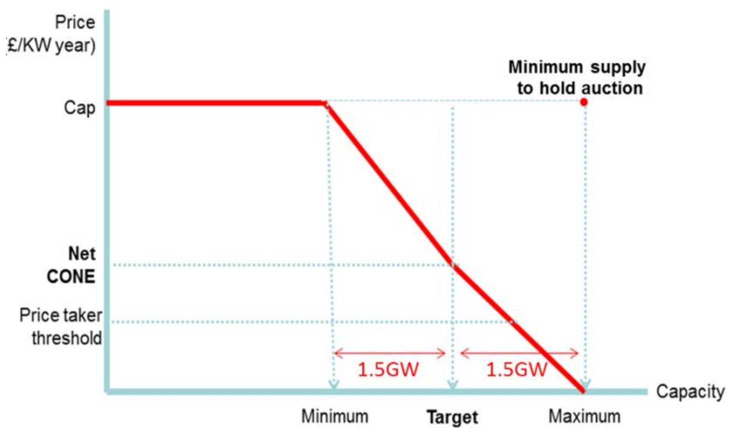
2. It is recognised that the derivation of the parameters set out in this paper depend significantly on the interactions between the Capacity Market and Energy Market – with the Capacity Market potentially restricting the potential for scarcity rents under some modelling approaches. The Annex sets out DECC's view of the impact of the Capacity Market on energy market rents.

Section 2: Background

3. This paper builds on recent publications, including:

   i. The previous Expert Group paper on Auction Parameters.[1] This paper set out that:
      i. The range for the volume contracted is 1.5 GWs[2] more or less than Target, with the slope of the demand curve set by the price cap, the Target, and the size of the range around the volume.
      ii. The minimum competition requirement for holding the four-year ahead auction is that 1.5 GWs more than Target must participate in the first round of the auction, i.e. at the price cap.

Figure 1: Illustrative Demand Curve



[1] 29 May EG paper "Determination of Auction Parameters", https://www.gov.uk/government/policy-advisory-groups/capacity-market-emr-expert-group
[2] Or =/-5% around the Target in the year-ahead auction.

ii. The Draft Delivery Plan[3] sets out the Government's estimates for Gross CONE (£47/KW), VoLL (£17/KWh), and the Reliability Standard (3 hours per year).
iii. Ofgem's Draft Cash Out Reform[4] sets out proposals to move to a single marginal price and to price in involuntary load shedding at £6/KWh.

Section 3: Net Cost of New Entry

4. Net CONE is the administrative estimate of the cost of capacity net of energy market revenue for the marginal plant. It is calculated by estimating the value of energy market rent for the marginal plant and subtracting this from Gross CONE.

5. As set out in the Draft Delivery Plan, Gross CONE is estimated to be £47/KW year and is based on assuming:

   i. The marginal plant is OCGT
   ii. Capital costs are the central estimate from a report by PB Power
   iii. The plant is financed at a 7.5% hurdle rate over 25 year

6. It is assumed that the marginal plant rarely runs – and can only recover its fixed costs in the three hours per year indicated in the reliability standard in which there is expected to be load shedding.

7. Ofgem has announced its intention to reform balancing arrangements so that from 2018 cash out goes to at least £6/KWh when there is load shedding.[5] It is therefore reasonable to assume that the marginal plant would earn this level of revenue for three hours per year, adding up to £18/KW. It is also reasonable to assume that this revenue is pure rent: while there may be some fuel costs, these costs will be negligible relative to the size of the energy rent.[6] This methodology suggests a Net CONE of £29/KW year.

8. Ofgem has also indicated its intention to introduce a £3/KWh price for load shedding in the period from 2015 to 2018, which covers the DSR transitional arrangements. Using the methodology above, Net CONE in this period would be estimated as £38/KW.

9. It is recognised that there is significant uncertainty around the estimate of energy market rent, for a number of reasons:

[3] July 2013, "Consultation on the Draft EMR Delivery Plan"; https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223650/emr_delivery_plan_consultation.pdf
[4] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/EBSCR%20Draft%20Decision.pdf
[5] This is a draft policy decision subject to consultation and is not expected to be finalised until early 2014.
[6] There is a possibility of high fuel costs if the event is due to a gas shortage. However this is expected to be very unlikely and generators should be able to hedge this risk if need be.

i. **Mark-ups**: Generators may earn rent outside of times of lost load if they are the marginal generation plant and so able to set the price. The ability of generators to charge a markup to recover their fixed costs may be aided by the proposed move to a single marginal cash out price, which should help prices better reflect scarcity outside of times of system stress.
ii. **Balancing Mechanism**: The methodology presumes that generators can earn the cash out price for their generation. This may be difficult in practice because the Balancing Mechanism (BM) is currently arranged on a pay-as-bid basis, so generators can only earn the cash out price if they bid it before gate closure or else are long in the BM.
iii. **Reserve Pricing**: A further part of Ofgem's cash out proposals is to price in the use of reserve plant – e.g. STOR. This may lead to rents for OCGT plants outside of periods when there is no load shedding. However it remains difficult to estimate the value of such rents in absence of further detail about how these arrangements will work in practice.
iv. **Ancillary service payment**: Providers may also receive payments for providing ancillary services to National Grid. To some extent the receipt of such revenue will foreclose the option of receiving equivalent energy market rent – for instance receipt of payment in STOR for being available at low cost in a stress event. However ancillary payments can also remunerate capacity for services not valued within the energy market price – such as capacity being located in useful places or being able to ramp up in under 15 minutes.
v. **Reliability standard**: While a standard has been set for three hours per year, in practice it is likely that there will be many years in which there are no events and some years with significantly more than three hours. This may make it hard for investors to take account of scarcity rents – although in theory this should be mitigated by the fact suppliers will have strong incentive to contract capacity to mitigate their exposure to cash out penalties. There may also be regulatory risk if investors think that Government will be overly cautious in procuring capacity: This risk should be mitigated in part by the use of the Panel of Technical Experts to provide independent scrutiny of the procurement decision. However if Government sets Target to procure more than the efficient level then plant should price higher into the auction, leading to less procurement that Target and leading to a more efficient level of capacity being procured.

10. However while there is uncertainty around the "true" level of Net CONE, the methodology proposed reflects a reasonable estimate and has the virtue of being simple to calculate.

11. Nevertheless it is important to set the price cap sufficiently high to take account of the uncertainty around this estimate, and to review the appropriateness of the methodology regularly, for instance as more DSR comes forward or as there is greater use of reserve pricing.

12. It is also noted that once the first auction is run, the clearing price in this auction should itself give an indication of Net CONE (which may be better than an administrative estimate). It is proposed that Net CONE in subsequent delivery years be set based on a weighted average of the administrative estimate and the clearing price in recent auctions – for instance 70% the average of the three most recent auctions and 30% the administrative estimate of Net CONE.

Comparison with Net CONE in PJM

An adjustment of around £23.50 is made to the Gross CONE figure to produce an administrative estimate of Net CONE in PJM. This is based on average ancillary service payments and energy market revenues for the past three years for the marginal plant.

This approach makes the reasonable assumption that investors will base future investment decisions on past revenues. However DECC considers the proposal to set energy rent at LOLE X Scarcity Price more appropriate for the GB market on the following grounds:

- The GB market does not have a pool – and so parties do not receive the same energy market revenues
- The GB market is expected to undergo a significant transformation over the next two decades – with a fifth of existing plant expected to retire this decade and with decarbonisation reducing the load factors of thermal generation.
- Ofgem's proposed reforms to cash out should significantly increase potential for scarcity revenues relative to past energy market arrangements. Unlike PJM, the proposed cash out arrangements would mean that prices will always rise to the scarcity price set (rather than to the cost of the marginal plant).

PJM sets the demand curve according to a mixture of its estimate of Net CONE and the clearing price in the three previous auctions.

Q1. Do you agree with the proposal for netting off energy market revenue?

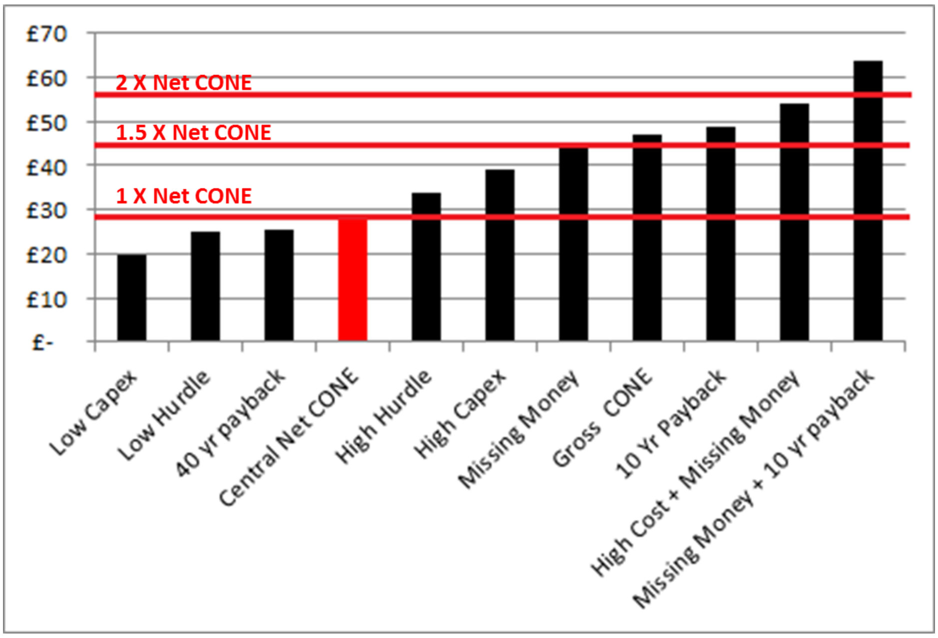
Section 4: Auction Price Cap

13. As noted, there is uncertainty around the estimate of Net CONE, and investors offering high prices into the auction may simply suggest that DECC had underestimated this parameter. Setting a price cap too low may therefore foreclose buying the efficient level of capacity, or lead to auctions being postponed as Government is forced to re-estimate Net CONE. However there are conversely risks around setting the price cap too high in that it reduces Government's ability to exert cost control and as it potentially enables greater gaming risk in the auction.

14. It is therefore desirable to set the price cap at a multiple of Net CONE – with the size of the multiple recognising the degree of uncertainty around the estimate. The factors that principally influence Net CONE are:
    i. Hurdle rates
    ii. The payback period
    iii. The capital cost estimates
    iv. The degree of energy market revenue assumed

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

Figure 1: Sensitivities around CONE with a £6000/MWh price in stress events



16. This analysis suggests they if investors assume they will earn at least £1000/MWh three hours a year (the "Missing Money" scenario) then they will be able to bid in at the 1.5 X Net CONE price cap. Similarly if they have high hurdle rates (9%), or high capital costs they will still be able to bid in at less than the 1.5 X Net CONE cap.

17. However if investors attempt to pay back their capacity over the ten contracted years, or if they have any combination of missing money as well as high costs, then the price cap will deter them from offering into the auction unless they are able to offer at up to 2X Net CONE.

18. The largest elements of uncertainty are around the calculation of Gross CONE and around the impact of cash out reform.

19. If investors are able to invest on the basis on uncertain scarcity rents then capacity prices should fall to close to zero. However cash out reform is a new policy proposal and so the impact of the policy is bound to be uncertain at least initially. Moreover there may be uncertainty initially as to whether DECC will

procure the efficient level of capacity – although this should reduce with experience.

20. Ultimately the decision of how to set the cap: Setting a low cap risks having to rearrange an undersubscribed auction and may cause reputational harm to DECC. However setting a high price limits certainty around maximum potential costs that may result from the auction, and could lead to increased cost of gaming if generators are able to bid up the price.

21. On the basis of this analysis it is proposed that we set a price cap of 1.5 X Net CONE (i.e. £44/KW).

Q2. Do you agree with the recommendation to set a price cap of 1.5 X Net CONE?

Section 5: Price Taker Threshold

22. The price taker threshold for existing plant needs to balance the administrative burden of requiring existing plant to submit a business case in order to bid above the threshold, with the risk of gaming if existing plant are able to price high without good justification.

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

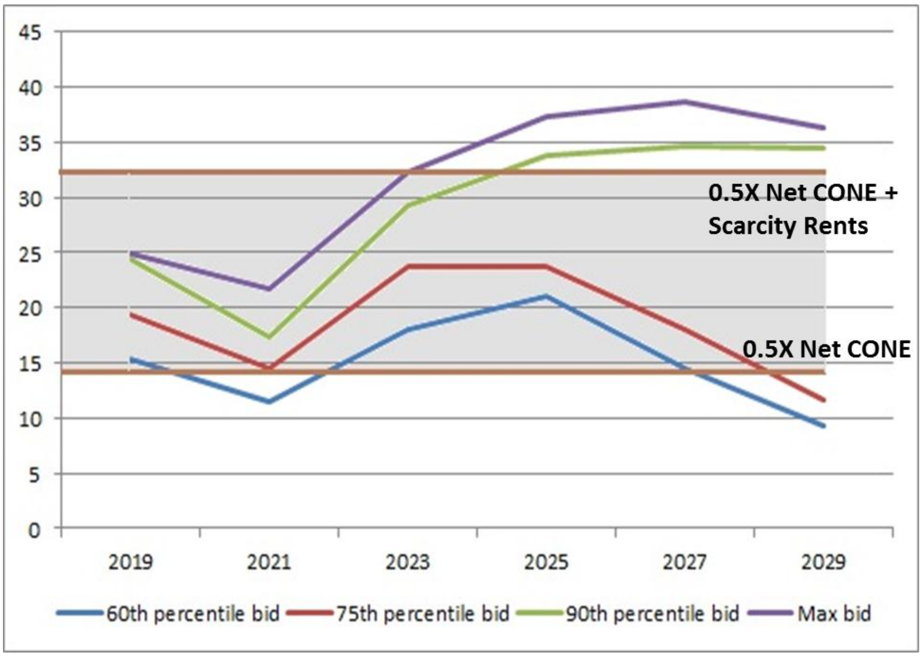
    i. 50% of Net CONE
    ii. 70% of the last clearing price set by new plant

24. This section reviews the analysis underpinning the threshold of 50% of Net CONE using DDM analysis, using the central modelling scenario in the Draft Delivery Plan. This shows how existing generators would bid on the basis of net going forward costs, i.e. the cost of staying open minus the profits from the energy market or ancillary services.[7] The DDM does not currently account for potential scarcity rents as it underestimates the degree of lost load associated with the capacity margin set (i.e. it does not show prices ever spiking towards VoLL). However the graph below illustrates the proportion of plants that will bid below the price-taker threshold if they take account of the expected £18/KW year in energy market profit through scarcity rents.

25. This shows that, to cover their net going forward costs, no more than 10% of existing plant should need to bid over 50% of Net CONE if they take account of the potential to make scarcity rents. However if plants take no such account of scarcity rents then around 40% of existing plants will need to bid above 0.5 X Net CONE and qualify as price makers.

[7] This does not take account of the risk premium that generators might expect for holding Capacity Obligations, although it is noted that providers holding obligations are as likely to be paid for overdelivery as they are to be penalised for underdelivery.

Figure 2: Net going forward costs for existing plant



Source: DECC DDM modelling – EMR Reference Case for Draft Delivery Plan

Q2. Do you agree with the recommendation to set a price taker threshold at 0.5 X Net CONE?

Section 6: Net Going Forward Costs

26. Capacity providers are expected to bid into the Capacity Market on the basis of "Net Going Forward Costs."

27. Previous Expert Group discussions have flagged concerns that existing competition powers (under the 1998 Competition Act) may not be specific enough to allow parties that offer capacity above their Net Going Forward Costs to be charged with abuse of market.

28. A potential remedy to this is therefore to impose a license condition on generators to offer a 'fair' price in to the auction, defined as "*the minimum capacity price required to make it profitable to enter the Capacity Market for that delivery year*".

29. This would help to mitigate gaming risk by allowing Ofgem to investigate participants for a breach of licence, which could require a lower evidential threshold than a breach of competition law. This approach follows the precedent set by the Transmission Constraint Licence Condition (TCLC), which sets a high-level requirement that a generator must not gain an "excessive benefit" during transmission constraints which is further elaborated by other parts of the licence condition and in a guidance document published by Ofgem.

30. However it is recognised that this approach also has disadvantages: It may create regulatory uncertainty for participants in the auction who are unclear as to how they may price into the auction, particularly in absence of detailed guidance as to how Ofgem interpret a “fair” price. It is also not demonstrated that there is a gap in existing competition powers that would allow existing plant to bid inappropriately into the auction. If such a gap were identified it would be possible to amend CM secondary legislation to add an appropriate licence condition going forwards.

Q3. Do you think a licence condition on generators should be added to require them to bid fairly into the auction?

Section 7: Definition of New and Refurbishing Plant

31. We are proposing to define new and refurbishing plant in the following way:

   i. **Use of Capex Thresholds**: Both new and refurbishing plant will be principally defined according to their capital expenditure. This recognises that in reality there is a spectrum between “new” and “existing” plant and that cost-efficient investment in new will likely make use of some existing infrastructure.

   ii. **Purpose of Investment**: “Refurbishment” will be defined as investment *for the purposes of reducing emissions* (likely to be calculated on a CO2 equivalent basis), while investment to qualify as “New” must be for “*purposes of increasing capacity or repowering the plant.*” This allows SCR plant to receive multi-year contracts but sets a high bar on existing plant seeking long term contracts.

32. The rationale for this proposal is to protect against the risk that the threshold is set in such a way that allows a significant amount of existing plant to receive multi-year contracts. We do not currently have reliable data on the cost of the various types of refurbishment. The cost of a given type of refurbishment varies significantly based on the age and configuration of a plant, meaning that it is unlikely we would be able to obtain precise estimates of different types of refurbishment even if we obtained cost estimates from independent sources. Finally, certain “routine” maintenance processes could be timed simultaneously to appear as significant refurbishment, which risks allowing a significant number of existing plant to access long term contracts if the threshold is set too low.

33. The proposed approach is consistent with the use of thresholds in ISO-New England to define plants eligible for multi-year contracts. It allows plant that fit selective catalytic reduction (SCR) equipment to qualify for multi-year contracts. The data we have suggests that fitting SCR is the most expensive category of refurbishment; it is also the refurbishment that is likely to result in the greatest cost saving for consumers, by reducing the need for coal plant to shut down under the Industrial Emissions Directive (IED).

34. It is proposed that the capex thresholds will be set at £250/KW for new plant and £125/KW for refurbishing plant. These thresholds are set to be just under the costs of building new OCGT plant and fitting SCR.

Figure 4: cost of building new gas plant and fitting SCR equipment, £/kW

£/kW	Low	Central	High
New CCGT	504	601	707
New OCGT	249	311	377
Coal SCR	125	140	150

Source: PB Power and Amec

35. It is proposed that "Refurbishing" plant will be eligible for 3 year contracts and that "New" plant will be eligible for 10 year contracts.

Q4. Do you agree with the proposed use of thresholds to define new and refurbishing plant?

Section 8: Ensuring the amount of capacity is robust to uncertainty.

36. Four years ahead of delivery year, Ministers will set out the demand curve for a Capacity Auction including the amount of capacity to contract in an auction. This would be based on National Grid's assessment of the amount of capacity which would need to be contracted in an auction in order to meet the reliability standard based on National Grid's assessment of the different possible scenarios. However, it is important to note that forecasts can and do change over time. So it is possible for example that although the analysis four years ahead suggested that 70GW of capacity was needed to meet the reliability standard, it may become apparent closer to the delivery date that due to a fall in demand, unanticipated at the four year ahead stage, in fact, only 66GW would be needed.

37. To a large extent, this uncertainty is inherent and cannot be fully mitigated. It is inherent in any market where the lead times to build new infrastructure are long – market conditions can change between the time that investment decisions are made and the time that the infrastructure becomes operational. This feature of the electricity market is not affected by whether or not we have a Capacity Market. However, it is important that this is not exacerbated by the fact of having a Capacity Market. There are a number of features of the design which will ensure that this is mitigated as far as possible.

    i. **The governance process for the analysis:** It is important that analysis is robust and that it is subject to external scrutiny. This will help to ensure that any changes in the analysis from year to year are not the result of swings in the methodology or analytical approach but instead reflect changes in the real world. The governance arrangements that are put in place by the System Operator and DECC will ensure that the analysis is robust. Each year, the System Operator will consult widely with industry and the public on the analysis that goes into the estimate of the amount of capacity to procure. In addition a Panel of Technical Experts will scrutinise the assumptions and provide advice and expert comment before the recommendation comes for Ministers to approve.

ii. **The slope of the demand curve**: As shown in section 2, there will be the ability to procure more or less capacity than the central target estimate in the auction. The main reason for the sloping demand curve is to ensure that demand is not inelastic which will help to mitigate gaming and or/a lumpy supply curve. However, it also has the helpful effect of allowing the market to respond to the central estimate of demand. If auction participants believe that the target level of capacity required to meet the reliability standard has been underestimated then they will anticipate greater scarcity revenues available in the wholesale electricity market in the delivery year. Participants ought to bid in a lower price into the capacity auction as a result. This will mean that we will end up buying more capacity than the central estimate which will reflect the fact that participants think that the target estimate is too low. The converse will be true if market participants think that central estimate for capacity is too high. Thus the auction supply curve provides a chance for the market to provide its own view of the amount of capacity required.

iii. The T-1 auction: For every delivery year there are two chances to purchase capacity. There is the T- 4 auction and the T-1 auction. At the T-4 stage, an estimate will be made of the amount of cost effective DSR that can be procured. This will then be held back from the auction. Based on very preliminary estimates we think that this could be around 5% of capacity contracted in an auction or around 2GW. If in the intervening period between the T-4 and the T-1 auction, the outlook changes significantly, then more or less capacity will be demanded in the year ahead auction. Of course there will be a limit on the amount of capacity that could ever be contracted year ahead because of the lead times involved in delivering new capacity. However, it is likely that there will be some additional capacity to contract in the event it is needed because typically there is some mothballed generating plant out there. It may also be possible to contract some higher cost DSR in the T-1 auction if it is available. If it turns out that less capacity is required in the T-1 auction then less DSR will be auctioned. However, we want to ensure that at least some DSR is contracted because this is an emerging technology. Therefore we propose that a minimum of 50% of the DSR that was reserved for the T-1 auction at the T-4 stage.

iv. The following year's auction: A capacity auction will be held every year. If there is a change in the outlook for demand for example from one year to the next, then that will be reflected in the following year's auction. As long as there is a significant proportion of capacity that is not on long term contracts, as will be the case, then readjustments can be made from year to year. This means that the effects of the inevitable four year out forecasting errors will be short lived and ought not to persist through time.

38. Taken together these mitigating factors will ensure that the amount of capacity contracted is robust to uncertainty in the analysis that underpins it.

Section 9: Publication of auction parameters

39. Government intends to consult on the Auction Parameters alongside the Secondary Legislation in October. Government will then announce the final auction parameters as part of the Delivery Plan in July. This will include final numbers for Net CONE, the Target volume, price taker threshold, slope of the demand curve and minimum participation requirements.

40. Government will retain discretion to revise the above auction parameters in subsequent years through the five-yearly Delivery Plan and possibly the yearly updates to the Delivery Plan.

ANNEX: CAPACITY AND ENERGY MARKET INTERACTIONS

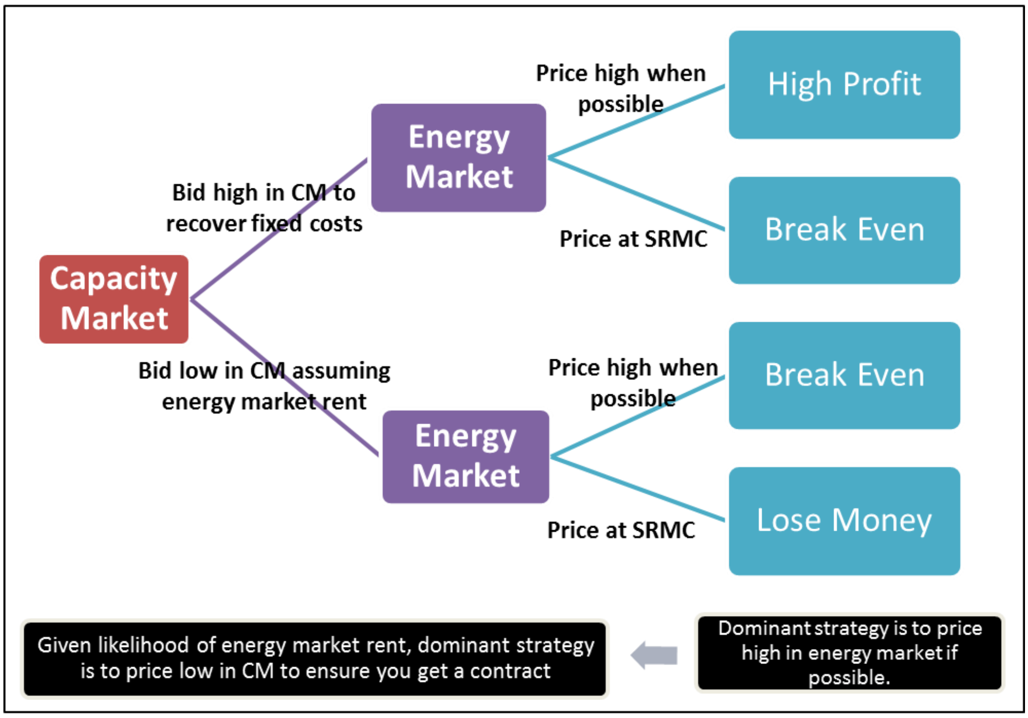
41. Understanding the impact of the Capacity Market on the wholesale energy market is important to being able to estimate how generators should bid into the capacity auction, as well as what impact the introduction of the CM will have on investment in low carbon capacity supported by the RO.

42. Some alternative energy modelling approaches have suggested that the CM could have a significant dampening effect on the wholesale price (i.e. by up to £10/MWh). This is based on a modelling assumption that the size of energy market rents are directly affected by the size of capacity payments – with generators pricing lower into the energy market than they would without a capacity payment.

43. DECC's analysis of the Capacity Market takes a different view: The Capacity Market directly affects the system margin, which in turn affects rents in the wholesale market. However the CM does not have any *direct* link between energy and capacity revenue. This is because the Capacity Market does not impose any caps or restrictions on pricing in the energy market (unlike the SEM, where participants are required to bid at SRMC).

44. The methodology for estimating energy and capacity prices can therefore be understood in a two-stage game: Providers decide how to price into the capacity market, and then once built decide how to price into the energy market. For most plants this will be based on the market price, although the marginal plant may be in a position to extract some rent. However once built, the marginal plant's dominant strategy (i.e. regardless of his capacity payment) is to price high into the energy market. Given that, parties should bid low into the energy market knowing that they will still be able to earn rent in the energy market. Thus the level of capacity payment set in the auction should reflect the level of "missing money" in the energy market as exists today, and should not increase that level of missing money. So as long as there is sufficient competition in the capacity auction, the continued presence of scarcity rents should not lead to "overpayment" to generators overall.

Figure 5: Illustration of energy/capacity price interaction as two stage game



45. Our analysis suggests that the Capacity Market should in theory be cost-neutral relative to a perfectly efficient energy-only market: If the energy market provided efficient investment signals then the market would bring forward the same level of capacity as we intend to target through the Capacity Market. However in practice we think that there are potentially significant market failures in the current energy market which means that the market would fail to invest sufficiently:

i. There is a lack of demand side response so prices are not set by customers values of turning down load.
ii. There is missing money – i.e. energy prices do not rise to reflect the value of scarcity – due to a variety of factors related to balancing arrangements.
iii. There is limited liquidity: there is no trading of options around the real-time price that would allow generators and suppliers to hedge the risk of volatile prices.
iv. Investment markets are prone to “boom and bust” cycles – and this is particularly the case in energy as power plants are significant investments with long lead times and recovery periods.
v. Decarbonisation exacerbates the investment risks as gas plant will increasingly run as “back up” plants – i.e. only running limited for limited periods when the wind isn’t blowing. This makes it more important that investors receive adequate scarcity rents when they do run, and that they are able to hedge their risk that such scarcity rents occur infrequently.

46. So while the Capacity Market is likely to dampen wholesale prices, it should only do so to the extent that the CM is bringing on additional capacity than would have come on in an Energy Only Market – reflecting the fact that such a market would be unlikely to adequately incentivise investment in new plant given the market failures addressed above.

47. However as the underlying failures in the energy market are addressed over the medium term (e.g. through cash out reform, smart metering and greater DSR), we would expect the level of revenue that industry receives through the CM to reduce.

48. This is in keeping with DECC's position that the CM is intended to be *complementary* to reforms to improve the functioning of the energy market, rather than a substitute for strengthening energy market signals for investment. Ofgem echoed this view in its Consultation document on the Electricity Balancing Significant Code Review:[8]

> *The CM aims to reduce the risk for investors from collecting all their revenues in the energy market, and instead offers a separate, more certain revenue stream. It also addresses the concern that cash out prices may be insufficient to incentivise the required investment if market players overly discount their exposure to low probability but high impact capacity shortages. Cash-out reform on the other hand focuses on improving the incentives in the energy market itself, including the incentives for flexible generation. Both cash-out reform and the CM are likely to affect investment decisions. However, it is unlikely that cash-out reform would have a large impact in the short term, but is more likely to affect investment decisions in the medium to longer term as the price signals work through the system.*

49. Given the anticipated impact on energy prices set out in Section 3, investors can use past observed relationships between capacity margins and energy prices to forecast future energy prices for a given CM reliability standard.

50. Of course, energy revenues for thermal plant will change over time due to decarbonisation, cash out reform, and greater take-up of DSR. However they will not change as a result of the CM *except* in so far as the CM delivers a different capacity margin or plant mix than an Energy Only Market would have.

Q6. Do you agree with the position that the presence of capacity payments does not change how providers will be expected to price into the energy market?

[8] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Electricity%20Balancing%20SCR%20initial%20consultation.pdf