Draft Drax response to CMA Updated Statement of Issues

Summary

In summary we agree with many of the initial conclusions reached by the CMA. The issues with which we are in general agreement with the CMA relate to:

- Cash-Out Reforms;
- Central-dispatch vs. self-dispatch;
- EMR;
- Unilateral Market Power in generation;
- Wholesale power market liquidity;
- Vertical integration; and
- Generation profitability.

We note that the CMA has raised some new issues that it believes may constitute an Adverse Effect on Competition (AEC) in the energy market (including an additional Theory of Harm). These issues are locational pricing of transmission constraints and losses and the Industry Codes.

On locational pricing, we agree with the CMA that in principle locational pricing can be expected to optimise total electricity system operation. However, in practice the assumed benefits are likely to be small and result in significant transitional costs due to the current national decarbonisation policy and emergence of new EU policy developments in this area.

On the Industry Codes, we believe that some simplification of the governance arrangements would be possible and helpful and may even reduce credit requirements. However, the Industry Codes by their nature are detailed industry rules and as such there is likely to be limited scope to reduce the inherent complexity of the content of the Codes. There is also merit in Ofgem assuming a more active role coordinating cross-cutting industry change. However, this is likely to require simply a change in behaviour by the regulator rather than require it to be furnished with additional regulatory powers.

We note that the CMA has raised numerous issues that impact the small business retail market. We continue to believe that the vast majority of business customers are best served by a highly competitive retail market and that this should be facilitated by the removal of counterproductive regulation. For example, a reduction in scope of the current Microbusiness definition to apply to only the very smallest business customers would result in significant consumer benefit. We believe that domestic customer style regulatory protections are only justified for the very smallest business customers.

Finally, we continue to have concerns with the operation of the ROC market and welcome the CMA's request for further information in this area. We believe that ROC prices achieved by generators are heavily discounted owing to the flawed market design. We have strong concerns that the discounts extracted by the Big Six are not passed on to their Standard Variable Tariff (SVT) customers owing to the Unilateral Market Power they exert over them in line with Theory of Harm 4. We believe this practice results in significant consumer detriment. As a result of the lack of transparency in the ROC market and residential supply sector, we consider that the CMA should definitively rule on the extent of consumer detriment being caused by using its extensive information gathering powers. If significant consumer harm is detected this would justify a recommendation from the CMA that the design of the ROC market should be reviewed urgently, and DECC should re-consider a move to introduce fixed price ROCs being brought forward from 2027 to 2018 – after the ROC scheme has closed to new generators. In addition, a remedy to increase competition for SVT customers should be considered by CMA. We suggest a form of competitive tendering which might be appropriate to address this. We discuss these options in greater detail below.

We discuss our views on the competition issues raised in the updated Statement of Issues in more detail in the following sections. The structure of the discussion of each issue is set out in order of specific Theory of Harm and, in addition to a discussion of key issues, sets out conclusions and potential further analysis and/or remedies which we believe the CMA should consider.

The ROC Market

Flawed market design and significant ROC discounting

We note that the CMA is still deliberating on the extent to which the Big Six might be able to exert buyer power in the ROC market and that in particular it is seeking evidence with regards to:

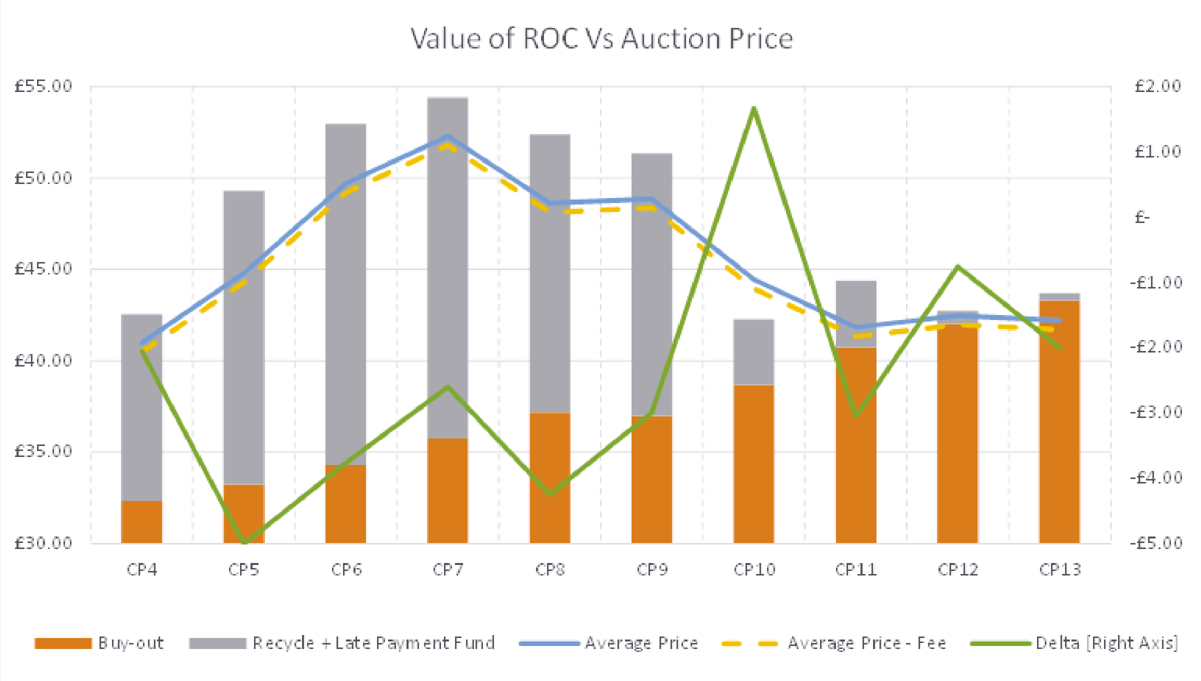
- How the price of ROCs have changed over time;
- The impact on investment; and
- The impact on retail customers.

We consider that the current flawed market design of the ROC market is liable to result in deep discounting of the value of ROCs. This is due to the potential oversupply of ROCs resulting from a Headroom calculation inaccuracy (in some circumstances), as well as the asymmetry in supply and demand bargaining power owing to the existence of the buy-out price mechanism. In addition, the demand for ROCs produced by independent generators is likely to be further reduced as the Big Six is able to source a significant proportion of their ROC obligation from their own renewable generation.

In our experience we witness discounts in the region of [REDACTED] per ROC (including a discount for the cost of cash). We would be happy to provide additional data helpful to the CMA if required. In addition, the eROC auction provides ROC pricing information, although the volumes traded only account for approximately two percent of total ROC supply. Finally, Poyry also track ROC discounts in long-term power and ROC purchase agreements, stating typical discounts of 8-10% for monthly settled sales.

The graph[1] below illustrates the final value of a ROC (Buy-Out plus Recycle value and late payment fund) compared to the average price that was achieved in the eROC auctions. Auctions were quarterly prior to CP10 (April 2011 – March 2012), but are now monthly, with average volumes of c. 80,000 per month trading. Including the advertised selling fee of 50p/ROC, the average discount to the final value of a ROC over the 9 Compliance Periods in question is £2.54/ROC. The green delta line shows the terminal value of a ROC compared to the outturn price in the Auction in each Compliance Period which varies materially each year.

[1] The data is sourced from the eROC auction website - http://www.epowerauctions.co.uk/erocrecord.htm



Any further data on ROC pricing is limited due to a lack of transparency and liquidity in the ROC market. Pricing information is confidential and likely to be contained in bespoke PPAs. We suggest that the CMA should request additional information in this area from small independent wind generators such as Infinis.

Moreover, the illiquidity of the ROC market is likely to deter the smallest suppliers from entering the market, which will result in them failing to take advantage of lower priced ROCs (relative to the Buy-Out price). There is no reason why such suppliers should not be able to achieve similar levels of observed ROC discounts. At present smaller suppliers tend to comply with their RO by paying the Buy-Out price[2].

It should also be noted that all suppliers collect cash from their customers in respect of the RO without having to pay that cash out for up to 18 months to either Ofgem or providers of ROCs. In our experience, if we ask for monthly settlement of ROCs delivered, the suppliers want to charge their cost of capital as a discount, when in fact paying early would leave them in a neutral position given they have already collected the cash from customers. The suppliers are essentially charging generators for the use of customers' cash, which is a design flaw in the RO market design. In addition, the supplier is collecting cash early from customers without paying this to generators, but it is not clear whether the customer is receiving a discount for paying in advance of the supplier's payment to the generator.

So to conclude, we consider that there is significant discounting of ROC prices due to the flawed market design, but that it would be sensible for the CMA to use its information gathering power to investigate the extent and significance of ROC discounting owing to the lack of transparency of ROC prices.

Are discounts reflected in customer bills?

If it were the case that these discounts that are negotiated by suppliers were passed on to end consumers, this would represent a clear consumer benefit. In the business market that Haven operates in it passes on some, if not all, of the discount to secure customer growth in the competitive SME and I&C retail markets. However, it is far from clear whether these discounts are passed on to end consumers in the domestic retail market where customer switching is less prevalent.

In line with Theory of Harm 4, we share the CMA's concern that the Big Six are able to exert Unilateral Market Power (UMP) over its Standard Variable Tariff (SVT) customers. Therefore we consider that the Big Six are able to withhold ROC discounts due to the lack of competitive pressure in the SVT market.

[2] https://www.ofgem.gov.uk/ofgem-publications/93414/roannualreport2013-14.pdf p73-p74

To consider the potential consumer detriment we can make a number of assumptions on the size of the ROC discounts and the Big Six customer base. The figures below should be considered indicative only as a consequence.

According to the Cornwall Energy report for Energy UK "Competition in British household energy supply markets – October 2014", in April 2014 there were 27.2 million residential electricity customer accounts[3]. The Big Six had a combined market share of 93.6%[4]. Therefore the Big Six would have 25.5m accounts on this basis. The CMA has noted that the Big Six have between 50% - 90% of their customers on SVTs. Therefore, we can assume that 70% (the midpoint) of the Big Six's customer base is on a SVT.

In 2013/14, 60.8m ROCs were issued[5]. Assuming that a £1-£2.50 discount is applied per ROC, [REDACTED], this results in a total ROC discount of £60.8m - £152m. Therefore if the Big Six all withhold these discounts from their SVT customers owing to the UMP they can exert, this results in a per customer account impact of somewhere between £3.40 - £8.50 p.a.

Moreover, this problem is only likely to get worse as the number of ROCs produced each year dramatically increases over the next three years. The quantity of ROCs is likely to be higher than at present in 2027 when the Fixed ROC scheme is introduced. The closure of the RO to new projects in 2017 will not alleviate the problem as there will still be a very significant quantity of ROCs issued in subsequent years.

Poyry's central projection[6] is that ROC production will peak in 2018 at 86 million ROCs. It will then slowly decline to 79 million ROCs in 2027. Therefore considering the peak ROC production year in 2018:

- 86 million ROCs will be produced. Assuming a constant £1 - £2.50 discount this results in a total ROC discount of £86m - £215m
- The Big Six will have 26.2 million customer accounts (increased in line with expected UK population growth over the period of 2.8% according to ONS forecasts and assuming constant market concentration)
- The Big Six will have 18.3 million SVT customers (assuming again that 70% of Big Six customers are on SVTs)

This will result in a per customer impact equal to between £4.70 - £11.75 p.a.

Of course, the above analysis requires a number of simplifying assumptions to be made due to the lack of transparency on ROC pricing, customer accounts etc. However, this analysis can be regarding as indicative of the ceiling on potential customer detriment. We consider that the impact is significant and worthy of further investigation by the CMA. With the CMA's information gathering powers we consider that it will be able to rule definitively on the actual customer impact.

To rule conclusively on the customer impact, we believe that the CMA should request from the Big Six data on the prices that they pay for ROCs (data gathered from independent market participants as noted above will be useful also) and the ROC cost that is charged to their SVT customers.

If the CMA determines that an AEC exists in relation to the ROC market, we believe it would be appropriate for the CMA to recommend to DECC that the design of the ROC market should be reviewed urgently, and DECC should re-consider a move to introduce fixed price ROCs being brought forward from 2027 to 2018 – after the ROC scheme has closed to new generators. Details of how this might work were set out in an earlier submission from Drax. In addition, the CMA should consider a remedy which seeks to increase competition for SVT customers. We set out more details on this potential remedy later in the response.

[3] http://www.energy-uk.org.uk/publication.html?task=file.download&id=4886 p11.
[4] Ibid. p14
[5] https://www.ofgem.gov.uk/ofgem-publications/93414/roannualreport2013-14.pdf p46
[6] Quarter 1 2015: Updated GB Wholesale Electricity ROC and LEC Price Projections: A Quarterly Update Note from Poyry Management Consulting to Drax Power Limited

Theory of Harm 1

Cash-out reforms

We agree with the arguments made that creating a more marginal cash-out price will more accurately reveal the costs of imbalance to market participants, thereby promoting more efficient balancing arrangements. However, we share the concerns raised by a number of parties (including Professor Stephen Littlechild) with regards to the proposal to lower the cash-out PAR value to 1MWh (PAR1). There are a number of risks associated with the adoption of PAR1, not least the potential for system pollution[7] of cash-out prices. Moreover, a PAR1 value is likely to result in more significant spikes in imbalance prices which will tend to place a disproportionate risk on smaller, more cash constrained market participants (although this impact might be expected to be most closely associated with the Reserve Scarcity Pricing (RSP) Function). This could represent an unnecessary barrier to entry.

For the reasons provided above, we consider that a more cautious approach should be taken in determining the PAR value. A value of somewhere between 50MWh and 100MWh appears to be an appropriate compromise from the analysis undertaken by Ofgem and Elexon[8]. The case for PAR1 could then be revisited at a later date in light of the experience gained from more marginal cash-out pricing.

With regards to the proposed RSP Function, we also have concerns with the proposal, but not for the same reasons as the CMA. We do not consider that there is a material risk of overcompensation for generators from the implementation of the RSP Function. As the CMA states there are strong arguments for introducing a Capacity Market, we assume it accepts that there is a 'missing money' problem inherent in the electricity market and that this is essentially a regulatory/political problem. We assume this as this is the rationale for introducing a capacity market. However, the CMA does not explain how the RSP Function would in effect solve the missing money problem. What is to stop regulatory/government organisations capping 'extreme' peak prices?

In addition, we expect that the Capacity Market will deliver the necessary capacity to deliver the Government's Reliability Standard. Therefore the occurrences of extreme peak prices in the future should be very rare. It appears more likely that high imbalance prices manufactured by the RSP Function will be associated with low probability and almost unforeseeable events, meaning that capturing sufficient value associated with these peak prices will be exceptionally difficult.

Our concerns with the RSP Function relate to the additional complexity associated with the mechanism, as well as potential for the wholesale market to 'dry up' in the event of scarcity. In terms of complexity, there has been insufficient testing of the model for market participants to have confidence that the RSP Function will deliver appropriate price signals in line with market fundamentals. A period of testing in a real world environment i.e. piloted before potential implementation should be a pre-requisite requirement for the adoption of the RSP Function.

In addition, on the rare occasions where the market is expecting high imbalance prices to be delivered by the RSP Function, there is likely to be a significant reduction in short term liquidity. This is because a generator will fear the penal imbalance prices that will materialise in the event of breakdown. Therefore the safer option is likely to be to spill power and capture the higher imbalance price (which would be facilitated by the adoption of a single imbalance price). This reduction in short term liquidity is likely to disproportionately impact suppliers with a short position, particularly small suppliers. This could then constitute an unnecessary barrier to entry.

To conclude, we consider that the introduction of PAR1 and the RSP Function will constitute an AEC. We believe that the CMA should recommend a PAR value of 100MWh and should rule against the

[7] National Grid takes a number of balancing actions, some for energy balancing reasons, some for system balancing reasons i.e. those unrelated to pure supply and demand. Cash-out prices should reflect the costs of energy balancing actions and not system balancing actions. National Grid is required to flag and tag system balancing actions to ensure the costs of system balancing do not feed into the calculation of cash-out prices. A move to PAR1 will make it more likely that system balancing actions will feed into the main cash-out price due to a reduction in bid/offer averaging. This is referred to as system pollution.

[8] Please see https://www.ofgem.gov.uk/ofgem-publications/87788/electricitybalancingsignificantcodereview-furtheranalysistosupportofgemsupdatedimpactassessment.pdf and https://www.elexon.co.uk/mod-proposal/p305/

introduction of a RSP Function, at least until the concept has been tested in a live environment with actual data for a significant period of time.

Locational pricing

In principle, there is merit with the idea that reflecting the different costs of electricity production (including costs which vary by location, such as congestion and losses) should allow the total costs of the system to be optimised to deliver the most efficient provision of electricity to the end consumer. However, evaluation of measures to introduce locational pricing must be considered in the context of the current market arrangements; we are not starting with a blank canvas. National energy policy priorities, practical considerations, other externalities and the potential realisable benefits must be considered.

National Policy priorities must take precedence

The Transmission Access Review was initiated shortly after the completion of the BETTA. After much debate in an attempt to develop the most efficient method of facilitating access to the transmission system, the Government took the decision to implement a policy of 'Connect and Manage'. This allows generators to connect to the transmission network ahead of the necessary transmission reinforcements being made to the wider network. The primary reason for the adoption of this policy was to ensure that the Government's renewables targets would be met in a timely fashion.

Firstly, a move to locational pricing may jeopardise the Government's renewables and low carbon objectives. This is because much low carbon investment has been undertaken in Scotland behind an export constraint and it can be expected that these projects' costs will increase significantly with a move to locational pricing thus challenging their economic viability. Whilst it is easy in principle to state that targets may be met by increasing low carbon support, this may prove challenging for the next government considering the pressures on the public finances.

Secondly, investors in generation will have acted in good faith based on investment signals that were in place at the time investment decisions were taken. To dramatically change investment signals through the introduction of locational pricing may jeopardise the fulfilment of the Government's decarbonisation objectives and also significantly damage investor confidence. The damage to investor confidence could significantly impact future investment behaviour which may be damaging to the future development of the GB electricity industry. Therefore a policy of grandfathering of the current arrangements for existing generation would be essential. However, this introduces the potential for another level of market distortion between existing generation with grandfathered charging arrangements and new entrants operating under the new charging arrangements.

Practical concerns with locational pricing

It was determined at the time of the Government's decision to implement a Connect and Manage approach that BSUoS would continue to be 'socialised'. A key reason for this position was due to the inability of existing plant to respond to a locational congestion charge that resulted from new plant connecting ahead of transmission investment. Therefore it is uncertain whether an optimisation of system operator costs would actually occur. Rather such a policy will only distribute the same total costs to different market participants.

It is uncertain as to whether a philosophy of 'generation leads transmission' can operate in a set of market arrangements with locational pricing. Clearly the costs of congestion and losses should be kept as low as possible, but this does not mean that some costs of congestion and losses are undesirable. A trade-off between the costs of congestion and transmission build is essential in ensuring the development of an efficient electricity system.

It is unclear whether this trade off will continue to be made efficiently, in particular where previous combined 'markets' e.g. the BETTA are split into different bidding zones. There is likely to be bias with regards to the reduction in congestion costs relative to transmission costs, even where it is more efficient to facilitate new transmission infrastructure. This is particularly the case where a 'generator leads transmission' philosophy is adhered to. This is because projects will be deterred from locating in an export constrained location unless there is a guarantee provided by the transmission owner to provide additional transmission capacity to accommodate its power output. Consideration of a shift in emphasis to a 'transmission leads generation' philosophy would need to be considered in the event of an introduction of locational pricing. A change in philosophy would represent a fundamental change to way National Grid currently plans and operates the transmission system.

Finally, it is also worth considering the future policy and regulatory changes that are expected in the next few years, particularly those emanating from Europe. Specifically, the Capacity Allocation and Congestion Management (CACM) Code introduces a new regulatory process to introduce market splitting where this meets the necessary CBA requirements. There is currently a great deal of uncertainty of how this new process will be followed, not just by our own regulator, but all European regulators. It would be premature to embark on the development of locational pricing in isolation whilst ignoring the arrangements being developed in Europe. Another key objective for the government is the creation of a Single European Market. The development of national market arrangements should not be undertaken if they could very quickly conflict with the 'target model' in Europe.

Moreover, in the event of an introduction of locational energy pricing, there would be a need to revisit the current TNUoS charging arrangements. It is unclear that there would be a need for locational pricing of Transmission Entry Capacity in conjunction with locational pricing of congestion. Multiple locational signals incentivising similar behaviour runs the risk of overcomplicating economic decision making processes. Over complicating the market arrangements may deter necessary investment. In any case, a review of the current transmission charging arrangements is likely to be premature at a time when ACER is undertaking a study of Member State transmission charging arrangements with a view to initiating a European Network Code that may to some extent harmonise national arrangements. This is likely to further caution against initiating national locational pricing policies in isolation of European policy developments.

Other externalities must be considered

It is also the case that there are many different types of transmission system constraint that are not related to power congestion. If locational pricing of constraints and congestion is introduced, there will likely be a need to introduce locational pricing of the other types of constraint to ensure efficient system development. For example, consider the situation in Scotland where the closure of Longannet can be expected to ease the export constraint on the Cheviot boundary, but at same time result in the creation of new system voltage management challenges for the SO.

One example of a non-congestion related transmission constraint is a voltage constraint. This is a major cost driver of BSUoS, the costs of which are fundamentally driven by the location in which voltage support is required. Currently National Grid is able to procure voltage support services (often on specific contracts) from conveniently located generators. However, the costs of these services are socialised through BSUoS. Some thought would need to be given to how the costs associated with voltage support may be targeted to ensure the costs of the service are kept to a minimum. As such, the introduction of locational pricing for constraints and losses would not end there. There will need to be further locational pricing of different system security elements. This will only increase the complexity of the regulatory arrangements.

The benefits are insignificant

With regards to losses, we consider that the benefits associated with zonal losses are likely to be small and uncertain, in keeping with Ofgem's assessment of P229. While theoretically speaking it would appear correct to introduce some form of locational signals to losses, in practice it is unlikely to materially impact the vast majority of market participants' economic decisions. In addition, the total losses associated with the transmission of electricity are exceedingly small compared to losses on the distribution system. Losses on the transmission network are approximately 1.8% of which half is fixed i.e. does not vary by location. In contrast, losses on the distribution network are somewhere between 4% - 8% depending on the voltage[9]. This further illustrates the exceedingly small benefits associated with a policy of pricing transmission losses according to location.

[9] For details on distribution losses see for example Western Power Distribution (West Midlands) plc Use of System Charging Statement.

However, the case for locational congestion charging appears stronger as it is more likely to influence generator investment decisions. The merits of this proposal need to be considered in the context of the current market arrangements (as noted above). However, in addition it should be noted that the introduction of the Transmission Constraint Licence Condition (TCLC) has reduced the costs associated with congestion by restraining generators' bid prices in the Balancing Mechanism. This view is corroborated by the views expressed by National Grid and Ofgem. In addition, Ofgem's recent enforcement action against SSE will further increase the deterrent effect. Moreover, the CBA undertaken to date indicates net benefits in the region of £70m. When considered in the context of the total costs of TNUoS and BSUoS (~£2.6bn and ~£1bn respectively), this indicates further that the costs of locational pricing (as noted above) are likely to dwarf any potential benefits.

To conclude we do not believe there is likely to be an AEC due to a lack of locational pricing of transmission constraints and losses particularly in the context of the current policy framework. Therefore we consider that a remedy is not required, particularly when considering the possibility of future EU policy development in this area.

Central-dispatch vs. Self-dispatch

We agree with the CMA's findings that there is not a material difference between central dispatch and self-dispatch approaches and the outcomes delivered by such approaches. In our experience the self-dispatch approach ensures efficient merit order dispatch based on Short Run Marginal Cost (SRMC). We note the concerns raised by Intergen with regards to inefficient dispatch in GB. However, we tend to agree with the CMA's suggestion that the behaviour Intergen is witnessing is likely to be explained by the different assumptions made by Intergen on start-up costs, maintenance costs etc.

It should be also be noted that a move to central dispatch will require generators to submit to the SO all plant dynamic parameters[10]. It will then be for the SO to interpret these costs and dispatch plant in an efficient merit order. We note the point made by National Grid referenced in the Wholesale Electricity Market Rules Working Paper (page 7) that it is likely that the introduction of self-dispatch has allowed individual generators to better reveal their dynamic parameter costs and this is likely to have resulted in more efficient dispatch of generation plant.

To conclude we do not believe an AEC is likely to emanate from the adoption of self-dispatch and as such there is no need to implement a remedy. Moreover, the CACM Code prohibits the use of central dispatch in markets operating self-dispatch.

CfD FiTs

We strongly agree with the CMA's initial conclusion that there are significant benefits associated with a switch in low carbon support mechanism, from the current RO scheme to the CfD FiT arrangements. Moreover, we agree with the findings from the analysis undertaken by the CMA that there is no incentive for market participants to manipulate the CfD Reference Price, especially in the context of the current market structure. This issue was looked at by DG COMP in its assessment of Hinkley Point C State Aid compatibility. Similarly, no competition issues were identified by DG COMP.

However, we note some concerns expressed by the CMA with specific aspects of the CfD FiT arrangements and other associated elements of the EMR programme. We do not consider that the aspects identified are likely to give rise to competition concerns.

With regards to the awarding of Investment Contracts (FIDeR), the purpose of this process was to address the investment hiatus introduced by the implementation and development of EMR. Projects bidding for an investment contract had to demonstrate that there was a significant risk of delay and/or cancellation of the project in the event that an Investment Contract was not awarded. Although, there was no competition on the strike price as part of the FIDeR process, there was strict qualification and evaluation criteria to determine the awarding of contracts. This ensured that of the projects that would otherwise be cancelled or delayed, those most likely to be delivered were awarded an Investment Contract. While the effectiveness of the process will have been weakened due to slippage in the FIDeR timetable and State Aid delays, we still consider that this was a valuable process.

[10] Ramp rates, minimum run time, minimum off time, notice to synchronise etc.

With regards to the allocation process for Enduring CfD FiTs, we consider that the use of different auction pots for established and non-established technologies is in line with the new EU Environmental and Energy State Aid guidelines (EEAGs). These EEAGs are designed to ensure that competition is not distorted by renewable support or capacity market schemes throughout the EU. In terms of where biomass conversions fit within the budget allocation, it is clear that as they are not an established technology they do not fit into the established pot and based on the results of the Round 1 auction, the administered strike price for biomass conversion would outcompete the less established technologies. This justifies the creation of a separate third pot.

It should be noted that biomass conversions will be at a competitive disadvantage with other low carbon technologies if full technology neutral auctions are implemented.

Firstly, the support for biomass conversion will cease in 2027 and therefore in each CfD allocation round such projects have a decreasing contract tenor, making it increasingly difficult to compete with projects that are able to recover the cost of investment over a 15 year CfD FiT contract.

Secondly, the costs of intermittent technologies will not be revealed in the auction due to (justified) policy decisions on how certain costs should be targeted (for example the costs to the System Operator associated with balancing). These externalities are likely to put biomass conversions at a competitive disadvantage as biomass does not contribute to an increase in such costs. Therefore technology neutral auctions at this stage are less likely to deliver the most cost effective solution for the end consumer.

Finally, it should also be mentioned that all biomass conversion projects above 250MW will be subject to automatic State Aid assessment to test for the potential for over compensation or any competitive distortions, even if awarded under a competitive process. This point also applies to the Investment Contracts awarded under the FIDeR mechanism.

However, the requirement for project developers to submit security ahead of the auction would improve the competitiveness of the auction by deterring inefficient new entrants. It has become apparent from the first auction that some solar projects may have bid in an economically inefficient manner, distorting the competitive process as it is uncertain whether such projects will be delivered.

We consider that the right of the Secretary of State to award CfD FiTs outside the competitive allocation process is likely to be justified in a number of limited cases (for example CCS and tidal projects). However, to ensure value for money it is clear that this process should only be used in limited circumstances.

We note the CMA's concern that the ability for developers to choose between the RO and CfD FiT up until 2017 may limit competition for competitively determined CfD FiTs. In principle, this could have an impact on the quantity of projects applying for a CfD FiT. However, it is unlikely to represent a major impact as the scope for a project developer to make a choice between the RO and the CfD FiT is increasingly limited as the 2017 cut off approaches.

To conclude, we consider that the CfD FiT design is likely to strike the right balance between promoting effective competition and meeting national policy objectives. However, a requirement to post security to permit participation in CfD FiT auctions may improve the competitive allocation of CfD FiTs.

The Capacity Market

We note the concerns raised by the CMA that the level of the penalty cap may in effect facilitate inefficient entry to the Capacity Market (CM) auctions. We do not believe the level of the cap is likely to give rise to competition concerns.

The CM penalty cap has been set at 100% in order to (a) ensure generators are not remunerated if they fail to deliver energy in a stress event and (b) ensure businesses are not placed in financial difficulty as a result of the penalty. It is likely that at a time of system stress, a generator that has an obligation to deliver volume under a CM agreement is likely to incur significant imbalance (cash-out) costs as a result of failing to deliver in addition to the CM penalty. Such costs will be significantly higher than today, should Ofgem's cash-out reforms be approved.

The level of the penalty cap was subject to significant discussion and consultation during the development of the Electricity Market Reform (EMR) package. Generators, particularly those that are out of merit, will rely on the CM to deliver a significant proportion (if not all) of its fixed costs. Some generators may remain uneconomic for years, effectively only contracted to deliver at times of extreme system stress (e.g. at winter peak during a cold snap that coincides with multiple plant failures). During a CM delivery year, any CM penalty incurred, i.e. the withholding of payments or part thereof, could impact a generator and its competitive positioning in the merit order. As such, the incentive is to remain available and deliver when obligated to do so. Moreover, the cap was set at 100% in light of concerns raised by investors that a higher cap would not facilitate new plant investments based on debt finance.

To conclude, we do not consider that the Capacity Market design is likely to constitute an AEC and as such a remedy is not required. The penalty cap set at 100% is appropriate for the reasons provided above.

Theory of Harm 2

Unilateral Market Power

We agree with the conclusions reached by the CMA that generators do not have the incentive or ability to exercise Unilateral Market Power (UMP). While the model developed by the CMA shows a number of instances where generators could exercise UMP, the CMA is correct to acknowledge that the model cannot take into account key limitations of the ability of generators to exercise UMP. These key limitations being uncertainty of market fundamentals, the prevalence of forward trading, the impact of dynamic parameters and the various regulatory protections in place. We consider that the CMA's use of an 'uncertainty filter' is an appropriate way to take into account these limitations within the model.

We further agree with the CMA that a co-ordinated capacity withdrawal strategy is not credible, in particular considering the significance of the competitive fringe in the generation sector.

To conclude, we do not believe that UMP in the generation market is likely to constitute an AEC and that as such there is not a requirement for a remedy.

National Grid SO contracts

We note that the CMA has not identified any competition concerns associated with Supplemental Balancing Reserve (SBR). However, we are concerned that the introduction of SBR will distort competition in the electricity market. Our concerns have only increased in light of the experience so far observed of National Grid's tendering process. The original concept underpinning SBR was to only procure generation plant which would otherwise exit the market i.e. plant procured should be truly 'additional'. However, following the first SBR tender for 2014/15 National Grid procured plant that was operating in the market, specifically one Littlebrook unit and the Rye House power station. National Grid even confirms that the plant it procured was not, at least totally, additional in its SBR Winter 2014-15 Market Report[11]. The same issue applies to National Grid's procurement of Corby, Barry and (part of) South Humber Bank for 2015/16.

Taking plant out of the market, which had been operating in the market, runs the risk of displacing economically viable plant and thus distorting the competitive process. This concern is compounded as there is no firm sunset clause to prevent the operation of SBR continuing in perpetuity. We consider that a sunset clause should be applied to the SBR product and that security of supply should be delivered by the Capacity Market from 2018. The Capacity Market is a superior instrument for delivering security of supply as it facilitates competition between both existing and new plant (as well as DSR and other resources). SBR is a poor policy option as it only applies to existing generating capacity.

In addition, National Grid's recent decision in March 2015 to procure voltage support in Scotland for 2016-17 risks further distorting competition in the market. The rationale provided by National Grid for these services is exceptionally weak. It appears that it is seeking to insure the Scottish system against

[11] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=37361 p1

a 1 in 600 year event[12] which any rational person would consider an unreasonably risk averse position to adopt. Moreover, it appears inconsistent with the Reliability Standard set for the whole of GB by the Secretary of State. To the contrary, it appears that Scotland already has sufficient total generating capacity as well as diversity of generation resources (hydro, nuclear, wind, interconnection etc.) to ensure efficient system operation. This again is likely to distort effective competition in the market by displacing more efficient England and Wales plant with less efficient Scottish plant.

We consider that the current procurement of SBR is likely to constitute an AEC and that a remedy should be considered in this area. At the very least a firm sunset clause should be applied to SBR ahead of the first Capacity Market delivery year. Moreover, there should be stronger regulatory oversight to ensure that National Grid's SO procurement does not distort competition.

Theory of Harm 3

Liquidity

We generally agree with the initial conclusions set out by the CMA on wholesale electricity market liquidity. Liquidity is generally good in the near term, but less so in the forward market. However, lower liquidity in the forward market is unlikely to constitute a barrier to entry for smaller parties.

In any case Ofgem intervened to improve the operation of the wholesale market for small suppliers. The Mandatory Market Maker (MMM), introduced under the Secure & Promote licence condition, has provided access to Baseload and Peak products across the forward curve. Market participants are now guaranteed access to such products up to four seasons ahead across the forward curve during two liquidity windows (one hour each) per day. The measure does not appear to have increased the volume traded in the market, but has delivered a concentration in activity, which could help deliver more efficient price discovery during the windows. However, one consequent downside is that the concentration of liquidity during the daily liquidity windows has led to less trading outside of the windows (although this is not to say that the shift in trading is of concern).

In terms of trading beyond four seasons forward, consideration must be given to the drivers for such trading. Ideally, generators may wish to hedge their assets beyond the current two year market. However, suppliers will only want to hedge as far forward as their customers are willing to contract. Demand must exist on both sides of the market for trading to occur – the majority of end consumers only require the ability to contract one to two years forward. In addition, the practicalities and risks of trading beyond four seasons must be considered. The credit requirements to trade beyond four seasons forward would be burdensome. In addition, uncertainty surrounding costs and the regulatory regime beyond two years forward act as a barrier (risk) to trading.

Overall, it is still early days since the introduction of Secure & Promote. The initial outcome appears to be positive, although we agree with Ofgem's position that the Secure & Promote regime should continue to be subject to monitoring and periodic review. Therefore we believe it is unlikely that the level of liquidity in the wholesale market will constitute an AEC and, at least for the moment, a remedy is not required in this area.

Vertical Integration

We agree with the CMA's initial conclusion that vertical integration does not provide the ability or incentive for the Big Six to foreclose the electricity market both upstream and downstream, unilaterally or in co-ordination with competitors. Factors such as the anonymity of trading, the significance of the competitive generation and supply fringes and the regulatory protections in place to guard against anti-competitive behaviour all limit the credibility of foreclosure strategies.

To conclude, we do not consider that vertical integration results in an AEC and therefore a remedy is not required in this area.

Theory of Harm 4

[12] Details of National Grid's rationale for procuring these services can be found at http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40027

Microbusinesses

The CMA notes some initial concerns in the microbusiness sector in terms of potential lack of engagement, transparency and higher profit margins. However, it also notes that a lack of data has hampered its analysis of the issues. We consider that any competition concerns will be confined to only the smallest microbusiness customers (the microbusiness definition is very broad[13]), particularly those customers who are inactive and remain with one of the Big Six.

To provide an understanding of how Haven treats its SME customers, Haven are forced to treat all SMEs as microbusiness to avoid compliance issues. The current definition is practically unworkable as little if any up to date information is available on the turnover / balance sheet of smaller businesses. Employee numbers fluctuate from month to month. The concept of an FTE is not well understood especially in the context of zero hours employment contracts. The only information “readily” available to suppliers is energy consumption and that is often estimated. Moreover, there is great difficulty involved in forecasting exchange rate fluctuations.

The definition includes the vast majority of businesses including businesses that would conventionally be classified as Small Businesses and Medium Businesses. These same businesses have a myriad of statutory obligations of much greater complexity than energy but have been granted protections in energy on the basis that they cannot be expected to understand it. This is inconsistent. The term ‘micro’ implies very small – certainly below small – but that is not how the definition is worded. As worded the definition includes most small and many medium sized businesses.

We agree that very small businesses that are akin to domestic customers need some protection and suggest a simple cut off at 12,000kWh electricity and 73,000 kWh gas – roughly the equivalent to a very large house. These limits were used in earlier regulation by Offer and Ofgas for similar purposes in the past. Setting the definition to these levels without the turnover and employee measures would ensure that the protections were targeted on and applied to the customers that really need them reducing regulatory risk for suppliers. This would help to ensure that the active competition that exists for non (truly) microbusiness continues to thrive. The effect of the very wide definition is to add cost and regulatory risk to the supply for microbusinesses. This will deter new entrants in line with Theory of Harm 4 and is causing Haven to consider carefully its activity in this sector.

We believe that the current definition of microbusinesses is unnecessarily constraining competition for most small business customers and is likely to constitute an AEC. We consider that a remedy to restrict the microbusiness definition to only the smallest business customers should be adopted.

Rollover contracts

Concerns have been raised in the past that rollover contracts in the business market (we are not suggesting that rollover contracts should be reintroduced to the domestic segment) can lead to customer detriment due to the relatively higher prices of these contracts. We believe that rollover contracts operate in the customers’ interest as they lead to lower prices compared to a disengaged scenario for customers that do not engage at the end of their contracts. Rollover contracts allow suppliers to minimise costs and this benefit can be passed on to customers in the form of lower prices.

We understand that many of those suppliers that have ceased rollover are now placing the customers that would have rolled over onto relatively more expensive short term rolling contracts. The lack of need for action and deadlines at the end of a contract without rollover may also be encouraging more customers to drop onto these rolling arrangements simply because they can defer a decision. We suspect that many customers do not revisit it and end up paying higher bills for long periods.

[13] To be classed as a microbusiness the customer must meet at least one of the following criteria, (a) it employs fewer than ten employees (or their full time equivalent) and has an annual turnover or balance sheet no greater than €2 million, (b) it consumes no more than 100,000 kWh of electricity a year; or (c) it consumes no more than 293,000 kWh of gas a year.

Ofgem has not found that rollover contracts are not in the customer's interest, but they continue to revisit this leading to regulatory uncertainty and to the best of our knowledge they have not followed up on the results of those suppliers who have stopped the practice.

Customers can choose the form of contract that they take, they can give notice at any time to prevent rollover and they should be allowed the convenience of rollover. Greater choice for the consumer is important to ensure that all customer needs are met.

To conclude we do not believe that rollover contracts will give rise to an AEC and that as such there is not a requirement for a remedy in this area.

SME profitability

We were interested in the profitability figures in the CMA initial analysis – they are at odds with our experience of the competitive SME market. The CMA analysis appears to suggest that the higher Big Six SME profitability results from lower relative costs associated with network charges and other obligation costs. This finding does not reflect our experience with the relative levels of such costs. Haven has yet to breakeven and we find our SME marketplace to be intensely competitive. These average margins disguise the difference between the margins for those customers that shop around which are much lower.

We suspect that profitability in the Big Six might be higher because of higher percentage margins from the smallest businesses needed to cover:

- the service costs and bad debt;
- the sales tactics of some brokers and lack of transparency around broker engagement (we are aware of some brokers who place business with the supplier who pays / agrees a high commission);
- the sticky customer bases that have never switched; and
- the higher margins associated with short term rolling contracts.

Ofgem has also said that some suppliers have a large number of long term customers on deemed rates and these will increase the margins as higher prices are needed to cover the balancing and debt risks associated with these customers. Some of these reasons can be justified by the greater risk and cost involved, however the additional margins achieved from sticky customers is likely to emanate from the UMP enjoyed by the Big Six over their sticky SVT customers. This we suggest represents an AEC.

We would expect any measures designed to tackle sticky customers to be applied to residential customers as well the smallest business customers and we expect this will reduce average margins. A potential remedy to increase competition for sticky customers is discussed below.

Sticky customers

We believe that a relatively simple and cost effective solution to providing the benefits of competition to sticky residential and the smallest business SVT customers would involve the tendering of such customers in a competitive auction. The remedy is designed to deliver:

1. Increased competition in the residential sector
2. Greater wholesale liquidity
3. Short term benefits for sticky customers in the form of lower prices
4. Greater engagement with the market for these customers so they could become more active over time
5. Longer term protection for those customers that remain sticky

The proposal would take the form of a Mandatory Collective Switching Scheme. The Big 6 would be obliged to identify their 'sticky customers', with the definition to be determined[14]. The Big 6 would then write to the identified sticky customers, informing them of the proposed Mandatory Collective

[14] This requires a clear and simple definition. Sticky customers could be defined as those customers who have never switched tariff or supplier. Large suppliers may try to over complicate this issue, but we believe a simple definition is workable.

Switching Scheme. The identified customers can opt out of the Scheme if they choose. The customer decision to opt out would be renewed every three years.

The Big 6 would organise the sticky customer demand into blocks[15] of 12,500 customers i.e. separate electricity and gas trading clips roughly 5 MW in size (Dual Fuel would be helpful, but would be complex to assemble as many sticky customers will have different gas and electricity suppliers). The relatively small blocks would appeal to new entrant suppliers and be manageable in the context of system capabilities.

Tenders for these blocks would run on a (potentially) daily basis by Ofgem (or some other entity if appropriate) to keep overall switching volumes manageable and to provide a flow of business. There would be a rolling programme of tenders; dual fuel/single fuel as appropriate. One year fixed price contracts would be bid by interested suppliers with no termination fee for early exit. In the absence of agreed action with the customer, customers would move to the supplier's SVT at the end of the year. The tenders would be open to all suppliers (including the Big 6) as this would be relatively simple and provide no restraint of trade. The lowest price tender would win the block. Consideration may also be given to a customer quality of service threshold to qualify for bidding to ensure that customers are not switched to poorly performing suppliers. This could be actively managed and would be a further incentive to provide good service.

The same process could be applied to sticky microbusinesses.

We suggest a review after one year of operation would be appropriate to consider the efficacy of the solution. For example, consideration may need to be given to placing restrictions on participation of Big 6 e.g. only allow bids at acquisition prices.

To conclude the UMP enjoyed by the Big Six over their SVT customers is likely to constitute an AEC and therefore a remedy along the principles noted above should be developed by the CMA. We would be happy to provide assistance to the CMA to help develop a more detailed proposal.

Retail Market Review

The RMR and its predecessor, the Energy Supply Probe, have been running for nearly seven years. As a result regulatory risk and uncertainty have increased in the business market and particularly the microbusiness market over this period.

We have seen a range of measures that have increased the protection for customers. Some of these have diminished suppliers' ability to differentiate their offerings in the market e.g. Haven had always accepted a termination notice at any stage in a contract. The Probe/RMR required all suppliers to accept termination notices in this way and part of Haven's customer friendly USP was lost as result at that point. We do not mind our ideas being copied by competitors in the spirit of competition, but it is frustrating when regulation removes points of difference. It is not at all clear what the customer benefits of these measures have been.

Latterly some of the RMR measures have been both difficult and expensive to implement. These include the requirements to print contract end dates on bills and current prices on renewal letters. Whilst these measures sound simple they are far from easy to implement and have absorbed substantial IT and business resource. It is not clear to us that there will be significant customer benefit from them amongst the customers that we supply.

One result of these measures is that we have had to delay bringing new products to market as we simply have not had the IT resource and management bandwidth to do both. This means that the

[15] We suggest blocks are assembled at random rather geographically or by meter type to avoid unattractive blocks.

marketplace is less competitive and innovative than it otherwise would have been and customers are missing out on the benefits as a result.

In parallel with the RMR we have seen a significant number of formal information requests. Although Ofgem has consulted on these, they are burdensome especially to independent suppliers and they absorb management time and business resource that would otherwise be spent delivering efficiencies to customers.

The RMR has also been a relatively (compared to the Big Six) much higher burden for independent suppliers. This is because we tend to have fewer regulation specialists and smaller management teams (in order to drive low costs and remain competitive). This has disadvantaged independent suppliers compared to the Big Six.

We consider the RMR measures are likely to constitute an AEC and that these measures should be repealed.

Theory of Harm 5

<u>Industry Codes</u>

Drax generally agrees with the position of the CMA. Where simplification and greater efficiency can be achieved in the industry codes, then modification to such codes should be pursued. A process to simplify industry code processes, the Code Governance Review (CGR), was initiated by Ofgem in 2007. The CGR led to the development of the Code Administrator Code of Practice (CACoP), which has sought to deliver a set of principles to be reflected in a number of specified industry codes (including the BSC and CUSC). Drax supports the CACoP process and believes that this model could be expanded to deliver greater harmonisation (therefore simplification) across a greater range of industry codes.

Simplification

Drax supports the view that the number of codes could be reduced. However, careful thought should be given to the outcomes and cost of change. A single code administrator could deliver a single point of contact/expertise with which market participants can engage, which may be particularly useful for new entrants. A single industry code, however, may result in the same codes simply being rebadged under a single umbrella. The complexity of industry codes is largely due to the complexity of market arrangements – these are, in effect, the detailed market rulebooks.

The main candidates for simplification are governance arrangements, administrative processes and credit efficiency (where netting can be achieved without increasing systemic risk). There may also be sections of the industry codes that are redundant (e.g. historic transitional arrangements and obsolete protective rights) that could now be removed or reorganised. Any reorganisation should avoid simply removing sections from the industry codes and placing them elsewhere in the regulatory hierarchy (e.g. in code subsidiary documents) – this would not reduce complexity, rather move it elsewhere. The simplification of industry codes should be performed alongside other code modification processes in a coordinated fashion. The introduction of the EU Network Codes and the implementation of smart metering, for example, are likely to result in significant changes to existing industry codes over the next few years. Duplication of work-streams with conflicting goals/principles must be avoided.

Pace of change

It is important to consider the reasoning behind the design of the code modification processes. They aim to be open to all, allowing any market participant (large or small) to identify a code defect and propose a solution, with little detail required at the outset on how the solution will work. The criteria used to assess code modifications includes the promotion of efficiency, promotion of competition and the meeting of relevant policy and regulatory requirements. Workgroups are open to any market participant and, at least under the BSC, require participants to act impartially in assessing modification proposals against the applicable code objectives.

It is fair to state that a certain level of inertia is built into code change processes. Workgroups, under the supervision and advice of the relevant code administrator, must be able to develop/procure relevant analysis, consultations must allow market participants the time to assess the impact of change and respond, consideration against applicable code objectives must be robust, implementation timescales must be achievable, etc. In our experience, insufficient regard is given to required implementation timescales to ensure the efficient delivery of change. Improved implementation planning could ultimately reduce the cost to the end consumer.

These are relevant checks and balances that aim to ensure timely and efficient change, whilst protecting consumers and investors from fast paced, knee jerk change that could negatively impact investor confidence and potentially lead to increased costs and/or the inefficient distribution/pass-through of costs.

Tools to drive change

The Significant Code Review (SCR) process was introduced as an outcome of Ofgem's Code Governance Review. The SCR process aims to identify potentially complex, contentious and/or strategic change to industry processes that may not be raised without intervention from the regulator or require a high degree of coordination. The process also includes the ability of the regulator to subsume industry code modifications into an SCR in order to ensure a coordinated outcome between the SCR and code modification processes.

The resulting SCR Direction, determined by the regulator, can be principles based or include a fully developed modification (the latter potentially negating the need for a further assessment phase as part of the code modification process). The original aim was to identify an issue, initiate an SCR and deliver an SCR Direction over a 12-18 month timescale.

Unfortunately, the SCR process has not been used effectively. The electricity SCRs initiated to date have taken much longer than 12-18 months to complete (i.e. deliver an SCR Direction) and, at the end of this period, have resulted in determinations that lack critical detail and analysis, for example Project Transmit and the Electricity Balancing SCR. This meant that much of the detailed analysis and policy design needed to be completed in the Code Modification Working Group phase meaning implementation timescales were no shorter and perhaps longer. In addition, the regulator, for whatever reason, has not intervened where greater coordination and guidance is required across the industry. This role is within Ofgem's current remit.

The recent BSC P272 modification process, cited by the CMA, identified an enabling change was required in DCUSA to support the modification. However, it is now clear that the assessment and impact analysis conducted during the modification process were deficient and this has led to further additional changes being identified during the implementation phase, for example to the CUSC, and additional sections of the BSC and code subsidiary documents. These further changes are having to be progressed quickly and it is becoming clear that the completion date for this change is not achievable[16]. A lack of early engagement from certain sectors of the industry highlighted the need for coordination and, more importantly, guidance at a strategic level. Whilst it is not Ofgem's role to manage individual code processes, facilitation of effective change across industry processes, particularly where delays to such change could negatively impact consumers, is a role that they are able to perform within the boundaries of current regulation.

We believe it is important that the regulator has the appropriate tools to identify potential market defects and coordinate appropriate change. The regulator is able to, and does, coordinate discussion between industry participants and bodies. In addition it can effect change via licences, the raising of industry code modifications related to EU legislation and directing modifications (detailed or otherwise) be raised as an outcome of an SCR. The regulator must be willing to use these tools effectively to coordinate change. Conferring additional powers on the regulator is not necessarily the correct answer. However, there is a case to ensure that the regulator has sufficient experience of electricity industry business processes (an area where we believe there is a skills deficiency) to ensure that policy is consistent with the systems and processes that are available and so can be implemented in an efficient manner.

[16] The March meeting of the BSC Panel recommended the time to complete P272 is extended by 12 months.

To conclude we do not consider that the current structure of the Industry Codes is likely to constitute an AEC. However, efficiencies in governance and administration should be explored. Moreover, a more strategic approach by the regulator within the current regulatory framework would be helpful in delivering cross-cutting change.

Half Hourly Settlement

Much has been made of the benefits that are expected to flow from the adoption of half hourly settlement which will be enabled by the introduction of smart meters. We fully support the introduction of smart meters and welcome the product and cost innovations that they enable.

Moving to half hourly settlement does however carry a significant cost in both economic and environmental terms. This is because of the need to store, extract, communicate and process vast quantities of data. To the best of our knowledge no assessment has been made of these costs or of the impact on carbon emissions of these activities. Although it is not generally understood the current non half hourly settlement system can support many of these products without the need to settle half hourly. This means that many and possibly the vast majority of benefits could be achieved without the need to migrate to half hourly settlement and this would help to keep costs low for customers and protect the environment. The option of settling half hourly would always be there for the minority of products that really needed the functionality but by adopting this selective approach to half hourly settlement costs would be lower for the vast majority of customers.

We suggest that the CMA asks government and the industry to ensure that the options are fully and properly explored rather than simply adopting the half hourly solution. We would be happy to explain how the existing settlement process can be used in this way if you would find it helpful.

Sector profitability

We agree with the CMA's assessment of the WACC for vertically integrated companies and standalone generators and suppliers. We further agree that based on these WACC estimates, the profitability of generation assets has been at or below the WACC. Specifically, for coal plant we agree with the CMA's assessment that the profitability of coal fired assets will decline in the future due to changes in various environmental legislation (Industrial Emissions Directive, Carbon Price Support etc.).

Conclusions and Remedies

Overall we consider that an AEC is unlikely to emanate from self-dispatch, the lack of locational pricing, the Capacity Market, rollover contracts, wholesale market liquidity and UMP in the generation sector. Therefore we do not believe that remedies are required in these areas.

Likewise we do not believe that an AEC is likely to be caused by the Industry Codes and CfD FiTs. However, improvements should be considered to increase the efficiency and strategic oversight of the Industry Codes. The requirement to post security as a pre-requisite of participating in CfD FiT auctions should also be considered to facilitate effective competition for CfD FiTs.

We consider that some of Ofgem's cash-out reforms, the procurement of SBR, the microbusiness definition, RMR, the ROC market and UMP of Big Six SVT customers constitutes an AEC. Remedies should be considered for these AEC as follows:

- Cash-out pricing: PAR set at 100MWh (PAR100) and postponement of RSP Function;
- SBR: A sunset clause on the measure ahead of the 2018/19 Capacity Market delivery year and stronger regulatory oversight of competition distorting National Grid interventions;
- Microbusiness definition: this should be reduced in scope to cover only the smallest business customers;
- Repeal the RMR measures; and
- ROC Market and UMP of Big Six SVT customers: competitive tendering of Big Six SVT customers is required.