E.ON UK plc
Westwood Way
Westwood Business Park
Coventry
CV4 8LG
eon-uk.com

Paul Jones
024 76 183 383

paul.jones@eon-uk.com

Anthony Mungall
Senior Manager Transmission Policy
Ofgem
Cornerstone
107 West Regent Street
Glasgow
G2 2BA

10 October, 2013

Dear Anthony,

Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology

Thank you for the opportunity to respond to the above consultation on CMP213. E.ON does not support the proposed modification on the grounds that:

- It has not been proven to be more cost reflective than the baseline.
- The Cost Benefit Analysis (CBA) shows an overall cost to customers up to 2024 with a subsequent benefit to 2030 which is based on a very specific and optimistic set of assumptions.
- That the minded to decision on CMP213 is inconsistent with the rejection of BSC modification P229.

We also believe that the proposed implementation date of April 2014 is inappropriate and that, should CMP213 be implemented, a delay of 5 years should be introduced to allow generator behaviour changes to feed properly into charges and to prevent the predicted shorter term increase in costs to customers associated with the change from being realised.

Our more detailed reasoning behind the views summarised above is set out in the following responses to the individual questions in the consultation.

E.ON UK plc

Registered in
England and Wales
No 2366970

Registered Office:
Westwood Way
Westwood Business Park
Coventry CV4 8LG

Question 1: Do you think we have identified the relevant impacts from NGET's modelling and interpreted them appropriately?

We have reservations about the robustness of the modelling itself rather than Ofgem's interpretation of what has been presented. Clearly, the modelling is somewhat of a "black box" as industry parties are not in position to replicate it. However, National Grid has helpfully provided a breakdown of results for interested parties to look at. The main conclusion from the modelling is that CMP213 increases total costs for customers up to around 2024, but after this costs reduce dramatically so that customers are better off overall in the period up to 2030. This is shown in figure 1 below.

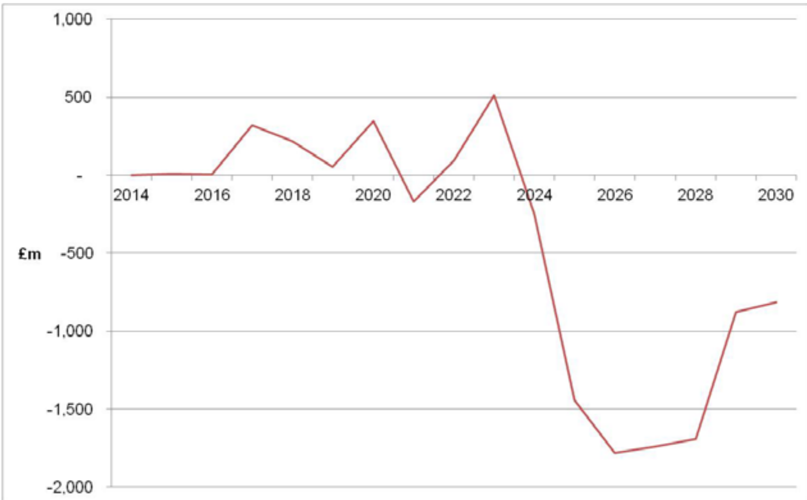

Figure 1 – Difference in total costs between Status Quo and Diversity 1

The sudden decrease in costs in 2024 seems to us something worthy of further investigation to ensure that it has a sound foundation. Therefore, we have looked at the main causes of the cost reduction. Figure 2 below shows a breakdown of the significant differences in cost between the Status Quo and Diversity 1 results.

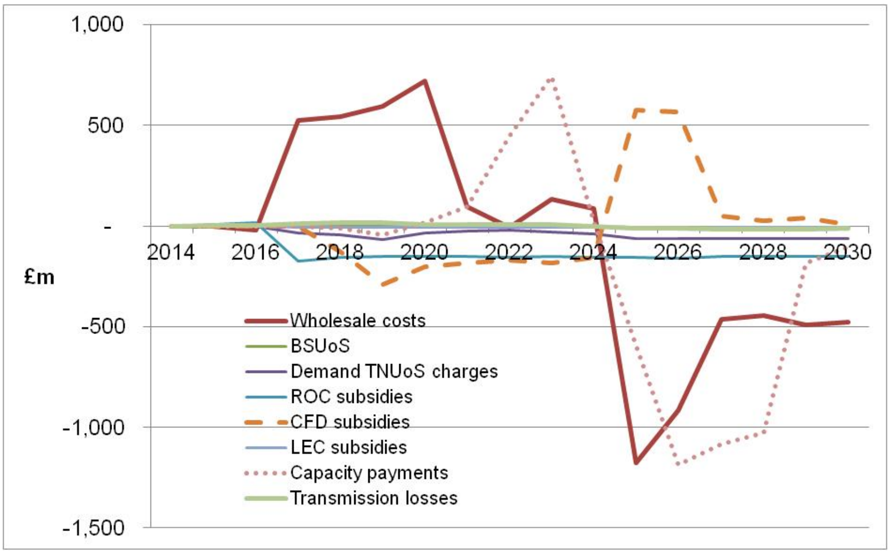

Figure 2 – Breakdown of cost differences between Status Quo and Diversity 1

It shows that the main contributors to the decrease in total costs are big reductions in wholesale costs and capacity payments under the proposed capacity market, which are offset to some extent by an increase in contract for difference (CfD) payments.

However, figure 2 does not explain what is causing these changes. We have therefore looked at the changes in plant running which were forecast to occur as a result of implementing the Diversity 1 option. Figure 3 shows this.

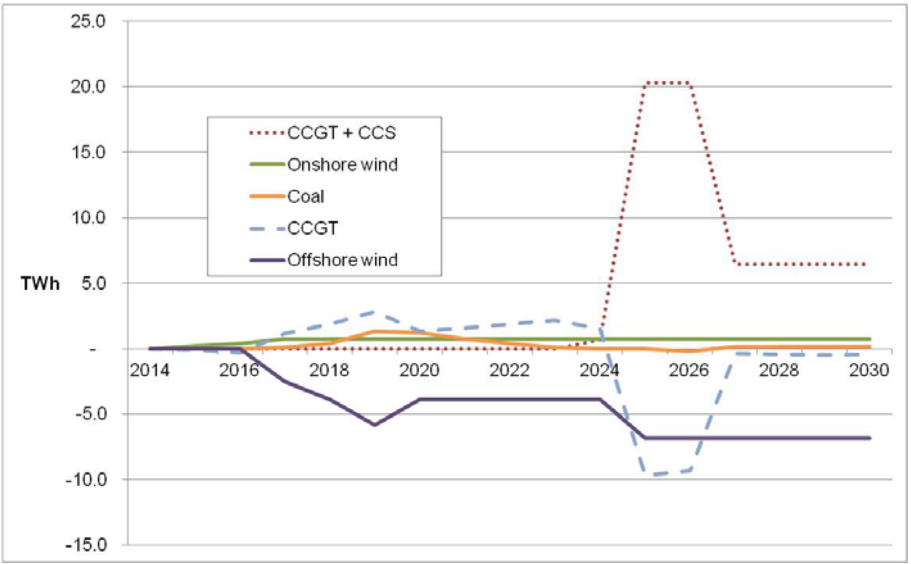

Figure 3 – Main changes in annual plant output between Status Quo and Diversity 1

Clearly, the main effects are a reduced amount of output from offshore wind and CCGT plant, which is offset by some additional 20TWh of running from CCGT plant with Carbon Capture and Storage (CCS). This would partly explain the forecast changes in EMR related payments, as CCGT plant paid through the Capacity Market is replaced by CCS plant covered by CfDs. When the generation capacity figures are analysed, it becomes clear that the modelling assumes that an additional 2.9GW of CCS plant would be built as a result of the Diversity 1 option being implemented. Indeed, both the Status Quo and Diversity 1 results show high assumed levels of CCS plant by 2025 of 6.4GW and 9.3GW respectively.

This seems to be a very specific and optimistic scenario to be basing the benefits of the modification on. If this scenario is not realised then it is not clear whether the forecast reduction in customer costs would be delivered all at. What is clear is that until 2024 the modelling shows an increased cost to customers if CMP213 is implemented without a reliance on scenarios which involve greater amounts of CCS CCGT plant.

Question 2: Do you have any further evidence of the impacts of the charging options not covered by NGET's analysis?

Whilst not specifically relating to the CBA element of the consultation, we do not believe that the effect that decisions of this nature can have on investment in GB has been suitably explored. As we mention below in our answer to question 6, we believe that the minded to decision on CMP213 appears to be inconsistent with that made on P229. Companies operating in this sector understand that the regulator and government will take decisions on policy which will affect the economics of their business. However, if they perceive that those decisions have are taken in an inconsistent manner, this increases their perception of the risk of operating in this market. Ultimately, investors could choose to invest in other markets which do not display the same degree of risk. The RIA has not addressed this issue as yet.

Question 3: Do you agree with our assessment of the options in terms of the strategic and sustainability impacts? In particular, are there any impacts that we have not identified?

Our responses to other questions are relevant to this section too. CMP213 has the potential to impact on a number of areas mentioned in Chapter 5 such as security of supply and achieving greenhouse gas reduction targets.

We do not necessarily believe that this modification will be sufficient to threaten security of supply. This is because this is such an important consideration it is unlikely that the lights will be allowed to go out. However, it is possible that CMP213 will increase the costs of securing supply if the economics of marginal plant are pushed further by large increases in charges. The CBA has concluded that there should not be an issue. However, this has been ascertained using generic data and approximate assumptions. In reality it is not possible to assess the exact implications, as only individual plant owners will know the exact economics and risks associated with each of their stations.

As we mention above, the CBA appears to assume that a significant reduction in greenhouse gases will be delivered by a large amount of coal and gas plant fitted with CCS building by 2024. This is at the expense of a certain amount of displaced offshore wind capacity. If the effect of CMP213 is to dissuade a large amount of offshore wind generation from building, then we would question what the situation would be if the highly optimistic CCS assumption does not transpire in practice. It will be difficult for onshore wind or nuclear generation to make up the difference in the time required. Therefore, either the targets will be missed or a greater cost will be incurred to ensure that the offshore generation is built after all.

Question 4: Do you think that socialising some of the cost of HVDC converter stations could lead to other wider benefits, such as technology learning? If so, please provide further evidence in this area.

Only a limited number of HVDC converter stations will be built in GB. Therefore, we do not believe that there is the scope to accrue significant learning benefits as each situation is likely to be different. Nevertheless, it is not the role of the transmission network charging regime to fund technology learning through an implicit subsidy. If such benefits are required they should be provided through explicit L&D support such as capital grants.

We do not believe that the costs of converter stations should be socialised. Currently, AC substations in the wider transmission circuit are socialised through the residual tariff.

However, the current charging methodology requires offshore generators to pay the entire cost of converter stations in the cable costs of their local charges. There is no relevant difference between the circumstances of offshore generators and the Transmission Owners putting in HVDC subsea links that would justify a difference in treatment of the costs of the converter stations. Therefore, were the costs to be socialised under CMP213, we believe that there would be a strong case to claim that offshore generators had been unduly discriminated against.

Question 5: Do you agree with our assessment of the options against the Relevant CUSC objectives? Please provide evidence to support any differing views.

We disagree with the conclusion that CMP213 is more cost reflective than the Status Quo. We do not believe that this has been proven yet.

We have concerns about the general principle of CMP213 where much of the network is assumed to be built for the year round scenario and to optimal levels so as to equalise the marginal cost of constraints and network investment. It is impossible in reality for the network to be built to that ideal equilibrium across multiple network boundaries and against a shifting constraint position caused by changes in generation running and demand patterns within and across years. Of course, the proposed approach may be defended by some as a necessary simplified assumption. However, it is important that this principle is correct rather than simple, as it underpins everything else that follows in the methodology.

We also feel that the assumption that a generator's impact on transmission investment will always follow its load factor is an over simplification. The analysis carried out in the work group showed some correlations using the ELSI model used by National Grid for its price control. However, there were also scenarios where correlations did not exist. Clearly, the more often a station runs, the more likely it is to run during a period of constraint. However, it is over simplistic to assume that this would follow a linear relationship to load factor. It is the profile of the generator which is important. That is, it is the amount of running that it does at times of constraints that determines the effect it has on constraint volumes. The load factor does not describe this profile but simply calculates an aggregate annual running figure. The CMP213 methodology also completely ignores the effects that different market prices and BM prices will have on constraint costs.

Additionally, we do not believe that CMP213 fully reflects the changes that were made to the SQSS under GSR009. We do not disagree with the principle that the charging methodology should reflect how investment is made under the SQSS. However, CMP213 does not seem to do so. The principle of the changes brought about under GSR009 is that the primary driver for reinforcements should be the demand security criterion with the economic criterion being used to justify investment over and above that. This is set out in the conclusions section to the GSR009 working group report (our emphasis):

"*The Review group concludes that a demand security criterion, in which there is no contribution from intermittent generation or interconnectors, should be introduced to the NETS SQSS to best meet the objective of ensuring security of supply.*

*The working group proposed that **any additional reinforcements** should be identified on an economic basis, as required by the economy and efficiency objective.*

Ideally these reinforcements should be identified through a CBA process aimed at finding the economic optimum. The working group argues that such a process has a number of drawbacks, and that, due to large data uncertainties, the drawbacks are not offset by the accuracy of a CBA method.
A pseudo-CBA method has been proposed that addresses a number of the difficulties of the CBA method whilst, in the view of the working group, not introducing further inaccuracies."[1]

Therefore, GSR009 was clear in that the main driver of investment should be to meet security of supply under peak conditions, whereas any additional investment should be identified using the pseudo CBA method. Conversely, what CMP213 does is make the CBA method the main driver of investment. Figure 4 illustrates this. It shows the MWkms from the indicative tariff model produced by National Grid for CMP213 Diversity 1 option. The graph clearly shows that the year round MWkms dominate those under the peak scenario.

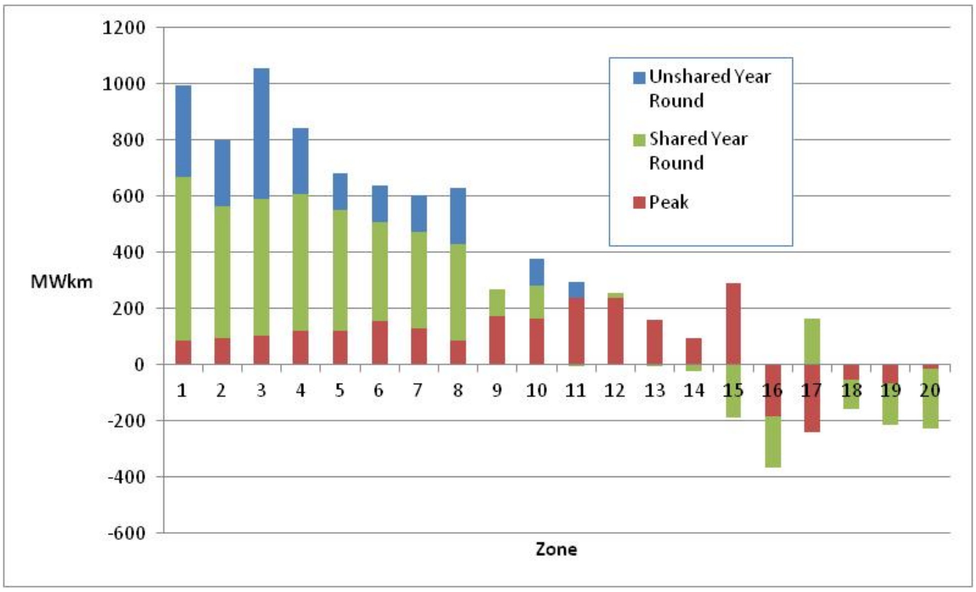

Figure 4 – MWkm per zone under the Diversity 1 methodology

We believe that it would have been more accurate to seek to allocate costs to the different charges on the true basis of the intent of GSR009. CMP213 allocates the full cost of a circuit to one of the charges based on whether that circuit is more highly loaded under a modelled peak or year round scenario. The rationale is that the more highly loaded scenario is more likely to trigger additional investment in the future. However, just because a circuit is more highly loaded in one scenario it doesn't follow that investment would not be needed against the other background.
This is an important consideration as this allocation method determines which costs are faced by intermittent generation or not, as well as which costs should be scaled down by the ALF. It therefore has a significant effect on the charges that generators eventually pay.

[1] Amendment Report GSR009 - Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation (page 23)

We also have significant concerns about the calculation of the ALF. There is a fundamental inconsistency associated with charging a forward looking signal based on a generator's past performance. The purpose of the locational element of charging regime is to provide signals about where to build new plant and also to affect behaviour of existing plant. At present plant can change TEC levels in response to signals which are based purely on a plant's capacity. However, CMP213 would introduce a signal which is also affected by its load factor. If it is believed that a plant's load factor affects the cost of the network going forward, it cannot be more cost reflective to base that on its historic value.

We do not believe that transmission companies would be allowed to make investments based on historic performance of plant when it was known that these stations were not going to be running in a similar manner going into the future. Therefore, assuming so in the charging methodology is inconsistent and therefore not cost reflective.

This is not some theoretical problem with what is being proposed. Generation plant is already changing load factor significantly and will continue to do so. HMG has implemented an increasing Carbon Support Price which will result in gas becoming the preferred fuel for generation over coal from around 2015/6. Also, the IED (in effect from 2016) will restrict the load factor of coal plant significantly below currently seen levels. Additionally, more conventional plant is likely to reduce load factor in response to the higher levels of wind on the system. If the methodology does not react to this, then the plant which changes load factor in this way will be subject to either favourable or unfavourable discrimination depending on how its load factor changes and where it is.

Also, if the load factor of the generator is deemed important, then if it should be able to respond by changing its load factor. If it does so, then the signal should change accordingly and the generator should see a subsequent change in its charges. However, with the current historic ALF approach this will only happen five years in the future. In effect a new signal is being created without giving generators the ability to respond to that signal.

Question 6: Do you agree with our assessment of the options against our statutory duties? Please provide evidence to support any differing views.

We would note that much of the assessment against statutory duties relies on the outputs from the cost benefit analysis. As we have significant concerns about the robustness of this analysis, we do not believe that it is appropriate to draw too many conclusions from it. We do not believe that CMP213 has been shown to be more cost reflective than the Status Quo, therefore we do not consider that it is possible to ascribe benefits to it in terms of better locating decisions by generators and improvements in competition.

We are concerned that the minded to decision for CMP213 contradicts the position that Ofgem took when rejecting BSC Modification P229 which aimed to apportion transmission losses to parties on a more cost reflective basis. Ofgem concluded that the modification was more cost reflective than the Status Quo but nevertheless decided not to implement it.

The reasons given for this were threefold:

1. *The cost benefit analysis only showed relatively small benefit for customers.* This conclusion is true of CMP213 as well. Indeed, until 2024 the CBA shows an additional cost to customers and as we mention above there are significant doubts over the assumptions which lead to benefit accruing subsequent to this.

2. *There were large re-distributional effects between parties.* Again this is the case for CMP213 where large amounts of costs will be redistributed between parties, mainly due to changes in charges made in respect of conventional coal and gas fired power stations.

3. *European arrangements could change soon anyway meaning that the benefits may only be delivered for a relatively short period of time.* Again this is the case in respect of CMP213. ACER has just announced that in 2014 it will start work on the development of Framework Guidelines on rules for harmonised electricity transmission tariff structures. We cannot prejudge the outcome of this work, but it is entirely possible that it will result in any arrangements implemented as a result of CMP213 having to be unwound to conform to the rules that are developed.

Given the clear similarities between the circumstances of CMP213 and P229, we are surprised that the potential decisions being taken are the complete opposite of each other. To us the decisions appear to be inconsistent.

Question 7: Do you agree with our assessment that it is appropriate to implement WACM2 in April 2014? Please provide evidence to support any alternative implementation date.

We do not agree. There are a number of reasons why, if CMP213 is to be implemented, this should not occur for April 2014.

Firstly, generation will have already contracted longer term in the market for the period from April 2014. Indeed a significant amount of generation will have contracted out up to two years ahead. They cannot possibly have factored in the cost of CMP213 into their prices. Although parties have been aware of the possibility of a change of methodology, they would not have been certain that a change would be made and if so what option would have been chosen.

Figure 5 below shows the types of uncertainty facing generators. It shows the estimated charges for our power station at Ratcliffe on Soar. It shows the actual charge that we are paying this year which we would have known in January. It then shows the various charges as calculated from the indicative tariffs published with the impact assessment in July. It then shows the new numbers for Diversity 1 published by National Grid in September. There is a wide range of uncertainty associated with the different options. Even knowing Ofgem's minded to decision, there is a significant difference between the two values for Diversity 1, published in July and September respectively. Whilst we have only illustrated what has happened at Ratcliffe, other stations we own have faced similar uncertain outcomes as have stations owned by other companies. Therefore, if CMP213 was to be implemented in April 2014 companies would be simply exposed to windfall gains and losses.

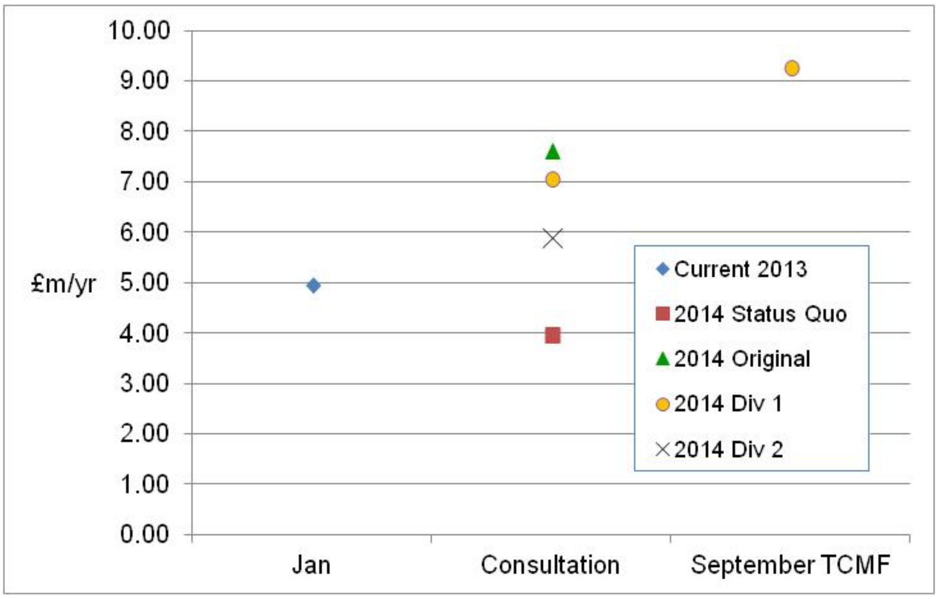

Figure 5 – Uncertainty in charges for Ratcliffe on Soar

Indeed, we are still facing uncertainty over the charges. National Grid has yet to publish its assessments of ALFs which would be used for next year. This requires the processing of significant amounts of data as well as ascertaining historic TEC details. These have to be sufficiently accurate so that TEC changes can be allocated to the date on which they occurred. Using the TEC register will not be sufficient as it has not always been as accurate as it could be in past years. The definitive source of TEC data is the schedules in the Bilateral Connection Agreements for each power station site and where relevant the Construction Agreements. This information will be held by each generator and they will require a period of time to be able to verify and, if necessary, challenge figures that they have been allocated. This process will take some time and add to the uncertainty around final tariffs.

Secondly, generators are not in a position to react to the new signals. New generators cannot build in time for April 2014 in response to new signals, or indeed in time for April 2015 or 2016). Existing generators cannot respond by reducing their TEC in time for April 2014 without being subjected to a penalty. If Ofgem were to make a decision on CMP213 tomorrow, generators would only be able to reduce their TEC in time for April 2015 at the earliest if they were to avoid incurring a TEC reduction charge. If generators wish to react by changing load factor it will take up to 5 years for this to feed into their charges. The introduction of the ALF element is an important distinction from methodology changes which have occurred before. Previous charging methodologies have been based on a generator's TEC alone. CMP213 will change this to base it on its load factor and therefore should allow generators to change load factor in response. With an historic 5 year average approach, the time required for that behavioural change to reflect itself charges is extended, compared with the current methodology.

Thirdly, even if you believe that the benefits under the CBA will accrue, this is only forecast to start happening from 2024. Prior to this, CMP213 is forecast to increase costs for customers. A deferred implementation date would signal that charges will change in a later year which generators could react to by making the appropriate investment decisions for the future, but without incurring the shorter term costs to customers which are forecast under the CBA.

If CMP213 was to be implemented, we would recommend that its implementation is deferred by 5 years. This would take implementation to April 2019 and would allow subsequent behavioural changes to work their way into the ALFs applicable for that time. Most importantly, it would reduce the amount of increased costs which CMP213 is predicted to cause for customers.

Conclusions

In summary E.ON believes:

- That CMP213 has not been proven to be more cost reflective than the current baseline. In particular it appears to be inconsistent with the approach taken in the SQSS.

- That the benefits that are credited to CMP213 long term in the CBA appear to be dubious in that they are based on a very specific and optimistic set of circumstances. It appears more likely that CMP213 will actually increase costs for customers.

- That that the minded to decision is inconsistent with that previously taken for BSC modification P229, even though the circumstances facing Ofgem appear to be the same.

- That if Ofgem still believes that CMP213 should be implemented, that participants cannot respond in time for an April 2014 start. This will simply result in windfall gains and losses for different generators with no possibility of benefit for customers. Implementation should be delayed by 5 years to allow changes in generator behaviour to be reflected in the ALFs they face and, most importantly, to reduce the potential for increased costs for customers in the short term.

I hope you find the above views and analysis helpful. Please do contact me in the first instance if you should have any further questions on this matter.

Yours sincerely

Paul Jones
Upstream Trading Arrangements Manager