nationalgrid

Stage 05 Draft CUSC Modification Report

Connection and Use of System Code (CUSC)

CMP201 Removal of BSUoS Charges from Generation

Volume 1

What stage is this document at?

01	Initial Written Assessment
02	Workgroup Consultation
03	Workgroup Report
04	Code Administrator Consultation
05	**Draft CUSC Modification Report**
06	Final CUSC Modification Report

This proposal seeks to modify the CUSC to better align GB market arrangements with other EU member states by removing BSUoS charges from GB Generators and, instead, recover BSUoS from GB Suppliers only.

Published on: **7 September 2012**
Responses by: **14 September 2012**

The Workgroup concludes:
that CMP201 Workgroup Alternative CUSC Modification 1 should be implemented as it better facilitates the Applicable CUSC objectives

High Impact:
Generators and Suppliers

Medium Impact:
Other CUSC Parties

Low Impact:
None

Contents

Any Questions?

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About this document

This is a draft of the CUSC Modification Report which has been prepared and issued by National Grid under the rules and procedures specified in the CUSC. The purpose of this document is to assist the Authority in their decision whether to implement CMP201.

Document Control

Version	Date	Author	Change Reference
0.1	7 September 2012	Code Administrator	Version for Industry Comment

1 Summary

1.1 CMP201 seeks to remove BSUoS charges from GB Generators, recovering BSUoS from GB Suppliers, in order to better align the GB market arrangements with those prevalent in other EU member states and thus facilitate efficient competition with generation in those EU markets which are not subject to such charges.

1.2 CMP201 was proposed by National Grid Electricity Transmission plc (NGET) and submitted to the CUSC Modifications Panel for their consideration on 8th December 2011. The Panel determined that the proposal should be considered by a Workgroup and that they should report back to the Panel within four months following a period of 15 business days for the Workgroup Consultation. The four months was subsequently increased by the Panel to allow for more in depth analysis by the Workgroup to be included in this report.

1.3 The Workgroup first met on 10th January 2012 and the members accepted the Terms of Reference. A copy of the Terms of Reference is provided in Annex 1. The Workgroup considered the issues raised by the CUSC Modification Proposal and worked through the Terms of Reference.

1.4 This document outlines the discussions held by the Workgroup, the responses to the Workgroup Consultation and the Code Administrator Consultation and the nature of the CUSC changes that are proposed. Summaries of the responses can be found in Section and 9 respectively. Copies of all representations received in response to the Workgroup Consultation and Code Administrator Consultation are contained within Volume 2 of this report.

1.5 This CUSC Modifications Report has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid website at www.nationalgrid.com/uk/Electricity/Codes, along with the CUSC Modification Proposal form

1.6 National Grid has initiated BSC amendment proposals[1] to address a possible interaction with the Residual Cashflow Reallocation Cashflow arrangements under the BSC.

What is BSUoS?

National Grid recovers the costs of balancing the system through BSUoS charges. BSUoS charges are paid for by all CUSC Parties, including Lead Parties for flows on Interconnector BM Units. The Statement of the Use of System Charging Methodology includes a detailed methodology for the calculation of daily BSUoS charges and information on the timing of the charges. The Statement of the BSUoS Charging Methodology was recently incorporated in the CUSC can be found at the following link CUSC Section 14:

National Grid's View

1.7 As Proposer, National Grid supports the implementation of CMP201 in that it helps to create a level playing field between Generators in the EU internal market for electricity which should facilitate further cross-border trading of electricity and benefit GB consumers in terms of the consequence of more competitive electricity prices and also in that it properly reflects its duties in the development of National Grid's business by promoting a single internal market in electricity and facilitating greater cross-border trading of electricity.

[1] P285 and P286 which can be found at http://www.elexon.co.uk/change/modifications/

Workgroup Conclusion

1.8 The Workgroup voted by majority that CMP201 better meets the Applicable CUSC Objectives, with marginally more votes in favour of WACM 1. A summary of the votes is provided in Section 7. Full details of the Workgroup vote are contained within Annex 6.

CUSC Modifications Panel's View

1.9 To be completed after the CUSC Panel Recommendation Vote.

2 Why Change?

2.1 The Transmission Licence allows NGET to recover revenue in respect of the Balancing Services activity through a Balancing Services Use of System (BSUoS) charge, which is recovered equally (50:50) from demand (represented by Suppliers) and generation (represented by Generators). Liable CUSC parties pay BSUoS on a non-locational MWh basis. The BSUoS methodology describes the parties liable for BSUoS charges and for setting the BSUoS tariff and is contained within Section 14 of the CUSC.

2.2 Being non-locational and applied equally to all liable CUSC parties, BSUoS is generally considered as a 'pass-through' i.e. is wholly factored in to the market prices. Therefore it contains little or no incentive on generation to despatch or demand to balance in an efficient manner. BSUoS tariffs are calculated ex-post and therefore the market price offered by GB Generators to Suppliers, and Suppliers to end consumers, will also contain an element to recover the variability risk associated with the BSUoS liability.

2.3 Within Europe, it is commonly the case that the equivalent of BSUoS is charged almost exclusively to demand rather than generation. As a result the wholesale electricity price in those markets will not include this cost. Consequently, GB Generators are disadvantaged when compared to equivalent Generators in other Member States if they trade, or wish to trade, in those markets.

2.4 Whilst the EU Third Package arrangements recognise that different types of market organisation will exist within the wider internal market in electricity, it also acknowledges the need to ensure a level playing field to deliver the full benefits of a competitive internal market in electricity. In particular the Third Package seeks to facilitate efficient cross border trading of electricity and coupling of markets. CMP201 will assist in this objective.

2.5 This proposal seeks to address this misalignment in cost allocation by aligning the GB Balancing Services charging arrangements with those more prevalent across the EU and so provide for a more competitive EU wholesale electricity market.

2.6 It should also be noted that a further proposal, CMP202, that specifically looks at the impact of BSUoS charges on Interconnectors and cross-border trades has also been raised in light of the EU Third Package arrangements. This can be found on the CUSC modifications website page.

3 Solution

3.1 CMP201 seeks to align the GB electricity Balancing Services charging arrangements with those prevalent within other EU Member States. Currently the GB cost of operating the system is recovered equally (50:50) from demand and generation CUSC parties who are liable to pay BSUoS. The liability is contained in Section 14 of the CUSC.

3.2 CMP201 proposes that BSUoS charges, which are currently charged to all liable CUSC Parties on a non-locational MWh basis are removed from GB Generators and recovered 100% from demand; i.e. GB Suppliers. This will effectively align the GB ‘generation stack’ with those in other EU markets (thus facilitating cross border trading of electricity by GB Generators) by removing the BSUoS element from generation prices offered to the markets. This facilitates efficient competition with generation in other EU markets which are not subject to such charges.

3.3 During discussions, covered in Section 4, the Workgroup established that in isolation there would be a net cost, if CMP201 were implemented, for GB consumers. However, in the context of this proposal; which is intended to promote the European market; there was an overall saving for EU consumers as a whole. The Workgroup discussed how negative impacts within GB could be minimised and why they occurred:

i) Timescales for implementation take account of existing contractual commitments. Removing the 50% BSUoS share from generation will allow generation to offer lower wholesale electricity market prices (net of BSUoS element) which should, in a competitive generation market, largely offset the corresponding increase in the BSUoS charge to Suppliers (from 50% to 100%).

ii) That competition between Generators should ensure the BSUoS charge removed from Generators is reflected in lower wholesale prices.

iii) The risk premium that Generators and Suppliers are exposed to due to the ex-post nature and volatility of BSUoS are similar but not necessarily the same for both parties. The Workgroup were divided on whether the transfer of this risk premium along with BSUoS would result in an overall increase or decrease in the risk premium passed through to end consumers.

iv) As the net effect of removing BSUoS from Generation results in a net increase in exports from GB the reduction in GB wholesale prices is less than the increase in BSUoS liability for Suppliers.

4 Summary of Workgroup Discussions

Presentation of Proposal

4.1 The Proposer, National Grid, presented the background and reasons for raising CMP201. The original proposal form is shown in Annex 2 and the supporting presentation is available on the CUSC Workgroup website. The Proposer's principle reason for seeking to remove BSUoS from GB Generators is to better align the GB electricity market arrangements with those prevalent in continental Europe, thus better facilitating cross border trading of electricity by GB Generators and providing more effective competition in the European electricity market.

4.2 There was broad agreement that in a competitive generation market the removal of a flat charge, such as BSUoS, would feed through to the wholesale market price for electricity in future contracts. Despite this the Workgroup did have significant concerns in a number of areas. These mainly centred on:

i) The potential to create windfall gains and losses associated with existing contracts;

ii) Whether Generators are better placed to manage the risk associated with BSUoS and so by transferring this to Suppliers it would increase end consumer cost;

iii) Does this proposal provide parity with other market arrangements in mainland Europe?

iv) Interaction with revenue flows in BSC cashout arrangements; and

v) The impact on credit arrangements for Suppliers;

vi) The impact to GB consumers.

Potential for winners and losers

4.3 The Workgroup first of all considered the transition risk resulting from this proposal for Suppliers in terms of the temporary winners and losers. This would arise where existing contracts between a Supplier and a Generator had been set based on a wholesale electricity price that included generation BSUoS. In these cases Suppliers would have agreed to pay the generation BSUoS (a forecast) in the forward contract price, however they would be exposed to this share of BSUoS again following implementation of this proposal.

4.4 For example, if a Generator has assumed a total BSUoS charge of £2, then currently it would factor into the price they offer the market, a BSUoS 'element' representative of their share (£1); the Supplier would also factor into the price they charge their share of BSUoS (£1). Overall, the Supplier charges for £2 of BSUoS, £1 directly and £1 indirectly in the wholesale price. If CMP201 were approved, and the Supplier was unable to renegotiate their contract with the Generator, then they would pay £3 (the £1 charged by the Generator in their price to the Supplier plus the 100% (£2) of the BSUoS charge recovered from demand).

4.5 The Workgroup broadly agreed this particular issue was related to the period after which the proposal has been agreed by the Authority and the commercial arrangements in the market adjust to take account of the changes.

4.6 Given the Supplier / end consumer contracting arrangements, some Suppliers would not necessarily be able to pass though all this cost. They could only pass on this cost to those customers:

i) whose contracts allowed for it as a specific pass-through element;

ii) whose contracts allowed for them to be 're-opened'; or

iii) those customers whose contract lapsed and / or were renewed during the CMP201 transition period.

4.7 For those customer contracts that did not have a pass through mechanism, a 're-opener', or whose duration extended beyond the CMP201 transition[2] period (such as a 'fixed price' contract), this would result in a one-off windfall gain to the Generator (and a corresponding one-off loss to the Supplier).

4.8 It was noted that in certain circumstances the Supplier maybe able to renegotiate their contract with the Generator to remove the BSUoS element, although this was understood not to be the normal arrangement.

4.9 In terms of magnitude it was acknowledged that due to commercial sensitivity, there is no information publicly available on Supplier's long-term contracts (both with their customers and with Generators) so it would be difficult to quantify this effect, and in any event highly subjective.

4.10 It was suggested that the recent Ofgem Retail Market Review report could provide information on the hedging strategy for the 'Big Six' which would give an indication of the length of time supply businesses are commitment to proving energy at a particular price.[3] From that report, it was subsequently noted that there were a number strategies, typically hedging over 12, 18 and 24 month periods, with 90% of domestic energy hedged / purchased over 18 months and 10% being purchase in the on the day market as a possible scenario for modelling.

4.11 Workgroup members noted that this report only covered domestic volume (approximately 2/3rds of supplied energy) and that the arrangements for Industrial and Commercial consumers could be different; i.e. contractually BSUoS may or may not be treated as a pass through. Again, due to the commercial sensitivity and individual nature of these contracts, there is no readily available information. The Workgroup however generally understood that contract negotiations normally occurred in October and April and understood to generally be for one or two years in duration.

4.12 The Workgroup also discussed the nature of energy purchase hedges highlighted in the Ofgem report. It was not clear whether those hedges were at a "fixed price" or "Contract for Differences" (CfDs) i.e. to the extent that those hedges were obligations or options. It was noted that where the contracts were based on CfDs around the wholesale electricity price that a shift in Generator revenue (i.e. a reduction from 50% to zero for BSUoS) would be reflected in the wholesale market price for electricity which would

[2] The period between the authority agreeing the change and it becoming 'live'

[3] Link to Ofgem's Electricity and Gas Supply Market Report document – see Appendix 2 for Hedging Strategies
http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Documents1/Electricity%20and%20Gas%20Supply%20Market%20Report%20December%202010.pdf

flow through to all Suppliers, thus possibly mitigating the potential for winners and losers.

4.13 It was also suggested that fully vertically integrated utilities (in this context, those with generation and supply interests) would be equally exposed to both the loss and gain so it would have no net effect at a Group level on those types of companies, and so therefore main risk (from CMP201) was to smaller non fully vertically integrated Suppliers. The Workgroup generally accepted that vertically integrated utilities operate separate Supply and Generation businesses and that such an interpretation could have serious negative consequences on competition, particularly in the supply arena.

Do Suppliers and Generators face the same risk on BSUoS volatility?

4.14 The risk of BSUoS volatility was discussed. Whereas the overall net loss and gain discussed above was mainly perceived as a transition issue, the redistribution of risk (from generation to demand) would be an enduring issue. The Proposer suggested that the overall risk is not being increased as a result of the CMP201, but rather that it was being transferred from Generator to Supplier.

4.15 One member raised an issue that the risk from BSUoS variability was asymmetrical and Generators were better positioned to manage that risk compared to Suppliers. That member suggested that if BSUoS is increased, it gets recycled to the Generators. Therefore the risk premium for Generators is lower than for Suppliers and so it is not simply a transfer of risk (from Generators to Suppliers) as suggested. However, some Workgroup members disputed this, suggesting that the risk is transferred but overall it remains the same.

4.16 A scenario was outlined whereby a Generator may receive constraint revenues, the cost of which feeds into BSUoS and is therefore shared across all parties. So whilst the BSUoS charge has risen for all parties, the Generator in receipt of the constraint revenue has less exposure to BSUoS volatility as a consequence.

4.17 Using the £2 total BSUoS example above, a Generator might receive 20p in constraint revenues but be liable to pay the £1 – hence their 'net' BSUoS cost is 80p (rather than £1). The Supplier, on the other hand, is less able to access constraint revenues; being limited, for example, to offering demand side response. Counter views were expressed by Workgroup members who noted that:

i) Constraint costs were only one element within BSUoS.

ii) The large majority of Generators could not predict if or when they may receive constraint revenues (indeed depending on their technology and / or location, some Generators may receive little, if any, constraint revenues over their lifetime).

iii) Provision of services is on a commercial basis and subject to competitive pressures and so individual Generators could not simply inflate the cost of services.

4.18 Some of the Workgroup acknowledged the view that some Generators benefit from payments that make up BSUoS, via constraint revenues etc., and so their risk maybe lower, and so by transferring BSUoS to demand, the overall risk premium may increase slightly.

4.19 One Workgroup member suggested that at the wholesale level Generators would be better able to manage the risk, whereas Suppliers would find it more difficult to pass the risk on to end consumers. Again, not all Workgroup members agreed with this.

4.20 Another Workgroup member pointed out that the wholesale electricity market was competitive and so Generators cannot price the cost of constraints etc., any more easily than Suppliers. They added that Generators are also to be bound (in the very near future) by the Transmission Constraint Licence Condition.

4.21 A Workgroup member suggested that for wind farms, the proposed change would remove a corrective signal of their actions and that this may increase overall BSUoS charges. It was noted that this applied to all liable parties, Generators and Suppliers. It was also noted that nature of the BSUoS charge is unlikely to be a good signal to modify behaviour:

i) because BSUoS is charged to all parties equally and not those that may have caused the need for the System Operator (SO) action, and

ii) given the ex-post determination of BSUoS it was difficult to predict and so react to.

4.22 It was agreed by the Workgroup that BSUoS is therefore mainly a cost recovery mechanism rather than a market signal to modify participant behaviour. Suppliers would (with CMP201) be taking on the whole BSUoS risk and that this could have negative consequences for end consumers although without a detailed understanding of individual risk mitigation strategies this could not be demonstrated. It was also suggested that the potential for mismanagement of this risk by parties, and the potential for negative consequences, is arguably inherent and will not increase or decrease as a consequence of changing which party manages the risk. The potential for mismanagement exists regardless of how and in what proportion BSUoS risk is allocated, be it on Generators, Suppliers or any proportion of the two entities.

4.23 The Workgroup considered what elements are most volatile within BSUoS and examined the graphs shown below (prepared by National Grid). Figure 1 shows the relative volatility of BSUoS internal costs (e.g. control centre costs), and those externally driven cost (payment for Balancing Services) arsing from real time System Operator actions. As may be expected, the external costs were the significant cause of volatility.

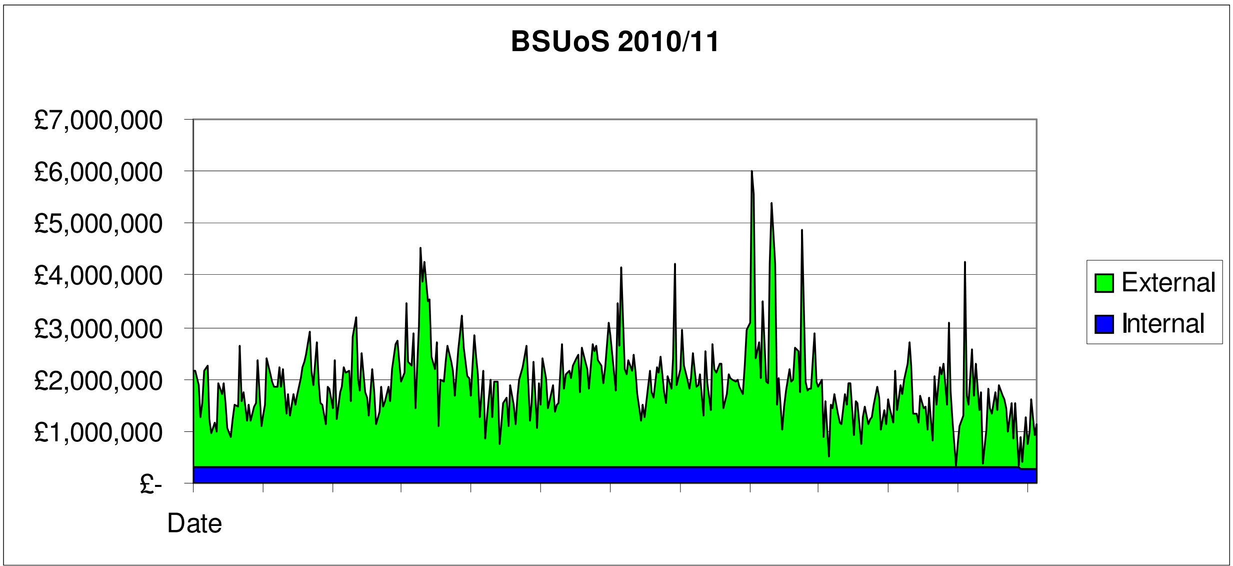


Figure 1: BSUoS by External /Internal Cost driver

4.24 Figure 2 then provides a breakdown of those external cost elements of which Balancing Services Settlement costs are the most variable, reflecting the nature of balancing the system.

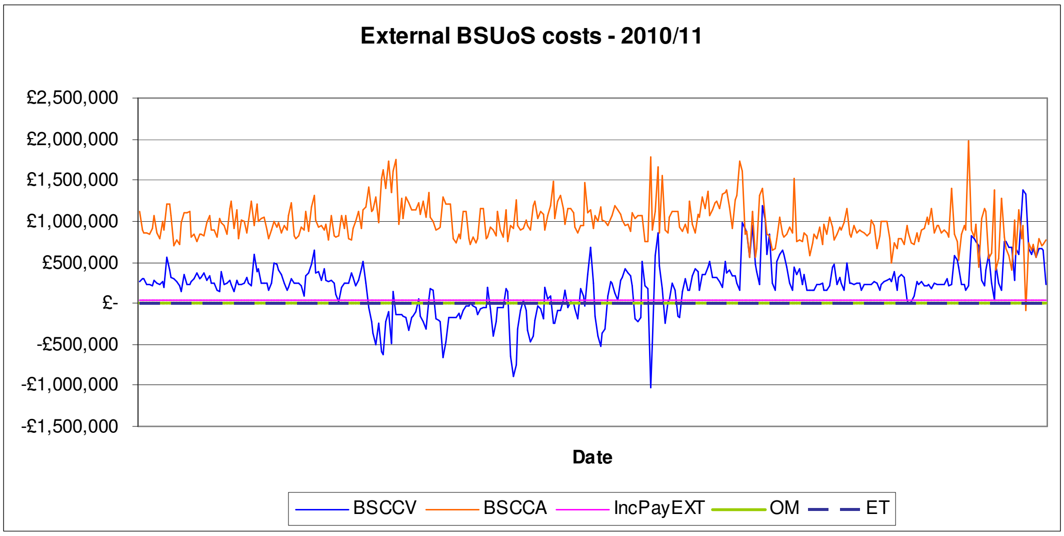


Figure 2: BSUoS External Cost elements

BSCCV: BS Settlement Costs – Settlement Period Specific
BSCCA: BS Settlement Costs – Non Settlement Period Specific
IncPayExt: Total forecast external incentive Payment
ET: Daily BS adjustment
OM: Provision of BS Services to others
Note that both ET and OM were zero throughout 2010/11.

Interaction of BSUoS and RCRC

4.25 The Workgroup considered the relationship with Residual Cashflow Reallocation Cashflow (RCRC) arising from participant's imbalance. Whilst acknowledging that there was some linkage between the two elements due to the SO costs arising from imbalance, it was commented that BSUoS is more than the cost of the Net Imbalance Volume (NIV). It was also highlighted to the Workgroup that RCRC has been both positive (payment to CUSC parties) and negative (charge on CUSC parties) and that all parties were likely to factor this into their contracts in a similar manner.

4.26 Under current market arrangements, RCRC and the energy balancing costs element of BSUoS are assumed to net off to zero, leaving a Party only exposed to Imbalance Charges[4]. This is because RCRC is, by definition[5], equal and opposite to the sum of energy balancing costs. This would no longer hold if CMP201 was implemented.

4.27 For example, as explained in Annex 12, a balanced party, who would face zero energy balancing costs under current market arrangements, would pay (or receive) energy balancing costs under CMP201, theoretically to the value of RCRC, despite being in balance. It was agreed by the Workgroup that it would not be practical to examine the future interaction of BSUoS and RCRC until the possible electricity cash-out Significant Code Review that

[4] This ignores the secondary effect of any incentivisation through the SO incentive scheme.

[5] This assumption, particularly in respect of dual imbalance pricing, will be reviewed by the Workgroup in more depth after the consultation.

Ofgem is considering holding is progressed as that will determine if it is a significant issue.

4.28 Following the Workgroup consultation the Workgroup considered further how revenues from imbalance payments accrue in RCRC, whereas the net cost associated with rebalancing the system are recovered as part of BSUoS. This is described in more detail in Annex 12. One Workgroup member felt that this issue was not a significant problem, as RCRC is collected from everyone's cash-out and redistributed evenly. It was generally felt that RCRC should be levied to the same parties as BSUoS, although not all members agreed.

4.29 Having considered the interaction the majority of the Workgroup understood that this was outside the scope of the CUSC and thus CMP201 Workgroup. The Workgroup discussed this being raised as a 'BSC issue' as it was not something that the CMP201 Workgroup could resolve. The Ofgem representative noted that it would be preferable if an initial view could be reached by a BSC or joint standing/issues group by the time CMP201 is sent to the Authority for a decision.

4.30 National Grid indicated that in order to resolve the issue in a timely manner it considered raising BSC modification proposals would be more appropriate and would investigate this approach bilaterally with ELEXON. This would not prevent alternatives being raised under the BSC and similar representation on the interactions made under the BSC process. Under the Transmission licence NGET has responsibility for ensuring consistency between codes. National Grid has now raised P285 and P286 under the BSC[6] to address this issue. These will now be progressed independently of any Ofgem decision on a potential 'cashout' Significant Code Review.

Consider the Impact on End Consumers

4.31 As discussed previously there is the potential for transitional windfall gains and loses, and the Workgroup was concerned that this could have a negative short to medium term impact on end consumers if not properly addressed. Along with this, the enduring redistribution of risk to Suppliers could also impact on end consumers. To mitigate both transitional and potentially enduring effects it was suggested that a number of options could be considered, for example:

i) a reasonable length of time allowed for transition to allow parties (Generators and Suppliers) to take account of the changes in their commercial agreements with each other and, in the case of Suppliers, with end consumers);
ii) fixed BSUoS charges for Suppliers; and
iii) changes to trading products to allow BSUoS liability to be efficiently passed through.

4.32 The Workgroup understood that some Suppliers are trading further out than 18 months, therefore products in the forward market will need to change in order to clearly show whether BSUoS is included or not. It was suggested that implementation of CMP201 should only take place when all forward trading arrangements have been amended to clearly state whether or not BSUoS is included. However, it was noted that there maybe a risk of a perverse behaviour whereby participants enter into very long term forward trading arrangements, such as with a single customer for 10 years, in order to extend the CMP201 transition period and thus frustrate the transition of

[6] P285 and P286 which can be found at http://www.elexon.co.uk/change/modifications/

CMP201. Furthermore, the Workgroup recognised that some Suppliers could be over-hedged and some may be under-hedged (depending on the commercial position they have chosen) and therefore it was not entirely clear what the impacts of implementing CMP201 sooner rather than later would be.

4.33 Following the closure of the Workgroup Consultation, further analysis was carried out on the impact on GB consumers. It was surmised that end users within Great Britain could initially be adversely impacted by around £178m equating to approximately a 1% rise per annum in GB market costs, however there was a small consumer benefit within a wider EU market of about £7m to £12m reduction in costs. GB generation would initially benefit by a similar £180m (3%) increase in surpluses, although within a wider EU market producer surpluses would fall slightly. This is due to the reductions in producer surplus in continental markets outweighing the increases observed in the GB market. Overall GB would be broadly neutral as would the wider EU market when considering the impact on continental generation. However, please note that the producer and consumer calculations are not directly comparable. The producer surplus is a proxy for profit i.e. the price a commodity is sold at minus cost. The consumer cost is a measure of the total cost of providing electricity. It is not a measure of consumer surplus in the Marshallian sense i.e. the difference between what a consumer is willing to pay for a commodity and what he or she actually pays. Therefore adding together the two calculations does not provide an overall market benefit/cost value.

4.34 There is an overall net gain to EU consumers and in time one would expect the additional GB surpluses to feedback into lower GB market prices via competitive pressures including encouraging new generation to enter the market. This is discussed further in Annex 13.

4.35 The Workgroup noted that this information was not available during the Workgroup consultation and therefore some respondents' views may change upon receiving this further information. The Workgroup acknowledged that the industry would be able to respond again via the Code Administrator consultation and also via a potential impact assessment that Ofgem may carry out.

4.36 The analysis also indicted that the reduction in the GB wholesale price that should arise from the transfer of BSUoS liabilities may not be fully realised by GB Suppliers. This would be due to GB generation gaining greater access to a wider EU market for their production. The analysis indicated a likely increase in net exports from GB to the other EU member states modelled which would place an upward pressure on GB prices. For example, if the cost of BSUoS was £1/MWh for both (GB) Generators and Suppliers, under CMP201 a Supplier would be exposed to £2/MWh BSUoS and the GB wholesale price in theory would reduce by £1/MWh. However, when the change in BSUoS results in increased export from GB, the GB wholesale price adjusts to reflect both the change in BSUoS (downwards) and increased export (upwards). This is why there is a net cost to GB consumers. The increased import to continental Europe results in a reduction in wholesale prices in Europe. Overall, there is a net benefit for European consumers as a whole which is a natural consequence of increased competition in harmonised markets. Annex 13 contains a brief description of the model used by National Grid to establish this and the results of the analysis performed.

4.37 It should be noted that much of the analysis within this report assumes that CMP202, which removes BSUoS liabilities from Interconnector BM Units is approved; this proposal (CMP201) addresses the competition consequence that arise from the CMP202 change. Should CMP202 not be approved, the impact of CMP201 if approved, would likely remain the same as Importing Interconnector BM units would continue to be treated as "generation" and thus BSUoS would be removed from both sets of parties simultaneously albeit 2 to 5 years later than if CMP202 is approved separately.

4.38 The Workgroup also discussed and noted that the analysis model assumes a "fully coupled" market where electricity would always flow from low to high market prices during each half hour and that in reality; Interconnectors can flow against market price. Whilst it is difficult to quantify, the impact of CMP201 may not be as great as modelled due to this sub-optimal trading.

4.39 To provide a broader view National Grid carried out a number of further scenarios. These included changes to the level of BSUoS, analysis based on 2011/12 data, and looking at the merit order to understand the effect a switch between Coal and Gas might have.

4.40 The results, available in Annex 13, showed that as BSUoS charges increased from £1.11/MWh (the annual average charge for 2010/11) to a scenario assuming a BSUoS charge of £1.75/MWh then, as expected, the total GB market cost also increased by between 1.1% and 1.7%. However, the analysis also showed that if CMP201 was not implemented then GB producer (generator) surpluses would also decline as a result of the higher BSUoS charge reflected in the GB wholesale price attracting greater imports into GB and thus reducing GB Generations' production.

4.41 If CMP201 was not implemented, an increase in BSUoS from £1.11/MWh to £1.75/MWh showed a 0.6% increased impact on consumers. GB producer surplus however would be reduced by 1.7% for the same rise.

4.42 The analysis based on 2011/12 prices was comparable with that performed for 2010/11 showing a 1.2% increase in GB market costs with a 2.5% increase in GB producer surpluses. Overall, the analysis showed a broadly neutral impact across the wider EU market with a marginal benefit to consumers.

4.43 Analysis of coal & gas prices for 2010/11 and 2011/12 showed that, on average, fuel prices favoured running coal plant 5% more in 2011/12 than in 2010/11. As a comparative measure of the potential change in plant merit order, the results from the 2011/12 study, for which the annual average BSUoS charge was £1.53MWh, were compared with the results from the 2010/11 study that included a similar annual BSUoS charge of £1.50/MWh.

4.44 Whilst other effects may have an impact on the comparison, such as underlying demand trends and the level of wind generation, these are likely to be a smaller effect compared to fuel prices (modelled demand variation <1%, additional wind capacity <0.2% increase between 2010 and 2011).

4.45 Between the two years, the model showed a GB market cost increase of 1.5% increase for 2010/11 and 1.9% for 2011/12. Given the accuracy of the model data and other underlying assumptions, there appears to be no significantly different outcome from differing generation plant merit orders.

Credit risk

4.46 The Workgroup discussed the subject of credit risk. Under the current CUSC arrangements, Generators and Suppliers have to provide credit cover for one months' BSUoS liability as notified by National Grid. Although this can be reviewed at any time, in the past National Grid has reviewed this quarterly, based on the BSUoS price and metered volumes for the last three months compared to the same period in the previous year and the likely metered volumes for the next quarter.

4.47 As Suppliers would potentially need to increase their credit holding (if CMP201 were implemented) it was suggested that, in particular for smaller Suppliers, the increased credit risk could have a negative impact on competition. Counter to this it was noted that smaller Generators would have reduced credit risk and therefore this could benefit competition.

4.48 It was also noted that overall credit risk to Suppliers would include a reduction of credit that they post in wholesales trades. This information is not available as it is largely a bilateral arrangement between Suppliers and Generators. This could largely net off the overall change to individual Suppliers requirement with National Grid – subject to an equal and opposite reduction in wholesale prices. The Workgroup noted that the analysis indicted the change was not exactly equal and opposite and would depend on the actual bilateral trading arrangements.

4.49 Overall the majority of the Workgroup believe that CMP201 would result in a transfer of credit risk between parties rather than a transfer plus fractional increase on one of the parties.

4.50 Following the Workgroup consultation the Workgroup considered the view that there is a lower credit risk on Generators than Suppliers due to the monies they receive via BSUoS. As discussed previously, some members of the Workgroup highlighted that this was not an issue that Generators can manage but it was generally recognised by some Workgroup members that Generators have a marginally lower credit risk than Suppliers.

4.51 Some Workgroup members felt that competition would be improved in the European[7] market were CMP201 to be implemented. Others felt that the local (GB) market would not be affected. One Workgroup member suggested that local competition would be improved to a marginal extent due to improved transparency surrounding credit risk (i.e. removed from wholesale price). This view was not shared by all Workgroup members.

4.52 National Grid reviewed the current holding of credit cover to quantify the extent of any credit cover changes. The results of this are summarised in Annex 10. This indicated that based on current levels of credit only four parties would be affected; none were a small Supplier. Of those four Suppliers, one may acquire sufficient additional cover through the payment history mechanism in a few months. The four affected parties identified all related to companies of significant size, two of which provide Parent Company Guarantees leaving potentially only one Supplier required to increase their credit cover with National Grid (noting it may reduce in other areas). If CMP201 were implemented then, given the likely implementation timescales, any affected party would have sufficient time to arrange for sufficient credit cover.

[7] In the context of this report "European" / "EU" markets refer to the none GB markets for electricity; although, in practice, GB is part of the EU.

Consider the Impact on Competition

4.53 The Workgroup all agreed that the Supplier risk would increase. Some Workgroup Members believe that Suppliers generally find it more difficult to predict BSUoS (compared with Generators), and that smaller Suppliers would be even less able to handle the risk. However, some Workgroup Members believe that Generators also face the same risk today and smaller independent Generators currently find it harder to predict risk.

4.54 Two Workgroup members provided an information paper to the Workgroup in order to demonstrate the CMP201 competition issues for Suppliers. This is included an Annex 7. The Workgroup discussed the paper (but did not unanimously agree, or disagree, with its contents). It was noted that System Operator balancing costs is only one element of BSUoS, and the majority of System Operator actions will not flow through to RCRC.

4.55 In reviewing the example presented in the paper that suggest a net loss (-0.12) it was suggested that this did not represent the whole picture. The premise of the original CMP201 proposal is that if BSUoS is removed from generation this would feed through to the wholesale electricity price, some members of the group indicated this was a premise rather than a fact. In addition, as BSUoS is paid ex-post, and is volatile, the market cannot predict nor accurately reduce power price by BSUoS reduction. Therefore whilst the Supplier would see an increase in BSUoS it should see an equal and opposite decrease in the wholesale electricity price that they pay; although it is noted elsewhere that increased exports from GB, as modelled under a CMP201 scenario, will result in a reduction in wholesale prices not being exactly equal to the increase in BSUoS.

Consider how the equivalent of BSUoS is charged for in other EU member states

4.56 The Proposer advised that steps had been taken to understand if Generators in Europe are compensated equivalently to Generators in GB for the services that they provide to the SO but that it had been difficult to locate this information.

4.57 The pan European TSO trade association (ENTSO-E) had produced a paper[8] in May 2011 which provided some information which the Workgroup considered. This seemed to suggest that the majority of the neighbouring electricity markets to which GB was (inter)connected had low (2%) or zero charges on Generators for network operator charges. In terms of the 25 EU member states surveyed (excludes Cyprus and Malta) 16 applied a zero charge on Generators, four charged between zero and 10%, two charged between 11-20% and three (including GB) charged between 20-30% with the balance, in all cases, falling on demand.

4.58 There was some uncertainty as to whether the 'network operator charges' surveyed by ENTSO-E fully equated to the GB BSUoS charge and the Workgroup asked National Grid if it could source additional information. An information request was sent by National Grid to a number of countries and of the three responses received it was found that Generators were compensated for all services; i.e. they pay little, if any, of what is believed to be broadly the same (as GB) BSUoS type charges. For one country, primary, secondary and tertiary reserves were recovered 100% from generation and other costs recovered 100% from demand. For the other two

[8] Transmission Tariffs in Europe: https://www.entsoe.eu/market/transmission-tariffs/

countries, the equivalent of BSUoS costs were confirmed as being recovered 100% demand.

4.59 A summary of these finding were presented to the Workgroup. This is included as Annex 9.

Examine the Impact of implementation on all relevant parties

The effect of BSUoS on inter-market operation.

4.60 BSUoS is the daily charge aimed at recovering the cost of operating the GB National Electricity Transmission System (NETS). It consists of fixed elements covering SO internal costs and Balancing Service contracts plus the variable elements of daily Ancillary Services, balancing and constraint costs.

4.61 As discussed above, in other European Member States, it is understood that it is commonly the case that their equivalent of BSUoS is charged almost exclusively to demand; Interconnector Users being liable solely for their energy imbalances in each market.

4.62 In the GB market, all CUSC parties are liable for BSUoS based on their energy taken from, or supplied to the transmission system. Being an unavoidable cost of generation (similar to fuel) this has the effect of raising the GB market price of electricity by a Generator's share (or forecast share + risk margin) of the BSUoS charge. GB Generators would therefore appear more expensive than their equivalent European counterparts.

Trading effects under the current arrangements

4.63 Currently, Interconnector Users are also charged BSUoS in the same manner as other GB BSUoS payers. The price of electricity imports to GB is therefore raised in a similar way as GB generation; the end consumer sees the same costs in the GB electricity market irrespective of its source (Figure 3).

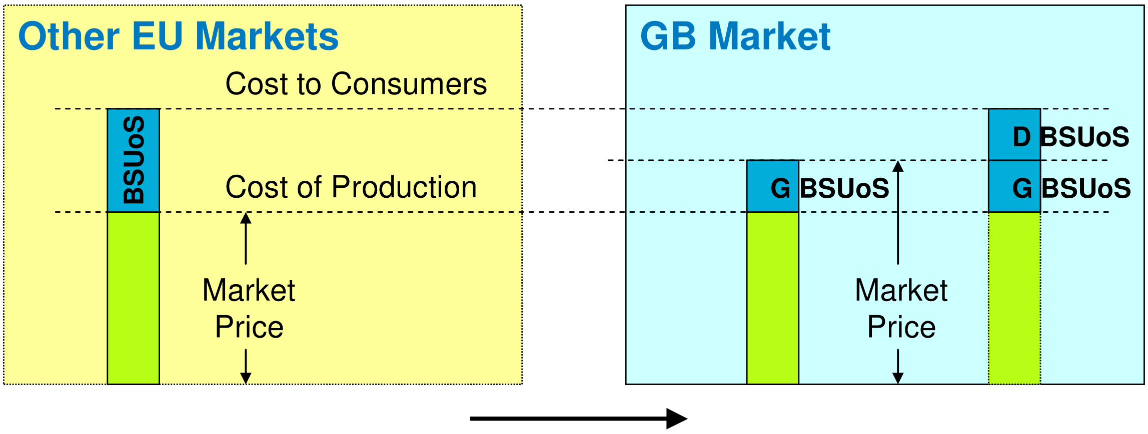


Figure 3 Current EU / GB BSUoS Arrangements – Imports

4.64 Under the current CUSC arrangements however, BSUoS charges create a potential barrier to GB electricity exports. Generation BSUoS charges inherent in the GB electricity market price, plus the demand BSUoS charges levied on the export of electricity from GB, can potentially raise the GB price of exporting electricity above that at which it would naturally flow if both markets were aligned (Figure 4).

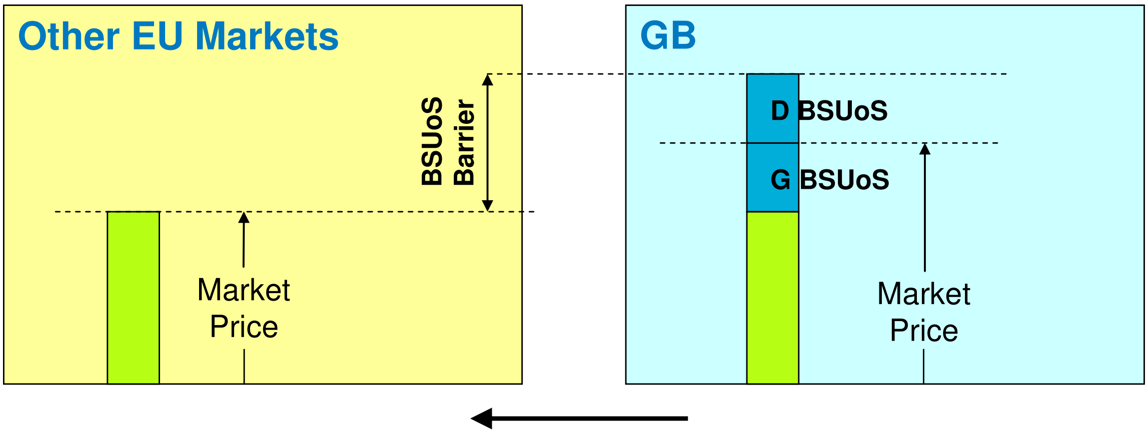


Figure 4 Impact of current BSUoS arrangements on GB exports.

4.65 This barrier to electricity exports is the economic rational for CMP202.

Trading effects if only CMP202 CUSC modification is implemented

4.66 An Interconnector User, not exposed to BSUoS, would see a greater electricity market price differential artificially caused by the GB Generator's exposure to BSUoS and may therefore trade to import electricity into GB on occasions other than when it would be economic under comparable market arrangements. In effect, the BSUoS charge levied on GB Generators would create a "subsidy" for electricity imported into GB. A secondary effect (approximately 2%) would be that BSUoS charges would also increase for all other GB BSUoS payers (both G & D) to recover the BSUoS revenue "lost" from Interconnector Users (Figure 5).

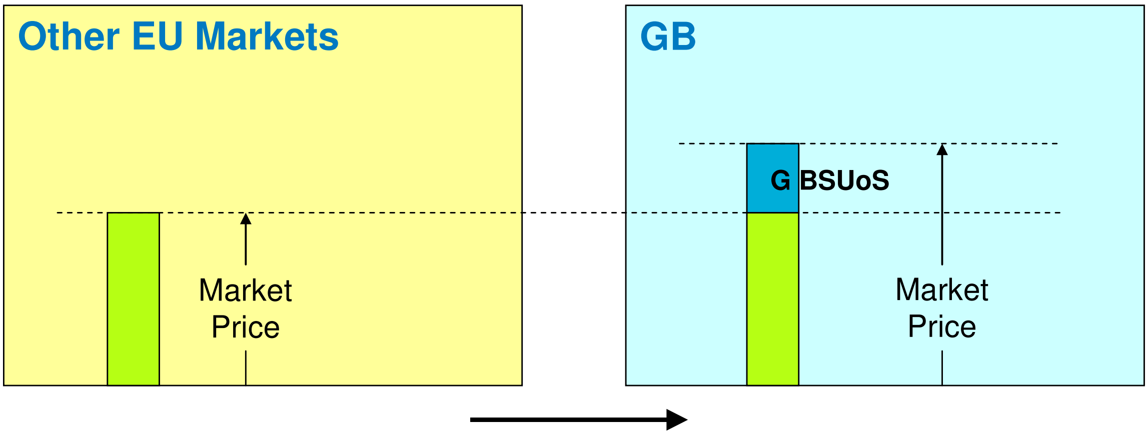


Figure 5: Potential distortion from uplift due to generation BSUoS

4.67 Whilst removing BSUoS charges from Interconnectors Users would reduce the "BSUoS" barrier on electricity exports, it does not totally remove it. The GB wholesale electricity price would still retain the generation element of BSUoS and consequently may be artificially higher than that in EU Member States. As a result, there may still be occasions when apparently economic electricity exports do not take place as a result of BSUoS charges on GB Generators (Figure 6).

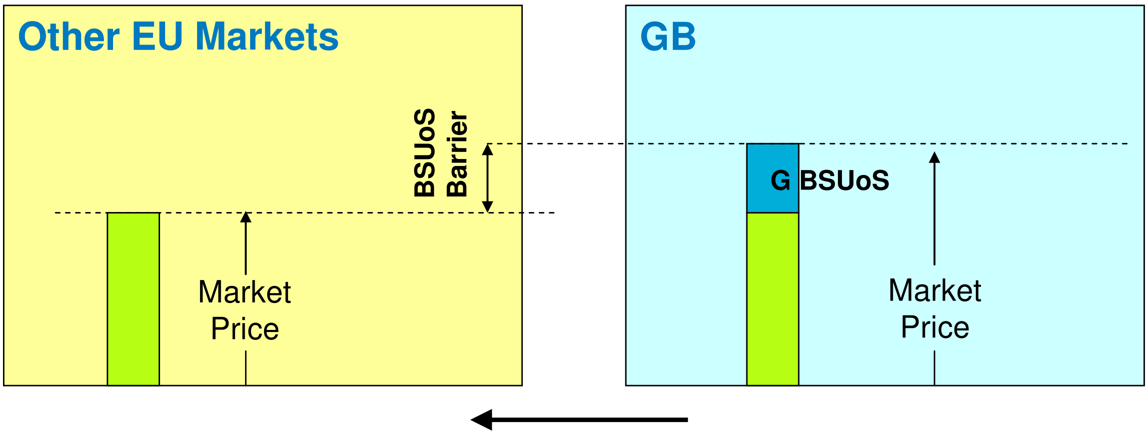


Figure 6: Impact of Generator BSUoS "uplift" on GB exports

<u>Trading effects if both CMP201 and CMP202 CUSC Modifications are implemented</u>

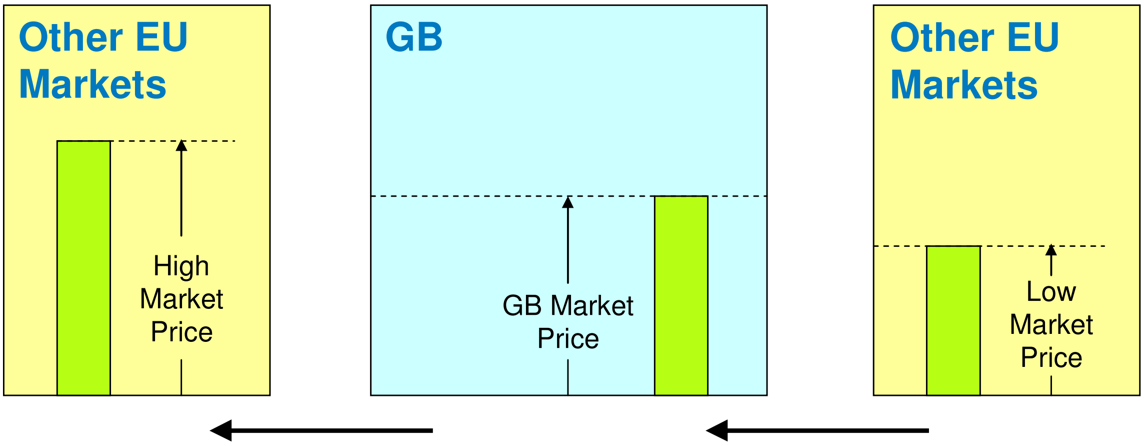


Figure 7 Market "equalisation" by removing BSUoS from Interconnectors and GB generation

4.68 Removing BSUoS charges from both Interconnector Users and GB Generators aligns both electricity markets making them directly comparable (Figure 7). Interconnector flows should therefore occur based on market price differentials without any market distorting effects caused by BSUoS.

4.69 In conclusion, by removing (with CMP201) BSUoS charges from GB Generators (in addition to those on Interconnector Users, with CMP202) would:

1) Facilitate further cross-border trading of electricity and greater use of interconnectors. This in turn should increase GB electricity market competition and security of supply to the benefit of consumers whilst improving GB Generators access to a wider EU market.

2) Further align the GB electricity market arrangements with those predominantly operating in other EU member states and, in doing so, further the EU Third Package objectives of a single EU market in electricity

3) Remove an apparent barrier to GB electricity exports due to the different treatment of BSUoS in the other European electricity markets.

4) Avoid a potential “subsidy” to Interconnectors and continental Generators on GB electricity imports as a consequence of a generation BSUoS charges being reflected in the GB market electricity prices were BSUoS charges to be removed only from Interconnectors.

4.70 In terms of generation, the Workgroup discussed that as there would be no BSUoS charge, there would be a lower wholesale electricity price and overall little benefit (for GB consumers). However it was noted that this proposal was aimed at facilitation pan European benefits rather than focused on GB.

4.71 It was noted that, with CMP201, there would be no exposure for GB Generators to the volatility of BSUoS so there would be a benefit in terms of the wider electricity market. It was also agreed that there may be a significant disbenefit if the proposal is implemented too early due to the windfall gain.

4.72 With regard to traders, it was noted that there would be more opportunity to trade with the EU electricity market on generation stacks so this would provide a benefit. It was also commented that improving cross border trade would improve the investment case for new interconnector. Annex 11 presents analysis on the possible impact on cross-border trades using a simple model. Overall this suggests that exports from GB increase. This is also shown through the more detailed modelling discussed in Annex 13.

4.73 The Workgroup considered a table of pros and cons for each type of party and how each issue could be quantified:

Table 1: Pros and Cons of CMP201 for each type of party

Party	Pro	How to Quantify	Con / Issue	How to Quantify
Interconnector Owner / Trader	Potentially optimises EU cross border trade in electricity – increased revenue with greater transactions			
Supplier			Potential windfall loss if implementation / transition is poorly managed: Require sufficient time for change to be reflected in Supplier / Gen and Supplier / customer contracts. Certainty of implementation date, with sufficient transition time required to avoid windfall loss Potential asymmetrical BSUoS volatility risk: Supplier might be more exposed to BSUoS volatility than Generation	Ofgem Retail market Review: Supplier contract strategy. Also Action 10 of Workgroup meeting 10th Jan. BSUoS forecast vs outturn Can we quantify additional Supplier risk? Paragraph 4.14 et al
Trading Unit			Possible slight increase in embedded benefit which may encourage further future Trading Units. Potential "snowball" effect on embedded benefit.	

Party	Pro	How to Quantify	Con / Issue	How to Quantify
Generator	Compete with other EU generation on equal basis. Greater opportunities to export electricity from GB – creates a level playing field with continental generation Removes potential electricity import (to GB) distortion; e.g. potential for higher cost imports, that only appear to be relatively 'cheap' due to the regulatory treatment of BSUoS type costs, to undercut GB generation as EU generation does not pay BSUoS	Market Review: ENSTO-E survey & synthesis report; review of TSO websites Potentially, analysis of historic prices and / or model of market interaction.	Potential windfall gains if implementation / transition is poorly managed: See Suppliers	As per Supplier Annex 9 Annex 13 & Paragraph 4.31 Annex 13

Party	Pro	How to Quantify	Con / Issue	How to Quantify
End Consumers	Promotion of efficient EU wide competition in electricity through removal of NTBs. Maximises allocative efficiency across the EU. Potentially no increase in risk if Generators' and Suppliers' BSUoS risk is symmetrical. Risk is only transferred. Under such circumstances, no effect on end consumers from changing the BSUoS charge allocation. Around £11m benefit to wider EU market end consumers.	Potentially from model of market interactions.	Short Term: End consumer electricity prices may increase as Generator / Supplier and Supplier / Customer contracts are adjust to reflect the new arrangements. Potential increase from asymmetric risk if significant. Potential wholesale prices do not decrease in line with decrease in BSUoS costs, possibly mitigated by implementation strategy and competition. Potential Increase in market costs to GB end consumers (around 1% / £178m) due to increase in exports from GB via the interconnector.	Potentially from model of market interactions. Annex 13 & Paragraph 4.31

BMU and trading unit considerations

4.74 Items 5 (e) and (h) of the Workgroup Terms of Reference (see Annex 1) cover issues of BMU unit definition and how using this affects how BSUoS is charged. The specific areas the Workgroup were charge to consider were [(e)] "Consider what is meant by Generators in the context of delivering and offtaking Trading Units and BM Units" and [(h)] "Consider the impact on embedded benefits". With respect to embedded benefits the Proposer advised the Workgroup that any change in BSUoS sharing factors (between Generators and Suppliers) would change both the charge and the overall benefit in equal proportions.

4.75 Currently embedded generation benefits from avoiding BSUoS charges; there are also benefits from reduced BSUoS demand charge as a consequence of that embedded generation. Under the CMP201 proposal, there would be no Generator BSUoS to avoid and the benefit arising from reduced demand would double. Overall the net embedded benefit should be the same under CMP201 as it currently is and the Workgroup also noted that the sharing of embedded benefit between Suppliers and embedded generation is as per their individual contracts.

4.76 The ELEXON observer provided an information paper summarising the (BSC) Balancing Mechanism Units and Trading Units definition issues that could arise with CMP201 in order for the Workgroup to consider the impacts and benefits more clearly. This is included as Annex 8 to this report.

4.77 It was recognised that the definition of generation in the CMP201 proposal could have consequences for embedded benefits. The Proposer confirmed that the original proposal did not intend to adjust or remove any embedded benefits. The Workgroup reviewed the ELEXON paper and broadly agreed with the conclusion that scenario 2 should be used to develop legal drafting.

Consider the Treatment of Pumped Storage

4.78 The Proposer presented an overview of the potential impact on Pumped Storage from CMP201 which indicated that ignoring plant efficiency the impact on Pumped Storage should be broadly neutral. This is shown diagrammatically in Figure 8 below:

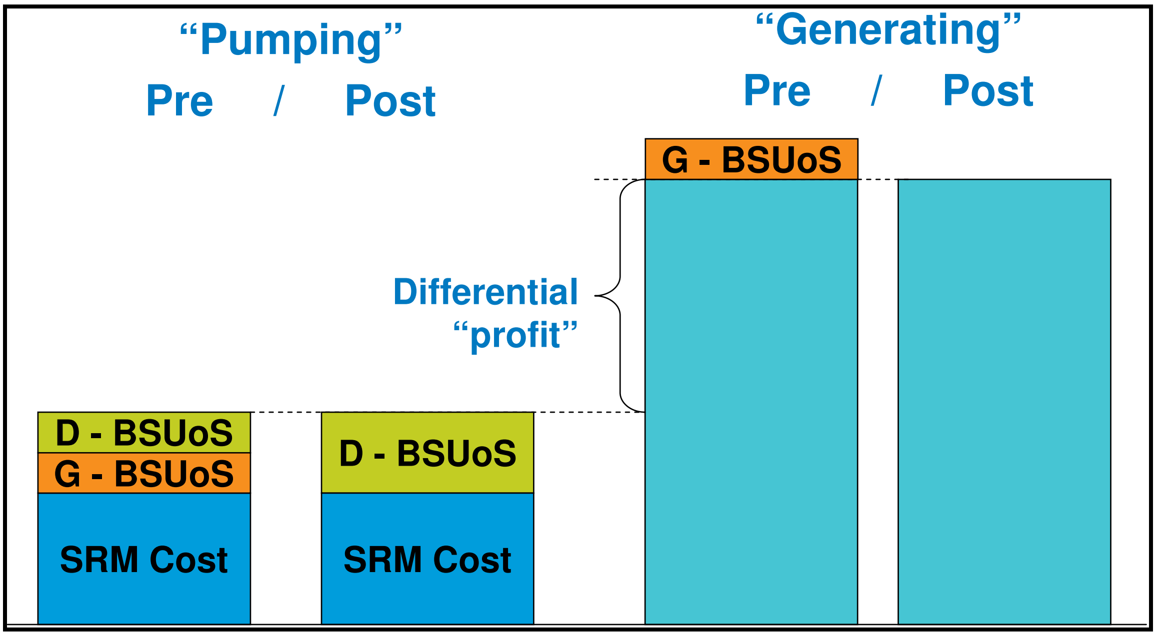


Figure 8 Redistribution impact on Pumped Storage

4.79 The principle impact for Pumped Storage arises from the efficiency of the plant; i.e. it requires approximately 25% more energy from pumping (which is treated as demand) than is provided when generating. Put another way, for every 100 units of electricity that a Pumped Storage power station produces it uses 125 units to pump the water to the top of the reservoir. Currently Pumped Storage pays 50% BSUoS on their demand for electricity (which is 25% greater than their production of electricity) and 50% on their production. Under CMP201 Pumped Storage would therefore pay the additional BSUoS charges (i.e. 100% on their demand) but not have to pay anything on their production. The materiality of this would depend on the BSUoS price differential paid when pumping and saved when generating.

4.80 Table 2 BSUoS Price Ratio for assumed Generation / Pump windows below, based on 2010/11 data attempts to quantify this. For the purposes of this analysis, it has been assumed that pumping will occur some time between 23:00 and 04:00 i.e. overnight. An average BSUoS price was calculated for each season during these hours. Similarly, average BSUoS prices were derived for various windows during the day when Pumped Storage may wish to generate. The table shows the ratio of these two values. A value greater than 100% indicates that the average BSUoS in that window was greater than the average BSUoS in the corresponding pump window.

4.81 In general it shows that, due to generally higher BSUoS in those periods where Pumped Storage could be expected to generate, the avoided generation BSUoS charge is sufficiently high compared with the addition BSUoS cost incurred when pumping.

Table 2 BSUoS Price Ratio for assumed Generation / Pump windows

Periods	Hours	Winter	Spring	Summer	Autumn
9 – 12	04:30 to 06:00	74%	78%	96%	100%
13 -21	06:30 to 10: 30	157%	172%	109%	142%
22 – 33	11:00 to 16:30	155%	149%	97%	114%
34 – 41	17:00 to 20:30	177%	175%	111%	145%
42 – 45	21:00 to 22:30	109%	179%	122%	100%
46 – 8	23:00 to 04:00	Assumed Pump Window			

4.82 The Workgroup agreed that the impact of CMP201 on Pumped Storage should be broadly neutral.

Charging BSUoS to Demand

4.83 The Workgroup was also requested by the Panel to consider if the mechanism for charging BSUoS to remaining parties continues to be beneficial and whether the CUSC Modifications Panel may wish to initiate further work outside the Workgroup on this subject

4.84 The Proposer confirmed that the original was drafted to consider the removal of BSUoS from generation rather than amend the manner in which it is paid by demand. The Workgroup acknowledged that this issue was being considered by National Grid separately in response to Customer Engagement through RIIO. National Grid considered this an important issue but outside the scope of CMP201 proposal.

Workgroup Alternative CUSC Modifications

4.85 Based on the discussion above in respect of winners and losses the Workgroup considered a number of options regarding transition and implementation for CMP201, which might have been included in either the original proposal or might have been raised as an alternative to the original:

- i) Two year transition;
- ii) Five year transition;
- iii) Phased implementation over two years;
- iv) Phased implementation over five years; and
- v) Two year delay then a phased implementation.

4.86 With options (i) and (ii) there would be a step-change in BSUoS liabilities after an implementation decision. In other words, assuming CMP201 were approved by the Authority during 2012/13, then it would come into effect from 1st April 2015 (option (i)) or 1st April 2018 (option (ii)). Thus with option (i) Generators would pay 50% of BSUoS charges in March 2015, as would Suppliers. Then in April 2015 Generators would not pay any BSUoS charge and Suppliers would pay 100% of BSUoS charges. A similar approach would apply with option (ii), but three years later than option (i).

4.87 With option (iii) there would be a phased introduction of the change. Again assuming CMP201 were approved by the Authority during 2012, then from 1st April 2013 to 31st March 2015 the proportion of the BSUoS charges paid by Generators would decline and, correspondingly, the Supplier share would increase. The logic for the phased approach is that, as noted above, the contracts between Generators and Supplier and Suppliers and end customers do not all start (or end) on the same date. Rather they are spread out over various timeframes. A phased introduction would mitigate the transition impact as contracts expired and renewed under the new arrangements. The Workgroup noted that there were a number of ways that the phasing might happen and a number of variations were discussed.

4.88 Variation (a) would see the 50% Generator share of BSUOS reduce by the same amount over the 24 month phased implementation period (this equates to approximately 2% per month). Thus, in this example, Generators would pay 50% of BSUoS in March 2013 (and Suppliers 50%). Then in April 2013 Generators would pay ~48% (and Suppliers ~52%) which would become, in May 2013, ~46% for Generators (and Suppliers ~54%) and so on until on 1st April 2015 Generators would pay no BSUoS charge (and Suppliers would pay 100% of BSUoS).

4.89 As noted above, the Workgroup was aware that the contracting arrangements for industrial and commercial consumers meant that negotiations normally occurred in October and April contracting 'rounds'; i.e. most, if not all, of these types of customer contracts tended to start / end on these months (be they for 6, 12, 18, 24 etc., months duration). Given this another variation (b) would be to phase the implementation of CMP201 linked to these dates. Assuming a similar two year period starting on 1st April 2013 then the phasing would be spread over the four subsequent contracting rounds. Thus Generators would pay 50% of BSUoS (and Suppliers 50%) from April 2013 to October 2013, then from October 2013 to April 2014 Generators would pay 37.5% (and Suppliers 62.5%) followed by 25% for Generators (and 75% for Suppliers) for the period April 2014 to October 2014 and then, for the final period from October 2014 to April 2015, Generators would pay 12.5% (and Suppliers 87.5%). Finally, from April 2015 Generators would pay no BSUoS charge (and Suppliers would pay 100% of BSUoS).

4.90 The Workgroup noted that given the contracting arrangements in the domestic sector that variation (a) was perhaps more closely aligned with these types of customers 'churn' rates etc., whilst given the contracting arrangements in the industrial and commercial sector that variation (b) was perhaps more closely aligned with these types of customers. Given this a possible further variation (c) would be to migrate Suppliers non half hourly demand on the basis of variation (a) and Suppliers half hourly demand on the basis of variation (b). Whilst perhaps more complex than applying either variation (a) or (b) it would, in principle, be possible to achieve variation (c) if this was felt to better reflect market conditions.

4.91 Having considered option (iii) the Workgroup noted that it could also be phased in over a longer period than two years, such as five years which was considered as option (iv). In this case (again assuming CMP201 were approved by the Authority during 2012) the phasing would also start from 1st April 2013. Therefore with variation (a) phasing would be spread over 60 months (instead of 24 months with option (iii)). Thus, with variation (a), instead of the rate of change being approximately 2% per month it would be approximately 0.8% per month. In other words starting from 1st April 2013 Generators would pay ~49.2% (and Suppliers ~50.8%) and so on, concluding with Generators paying no BSUoS charge (and Suppliers pay

100%) from 1st April 2018.

4.92 With variation (b) the phasing would be over ten contracting rounds (rather than the four with option (iii)). This would mean that the phasing would be 5% per contracting round (rather than the 12.5% per round in option (iii)). Thus starting with the October 2013 to April 2014 round Generators would pay 45% (and Suppliers 55%) and so on until, from 1st April 2018, Generators pay no BSUoS charge (and Suppliers pay 100%).

4.93 The final options considered at this stage by the Workgroup (noting that there are many potential options and variations on those options) was option (v) which would move the start of the phasing implementation dates in option (iii) or (iv) from 1st April 2013 to 1st April 2015. Thus with option (v), if the option (iii) based approach of two year phasing were adopted then Generators would end up paying no BSUoS charge (and Suppliers pay 100%) from 1st April 2017. In the case of the option (iv) five year phasing approach then, under option (v), the date when Generators would end up paying no BSUoS charge (and Suppliers pay 100%) would be 1st April 2020.

4.94 At the post-consultation meeting, the Workgroup considered the responses received in relation to transition and implementation and the majority of the Workgroup agreed that a fixed lead time for implementation would be preferable. The majority of the Workgroup felt that phasing would be too complex, but not insurmountable.

4.95 No Workgroup members supported an implementation time of less than 2 years. As suggested by the Proposer in the Workgroup Consultation, it was agreed that based on the information available, the CMP201 Original would contain an implementation arrangement of the 1st April following 2 years after the Authority decision on CMP201. So for example, if a decision was made on or prior to 31st March 2013, the implementation date would be 1st April 2015: a decision thereafter and before 1st April 2014 would result in an implementation date of 1st April 2016.

4.96 The Workgroup considered a number of Draft alternative CUSC Modifications regarding implementation and came up with the following options:

a) Original – the 1st April following 2 year after a Regulatory decision.
b) Draft Alternative(i) – the 1st April following 3 year after a Regulatory decision.
c) Draft Alternative (ii) - the 1st April following 4 year after a Regulatory decision.
d) Draft Alternative (iii) – the 1st April following 5 year after a Regulatory decision.

4.97 The Workgroup Chair asked the group to provide their views on the above options in respect of better facilitating the Applicable Objectives. There was majority Workgroup support for Draft Alternative (i), but not for Draft Alternative (ii). Four members of the Workgroup supported the 5 year option (Draft Alternative (iii)) and although this did not form a majority of the Workgroup, the Chair decided to progress this option using his powers under the CUSC governance rules.

4.98 Therefore, the final conclusion of the Workgroup was that, in addition to the Original Proposal, there should be two Workgroup Alternative CUSC Modifications (WACMs) as follows:

a) Original – 1st April following 2 year after an Authority decision
b) WACM1 – 1st April following 3 year after an Authority decision.

c) WACM 2 – 1st April following 5 year after an Authority decision

4.99 For clarity, and assuming an Authority decision on or prior to 31st March 2013, then the above proposals would be implemented in 2015, 2016 and 2018 respectively as shown below:

	Implementation Date		
Authority Decision Date:	Original: 2 years	WACM1: 3 Years	WACM2: 5 Years
On or before 31st March 2013	1st April 2015	1st April 2016	1st April 2018
Between 1st April 2013 and 31st March 2014	1st April 2016	1st April 2017	1st April 2019
Between 1st April 2014 and 31st March 2015 Etc.	1st April 2017	1st April 2018	1st April 2020

5 Impacts

Impact on the CUSC

5.1 CMP201 requires amendments to the following parts of the CUSC:

• Section 14 – Charging Methodologies, Part 2 – The Statement of the Use of System Charging Methodology,

• Section 2 – the Statement of the Balancing Services Use of System Charging Methodology.

5.2 The text required to give effect to the Proposal is included as Annex 14 to this report.

Impact on Greenhouse Gas Emissions

5.3 Neither the Proposer nor the Workgroup identified any material impact on greenhouse gas emissions.

Impact on Core Industry Documents

5.4 The Workgroup considered the interaction with the cashout arrangements in the BSC, and particularly the relationship with the Residual Cashflow Reallocation Cashflow. This has been discussed above in part 4 of this report.

5.5 The Workgroup appreciate that parties generally considered that there was a linkage between BSUoS and the cashout arrangements in the BSC. This manifests itself when NGET takes an energy balancing action and recovers the net cost through BSUoS. The energy imbalance that led to the NGET action would result in a revenue in the Residual Cashflow Reallocation Cashflow (RCRC). RCRC is 'cashed out' to the lead parties of BMUs based on their metered volumes. This redistribution was understood to have the effect of reinforcing the incentive for an individual party to balance. It was also noted that BSUoS covered many more costs beyond energy balancing.

5.6 The Workgroup also noted that Ofgem recently consulted on the possibility of it undertaking a Significant Code Review into the (BSC) cashout arrangements and the Workgroup believed that any consequential changes as a result of CMP201 could be covered by that Ofgem review.

5.7 Following consideration by the Workgroup, where a number of members believed their was a strong interaction with RCRC, National Grid raised two amendment proposals under the BSC to ensure this possible interaction is fully considered in the appropriate forum and that any consequential proposals could be developed and brought before the Authority.[9]

Impact on other Industry Documents

5.8 Neither the Proposer nor the Workgroup identified any impacts on other Industry Documents.

[9] P285 and P286 which can be found at http://www.elexon.co.uk/change/modifications/

Impact on IS systems

5.9 National Grid indicated that there will be an impact on central IS systems to adjust revenue recovery to demand parties; however at this stage it is understood that it is likely to be relatively minor (less than £100k) and not a critical path item for implementation (assuming a minimum two years lead time for contractual reasons).

5.10 No significant IS issues for Users were identified as part of the Workgroup consultation.

6 Proposed Implementation

6.1 The CMP201 Original Proposal suggests an implementation date of 24 months should give the industry sufficient time to respond and therefore limit any windfall gain / loss.

6.2 The Workgroup noted the Proposer's suggestion and considered a number of possible implementation approaches which they have developed into subsequent Workgroup Alternative CUSC Modifications (as detailed in paragraphs 4.85-4.99 above).

6.3 The final conclusion of the Workgroup was that, in addition to the Original Proposal, there should be two Workgroup Alternative CUSC Modifications (WACMs) with the following implementation approach for each:

a) Original – 1st April following 2 year after an Authority decision
b) WACM1 – 1st April following 3 year after an Authority decision
c) WACM 2 – 1st April following 5 year after an Authority decision

6.4 For clarity, and assuming an Authority decision on or prior to 31st March 2013, then the above proposals would be implemented in 2015, 2016 and 2018 respectively as shown below:

	Implementation Date		
Authority Decision Date:	Original: 2 years	WACM1: 3 Years	WACM2: 5 Years
On or before 31st March 2013	1st April 2015	1st April 2016	1st April 2018
Between 1st April 2013 and 31st March 2014	1st April 2016	1st April 2017	1st April 2019
Between 1st April 2014 and 31st March 2015 Etc.	1st April 2017	1st April 2018	1st April 2020

7 Views

Workgroup Conclusion

7.1 The Workgroup believes that the Terms of Reference have been fulfilled and CMP201 has been fully considered.

7.2 For reference the Applicable CUSC Objectives for the Use of System Charging Methodology are:

(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

7.3 The Workgroup voted (via email) by majority that CMP201 does better facilitate Applicable Objective (a) and (c) and were Neutral on (b). The majority of the Workgroup expressed a preference for the CMP201 WACM 1. The table below summarises the votes: Full details of the vote can be found in Annex 6.

Vote 1: Whether each Proposal better facilitates the Applicable CUSC Objectives

Name	**Original**			**WACM1**			**WACM2**		
	(a)	**(b)**	**(c)**	**(a)**	**(b)**	**(c)**	**(a)**	**(b)**	**(c)**
Cem Suleyman	Yes	Neutral	Yes	Yes	Neutral	Yes	Yes	Neutral	Yes
Iain Pielage	Yes	Neutral	Yes	Yes	Neutral	Yes	No	Neutral	No
James Anderson	Yes	Neutral	Yes	Yes	Neutral	Yes	Yes	Neutral	Yes
Michael Dodd	Yes	Neutral	Yes	Yes	Neutral	Yes	Yes	Neutral	No
Sarah Owen	No	Neutral	No	No	Neutral	No	No	Neutral	No
Helen Inwood	No	Neutral	No	No	Neutral	Neutral	Yes	Neutral	No
Esther Sutton	Neutral	Neutral	Yes	Yes	Neutral	Yes	Yes	Neutral	Yes

Paul Mott	Yes	Neutral	Yes	Yes	Neutral	Yes	Yes	Neutral	Yes
Rob Hill	No	Neutral	Yes	No	Neutral	Yes	Yes	Neutral	Yes
Garth Graham	Yes	Neutral	Yes	Yes	Neutral	Yes	No	Neutral	No

Vote 2: Whether each WACM better facilitates the Applicable CUSC Objectives than the Original.

Name	**WACM1**			**WACM2**		
	(a)	**(b)**	**(c)**	**(a)**	**(b)**	**(c)**
Cem Suleyman	Yes	Neutral	Yes	No	Neutral	No
Iain Pielage	Neutral	Neutral	Neutral	No	Neutral	No
James Anderson	No	Neutral	No	No	Neutral	No
Michael Dodd	No	Neutral	No	No	Neutral	No
Sarah Owen	Neutral	Neutral	Neutral	Neutral	Neutral	Neutral
Helen Inwood	Neutral	Neutral	Neutral	Yes	Neutral	Neutral
Esther Sutton	Yes	Neutral	Yes	Yes	Neutral	Yes
Paul Mott	Yes	Neutral	Yes	No	Neutral	No
Rob Hill	Yes	Neutral	Yes	Yes	Neutral	Yes
Garth Graham	Yes	Neural	Yes	No	Neutral	No

Vote 3: Which option BEST facilitates achievement of the Applicable CUSC Objectives? (inc. the CUSC baseline; i.e. ‘status quo’)

Name	**Best Option**
Cem Suleyman	WACM 1
Iain Pielage	Original
James Anderson	Original
Michael Dodd	Original
Sarah Owen	Baseline
Helen Inwood	WACM 2
Esther Sutton	WACM 1
Paul Mott	WACM 1
Rob Hill	WACM 2
Garth Graham	WACM 1

National Grid View

7.4 National Grid considers that CMP201 would better facilitate Applicable Use of System Charging Methodology (CUSC) Objective (a) in that it helps to create a level playing field between Generators in the EU internal market for electricity which in turn should facilitate further cross-border trading of electricity and benefit GB consumers in terms of the consequence of more competitive electricity prices and Applicable Use of System Charging Methodology (CUSC) Objective (c) in that it properly reflects its duties in the development of National Grid's business by promoting a single internal market in electricity and facilitating greater cross-border trading of electricity. National Grid believes that in respect of Objective (b), that the CMP201 proposal is neutral. The BSUoS cost methodology will continue to reflect costs and therefore the charges in the appropriate time periods. Given that under the current regime these are regarded as a pass through, and therefore a revenue recovery issue, the CMP201 proposal will neither improve nor weaken cost reflectivity.

8 Workgroup Consultation Response Summary

8.6 13 responses were received to the Workgroup Consultation. These responses are contained within Volume 2 of this document. The following table provides an overview of the representations received.

Company	Initial Views	Views against Applicable CUSC Objectives (ACOs)	Implementation	Other Comments
Centrica	Do not support – Proposal is flawed. End users adversely impacted and risk to suppliers due to volatility. Also, results in disconnect between industry subject to RCRC and BSUoS which should be resolved under CMP201.	Does not better facilitate the ACOs. Detrimental impact on (a) as adverse affect on competition in supply due to uncertain cash-flows.	At least 2 year delay to prevent windfall losses/gains. Phasing would cause complications and risk.	Ofgem could undertake an impact assessment. A change to the volume of credit posted may be required to ensure sufficient credit cover.
Consumer Focus	Status quo should be maintained due to number of risks identified. Should be reconsidered when EU member states are more advanced in liberalising their energy markets. Also, risk to consumers if generators do not pass their savings from BSUoS to suppliers.	Doesn't better facilitate (a) or (b). Negative impact on competition and harder for new entrants due to increase in suppliers credit holding. Neutral on (c).	Do not support – should be postponed until other member states are more advanced in liberalising their energy markets.	Welcome assessment of total annual value of current BSUoS by generators. Generators are better positioned to manage variability risk than suppliers and are naturally hedged.
Drax and Haven	Agree with intentions as will better align GB balancing services charging arrangements. Must be implemented alongside CMP202. Levying BSUoS on demand will result in a transfer of risk rather than increase or decrease, BSUoS is a cost recovery mechanism.	Better facilitates (a) and (c).	Reasonable length of time should be given for transition, ideally 3 years to avoid any perverse outcomes. 5 years would be disproportionate to the potential cost to suppliers.	Small impact on supplier's credit risk costs. Impacts outweighed by benefits of CMP201. Disagree that end consumer costs will rise due to asymmetric risk, don't believe any interaction between RCRC and BSUoS.
EON	Supportive	Better facilitate (a) and (c)	Support a longer timeframe. 3 year transition period may not be enough.	Any negative impact on competition due to credit arrangements will be offset by generators having the opposite effect.

Company	**Initial Views**	**Views against Applicable CUSC Objectives (ACOs)**	**Implementation**	**Other Comments**
EDF Energy	Supportive.	Better facilitate (a) and (c)	Timescales need to take some account of existing contractual arrangements. At least 18 months is required. Neutral on phasing.	Do not regard RCRC as natural hedge for BSUoS. Could be merit in the RCRC charging base being considered in the future but not proper business for CMP201. On enduring basis, suppliers should not face significant difficulty in increased credit exposure.
Eggborough	Supportive.	Better facilitates the ACOs.	2 years is too long, 1 year is reasonable time for suppliers.	Limited credit risk on suppliers. Solution could be to double number against which credit is raised.
First Utility	Not supportive – forcing suppliers to take the whole risk is disproportionate.	Will not better facilitate the ACOs due to negative impact on competition.	2 years may reduce potential windfall effect but still create barriers to entry for smaller suppliers.	Increased credit costs will disproportionately affect smaller players.
International Power	Supportive. Do not believe that generation or supply is able to hedge BSUoS to any meaningful extent and the collection of BSUoS is simply a revenue recovery exercise.	Yes, will bring the cost base of GB generation in line with Europe.	Supportive as long as adequate notice to the market to ensure no windfall gains or losses. 36 months is adequate.	No party should be required to hold more security than is required currently, or should be justified if so. Potential impact on retail IS systems.
RWE	Concern at lack of clarity around implementation. Consultation does not provide analysis on impact on end consumers. Suppliers have higher risk.	No. Impact on market participants is unclear and link between RCRC and BSUoS has not been addressed.	Support approach as long as impact analysis is undertaken and is outside current hedging timescales	Full impact assessment is required. Detrimental impact on credit cover, particularly for small parties. CMP201 forms part of the SCR on cash out.

Company	Initial Views	Views against Applicable CUSC Objectives (ACOs)	Implementation	Other Comments
Scottish Power	Support, should be implemented with CMP202.	Better facilitates (a) and (c).	Support 2 year approach, minimises windfall losses / gains. Single transition date is preferable.	Any supplier issues over forecasting could be addressed by a subsequent change. Under-securing of BSUoS by suppliers would be short-term. Correlation between RCRC and BSUoS has largely broken down due to use of more economic constraint management.
Smartest Energy	Supportive to extent, if in combination with market coupling.	CMP201 alone does not facilitate ACOs. Constraint costs are best dealt with by transferring costs into day ahead market.	Yes, should be made at time that market coupling effects regional day ahead wholesale pricing.	Credit is issue for smaller parties. Not convinced RCRC / BSUoS interaction is a serious issue. Total costs should be the same due to completion in generation market.
SSE	Support principle but clarity required on some aspects.	Yes, particularly (a) as it facilitates competition.	Agree with approach (2 year). Appreciate desire for phased transition.	Phased transition may reduce credit risk.
Total Gas & Power	Broadly supportive.	Yes.	2 years not enough. Strongly support 5 year transition. Phased implementation would be disruptive.	Credit risk will add to the burden of smaller suppliers and may therefore impact competition, but this impact is small. Potential impact on IS systems if phased or inefficient notice period for implementation.

9 Code Administrator Consultation Response Summary

8.7 11 responses were received to the Code Administrator Consultation. These responses are contained within Volume 2. The following table provides an overview of the representations received.

Company	Views against ACOs	Implementation	Other Comments
Centrica	Does not better facilitate the ACOs. Detrimental impact to GB end consumers	Do not support proposal but 5 year delay would be preferable	Proposal should not be considered at this time as a more holistic approach will be developed under the Electricity Balancing SCR.
Drax Power	Better facilitates (a) and (c).	WACM 1 (3 year) provides optimal notice period	Objections raised against modification have not been substantiated.
E.ON	Better facilitates ACOs (a) and (c).	Should be implemented sooner rather than later, particularly now CMP202 is implemented. Original best achieves this.	Desirable for treasury announcements on Carbon price support to be taken into account by the Authority when making their decision.
Ecotricity	Mixed views – may improve comparability between GB and Europe and improve competition but concern over transfer of risk to suppliers.	No answered.	Generators should reduce prices and not treat removal of BSUoS as a windfall. Also raises importance of ensuring reporting transparency.
EDF Energy	Slightly better facilitates (a) and (c) due to levelling the playing field and benefitting competition.	Agree with original (2 years) – beyond this is inefficient and lacks justification.	
Eggborough	Better facilitates (a) and (c) as levels the playing field and improves competition and makes charges more direct.	Support original but 2 years is too long, would prefer 1 year.	
InterGen	Better facilitates (a) by aligning arrangements with EU member states	2 years is more than sufficient, would support one off implementation over phased approach.	
NPower	Depends on implementation, does	Long lead time required for industry to manage	

	not meet ACOs in its current form.	changes to charging – suppliers will be exposed to double the risk – so support 5 years.	
Scottish Power	Better facilitates (a) and (c).	Support 2 year implementation as allows time to reach the end of the majority of contract positions.	Should be implemented as soon as possible now CMP202 is in place.
Smartest Energy	Meet ACOs in part, in combination with market coupling.	2 years is adequate. Phased approach would be overly complex.	Scenario which ensures that embedded benefits are unaffected should be used.
SSE	Original and WACMs 1 and 2 better facilitate ACOs but Original best.	Agree with approaches in consultation with a preference for the Original (2 years).	No evidence provided that parties will be materially affected if implemented sooner than 5 years.

Annex 1 - Workgroup Terms of Reference

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal CMP201 'Removal of BSUoS Charges from Generation' tabled by National Grid at the CUSC Modifications Panel meeting on 16 December 2011.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

Use of System Charging Methodology

(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

a) Review the illustrative legal text
b) Consider the impact on end consumers
c) Consider the impact on competition

d) Consider how the equivalent of BSUoS is charged for in other EU member states
e) Consider what is meant by Generators in the context of delivering and off taking Trading Units and BM Units
f) Examine the impact of implementation on all relevant parties
g) Consider the treatment of pumped storage
h) Consider the impact on embedded benefits
i) The Workgroup is also requested by the Panel to consider if the mechanism for charging BSUoS to remaining parties continues to be beneficial and whether the CUSC Modifications Panel may wish to initiate further work outside the Workgroup on this subject.

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Workgroup discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Workgroup and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of three weeks as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on 19 April 2012 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 27 April 2012.

Membership

13. It is recommended that the Workgroup has the following members:

Role	Name	Representing
Chairman	Patrick Hynes	Code Administrator
*National Grid Representative**	Iain Pielage	National Grid
*Industry Representatives**	Paul Mott	EDF Energy
	Garth Graham	SSE
	James Anderson	Scottish Power
	Esther Sutton	EON
	Cem Suleyman	Drax
	Michael Dodd	ESBI
	Helen Inwood	Npower
	Bob Brown	Conoco Philips
	Sarah Owen	Centrica
Observer	David Kemp	ELEXON
Authority Representative	Matthew Grant	
Technical secretary	*Emma Clark*	Code Administrator

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP201 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;

- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal;
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

CUSC Modification Proposal Form (for Charging Methodology proposals)	CMP201

Title of the CUSC Modification Proposal: *(mandatory by proposer)*

Removal of BSUoS charges from Generation

Submission Date *(mandatory by Proposer)*

8th December 2011

Description of the CUSC Modification Proposal: *(mandatory by proposer)*

This proposal seeks to align GB market arrangements with those prevalent within other EU member states. This will deliver more effective competition and trade across the EU and so deliver benefits to all end consumers.

It is proposed that Balancing Services Use of System (BSUoS) charges, which are currently charged to all liable CUSC parties on a non locational MWh basis, are removed from GB Generators. This will effectively align the GB 'generation stack' with those in other EU markets, thus facilitate equitable competition with generation in other EU markets which are not subject to such charges.

There should be no adverse effects for GB end consumers, subject to implementation taking account of existing contractual commitments. Aligning the GB market arrangements with other member states better facilitates an efficient functioning internal market in electricity. To that end, GB consumers will benefit from more competitive arrangements delivered through a wider fully functioning competitive market in generation.

Whilst the EU Third Package arrangements recognise that different types of market organisation will exist within the wider internal market in electricity, it also acknowledges the need to ensure a level playing field to deliver the full benefits of a competitive internal market in electricity. These objectives are broadly comparable with the objectives applicable to the Charging Methodologies within the CUSC.

Description of Issue or Defect that the CUSC Modification Proposal seeks to Address: *(mandatory by proposer)*

The Transmission Licence allows NGET to recover revenue in respect of the Balancing Services Activity, including the operation of the transmission system, through BSUoS charges. Liable CUSC parties pay BSUoS charges, based on their energy taken from, or supplied to the transmission system on a non locational MWh basis. Being non locational and applied equally to all, they are considered as 'pass through' and so contain little or no incentive on generation to despatch in an efficient manner. The charges are also calculated ex post and therefore the market price offered by GB Generators will contain an element to recover the cost and variability risk associated with their BSUoS charge.

Within Europe, it is commonly the case that the equivalent of BSUoS is charged almost exclusively to demand[10]. Consequently, GB Generators is disadvantaged when compared to equivalent generation in other member states.

Removing BSUoS from GB Generators will allow generation to offer market prices that are comparable and competitive with other generation across the EU, recognising that energy trade is facilitated mainly on a 'generation stack' price.

Impact on the CUSC: *(this should be given where possible)*

Revision to Section 14 – Charging Methodologies, Part 2 – The Statement of the Use of System Charging Methodology, Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

Main Sections affected are 14.29 and 14.30

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? ~~Yes~~/No *(assessed in accordance with Authority Guidance – see guidance notes for website link)*

Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information: *(this should be given where possible)*

BSC ☒

Grid Code ☐

STC ☐

Other ☐

(please specify)

Wider implications on BSC cash-flows may need to be explored.

Urgency Recommended: ~~Yes~~ / No *(optional by Proposer)*

Justification for Urgency Recommendation *(mandatory by Proposer if recommending progression as an Urgent Modification Proposal)*

Self-Governance Recommended: ~~Yes~~ / No *(mandatory by Proposer)*

10 https://www.entsoe.eu/fileadmin/user_upload/_library/Market/Transmission_Tariffs/TariffSynthesis_2011_FINAL.PDF

Justification for Self-Governance Recommendation *(mandatory by Proposer if recommending progression as Self-governance Modification Proposal)*

Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews? *(mandatory by Proposer in order to assist the Panel in deciding whether a Modification Proposal should undergo a SCR Suitability Assessment)*

Yes. As this proposal seeks to make revisions to the BSUoS Methodology only, it has no interaction with the ongoing TNUoS SCR.

Impact on Computer Systems and Processes used by CUSC Parties: *(this should be given where possible)*

Minor Impact on National Grid Electricity Transmission's BSUoS charging system.

Mainly depending on the consideration of BSC cash flow implications, on BSC and User systems. Possibly also on how volumes are notified and treated. .

Details of any Related Modifications to Other Industry Codes (including related CUSC Modification Proposals): *(where known)*

Justification for CUSC Modification Proposal with reference to Applicable CUSC Objectives: *(mandatory by proposer)*

Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

☒ (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

☐ (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

☒ (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

Full justification:

National Grid believes that this proposal better meets the relevant objective of facilitating competition.

It helps to create a level playing field between Generators in the EU internal market for electricity which in turn should facilitate further cross-border trading. GB consumers should therefore benefit from more competitive prices as a consequence.

In that an objective of EU legislation is to promote a single internal market in electricity and facilitate greater cross-border trading, National Grid believes that this proposal properly reflects its duties in the development of its transmission business.

Details of Proposer: (Organisation's Name)	National Grid Electricity Transmission Ltd.
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party, "National Consumer Council" or Materially Affected Party)	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Iain Pielage National Grid Electricity Transmission Ltd 01926 656360 Iain.Pielage@uk.ngrid.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Andy Wainwright National Grid Electricity Transmission Ltd 01926 655944 Andy.Wainwright@uk.ngrid.com
Attachments (~~Yes~~/No): If Yes, Title and No. of pages of each Attachment:	

Annex 3 - Workgroup Attendance Register

Name	Organisation	Role	Meeting 1	Meeting 2	Meeting 3	Meeting 4	Meeting 5
Patrick Hynes	National Grid	Chairman	Yes	Yes	Yes	Yes	Yes
Emma Clark	National Grid	Technical Secretary	Yes	Yes	Yes	Yes	No
Iain Pielage	National Grid	National Grid Proposer	Yes	Yes	Yes	Yes	Yes
Heather Carter	National Grid	Observer	Yes	Yes	Yes	Yes	Yes
David Kemp	ELEXON	Observer	Yes	Yes	No	No	No
Matthew Grant	Ofgem	Authority Representative	Yes	Yes	Yes	No	No
Evridiki Kaliakatsou	Ofgem	Observer	No	Yes	Yes	No	No
James Anderson	Scottish Power	Workgroup Member	Yes	Yes	No	Yes	Yes
Sarah Owen	Centrica	Workgroup Member	Yes	Yes	Yes	Yes	Yes
Esther Sutton	E.ON UK	Workgroup Member	Yes	Yes	No	Yes	Yes
Cem Suleyman	Drax	Workgroup Member	Yes	Yes	Yes	Yes	Yes
Rob Hill	Conoco Philips	Workgroup Member	Yes	Yes	Yes	Bob Brown	Yes
Paul Mott	EDF Energy	Workgroup Member	Yes	Yes	Yes	Yes	Yes
Helen Inwood	NPower	Workgroup Member	Yes	Yes	Yes	Yes	Jon Wisdom
Garth Graham	SSE	Workgroup Member	No	Yes	Yes	Yes	Yes
Michael Dodd	ESBI	Workgroup Member	No	Yes	Yes	Yes	No
Sheona MacKenzie	Ofgem	Authority Representative	No	No	No	Yes	Yes

Annex 4 – Glossary of Terms

BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
BSUoS	Balancing Services Use of System
ENTSO-E	European Network of Transmission System Operators for Electricity
NETS	National Electricity Transmission System
NGET	National Grid Electricity Transmission plc
NIV	Net Imbalance Volume
RCRC	Residual Cashflow Reallocation Cashflow
RIIO	Revenue, Incentives, Innovation and Outputs
SO	System Operator
TLM	Transmission Loss Multiplier
WACM	Workgroup Alternative CUSC Modification

Annex 5 – CMP201 Timeline

16 December 2011	Panel to agree progression
10 January 2012	Workgroup meeting
2 February 2012	Second Workgroup meeting
9 February 2012	Issue draft Workgroup Consultation for Workgroup comment (5 days)
16 February 2012	Deadline for comments on draft Workgroup Consultation
29 February 2012	Publish Workgroup consultation (for 4 weeks)
28 March 2012	Deadline for responses to Workgroup consultation
W/C 16 April 2012	Post-consultation Workgroup meeting
10 May 2012	Second post-consultation Workgroup meeting
27 July 2012	Present Workgroup report to CUSC Modifications Panel
1 August 2012	Issue Code Administrator Consultation
30 August 2012	Deadline for responses
5 September 2012	Publish draft final report for industry review
20 September 2012	Publish draft final modification report with Panel Papers
28 September 2012	Panel Vote
10 October 2012	Send final report to Ofgem
14 November 2012	Indicative Authority decision date (based on 25 day KPI)

Annex 6 – Workgroup Votes

Name:	Cem Suleyman

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)
Yes	Neutral	Yes
The Modification will eliminate all trade barriers related to the method of levying BSUoS. This will promote the efficient cross border trade of power. As a consequence the Modification will facilitate efficient competition in generation and supply for the benefit of consumers.	This ACO is not relevant to this Modification. Therefore the Modification will neither have a positive or negative effect against this ACO.	The Modification properly reflects National Grid's duty to develop its business by promoting a single internal electricity market. This will help facilitate efficient cross border trade and competition.

b) WACM1 (3 yr implementation)

(a)	(b)	(c)
Yes	Neutral	Yes
The Modification will eliminate all trade barriers related to the method of levying BSUoS. This will promote the efficient cross border trade of power. As a consequence the Modification will facilitate efficient competition in generation and supply for the benefit of consumers.	This ACO is not relevant to this Modification. Therefore the Modification will neither have a positive or negative effect against the ACO.	The Modification properly reflects National Grid's duty to develop its business by promoting a single internal electricity market. This will help facilitate efficient cross border trade and competition.

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
Yes	Neutral	Yes
The Modification will eliminate all trade barriers related to the method of levying BSUoS. This will promote the efficient cross border trade of power. As a consequence the Modification will facilitate efficient	This ACO is not relevant to this Modification. Therefore the Modification will neither have a	The Modification properly reflects National Grid's duty to develop its business by promoting a single internal electricity market. This will help facilitate efficient cross

competition in generation and supply for the benefit of consumers.	positive or negative effect against the ACO.	border trade and competition.

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	**(b)**	**(c)**
Yes	Neutral	Neutral
WACM1 better meets the ACO relative to the Original. This is because WACM1 provides the optimal lead time for market participants operating in generation and supply to react to the change to minimise any wind fall losses/gains. This lead time will ensure that competition is not distorted and that the benefits of CMP201 are realised in good time. This will ensure that consumers benefit fully from the Modification.	Neither the Original nor WACM1 is relevant to the achievement of this ACO.	Both the Original and WACM1 will equally reflect National Grid's duty to develop its business by promoting a single internal electricity market.

b) WACM2 (5 year)

(a)	**(b)**	**(c)**
No	Neutral	Neutral
WACM2 does not better meet the ACO relative to the Original. This is because the implementation time scale (at least 5 years lead time between an Authority decision and implementation) unnecessarily delays the achievement of the benefits of the Modification, whilst providing no additional benefit in terms of allowing market participant's sufficient time to react to the change to minimise perverse consequences.	Neither the Original nor WACM2 is relevant to the achievement of this ACO.	Both the Original and WACM2 will equally reflect National Grid's duty to develop its business by promoting a single internal electricity market.

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	**Reason**
WACM1	The Original, WACM1 and WACM2 all better facilitate the achievement of the ACOs relative to the CUSC baseline (as they are essentially the same modification with only the implementation timescales differing). However, WACM1 best facilities the achievement of the ACOs compared with the other three options (including the CUSC baseline). This is because

	WACM1 provides the optimal notice period for market participants to react to the change to minimise any perverse outcomes which might distort competition. It also allows the benefits of the Modification to be achieved fully as soon as possible. Ultimately WACM1 maximises the benefits for consumers relative to the other options.

Name:	**Iain Pielage**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	**(b)**	**(c)**
Yes	Neutral	Yes
The proposal better aligns the GB market with that prevalent in other EU Member Countries. It removes both the potential import and export barrier that currently arise on cross-border trades and any disparity that may arise as consequence of CMP202, if approved.	Not applicable to this objective.	The proposal acknowledges the influence that Europe and the 3rd Package is having on GB market and is a proportionate response to those developments.

b) WACM1 (3 yr implementation)

(a)	**(b)**	**(c)**
Yes	Neutral	Yes
This alternative proposal achieves same objective as Original albeit delayed by a further year.	Not Applicable to this objective	This alternative proposal achieves same objective as Original albeit delayed by a further year.

b) WACM2 (5 yr implementation)

(a)	**(b)**	**(c)**
No	Neutral	No
Whist the alternative will eventually achieve the same result as the original proposal, it effectively signals to the market that efficient competition should not occur for 5+ years.	Not Applicable to this objective	Similarly, whilst eventually achieving the same result as the original proposal, this alternative signals that the licensee should not take this development into account for 5+ years.

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	(b)	(c)
Neutral	Neutral	Neutral
Whilst meeting same end objective as Original, there has been little substantive evidence provided that would support the additional delay.	Not Applicable to this objective	As per (a)

b) WACM2 (5 year)

(a)	(b)	(c)
No	Neutral	No
Long implementation timescales effectively means that effective competition in this area would be placed "on hold" for 5+ years Other proposals could subsequently be raised that un-wind or supersede this alternative: any competitive benefit would therefore be lost.	Not Applicable to this objective	The protracted timescales could hinder future developments as all new proposals would need to be assessed against both pre and post implementation positions

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
Original	On evidence available, the Original provides best balance between better facilitating competition in generation and addressing the contractual needs of Suppliers.

Name:	**James Anderson**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)

Yes	*Neutral*	*Yes*
CMP201 better achieves Objective (a) as it better facilitates effective competition in the generation of electricity both within GB and across Europe through the removal of a barrier to trade.	*Implementation of CMP201 will be neutral in facilitating achievement of Objective (b). As in the existing baseline, the cost allocation methodology will continue to accurately reflect charges into the appropriate time periods but will neither improve nor weaken cost reflectivity.*	*CMP201 will better reflect developments in the transmission licensees' businesses as it will take account of the increased interconnectivity between GB and continental Europe and promote development of cross-border trading in accordance with a single European market for electricity.*

b) WACM1 (3 yr implementation)

(a)	(b)	(c)
Yes	*Neutral*	*Yes*
CMP201 better achieves Objective (a) as it better facilitates effective competition in the generation of electricity both within GB and across Europe through the removal of a barrier to trade.	*Implementation of CMP201 will be neutral in facilitating achievement of Objective (b). As in the existing baseline, the cost allocation methodology will continue to accurately reflect charges into the appropriate time periods but will neither improve nor weaken cost reflectivity.*	*CMP201 will better reflect developments in the transmission licensees' businesses as it will take account of the increased interconnectivity between GB and continental Europe and promote development of cross-border trading in accordance with a single European market for electricity.*

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
Yes	*Neutral*	*Yes*
CMP201 better achieves Objective (a) as it better facilitates effective competition in the generation of electricity both within GB and across Europe through the removal of a barrier to trade.	*Implementation of CMP201 will be neutral in facilitating achievement of Objective (b). As in the existing baseline, the cost allocation methodology will continue to accurately reflect charges into the appropriate time periods but will neither improve nor*	*CMP201 will better reflect developments in the transmission licensees' businesses as it will take account of the increased interconnectivity between GB and continental Europe and promote development of cross-border trading in accordance a single European*

	weaken cost reflectivity.	*market for electricity.*

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	(b)	(c)
No	*Neutral*	*No*
As CMP201 improves competition within GB and across Europe its implementation should not be unduly delayed. A 24 month implementation period should be adequate to allow Parties' existing contract positions to unwind and to allow for modification to parties' systems.	*A delay in implementation from 24 to 36 months will neither improve nor reduce cost reflectivity.*	*As CMP201 will promote development of cross border trading to the benefit of GB consumers, delaying its implementation from 24 to 36 months will not better meet Applicable Objective (c).*

b) WACM2 (5 year)

(a)	(b)	(c)
No	*Neutral*	*No*
As CMP201 improves competition within GB and across Europe its implementation should not be unduly delayed. A 24 month implementation period should be adequate to allow Parties' existing contract positions to unwind and to allow for modification to parties' systems.	*A delay in implementation from 24 to 60 months will neither improve nor reduce cost reflectivity.*	*As CMP201 will promote development of cross border trading to the benefit of GB consumers, delaying its implementation from 24 to 60 months will not better meet Applicable Objective (c).*

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
CMP201 Original	*CMP201 better meets CUSC Applicable Objectives (a) and (C) for the reasons outlined above. Therefore, in order for its benefits to be delivered as soon as possible (commensurate with taking account of both Parties' contracted positions and the requirement to change their systems) implementation should not be unduly delayed.* *The two year implementation proposed in the Original proposal achieves this objective.* *Further, should CMP202, Removal of BSUoS charges from Interconnector Users, be approved with a short implementation timescale, generators within GB will be at a significant competitive disadvantage to interconnector users until CMP201 is implemented. This would further establish the requirement for an early implementation date.*

Name:	Michael Dodd

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)
Yes	Neutral	Yes
BSUoS on generators is an impediment to cross-border trading and places GB generation at a significant competitive disadvantage. The impact on supply competition is neutral as we believe the lead time to implementation (at least 2 years) is sufficient for suppliers of all sizes to hedge.	The proposal simply reallocates an arbitrarily allocated cost from generation to supply.	The modification facilitates the move to a single European market for electricity by promoting cross-border trade. Transmission charges have a key role within this and this modification is consistent with this ACO.

b) WACM1 (3 yr implementation)

(a)	(b)	(c)
Yes	Neutral	Yes
BSUoS on generators is an impediment to cross-border trading and places GB generation at a significant competitive disadvantage. The impact on supply competition is neutral as we believe the lead time to implementation (at least 2 years) is sufficient for suppliers of all sizes to hedge.	The proposal simply reallocates an arbitrarily allocated cost from generation to supply.	The modification facilitates the move to a single European market for electricity by promoting cross-border trade. Transmission charges have a key role within this and this modification is consistent with this ACO.

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
Yes	Neutral	Yes
BSUoS on generators is an impediment to cross-border trading and places GB generation at a significant competitive disadvantage. The impact on supply	The proposal simply reallocates an arbitrarily allocated cost from generation to	The modification facilitates the move to a single European market for electricity by promoting cross-border trade.

competition is neutral as we believe the lead time to implementation (at least 2 years) is sufficient for suppliers of all sizes to hedge.	supply.	Transmission charges have a key role within this and this modification is consistent with this ACO.

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	(b)	(c)
No	Neutral	No
The additional lead time means that the improvements to generation competition are not as immediate as those realised by the Original.		Whilst this alternative would remove generation BSUoS, the additional lead time is means it does not facilitate the ACO as well as the Original.

b) WACM2 (5 year)

(a)	(b)	(c)
No	*Neutral*	*No*
The additional lead time means that the improvements to competition are not as immediate as those realised by the Original		Whilst this alternative would remove generation BSUoS, the additional lead time is means it does not facilitate the ACO as well as the Original.

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
CMP201 Original	*This is the option that facilitates the removal of a significant barrier to cross-border trade quickest. It provides at least 2 years for suppliers to price the change into customers' contracts and we believe this is sufficient. A longer lead time would negate the benefits and delay the improvement in cross-border trading that will arise from the modification.*

Name:	**Sarah Owen**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)
No	*Neutral*	*No*
Increased risk on Suppliers in managing rising BSUoS costs. Impacts non-integrated suppliers more than fully integrated suppliers, therefore has a detrimental impact on supplier competition. *Detrimental impact on GB end consumers.* *Creates disconnect between liable parties of BSUoS and RCRC.*		*There are no developments within Europe that facilitate the raising of this modification*

b) WACM1 (3 yr implementation)

(a)	(b)	(c)
No	*Neutral*	*No*
Increased risk on Suppliers in managing rising BSUoS costs. Impacts non-integrated suppliers more than fully integrated suppliers, therefore has a detrimental impact on supplier competition. *Detrimental impact on GB end consumers.* *Creates disconnect between liable parties of BSUoS and RCRC.*		*There are no developments within Europe that facilitate the raising of this modification*

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
No	*Neutral*	*No*
Increased risk on Suppliers in managing rising BSUoS costs. Impacts non-integrated suppliers more than fully integrated suppliers, therefore has a detrimental impact on supplier competition. *Detrimental impact on GB end consumers.* *Creates disconnect between liable parties of BSUoS and RCRC.*		*There are no developments within Europe that facilitate the raising of this modification*

Vote 2: Whether each WACM better facilitates the ACOs than the <u>ORIGINAL</u>

a) WACM1 (3 year)

(a)	(b)	(c)

Neutral	*Neutral*	*Neutral*

b) WACM2 (5 year)

(a)	(b)	(c)
Neutral	*Neutral*	*Neutral*

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
CUSC Baseline	*No impact on supplier competition, no impact to GB end consumers. No increased risk to suppliers*

Name:	**Helen Inwood**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)
No	*Neutral*	*No*
The transition period will result in suppliers paying more than they should due to the nature of commodity contracts. *Need clarification on treatment of RCRC*		*CMP202 meets the European directive*

b) WACM1 (3 yr implementation)

(a)	(b)	(c)
No	*Neutral*	*Neutral*
The transition period will result in suppliers paying more than they should due to the nature of commodity contracts. *Need clarification on treatment of RCRC*		*CMP202 meets the European directive*

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
Yes	*Neutral*	*No*
Transition period timescales are adequate to address original issue highlighted above *Need clarification on RCRC*		*CMP202 meets the European directive*

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	(b)	(c)
Neutral	*Neutral*	*Neutral*

b) WACM2 (5 year)

(a)	(b)	(c)
Neutral	*Neutral*	*Neutral*

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
WACM2	*We support this option because transition period timescales are adequate to address the issue of payment twice by suppliers.*

Name:	Esther Sutton

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)
Neutral	*Neutral*	*Yes*
CMP201 seems likely to have a detrimental impact on Objective (a) through impacting Suppliers who	*However, the analysis has also suggested that is it unlikely that*	*No impact.*

have already contracted beyond 3 years, and it should not be assumed that these numbers are insignificant. It should also be born in mind that contracts of any duration can be signed many months before they begin, e.g. a 2-year contract may be agreed with a customer 2 years and 9 months before the contract start date. It is not only contract durations but the negotiation lead-time that should be considered in assessing the BSUoS risk to Suppliers. The analysis also suggests that the overall cost to consumers appears higher than the benefits to generation.	*parties would have to increase their security cover as a result of CMP201. Rather, generators would be required to hold less and may also require a lower level of credit cover from Suppliers.*	

b) WACM1 (3 yr implementation)

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Yes*
There is a stronger case for WACM1 than the original proposal; like the original, from the 3 year implementation CMP202 WACM1 would make GB generation more competitive with European generation. It would also have less potential for negative impacts on Suppliers by delaying the	-	*As per the original proposal, adjusting the GB market arrangements to better align with those across the continent would progress GB arrangements to take due account of European development of a pan-European liberalised market.*

b) WACM2 (5 yr implementation)

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Yes*
Again CMP202 WACM2 would also make GB generation more competitive with European generation once implemented. It would also avoid negative impacts on Supplier competition that might arise through an earlier implementation.	-	*Whether CMP202 was implemented to the original, WACM1 or WACM2 timescales, this should still better align GB balancing charges with European arrangements. Delaying implementation might also enable relevant changes to be raised in the interim*

		should there be unexpected developments in the European market, rather than making a significant change to GB arrangements that could potentially be negated by subsequent changes in evolution of the European market.

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Yes*
A minimum 3-year notice as per the original would have an adverse effect on Suppliers who may have contracted beyond these timescales and may not be able to amend agreements on BSUoS. Transitional risk would be minimised by WACM1 and this would also allow more time for development of market arrangements in other European states.	-	*As per vote 1, whether CMP202 was implemented to the original, WACM1 or WACM2 timescales, this would still better align GB balancing charges with other European States. A year's delay as WACM1 would provide seems unlikely to be of detriment to overall harmonisation. The single market for energy may well still be developing (and amongst the many challenges to achieve this, those other states not currently charging 100% to supply would also have to change their arrangements). Delaying might be beneficial should European progress take an unexpected turn reducing the benefit of CMP201, in that there would be more time to address*

		that, potentially with new modifications, to better align with Europe before instigating a major change in GB.

b) WACM2 (5 year)

(a)	(b)	(c)
Yes	*Neutral*	*Neutral*
5-6 years lead time should effectively negate the transitional risk to Suppliers.	-	*As per WACM1, delaying this change further would not be a significant barrier to cross-border trade (while we note that the analysis suggested that under CMP201 flows from GB to France would increase by 30%, it also noted that interconnector flows can be against market price for 32% of the time). It may seem desirable to adjust the GB arrangements sooner (but not too soon), but the market might not be fully coupled even within WACM2 timescales. Without this the full benefits of CMP201 would not be realised anyway. However 5-6 years could potentially increase uncertainty and delay harmonisation.*

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
WACM1	*The move towards harmonisation across the European market supports CMP201 over the baseline.* *However a minimum of 2 years per CMP201 original is not enough to avoid negative impacts on Suppliers.* *3-4 years as per WACM1 is desirable to reduce the transitional risk to all*

	concerned and help facilitate market coupling. *5-6 years per WACM2 would be better than the baseline or CMP201 Original but perhaps an excessive lead time given the challenging timescales sought for European harmonisation.*

Name:	**Paul Mott**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Yes*
I believe that CMP201 would, if passed, better facilitate System Charging Method objective (a). This is because if passed, it would help to create a level playing field between Generators in the EU which in turn should facilitate further cross-border trading of electricity and benefit GB consumers from more competitive wholesale prices. However, the transition to implementation (the lead time from an Ofgem decision) in the original is only just sufficient, at a minimum of 2 full years and a maximum of 3.	*It is not clear how CMP201 (original) better or worse facilitates (b), "that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs". I consider it to be neutral against this objective. CMP201 if passed would neither improve nor weaken cost reflectivity.*	*I believe that CMP201 would, if passed, better facilitate System Charging Method objective (c). This is because if passed, the change would better reflect the duties associated with National Grid's business by promoting a single internal market in electricity. This in turn would promote efficient cross border trade (in line with the intent of the Third Package), all in the context of the growth over time in the extent of interconnection capacity between GB and Europe, and the improvements in cross-border trading that should arise, if they are sensibly implemented here, from CACM as per the European Target Model.*

b) WACM1 (3 yr implementation)

(a)	(b)	(c)
Yes	*Neutral*	*Yes*
I believe that CMP201 (WACM1) would, if passed, better facilitate System Charging Method objective (a). This is because if passed, it would help to create a level playing field between Generators in the EU which in turn should facilitate further cross-border trading of electricity and benefit GB consumers from more competitive wholesale prices. The transition to implementation (the lead time from an Ofgem decision) in WACM1 is very sufficient, unlike the Original, at a minimum of 3 full years and a maximum of 4. This more than exceeds trading horizons and should be fair and workable for all parties.	*It is not clear how CMP201 (WACM1) better or worse facilitates (b), "that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs". I consider it to be neutral against this objective. CMP201 (WACM1) if passed would neither improve nor weaken cost reflectivity.*	*I believe that CMP201 (WACM1) would, if passed, better facilitate System Charging Method objective (c). This is because if passed, the change would better reflect the duties associated with National Grid's business by promoting a single internal market in electricity. This in turn would promote efficient cross border trade (in line with the intent of the Third Package), all in the context of the growth over time in the extent of interconnection capacity between GB and Europe, and the improvements in cross-border trading that should arise, if they are sensibly implemented here, from CACM as per the European Target Model.*

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
Yes	*Neutral*	*Yes*
I believe that CMP201 (WACM2) would, if passed, better facilitate System Charging Method objective (a). This is because if passed, it would help to create a level playing field between Generators in the EU which in turn should facilitate further cross-border trading of electricity and benefit GB consumers from more competitive wholesale prices. The transition to implementation	*It is not clear how CMP201 (WACM2) better or worse facilitates (b), "that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably*	*I believe that CMP201 (WACM2) would, if passed, better facilitate System Charging Method objective (c). This is because if passed, the change would better reflect the duties associated with National Grid's business by promoting a single internal market in electricity. This in turn would*

(the lead time from an Ofgem decision) in WACM2 is unnecessarily long, at a minimum of 5 full years and a maximum of 6. This exceeds trading horizons by quite some margin, and it seems sub-optimal to have a change that is forthcoming, yet not yet in force, over quite such a long horizon without good reason. It would increase the net complexity of the commercial landscape which participants must commercially be fully aware of, prior to the eventual full implementation of CMP201 (WACM 2) , for several years.	*practicable, the costs". I consider it to be neutral against this objective. CMP201 (WACM2) if passed would neither improve nor weaken cost reflectivity.*	*promote efficient cross border trade (in line with the intent of the Third Package), all in the context of the growth over time in the extent of interconnection capacity between GB and Europe, and the improvements in cross-border trading that should arise, if they are sensibly implemented here, from CACM as per the European Target Model.*

Vote 2: Whether each WACM better facilitates the ACOs than the <u>ORIGINAL</u>

a) WACM1 (3 year)

(a)	**(b)**	**(c)**
Yes (slightly)	*Neutral*	*Yes (slightly)*
The transition to implementation (the lead time from an Ofgem decision) in WACM1 is very sufficient, unlike the Original, at a minimum of 3 full years and a maximum of 4. This more than exceeds trading horizons and should be fair and workable for all parties.		*The transition to implementation (the lead time from an Ofgem decision) in WACM1 is very sufficient, unlike the Original, at a minimum of 3 full years and a maximum of 4. This more than exceeds trading horizons and should be fair and workable for all parties.*

b) WACM2 (5 year)

(a)	**(b)**	**(c)**
No (slightly)	*Neutral*	*No (slightly)*
The transition to implementation (the lead time from an Ofgem decision) in WACM2 is unnecessarily long, at a minimum of 5 full years and a maximum of 6. This exceeds trading horizons by long way, and it seems sub-optimal to have a change that is forthcoming, yet not yet in force, over quite such a long horizon without good reason. It would increase		*The transition to implementation (the lead time from an Ofgem decision) in WACM2 is unnecessarily long, at a minimum of 5 full years and a maximum of 6. This exceeds trading horizons by a long way, and it*

the net complexity of the commercial landscape which participants must commercially be fully aware of, prior to the eventual full implementation of CMP201 (WACM 2), for several years.		*seems sub-optimal to have a change that is forthcoming, yet not yet in force, over quite such a long horizon without good reason. It would increase the net complexity of the commercial landscape which participants must commercially be fully aware of, prior to the eventual full implementation of CMP201 (WACM 2) , for several years.*

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	Reason
WACM1	*The transition to implementation (the lead time from an Ofgem decision) in WACM1 is very sufficient, unlike the Original, at a minimum of 3 full years and a maximum of 4. This more than exceeds trading horizons and should be fair and workable for all parties. WACM 2 is unduly long in the transition, and would increase the net complexity of the commercial landscape which participants must commercially be fully aware of, prior to the eventual full implementation of CMP201 (WACM 2), for several years. The transition to implementation (the lead time from an Ofgem decision) in the original is acceptable, as it does exceed trading horizons - but might be said by some parties to be only just sufficient, at a minimum of 2 full years and a maximum of 3. We believe WACM1 to represent a fair solution to the timescale / transition issue.*

Name:	**Rob Hill**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	(b)	(c)
No	*Neutral*	*Yes*

The original modification proposal improves cross border competition in generation but would distort competition for GB supply as existing customer and wholesale contracts unwind.	*The proposal has no impact on cost reflectivity of the system charging methodology.*	*The proposal would improve cross border trading and market coupling. If the EU Third package is considered "developments in the transmission licensees' transmission businesses' then the modification proposal properly takes account of this development.*

b) WACM1 (3 yr implementation)

(a)	**(b)**	**(c)**
No	*Neutral*	*Yes*
Whilst still distorting competition in supply, the longer implementation timescales in the WACM1 reduces this when compared to the original proposal as it is likely that most commercial arrangements will be able to take account of the proposed changes.	*The proposal has no impact on cost reflectivity of the system charging methodology.*	*The proposal would improve cross border trading and market coupling. If the EU Third package is considered "developments in the transmission licensees' transmission businesses' then the modification proposal properly takes account of this development.*

b) WACM2 (5 yr implementation)

(a)	**(b)**	**(c)**
WACM2 has the greatest likelihood of minimal competitive distortion as it is likely that all commercial arrangements will be able to take account of the proposed changes given the long implementation timescales	*The proposal has no impact on cost reflectivity of the system charging methodology*	*The proposal would improve cross border trading and market coupling. If the EU Third package is considered "developments in the transmission licensees' transmission businesses' then the modification proposal properly takes account of this development.*
WACM2 has the greatest likelihood of minimal competitive distortion as it is likely that all commercial arrangements will be able to take account of the proposed changes given the long implementation	*The proposal has no impact on cost reflectivity of the system charging methodology*	*The proposal would improve cross border trading and market coupling. If the EU Third package is considered "developments in the transmission licensees'*

timescales		*transmission businesses' then the modification proposal properly takes account of this development.*

Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

a) WACM1 (3 year)

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Neutral*
Less distortion in supply competition.		

b) WACM2 (5 year)

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Neutral*
Less distortion in supply competition.		

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	**Reason**
WACM2	*The longer implementation timescales allow all parties to ensure that commercial agreements are in place to accommodate these changes*

Name:	**Garth Graham**

Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

a) Original Proposal

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Yes*
I believe that CMP201 (Original) would, if passed, better facilitate System Charging Method objective (a). This is because if passed, it would help to create a level playing	*It is not clear how CMP201 (Original) better or worse facilitates (b), "that compliance with the*	*I believe that CMP201 (Original) would, if passed, better facilitate System Charging Method objective (c). This is*

field between Generators in the EU which in turn should facilitate further cross-border trading of electricity and benefit GB consumers from more competitive wholesale prices. This would facilitate competition in the sale, distribution and purchase of electricity and thus better facilitate the Applicable Objectives. However, the transition to implementation (the lead time from an Ofgem decision) in the CMP201 (Original) is only just sufficient, at a minimum of 2 full years and a maximum of 3.	*use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs". I consider it to be neutral against this objective. CMP201 (Original) would, if passed, neither improve nor weaken cost reflectivity.*	*because if passed, the change would better reflect the duties associated with National Grid's business by promoting a single internal market in electricity. This in turn would promote efficient cross border trade (in line with the intent of the Third Package), all in the context of the growth over time in the extent of interconnection capacity between GB and other EU Member States, and the improvements in cross-border trading that should, in principle, arise from the appropriate implemented of the European Target Model via, for example, the CACM Network Code.*

b) WACM1 (3 yr implementation)

(a)	**(b)**	**(c)**
Yes	*Neutral*	*Yes*
I believe that CMP201 (WACM1) would, if passed, better facilitate System Charging Method objective (a). This is because if passed, it would help to create a level playing field between Generators in the EU which in turn should facilitate further cross-border trading of electricity and benefit GB consumers from more competitive wholesale prices. This would facilitate competition in the sale, distribution and purchase of electricity and thus better facilitate the Applicable Objectives. The transition to implementation (the lead time from an Ofgem decision) in WACM1 is certainty sufficient (whereas the Original is just sufficient) at a minimum of 3 full years and a maximum	*It is not clear how CMP201 (WACM1) better or worse facilitates (b), "that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs". I consider it to be neutral against this objective. CMP201 (WACM1) if passed would neither*	*I believe that CMP201 (WACM1) would, if passed, better facilitate System Charging Method objective (c). This is because if passed, the change would better reflect the duties associated with National Grid's business by promoting a single internal market in electricity. This in turn would promote efficient cross border trade (in line with the intent of the Third Package), all in the context of the growth*

of 4 for a transition / implementation period. This more than exceeds trading horizons and should be fair and workable for all parties. *A longer transition period than that in WACM1 would unduly (and unfairly) delay the application of this change to the CUSC which would distort competition in the sale, distribution and purchase of electricity and thus not better facilitate the Applicable Objectives.*	*improve nor weaken cost reflectivity.*	*over time in the extent of interconnection capacity between GB and other EU Member States, and the improvements in cross-border trading that should, in principle, arise from the appropriate implemented of the European Target Model via, for example, the CACM Network Code.*

b) WACM2 (5 yr implementation)

(a)	(b)	(c)
No	*Neutral*	*No*
The transition to implementation (the lead time from an Ofgem decision) in WACM2 is to great as it more than more exceeds the trading horizons. This longer transition period would unduly (and unfairly) delay the application of this change to the CUSC which would distort competition in the sale, distribution and purchase of electricity and thus not better facilitate the Applicable Objectives.		*The transition to implementation (the lead time from an Ofgem decision) in WACM2 is inappropriate. This longer transition period would unduly (and unfairly) delay the application of this change to the CUSC which; if done in a timely manner, as per the Original and WACM1 (but not WACM2); would properly take account of the developments in transmission licensees' transmission businesses.*

Vote 2: Whether each WACM better facilitates the ACOs than the <u>ORIGINAL</u>

a) WACM1 (3 year)

(a)	(b)	(c)
Yes (slightly)	*Neutral*	*Yes (slightly)*
The transition to implementation (the lead time from an Ofgem decision) in WACM1 is sufficient, unlike the Original, at a minimum of 3 full years and a maximum of 4. This more than exceeds trading horizons and should be fair and workable for all parties.		*The transition to implementation (the lead time from an Ofgem decision) in WACM1 is sufficient, unlike the Original, at a minimum of 3 full years*

		and a maximum of 4. This more than exceeds trading horizons and should be fair and workable for all parties.

b) WACM2 (5 year)

(a)	**(b)**	**(c)**
No	*Neutral*	*No*
The transition to implementation (the lead time from an Ofgem decision) in WACM2 is to great as it more than more exceeds the trading horizons. This longer transition period would unduly (and unfairly) delay the application of this change to the CUSC which would distort competition in the sale, distribution and purchase of electricity and thus not better facilitate the Applicable Objectives.		*The transition to implementation (the lead time from an Ofgem decision) in WACM2 is inappropriate. This longer transition period would unduly (and unfairly) delay the application of this change to the CUSC which; if done in a timely manner, as per the Original and WACM1 (but not WACM2); would properly take account of the developments in transmission licensees' transmission businesses.*

Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

BEST option	**Reason**
WACM	*It is clear from the Workgroup deliberations that there is broad acceptance that the proposed change (that is removing BSUoS charges from Generators and applying them solely to Suppliers) has merit – in terms of better facilitating competition in the sale, distribution and purchase of electricity - the main issue of disagreement centres on the period of transition to implementation.* *The transition to implementation period (the lead time from an Ofgem decision) in WACM1 is certainty sufficient (whereas the Original is just sufficient) at a minimum of 3 full years and a maximum of 4 for a transition / implementation period. This more than exceeds trading horizons and should be fair and workable for all parties.* *It should ensure that the proposed change comes into effect as soon as reasonably practical such that the clear benefits of the change; in terms of better facilitating competition in the sale, distribution and purchase of electricity; are realised. Delaying implementation would negate the*

	benefits of the proposed change being realised over the period of the lengthened implementation period. This would be detrimental to competition in the sale, distribution and purchase of electricity.

Annex 7 CMP201- Removal of BSUoS from Generators: Supplier Issues Paper

[This information paper was provided to the Workgroup by two Members in order to outline the CMP201 competition issues for Suppliers. The Workgroup discussed the paper (but did not unanimously agree, or disagree, with its contents).]

Interaction of BSUoS and RCRC

A8.1. Ofgem has explained the theoretical importance of the current relationships between BSUoS and RCRC, as part of the recent Electricity Cash-Out Issues Papers[11].

'In theory a participant who is perfectly balanced should receive a rebate through RCRC equivalent to what it pays for energy balancing via BSUoS. Due to the separation of RCRC and BSUoS, as well as the fact that BSUoS is not broken down into energy and system balancing costs, it is not readily apparent whether or not this is occurring. We are concerned that if it is not, there may be a less than efficient allocation of costs.'

A8.2. We have completed some simplistic modelling of the effect of this BSUoS proposal on a *perfectly balanced party*. The results of this are summarised below.

£/MWh (-ve :credit to party)	Current			
Balanced Party	BSUoS[12]	RCRC	Imbalance	Total
Supplier	£0.12	-£0.12	£0.00	£0.00
Generator	£0.12	-£0.12	£0.00	£0.00
	Under CMP201			
Balanced Party	BSUoS	RCRC	Imbalance	Total
Supplier	£0.24	-£0.12	£0.00	£0.12
Generator	£0.00	-£0.12	£0.00	-£0.12

A8.3. This scenario is one in which parties are overall 'short' and Grid are buying energy. Clearly, different assumptions of NIV and System Prices will give different answers, but the theoretical misallocation of energy balancing costs will be the level of RCRC.

A8.4. It is clear that parties no longer, both in theory or in practice, will receive the correct level of energy balancing costs and so can no longer be receiving the efficient allocation of costs.

[11] Electricity Cash-out issues Ref: 143/11
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/Electricity%20cash-out%20issues%20paper.pdf

[12] This represents the theoretical sum of energy balancing costs which, by definition is the equal and opposite of RCRC

Effect on Supplier risk

A8.5. Regardless of whether the change is cost-neutral, it will increase the effective risk on Suppliers and so, in turn, consumers.

A8.6. It is generally accepted that due to its inherent volatility and the ex-post nature of pricing that BSUoS places a considerable risk on Suppliers. This risk is currently mitigated, to a degree, by the natural hedge that exists between BSUoS and RCRC (as described by Ofgem above).

A8.7. Thus, this change will increase the risk borne by Suppliers in 2 main ways:

- Doubling the level of the charge
- Breaking the relationship between BSUoS and RCRC

Doubling the level of the charge

A8.8. It is self-evident that doubling the level of an unpredictable charge will increase the risk unless actions are taken to address the root causes (the inherent volatility and the ex-post pricing).

A8.9. It may be claimed that this additional risk is already captured in the forward curve. However Generators clearly do not bear the same BSUoS risk as Suppliers. BSUoS costs' rising implies that National Grid is spending more money on Balancing Services. This money is spent almost exclusively with Generators. Hence the generation community, as a whole, is naturally and necessarily protected, to a degree, against BSUoS.

A8.10. Against this, it may be argued that whilst true of the generation community as a whole, it is not true of each individual Generator and so the link to forward curve is not clear. However, it is logical that marginal plant are the most likely to be affected by increases (and decreases) in unforeseen spending in Balancing Services, as they are more likely to be 'called' by Grid, and so are at less risk to BSUoS variations that the 'average' generator. Hence it is likely that minimal BSUoS risk is priced into the curve (as the marginal Generator is particularly well hedged against BSUoS risk), and certainly less than a Supplier will be exposed directly to.

Breaking the relationship between BSUoS and RCRC

A8.11. The table below illustrates the volatility of BSUoS since the start of 2008- both 'gross' and 'net' of RCRC. (Effectively, 'gross' is all balancing costs and 'net' theoretically is system balancing costs). As can be seen, the range for 'net' BSUoS is lower both for daily average prices and rolling yearly averages.

	Daily BSUoS Price (Gross)	Daily BSUoS Price (Net)	Rolling Year BSUoS Price (Gross)	Rolling Year BSUoS Price (Net)
Max	£5.09	£3.79	£1.55	£1.36
Min	-£0.75	-£0.28	£1.10	£0.99
Range	£5.84	£4.07	£0.45	£0.37

Next Steps

A8.12. As can be seen, this modification has consequences for the efficient allocation of energy balancing costs, and also creates additional risk.

A8.13. If this modification is to progress any further the issue of allocation of energy allocation will need to addressed, and the scope should be widened to include measures to manage volatility and predictability. This could include moving towards fixing BSUoS prices in advance for a period of 6 or 12 months, as is currently the case for Gas System Operator costs.

Annex 8 – Elexon paper on BMU defining 'generation' under CMP201

[This information paper was provided to the Workgroup by Elexon in order to outline the CMP201 issues with respect to the (BSC) definitions of BMUs etc. The Workgroup discussed the paper (but did not agree, or disagree, with its contents).]

What is a Trading Unit?

A9.1 A Trading Unit is a collection of one or more BM Units established in accordance with BSC Section K4.Forming a Trading Unit with other BM Units (which may have different Lead Parties) can enable a BM Unit to receive benefits in certain areas such as:

- Transmission Loss Multipliers (TLMs);
- Production/Consumption Status;
- Certain BSC costs;
- Residual Cashflow Reallocation Cashflow (RCRC); and
- Balancing Services Use of System (BSUoS) charges.

A9.2 A description of the different types of Trading Unit can be found in BSC Section K4 and BSC Procedure (BSCP) 31. In each Settlement Period, the BSC deems a Trading Unit to be either a 'delivering' Trading Unit or an 'offtaking' Trading Unit as follows:

- If the sum of all the BM Unit Metered Volumes (QMij) in the Trading Unit is greater than zero for that Settlement Period, the Trading Unit is a 'delivering' Trading Unit.
- If the sum of all the BM Unit Metered Volumes in the Trading Unit is less than or equal to zero for that Settlement Period, the Trading Unit is an 'offtaking' Trading Unit.

A9.3 *For example, a generation site consists of three BM Units: two generation units and a Station Demand unit. In a particular Settlement Period, they produce the following Metered Volumes:*

BM Unit	Metered Volume
T_GEN-1	100MWh
T_GEN-2	80MWh
T_DEM-1	-40MWh

A9.4 *In this case, the net Metered Volume across all the BM Units in this Trading Unit is 140MWh. As this is greater than zero, the Trading Unit is a delivering Trading Unit in this Settlement Period.*

What is the difference between Production/Consumption status and delivering/offtaking status?

A9.5 There commonly tends to be confusion about the difference between Production/Consumption (P/C) status and delivering/offtaking status. P/C Status is usually determined at the Trading Unit level, based on the Generation Capacity and Demand Capacity values submitted by its BM Units for the current BSC Season. These values are the BM Units' estimates of their maximum generation/demand for that BSC Season.

Delivering/offtaking status is also determined at the Trading Unit level, but is based on the actual Metered Volumes of its BM Units in a given Settlement Period. Certain BM Units can choose to fix their P/C Status independently of their Trading Unit (currently Exempt Export BM Units, plus Interconnector BM Units if P277 is approved). Others have their P/C Status fixed automatically by BSC Systems (currently Interconnector BM Units, plus Supplier BM Units will always have a fixed P/C Status of Consumption when P269 is implemented on 23 February 2012).

A9.6 The important thing to note is that delivering/offtaking status is completely independent of a BM Unit's P/C Status. It is therefore possible for a Production BM Unit to be part of an offtaking Trading Unit, or for a Consumption BM Unit to be part of a delivering Trading Unit. In addition, both of these are independent of the BM Unit's individual Metered Volume in a given Settlement Period.

A9.7 For example, P269 will fix the P/C Status of all Supplier BM Units as Consumption in every Settlement Period. However, it will still be possible for an individual Supplier BM Unit to export ($QM_{ij} > 0$) in a given Settlement Period even though its Base Trading Unit is offtaking in that Settlement Period. Similarly, it will still be possible for a Base Trading Unit to export in a given Settlement Period, even though all of its Supplier BM Units have a Consumption P/C Status and some of these BM Units may be importing ($QM_{ij} \leq 0$) in that Settlement Period.

What are the current arrangements with BSUoS?

A9.8 In any given Settlement Period, a BM Unit's BSUoS charge is based on their proportion of BM Unit Metered Volume (QM_{ij}) relative to the total BM Unit Metered Volume in that Settlement Period, and is calculated as follows:

- For a BM Unit in a delivering Trading Unit:

  $BSUoSTOT_{ij} = \{BSUoSTOT_j * QM_{ij} * TLM_{ij}\} / \{|\sum^{+}(QM_{ij} * TLM_{ij})| + |\sum^{-}(QM_{ij} * TLM_{ij})|\}$

- For a BM Unit in an offtaking Trading Unit:

  $BSUoSTOT_{ij} = \{-1 * BSUoSTOT_j * QM_{ij} * TLM_{ij}\} / \{|\sum^{+}(QM_{ij} * TLM_{ij})| + |\sum^{-}(QM_{ij} * TLM_{ij})|\}$

A9.9 For more information, please see CUSC Section 14.30.

A9.10 Each BM Unit is charged BSUoS based on its Metered Volume for the relevant Settlement Period as a ratio of the total Metered Volume over all BM Units in that Settlement Period. However, it should be noted that BM Units are charged on a 'net Trading Unit basis', as explained in CUSC Section 14.30.3.

A9.11 In essence, this means if a BM Unit is operating in the opposite direction of the Trading Unit to which it belongs (i.e. importing when the Trading Unit is delivering, or exporting when the Trading Unit is offtaking) then it is paid BSUoS. This is because, in this situation, the relevant equation will give a negative result, which results in a payment to the BM Unit.

A9.12 This can be summarised as follows:

Current Arrangements		Trading Unit is… Delivering (net $TUQM_{ij} > 0$)	Trading Unit is… Offtaking (net $TUQM_{ij} \leq 0$)
BM Unit is…	Exporting ($QM_{ij} > 0$)	Charged BSUoS	Paid BSUoS
BM Unit is…	Importing ($QM_{ij} \leq 0$)	Paid BSUoS	Charged BSUoS

A9.13 *Let us consider the earlier example. In this scenario, the Trading Unit is a delivering Trading Unit. T_GEN-1 and T_GEN-2 are both exporting (positive Metered Volumes), and so they are charged BSUoS accordingly.*

A9.14 *However, T_DEM-1 is importing, and so it is paid BSUoS accordingly. In this case, the Lead Party of these three BM Units will have the payment they receive from T_DEM-1 netted off from their charges against the generation units, giving them a reduced BSUoS charge overall.*

How can we define a 'generator' under CMP201?

A9.15 CMP201 proposes to remove BSUoS charges from 'generation', in order to better align with arrangements in other EU Member States. In essence, anyone who is currently charged BSUoS for exporting onto the Transmission System will no longer pay BSUoS, while anyone who is charged BSUoS for importing off the Transmission System will continue to pay (albeit at a higher tariff).

A9.16 However, it is not the intention of CMP201 to change any benefits that may occur through being part of a Trading Unit, such as a BM Unit being paid BSUoS for flowing in the opposite direction to its Trading Unit. A definition of 'generation' is needed that would retain these benefits for any BM Units that will not be exempt from BSUoS under CMP201.

A9.17 Two possible definitions for a 'generator' were suggested in the first CMP201 Workgroup meeting:

1) A BM Unit that is exporting (BM Unit's $QM_{ij}>0$); or
2) A BM Unit that is in a delivering Trading Unit (net TU $QM_{ij}>0$ even if BM Unit's $QM_{ij}\leq0$).

A9.18 Both of these are Settlement Period-based determinations – i.e. they can change from half-hour to half-hour.

1) A BM Unit that is exporting

A9.19 Under this definition, a BM Unit would be charged BSUoS if it was importing in a Settlement Period, but would not be charged if it was exporting. However, there is a question as to whether the Trading Unit status should still be considered. This gives two sub-scenarios:

a) The Trading Unit status is not considered; or
b) The Trading Unit status is considered.

1a) The Trading Unit status is not considered

A9.20 Here, an importing BM Unit would be charged BSUoS based only on its own Metered Volume in the Settlement Period, and it would not matter whether its Trading Unit was delivering or offtaking in that Settlement Period. This would mean that BM Units would not be paid BSUoS if they were flowing in the opposite direction to their Trading Unit, as they currently would, as the Trading Unit would not be considered.

A9.21 This can be summarised as follows:

Scenario 1a **BMU that is exporting (TU is not considered)**		**Trading Unit is…**	
		Delivering (net TU $QM_{ij} > 0$)	**Offtaking** (net TU $QM_{ij} \leq 0$)
BM Unit s…	**Exporting** ($QM_{ij} > 0$)	No BSUoS	No BSUoS
	Importing ($QM_{ij} \leq 0$)	Charged BSUoS	Charged BSUoS

A9.22 *Let us consider the earlier example. In this scenario, the Trading Unit is a delivering Trading Unit. T_GEN-1 and T_GEN-2 are both exporting BM Units (positive Metered Volumes), and so they would not be charged BSUoS.*

A9.23 *However, T_DEM-1 is importing. In this case, it would be charged BSUoS. This is different to the current arrangements, where T_DEM-1 would be paid BSUoS.*

1b) The Trading Unit status is considered

A9.24 Here, an importing BM Unit would be subject to BSUoS in the same way as currently, and any importing BM Units in delivering Trading Units would benefit from a negative BSUoS charge (i.e. they would be paid BSUoS).

A9.25 This can be summarised as follows:

Scenario 1b **BMU that is exporting (TU is considered)**		**Trading Unit is…**	
		Delivering (net TU $QM_{ij} > 0$)	**Offtaking** (net TU $QM_{ij} \leq 0$)
BM Unit is…	**Exporting** ($QM_{ij} > 0$)	No BSUoS	No BSUoS
	Importing ($QM_{ij} \leq 0$)	Paid BSUoS	Charged BSUoS

A9.26 *Let us consider the earlier example. In this scenario, the Trading Unit is a delivering Trading Unit. T_GEN-1 and T_GEN-2 are both exporting BM Units (positive Metered Volumes), and so they would not be charged BSUoS.*

A9.27 *T_DEM-1 is importing, but as the Trading Unit is delivering, it would be paid BSUoS as it would under the current arrangements.*

A9.28 It should be noted that counting any BM Unit that is exporting as 'generation' would mean that Supplier BM Units, which are traditionally considered as demand, would fall under the generation bracket should they export in any given Settlement Period (for example, due to large amounts of SVA embedded generation). In either of the above scenarios, should a Supplier BM Unit export in any Settlement Period, it would be considered generation and would not be subject to BSUoS for that Settlement Period, regardless of what its Base Trading Unit was doing.

2) A BM Unit that is in a delivering Trading Unit

A9.29 Under this definition, a BM Unit would be charged BSUoS if it was part of a Trading Unit that was offtaking in the Settlement Period, but would not be charged if the Trading Unit was delivering. This definition would be similar to the current arrangements, except that delivering Trading Units would not pay BSUoS. This would imply that any BM Unit that is exporting while in an offtaking Trading Unit will still be paid BSUoS, rather than charged.

A9.30 This can be summarised as follows:

Scenario 2 **BMU that is in delivering TU**		**Trading Unit is…**	
		Delivering (net TU $QM_{ij} > 0$)	**Offtaking** (net TU $QM_{ij} \leq 0$)
BM Unit is…	**Exporting** ($QM_{ij} > 0$)	No BSUoS	Paid BSUoS
	Importing ($QM_{ij} \leq 0$)	No BSUoS	Charged BSUoS

A9.31 *Let us consider the earlier example. In this scenario, the Trading Unit is a delivering Trading Unit. T_GEN-1 and T_GEN-2 are both exporting BM Units (positive Metered Volumes), and T_DEM-1 is importing. However, as they are all part of a delivering Trading Unit, none of them are charged BSUoS.*

A9.32 Returning to the Supplier BM Unit that had large amounts of SVA embedded generation, then under this scenario it would be charged BSUoS as currently – as long as the Base Trading Unit it belonged to was offtaking in each Settlement Period. This means it would still be paid BSUoS, as currently, if it was itself exporting. In the event that the Base Trading Unit was a delivering Trading Unit in any Settlement Period, all of the BM Units in that Base Trading Unit (whether importing or exporting) would not be charged BSUoS in that Settlement Period.

How should we define a 'generator' under CMP201?

A9.33 The table below summarises what would happen in each scenario under the current arrangements and under each of the possible definitions described above:

Scenario (Def'n of 'generator')		**Exporting BM Unit in a…**		**Importing BM Unit in a…**	
		Delivering TU	**Offtaking TU**	**Delivering TU**	**Offtaking TU**
	Current Arrangements	Charged BSUoS	Paid BSUoS	Paid BSUoS	Charged BSUoS
1a	BMU that is exporting (TU is not considered)	No BSUoS	No BSUoS	Charged BSUoS	Charged BSUoS
1b	BMU that is exporting (TU is considered)	No BSUoS	No BSUoS	Paid BSUoS	Charged BSUoS
2	BMU that is in delivering TU	No BSUoS	Paid BSUoS	No BSUoS	Charged BSUoS

A9.34 Under all scenarios, exporting BM Units in delivering Trading Units, which are charged BSUoS currently would no longer pay BSUoS. Importing BM Units in offtaking Trading Units, which are also charged BSUoS currently, would continue to be charged BSUoS. However, the BM Units that are currently paid BSUoS would be treated differently in each scenario, which would affect the BSUoS calculations.

- **Scenario 1a**: It would be relatively simple to calculate and allocate BSUoS under this scenario as the algebra would simply split BSUoS based on each BM Unit's Metered Volume. As all the BM Units liable for BSUoS would have a negative Metered Volume in the relevant Settlement Period, the calculation should be fairly straightforward. However, this scenario does not retain the BSUoS benefits that are currently enjoyed by BM Units flowing in the opposite direction to their Trading Unit. As such, this does not meet the criterion that these benefits should be retained.
- **Scenario 1b**: This scenario does retain the BSUoS benefits that apply under the current arrangements. However, this method of allocating BSUoS would be more complicated as the Trading Unit status would need to be factored in. Additionally, if BSUoS is being charged based on whether an individual BM Unit is importing or exporting, then it is questionable as to whether considering its Trading Unit status is actually relevant and how practical this would be.
- **Scenario 2**: This scenario retains the BSUoS benefits, and would also be relatively simple as the calculations would be similar to those used currently. The main difference would be that the equation for delivering Trading Units would equal zero. As such, ELEXON suggests that this would be the best scenario to use for CMP201.

A9.35 Scenario 2 is normally used as the definition of 'generation' under the BSC. Also, many of the benefits which arise from being in a Trading Unit with other BM Units depend on whether the Trading Unit is delivering or offtaking in a given Settlement Period. For example, the allocation of TLMs to BM Units is based on their Trading Unit's delivering or offtaking status rather than whether the BM Unit is exporting or importing. Using this definition would therefore retain consistency in this regard. In addition, the algebra for the BSUoS calculations is likely to be easier under Scenario 2 than under Scenario 1b. These reasons would favour defining 'generation' at the Trading Unit level.

Belgium: Elia

I. What charges do generators pay to the TSO, other than connection charges? Network tariffs

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	Fixed payment for the provision of the service	100% Demand
Internal Congestion Management	✓	Payments/charges based on prices submitted by the generator	
Primary Reserve	✓	Fixed monthly payment	100% Generation
Secondary Reserve	✓	Fixed payment for the provision of the service Payment for activated volumes	
Tertiary Reserve	✓	Fixed payment for the provision of the service Payment for activated volumes	
Voltage Control/Reactive Power	✓	Fixed payment for the provision of the service Payment for activated volumes	100% Demand

France: RTE

I. What charges do generators pay to the TSO, other than connection charges? G-comp: €0.19/MWH. There is no specific cost allocation between producers and load – the split is considered to be 3:97

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	Compulsory Service – No compensation	
Internal Congestion Management	✓	Pay-as-bid payment of energy through balancing mechanism auction	100% Demand
Primary Reserve	✓	Fixed payment for the provision of the service	
Secondary Reserve	✓	Fixed payment for the provision of the service Payment for activated volumes	
Tertiary Reserve	✓	Pay-as-bid payment of energy through balancing mechanism auction	
Voltage Control/Reactive Power	✓	Fixed payment for the provision of the service Payment based on operating time of the unit	

Germany: Amprion

I. What charges do generators pay to the TSO, other than connection charges? None

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	Compensation is provided	
Internal Congestion Management	✓	Contractual arrangements: Payment for fuel cost increases Receipt for fuel cost savings	100% Demand
Primary Reserve	✓		
Secondary Reserve	✓	Tendering process	Contracted power recovered from demand Balancing energy recovered from balancing responsible parties
Tertiary Reserve	✓		
Voltage Control/Reactive Power	✓	Contractual agreements: Payment for the reactive energy in proportion to PX prices	100% Demand

Netherlands: TenneT

I. What charges do generators pay to the TSO, other than connection charges? None

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	The compensation is based on prices agreed in contracts with the relevant generators after a call for tender	100% Demand
Internal Congestion Management	✓	Payments based on prices submitted by the generator	Currently 100% Demand, but there is a proposal to let Generators in the congestion area pay 100% of the costs for internal congestion management. Renewable generators might be exempted from the obligation.
Primary Reserve	✓	All generators above 5 MW are currently obliged to provide the service and are not compensated for it. There are discussions on abolishing the obligation and contracting primary reserve from generators after a call for tender	100% Demand

Secondary Reserve	✓	Compensation for balancing energy is based on a settlement price for balancing Compensation for the capacity is based on a call for tender	The costs for balancing energy are recovered from balancing responsible parties according to their balancing position The cost for the capacity is paid 100% by Demand
Tertiary Reserve	✓	Compensation for the balancing energy is based on the settlement price for balancing Compensation for the capacity is based on a call for tender	The costs are recovered from balancing responsible parties according to their balancing position The cost for the capacity is paid 100% by Demand
Voltage Control/Reactive Power	✓	The compensation is based on prices agreed in contracts with the relevant generators after a call for tender. The compensation often consists of a fixed and variable component.	100% Demand
Additional Comments: There is an incentive scheme in place, based on which the costs recovered through tariffs charged to load customers are not fully pass-through. The incentive is based on a budget and a sliding scale with cap and floor. For outperformance or underperformance of not more than 20% of the budget, TenneT keeps or pays 25% of this outperformance or underperformance. Anything above or below 20% of the budget is settled through the tariffs.			

Spain: Red Electrica de Espana

I. What charges do generators pay to the TSO, other than connection charges? All generators pay an access tariff (0,5 €/MWh)

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	No Compensation - compulsory	
Internal Congestion Management	✓	Through market mechanisms – pay as bid	100% Demand
Primary Reserve	✓	No Compensation - compulsory	
Secondary Reserve	✓	Through market mechanisms Payment for provision of service according to marginal price Payment for activated volumes according to marginal price	Capability: 100% Demand Activated Volumes: Gen & Dem according to deviations in programmes
Tertiary Reserve	✓	Through market mechanisms according to marginal price	Gen & Dem according to deviations in programmes

Voltage Control/Reactive Power	✓	“Special Regime”* generators: 4% of 8.29 c€/kWh if they maintain cosφ within a specific range. **Those which receive feed-in tariff or market premium, cogeneration and RES*	
Additional Comments: All these services are provided into the market and the associated costs are included in the final energy market price. They are not purchased by the TSO so it has not to recover any cost. TSO’s role is managing and settling this market, but not purchasing.			

Great Britain: National Grid

I. What charges, if any, do generators pay to the TSO, other than connection charges? None

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	Monthly payment for provision of the service	50% Demand 50% Generation
Internal Congestion Management	✓	Payment/Charge based on prices submitted by the generator	
Primary Reserve	✓	Payment for provision of the service Payment for activated volumes	
Secondary Reserve	✓	Procured through contracts	
Tertiary Reserve	✓	Payment for provision of the service	
Voltage Control/Reactive Power	✓	Procured through contracts	

Ireland: Eirgrid

I. What charges, if any, do generators pay to the TSO, other than connection charges?

Short Notice Declarations (SNDs)

A charge for an SND may be incurred by a User if it does not give the required notice to the System Operator of certain types of reductions in MW availability (MDMW). The charge reflects the period of notice given, the size of reduction and the Reason Code.

Trips

A User incurs a Trip Charge when the output from a unit rapidly and unexpectedly reduces. The size of the charge will reflect the speed and the size of the reduction in output. Incidents are categorised as below:

- Direct Trip: A reduction rate of 15MW/s
- Fast Wind Down A reduction rate of 3MW/s
- Slow Wind Down: A reduction rate of 1MW/s

Generator Performance Incentives (GPIs)

The Grid Codes specify minimum standards of capability and performance that Users must meet. Generators will incur a charge if the minimum Grid Code requirements are not met for the following:

- Operating Reserve
- Reactive Power
- Minimum Generation
- Minimum On Time
- Maximum Starts
- Governor Droop
- Loading / Deloading
- Late/Early Synchronisation

II. Compensation for generators:

Service	Do generators provide this service to the TSO?	If they are compensated, how?	Who does the TSO recover the costs from?
Black Start	✓	Monthly payment for provision of the service	100% Demand
Internal Congestion Management	✓	Constraint payments keep generators financially neutral for the difference between the market schedule and the actual dispatch.	Single Electricity Market Operator Imperfections Charge: funded by Energy Imbalances and Make Whole Payments
Primary Reserve	✓	Monthly payment for each MW of capability	100% Demand
Secondary Reserve	✓		
Tertiary Reserve	✓		
Voltage Control/Reactive Power	✓	Capability payment	

Annex 10 Paper on Credit risk issue

Introduction

A11.1. CMP201 proposes to remove BSUoS liability from Generators, reallocating the charge 100% on Suppliers. It was noted by the Workgroup that Supplier's may be required to hold additional credit cover as a consequence of this reallocation. This note provides an assessment of the potential impact on Suppliers.

Current Credit Arrangements:

A11.2. CUSC Parties are required to maintain security cover for both TNUoS and BSUoS in accordance with the requirements set out in the CUSC (Section 3).

A11.3. National Grid extends unsecured credit to CUSC Parties in accordance with the "Best Practice Guideline for Gas and Electricity Network Operator Credit Cover", depending on a party's Approved Credit Rating. Where this is insufficient or does not have an Approved Credit Rating, the CUSC Party is required to provide additional security cover, typically in the form of:

- Parent Company Guarantee
- Letter of Credit
- Monies lodged in Escrow account
- Other Insurance, Bond or Security arrangements agreed with National Grid

A11.4. In addition, National Grid also extends credit based on their payment history. This is calculated at 0.4% per 12 month period of the Maximum Credit Allowance (the Maximum Credit Allowance is 2% of RAV). This is incremented equally each month up to a maximum of 2% after 60 months. This credit is conditional on timely settlement of National Grid's charges. Where a party misses the due date, the credit extended by National Grid is reduced by 50%.

A11.5. With the current RAV of £7.9bn, this equates to credit cover being extended at approximately £53k per month up to a maximum of approximately £3m for each party. A new entrant would need to provide approved credit cover, such as a letter of credit, until such times as their payment history is sufficient to cover their forecast liabilities.

A11.6. For Suppliers, the BSUoS element of the security cover required is determined from a forecast of a party's likely BSUoS liabilities over a 32-day period.

A11.7. Whilst not codified, National Grid's practice is to review the level of security cover extended for BSUoS to on a regular (quarterly) basis. In doing so, it looks at the last 3 months' liabilities and the equivalent period in the previous year. A party is then informed if any change in the level of credit cover is required; a party thereafter has typically a month to establish that new level of cover. Given the likely timescales of CMP201, if implement, a Supplier should have sufficient time in advance of any notice to discuss with National Grid and establish new credit arrangements, if needed.

A11.8. It should also be noted that some Suppliers, by associating themselves in a trading unit with embedded generation, avoid the need for credit cover as the generation embedded benefit offsets the demand liabilities associated with the supply business.

A11.9. To assess the impact of the CMP201 proposal, the total credit cover, from payment history and other credit arrangements, for each Supplier was examined and any TNUoS credit requirement deducted thus leaving an indicative amount of credit available to cover BSUoS liabilities. This was compared with their current BSUoS liability requirement and the level of BSUoS credit cover (as a ratio of the two) derived: A BSUoS cover ratio less than two would indicate that that CUSC Party would need to increase their cover prior to the introduction of CMP201, if approved.

Findings:

A11.10. From the data available, only four CUSC Parties that are required to hold security cover had a BSUoS cover ratio less that two. Of those four, one may acquire sufficient additional cover through the payment history mechanism in a few months. All the parties identified are related to companies of significant size, two of which provide Parent Company Guarantees.

A11.11. Figure A10.1 below shows the distribution of Suppliers required to hold security cover and the level of cover extended through the payment history mechanism. As noted above, there are also a number of Suppliers who, through their relationship with embedded generation, do not require credit cover for BSUoS. These Suppliers are not included within this analysis.

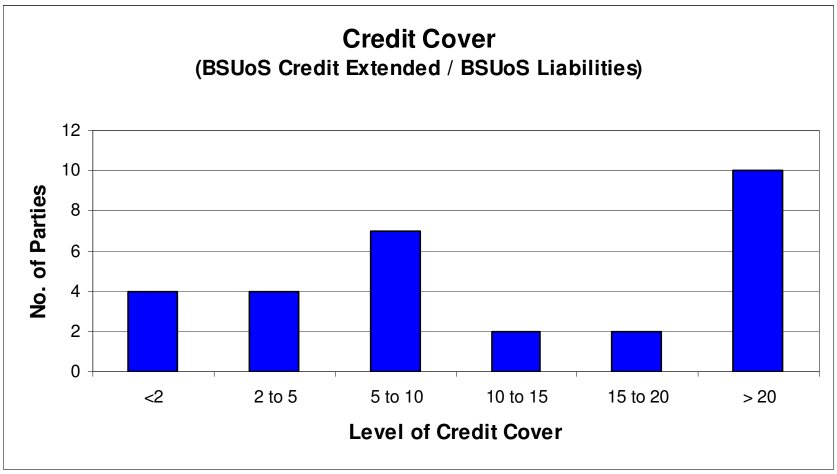


Figure A10.1: Distribution of Supplier Credit cover

A11.12. It should be noted that the majority of Suppliers identified rely on the security cover extended by National Grid. It should also be noted that, whilst this note focuses on the impact on credit arrangements between National Grid and Suppliers, Generators would be required to hold less security cover as a consequence of the CMP201 proposal. Similarly, Generators may also require a reduced level of credit cover from a Supplier as a consequence of potentially lower wholesale prices arising from the transfer of BSUoS liabilities.

Annex 11 Changes to interconnector flows with no Generator BSUoS

A12.1. The analysis aims to quantify the impacts of GB generation BSUoS on trade with Europe. As GB generation currently pay a proportion of BSUoS, the removal of this as proposed will mean that the GB wholesale price is reduced.

A12.2. This analysis calculates the percentage of time that the GB Generators would export or sell their energy domestically based on spot prices and day-ahead prices. Under CMP 201, the GB price is reduced by the BSUoS charge in that period however there is still a charge for the price of capacity (C). For the purpose of this analysis, the capacity price is assumed to be static.

A12.3. This analysis is based on historic prices adjusted by BSUoS. Further modelling by NGET calculates that the GB wholesale price will react to this; i.e. if imports into GB increase, the GB wholesale price will fall. The opposite effect on wholesale prices will occur if exports from GB increase. Therefore this conclusion represents the overall trend rather than a forecast of the absolute flows. Other factors, such as market liquidity and trading arrangements will also have an impact on the overall level of trade.

Spot Prices

A12.4. A GB generators decision

- If GB-BSUoS > FR-C, the GB generator will sell their power domestically
- If GB-BSUoS < FR-C, the GB generator will export their power to France

A12.5. A FR generators decision

- If FR > GB-BSUoS-C, the FR generator will sell their power domestically
- If FR < GB-BSUoS-C, the FR generator will export their power to GB

The results are included in the table below:

	GB Generator	FR Generator
Total Hours Selling Domestically	4921 *(56%)*	3839 *(44%)*
Total Hours Exporting via the interconnector	3839 *(44%)*	4921 *(56%)*

Day-ahead Prices

A12.6. A GB generators decision

- If GB_{BL}-$BSUoS_{BL}$>FR_{BL}-C_{BL} *or* GB_{PK}-$BSUoS_{PK}$>FR_{PK}-$C_{PK,}$ GB generator will sell energy domestically
- If GB_{BL}-$BSUoS_{BL}$<FR_{BL}-C_{BL} *or* GB_{PK}-$BSUoS_{PK}$<FR_{PK}-$C_{PK,}$ GB generator will export their power to France

A12.7. A FR generators decision

- If FR_{BL}>GB_{BL}- $BSUoS_{BL}$-C_{BL} *or* FR_{PK}>GB_{PK}- $BSUoS_{PK}$-C_{PK}, FR generator will sell energy domestically

- If $FR_{BL}<GB_{BL}-BSUoS_{BL}-C_{BL}$ *or* $FR_{PK}<GB_{PK}-BSUoS_{PK}-C_{PK}$, FR generator will export their power to GB

A12.8. The results are included in the table below:

	Based on Baseload Prices		Based on Peak Prices	
	Total Days Selling Domestically	Total Days Exporting via the interconnector	Total Days Selling Domestically	Total Days Exporting via the interconnector
GB Generator	124 *(50%)*	126 *(50%)*	98 *(39%)*	152 *(61%)*
FR Generator	*126 (50%)*	*124 (50%)*	152 (61%)	*98 (39%)*

Comparison of Results

A12.9. Below are a comparison of the results with the status quo and the post implementation of CMP 202.

A12.10. The status quo assumes that there is a BSUoS charge included in the price of GB generation, a BSUoS charge for access to the interconnector and a charge for the interconnector capacity.

A12.11. Post CMP 202 assumes that CMP 202 has been implemented so there is no BSUoS charge for access to the interconnector. However, there is still a BSUoS charge included in the price of GB generation and a charge for the interconnector capacity.

A12.12. Under CMP 201, the assumption is that CMP 202 is already implemented. It also assumes that BSUoS has been removed from the price of GB generation, so there is only the price of capacity included.

Spot Market

	Status Quo		Post CMP 202		Under CMP 201	
	Export	Sell Domestically	Export	Sell Domestically	Export	Sell Domestically
GB	35%	65%	39%	61%	44%	56%
FR	54%	46%	59%	41%	56%	44%
Total Export	89%		98%		100%	

Day-Ahead Market: Baseload

	Status Quo		Post CMP 202		Under CMP 201	
	Export	Sell Domestically	Export	Sell Domestically	Export	Sell Domestically
GB	31%	69%	42%	58%	50%	50%
FR	36%	34%	45%	55%	50%	50%
Total Export	67%		87%		100%	

Day-Ahead Market: Peak

	Status Quo		Post CMP 202		Under CMP 201	
	Export	Sell Domestically	Export	Sell Domestically	Export	Sell Domestically
GB	32%	68%	44%	56%	61%	39%
FR	37%	63%	45%	55%	39%	61%
Total Export	69%		89%		100%	

A12.13. Overall, the results indicate that the removal of BSUoS from GB generation and interconnectors better facilitates competition between a GB and French generator. Exports from GB increase in all scenarios under the implementation of CMP 201 and 202 compared with the current situation. Under the current arrangements and the implementation of CMP 202 alone, there is a period of time where no trade between the two countries would occur because the price differential between the countries was not great enough to cover the expected cost of BSUoS and the price of capacity. As BSUoS is calculated ex-post, the price differential needs to be great enough to provide the trader with certainty that the trade will be profitable once the cost of BSUoS and the price of capacity have been taken account of. Under the proposed changes of CMP 201, a trade would occur 100% of the time as the BSUoS charge no longer creates a barrier.

Implementation

A12.14. Under the implementation of CMP 202 and 201, there is no barrier to trade for the (GB and none GB) generators as they can access each others market with no additional charges. However, under the implementation of CMP 202 alone, the GB price is still inflated by the BSUoS charge. This means that the GB price is greater than the FR price, for more time than what it would be under the implementation of CMP 202 & 201. The greater price coupled with the ability for the FR generator to greater access the GB market, means that the FR generator can take advantage of the higher price. This results in GB importing more and effectively losing the ability to compete with the cheaper FR generators.

A comparison of results is included in the table below.

Spot Prices

	Under CMP 202 alone (% of time)	Under CMP 201 & CMP 202 (% of time)
GB Import	61%	56%

Day-ahead Prices

	Based on Baseload Prices		Based on Peak Prices	
	Under CMP 202 alone (% of time)	Under CMP 201 & CMP 202 (% of time)	Under CMP 202 alone (% of time)	Under CMP 201 & CMP 202 (% of time)
GB Import	57%	50%	48%	39%

A12.15. Based on these results, GB generators are going to be disadvantaged 5% of the time based on spot prices and 7-9% of the time based on day-ahead prices if CMP 202 is implemented alone.

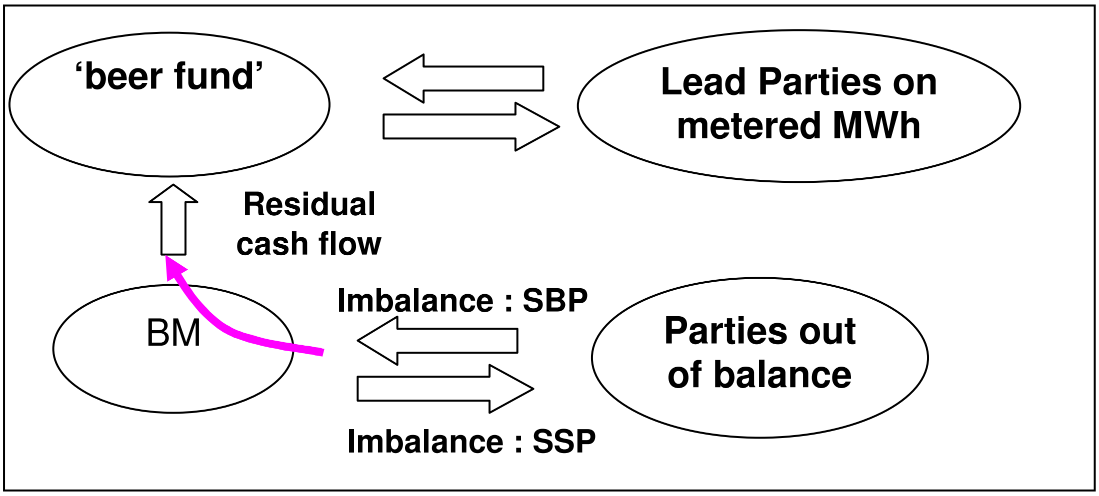
Cashout and BSUoS.

A13.1. This Workgroup paper presents an overview of the possible interaction of BSUoS and the cashout regime for discussion by the Workgroup. In summary, revenues from imbalance payments accrue in Residual Cashflow Reallocation Cashflow (RCRC)[13], whereas the net cost associated with rebalancing the system are recovered as part of BSUoS. BSUoS also recovers the cost of maintaining security of the system and internal SO costs (e.g. control centre costs).

Background

A13.2. The diagrams below describe the revenue flows associated with balancing actions.

BSC revenue flows:



A13.3. When a party is out of balance they pay or are paid at the System Buy Price (SBP) or System Sell Price (SSP). To balance the system the SO uses the Balancing Mechanism, buying or selling energy (taking offers and bids respectively).

A13.4. Parties that drive the market out of balance are subject to the main price. However if their imbalance is assisting to maintain balance they receive a market price (the reverse price). The marginal nature of the main price is intended to encourage parties to contract. SBP and SSP are derived from a methodology in the BSC, one will be the main price and the other the reverse price depending on the 'length' of the system[14].

A13.5. If the system is long (too much power / demand low or over contracted) the SO takes bids and the SSP is set on these bids, SBP is set by a market price. If the system is short (not enough power / demand high or

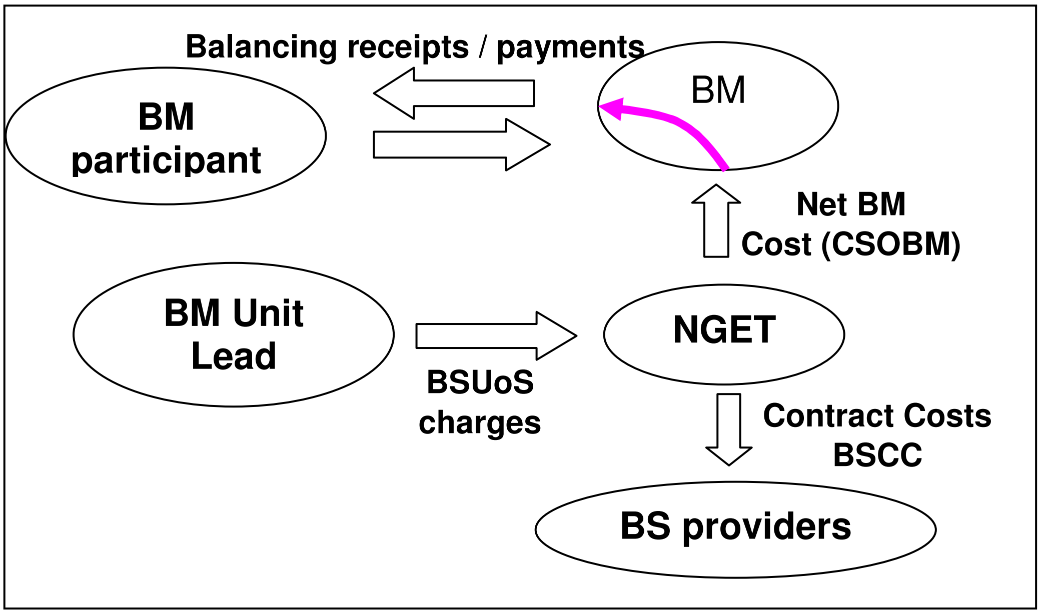
[13] Residual Cashflow Reallocation Cashflow (RCRC) commonly called the 'beer fund'

[14] http://www.elexon.co.uk/ELEXON%20Documents/imbalance_pricing_guidance_note.pdf

under contracted) the SO takes offers and these set the SBP, with the SSP set by the market price.

A13.6. Therefore there are two effects that determine the size of the 'beer fund', firstly the volume of parties who are out of balance and the pricing (SBP/ SSP). The monies that accrue (positive or negative) are paid by or to all BSC lead parties on a half-hourly MWh.

SO revenue flows:



A13.7. The net cost of the SO actions in the Balancing Mechanism (CSOBM) is paid to or by the SO to / from the BSC. The SO also pays contract services outside the Balancing Mechanism; e.g. options for forward contracts, warming contracts, reserve contracts. These contract costs, along with other SO costs, such as SO internal costs (control centre) and any incentive payments (positive or negative) are summed up with CSOBM and recovered in the form of BSUoS. BSUoS and is recovered from all BSC lead parties (currently) on a half hourly (MWh) basis.

A13.8. This is best explained through a number of examples[15]: i) Balancing the system (energy); ii) impact of dual balancing, iii) Securing the system (transmission constraints).

i) Energy balancing

A13.9. In this example we have one supplier that has under-contracted leaving the system short by 1000MW (it could equally be a generator not running). If this were the only issue on the system, the SO would buy power in the Balancing Mechanism, say for £80/MWh.

A13.10. Theoretically, under a perfect marginal imbalance pricing methodology, this would set the out of balancing cost for being under-contracted at £80MWh (SBP).

[15] Ignoring losses and assuming BSAD is zero, all actions are unflagged and priced, BPA and SPA are zero. For simplicity the a period has been assumed to be 1h.

A13.11. The supplier would then pay £80k into the BSC as an imbalance cost. As this is the only imbalance RCRC =£80k. In this hour the demand is 40GWh, so total metered power supplied and delivered is 80GWh. RCRC is therefore a £1MWh (£80k/80GWh) payment to BSC lead parties.

A13.12. In practice it the actions to balance the system will be a mixture of contract and Balancing Mechanism costs, and these action will be for both energy and system balancing. BSUoS would also include SO internal and incentive costs. However for this example we are conveniently assuming these are all zero. Therefore BSUoS would be net cost of the Balancing Mechanism (CSOBM= £80/MWh *1000MW = £80k, paid by the SO), so BSUoS would be £80k/80GW = £1/MW. So in this extremely simplified example, RCRC and BSUoS are equal and opposite. Therefore a third party supplier or generator would not be exposed to a cost.

ii) Dual imbalance pricing

A13.13. We now consider this impact of the same supplier being short whilst a generator is spilling. A generator spills 200MW and the market price is say £50MW (setting the reverse price).

A13.14. Now the system operator only has to take 800MW corrective action at £80/MW. SBP is still set at £80/MWh, and SSP is set at £50/MWh (from pre-gate closure market).

A13.15. Within the BSC the supplier would still pay £80k, but the spilling generator would also get paid £10k (200MW*£50/MWh). Therefore RCRC becomes £70k, or a payment of £0.875/MWh (£70k/80GWh) to all parties.

A13.16. The net cost of SO actions is £64k (800MW at £80/MWh); this is paid as CSOBM by the SO to the BSC (and passed on as an offer payment).

A13.17. Assuming all else is zero, BSUoS would be £64k/80GWh = £0.8/MWh. So as a result of dual imbalance pricing, in this example, which is more representative of the real system than first example BSUoS and RCRC does not net off.

A13.18. [If main = reverse = £80/MWh; RCRC would be £64k which is the same as CSOBM]

iii) Solving constraints

A13.19. In this example the SO need to solve a constraint on a balanced system (everyone is in perfect balance).

A13.20. Because everyone is balanced there are no imbalance payments and so RCRC is zero.

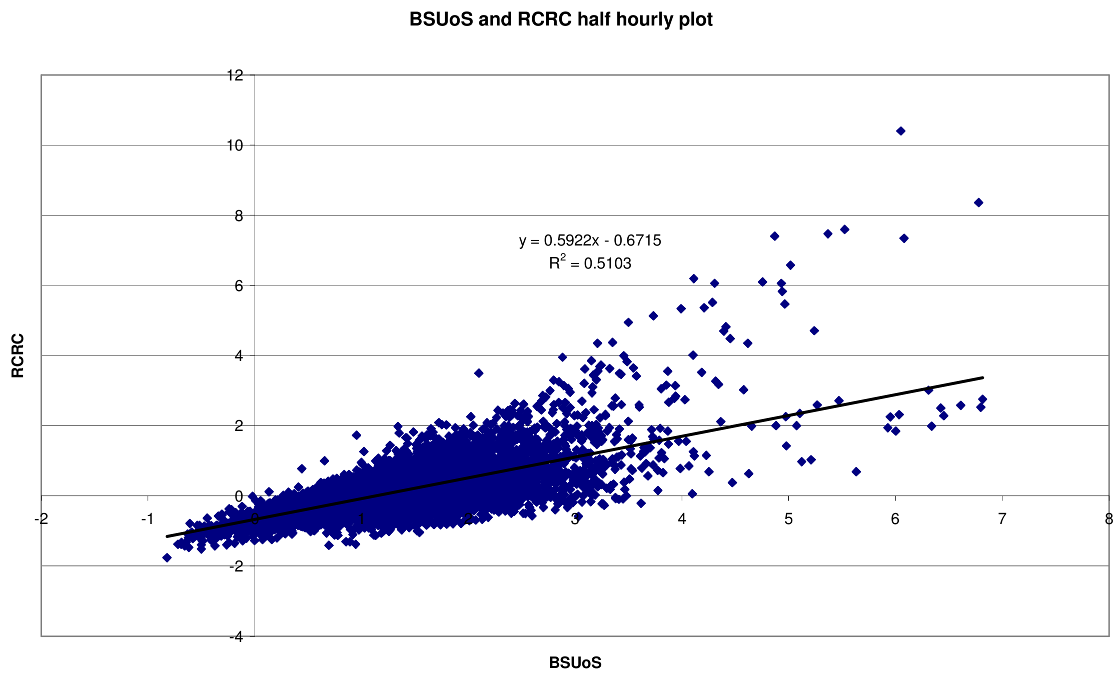
A13.21. The SO is required to take off 1000MW behind an export constraint at a bid price of £25/MW and replace it on the other side of the constraint with an offer at £80/MWh. The net cost of the constraint is £55/MWh*1000MW= £55k.

A13.22. Assuming a demand of 40GW as previously, BSUoS would be (£55k /(40GWh+40GWh)) £0.6875MWh.

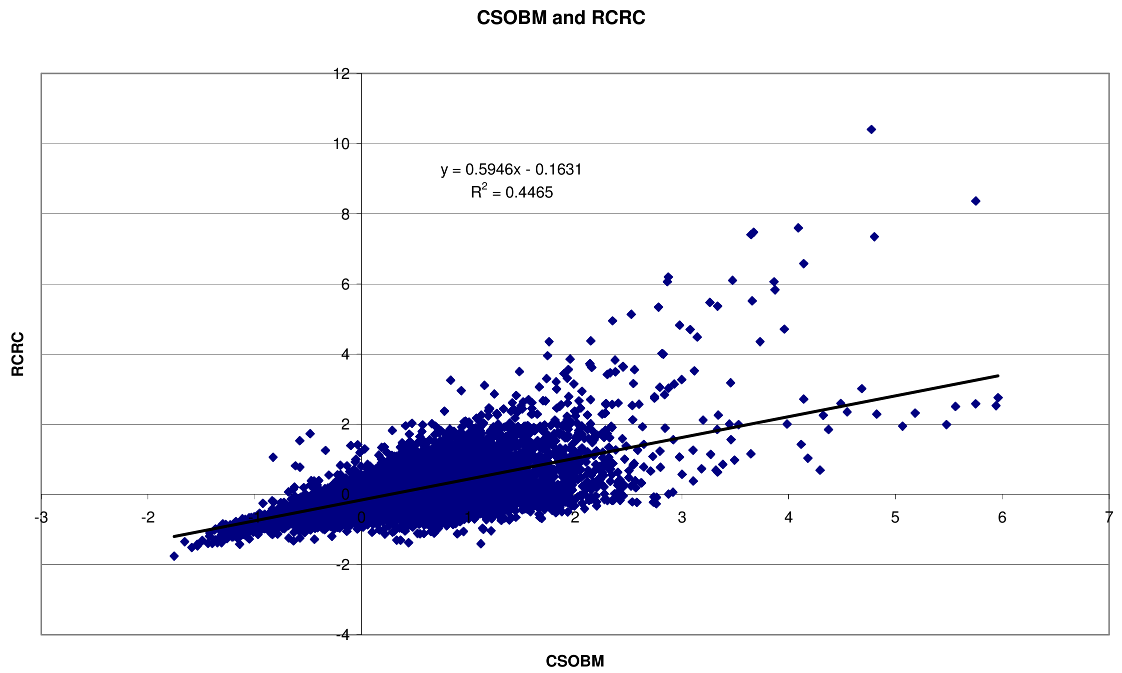
A13.23. So for the example of a constraint BSUoS and RCRC are not related. However in practice the System Operator with simultaneously solve constraints and energy imbalance so there could be some form of interaction.

Analysis of interaction.

A13.24. In order to understand the extent of interaction National Grid presented information highlighting the correlation of BSUoS charge (payment to National Grid shown as positive) and the RCRC payment (payment to market participants shown as positive). The graph below shows the corrections between these two revenue streams:

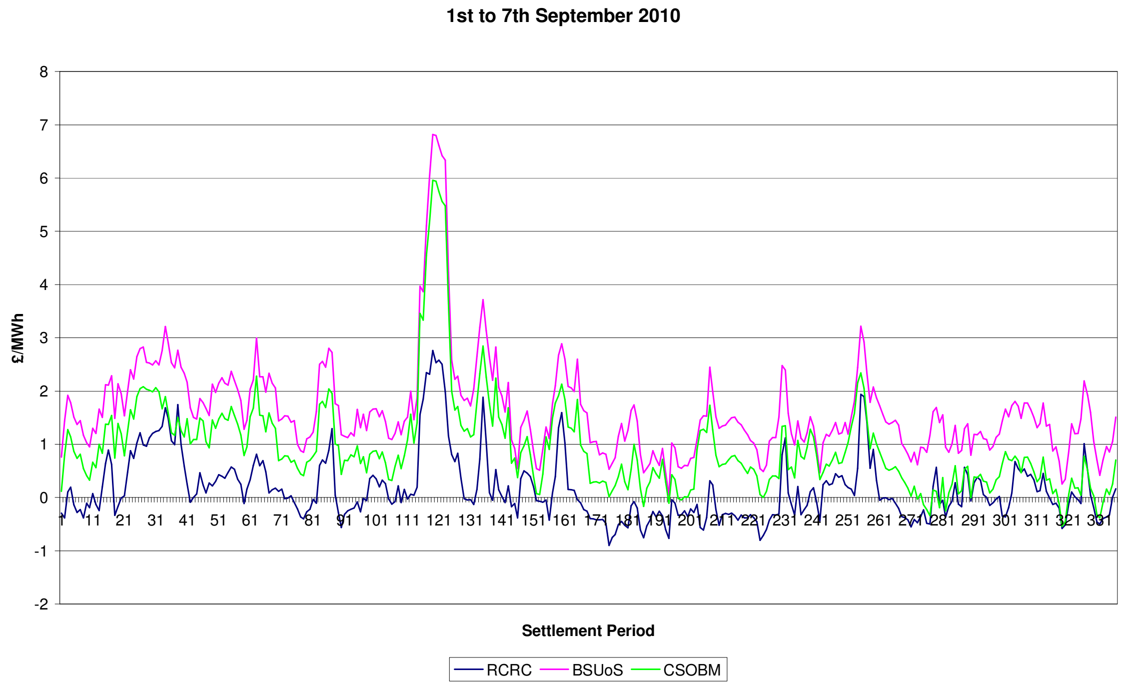


A13.25. Whilst this shows some correlation it is distorted by other revenue flows through BSUoS. Using the revenue stream CSOBM (from BSC to SO and included in BSUoS) rather than BSUoS itself shows an interaction:

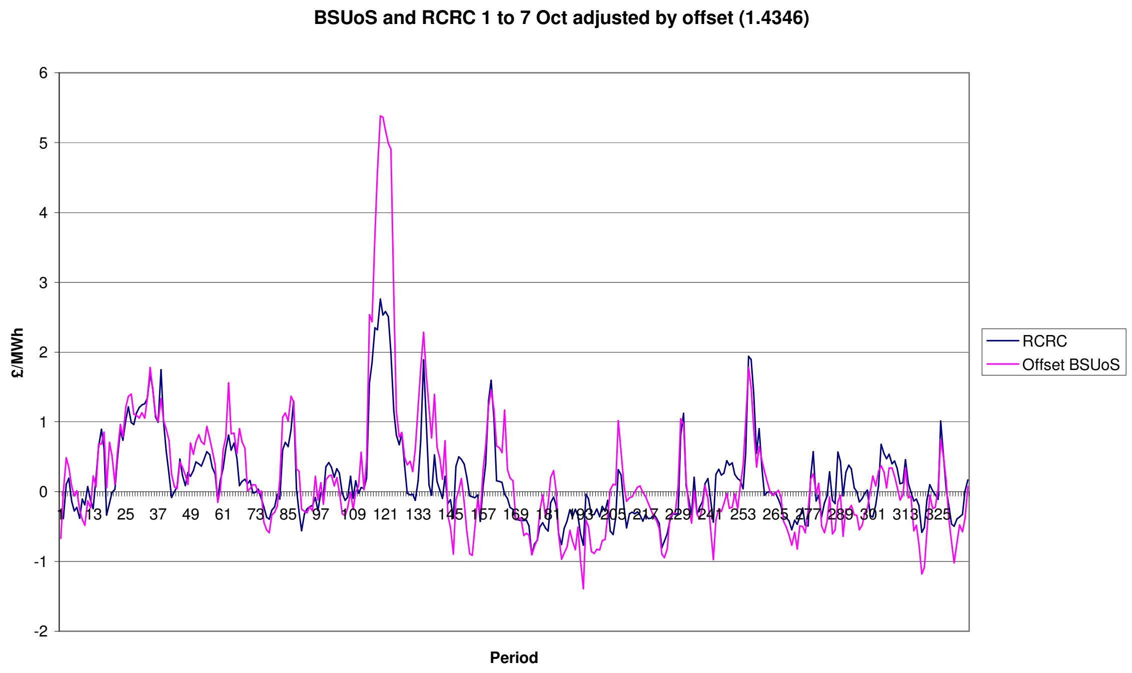


A13.26. Again the overall interaction is clear, although it is not as strong as between BSUoS and RCRC. This is likely due to element the inclusion in BSUoS of energy balancing actions that are missing in CSOBM due to SO forward trading.

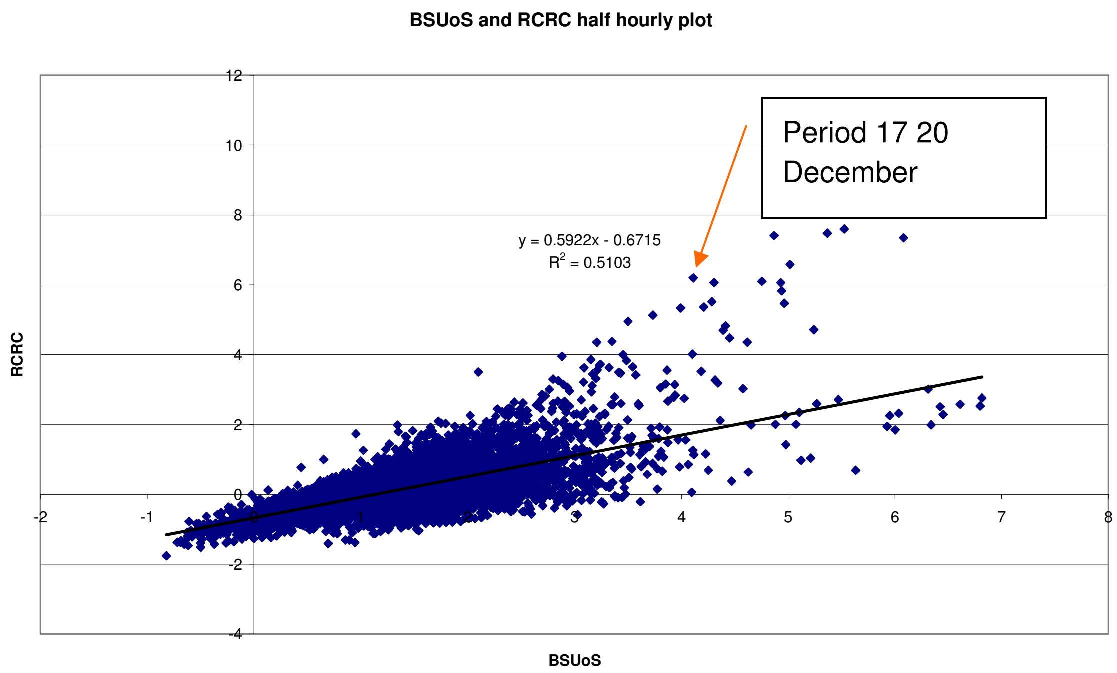
A13.27. Another way of viewing this data is by picking an individual week. The graph below shows the first week in October 2010. In this particular week the R Squared value for the correlation between BSUoS and RCRC is 0.766.



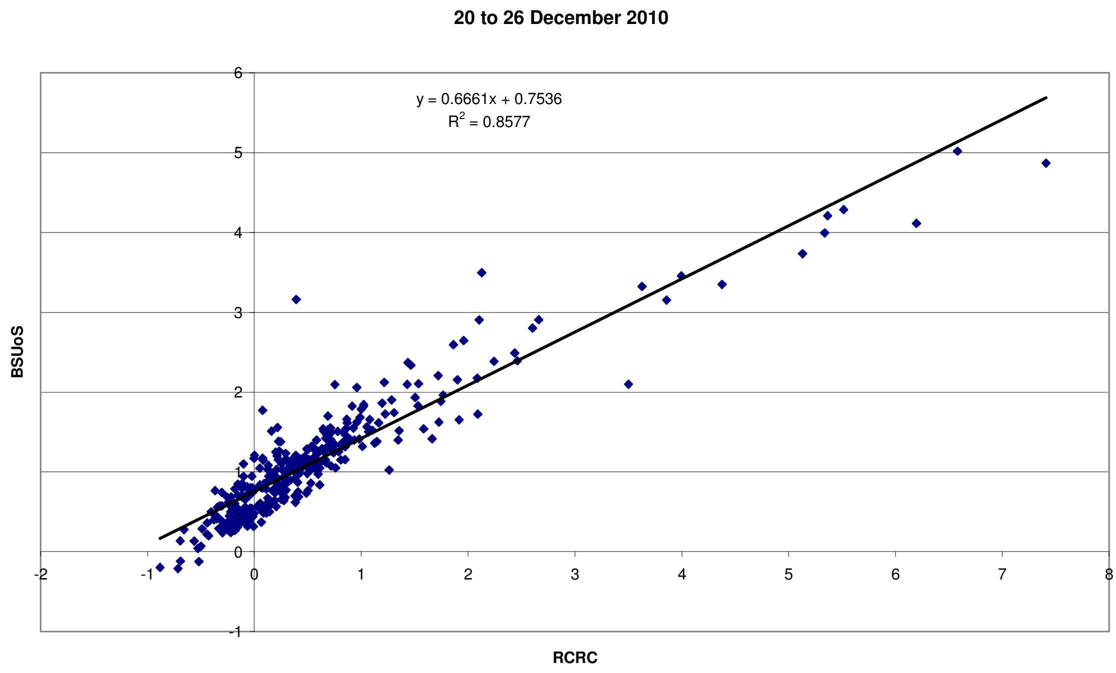
A13.28. Applying an offset to BSUoS clearly shows the correlation:



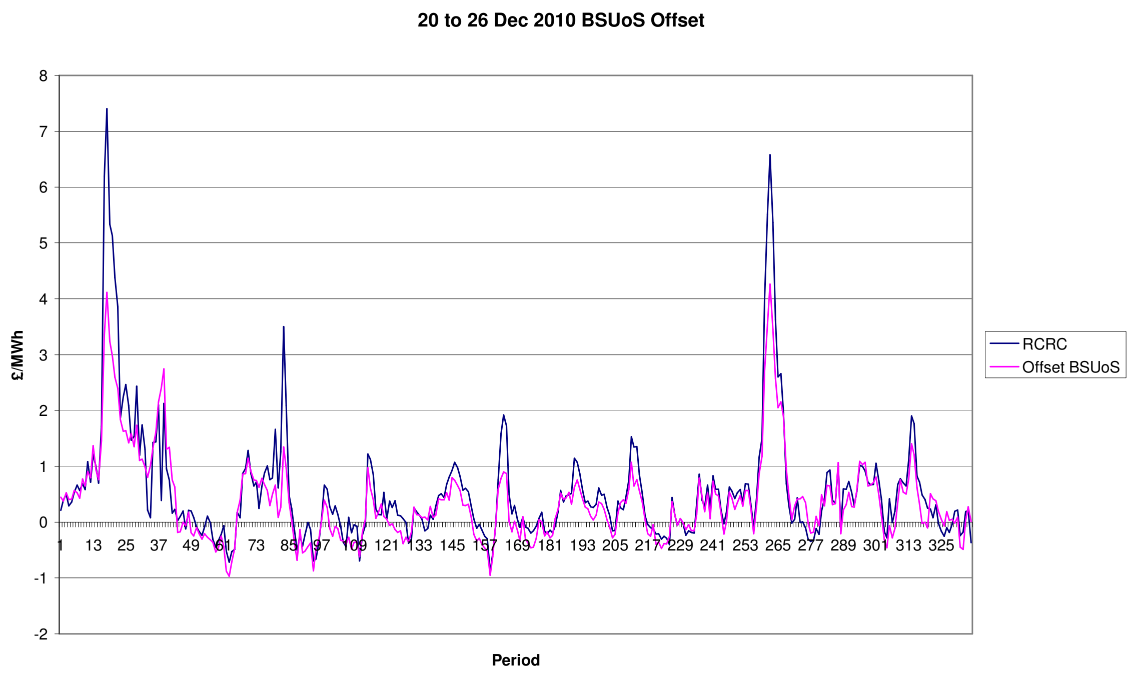
A13.29. Going back to the original scatter plot and picking a point off the main trend line we are able to see that the correlation is much more consistent on a weekly basis:



A13.30. Using this point we can plot the week commencing 20 December 2010:



A13.31. Here we can see that the correlation within this week between BSUoS and RCRC is much better. The final graph below shows this as and offset to BSUoS, again showing a clear correlation:



Summary

A13.32. BSUoS is made up of a number of elements, one part of this is related to energy imbalance and thus nets to RCRC. Due to the nature of imbalance pricing the energy element in BSUoS is not exactly the same as RCRC. The direct relationship will be 'skewed' by the total volumes of imbalance in both directions and the difference between the main and reverse prices. As the SO optimises actions in the Balancing

Mechanism some actions will be taken to solve energy and system constraints simultaneously.

A13.33. Suppliers and Generators will consider the combined effect of BSUoS and RCRC in deciding operational strategies as they are both avoidable MWh charges.

Annex 13 Modelling of flows on Interconnected system

Modelling the Impact of CMP202: Removing BSUoS from Interconnectors.

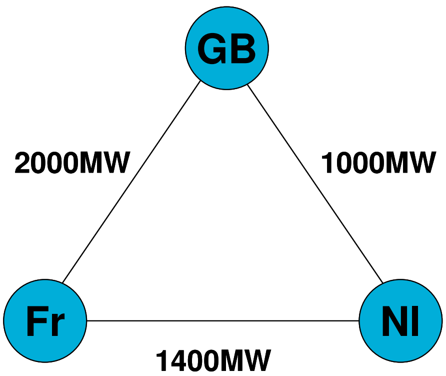
Introduction

A14.1. CMP201 proposes to remove the current 50% BSUoS liability from Generators, reallocating the charge 100% on Suppliers. Given that BSUoS is effectively a "pass-through" charge to CUSC Parties, the proposer postulates that the effect of CMP201 should be to reduce the GB wholesale price by the BSUoS 'cost' covering that charge and any risk premium (due to the ex-post nature of BSUoS).

A14.2. This note outlines the modelling approach taken by National Grid to examine the impact of the proposal on Interconnector flows.

The Model Principles

A14.3. The basic model consists of three interconnected nodes representing the GB, French & Netherland electricity markets. The interconnector flow limits were set as follows:



GB-Fr 2000MW
GB-Nl 1000MW
Fr-Nl 1400MW

France to Netherland transfers were determined by looking at flows between France, Belgium and Netherlands.[16]

A14.4. Each node has a generation price-stack, used to determine the market prices for a given demand level, and a corresponding set of demand data representative on the annual load profile for each country.

A14.5. The model has been built using Excel and the "Solver" analysis package to determine optimal market positions given the constraints on the Interconnectors. When run, solver optimises the amount of generation in each market such that it meets each countries demand and flows on the interconnectors are within their defined limits. The model outputs the MW run at each price point in the generation stack for each country, and

[16] Further data from RTE Elia and Tennet websites indicate that this limit could be increased.

a wholesale market (shadow) price of production (cost of providing the next MW).

A14.6. The model was run twice, once with an unadjusted price stack representative of the current position with BSUoS inherent within the offered prices, and once with the GB generation price reduced to reflect the effect of removing BSUoS from generation.

A14.7. To replicate cost transfer of the BSUoS implicit within the generator price, the volume of GB generation priced at average BSUoS charge was added back into the overall GB market cost.

A14.8. Comparing the results from each run provides a quantitative indication of the change in interconnected flows, the impact on production and consumption in each market, and overall change in social benefit.

A14.9. Data used for the model covered Financial year 2010 / 11 with an average BSUoS price of £1.11 used when reducing the GB wholesale prices. Demand and Price data for France & Netherland was appropriately "shifted" to account for GB / Continent time differences.

A14.10. Further analysis was also performed assuming different levels of BSUoS based on the 2010/11 data. This was achieved by "subtracting" the assumed £1.11/MWh BSUoS charge within the modelled fuel price the "adding back" different amounts up to £1.75/MWh when doing the pre (with BSUoS in fuel price) and post (without BSUoS in fuel price) proposal comparisons.

A14.11. The assumptions within the model are that the Interconnectors are available all the time, capacities are the same in both direction and that there is no cost to using the Interconnector (either in the form of losses or capacity prices).

Demand Profiles

A14.12. Demand data for each half hour was obtained for GB and for France (from the RTE website). Exact equivalent data was not available for Netherlands and so a profile was derived by scaling the French demand figures by the ratio of Dutch energy consumption (from TenneT website) and French energy consumption.

A14.13. Sample data was then taken for each of three seasons; Winter, Spring + Autumn and Summer, to provide a representation of the annual loads. In total, 504 demand values were derived for each country split 25%, 50%, 25% between each season time.

Generation Prices

A14.14. For the model to determine a wholesale price for given demand levels, and hence interconnector flows, spot price data was used to derive a price curve as follows:

1. A load duration curve was produced for each country from the demand data. Essentially, 17,520 periods of demand data ranked in ascending order.

2. An equivalent price duration curve was produced for each country by ranking the 8,760 hourly spot prices (average of two GB period prices) in ascending order.

3. Fourteen points were then chosen on the load duration curve, ensuring they covered significant points on the curve such as low / high demand.

4. The equivalent price points were then taken from the price duration curves.

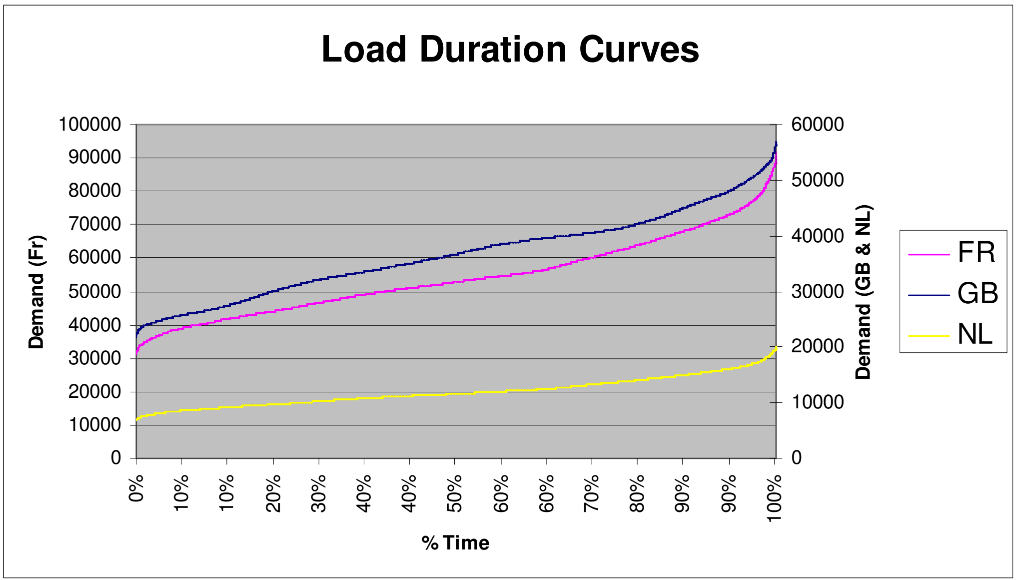
A14.15. For example, and referring to graphs / tables below:

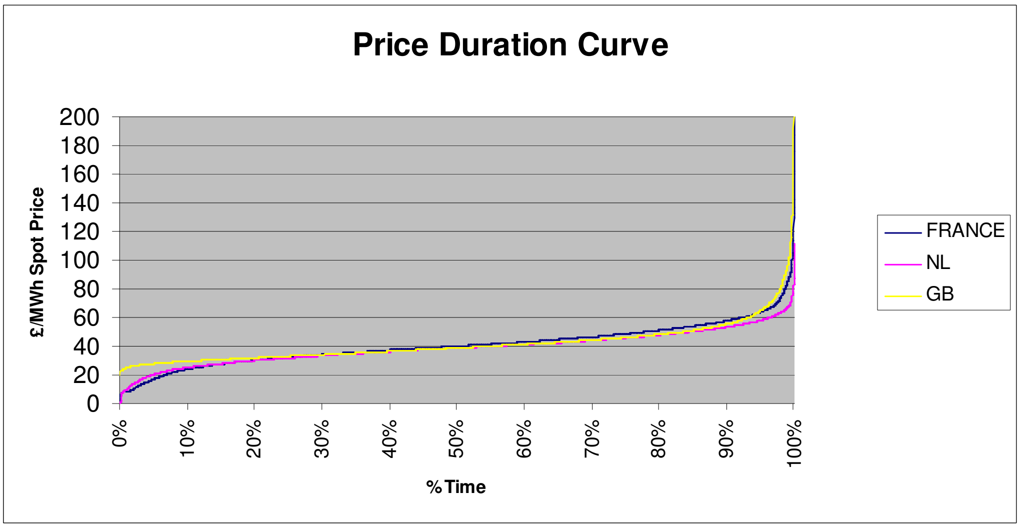
The first point of GB load curve (at 1%) corresponds to GB demand of 21,709MW and a price point of £26.3/MWh on the price curve.

The next point (at 5%), corresponds to an *additional* 3,482MW of GB generation at a corresponding GB price of £29.89/MWh.

The above approach was repeated for all points for all markets. The exercise was also repeated using 2011/12 data for the comparative runs on that financial year.

Duration curves and Prices for 2010/11





Demand Load Duration points			
Point	GB	FR	NL
1%	21709	31037	6838
5%	25191	37894	8349
10%	26337	40100	8835
20%	29514	43632	9613
30%	32436	47083	10373
40%	34479	50333	11089
50%	36721	52836	11640
60%	38994	55332	12190
70%	40341	59576	13125
80%	42670	64738	14263
90%	46846	70983	15639
95%	49498	75364	16604
99%	53219	83867	18477
99.9%	56149	88440	19485

Corresponding Price Points		
GB £/MWh	Fr £/MWh	Nl £/MWh
26.315	8.572	10.17
29.89	17.174	21.2
32.19	24.933	26.95
35.265	31.822	32.51
37.82	35.969	36.08
39.995	38.804	38.52
42.11	41.428	40.85
44.4	44.23	43.26
47.29	47.754	46.61
50.87	52.377	50.99
57.94	57.172	55.77
67.63	61.48	59.02
96.91	79.444	67.8
407.44	212.27	219.6

Min	21709	31037	6838
Max	57079	91718	20207

21.74	0.729	0.73
407.44	212.27	219.6

Calculation of Producer Surpluses

A14.16. In addition to the direct impact on the market costs, producer surpluses were also calculated. An explanation of how this was derived is provided below.

A14.17. In a single market, as demand increases, then more expensive plant is required to meet that demand (the generation price volume curve).

A14.18. At any given demand level, the producer surplus is determined from the difference between the wholesale price and a generator's costs (fuel price).

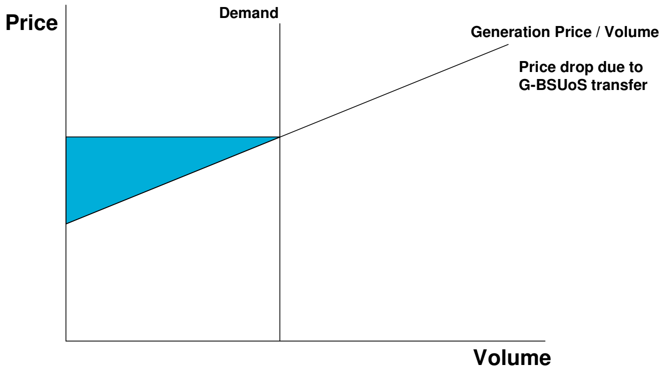


Figure A14.1: Basis of Producer Surpluses

A14.19. If BSUoS is removed from generation, then there should be a corresponding decrease in a Generator's costs and the wholesale price would, with all other factors being equal, drop by the cost of Generation BSUoS (G-BSUoS). Producer surpluses would remain unchanged; however the G-BSUoS element would transfer to, and be paid by Suppliers, returning the effective cost to its original position.

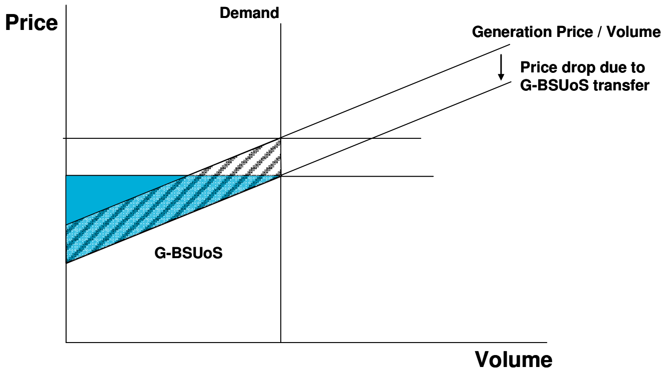


Figure A14.2: Local Impact of Removing G-BSUoS

A14.20. However with a lower GB wholesale price, interconnector exports from GB are likely to increase. This increase would result in a higher GB "gross demand" with an increase in the GB wholesale price. GB producer surpluses would increase accordingly. There would also be additional revenues corresponding to the export volume and the price differential between the exporting (from) and importing (to) markets.

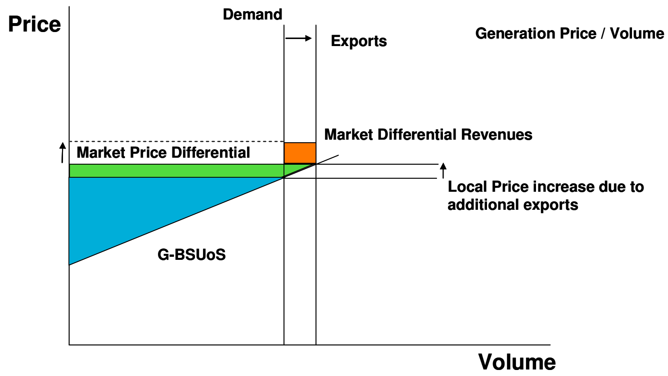


Figure A14.3: Wider Impact when considering Interconnections.

Analysis Results based on 2010/11 Prices

A14.21. To assess the impact of the CMP201 proposal for differing levels of BSUoS, the analysis model was effectively run twice to determine costs for both pre and post proposal scenarios. The base case for the analysis used 2010/11 demand and spot prices with an average 2010/11 BSUoS charge of £1.11/MWh inherent within GB spot prices. It is assumed that Interconnector flows are not subject to BSUoS charges.

A14.22. Total GB demand modelled came out as 320TWh indicating that the demand curves adequately represented the full year. This was met by a combination of GB generation and net imports / exports. The table below shows the impact of varying BSUoS levels on the GB demand weighted wholesale price and gross demand met by GB generation.

BSUoS Level £/MWh	Gross Dmd GWh	Mkt Price £/MWh
0.00 (BSUoS removed)	316.4	49.30
1.11 (2010/11) Base	312.6	49.84
1.25	312.5	49.91
1.50	312.2	50.04
1.75	311.6	50.16

`

A14.23. As anticipated, the impact of removing BSUoS from the generation fuel price lead to decrease in the local (GB) wholesale price but not by the full value of G-BSUoS. Removing -BSUoS from GB generation led to a net reduction in relatively cheap imports from France to GB (raising the GB wholesale price), and thus an increase in GB gross demand. Conversely applying BSUoS to GB generation led to increased imports to GB / reduced exports from GB and lower GB production. In all cases, removing BSUoS from generation prices increased the level of GB exports by approximately 30%.

A14.24. This represents the increased convergence of EU wholesale markets, with GB generation becoming more competitive with the removal of BSUoS from the GB wholesale price (as is common practice in continental markets).

A14.25. The model produced a GB wholesale cost of meeting demand *without* BSUoS being inherent to the Generator's fuel price. This totalled £15,793m.

A14.26. Under the CMP201 proposal, the amount of BSUoS a GB Generator (G-BSUoS) would have paid (the product of their MWh generation and the appropriate BSUoS charge) is transferred to demand. This amount therefore needs added to the "without BSUoS" market scenario cost to provide the comparable pre-proposal GB Market Total Cost. Theses values are shown below.

BSUoS Level £/MWh	G-BSUoS £m	GB Market Total Cost £m
1.11	351	16,144
1.25	395	16,189
1.50	475	16,268
1.75	554	16,347

9.1 The table below provides a comparison between pre and post CMP201 proposal results (BSUoS inherent in GB Generator price versus no BSUoS in GB Generator price) for differing levels of BSUoS. Please note that the overall benefit calculations should be treated with a large degree of caution. This is because the producer and consumer calculations are not directly comparable. The producer surplus is a proxy for profit i.e. the price a commodity is sold at minus cost. The consumer cost is a measure of the total cost of providing electricity. It is not a measure of consumer surplus in the Marshallian sense i.e. the difference between what a consumer is willing to pay for a commodity and what he or she actually pays. Therefore adding together the two calculations does not provide an overall market benefit/cost value.

A14.27.

	Total GB Market Cost £m		Difference Pre - Post		GB Producer Surpluses £m		Difference Post - Pre		Overall Benefit £m
BSUoS	Pre	Post	£m	%	Pre	Post	£m	%	GB Total
1.11	15,967	16,144	-177	1.1	5,936	6,117	181	3.0	4
1.25	15,990	16,189	-199	1.2	5,914	6,117	203	3.4	4
1.50	16,031	16,268	-237	1.5	5,875	6,117	242	4.2	5
1.75	16,071	16,347	-276	1.7	5,836	6,117	281	4.8	5

A14.28. As can be expected, as BSUoS rises, the total market cost (i.e. total cost of GB production) increases by between 1.1% and 1.7%. Pre-proposal GB producer (Generator) surpluses however decline as consequence of greater imports into GB reducing their output.

A14.29. Whilst the CMP201 proposal appears to show a negative impact on consumer costs, taking account of GB Producer Surpluses, there is a small benefit for GB overall.

A14.30. The table below show the model results across all the markets modelled (GB, Fr & NI).

	Total EU Market Cost £m		Difference Pre - Post		EU Producer Surpluses £m		Difference Post - Pre		Overall Cost £m
BSUoS	Pre	Post	£m	%	Pre	Post	£m	%	EU Total
1.11	44,728	44,721	7	0.01	23,483	23,473	-10	0.01	-2
1.25	44,774	44,765	9	0.01	23,485	23,473	-12	0.01	-3
1.50	44,856	44,844	12	0.01	23,489	23,474	-15	0.01	-4
1.75	44,935	44,923	12	0.01	23,491	23,471	-17	0.01	-5

A14.31. The model results showed a small benefit to EU consumers of between £7m and £12m however, if all Producer Surpluses are also considered, there appears to be a small dis-benefit of about -£2m to -£5m: Considering the magnitude of the market costs and Producer Surpluses (£45bn & £24bn) and other model assumptions, this can be considered insignificant within the accuracy of the model. Also, please note the methodological inconsistencies associated with deriving overall cost/benefit values based on differing economic concepts i.e. costs and surpluses as discussed in paragraph 4.33

A14.32. The main conclusion revealed by the analysis is that on a wider European market basis, total consumer costs reduce while producer surpluses fall following the implementation of CMP201. This finding is not surprising as by facilitating efficient competition there are two important effects. The first effect can be described as a productive efficiency effect i.e. the market employs a more efficient allocation of resources. This reduces total consumer costs. The second effect can be characterised as the competing away of producer rents due to the increase in competitive activity. This results in reducing total producer surplus.

A14.33. It is possible that due to competitive pressure, a proportion of the increase GB producer surpluses will be competed away thus reducing the impact on GB consumers as wholesale prices fall. This is discussed further below.

A14.34. Furthermore, it should be noted that the figures from the model analysis represent a “fully coupled” market where electricity would always from high to low market prices during each half hour. In reality much of the trading across the Interconnectors occurs day ahead. Previous analysis has shown that the interconnectors can flow against market price for up to 32% of the time. Whilst it is difficult to quantify, the impact of CMP201 may not be as great as modelled due to this sub-optimal trading.

A14.35. The results show that BSUoS when applied to GB generation appears to distort the GB market in favour of continental imports into GB. Whilst this “benefits” GB consumers in the short term, it prevents efficient competition between generation in both the local (GB) market and the wider (EU) market: costs across the EU as a whole increase as a consequence.

A14.36. There may also be a consequential impact on supply security if the GB market becomes less attractive for new generator investment. Whilst the relative impact on consumers of increasing BSUoS is 0.6% for a range of BSUoS at £1.11MWh and £1.75MWh, GB production reduces by 1.8% over the same range. This position may become worse as the level of interconnection increases and further continental imports are attracted by the effect that BSUoS has on the GB wholesale price.

A14.37. For completeness the costs and surpluses for the French and Netherland markets are provided below. Note however that these markets are also interconnected with other EU markets; any individual market effect will here will probably be diluted by trading within this wider pan European market.

	Total Fr Market Cost £m		Difference Post - Pre		Fr Producer Surpluses £m		Difference Post - Pre	
BSUoS	Pre	Post	£m	%	Pre	Post	£m	%
1.11	23,563	23,413	150	0.6	14,491	14,336	-154	-1.1
1.25	23,583		170	0.7	14,510		-174	-1.2
1.50	23,616		203	0.9	14,545		-209	-1.4
1.75	23,649		236	1.0	14,579		-243	-1.7

	Total Nl Market Cost £m		Difference Post - Pre		Nl Producer Surpluses £m		Difference Post - Pre	
BSUoS	Pre	Post	£m	%	Pre	Post	£m	%
1.11	5,197	5,163	34	0.7	3,056	3,021	-35	-1.1
1.25	5,201		38	0.7	3,061		-40	-1.3
1.50	5,201		45	0.9	3,069		-48	-1.6
1.75	5,215		52	1.0	3,076		-55	-1.8

Analysis Results based on 2011/12 Prices

A14.38. A repeat of the base case analysis was performed using 2011/12 prices. GB national demand was 318.2TWh. Again two model runs were compared; one with BSUoS in the Generator's fuel price and one with the fuel price reduced by £1.53MWh; the average BSUoS for that year.

A14.39. The results were similar to the 2010/11 analysis. Reducing GB Generation prices by the average BSUoS charge for that year resulted in a small increase in exports from GB to continental markets (~1%) and a similar reduction on imports (~15%). Again though there was a drop in the GB market price, the additional GB exports and reduced imports limited the drop. This is shown in the table below.

BSUoS Level £/MWh	Gross Dmd GWh	Mkt Price £/MWh
0.00 within price	313.0	52.63
1.53 (2011/12) Base	309.7	52.68

A14.40. Comparing market costs from the pre and post CMP201 proposal scenarios also show similar results to 2010/11 results with a market cost increase of ~1.2%. Again, GB producer benefit from the proposal by ~£12m whilst the overall benefit across all markets; i.e. the sum of all market costs and producer surpluses; was £29m.

	Total GB Market Cost £m		Difference Post - Pre		GB Producer Surpluses £m		Difference Post - Pre		Overall Benefit £m	
BSUoS	Pre	Post	£m	%	Pre	Post	£m	%	GB Total	EU Total
1.53	16,300	16,478	-178	1.2	7,183	7,369	12	2.8	-181	29

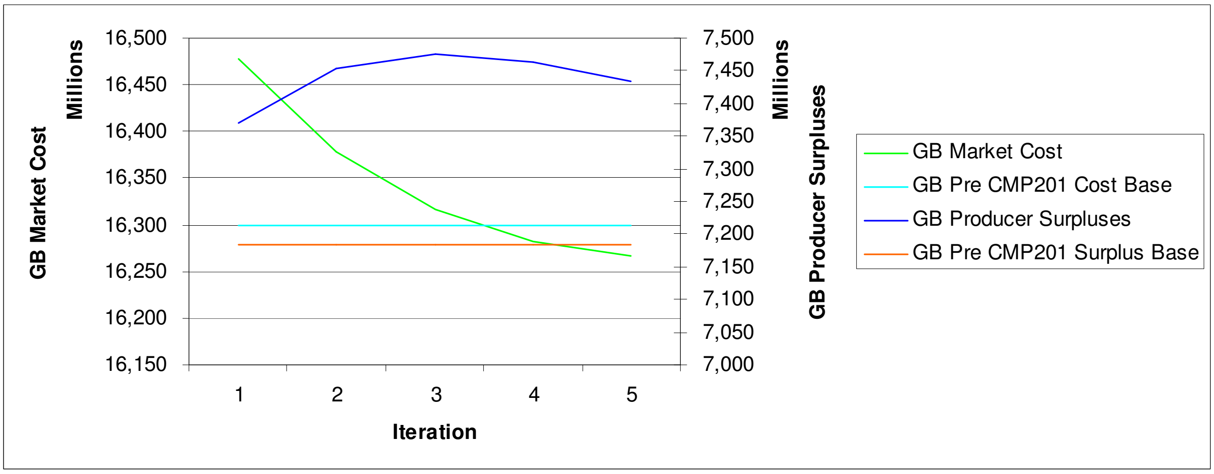
Impact of Competition

A14.41. Two effects were considered, one short term and one long.

A14.42. In the short term, some generation would use the additional surpluses to attempt to increase market share by reducing their prices. Other generation would then respond, also reducing their prices so as to maintain their markets share (competition). The effect would be to reduce GB prices for consumers and further increase interconnector exports.

A14.43. In the longer term, new generation may invest in the GB market encouraged by the increase in available surpluses. This would displace more expensive marginal plant and again reduce the cost to GB consumers. A number of additional scenarios were run using the 2011/12 model data to investigate these effects.

A14.44. To demonstrate the “short term” effect, the price curve for GB generation was adjusted by taking the additional revenue at each demand point and reducing the price by the additional surpluses for the MWh generated. For example if a block of generation made on average an additional £0.60/MWh in the post-proposal scenario, then the price for that block was reduced by £0.60/MWh. Marginal plant would just cover their cost and so no cost change was made for this generation. This process was repeated a number of times as producer surpluses change on each iteration. A graph and table showing the impact on cost, surpluses and interconnector exports & imports is shown below.



Iteration	1	2	3	4	5
% Change in exports	1%	6%	23%	24%	24%
% Change in imports	-15%	-27%	-34%	-38%	-34%

A14.45. Over the iterations performed, the market cost (to consumers) drops significantly at first, then progressively less over further iterations: By the 4th iteration, the model was producing a market cost less than the pre-proposal base case. Interconnector exports volumes also progressively increased over the same iterations by 1% to approximately 23%. Whilst producer surpluses initially increased, along with the interconnector exports, they peak then reduce as the level of exports stabilise, leaving competition within the GB market as the main mechanism for gaining a greater market share.

A14.46. The "long term" effect of new generation entering the market was modelled by introducing an additional 500MW and 1000MW of generation, first assuming a base-load generation price, then repeated assuming a more mid-merit plant price.

A14.47. As shown in the table below, the introduction of between 500MW and 1000MW brought the market cost down to a level comparable with, or lower than that of market cost of the pre-proposal (base-case) scenario.

	Market Cost £m	Producer Surplus £m
Pre-proposal	16,300	7,183
Post Proposal / Pre-investment	16,478	7,369
+500MW "base-load"	16,359	7,374
+1000MW "base-load"	16,207	7,341
+500MW "mid-merit"	16,394	7,325
+1000MW "mid-merit"	16,279	7,246

A14.48. Whilst the model cannot predict the timescales over which competition or new investment will occur, it does show that, under both the short term and long term scenarios describe above, producer surpluses should feed back to GB consumers in the form of lower prices.

Potential Impact of Coal & Gas Prices

A14.49. Historic Gas and Coal prices were also examined to determine if there was any likely impact from merit order changes between these two types of plant. The prices were converted from their market units ($/tonne for coal and p/therm for gas) to a common unit of £/MWh equivalent using the appropriate monetary exchange rate and a coal conversion 23456MJ / tonne. Accounting for the relative thermal efficiency of coal plant (34%) and CCGTs (50%), the price differential over 2010 and 2011 was examined to determine the relative position in the merit order for the two year. This is shown in the table below;

Year	% Time Coal > Gas	% Time Coal < Gas
2010 / 11	3%	97%
2011 / 12	8%	91%

A14.50. Between the two year, on average, coal and gas prices favoured running coal plant 5% more in 2011/12 than in 2010 / 11. Assuming this was reflected in the generation run in those years then comparing the two scenarios for 2010 / 11 with a BSUoS level of £1.50MWh and 2011/12 where average BSUoS was £1.53MWh, should provide an indication of the impact of a merit order change.

		Total GB Market Cost £m		Difference Post - Pre		GB Producer Surpluses £m		Difference Post - Pre	
Year	BSUoS	Pre	Post	£m	%	Pre	Post	£m	%
2011/12	1.53	16,300	16,478	-178	1.1	7,183	7,369	186	2.6
2010/11	1.50	16,031	16,268	-237	1.5	5,836	6,117	281	4.8

A14.51. It should be noted that other factors such as the underlying demand difference and possibly new wind generation may also influence the results. However, demand variation for each country was less that 1% between the years (for GB 320 TWh vs 318TWh) and the amount of new wind generation added in each country relatively small. Both GB and France added approximately 1GW of additional capacity in 2011 compared to the 5GW already installed; the Netherlands added 100MW to their existing 2GW[17]. The impact this would have had on the remaining plant and interconnector transfers would therefore be negligible.

A14.52. Within the accuracy of the model, its underlying data and assuming other minimal effects, the merit order impact on GB consumer is small. The overall EU benefit however is significantly higher which *may* correspond to higher volumes of coal generation available in GB compared to Netherlands and France.

[17] Source: Wikipedia: http://en.wikipedia.org/wiki/Wind_power_in_the_European_Union

A14.53. In particular the Netherland predominantly meets demand from Gas fired plant; on 2009 data this was 60% for gas and 23% for coal. Consequently increases in gas prices will affect then more that GB where the volumes of coal and gas generation are more equally balanced (44% gas, 28% Coal). With coal appearing relatively cheaper in 2011/12, the EU benefit may therefore increase from relatively cheaper GB exports derived from coal replacing potentially more expensive continental gas plant.

A14.54. A scenario was also run, based on the 2010/11 data to assess the impact of potential fuel price rises. The scenario assumed a 5% increase in fossil fuel prices was assumed, that nuclear / renewable prices would remain unchanged and that this plant would run in preference to fossil. Examining the relative levels of each plant type in each country, the fuel prices at the demand levels at which we would expect the fossil plant to run were incremented accordingly.

A14.55. Wholesale prices here were comparable, £48.29/MWh with BSUoS in the fuel price and £47.29/MWh without. Overall the impact on consumer cost was less (£158m) due to additional imports from cheap nuclear plant in France. The producer surpluses where also comparable at approximately £6,193m (with BSUoS in the fuel price) and £6,358m (without BSUoS in the fuel price).

Annex 14 – Draft Legal Text

The following extracts of the text in blue is the proposed additional text for CMP201 and the text to be deleted as part of CMP201 is in red. Green text will only be present if CMP202 has been approved.

Note that given the date at which this proposal may become effective is in advance of the Authorities decision, the appropriate implementation date will be substituted into the legal text at that time.

See paragraphs 4.98 to 4.99 for an indication of applicable dates.

14.29.4 All CUSC Parties acting as Generators and Suppliers [(for the avoidance of doubt excluding all BMUs associated with Interconnectors)], and from <implementation date> those parties acting as Suppliers only, are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period. (For the avoidance of doubt, Embedded Exemptible Generation will be treated as negative demand).

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QM_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QM_{ij} * TLM_{ij})\right|\right\}}$$

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QM_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QM_{ij} * TLM_{ij})\right|\right\}}$$

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QM_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$BSUoSTOT_j$ Total BSUoS Charge applicable for Settlement Period j

QM_{ij} BM Unit Metered Volume **

$QMBSUoS_{ij}$ BSUoS Liable BM Unit Metered Volume

TLM_{ij} Transmission Loss Multiplier **

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code [(excluding all Interconnector BMUs and Trading Units)]

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge. ~~Note this includes the Interconnector BM Units that belong to the Interconnector Error Administrator~~

Interconnector and Generator BM Units

14.30.4 ~~The Lead Party of an Interconnector~~ BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator and those associated with Generators are not ~~will be~~ liable for BSUoS charges. ~~based on their proportion of the total BM Unit Metered Volume of each Settlement Period adjusted for Transmission Losses by the application of the relevant Transmission Losses Multiplier. Note this includes the Interconnector BM Units that belong to the Interconnector Error Administrator.~~

External BSUoS Charge for each Settlement Period ($BSUoSEXT_{jd}$)

14.30.6 The External BSUoS Charges for each Settlement Period ($BSUoSEXT_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow ($CSOBM_j$) and Balancing Service Variable Contract Cost ($BSCCV_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} + [\ (IncpayEXT_d + BSCCA_d + ET_d - OM_d)$$
$$* \{\ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right|\ \} /$$
$$\sum_{j \in d} \{\ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right|\ \}\ ]$$

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} + [\ (IncpayEXT_d + BSCCA_d + ET_d - OM_d)$$
$$* \{\ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right|\ \} /$$
$$\sum_{j \in d} \{\ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right|\ \}\ ]$$

Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{jd}$)

14.30.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.

$$BSUoSINT_{jd} = (CSOC_d + IncpayINT_d + NC_d + IAT_d + IONT_d)$$
$$* \{\ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right|\ \}$$
$$/ \sum_{j \in d} \{\ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right|\ \}$$

$$BSUoSINT_{jd} = (CSOC_d + IncpayINT_d + NC_d + IAT_d + IONT_d)$$
$$* \{\ \left|\sum^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QM_{ijd} * TLM_{ijd})\right|\ \} / \sum_{j \in d} \{\ \left|\sum^{+}(QM_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QM_{ijd} * TLM_{ijd})\right|\ \}$$

14.31.8 **Balancing Services Use of System Acronym Definitions**

BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS