nationalgrid

Stage 02: Workgroup Report

Connection and Use of System Code (CUSC)

CMP262

‘Removal of SBR/DSBR Costs from BSUoS into a “Demand Security Charge”’.

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

CMP262 aims to create a new cost recovery mechanism, a “Demand Security Charge” specifically for recovery of all SBR/DSBR costs, which is only levied on demand side Balancing Mechanism Units (BMUs).

This document contains the discussion of the Workgroup which formed in April 2016 to develop and assess the proposal.

Published on: **14 July 2016**

The Workgroup concludes *that they have met their terms of reference. Overall, the Workgroup supported WACM2 by majority as better facilitating the applicable CUSC objectives. Four votes supported WACM2, two Workgroup members supported the Original and one Workgroup member supported WACM3.*

High Impact: *Generators, Suppliers, Demand Customers and End Consumers*

Medium Impact: *National Grid*

Contents

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About this document

This is the final Workgroup Report, which includes the deliberations of the Workgroup, responses from the Workgroup Consultation and the final conclusions of the Workgroup. An electronic version of this document and all other CMP260 related documentation can be found on the National Grid website via the following link:
http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP262/

Document Control

Version	Date	Author	Change Reference
2.0	16 May 2016	Code Administrator	Workgroup Consultation to Industry
5.1	14 July 2016	Code Administrator	Workgroup Report to CUSC Panel

1 Summary

1.1 This document describes the Original CMP262 CUSC Modification Proposal (the Proposal), summarises the deliberations of the Workgroup and sets out the Workgroup Alternative CUSC Modifications (WACMs).

1.2 CMP262 was proposed by VPI Immingham and was submitted to the CUSC Modifications Panel for their consideration on 18 March 2016. A copy of this Proposal is provided within Annex 1. The Panel agreed with the Proposers request that the Proposal be developed and assessed against the CUSC Applicable Objectives in accordance with an urgent timetable. This request for 'urgency' was approved by Ofgem on 31 March 2016 (Annex 4). The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the CUSC Applicable Objectives. The Workgroup was required to consult on the Proposal during this period to gain views from the wider industry. Following the Workgroup Consultation, the Workgroup considered responses, voted on the proposals to the defect to report back to the Panel at the Special CUSC Panel meeting in July 2016.

1.3 CMP262 aims to create a new cost recovery mechanism, a "Demand Security Charge" specifically for recovery of all SBR/DSBR costs, which is only levied on demand side Balancing Mechanism Units (BMUs).

1.4 This Workgroup Report has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid Website, http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP262/ along with the Modification Proposal Form.

1.5 Sixteen responses were received to the Workgroup Consultation

1.6 The Workgroup met on 9 June 2016 to review the Workgroup Consultation responses and met again on 27 June to vote on the Original Proposal and the three Workgroup Alternative CUSC Modifications raised by Workgroup members. The Workgroup voted on the Original Proposal and the three Workgroup Alternative CUSC Modifications. Overall, the Workgroup supported WACM2 by majority as better facilitating the applicable CUSC objectives. Four votes supported WACM2, two Workgroup members supported the Original and one Workgroup member supported WACM3.

2 Background

Issue

2.1 The Proposer believes that Supplemental Balancing Reserve (SBR) utilisation costs are likely to become increasingly volatile and virtually impossible to forecast in winter 16/17 as a result of lack of transparency as to how SBR plant will be despatched and their true utilisation costs. They are concerned that the inability to forecast BSUoS as a result of this lack of transparency will result in a lack of appropriate signal and hence a distortion in competition between generators resulting in inefficient despatch as a result of erroneous and nebulous forecasts.

2.2 Furthermore, the Proposer has concerns that the result of this potential volatility across different settlement periods will provide:

i) Increased costs to consumers as a result of the addition of a risk premium;

ii) Perverse incentives for generators in terms of a signal to generate, particularly in the shoulder periods (due to very high BSUoS costs);

iii) Inaccuracy of cost forecasts leads to significant suboptimal despatch of generation leading to market inefficiency; and

iv) Outturn costs in excess of the forecast are irrecoverable by generators as they are recovered ex-post.

Further context

2.3 Balancing Service Use of System (BSUoS) charges are the means by which the System Operator (SO) recovers the costs associated with balancing the transmission system. BSUoS charges are levied on both generation and demand on a 50:50 split basis. The value of BSUoS varies in each half hour settlement period reflecting the different costs incurred by the SO in each period.

2.4 Currently, all SBR and Demand Side Balancing Reserve (DSBR) procurement and utilisation costs are recovered via BSUoS from both Suppliers and Generators. Both SBR and DSBR procurement costs are known ahead of time (and have almost quadrupled from 15/16 to 16/17) and are distributed across all settlement periods in the 4 months' winter season, reducing volatility. However, it is the Proposer's view that utilisation costs are opaque, impossible to forecast, are not known until 16 working days after the event and are applied within the settlement period that they are incurred, driving highly volatile BSUoS prices.

2.5 Given the concerns regarding security of supply in winter 16/17 and the likelihood that SBR will be despatched, the Proposer believes that it is likely that BSUoS will become highly volatile and increasingly difficult to predict. The Proposer believes that the range of utilisation costs associated with SBR and DSBR, coupled with the lack of ability to predict which plant will be despatched and when, make it increasingly difficult to forecast what the outturn BSUoS costs will actually be. In addition they believe this is further exacerbated by the lack of transparency around some of the utilisation costs where there is a £/MWh charge plus fuel and carbon costs, the latter two only known by the SBR generator itself with industry only able to make broad assumptions.

2.6 Generators are expected to recover BSUoS from the wholesale price. However, the actual cost of BSUoS will only be known ex-post, so despatch decisions can only be made on a forecast, and (in the Proposer's view) a very nebulous forecast at that due to the lack of transparency. National Grid only forecast an average BSUoS and The Proposer believes that this will be increasingly inaccurate going forward due to the changing nature of the market and balancing services procured.

2.7 The Proposer is concerned that, in such circumstances, generators must add an increasing risk premium into their BSUoS forecasts resulting in far higher costs for consumers plus risking uneconomical despatch. With the information required to accurately forecast SBR requirements not available to the market in the required timescales, or at all, the Proposer suggests that there is no way that parties can accurately quantify the level of SBR costs incurred. (For example, the de-rated margin published as part of the cash out changes is published at 12 o'clock day ahead, yet some plant has 48 hour warming timescales). Furthermore, the Proposer understands that DSBR can be despatched on short notice with very little notice given to the market.

2.8 The Proposer notes that the costs associated with warming, starting and running SBR may occur in periods of the day in which system margin may not be tight. This is because some SBR take a long period to become ready to provide the service. (For example, if SBR is required for Block 5b, yet due to warming timescales, its costs are imposed through blocks 3, 4 and 5a, up to 48 hours ahead.) As a result, the Proposer believes that BSUoS may be both high and volatile for these periods. This could result in generators delaying their start until as close as possible to the periods where they know the market price is guaranteed to cover the risk of high BSUoS. The Proposer also believes that having more generation starting up just before the block where SBR is required is likely to drive even higher risk premiums and hence will end up costing consumers more, notwithstanding that it comes about through a market distortion in the first place.

2.9 The Proposer is concerned that for non-vertically integrated generators who are not able to offset any higher than expected BSUoS charges against their customer base, this results in a market distortion and could become a barrier to entry for independent generators, as independent generators are most exposed to this risk. The Proposer understands that, in the worst case, consistent usage of SBR could result in a generator going bankrupt due to cash flow issues and hence the security of supply issue being exacerbated. The Proposer, VPI Immingham, proposes moving all of the SBR and DSBR costs, in place to ensure security of supply rather than to balance the system, into a "Demand Security Charge", fully recovered over gross [1] demand in the SBR or DSBR window, in line with the capacity mechanism which recovers costs 28 days after the event.

2.10 They believe that placing SBR/DSBR costs onto customers via a "Demand Security Charge" would more economically charge the parties who are benefiting from the product at the same time as aligning and being consistent with capacity mechanism cost recovery, i.e. recovery from suppliers. They also believe that such a move would further protect generators from yet more unforeseen and unforecastable costs without increasing the overall cost burden on consumers. In fact, they believe it should reduce overall costs to consumers due to a lower risk premium being applied by generators. The Proposer believes that their proposal should also protect customers from paying for a lack of efficiency in generation despatch as a result of the uncertainty. They understand the otherwise likely addition of extensive risk premia to mitigate for the uncertainty, as a result of

[1] The practicalities associated with a gross charging solution would make its implementation in time for the forthcoming winter unlikely. Following these discussions, the Proposer has amended the Original Proposal, such that the "Demand Security Charge" would collect total SBR and DSBR costs from net (instead of gross) demand over the winter.

generators seeking to manage the costs of BSUoS charges they cannot see nor forecast, can only drive higher costs for consumers.

Purpose of Proposal

2.11 This modification proposal proposes to create a new cost recovery mechanism, a “Demand Security Charge” specifically for recovery of all SBR/DSBR costs, which is only levied on demand side Balancing Mechanism Units (BMUs). The Proposer believes that this is the best way to reduce the risk premia applied by Generators, hence minimising costs to the consumer, and to ensure efficient despatch of plant.

2.12 Whilst it is expected that the Workgroup develop the solution in detail, the Proposer would expect the total costs to be collected from gross [2] demand over winter, i.e. November to February. This would ensure that the costs would not be volatile across different settlement periods.

2.13 SBR is in place to maintain security of supply, similar to the capacity mechanism which aims at longer term, and the Proposer believes that it is therefore more appropriate that all costs fall on suppliers who are better able to recover the actual costs from customers.

2.14 Given some of the costs are known ahead of winter, the Proposer believes that National Grid could continue to forecast the SBR costs (the Proposer understands that procurement costs are already known) so that suppliers can estimate costs over the winter period and then a winter only charge, mirroring the SBR window, could be applied. The Proposer believes that the proposal should reduce the cost to consumers as significant risk premia will no longer be added by generators.

Additional Considerations

2.15 The Government has confirmed its intention to bring forward the Capacity Market (CM) auction by one year, so that it provides enough generation capacity to meet the Government’s reliability standard for winter 17/18. On 1 March 2016, Ofgem published an open letter setting out that they expect a 2017/18 CM auction to procure enough capacity to meet the government’s reliability standard. Therefore, SBR and DSBR services would not be needed for that year and thus it is expected that cost recovery of SBR and DSBR through BSUoS will only continue for one more winter (2016/17).

Post Workgroup meeting amendments to proposal

2.16 During discussion within the CMP262 Workgroup, it was highlighted that the practicalities associated with a gross charging solution would make its implementation in time for the forthcoming winter unlikely. Following these discussions, the Proposer has amended the Original Proposal, such that the “Demand Security Charge” would collect total SBR and DSBR costs from net (instead of gross) demand over the winter.

2.17 In addition, it was discussed whether the total costs of SBR/DSBR should be included or whether just the utilisation costs should be included. Although the Proposer supported all costs being recovered from suppliers, it was recognised that the issue is caused by the utilisation costs and therefore,

2 The practicalities associated with a gross charging solution would make its implementation in time for the forthcoming winter unlikely. Following these discussions, the Proposer has amended the Original Proposal, such that the “Demand Security Charge” would collect total SBR and DSBR costs from net (instead of gross) demand over the winter.

practically, it made more sense to just recover these, as procurement costs should already have been factored in as they are already known.

3 Workgroup Discussions

3.1 This section provides information regarding Workgroup discussion in relation to this proposal captured in three key areas;

- Who pays what?
- Who should pay which component of SBR/DBSR costs?
- When and how are costs paid?
- Interactions with wider market arrangements.

3.2 Implementation and transitional arrangements are covered in Section 5 of this document.

Who should pay which component of SBR/DBSR costs?

3.3 The Proposer has highlighted a concern that, due to their nature, DSBR and SBR costs for winter 2016/17 are very difficult to forecast which will likely result in a distortion of competition between generators. This is because all SBR/DSBR costs are recovered via BSUoS from both suppliers and generators and are not known until 16 working days after the event. The Workgroup have considered the merits of charging the entirety of these costs to demand (as proposed under the original) against the existing methodology of splitting these evenly between generation and demand.

3.4 SBR/DBSR costs are made up of Procurement costs (£27m 2015/16 and £122m for 2016/17) which are effectively availability payments and are known in advance and Utilisation costs which are very difficult to forecast as they are dependent upon the level of service utilisation (which cannot be known until actual market and weather conditions on the day are known). There is a concern that the market does not have enough visibility of how SBR plant will be despatched or understanding of Utilisation prices (as these may include fuel index, fuel and carbon costs) to make an informed judgement on the likely level of Utilisation costs to be recovered via BSUoS. The inconsistency between warming and both general system notifications and System Warning publication timescales, means that some plant could be warmed well in advance of these notices may exacerbate this issue. However, it was recognised by some of the Workgroup that warming instructions are made available by National Grid via other mechanisms (e.g. via the System Operator Notification and Reporting system (SONAR)).

3.5 The increased volume procured, plus level of SBR and DSBR procurement costs and forecast capacity margins for winter 2016/17, would indicate that there is an increased likelihood of SBR plant being despatched than in previous winters. If utilised multiple times, some Workgroup members believed the costs could run into tens of millions of pounds. These utilisation costs are then recovered through BSUoS charges for the days in which they are incurred (whereas procurement costs are spread over total winter demand and generation volumes).

3.6 There is a concern that this could drive very high, highly volatile BSUoS prices in periods where SBR plant is warmed and run in earnest, particularly when coal SBR plant is used, due to its different operating parameters, namely longer timeframes. In order to mitigate this risk, generators could be forced to add a significant risk premium to their prices, driving higher costs for consumers. Please refer to Annex 5 which provides analysis which illustrates the changes in BSUoS from the status quo to the proposed solution.

3.7 It was noted that Suppliers would also have to factor such a risk premium into their prices, and could lead to independent Suppliers in particular feeling exposed to the risk due to the potential negative impact on their cash flow, and in turn their ability to remain competitive.

3.8 Some Workgroup members highlighted that a considerable volume of energy had already been traded for winter 2016/17, and that generators may have already included a risk premium within their prices for this based upon the current arrangements. As a result, the proposal could result in additional costs to end consumers, as suppliers would be exposed to the potential costs through the proposed "Demand Security Charge", as well as already having paid the same cost in the price paid for energy purchased to date. However, it was noted that the announcement of the SBR tender results in December 2015 and the £122m of costs incurred had no notable impact on wholesale prices, despite the fact that these costs feed straight through to BSUoS and would have a significant impact on BSUoS for each settlement period. Please refer to Annex 5 which provides analysis.

3.9 It was noted that some Suppliers provide a fixed 1, 2 and 3 year contract to their customers and it was unclear how these additional costs could be recovered from these customers, especially if no re-opener existed. It is likely that some Suppliers would have no option but to recover the additional 50% of SBR and DSBR costs from customers with a variable contract or to factor these in to future prices. It was also noted that some customers may be disadvantaged as some Suppliers will be able to absorb these costs better than others.

3.10 As BSUoS is currently charged 50% to generation and 50% to demand, by removing the demand element and proposing a new 100% net demand charge the Workgroup debated if in reality this would be 100% of demand or 90% due to some offset of embedded generation. One member of the Workgroup pointed out that gross demand could be up to 150% of that currently charged (net demand), depending on future policies.

3.11 The Workgroup discussed the merits of charging gross instead of net demand, and the Proposer highlighted that they did not think it was appropriate for any embedded benefit to be provided through the new charge proposed under the original. However, the Workgroup agreed that charging on a gross demand basis would involve a fundamental market change and as a result would be difficult to implement in time for this winter (after which use of SBR is considered unlikely). On this basis, the Proposer stated that on balance, to enable implementation for the forthcoming winter, they would alter the original so that the proposed charge would be charged on a net demand basis.

3.12 The Workgroup raised a concern over the difficulty in forecasting the future costs ahead of publishing of the winter outlook report, given the lack of information available regarding the likelihood of SBR and DSBR being utilised. It was highlighted that the likely utilisation level for the forthcoming winter could not yet be assessed, as it is too early to predict the likely weather conditions or plant availability accurately.

3.13 The Workgroup also discussed the impact of extremes in weather conditions on volatility of costs and if any comparison could be made to last winter. This was ruled out as last winter had been particularly mild, the profiles of the SBR plants were very different and that it had not actually been used (with only DSBR used on one occasion). Please refer to Annex 5 which provides analysis.

3.14 The Proposer provided analysis (Table 1) of costs if all SBR plants are run, noting that two scenarios were modelled. The first scenario looked at when SBR is used in earnest for one hour and a second scenario considered when it is used in earnest for two hours. Wherever no actual costs were provided it is assumed the cost of the nearest equivalent station as a proxy.

The Proposer observed that the need to use such a proxy demonstrates the difficulty in accurately assessing the costs. They also highlighted that even with the operational methodology and the market information available. They felt that it was not clear what costs would be incurred and when (such as start-up costs and hot standby costs). National Grid highlighted that it was currently looking to improve the level of information published, and was planning a session at the June Operational Forum to talk through some scenarios ahead of next winter. The Workgroup considered analysis that would assist the benefit case for this modification and agreed to assess the material available for the Operations Forum after the Workgroup Consultation in June.

Table 1

	Capability	SEL	NDZ	MNZT	Run up	Run Down	Price	Start Up	Hot Standby	1 hour	2 hours
	MW	MW	hrs	hrs	hrs	hrs	£/MWh	£/hr	£/hr		
SHB	750	540	18.0	6.0	4.7	0.3	200	£1,000	1000	554,250	704,250
SHB2	20	20	-	0.5	1.0	0.0	250			7,583	12,583
Deeside	250	100	1.5	2.4	0.9	0.2	225			90,656	144,844
Rugeley	25	10	0.2	0.5	0.1	0.0	500			12,917	25,417
Eggborough	775	280	48.0	4.0	0.9	0.6	500	3908	11513	1,096,643	1,283,598
Corby	353	220	1.4	6.0	5.8	0.2	200			280,047	350,647
Fiddlers Ferry Coal	480	240	24.0	4.0	2.0	0.9	500	3000	3000	644,000	916,000
FF GT	17	17	0.5	1.0	0.0	0.0	550			9,506	18,856
FF GT	17	17	0.5	1.0	0.0	0.0	550			9,506	18,856
Keadby GT	23	23	0.5	1.0	0.1	0.1	550			14,126	26,776
Peterhead	375	249	3.7	4.0	2.2	0.7	250	1200		224,613	330,294
Peterhead	375	249	3.7	4.0	2.2	0.7	250	1200		224,613	330,294
Killingholme	600	240	1.3	1.0	0.3	0.3	200			158,000	278,000
										3,326,458	**4,440,413**

Exact utilisation costs not known. Assumed cost figures provided by Mary Teuton.

Table 1

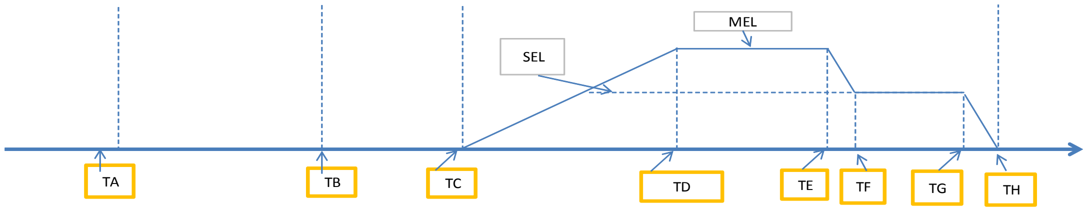
3.15 In relation to the improvements in the level of information provided, National Grid currently considering the following (the paragraphs in brackets are updated after June, following the Operations Forum):

- Confirming which units are contracted for SBR by September – (if SBR providers confirm units by end August, National Grid will be able to publish the information by early September).Providing expected capability costs (including testing) and timings – (these costs are already published on National Grid's website);
- Providing clarity over when start-up, warming, and utilisation instructions have been issued for SBR – (Session has been held at June Operational forum to talk through decision making processes. Final operational methodology will be published at end of August setting out detailed steps);
- Publishing MW profiled load contracted for DSBR – (National Grid will be able to do this in September once contracts are signed and verified); and
- Publishing full DSBR dispatch information by settlement period shortly after instruction on day D – (this work is under the BSC Modification Proposal P333)

3.16 It is worth noting that the assumptions below have been adopted throughout the analysis (including those in Annex 5).

i) Wherever possible, units are run straight up to MEL (Maximum Export Limit) for the time needed, and not held at SEL (Stable Export Limit). (i.e. minimising hot standby duration). In this model it was assumed that hot standby hours are zero.

ii) If utilised, a unit is held at the MW required for the time needed, and run down to either SEL (if MNZT-run up - run down > time needed), or 0 (if MNZT-run up - run down <= time needed) – please see the figure below (Figure 1) for illustration.



iii) ***Figure 1*** – Illustrative Unit Output

iv) For the purpose of calculating BSUoS volume, HH demand profile was obtained from the metered 2015/16 winter data surrounding the maximum national demand snapshot. There is no correlation assumed between the demand level and the amount of SBR utilised.

v) Assuming linear ramp up.

vi) Assuming all the SBR units are available (i.e. no unit breakdown etc.).

vii) The 2015/16 winter BSUoS volume and BSUoS price data were obtained from National Grid website http://www2.nationalgrid.com/bsuos/ (for current SF BSUoS data)

viii) Utilisation Price assumptions are shown in Table1 (provided by Vitol Group).

3.17 Using these parameters as a basis, National Grid provided a breakdown of the impact of these costs on half-hourly basis, assuming that SBR was utilised at a period of peak demand similar to that level in 2015/16. The result of this analysis (Figure 2) show additional costs of between £0.1/MWh (for warming cost) and £12.7/MWh (for utilisation) if all units are utilised.

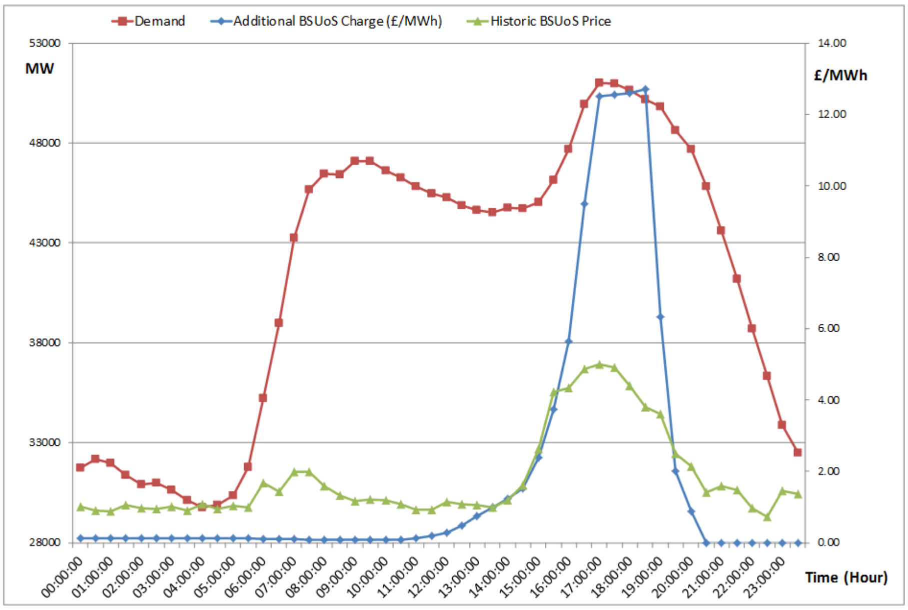


Figure 2: Breakdown of SBR cost by each settlement period, assuming generators and suppliers pay on a 50:50 basis

3.18 The impacts of the modification were recognised as being varied from party to party. Some vertically integrated businesses could be operating their group finance and regulatory department separately and benefit differently to Independent Suppliers that would see a greater impact on their cash flow. The modification may be of different impact to Suppliers based on their focus between fixed and variable contracts with customers.

3.19 The Proposer highlighted that currently generators had perverse incentives in terms of signals to generate, particularly in the shoulder periods when SBR would be running, but not required, yet BSUoS could be very high (as shown in figure 2, during the hours between 12:30 to 16:30), the additional BSUoS price due to SBR ranges from £0.49/MWh to £9.495/MWh if broken down to half hourly basis. The Proposer noted that prices should be high enough when used SBR was in earnest. This signal could lead to market inefficiency as a result of inefficient despatch of plant based on an unclear forecast and could exacerbate the security of supply issue as generators delayed their start until they could be sure that they would recover their costs.

3.20 For example, SBR may only be required for Block 5b, but could be warmed up to 48 hours ahead of need driving high and volatile BSUoS. This could result in generators delaying their start until they are sure that they will recover their costs. This could drive ever higher risk premium and cost consumers more. This led to the suggestion that costs could be spread across the appropriate block to incentivise the right behaviour.

3.21 The Proposer also noted that this could be a potential barrier for entry, particularly for independent generators who are not able to offset higher costs against a customer base. At worst, an independent generator would likely be most exposed, struggling with low spreads and low load factors, could go bankrupt, worsening security of supply and exacerbating the very issue that SBR is trying to solve.

3.22 The Workgroup discussed the impact of this proposal on competition and at which point does it prevent the market from reacting in a competitive manner noting that both generators and suppliers will manage their businesses in a competitive manner. SBR is used as a last resort product and more generators would want to be incentivised to generate with a penalty to those that didn't generate (although it was recognised that the latter would be a difficult arrangement to introduce).

3.23 The Proposer noted that it would be useful to have the same signal for generators and suppliers.

3.24 Following workgroup consultation and industry responses, National Grid have re-done the cost analysis, based on National Grid's generic assumption about fuel and carbon costs. The revised results are attached in Annex 6. Compared to the results shown in 3.17 – 3.19, the revised results show a moderate downward adjustment.

When and how are costs paid?

3.25 Under the existing arrangements, SBR and DSBR utilisation and preparation costs (e.g. warming of SBR plant) are fed into the BSUoS charges for the Settlement Day in which they are incurred (even though some of these costs are in preparation for use in a later Settlement Day). Under the original proposal these cost would be smeared across the winter. The group highlighted two ways in which this could be done: a. across all Settlement Periods; and b. across Settlement Periods in EFA Block 5b (assuming 17:00-19:00 during winter season, and assuming monthly invoices). The group has considered the merits of each option.

3.26 The Workgroup has noted that smearing of the SBR and DSBR utilisation costs would result in more stable charges for suppliers, but that focusing the costs in the period when required would incentivise suppliers to reduce demand and therefore reduce the need to despatch SBR. The Workgroup agreed that an incentive to reduce demand at the time SBR was required sent the right price signal to the market. Whilst under the Original proposal, this changes the level of risk profile for Suppliers, it does not remove it.

3.27 It was agreed that the cost would remain ex post however Suppliers reaction to this modification will depend on the type of customer they are and the type of contracts they have in place. It also led to a discussion as to whether the costs could be recovered in advance and reconciled at a later date.

3.28 A proportion of generation is sold ahead of time with a risk premium already built in. The Workgroup revisited this in the context of smearing, and considered if SBR/DSBR is not already factored into the risk premium who would be the best person to manage this risk. Smearing costs may work better for Suppliers (if they have variable price contract with their customers) rather than Generators, with concerns raised that baseload generators may pick up proportionally more of the costs if smeared over a longer period, despite not contributing to the issue. However, it was noted that a signal to incentivise the right behaviour would be welcome.

3.29 Options for spreading the costs over different periods were considered including peak, daily, monthly and spreading the costs over Triad (Table 2). The Workgroup did not support smoothing these costs over a longer (than winter) period of time as this could potential add risk to the market should the Supplier or generator go into administration. The Workgroup agreed with the principle that costs should be incurred by the users at the point in time of use. It was also noted, that there was no guarantee that SBR would be used at winter peak and that it could be used at any point during the winter. If this was the case, then it may be inappropriate to recover costs against volumes at winter peak. In the example shown in figure 2, the indicative costs of various options are shown in the following table. Please note all the options are based on 50:50 cost sharing between generators and suppliers. If the SBR cost were to be borne by suppliers only, the figures will double accordingly.

Duration = 2 hour		Capacity = 4000 MW		
Cost Spread 24/7 over Triad Season	Cost Spread over 5b on three Triad days (£/MWh)	Cost Spread over 5b over Triad Season (£/MWh)	Cost Spread 24/7 over the month (£/MWh)	Cost Spread over the day (£/MWh)
0.03	7.90	0.32	0.09	2.24
Total Cost (£k) per Utilisation				4336

Table 2

3.30 There was discussion on whether licence changes and other consequential code change are required should BSUoS not be recovered on a 50/50 split basis. Further investigation confirmed that there is no statement in the Code that BSUoS needs to be recovered as 50/50 split as the recovery is based on Volume, therefore no licence change is required if the above mentioned SBR/DSBR utilisation cost is part of BSUoS, and is recovered in accordance with the CUSC. National Grid did however confirm that a separate charge outside BSUoS will result in a licence change.

3.31 There was also a discussion on whether costs can be allocated in future years recovered from future network users, and what the timescales are required to implement changes to the licence and or subsidiary documents.

3.32 Ofgem have confirmed that a licence change would take at least 3 to 6 months with a 28 day consultation period and a 56 day standstill period. National Grid confirmed that the reference to “Relevant Year t” in the definition of LBSt in Special Condition 4K of the Transmission Licence meant that a licence change would be required to recover SBR and DSBR costs from users in future years.

3.33 National Grid were asked to clarify how Blackstart will work for reconciliation purposes, and assess how this will relate to this modification should it take place mid-year.

3.34 A link to the recent Blackstart income adjustment event consultation can be found here https://www.ofgem.gov.uk/system/files/docs/2016/06/notice_of_proposed_iae_submitted_by_nget_on_2015-17_incentive_scheme.pdf which explains how the intended cost recovery plan works.

Interactions with wider market arrangements

3.35 A list of related BSC modifications and change proposals that could potentially impact CMP262 have been identified and reviewed. It was concluded that these would not have any impact on CMP262 (and vice-versa) as they relate to ex post information. These BSC modifications were P333 and CP1460.

3.36 The Workgroup acknowledged the work that has been carried out for CMP250. One respondent to the Workgroup Consultation for this modification noted that National Grid produced a lot of information that could be factored in into trading position and would enable market participants to react to the National Grid forecast and also assess and identify risk premiums for the short and medium term.

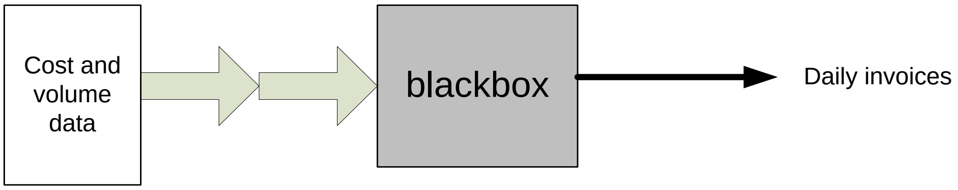
3.37 The impact of RCRC has also been captured as part of CMP250. Traditionally generators are paid RCRC but pay BSUoS resulting in an offset between the two, and that the proposal may introduce disconnect between the two. It is recognised that a disconnect already exists between these when SBR is utilised as imbalance (cash-out) is priced at the Value of Lossed Load (currently £3000/MWh) providing a strong signal for parties to meet their notified positions in a half-hour in which SBR is utilised. One Workgroup member stated that generators would prefer relief from BSUoS as in some cases imbalance may result in residual payments. Another member stated that the settlement run was to ensure not too much is collected through imbalance (which in turn affects BSUoS costs) and struggled to see how change can be applied from the proposal without it impacting imbalance charges, RCRC and BSUoS. It was also noted that there was an interaction with the cash out prices with P323 resulting in cashout prices of VoLL when SBR plant was despatched above SEL.

Post Workgroup Consultation Discussions

3.38 The Workgroup reviewed the Workgroup Consultation responses and discussed various options that could be considered as WACMs to the Original proposal including smearing options (Table 3). The following table highlights the variations considered and Workgroup members indicated the options they would supports as a WACM should the option be supported ahead of voting. The impact these options would have on systems, the industry and consumer are further summarised in Table 4.

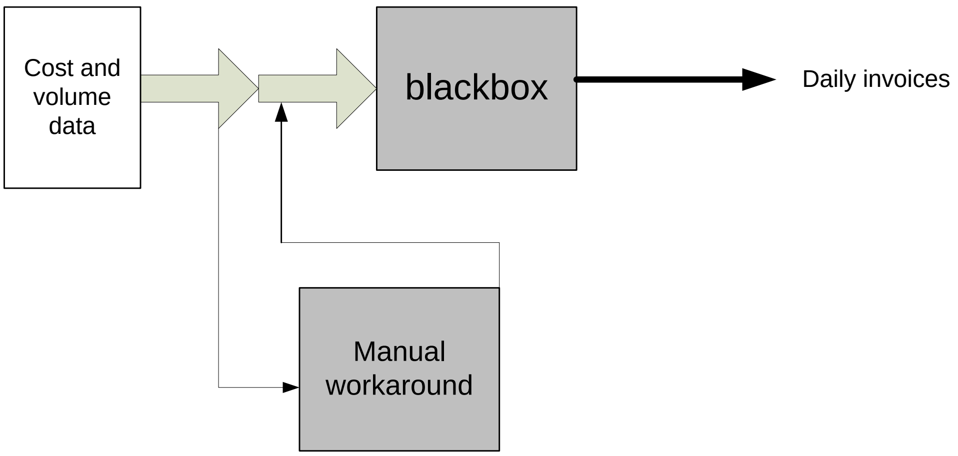
3.39 In terms of how the manual process would work in practice, the National Grid representative provided the following analysis that demonstrates the interaction between different systems;

3.40 Background: The BSUoS invoice and billing system is a "black box" which is fed with data from Elexon and National Grid, and the box does the calculation and produce daily invoice.



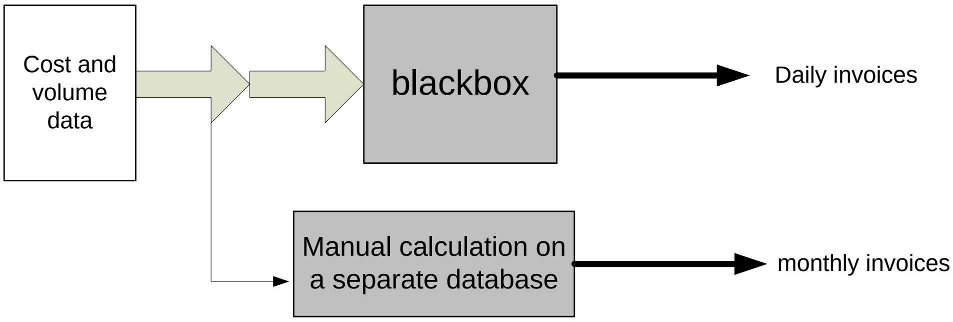
Option a. G:D split 50:50 (as status quo), and smear the Utilisation cost across all 48 Settlement Periods

3.41 The Utilisation cost will be manually "blocked" before it travels into the "black box", cost then get smeared by MWh volumes (outturn + forecasted), and then fed back into the "black box" for it to calculate the daily invoice.



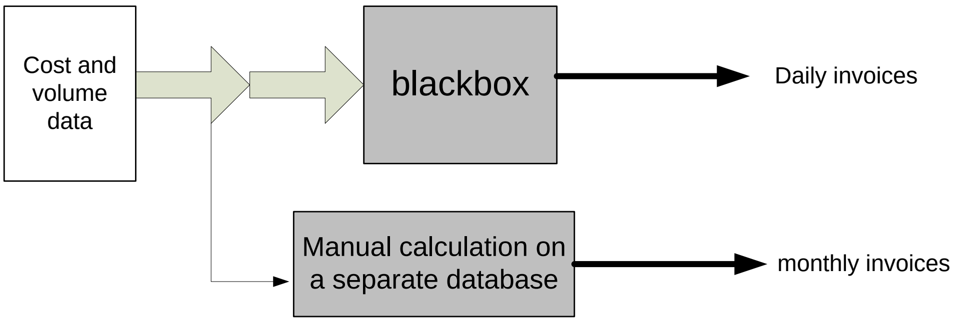
Option b. Utilisation cost charged to "offtaking trading units" (approximately suppliers) only and smeared across winter

3.42 The Utilisation cost and the MWh information will be diverted into a separate database (manually built and tested) which would calculate this cost element, and this cost element will be manually combined with other BSUoS charge, to produce invoice. Hence the utilisation cost calculation will "bypass" the BSUoS black box - more complicated, more manual handling required, and more prone to human errors. Cost wise also more expensive as manual invoicing may be needed.



Option c. Smearing cost to certain time period (e.g. 7am - 7pm), as opposed to all 48 settlement periods -

3.43 The "black box" reads HH data as part of BSIS, thus it is not possible to manually intervene the HH cost that goes into the "black box". In order to get round it, another bypass database will be needed, and information diverted into the bypass database in a similar way as option b. Similarly, it is more complicated, more manual handing and more prone to human errors.



3.44 Additionally, the Workgroup concluded the impact on various sectors of the market under the Original and each WACMs. For the winter of 2016/17, impact assessment would require information on the trading contracts and risk premiums already in place. It would therefore be very difficult to quantify the actual impact this proposal would have on various sectors of the market.

3.45 The Workgroup also concluded that it would not be able to quantify the ultimate cost impact on end consumers, partly due to similar reason described in the above paragraph. In addition, this would only be concluded post utilisation of SBR/DSBR. The likely utilisation costs would need to consider many variables including the portfolio mix of generators and suppliers and if these costs had already been factored into their risk premium and whether their contracts with their end consumers were fixed or variable.

Option / WACM reference	Owner	**New / Existing** (Develop new charge or include in existing BSUoS charge)	**Demand / Generation (charging demand only?)**	**Gross / Net**	**Current Year**	Smearing Options						
						A	B	C	D	E	F	G
						Across next winter (17/18) and same settlement period (Future)	Across actual settlement period (16/17). i.e. when cost occurred (Current)	Across actual settlement period when SBR required in 16/17 (Current)	Across 6am to 8pm (whole winter cost, Nov to Feb) (Current or Future)	Across whole winter, all settlement periods, Nov to Feb (Current or Future)	Across 6am to 8pm on the day that the cost is occurred (28 periods)	Across from the day SBR/DSBR utilisation cost is incurred, until 31st March 2017 (inclusive), across 48 periods daily, current Financial year
Original Proposal	Mary Teuton - VPI Immingham	Existing	Demand	Net	Current	No	No	No	No	**Yes**	No	No
Option 1 for WACM	*Guy Phillips - Uniper*	*Existing*	*Demand*	*Gross*	*Future (2017/2018)*	No	No	No	No	**Yes**	No	No
Option 2 for WACM	Andrew Colley - SSE	Existing	Demand	Net	Current	No	No	No	No	No	**Yes**	No
Option3 for WACM	*Sarah Owen - Centrica*	*Existing*	*Both*	*Gross*	*Future (2017/2018)*	No	No	No	No	**Yes**	No	No
Option 4 for WACM	Daniel Hickman - npower	Existing	Both	Net	Current	No	No	No	No	**Yes**	No	No
Option 5 for WACM	*Daniel Hickman - npower*	*Existing*	*Both*	*Net*	*Future (2017/2018)*	No	No	No	No	**Yes**	No	No
Option 6 for WACM	Daniel Hickman - npower	Existing	Both	Net	Current	No	No	No	**Yes**	No	No	No
Option 7 for WACM	*Daniel Hickman - npower*	*Existing*	*Both*	*Net*	*Future (2017/2018)*	No	No	No	**Yes**	No	No	No
Option 8 for WACM	Sarah Owen - Centrica	Existing	Both	Net	Current	No	No	No	No	No	**Yes**	No

***Table 3* – Options and support for potential for WACMs**

	Demand / Generation (charging demand only?)	Gross / Net	Current Year	Smearing Option A	Smearing Option B	Smearing Option C	Smearing Option D	Smearing Option E	Smearing Option F	Smearing Option G
				Across next winter (17/18) and same settlement period (Future)	Across actual settlement period (16/17). i.e. when cost occurred (Current)	Across actual settlement period when SBR required in 16/17 (Current)	Across 6am to 8pm (whole winter cost, Nov to Feb) (Current or Future)	Across whole winter, all settlement periods, Nov to Feb (Current or Future)	Across 6am to 8pm on the day that the cost is occurred (28 periods)	Across from the day SBR/DSBR utilisation cost is incurred, until 31st March 2017 (inclusive), across 48 periods daily, current Financial year
IS Impact (Yes / No)	manual workaround	Yes	Pros - Current year provides cost reflectivity and future year provides predictability of costs. there are concerns with cashflow, and charging cost to future users may be considered a barrier to entry.	manual workaround	n/a - status quo	manual workaround	manual workaround	manual workaround	manual workaround	manual workaround
Are National Grid able to support an IS System change (Yes / No) If 'No', please provide justification	No: circa £1m and long lead time	No: requiring BSC mod + millions of IT cost (Elexon + NG system changes)		No: expensive to change IS system (circa £1m) to accommodate this one-off change		No: expensive to change IS system (circa £1m) to accommodate this one-off change	No: expensive to change IS system (circa £1m) to accommodate this one-off change	No: expensive to change IS system (circa £1m) to accommodate this one-off change	No: expensive to change IS system (circa £1m) to accommodate this one-off change	No: expensive to change IS system (circa £1m) to accommodate this one-off change
Are National Grid able to support a manual workaround? (Yes / No) If 'No', please provide justification	Possible but Not preferred: less consistency as Trading Units can flip input/output; higher complexity and higher risk of human errors; more expensive to implement manual workaround (circa £250k)	No: manual workaround is not supported by the existing IT system for gross charging		Np: not practical as people may change behaviour to avoid this charge		No: will make BSUoS more volatile	Possible but Not preferred - there is a risk of impact on other functions (BSIS for example), if individual HH data are manually fed into the system; mitigating this risk means higher cost for manual workaround	Yes	Possible but Not preferred - there is a risk of impact on other functions (BSIS for example), if individual HH data are manually fed into the system; mitigating this risk means higher cost for manual workaround	Yes
Does this option impact Elexon? Please provide details.	No (assuming net demand)	Yes. requiring BSC mod + system change		No (assuming net demand)		No (assuming net demand)	No (assuming net demand)	No (assuming net demand)	No (assuming net demand)	No (assuming net demand)
What are the Pro / Cons for industry with this option	Cons -DSBR/SBR will facilitate demand/generation balance, and thus generators also benefit from stable operation conditions provided by the grid. Charging the cost to demand only will also create another type of embedded benefit.	Pros - This is how the system currently works. Option is only practical for one year. Cons - Embedded benefits already exist and this gives more to this sector. There a wider review on charging already taking place.		Cons - not cost reflective; may provide barrier to entry		Cons - intermittent generators are unlikely to run when SBR runs, leaving despatchable generators to pick up the cost; also due to the technology of SBR units this year, it may take up to 48 hours to ramp up before using SBR, thus within-day charge may not cover the true cost	Cons - pre-defined time slot may have unwanted consequence in users' behaviour; customers with “behind the meter” onsite generators may be able to avoid this charge while domestic users are likely to be charged	Pros - this is similar to SBR/DSBR availability and testing payment, and will reduce BSUoS volatility, thus providing certainty to the industry	Cons - this option does not address the inconsistency between despatchable and intermittent generators in terms of SBR/DSBR utilisation payment	Cons - more complicated than option E, while E can deliver the same outcome with greater transparency
What are the Pro / Cons for consumers with this option	Cons -Consideration the implementation timescale (winter 2016/17), consumers may end up paying twice if the cost is transferred from generators to suppliers.	Cons - Domestic customers are likely to be picking up more of the costs if net option approved		Pros – Under winter smearing, BSUoS will be less sensitive to SBR/DSBR utilisation, thus independent generators are more likely to generate this winter, resulting in better demand security and less DSBR/SBR payment for end consumers		Cons - volatile BSUoS does not provide industry with certainty, and ultimately consumers are worse off due to capacity scarcity	Pros - Under winter smearing, BSUoS will be less sensitive to SBR/DSBR utilisation, thus independent generators are more likely to generate this winter, resulting in better demand security and less DSBR/SBR payment for end consumers Cons - domestic users are	Pros - Under winter smearing, BSUoS will be less sensitive to SBR/DSBR utilisation, thus independent generators are more likely to generate this winter, resulting in better demand security and less DSBR/SBR payment for end consumers	Cons - domestic users are likely to pay while those who can run "behind the meter" generators are able to avoid this payment	Cons - more complicated than option E, while E can deliver the same outcome with greater transparency

				Cons - consumers may have already paid up front for this year's cost; and then may pay again next year			likely to pay while those who can run "behind the meter" generators are able to avoid this payment			

***Table 4* – Impact of Options**

3.46 When review the impact identified in Table 4, the Workgroup agreed that any option requiring ‘Gross’ charging and recovering in future years could not be considered viable solutions to this proposal. Gross Charging was discounted as it resulted in the requirement of a consequential modification being raised with Elexon which could not be implemented within the required timescales, discussions with Elexon highlighted that any changes to the BSC would require a 12 to 18 month lead time. Additionally, any solutions requiring recovery in future years would result in a licence change as per Special Condition 4k of the Transmission Licence. Ofgem were able to confirm that any licence changes would take three to six months with a 28 consultation period and 56 day standstill period. For these reasons options 1, 3, 5 and 7 were discounted as options for potential WACMs by the Workgroup.

4 Original Proposal and Workgroup Alternatives

4.1 Following on from the Workgroup Consultation, the workgroup considered the options that could be considered as WACMs and WACM ownership was agreed. The Proposer also agreed what the Original Proposal would consider within its scope. For the avoidance of doubt the following table shows the scope of each proposal.

Option / WACM reference	Owner	**New / Existing** (Develop new charge or include in existing BSUoS charge)	**Demand / Generation (charging demand only?)**	**Gross / Net**	**Current Year**	Smearing Options			
						D	**E**	**F**	**G**
						Across 6am to 8pm (whole winter cost, Nov to Feb) (Current or Future)	Across whole winter, all settlement periods, Nov to Feb (Current or Future)	Across 6am to 8pm on the day that the cost is occurred (28 periods)	Across from the day SBR/DSBR utilisation cost is incurred, until 31st March 2017 (inclusive), across 48 periods daily, current Financial year
Original Proposal	Mary Teuton - VPI Immingham	Existing	Demand	Net	Current	No	**Yes**	No	No
WACM1 (Option 2)	Andrew Colley - SSE	Existing	Demand	Net	Current	No	No	**Yes**	No
WACM 2 (Option 4)	Daniel Hickman - npower	Existing	Both	Net	Current	No	**Yes**	No	No
WACM 3 (Option 6)	Daniel Hickman - npower	Existing	Both	Net	Current	**Yes**	No	No	No
WACM 4 (Option 8)	Sarah Owen - Centrica	Existing	Both	Net	Current	No	No	**Yes**	No

***Table 5* –** Variable of Original Proposal and WACMs

5 Impact and Assessment

Impact on the CUSC

5.1 Changes to Section 14.

Impact on Greenhouse Gas Emissions

5.2 None identified.

Impact on Core Industry Documents

5.3 The Workgroup identified that there may be a potential amendment that would be required to the BSC. This would be required should an option for Gross Demand charge be supported by the Workgroup. Upon further investigation, the Workgroup recognised that any changes required to the BSC would not be implemented in time to meet the requirement of the defect and therefore this option was not supported by the Workgroup.

Impact on other Industry Documents

5.4 None identified.

6 Proposed Implementation and Transition

6.1 The billing and payment timescales for the proposed new charge were discussed. If the approved solution for this option is agreed to be a manual database workaround, then a monthly charge would be preferred, given the need for manual workaround. Various arrangements were discussed, including using user based forecasts, as with TNUoS and billing monthly based upon metering. It was agreed that monthly based upon actual metering would be the easiest approach to implement, but would result in National Grid having to finance expenditure for an extended period. Billing 28 days in arrears from the end of each month, would result in some days being billed at least 59 days in arrears, with payment being even later than this. It was noted however that every time DSBR/ SBR is utilised, National Grid needs to write to Ofgem providing evidence that utilisation costs have been economically and efficiently incurred. This request and assessment process will typically take longer than 29 days and therefore any agreed costs will be too late for input in the SF invoice and will instead feature as part of the RF invoice 14 months later.

6.2 National Grid have confirmed that it was unlikely to be able to implement an IS solution to implement the proposal within the required timescales of the proposal, and that such a solution would cost between £800k and £1m. However, it was noted that a manual workaround could be implemented, and to smear the costs over part or whole days across the 4 month winter period in the existing BSUoS system. Each solution would cost between £45k and £120k depending on whether and how frequent the services are utilised. For the new charge, this assumes monthly billing in arrears for the proposed "Demand Security Charge". It was noted that due to the proposed implementation timescales, National Grid would need to commence work on setting up these processes in early July 2016, meaning that additional costs could be incurred as a result of having to develop a solution prior to approval of the proposal.

6.3 The National Grid representative highlighted that it was unable to alter the balance of charges between generation and demand within the existing BSUoS IT system. Any solution altering this balance, would therefore be introducing the requirement to develop a new tool to undertake a manual calculation.

6.4 It was noted that as the calculation of components of the Balancing Services Revenue Restriction are set out in National Grid's Transmission Licence, this may need to be modified to implement a new charge separate from BSUoS. This would require Ofgem to undertake licence change consultation. The National Grid representative highlighted that in order to avoid licence changes any new charge would effectively need to be considered part of BSUoS, and named as such.

6.5 The Workgroup discussed the cost recovery options highlighted within the proposal and acknowledged that any changes may result in additional industry costs as a result of implementing the new charge. From a Supplier's perspective, changes to billing systems are anticipated to be complex and the cost to individual participants is not known by the Workgroup.

6.6 The Workgroup discussed the need to commence the implementation of any manual workaround ahead of any Ofgem decision due to the tight timescales to deliver this modification and identified that the costs for these works would need to be addressed as these will be incurred from July. Currently, the only way in which these this costs can be avoided is if the modification is withdrawn. One Workgroup member suggested it would be sensible to limit the number of WACMs to help keep these down.

7 Workgroup Consultation Responses

7.1 Sixteen responses were received to the Workgroup Consultation. These responses are contained within Annex 4 of this report. Overall 6 responses supported the Original Proposal.

7.2 The following table provides an overview of the Standard Workgroup question responses received.

	1 Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?	2 Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?	3 Do you have any other comments?	4 Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?
Calon Energy	**Yes**.	Yes.	SBR/DSBR is inconsistent with the logic of other security of supply principles as embodied in the capacity mechanism should not preclude these changes occurring due to the perceived switching costs.	No
Centrica	**No**, worse under objective a) benefits certain suppliers over others; • Suppliers that do not forward hedge their winter electricity requirements benefit whilst others will be penalised. • Generators that have forward sold their power will benefit as the risks they had factored into their forward hedge price will not now materialise. • Those suppliers that offer fixed priced contracts for their customers will also be adversely impacted.	No, for this modification, there should be a notice period of at least a year, if not longer, to ensure a subsection of the industry do not incur unanticipated additional costs.	This risk has been present since SBR and DSBR were first contracted by National Grid in 2014. A low margin, and therefore, an expected increase in the contracted volume, and risk of these contracts being utilised has also been predicted for winter 16/17 for a significant period of time. Given this, and the potentially significant impacts of this change to suppliers, we do not support the implementation of this urgent modification.	
Drax	**Yes**. SBR and DSBR utilisation costs could cause BSUoS prices to become highly volatile over the winter of 2016/17 as charging utilisation costs on a half hourly basis is not sending appropriate signals, thereby resulting in a distortion in competition between generators. Currently generators have low visibility of SBR/DSBR dispatch information, which is likely to lead to inaccurate dispatch decisions during times of SBR/DSBR dispatch. Smearing the utilisation cost of SBR/DSBR as the CMP262 proposal suggests will result in a more stable charge for market participant's leading to efficient dispatch decisions, reduced risk premia, and a lower overall cost to end consumers. CMP262 therefore better facilitates Applicable CUSC Objectives (a) and (c) in this respect. We agree with the notion that recovering all SBR/DSBR costs from demand side Balancing Mechanism Units (BMUs) would better facilitate the ACOs. This protects generators from unforeseen costs which can dramatically impact short run dispatch decisions. Moreover,	Yes this seems sensible.	Not at this time.	No.

	recovering these costs from demand better attributes the cost of the service to those market participants which ultimately benefit from the security provided by SBR/DSBR. This being said, the short timescales under which the modification is progressing and the limited duration associated with any solution (i.e. Winter 2016/17 only) means that retaining the 50:50 G:D BSUoS split may be a much easier solution to implement. We strongly encourage the workgroup to look at this solution either under the Original or as a WACM.			
EDF Energy	**No**, proposal exposes Suppliers to extra BSUoS costs at very short notice. Suppliers would be exposed to the potential costs through the proposed "Demand Security Charge", as well as already having paid for energy purchased which they had considered fixed at almost no notice leading to additional costs to end consumers, as well as Suppliers with some consumers on "pass through" terms. There is scope for error in Grid's proposed manual billing solution, for something that would only have effect for this winter anyway, as SBR and DSBR then cease to exist.	-	-	No
Engie	**No**. From a supplier perspective, this modification does not meet objective (a) and does not facilitate effective competition. The proposal would introduce additional costs to the supplier which would be borne by the customer. The complexity and volatile nature of the new charge proposal makes it difficult for participants such as suppliers to manage and potentially confuses the marketplace.	No. This does not work in its current format for suppliers.	No further comments.	
EON	On balance **yes** as the risk associated with SBR/DSBR is allocated so that there is less risk to security of supply, although we accept that this may pose a risk of a small supplier being put out of balance should a significant period of usage of SBR/DSBR be experienced. Although this would be highly undesirable outcome, the potential alternative of a generator going out of business is worse at a time of tight generation margins. There is a supplier of last resort mechanism in the event that a supplier ceases trading. No such mechanism exists for generators and given that security of supply is paramount, if there is an increased risk to security of supply with independent generators no longer trading as a result of excessive DSBR/SBR utilisation costs in winter 2016-17 and therefore support transferring recovery of these costs to Suppliers. DSBR/SBR is a last resort proxy for demand reduction, which is why its usage is priced at VOLL in imbalance pricing, and is in effect an interim short term substitute for the capacity market to secure demand. As capacity market costs are recovered from Suppliers it seems appropriate to treat these costs in the same way. We recognise this is an increased cost to Suppliers and extremely clear that no supplier would have factored this into their recovery of costs for 2016. To mitigate this we would	Please see our response to question 1 on extending the timescales for recovering the DSBR/SBR utilisation costs.	No	No, although we would ask the workgroup to consider our suggestions in our response to question 1.

	agree that the Demand Security Charge should be strictly limited to DSBR/SBR utilisation costs only and strongly advocate extending the timescales for recovery of the utilisation costs to winter 2017-18 as actual DSBR/SBR utilisation costs would be known and recovery could be included in the October 2017 Supplier contracting round enabling costs to be recovered over Gross Demand as there would be sufficient time to create a suitable billing system on this basis and remove any further distortions to winter 2016-17 and winter 2017-18 embedded benefits. National Grid should be kept whole of the cash flow costs by being able to recover appropriate interest on the total utilisation cost.			
First Utility	**No**, as it does not facilitate effective competition in the supply of electricity in accordance with objective a. as; Risk and cost is reallocated on the premise is that Suppliers are better placed to manage this risk than generators. Generators and suppliers are not homogeneous groups and have very different financial strengths and abilities to manage short-term changes, risks and costs presented by short notice changes such as this. Fully fixed pass-through products represent the largest number of products in the market and tend to be the business of many of the smaller new entrant suppliers targeting domestic and SME customers. By the 18th October 2016 most parties on fixed price contracts will have been committed prices for the winter period. Suppliers of these will therefore have virtually no opportunity to adjust their prices to cover off this transfer of risks. The full cost of the changes that generators are seeking to manage will then be borne by Suppliers which may be unable to manage . In addition suppliers have already paid for the generators element of cost in any contracts already traded for this winter. We do not believe the risk to Generators is as large as suggested. Generators can monitor plant margin and make a reasonable forecast of BSUoS associated with the scale of the plant margin On balance we believe that the forecast error risk here is less than the adverse impact this may have on suppliers and therefore it is not in the interests of consumers to implement this modification.	We do not support the proposed implementation approach as many of our customers are on fixed price contracts with insufficient opportunity for us to mitigate the additional costs.	This risk is not new. It has been present since P305 was approved on 2nd April 2015. In order for Suppliers to manage their businesses effectively any such change should have been proposed in sufficient time to allow the market to adjust. The short notice of this proposal does not allow time for affected parties to implement the necessary changes.	No
Haven Power	**No**. We do not believe that passing these costs separately to Suppliers will reduce overall costs to consumers as there is no clean mechanism for Suppliers to pass these through directly. Suppliers would face further costs in order to build the new class of costs into their systems and processes. It would not be possible for customers to take action to manage these costs so there is no benefit to competition of showing them separately.	No. Changes to the agreed charging methodology to place the whole charge on Suppliers at such short notice will not enable Suppliers to pass-through these additional costs to customers and will either need to be absorbed by Suppliers directly or factored into future prices, thus putting an unfair burden on Suppliers. These costs are properly incurred to ensure that the system	Please see responses.	

		can be balanced and as such should be part of BSUoS. The need arises as much from shortcomings of the generation markets as it does from the supply side and it is appropriate that both Generators and Suppliers pay a share.		
Hudson Energy	**No**. As SBR is a short term arrangement, dealing with security supply concerns and provide a bridge before the Capacity Market is introduced in 17/18 it is appropriate that both Generators and Suppliers are equally burdened with the cost. The implementation date of the proposal means that the impact on Suppliers and their competitiveness counters any justification outlined. This proposal now seeks to place the burden squarely on the shoulders of Suppliers who will have to absorb this extra cost and carry the losses even though both parties were informed of the £122m SBR costs for 16/17 in Dec15. Whilst larger integrated players might see this cost as neutral, Supplier downside is offset by their Generation upside. For independent retail suppliers this will directly impact their bottom line.	We do not support the proposed implementation	No.	No.
Intergen	**Yes** (a) (c) a) The difficulty in forecasting SBR/DSBR costs and the lack of transparency surrounding utilisation of SBR/DSBR units and the associated costs are likely to distort market signals to generate, and can therefore lead to inefficient plant dispatch. This is detrimental to competition and a significant issue for independent generators who are unable to recover shortfalls ex post. c) Levying additional costs onto generators increases likelihood of further plant closure, therefore does not take into account developments in the transmission business.	Given the amount of the time available and the temporary nature of the proposed Demand Security Charge, a manual work around seems appropriate.	We believe all costs relating to SBR / DSBR as per the original proposal should be fully passed on to the demand side as it primarily benefits the end consumer.	No
Npower	**No.** We believe generators are in a better position to manage these short term price shocks.	We do not support the original proposal. The creation of a new “Demand Security Charge” would not only require costly changes to billing and validation systems but would also require customer contracts to be reopened with potentially seriously damaging impact on customer supplier relationships. These high costs would only deliver a solution to be used in winter 2016/17 given Capacity Market being brought forward to 2017/18.	We do not believe the introduction of a new “Demand Security Charge” particularly at such short notice with the associated financial and customer impacts to be an appropriate or proportional solution to the defect the proposer describes. There are simpler and more cost effective methods to remove the issue that CMP262 seeks to resolve. One such approach would be to smear any SBR utilisation costs over the winter period within the current BSUoS framework keeping the current sharing of costs between supply and generation.	Yes
Opus Energy	**No**, Regarding CUSC objective (a), competition in supply may be adversely affected; some suppliers may not have fixed contracts, and would be able to change their prices to allow for the increased costs, whereas by far the majority could not, so wouldn’t be able to recover the additional costs.	The implementation date from 1st November 2016 is extremely short notice for suppliers to incorporate the additional cost in customer prices, and it will be impossible to do so in most cases where customer contracts are	Would the calculation of net demand be identical to that currently used in BSUoS?	No.

	Just as generators income is fixed through their forward energy sales, suppliers income is fixed through their customer contracts; neither of these will respond to very short term volatility in cost. Therefore as drafted, the modification is simply a cost shift from the whole market, to suppliers only, which is inequitable and whilst beneficial to generators will have no impact on the risk premia that suppliers will need to charge customers. In terms of competition in generation, the proposal would remove the perverse incentive on generators not to generate at times when the system is short and SBR/DSBR is called. We believe that the current defect can be removed without a short notice transfer of costs to suppliers by smearing the utilisation costs quarterly or across the whole winter, rather than just recovering them on the settlement dates when SBR/DSBR is used. Smearing the costs would also increase the incentive to generate, as increased generation would reduce the need for SBR/DSBR, and therefore reduce the costs paid by generators.	fixed several years in advance. Since the issue is caused by utilisation costs, we agree that it makes sense and is fairest to only move the SBR/DSBR utilisation costs into a separate “Demand Security Charge”, keeping the cost recovery of the other SBR/DSBR costs as they are.		
Ovo Energy	OVO have no comments on this aspect of the consultation	OVO have some concerns with regard to this proposed modification. We support the two post workgroup meeting amendments1, however we think that more work needs to be done to ensure that the implementation of a demand security charge (DSC) does not result in customers paying more than 100% of the cost of DSBR and SBR utilisation during the oncoming winter. As the workgroup consultation noted “suppliers would be exposed to the potential costs through the proposed “Demand Security Charge”, as well as already having paid the same cost in the price paid for energy purchased to date.” OVO shares this concern and would also refute the point made that a lack of “notable impact” on wholesale prices, is evidence that generators have not already priced in the expected impact of SBR and DSBR utilisation costs into their generation bids. 1Our suggestion is that the working assumption should be adopted that the prices suppliers have negotiated with generators for winter 16/17 power, includes an assumption about the likely cost to the generator BSUoS, including but not limited to DBSR and SBR . Therefore the likely cost of this proposed modification for final customers is 150% of the expected cost of DBSR and SBR utilisation (100% coming from the demand security charge + 50%	No	No

		contained in the power prices already negotiated with generators). Once this assumption has been adopted, the cost to energy customers of introducing a demand security charge could be calculated and compared to the benefit of more efficient despatch of generation during winter 2016/17. This would enable the modification to be assessed on the basis of whether or not the proposal to introduce a DSC was to the benefit of final energy customers (Please note that if this cost - benefit analysis indicated that customers would in fact be worse off as a result of this modification, OVO would not support the introduction of the DSC as proposed. OVO believe the best means of calculating the benefit to customers of introducing a DSC is to estimate the savings to customers made by generators despatching more efficiently during the coming winter. Naturally contracts for power negotiated before this modification was proposed would be excluded from this analysis, as the prices negotiated will not change. Separately, OVO also shared the concern raised from the WG that suppliers with a large proportion of customers on fixed price contracts may find it difficult to recover the demand security charge from their customers. This may potentially result in the cost burden of this proposal falling on standard variable tariff customers, a disproportionate number of whom are likely to be disengaged and potentially vulnerable according to the CMA.		
Scottish Power	**Yes**. We agree with the Proposer's assertion that SBR & DSBR utilisation costs are "opaque, impossible to forecast and are not known until 16 working days after the event." Their recovery through BSUoS which is already provides an inefficient ex-post market signal exacerbates the uncertainty faced by market participants. By reducing this uncertainty and potentially reducing the risk premium applied, the Proposal may result in lower costs to consumers and better facilitate competition. However, market participants trade a significant proportion of their requirements ahead of the delivery period. Due to the timing of this modification, a considerable volume of energy may already have been traded for winter 206/17and this modification could result in windfall gains and losses to market participants which would be detrimental to	If the Proposal is to be implemented and effective for winter 2016/17, we accept that a manual workaround would be appropriate due to the excessive cost of an IS solution to a problem which may only persist for one winter period.	No.	No.

	competition. The proposed recovery of the Demand security Charge from net demand would potentially give rise to an additional embedded benefit when it is clear that value of offsetting demand by embedded generation is already significantly overstated which would not be cost-reflective of any avoided transmission investment costs.			
Smartest Energy	**No**. We do not believe that the proposal better facilitates any of the CUSC Objectives. The proposer apparently believes that placing SBR/DSBR costs onto customers via a gross "Demand Security Charge" would more economically charge the parties who are benefiting from the product. There are two fundamental problems with this view: 1) generation also benefits from a well-balanced system; blackouts are not in anyone's interests. 2) the principle of moving away from net charging has not been justified and should be subject of the wider charging arrangements review. It seems to be a presumption of the proposal that generation is able to respond to price signals but that demand cannot and that if generation cannot respond to a price signal it should be exempt. This simply does not follow. Indeed demand is increasingly flexible anyway.	**We do not support** the implementation approach and are not aware of any further implementation implications over and above those we highlight elsewhere in this response. Changes to billing arrangements would not be welcome.	If this is genuinely a matter of transparency, perhaps that ought to have been the focus of the proposal. We note that National Grid has already highlighted that it is currently looking to improve the level of information published, and is planning a session at the June Operational Forum to talk through some scenarios ahead of next winter and we support the provision of additional information as an alternative to this modification.	No
VPI Immingham	**Yes**, we believe that CMP262 better facilitates the applicable CUSC objectives, namely (a) and (c). The lack of any market signal and ability to accurately forecast the SBR/DSBR costs, coupled with potential volatility negatively impacts competition in the wholesale electricity market, distorting competition. This potential inaccuracy of costs may lead to sub-optimal and uneconomic despatch of generation. Coupled with the perverse incentive to generate in shoulder periods around when SBR might be used, this has a significant impact on competition. Furthermore, the introduction of SBR and application of the costs to the generators, further putting them at risk of closure, does not properly take account of developments in the transmission business, specifically the impact of an increasing number of plant closures.	**Yes**, we support the proposed implementation approach. Whilst a manual workaround is never ideal, given the fact that SBR/DSBR is not intended to be extended beyond Winter 16/17, it makes economic sense to go for the lowest cost solution under these circumstances. Given the potential magnitude of the issue for generators, we think that this is an appropriate measure.	We remain disappointed with the level of analysis provided by National Grid in relation to the use of SBR/DSBR. It has reinforced our view that these costs are impossible to forecast. It would be useful, in order to quantify the issue, to understand the scenarios under which SBR might be utilised – National Grid would appear to be the most appropriate party to provide this information. We also note that National Grid used VPI Immingham's proxy numbers where actual utilisation costs were not available for their own analysis of BSUoS costs. We would hope that National Grid could use true numbers to provide industry with a more accurate view of costs should everything be run. To avoid sharing any commercially sensitive information, these numbers could be totalled so that specific plant utilisation costs are not identifiable.	No.

7.3 The following table provides an overview of the CMP262 Specific Workgroup question responses received;

	Q5: Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Q6: Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Q7: What is the impact of the proposal on your business?
Calon Energy	**No**. Due to the potential impact, we do not believe that it appropriate to not implement the proposed change even though SBR has only been contracted for this winter. It is our view that although it may be difficult for suppliers to recover costs, any generator that has forward contracted has no opportunity. Retailers still have some ability to adjust tariffs (should they wish to do so). A charge that increases as SBR is called, all other things being equal, would cause electricity production to be less attractive. SBR has two effects: i) it decreases the probability of supply interruptions – a benefit to customers ii) it subsidises otherwise uneconomic generators to remain on the system – a disbenefit to efficient generators Therefore, we do not see an economic reason why SBR costs should be paid by generators via BSUOS.	In principle, we do not consider that smearing costs for utilisation outside periods in which the utilisation occurs leads to an efficiently functioning price mechanism.	Positive but not outweighing the negative effect of SBR as a tool and its flawed implementation.
Centrica	**No** industry player is better positioned to manage large non-forecastable costs.	No, we do not support the smearing of these charges; it adds complications to suppliers as customer numbers and therefore volumes can change quite quickly, which will inevitably lead to further winners and losers.	Our supply business will incur additional costs via this demand security charge. Some of this additional cost would already have been incurred as a direct result of hedging our winter demand profile, so in effect these costs will be incurred twice on hedged volumes. All suppliers would be subject to intense media scrutiny if this new charge results in increases to domestic tariffs.
Drax	**Yes**. We agree with the Proposer that suppliers are generally better placed to manage the utilisation cost of SBR/DSBR. However, the short timescale to implement the modification ahead of winter 2016/17 is not ideal in terms of suppliers being able to pass through their costs to consumers. As such, we believe that CMP262 would better facilitate the ACOs if the current method of charging the utilisation cost to generators and suppliers, i.e. on a 50:50 basis,	Yes. BSUoS prices in each half hour can be very volatile if SBR/DSBR is utilised. Even in the unlikely event that a generator can anticipate when SBR/DSBR is likely to be utilised, the current methodology does not send the correct signal to generators and will therefore result in inefficient dispatch decisions. We believe that a smearing approach across the winter period better facilitates the ACOs with respect to the baseline. This would provide a more stable charge for industry participants and will present much lower risk.	Smearing the utilisation cost of SBR/DSBR as the CMP262 proposal suggests will result in a more stable charge for market participants. This increased certainty will allow us to make efficient dispatch decisions and more confidently price our wholesale power.
EDF Energy	**No**. It is a well-established principle that BSUoS is charged intact . We do not support splitting out BSUoS into different	We believe the best approach is to treat these costs in the same way as BSUoS. We do not support a different	The proposal, if it were passed, would give a sudden uplift to Supplier costs at short notice;

	components and charging them each differently; the complexity would add no value. Moreover, SBR is a phenomenon for this winter only; the system or workaround costs (and risks, with a workaround, of errors) in making this change would be large for such a transient change.	treatment to their recovery in terms of smearing approaches.	where the contract with a customer is of a pass-through basis in relation to BSUoS, there would be a need to communicate that part of what was BSUoS, now has a completely new name and is charged differently so that Suppliers would pay double what they did before in relation to these costs. No doubt there would be many debates as to Where the contract with a customer was of a non-pass-through basis in relation to BSUoS, Suppliers, including our own Supply business, would be left with an extra cost of uncertain magnitude, and would know this at virtually no notice ahead of this winter's SBR season. Settlements would need to undertake staff training so as to understand, incorporate in our systems and attempt to validate the new demand security charge.
Engie	Utilisation costs are not known until 16 working days after the event. Generators that have had exposure to the SBR costs are already better equipped to manage and monitor this cost.	No comment.	Implementing this proposal is likely to result in the need for suppliers to create a means of recovering the SBR and DSBR costs. Furthermore, to accommodate this change, system developments, time and additional resources would be required to analyse and forecast this cost.
EON	Certain Suppliers, depending on their contract terms and conditions, although not preferable, may be able to pass through some of these costs to their customers if the Demand Security Charge is created as a new charge, through change of law provisions.	Notwithstanding our suggestions in our response to question 1, we support the option that has the smallest impact on Suppliers' cash flow. Of the options considered this would seem to be spreading the cost 24/7 over the Triad season.	For our supply business this may result in an increase of costs that we may or may not be able to recover, depending to what extent DSBR/SBR is utilised this coming winter. For our generation business this would see a reduction in risk by removing the potential to be exposed to uncertain costs.
First Utility	It is the business of generators to manage their plant and optimise its value. Generators need to know when and what to bid. The main business of Suppliers is to manage customers and satisfy their needs. Suppliers of fixed price contracts need to make estimations of their costs and build them into their pricing. Once an offer is made a supplier will seek to hedge (via trades) the price risk associated with that volume. It is not the core business of Suppliers to monitor and forecast plant margins. Unfortunately instruments to manage BSUoS price risk do not exist. Therefore a Supplier has to absorb the BSUoS price risk. A generator on the other hand can adjust and re-adjust their bid/offer prices to manage their risks. On balance we therefore believe that a generator can manage this risk more effectively than a fixed price contract supplier. The other aspect of this issue is the financial ability to manage risk and uncertainty. Added uncertainty impacts Suppliers (especially small suppliers with limited reserves)	The smearing approaches across the winter period lessons the cash flow impact on suppliers. However, the uncertainty created by under or over recovery of the smearing given the costs to be recovered will only be known after the event makes this an extremely complex and potentially costly approach. Suppliers will not have budgeted for the additional funding aspect of the cost of smearing, nor for the additional credit risk this may impose.	First Utility offers mainly fixed priced tariffs to the market, a very large proportion of this is now fixed for the coming winter. Included in the pricing is an allowance for 50% of SBR/DSBR costs. We have not factored in the remaining costs and therefore this will present an adverse impact on the business. All forward sales are hedged to some extent; the hedges assume that the generators share of SBR/DSBR is included within the price. We have already paid for the generator share of this charge in the GTMA hedge instruments. To be asked to pay again for the product we have already purchased cannot be effective competition in the market.

	more than generators.		
Haven Power	Given the short timescales we do not agree that Suppliers are best placed to manage the utilisation costs. Suppliers generally fix costs for one, two or three year contracts. It is unlikely that Suppliers will be able to recover the additional costs from these customers. Our customers have fixed contracts or pass-through contracts (where certain Third Party Costs are passed-through). If a customer has a pass-through contract than we are only able to pass-through that customer's share of the costs – we are unable to recover the share of costs that we are don't recover from other customers. Even if a customer's contract allows for the pass through of charges, this does not mean that a Supplier will be able to do so. Supplier billing systems are incredibly complex and it is highly unlikely that they will be able to add an additional line to customers' bills in time for winter 16/17. The only way to pass-through the costs would be via a manual work around outside of the billing systems which would have a cost attached and as a result may lead to costs being absorbed directly by Suppliers and/or factored into costs for customers at a later date. This is likely to have a more detrimental impact on independent/smaller suppliers who are less able to absorb these costs. Generators have been aware of these costs for as long as Suppliers and will have built them into their pricing. If Generators are now exempted they will receive a windfall which will be ultimately paid for by customers.	Yes – spreading over the winter period would provide for a more stable charge across the period for all industry participants.	This proposal would have a detrimental impact for us as a Supplier. During the November – February SBR/DSBR window, we would need to add a line to the invoice for customers affected by the change. As noted above (5) this is not a simple thing to do and would likely require significant manual intervention as we are unlikely to be able to complete the system changes in time. The billing lines would also be subject to reconciliation which would add an additional layer of complexity to manual intervention. We are also unlikely to be able to be able to recover any additional costs directly from fixed price customers. It is also worth noting that this change would come at a time where our resources are stretched with other regulatory change (P272, introduction of EII exemption, AMR, Smart metering etc).
Hudson Energy	Neither party is better place, what is clear is that suppliers are not in control of when electricity is consumed and therefore are more likely to be in imbalance compared with a Generator. When SBR is utilised the cash out price will hit £3000/MWh, and therefore penalise Suppliers. Furthermore a generator will receive the benefit of the RCRC, which is expected to be of higher value during these times.	We believe that utilisation costs should be applied on periods when SBR is dispatched.	The proposal will cost our business hundreds of thousands of pounds.
Intergen	As BSUoS costs are not known at the time of generation it is likely that a generator will either over or under forecast during those settlement periods where SBR/DSBR has been utilised. If outturn BSUoS is higher than expected this cost is not recoverable by generators ex post. If outturn BSUoS is below expectations this results in a higher wholesale price and hence a higher cost to the consumer. Suppliers on the other hand are able to recover shortfalls or pass windfall gains to consumers ex post. Suppliers should therefore be better able to manage costs arising from SBR/DSBR.	Given that SBR / DSBR are procured to benefit consumers to ensure that there is sufficient capacity, it seems apt for this cost to be spread across all consumers. Furthermore, due to the unpredictability and uncertainty it seems appropriate to smear any costs over the entire winter season to minimise further market distortions.	InterGen as an independent generator would be better able to forecast BSUoS if costs associated with SBR/DSBR were recovered solely from suppliers. This in turn will allow for more efficient dispatch decisions and lower risk premia with associated lower wholesale prices that should feed through to benefit the consumer.
Npower	We believe that some generators are in a better position than other market participants to manage these short term price shocks depending on their contracting strategy. Least cost solution would be to continue to apply costs to both generators and suppliers.	Smearing over any time period would help to better manage the costs by removing or diluting the disincentive for plant to generate during periods they believed that the utilisation of SBR was more likely.	If this proposal were to be implemented it would require costly changes to billing and validation systems as well as amendments to customer contracts which would be very damaging to relationships with our customers.

			For a large portion of our portfolio, this would be an additional cost we would have to absorb, as we would end up paying for the generator SBR costs a second time.
Opus Energy	It is hard for both to manage the utilisation cost as it is so difficult to forecast SBR utilisation. It is arguable that SBR cannot be managed by any party, it is simply a cost associated with the changing electricity market infrastructure so should be borne by all market participants.	If the cost is smeared quarterly, this would remove the perverse incentive on generators to not generate, without changing where the cost is located and causing problems for suppliers. Most consumers do not have time of use tariffs and in any case these costs cannot be reliably forecast very far in advance, so putting the cost just on demand in peak periods would not provide an actionable incentive to reduce demand.	Increased costs which we cannot recover from customers as there is not enough notice to include them in prices, especially as the true cost won't be known until after SBR / DBSR is called.
Ovo Energy	OVO believe that neither suppliers nor Generators have a greater ability better placed to forecast and manage the risk of these costs than the other, especially with regard to SBR utilisation costs which are priced ex post. Thus far we believe the workgroup has provided little evidence that suppliers are in a better position to manage these costs. Suppliers with high proportions of fixed tariff customers may struggle to recover the added cost without resorting to increasing prices to their standard variable tariff customers.	OVO would be in favour of a smearing approach. Our suggestion is that the cost of SBR utilisation should be spread over a daily period e.g. 7am to 7pm. We feel that a daily period achieves the correct balance between providing a signal to the market on days of low capacity, yet does not unfairly attribute utilisation costs to one particular group of customers. SBR utilisation costs will not always be incurred during peak consumption hours, we therefore agree that it would be unfair to recover SBR utilisation costs solely from customers who consume power during periods of peak demand. Our hope is that by selecting a daily charging window in preference to a peak window, neither non-domestic nor domestic customers are unfairly assigned the costs of DSRB/SBR utilisation.	Suppliers such as OVO find it difficult to recover unforeseen costs, which manifest less than a year ahead. This is especially the case for suppliers with large numbers of fixed tariff customers amongst their customer portfolio. For this reason it is likely that this proposal will negatively impact our bottom line. The proposed amendment to recover only the utilisation costs associated with SBR and DSBR is therefore welcome, especially given that generators had foresight of the procurement costs of SBR/ DSBR when pricing their bids, whereas suppliers could not have foreseen that they would have to pay 100% of these costs when pricing their tariffs last year.
Scottish Power	Generators are in a position to forecast the utilisation of SBR/DSBR and respond to the corresponding price signals and in the short-term neither are suppliers. However, as these services are being procured to reduce the frequency of involuntary demand disconnection we consider that the costs should be recovered from demand but spread over the entire winter period.	Given the impact of SBR utilisation on adjacent settlement periods and the potential impact this may have on participant behaviour, some form of cost smearing would be appropriate. The smaller the time period over which the costs are recovered e.g. EFA Block 5b during winter season, the greater the potential "embedded benefit" available to embedded generators from generating over this narrow period. We support smearing over all settlement periods over winter 2016/17.	If implemented, we would require to develop settlement systems to validate Demand Security Charges.
Smartest Energy	Generators are probably better placed to manage the utilisation cost of SBR. However, it is correct that the costs are shared (as both generation and demand benefit from a well-balanced system) and that the same incentive is given to both generation and demand.	No, we are not in favour of smearing. We believe that focusing the costs in the period when required would incentivise suppliers/customers to reduce demand and therefore reduce the need to despatch SBR.	Aside from the operational hassle of re-opening contracts we would be largely indifferent to the change as we would seek to pass through additional costs. However, we believe that this modification should be assessed on its economic impact for which we see no justification.
VPI Immingham	We believe that suppliers are better placed to manage the utilisation costs of SBR given their ability to recover costs over a longer timeframe. Having a more stable charging base should enable volatility across the charges to be more easily managed enabling variation to average out. For generators	We would like to see the recovery of SBR/DSBR costs provide an incentive to the market to reduce demand, either by genuinely turning down demand or by switching on onsite generation. This should reduce the requirement for SBR in the first place and reduce the	The proposal would allow us to compete more effectively based on more accurate forecasts of BSUoS and subsequently could change running pattern, depending on magnitude of costs.

	who have a far more varied and peaky running profile, potential volatility could have huge impacts if it is hit with a large charge when not expected. Furthermore, if generators under forecast BSUoS, then they have no real means to recover these lost costs in future, unless they price themselves out of what is already a highly competitive market. This could have disastrous consequences for generators who may have to increase their risk premium to adjust for previous under forecasts and hence drive higher costs for consumers. Whilst clearly neither is desirable, we believe that risks of generators closing is more extreme than the risk of suppliers closing due to the nature of a supplier of last resort. No such measure exists for generation and closure of power station, when the system is already stressed could result in the lights going out.	requirement for the volume procured to be utilised. We think that the cash out arrangements implemented on the back of P305 and subsequently P323, provide a sufficient signal to the market. Also, we view SBR as the procurement of sufficient capacity for consumers rather than a balancing service – benefitting all consumers across the network and therefore appropriate that all consumers should pay for this service. As there is no guarantee that SBR be required for period 5b, it is not appropriate to recover the costs over this period. It would also provide a potentially huge embedded benefit under the proposed solution, one that cannot be justified. Therefore, it is more appropriate to smear the costs over the full Winter period. Given the short term nature of this proposed modification, this may also enable an easier cost recovery across all parties.	

	Q8: What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	Q9: How do you believe this proposal could impact the end consumer?	Q10: Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?
Calon Energy	The impact will inevitably be a redistribution of risk from generators to suppliers.	Assuming efficient procurement and utilisation of SBR, the impact will be consistent with the benefit gained if the services are utilised. In the longer-term, the proposal will signal that the industry will introduce economically rational modifications which should lower risk premia and benefit consumers.	Full transparency of not only the BSUoS calculation methodology but also the costing model itself. Furthermore, the timely publishing of any assumptions and forecasts that NG is using in its decision-making with respect to SBR and DSBR, for example, assumptions impacting NG's planning margin.
Centrica	We believe that all industry parties that hedge their positions are likely to be impacted in a similar manner. All suppliers will be adversely impacted under this proposal as they will be liable for the full costs of SBR and DSBR utilisation, previously this was spread amongst all participants. We find it incredible that an assumption has been made that integrated utilities are better able to manage these costs. All integrated utilities manage their businesses separately, with no benefits passing between supply and generation businesses.	We think this proposal could increase costs to the consumer, as the hedged supplier would see overall costs significantly increase.	No
Drax	It will greatly assist smaller parties as they will have less resource to assign to the prediction of SBR/DSBR utilisation compared to larger firms.	We believe that the increased certainty provided to generators will result in more efficient dispatch decisions and a lower risk premia factored into wholesale prices. This will directly translate to lower costs to end consumers.	While an improvement to the level of SBR/DSBR dispatch information may be a positive step, it does not fully address the issue CMP262 is highlighting. We believe that if any SBR/DSBR dispatch information could be provided it would be in a too short a time scale to be considered useful, particularly when considering forward trading timescales. We consider CMP262 to be the best way to address the defect.
EDF Energy	All sectors of the market will be affected by this proposal, if implemented. Smaller independent companies will be adversely affected the most by the uncertainty and the increased risk of disputes over liability for the "Demand Security Charge".	This change will create uncertainty in the short term and lead to an increase in costs overall, which will ultimately be paid by customers. It will not increase competition.	Perhaps some BSUoS costs could be spread over a longer period of time than at present, to reduce the BSUoS volatility that concerns the proposer of CMP262.
Engie	Although this proposal aims to reduce the volatile aspect of BSUoS into another cost component, it would seem there could be a significant commercial impact on suppliers that would pay the full cost via a "demand security charge". This liability would be passed onto our customers and there would be a need to work out how to effectively manage this cost with customers.	A separate cost is likely to be passed onto the customer potentially making it harder for some customers to pay their bills. With the introduction of CFD FiT and Capacity Market within the last 2 years, customers would see an additional cost which is likely to increase along with all of the other existing third party charges. Furthermore, there is the potential risk of generators not reducing costs in proportion to the risk suppliers would be assuming with the new "demand security charge".	No comment
EON	This depends on the respective strengths of individual parties' balance sheets. Although integrated utilities may have more diversification and are therefore better able to shoulder a loss from a subsidiary, that subsidiary itself still incurs the loss. Those perhaps more at risk are independent generators if	If this reduces the risk of independent generators going bankrupt this will enhance security of supply for the end consumer. In the event that DSBR/SBR utilisation costs are realised there will be increased costs to be recovered.	We think information provision for DSBR/SBR utilisation is being dealt with elsewhere, either through the relevant C16 statements or in relation to P323 and P333 under the BSC.

	there is a risk of bankruptcy or independent suppliers if their contractual arrangements mean that they are unable to pass through these costs to their customers. This is also assuming neither of this type have other means to raise funds for short term cost increases or, where they do, if these facilities are sufficient depending on the size of the DSBR/SBR utilisation costs.	It would be expected that these costs will feed through in to the wholesale price in the case of generators or be passed through to the end consumer by Suppliers as a result of increased BSUoS and the wholesale price effects.	
First Utility	This proposal adversely impacts the fixed price section of the market. The effect is exacerbated in that many of the new players who are growing their portfolios are in this sector. Introducing additional costs at very short notice is an unacceptable risk that they cannot manage.	Customers with pass through contracts will pick up the costs of this directly. For those on flexible traded contracts they may have already paid for the generators SBR/DSBR costs implied within the wholesale market. They will therefore be paying twice for the same benefit. Similarly with Suppliers, if they factor this cost in now to new contracts and the modification is not approved then, the customer will have paid more than necessary.	The issue seems to be the visibility of SBR/DSBR incidents and the ability for generators to adjust their prices accordingly. P305 and associated modifications has sought to achieve this, additional refinements on market shortage information is always welcome.
Haven Power	The impact on Suppliers is covered in our other answers.	Aside from the fact that if Suppliers have to absorb costs these are likely to be factored into future pricing, the addition of an a new cost adds extra complexity for customers who are already facing additional costs through recently introduced schemes such as CfD and CM and changes such as the proposed exemption from RO and FiT for Energy Intensive Industries.	No.
Hudson Energy	We believe independent suppliers will be disproportionally impacted by this changes for the reasons outlined.	If approved these additional costs will be factored into our customer's electricity prices going forward.	No Comment.
Intergen	We believe that Independent generators are most exposed as it is not possible to recover higher than expected outturn costs ex post. The level of exposure will largely depend on the running profile of the plant, with base load plants having the most exposure. Suppliers should be better placed to manage SBR/ DSBR costs as it is possible to recover shortfalls or pass windfall gains to their customer base ex post.	Bringing greater certainty to generators should therefore lower costs and facilitate a more efficient market which is beneficial to the end consumer.	Publish BSUoS ahead of/ in real time such that BSUoS costs are known with certainty at time of generation.
Npower	This proposal risks giving a windfall gain to some generators depending on contracting strategy, as they will already have built SBR costs into energy already contracted. In this instance there would be a corresponding unplanned cost on suppliers.	The impact of this proposal would be increased costs to end consumers due to the costs of system and process changes to implement a new charge with an expected 'lifespan' of only one winter. As generators may have included some forecast SBR utilisation into their prices for the winter ahead, moving the costs to supply only would mean that the customer would pay for SBR utilisation more than once.	If an SBR indicative cost and impact to BSUoS rate was published at the same time as the SBR notification, we believe this would help generators make the appropriate dispatch decisions and set prices correctly without the need to withdraw from the market, and stop the price increasing unnecessarily for units already contracted.
Opus Energy	Generators – reduced uncertainty in the cost of BSUoS, so probability of increased margin. Suppliers – as customers tend to have fixed price contracts, a probability of reduced margin. The impact on integrated utilities will depend on their relative balance of supply/generation and forward hedging activity.	Increased prices, due to double charging, as the cost may have already been factored into generators' prices, but would also need to be included in suppliers' prices.	Regardless of this modification proposal, National Grid should provide more estimates of what the costs could be. This should include all of the SBR/DSBR costs. We appreciate that the utilisation costs are difficult to forecast, but different scenarios could be considered, such as "If it's a colder than average winter, SBR might be called x times, costing £y in utilisation costs." Suppliers would then be more able to take a view on the likely costs to price in.

Ovo Energy	As we have stated before, we believe that the proposed modification will impact suppliers with higher proportions of fixed tariff customers amongst their base to a greater extent than suppliers with high proportions of variable priced tariffs.	We have some concerns about the potential on final energy customers. Our suggestion was for the work group to undertake some analysis to ensure that the likely cost of this modification to customers does not outweigh the likely benefits. We think the result of this analysis should underpin the decision whether or not to progress this modification further.	Our suggestion is that if this modification is proved not to be in the best interests of final customers that efforts are made to improve the level of information available to generators, in order to increase the efficiency of market despatch.
Scottish Power	We do not support the assertion that there would be a different impact on participants depending on whether they were vertically-integrated or not. Economic decisions on whether to despatch generation or to procure energy to meet demand are each taken against the prevailing market price. The ability to withstand market price shocks will relate directly to participants' credit standing and capital structure.	Any measure which reduces uncertainty should result in lower risk premia and lower prices to end consumers.	Improved timeliness and quality of information on SBR/DSBR despatch would potentially help address the defect. However, there may still be uncertainty as to the impact of despatch upon BSUoS until out-turn BSUoS charges are publishes and there may be a competitive advantage to those organisations with sufficient resources to interpret the data in real time.
Smartest Energy	If it is true that independent parties are more exposed than integrated parties we do not see any justification in effectively throwing the whole of what is currently a shared cost onto suppliers as it is independent suppliers who are at greater risk.	We believe that this would lead to increased costs through additional risk premia and double payment in the light of costs already factored into the wholesale price.	We are supportive of National Grid carrying out the following: - Confirming which units are contracted for SBR by September; - Providing expected capability costs (including testing) and timings; - Providing clarity over when start-up, warming, and utilisation instructions have been issued for SBR; - Publishing MW profiled load contracted for DSBR; and - Publishing full DSBR dispatch information by settlement period shortly after instruction on day D.
VPI Immingham	With the existing arrangements continuing, independent generators are most exposed given the cash flow risks of prolonged usage of SBR and subsequent huge BSUoS costs. With most thermal generators struggling in recent years, this could cause further cash flow issues. The reason independents are more exposed is that they have no customer base to recover costs from at a later date. Whilst most vertically integrated generation and supply business are run separately, there is still a parent company and larger reserves available than in smaller independents. This could also pose issues for independent suppliers should the whole charge be put on suppliers, but believe that the nature of the charging base makes this the better solution. For generators, the running profile of the plant, e.g. baseload versus peaking, could also dictate how exposed a generator is. Those that have must run characteristics, or are running baseload, will pick up a larger share of the costs, despite not contributing to the issue due to the operating parameters of some of the SBR plant. To charge those generators that are helping to fix the issue would seem to be highly perverse.	We do not believe that there will be any significant impact on end consumers – it is purely a transfer of money from generators to suppliers. Whilst there may be a small risk of a double risk premium should some generators already have included it in their prices for Winter 16/17, in reality, we do not believe that this is material. We believe that this risk premium may also be traded out over time, depending on hedging profiles and the risk premia applied by generators. Also, we remain unconvinced that a sufficient risk premium has been factored into forward prices, given the lack of any material impact on prices on the announcement of the procurement volume and costs. With the volume of SBR procured and the corresponding costs being a surprise for all industry players, you could expect some impact even if a level of risk had already been factored in. This is clearly not the case.	Unfortunately there is no means to solve the outlined defect completely due to the inability of anyone to forecast next Winter's weather and plant availability. However, an improved level of granularity and transparency would help all. We remain disappointed with the level of analysis provided by National Grid in relation to the use of SBR/DSBR. It has reinforced our view that these costs are impossible to forecast. It would be useful, in order to quantify the issue, to understand the scenarios under which SBR might be utilised – National Grid would appear to be the most appropriate party to provide this information. This could include various scenarios with assumed generation volumes available in the market and different weather conditions. Industry understands that these are forecasts and it would enable a much better understanding of SBR. We would hope that National Grid could use true numbers to provide industry with a more accurate view of costs should everything be run. To avoid sharing any commercially sensitive information, these numbers could be totalled so that specific plant utilisation costs are not identifiable.

8 Views

Workgroup View

8.1 The Workgroup believes that the Terms of Reference have been fulfilled and CMP262 has been fully considered and is evidenced in the table below;

Issue	Evidence
a. To investigate if there is a better risk management tool. Issue discharged by CUSC Panel.	This issue was de-scoped by the Panel as it was agreed that this would be addressed in d.
b. To look at what the impact of the proposal would be on various sectors of the market.	Section 3
c. What would be the ultimate impact on customers?	Section 3, Table 4
d. Are there any other options that can address improving the quality and timeliness of information to market participants?	Section 3
e. What are the implications on RCRC?	Section 3
f. What is the cost of implementing a new billing system and how is the benefit of this assessed against the short life of this modification proposal.	Section 3, Section 6, Table 4
g. Workgroup to consider other solutions that spread the costs to generators and suppliers over a longer period of time.	Section 3, Table 4
h. What is the impact of this proposal on competition and at which point does this prevent the market from reacting in a competitive manner.	Section 3, Table 4
i. There are currently a number of related BSC modifications in progress, the Workgroup are requested to review these and identify any impact these may have on this proposal.	Section 3, Table 4

8.2 For reference the Use of System Charging Methodology Objectives 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.

(d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.
Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

National Grid Initial View

8.3 National Grid prefers WACM2 as it provides more certainty to Industry participants by mitigating BSUoS volatility thus facilitating competition in the winter market potentially at times of scarce capacity. It is less cost reflective than HH charge, but appropriately so and consistent with treatment of availability and testing costs. A manual workaround is still required but the methodology is simple, transparent and easy to implement. Overall, WACM 2 provides equal treatment of both generators and suppliers.

Workgroup Vote

8.4 The Workgroup met on 27 June 2016 and initially voted to support the proposed options for Workgroup Alternative CUSC Modifications (WACMs). The Workgroup agreed by majority to support Options 2, 4 and 6 which were subsequently re-named to WACM1, WACM2 and WACM3 respectively.

8.5 The Workgroup voted on the Original Proposal and the three Workgroup Alternative CUSC Modifications. As Jo Zhou was on leave, Nick Pittarello attended the meeting and voted on her behalf. Overall, the Workgroup supported WACM2 by majority as better facilitating the applicable CUSC objectives. Four votes supported WACM2 and two Workgroup members supported the Original and one Workgroup member supported WACM3 as the preferred option. The votes were received are as follows;

WACM Support

Member	WACM1 (Andrew Colley) (Support / Don't Support)	WACM2 (Daniel Hickman) (Support / Don't Support)	WACM3 (Daniel Hickman) (Support / Don't Support)	WACM4 (Sarah Owen) (Support / Don't Support)
Mary Teuton	Yes	No	No	No
Guy Phillips	Yes	No	No	No
Andrew Colley	Yes	Yes	Yes	Yes
James Anderson	Yes	Yes	Yes	No
Daniel Hickman	No	Yes	Yes	No
Sarah Owen	No	Yes	Yes	Yes
Nick Pittarello (Alternate for Jo Zhou)	No	Yes	No	No
Overall	4/7	5/7	4/7	2/7
Supported by Chair if applicable (yes / no)	Yes	Yes	Yes	No

Vote 1: Whether each proposal better facilitates the Applicable Objectives against the CUSC baseline

	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Overall (Y/N)
Mary Teuton					
Original	Yes	Yes	Neutral	Neutral	Yes
WACM1	Yes	Yes	Neutral	Neutral	Yes
WACM2	Yes	Yes	Neutral	Neutral	Yes
WACM3	Yes	Yes	Neutral	Neutral	Yes
Guy Phillips					
Original	Yes	Yes	Yes	Neutral	Yes
WACM1	Yes	Yes	Yes	Neutral	Yes
WACM2	Yes	Yes	Yes	Neutral	Yes
WACM3	yes	Yes	Yes	Neutral	Yes
Andrew Colley					
Original	No	Neutral	Neutral	Neutral	No
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
James Anderson					
Original	No	Neutral	Neutral	Neutral	No
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes

Daniel Hickman					
Original	No	Neutral	Neutral	Neutral	No
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
Sarah Owen					
Original	No	Neutral	Neutral	Neutral	No
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
Nick Pittarello (Alternate for Jo Zhou)					
Original	No	Neutral	No	Neutral	No
WACM1	No	Neutral	No	Neutral	No
WACM2	Yes	Neutral	No	Neutral	Yes
WACM3	No	Neutral	No	Neutral	No

Vote 2: Whether each proposal better facilitates the Applicable Objectives against the Original Proposal

	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Overall (Y/N)
Mary Teuton					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	No	No	Neutral	Neutral	No
WACM3	No	Neutral	Neutral	Neutral	No
Guy Phillips					

WACM1	No	Neutral	Neutral	Neutral	No
WACM2	No	No	Neutral	Neutral	No
WACM3	No	No	Neutral	neutral	No
Andrew Colley					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
James Anderson					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
Daniel Hickman					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
Sarah Owen					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	Yes	Neutral	Neutral	Neutral	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes
Nick Pittarello (Alternate for Jo Zhou)					
WACM1	No	Neutral	No	Neutral	No
WACM2	Yes	Neutral	Yes	Neutral	Yes
WACM3	No	Neutral	No	Neutral	No

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

Panel Member	BEST Option?
Mary Teuton	Original
Guy Phillips	Original
Andrew Colley	WACM3
James Anderson	WACM2
Daniel Hickman	WACM2
Sarah Owen	WACM2
Nick Pittarello (Alternate for Jo Zhou)	WACM2

8.6 In addition to the Workgroup members voting summary above, each Workgroup member provided the following voting statement supporting their reasons for their vote;

Mary Teuton

- Smearing over longer time period should remove volatility and improve competition whilst reducing risks to security of supply
- Suppliers better able to manage these costs
- Arbitrary risk premium should be removed from generators
- Suppliers better able to manage the risk
- Should be spread over a longer timeframe so as to not make it an embedded benefits, particularly if wholly on suppliers

Guy Phillips

Vote 1: All options better facilitate objectives a), b) and c) and are better overall than the baseline. They are better under objective a) because of the inability of market participants to accurately forecast the SBR/DSBR utilisation costs, which impacts competition in the wholesale electricity market, thereby distorting competition. This potential inaccuracy of costs may lead to sub-optimal and uneconomic despatch of generation in particular. They are better under objective b) because they all enable unknown costs to be recovered over a greater period of time, some more than others, thereby enabling cost recovery whilst smoothing any distortionary effects in particular periods. They are better under objective c) because for those that target recovery from both generation and demand, it reduces the risk of independent generators closing under extreme scenarios by reducing the risk of higher more volatile cost exposure in particular periods. For those options that recover the cost from demand only it removes the risk of independent generators closing whilst spreading the period of time that the cost is recovered from suppliers. In both cases the implications for security of supply are relevant to National Grid's transmission business with potential further closures of generation.

Vote 2: None of the proposed WACM's are better than the Original Proposal. For WACM 1 this is because it recovers the unknown costs from Demand only over a shorter period of time compared to the Original, which would have a greater impact on competition between Suppliers. WACM 2 and WACM 3 are not better than the original as they target recovery of the costs from both generation and demand albeit over longer periods of time, so therefore do not fully mitigate the risk of independent generators closing as they would still be exposed to, unknown at this time, higher costs which if prolonged may still result in some generators closing under extreme scenarios of high SBR/DSBR utilisation costs.

Vote 3: The original is the best option as this removes the potential risk that under extreme scenario's, where high SBR/DSBR utilisation costs are incurred for an extended period of time, independent generators are not put at risk of closure, which could otherwise exacerbate security of supply in those circumstances.

Andrew Colley

As identified by the proposer, the cost recovery of SBR and DSBR through the CUSC charging arrangements, particularly in relation to SBR utilisation costs, imposes considerable uncertainty to market participants as to where BSUoS prices might outturn in the event that the reserve is used. The uncertainty is such that it limits participants' ability to forecast BSUoS costs and therefore limits their ability to hedge potential risks within their market prices. This is detrimental to competition.

In principle, SBR and DSBR products have a common aim to the Capacity Market in ensuring that adequate flexible capacity is available to meet the balancing needs of the System Operator without having to resort to involuntary demand control and disconnection. Therefore the proposal has many merits in that it aims to emulate Capacity Market arrangements to recover the costs of the arrangements solely through Suppliers, on behalf of consumers who are the principle beneficiaries; at the same time alleviating concerns that independent generation could become insolvent as a result of sudden price shocks, which in itself would exacerbate security of supply concerns as available capacity reduces.

However, implementing a change for winter 16/17 that recovers all utilisation costs from Suppliers, with little or no opportunity to pass on these costs through retail prices, seems to be at least equally, if not more detrimental to competition. Suppliers will have already contracted a significant proportion of their portfolio needs, with a limited ability to pass through the change to fixed price contract customers, leaving either tariff customers to pick up the residual cost or where a Supplier has no tariff customers, a potentially stranded cost. This does not seem to support effective competition, and would seem to discriminate against niche Suppliers that operate solely in the fixed price contract market, as well as potentially result in cross-subsidisation of costs by tariff customers.

On balance therefore, it does not seem appropriate to amend the charging arrangements for Winter 16/17 to remove the 50/50 split of BSUoS costs between generation and supply currently provided for in the CUSC, and as such both the Original and WACM2 are detrimental to Applicable Charging Objective a) compared to the current baseline.
The question then remains however, as to how to mitigate the legitimate concerns from industry regarding the unpredictable and volatile nature of when utilisation costs might be priced into BSUoS. Both WACM4 and WACM6 help in this respect as both solutions smear costs throughout the winter, albeit over different times of the day, thus helping to flatten the cost recovery from participants. This in turn reduces the uncertainty associated with SBR and DSBR utilisation costs, a key concern of the proposer, reducing risk and potentially reducing risk premia applied by the market within prices to the ultimate benefit of end consumers. Both WACM4 and WACM6 therefore better facilitate Applicable Charging Objective a) compared to the current baseline and compared to the Proposal.
Whilst WACM4 provides a larger number of Settlement Periods over which to recover costs and flatten prices, WACM6 retains a stronger link to the intended utilisation period of SBR and DSBR when procured, and should sufficiently spread costs to alleviate concerns regarding the uncertainty of where BSUoS prices might outturn in the event that the products are used by the System Operator.
Overall therefore, WACM6 better facilitates Applicable Charging Objective a) when compared to the baseline and all other options.

James Anderson
The recovery of SBR & DSBR through BSUoS under the CUSC baseline presents considerable uncertainty to market participants which is detrimental to competition. However, implementing a change for Winter 2016/17 which recovers all of the utilisation costs from suppliers could result in windfall gains and losses which would be detrimental to competition as many parties will have already contracted for a significant proportion of their requirements in advance. In addition, as recovery of the total utilisation cost would be based on net demand, there is the potential for additional non-cost reflective embedded benefit. Therefore, both the Original Proposal and WACM1 do not better meet Applicable Charging Objective (a). The Original and WACM1 are neutral against the other Charging Objectives and overall do not better facilitate the Charging Objectives than the baseline.

WACM1 focusses cost recovery into 24 settlement periods on the day that SBR & DSBR is utilised which does little to mitigate the uncertainty compared to the Original which recovers costs over all the winter settlement periods. WACM1 therefore facilitates the Charging Objectives less well than the Original Proposal.

WACM2 and WACM3 mitigate the impact of unpredictable utilisation costs by smearing the costs over all the winter periods (WACM2) and SBR utilisation window, winter 6am to 8pm (WACM3). This reduces the uncertainty associated with SBR & DSBR utilisation costs, potentially reducing the risk premium applied by market participants and may result in lower costs to consumers. WACM2 and WACM3 thus better facilitate competition

and Applicable Charging Objective (a). WACM2 and WACM3 are neutral against the other Charging Objectives and overall better facilitate the Charging Objectives than the baseline.
WACM2 & WACM3 both better facilitate the Charging Objectives than the Original Proposal.

Overall, due to the larger number of settlement periods over which utilisation costs are recovered, which both reduces uncertainty and reduces the potential for further non cost-reflective embedded benefit, WACM2 best meets the Charging Objectives.

Daniel Hickman

Both the original and WACM 1(option 2) would lead to windfall gains and losses as a significant proportion of energy for the winter ahead will already have been contracted moving the share of costs to demand only will result in suppliers and end users paying more than once for the cost of SBR utilisation as a proportion of the expected cost will have been included in the power price this could distort competition in supply depending upon the level of fixed price contracts in any suppliers portfolio and are therefore worse than the baseline against ACO (a)

WACM 3 & 4 mitigate parties cashflow issues and the risk of inefficient dispatch decisions leading to increased SBR usage by smearing the costs over a longer period therefore removing the disincentive to generate at times when system margins are already tight. Both these options also have the benefit of lower industry costs to implement as current demand generation split is maintained therefore removing the requirement for industry parties to change their billing and validation systems and are therefore better against ACO(a)

Sarah Owen

For Applicable Objective A. No for the Original as the implementation timescales will result in overall gains for generators that have already forward sold their power and adverse impacts to those suppliers that have already forward hedged any of their demand . This will result in additional costs to end suppliers. No for WACM 1, the implementation timescales will result in overall gains for generators that have already forward sold their power and adverse impacts to those suppliers that have already forward hedged any of their demand. This will result in additional costs to end suppliers. Yes for WACM2, as the volatile and unpredictable utilisation charges are smeared over a period of time, reducing the uncertainty for all players. Yes for WACM 3, as the volatile and unpredictable utilisation charges are smeared over a period of time, reducing the uncertainty for all players

WACM2 reduces the uncertainty of SBR and DSBR utilisation costs and negates the potential for a large impact across a small number of settlement periods. It also minimising the potential embedded benefit gain due to the large smearing period.

Nick Pittarello (Alternate for Jo Zhou)

Original: For applicable objective A: No, different treatment of gens/ suppliers with very short transition period means suppliers (and ultimately consumers) may have to pay twice as generators have forward sold power and a risk premium may already be included. For applicable objective C: No, urgent implementation timeline and complex algorithm may give rise to risks of human error.

WACM1: For applicable objective A: No, Different treatment of gens/ suppliers with very short transition period means suppliers (and ultimately consumers) may have to pay twice. Smearing approach is more volatile than it could be if smeared across the winter. May create additional embedded benefit as behind the meter demand onsite generation may be capable of avoiding the specific timeslot, while domestic consumers may have to pay. For applicable objective C: No, urgent implementation timeline and complex algorithm may give rise to risks of human error.

WACM2: For applicable objective A: Yes, provides more certainty to industry by mitigating BSUoS volatility thus facilitating competition in the winter market potentially at times of scarce capacity. For applicable objective B: Less cost reflective than HH charge, but appropriately so and consistent with treatment of availability and testing costs. For applicable objective C: Yes, manual workaround still required but methodology is simple, transparent and relatively easy to implement.

WACM3: For applicable objective A: No, may create additional embedded benefit as behind the meter demand onsite generation may be capable of avoiding the specific timeslots, while directly connected will have to pay.

Annex 1 – CMP262 CUSC Modification Proposal Form

Title of the CUSC Modification Proposal

Removal of SBR/DSBR costs from BSUoS into a “Demand Security Charge”

Submission Date

10th March 2016

Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

Summary of Issue

Supplemental Balancing Reserve (SBR) utilisation costs are likely to become increasingly volatile and virtually impossible to forecast in Winter 16/17 as a result of lack of transparency as to how SBR plant will be despatched and their true utilisation costs. This lack of appropriate signal is likely to result in a distortion in competition between generators resulting in inefficient despatch as a result of erroneous forecasts.

Furthermore, the result of this potential volatility across different settlement periods is:

i) Increased costs to consumers as a result of the addition of a risk premium
ii) Perverse incentives for generators in terms of a signal to generate
iii) Inaccuracy of cost forecasts leads to significant suboptimal despatch of generation leading to market inefficiency
iv) Outturn costs in excess of the forecast are irrecoverable by generators as they are recovered ex-post

Further context

Balancing Service Use of System (BSUoS) charges are the means by which the System Operator (SO) recovers the costs associated with balancing the transmission system. BSUoS charges are levied on both generation and demand on a 50:50 split basis. The value of BSUoS varies in each half hour settlement period reflecting the different costs incurred by the SO in each period.

Currently, all SBR procurement and utilisation costs are recovered via BSUoS from both Suppliers and Generators. SBR and Demand Side Balancing Reserve (DSBR) procurement costs are known ahead of time (and have almost quadrupled from 15/16 to 16/17) and are distributed across all settlement periods in the SBR/DSBR window, reducing volatility. However, utilisation costs are opaque, impossible to forecast, are not known until 16 working days after the event and are applied within the settlement period that they are incurred, driving highly volatile BSUoS prices.
Given the concerns regarding security of supply in Winter 16/17 and the likelihood that SBR will be despatched, it is likely that BSUoS will become highly volatile and increasingly difficult to predict.

The range of utilisation costs associated with SBR and DSBR, coupled with the lack of ability to predict which plant will despatched when, make it increasingly difficult to forecast what the outturn BSUoS costs will actually be. This is further exacerbated by the lack of transparency around some of the utilisation costs where there is a £ charge plus fuel and carbon costs, the latter two only known by the SBR generator itself with industry only able to make broad assumptions.

Generators are expected to recover BSUoS from the wholesale price. However, the actual cost of BSUoS will only be known ex-post, so despatch decisions can only be made on a forecast, and a very nebulous forecast at that due to the lack of transparency. National Grid only forecast an average BSUoS and we believe that this will be increasingly inaccurate going forward due to the changing nature of the market and balancing services procured.

In such circumstances, generators must add an increasing risk premium into their BSUoS forecasts resulting in far higher costs for consumers plus risk uneconomical despatch. With the information required to accurately forecast SBR requirements not available to the market in the required timescales, or at all, there is no way that parties can accurately quantify the level of SBR costs incurred. For example, the de-rated margin published as part of the cash out changes is published at 12 o'clock day ahead, yet some plant has 48 hour warming timescales. Furthermore, DSBR can be despatched on short notice with very little notice given to the market.

The costs associated with warming, starting and running SBR occur in periods of the day which are unlikely to be tight and hence SBR is not required. For example, it is likely that SBR only be required for Block 5b, yet its costs are imposed through blocks 3, 4 and 5a, up to 48 hours ahead. As a result, BSUoS may be both high and volatile for these periods. This could result in generators delaying their start until as close as possible to the periods where they know the market price is guaranteed to cover the risk of high BSUoS. Having more generation starting up just before block 5b is likely to drive even higher risk premium and hence will end up costing consumers more, notwithstanding that it comes about through a market distortion in the first place.

For non vertically integrated players who are not able to offset any higher than expected BSUoS charges against their customer base, this results in a market distortion and could become a barrier to entry for independent generators.

We propose moving all of the SBR and DSBR costs, in place to ensure security of supply rather than to balance the system, into a "Demand Security Charge", fully recovered over gross demand in the SBR/DSBR window, in line with the capacity mechanism cost recovery.

Placing SBR/DSBR costs onto customers via a "Demand Security Charge" would more economically charge the parties who are benefiting from the product at the same time as aligning and being consistent with capacity mechanism cost recovery, i.e. recovery from suppliers. It would further protect generators from yet more unforeseen and unforecastable costs without increasing the overall cost burden on consumers. In fact, it should reduce overall costs to consumers.

It should also protect customers from paying for a lack of efficiency as a result of the uncertainty. The likely addition of extensive risk premia to mitigate for the uncertainty, as a result of generators will seek to manage the costs of the BSUoS charges they cannot see nor forecast, can only drive higher costs for consumers

Description of the CUSC Modification Proposal

This modification proposes to create a new cost recovery mechanism, a “Demand Security Charge” specifically for recovery of all SBR/DSBR costs, which is only levied on demand side Balancing Mechanism Units (BMUs). This is because it is the best way to reduce the risk premia applied by Generators, hence minimising costs to the consumer, and to ensure efficient despatch of plant.

Whilst we would expect the working group to develop the solution in detail, we would expect the total costs to be collected from gross demand over the SBR/DSBR window, i.e. November to February. This would ensure that the costs would not be volatile across different settlement periods.

SBR is in place to maintain longer term security of supply, similar to the capacity mechanism, and it is therefore more appropriate that all costs fall on suppliers who are better able to recover the actual costs from customers.

Given some of the costs are known ahead of Winter, National Grid could continue to forecast the SBR costs (procurement costs will be known) so that suppliers can estimate costs over the Winter period and then a Winter only charge, mirroring the SBR window, could be applied. It should reduce the cost to consumers as significant risk premia will no longer be added by generators.

Impact on the CUSC

Section 14, Charging Methodologies, of the CUSC would be impacted.

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? No

No, there would be no material impact on greenhouse gas emissions

Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information

BSC ☒

Grid Code ☐

STC ☐

Other ☐
(please specify)

This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.

Urgency Recommended: Yes

Yes, we believe that this modification should be treated as urgent

Justification for Urgency Recommendation

If you have answered yes above, please describe why this Modification should be treated as Urgent.

We have serious concerns that without an immediate resolution of this issue, generators will have to consider either charging very high prices on the basis of no robust information, or may go bankrupt over the coming winter turning a tight system into one with negative plant margins.

With these costs incurred from November 2016, we believe that it is essential that any change be implemented ahead of this date.

We believe that SBR utilisation costs in Winter 16/17 have the potential to have a significant commercial impact on generators who are unable to forecast SBR and DSBR utilisation costs. For generators who have already hedged their position for Winter 2016/17, this impact could be catastrophic.

This could result in plant frequently despatching at a loss due to higher than expected outturn BSUoS costs. We do not believe that accurate BSUoS costs are currently reflected in wholesale prices, as demonstrated by the lack of change in price on the back of the tender results for the Winter 16/17 SBR procurement round (£122million over 14/15 winter demand figures equates to approximately £0.5/MWh, yet there was no movement in the market).

Whilst CMP250 does address the issue of BSUoS volatility, it is not due to be implemented by November 2016 and therefore this modification is urgent.

Self-Governance Recommended: No

No, this is not a self-governance modification

Justification for Self-Governance Recommendation

- N/A

Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?

No

Impact on Computer Systems and Processes used by CUSC Parties:

Details of any Related Modification to Other Industry Codes

CMP250 ‘Stabilising BSUoS with at least a twelve month notice period’

Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:

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.

☐ (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

This proposal improves delivery against Use of Charging Methodology objectives a and c. The lack of any market signal and ability to accurately forecast the SBR/DSBR costs, coupled with potential volatility negatively impacts competition in the wholesale electricity market, distorting competition. Furthermore, the introduction of SBR and application of the costs to the generators, further putting them at risk of closure, does not properly take account of developments in the transmission business, specifically the impact of an increasing number of plant closures.

Additional details

Details of Proposer: (Organisation Name)	VPI Immingham
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Mary Teuton VPI Immingham 0207 312 4469 mteuton@vpi-i.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	 Lisa Mackay Intergen 0131 624 6769 lmackay@intergen.com
Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:**	

Contact Us

If you have any questions or need any advice on how to fill in this form please contact the Panel Secretary:

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

For examples of recent CUSC Modifications Proposals that have been raised please visit the National Grid Website at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/

Submitting the Proposal

Once you have completed this form, please return to the Panel Secretary, either by email to heena.chauhan@nationalgrid.com and copied to cusc.team@nationalgrid.com, or by post to:

Heena Chauhan
CUSC Modifications Panel Secretary,
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If no more information is required, we will contact you with a Modification Proposal number and the date the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, the Proposal can be rejected. You will be informed of the rejection and the Panel will discuss the issue at the next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform you.

Annex 2 – CMP262 Terms of Reference

nationalgrid

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP262 WORKSHOP

CMP262 aims to aims to create a new cost recovery mechanism, a “Demand Security Charge” specifically for recovery of all SBR/DSBR costs, which is only levied on demand side Balancing Mechanism Units (BMUs).

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP262 ‘Removal of SBR/DSBR Costs from BSUoS into a “Demand Security Charge’** tabled by **VPI Immingham** at the Modifications Panel meeting on 18 March 2016.

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.

(d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

(d) in addition, the objective, in so far as consistent with sub-paragraphs (a) above, of facilitating competition in the carrying out of works for connection to the national electricity transmission system.

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. ~~To investigate if there is a better risk management tool.~~ Issue discharged by CUSC Panel.
   b. To look at what the impact of the proposal would be on various sectors of the market.
   c. What would be the ultimate impact on customers?
   d. Are there any other options that can address improving the quality and timeliness of information to market participants?
   e. What are the implications on RCRC?
   f. What is the cost of implementing a new billing system and how is the benefit of this assessed against the short life of this modification proposal.
   g. Workgroup to consider other solutions that spread the costs to generators and suppliers over a longer period of time.
   h. What is the impact of this proposal on competition and at which point does this prevent the market from reacting in a competitive manner.
   i. There are currently a number of related BSC modifications in progress, the Workgroup are requested to review these and identify any impact these may have on this proposal.

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group 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 Group 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 10 working days 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 16 June 2016 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 24 June 2016.

Membership

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

Role	Name	Representing
Chairman	Andrew Wainwright	National Grid
National Grid Representative*	Wayne Mullins / Jo Zhou	National Grid
Industry Representatives*	Mary Teuton (Proposer)	VPI Immingham
	Guy Phillips	EON
	Andrew Colley	SSE
	Tom Breckwoldt	Gazprom
	James Anderson	Scottish Power
	Daniel Hickman	Npower
	Simon Lord	Engie
	Sarah Owen	Centrica
	Jeremy Guard	First Utility
Authority Representatives	Leonardo Costa / Natasha Smith	Ofgem
Technical secretary	Heena Chauhan	National Grid
Observers		

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 CMP262 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.

Appendix 1 – Indicative Workgroup Timetable (Urgent)

The following timetable is indicative for CMP260

10 March 2016	CUSC Modification Proposal and request for Urgency submitted
18 March 2016	CUSC Panel meeting to consider proposal and urgency request
21 March 2016	Panel's view on urgency submitted to Ofgem for consultation
18 March 2016	Request for Workgroup members (7 Working days)
29 March 2016	Ofgem's view on urgency provided
28 April 2016	Workgroup meeting 1
6 May 2016	Workgroup meeting 2
16 May 2016	Workgroup Consultation issued (10 Working days)
30 May 2016	Deadline for responses
w/c 6 June 2016	Workgroup meeting 3
~~16 June 2016~~ ~~5 June 2016~~ 14 July 2016	Workgroup report issued to CUSC Panel
~~24 June 2016~~ ~~12 July 2016~~ 19 July 2016	Panel meeting to approve WG Report

Post Workgroup modification process

~~5 July 2016~~ ~~14 July 2016~~ 20 July 2016	Code Administrator Consultation issued (15 Working days)
~~26 July 2016~~ ~~4 August 2016~~ 10 August 2016	Deadline for responses
~~4 August 2016~~ ~~11 August 2016~~ 15 August 2016	Draft FMR published for industry comment ~~(5 Working days)~~ (3 Working Days)
~~11 August 2016~~ 18 August 2016	Deadline for comments
18 August 2016	Draft FMR circulated to Panel
26 August 2016	Panel meeting for Panel recommendation vote
7 September 2016	FMR circulated for Panel comment (5 Working day)
14 September 2016	Deadline for Panel comment
20 September 2016	Final report sent to Authority for decision
18 October 2016	Indicative Authority Decision due (20 Working days)
1 November 2016	Implementation date

Annex 3 – Workgroup attendance register

A – Attended
X – Absent
O – Alternate
D – Dial-in

Name	Organisation	Role	28 April 2016	6 May 2016	9 June 2016	15 June 2016	27 June 2016
Andrew Wainwright (John Martin Alternate)	National Grid	Chair	A	A	A	O	A
Heena Chauhan	National Grid	Technical Secretary	A	A	A	A	A
Mary Teuton	VPI Immingham	Proposer	A	A	A	A	D
Jo Zhou (Nick Pittarello Alternate)	National Grid	Workgroup member	A	D	A	A	O
Wayne Mullins	National Grid	Workgroup member	A	A	X	X	X
Guy Phillips	EON	Workgroup member	A	A	A	A	D
Andrew Colley (Garth Graham Alternate)	SSE	Workgroup member	A	A	OD	A	X
Tom Breckwoldt	Gazprom	Workgroup member	X	X	D	X	X
James Anderson	Scottish Power	Workgroup member	A	A	A	A	D
Daniel Hickman	Npower	Workgroup member	A	A	A	A	D
Simon Lord	Engie	Workgroup member	D	D(first hour only)	X	X	X
Sarah Owen	Centrica	Workgroup member	X	A	A	A	D
Jeremy Guard	First Utility	Workgroup member	X	A	X	X	X
Leonardo Costa	Ofgem	Authority Representative	A	A	X	Z	X
Natasha Smith	Ofgem	Authority Representative	X	X	D	A	X

The Workgroup attendance register tracks the attendance of the Workgroup so that you can see how many people have attended when it comes to the Workgroup vote. In order to vote, Workgroup members need to have attended at least 50% of Workgroup meetings (either in person, teleconference or by sending an alternate) to be eligible to vote.

Annex 4 – Ofgem view on Urgency

Mike Toms
CUSC Panel Chair
c/o National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick CV34 6DA

Direct Dial: 020 3263 9662
Email: mark.copley@ofgem.gov.uk

Date: 31 March 2016

Dear Mr Toms

CUSC Modification Panel request for urgency for CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge'.

On 10 March 2016, VPI Immingham raised Modification proposal CMP262, with a request for the proposal to be treated as an Urgent CUSC Modification Proposal. The CUSC Modifications Panel ("the Panel") considered CMP262 and the associated request for urgency at the CUSC Modifications Panel meeting held on 18 March 2016. The Panel considered the request for urgency with reference to Ofgem's Guidance on Code Modification Urgency Criteria[1]. The majority view of the Panel is that CMP262 should be treated as an 'Urgent CUSC Modification Proposal'. This letter sets out our decision **accepting** the request for urgency.

Background to the proposal

Balancing Service Use of System (BSUoS) charges are the means by which National Grid Electricity Transmission (NGET) as the System Operator (SO) recovers the costs associated with balancing the transmission system. BSUoS charges are levied on both generation and demand on a 50:50 split basis. The value of BSUoS varies in each half hour settlement period reflecting the different costs incurred by the SO in each period.

In December 2013, the Authority approved NGET's application to introduce two new balancing services, the Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR). These services provide NGET with additional tools to help balance the system in the event that the market is unable to provide sufficient reserves to do so. The relevant licence condition (Special condition (SpC) 4K of NGET's Electricity Transmission Licence) came into effect on 6 June 2014. The cost recovery arrangements allow for both the capacity and utilisation costs of SBR and DSBR to be recouped via BSUoS charges.

The Government is currently consulting on bringing forward the Capacity Market (CM) auction by one year, so that it provides enough generation capacity to meet the Government's reliability standard for winter 17/18. On 1 March 2016 we published an open letter[2] setting out that we would expect a 2017/18 CM auction to procure enough capacity

[1] https://www.ofgem.gov.uk/system/files/docs/2016/02/160217_urgency_letter_and_amended_criteria_2.pdf
[2] https://www.ofgem.gov.uk/publications-and-updates/open-letter-sbr-and-dsbr-201718-given-government-s-consultation-run-ca-delivery-same-year

to meet the government's reliability standard. Therefore, SBR and DSBR services would not be needed for that year and thus it is possible that cost recovery of SBR and DSBR through BSUoS will only continue for one more winter.

The proposal

CMP262 proposes to amend the CUSC so that all SBR and DSBR costs are removed from BSUoS charges. Instead the proposal is for the money to be recouped from demand side only Balancing Mechanism Units via a "demand security charge". The proposer requests that the modification be treated as urgent because it considers there a strong likelihood that there could be a significant commercial impact on generators. If the modification is not treated urgently, the proposer considers that there would be no prospect of resolving the issue ahead of winter 16/17.

Panel Discussion

The Panel recommends urgency and notes three concerns if urgency was not granted:

- In order to meet the November 2016 deadline for the implementation of this modification it would need to be treated as urgent otherwise there would be little value in establishing a Workgroup.
- The CUSC Panel recognised that although there were many issues that need to be addressed by the Workgroup, many of these could be sourced from existing evidence gathered in current modifications that were being progressed by the industry.
- It would be difficult to fully assess whether CMP262 fully met Urgency Criteria 'a) A significant commercial impact on parties, consumers or other stakeholder(s)' without fully understanding material impact which could only be assessed once the Workgroup is formed and able to articulate this position.

Our Views

In deciding whether this modification proposal should be considered urgently, we have referred to the illustrative, but not exhaustive criteria set out in Ofgem's guidance. Specifically that the modification is linked to an imminent issue or a current issue that if not urgently addressed may cause:

a) A significant commercial impact on parties, consumers or other stakeholder(s); or

b) A significant impact on the safety and security of the electricity and/or gas systems; or

c) A party to be in breach of any relevant legal requirements.[3]

We agree with the Panel that there is potential for this issue to have significant financial and commercial impact on a number of market participants in the lead up to and during winter 16/17. We also agree it is appropriate to treat this modification as urgent in order that this issue can be considered ahead of winter 16/17.

We are supportive of the Panel setting up a Workgroup to discuss this issue and see a number of challenging issues to resolve. We strongly encourage participation from suppliers in these discussions given the likely impact of the proposal on them.

[3] https://www.ofgem.gov.uk/system/files/docs/2016/02/160217_urgency_letter_and_amended_criteria_2.pdf

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

We note the proposed timetable indicates that the final report will be sent to us by 20 September 2016, and proposes an Ofgem decision is made within 20 working days, ie by 18 October 2016. We accept this proposed timetable in order to allow the Workgroup time to develop the required evidence to inform our decision and we will endeavour to make a decision within the timescales requested.

We have reviewed this proposal on the issue of urgency and not its substantive merits, which will be assessed once the proposal is submitted for a decision on whether or not to approve it. This decision on urgency should not be taken as indicating the conclusions the Authority will reach at that stage.

Yours sincerely

Mark Copley
Associate Partner, Wholesale Markets
For and on behalf of the Gas and Electricity Markets Authority

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Annex 5 – VPI Immingham Analysis - CMP262 Analysis (pre Workgroup Consultation)

1 Assumptions

The assumptions below have been adopted throughout the analysis.

1. Wherever possible, units are run straight up to MEL for the time needed, and not held at SEL. (i.e. minimising hot standby duration). In this model it was assumed that hot standby hours are zero.
2. If utilised, a unit is held at the MW required for the time needed, and run down to either SEL (if MNZT-run up - run down > time needed), or 0 (if MNZT-run up - run down <= time needed) – please see the figure below (Figure 1) for illustration.

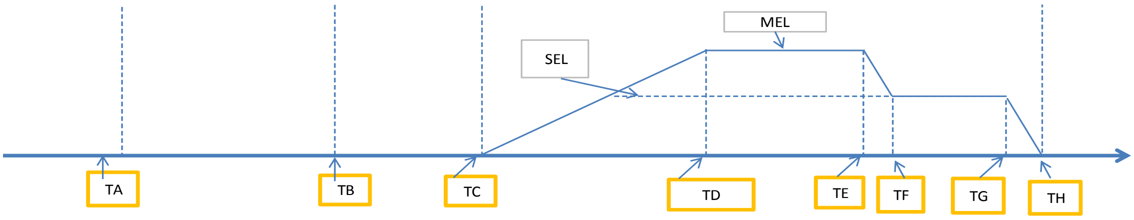


Figure 1 – Illustrative Unit Output

3. For the purpose of calculating BSUoS volume, HH demand profile was obtained from the metered 2015/16 winter data surrounding the maximum national demand snapshot. There is no correlation assumed between the demand level and the amount of SBR utilised.
4. Assuming linear ramp up.
5. Assuming all the SBR units are available (i.e. no breakdown etc).
6. Historic half hour demand data were obtained from National Grid's website http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/ (DemandData_2015 and DemandData_2016).
7. The 2015/16 winter BSUoS volume and BSUoS price data were obtained from National Grid website http://www2.nationalgrid.com/bsuos/ (for current SF BSUoS data)
8. Utilisation Price assumptions are shown in Table1 below (provided by Vitol Group).

Unit	MEL MW	SEL MW	Max NDZ hrs	MNZT hrs	max Run up hrs	Assumed ramp up rate MW/hr	Run Down hrs	Assumed ramp down rate (MW/hr) MW/hr	Price £/MWh	Start Up £/hr	Hot Standby £/hr
SHB2 GT	20	20	0.5	1.0	0.0	600.0	0.0	600.0	250		
Rugeley GT	25	10	0.2	0.5	0.1	500.0	0.0	1,500.0	500		
FF GT SBR1	17	17	0.5	1.0	0.0	1,020.0	0.0	1,020.0	550		
FF GT SBR2	17	17	0.5	1.0	0.0	1,020.0	0.0	1,020.0	550		
Keadby GT	23	23	0.5	1.0	0.1	197.1	0.1	197.1	550		
Killingholme	600	240	1.3	1.0	0.3	1,894.7	0.3	1,894.7	200		
Deeside	250	100	1.5	2.4	0.9	267.9	0.2	1,153.8	225		
Peterhead SBR1	375	249	3.7	4.0	2.2	173.1	0.7	548.8	250	1200	
Peterhead SBR2	375	249	3.7	4.0	2.2	173.1	0.7	548.8	250	1200	
Corby	353	220	1.4	6.0	5.8	61.4	0.2	1,925.5	200		
SHB	750	540	18.0	6.0	4.7	158.5	0.3	2,647.1	200	1000	1000
Fiddlers Ferry Coal	480	240	24.0	4.0	2.0	244.1	0.9	553.8	500	3000	3000
Eggborough	775	280	48.0	4.0	0.9	830.4	0.6	1,223.7	500	3908	11513

Exact utilisation costs not known. Assumed cost figures provided by Mary Teuton

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.

Table 1 – Assumed Parameters of SBR Units

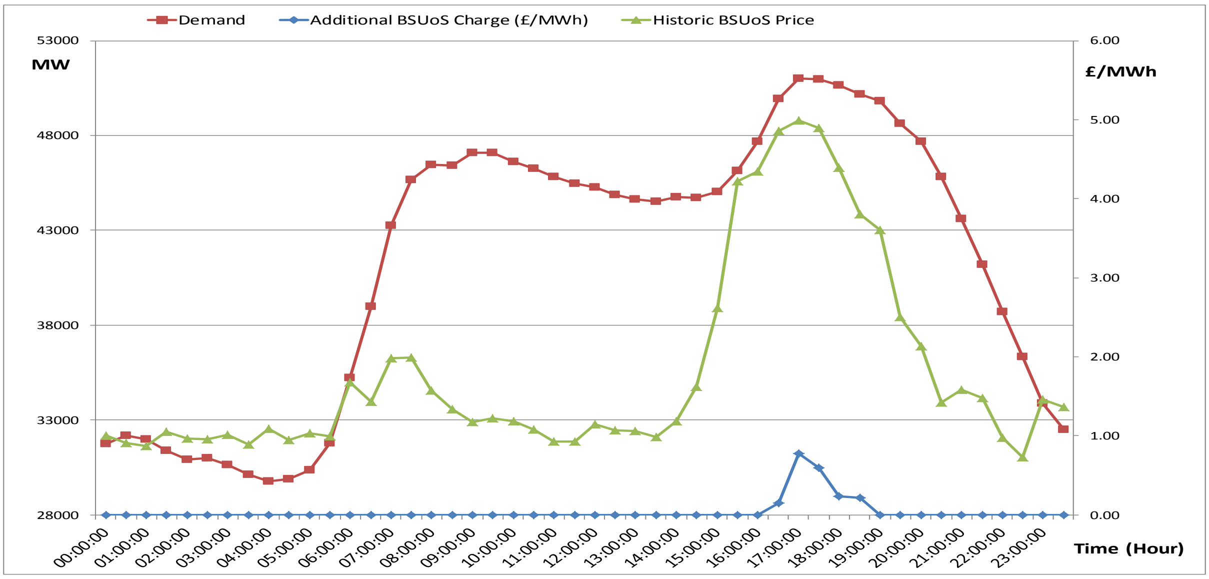
NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2 Results

The cost calculation in this section is based on one SBR utilisation per winter season. The "Duration" and "Capacity" figures refer to the SBR capacities that are despatched, and the hours that SBR units are required to meet the plant margin deficit. The demand curve plotted in this section was based on the historic outturn demand on the day of peak demand in 2015/16 winter (19th January when the highest demand occurred). Similarly, the BSUoS costs were the "snapshot" figures on that day, over the 48 settlement periods.

2.1 Duration = 0.5 Hour, Capacity = 250MW

These indicative results are based on the assumptions listed in the previous section.



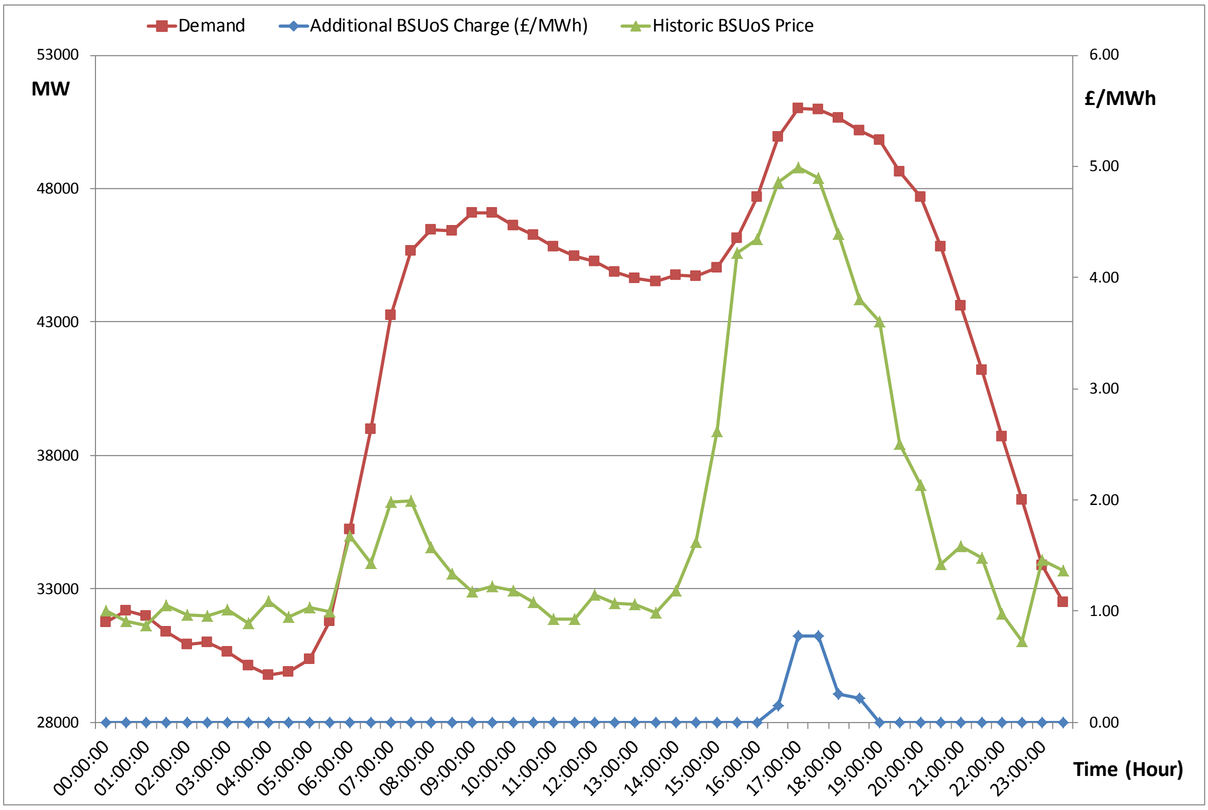
Duration =	0.5 hour	Capacity =	250 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.00	0.17	0.01	0.00	0.05
Total Cost (£k) per Utilisation				95

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.2 Duration = 1 Hour, Capacity = 250MW

These indicative results are based on the assumptions listed in the previous section.



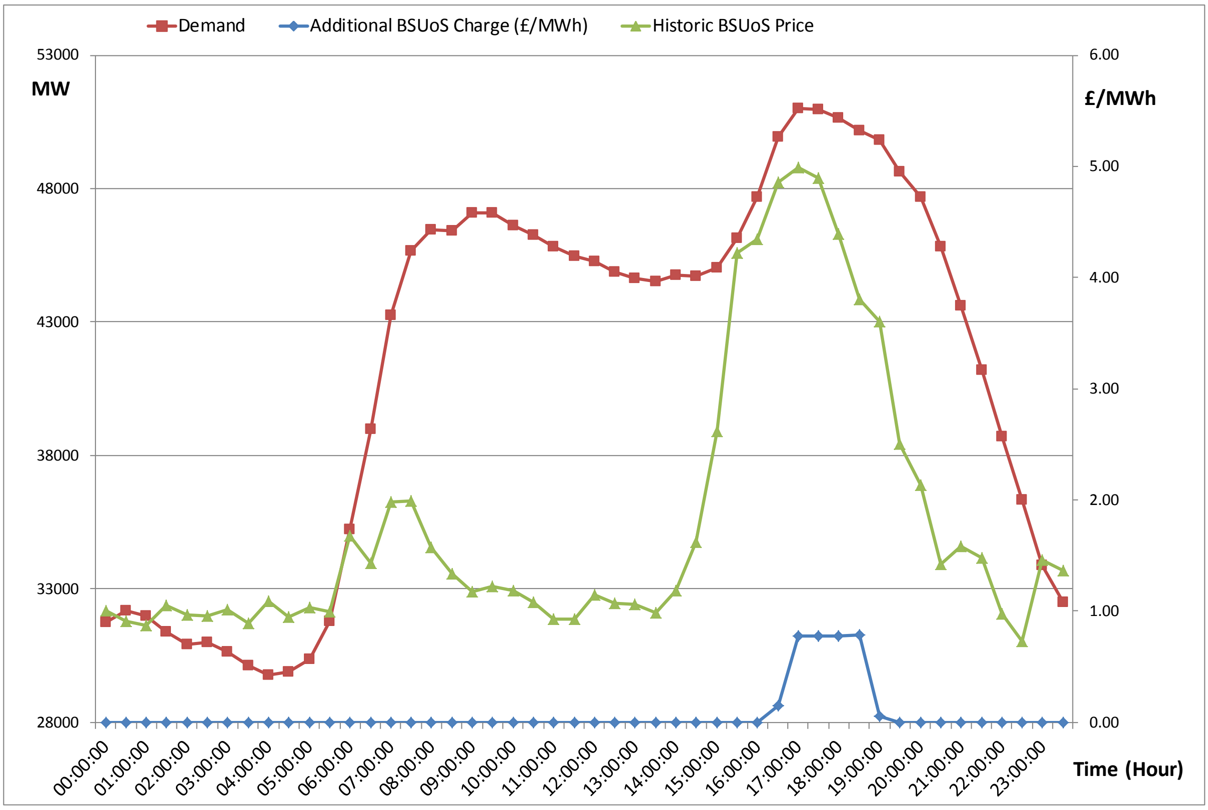
Duration =	1 hour	Capacity =	250 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.00	0.19	0.01	0.00	0.05
Total Cost (£k) per Utilisation				105

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.3 Duration = 2 Hour, Capacity = 250MW

These indicative results are based on the assumptions listed in the previous section.



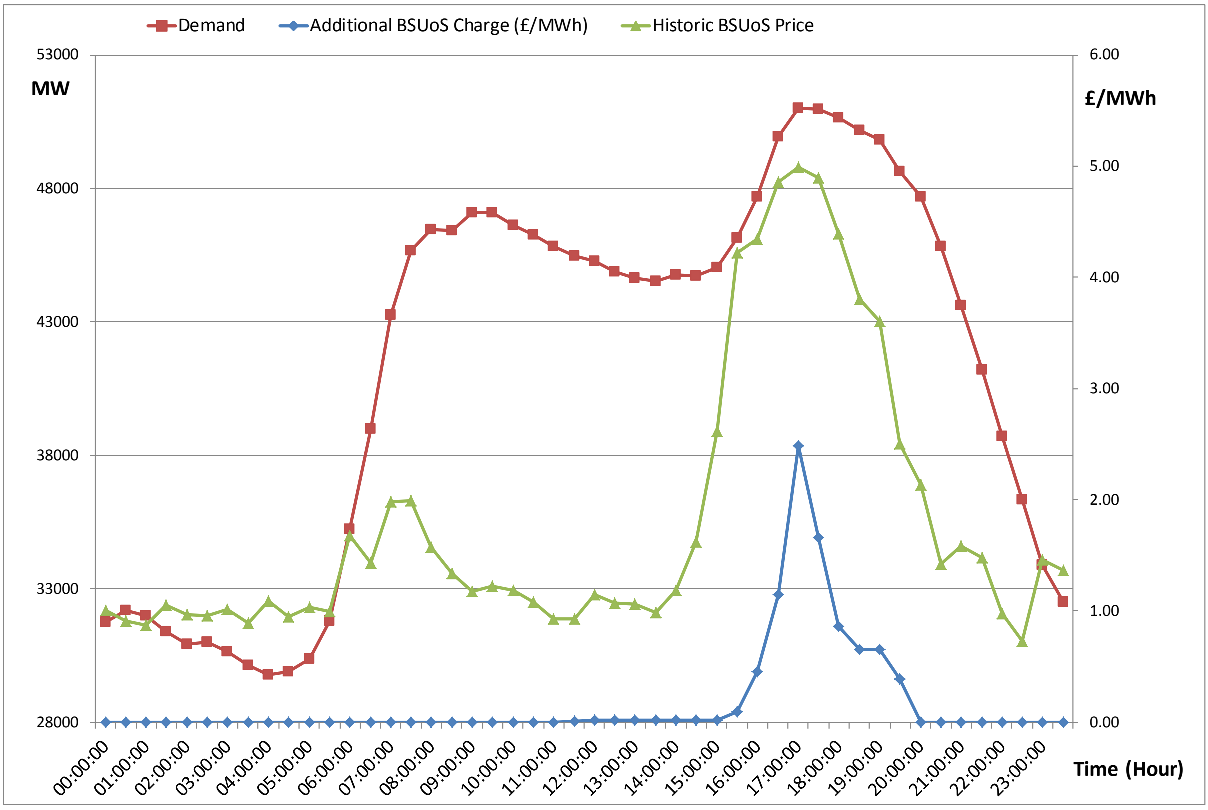
Duration =	2 hour	Capacity =	250 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.00	0.29	0.01	0.00	0.08
Total Cost (£k) per Utilisation				159

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.4 Duration = 0.5 Hour, Capacity = 1GW

These indicative results are based on the assumptions listed in the previous section.



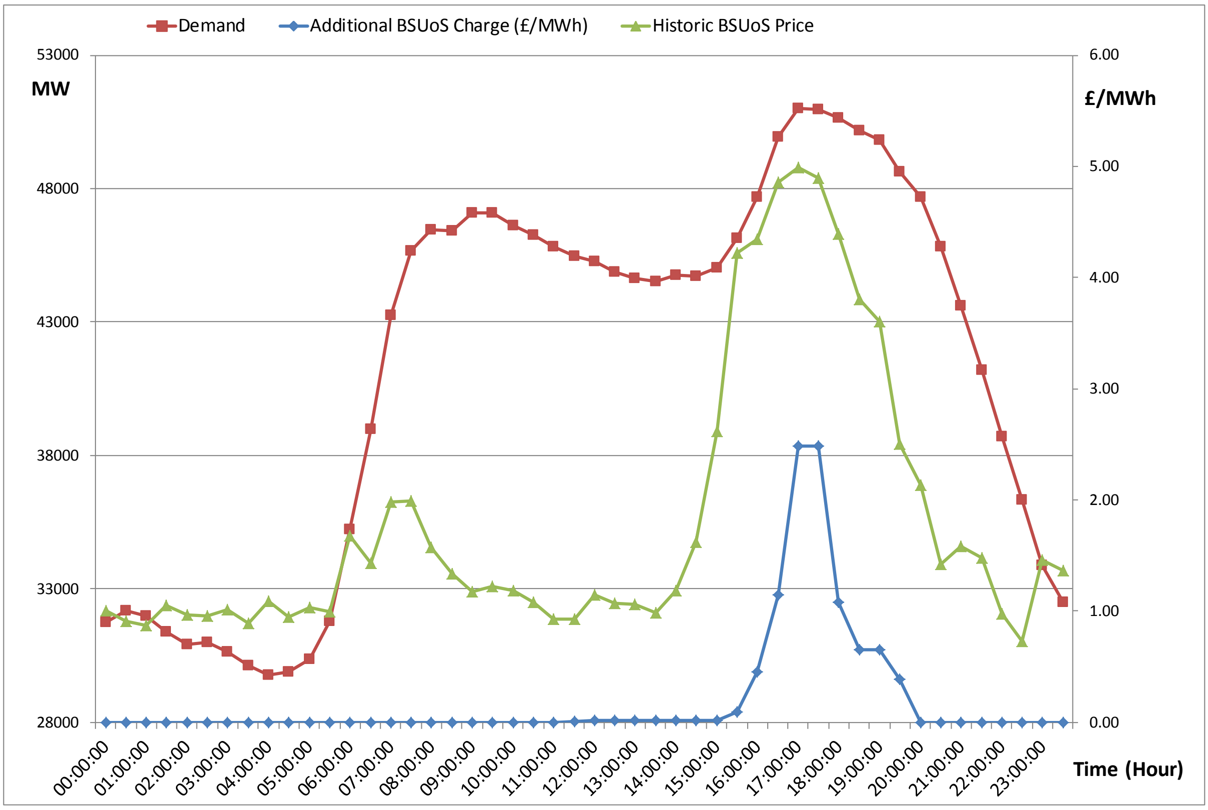
Duration =	0.5 hour	Capacity =	1000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.00	0.74	0.03	0.01	0.21
Total Cost (£k) per Utilisation				406

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.5 Duration = 1 Hour, Capacity = 1GW

These indicative results are based on the assumptions listed in the previous section.



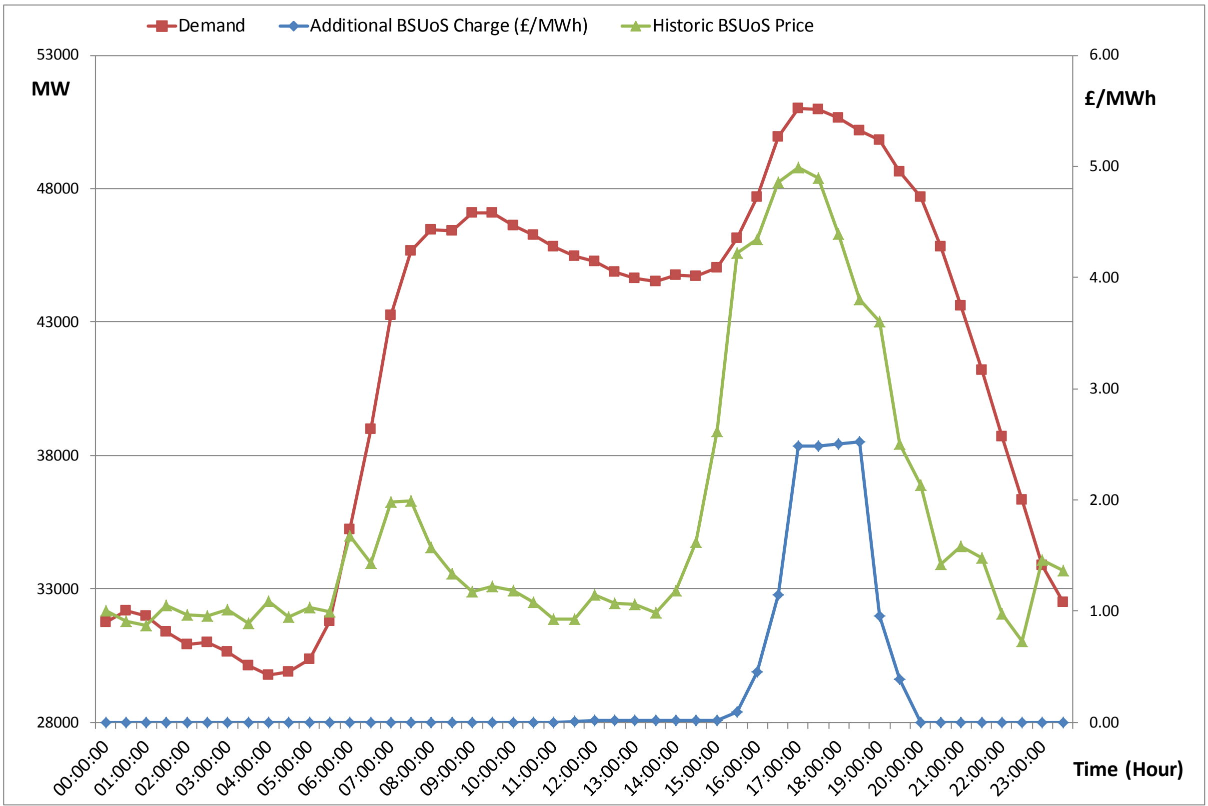
Duration =	1 hour	Capacity =	1000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.00	0.83	0.03	0.01	0.24
Total Cost (£k) per Utilisation				457

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.6 Duration = 2 Hour, Capacity = 1GW

These indicative results are based on the assumptions listed in the previous section.



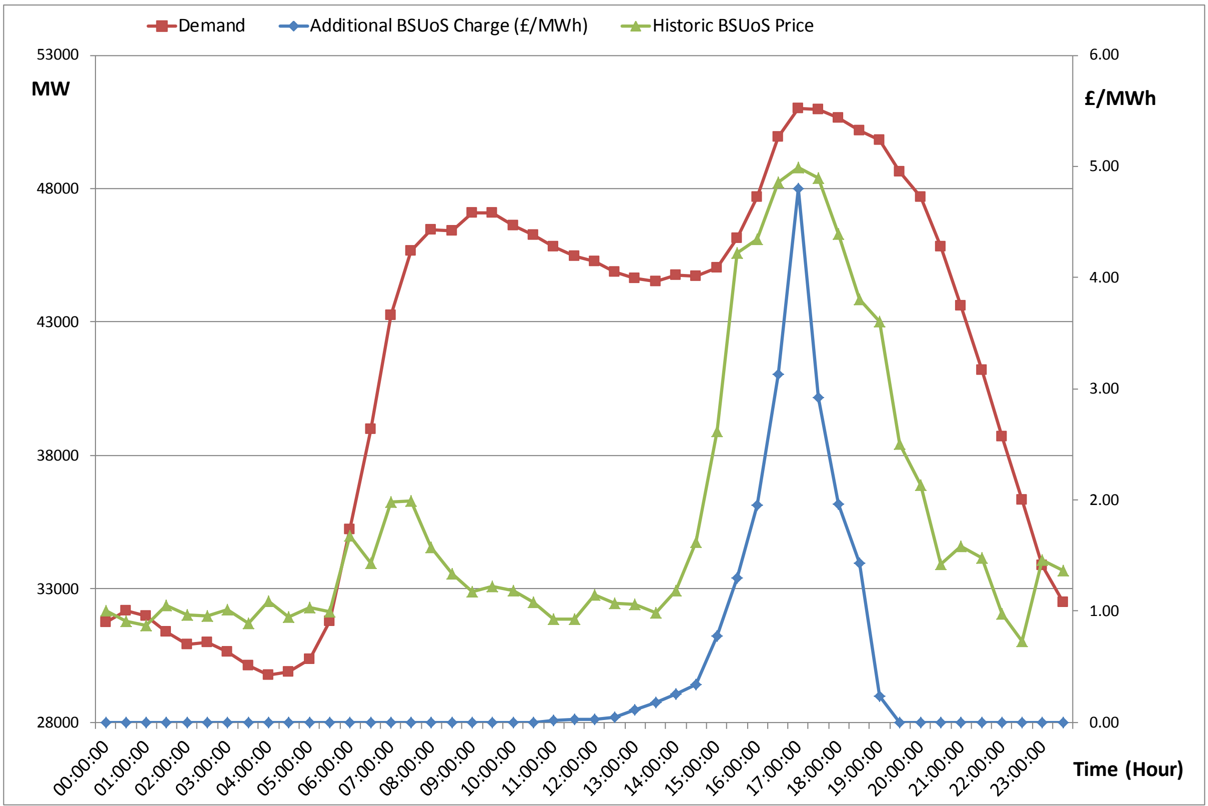
Duration =	2 hour	Capacity =	1000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.00	1.15	0.05	0.01	0.32
Total Cost (£k) per Utilisation				629

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.7 Duration = 0.5 Hour, Capacity = 2GW

These indicative results are based on the assumptions listed in the previous section.



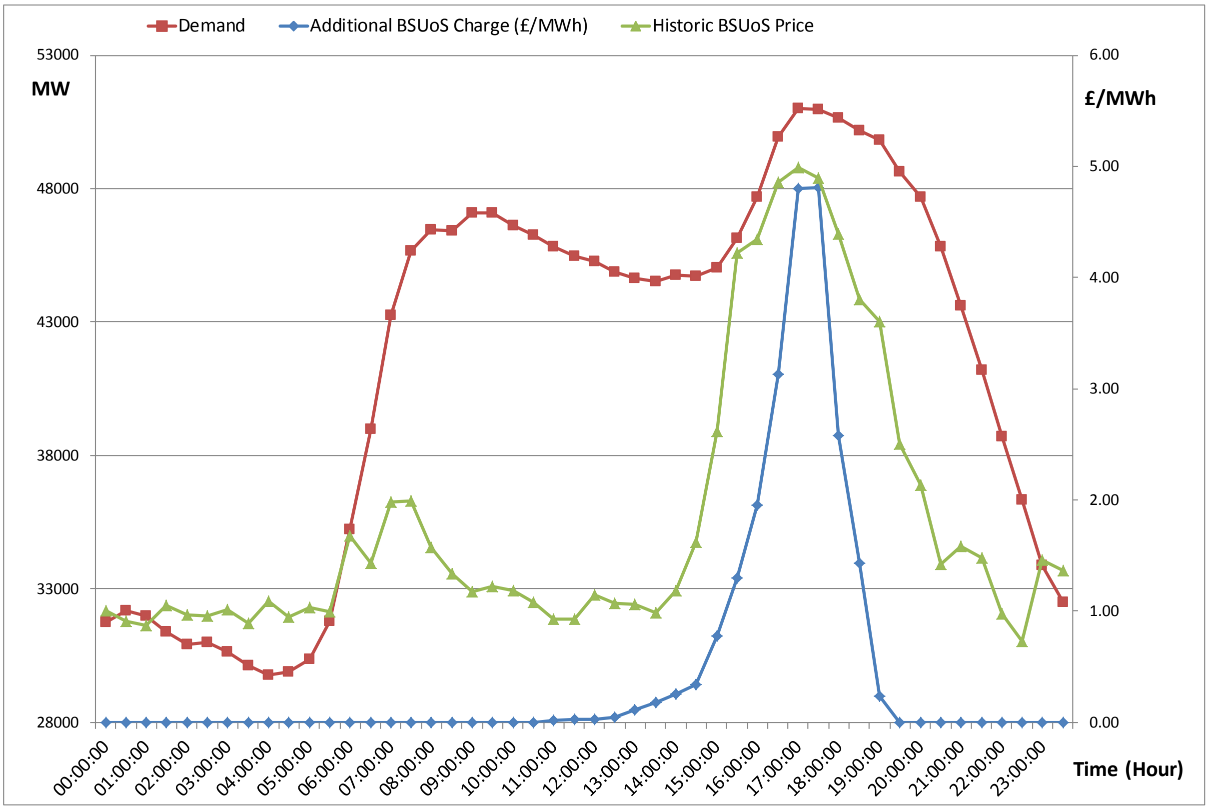
Duration = 0.5 hour		Capacity = 2000 MW		
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.01	1.68	0.07	0.02	0.48
Total Cost (£k) per Utilisation				922

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.8 Duration = 1 Hour, Capacity = 2GW

These indicative results are based on the assumptions listed in the previous section.



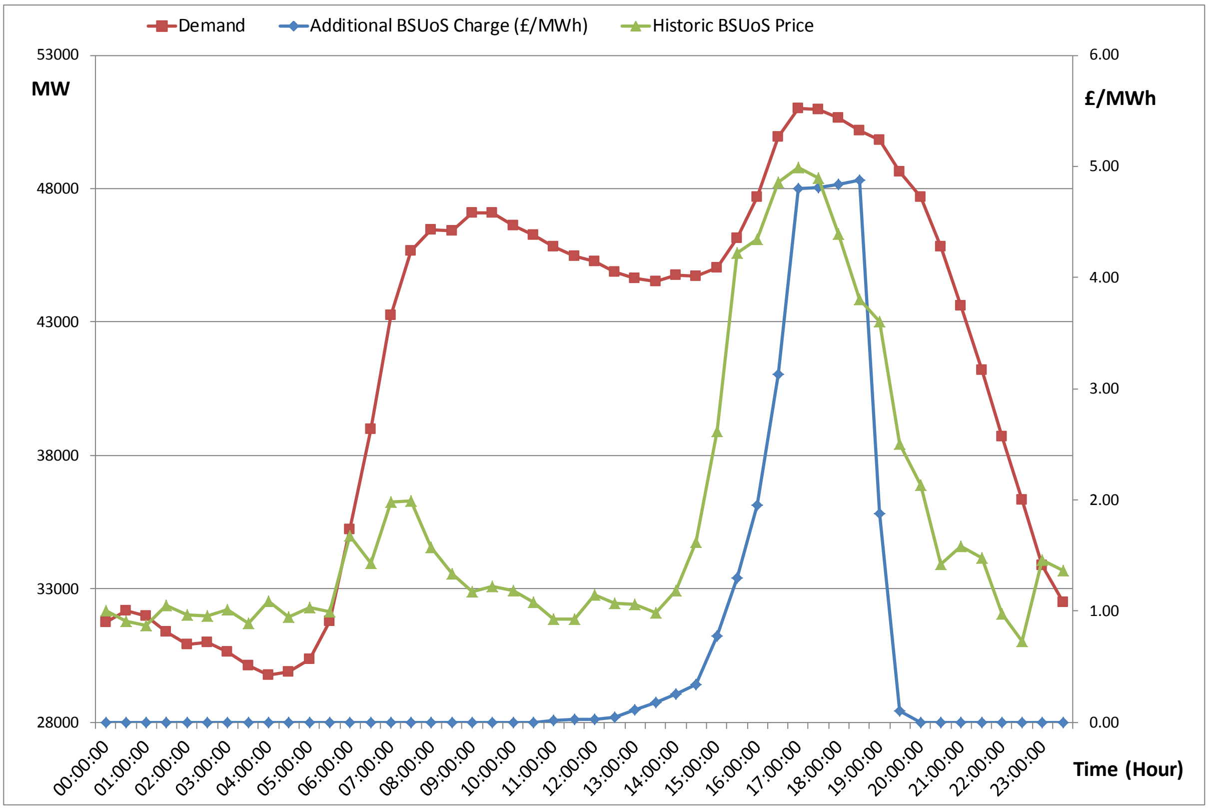
Duration =	1 hour	Capacity =	2000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.01	1.90	0.08	0.02	0.54
Total Cost (£k) per Utilisation				1043

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.9 Duration = 2 Hour, Capacity = 2GW

These indicative results are based on the assumptions listed in the previous section.



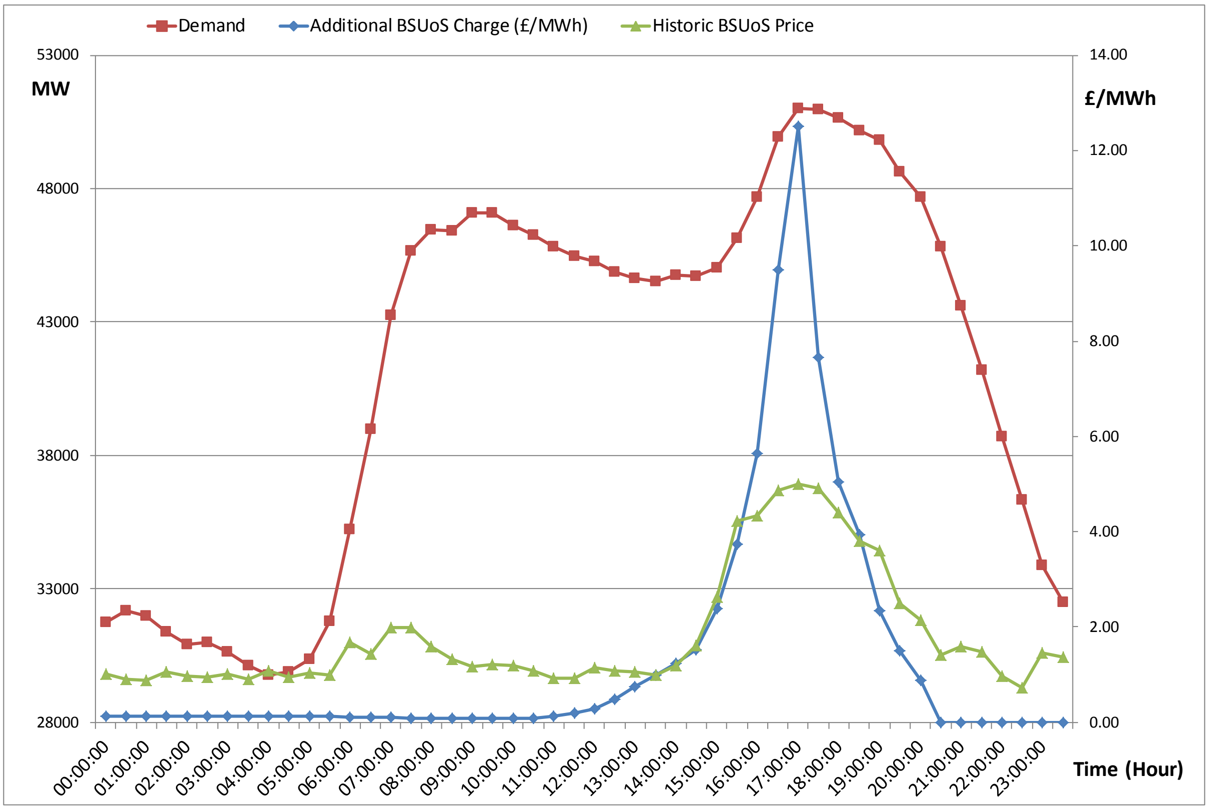
Duration =	2 hour	Capacity =	2000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.01	2.55	0.10	0.03	0.72
Total Cost (£k) per Utilisation				1399

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.10 Duration = 0.5 Hour, Capacity = 4GW

These indicative results are based on the assumptions listed in the previous section.



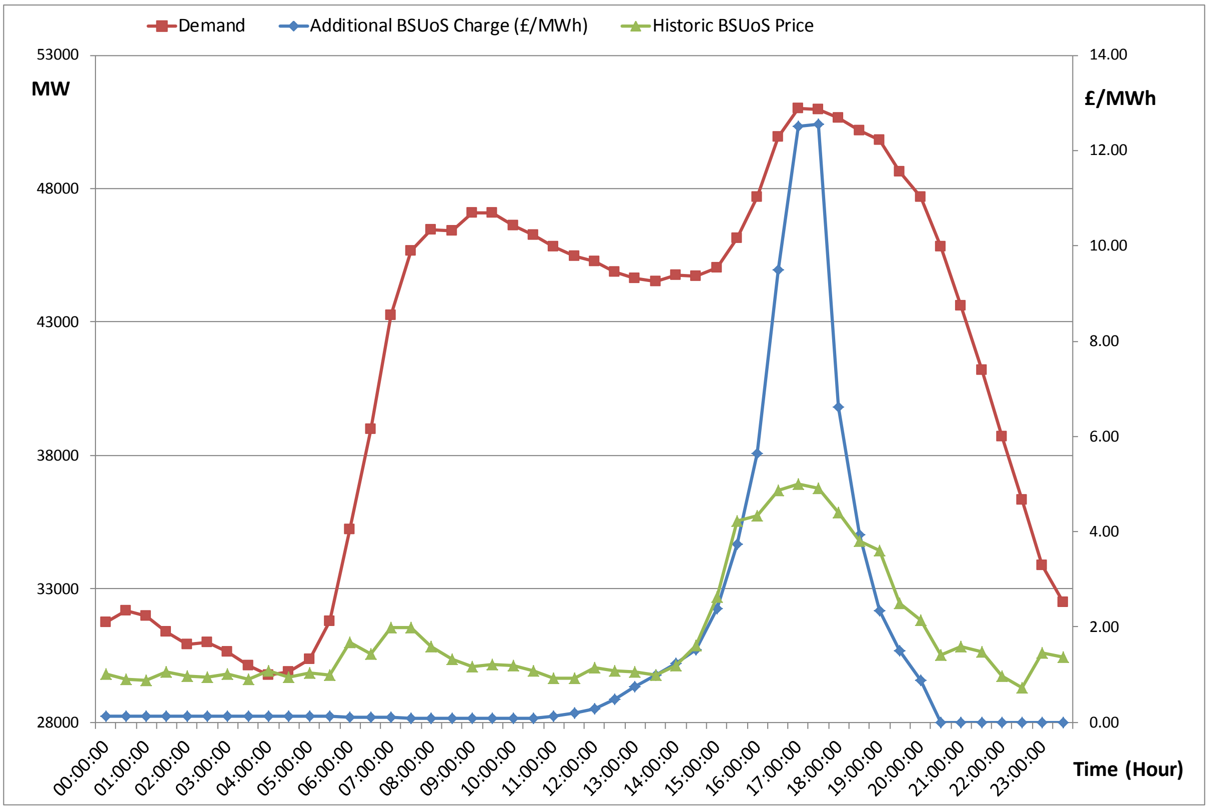
Duration =	0.5 hour	Capacity =	4000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.02	5.65	0.23	0.06	1.60
Total Cost (£k) per Utilisation				3101

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.11 Duration = 1 Hour, Capacity = 4GW

These indicative results are based on the assumptions listed in the previous section.



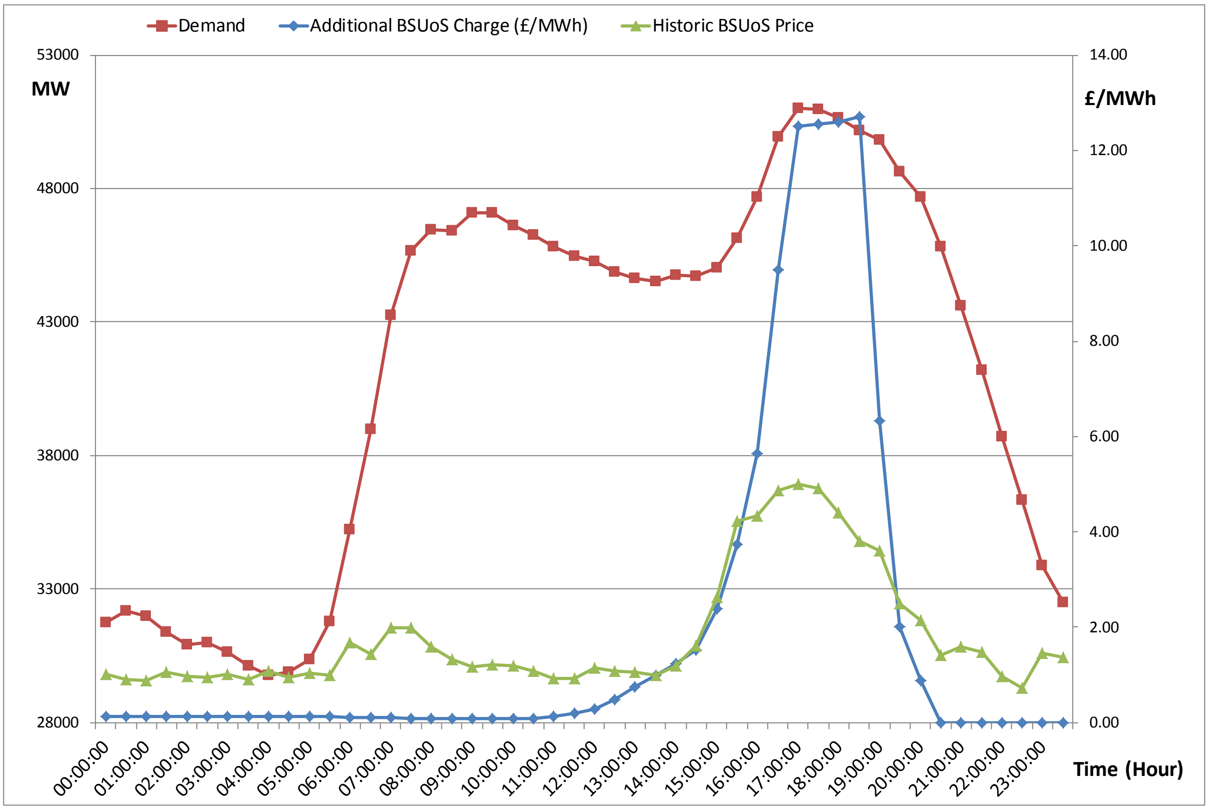
Duration =	1 hour	Capacity =	4000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.03	6.22	0.25	0.07	1.76
Total Cost (£k) per Utilisation				3415

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.12 Duration = 2 Hour, Capacity = 4GW

These indicative results are based on the assumptions listed in the previous section.



Duration =	2 hour	Capacity =	4000 MW	
Cost Spreaded 24/7 over Triad Season	Cost Spreaded over 5b on three Triad days (£/MWh)	Cost Spreaded over 5b over Triad Season (£/MWh)	Cost Spreaded 24/7 over the month (£/MWh)	Cost Spreaded over the day (£/MWh)
0.03	7.90	0.32	0.09	2.24
Total Cost (£k) per Utilisation				4336

Note: Cost spreading is based on 50:50 sharing between generators and suppliers. If the cost is to be paid by suppliers only, the cost figures (in £/MWh) will double accordingly.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

Annex 6 – National Grid Analysis - Post Workgroup Consultation

1 Assumptions

The assumptions below have been adopted throughout the analysis.

1. Wherever possible, units are run straight up to MEL for the time needed, and not held at SEL. (i.e. minimising hot standby duration). In this model it was assumed that hot standby hours are zero.
2. If utilised, a unit is held at the MW required for the time needed, and run down to either SEL (if MNZT-run up - run down > time needed), or 0 (if MNZT-run up - run down <= time needed) – please see the figure below (Figure 1) for illustration.

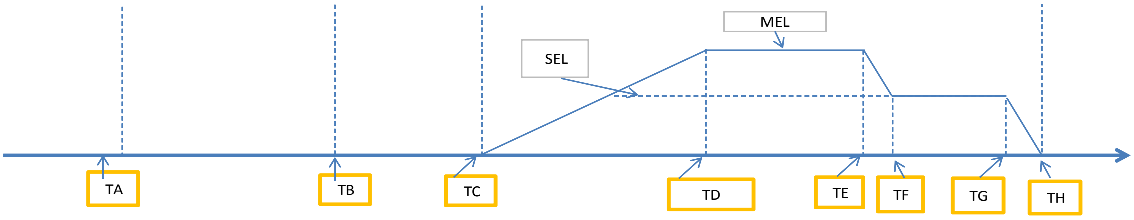


Figure 1 – Illustrative Unit Output

3. For the purpose of calculating BSUoS volume, HH demand profile was obtained from the metered 2015/16 winter data surrounding the maximum national demand snapshot. There is no correlation assumed between the demand level and the amount of SBR utilised.
4. Assuming linear ramp up.
5. Assuming all the SBR units are available (i.e. no breakdown etc).
6. The 2015/16 winter BSUoS volume and BSUoS price data were obtained from National Grid website http://www2.nationalgrid.com/bsuos/ (for current SF BSUoS data)

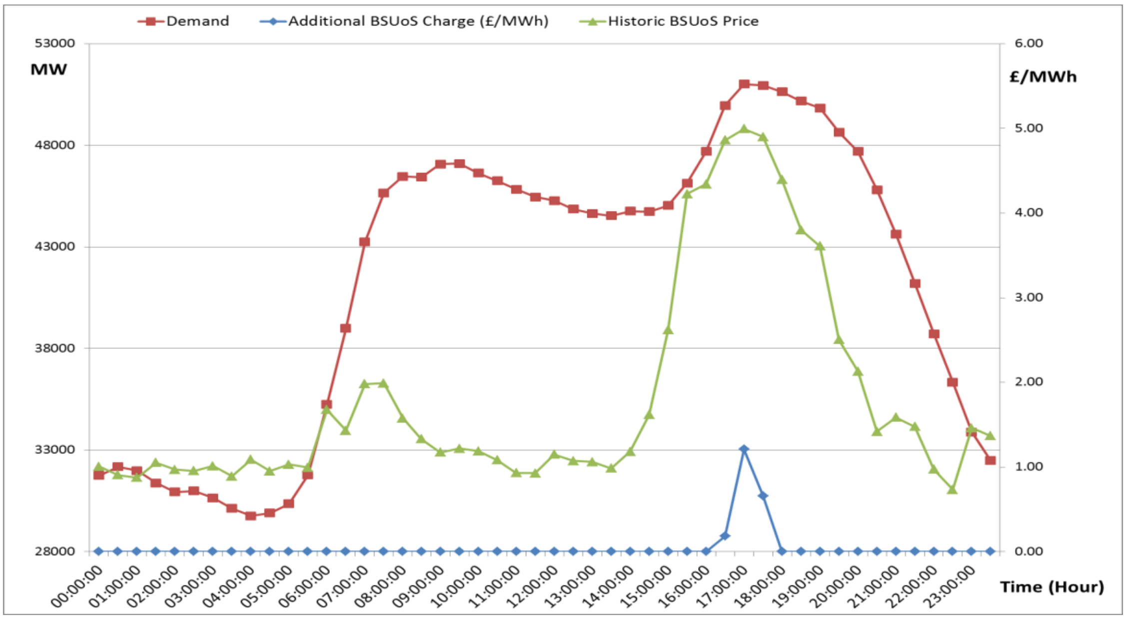
NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2 Results

The cost calculation in this section is based on one SBR utilisation per winter season. The "Duration" and "Capacity" figures refer to the SBR capacities that are despatched, and the hours that SBR units are required to meet the plant margin deficit. The demand curve plotted in this section was based on the historic outturn demand on the day of peak demand in 2015/16 winter (19th January when the highest demand occured). Similarly, the BSUoS costs were the "snapshot" figures on that day, over the 48 settlement periods.

2.1 Duration = 0.5 Hour, Capacity = 500MW

These indicative results are based on the assumptions listed in the previous section.



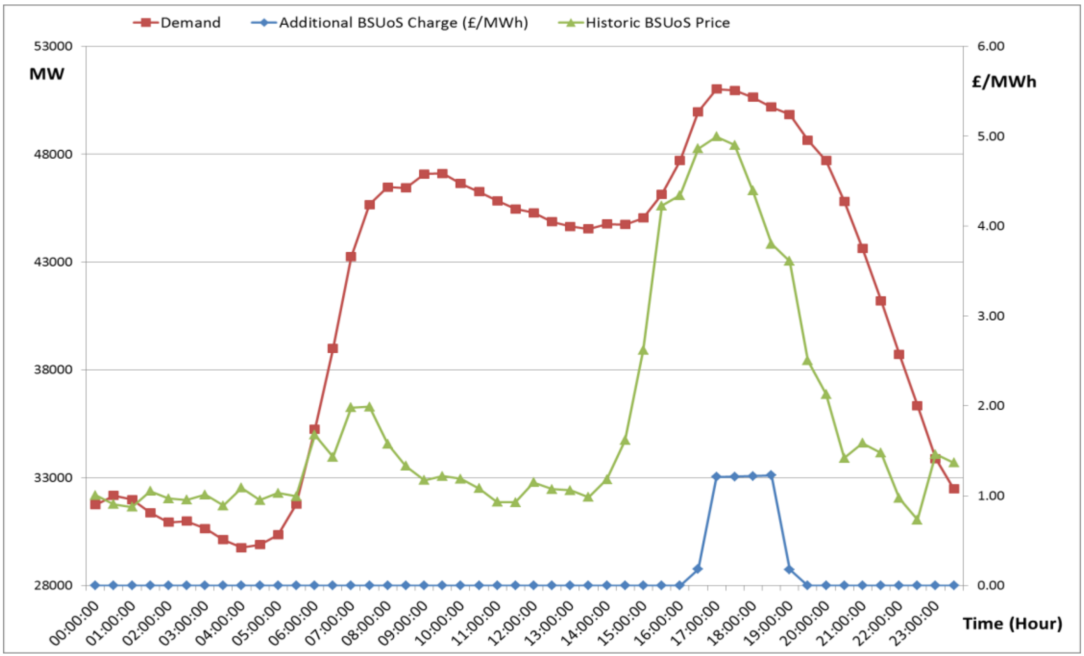
Duration =	0.5 hour	Capacity =	500 MW	
Original Proposal (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.00	0.16	0.00	0.00	0.05
Total Cost (£k) per Utilisation				99

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.2 Duration = 2 Hour, Capacity = 500MW

These indicative results are based on the [assumptions](#) listed in the previous section.



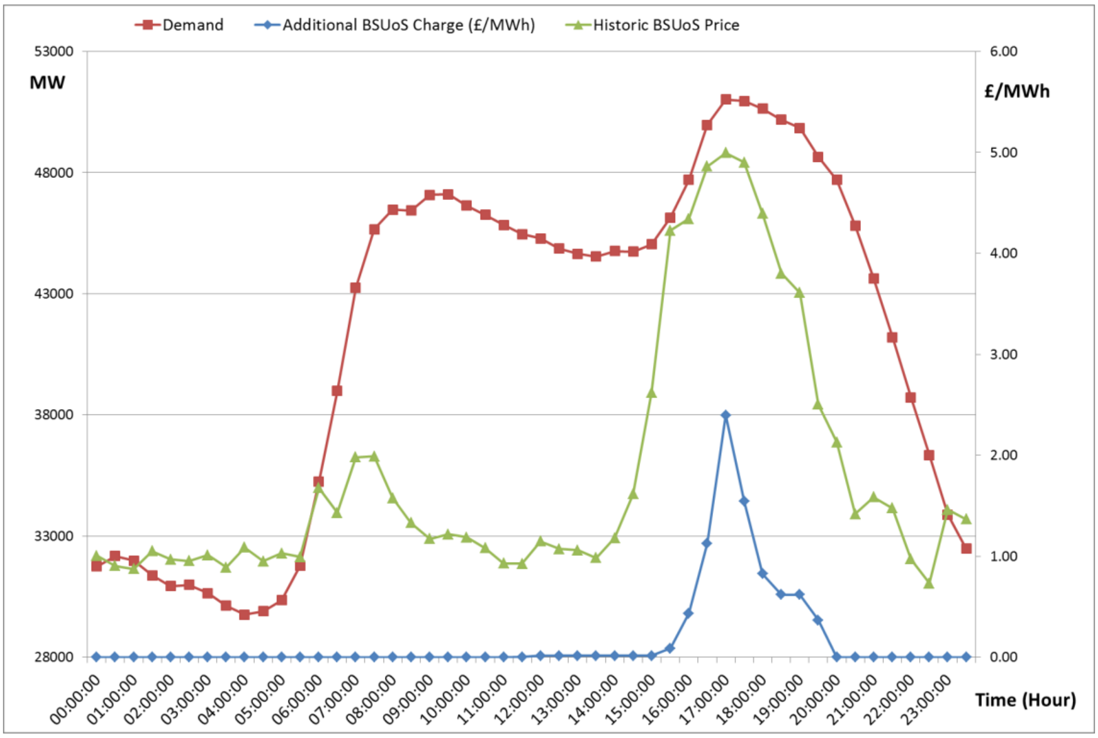
Duration =	2 hour	Capacity =	500 MW	
Original Proposal (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.00	0.40	0.00	0.00	0.13
Total Cost (£k) per Utilisation				252

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.3 Duration = 0.5 Hour, Capacity = 1GW

These indicative results are based on the assumptions listed in the previous section.



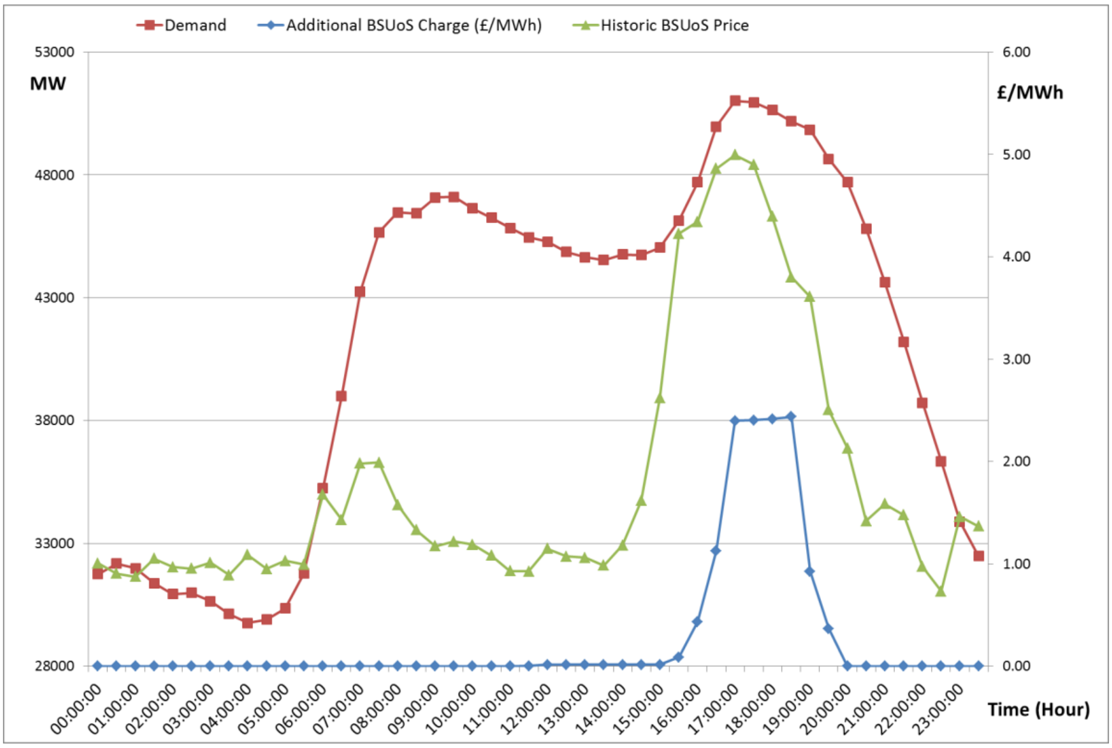
Duration =	0.5 hour	Capacity =	1000 MW	
Original Proposal (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.00	0.62	0.00	0.00	0.20
Total Cost (£k) per Utilisation				389

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.4 Duration = 2 Hour, Capacity = 1GW

These indicative results are based on the assumptions listed in the previous section.



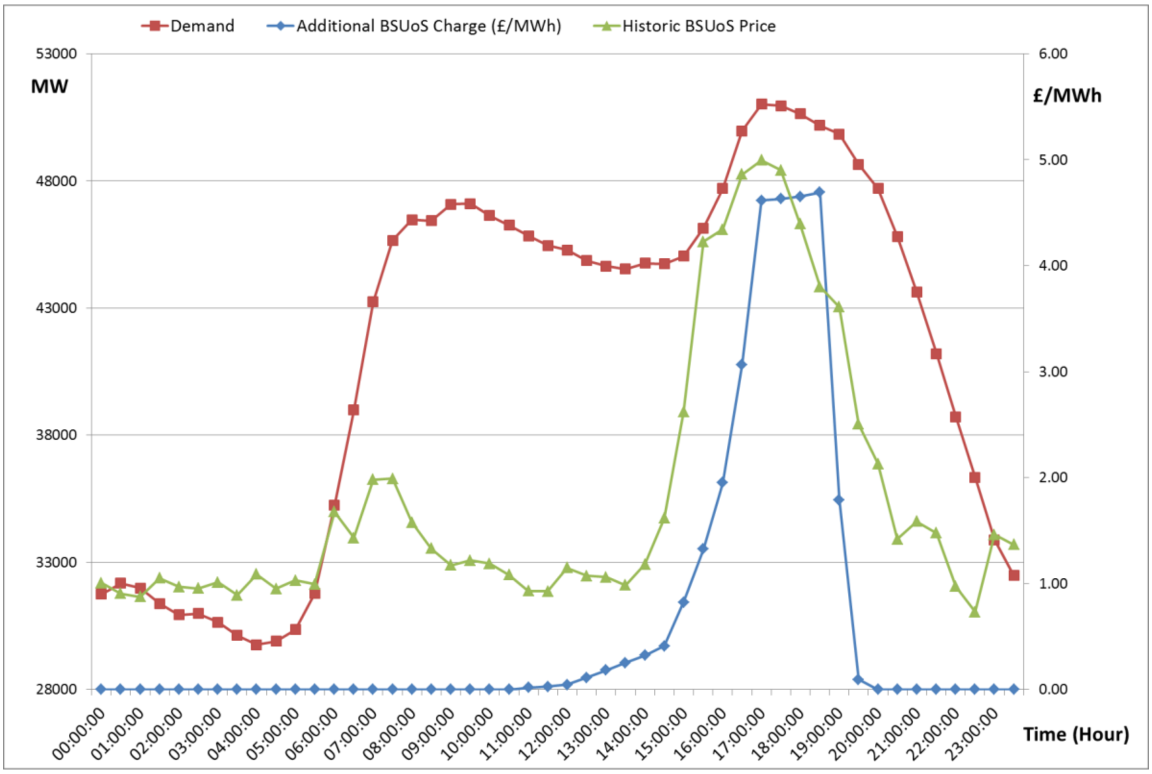
Duration =	2 hour	Capacity =	1000 MW	
Original Proposal (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.01	0.97	0.00	0.00	0.31
Total Cost (£k) per Utilisation				608

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.

2.5 Duration = 2 Hour, Capacity = 2 GW

These indicative results are based on the assumptions listed in the previous section.



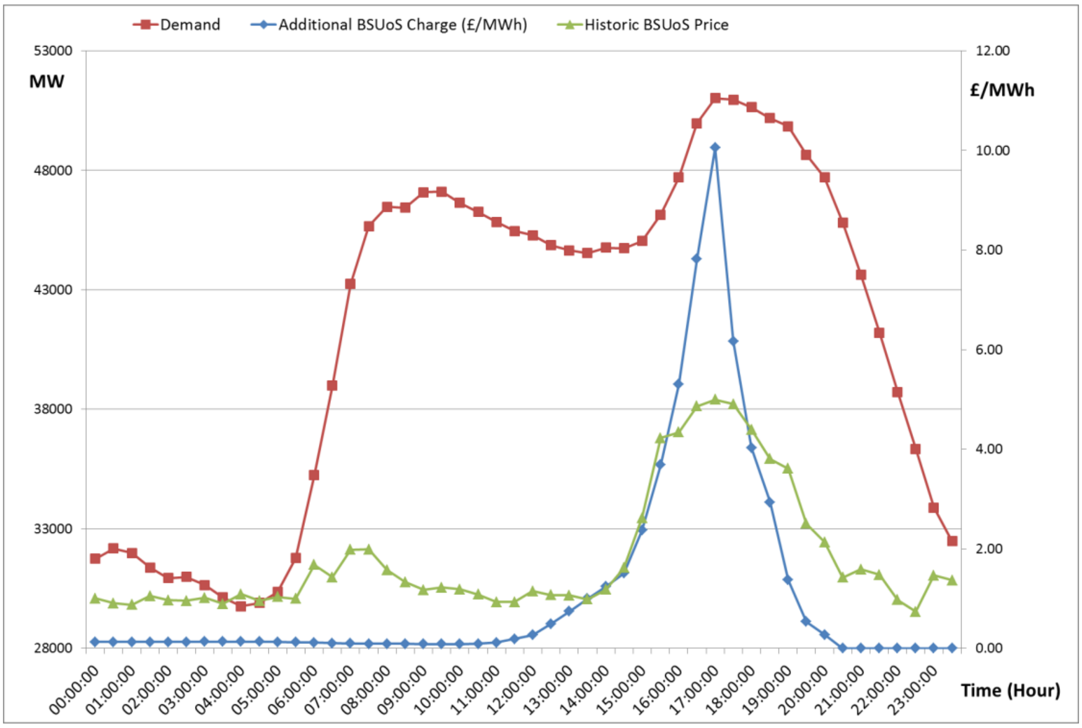
Duration =	2 hour	Capacity =	2000 MW	
Original (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.01	2.19	0.01	0.01	0.71
Total Cost (£k) per Utilisation				1377

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.6 Duration = 0.5 Hour, Capacity = 4GW

These indicative results are based on the assumptions listed in the previous section.



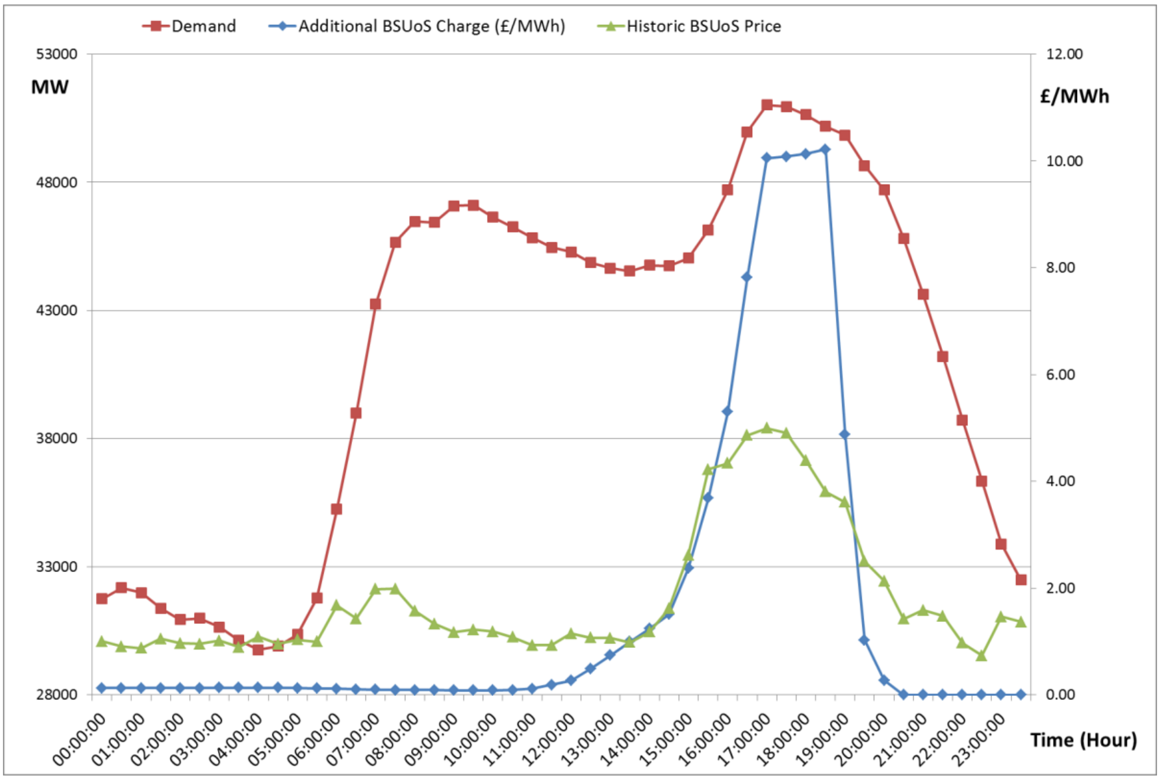
Duration =	0.5 hour	Capacity =	4000 MW	
Original (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.03	4.13	0.01	0.02	1.34
Total Cost (£k) per Utilisation				2596

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers.

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

2.7 Duration = 2 Hour, Capacity = 4GW

These indicative results are based on the assumptions listed in the previous section.



Duration =	2 hour	Capacity =	4000 MW	
Original (D charge only) (£/MWh)	WACM1 (D charge only) (£/MWh)	WACM2 (£/MWh)	WACM3 (£/MWh)	Cost Spread over the day (£/MWh)
0.04	5.76	0.02	0.03	1.87
Total Cost (£k) per Utilisation				3616

Note: Figures under the Original and WACM1 are the SBR utilisation cost to be paid by suppliers; figures under other options are the SBR utilisation cost to be paid by both generators and suppliers..

NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity required.	

Annex 7 – Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Phil Robinson, Head of Commercial*
Company Name:	*Calon Energy Limited (parent company of Baglan Bay, Severn and Sutton Bridge power stations)*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	Yes. The extensive capacity market consultation process conducted in the UK has concluded unequivocally that the costs of security of supply should for economic reasons rest with the consumer of those benefits i.e. the supply side rather than the generator. It is clear that SBR is an inferior instrument to the capacity mechanism but it is also undoubted that it is a substitute mechanism as shown by its removal for 2017/18 when an early capacity delivery period has been scheduled. Therefore, it seems entirely logical and consistent with the economics of security of supply that this proposal should be adopted.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We consider that the implementation should be feasible given the potential workaround suggested. In any case, the principle of which party should pay the costs should be established clearly.
3	**Do you have any other comments?**	The fact that SBR/DSBR was created and pushed through in a form inconsistent with the logic of other security of supply principles as embodied in the capacity mechanism should not preclude these changes occurring due to the perceived switching costs. As an industry, it is important to demonstrate that rational economics will be adhered to.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Due to the potential impact, we do not believe that it appropriate to not implement the proposed change even though SBR has only been contracted for this winter. It is our view that although it may be difficult for suppliers to recover costs, any generator that has forward contracted has no opportunity. Retailers still have some ability to adjust tariffs (should they wish to do so). Furthermore, when SBR is called what is required is a) more generation and b) less consumption. A charge that increases as SBR is called, all other things being equal, would cause electricity production to be less attractive. Our final point is that the question is not just one of managing costs but also for economic efficiency costs and benefits should be commensurate. SBR has two effects: i) it decreases the probability of supply interruptions – a benefit to customers ii) it subsidises otherwise uneconomic generators to remain on the system – a disbenefit to efficient generators Therefore, we do not see an economic reason why SBR costs should be paid by generators via BSUOS.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	In principle, we do not consider that smearing costs for utilisation outside periods in which the utilisation occurs leads to an efficiently functioning price mechanism.
7	What is the impact of the proposal on your business?	Positive but not outweighing the negative effect of SBR as a tool and its flawed implementation.

Q	Question	Response
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	The impact will be to address the current issues so there will inevitably be a redistribution of risk from generators to suppliers.
9	How do you believe this proposal could impact the end consumer?	Assuming efficient procurement and utilisation of SBR, the impact will be consistent with the benefit gained if the services are utilised. In the longer-term, the proposal will signal that the industry will introduce economically rational modifications which should lower risk premia and benefit consumers.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	Full transparency of not only the BSUoS calculation methodology but also the costing model itself. Furthermore, the timely publishing of any assumptions and forecasts that NG is using in its decision-making with respect to SBR and DSBR, for example, assumptions impacting NG's planning margin.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

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Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

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These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Sarah Owen sarah.owen@centrica.com*
Company Name:	*Centrica*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	No, it is worse under objective a) in that it benefits certain suppliers over others, suppliers that do not forward hedge their winter electricity requirements benefit whilst others will be penalised. Additionally, those generators that have forward sold their power will benefit as the risks they had factored into their forward hedge price will not now materialise. Additionally, those suppliers that offer fixed priced contracts for their customers will also be adversely impacted.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	No, the impact to participants is entirely down to the short notice between this modification being raised and its proposed implementation date. For changes that could have significant impacts on some industry parties there should be a sufficient notice period to minimise the impact to these parties. For this modification, there should be a notice period of at least a year, if not longer, to ensure a subsection of the industry do not incur unanticipated additional costs.
3	**Do you have any other comments?**	This risk has been present since SBR and DSBR were first contracted by National Grid in 2014. A low margin, and therefore, an expected increase in the contracted volume, and risk of these contracts being utilised has also been predicted for winter 16/17 for a significant period of time. Given this, and the potentially significant impacts of this change to suppliers, we do not support the implementation of this urgent modification.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	No industry player is better positioned to manage large non-forecastable costs. Please see our answer to Question 3, the introduction of this demand charge will be difficult for all suppliers to manage over such a short implementation period.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	No, we do not support the smearing of these charges, it adds complications to suppliers as customer numbers and therefore volumes can change quite quickly, which will inevitably lead to further winners and losers.
7	What is the impact of the proposal on your business?	Our supply business will incur additional costs via this demand security charge. Some of this additional cost would already have been incurred as a direct result of hedging our winter demand profile, so in effect these costs will be incurred twice on hedged volumes. All suppliers would be subject to intense media scrutiny if this new charge results in increases to domestic tariffs.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	We believe that all industry parties that hedge their positions are likely to be impacted in a similar manner. All suppliers will be adversely impacted under this proposal as they will be liable for the full costs of SBR and DSBR utilisation, previously this was spread amongst all participants. We find it incredible that an assumption has been made that integrated utilities are better able to manage these costs. All integrated utilities manage their businesses separately, with no benefits passing between supply and generation businesses.
9	How do you believe this proposal could impact the end consumer?	We think this proposal could increase costs to the consumer, as the hedged supplier would see overall costs significantly increase.

Q	Question	Response
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	No

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Joe Underwood – Joseph.Underwood@drax.com*
Company Name:	*Drax*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We believe that the proposal could better facilitate the Applicable CUSC Objectives. However, we note the short timescales involved and recommend retaining the 50:50 G:D BSUoS split. Please see our answers to the Questions below for further explanation.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	Yes. SBR and DSBR utilisation costs could cause BSUoS prices to become highly volatile over the winter of 2016/17. We believe that charging industry participants SBR/DSBR utilisation costs on a half hourly basis is not sending an appropriate signal, thereby resulting in a distortion in competition between generators. Currently generators have low visibility of SBR/DSBR dispatch information, which is likely to lead to inaccurate dispatch decisions during times of SBR/DSBR dispatch. Smearing the utilisation cost of SBR/DSBR as the CMP262 proposal suggests will result in a more stable charge for market participants. This increased certainty will lead to efficient dispatch decisions, reduced risk premia, and a lower overall cost to end consumers. CMP262 therefore better facilitates Applicable CUSC Objectives (a) and (c) in this respect. We agree with the notion that recovering all SBR/DSBR costs from demand side Balancing Mechanism Units (BMUs) would better facilitate the ACOs. This will protect generators from unforeseen costs which can dramatically impact short run dispatch decisions. Moreover, recovering these costs from demand better attributes the cost of the service to those market participants which ultimately benefit from the security provided by SBR/DSBR. This being said, the short timescales under which the modification is progressing and the limited duration associated with any solution (i.e. Winter 2016/17 only) means that retaining the 50:50 G:D BSUoS split may be a much easier solution to implement. We strongly encourage the workgroup to look at this solution either under the Original or as a WACM.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Yes this seems sensible.
3	**Do you have any other comments?**	Not at this time.

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	We agree with the Proposer that suppliers are generally better placed to manage the utilisation cost of SBR/DSBR. However, the short timescale to implement the modification ahead of winter 2016/17 is not ideal in terms of suppliers being able to pass through their costs to consumers. As such, we believe that CMP262 would better facilitate the ACOs if the current method of charging the utilisation cost to generators and suppliers, i.e. on a 50:50 basis, is retained. Please see our answer to Question 1 above.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Yes. BSUoS prices in each half hour can be very volatile if SBR/DSBR is utilised. Even in the unlikely event that a generator can anticipate when SBR/DSBR is likely to be utilised, the current methodology does not send the correct signal to generators and will therefore result in inefficient dispatch decisions. We believe that a smearing approach across the winter period better facilitates the ACOs with respect to the baseline. This would provide a more stable charge for industry participants and will present much lower risk.
7	What is the impact of the proposal on your business?	We currently have low visibility of SBR/DSBR dispatch information which will potentially lead to inaccurate dispatch decisions. Smearing the utilisation cost of SBR/DSBR as the CMP262 proposal suggests will result in a more stable charge for market participants. This increased certainty will allow us to make efficient dispatch decisions and more confidently price our wholesale power.

Q	Question	Response
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	It will greatly assist smaller parties as they will have less resource to assign to the prediction of SBR/DSBR utilisation compared to larger firms.
9	How do you believe this proposal could impact the end consumer?	As discussed in our answer to question 1, we believe that the increased certainty provided to generators will result in more efficient dispatch decisions and a lower risk premia factored into wholesale prices. This will directly translate to lower costs to end consumers.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	While an improvement to the level of SBR/DSBR dispatch information may be a positive step, it does not fully address the issue CMP262 is highlighting. We believe that if any SBR/DSBR dispatch information could be provided it would be in a too short a time scale to be considered useful, particularly when considering forward trading timescales. We consider CMP262 (taking into account our additional comments in response to Question 1) to be the best way to address the defect.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	Paul Mott
Company Name:	EDF Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	No, the proposal would expose Suppliers to extra BSUoS costs at very short notice indeed – it is expected that Ofgem decide whether to pass it or not, only on 1st November, effect being immediate. Suppliers would be exposed to the potential costs through the proposed "Demand Security Charge", as well as already having paid for energy purchased to date at a price that they thought was fixed, and which may have included BSUoS; with this mod, extra costs would arise at almost no notice. The proposal could result in additional costs to end consumers, as well as Suppliers – some consumers are on "pass through" terms in relation to each component purchase cost. Insofar as the proposed "Demand Security Charge" doesn't exist at present, disputes between Suppliers and customers could arise as to whether or not this is part of BSUoS, which some contracts between a Supplier and its customer may specify is passed-through. The uncertainty and very-short-notice shift in costs so created would not seem to methodology facilitate effective competition in the supply of electricity. There is scope for error in Grid's proposed manual billing solution, for something that would only have effect for this winter anyway, as SBR and DSBR then cease to exist.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	-
3	**Do you have any other comments?**	-

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	SBR costs are associated with the same drivers as other parts of BSUoS. These costs relate to security of supply – reserve, frequency response, and black start plus some PGBTs and offer acceptances, and arguably the management of voltage profiles/local reactive power, are all among BSUoS costs that also contribute or relate to security of supply. It is a well-established principle that BSUoS is charged intact . We do not support splitting out BSUoS into different components and charging them each differently; the complexity would add no value. Moreover, SBR is a phenomenon for this winter only; the system or workaround costs (and risks, with a workaround, of errors) in making this change would be large for such a transient change.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	We believe the best approach is to treat these costs in the same way as BSUoS. We do not support a different treatment to their recovery in terms of smearing approaches.

Q	Question	Response
7	What is the impact of the proposal on your business?	The proposal, if it were passed, would give a sudden uplift to Supplier costs at short notice; where the contract with a customer is of a pass-through basis in relation to BSUoS, there would be a need to communicate that part of what was BSUoS, now has a completely new name and is charged differently so that Suppliers would pay double what they did before in relation to these costs. No doubt there would be many debates as to whether the change was, or much more probably (but hard to "prove") was not, manifest in a change in wholesale prices; a lot of time would be taken up. Where the contract with a customer was of a non-pass-through basis in relation to BSUoS, Suppliers, including our own Supply business, would be left with an extra cost of uncertain magnitude, and would know this at virtually no notice ahead of this winter's SBR season. Settlements would need to undertake staff training so as to understand, incorporate in our systems and attempt to validate the new demand security charge. The change would represent an unwelcome distraction in a world where so many other aspects of electricity charging are in play, including a real prospect of zonal loss charging that may soon be taking training/discussion/system-preparatory time.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	All sectors of the market will be affected by this proposal, if implemented. Smaller independent companies will be adversely affected the most by the uncertainty, and the increased risk of disputes over liability for the "Demand Security Charge".
9	How do you believe this proposal could impact the end consumer?	This change will create uncertainty in the short term and lead to an increase in costs overall, which will ultimately be paid by customers. It will not increase competition.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	Perhaps some BSUoS costs could be spread over a longer period of time than at present, to reduce the BSUoS volatility that concerns the proposer of CMP262.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	*Anton Smith* *Anton.Smith@Engie.com*
Company Name:	*ENGIE*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	From a supplier perspective, this modification does not meet objective (a) and does not facilitate effective competition. The proposal would introduce additional costs to the supplier which would be borne by the customer. The complexity and volatile nature of the new charge proposal makes it difficult for participants such as suppliers to manage and potentially confuses the marketplace.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	No. This does not work in its current format for suppliers.
3	**Do you have any other comments?**	No further comments.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Utilisation costs are not known until 16 working days after the event. Generators that have had exposure to the SBR costs are already better equipped to manage and monitor this cost. The tight timescales are likely to put pressure on suppliers who are having to start from scratch on something that they have had little or no exposure to before.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	No comment.
7	What is the impact of the proposal on your business?	Implementing this proposal is likely to result in the need for suppliers to create a means of recovering the SBR and DSBR costs. Furthermore, to accommodate this change, system developments, time and additional resources would be required to analyse and forecast this cost.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	Although this proposal aims to reduce the volatile aspect of BSUoS into another cost component, it would seem there could be a significant commercial impact on suppliers that would pay the full cost via a "demand security charge". This liability would be passed onto our customers and there would be a need to work out how to effectively manage this cost with customers.
9	How do you believe this proposal could impact the end consumer?	As mentioned above this separate cost is likely to be passed onto the customer potentially making it harder for some customers to pay their bills. With the introduction of CFD FiT and Capacity Market within the last 2 years, customers would see an additional cost which is likely to increase along with all of the other existing third party charges. Furthermore, there is the potential risk of generators not reducing costs in proportion to the risk suppliers would be assuming with the new "demand security charge".

Q	Question	Response
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	No comment

CUSC Workgroup Consultation Response Proforma

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Guy Phillips (guy.phillips@uniper.energy)*
Company Name:	*E.ON Group (including Uniper)*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	On balance yes. This is because the risk associated with SBR/DSBR is allocated so that there is less risk to security of supply, although we accept that this may pose a risk of a small supplier being put out of balance should a significant period of usage of SBR/DSBR be experienced. Although this would be highly undesirable outcome, the potential alternative of a generator going out of business is worse at a time of tight generation margins. In the case of suppliers there is a supplier of last resort mechanism in the event that a supplier ceases trading. As there is no such mechanism for generators and given that security of supply is paramount, if there is an increased risk to security of supply with independent generators no longer trading as a result of excessive DSBR/SBR utilisation costs in winter 2016-17, we would support transferring recovery of these costs to Suppliers. We also think that there is rationale for this in that DSBR/SBR is a last resort proxy for demand reduction, which is why its usage is priced at VOLL in imbalance pricing, and is in effect an interim short term substitute for the capacity market to secure demand. As capacity market costs are recovered from Suppliers it seems appropriate to treat these costs in the same way. However, we recognise that this is an increase in costs to Suppliers. As such it is extremely clear that no supplier would have expected such a modification to have been raised, and factored this into their recovery of costs for 2016. To mitigate the short notice we would agree that the Demand Security Charge should be strictly limited to DSBR/SBR utilisation costs only, as the procurement costs are already known and should be factored in by all participants under the existing arrangements. We see no justification in changing this approach now. Although this breaks the link between the period of use and prevailing market participants at that time; we strongly advocate extending the timescales for recovery of the utilisation costs to winter 2017-18. At this point the actual DSBR/SBR utilisation costs would be known and recovery could be included in the October 2017 Supplier contracting round. This would enable the costs to be recovered over Gross Demand as there would be sufficient time to create a suitable billing system on this basis and remove any further distortions to winter 2016-17 and winter 2017-18 embedded benefits. We would envisage that National Grid would be kept whole of the cash flow costs by being able to recover appropriate interest on the total utilisation cost.

Q	Question	Response
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Please see our response to question 1 on extending the timescales for recovering the DSBR/SBR utilisation costs.
3	**Do you have any other comments?**	No
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No, although we would ask the workgroup to consider our suggestions in our response to question 1.

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Generators' primary revenue stream is the wholesale markets for their energy. Their ability to recover an unknown cost at this stage is limited by the extent to which these potential costs are factored in to wholesale prices. Certain Suppliers, depending on their contract terms and conditions, although not preferable, may be able to pass through some of these costs to their customers if the Demand Security Charge is created as a new charge, through change of law provisions.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Notwithstanding our suggestions in our response to question 1, we support the option that has the smallest impact on Suppliers' cash flow. Of the options considered this would seem to be spreading the cost 24/7 over the Triad season. With the proposed bespoke monthly billing system and the availability of metered data this would mean that some days would be up to 59 days in arrears, with payment being later than this. This additional period of time should give parties additional time to assess their likely charge in the event that DSBR/SBR is utilised.
7	What is the impact of the proposal on your business?	For our supply business this may result in an increase of costs that we may or may not be able to recover, depending to what extent DSBR/SBR is utilised this coming winter. For our generation business this would see a reduction in risk by removing the potential to be exposed to uncertain costs.

Q	Question	Response
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	This depends on the respective strengths of individual parties' balance sheets. Although integrated utilities may have more diversification and are therefore better able to shoulder a loss from a subsidiary, that subsidiary itself still incurs the loss. Those perhaps more at risk are independent generators if there is a risk of bankruptcy or independent suppliers if their contractual arrangements mean that they are unable to pass through these costs to their customers. This is also assuming neither of this type have other means to raise funds for short term cost increases or, where they do, if these facilities are sufficient depending on the size of the DSBR/SBR utilisation costs.
9	How do you believe this proposal could impact the end consumer?	If this reduces the risk of independent generators going bankrupt this will enhance security of supply for the end consumer. In the event that DSBR/SBR utilisation costs are realised there will be increased costs to be recovered. Whether these costs are recovered via BSUoS or the proposed Demand Security Charge it would be expected that these costs will feed through in to the wholesale price in the case of generators or be passed through to the end consumer by Suppliers as a result of increased BSUoS and the wholesale price effects.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	We think information provision for DSBR/SBR utilisation is being dealt with elsewhere, either through the relevant C16 statements or in relation to P323 and P333 under the BSC.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	*Jeremy Guard* *Senior Industry Codes Manager* M: +44 (0)7800 912 665
Company Name:	*First Utility Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	First Utility does not believe that the added uncertainty presented to Suppliers by CMP 262 facilitates effective competition in the supply of electricity in accordance with objective a. for the following reasons: The proposal has the effect of reallocating risk and cost of SBR/DSBR between generators and suppliers. The premise is that Suppliers are better placed to manage this risk than generators. It should be noted that generators and suppliers are not homogeneous groups and have very different financial strengths and abilities to manage short-term changes, risks and costs presented by short notice changes such as this. Suppliers offer a wide variety of products into the market, ranging from a full pass through of charges to a fully fixed product. The fully fixed products represent the largest number of products in the market and tend to be the business of many of the smaller new entrant suppliers targeting domestic and SME customers. According to the timetable the decision by OFGEM is expected on the 18^{th} October 2016 with an implementation of 1^{st} November 2016. By the 18^{th} October most parties on fixed price contracts will have been committed prices for the winter period. Suppliers of these will therefore have virtually no opportunity to adjust their prices to cover off this transfer of risks. The full cost of the changes that generators are seeking to manage will then be borne by Suppliers many of which will be unable to manage them. In addition suppliers have already paid for the generators element of cost in any contracts already traded for this winter. Suppliers could take an approach of increasing their prices now to take care of this. However, two things may happen, either customers will overpay as the risk may not be transferred or the supplier may not be as competitive as they intend in which case customers are also worse off. We do not believe the risk to Generators is as large as suggested. Generators can monitor plant margin and make a reasonable forecast of BSUoS associated with the scale of the plant margin. In reality the error band on the plant margin forecast error is likely to be low, and therefore a reasonable forecast could be made. On balance we believe that the forecast error risk here is less than the adverse impact this may have on suppliers and therefore it is not in the interests of consumers to implement this modification.

Q	Question	Response
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We do not support the proposed implementation approach as many of our customers are on fixed price contracts with insufficient opportunity for us to mitigate the additional costs.
3	**Do you have any other comments?**	This risk is not new. It has been present since P305 was approved on 2nd April 2015. In order for Suppliers to manage their businesses effectively any such change should have been proposed in sufficient time to allow the market to adjust. The short notice of this proposal does not allow time for affected parties to implement the necessary changes. First Utility fully recognises the potential issue with uncertain charges as a result of P305 and the additional risks this places on all counterparties. Smaller players often find many of these risks are more difficult to manage, therefore such changes create an inefficient market. We are generally supportive of proposals that reduce artificial unmanageable risks.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No* *If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP262

Q	Question	Response

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	It is the business of generators to manage their plant and optimise its value. Generators need to know when and what to bid. Therefore their primary focus of attention is the generation market. The main business of Suppliers is to manage customers and satisfy their needs. Suppliers of fixed price contracts need to make estimations of their costs and build them into their pricing. Once an offer is made a supplier will seek to hedge (via trades) the price risk associated with that volume. It is not the core business of Suppliers to monitor and forecast plant margins. Unfortunately instruments to manage BSUoS price risk do not exist. Therefore a Supplier has to absorb the BSUoS price risk. A generator on the other hand can adjust and re-adjust their bid/offer prices to manage their risks. On balance we therefore believe that a generator can manage this risk more effectively than a fixed price contract supplier. The other aspect of this issue is the financial ability to manage risk and uncertainty. Added uncertainty impacts Suppliers (especially small suppliers with limited reserves) more than generators as they generally do not have the financial strength to weather the risks.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	The smearing approaches across the winter period lessons the cash flow impact on suppliers. However, the uncertainty created by under or over recovery of the smearing given the costs to be recovered will only be known after the event makes this an extremely complex and potentially costly approach. Suppliers will not have budgeted for the additional funding aspect of the cost of smearing, nor for the additional credit risk this may impose.

Q	Question	Response
7	What is the impact of the proposal on your business?	First Utility offers mainly fixed priced tariffs to the market, a very large proportion of this is now fixed for the coming winter. Included in the pricing is an allowance for 50% of SBR/DSBR costs. We have not factored in the remaining costs and therefore this will present an adverse impact on the business. All forward sales are hedged to some extent; the hedges assume that the generators share of SBR/DSBR is included within the price. We have already paid for the generator share of this charge in the GTMA hedge instruments. To be asked to pay again for the product we have already purchased cannot be effective competition in the market.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	As previously mentioned, this proposal adversely impacts the fixed price section of the market. The effect is exacerbated in that many of the new players who are growing their portfolios are in this sector. Introducing additional costs at very short notice is an unacceptable risk that they cannot manage.
9	How do you believe this proposal could impact the end consumer?	Customers with pass through contracts will pick up the costs of this directly. For those on flexible traded contracts they may have already paid for the generators SBR/DSBR costs implied within the wholesale market. They will therefore be paying twice for the same benefit. Similarly with Suppliers, if they factor this cost in now to new contracts and the modification is not approved then, the customer will have paid more than necessary. If the Supplier prices it in and others do not, then customers may lose out as they will not necessarily have accepted the lowest price available.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	The issue seems to be the visibility of SBR/DSBR incidents and the ability for generators to adjust their prices accordingly. P305 and associated modifications has sought to achieve this, additional refinements on market shortage information is always welcome.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

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Respondent:	*Chloe Drew chloe.drew@havenpower.com*
Company Name:	*Haven Power*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	No. Although we acknowledge that SBR and DSBR utilisation costs could cause BSUoS to become more volatile we do not believe that passing these costs separately to Suppliers will reduce overall costs to consumers as there is no clean mechanism for Suppliers to pass these through directly. In fact, Suppliers would face further costs in order to build the new class of costs into their systems and processes. It would not be possible for customers to take action to manage these costs so there is no benefit to competition of showing them separately.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	No. We feel that changing the agreed charging methodology to place the whole charge on Suppliers at such short notice will not enable Suppliers to pass-through these additional costs to customers and therefore they will either be absorbed by Suppliers directly or factored into future prices, thus putting an unfair burden on Suppliers. These costs are properly incurred to ensure that the system can be balanced and as such should be part of BSUoS. The need arises as much from shortcomings of the generation markets as it does from the supply side and it is appropriate that both Generators and Suppliers pay a share.
3	**Do you have any other comments?**	Please see responses below.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at* *cusc.team@nationalgrid.com*

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Given the short timescales we do not agree that Suppliers are best placed to manage the utilisation costs. Suppliers generally fix costs for one, two or three year contracts and many of these contracts will already have been signed. It is therefore unlikely that Suppliers will be able to recover the additional costs from these customers. It is also incorrect to state that if Suppliers are unable to recover costs from fixed price customers they will be able to collect them from those on variable contracts. Our customers will either have fixed contracts or pass-through contracts (where certain Third Party Costs are passed-through). If a customer has a pass-through contract than we are only able to pass-through that customer's share of the costs – we are unable to recover the share of costs that we are don't recover from other customers. More specifically, even if a customer's contract allows for the pass through of charges, this does not mean that a Supplier will be able to do so. Supplier billing systems are incredibly complex and it is highly unlikely that they will be able to add an additional line to customers' bills in time for winter 16/17. This means that the only way to pass-through the costs would be via a manual work around outside of the billing systems. This would have a cost attached and as a result may lead to costs being absorbed directly by Suppliers and/or factored into costs for customers at a later date. This is likely to have a more detrimental impact on independent/smaller suppliers who are less able to absorb these costs. It should also be noted that Generators have been aware of these costs for as long as Suppliers and will have built them into their pricing. If Generators are now exempted they will receive a windfall which will be ultimately paid for by customers.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Yes – spreading over the winter period would provide for a more stable charge across the period for all industry participants.

Q	Question	Response
7	What is the impact of the proposal on your business?	This proposal would have a detrimental impact for us as a Supplier. During the November – February SBR/DSBR window, we would need to add a line to the invoice for customers affected by the change. As noted above (5) this is not a simple thing to do and would likely require significant manual intervention as we are unlikely to be able to complete the system changes in time. The billing lines would also be subject to reconciliation which would add an additional layer of complexity to manual intervention. We are also unlikely to be able to be able to recover any additional costs directly from fixed price customers. It is also worth noting that this change would come at a time where our resources are stretched with other regulatory change (P272, introduction of EII exemption, AMR, Smart metering etc).
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	The impact on Suppliers is covered in our other answers.
9	How do you believe this proposal could impact the end consumer?	Aside from the fact that if Suppliers have to absorb costs these are likely to be factored into future pricing, the addition of an a new cost adds extra complexity for customers who are already facing additional costs through recently introduced schemes such as CfD and CM and changes such as the proposed exemption from RO and FiT for Energy Intensive Industries.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	No.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	*Please insert your name and contact details (phone number or email address)*
Company Name:	*Please insert Company Name*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	Given that SBR is a short term arrangement, designed to deal with security supply concerns and provide a bridge before the Capacity Market is introduced in 17/18 it is appropriate that both Generators and Suppliers are equally burdened with the cost. Whilst there may be a case to suggest that CMP262 better facilitates the Applicable CUSC objectives, the implementation date of the proposal means that the impact on Suppliers and their competitiveness counters any justification outlined. Both parties were informed of the £122m SBR costs for 16/17 in Dec 15 and were both able to consider this cost in reference to the BSUoS charging methodology and structure this cost appropriately into forward contracts. This proposal now seeks to place the burden squarely on the shoulders of Suppliers who will have to absorb this extra cost and carry the losses. Whilst larger integrated players might see this cost as neutral, Supplier downside is offset by their Generation upside. For independent retail suppliers this will directly impact their bottom line.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We do not support the proposed implementation
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Neither party is better place, what is clear is that suppliers are not in control of when electricity is consumed and therefore are more likely to be in imbalance compared with a Generator. When SBR is utilised the cash out price will hit £3000/MWh, and therefore penalise Suppliers. Furthermore a generator will receive the benefit of the RCRC, which is expected to be of higher value during these times.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	We believe that utilisation costs should be applied on periods when SBR is dispatched.
7	What is the impact of the proposal on your business?	The proposal will cost our business hundreds of thousands of pounds.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	We believe independent suppliers will be disproportionally impacted by this changes for the reasons outlined above.
9	How do you believe this proposal could impact the end consumer?	If approved these additional costs will be factored into our customer's electricity prices going forward.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	No Comment.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

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Respondent:	*Lucas Lilja llilja@intergen.com*
Company Name:	*InterGen*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	Yes (a) (c) a) The difficulty in forecasting SBR/DSBR costs and the lack of transparency surrounding utilisation of SBR/DSBR units and the associated costs are likely to distort market signals to generate, and can therefore lead to inefficient plant dispatch. This is detrimental to competition and a significant issue for independent generators who are unable to recover shortfalls ex post. c) Levying additional costs onto generators increases likelihood of further plant closure, therefore does not take into account developments in the transmission business.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Given the amount of the time available and the temporary nature of the proposed Demand Security Charge, a manual work around seems appropriate.
3	**Do you have any other comments?**	We believe all costs relating to SBR / DSBR as per the original proposal should be fully passed on to the demand side as it primarily benefits the end consumer.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	A generator's decision to generate on a particular day is directly influenced by BSUoS costs which could be highly volatile and difficult to forecast if SBR/DSBR is utilised, resulting in suboptimal dispatch. As BSUoS costs are not known at the time of generation it is likely that a generator will either over or under forecast during those settlement periods where SBR/DSBR has been utilised. If outturn BSUoS is higher than expected this cost is not recoverable by generators ex post. If outturn BSUoS is below expectations this results in a higher wholesale price and hence a higher cost to the consumer. Suppliers on the other hand are able to recover shortfalls or pass windfall gains to consumers ex post. Suppliers should therefore be better able to manage costs arising from SBR/DSBR.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Given that SBR / DSBR are procured to benefit consumers to ensure that there is sufficient capacity, it seems apt for this cost to be spread across all consumers. Furthermore, due to the unpredictability and uncertainty it seems appropriate to smear any costs over the entire winter season to minimise further market distortions.
7	What is the impact of the proposal on your business?	InterGen as an independent generator would be better able to forecast BSUoS if costs associated with SBR/DSBR were recovered solely from suppliers. This in turn will allow for more efficient dispatch decisions and lower risk premia with associated lower wholesale prices that should feed through to benefit the consumer.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	We believe that Independent generators are most exposed as it is not possible to recover higher than expected outturn costs ex post (see question 7 for impacts). The level of exposure will largely depend on the running profile of the plant, with base load plants having the most exposure. Suppliers should be better placed to manage SBR/ DSBR costs as it is possible to recover shortfalls or pass windfall gains to their customer base ex post.

Q	Question	Response
9	How do you believe this proposal could impact the end consumer?	A volatile and uncertain BSUoS charge during SBR/DSBR utilisation incentivises generators to increase risk premia and limit generation which could cause additional stress to the system and additional costs to balance the system. Bringing greater certainty to generators should therefore lower costs and facilitate a more efficient market which is beneficial to the end consumer.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	Publish BSUoS ahead of/ in real time such that BSUoS costs are known with certainty at time of generation.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Respondent:	*Daniel Hickman*
Company Name:	*RWE npower*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	No. We believe generators are in a better position to manage these short term price shocks.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We do not support the original proposal. The creation of a new “Demand Security Charge” would not only require costly changes to billing and validation systems but would also require customer contracts to be reopened with potentially seriously damaging impact on customer supplier relationships. These high costs would only deliver a solution to be used in winter 2016/17 given Capacity Market being brought forward to 2017/18.
3	**Do you have any other comments?**	We do not believe the introduction of a new “Demand Security Charge” particularly at such short notice with the associated financial and customer impacts to be an appropriate or proportional solution to the defect the proposer describes. There are simpler and more cost effective methods to remove the issue that CMP262 seeks to resolve. One such approach would be to smear any SBR utilisation costs over the winter period within the current BSUoS framework keeping the current sharing of costs between supply and generation.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*Yes*

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	We believe that some generators are in a better position than other market participants to manage these short term price shocks depending on their contracting strategy. Least cost solution would be to continue to apply costs to both generators and suppliers.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Smearing over any time period would help to better manage the costs by removing or diluting the disincentive for plant to generate during periods they believed that the utilisation of SBR was more likely.
7	What is the impact of the proposal on your business?	If this proposal were to be implemented it would require costly changes to billing and validation systems as well as amendments to customer contracts which would be very damaging to relationships with our customers. For a large portion of our portfolio, this would be an additional cost we would have to absorb, as we would end up paying for the generator SBR costs a second time.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	This proposal risks giving a windfall gain to some generators depending on contracting strategy, as they will already have built SBR costs into energy already contracted. In this instance there would be a corresponding unplanned cost on suppliers.
9	How do you believe this proposal could impact the end consumer?	The impact of this proposal would be increased costs to end consumers due to the costs of system and process changes to implement a new charge with an expected 'lifespan' of only one winter. Additionally as generators are likely to have included some forecast SBR utilisation into their forward prices for the winter ahead to now move the costs to supply only would mean that the customer would pay for SBR utilisation more than once.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	If an SBR indicative cost and impact to BSUoS rate was published at the same time as the SBR notification, we believe this would help generators make the appropriate dispatch decisions and set prices correctly without the need to withdraw from the market, and stop the price increasing unnecessarily for units already contracted.

CUSC Workgroup Consultation Response Proforma

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	Paul Bedford Regulatory Compliance Specialist Tel: 01604 673256 Email: Paul.bedford@opusenergy.com
Company Name:	Opus Energy Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	With regards to CUSC objective (a), competition in supply may be adversely affected; some suppliers may not have fixed contracts, and would be able to change their prices to allow for the increased costs, whereas by far the majority could not, so wouldn't be able to recover the additional costs. The modification appears to ignore the fact that just as generators income is fixed through their forward energy sales, suppliers income is fixed through their customer contracts; neither of these will respond to very short term volatility in cost. Therefore as drafted, the modification is simply a cost shift from the whole market, to suppliers only, which is inequitable and whilst beneficial to generators will have no impact on the risk premia that suppliers will need to charge customers. In terms of competition in generation, the proposal would remove the perverse incentive on generators not to generate at times when the system is short and SBR/DSBR is called. We believe that the current defect can be removed without a short notice transfer of costs to suppliers by smearing the utilisation costs quarterly or across the whole winter, rather than just recovering them on the settlement dates when SBR/DSBR is used. This would have the same effect of removing the disincentive to generate, without having the negative impact on suppliers. Smearing the costs would also increase the incentive to generate, as increased generation would reduce the need for SBR/DSBR, and therefore reduce the costs paid by generators.

Q	Question	Response
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	It is proposed that a decision is made by Ofgem by 18th October 2016, for implementation from 1st November 2016. This is extremely short notice for suppliers to incorporate the additional cost in customer prices, and it will be impossible to do so in most cases where customer contracts are fixed several years in advance. Since the issue is caused by utilisation costs, we agree that it makes sense and is fairest to only move the SBR/DSBR utilisation costs into a separate “Demand Security Charge”, keeping the cost recovery of the other SBR/DSBR costs as they are.
3	**Do you have any other comments?**	Would the calculation of net demand be identical to that currently used in BSUoS?
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	It is hard for both to manage the utilisation cost as it is so difficult to forecast SBR utilisation. It is arguable that SBR cannot be managed by any party, it is simply a cost associated with the changing electricity market infrastructure so should be borne by all market participants.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	If the cost is smeared quarterly, this would remove the perverse incentive on generators to not generate, without changing where the cost is located and causing problems for suppliers. Most consumers do not have time of use tariffs and in any case these costs cannot be reliably forecast very far in advance, so putting the cost just on demand in peak periods would not provide an actionable incentive to reduce demand.

Q	Question	Response
7	What is the impact of the proposal on your business?	Increased costs which we cannot recover from customers as there is not enough notice to include them in prices, especially as the true cost won't be known until after SBR / DBSR is called.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	Generators – reduced uncertainty in the cost of BSUoS, so probability of increased margin. Suppliers – as customers tend to have fixed price contracts, a probability of reduced margin. The impact on integrated utilities will depend on their relative balance of supply/generation and forward hedging activity. Across the market, this is likely to simply move cost from everybody to supply only.
9	How do you believe this proposal could impact the end consumer?	Increased prices, due to double charging, as the cost may have already been factored into generators' prices, but would also need to be included in suppliers' prices.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	Regardless of this modification proposal, National Grid should provide more estimates of what the costs could be. This should include all of the SBR/DSBR costs. We appreciate that the utilisation costs are difficult to forecast, but different scenarios could be considered, such as "If it's a colder than average winter, SBR might be called x times, costing £y in utilisation costs." Suppliers would then be more able to take a view on the likely costs to price in.

CMP 262 -

Response to Workgroup Consultation

31st May 2016

1. Response to standard workgroup Consultation questions

Q1: Do you believe that CMP262 Original proposal or either of the potential options for change better facilitate the Applicable CUSC Objectives?

1.1. OVO have no comments on this aspect of the consultation

Q2: Do you support the proposed implementation approach?

1.2. OVO have some concerns with regard to this proposed modification. We support the two post workgroup meeting amendments[1], however we think that more work needs to be done to ensure that the implementation of a demand security charge (**DSC**) does not result in customers paying more than 100% of the cost of DSBR and SBR utilisation during the oncoming winter.

1.3. As the workgroup consultation noted, suppliers are likely to have purchased the majority of their power requirements for the oncoming winter. Therefore the power purchased by suppliers includes the generators estimate of the likely cost of BSuos in general and DSBR/SBR utilisation costs in particular. The workgroup consultation highlighted a concern that this proposal may result in additional costs to end customers, as:

"suppliers would be exposed to the potential costs through the proposed "Demand Security Charge", as well as already having paid the same cost in the price paid for energy purchased to date."

OVO shares this concern and would also refute the point made that a lack of "notable impact" on wholesale prices, is evidence that generators have not already priced in the expected impact of SBR and DSBR utilisation costs into their generation bids.

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a) [1]To collect total SBR and DSBR costs from net (instead of gross) demand over the SBR/DSBR window, and
b) To recover only the SBR and DSBR utilisation costs by means of the proposed demand security charge, excluding procurement costs.

1.4. Our suggestion is that the working assumption should be adopted that the prices suppliers have negotiated with generators for winter 16/17 power, includes an assumption about the likely cost to the generator BSuos, including but not limited to DBSR and SBR . Therefore the likely cost of this proposed modification for final customers is 150% of the expected cost of DBSR and SBR utilisation (100% coming from the demand security charge + 50% contained in the power prices already negotiated with generators).

1.5. Once this assumption has been adopted, the cost to energy customers of introducing a demand security charge could be calculated and compared to the benefit of more efficient despatch of generation during winter 2016/17. This would enable the modification to be assessed on the basis of whether or not the proposal to introduce a DSC was to the benefit of final energy customers (Please note that if this cost - benefit analysis indicated that customers would in fact be worse off as a result of this modification, OVO would not support the introduction of the DSC as proposed.

1.6. OVO believe the best means of calculating the benefit to customers of introducing a DSC is to estimate the savings to customers made by generators despatching more efficiently during the coming winter. Naturally contracts for power negotiated before this modification was proposed would be excluded from this analysis, as the prices negotiated will not change.

1.7. Separately, OVO would also share the concern raised from the workgroup that suppliers with a large proportion of customers on fixed price contracts, may find it difficult to recover the demand security charge from their customers. This may potentially result in the cost burden of this proposal falling on standard variable tariff customers, a disproportionate number of whom are likely to be disengaged and potentially vulnerable according to the CMA.

Q3: Do you have any other comments?

1.8. No

Q4: Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?

1.9. No

2. Response to specific workgroup Consultation questions

Q5: Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?

2.1. Given the challenges in forecasting utilisation costs outlined by the Proposer, OVO believe that neither suppliers nor Generators have a greater ability better placed to forecast and manage the risk of these costs than the other. This is especially the case with regard to SBR utilisation costs which are priced ex post.

2.2. Thus far we believe the workgroup has provided little evidence that suppliers are in a better position to manage these costs. In fact, as we mentioned in paragraph 1.7, suppliers with high proportions of fixed tariff customers may struggle to recover the added cost without resorting to increasing prices to their standard variable tariff customers.

Q6: Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?

2.3. In light of the expected volatility of costs, mentioned by the workgroup, OVO would be in favour of a smearing approach to reduce the volatility and help manage the risk of high in-period costs. Our suggestion is that the cost of SBR utilisation should be spread over a daily period e.g. 7am to 7pm. We feel that a daily period achieves the correct balance between providing a signal to the market on days of low capacity, yet does not unfairly attribute utilisation costs to one particular group of customers.

2.4. As the workgroup consultation indicated, SBR utilisation costs will not always be incurred during peak consumption hours, we therefore agree that it would be unfair to recover SBR utilisation costs solely from customers who consume power during periods of peak demand. We note that the choice of smearing window has implications on the split of utilisation costs between domestic and non-domestic customers. Our hope is that by selecting a daily charging window in preference to a peak window, neither non-domestic nor domestic customers are unfairly assigned the costs of DSRB/SBR utilisation.

Q7: What is the impact of the proposal on your business?

2.5. As a general rule, suppliers such as OVO find it difficult to recover unforeseen costs, which manifest less than a year ahead. This is especially the case for suppliers with large numbers of fixed tariff customers amongst their customer portfolio. For this reason it is likely that this proposal will negatively impact our bottom line.

2.6. The work group's proposed amendment to recover only the utilisation costs associated with SBR and DSBR is therefore welcome, especially given that generators had foresight of the procurement costs of SBR/ DSBR when pricing their bids, whereas suppliers could not have foreseen that they would have to pay 100% of these costs when pricing their tariffs last year.

Q8: What are your views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.

2.7. As we have stated before, we believe that the proposed modification will impact suppliers with higher proportions of fixed tariff customers amongst their base to a greater extent than suppliers with high proportions of variable priced tariffs.

Q9: How do you believe this proposal could impact the end consumer?

2.8. As we stated in paragraphs 1.2 – 1.7, we have some concerns about the potential impact of this modification on final energy customers. Our suggestion was for the work group to undertake some analysis to ensure that the likely cost of this modification to customers does not outweigh the likely benefits. We think the result of this analysis should underpin the decision whether or not to progress this modification further.

Q10: Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?

2.9. OVO have no suggestions with regard to how the information made available to market participants could be improved. Our suggestion is that if this modification is proved not to be in the best interests of final customers that efforts are made to improve the level of information available to generators, in order to increase the efficiency of market despatch.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	James Anderson james.anderson@scottishpower.com
Company Name:	ScottishPower Energy Management Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	We agree with the Proposer's assertion that SBR & DSBR utilisation costs are "opaque, impossible to forecast and are not known until 16 working days after the event." Their recovery through BSUoS which is already provides an inefficient ex-post market signal exacerbates the uncertainty faced by market participants. By reducing this uncertainty and potentially reducing the risk premium applied, the Proposal may result in lower costs to consumers and better facilitate competition. However, market participants trade a significant proportion of their requirements ahead of the delivery period. Due to the timing of this modification, a considerable volume of energy may already have been traded for winter 206/17and this modification could result in windfall gains and losses to market participants which would be detrimental to competition. The proposed recovery of the Demand security Charge from net demand would potentially give rise to an additional embedded benefit when it is clear that value of offsetting demand by embedded generation is already significantly overstated which would not be cost-reflective of any avoided transmission investment costs.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	If the Proposal is to be implemented and effective for winter 2016/17, we accept that a manual workaround would be appropriate due to the excessive cost of an IS solution to a problem which may only persist for one winter period.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	We do not believe that generators are in a position to forecast the utilisation of SBR/DSBR and respond to the corresponding price signals. In the short-term neither are suppliers able to respond to these signals. However, as these services are being procured to reduce the frequency of involuntary demand disconnection we consider that the costs should be recovered from demand but spread over the entire winter period.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	Given the impact of SBR utilisation on adjacent settlement periods (explained at 2.8 and 3.24) and the potential impact this may have on participant behaviour, some form of cost-smearing would be appropriate. The smaller the time period over which the costs are recovered e.g. EFA Block 5b during winter season, the greater the potential "embedded benefit" available to embedded generators from generating over this narrow period. We would therefore support smearing over all settlement periods over the winter 2016/17 period.
7	What is the impact of the proposal on your business?	If implemented, we would require to develop settlement systems to validate Demand Security Charges.
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	We do not support the assertion that there would be a different impact on participants depending on whether they were vertically-integrated or not. Economic decisions on whether to despatch generation or to procure energy to meet demand are each taken against the prevailing market price. The ability to withstand market price shocks will relate directly to participants' credit standing and capital structure.
9	How do you believe this proposal could impact the end consumer?	Any measure which reduces uncertainty should result in lower risk premia and lower prices to end consumers.
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	Improved timeliness and quality of information on SBR/DSBR despatch would potentially help address the defect. However, there may still be uncertainty as to the impact of despatch upon BSUoS until out-turn BSUoS charges are publishes and there may be a competitive advantage to those organisations with sufficient resources to interpret the data in real time.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Colin Prestwich*
Company Name:	*SmartestEnergy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response

1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	No. We do not believe that the proposal better facilitates any of the CUSC Objectives. The proposer apparently believes that placing SBR/DSBR costs onto customers via a gross "Demand Security Charge" would more economically charge the parties who are benefiting from the product. There are two fundamental problems with this view: 1) generation also benefits from a well-balanced system; blackouts are not in anyone's interests. 2) the principle of moving away from net charging has not been justified and should be subject of the wider charging arrangements review. It seems to be a presumption of the proposal that generation is able to respond to price signals but that demand cannot and that if generation cannot respond to a price signal it should be exempt. This simply does not follow. Indeed demand is increasingly flexible anyway. The Proposer states concerns that the result of any potential volatility across different settlement periods will provide: i) Increased costs to consumers as a result of the addition of a risk premium; ii) Perverse incentives for generators in terms of a signal to generate, particularly in the shoulder periods (due to very high BSUoS costs); iii) Inaccuracy of cost forecasts leads to significant suboptimal despatch of generation leading to market inefficiency; and iv) Outturn costs in excess of the forecast are irrecoverable by generators as they are recovered ex-post. However, all of this is true of the flexible demand side. In our opinion the consultation document correctly states that "Suppliers would also have to factor such a risk premium into their prices, and could lead to independent Suppliers in particular feeling exposed to the risk due to the potential negative impact on their cash flow, and in turn their ability to remain competitive." Some generators will have costed an increase in BSUoS in when selling forward and this would gives a windfall gain if there is a change. Again, the consultation document correctly states that "a considerable volume of energy had already been traded for winter 2016/17, and that generators may have already included a risk premium within their prices for this based upon the current arrangements. As a result, the proposal could result in additional costs to end consumers, as suppliers would be exposed to the potential costs through the proposed "Demand Security Charge", as well as already having paid the same cost in the price paid for energy purchased to date.

2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We do not support the implementation approach and are not aware of any further implementation implications over and above those we highlight elsewhere in this response. Changes to billing arrangements would not be welcome. We note that the consultation document states the following: "It was noted that as the calculation of components of the Balancing Services Revenue Restriction are set out in National Grid's Transmission Licence, this may need to be modified to implement a new charge separate from BSUoS. This would require Ofgem to undertake a 28 day consultation. The National Grid representative highlighted that in order to avoid licence changes any new charge would effectively need to be considered part of BSUoS, and named as such." Either this is BSUoS or it is not BSUoS. We happen to believe that it is.
3	**Do you have any other comments?**	As the consultation document states: "Both SBR and DSBR procurement costs are known ahead of time (and have almost quadrupled from 15/16 to 16/17) and are distributed across all settlement periods in the 4 months' winter season, reducing volatility." The original proposal seemed to be attempting to remove both the procurement and utilisation costs from generation. This in itself was not logical, although we would also argue that generation in the modern world should not see itself as anything special with respect to either known or unknown costs. If this is genuinely a matter of transparency, perhaps that ought to have been the focus of the proposal. We note that National Grid has already highlighted that it is currently looking to improve the level of information published, and is planning a session at the June Operational Forum to talk through some scenarios ahead of next winter and we support the provision of additional information as an alternative to this modification.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP262

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	Generators are probably better placed to manage the utilisation cost of SBR. However, it is correct that the costs are shared (as both generation and demand benefit from a well-balanced system) and that the same incentive is given to both generation and demand.
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	No, we are not in favour of smearing. We believe that focusing the costs in the period when required would incentivise suppliers/customers to reduce demand and therefore reduce the need to despatch SBR.
7	What is the impact of the proposal on your business?	Aside from the operational hassle of re-opening contracts we would be largely indifferent to the change as we would seek to pass through additional costs. However, we believe that this modification should be assessed on its economic impact for which we see no justification.
8	What are your views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	If it is true that independent parties are more exposed than integrated parties we do not see any justification in effectively throwing the whole of what is currently a shared cost onto suppliers as it is independent suppliers who are at greater risk.
9	How do you believe this proposal could impact the end consumer?	We believe that this would lead to increased costs through additional risk premia and double payment in the light of costs already factored into the wholesale price.

Q	Question	Response
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	We are supportive of National Grid carrying out the following: - Confirming which units are contracted for SBR by September; - Providing expected capability costs (including testing) and timings; - Providing clarity over when start-up, warming, and utilisation instructions have been issued for SBR; - Publishing MW profiled load contracted for DSBR; and - Publishing full DSBR dispatch information by settlement period shortly after instruction on day D.

CUSC Workgroup Consultation Response Proforma

CMP262 'Removal of SBR/DSBR Costs from BSUoS into a "Demand Security Charge"'.

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **31 May 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Mary Teuton (mteuton@vpi-i.com; 0207 312 4469)*
Company Name:	*VPI Immingham*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP262 Original Proposal better facilitates the Applicable CUSC Objectives?**	Yes, we believe that CMP262 better facilitates the applicable CUSC objectives, namely (a) and (c). The lack of any market signal and ability to accurately forecast the SBR/DSBR costs, coupled with potential volatility negatively impacts competition in the wholesale electricity market, distorting competition. This potential inaccuracy of costs may lead to sub-optimal and uneconomic despatch of generation. Coupled with the perverse incentive to generate in shoulder periods around when SBR might be used, this has a significant impact on competition. Furthermore, the introduction of SBR and application of the costs to the generators, further putting them at risk of closure, does not properly take account of developments in the transmission business, specifically the impact of an increasing number of plant closures.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Yes, we support the proposed implementation approach. Whilst a manual workaround is never ideal, given the fact that SBR/DSBR is not intended to be extended beyond Winter 16/17, it makes economic sense to go for the lowest cost solution under these circumstances. Given the potential magnitude of the issue for generators, we think that this is an appropriate measure.

Q	Question	Response
3	**Do you have any other comments?**	We remain disappointed with the level of analysis provided by National Grid in relation to the use of SBR/DSBR. It has reinforced our view that these costs are impossible to forecast. It would be useful, in order to quantify the issue, to understand the scenarios under which SBR might be utilised – National Grid would appear to be the most appropriate party to provide this information. This could include various scenarios with assumed generation volumes available in the market and different weather conditions. Industry understands that these are forecasts and it would enable a much better understanding of SBR. We also note that National Grid used VPI Immingham's proxy numbers where actual utilisation costs were not available for their own analysis of BSUoS costs. We would hope that National Grid could use true numbers to provide industry with a more accurate view of costs should everything be run. To avoid sharing any commercially sensitive information, these numbers could be totalled so that specific plant utilisation costs are not identifiable.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP262

Q	Question	Response

Q	Question	Response
5	Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR, recognising that SBR has only been contracted for this winter given the proposed implementation date for this proposal?	We believe that suppliers are better placed to manage the utilisation costs of SBR given their ability to recover costs over a longer timeframe. Whilst both generators and suppliers must forecast BSUoS, having a more stable charging base should enable volatility across the charges to be more easily managed as over the course of a season, variation should average out. For generators who have a far more varied and peaky running profile, potential volatility could have huge impacts if it is hit with a large charge when not expected. Furthermore, if generators under forecast BSUoS, then they have no real means to recover these lost costs in future, unless they price themselves out of what is already a highly competitive market. This could have disastrous consequences for generators who may have to increase their risk premium to adjust for previous under forecasts and hence drive higher costs for consumers. Whilst clearly neither is desirable, we believe that risks of generators closing is more extreme than the risk of suppliers closing due to the nature of a supplier of last resort. No such measure exists for generation and closure of power station, when the system is already stressed could result in the lights going out.

Q	Question	Response
6	Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?	We would like to see the recovery of SBR/DSBR costs provide an incentive to the market to reduce demand, either by genuinely turning down demand or by switching on onsite generation. This should reduce the requirement for SBR in the first place and reduce the requirement for the volume procured to be utilised. However, we think that the cash out arrangements implemented on the back of P305 and subsequently P323, provide a sufficient signal to the market. Also, we view SBR as the procurement of sufficient capacity for consumers rather than a balancing service – benefitting all consumers across the network. Therefore, it is appropriate that all consumers should pay for this service. As there is no guarantee that SBR be required for period 5b, it is not appropriate to recover the costs over this period. It would also provide a potentially huge embedded benefit under the proposed solution, one that cannot be justified. Therefore, it is more appropriate to smear the costs over the full Winter period. Given the short term nature of this proposed modification, this may also enable an easier cost recovery across all parties.
7	What is the impact of the proposal on your business?	The proposal would allow us to compete more effectively based on more accurate forecasts of BSUoS and subsequently could change running pattern, depending on magnitude of costs.

Q	Question	Response
8	What are you views on the impact of proposal on different sectors of the market e.g. integrated utilities, independent generators, independent suppliers.	We believe that with the existing arrangements continuing, independent generators are most exposed given the cash flow risks of prolonged usage of SBR and subsequent huge BSUoS costs. With most thermal generators struggling in recent years, this could cause further cash flow issues. The reason independents are more exposed is that they have no customer base to recover costs from at a later date. Whilst most vertically integrated generation and supply business are run separately, there is still a parent company and larger reserves available than in smaller independents. We recognise that this same issue could also pose issues for independent suppliers should the whole charge be put on suppliers, but believe that the nature of the charging base makes this the better solution. For generators, the running profile of the plant, e.g. baseload versus peaking, could also dictate how exposed a generator is. Those that have must run characteristics, or are running baseload, will pick up a larger share of the costs, despite not contributing to the issue due to the operating parameters of some of the SBR plant. To charge those generators that are helping to fix the issue would seem to be highly perverse.
9	How do you believe this proposal could impact the end consumer?	We do not believe that there will be any significant impact on end consumers – it is purely a transfer of money from generators to suppliers. Whilst there may be a small risk of a double risk premium should some generators already have included it in their prices for Winter 16/17, in reality, we do not believe that this is material. We believe that this risk premium may also be traded out over time, depending on hedging profiles and the risk premia applied by generators. Also, we remain unconvinced that a sufficient risk premium has been factored into forward prices, given the lack of any material impact on prices on the announcement of the procurement volume and costs. With the volume of SBR procured and the corresponding costs being a surprise for all industry players, you could expect some impact even if a level of risk had already been factored in. This is clearly not the case.

Q	Question	Response
10	Are there any other options that can address improving the quality and timeliness of information to market participant? To what extent would this solve the defect?	Unfortunately there is no means to solve the outlined defect completely due to the inability of anyone to forecast next Winter's weather and plant availability. However, an improved level of granularity and transparency would help all. As set out in question 3 above, we remain disappointed with the level of analysis provided by National Grid in relation to the use of SBR/DSBR. It has reinforced our view that these costs are impossible to forecast. It would be useful, in order to quantify the issue, to understand the scenarios under which SBR might be utilised – National Grid would appear to be the most appropriate party to provide this information. This could include various scenarios with assumed generation volumes available in the market and different weather conditions. Industry understands that these are forecasts and it would enable a much better understanding of SBR. We also note that National Grid used VPI Immingham's proxy numbers where actual utilisation costs were not available for their own analysis of BSUoS costs. We would hope that National Grid could use true numbers to provide industry with a more accurate view of costs should everything be run. To avoid sharing any commercially sensitive information, these numbers could be totalled so that specific plant utilisation costs are not identifiable.

Annex 8 – Legal Text

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

[Original Proposal]

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) 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.

14.29.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs

14.30 Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$\cancel{BSUoSTOT_{cd} = \sum_{i\in c}\sum_{j\in d} BSUoSTOT_{ij}}$$

$$\underline{BSUoSTOT_{cd} = \sum_{i\in c}\sum_{j\in d}(BSUoSTOTC_{ij} + BSUoSTOTS_{ij})}$$

Where:

i - refers to the individual BM Unit

j - refers to an individual Settlement Period

$\sum_{i\in c}\sum_{j\in d}$ - refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

$\underline{BSUoSTOTC_{ij}}$ <u>- the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in either delivering Trading Units or offtaking Trading Units</u>

$\underline{BSUoSTOTS_{ij}}$ <u>- the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in offtaking Trading Units</u>

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:

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

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

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

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

* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party
** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

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

and $$BSUoSTOTS_{ij} = \frac{-1*ALBSU_j*QMBSUoS_{ij}*TLM_{ij}}{\left|\sum^{-}(QMBSUoS_{ij}*TLM_{ij})\right|}$$

Where

$ALBSU_j$ refers to the total BSUoS winter margin charge applicable for Settlement Period "j"

$$ALBSU_j = \frac{(\sum_{k \in WindowC} DSBRSBRU_k)*\left\{\left|\sum^{+}(QMBSUoS_{ij}*TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij}*TLM_{ij})\right|\right\}}{\sum_{k \in WindowC}\left\{\left|\sum^{+}(QMBSUoS_{ik}*TLM_{ik})\right| + \left|\sum^{-}(QMBSUoS_{ik}*TLM_{ik})\right|\right\}}$$

if $j \in WindowC$, else $ALBSU_j = 0$

$DSBRSBRU_j$ is the DSBR and SBR utilisation cost applicable for BSUoS Settlement Period "j", and

$$DSBRSBRU_j = (DSBRU_d + SBRU_d)*$$
$$\left\{\left|\sum^{+}(QMBSUoS_{ij}*TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij}*TLM_{ij})\right|\right\}$$
$$/\sum_{k \in d}\left\{\left|\sum^{+}(QMBSUoS_{ik}*TLM_{ik})\right| + \left|\sum^{-}(QMBSUoS_{ik}*TLM_{ik})\right|\right\}$$

k refers to any individual Settlement Period

$BSUoSTOT_j$	Total BSUoS Charge applicable for Settlement Period j
$DSBRU_d$	DSBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$SBRU_d$	SBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
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)

WindowC	is the period between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year
Relevant Year	is the year defined in the Transmission Licence

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.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

14.30.5 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

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.

$$\begin{aligned}
&BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} \\
&+[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + RFIIR_d + ROV_d + BSFS_d + NC_d + IONT_d + LBS_d \\
&* \left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} / \\
&\sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}]
\end{aligned}$$

Calculation of the daily External Incentive Payment ($IncpayEXT_d$)

14.30.7 In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme (ξk=1≡d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

14.30.8 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayEXT_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

14.30.9 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

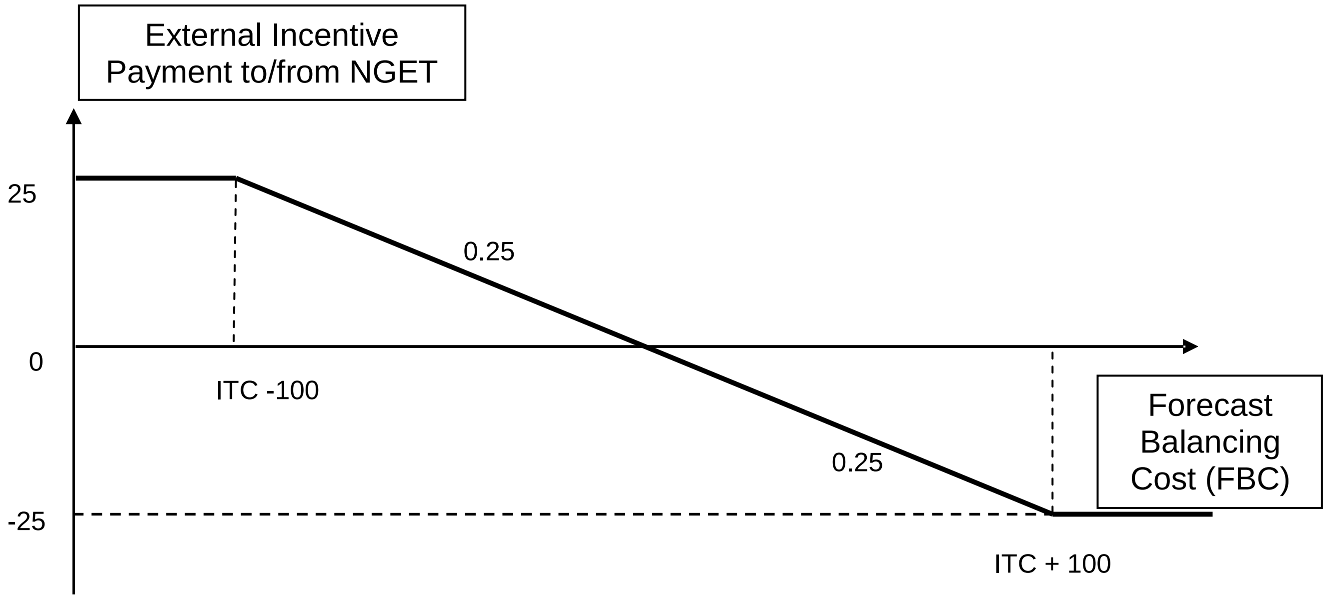
14.30.10 The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

14.30.11 The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	25
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	25%	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	25%	0
(Incentive Target Cost + 100)	0	0	-25



14.30.12 In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

14.30.13 Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

$$IBC_d = \sum_{j \in d} (CSOBM_{jd} + BSCCV_{jd}) + BSCCA_d - OM_d - RT_d - BSFS_d$$

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

14.30.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j 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.

$$BSUoSINT_{jd} = \left[(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t\right]$$
$$* \left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\}$$
$$/ \sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}$$

Inclusion of Profiling Factors

14.30.15 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme

14.31 Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do

the calculations then The Company will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BSUoS winter margin charge	$ALBSU_j$	£	the total BSUoS winter margin charge applicable for Settlement Period j, and is equal to that value calculated in accordance with paragraph 14.30.2 of Part 2 of this Statement
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Black Start Feasibility Costs	BSFS	£	As defined in the Transmission Licence
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j

EXPRESSION	ACRONYM	Unit	Definition
BSUoS charge – delivering or offtaking	$BSUoSTOTC_{ij}$	£	the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in either delivering Trading Units or offtaking Trading Units
BSUoS charge – offtaking only	$BSUoSTOTS_{ij}$	£	the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in offtaking Trading Units
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
DSBR and SBR utilisation cost	$DSBRSBRU_j$	£	Is equal to that value calculated in accordance with paragraph 14.30.13~~14.30.2~~ of Part 2 of this Statement
DSBR Utilisation Payments	*DSBRU*	£	As defined in the Transmission Licence
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
External Incentive payment to date	$FKIncpayEXT_d$	£	Total External Incentive Payment to date up to and including settlement day d
Total Forecast External incentive payment	$FYIncpayEXT_d$	£	Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
Daily Incentivised Balancing Cost	IBC_d	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
Daily External incentive payment	$IncpayEXT_d$	£	External Incentive payment for Settlement Day d
Outage Cost Adjustment	IONT	£	As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
Demand Side Balancing Reserve and Supplementary Balancing Reserve costs	LBS	£	As defined in the Transmission Licence
Non-Incentivised Costs	NC	£	As defined in the Transmission Licence
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Outage change allowance amount	ON	£	As defined in the Transmission Licence
Incentivised Balancing Cost daily profiling factor	PFT_d		The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
Wind Forecast Incentive Cost	RFIIR		As defined in the Transmission Licence
System Operator Innovation Roll-Out Value	ROV		As defined in the Transmission Licence
Retail Price Index Adjustment Factor	RPIF		As defined in the Transmission Licence
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
SBR Utilisation Payments	*SBRU*	£	As defined in the Transmission Licence
SOEMR Preparation Costs	SOEMR	£	As defined in the Transmission Licence
SOEMR Preparation Costs Adjustment	SOEMRCO	£	As defined in the Transmission Licence
Incremental change from SO Opening Base Revenue Allowance	SOMOD		As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
SO Opening Base Revenue Allowance	SOPU		As defined in the Transmission Licence
Revenue Adjustment with respect to actual and assumed RPI values	SOTRU		As defined in the Transmission Licence
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Relevant Year			is the year defined in the Transmission Licence
WindowC			is the period between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year

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

[WACM1]

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) 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.

14.29.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs

14.30 Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$\cancel{BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}}$$

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} (BSUoSTOTC_{ij} + BSUoSTOTS_{ij})$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'
$BSUoSTOTC_{ij}$		the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in either delivering Trading Units or offtaking Trading Units
$BSUoSTOTS_{ij}$		the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in offtaking Trading Units

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:

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

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

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

* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party
** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

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

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

and $$BSUoSTOTS_{ij} = \frac{-1 * ALBSU_j * QMBSUoS_{ij} * TLM_{ij}}{\left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|}$$

Where

$ALBSU_j$ refers to the total BSUoS winter margin charge applicable for Settlement Period "j"

$$ALBSU_j = \frac{\left(\sum_{k \in WindowU} DSBRSBRU_k\right) * \left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}{\sum_{k \in WindowC} \left\{\left|\sum^{+}(QMBSUoS_{ik} * TLM_{ik})\right| + \left|\sum^{-}(QMBSUoS_{ik} * TLM_{ik})\right|\right\}}$$

if $j \in WindowC$, else $ALBSU_j = 0$

$DSBRSBRU_j$ is the DSBR and SBR utilisation cost applicable for BSUoS Settlement Period "j", and

$$DSBRSBRU_j = (DSBRU_d + SBRU_d) * \left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\} / \sum_{k \in d} \left\{\left|\sum^{+}(QMBSUoS_{ik} * TLM_{ik})\right| + \left|\sum^{-}(QMBSUoS_{ik} * TLM_{ik})\right|\right\}$$

k refers to any individual Settlement Period

$BSUoSTOT_j$	Total BSUoS Charge applicable for Settlement Period j
$DSBRU_d$	DSBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$SBRU_d$	SBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
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)

WindowC	is the period of time between Settlement Periods 13 to 40 (inclusive) during the relevant WindowU
Relevant Year	is the year defined in the Transmission Licence

WindowU is a Settlement Day on which DSBR Utilisation Payments and/or SBR Utilisation Payments are incurred

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.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

14.30.5 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

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.

$$\begin{aligned}
&BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} \\
&+[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + RFIIR_d + ROV_d + BSFS_d + NC_d + IONT_d + LBS_d \\
&* \left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} / \\
&\sum_{j\in d}\left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}]
\end{aligned}$$

Calculation of the daily External Incentive Payment ($IncpayEXT_d$)

14.30.7 In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme (ξk=1≡d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

14.30.8 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayEXT_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

14.30.9 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

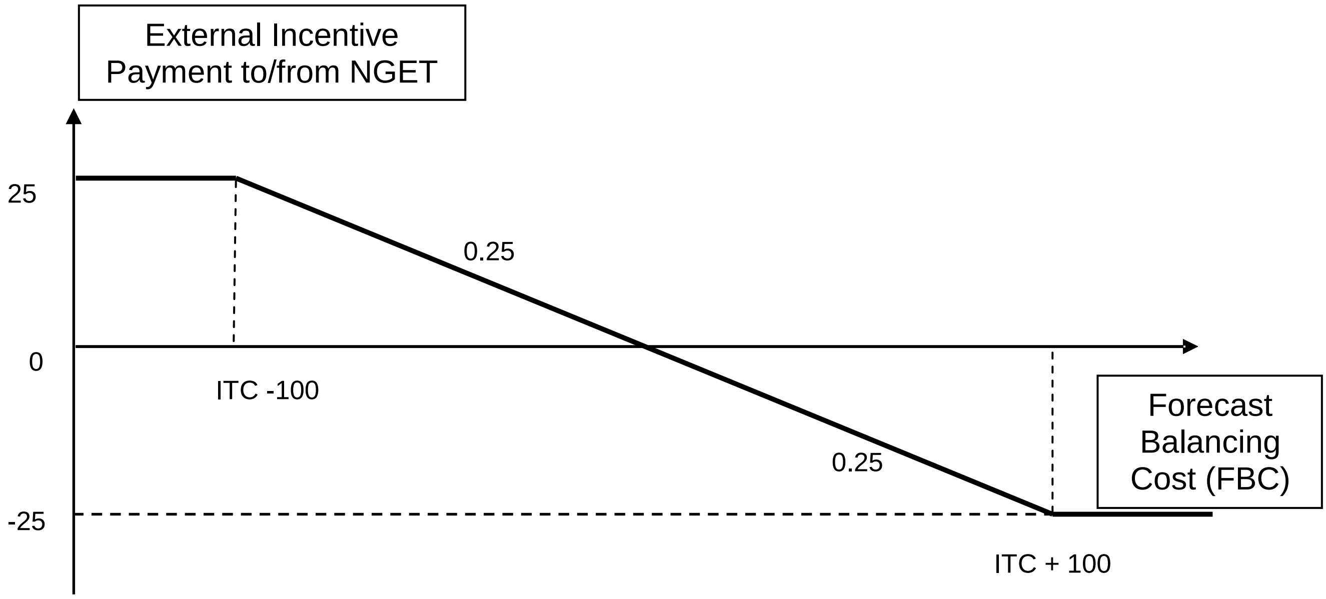
14.30.10 The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

14.30.11 The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	25
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	25%	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	25%	0
(Incentive Target Cost + 100)	0	0	-25



14.30.12 In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

14.30.13 Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

$$IBC_d = \sum_{j \in d} (CSOBM_{jd} + BSCCV_{jd}) + BSCCA_d - OM_d - RT_d - BSFS_d$$

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

14.30.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j 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.

$$BSUoSINT_{jd} = \left[(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t \right]$$
$$* \left\{ \left| \sum^{+} (QMBSUoS_{ijd} * TLM_{ijd}) \right| + \left| \sum^{-} (QMBSUoS_{ijd} * TLM_{ijd}) \right| \right\}$$
$$/ \sum_{j \in d} \left\{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \right\}$$

Inclusion of Profiling Factors

14.30.15 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme

14.31 Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do

the calculations then The Company will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BSUoS winter margin charge	$ALBSU_j$	£	the total BSUoS winter margin charge applicable for Settlement Period j, and is equal to that value calculated in accordance with paragraph 14.30.2 of Part 2 of this Statement
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Black Start Feasibility Costs	BSFS	£	As defined in the Transmission Licence
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j

EXPRESSION	ACRONYM	Unit	Definition
BSUoS charge – delivering or offtaking	$BSUoSTOTC_{ij}$	£	the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in either delivering Trading Units or offtaking Trading Units
BSUoS charge – offtaking only	$BSUoSTOTS_{ij}$	£	the element of BSUoS charge applicable for Settlement Period j for all liable BM units i, in offtaking Trading Units
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
DSBR and SBR utilisation cost	$DSBRSBRU_j$	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
DSBR Utilisation Payments	*DSBRU*	£	As defined in the Transmission Licence
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
External Incentive payment to date	$FKIncpayEXT_d$	£	Total External Incentive Payment to date up to and including settlement day d
Total Forecast External incentive payment	$FYIncpayEXT_d$	£	Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
Daily Incentivised Balancing Cost	IBC_d	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
Daily External incentive payment	$IncpayEXT_d$	£	External Incentive payment for Settlement Day d
Outage Cost Adjustment	IONT	£	As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
Demand Side Balancing Reserve and Supplementary Balancing Reserve costs	LBS	£	As defined in the Transmission Licence
Non-Incentivised Costs	NC	£	As defined in the Transmission Licence
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Outage change allowance amount	ON	£	As defined in the Transmission Licence
Incentivised Balancing Cost daily profiling factor	PFT_d		The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
Wind Forecast Incentive Cost	RFIIR		As defined in the Transmission Licence
System Operator Innovation Roll-Out Value	ROV		As defined in the Transmission Licence
Retail Price Index Adjustment Factor	RPIF		As defined in the Transmission Licence
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
SBR Utilisation Payments	*SBRU*	£	As defined in the Transmission Licence
SOEMR Preparation Costs	SOEMR	£	As defined in the Transmission Licence
SOEMR Preparation Costs Adjustment	SOEMRCO	£	As defined in the Transmission Licence
Incremental change from SO Opening Base Revenue Allowance	SOMOD		As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
SO Opening Base Revenue Allowance	SOPU		As defined in the Transmission Licence
Revenue Adjustment with respect to actual and assumed RPI values	SOTRU		As defined in the Transmission Licence
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Relevant Year			is the year defined in the Transmission Licence
WindowC			is the period of time between Settlement Periods 13 to 40 (inclusive) during the relevant WindowU
WindowU			is a Settlement Day on which DSBR Utilisation Payments and/or SBR Utilisation Payments are incurred

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

[WACM2]

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) 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.

14.29.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs

14.30 Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

Where:

i - refers to the individual BM Unit

j - refers to an individual Settlement Period

$\sum_{i \in c} \sum_{j \in d}$ - refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

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:

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

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

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

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

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

Where

$ALBSU_j$ refers to the total BSUoS winter margin charge applicable for Settlement Period "j"

* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$$ALBSU_j = \frac{(\sum_{k \in WindowC} DSBRSBRU_k) * \left\{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \right\}}{\sum_{k \in WindowC} \left\{ \left| \sum^{+} (QMBSUoS_{ik} * TLM_{ik}) \right| + \left| \sum^{-} (QMBSUoS_{ik} * TLM_{ik}) \right| \right\}}$$

if $j \in WindowC$, else $ALBSU_j = 0$

$DSBRSBRU_j$ is the DSBR and SBR utilisation cost applicable for BSUoS Settlement Period "j", and

$$DSBRSBRU_j = (DSBRU_d + SBRU_d) * \left\{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \right\} / \sum_{k \in d} \left\{ \left| \sum^{+} (QMBSUoS_{ik} * TLM_{ik}) \right| + \left| \sum^{-} (QMBSUoS_{ik} * TLM_{ik}) \right| \right\}$$

k refers to any individual Settlement Period

$BSUoSTOT_j$	Total BSUoS Charge applicable for Settlement Period j
$DSBRU_d$	DSBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$SBRU_d$	SBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
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)

WindowC	is the period between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year
Relevant Year	is the year defined in the Transmission Licence

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.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

14.30.5 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

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.

$$\begin{aligned}
&BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} \\
&+[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + RFIIR_d + ROV_d + BSFS_d + NC_d + IONT_d + LBS_d \\
&*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} / \\
&\sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}]
\end{aligned}$$

Calculation of the daily External Incentive Payment ($IncpayEXT_d$)

14.30.7 In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme (ξk=1≡d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

14.30.8 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayEXT_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

14.30.9 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

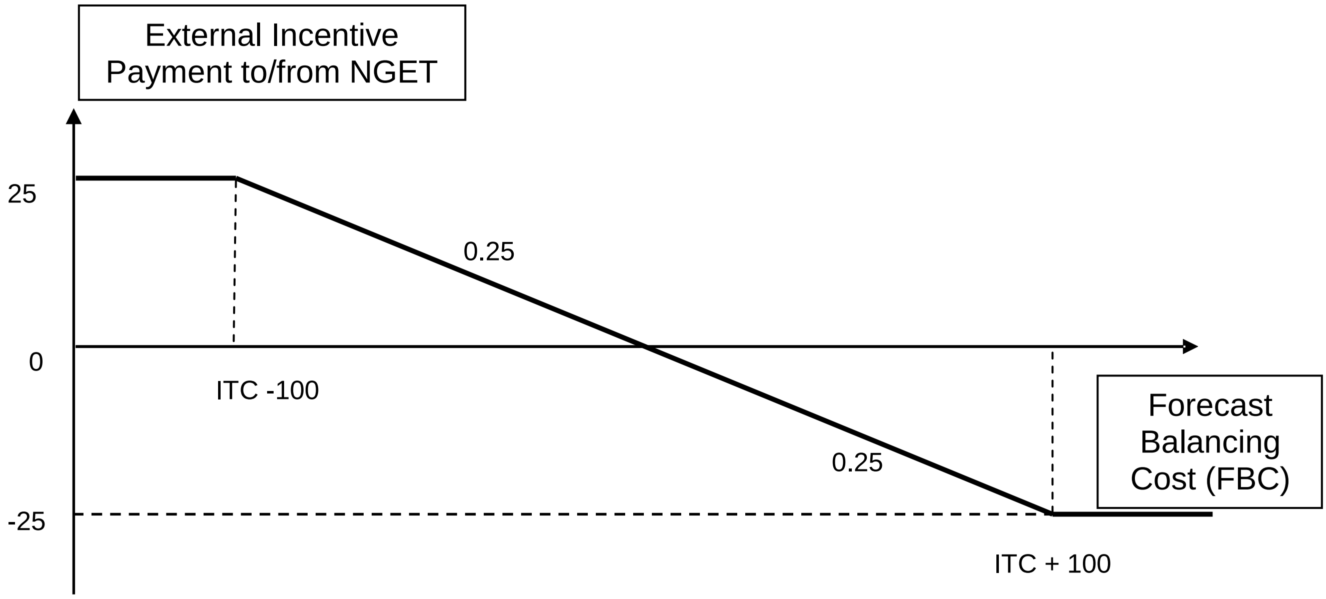
14.30.10 The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

14.30.11 The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	25
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	25%	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	25%	0
(Incentive Target Cost + 100)	0	0	-25



14.30.12 In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

14.30.13 Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

$$IBC_d = \sum_{j \in d} (CSOBM_{jd} + BSCCV_{jd}) + BSCCA_d - OM_d - RT_d - BSFS_d$$

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

14.30.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j 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.

$$BSUoSINT_{jd} = [(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t]$$
$$* \{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \}$$
$$/ \sum_{j \in d} \{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \}$$

Inclusion of Profiling Factors

14.30.15 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme

14.31 Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do

the calculations then The Company will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BSUoS winter margin charge	$ALBSU_j$	£	the total BSUoS winter margin charge applicable for Settlement Period j, and is equal to that value calculated in accordance with paragraph 14.30.2 of Part 2 of this Statement
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Black Start Feasibility Costs	BSFS	£	As defined in the Transmission Licence
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j

EXPRESSION	ACRONYM	Unit	Definition
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
DSBR and SBR utilisation cost	$DSBRSBRU_j$	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
DSBR Utilisation Payments	*DSBRU*	£	As defined in the Transmission Licence
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
External Incentive payment to date	$FKIncpayEXT_d$	£	Total External Incentive Payment to date up to and including settlement day d
Total Forecast External incentive payment	$FYIncpayEXT_d$	£	Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
Daily Incentivised Balancing Cost	IBC_d	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
Daily External incentive payment	$IncpayEXT_d$	£	External Incentive payment for Settlement Day d
Outage Cost Adjustment	IONT	£	As defined in the Transmission Licence
Demand Side Balancing Reserve and Supplementary Balancing Reserve costs	LBS	£	As defined in the Transmission Licence
Non-Incentivised Costs	NC	£	As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Outage change allowance amount	ON	£	As defined in the Transmission Licence
Incentivised Balancing Cost daily profiling factor	PFT_d		The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
Wind Forecast Incentive Cost	RFIIR		As defined in the Transmission Licence
System Operator Innovation Roll-Out Value	ROV		As defined in the Transmission Licence
Retail Price Index Adjustment Factor	RPIF		As defined in the Transmission Licence
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
SBR Utilisation Payments	*SBRU*	£	As defined in the Transmission Licence
SOEMR Preparation Costs	SOEMR	£	As defined in the Transmission Licence
SOEMR Preparation Costs Adjustment	SOEMRCO	£	As defined in the Transmission Licence
Incremental change from SO Opening Base Revenue Allowance	SOMOD		As defined in the Transmission Licence
SO Opening Base Revenue Allowance	SOPU		As defined in the Transmission Licence
Revenue Adjustment with respect to actual and assumed RPI values	SOTRU		As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Relevant Year			is the year defined in the Transmission Licence
WindowC			is the period between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year

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

[WACM3]

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) 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.

14.29.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs

14.30 Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party∗ summed over all Settlement Periods 'j' on a Settlement Day 'd'

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:

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

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

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

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

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

Where

$ALBSU_j$ refers to the total BSUoS winter margin charge applicable for Settlement Period "j"

∗ or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party
** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$$ALBSU_j = \frac{(\sum_{k \in WindowU} DSBRSBRU_k) * \left\{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \right\}}{\sum_{k \in WindowC} \left\{ \left| \sum^{+} (QMBSUoS_{ik} * TLM_{ik}) \right| + \left| \sum^{-} (QMBSUoS_{ik} * TLM_{ik}) \right| \right\}}$$

if $j \in WindowC$, else $ALBSU_j = 0$

$DSBRSBRU_j$ is the DSBR and SBR utilisation costs applicable for BSUoS Settlement Period "j", and

$$DSBRSBRU_j = (DSBRU_d + SBRU_d) * \left\{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \right\} / \sum_{k \in d} \left\{ \left| \sum^{+} (QMBSUoS_{ik} * TLM_{ik}) \right| + \left| \sum^{-} (QMBSUoS_{ik} * TLM_{ik}) \right| \right\}$$

k refers to any individual Settlement Period

$BSUoSTOT_j$	Total BSUoS Charge applicable for Settlement Period j
$DSBRU_d$	DSBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$SBRU_d$	SBR Utilisation Payments as defined in the Transmission Licence, incurred during Settlement Day "d"
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
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)

WindowC	is any of the periods of time between Settlement Periods 13 to 40 (inclusive) within the Settlement Days between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year
Relevant Year	is the year defined in the Transmission Licence
WindowU	is the period between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year

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.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

14.30.5 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

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.

$$\begin{aligned}
&BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd} \\
&+[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + RFIIR_d + ROV_d + BSFS_d + NC_d + IONT_d + LBS_d \\
&*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\}/ \\
&\sum_{j \in d}\left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}]
\end{aligned}$$

Calculation of the daily External Incentive Payment ($IncpayEXT_d$)

14.30.7 In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme (ξk=1≡d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

14.30.8 The forecast incentive payment made to date (from the commencement of the scheme) ($FKIncpayEXT_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

14.30.9 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The

Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

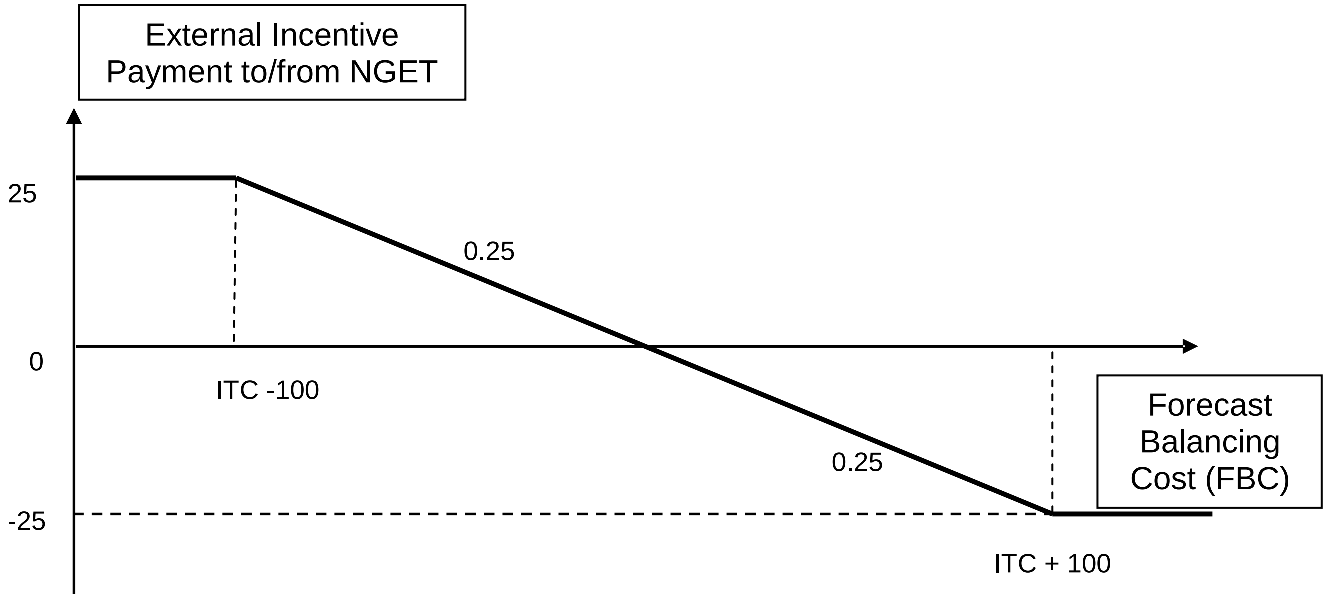
14.30.10 The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

14.30.11 The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	**M_t £m**	**SF_t**	**CB_t £m**
FBC < (Incentive Target Cost – 100)	0	0	25
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	25%	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	25%	0
(Incentive Target Cost + 100)	0	0	-25



14.30.12 In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

14.30.13 Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

$$IBC_d = \sum_{j \in d} (CSOBM_{jd} + BSCCV_{jd}) + BSCCA_d - OM_d - RT_d - BSFS_d$$

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

14.30.14 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j 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.

$$BSUoSINT_{jd} = \left[(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t\right]$$
$$* \left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\}$$
$$/ \sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}$$

Inclusion of Profiling Factors

14.30.15 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme

14.31 Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do

the calculations then The Company will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BSUoS winter margin charge	$ALBSU_j$	£	the total BSUoS winter margin charge applicable for Settlement Period j, and is equal to that value calculated in accordance with paragraph 14.30.2 of Part 2 of this Statement
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Black Start Feasibility Costs	BSFS	£	As defined in the Transmission Licence
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j

EXPRESSION	ACRONYM	Unit	Definition
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
DSBR and SBR utilisation cost	$DSBRSBRU_j$	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
DSBR Utilisation Payments	*DSBRU*	£	As defined in the Transmission Licence
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
External Incentive payment to date	$FKIncpayEXT_d$	£	Total External Incentive Payment to date up to and including settlement day d
Total Forecast External incentive payment	$FYIncpayEXT_d$	£	Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
Daily Incentivised Balancing Cost	IBC_d	£	Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement
Daily External incentive payment	$IncpayEXT_d$	£	External Incentive payment for Settlement Day d
Outage Cost Adjustment	IONT	£	As defined in the Transmission Licence
Demand Side Balancing Reserve and Supplementary Balancing Reserve costs	LBS	£	As defined in the Transmission Licence
Non-Incentivised Costs	NC	£	As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Outage change allowance amount	ON	£	As defined in the Transmission Licence
Incentivised Balancing Cost daily profiling factor	PFT_d		The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
Wind Forecast Incentive Cost	RFIIR		As defined in the Transmission Licence
System Operator Innovation Roll-Out Value	ROV		As defined in the Transmission Licence
Retail Price Index Adjustment Factor	RPIF		As defined in the Transmission Licence
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
SBR Utilisation Payments	*SBRU*	£	As defined in the Transmission Licence
SOEMR Preparation Costs	SOEMR	£	As defined in the Transmission Licence
SOEMR Preparation Costs Adjustment	SOEMRCO	£	As defined in the Transmission Licence
Incremental change from SO Opening Base Revenue Allowance	SOMOD		As defined in the Transmission Licence
SO Opening Base Revenue Allowance	SOPU		As defined in the Transmission Licence
Revenue Adjustment with respect to actual and assumed RPI values	SOTRU		As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Relevant Year			is the year defined in the Transmission Licence
WindowC			is any of the periods of time between Settlement Periods 13 to 40 (inclusive) within the Settlement Days between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year
WindowU			is the period between and including 1st November and 28th February, or 29th February where applicable, in the Relevant Year