## Stage 02: Workgroup Consultation

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. Any interested party is able to make a response in line with the guidance set out in Section # of this document.

| | |
|---|---|
| **Published on:** | **16 May 2016** |
| **Length of Consultation:** | **10 Working days** |
| **Responses by:** | **31 May 2016** |

***High Impact: Generators, Suppliers, demand customers and End Consumers***

***Medium Impact: National Grid***

## Contents



## About this document

This document is a Workgroup consultation which seeks the views of CUSC and interested parties in relation to the issues raised by the Original CMP262 CUSC Modification Proposal which was raised by Mary Teuton, VPI Immingham and developed by the Workgroup. Parties are requested to respond by **5pm** on Tuesday 31 May 2016 to CUSC.team@nationalgrid.com using the Workgroup Consultation Response Proforma which can be found on the following link:
http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP262/

## Document Control

| Version | Date | Author | Change Reference |
|---|---|---|---|
| 2 | 16 May 2016 | Code Administrator | Workgroup Consultation to Industry |


**Any Questions?**
Contact:
**Heena Chauhan**

Code Administrator

**Heena.chauhan@nationalgrid.com**

**07811 356637**

**Proposer:**
Mary Teuton
VPI Immingham
0207 312 4469
**mteuton@vpi-i.com**

# 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 options for potential Workgroup Alternative CUSC Modifications (WACMs). Prior to confirming any alternative proposals the Workgroup are seeking views on the options they have identified, what is the best solution to the defect and also any other further options that respondents may propose.

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 is required to consult on the Proposal during this period to gain views from the wider industry (this Workgroup Consultation). Following this Consultation, the Workgroup will consider any responses, vote on the best solution to the defect and report back to the Panel at the June 2016 Panel meeting.

1.3 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).

1.4 This Workgroup Consultation 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.

## 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/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 SBR/DSBR window.

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 the SBR/DSBR window, 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 SBR/DSBR window.

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 SBR/DSBR window.

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 settlement periods 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, 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. Where 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 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.

3.15 In relation to the improvements in the level of information provided, National Grid currently considering 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.

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

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.

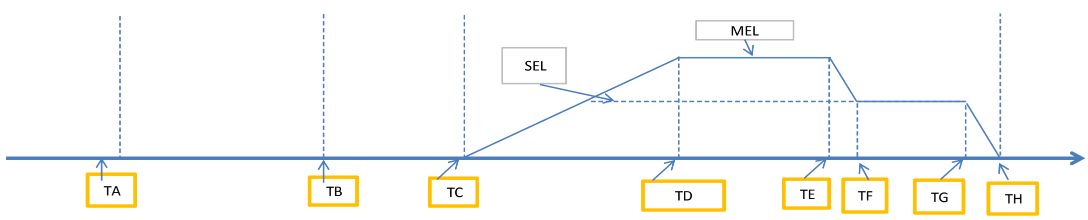



Figure 1 – Illustrative Unit Output

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 (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 BSUoS prices, assuming that SBR was utilised at a period of peak demand similar to that observed 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.

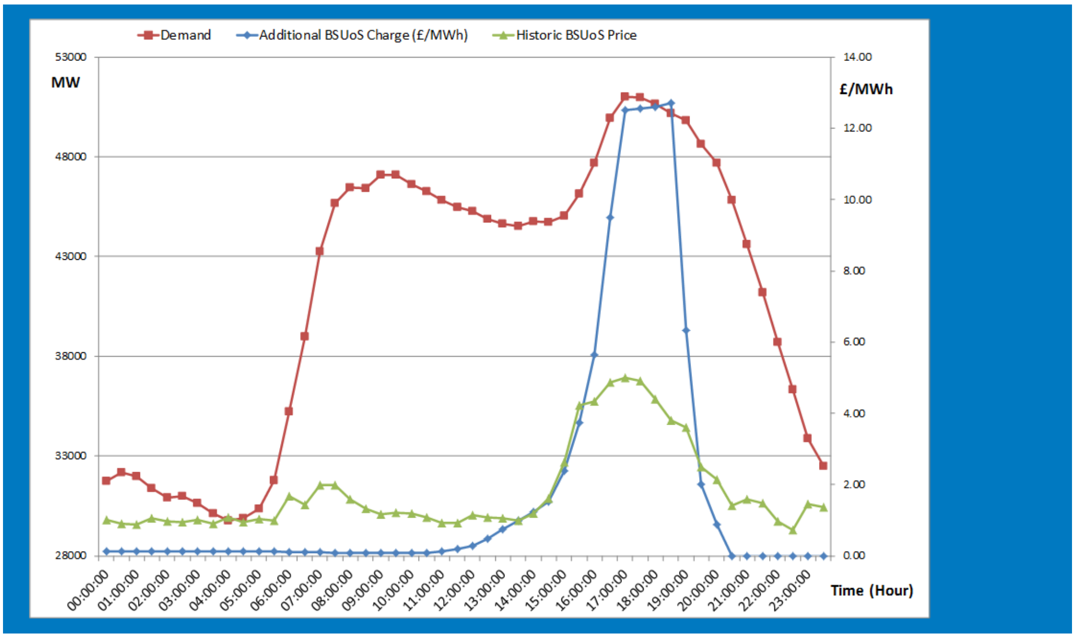



**Figure 2:** Breakdown of SBR cost by each settlement period and by BSUoS MWh, assuming generators and suppliers pay on a 50:50 basis

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. 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.

**When and how are costs paid?**

3.24 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 Period in which they are incurred (even though some of these costs are in preparation for use in a later Settlement Period. 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). The group has considered the merits of each option.

3.25 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.

3.26 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.

3.27 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.

3.28 Options for spreading the costs over different periods were considered including peak, daily, monthly and spreading the costs within the year. The Workgroup did not support smoothing these costs over a longer 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. 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 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 |

**Workgroup Consultation Question 5:**
Are Generators or Suppliers or combination of both better placed to manage the utilisation cost of SBR given the proposed implementation date for this proposal?, recognising that SBR has only been contracted for this winter

**Workgroup Consultation Question 6:**
Do you believe that any of the smearing approaches discussed above enable the utilisation costs to be managed more efficiently?

**Workgroup Consultation Question 7:**
What is the impact of the proposal on your business?

**Workgroup Consultation Question 8:**
What are you views on the impact of proposal on different sectors of the market e.g. Integrated utilities; independent generators; independent suppliers.

**Workgroup Consultation Question 9:**
5. How do you believe this proposal could impact the end consumer?

**Workgroup Consultation Questions 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?

**Interactions with wider market arrangements**

3.29 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.

3.30 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.

3.31 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.

# 4 Impact and Assessment

## Impact on the CUSC

4.1 Changes to Section 14.

## Impact on Greenhouse Gas Emissions

4.2 None identified.

## Impact on Core Industry Documents

4.3 None identified.

## Impact on other Industry Documents

4.4 None identified.

# 5 Proposed Implementation and Transition

5.1 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 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.

5.2 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 for both creating the proposed new charge, 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 £45 and £120k depending on whether 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.

5.3 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.

5.4 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 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.

5.5 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.

5.6 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.

## 6 Workgroup Consultation

6.1 This Workgroup is seeking the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

**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?

**Q2:** Do you support the proposed implementation approach?

**Q3:** Do you have any other comments?

**Q4:** Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider? Please see 8.3.

**As well as the standard consultation questions above, the Workgroup also seek views on the specific questions below;**

**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?

**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?

6.2 Please send your response using the response proforma which can be found on the National Grid website via the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP262/

6.3 In accordance with Section 8 of the CUSC, CUSC Parties, BSC Parties, the Citizens Advice and the Citizens Advice Scotland may also raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

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

6.4 Views are invited upon the proposals outlined in this report, which should be received by **5pm** on Tuesday 31 May 2016. Your formal responses may be emailed to: cusc.team@nationalgrid.com

6.5 If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response market "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

6.6 Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential".

# Annex 1 – CMP262 CUSC Modification Proposal Form

# CUSC Modification Proposal Form CMP262

nationalgrid

## Connection and Use of System Code (CUSC)

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

# 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** | Ryan Place | National Grid |
| **National Grid Representative*** | Wayne Mullins | 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 |
| **Authority Representatives** | Leonardo Costa | 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 | Workgroup report issued to CUSC Panel |
| 24 June 2016 | Panel meeting to approve WG Report |

Post Workgroup modification process

| | |
|---|---|
| 5 July 2016 | Code Administrator Consultation issued (15 Working days) |
| 26 July 2016 | Deadline for responses |
| 4 August 2016 | Draft FMR published for industry comment (5 Working day) |
| 11 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 |
|---|---|---|---|---|
| Andrew Wainwright | National Grid | Chair | A | A |
| Heena Chauhan | National Grid | Technical Secretary | A | A |
| Mary Teuton | VPI Immingham | Proposer | A | A |
| Jo Zhou | National Grid | Workgroup member | A | D |
| Wayne Mullins | National Grid | Workgroup member | A | A |
| Guy Phillips | EON | Workgroup member | A | A |
| Andrew Colley | SSE | Workgroup member | A | A |
| Tom Breckwoldt | Gazprom | Workgroup member | X | X |
| James Anderson | Scottish Power | Workgroup member | A | A |
| Daniel Hickman | Npower | Workgroup member | A | A |
| Simon Lord | Engie | Workgroup member | D | D(first hour only) |
| Sarah Owen | Centrica | Workgroup member | X | A |
| Jeremy Guard | First Utility | Workgroup member | X | A |
| Leonardo Costa | Ofgem | Authority Representative | A | A |

*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


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

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 – CMP262 Analysis

# 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.

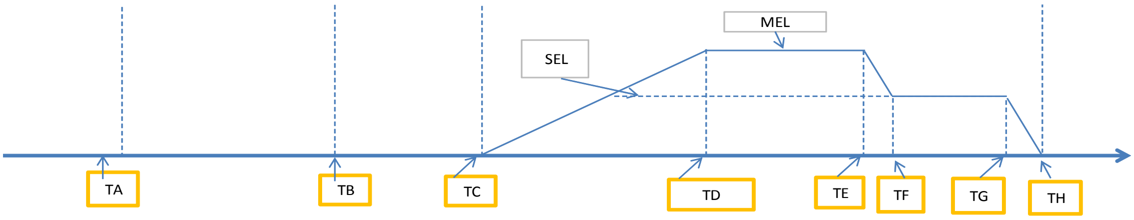



Figure 1 – Illustrative Unit Output

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/](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/](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

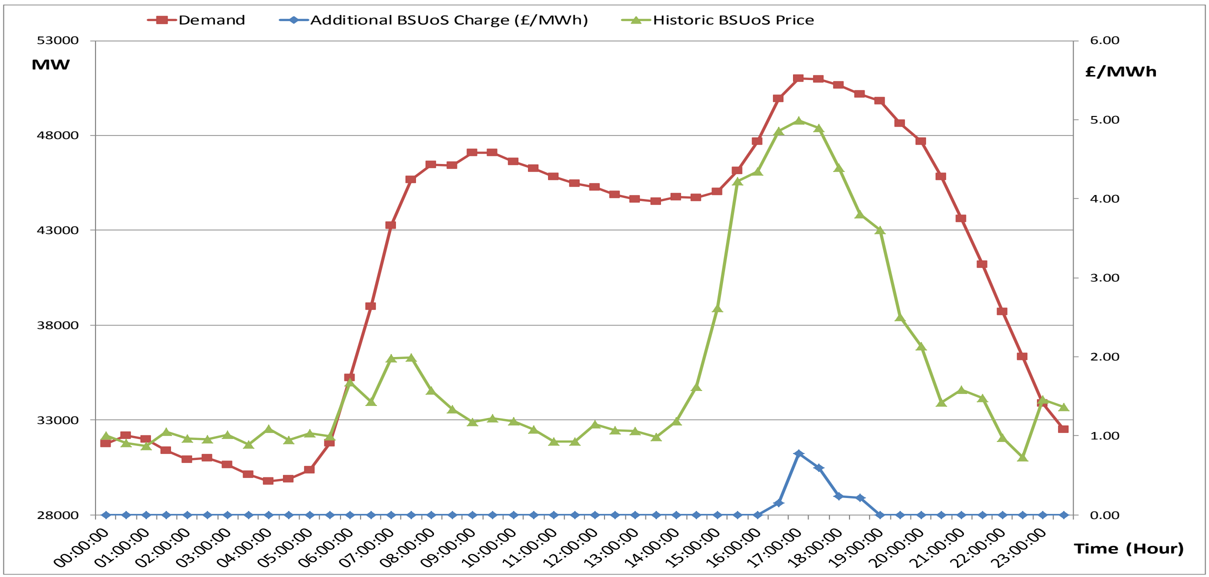
| | |
|---|---|
| NOTE: The above analysis results are indicative and solely for the purpose of CMP262 workgroup. They should not be assumed in any way to be representative of the anticipated level of utilisation cost for SBR plants. No correlation is assumed between demand level and the SBR capacity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



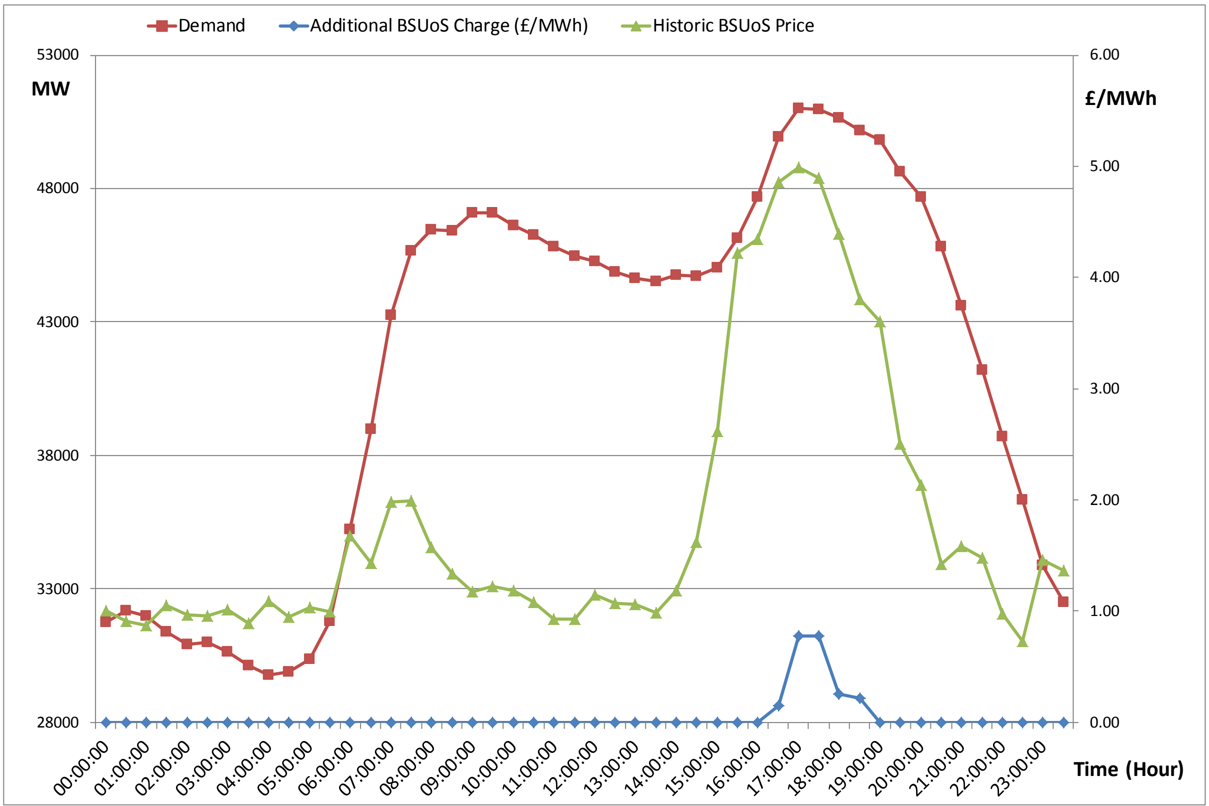

| Duration = | 0.5 hour | Capacity = | 250 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.00 | 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.***



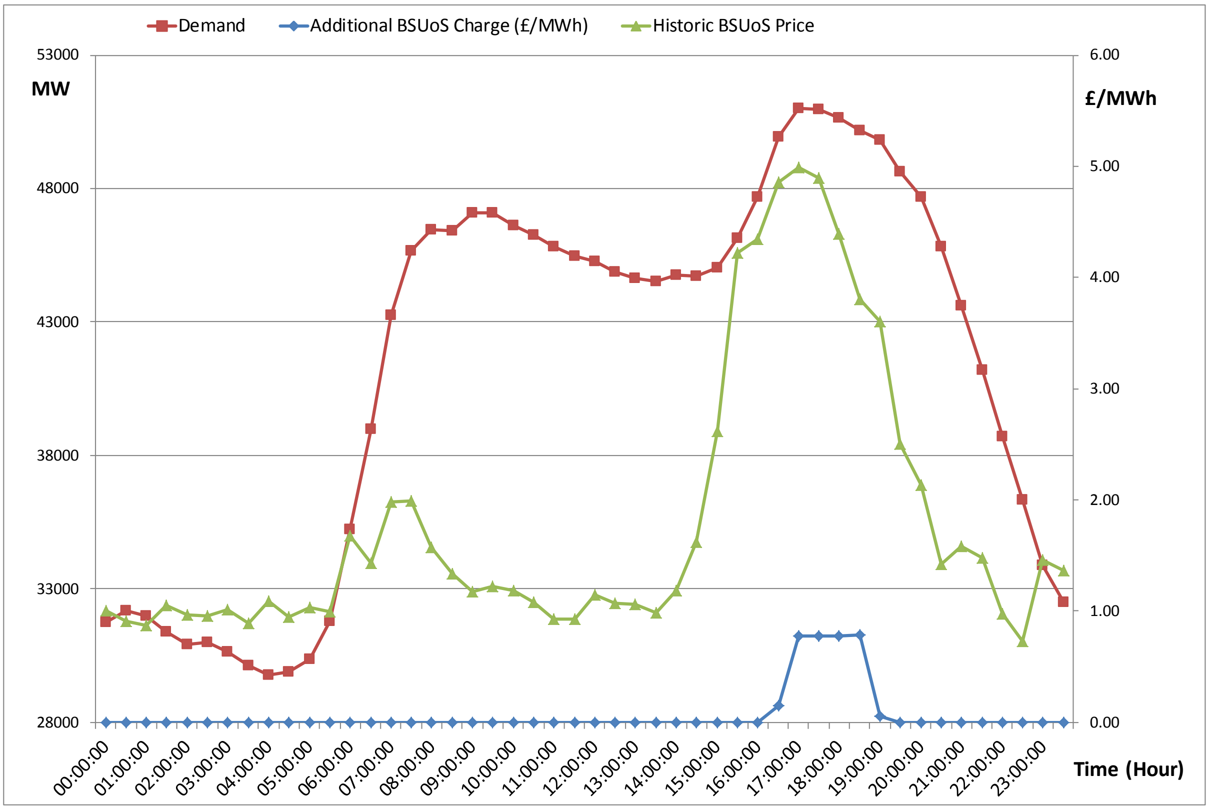

| Duration = | 1 hour | Capacity = | 250 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.00 | 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.***



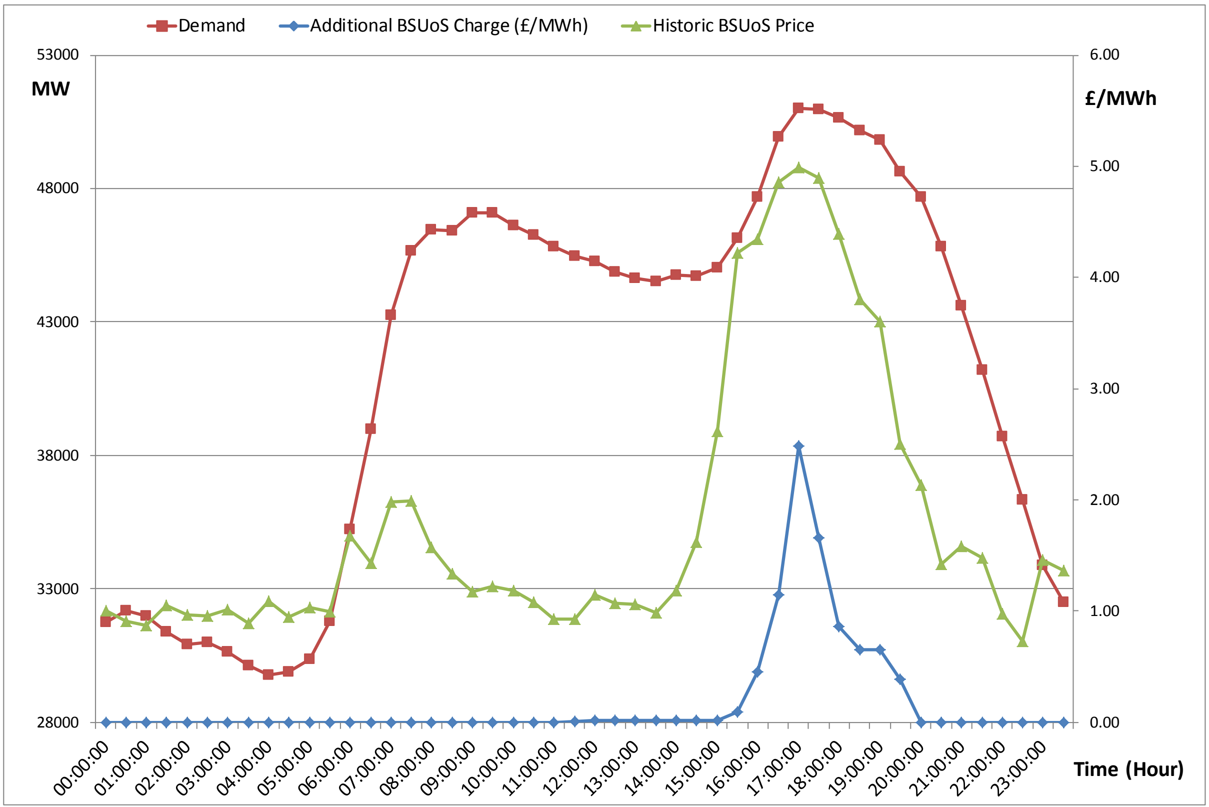

| Duration = | 2 hour | Capacity = | 250 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.00 | 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.***



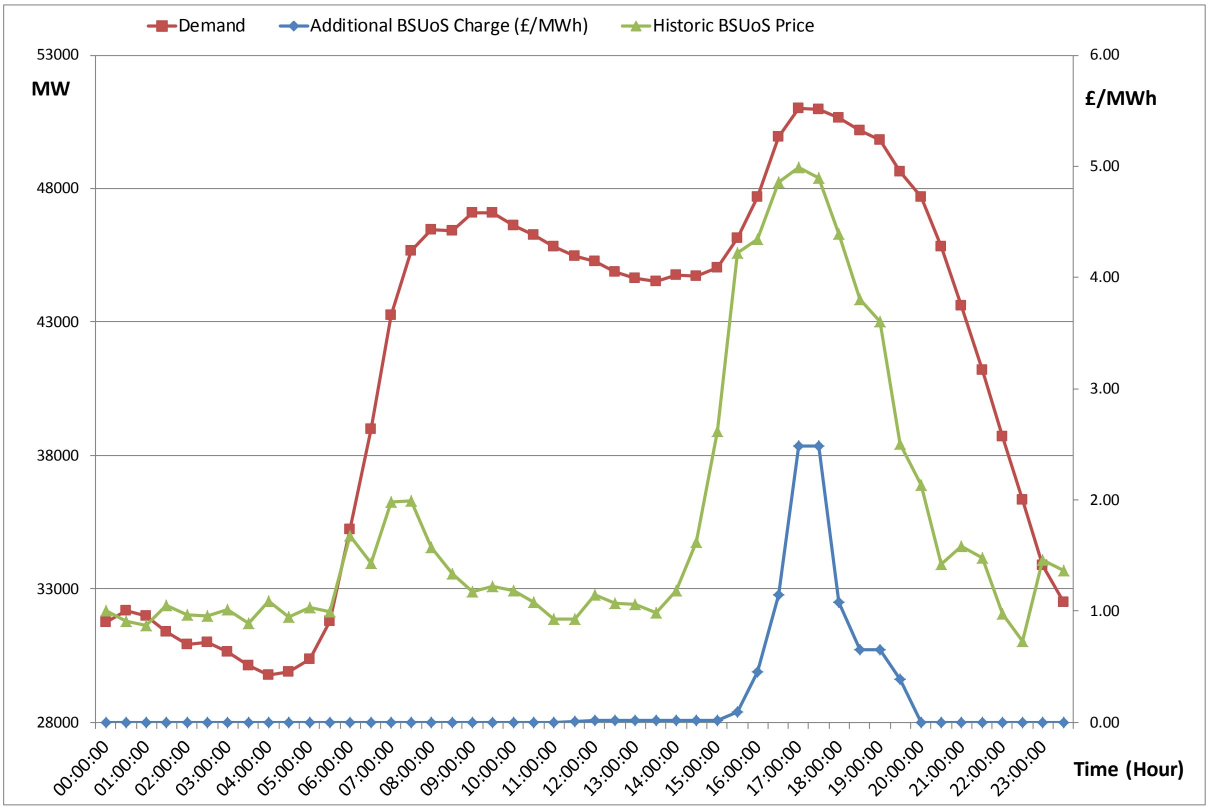

| Duration = | 0.5 hour | Capacity = | 1000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.00 | 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.***



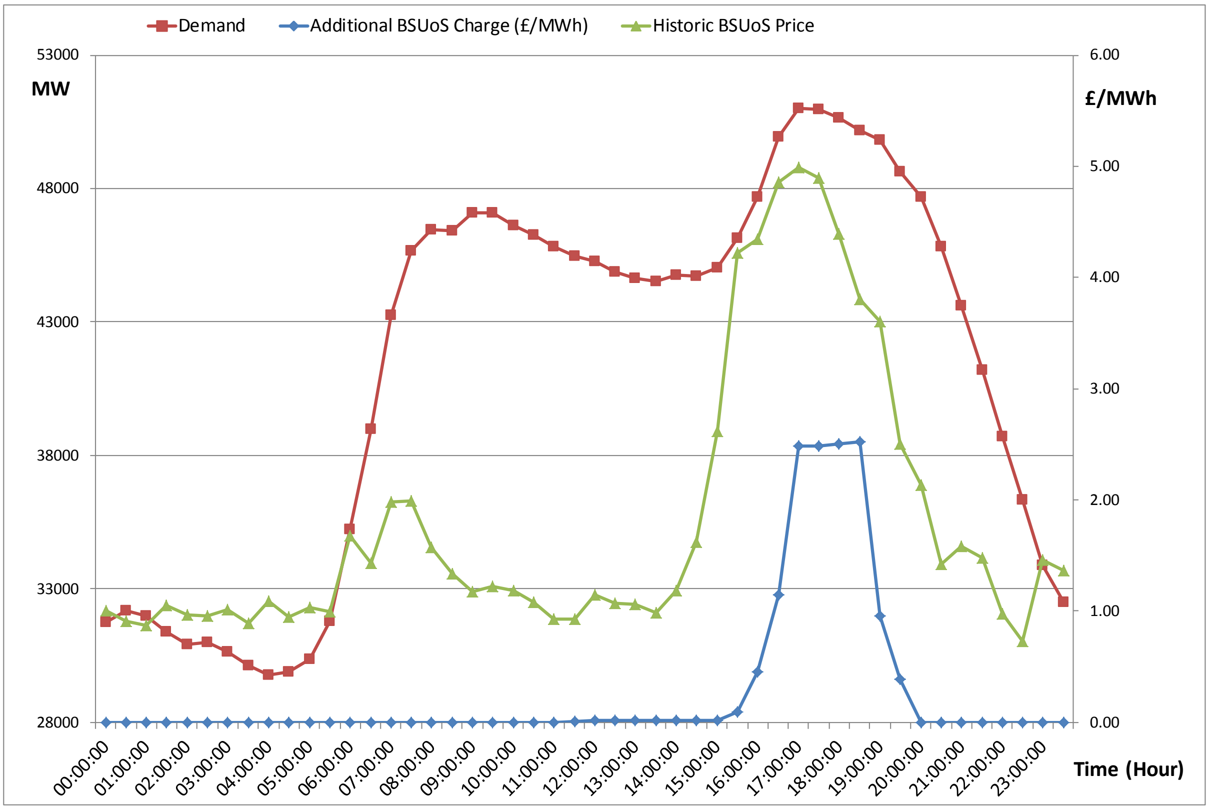

| Duration = | 1 hour | Capacity = | 1000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.00 | 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.***



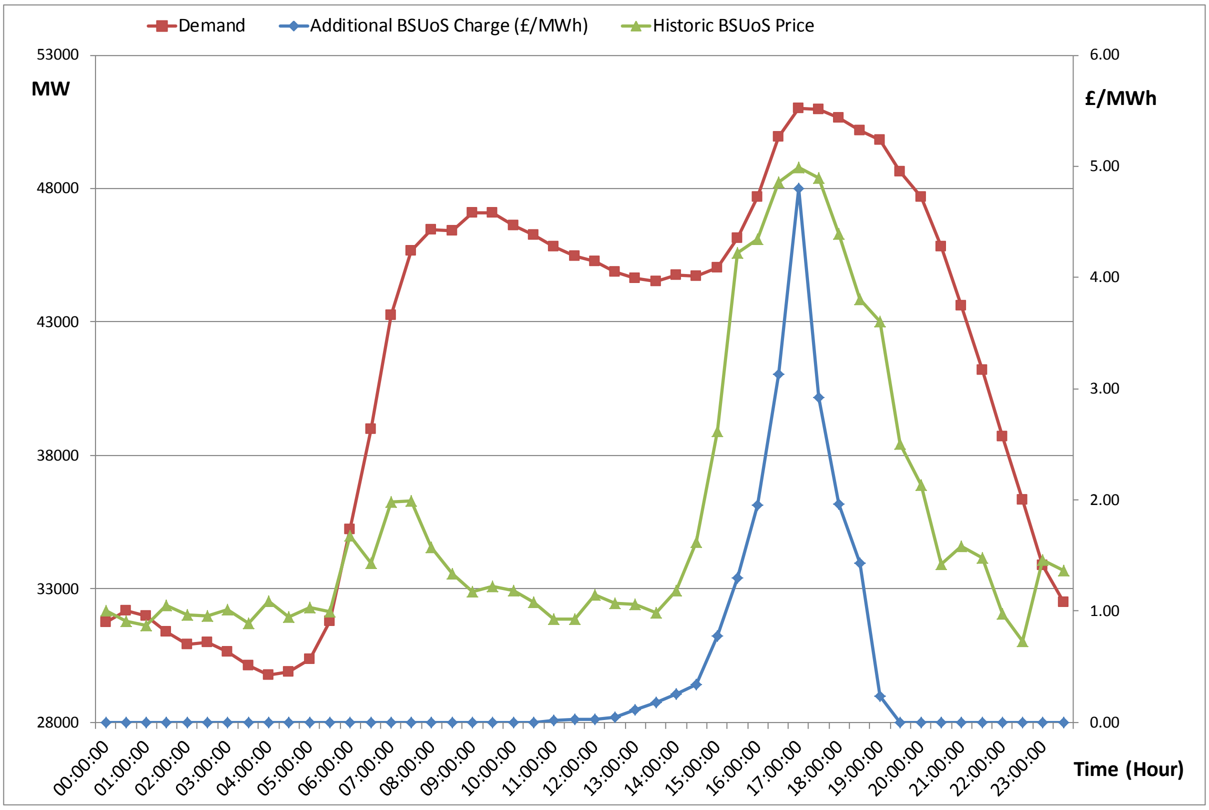

| Duration = | 2 hour | Capacity = | 1000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.00 | 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.***



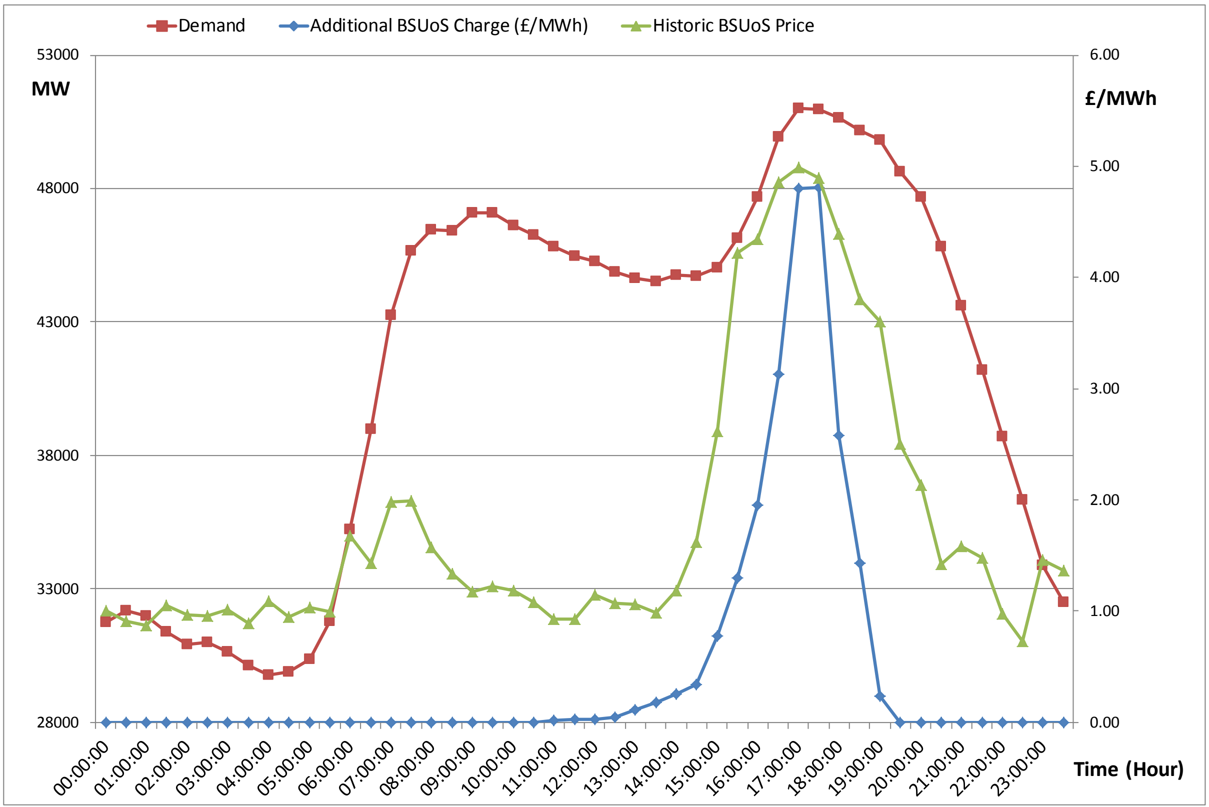

| Duration = | 0.5 hour | Capacity = | 2000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.01 | 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.***



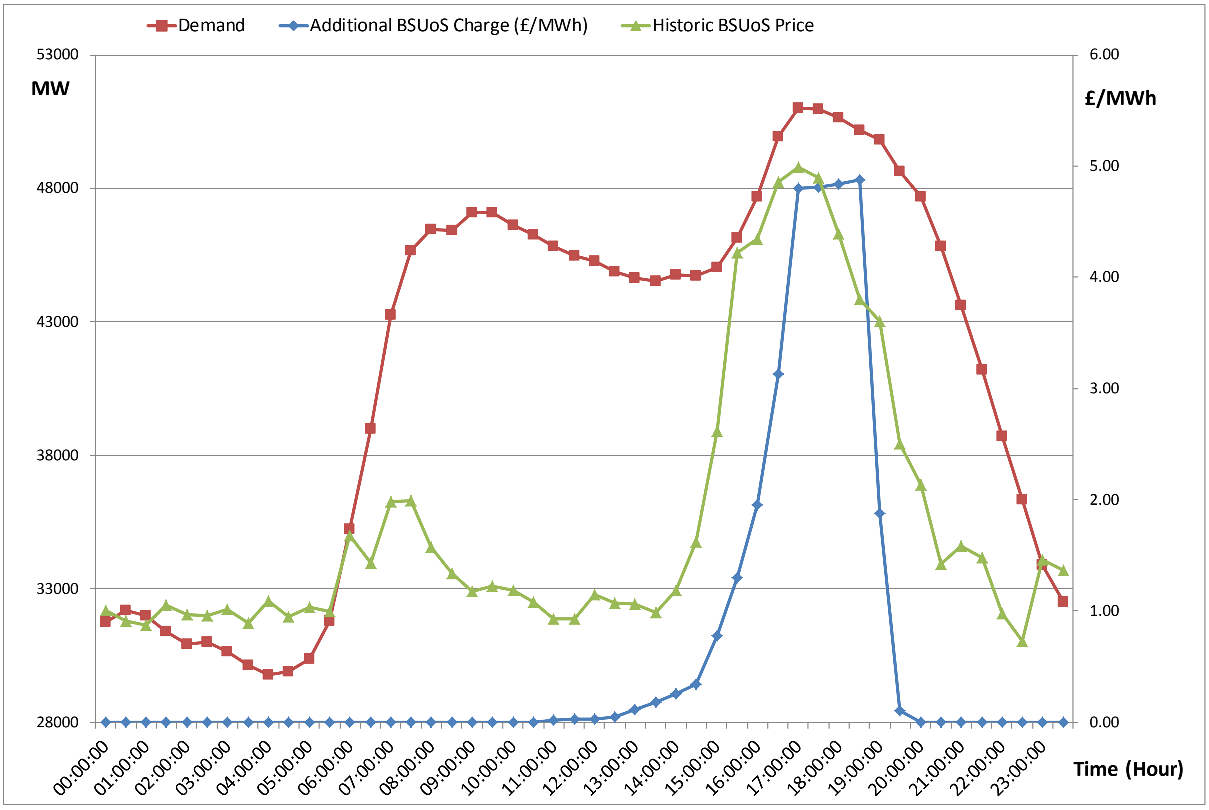

| Duration = | 1 hour | Capacity = | 2000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.01 | 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.***



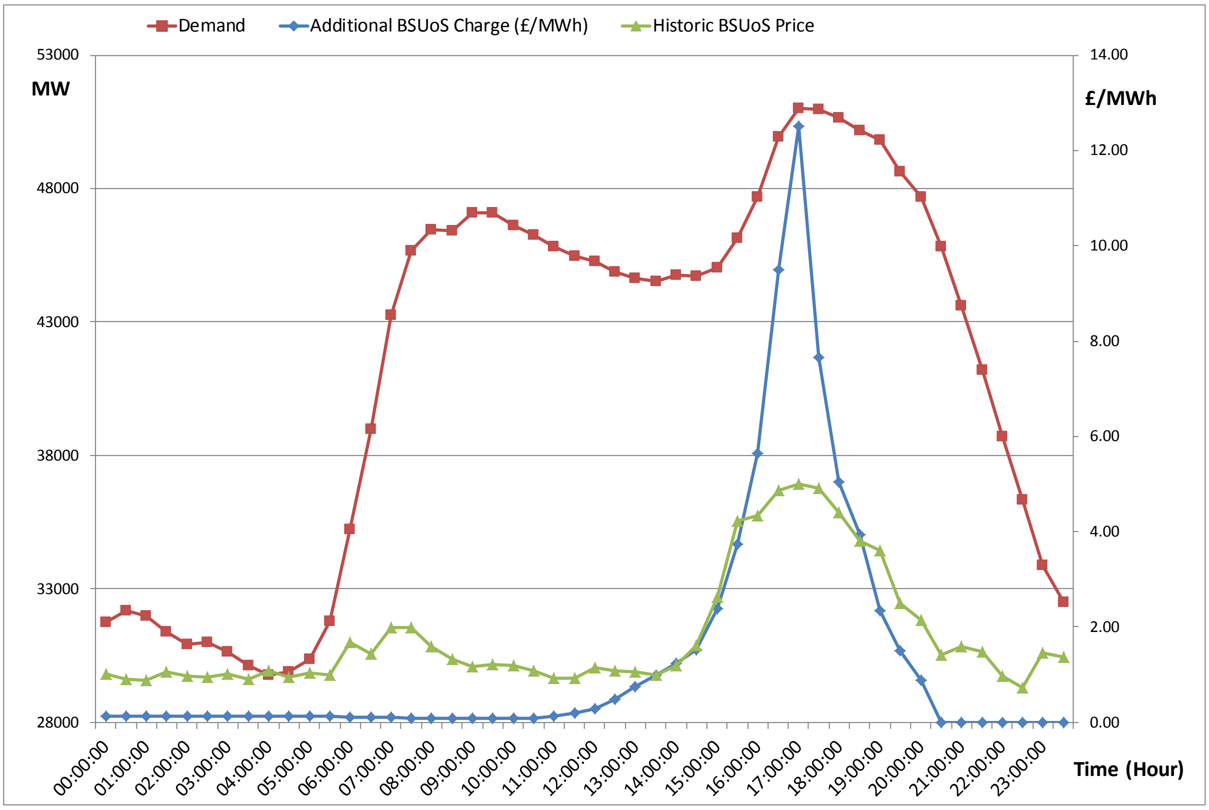

| Duration = | 2 hour | Capacity = | 2000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.01 | 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.***



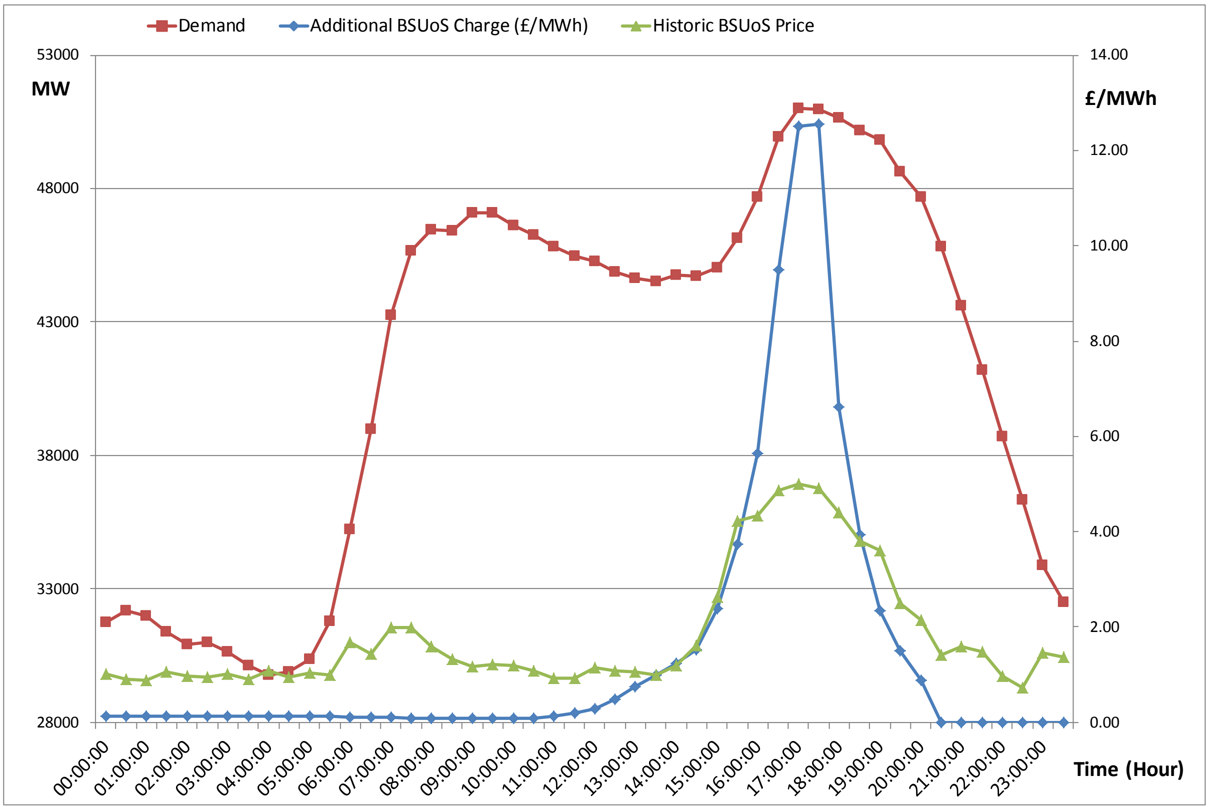

| Duration = | 0.5 hour | Capacity = | 4000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.02 | 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.***



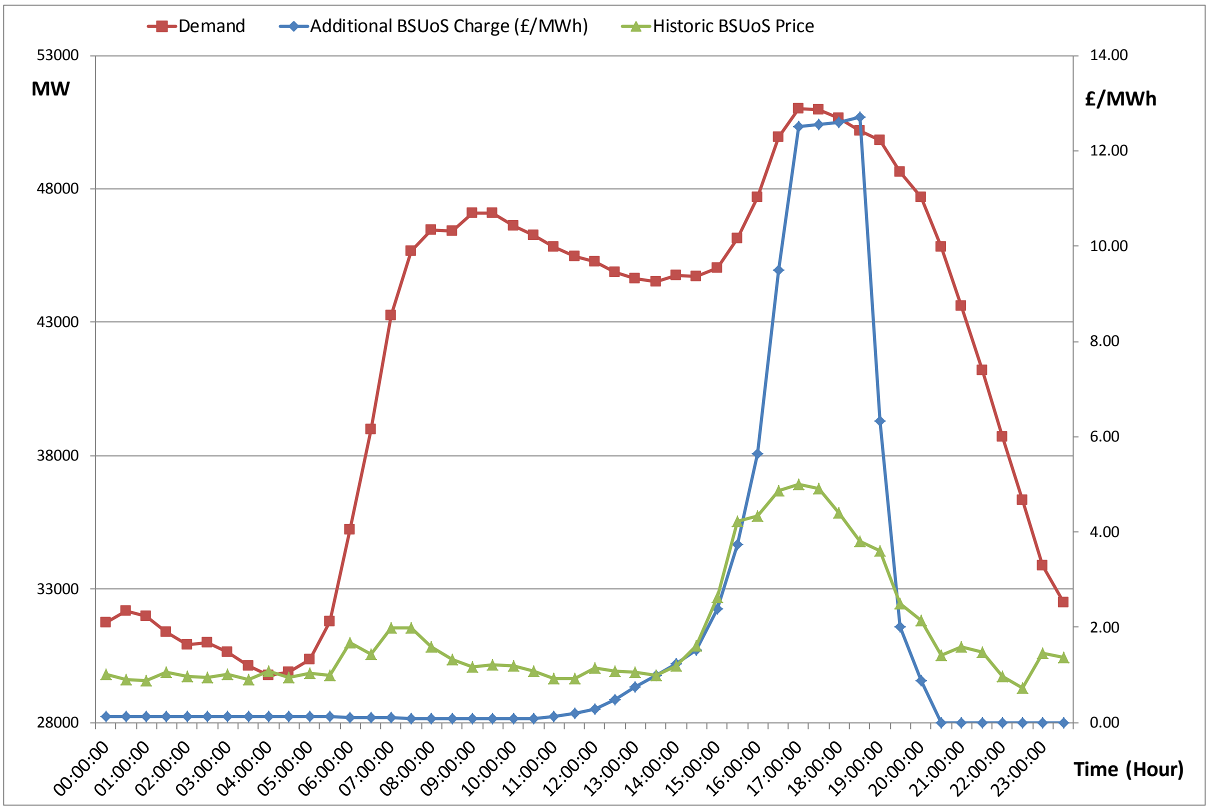

| Duration = | 1 hour | Capacity = | 4000 MW | |
|---|---|---|---|---|
| Cost Spreaded 24/7 over Triad Season | Cost Spreaded over 5b on three Triad days (£/MWh) | Cost Spreaded over 5b over Triad Season (£/MWh) | Cost Spreaded 24/7 over the month (£/MWh) | Cost Spreaded over the day (£/MWh) |
| 0.03 | 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. | |