nationalgrid

Stage 02: Workgroup Consultation

Connection and Use of System Code (CUSC)

CMP250

'Stabilising BSUoS with at least a twelve month notification period'

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

CMP250 seeks to eliminate BSUoS volatility and unpredictability by proposing to fix the value of BSUoS over the course of a season, with a notice period for fixing this value being at least 12 months ahead of the charging season.

This document contains the discussion of the Workgroup which formed in October 2015 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 6 of this document.

Published on: 15th March 2016
Length of Consultation: 20 Working days
Responses by: 14th April 2016

High Impact:
Any Customer liable for BSUoS charges

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 CMP250 CUSC Modification Proposal which was raised by Cem Suleyman, Drax Power and developed by the Workgroup. Parties are requested to respond by **5pm on 14th April 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/CMP250/

Document Control

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1.0	04/03/2016	Code Administrator	Draft Workgroup Consultation for Workgroup Comment
1.1	15/03/2016	Code Administrator	Workgroup Consultation to Industry

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1 Summary

1.1 This document describes the Original CMP250 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 CMP250 was proposed by Drax Power and was submitted to the CUSC Modifications Panel for their consideration on 28th August 2015. A copy of this Proposal is provided within Annex 1. 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 CUSC Panel.

1.3 The defect CMP250 attempts to address issues which relates to the fact that BSUoS is only known after the event (ex post) and is becoming significantly more volatile and unpredictable as a consequence of the dramatically changing generation mix. As a result, there is an increasing risk for market participants that their attempts to forecast the cost of BSUoS could be incorrect and could result in loss making and/or uncompetitive market activity. The unpredictability and volatility of BSUoS results in the application of risk premia in the market which will tend to inflate the costs borne by the end consumer. CMP250 aims to eliminate BSUoS volatility and unpredictability by proposing to fix the value of BSUoS over the course of a season, with a notice period for fixing this value being at least 12 months ahead of the charging season. Any under or over recovery of BSUoS costs is then recovered/returned in a future period. It is argued this will reduce the BSUoS risk premium and deliver better value for money compared to the current charging arrangements.

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/CMP250/ along with the Modification Proposal Form.

2 Workgroup Discussions

Defect

2.1 Balancing Services 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 for each half hour settlement period mostly reflecting the actual costs incurred by the SO in each period. The charge is currently levied on an ex post basis (after the event).

2.2 The Proposer identified the defect as due to the growing unpredictability of BSUoS prices, industry participants have no real certainty of their BSUoS costs when forward contracting for power. This lack of certainty ahead of time can result in increasing risk premia being applied by Generators and Suppliers to their product sales, which are ultimately borne by the consumer. It was argued that participants are exposed to events beyond their control, trading prior to a known cost. The Proposer therefore suggests that an ex ante charge would better meet the CUSC objectives.

Proposal - Scope of the Modification

2.3 The workgroup discussed key scoping assumptions that frame the context of the proposal:

1. No optionality – the workgroup considered that the solution to the defect should be mandatory for all participants, and not optional. In other words, it would not be possible for some market participants to opt out of a fixed BSUoS price and remain exposed to an ex post half hourly charge, for example.

2. One solution to reducing BSUoS volatility could be to make changes to the "Connect and Manage" regime. The workgroup agreed that this modification is not about the absolute costs of BSUoS in terms of how it is incurred today, and that therefore an alternative proposal along these lines would be out of scope.

3. Another solution might be to allocate all the costs of BSUoS to demand, for example. The workgroup agreed to look at the impact on market participants but changing the split of who pays BSUoS from 50:50 is out of scope. It is not a question of how to allocate the costs but whether the current ex-post charge is the best approach.

Components of BSUoS

2.4 The table below shows a breakdown of the main categories that made up total BSUoS costs in 2014/15, the grand total amounting to just over £1bn.

2014/15	Total Cost (£m)
Energy Imbalance	-11.8
Operating Reserve	80.7
Balancing Mechanism Startup	1.1
Short Term Operatin Reserve	62.3
Constraints	292.6
Footroom	7.4
Fast Reserve	130.1
Response	174.4
Reactive	72.0
Minor compnents	40.4
Internal costs	141.3

Balancing Services Incentive Scheme + Wind incentive	25.8
SBR/DSBR (including testing costs)	31.7
Total	**1043.0**

Table 1: Breakdown of BSUoS costs in 2014/15

Calculation of BSUoS

2.5 The precise calculation of BSUoS Charges is described in The Statement of the Balancing Services Use of System Charging Methodology Sections 14.29 to 14.32. Simplified examples of how specific basic actions taken by the SO translate into a BSUoS price are shown in Annex 4 (How RCRC interacts with BSUoS prices).

BSUoS Volatility

2.6 BSUoS accounts for varying proportions of the wholesale energy price, in some cases very large proportions. The graph below shows BSUoS as a percentage of the wholesale price (APX Mid P) over approximately the last 6 months. Please note that all wholesale power prices of less than £8/MWh have been removed from the data set to allow the graph to be viewed easily. Leaving these prices in the data set would result in very large percentages and make the graph unreadable. Less than 1% of prices have been removed from the data set so the high level conclusions are not impacted by their removal. The data shows that BSUoS can account for over 80% of the wholesale energy price (although when the wholesale price is very low it can account for over 100%) and has on a number of occasions accounted for over 20% of the wholesale energy price.

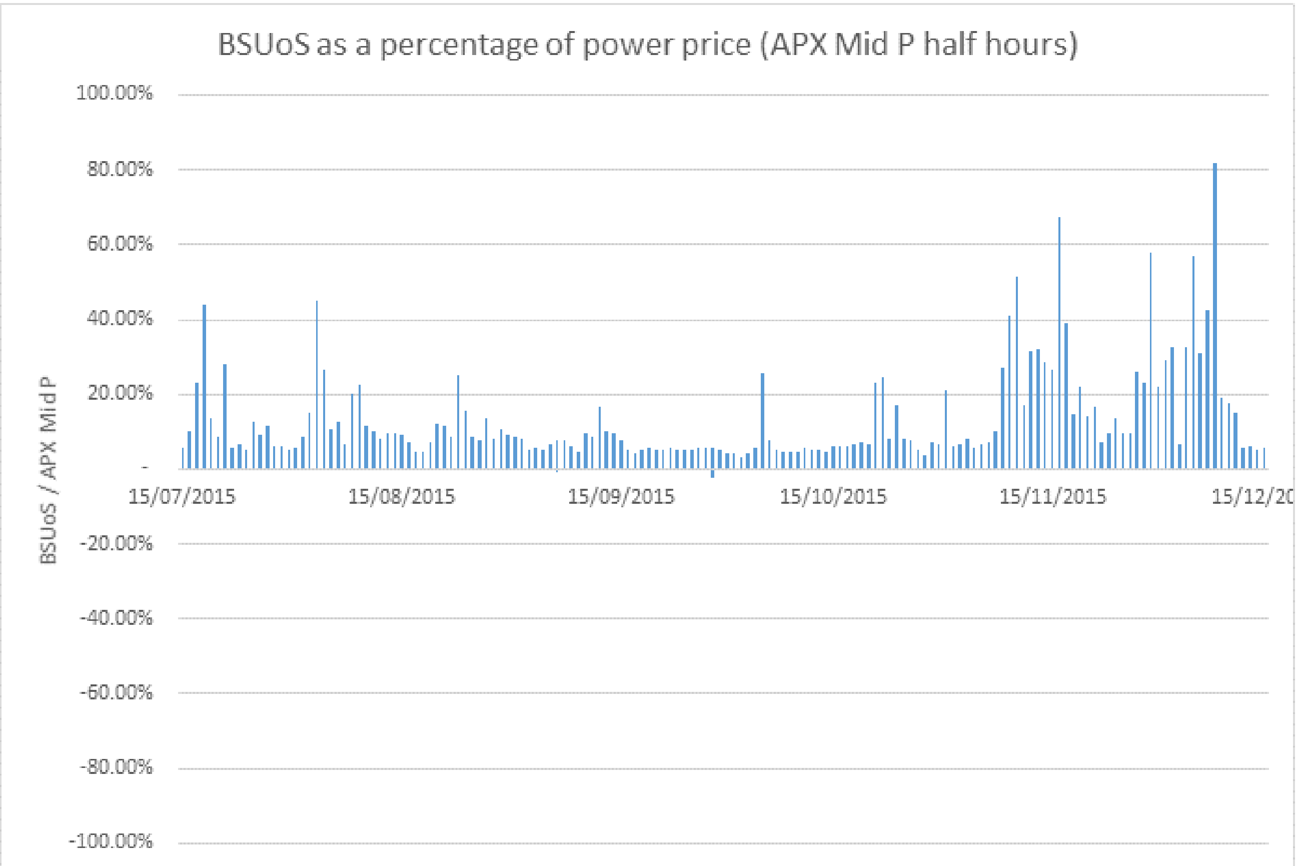


Figure1: BSUoS as a percentage of power price

2.7 The average cost of BSUoS can also be compared to the average price of different wholesale power products. For example, the average cost of BSUoS in 2015 was £2.24/MWh and the average price of day ahead power in 2015 was £40.43/MWh. As such BSUoS constituted 5.54% of the average day ahead price for 2015. Moreover, the average

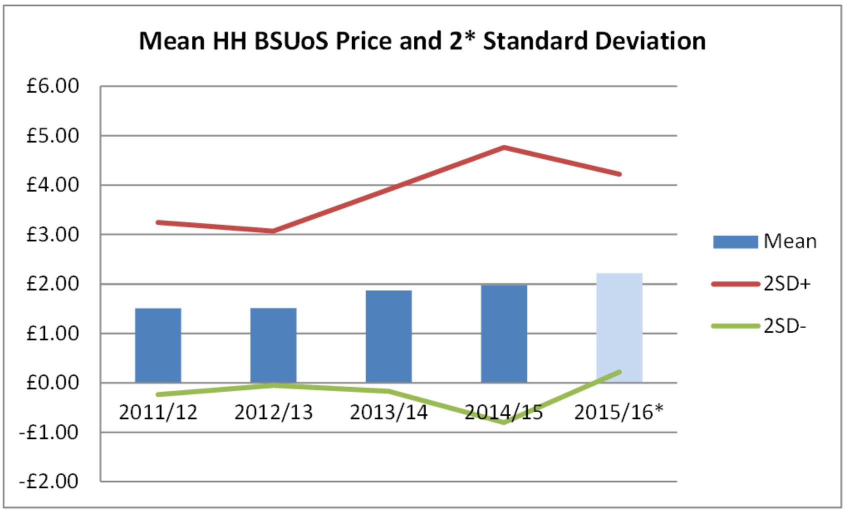
Summer BSUoS cost in 2015 was £2.14/MWh. As the average Summer 2015 power price at season ahead was £45.36, this means that the average BSUoS cost in Summer 2015 constituted 4.71% of the season ahead average Summer 2015 power price.

2.8 BSUoS is expected to become a more significant element of the wholesale price as the wholesale price falls with increased renewables penetration whilst the cost of balancing the system increases simultaneously. The Workgroup discussed analysis provided by National Grid showing increasing volatility in BSUoS prices. The data below shows an increasing trend in the absolute price of BSUoS and increases in the standard deviation around the mean. The graph shows the expected range of BSUoS prices with 95% confidence assuming BSUoS prices are normally distributed.

BSUoS Volatility (1)

BSUoS Year	Standard Deviation	Mean HH BSUoS	SD as % of Mean
2011/12	£0.87	£1.50	57.8%
2012/13	£0.78	£1.51	51.7%
2013/14	£1.02	£1.87	54.5%
2014/15	£1.39	£1.98	70.2%
2015/16*	£1.00	£2.22	45.0%

*Summer Only



*Data to Oct 2015

Figure 2: Expected range of BSUoS prices

2.9 The following graph shows how the number of incidences of higher price spikes has increased over the last four years.

BSUoS Volatility (2)

Falling demand increasing price elasticity of half hour prices

	BSUoS Year	> £5.00/MWh	> £7.50/MWh	> £10.00/MWh	< £0.00/MWh
	2011/12	98	12	4	167
	2012/13	51	3	0	124
638TWh	2013/14	249	28	0	53
599TWh	2014/15	504	130	60	48
	2015/16*	322	90	8	142

***Summer Only**

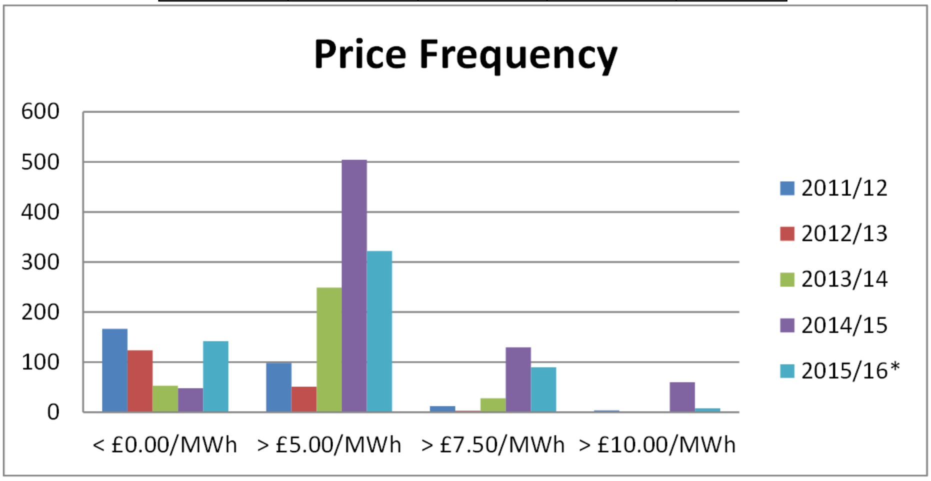


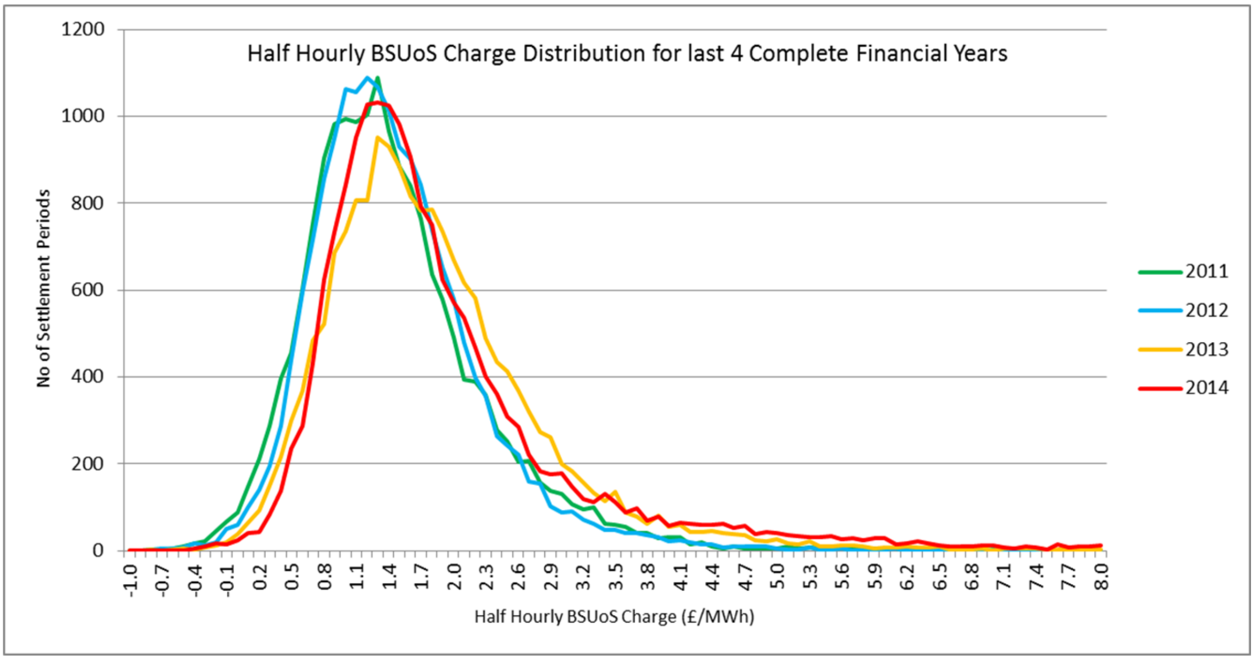
Figure 3: Price Frequency of BSUoS

2.10 There are two primary drivers for the increasing price elasticity of half hour prices:

- Falling transmission demand (including an increase in embedded generation) which is a key factor in the determination of the BSUoS price
- Increased constraint costs resulting from the “Connect and Manage” regime (where generators are permitted to connect to the transmission network ahead of reinforcement)

2.11 The following graph illustrates the BSUoS price distribution curves over the last four years:

HH BSUoS Charge Distribution Curves (FY 2011 – FY 2014)



Upper range of half hourly BSUoS charges has been trimmed to £8.00/MWh to improve visibility of distribution curves.

Figure 4: HH BSUoS Charge distribution curves

2.12 It can be seen that the tail of the distribution curve is getting longer with each passing year suggesting a wider price range for BSUoS prices and evidence for increased volatility.

2.13 Within Annex 4 of this document, there are four graphs showing Monthly BSUoS from 2011-2015. In the four graphs the following can be observed:

- Little or no pattern in the overall monthly BSUoS costs, with higher aggregate costs possible in winter or summer seasons
- Falling transmission system demand over the past 5 years.
- Little or no pattern in the overall monthly BSUoS charge, with higher monthly costs possible in winter or summer seasons

Workgroup Consultation Question: Do you agree Balancing Services Use of System Charges are becoming more volatile? If not, please explain why.

Workgroup Consultation Question: Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.

Modification Proposal Benefits

2.14 The Proposer envisages the following benefits to the modification proposal:

- An ex ante price allows generators to precisely reflect BSUoS costs in the Short Run Marginal Cost (SRMC) in wholesale power sales, bid and offer prices and ancillary services
- An ex ante price with notice period allows Suppliers to forward contract with certainty
- The product is not hedgeable and therefore it makes sense for the entity with the most control over the costs to assume the risk on behalf of industry

Competition

2.15 The Proposer contends that it is not possible to compete with other parties on BSUoS, in that it is not possible to be better at forecasting BSUoS than other players. In other words there is no comparative advantage in this area. Moreover, the Proposer does not believe that BSUoS provides a useful signal to market participants. Firstly, BSUoS is extremely difficult to predict particularly when the prevalence of forward power contracting is recognised. Therefore it appears very difficult to react to, pretty much impossible where power has been sold far ahead of delivery. Secondly, BSUoS, even if it can be predicted, can provide perverse signals. For example, a high BSUoS charge could be caused by intermittent generation being bought down/off behind a transmission export constraint. However, the high BSUoS charge could conceivably incentivise flexible generation to turn down/off which may not be optimal in terms of system operation.

Workgroup Consultation Question: Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business? Please explain your answer

2.16 One Workgroup member considered that the calculation of BSUoS charges on an ex post basis for each settlement period does provides a price signal, to which market participants can respond. Whether parties are able, or choose to respond to such a signal is another matter however. What is clear is that different classes of market participant will face different commercial drivers affecting how they might respond. Portfolio players will not necessarily face the same risks as say a single site independent generator and peaking plant, “must run” CHP plant output, or wind generators will need to respond differently to changes in the market. Some market participants may be able to forecast BSUoS charges better than National Grid or other market participants. In a competitive market, the size of BSUoS risk premia that can be passed through to customers will depend on the ability of market participants to respond to pricing signals and the extent to which the parties that are best able to forecast BSUoS set market prices. Any apparent benefits from charge stability under CMP250 or any other suggested alternatives should be judged against the efficacy of existing pricing signals that would be removed and the loss of competitive advantage to those parties that are most skilled at forecasting BSUoS prices.

2.17 The Proposer notes that small players may be at a greater disadvantage than bigger players in forecasting BSUoS as they have fewer resources to commit to accurately assessing the price risks. Smaller Suppliers may therefore be under-pricing the risk if they just use the year-ahead National Grid forecast.

2.18 One Workgroup member discussed comments on cost reflectivity of a fixed price BSUoS and the effect on some parties that may believe they have a competitive advantage from forecasting it. The Workgroup carried out further discussion with a split view on whether BSUoS is seen as a signal or cost recovery tool. The Workgroup agreed that the signal needs to be doing something good and positive for the system and that it would be beneficial to gain the views of the Industry on this area when the Workgroup Report is issued out to consultation.

Workgroup Consultation Question: Fixing BSUoS charges on an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period.

Risk Transfer

2.19 By providing a fixed price, the proposed modification effectively transfers cashflow risk from industry to the System Operator.

BSUoS as a Market Signal or cost recovery mechanism?

2.20 When first developed, it was thought that BSUoS would generate some form of signal to market participants through the cost reflectivity of the charge itself. The Wrkgroup discussed whether BSUoS is a market signal or a cost recovery mechanism. As market participants are unable to respond to an ex post price, a majority of the group considered that the charge is a cost recovery mechanism and not a market signal.

Workgroup Consultation Question: Do the existing, es post, BSUoS charges provide price signals to which your business is able to respond? If your answer is YES, please describe how you respond to such signals.

2.21 Targeting BSUoS costs to individual half hours is only partially achieved:

- Constraint costs are smeared across all market participants, and not to those that cause them
- Only the following costs are actually allocated to specific half hours:
    - Bid/ Offer Acceptances
    - Trading Costs
    - STOR week ahead availability costs. Balancing actions taken by the SO are not necessarily specific to the settlement period where the action is required due to specific plant dynamics i.e. the need for plant warming, ramp rates etc.

2.22 All other costs and incentive allowances are computed on a daily basis and allocated to settlement periods through volume weighting. This suggests that about a third of total spend can be allocated precisely by half hour. The rest of the costs are smeared across the day.

2.23 One Workgroup member stated that as far as reasonably possible, existing BSUoS charges seek to target the cost of day to day operation of the transmission system to relevant settlement periods in which such costs are incurred. Fixing BSUoS charges will result in a reallocation of costs between settlement periods. For example, any 'flattening' of charges across a day or longer period will, depending on the actual operating pattern of particular generation plant, alter the size of the BSUoS bill faced by such parties. For embedded generators for example, this change to BSUoS charges would be expected to reflect the level of embedded benefits passed through to them by Suppliers.

2.24 In addition, determining the current level of BSUoS charges on an ex-post basis means there can be an exact recovery of costs in the relevant charging year. However, any ex-ante fixing of charges under CMP250 necessarily leads to a 'misallocation' of costs from one year to another because of over or under-recovery of revenues. The speed with which these adjustments can be made also affects the appropriate cost allocation. Thus CMP250 or any of the alternatives suggested would make BSUoS charges inherently less cost reflective. Any apparent benefits of these proposals from charge stability should therefore be judged against any reduction in overall cost reflectivity.

Product

2.25 The group considered whether the fixed price should be profiled or just one flat number. The Workgroup recognised that the justification for any profiling would need to be clear in terms of what the signal would be designed to achieve and to whom. Historic data was examined to see whether there was an obvious natural profile.

2.26 Analysis of data from the last four years suggests little obvious pattern in BSUoS prices by day or half hour. The monthly split of prices shown in the graph within Annex 4 of this document also illustrates how prices can be very different across the year. The table below shows winter-summer seasonal splits:

EFA Year	Season	Total	Data Type
2011	Summer	£1.45	RF
	Winter	£1.56	RF
2012	Summer	£1.56	RF
	Winter	£1.46	RF
2013	Summer	£1.92	RF
	Winter	£1.80	RF
2014	Summer	£1.55	SF
	Winter	£2.42	SF
2015	Summer	£2.22	SF

Table 2: Winter-Summer seasonal splits

2.27 Only 2014 exhibited a clear winter-summer seasonal split. However, further inspection of data shows some differences between Weekend and Weekday splits, and Overnight and Extended Peak (07:00-19:00) splits, as shown in the tables below:

	WE-WD	ON-EP	Win-Sum	Data Type
2011	£0.25	£0.11	£0.11	RF
2012	£0.21	£0.23	-£0.11	RF
2013	£0.29	£0.18	-£0.12	RF
2014	£0.41	£0.60	£0.87	SF Only
2015	£0.93	£1.07		SF Only

Table 3: Weekend and weekday splits

Year	Ex-Peak	Overnight	Difference	Data Type
2011	£1.47	£1.58	£0.11	RF
2012	£1.43	£1.66	£0.23	RF
2013	£1.80	£1.98	£0.18	RF
2014	£1.78	£2.38	£0.60	SF Only
2015	£1.86	£2.93	£1.07	SF Only

Table 4: Overnight and extended peak splits

2.28 If any profiling is included in an ex ante price, weekend-weekday, and/or overnight-extended peak would be the most obvious candidates, based on historic observations.

2.29 However, the Workgroup noted that shaping BSUoS requires an extremely accurate view of market developments in the future. Assumptions on future profiles could be undone by changes in the market happening in timeframes after an ex-ante BSUoS price has been notified. One example might be the effect of the Western HVDC project which might be expected to decrease the level of constraint payments, which is one of the primary drivers for BSUoS volatility.

2.30 Profiling would only have value if the System Operator is able to forecast the shape, and history shows that there is no strong or consistent pattern of half hourly charge.

2.31 The Workgroup noted there may be merit in a profile of some kind if this can be shown to reduce the overall costs of ex ante pricing. The Workgroup also considered it may be appropriate to retain the flexibility to generate a profiled shape, even if at present, there may not be a case to profile BSUoS prices. On this basis, and for simplicity, the Workgroup agreed to consider only options that are a flat fixed price (one number for each half hour).

Workgroup Consultation Question: Do you believe BSUoS is a useful price signal?

Workgroup Consultation Question: If a fixed BSUoS price was implemented, should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry? Please explain your reasons.

<u>Notification and Fixed Price Periods</u>

2.32 The diagram within Annex 7 of this document shows a number of possible options and the interaction between notification and fixed price time periods. The options are defined by a combination of the notice period (shown in blue), the fixed price time period (shown in orange), and the reconciliation process following the relevant charge phase (shown in grey).

2.33 The first point to note is that for options where the combined notification and fixed price period is more than 18 months, reconciliation of the over/under recovery cannot occur until yr+3. Only in options 6m notice: 12m fix (6:12) and 12m notice: 6m fix (12:6) is reconciliation in yr+2 possible.

2.34 The Workgroup did consider whether it might be possible to have a fixed period of 11 months and 3 weeks or 5 months and 3 weeks to enable some late calculations that would deliver a yr+1 reconciliation. However National Grid advised that there is a 3 month process following each financial year where over or under recovery that results in a given year is adjusted through a "K" adjustment methodology approved by Ofgem. Condition B15 of the NGET Transmission Licence requires National Grid to comply with the Regulatory Instructions and Guidance which National Grid carries out through delivery of its Regulatory Reporting Pack by 31st July of each year. The principles elsewhere are that "K" is measured in the year and reported as part of the regulatory return in year 2. Such a mechanism would suggest a requirement for an additional process in the 12m:6m proposal.

2.35 National Grid described the key variables driving any forecasting lead time. Generator TEC positions are generally known 12 months ahead, though TEC reductions could still happen after the cut-off date. The BSUoS energy component is relatively stable and reasonably well understood ahead of time. However volatility in BSUoS tends to arise from the constraints side of balancing costs which are mainly a consequence of:

(i) Transmission system outages

(ii) Intermittent wind generation.

2.36 One of the key pieces of information affecting any future BSUoS forecast would be the year-ahead outage plan. This is because constraints are such a large component of the overall BSUoS costs. Understanding when specific transmission circuits are to be switched out would remove a significant uncertainty in attempting to forecast a fixed price. The higher the uncertainty, the larger the cashflow financing provision will need to be, and hence increase overall costs to consumers. The outage plan is firmed-up mid-October for the financial year ahead. An indicative plan could probably be generated to accommodate a possible September forecast date (6 months ahead). If this could be done, the 6m:12m product may offer the best balance between forecast accuracy, overall cost and industry certainty.

Benefits of a longer notice period

2.37 According to Ofgem's Wholesale Power Market Liquidity: Annual Report 2015 (9 September 2015), in Quarter 2 2015 approximately 50% of OTC baseload products were traded up to six months ahead of delivery (Baseload S+1). However, an approximately additional 20 percentage points of OTC baseload trading was undertaken up to 12 months ahead of delivery (Baseload S+2). The data can be seen in the graph below. This represents the additional traded volumes which would benefit from a CMP250 solution that includes a 12 month as opposed to six month notice period.

2.38 A CMP250 solution with 12 months rather than six months' notice could be expected to reduce the BSUoS risk premium by an additional 20% (which could be valued at somewhere between £40m and £16m – please see the BSUoS risk premium section for the full results of this analysis).

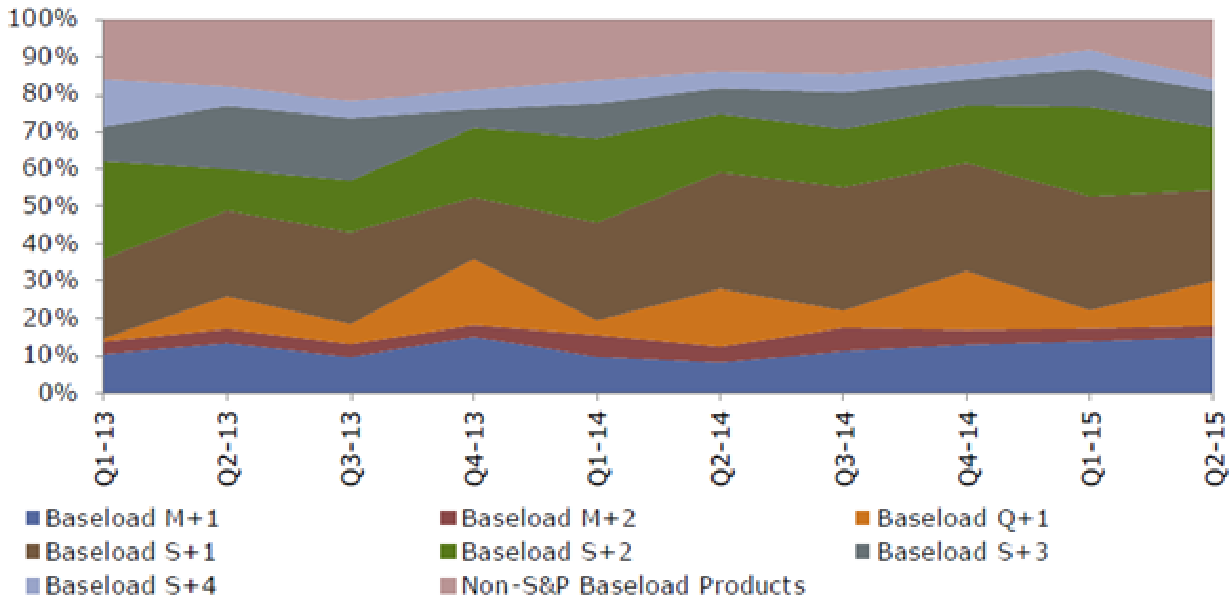


Figure 5: OTC baseload trading since Q1 2013

2.39 One Workgroup member noted the trade-off between the notification period and the size of the cashflow provision required to ensure sufficient finance is available in the event the fixed price forecast is inaccurate – the chances of which are higher, the longer the notification period.

Workgroup Consultation Question: What is your preferred notification lead times and what should be the length of the price fix period? Please provide details to support your answer.

Cashflow Implications

2.40 The Workgroup considered how a fixed price mechanism may affect SO cashflow. Analysis was performed to examine how the SO cashflow position would have been affected if a fixed price mechanism had been in place for the last four years. It should be noted that the fixed price used in the analysis is one month ahead, as no longer term forecasts of BSUoS price exist. The analysis therefore does not consider the accuracy of BSUoS forecasting with longer notification lead times. It is purely an indication of the possible movement in cashflows that might be observed as a result of over or under-recoveries.

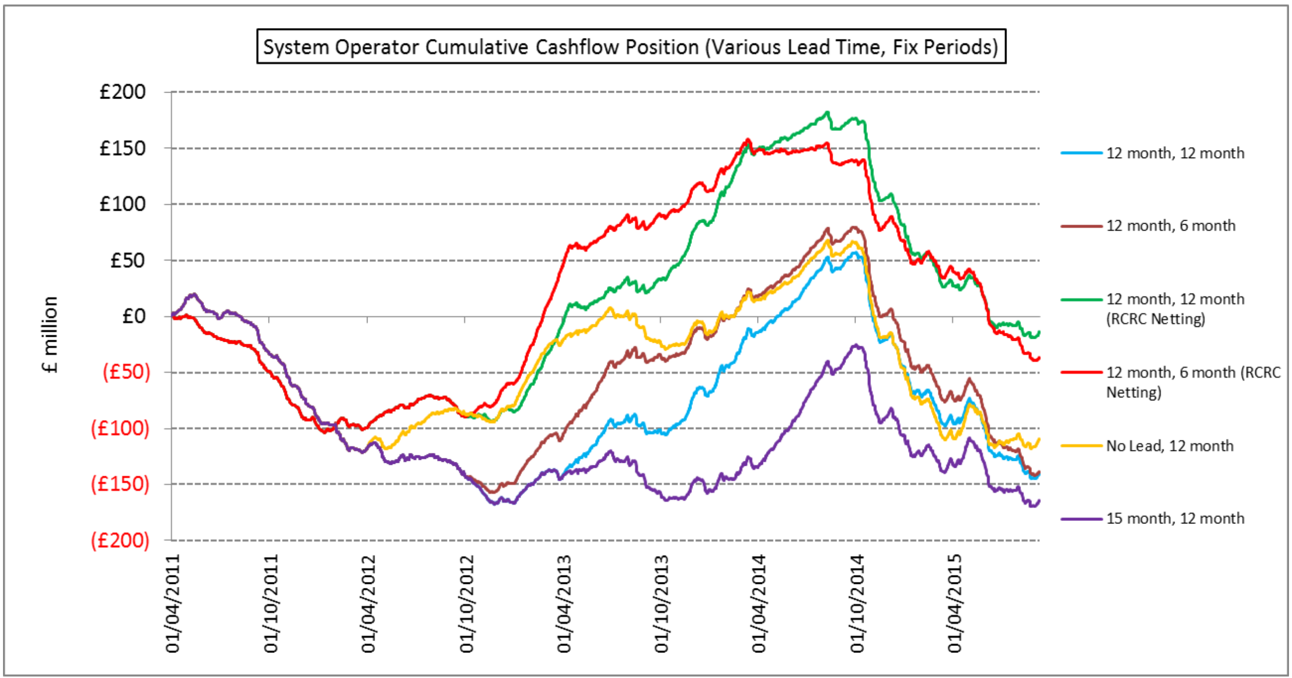


Figure 6: SO cumulative cashflow position

2.41 Cashflow recovery is calculated by comparing actual half hourly balancing costs to the year ahead half hourly BSUoS forecast multiplied by total half hourly System Demand N0312 (multiplied by 2 to represent both generation and demand). Any differences between the Balancing Services Incentive Scheme (BSIS) costs included in the forecast and the outturn BSIS SO costs to the industry have been stripped out of the under/over-recovery figures. Any over/under-recoveries are assumed to be addressed in the next available period (rather than yr+2 as described above) except the 15m:12m scenario where recovery is in yr+2.

2.42 The analysis shows that the cashflow position can fluctuate significantly broadly + or - ~£175m. However, it is also important to note that the analysis does not include consideration of any notification period, it just assumes a fixed price from the beginning of the charging year. (It is not possible to model a notification period, because no forecast is available to cover this). Therefore, the price forecasts above were made by reference to an outage plan, which would not be possible were the notification period to exceed 6 months, and therefore it is realistic to suggest the fluctuation parameters could be significantly wider.

2.43 The most positive cashflow scenarios are those where RCRC is netted out of the BSUoS calculation, and this is discussed further in paragraph 2.44 below. Generally, the longer the notification and fix period, the longer any over or under-recovery persists.

2.44 The Workgroup noted that the current state of potential under or over recovery by National Grid is likely to be over-stated as there is no incentive, either risk or reward based, on the SO to accurately forecast BSUoS over a longer time frame. Under any changes as a result of CMP250 BSUoS forecasting would become an issue that the SO would need to manage. The Workgroup considered that this would both be an exposure to risk which the SO would mitigate through improved forecasting and a potential incentive to ensure that under or over recovery was within a specific tolerance.

Impact of RCRC

2.45 Net Residual Cash-flow Reallocation Cash-flow (RCRC) is a term used to reallocate surpluses or deficits generated from a dual cash-out price. In the Balancing Mechanism, bids and offers have different prices so when the SO takes balancing actions to resolve energy imbalances these actions do not net to zero. As the system is generally long, a surplus is more usual, and this is reallocated to those parties that had balanced positions in the market.

2.46 It can be seen in the graph above that if RCRC was netted from the BSUoS price before being reallocated to market participants, the cashflow position would be significantly more positive, and therefore the cashflow costs of fixing a BSUoS price would be lower.

2.47 The Workgroup considered whether netting RCRC should be an additional feature of the modification proposal. Whilst carrying out its analysis, Balancing Code modification P305 was implemented on 5th November 2015. This modification included the implementation of a single cashout price. It is expected therefore that RCRC surpluses will significantly reduce following the implementation of this modification. The Workgroup kept this position under review, and the following data was captured:

FY	Month	Sum of ES_TRC_J_GBP
2011	11	1,489,287
2011	12	10,607,365
2011	1	6,987,875
2011	2	19,428,558
2012	11	5,444,312
2012	12	5,255,767
2012	1	6,710,231
2012	2	7,008,327
2013	11	5,667,778
2013	12	4,660,882
2013	1	9,858,899
2013	2	8,004,474
2014	11	9,175,818
2014	12	10,198,149
2014	1	7,325,075
2014	2	5,242,459
2015	11	8,782,475
2015	12	-1,732,084
2015	1	3,410,396
2015	2	2,209,184

Table 5: RCRC Surpluses

2.48 The table above shows a reasonable reduction in the level of RCRC since implementation of a single cashout price in November 2015. The graph below shows the sum of Total Residual Cashflow (TRC) for the period 5th November (commencement of single cashout) to 14th February (latest data) inclusive of these dates for the five financial years. The data suggests that the RCRC value is diminishing.

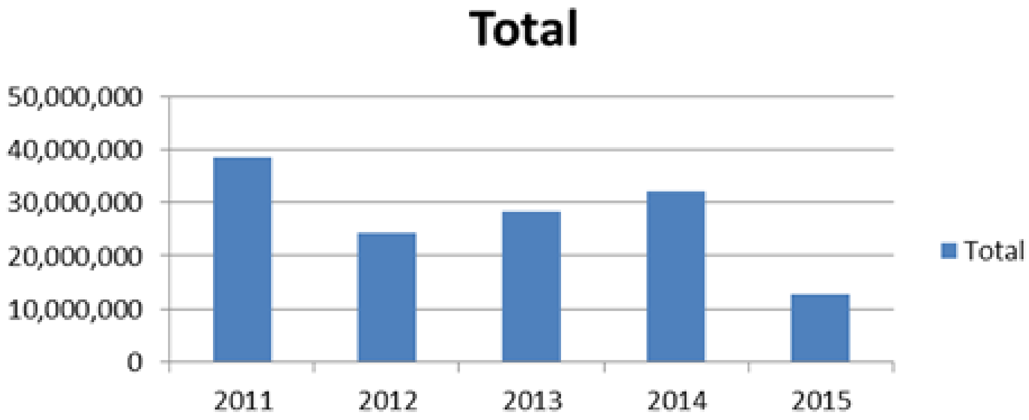


Figure 7: Total residual cashflow (TRC)

2.49 On the basis of the above information, the Workgroup agreed to leave RCRC calculations unchanged.

Impact of demand forecasting on future cashflow risk

2.50 Workgroup members noted that the cashflow analysis was conducted over a period when National Grid's demand forecasting had yet to take account of significant new market developments relating to embedded generation. This had the effect of exacerbating the under-recoveries in the analysis. Workgroup members were therefore interested in the effect improved demand forecasting could have on BSUoS cashflow exposures.

2.51 Whilst improvements are being made to demand forecasting modelling, demand forecasting (particularly for BSUoS applicable volume net of embedded generation) for the year ahead, 12-18 or 12-24 months ahead, can still be very difficult given a host of unknowns. Using solar PV as an example the SO and the market would have struggled to predict an ~2.5GW rush to solar PV in Q1 '15 prior to the government closing the >5MW Renewable Obligation scheme early. The DECC consultation announcement was made 13th May 2014 which would have been post BSUoS forecast for summer 2015.

2.52 There is also still a large portion of demand forecasting that is weather dependent, both in terms of temperature deviations and embedded renewable generation. Whilst better demand forecasting may improve the annual BSUoS forecast it does not improve the volatility in underlying half hourly demand movements resulting from swings in intermittent renewable generation. Therefore, even with a perfect annual demand forecast, large cost variations can still arise.

Risk Premia

2.53 The Workgroup recognised that one of the key pieces of evidence for the success of the modification proposal would be establishing whether the costs associated with the existing regime were higher or lower than the proposed arrangement, and whether GB consumers would benefit overall. To this extent the Workgroup noted the difficulty in finding robust quantitative evidence for the risk premia currently attributed to BSUoS prices and suggested that this issue should be one of the questions in the Workgroup Consultation Report, and perhaps the subject of a separate Ofgem consultation, given the commercially sensitive nature of this information.

2.54 The modification proposal is clear that all balancing costs are reconciled. It is only the timing element of that reconciliation that changes. Presently, System Operator costs of balancing the system are reconciled ex post within 28 days of those costs being incurred, with a final reconciliation d+14 months when the majority of metering data and any Income Adjusting Events are known.

2.55 The proposal seeks to fix the BSUoS price ex ante thereby transferring cash flow risk from market participants to the System Operator. Cash flow risk is the money required to continue to function as an operating concern, the working capital. In other words, if the BSUoS price is set too low, the System Operator would be required to borrow money to continue to procure services to balance the system, and if it is set too high, the System Operator will be in receipt of a considerable financial surplus. The challenge therefore is how to make available the cash to balance the system at least cost, and to optimise that level so that only an efficient amount of cash is required.

2.56 Industry participants made the point that for them there was real profit and loss at stake in the event their risk margins were set incorrectly, whereas moving to an ex ante regime and centralising the risk would just be a cash flow timing issue for the entity taking the risk.

2.57 The Workgroup attempted to quantify the absolute level of risk to which market participants are potentially exposed. One Group member noted that the risk margin is the price which market participants would be prepared to pay in order to have certainty over the BSUoS price.

2.58 It was noted that there were two risk components resulting from volatile BSUoS prices:

(i) The contractual risk faced by Suppliers; and

(ii) The wholesale risk faced by Generators

2.59 The Workgroup noted the difficulty in estimating and even discussing the risk premia applied by market participants given the commercially sensitive nature of the information. It was also noted that risk premia would be a function of a given company’s risk appetite, and market competitiveness.

2.60 The Workgroup discussed at great length how the risk premia might be valued. A couple of different approaches are discussed below, though they lean on significant assumptions.

2.61 The Workgroup discussed how BSUoS price risk was different to other types of risk such as credit risk and volume risk. One key difference noted is that most types of risk can be hedged, but that is not possible with ex post BSUoS. It was also suggested that BSUoS price risk might have a diversification effect but the Group considered that BSUoS risk is not a diversifier.

2.62 The Workgroup discussed the extent to which competition might limit the application of risk premiums. The Group considered that the risk premium would be reflected in the market price, and since most Workgroup Members believe that no party had a competitive advantage in forecasting BSUoS, in theory all market participants should broadly have similar risk margins. It was noted that the lengthening tail of the most recent distribution curves in Section 10 means that some small parties may not be able to transact because this risk is too large, and therefore may constitute a barrier to entry.

National Grid BSUoS forecast and supplier risk premium

2.63 The following graph shows the National Grid Year Ahead BSUoS Price Forecast versus actual outturn.

Outturn BSUoS Price v NG Forecast

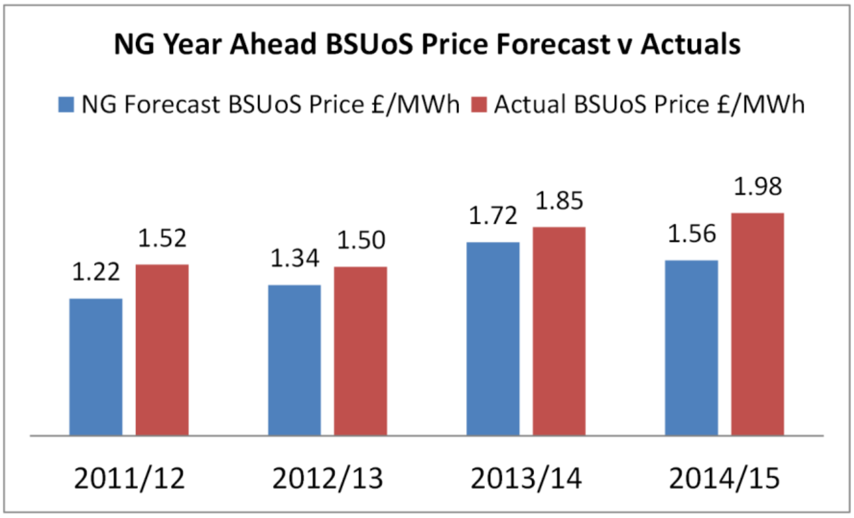


Figure 8: NG Year Ahead BSUoS Price Forecast v Actuals

2.64 The Graph shows that over recent years National Grid has tended to under-forecast the annual average BSUoS price, and if Suppliers are using the National Grid forecast without applying a risk margin, they are potentially exposed. The Workgroup discussed the degree to which the National Grid forecast was used, and it was argued that larger companies are perhaps more able to take their own view of BSUoS prices, whereas smaller participants are more likely to take the National Grid forecast at face value.

2.65 In an attempt to quantify the value of the “appropriate” risk margin that Suppliers should have applied if they had used the National Grid forecast and had perfect hindsight, then one could take the average difference between forecast and actuals over the period 2011/12 and 2014/15 which equates to £0.25/MWh. If multiplied by the demand base of approximately 300TWh, then the value of the Supplier risk premium is approximately £75m per annum. The Workgroup discussed the merits of this approach to quantifying the costs to consumers of ex post BSUoS pricing.

2.66 The Workgroup discussed whether it was appropriate to use 300TWh, as large customers are likely to have pass-through contracts with their Suppliers. It was however noted that large consumers would still need to manage this risk themselves. If one was to exclude broadly 100TWh of large industrial consumption, the value of the “appropriate“ risk premium would be approximately £50m pa.

Generation and Supply BSUoS risk premium analysis

2.67 The Proposer explained what the BSUoS risk premium is and how it arises. Generators and suppliers do not know what the price of BSUoS will be in any half hour Settlement Period (SP) until after the event. National Grid provides a forecast of the mean average annual BSUoS charge ahead of time. However the price of BSUoS in any SP can deviate greatly from this average. If a generator or supplier assumes that it will be charged the average annual BSUoS cost when selling, there is a risk that the generator or supplier will face a higher cost where the BSUoS price outturns higher than the average. This is particularly the case where a generator or supplier does not produce or ‘consume’ all year round.

2.68 To mitigate against this risk of higher than average BSUoS costs, a generator or supplier will add a risk premium to the price it is willing to sell into the market. This is particularly important to market participants with low profit margins (likely the marginal ‘price setting’ producers) as only a small increase in BSUoS prices above the average can wipe out any profit assumed and even result in a party incurring losses.

Calculating the BSUoS risk premium

2.69 The Proposer suggested that a statistic method could be employed to quantity the size of the BSUoS risk premium. This statistic method is explained below.

2.70 Firstly, distributions of outturn half hourly (HH) BSUoS prices for financial years 2011/12 to 2015/16 (noting 2015/16 is not yet complete) were established. To create these distributions, HH BSUoS data was obtained from the National Grid Website[1]. BSUoS Distributions were created for different trading periods within the five financial years. The following trading periods have been used to develop BSUoS distributions:

- Peak - 0700-1900, all week
- Extended Peak – 0700-2300, all week
- Block 5 – 1500-1900, all week
- Baseload – 2300-2300, all week

2.71 This means that BSUoS prices in settlement periods outside the trading period are not included in the specific BSUoS distribution. For example, a Peak BSUoS distribution does not contain HH BSUoS prices set between 1900-0700. These BSUoS Distributions were created by a software package. Two graphical examples of the BSUoS distributions are provided under (i) and (ii) of Annex 8 of this document.

2.72 With these BSUoS price distributions, different probabilistic values can be deduced to reflect different risk appetites (P numbers). For example P50 reflects the cost assumption that would need to be made to ensure that the market participant does not make a loss in 50% of applicable SPs, P60 relates to 60% of applicable SPs and so forth. P numbers are produced for risk mitigation strategies ranging from P10 (reflecting a very aggressive risk appetite) and P100 (reflecting a very conservative risk appetite).

2.73 So for example, if a generator selling peak electricity in 2014/15 wanted to ensure that it avoided the risk of losses in 70% of the trading period, it would need to assume a BSUoS cost of £1.96/MWh and price its power accordingly. All P values for different trading periods and financial years are presented in the tables under (iii) within Annex 8 of this document

2.74 Clearly a limitation with this approach is that it is backward looking, focussing on actual outturn BSUoS values. A market participant would not have foresight of these values when making pricing decisions on its trades ahead of delivery. But for the purposes of the analysis it gives an indication of the risk facing market participants and quantifies the costs that should be assumed to mitigate risk to varying degrees depending on individual risk appetite.

Comparing P BSUoS Distribution Values with actual outturn average BSUoS values

2.75 The P values are then compared with the average outturn BSUoS for the relevant trading period. This shows the discount or premium that a market participant would need to apply to the outturn BSUoS average to adopt any of the P value risk mitigation approaches. So for example if a generator selling peak electricity in 2014/15 wanted to ensure that it avoided the risk of losses in 70% (P70) of the trading period, it would apply a premium of £0.21/MWh to the outturn average BSUoS in the peak trading period (£1.96/MWh minus £1.75/MWh).

2.76 The BSUoS discounts or premiums to outturn BSUoS values are presented in the tables under (iv) within Annex 8, along with the outturn BSUoS averages for the relevant trading periods under (v).

[1] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Historic-BSUoS-data/

Estimating the impact of the BSUoS risk premium on total system costs

2.77 Finally, an attempt is made to determine the costs (or benefits) to the total system in terms of BSUoS cost over (or under) recovery associated with pursuing different risk strategies. Firstly, for the purpose of the analysis, it is assumed that there is a uniform approach to risk mitigation across the market. This is unlikely to be the case, but to assume a heterogeneous approach to risk appetite would be overly complicated to model/analyse.

2.78 Secondly, to estimate how these risk premia could impact the costs to the system and thus costs to the end consumer, we need to make assumptions on what generation and supply volumes these risk premia are likely to be applied to. As noted above, risk premia is more likely to be applied by those market participants operating on small profit margins and as such is an important determinant of the likely generation and supply volumes that will have a risk premium applied.

Generation output

2.79 In terms of the generation volume, while there is some variation in the profit margins being made by different technologies, with some having higher profit margins than others[2], it is the marginal source of production that determines the wholesale power price. As the 'marginal generator' is highly likely to be earning very slim profit margins (and this is borne out from historical experience), it is likely that it will apply a BSUoS risk premium. This will drive up the wholesale power price which will be received by all (or at least the vast majority) of generators. Therefore we assume that while certain generators can be classified as 'price takers' and therefore do not necessarily apply a risk premium themselves, as the marginal generator is likely to apply a risk premium this means the total generation volume will have a BSUoS risk premium attached to it.

2.80 However, we should also note that as power is transacted in multiple timescales in the wholesale market (for example thermal plant is likely to sell a large proportion of its output in the forward market, whereas this is less the case for wind plant) it may not be the case that all generation volume is subject to a BSUoS risk premium. Therefore, the assumption that all generation volume is subject to a risk premium will represent the upper limit on the volume that may be impacted. However, as the vast majority of power is sold ahead of delivery we expect that a large proportion of generation volume will be subject to a BSUoS risk premium.

Supply volume

2.81 In terms of supply volume, as all suppliers are operating on small profit margins (at least relative to the potential variation in BSUoS costs), we expect that all supply volume will have a risk premium attached. However, the exception to this is that some customers have BSUoS cost pass through arrangements in their contracts (likely to be I&C Flex customers and Extra High Voltage Customers). As such we have not assumed that a risk premium is applied by suppliers to the volume consumed by these customers. We estimate this volume is approximately 60TWh.

2.82 However, it is important to note that whilst suppliers will not be applying a risk premium to I&C Flex and Extra High Voltage Customer volumes, these customers will still be exposed to the risk of BSUoS cost variation above the annual mean average. Therefore we expect that a risk premium is likely to be applied to the products and services these companies provide to their respective markets. In summary there is still likely to be a cost impact to the wider economy.

2.83 For the reasons given above we estimate that the following energy volumes will have a risk premium (or discount) attached to them.

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[2] For example nuclear plant has higher gross profit margins than gas plant.

	2011/12	2012/13	2013/14	2014/15	2015/16
Applicable Volume (TWh)	655	662	637	623	600

Table 6: Energy volumes to apply BSUoS risk premiums or discounts

2.84 Moreover, for trading periods (apart from Baseload) we only apply premiums and discounts to a proportion of the total energy volumes. These proportions are set out in the table below.

	Volume proportion
Peak	0.50
Extended Peak	0.67
Block 5	0.17
Baseload	1.00

Table 7: proportion of total energy volumes

2.85 To calculate the total system cost (or benefit), one should multiply the discount or premium to outturn BSUoS by the applicable volume multiplied by the trading volume proportion. So for example, if market participants adopted a risk mitigation strategy to ensure that they avoided BSUoS losses 70% of time (P70) in the peak trading period 2014/15, this would result in the market over recovering £67m from consumers (£0.21/MWh multiplied by 623/TWh multiplied by 0.5 (reflecting that the peak trading period covers half of the total financial year)). All the total system cost results are set out in the tables under (vI) within Annex 8 of this document.

Conclusions

2.86 The analysis suggests that if a market participant wished to ensure that in half of all periods (P50) it would not be exposed to losses associated with BSUoS, it would need to assume a BSUoS cost at a discount to the outturn average BSUoS of between £0.10/MWh and £0.36/MWh depending on the financial year and trading period. This could result in the market under recovering BSUoS from customers by between £74m and £224m. This indicates that a market participant is likely to price BSUoS to ensure that BSUoS loss making transactions are restricted to less than 50% of settlement periods.

2.87 For market participants to reduce their risk appetite by 20 percentage points (P70 – ensure that 70% of the time there would be no losses made attributable to BSUoS volatility), the premium above the average BSUoS outturn would need to increase to somewhere between £0.13/MWh and £0.42/MWh. Applying this risk mitigation strategy would result in an over recovery of BSUoS costs from consumers of somewhere between £81m and £201m.

2.88 The analysis above and the National Grid analysis (in 2.33 of the Report) show the estimated financial magnitude of under and over recoveries of BSUoS with perfect hinsight. It is likely that market participants and National Grid would either over or under recover BSUoS costs whichever takes on this risk. The data produced by both these pieces of analysis appear to be broadly consistent in terms of the value that could be expected to be over-recovered from consumers.

2.89 Importantly, in the long run over recovery is more likely to occur where the risk is placed on market participants rather than National Grid (under a CMP250 solution). This is because consistent under recovery is not financially sustainable in a liberalised market. Moreover, the view that over recovery is more likely than under recovery is consistent with the concept of loss aversion. There is a risk of a party foregoing opportunity if it over estimates BSUoS and there is a risk that a party will make a loss if it under estimates BSUoS. However, much of the academic literature suggests that losses are more powerful psychologically relative to gains.

2.90 Crucially though, under the current method of recovering BSUoS costs there is not a mechanism to recoup BSUoS under or over recoveries. This can weaken competition or result in consumers paying more than is necessary for balancing services.

2.91 However, the proposed CMP250 solution would provide a mechanism to ensure that any under or over recoveries of BSUoS are recouped in future years. This is better for competition and ensures that consumers pay no more than necessary for balancing services.

2.92 Moreover, while National Grid will incur a cost in managing the financial implications of BSUoS under recovery, market participants will similarly face a cost of under recovering BSUoS. This opportunity cost is accompanied by the risk of market exit. As the WACC for the industry will be higher than that for National Grid, the cost of managing over recovery is likely to lower under CMP250 than the current baseline also (though National Grid's existing WACC does not factor in the additional cashflow risk associated with this modification).

Workgroup Consultation Question: What are your thoughts on the methodology and calculation of possible industry risk premia as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?

Workgroup Consultation Question: Does your business use the National Grid BSUoS forecast as an input into trading costs either in isolation or in combination with other factors?

Workgroup Consultation Question: If applicable, are you able to share your approach to calculating risk premia?

Alternative approaches to managing BSUoS price risk?

2.93 The Workgroup discussed where the cost of BSUoS price risk currently sits today and the following diagram illustrates how risk premia are effectively passed through to consumers.

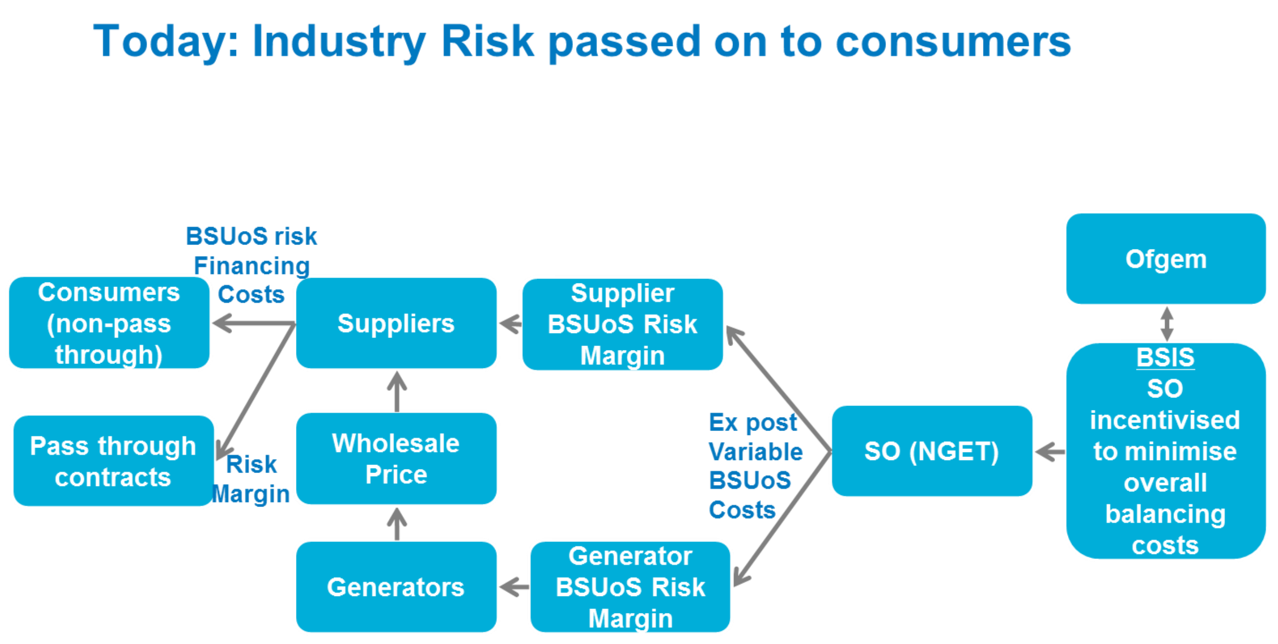


Figure 9: How risk premia is passed through to customers - today

2.94 The Workgroup discussed a number of scenarios describing how different entities could best manage the costs of the risk and the following options were identified:

1. Transmission System Operator (the Original proposal)
2. Independent System Operator
3. Industry Consortium
4. All Transmission Owners

2.95 These options are described in the following flow charts for background information, though it is only the Original proposal (Scenario 1) that is currently being taken forward and forms the basis of CMP250.

2.96 If the move to an ex ante pricing mechanism requires finance to be provided (e.g. for a stability fund) then that finance will result in a cost being incurred. This cost will need to be remunerated. Additionally, there is an option of adding incentive arrangements to ensure the overall financing costs are as efficient as possible.

2.97 Scenario 1 considers the SO providing a fixed BSUoS price and NGET as the licensed entity financing the cashflow required to manage it:

<u>Scenario 1</u>

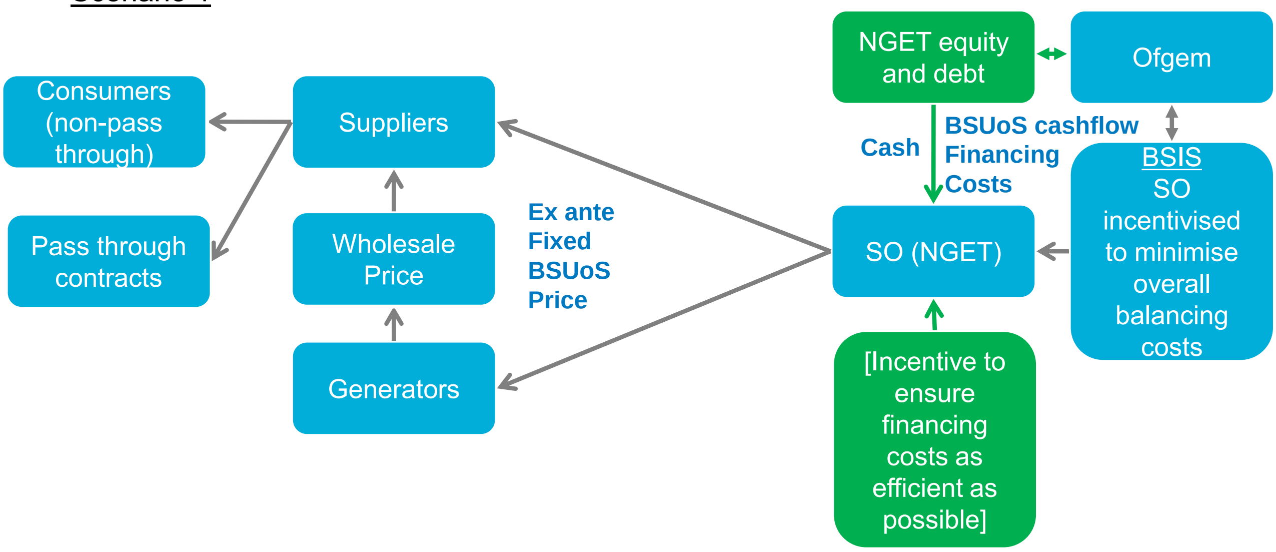


Figure 10: Scenario 1

2.98 The assumption in this scenario is that working capital financing is permitted under the NGET Transmission Licence.

2.99 Scenarios 2a and 2b contemplate the prospect of the SO managing the risk under separate Licence. These are relevant considerations given the ongoing industry discussions relating to the role of the System Operator. In Scenario 2a, equity (of ISO shareholders) and debt is used to finance the cashflow costs. The use of equity may be required to avoid excessive gearing.

Scenario 2a

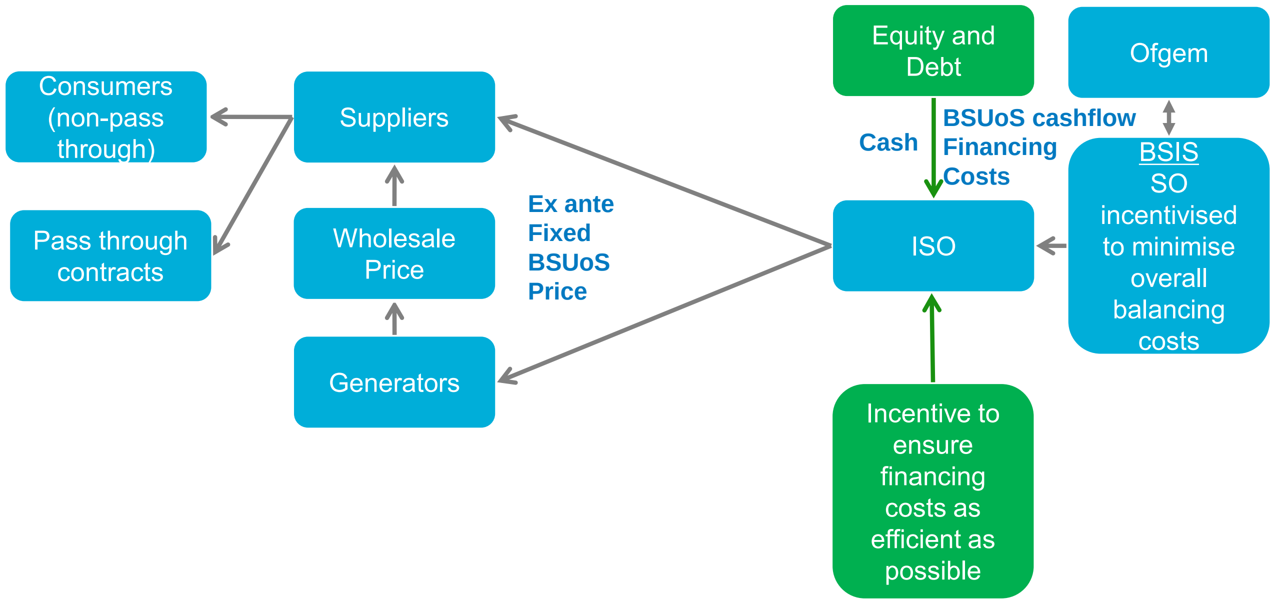


Figure 11: Scenario 2a

2.100 In Scenario 2b, the cashflow is only financed through debt. Given that an ISO would have next to no assets, the terms of any borrowing implications are unclear.

Scenario 2b

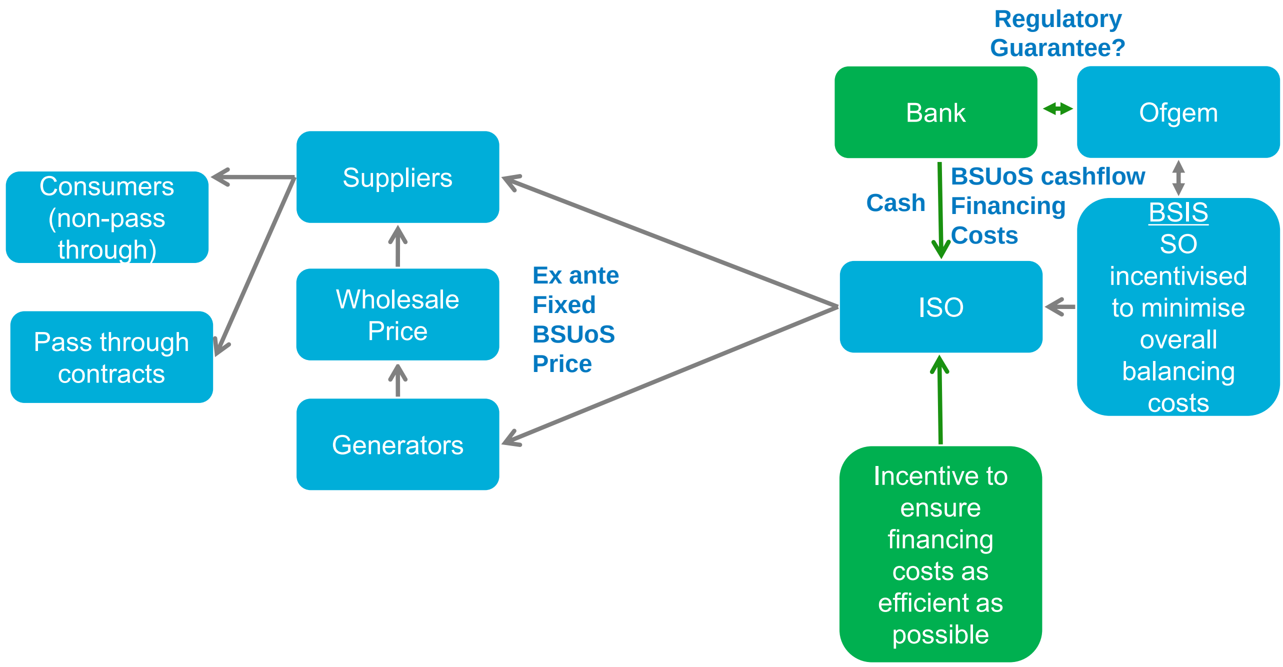


Figure 12: Scenario 2b

2.101 The Workgroup noted that "Regulatory Guarantee" means that the SO would be allowed to recover its costs i.e. a revenue guarantee rather than a financing guarantee.

2.102 Scenario 3 shows that market participants could form a consortium to put the finance in place to enable an ex ante BSUoS price:

Scenario 3

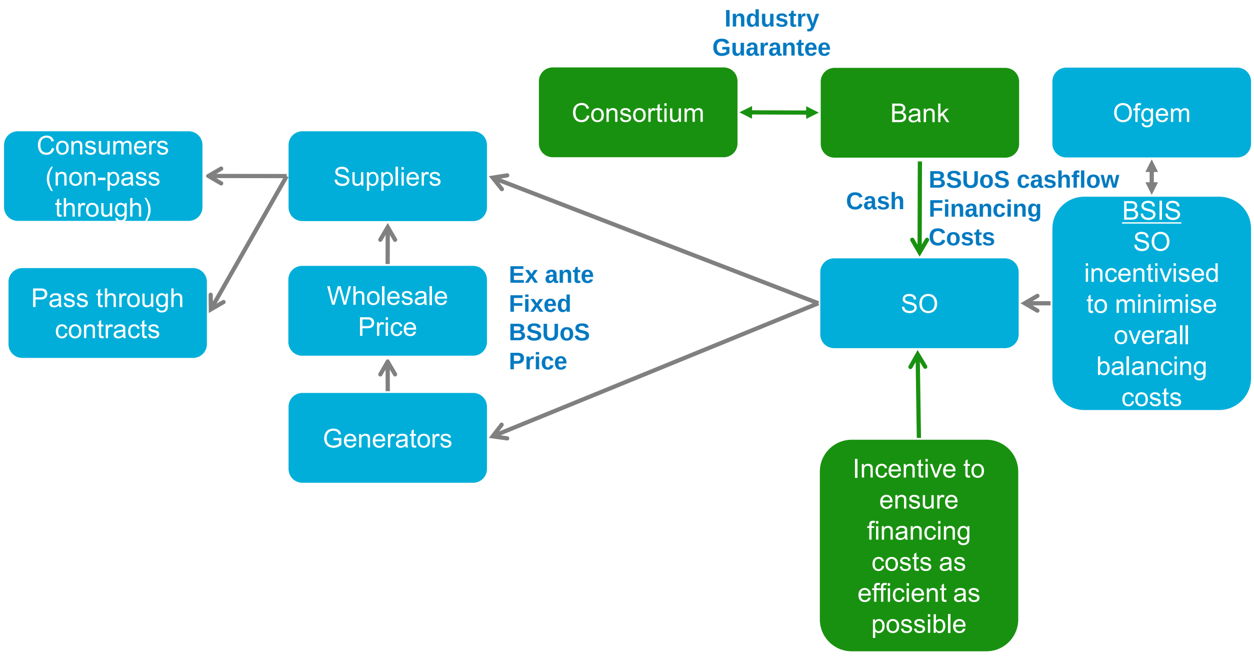


Figure 13: Scenario 3

2.103 Finally, Scenario 4 shows an option where all TOs collectively provide the financing. The rationale for this approach is that some Workgroup members considered that the entities with the lowest cost of capital should finance the cashflow risk as this represents the best deal for GB consumers. However, the cost of capital would have been different for these entities if this cashflow risk had been included, though as regulated entities, would still likely retain lower costs of capital than other market participants.

Scenario 4

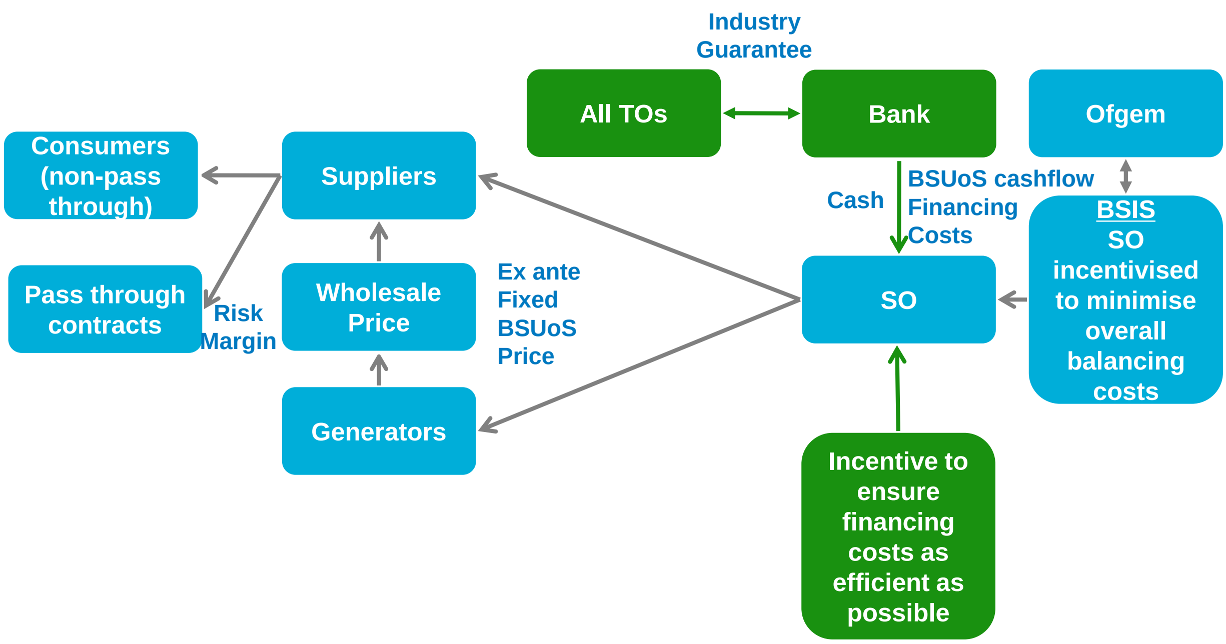


Figure 14: Scenario 4

2.104 The table on the following page summarises the advantages and disadvantages of each entity financing the cashflow costs (not the advantages and disadvantages of an ex ante BSUoS price managed by the SO).

Risk Owner	Scenario	Pros	Cons
Today		• No Funding issue for National Grid	• Market participants applying risk premia to manage unknown BSUoS costs ahead of time. • Consumers exposed to market participant cost of capital of between 8.2% and 11.5% according to the CMA – See Annex 5 (NGET nominal WACC is 7.5%)
National Grid as TSO (NGET Licence)	Scenario 1 - Financing costs (National Grid debt and equity) recovered though BSUoS	• Simplicity of one party financing the cashflow costs • Lower cost of capital	• Question around whether it is legal/ appropriate for the TSO to use its balance sheet to finance market participant costs.
ISO, still part of National Grid Group (but not NGET Licence)	2a – funded by National Grid debt and equity 2b – funded only by debt, backed by Regulatory guarantee	• Simplicity of one party financing the cashflow costs • ISO still has licence framework to recover costs • Potentially lower cost of capital due to regulatory guarantee/monopoly business	• SO doesn't own any assets therefore WACC potentially higher than for TSO.
Industry consortium	3 – Funded by debt, backed by industry guarantee	• Market participants continue to fund cashflow costs as today without the need to apply risk premia • Consortium borrowing rate lower than companies financing the cost individually	• Who owns the fund? Market share changes from year to year • More complex than one party doing it • Possible barrier to entry (further bureaucracy) • Administration costs • Higher cost of capital than regulated entity
TO consortium (including OFTOS, and Scottish TOs)	4 – Funded by TOs backed by an industry guarantee	• Consortium of TOs borrowing rate possibly lower than companies financing the cost individually	• TOs not financed for this purpose, therefore difficult to understand rationale for why they should finance this cost • National Grid TO would have the lion's share so why bother adding the complexity? • How would you divide contribution of shares (by RAV?) • More complex than one party doing it

Table 8: Advantages and disadvantages of each scenario

Workgroup Consultation Question: Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid, or is there another entity that should be considered? Please explain your reasoning.

Working Capital Financing Costs

2.105 Regardless of which entity is best placed to finance the cashflow to enable a fixed BSUoS price, there remains the issue of calculating how much this would cost, and how those costs are recovered. From National Grid's perspective broadly there are two options: on balance sheet options, and off balance sheet options

On National Grid Balance Sheet Options	Off National Grid Balance Sheet Options
Scenario 1: NGET Finance with equity and debt	Scenario 3: Debt Only Special Purpose Vehicle (SPV) – Loan facility
Scenario 2: Industry Finance by providing security up front	Scenario 4: Debt Only Special Purpose Vehicle (SPV) – Rolling credit facility
	Scenario 5: Partially capitalised SPV

Table 9: On National Grid balance sheet and off National Grid balance sheet options.

2.106 These options are described below:

1. In Option 1 NGET would finance the cost on balance sheet using equity and debt. The cost would be the maximum borrowing requirement * Rate of Return. It may also be appropriate to build in a within year incentive to ensure the principal sum is invested as efficiently as possible and a longer term incentive to ensure the principal sum is as small as possible. It is understood that this is the preferred approach in the Original Proposal.

2. In Option 2 NGET would finance the cost on balance sheet by first building up a surplus generated from a premium levied on each £/MWh until a sufficient credit has been built up to draw down when BSUoS costs are higher than the fixed price. The aim would be to target a surplus level so that NG shareholders' interests are not affected by the transfer of risk and there is no additional burden to the parent company's debt burden.

3. In Options 3, 4 and 5, SPVs are entities created for a specific, limited and normally temporary purpose. They are limited companies or partnerships to which debt is transferred. By transferring debt off balance sheet into an SPV, a company is able to isolate itself from any risk that the debt might pose. SPVs are often used in the securitisation of loans or other instruments. For example banks may issue a BSUoS backed security, the income from which is derived from repayments from a pool of market participants. The bank may wish to legally separate itself from the loans and does so by setting up an SPV and transferring the loans to it. This would allow BSUoS cashflow to be financed without affecting (NG) shareholders' interests or adding to the parent company's debt burden. The details of such a potential arrangement are currently under investigation.

2.107 While more precise costs are being calculated, it is not anticipated that the annual cost for any of the above options will exceed £20m per annum (0.07p/MWh) for a committed facility of £200m.

Workgroup Consultation Question: What is your view on the above cashflow financing approaches?

Workgroup Consultation Question: How important is fixing BSUoS to your organisation?

Workgroup Consultation Question: How much would you be willing to pay, if anything, in return for fixing BSUoS either 6 or 12 months in advance for a period of 12 months? Are you able to quantify this in £/MWh? i.e. a range of £0.06/MWh to £0.08/MWh for 6 months notice, and £0.07/MWh to £0.09/MWh for 12 months notice?

Recovery Mechanisms

2.108 It is anticipated that any expected cashflow costs will be recovered through a flat £/MWh charge. Any under or over recoveries for the given fixed period would be rolled over into the following period, and the new fixed price would be adjusted accordingly.

3 Workgroup Alternatives

3.1 At this point in time the Workgroup have not considered any formal alternative options to the Original Proposal. However, following the Workgroup Consultation, the Workgroup will consider responses and alternatives may be suggested.

4 Impact and Assessment

Impact on the CUSC

4.1 Changes to Section 14 BSUoS Charging Methodology

Impact on Greenhouse Gas Emissions

4.2 None identified.

Impact on Core Industry Documents

4.3 Potential licence change depending on funding approach

Impact on other Industry Documents

4.4 None identified.

5 Proposed Implementation and Transition

5.1 The Workgroup suggest implementation into the CUSC on 1st April 2017 , this would mean the notification of a fixed price would be given on the 1st April 2017 and that fixed price would commence on the 1st April 2018 for a period of 6 months ending 30th September 2018.

6 Responses

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 CMP250 Original proposal or either of the potential options for change better facilitates 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: Do you agree Balancing Services Use of System Charges are becoming more volatile?

Q6: Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.

Q7: Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?

Q8: Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years**.** Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.

Q9: Do you believe BSUoS is a useful price signal?

Q10: If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.

Q11: What are your thoughts on notification lead times and the length of the price fix period?

Q12: What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?

Q13: Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?

Q14: If applicable, are you able to share your approach to calculating risk premia?

Q15: Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.

Q16: What is your view on the above cashflow financing approaches?

Q17: What would you regard as good value to enable a fixed BSUoS price?

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/CMP250/

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 14th April 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 – CMP250 CUSC Modification Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP250

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Stabilising BSUoS with at least a twelve month notification period

Submission Date

19/08/15

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

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.

Generators seek to recover the cost of BSUoS from prices available in the wholesale market. In effect the cost of BSUoS is one component of a generator's Short Run Marginal Cost (SRMC). Unfortunately, the cost of BSUoS is only known ex-post once values are published by the SO, so a generator can only estimate the cost of BSUoS. This has not been particularly problematic in the past as the cost of BSUoS was relatively stable. However, with a fast evolving generation mix, specifically the rapid increase in intermittent renewable generation, the costs of balancing the system are increasing and becoming much more volatile between settlement periods. This impact will persist and intensify with the drive to meet government environmental targets.

The lack of certainty ahead of time and increasing volatility is making it increasingly difficult for generators to estimate the cost of BSUoS. This unpredictability leads to two clear problems:

1. If the generator underestimates the cost of BSUoS there is a risk that the generator could sell power at a loss.
2. If the generator overestimates the cost of BSUoS it could result in the generator pricing itself out of the wholesale market.

Ultimately, increased volatility and unpredictability ahead of time can result in increasing risk premiums being applied by generators to their power and ancillary service sales. Where this is uniformly applied, it will result in an increased cost to the consumer.

Suppliers (and some generators) commit to power sales seasons in advance to match the length of customer contracts. Suppliers need to estimate the cost of BSUoS over the length of the customer contract. Suppliers may add a risk premium to their estimate of BSUoS, as underestimating BSUoS could result in loss making contracts owing to current low profit margins prevalent in the market. However, overestimating BSUoS could make a supplier uncompetitive in the retail market and thus damage its competitive position, reducing profitability. Again, where risk premiums are applied uniformly in the retail market, the cost will ultimately be borne by the end consumer.

The defect this modification seeks to address is that industry parties have no real certainty of their BSUoS costs when forward contracting their power. This is directly caused by the current BSUoS charging methodology that produces a highly volatile and unpredictable cost. This modification allows parties to know ahead of time what their BSUoS charge will be, and to reallocate this risk from those parties that are poorly placed to manage the risk, in particular smaller market participants, to a party that is better suited to deal with it thereby better facilitating Applicable CUSC Charging Objective (a). Consequently, the total risk premium, and therefore total cost of BSUoS recovered from end consumers, will decrease, thereby increasing competition throughout the industry and benefiting consumers through lower costs and increased certainty surrounding their energy bills.

Description of the CUSC Modification Proposal

The best way to reduce the risk premia applied by market participants is to eliminate BSUoS volatility and unpredictability. We initially propose this be achieved by fixing the value of BSUoS over the course of a season (April – September, October – March). The length of the fix (initially suggested as a season) and the profile of how this is set is open to discussion by the workgroup. A notification period of at least 12 months ahead of the charging season should be introduced. A Working Group should evaluate the optimum notification period. The within season risk of over and under recovery of BSUoS revenues will be borne by the SO. This risk could be outsourced to a party with a large credit portfolio to appropriately manage the risk (e.g. a financial institution). The proposal transfers the forecasting risk from suppliers and generators to the SO. We consider this to be appropriate as the risk will be better managed by a regulated business with a better credit rating and lower cost of capital to fund. Further, the SO are already well placed to handle this responsibility as they have the resources and experience surrounding BSUoS and will be able to calculate and communicate the over/under recoveries to the rest of the industry.

BSUoS under/over recoveries would be redistributed through a higher/lower charge respectively in a charging season 12 months, or the length of the notification period, after the initial under/over recovery. For example, an under recovery in summer of the 15/16 charging year could be reflected in a higher BSUoS charge winter of the 16/17 charging year. The exact under/over arrangements should be determined by the Working Group.

Further, the current half hourly settlement of BSUoS should still be published in the spirit of openness and transparency. The publication of the cost of half hourly periods would allow the industry to better predict future BSUoS costs and allows for better transparency as to what has transpired.

Impact on the CUSC

Changes to section 14.

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No
No
Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information
BSC ☐ **Grid Code** ☐ **STC** ☐ **Other** ☒ BSIS It is possible that Ofgem may review some of the parameters in the RIIO-T1 price control to ensure that the SO can efficiently finance them given the need to stabilise revenues collected by BSUoS at least 12 months ahead. This may result in a need to change the Transmission Licence (subject to consultation). A specific BSUoS incentive scheme (which may include an incentive to minimise BSUoS over/under recovery) may be necessary. A possible impact on SO incentive scheme may also need to be considered. Documentation relating to BSUoS forecasting will need to be updated – potentially supplementing the CMP208 solution.
Urgency Recommended: Yes / No
No
Justification for Urgency Recommendation
N/A
Self-Governance Recommended: Yes / No
No

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:

There will be an impact on computer systems used by CUSC parties and possibly a large impact to the SO's computer systems.

Details of any Related Modification to Other Industry Codes

N/A

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

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

Use of System Charging Methodology

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

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

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

☐ (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under

Standard Condition C10, paragraph 1. *Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).* **Full justification:** Both suppliers and generators often sell power months or years ahead meaning a volatile and unpredictable BSUoS charge creates a financial risk which is ultimately passed onto the consumer. Fixing the BSUoS charge ahead of time and moving the risk onto a party that is more financially capable of dealing with it means suppliers and generators will be able to price their power more competitively, thereby better facilitating Applicable CUSC Objectives (charging) (a). Further, reducing the risk will facilitate market entry thereby further increasing competition.

Additional details

Details of Proposer: (Organisation Name)	Drax Power Limited
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	 Cem Suleyman Drax Power Limited 01757 612338 cem.suleyman@drax.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	 Joseph Underwood Drax Power Limited 01757 612736 joseph.underwood@drax.com
Attachments (Yes/No): No. **If Yes, Title and No. of pages of each Attachment:**	

Contact Us

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

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

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

Submitting the Proposal

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

Jade Clarke
CUSC Modifications Panel Secretary, TNS
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 – CMP250 Terms of Reference

nationalgrid

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP250 WORKGROUP

CMP250 aims to eliminate BSUoS volatility and unpredictability by proposing to fix the value of BSUoS over the course of a season, with a notice period for fixing this value being at least 12 months ahead of the charging season.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP250 'Stabilising BSUoS with at least a twelve month notice period'** tabled by Drax Power at the CUSC Modifications Panel meeting on 28th August 2015.

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 (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 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.

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) *Implementation*
   b) *Review draft legal text*
   c) *Consider who picks up the costs of transferring the risk.*
   d) *Consider whether transferring the risk has a consumer benefit*
   e) *Can CMP250 be applied with an independent SO?*
   f) *Technical and commercial implementation for customers*
   g) *Consider effect of charging volatility/ predictability/ HH/ Day ahead/Year ahead/*
   h) *Minimum notification period required to make a material difference*

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 3 weeks as determined by the Modifications Panel.

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

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

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on 21st July 2016 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 29th July 2016.

Membership

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

Role	Name	Representing
Chairman	Nikki Jamieson	Code Administrator
*National Grid Representative**	Nick Pittarello	National Grid
*Industry Representatives**	Garth Graham	SSE
	Jon Wisdom	Npower
	Peter Bolitho	Waters Wye
	Lee Taylor	GDF Suez
	Christopher Granby	Infinis
	Cem Suleyman (proposer)	Drax Power
	Paul Jones	EON
	Binoy Dharsi	EDF
	James Anderson	Scottish Power
Authority Representatives	Donald Smith	Ofgem
Technical secretary	Heena Chauhan	Code Administrator
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 CMP250 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

The following timetable is indicative for CMP250

7TH September 2015	Deadline for comments on Terms of Reference / nominations for Workgroup membership
7th October 2015	Workgroup meeting 1
20th October 2015	Workgroup meeting 2
2nd November 2015	Workgroup meeting 3
3rd December 2015	Workgroup meeting 4
19th January 2016	Workgroup meeting 5
29th February 2016	Workgroup meeting 6
7th March 2016	Workgroup Consultation issued for 1 week Workgroup comment
14th March	Deadline for comment
15th March 2016	Workgroup Consultation published (for 20 working days)
14th April 2016	Deadline for responses
w/c 18th April 2016	Workgroup meeting 7 (Review consultation comments)
w/c 2nd May 2016	Workgroup meeting 8 (Workgroup vote)
5th May 2016	Circulate draft Workgroup Report

12th May 2016	Deadline for comment
19th May 2016	Submit final Workgroup Report to Panel
27th May 2016	Present Workgroup Report at CUSC Modifications Panel

Post Workgroup modification process

31st May 2016	Code-Administrator Consultation published (15days)
21st June 2016	Deadline for responses
27th June 2016	Draft FMR published
4th July 2016	Deadline for comments
21st July 2016	Draft FMR issued to CUSC Panel
29th July 2016	CUSC Panel Recommendation vote
12th August 2016	Final CUSC Modification Report submitted to Authority

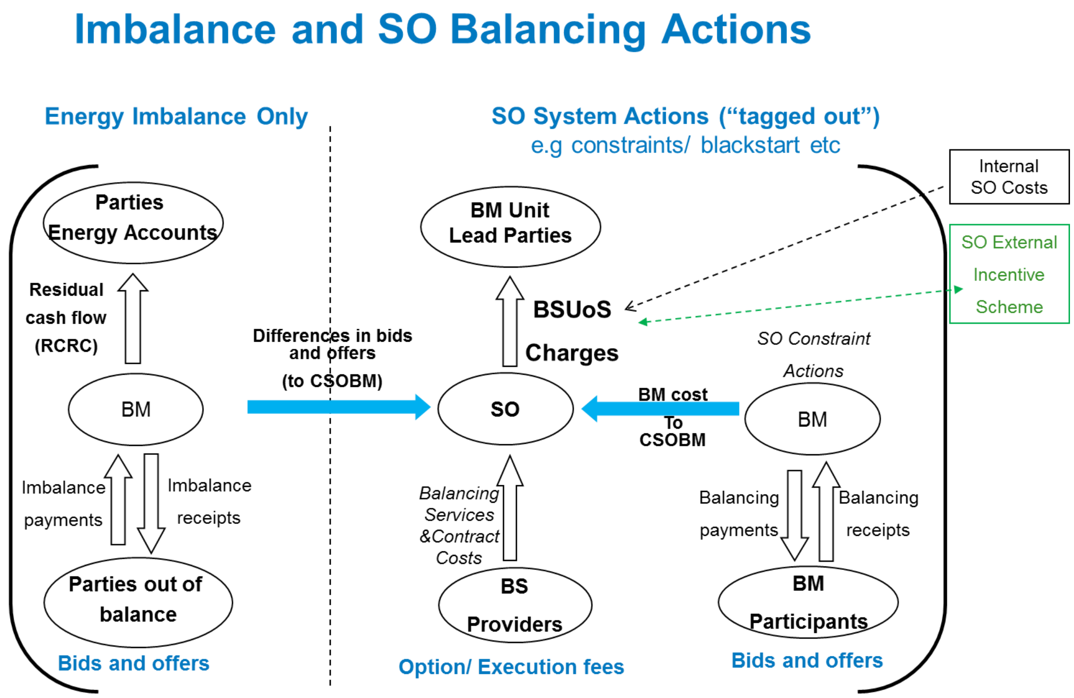
Annex 3 – Workgroup attendance register

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

Name	Organisation	Role	7th Oct 2015	20th Oct 2015	2nd Nov 2015	3rd Dec 2015	19th Jan 2016	29th Feb 2016
Nikki Jamieson (Pat Hynes for first meeting and John Martin alternate)	National Grid	Chair	O (Pat Hynes)	A	O	A	A	D
Heena Chauhan (Alternate is Jade Clarke)	National Grid	Technical Secretary	A	A	A	A	A	O D
Cem Suleyman	Drax Power	Proposer	A	A	A	A	A	D
Nick Pittarello	National Grid	Workgroup member	A	A	A	A	A	D
Jonathan Wisdom	N Power	Workgroup member	A	A	A	A	A	D
Garth Graham (Alternate is John Tindall)	SSE	Workgroup member	A	A	D	X	O D	O D
Peter Bolitho	Waters Wye	Workgroup member	A	A	A	A	A	D
Lee Taylor	GDF Suez	Workgroup	A	X	D	A	O D	D

(Alternate is Simon Lord)		member						
Paul Jones (Alternate is Guy Phillips)	EON	Workgroup member	A	X	X	A	A	O D
Binoy Dharsi (Alternate is Simon Vicary)	EDF Energy	Workgroup member	A	A	O	A	A	D
James Anderson	Scottish Power	Workgroup member	A	A	A`	D	A	D
Christopher Granby	Infinis	Workgroup member	A	X	X	X	D	D
Donald Smith	Ofgem	Authority Representative	D	A	A	X	A	D

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.



Balancing Services Use of System Charges are made up of a number of component parts, but they fall into two camps, either those costs relating purely to energy imbalance – whether the market is long or short, and those costs relating to actions taken by the SO for resolving constraints and maintaining system integrity – holding reserve generation, voltage control, and black start.

Looking at energy imbalance, any costs incurred by the SO to resolve energy imbalance become part of CSOBM (Costs to the SO taken in the BM). However any imbalance payments made by out of balance market participants are redistributed across all market participants.

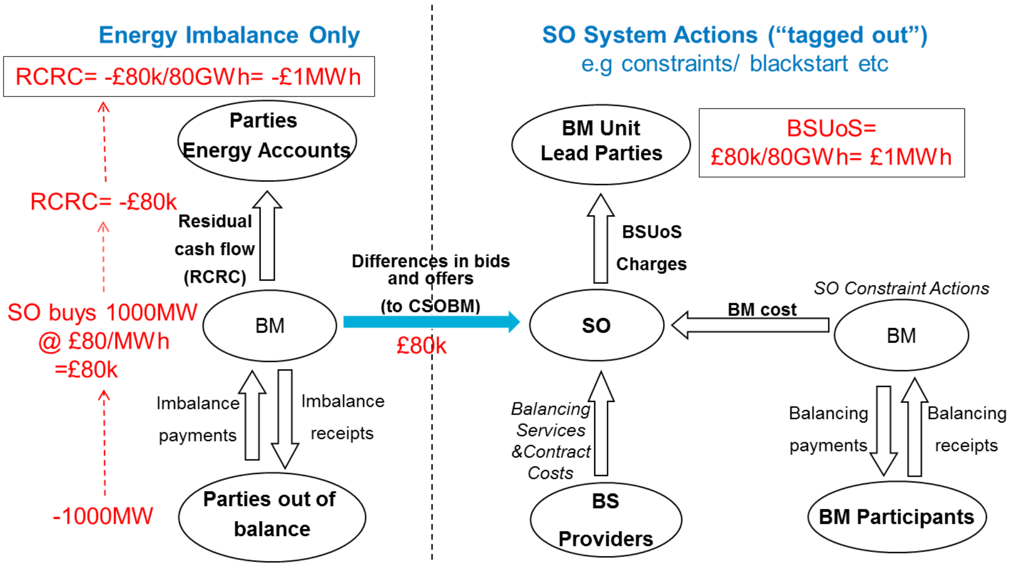
The SO may also take actions in the BM to resolve constraints, reducing output from power stations behind constrained boundaries and replacing that energy in zones not affected by that constraint. This costs money and these costs feed through to CSOBM.

Finally, the SO also signs contracts with parties to provide specific services, and these option and execution fees are apportioned across relevant settlement periods.

BSUoS charges also include internal SO costs – which would include our control rooms and my salary, and an external incentive scheme also known as BSIS (Balancing Services Incentive Scheme) where National Grid is incentivised to keep costs to a minimum. The current scheme has a 30% sharing factor, so for every £1 saved against the target price, £0.70 is shared with industry, up to a cap of £30m either way.

Example 1 – Simple Imbalance

- Supplier under-contracted by 1000MW (SO incurs £80k,Supplier pays £80k)
- Total demand for the half hour = 80GWh, SBP £80/MWh

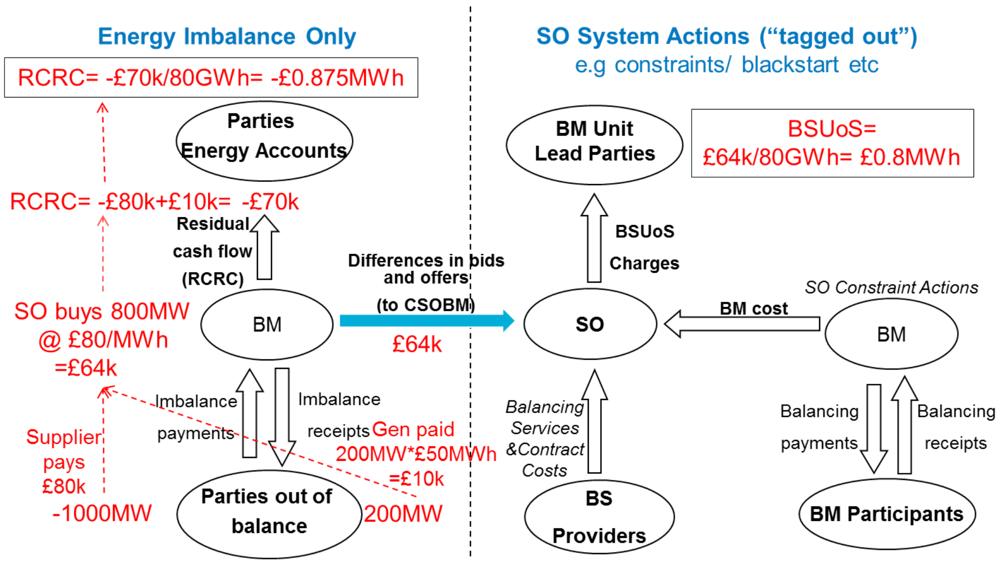


RCRC and BSUoS net to zero, 3rd parties not exposed

The following slides explain some simple scenarios. In this example we have a supplier under-contracted by 1000MW. The SO would need to resolve that imbalance and would buy 1000MW in the market at £80/MWh and incur a cost of £80k. The Supplier would pay an imbalance payment of £80k and this would go into the RCRC pot. RCRC would then be -£1/MWh. Similarly, if this was the only action that the SO had taken, market participants would be charged £1/MWh. So clearly the two net to zero, and only the out of balance supplier forks out. This acts as an incentive for market participants to balance their positions.

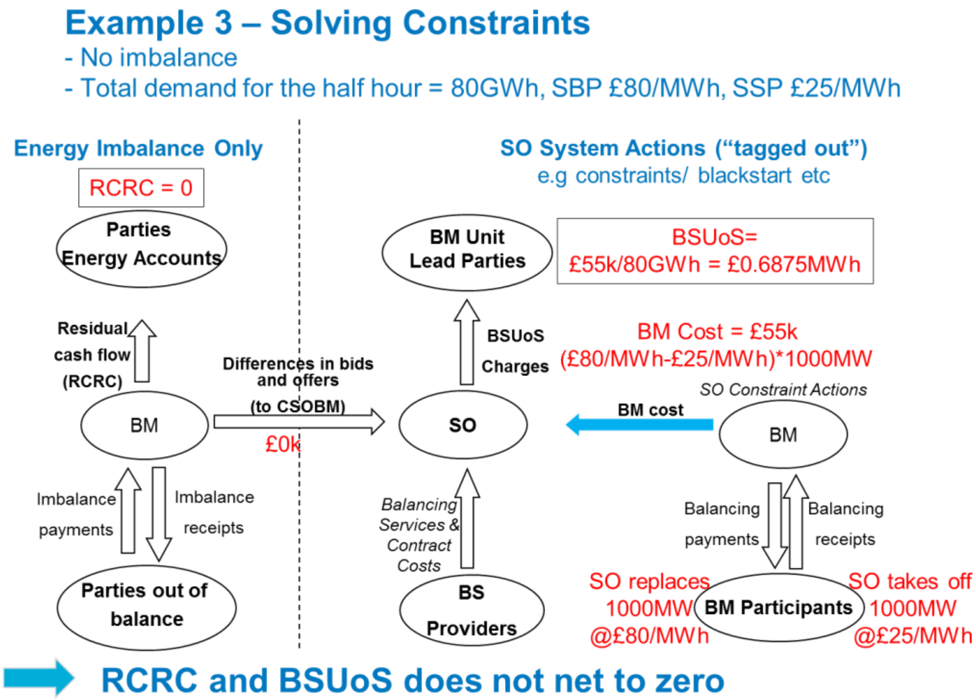
Example 2 – Dual Imbalance

- Supplier under-contracted by 1000MW, Generator spills 200MW
- Total demand for the half hour = 80GWh, SBP £80/MWh, SSP £50/MWh



RCRC and BSUoS are not related

If a party is now added that is spilling onto the system, they would be cashed out at SSP (System Sell Price), in this example £50/MWh and receive £10k. Combined with the £80k of our out of balance Supplier, the RCRC pot would be a bit lower at £70k. The SO however would only need to procure 800MW and would spend £64k in the BM. In this case, RCRC and BSUoS are not the same and do not net-off.



Finally, in this example, there is perfect energy balance, but the SO needs to resolve a constraint. With RCRC equal to zero as there is no energy imbalance, the BSUoS charge is the cost of resolving the constraint.

Appendix 10.4: Cost of capital

Contents

Page

Introduction

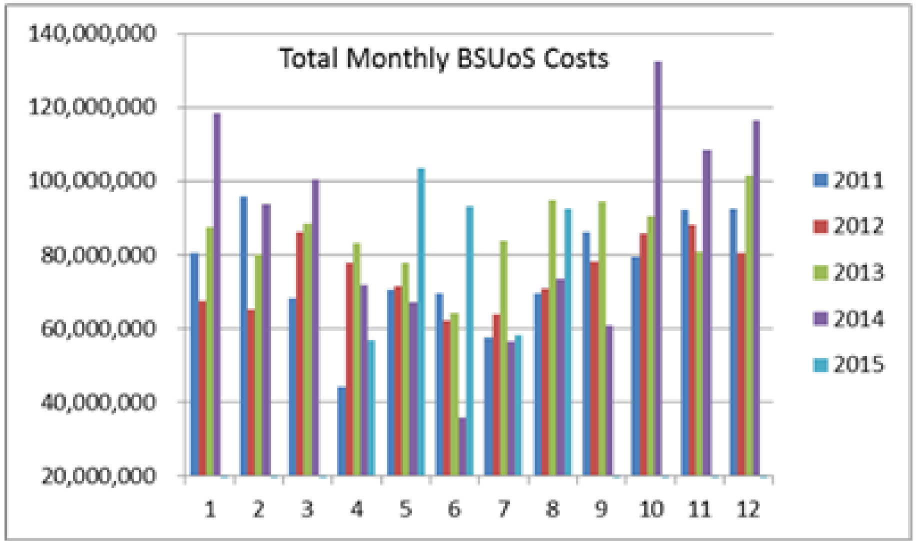
1. The approach to assessing profitability, as set out in the Guidelines,[1] is to compare the profits earned with an appropriate cost of capital. In this appendix, we set out our estimate of the nominal pre-tax weighted average cost of capital (WACC) for the various elements of the energy value chain in Great Britain (GB), based on data for the period January 2007 to March 2014.

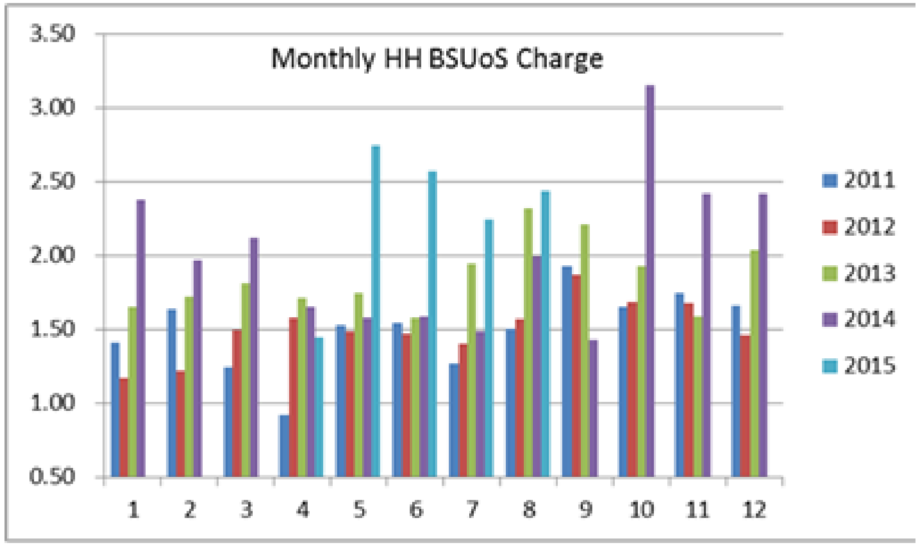
2. Our estimate of the WACC of a stand-alone electricity generator is between 8.2 and 10.0%, while a retail supply business would be entirely equity funded with a cost of equity of 9.3 to 11.5%.

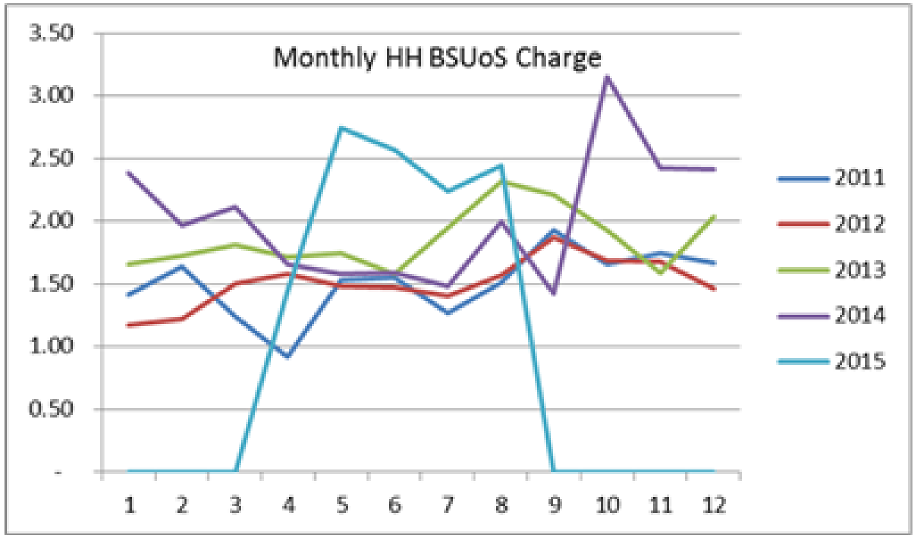
Table 1: CMA estimates of the WACC for the elements of the energy value chain

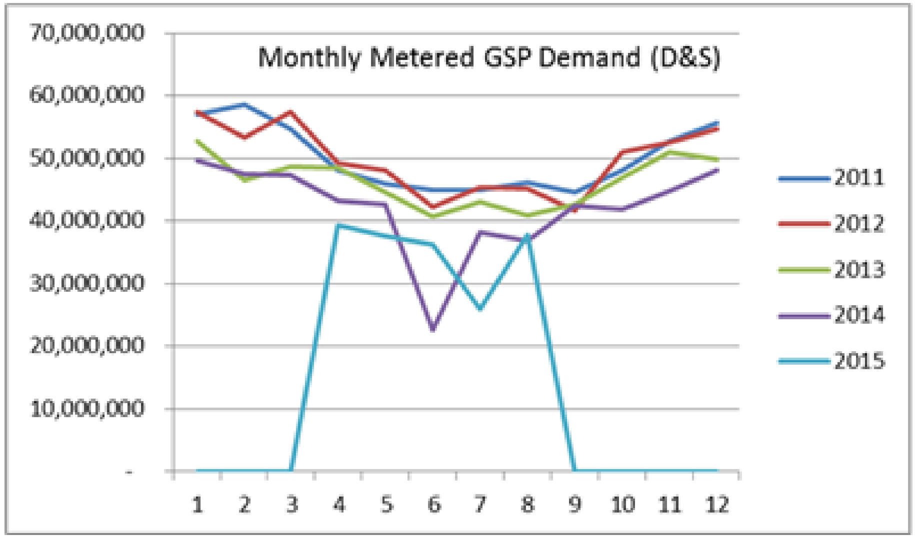
		Retail supply
Generation		
Real risk-free rate (%)	1.0	1.0
Nominal risk-free rate (%)	4.0	4.0
Equity risk premium (%)	4.0–5.5	4.0–5.5
Asset beta	0.5–0.6	0.7–0.8
Pre-tax Ke (%)	9.1–10.4	9.3–11.5
Pre-tax cost of debt (Kd) (%)	6.0–7.0	-
Gearing (%)	10.0–30.0	0
Tax rate (%)	27.0	27.0
Pre-tax WACC (%)	**8.2–10.0**	**9.3–11.5**

Annex 6 – Monthly BSUoS charts 2011-2015

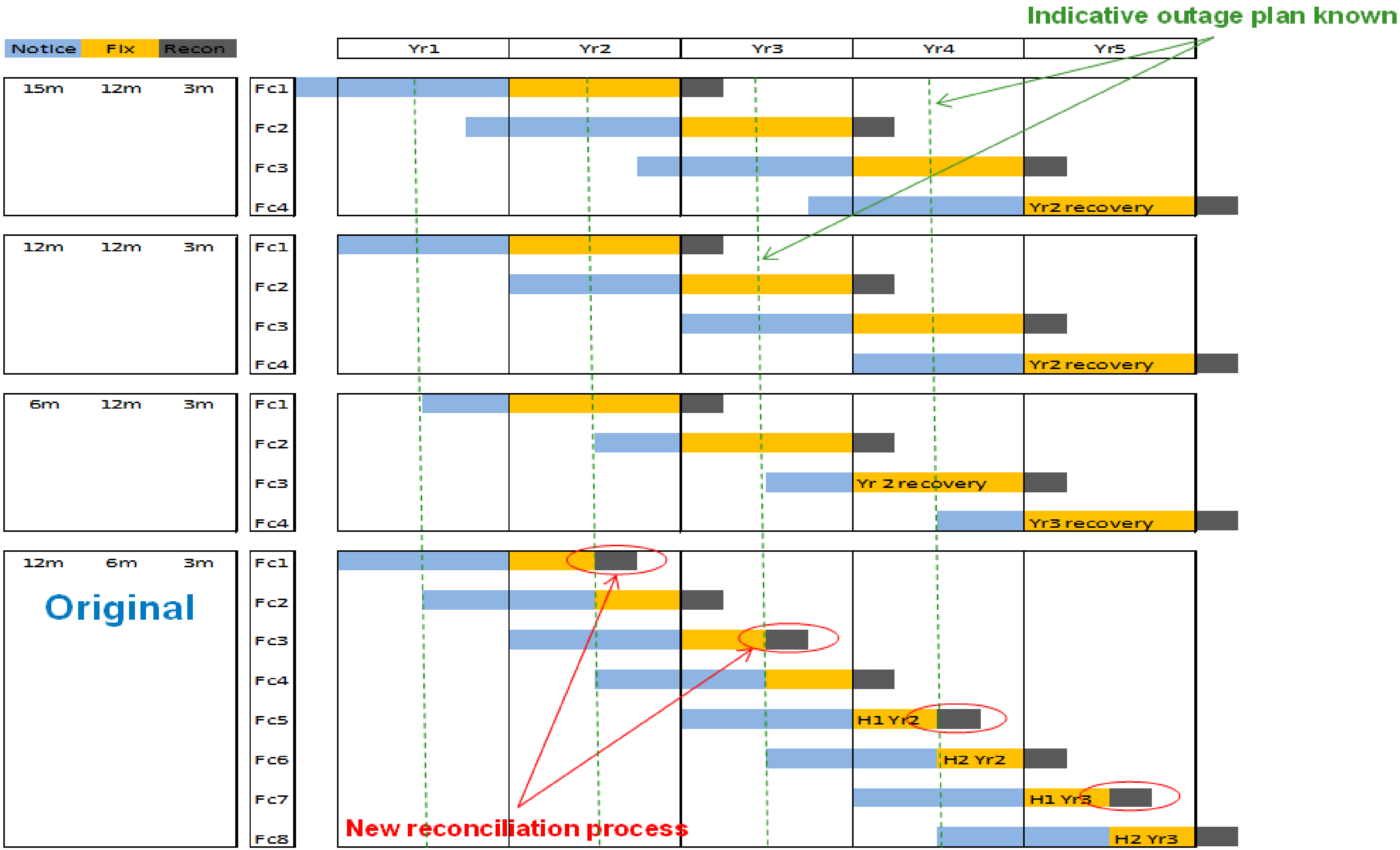






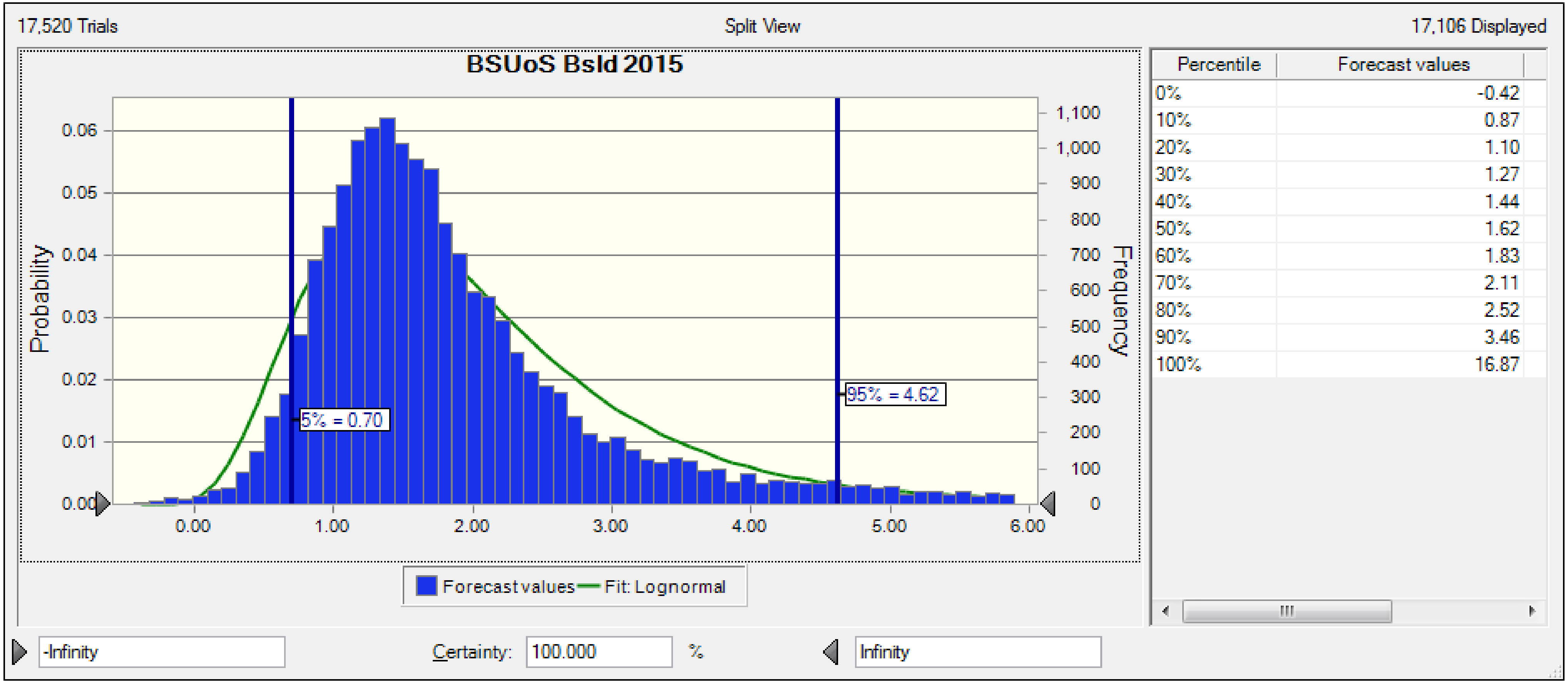


Annex 7 – Interaction between notification and fixed price time periods

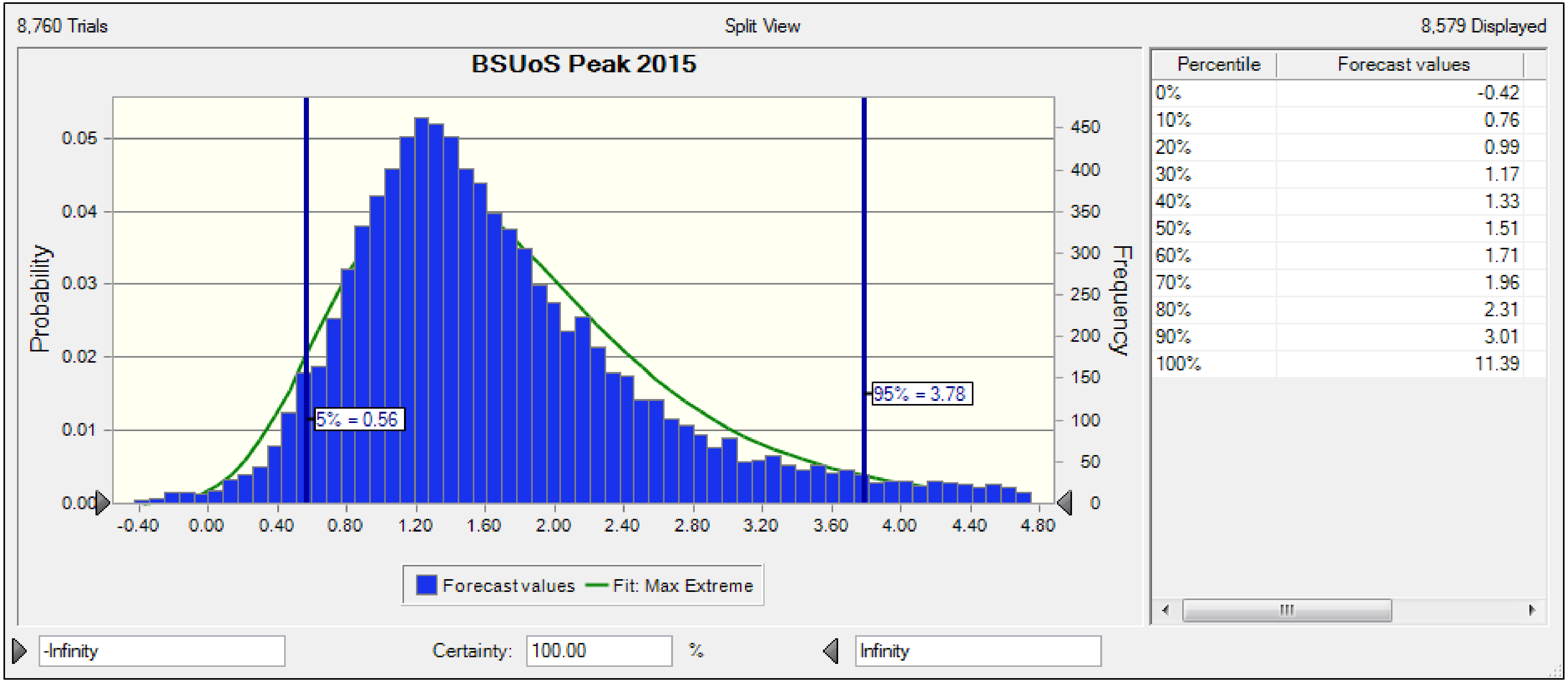


Annex 8 – Generation and Supply BSUoS risk premium analysis

(i) BSUoS Distribution for Baseload trading period in 2014/15



(ii) BSUoS Distribution for Peak trading period in 2014/15



(iii) BSUoS Distributions

2011/12 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.58	0.84	1.02	1.20	1.37	1.55	1.77	2.08	2.54	2.99	6.97
Extended Peak	0.60	0.85	1.04	1.22	1.38	1.55	1.77	2.05	2.50	2.94	6.97
Block 5	0.50	0.77	0.97	1.17	1.34	1.55	1.77	2.11	2.66	3.06	6.65
Baseload	0.60	0.85	1.04	1.22	1.39	1.57	1.78	2.08	2.60	3.13	10.65

2012/13 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.51	0.75	0.94	1.11	1.29	1.49	1.73	2.01	2.46	2.91	6.64
Extended Peak	0.55	0.79	0.98	1.14	1.32	1.51	1.73	2.00	2.45	2.88	7.29
Block 5	0.42	0.69	0.89	1.07	1.25	1.48	1.76	2.12	2.60	3.15	6.64
Baseload	0.62	0.86	1.05	1.21	1.39	1.58	1.80	2.06	2.50	2.96	8.56

2013/14 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.66	0.96	1.20	1.42	1.64	1.86	2.12	2.48	3.02	3.59	9.56
Extended Peak	0.73	1.02	1.25	1.45	1.66	1.87	2.13	2.47	3.00	3.57	9.56
Block 5	0.60	0.92	1.15	1.38	1.64	1.89	2.21	2.58	3.14	3.73	9.10
Baseload	0.78	1.07	1.29	1.49	1.69	1.91	2.17	2.51	3.08	3.72	9.56

2014/15 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.76	0.99	1.17	1.33	1.51	1.71	1.96	2.31	3.01	3.78	11.39
Extended Peak	0.81	1.05	1.22	1.38	1.55	1.75	1.99	2.34	3.00	3.75	11.39
Block 5	0.78	1.02	1.20	1.38	1.57	1.77	2.07	2.47	3.20	3.98	9.41
Baseload	0.87	1.10	1.27	1.44	1.62	1.83	2.11	2.52	3.46	4.62	16.87

2015/16 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.56	0.93	1.18	1.41	1.62	1.87	2.19	2.64	3.38	4.13	11.57
Extended Peak	0.66	0.99	1.24	1.46	1.67	1.93	2.24	2.67	3.39	4.11	11.57
Block 5	0.53	0.90	1.15	1.40	1.62	1.88	2.19	2.62	3.36	4.00	9.33
Baseload	0.77	1.10	1.36	1.58	1.83	2.12	2.50	3.04	4.01	5.38	11.57

(iv) BSUoS premiums and discounts compared to outturn BSUoS

2011/12 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-0.91	-0.65	-0.47	-0.29	-0.12	0.06	0.28	0.59	1.05	1.50	5.48
Extended Peak	-0.88	-0.63	-0.44	-0.26	-0.10	0.07	0.29	0.57	1.02	1.46	5.49
Block 5	-0.98	-0.71	-0.51	-0.31	-0.14	0.07	0.29	0.63	1.18	1.58	5.17
Baseload	-0.92	-0.67	-0.48	-0.30	-0.13	0.05	0.26	0.56	1.08	1.61	9.13

2012/13 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	80	P90	P95	P100
Peak	-0.90	-0.66	-0.47	-0.30	-0.12	0.08	0.32	0.60	1.05	1.50	5.23
Extended Peak	-0.88	-0.64	-0.45	-0.29	-0.11	0.08	0.30	0.57	1.02	1.45	5.86
Block 5	-1.00	-0.73	-0.53	-0.35	-0.17	0.06	0.34	0.70	1.18	1.73	5.22
Baseload	-0.88	-0.64	-0.45	-0.29	-0.11	0.08	0.30	0.56	1.00	1.46	7.06

2013/14 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-1.12	-0.82	-0.58	-0.36	-0.14	0.08	0.34	0.70	1.24	1.81	7.78
Extended Peak	-1.06	-0.77	-0.54	-0.34	-0.13	0.08	0.34	0.68	1.21	1.78	7.77
Block 5	-1.19	-0.87	-0.64	-0.41	-0.15	0.10	0.42	0.79	1.35	1.94	7.31
Baseload	-1.07	-0.78	-0.56	-0.36	-0.16	0.06	0.32	0.66	1.23	1.87	7.71

2014/15 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-0.99	-0.76	-0.58	-0.42	-0.24	-0.04	0.21	0.56	1.26	2.03	9.64
Extended Peak	-0.97	-0.73	-0.56	-0.40	-0.23	-0.03	0.21	0.56	1.22	1.97	9.61
Block 5	-1.04	-0.80	-0.62	-0.44	-0.25	-0.05	0.25	0.65	1.38	2.16	7.59
Baseload	-1.11	-0.88	-0.71	-0.54	-0.36	-0.15	0.13	0.54	1.48	2.64	14.89

2015/16 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-1.29	-0.92	-0.67	-0.44	-0.23	0.02	0.34	0.79	1.53	2.28	9.72
Extended Peak	-1.23	-0.90	-0.65	-0.43	-0.22	0.04	0.35	0.78	1.50	2.22	9.68
Block 5	-1.29	-0.92	-0.67	-0.42	-0.20	0.06	0.37	0.80	1.54	2.18	7.51
Baseload	-1.42	-1.09	-0.83	-0.61	-0.36	-0.07	0.31	0.85	1.82	3.19	9.38

(v) Outturn BSUoS

Average BSUoS Outturns (£/MWh)	2011/12	2012/13	2013/14	2014/15	2015/16
Peak	1.49	1.41	1.78	1.75	1.85
Extended Peak	1.48	1.43	1.79	1.78	1.89
Block 5	1.48	1.42	1.79	1.82	1.82
Baseload	1.52	1.50	1.85	1.98	2.19

(vi) Total system costs – under or over recovery

2011/12 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	298)	(213)	(154)	(95)	(39)	20	92	193	344	491	1,794
Extended Peak	(386)	(277)	(194)	(116)	(46)	28	124	247	443	635	2,394
Block 5	(106)	(77)	(55)	(33)	(15)	8	32	69	129	173	565
Baseload	(603)	(440)	(315)	(197)	(86)	32	169	366	706	1,053	5,976

2012/13 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(298)	(219)	(156)	(100)	(40)	26	105	198	347	495	1,729
Extended Peak	(387)	(281)	(197)	(127)	(47)	37	134	253	451	641	2,586
Block 5	(110)	(81)	(59)	(39)	(19)	6	37	77	130	191	575
Baseload	(583)	(425)	(299)	(193)	(74)	52	197	369	660	965	4,669

2013/14 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(355)	(260)	(183)	(113)	(43)	27	110	225	397	578	2,481
Extended Peak	(452)	(329)	(231)	(146)	(57)	32	143	287	512	755	3,300
Block 5	(126)	(92)	(68)	(43)	(16)	11	45	84	144	206	777
Baseload	(685)	(500)	(360)	(233)	(105)	35	201	418	781	1,189	4,911

2014/15 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(307)	(236)	(180)	(130)	(74)	(11)	67	176	394	633	3,004
Extended Peak	(403)	(303)	(233)	(166)	(95)	(12)	87	233	507	818	3,991
Block 5	(108)	(83)	(65)	(46)	(26)	(6)	26	67	143	224	788
Baseload	(692)	(548)	(443)	(337)	(224)	(94)	81	336	922	1,644	9,275

2015/16 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(386)	(275)	(200)	(131)	(68)	7	103	238	460	685	2,917
Extended Peak	(493)	(361)	(261)	(173)	(89)	15	139	311	599	887	3,871
Block 5	(129)	(92)	(67)	(42)	(20)	6	37	80	54	218	751
Baseload	(854)	(656)	(500)	(368)	(218)	(44)	184	508	1,090	1,912	5,626