ASSESSMENT REPORT for Modification Proposal P211

'Main Imbalance Price based on an Ex-post Unconstrained Schedule'

Prepared by: P211 Modification Group

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This document has been distributed in accordance with Section F2.1.10 of the Balancing and Settlement Code.[1]

Proposed Modification P211 seeks to amend the calculation of the "main" imbalance price such that when the market is short (NIV>0), System Buy Price (SBP) will be based on the least expensive Offers that the System Operator (SO) could have utilised on an unconstrained system. Conversely, when the market is long (NIV<0), System Sell Price (SSP) will be based on the least expensive Bids that the SO could have utilised on an unconstrained system. PAR Tagging would then be applied to the new Ex-Post Unconstrained Schedule (EPUS) price stack to ensure that only the most expensive 500 MWh of Bids or Offers are used to set the main price. The 'reverse' price would remain unchanged.

A **Potential Alternative Modification** was developed by the Modification Group. However the majority of the Group did not believe that this would better facilitate the Applicable BSC Objectives when compared to the Proposed Modification and thus has not put it forward as an Alternative Modification for consideration by the Panel. This potential Alternative was the same as the Proposed Modification described above but also used spot values and dynamic parameters to modify the Bid and Offer volumes that make up the EPUS stack. The aim of this potential Alternative was to better reflect the Bid and Offer volumes that the SO could have utilised to resolve energy imbalances.

MODIFICATION GROUP'S RECOMMENDATIONS

The P211 Modification Group invites the Panel to:

- **AGREE a provisional recommendation that Proposed Modification P211 should not be made;**
- **NOTE that the Modification Group developed a potential Alternative Modification but agreed by majority that this did not better facilitate the Applicable BSC Objectives when compared to the Proposed Modification;**
- **AGREE a provisional Implementation Date for Proposed Modification P211 of 6 November 2008 if an Authority decision is received on or before 28 February 2008, or 25 June 2009 if the Authority decision is received after 28 February 2008 but on or before 16 October 2008;**
- **AGREE the draft legal text for Proposed Modification P211;**
- **AGREE that Modification Proposal P211 be submitted to the Report Phase; and**
- **AGREE that the P211 draft Modification Report be issued for consultation and submitted to the Panel for consideration at its meeting of 11 October 2007.**

[1] The current version of the Code can be found at http://www.elexon.co.uk/bscrelateddocs/BSC/default.aspx.

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SUMMARY OF IMPACTED PARTIES AND DOCUMENTS

As far as the Modification Group has been able to assess, the following parties/documents would be impacted by P211.

Please note that this table represents a summary of the full impact assessment results contained in Appendix 4.

Parties	
Distribution System Operators	☐
Generators	☒
Interconnectors	☒
Licence Exemptable Generators	☒
Non-Physical Traders	☒
Suppliers	☒
Transmission Company	☒
Party Agents	
Data Aggregators	☐
Data Collectors	☐
Meter Administrators	☐
Meter Operator Agents	☐
ECVNA	☐
MVRNA	☐
BSC Agents	
SAA	☒
FAA	☐
BMRA	☒
ECVAA	☐
CDCA	☐
TAA	☐
CRA	☐
SVAA	☐
Teleswitch Agent	☐
BSC Auditor	☐
Profile Administrator	☐
Certification Agent	☐
Other Agents	
Supplier Meter Registration Agent	☐
Unmetered Supplies Operator	☐
Data Transfer Service Provider	☐

Sections of the BSC	
A	☐
B	☐
C	☐
D	☐
E	☐
F	☐
G	☐
H	☐
I	☐
J	☐
K	☐
L	☐
M	☐
N	☐
O	☐
P	☐
Q	☒
R	☐
S	☐
T	☒
U	☐
V	☒
W	☐
X	☒

Code Subsidiary Documents	
BSC Procedures	☒
Codes of Practice	☐
BSC Service Descriptions	☐
Party Service Lines	☐
Data Catalogues	☒
Communication Requirements Documents	☐
Reporting Catalogue	☒
Core Industry Documents	
Ancillary Services Agreement	☐
British Grid Systems Agreement	☐
Data Transfer Services Agreement	☐
Distribution Code	☐
Distribution Connection and Use of System Agreement	☐
Grid Code	☐
Master Registration Agreement	☐
Supplemental Agreements	☐
Use of Interconnector Agreement	☐
BSCCo	
Internal Working Procedures	☒
BSC Panel/Panel Committees	
Working Practices	☐
Other	
Market Index Data Provider	☐
Market Index Definition Statement	☐
System Operator-Transmission Owner Code	☐
Transmission Licence	☐

1 EXECUTIVE SUMMARY

The key conclusions of the P211 Modification Group ('the Group') are outlined below.

The Group:

- **AGREED** by majority that the Proposed Modification would not better facilitate the achievement of Applicable BSC Objectives (b), (c), and (d)[2];
- **DEVELOPED** a potential Alternative Modification which sought to better reflect what Bid and Offer volumes are actually available to the SO;
- **AGREED** by majority that the potential Alternative Modification developed by the Group did not better facilitate the achievement of Applicable BSC Objectives when compared to the Proposed Modification and therefore should not be put forward as an Alternative Modification;
- **NOTED** that the implementation costs for the Proposed Modification were estimated to be £346,000 for BSCCo and BSC Central Systems and approximately £80,000 for the Transmission Company;
- **AGREED** that an implementation solution that required the Transmission Company to calculate the EPUS stack or main Energy Imbalance Price and provide this to BSC Central Systems should not to be pursued for the implementation of the Proposed Modification. This was due to the Transmission Company stating that it was not feasible to develop an appropriate solution in terms of both cost and time in comparison to the solution developed for implementation by BSC Agents;
- **AGREED** an Implementation Date for the Proposed Modification of 6 November 2008 if an Authority decision is received on or before 28 February 2008, or 25 June 2009 if the Authority decision is received after 28 February 2008 but on or before 16 October 2008; and
- **AGREED** that the draft legal text delivers the intended solution for the Proposed Modification.

A description of the P211 solution is provided in Section 2. Further information regarding the Group's discussions of the areas set out in the P211 Terms of Reference is contained in Section 3, including details of the Group's recommended implementation approach and the estimated implementation costs of P211.

A summary of the Group's views regarding the merits of the Proposed Modification and rejected potential Alternative considered can be found in Section 4. A copy of the Group's full Terms of Reference can be found in Appendix 2, whilst a summary of the responses to the Assessment Procedure consultation and impact assessment can be found in Appendices 3 and 4 respectively.

The Modification Group undertook substantial work developing a potential Alternative and sought views on this during the Assessment Procedure consultation. A description of the solution, the BSC Agent Impact Assessment, and views of the potential Alternative against the Applicable BSC Objectives can be found in Appendices 5, 6 and 7 respectively.

2 DESCRIPTION OF MODIFICATION

This section outlines the solution for the Proposed Modification as developed by the Modification Group.

For a full description of the original Modification Proposal as submitted by [EDF Energy] ('the Proposer'), please refer to the P211 Initial Written Assessment (IWA).

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[2] (b) The efficient, economic and co-ordinated operation of the GB transmission system;
(c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity; and
(d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements.

2.1 Current Arrangements

Under the current baseline, actions taken by the System Operator (SO) to balance Supply and Demand for a Settlement Period set the main Energy Imbalance Prices (System Buy Price (SBP) when the system is 'short' and System Sell Price (SSP) when the system is 'long').

The current methodology for determining system length (whether the system is 'long' or 'short') was introduced under Approved Modification P78 'Revised Definitions of System Buy Price and System Sell Price'. Overall system imbalance (i.e. Net Imbalance Volume or 'NIV') is currently determined by summing the Pre-Gate Closure trades (reflected in Balancing Services Adjustment Data or 'BSAD'[3]) with the Bids and Offers accepted by the SO. The system is 'long' when the volume of Bids and / or Relevant Balancing Services predominate and the system is 'short' when the volume of Offers and / or Relevant Balancing Services predominate.

The following information contributes to the calculation of the main Energy Imbalance Price:

- Actions taken within the Balancing Mechanism to increase the total energy on the system (Accepted Offers), or actions within the Balancing Mechanism to decrease the total energy on the system (Accepted Bids); and
- Relevant Balancing Services provided outside the Balancing Mechanism, represented via BSAD.

When the system is estimated by the method above to be short of energy, the main price (i.e. SBP as the price applied to imbalances in the same direction as the system) is based on the volume weighted average of the most expensive 500MWh[4] of priced balancing actions (accepted Offers and BSAD) remaining, following the application of the following rules:

- **De Minimis:** Individual accepted Bid and Offer Volumes below a defined threshold (1 MWh) are excluded from the price calculation completely. This approach is intended to remove 'false' actions created due to the finite accuracy of the systems used to calculate Bid and Offer Volumes;
- **Arbitrage:** Accepted Bids and Offers where no net energy has been delivered to the system but which have provided an overall financial benefit to the system are excluded from the price calculation completely (i.e. where the price of an accepted Offer Volume is less than the price of an accepted Bid Volume);
- **CADL:** Acceptance Volumes associated with Acceptances of short duration (below the Continuous Acceptance Duration Limit (CADL) currently 15 minutes) are treated as un-priced[5] in the price calculation;
- **BSAD:** The SO determines whether Relevant Balancing Services will be treated as priced or un-priced. BSAD is calculated net[6] and represents both priced and un-priced Relevant Balancing Services in aggregate form;
- **Emergency Instructions:** On the determination of the SO, Accepted Bids and Offers associated with Emergency Instructions may be tagged as Excluded Emergency Acceptances and therefore treated as un-priced for the purpose of Energy Imbalance Price Calculation; and

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[3] Note that BSAD data also includes a Buy Price Adjuster (BPA) and a Sell Price Adjuster (SPA) which are added to the relevant Main Price (SBP or SSP).

[4] This is known as the Price Average Reference (PAR) volume. PAR is currently 500MWh. When the system has excess energy (said to be 'long') then the main price (SSP) will be based on the volume weighted average of the most expensive 500MWh of priced balancing actions (accepted Bids and Energy BSAD) remaining following the application of the tagging mechanism rules. If the NIV is less than 500 MWh then no volumes will be PAR tagged.

[5] Un-priced volumes contribute to the determination of which actions set the main Energy Imbalance Price, however the costs of these actions are not included in the main Energy Imbalance Price.

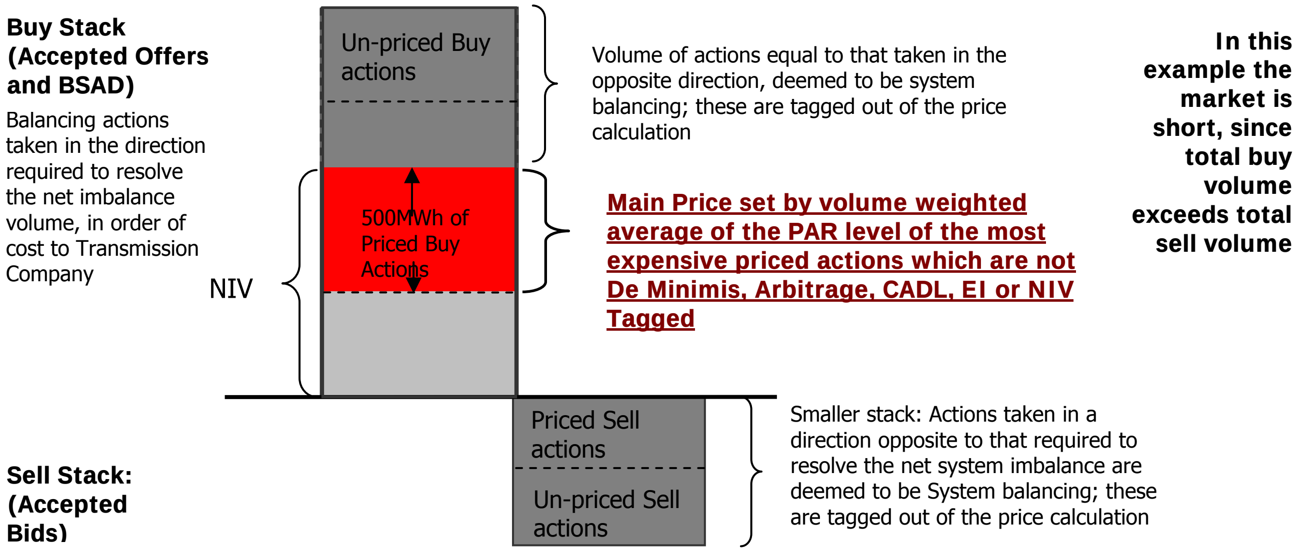
[6] This means that in any Settlement Period there can only be one non-zero volume of Energy BSAD (EBVA or ESVA), and one non-zero volume of System BSAD (either SBVA or SSVA).

- **NIV Tagging:** Following application of the rules outlined previously, the Net Imbalance Volume (NIV) tagging process is applied to determine which of the priced actions will be subject to PAR tagging.

These processes are collectively known as the 'tagging mechanism'. The de-minimis, CADL, emergency instructions and NIV Tagging functions are the processes to remove what are deemed to be system balancing actions from the main price.

In addition, trades undertaken on power exchanges feed into market prices provided by Market Index Data Providers (or a single provider, as it currently stands). The reverse Energy Imbalance Price (i.e. the price applied to imbalances in the opposite direction to the system) is based on the market price derived from data submitted by Market Index Data Providers.

Figure 1. Example of the Existing Arrangements Main Imbalance Price Calculation (Short System)



2.2 Proposed Modification

Under P211, the mechanism for calculating Energy Imbalance prices compares to the current baseline as follows:

- Rather than using actions taken within the Balancing Mechanism to increase the total energy on the system (Accepted Offers), or actions within the Balancing Mechanism to decrease the total energy on the system (Accepted Bids), the information that contributes to the calculation of the main Energy Imbalance Price in each Settlement Period will be Deemed Available Offer Volumes (DAOV) and Deemed Available Bid Volumes (DABV) for each price band for each BM Unit which submits bid-offer volumes;

- DABV and DAOV values in each period will be determined from the time weighted average Final Physical Notification (FPN) and the levels of submitted bid-offer bands capped by time weighted average Maximum Import Limit (MIL) and time weighted average Maximum Export Limit (MEL) where relevant. The FPN, MIL and MEL data are all sourced from submissions made under the Grid Code and for the purposes of this Modification, the BSC will use the Grid Code definitions;

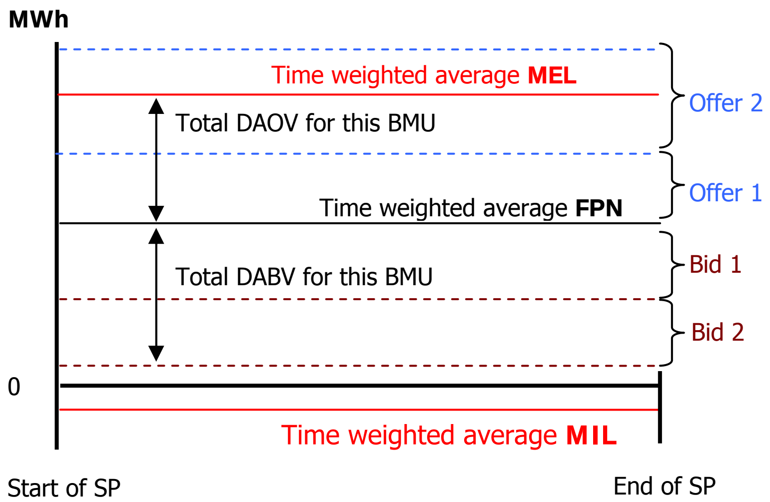
- Thus, for each BM Unit (BMU):

  - The total time weighted average DABV cannot exceed the difference between the time weighted average MIL less the time weighted average FPN;

- o The total time weighted average DAOV cannot exceed the difference between the time weighted average MEL less the time weighted average FPN; and
- o Any volumes between time weighted average MEL and time weighted average FPN plus the sum of all positive numbered offer volume intervals for that BMU or between time weighted average MIL and time weighted average FPN less the sum of all negatively numbered bid volume intervals for that BMU shall be deemed to be 'unpriced' and will not enter the EPUS stack.

This relationship of FPN, and MIL and MEL and the resultant volumes are shown in Figure 2.

Figure 2. Deemed Available Offer Volumes (DAOV) and Deemed Available Bid Volumes (DABV)



- The MIL and MEL used will be the latest available at the end of the relevant Settlement Period (and which apply to that Settlement Period for the purposes of calculating the time weighted average);
- The determination of Relevant Balancing Services provided outside the Balancing Mechanism, represented via BSAD, will not change;
- The existing process for determining whether SSP or SBP is the main Energy Imbalance Price (the existing NIV process) will not change;
- The existing process for determining the MWh size of the NIV (using accepted bids, offers and BSAD) will not change other than to remove De-minimis tagging. However, as the prices of actual acceptances making up NIV would not be used for the main Energy Imbalance Price calculation it should be noted that the existing process should be simplified as described in the P211 Requirement Specification[7];
- A new stack will be built from collating the available Bids (DABV) and Offers (DAOV) plus Energy BSAD[8]. This stack will form the Ex-Post Unconstrained Schedule (EPUS);
- De-Minimis and Emergency Instruction tagging will not apply to the EPUS stack;
- EPUS Arbitrage tagging[9] will apply to the EPUS stack to remove any DAOV that are priced less than or equal to DABV. This process for EPUS Arbitrage tagging is the same as the current process for

[7] This includes the removal of CADL tagging, De-Minimus tagging and Emergency instruction tagging. The P211 Requirement Specification can be found here: http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=231

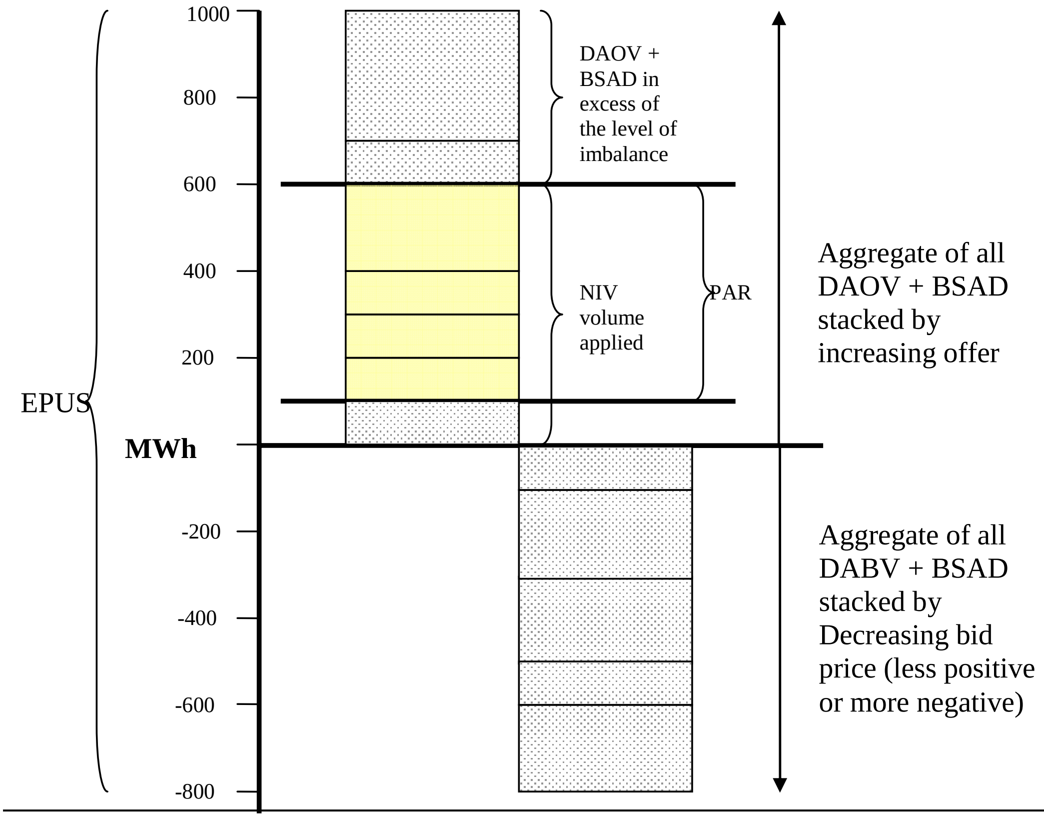
[8] Energy BSAD excludes System Buy Price Volume Adjuster (SBVA) and System Sell Price Volume Adjuster (SSVA) which are not to be included in the EPUS stack.

Arbitrage tagging except it is applied to the DABV and DAOV volumes instead of accepted Bid and Offer volumes;

- EPUS NIV tagging will be applied to the EPUS stack (after the EPUS Arbitrage tagging) to exclude the DABV, DAOV and BSAD that will not be required for determining the main Energy Imbalance Price such that:
    - When NIV is positive, starting from the least expensive, only priced buy volumes up to the volume of NIV are included; and
    - When NIV is negative, starting from the least expensive, only priced sell volumes up to the volume of NIV are included.
- EPUS PAR tagging will be applied such that a volume weighted average of the PAR volume portion of the most expensive[10] priced un-(EPUS)-tagged volumes will set the main price;
- The PAR volume will not change from the existing value of 500MWh;
- Transmission Loss Multipliers will still be used in the main Imbalance Price Calculation as currently;
- The Buy Price Adjuster (BPA) or Sell Price Adjuster (SPA) will be added to the relevant Main Price (SBP or SSP); and
- The method for calculating the reverse price will not change.

An example of how the main Energy Imbalance Price is calculated under the Proposed Modification is shown in Figure 3.

Figure 3. Example of the P211 Arrangements Main Imbalance Price Calculation when Short



[9] The terms 'EPUS Arbitrage tagging', 'EPUS NIV tagging' and 'EPUS PAR tagging' are used here to differentiate from the tagging that occurs in the determination of the NIV and under the main Energy Imbalance Price calculation under the current arrangements.

[10] It should be noted that 'least expensive' should, in this context, be considered in relation to the benefit of the System. Offers are bought by the System for an increase in energy, thus the 'least expensive' will be the lowest priced Offer. Since Bids are paid to the System by Parties for a reduction in energy, the least expensive Bid will be the highest priced Bid. A negative Bid price will be expensive to the System, as the System is paying (rather than being paid) to reduce energy. Similarly, when using the term 'most expensive', it should be considered in this context.

2.2.1 Background to the Proposal

It has been shown by the SO that the current main Energy Imbalance Price calculation includes actions taken by the SO for reasons considered to be 'energy plus' even though a number of the current tagging mechanisms are used to try to remove some of these. Recent documentation available in support of the current tagging mechanism deficiencies has been provided in the Approved Modification P205 'Increase in PAR volume from 100MWh to 500MWh' decision letter[11] and from within the Ofgem led Cash-out Review[12]. It should be noted that some Modification Group members believe that a sufficient level of materiality of this defect has not yet been established. 'Energy plus' actions are intended to encapsulate all those actions taken by the SO for more than just energy reasons. An 'energy plus' action might be taken for energy balancing reasons, but would also include actions taken for any one or more of the following reasons:

- Frequency response;
- Reserve creation;
- Intra half-hour demand balancing (including events such as TV pickup); and
- Constraint activities (including resolving locational issues).

The Proposer suggests that P211 would remove the impact of imperfections of the tagging mechanism on the main Energy Imbalance Prices. Thus Parties would be exposed to cash-out prices that are reflective of the true costs of energy balancing the system (i.e. non 'energy plus' actions) and this would more appropriately target the costs of energy balancing the system. Additionally, it is suggested that liquidity in the short term market would increase as Parties are more likely to sell volume rather than using it to self-hedge. Finally, it is believed that P211 would simplify the current BSC arrangements by making it easier for both existing Parties and new entrants to understand the imbalance pricing mechanism. It is therefore suggested that these three points have a positive impact on Applicable BSC Objective (c) "Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity".

As P211 would remove much of the complex tagging mechanisms, it is also put forward by the Proposer that this simplification will positively impact Applicable BSC Objective (d), "Promoting efficiency in the implementation and administration of the balancing and settlement arrangements".

The Proposer suggests that P211 will reduce the volatility and improve the predictability of the main Energy Imbalance prices, thus reducing the incentive for Parties to take a longer position into cash-out to avoid the risk of a high SBP. This will better facilitate Applicable BSC Objective (b) "the efficient, economic and co-ordinated operation of the Transmission System by the Transmission Company" by reducing the level of balancing required by the SO.

The Group discussed whether arbitrage tagging should be retained for the EPUS stack as this was not identified in the original proposal. It was agreed to include this as the Group felt that this would make the market more efficient by removing trades that would have otherwise been made prior to Gate Closure. Additionally, the Group concluded that retaining arbitrage tagging would limit the ability for price manipulation.

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[11] Available from Ofgem's website at:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=86&refer=Markets/WhlMkts/CompandEff/CashoutRev

[12] See:

- NGET presentation to Cash-out Review ' What is the Impact of Non Exclusive Energy Actions on Imbalance Pricing', 30 March 2007;
- Cash-out Review 2007 'An Independent Perspective', Nigel Cornwall, published 22 March 2007.

Ofgem documentation of the Cash-out Review can be found at:
http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/CASHOUTREV/Pages/CashoutRev.aspx

2.3 Rejected Alternative Modification Developed

The Group has undertaken substantial work on developing a potential Alternative that includes dynamic parameters. The reason for undertaking this development work is to better reflect the Bid and Offer volumes that the SO could have utilised to resolve energy imbalances and is discussed further in 3.1.1 below. A detailed description of this potential Alternative is contained in Appendix 5.

Energy Imbalance Prices for certain periods were calculated for two different sets of dynamic parameter rules. The two sets of rules are also described in Appendix 5.

Upon reviewing the analysis and draft legal text, the Group concluded by majority that the potential Alternative would not better facilitate the Applicable BSC Objectives when compared to the Proposed Modification and therefore did not include it as an Alternative for Panel consideration. The majority of the Group believed that:

- The additional complexity (highlighted by the solution detailed in Appendix 5 and reflected in the preliminary draft of the potential Alternative Legal Text included as Attachment 7[13]) would be detrimental to both competition and the efficient operation of the market; and
- The potential for spurious results caused by the approximate nature of the dynamic rules that were developed would also be detrimental to competition. For example, if volume is removed from the EPUS stack which the SO could have actually accessed then SBP could rise to a level that is not reflective of the costs of the SO in balancing the system. Such spurious results would not reflect the true costs of balancing the system and could threaten the solvency of smaller Parties.

3 AREAS RAISED BY THE TERMS OF REFERENCE

This section outlines the initial conclusions of the Modification Group (the 'Group') regarding the areas set out in the P211 Terms of Reference. This covers the following areas:

- Derivation of the Ex-Post Unconstrained Schedule;
- Impact on Energy Imbalance Prices;
- Cashflow Analysis;
- Incentives;
- Impact on Settlement;
- Default Rules; and
- Implementation.

3.1 Derivation of the Ex-Post Unconstrained Schedule

3.1.1 Modification Group's Initial Discussions

3.1.1.1 The effect of dynamic parameters

Under the Proposed Modification, the derivation of the EPUS was well defined. This definition specifically excludes the consideration of any dynamic parameters. The Proposer suggested that the inclusion of dynamic parameters could potentially overcomplicate the solution and necessitate the inclusion of assumptions that could exclude volumes that might have actually been available to the SO. For the Proposed

[13] Note that the preliminary draft legal text for the potential Alternative is included as an indication of the complexity of the potential Alternative. It is not a complete solution and has not been subject to formal internal ELEXON or Modification Group review.

solution, the only limitation for Bids and Offers submitted by Parties to enter the EPUS stack is the capping by time weighted MIL and time weighted MEL.

The majority of the Group considered that this Proposed Solution would not be representative of what was actually available to the SO to use given the various real time and dynamic constraints they operate under. The majority of the Group were therefore in favour of assessing the impact of dynamic parameters (which could be developed into a potential Alternative) by incorporating some elements of dynamic parameters that reflected those imposed on the SO when balancing the system. The Group came up with two sets of rules as described in Appendix 5 (the first set of rules included an extra dynamic rule for when FPN is zero but was rejected prior to the Assessment Procedure Consultation and the second set of rules were rejected after the Assessment Procedure Consultation[14]). The effect of including the first set of dynamic parameters is shown in Attachment 1 (Figure 28) for 29 December 2005. This shows that including the set of dynamic parameters (with the first set of rules) led to an average 55% reduction in the size of the DAOV stack and a 13% decrease in the size of the DABV stack when compared to the Proposed Modification[15].

Additionally some Group members felt that the set of rules that were assessed as a potential Alternative still did not represent the full set of actions available to the SO. This is because the potential Alternative looked at each Settlement Period in isolation. The SO however has to take a wider view across a number of Settlement Periods. For example, if a unit is required only for 1 hour of the peak but has a minimum non-zero time (MNZT) of 4 hours then the SO has to bring that unit on for the full 4 hours or not at all.

One Group member noted however that the current cash-out rules do not try to re-create the physical system as certain trades are removed. The Proposed Modification and the potential Alternative are simply different ways of providing a proxy for the cost of energy imbalance.

The impact of including and excluding dynamic parameters is also represented by the price differentials that are discussed in Section 3.2 below.

3.1.1.2 Application of BSAD and De- Minimis

How Balancing Services Adjustment Data (BSAD) would enter the EPUS was discussed by the Group. The Proposed solution clearly stated that the methodology for calculating BSAD should not change and that this would enter the EPUS stack at the price and in the manner that BSAD is currently determined.

Some Group members felt that the proposed treatment of energy BSAD was inconsistent with the concept of the Proposed solution. This is because energy BSAD may include contracts procured by the SO for services such as reserve provision and therefore includes actions taken for 'energy-plus' reasons (and not exclusively 'energy only' actions). The SO currently decides which items are included in BSAD by determining whether the actions are considered for 'energy' or 'system' purposes (see BSAD Methodology Statement[16]). Also, the Group noted that BSAD included actual buy and sell volumes 'accepted' by the SO ("physical actions") whereas the EPUS was based on offers/bids 'available' to the SO ("theoretical actions"). However, the Group recognised that reviewing the calculation of BSAD for the purposes of this Modification is outside the scope of the BSC and agreed to note this point in their assessment.

The Group also considered the application of De-Minimis Bids and Offers in the EPUS stack. It was noted that the current practice of removing Bids or Offers of 1MWh or less is used to remove 'false' actions created due to the finite accuracy of the SO and BSC Systems. However, the Group did not believe this to be a substantial issue in the current baseline due to the nature of the size of De-Minimis volumes. The Group believed that, in line with the principle of the Modification to include all submitted Bids and Offers in an EPUS

[14] Note that when referring to the 'potential Alternative' within this document it is in reference to both sets of rules. Where the Report refers to a certain set of rules is this will be clarified in the text. Additionally, for the avoidance of doubt both sets of rules (or potential alternatives) were abandoned by the Group.

[15] As the Group did not have the potential Alternative analysis for the second set of rules prior to the consultation, it is noted that the set of dynamic parameters (with the second set of rules) led to an average 33% reduction in the size of the DAOV stack and a 12% decrease in the size of the DABV stack when compared to the Proposed Modification (for the period 2 November 2006 to 31 March 2007).

[16] Available on National Grid's website at http://www.nationalgrid.com/uk/Electricity/Balancing/transmissionlicensestatements/BSAD/

no De-Minimis tagging would be applied when constructing the EPUS. In addition the Group agreed that that the De-Minimis tagging rule should be removed from the NIV calculation for the Proposed solution.

3.1.1.3 Other Markets

The Group investigated the Single Electricity Market (SEM) in Ireland and the Australian Electricity Pool that were identified as using an EPUS based approach. The similarities and differences between the BSC arrangements and those in the other markets were identified. The Group noted that there were no other markets identified that would have a similar arrangement as that of the Proposed or potential Alternative. That is, there are no markets that use an ex-post unconstrained schedule for calculating imbalance prices in a residual balancing market.

Irish Market

The SEM in Ireland will go live on 1 November 2007. This will be a central commitment market with a single clearing price for each trading period. Additionally, it will have an explicit capacity payment mechanism. This single price will be set ex-post on an unconstrained (in terms of network constraints but not generator constraints) basis[17]. The SEM will have a single system marginal price (SMP) that is set for each half hour, based on an ex post optimised schedule for the whole trading day.

The ex-post SMP for each half hour trading period will be based on an unconstrained stack of available generation optimised over the 'optimisation time horizon' which runs from 6am on the trading day until (but not including) midday on the day after the trading day. The optimisation takes into account the plant on the system at the end of the previous trading day as well as the actual demand and renewable generation which occurred during that trading day.

A SMP is produced for each half hour trading period. Uplift is applied to the SMP to ensure that energy prices should reflect underlying market dynamics. The purpose of the uplift is to ensure that the production cost for each generator is recovered through the SMP within that period of operation in the optimisation time horizon. A price cap and price floor is set by the regulator from time to time, and is applied if the software calculates SMP outside these limits.

The full rules governing the all available dynamics to be considered in the SEM was not available when the Group analysed the market. However, the most recent draft of the rules available to the Group highlighted the following areas. The objective of each price calculation run is to minimise the aggregate sum of schedule production costs over the optimisation time horizon subject to:

a) Scheduling generation to meet demand in each trading period within the optimisation time horizon;

b) Scheduling each generation unit to be at an output level between its minimum and its maximum availability; and

c) Scheduling each generation unit within its technical capabilities including (but not limited to) its minimum stable limit, ramp rates, and minimum on and off time. Additionally, consideration is given to restarting a unit if it is to be taken off.

The Group noted that there was a fundamental difference between the SEM and the BSC arrangements in that the SEM is optimised over an entire day and uses an ex-post unconstrained schedule with a full set of dynamic parameters. Additionally, SEM final prices will be published significantly later after the Settlement Period (4 days after the trading day although indicative prices are available earlier) and thus prompt pricing signals would be lost. Finally, the Group noted that the move toward an EPUS solution in the SEM has been part of substantial change in that market that has been subject to much consideration and developed over a significant period of time.

Australian Market

[17] Constrained on and constrained off payments will be made to participants in well defined circumstances.

The National Electricity Market (NEM) in Australia is a physical energy only spot market traded through a gross pool in which 'spot' prices are produced for every five minute period. A complex linear program produces a dispatch instruction for each unit every five minutes and also produces location based prices. Prices are calculated at the marginal price although these are capped at A$10,000/MWh. The Group concluded that the market was significantly different from the BSC arrangements. The NEM does not have any imbalance cash-out mechanism comparable to the BSC and does not use an EPUS. Therefore, it was not considered comparable for this Modification.

Historic Pool Arrangement

How an unconstrained Schedule was used under the pre NETA arrangements (the Pool) was also discussed by the Group. However, the Group noted that the Irish SEM was partly based on the arrangement under the Pool and felt that the same considerations also applied to the Pool. Therefore, it was not considered useful for the assessment for this Modification.

The Group noted the operation of an EPUS in other markets, but did not conclude that there are any significant benefits or parallels that they felt could be used in the solutions for P211 Proposed and potential Alternative Modification's or in the Group's assessment thereof.

3.1.2 Views of Respondents to Assessment Procedure Consultation

The Assessment consultation sought views on a potential Alternative that included some form of dynamic parameter rules. There was a split view of respondents (9 each with 3 neutral) as to whether there was a preference for the potential Alternative or the Proposed Modification. Two respondents who preferred the potential Alternative indicated that this was with the caveat that the potential for spurious results would be removed. The majority of respondents (9 to 6, with 6 neutral) still preferred the current baseline to the potential Alternative.

Some of those respondents who preferred the potential Alternative over the Proposed Modification felt that the disregarding of plant dynamics in determining the accessibility of the actual megawatt volumes available was an oversimplified approach with the consequence that it compromises the accuracy and appropriateness of the Energy Imbalance Price generated by P211. It would allow plant that would not realistically be accessible to the SO to be included in the EPUS and is likely to result in more benign prices than those that reflect the costs of the SO.

Some respondents also indicated that including dynamic parameters would assist in reducing the potential for Parties to game. It was also noted by some respondents that Parties could inadvertently influence Energy Imbalance Prices due to the dynamic parameters associated with their plant and how these affect the Energy Imbalance Prices.

One respondent also indicated that dynamic parameters allow for the Energy Imbalance Price to respond (albeit imperfectly) to market shocks.

With regard to the potential Alternative developed by the Group, some respondents believed that there was also potential that the rules could remove volume from the EPUS stack that were actually available to the SO and therefore would produce a less cost reflective price. It was also argued that the inclusion of the dynamic parameter rules in the potential Alternative increases complexity and reduces transparency of the main Energy Imbalance Price[18].

Additionally, one respondent felt that the analysis[19] showed that the inclusion of the dynamic parameters rules produced Energy Imbalance Prices that were on average not too dissimilar to the Proposed Modification. Therefore, they believed that with the added complexity, there was not much benefit in the dynamic parameter rules of the potential Alternative.

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[18] This is a view that was later shared by a majority of the Modification Group.
[19] See Attachment 2 for the analysis that the respondent is referring to.

Two respondents believed that a different alternative solution could be a fully functioning ex-post unconstrained schedule, which created an optimised dispatch solution and took into account full plant dynamics. This solution would remove the potential for spurious results that could occur under the potential Alternative. However, they recognised that the definition of such an EPUS was a significant exercise and that there was not sufficient time to undertake this as part of the assessment of P211.

3.1.3 Modification Group's Conclusions

A majority of the Group believed that, whilst the principle of the potential Alternative was to better reflect the energy volumes that could feasibly be accessed by the SO, the rules applied did not deliver an acceptable level of accuracy. The majority agreed with the view that the appropriate way in which to incorporate dynamic parameters would be with a fully functioning ex-post unconstrained schedule that took into account full plant dynamics. However, the Group agreed that the definition of such an EPUS was a considerable undertaking and that there was not enough time to undertake this as part of the assessment of P211 and would need to be considered outside the P211Modification process.

Additionally, the majority of the Group believed that the level arising from complexity of including the dynamic parameters in the potential Alternative (even with the simplified set of dynamic rules used) would be detrimental to Applicable BSC objectives (c) and (d). Therefore, this would outweigh any benefit of increased cost reflectivity that the potential Alternative had over the Proposed Modification.

Finally, the Group noted that the potential for spurious results caused by the approximate nature of including dynamic parameter rules that are not always representative of the true state of the system would be detrimental to competition. For example, if volume is removed from the EPUS stack which the SO could have actually accessed then SBP could rise to a level that is not reflective of the costs of the SO in balancing the system. This could potentially threaten the solvency of Parties, particularly smaller players.

The Group concluded that this potential option for an Alternative Modification, based on dynamic parameters, would not better facilitate the Applicable BSC Objectives when compared to the Proposed Modification. Therefore, it would not form an Alternative Modification.

3.2 Impact on Energy Imbalance Prices

3.2.1 Modification Group's Initial Discussions

3.2.1.1 Evaluating the Defect

It is suggested by the Proposer that the Energy Imbalance Prices under the current arrangements are impacted by imperfections in the tagging mechanism (further details are contained in Attachment 3 – Proposer's Presentation). This is considered to be of concern due to the negative impacts of exposing Parties to cash-out prices that are not reflective of the true cost of energy balancing for the system. The Proposer confirmed that his definition of "system balancing actions" includes any action that has a dual purpose (i.e. the action was not taken purely for the purpose of the resolution of Half Hourly energy imbalance).

The Proposer provided some further analysis to supplement the information already in the public domain on the degree to which system balancing actions enter Energy Imbalance Prices under the existing arrangements (See Attachment 4). The Proposer noted that it is difficult to assess the degree of the defect as only the SO can say why any individual action was taken. However, the Proposer suggests that Bids or Offers taken out of merit order is a good indication that an action is 'energy plus'. Additionally it is suggested that where SSP in a long market falls significantly below the cost of generation (and of other, unaccepted, Bids present at that time), that this also provides likely evidence of the defect.

The Proposer provided an example of a specific Settlement Period (SP 19 on 26 September 2005) in which the buy and sell stacks were analysed. This was when the SO took actions to resolve an export constraint in Scotland. These actions also had the effect of reducing the supply/demand imbalance. The Proposer notes that there were no opposing actions to 'tag' out the accepted constraint actions. This therefore represents one Settlement Period in which constraint activity was shown to impact Energy Imbalance Prices.

One member noted that the strongest examples of constraint activity affecting Energy Imbalance Prices were concentrated in a period not long after the start of the British Electricity Trading and Transmission Arrangements (BETTA) in April 2005. Some Group members noted this occurrence and noted that further examples may have occurred since BETTA go-live but did not feel it has been proven to be a significant issue.

The Group have considered the extent to which the current Energy Imbalance Prices reflect the true energy costs of the SO balancing the system. However, the Group noted that this would not be an easy exercise due to the difficulty in working out whether each action taken by the SO should be included, or not, in the Energy Imbalance Price calculation. Furthermore, for any action considered to be 'energy plus', a portion of that action could have been required for energy purposes by the SO. Therefore, this portion should theoretically be included in an Energy Imbalance Price that is not impacted by tagging imperfections.

The Group considered that determining an Energy Imbalance Price that reflects the true energy costs of the SO balancing the system would be too difficult to do on any large scale, because each Settlement Period would have to be scrutinised in detail. Furthermore, when scrutinising each action, there would need to be a potentially subjective method by which each action taken by the SO can be categorised as one that should, partially should, or should not be included in Energy Imbalance Prices. This applies equally to the Proposed Modification as to any other potential solutions.

Some Group members expressed the view that the overall objective of any cash-out regime, is that the cash-out prices should be a proxy of the short term costs of the SO in balancing the system. The cash-out prices should reflect the opportunity costs of energy balancing. These should then be targeted on those Parties that are out of balance. Therefore, any solution should ensure that the BSC arrangements do not move away from reflecting the costs faced by the SO in energy balancing.

Whilst there was a unanimous view that a defect has been shown to exist in certain Settlement Periods, some Group members were still not satisfied that evidence proving significant materiality of the defect existed.

3.2.1.2 Recalculated Energy Imbalance Prices

The Group considered the analysis illustrating the difference between the Energy Imbalance Prices calculated under the current baseline and those of the Proposed Solution. The analysis is included as Section 2 of Attachment 1. On consideration of this analysis the Group noted that:

- The P211 Proposed prices are only directly comparable with the current prices from 2 November 2006 when PAR500 was introduced (prior to this a volume weighted average price of balancing actions not removed via the Tagging Mechanisms was used and thus prices were by definition equal to or lower than a PAR500 price). For the period 2 November 2006 until 31 March 2007:
    - When the system was short, the P211 Proposed SBP was on average £10.25/MWh (or 16%) lower than the current arrangements (with a maximum decrease of £193/MWh);
    - When the system was long, the P211 Proposed SSP was on average £1.20/MWh (or 7%) higher than the current arrangements (with a maximum increase of £20.50/MWh);
    - There were 258 out of 7,197 Settlement Periods in which either P211 SBP was greater than the current arrangements or P211 SSP was less than the current arrangements. The Group identified three Settlement Periods (SP 1 to 3) on 2 September 2005 (See Figure 13 in Attachment 1) in which this was the case. The reason for this is that NIV was very small and negative (so the system was long and SSP was the main Energy Imbalance Price). P211 SSP is higher than PAR500 SSP as expected intuitively. P211 SSP is also higher than the

market price. Therefore, P211 SBP defaulted to P211 SSP (as defined in the BSC, T4.4.6(b)) and this caused P211 SBP to be higher than PAR500 SBP.

- Recalculated prices for known periods of constraint activity (2 September 2005 and 18-20 October 2005) and also for periods of system stress (29 December 2005 - Notice of Inadequate Margin (NISM) notice issued, 13 March 2006 – Gas Balancing Alert (GBA), and 18 July 2006 – High Risk of Demand Reduction (HRDR) notice issued), can be seen in Attachment 1 (Figures 13 to 19).
- Indicative prices[20] for the potential Alternative with the first set of dynamic parameter rules are only available for the periods of constraint activity and system stress noted above. These can be seen in Figures 21 to 27 of Attachment 1. Indicative prices for the potential Alternative that included the second set of dynamic parameter rules are included in Attachment 2[21]. Note that these were not available for the Group to form an initial view prior to the Assessment Consultation.

Therefore, the Group concluded that there is, on average, a divergence between the Energy Imbalance prices calculated from the current arrangements and those calculated under P211 Proposed. The Group noted that this divergence appeared to be more substantial in periods of system stress. However, without any benchmark for where an optimal price (without any tagging imperfections) would lie (and acknowledging that this was unlikely to be achievable), the Group could not conclude whether the P211 Proposed or potential Alternative were better estimates of the true energy costs of the SO balancing the system than the current arrangements. The Proposer noted that it was their belief that a benchmark for an optimal price did exist, particularly in periods where the SO had identified that constraints had impacted imbalance prices. It is the Proposer's view that in these periods, both the Proposed Modification and potential Alternative produced similar prices that better represented the cost of energy imbalance.

3.2.2 Views of Respondents to Assessment Procedure Consultation

3.2.2.1 Evaluating the Defect

Nineteen respondents provided a view on the existence of the defect. All respondents agreed that it has been shown that a defect exists during *certain* Settlement Periods.

However, the most common response was that the materiality of the defect had not been proven. Additionally, some respondents highlighted that transmission constraint actions have been proven to affect the Energy Imbalance Prices in certain Settlement Periods and this introduces costs that are not reflective of the short term cost of the SO balancing the system. It was those respondents' view that the issue of transmission constraints entering the Energy Imbalance Prices should be considered as the defect. Therefore this was the defect that should be resolved and not the removal of all 'energy plus' actions as the Proposed Modification would do. Some respondents suggested that the days in which the Cheviot constraint was active (2 September 2005, and 18-20 October 2005 used in the analysis) has now been alleviated by National Grid's actions in the forward market and this is an example of one of the other ways of addressing the transmission constraint issue. One respondent commented that as they felt that P211 was not cost reflective, it would mean that P211 would introduce a greater defect than the one it is seeking to address in the current arrangements.

One respondent stated that there had not been any recent days in which the defect had been identified as the analysis looked at Settlement Periods in which the Cheviot constraint was active after the introduction of BETTA[22].

[20] Due to time restrictions, the prices are indicative only because they do not have Rule 4 and Rule 6 applied. Additionally, the modelling has not been independently verified and tested.
[21] Note that due to the late availability of this data for the Assessment Procedure consultation, the Modification Group extended the time in which industry could provide responses on this analysis.
[22] This statement was made prior to the further analysis provided by the Proposer which confirmed more recent Settlement Periods have had Energy Imbalance Prices impacted by transmission constraints. This is discussed in Section 3.2.3.1 below.

There was a strong minority view that the defect has been proven to be a significant issue and that the P205 decision letter and the Ofgem-led cash-out review have already provided evidence of this.

As part of their response, the Proposer provided analysis (as an attachment to their response) for the purpose of assisting the Group in understanding the extent of the defect. The analysis identifies days where SSP falls significantly below a "proxy" daily cost of generation. Some of these days were then looked at in more detail to see if out of merit actions were taken by the SO. Where this was the case, the Proposer contacted the SO to find out if any non-energy actions occurred on these days, and if these impacted the main Energy Imbalance Price. This analysis was discussed at the final Modification Group meeting and is captured in 3.2.3.1 below.

3.2.2.2 Recalculated Energy Imbalance Prices

Two respondents believed the analysis provided for P211 shows that there would be a more cost reflective main Energy Imbalance Price. It was their view that on the days of known system stress the P211 prices rise to reflect the energy scarcity. (See attachment 1, Figures 17 to 19). Therefore, the P211 prices would send the correct signals to market participants to make efficient energy balancing decisions. It was also noted that the P211 prices would be less volatile than the current baseline due to the nature of the EPUS stacks.

One respondent noted that the lack of dynamic considerations might result in increased random price volatility due to inaccessible and unreflectively priced volumes being included in the EPUS stack. This may drive volatility in the behaviour of Market Participants.

Some respondents indicated that because the EPUS includes actions that the SO could not actually take, the main Energy Imbalance Prices will be too benign to be reflective of the costs faced by the SO in balancing the system. The P211 prices would therefore provide weaker and less accurate signals to balance. Therefore the SO costs would then be appropriately targeted onto those Parties who are in energy imbalance.

One respondent[23] provided qualitative analysis in an attachment to their response to illustrate why they do not believe P211 will better meet the aim of cost reflectivity. The analysis uses stylised supply curves to show how a 'perfect' energy price might be achieved. The analysis indicates that P211 prices would be less accurate than the current baseline as the P211 prices will be suppressed due to the P211 supply curve being shifted down and to the right in comparison to the current baseline. This would result in main Energy Imbalance Prices (SBP) being suppressed to a level below that which would be economically efficient. Thus it was the respondent's view that P211 would not achieve a more cost reflective price and would be a less efficient solution than the current baseline.

One respondent also highlighted that the analysis showed that the P211 prices were still on average below the volume weighted prices calculated prior to November 2006 (when a PAR level of 500MWh was introduced). Additionally, these volume weighted average prices were ones in which, based on the information available to them at the time of their P194 'Revised Derivation of the Energy Imbalance Price' decision letter, the Authority indicated were not reflective of the costs faced by the SO in balancing the system.

3.2.3 Modification Group's Conclusions

3.2.3.1 Evaluating the Defect

The Proposer stepped through the additional analysis they had provided with their consultation response. (see EDF Energy's response in Attachment 6). The analysis compares SSP to a proxy cost of generation with the assumption that in a well functioning competitive market, SSP should be just below the cost of generation. Where SSP falls significantly below the cost of generation this would indicate that out of merit actions are being taken for other non-energy reasons and affecting the main Energy Imbalance Price. The

[23] See Assessment Procedure consultation responses in Attachment 6.

Proposer provided a graph of daily average SSP (when the system is long) against the proxy for the marginal cost of generation and used this to identify potential days between December 2006 and August 2007 where the defect might be active. The SO confirmed that all three Settlement Periods identified by the Proposer had other non-energy activity that fed into the main Energy Imbalance Price calculation. The Proposer noted that there were only three Settlement Periods analysed because of the time-consuming manual process required for the SO to confirm what activity occurred in any Settlement Period.

The Proposer concluded that the analysis shows conclusively that non-energy actions such as reserve constraints, transmission constraints and actions to resolve intra half hour demand fluctuations have a detrimental impact on SSP. Additionally, the graph shows a significant number of Settlement Periods where SSP falls significantly below the proxy cost of generation and the Proposer concludes that it is highly likely that the SSP in these periods are also polluted by other non-energy actions.

Some members queried whether SSP falling below the measure used as a proxy for the cost of generation necessarily led to the conclusion that SSP was being polluted on those days or that there was not a well functioning competitive market.

One member questioned whether the analysis took into account the running regimes of different plant (that faced different marginal costs) and whether this would account for some of the difference between the proxy cost of generation and SSP. Another member also queried whether the proxy costs of generation was based purely on fuel prices and if so that there were other costs of generation which may make up some of the difference. The Proposer confirmed that it was purely the fuel and carbon cost but that this was only meant to represent a proxy for the short run marginal cost of generation.

Some members noted that they believed the analysis was limited because whilst all three of the selected Settlement Days had contained non-energy actions, these selected days were not obvious choices from the November 2006 to August 2007 date range of the graph. The difference between the SSP and proxy cost of generation was significantly higher on other days and it could not necessarily be concluded that just because the difference between the two is high that there is likely to be constraints active on those days. The Proposer commented that the graph showed daily averages for the ease of viewing but that individual Settlement Periods within that day may have had a high difference. Additionally, when the days were requested to be investigated by the SO, the Proposer only had data for November 2006 and January 2007. Some members still noted that in those three months there seemed to be numerous days that have a higher difference.

The Group noted that the analysis provided by the Transmission Company at the Cash-out Review should not be taken out of context. The Transmission Company representative clarified their analysis as follows. Although not conclusive, analysis provided previously estimated that in the year 06/07 approximately 70% of offers and 60% of bids that were used to resolve NIV were also used to manage other issues faced by the SO in balancing the system. This included actions taken to create reserve, actions taken to resolve intra half hour volatility, and actions taken to resolve constraint issues. However, it is important to differentiate between the reasons activity was undertaken and the impact that activity had on altering the Energy Imbalance Price. A large proportion of activity taken to resolve the issues indicated would be taken in cost order. Again although not conclusive, this is demonstrated in the analysis provided to the Cash-out Review meeting in March 2007 that roughly estimated that in November 2006 the average differential in costs that this activity caused had in relation to resolving a notional half hourly demand position was somewhere between 0% and 9% difference in the cost of offers accepted and somewhere between 0% and 7% difference in the cost of bids accepted[24].

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[24] Note that National Grid expressed in the presentation that they had no view as to whether there was a correct methodology for constructing an idealised price stack but for the purposes of providing analysis to the Cash-out Review they assumed that:

- Services procured through forward options are included in stack from which a price is calculated;
- A snap shot of perfect SO foresight of 89 minutes ahead (Gate Closure) is used;
- All BMU's with NDZ greater 89 minutes are excluded;
- Accessible Bids and Offers are based on MEL at Real Time; and
- All the prices are net of the Buy Price Adjustment (BPA) and Sell price Adjustment (SPA) component.

The Group noted that some respondents had commented that the issue of transmission constraints entering the Energy Imbalance Prices should be considered as the defect and that is the defect that should be resolved. The Group noted that there are other initiatives outside the BSC which may look at this issue including work under the Connection and use of System Code (CUSC), Ofgem's Transmission Access Review[25], and SO incentive scheme.

The Group noted that some respondents had commented on previous decisions by Ofgem. However, since that time, Ofgem has provided comment at the Cash-out Review and at a presentation to the BSC Panel[26] that they are keen to understand whether any simpler models could be considered when constructing an Energy Imbalance Price.

No members changed their initial views with regard to the defect with a majority still believing that the materiality had not been proven and a strong minority view that there was ample evidence of the defect.

3.2.3.2 Recalculated Energy Imbalance Prices

The Group did not alter its initial views on the recalculated prices for P211.

Some members did note that the recalculated prices for the potential Alternative were as expected (that is they were, on average, between the Proposed Modification Prices and the current baseline prices). One member noted that (because the dynamic rules are only estimates of actual plant dynamics) under the potential Alternative, a situation could arise where in a very short system there may be insufficient availability of DAOV in the stack to be able to resolve the NIV. Therefore, prices would be constructed from a set of DAOVs that are less than NIV.

The Group noted that there were spurious prices produced by the first set of dynamic parameter rules that were not apparent in the second set of rules[27]. However, the majority of the Group felt that the potential for spurious price outcomes still existed with the second set of dynamic parameter rules as they were still approximations of how plant dynamics would actually be applied.

3.3 Cashflow Analysis

3.3.1 Modification Group's Discussions

For otherwise identical conditions, the Group believe that P211 Proposed will generally decrease Energy Imbalance Prices as compared to the current baseline and have done so (on average) throughout the whole period of analysis conducted. It therefore follows that under otherwise identical conditions, P211 Proposed will decrease the Account Energy Imbalance Cashflow (CAEI)) and therefore the Residual Cashflow Reallocation Cashflow (RCRC). However, if the prices are lower and this leads to less incentive to balance, this may result in upward pressure on CAEI and RCRC could increase. The impact on RCRC in otherwise identical conditions for P211 Proposed can be seen in Figure 20 of Attachment 1.

Some members of the Group noted under P136 'Marginal Definition of the 'main' Energy Imbalance Price', P137 'Revised Calculation of System Buy Price and System Sell Price' and P194 'Revised Definition of the Main Energy imbalance Price', the impacts of CAEI and RCRC on incentives to balance had been well documented. It was those members' belief that analysing RCRC alone could be considered of little value as it is a side effect to the Settlement calculations. The relative difference of SBP and SSP can lead to the total system Energy Imbalance Cashflow being either positive or negative resulting in RCRC being either a debit or a credit. In addition, the inability to predict the resultant RCRC means that RCRC alone would have little or not influence on Parties incentives and will not cause any change in their behaviour. Therefore those

[25] See http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx
[26] BSC Panel meeting 130 – 9 August 2007: This can be found at http://www.elexon.co.uk/bscpanelandcommittees/panelmeetings/default.aspx?year=2007
[27] Note that in the Assessment Procedure consultation these were classified as 'Rule 2a' and 'Rule 2b' respectively.

members concluded that RCRC does not distort the incentive to balance provided by Energy Imbalance Prices.

3.3.2 Views of Respondents to Assessment Procedure Consultation

There were no specific comments from respondents on the cashflow analysis.

3.4 Incentives

3.4.1 Modification Group's Initial Discussions

The Group noted that under identical conditions, because on average under the P211 Proposed solution SBP is lower and SSP higher, those Parties exposed to Energy Imbalance Prices would be less liable (on average) to Energy Imbalance Charges as compared to the current baseline. Therefore it was noted that P211 would provide less incentive to avoid being out of balance in the same direction of the system.

However, some members felt that because the P211 prices would be more reflective of the cost of resolving "energy" imbalance then this would decrease the likelihood of Parties being consistently long (to avoid what in their view might be penal SBP). Thus P211 would create greater incentives to balance by being less long. One Group member noted that whilst on average there is a tendency for Parties to be long, that there is also evidence that Parties are short during peak stress periods. Some members of the Group noted that Parties make rational decisions based on the opportunity cost of being out of balance (i.e. the difference between the cost of trading out imbalances at the forward price when compared with the cost of cash-out). The fact that Parties are long on average reflects the asymmetric risks associated with being long compared to being short. For Parties to be balanced on average, this would assume identical risks and symmetrical bid and offer curves, which is not a likely outcome under P211. Since under P211 SBP is likely to be more volatile it should be expected that it would be rational for Parties to be more likely to be long than short.

Some members of the Group recognised that there could be a step change in Parties trading strategies that could occur with the introduction of a P211 Proposed or potential Alternative solution and that these strategies would be developed over time. This would be based on rational decisions that arise from the incentives faced by Parties and whether it would be more beneficial to go into imbalance or trade out their positions in the forward market. The Proposer believed that the majority of the time the incentives will be the same as currently exists to ensure that people balance.

Some members believed that the current arrangements are volatile but this feature is predictable. For example, if an expensive generator is being warmed to provide reserve or generation at the peak, then the market may expect that the system may be short resulting in a high and potentially volatile Energy Imbalance Price that reflects the costs to the SO of accepting an offer from that unit. It was the view of those members that the P211 Proposed solution could reduce volatility and create a situation where it could no longer be predicable that having a high priced unit on (for whatever reason) will actually lead to a high Energy Imbalance Price. Without the information that enables Parties to anticipate the high cost of imbalance, trading opportunities are lost and there is reduced incentive for a Party to trade out its imbalance. A minority of the Group disagreed that volatility would be significantly reduced highlighting that the recalculated prices (seen in Attachment 1 – particularly Figures 18 and 19) still display elements of volatility and price increases during periods of system stress.

Additionally, some Group members believed that the P211 Proposed solution will lead to a greater amount of actions having to be taken by the SO because the feedback loop to the SO costs to balance the system have been removed, thus reducing cost reflectivity and reducing the incentive to balance. This in turn increases the SO costs as the SO has to take extra actions which, as the P211 Imbalance Prices were unlikely to reflect the SO's costs, would not be targeted to those Parties who are out of balance.

The Group noted that the exclusion of dynamic parameters in the Proposed solution provides a set of rules in which Parties' legitimate behaviour can affect prices. The main concern raised was that Bids or Offers would be included in the EPUS stack even if their dynamics prevented the SO from using them in reality. This would have the effect of unduly suppressing imbalance prices leading to an inappropriate reduction in incentives for Parties to balance. This issue was of most concern under the original modification, but could also be an issue under the potential Alternative that was considered.

Another concern was that Parties may seek to influence prices. An example would be where a Party re-submits prices for a BMU that cannot be accessed by the SO due to either ramp rates or its notice to deviate from zero (NDZ). Whilst the BMU would effectively be excluded (by the dynamics) from being accepted in the balancing mechanism (from being paid at its Offer price) it could still be used by that Party to make cash-out prices unduly low if the BMU were priced so low as to fall within the part of the EPUS stack which is used to calculate the main Energy Imbalance Price. It was argued by some members that Parties might seek to reduce the main Energy Imbalance Price to their advantage. One member noted that any behaviour of this nature by Parties could be in breach of the FSA's market abuse rules, since this would be distorting the market (cash-out prices are an important applied index, and can affect forward prices) and could also be viewed as a "manipulating device" under the changes to the Market Abuse Regime that were brought in under the Market Abuse Directive. The FSA has in place a formal concordat whereby it can exchange data freely with Ofgem. However, it was noted by the Group that because of the numerous actions taken by a large number of Parties every day that it could be a very difficult exercise to identify and then prove any anti-competitive behaviour. To provide some data volume context to this issue, there are approximately 200 active BMUs in the balancing mechanism, all of whom have the ability to submit 5 Offer and 5 Bid price pairs per Settlement Period. These prices can be resubmitted by the BMU for every Settlement Period in the day. Therefore the number of prices that would potentially have to be scrutinised on a daily basis is 48*200*10 = 96,000 prices. Each of these prices may have been resubmitted several times in one day.

A number of Group members believe that the Proposed and (to a lesser extent) the potential Alternative solution do not reflect the costs of post Gate Closure plant loss. Parties whose plant trips would receive a depressed signal as potentially very expensive short term actions taken to alleviate the trip would be lost from the calculation.

These Group members also felt that there could be a reduced incentive for Parties to trade out the imbalance created by such plant failures given that the Energy Imbalance Prices would be less material than at present, being set based on submitted bids and offers (DAOV and DABV) rather than potentially very expensive actions that could be taken in such short timescales. This would also decrease the long term incentive on Parties to maintain their plant to ensure an efficient level of plant reliability. Less reliable plant would create greater potential for future plant failure and would increase the costs for the SO to balance the system and also require the SO to hold more reserve. A Group member noted that this would also lead to long term security of supply issues.

The Group as a whole noted that although Parties face uncertainty as to whether the overall imbalance of the system will be long or short, the incentive for Parties to be in imbalance in the opposite direction to the overall imbalance of the system will remain unchanged (since the derivation of the market price will be the same).

3.4.2 Views of Respondents to Assessment Procedure Consultation

A number of respondents reiterated the view that the Proposed Modification (and the potential Alternative) would lead to a decrease in how cost reflective the Energy Imbalance Prices are of the costs faced by the SO in balancing the system. This is primarily due to the potential for the Proposed Modification to include Bids and Offers in the price calculation that cannot actually be accessed by the SO resulting in Energy Imbalance prices that would be more benign than that which would occur with fully cost reflective prices. This leads to inappropriate price signals being sent to the forward market to trade out imbalance positions with, on average less incentive to balance. Two respondents also indicated that a cross subsidy would exist due to the appropriate SO costs being targeted on those out of balance being too low. This would compound the reduced incentive to balance.

Some respondents reiterated the point made in the initial Group discussions that there would be less incentive to trade out imbalances caused by post-Gate Closure plant loss as the Proposed Modification would not accommodate any events after Gate Closure. This was because high costs faced by the SO to balance in such situations would not be targeted onto those out of balance.

Reduced Party balancing would require the SO to have to take more actions than they would under the current arrangements to balance the system. The SO would also be required to hold extra reserve to make up for the fact that Parties would be holding less of their own (due to the fact they are less long).

A smaller number of respondents indicated that they believed that Energy Imbalance Prices would be less volatile and more cost reflective due to the removal of the defect. This would create a rational decision to trade out imbalance and to act in an economic and efficient manner. Parties would be less long on average as there was less fear of extreme and volatile Energy Imbalance prices. One respondent noted that this would lead to less actions being required to be taken by the SO.

Some respondents were concerned that Parties could submit unrealistic (in terms of their dynamic parameters) Bids and Offers in an attempt to influence the Energy Imbalance Prices as highlighted by the initial Group's discussions in 3.4.1 above. One respondent noted that any gaming would be highly unlikely as Parties would act rationally under the law (including the Competition Act). In particular, that respondent could not understand why any Party would risk breaching market abuse rules in relation to its distortion of or misleading the market. Another respondent noted that the equities market is regulated by the FSA and that the volume of trades made each day is much more substantial than those trades made of submitted in the Balancing Mechanism.

One respondent indicated they did not believe there would be any impact on participants' or the SO's behaviours.

3.4.3 Modification Group's Conclusions

The views initially expressed by Group members in relation to incentives did not change as a result of the consultation responses.

In relation to the point on the detection of gaming or manipulation from the appropriate authority[28], the Group wished to reiterate that it was intended to note only that it would be a difficult exercise to monitor the electricity market due to the vast amounts of data regardless of the appropriate Authority's previous experience. The dynamic parameters involved in the structure of the electricity market (which do not exist in other markets) would also add further complication. One member noted that it was their belief that it is currently only the responsibility of the SO to monitor Bids and Offers.

3.5 Impact on Settlement

3.5.1 Modification Group's Initial Discussions

The requirement to build an EPUS stack of all DAOV and all DABV for every Settlement Period would be a significant increase to the amount of computation required by the BSC Central Systems. This would have a potentially large impact on the ability for prompt prices to be produced within current timescales.

The Group agreed that it may be inefficient to require BMRA and SAA to calculate MIL, MEL, DAOV and DABV for all BM Units, when many of these values will then be EPUS NIV Tagged (and hence have no impact on Energy Imbalance Prices). This would be a particular concern in the context of BMRS, where prompt price reporting is of the essence. This issue was addressed by only requiring the BMRA and SAA to build enough of the DAOV/DABV stack to calculate Energy Imbalance Prices (i.e. allow them to start building the stack with the cheapest Bids and Offers, and to stop when a sufficient volume of stack has been constructed

[28] The FSA, Competition Commission and Ofgem were cited as Authorities with potential concern.

in order to complete EPUS Arbitrage tagging and then ensure that all remaining DAOV and DABV volumes would be NIV tagged).

Through doing so it has been confirmed that the P211 Proposed Solution would not have any detrimental impact on prompt prices.

Views were sought from Parties on whether the above approach of only building enough of the DAOV/DABV stack to calculate Energy Imbalance Prices would be acceptable (given that it would prevent the reporting of MIL, MEL, DAOV and DABV for those Bids and Offers that were wholly EPUS NIV Tagged).

3.5.2 Views of Respondents to Assessment Procedure Consultation

All but one respondent either agreed with or were neutral to the approach presented in 3.5.1 above. The respondent who disagreed believed that all volumes which have the potential to set prices should be reported, even if they did not actually set the price.

3.5.3 Modification Group's Conclusions

The Group noted the point of the respondent who disagreed but did not change its initial view that the approach was appropriate to ensure prices were published in prompt timescales.

3.6 Default Rules

3.6.1 Modification Group's Discussions

The Proposer suggested that the default rules may require review. Therefore the Group undertook to identify the likelihood of there being insufficient volume in the EPUS to resolve the NIV. The analysis of the EPUS stacks identified that there is normally substantial volumes of DAOV and DABV to resolve NIV. This is included in the analysis in Figure 1 and Table 1 of Attachment 1 where the lowest margin between the EPUS stack and NIV was 1,249MW in Settlement Period 33 on the High Risk of Demand Reduction (HRDR) day of 18 July 2006.

The Group noted that a default rule is still required in the event that NIV exceeded the volume in the EPUS stack[29]. The Group agreed to retain the existing rules such that in the event of not enough EPUS volume, the main Energy Imbalance Price will be the volume weighted average of the most expensive DAOV or DABV that is available[30] (whilst also remaining subject to the existing set of default rules).

3.6.2 Views of Respondents to Assessment Procedure Consultation

There were no specific comments from respondents on the default rules.

3.7 Implementation Approach and Costs

3.7.1 Modification Group's Initial Discussions

The Modification Group has identified indicative costs and implementation lead times for P211 Proposed and P211 potential Alternative.

Two options were identified for implementing the Proposed Modification based on the level of involvement of the Transmission Company in producing either the raw data to BSC Central Systems or producing the EPUS stack or the Energy Imbalance prices and providing these to BSC Central Systems.

[29] Although the Group did not conclude whether such a scenario could occur.
[30] For example, if NIV is 500MWh and the amount of DAOV is 400MWh then the price is calculated from the volume weighted average of the 400MWh of DAOV.

The Transmission Company was therefore requested to provide an estimate of the development, capital and operating costs (broken down in reasonable detail) which the Transmission Company anticipates that it would incur in, and as a result of, implementing the Proposed Modification if the Transmission Company were also to produce:

a) And provide the raw data to BSC Central Systems (no change from current arrangements);

b) the EPUS stack (as defined in section 2.1-2.4 of the P211 Requirement Specification), after the application of EPUS Arbitrage Tagging, required to resolve NIV and provide this to BSC Central systems; or

c) the main Energy Imbalance Price as derived in the P211 Requirement Specification (section 2) and provide this to BSC Central systems (BMRA) such as to enable prompt price reporting in the same (or similar) timescales as present.

Two estimates for the changes to BSC Central Systems were therefore provided:

d) Producing the main Energy Imbalance Price based; or

e) Publishing the main Energy Imbalance Price as provided by the Transmission Company or producing and publishing the main Energy Imbalance Price based on the EPUS stack provided by the Transmission Company.

The Transmission Company indicated that to provide the requested estimates for (b) and (c) above would be a significant piece of work and they regrettably could therefore not provide any meaningful estimates within the timeframe of the Assessment of P211.

On getting the costs for changes to the BSC Central Systems, the Group noted that the savings in costs for having the Transmission Company produce the Main Energy Imbalance prices or the EPUS stack was £35,000. Given the indication of the Transmission Company above, the Group agreed that there was no value in pursuing options (b) or (c) above as the work required to implement the solution (as well as resource required to produce the estimates) by the Transmission Company would not have been under £35,000.

3.7.2 Results of Proposed Modification Impact Assessment

[Option (d) PROPOSED MODIFICATION IMPLEMENTATION COSTS[31]

		Stand Alone Cost	Tolerance
Service Provider[32] Cost			
	Change Specific Cost	£ 133,650	+/- 0%
	Release Cost	£ 51,850	+/- 0%
	Total Service Provider Cost	£ 185,500	+/- 0%
Implementation Cost			

[31] An explanation of the cost terms used in this section can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf

[32] BSC Agent and non-BSC Agent Service Provider and software costs.

	External Audit	£ 0	+/- 0%
	Design Clarifications	£ 9,275	+/- 0%
	Additional Resource Costs	£ 0	+/- 0%
	Additional Testing and Audit Support Costs	£ 5,000	+/-20%
	TOMAS changes	£ 50,000	+/-20%
Total Demand Led Implementation Cost		£ 249,775	+/- 10%

Port and Migrate Costs

Service Provider Cost	Port and Migrate[33]	£ 45,000	+/- 0%

ELEXON Implementation Resource Cost		231 man days £ 50,820	+/- 5%
Total Implementation Cost		£ 345,595	+/- 20%

Note that for Option (e) the only difference is to the Total Service Provider Cost (and Total Implementation Cost) which would be £150,500 (and £310,595 respectively). That is a difference of £35,000.

Implementation Approach for Proposed Modification:

Due to the size of the changes required for P211 Proposed Modification it is recommended that P211 should form a complete Release on its own; no P211 cost benefits would be derived from the inclusion of other Change Proposals or Modifications in the same release as P211 (although there may be cost benefits for the other items included).

a) BSC Agent Impact

Work required includes:

- Expand BMRA and SAA Settlement data checking functions to include MIL/MEL data.
- Defining a new database table to hold DAOV and DABV data.
- Modifying the F009 functionality to include P211 functionality for P211 effective Settlement Dates.

For SAA reporting, a new DTC version of the SAA-I014 flow will be defined. The SAA-I014 module will be modified so that for P211 effective Settlement Dates additional data reporting will be included in the report. Where a Bid-Offer Pair has associated DAOV or DABV data defined by the Settlement Calculation Process

[33] The Port and Migrate costs are an indicative cost related to Project Isis interaction. This cost covers the porting and migrating of the P211 changes from Tru-64 and Oracle 9i to HP-UX and Oracle 10g. This cost assumes that LogicaCMG is doing all calculations and also it is assumed that this work follows the main CVA Port and Migrate project. Note that the optional BMRA reporting was ignored for this indicative cost

then this data will be reported against the Bid-Offer Pair. Some existing fields will not be reported for post-P211 dates as they will no longer be relevant.

The lead time is 26 weeks and all prices assume a November 2008 target release.

b) Transmission Company Impact

The Transmission Company will be required to modify systems receiving SAA data and business processes to cope with the new SAA-I14 variables. The initial cost estimate for implementing this P211 Proposed is approximately £80K with a lead time of approximately 7 months.

c) BSCCo Impact

ELEXON acceptance testing (4 weeks), new service provide acceptance testing (4 weeks) and go-live decision and deployment (2 weeks) will take a total of 10 weeks from the conclusion of the changes to the BSC Central Systems identified above (26 weeks). It is therefore proposed that the Implementation Date for Proposed Modification P211 should be 6 November 2008 if an Authority decision is received on or before 28 February 2008, or 25 June 2009 if the Authority decision is received after 28 February 2008 but on or before 16 October 2008.

Due to the size of the changes required for P211 Proposed Modification it is recommended that P211 should form a complete Release on its own; no P211 cost benefits would be derived from the inclusion of other Change Proposals or Modifications in the same release as P211 (although there may be cost benefits for the other items included).

3.7.3 Views of Respondents to Assessment Procedure Consultation

All but one respondent either agreed with or were neutral to the Implementation Approach described above. The one respondent who disagreed suggested the approach would lead to excess data computation and delays in data being published.

One respondent suggested there might be some value in having the Implementation coincide with the contractual rounds (i.e. 1 April or 1 October).

3.7.4 Modification Group's Conclusions

The Group noted the concerns of the respondent who disagreed with the Implementation Approach. However the Group reiterates that the results of the Impact Assessment from the BSC Agents did not indicate there would be any impact on the timescales of prices being published. The Group also did not believe there was any benefits in having the Implementation Date coincide with the contractual rounds.

3.7.3 Results of rejected Alternative Modification Impact Assessment

An impact assessment was also carried out for the rejected potential Alternative Modification. This is contained in Appendix 6 for information.

3.8 Legal Text

The Modification Group has reviewed the text and agreed that it delivers the solution developed by the Group.

Some members noted that whilst the Proposed Modification may be seen as a simplification to the current arrangements that there were still some complex changes required to the BSC.

A copy of the draft Legal Text can be found in Appendix 1. It should be noted that changes have been made to the embedded text contained in Annex T-1, which simply reflect changes made in Section T and Annex T-1, however such changes have not been shown as tracked changes.

4 ASSESSMENT OF MODIFICATION AGAINST APPLICABLE BSC OBJECTIVES

This section outlines the views of consultation respondents and the Modification Group regarding the merits of P211 against the Applicable BSC Objectives.

4.1 Proposed Modification

4.1.1 Modification Group's Initial Discussions

The initial **MAJORITY** view of the Modification Group was that the Proposed Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline, for the following reasons:

Applicable BSC Objective (b)

- Cost reflectivity will be reduced as the Proposed Modification moves away from what the SO actually did to resolve the imbalance on the system. Cost reflective Energy Imbalance Prices are essential to provide the correct incentives for parties to balance. These costs should then be appropriately targeted on those who are out of balance. As P211 will reduce the degree to which the SO's costs are reflected in Energy Imbalance Prices it follows that these costs will not be appropriately targeted and the incentives for Parties to balance will decrease. This in turn increases the actions required to be taken by the SO and increases the costs faced by the SO. This would be detrimental to the efficient operation of the GB transmission system;
- The Modification creates a trade-off where more cost reflective Energy Imbalance Prices are sacrificed in all Settlement Periods for removing a defect that has only been shown to occur from time to time. It is accepted that transmission constraints have an impact on the Energy Imbalance Price but there is currently a tagging mechanism to deal with these (even if it can be shown to occasionally be defective). The issue of transmission constraints should arguably be resolved in a different manner such that it is not at the expense of cost reflective prices;
- The increase in SO activities is in conflict with NETA principles in which it is assumed that it is more efficient for Parties to balance than the SO. With less incentives to balance then this is moving away from Parties balancing and puts this cost onto the SO; and
- Parties will not respond appropriately in periods of system stress if the signals are distorted due to prices not being reflective of actual SO costs of balancing the system. If, on average, Parties expect a more benign Energy Imbalance Price due to the EPUS stack including volumes that the SO cannot feasibly access then they will make a rational decision to only trade in the forward market at a price lower than the forward price under the current arrangements. The reduced incentive to trade results in more imbalance and higher costs for the SO.

One Group member stated that the Modification did better facilitate the objective for the following reasons:

- Prices will be more cost reflective because the proposal will remove the impact of system balancing actions which, it was argued, has a significant impact on the main imbalance price. The analysis also shows that the P211 prices do rise at times of system stress therefore retaining appropriate signals to balance; and
- There is a reduced incentive for Parties to go long on average. Therefore the actions the SO needs to take to balance the system will decrease resulting in lower costs and greater efficiency to balance the system.

Applicable BSC Objective (c)

- All Parties contribute proportionately to the costs of balancing via the Balancing Services Use of System (BSUoS) charge and those that are out of balance via SBP and SSP. The Proposal moves away from reflecting the costs incurred by the SO to resolve the net imbalance on the system. This results in a greater proportion of balancing costs being socialised across all Parties rather than being targeted at those out of balance. This cross subsidy will be detrimental to competition.
- There will be changes to Parties' behaviour based on the P211 arrangements. Parties would be able to take advantage of the rules that exclude dynamic parameters to influence the Energy Imbalance Price. Similarly, Parties may inadvertently impact (or, due to competition or market abuse issues be very wary of inadvertently impacting) the Energy Imbalance Price whenever they update their data. This would create distortions in the Energy Imbalance Prices that would not reflect the true costs of balancing. As the forward price is driven by the Energy Imbalance prices this will create the wrong signals to the market and therefore hinder competition. Where any attempt to take advantage of the P211 rules occurs, this will be very difficult to track;
- Appropriate signals to the market are distorted if the costs of high priced plant being used to balance the system are not reflected in the Energy Imbalance Prices. This would occur when the EPUS stack contains many offers which the SO cannot actually use; and
- The prices will be benign most of the time with a decreased level of volatility. Thus there is less incentive to balance or trade.

One Group member stated that the Modification did better facilitate the objective for the following reasons:

- It is simpler to understand encouraging new entrants as well as encouraging existing Parties to trade;
- Liquidity will increase as Parties are more likely to sell available volume in the forward market than hold it to self-hedge;
- Parties will pay a better cost of energy imbalance and not a price that contains actions taken for system balancing reasons.

Applicable BSC Objective (d)

- It has not been proven that there is a case for change in that the perceived defect has been shown to occur but has not been shown to be a substantive issue. Therefore there is no justification for the costs of this change;
- P211 introduces a new and approximate arrangement for cash-out, there is no evidence that it would be administered more efficiently; and
- The current arrangements are based on a simple concept; to reflect the costs of the SO when balancing the system. P211 would move away from this simple concept.

One Group member stated that the Modification did better facilitate the objective for the following reasons:

- Current actions taken by the SO for system balancing are impacting Energy Imbalance Prices and P211 provides a better reflection of the actions that could have been taken so the price is more cost reflective; and
- The Proposed solution is simpler for Parties to understand and for the industry to implement and operate.

One Group member additionally argued that potential issues arising from security of supply would not better facilitate the achievement of Applicable BSC Objectives (a).

4.1.2 Views of Respondents to Assessment Procedure Consultation[34]

The majority view of respondents to the Assessment Procedure consultation was that the Proposed Modification would not better facilitate the achievement of **Applicable BSC Objectives (a), (b), (c) and (d)**.

The following arguments were expressed by respondents in support of this view:

Applicable BSC Objective (a)

- If individual Parties face lower costs than those of the balancing actions taken on their behalf, there must be a risk to either security of supply (because individual Parties would not procure enough energy for all situations) or to efficient balancing activity because the SO will have to procure actions which Parties could have procured more cheaply themselves.

Applicable BSC Objective (b)

- No consideration is given to dynamic parameters and this would result in less cost reflective and more benign prices. This leads to less incentive to balance which increases the costs to the SO in balancing the system on Parties' behalf.
- The lack of dynamic parameters would also lead to greater random volatility as inaccessible volumes are included in the main Energy Imbalance Price calculation;
- Plant that could have profitably sold its output in the forward market under the current arrangements would be more likely to reserve output for the balancing mechanism;
- Any plant loss post Gate Closure would be likely to require expensive actions to be taken by the SO and these are not accommodated for by the Proposed Modification. The dampened price signals would reduce short term incentives to trade out the imbalances and reduces the incentive to invest in reliable plant technologies which results in the potential for increased future plant loss which will increase costs to the SO as they will have to procure more reserve.

The minority view of respondents to the Assessment Procedure consultation was that the Proposed Modification would better facilitate the achievement of **Applicable BSC Objective (b)**

The following arguments were expressed by respondents in support of this view:

- Prices will be more cost reflective because the proposal will remove the impact of system balancing actions which, it was argued, has a significant impact on the main imbalance price. The analysis also shows that prices do rise at times of system stress therefore retaining appropriate signals to balance; and
- There is a reduced incentive for Parties to go long on average. Therefore the actions the SO needs to take to balance the system will decrease resulting in lower costs and greater efficiency to balance the system.

Applicable BSC Objective (c)

- No consideration is given to dynamic parameters by the Proposed Modification and this would result in less cost reflective prices due to the EPUS stack containing volumes that the SO could not actually access. This provides weaker and less accurate signals to the market for them to make efficient

[34] Other comments and issues raised by the Assessment Procedure consultation not directly related to the Applicable BSC Objective are contained in Appendix 3 or in the discussions of Section 3.

balancing decisions. It would also lead to more benign prices and not be targeting the full costs faced by the SO in balancing the system;

- If costs are not appropriately targeted then this creates a cross subsidy where the costs are recovered from the industry as a whole through BSUoS charges;
- The potential for gaming, price manipulation within the rules and also spurious results due to Parties providing dynamic parameter data that inadvertently impacts the Energy Imbalance Price data would be detrimental for competition; and
- The Proposed Modification effectively removes all actions that have a dual purpose ('energy plus') from feeding into Energy Imbalance Prices and would also result in less cost reflective prices.

The minority view of respondents to the Assessment Procedure consultation was that the Proposed Modification would better facilitate the achievement of **Applicable BSC Objective (c)**.

The following arguments were expressed by respondents in support of this view:

- It is simpler to understand and a more equitable arrangement encouraging new entrants as well as encouraging existing Parties to trade;
- Liquidity will increase as Parties are more likely to sell available volume in the forward market than hold it to self-hedge. Additionally, the reduction in Energy Imbalance Price volatility stimulates an increased level of financial products becoming available;
- Smaller players are currently cross subsiding larger players as they are disproportionately exposed to higher costs due to being more likely to be out of balance;
- It would reduce current competition distortions that exist; and
- Parties will pay a better cost of energy imbalance and not a price that contains actions taken for system balancing reasons.

Applicable BSC Objective (d)

- There would be likely to be further modifications required after such a fundamental change to enable it to bed in;
- It has not been proven that there is a case for change in that the perceived defect has been shown to occur but is not shown to be a substantive issue. Therefore there is no justification for the costs of this change; and
- The current arrangements are based on a simple concept, to reflect the costs of the SO when balancing the system. P211 would move away from this simple concept.

The minority view of respondents to the Assessment Procedure consultation was that the Proposed Modification would better facilitate the achievement of **Applicable BSC Objective (d)**.

The following arguments were expressed by respondents in support of this view:

- Current actions taken by the SO for system balancing are impacting Energy Imbalance Prices and P211 provides a better reflection of the actions that could have been taken so the price is more cost reflective; and
- The Proposed solution is simpler for Parties to understand and for the industry to implement and operate.

4.1.3 Modification Group's Assessment

The majority view of the Modification Group was that the Proposed Modification would not better facilitate the achievement of **Applicable BSC Objectives (a), (b), (c) and (d)** when compared to the current Code baseline. The majority felt that the reasons initially expressed had not changed and that the additional points expressed by the respondents reflected their view.

The minority view of the Modification Group was that the Proposed Modification would better facilitate the achievement of **Applicable BSC Objectives (b), (c) and (d)** when compared to the current Code baseline. The minority felt that the reasons initially expressed had not changed.

4.2 Rejected Alternative Modification

The potential Alternative was abandoned by the Group. Discussion of the potential Alternative against the Applicable BSC Objectives is contained in Appendix 7.

The Group abandoned the potential Alternative because the majority did not believe it better facilitated the Applicable BSC Objectives when compared to the Proposed Modification[35]. This was due to the potential for spurious results from the approximate nature of the dynamic parameters being applied and also due to the complexity. Additionally, the dynamic parameter rules developed were only an approximation of the actual dynamic parameters that exist and are therefore will not always remove accurate volumes from the EPUS stack.

Whist the majority of the Group believed the concept of including dynamic parameters was a justifiable aim, the complexity manifested itself when developing a detailed solution and is reflected in the preliminary draft of the potential Alternative Legal Text (see Attachment 7). The complexity lay in the required changes to Section T. This primarily included the necessary algebra to account for spot values and all of the dynamic parameters but also included:

- Defining Submitted Bid-Offer Upper Range (SBOUR) and Submitted Bid-Offer Lower Range (SBOLR). these would be the same as BOUR / BOLR but unaffected by Acceptances;
- Changes to calculation of Period Maximum Export Limit (MEL);
- Determining the 'Applicable Dynamic Data' for the Settlement Period;
- Determining a Run-Up profile and Run-Down Profile, based on running up and down from FPN at Gate Closure;
- Determine the Unadjusted DAOV / DABV (i.e. prior to weighting the prices of volumes between the Stable Import Limit (SIL) and Stable Export Limit (SEL)); and
- Splitting out volumes between SIL and SEL (and assign them volume-weighted prices) to get final DAOV / DABV.

4.3 Final Recommendation to the Panel

On the basis of the above assessment, the Modification Group therefore agreed a **MAJORITY** recommendation to the Panel that the Proposed Modification **SHOULD NOT** be made.

Details of the Group's recommended Implementation Date and legal text can be found in Section 3.

5 TERMS USED IN THIS DOCUMENT

Other acronyms and defined terms take the meanings defined in Section X of the Code.

[35] Note that there was a split view from Assessment Consultation respondents as to whether the potential Alternative would better facilitate the Applicable BSC Objectives when compared to the Proposed Modification.

Acronym/Term	Definition
BMRA	Balancing Mechanism Reporting Agent
BSAD	Balancing Services Adjustment Data
DABV	Deemed Available Bid Volumes - Determined by the difference between the time weighted FPNs and time weighted MILs
DAOV	Deemed Available Offer Volumes – Determined by the difference between the time weighted FPNs and time weighted MELs
EPUS	Ex-Post Unconstrained Schedule – The stack of all Bids and Offers that are available to the SO. The EPUS is made up of the differences between FPN and MEL and FPN and MEL for all relevant BMUs.
FPN	The Final Physical Notification is the level of generation or demand that the BMU expects to generate or consume. Submitted as a ramped profile to National Grid prior to Gate Closure.
Main Energy Imbalance Price	The Energy Imbalance Price applied to imbalances in the same direction as the system.
MIL	Minimum Import Limit
MEL	Maximum Export Limit
MNZT	The minimum time in minutes that a BM Unit can operate at a non-zero level as a result of a Bid-Offer Acceptance
NISM	Notice of Inadequate System Margin
NIV	Net Imbalance Volume
PAR	Price Average Reference
PAR Tagging	The process of removing Acceptance Volumes from the calculation of Energy Imbalance Prices
PAR Volume	Price Average Reference Volume, the volume of actions that are used to set the Main Energy Imbalance Price
RCRC	Residual Cashflow Reallocation Cashflow
Reverse Price	The price applied to imbalances in the opposite direction to the system. This is based on the market reference price derived from data submitted by Market Index Data Providers (currently only APX).
RDR	Run Down Rate
RUR	Run Up Rate
SBP	System Buy Price
SEL	Stable Export Limit
SIL	Stable Import Limit
SO	System Operator
SSP	System Sell Price

6 DOCUMENT CONTROL

6.1 Authorities

Version	Date	Author	Reviewer	Reason for Review
0.1	31/08/07	Chris Stewart		For peer review
0.2	31/08/07	Chris Stewart	David Jones	For peer review
0.3	3/9/07	Chris Stewart	Modification Group	For Modification Group review
0.4	5/09/07	Chris Stewart	Justin Andrews	For technical review
0.5	5/09/07	Chris Stewart	Chris Rowell	For quality review
1.0	dd/mm/yy	Change Delivery		For Panel decision

6.2 References

Ref.	Document Title	Owner	Issue Date
1	Ofgems Cash-out Review – Independent Consultants' Reports http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/CASHOUTREV/Pages/CashoutRev.aspx	Ofgem	22/03/2007
2	P205 'Increase in PAR volume from 100MWh to 500MWh' - Decision Letter http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=86&refer=Markets/WhlMkts/CompandEff/CashoutRev	Ofgem	22/03/2007
3	P194 'Revised Derivation of the Energy Imbalance Price' – Decision Letter http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Pages/CashoutRev.aspx	Ofgem	23/03/2006

APPENDIX 1: DRAFT LEGAL TEXT

Draft legal text for the Proposed Modification is attached as a separate document, Attachment 5.

Draft legal text for the rejected Alternative Modification is attached as a separate document, Attachment 7. This has been included as evidence of the complexity of the solution developed by the Group which contributed to the potential Alternative being rejected.

Note that the potential Alternative draft legal text in Attachment 7 is a preliminary draft only and does not intend to provide a complete solution. The potential Alternative draft legal text has not been subject to formal internal ELEXON or Modification Group review and may therefore contain minor typographical errors. It does not contain reflective changes required for Section X. This was in an effort to save time and further costs since the Group determined that they wish to reject the Alternative solution. Additionally, it should be noted that changes have been made to the embedded text contained in Annex T-1, which simply reflect changes made in Section T and Annex T-1, however such changes have not been shown as tracked changes.

APPENDIX 2: PROCESS FOLLOWED

Copies of all documents referred to in the table below can be found on the BSC Website at: http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=231

Date	Event
16/04/07	Modification Proposal raised by EDF Energy
10/05/07	IWA presented to the Panel
15/05/07	First Assessment Procedure Modification Group meeting held
22/05/07	Second Assessment Procedure Modification Group Meeting held
06/06/07	Third Assessment Procedure Modification Group Meeting held
13/06/07	Fourth Assessment Procedure Modification Group Meeting held
18/06/07	Request for Transmission Company analysis on Proposed Solution issued
18/06/07	Proposed Requirements Specification issued for BSC Agent impact assessment
19/0607	Proposed Modelling exercise undertaken
2/07/07	Party Agent Proposed impact assessment responses returned
2/07/07	Transmission Company analysis for Proposed returned
4/07/07	Fifth Assessment Procedure Modification Group Meeting held
18/07/07	Modelling Exercise Results
23/07/07	Sixth Assessment Procedure Modification Group Meeting held
24/07/07	Potential Alternative Modelling exercise undertaken
27/07/07	Potential Alternative Requirements Specification issued for BSC Agent impact assessment
8/08/07	BSC Agent Proposed impact assessment responses returned

Date	Event
8/08/07	Transmission Company analysis for Proposed returned
13/08/07	Seventh Assessment Procedure Modification Group meeting held
15/08/07	Issue Consultation Document
21/08/07	Potential Alternative Modelling results
29/08/07	Eighth Assessment Procedure Modification Group meeting held

ESTIMATED COSTS OF PROGRESSING MODIFICATION PROPOSAL[36]

Meeting Cost	£2,750
Legal/Expert Cost	£5000
Impact Assessment Cost	£10000
ELEXON Resource	160 man days £50,070

Note that this has increased from the figures quoted in the IWA by 30 man days of ELEXON resource. This is primarily due to the additional analysis required by the Group for two potential Alternatives and the drafting of the potential Alternative Legal Text.

[36] Clarification of the meanings of the cost terms in this appendix can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf

MODIFICATION GROUP MEMBERSHIP

Member	Organisation	15/05	22/05	06/06	13/06	04/07	23/07	08/08	29/08
David Jones	BSCCo (Chairman meetings 3 to 8)			√	√	√	√	√	√
Justin Andrews	BSCCo (Chairman meetings 1 and 2)	√	√		√	√	√		√
Chris Stewart	BSCCo (Lead Analyst)	√	√	√	√	√		√	√
David Lewis	EDF (P211 Proposer)	√	√	√	√	√		√	√
Rob Smith	National Grid	√	√	√	√	√	√	√	√
Lisa Waters	WatersWye	√	√	√					√
Bill Reed	RWE Trading	√	√	√	√			√	√
Libby Glazebrook	First Hydro Company		√	√	√	√	√	√	
Man Kwong Liu	SAIC (on behalf of Scottish Power)	√	√	√	√		√	√	√
Ian Moss	APX Group	√	√	√		√			
Paul Jones	E.ON UK	√	√	√		√	√	√	√
Paul Dawson	Barclays Capital		√						
David Wilkerson	Centrica	√	√	√		√			√
Andrew Colley	Scottish and Southern	√	√	√	√	√	√	√	√
Martin Mate	British Energy	√	√	√	√			√	√
Keith Munday	BizzEnergy				√				
Bob Brown	Cornwall Energy Associates	√	√	√	√				√
Alison Hughes	BizzEnergy	√	√						

Attendee	Organisation	15/05	22/05	06/06	13/06	04/07	18/07	08/08	29/08
Natasha Hall	BSCCo (Lawyer)	√	√		√	√			
Shantok Karavadra	BSCCo (Lawyer)	√	√	√	√				√ (part)
Kevin Swinton	BSCCo	√	√	√	√				
John Guest	Logica	√	√	√		√	√		
Mark Gribble	Logica		√	√	√	√			

Ben Woodside	Ofgem	√	√	√			√		
Duncan Mills	Ofgem			√	√	√		√	√
Richard Jones	npower	√		√	√	√	√	√	√
Duncan Sinclair	Ofgem				√				
Kate Boon	First Hydro Company	√							
Alexandra Campbell	E.ON UK	√							
Colin Prestwich	Smartest Energy	√	√	√	√	√			
Colin Berry	BSCCo	√ (part)							
Sebastian Eyre	EDF Energy	√					√	√	√
John Sykes	BSC Panel	√	√				√		√
Barbara Vest	BSC Panel	√ (part)							
Paul Mott	EDF Energy		√			√	√	√	√
Ben Sheehy	E.ON UK				√				
Nigel Cornwall	Panel					√			
Rekha Patel	WatersWye						√		
Jonathan Blott	LogicaCMG						√	√ (part)	
Alex Kay	EDF Energy						√		
Jessie He	Npower						√		
Grahame Swinton	BSCCo						√	√	√ (part)
John Lucas	BSCCo								√ (part)

MODIFICATION GROUP TERMS OF REFERENCE

(Version 1.0)

Annex for Modification Proposal P211

Modification Proposal P211 will be considered by a new Modification Group, the P211 Modification Group, comprised of members of the Pricing Standing Modification Group (PSMG), and members of other Modification Standing Groups with the relevant expertise in the areas of Cash-out, Energy Imbalance Pricing, energy and system balancing, tagging and default price rules.

P211 – Main Imbalance Price based on Ex-Post Unconstrained Schedule

1. ASSESSMENT PROCEDURE

1.1 The Modification Group will consider Modification Proposal P211 pursuant to section F2.6 of the Balancing and Settlement Code.

1.2 The Modification Group will produce an Assessment Report for consideration at the BSC Panel Meeting on 13 September 2007.

1.3 The Modification Group shall consider and/or include in the Assessment Report as appropriate:

Ex Post Unconstrained Schedule (EPUS) Derivation

- The degree to which the EPUS may include Bids and Offers that could not be delivered by the BMU or that the SO could not take for any physical reason.
- The impact of including/excluding dynamic parameters on the derivation of the EPUS. The Modification Group should determine which (if any) dynamic parameters should be included or excluded. This may require data to be provided by National Grid Electricity Transmission (NGET) on these parameters and potentially modelling of the derivation of the EPUS by NGET. In addition, consideration should be given to the appropriateness of despatch algorithms for constructing the EPUS;
- The impact of using the difference between Final Physical Notice (FPN) and Maximum Export Limit / Maximum Import Limit (MEL/MIL) as a measure of available Bids and Offers to the System Operator.
- Are there are any other methods for deriving the EPUS that can be identified and the relevant costs and benefits of any such derivations. An ex-post unconstrained schedule is currently used in other wholesale electricity market jurisdictions in the formulation of wholesale electricity prices thus where the information is readily available the Modification Group shall consider:
    - The reasons for introducing the EPUS into these jurisdictions including any benefit/dis-benefit (including costs) information; and
    - The similarities and differences between the BSC arrangements and those of the other jurisdictions;
- How an Unconstrained Schedule was used under the pre NETA arrangements (Pool);
- How Balancing Services Adjustment Data (BSAD) is treated and how it will enter the EPUS; and
- How de-minimus Bids and Offers should be treated within the EPUS.

Impact on Prices

- The degree to which system balancing actions enter Energy Imbalance Prices under the existing Energy Imbalance Price calculation;
- The degree to which including/excluding dynamic parameters in the EPUS affects prices;
- Using historic data, the calculation of the Energy Imbalance Prices that would have been generated had the P211 mechanism been applied for certain historic Settlement Days including those in which it has been identified that system balancing actions have entered the Energy Imbalance Price; and
- The Energy Imbalance Prices generated for historic Settlement Days by both the current mechanism and that proposed by P211 in the context of the prevailing market conditions. This will also support the assessment of whether the proposed mechanism provides more cost reflective prices than the current baseline.

Cashflow Analysis

The impact on Residual Cashflow Reallocation Cashflow (RCRC) including any distributional impacts identified.

Incentives

- Having regard for the fact that price volatility is made up of volatility that correctly represents conditions in the market and volatility which bears little relationship to market/system conditions, the Modification Group should consider the degree to which price volatility is impacted and the resulting incentives to take an unbalanced position into cash-out;
- A qualitative assessment of how using the current operational parameters of FPN, MEL and MIL (and any other relevant Grid Code parameters) in the formation of the EPUS might introduce a commercial driver to use these as trading parameters. Additionally, the degree to which this might have a detrimental impact on the ability of the SO to use the submitted values as true indications of capability;
- A qualitative assessment of the potential for Market Participants to manipulate the operational parameters or any dynamic parameters that form part of the solution.
- Identifying any ways in which any potential for manipulation identified can be mitigated; and
- A qualitative view of the degree to which liquidity might be impacted and the incentive to enter forward contracts.

Impact on Settlement

The impact of P211 on the Settlement calculation and the publication of prompt prices. This will be informed by the BSC Agent impact assessments and information provided by the Transmission Company. The Modification Group should identify if there is any difference in prompt prices between P211 and the current arrangements and establish a view on the materiality of any disparity in the timeliness of calculating this data.

Default Rules

The default rules should be reviewed including:

- When there is insufficient deemed volume of Bids/Offers to resolve the NIV will be required; and
- Interaction of volumes covered by Bid / Offer pairs and the volumes up to the MEL / MEL that are not priced.

Implementation

Any Potential Alternative routes for implementation and the impact this has on implementation costs and timescales. Such a Potential Alternative might be NGET producing the prices or an EPUS as opposed to the costs of doing this centrally. The Modification Group should also consider any resulting impact on transparency.

The derivation of NIV and the PAR level of 500MWh are excluded from these terms of reference.

APPENDIX 3: RESULTS OF ASSESSMENT PROCEDURE CONSULTATION

21 responses (representing 71 Parties and 3 non-Parties) were received to the P211 Assessment Procedure consultation.

A summary of the consultation responses is provided in the table below (bracketed numbers represent the number of Parties and non-Parties represented by respondents).

Q	Consultation question	Yes	No	Neutral
1.	Do you have a view of the extent/impact of the perceived defect identified under P211?	19 (71 + 2)	1 (0 + 1)	
2.	What are your views on 'simplicity' versus 'cost-reflectivity' on the calculation of the main imbalance price?	-	-	-
3.	Do you believe Proposed Modification **P211** would better facilitate the achievement of the Applicable BSC Objectives?	9 (21 + 2)	11 (50 + 0)	1 (0 + 1)
4.	Do you believe potential Alternative Modification **P211** would better facilitate the achievement of the Applicable BSC Objectives when compared to the current baseline?	6 (18 + 0)	9 (48 + 0)	6 (5 + 3)
5.	Do you believe Alternative Modification **P211** would better facilitate the achievement of the Applicable BSC Objectives when compared to the Proposed Modification?	9 (36 + 0)	9 (29 + 2)	3 (6 + 1)
6.	Do you have any views on how these solutions will influence market participants' balancing behaviours and any subsequent impact on the SO?	19 (71 + 2)	1 (0 + 1)	1 (0 + 1)
7.	Do you believe there are any alternative solutions that the Modification Group has not identified and that should be considered?	5 (19 + 0)	15 (52 + 2)	1 (0 + 1)
8.	Do you support the implementation approach for the Proposed solution described in the consultation document?	19 (71 + 2)	1 (0 + 1)	1 (0 + 1)
9.	Do you support the approach of only building enough of the DAOV/DABV stack to calculate Energy Imbalance Prices to ensure minimal impact on prompt prices (see section 3.5 of consultation)?	17 (64 + 1)	1 (5 + 0)	3 (2 + 2)
10.	Does **P211** raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure?	6 (10 + 2)	15 (61 + 1)	0
11.	Are there any further comments on **P211** that you wish to make?	11	10	0

Details of the arguments made by respondents can be found in Sections 3 and 4, along with the Modification Group's consideration of these arguments. Responses to questions not captured in those sections are captured below. Full copies of the consultation responses are attached as a separate document (Attachment 6).

Question 3. Respondent's views on simplicity versus cost reflectivity

The Modification Group decided to ask this question (Question 3) to get the industry views on the value of simplicity.

The most common view of respondents was that whilst simplicity is desirable, it should not be delivered at the expense of cost reflective prices. Some members noted that there would be a trade-off between the two. However the most common view was that cost reflective prices are essential to achieving efficient balancing and should be seen as a factor in encouraging and not deterring market entry. Simplicity should not be a sole criterion for setting Energy Imbalance Prices. Prices should be a proxy of the short term costs of the SO in balancing the system. Costs should be targeted on those out of balance to ensure there is the most efficient outcome that will facilitate competition.

Some respondents also suggested that the current arrangements based on trying to achieve cost reflectivity are very simple in concept. The Proposed Modification would move away from that concept. Further, the electricity industry is not a simple one and any sensible solution would require a certain level of complexity.

One respondent noted that in addition to producing prices that are cost reflective, the cash-out mechanism should also meet the BSC objectives and be transparent and noted that the BSC Objectives do not specifically mention simplicity. One respondent noted that simplicity is not synonymous with transparency.

There was a counter view expressed by some respondents. This was that simplicity would promote competition by facilitating new entry and there should be more emphasis placed on this. There is no benefit in having cost reflective prices if only large participants have the resource to be able to understand them.

One respondent noted that it is not possible to have a fully cost reflective price due to the wide range of actions taken by the SO that are not primarily for restoring the net energy imbalance.

The Modification Group noted the responses and that it was a general view of smaller Parties to give more weight to simplicity. One member noted that the number of small Parties that had entered the market under the current arrangements indicated that they have not been deterred from entering the market. Another member noted that a simple solution would be to fix SBP at a high price to incentivise Parties to balance but this would not help Parties to enter the market. The member expressed the view that perhaps it was volatility and high prices that would be more likely to be deterring any potential new entrants.

Some members felt that it is complex to calculate Energy Imbalance Prices that reflect the costs of the SO. Where this can be simplified without losing accuracy then that would be beneficial.

One member noted that a simple solution would be to have a set of arrangements which were synonymous with the arrangements in the gas market where the Energy Imbalance Price is a single price based on the marginal action taken. The Group agreed that this would be a concept that might be discussed under the Ofgem-led cash-out review.

Question 10. Any Other issues that should be progressed as part of the Assessment Procedure

One respondent believed that more analysis on recent days to establish evidence of the defect would be beneficial. Group discussion on some additional analysis provided by the Proposer is described in 3.2.3 above.

One respondent noted that the Proposed Modification, by moving away from cost reflective prices would introduce a defect that is more substantial than the one it would remove.

Three respondents indicated that the costs of within Half Hour actions had not been assessed. This is where Parties that are balanced for a half hour may not have been balanced on a minute by minute basis. This would cause the SO to have to take intra half hour actions that, if not filtered out by the existing tagging mechanisms would feed into Energy Imbalance Prices. A half hour balanced Party would not face the costs of this and this cost would therefore be disproportionately borne by those Parties out of balance on a half hour basis. This means that those Parties that find it more difficult to balance due to the nature of their portfolio face increased costs than in a perfectly efficient market.

Question 11. Any other comments

Respondents had the following additional comments to make:

- For the defect:
    - The Group could have looked in depth at the current price stack to form a better understanding of the issues with the current tagging mechanism;
    - The materiality of the defect needs to be fully established; and
    - The defect could be better understood if the SO were to develop a method for categorising acceptances as they occur.
- Such a fundamental change could erode the value of existing contracts that were struck under the current arrangements.
- An unconstrained schedule should be in terms of a transmission system without constraints and not include generation and demand with no dynamic limitations (as P211 would).

The Group believed that the points on the defect are areas that should be picked up and considered outside of this Assessment, potentially in the cash-out review.

The Group also noted that the value of existing contracts were always subject to some element of regulatory risk. This would be the same for any pricing related modification.

APPENDIX 4: RESULTS OF IMPACT ASSESSMENT

During the Assessment Procedure an impact assessment was undertaken in respect of all BSC systems, processes, documentation and parties. The following have been identified as impacted by P211.

For details of the costs associated with these impacts, please refer to Section 3.

Unless otherwise noted, the impacts below are for both the Proposed and Alternative Modifications.

a) Impact on BSC Systems and Processes

System / Process	Impact of Proposed/Alternative Modification
Settlement	The amendment of the Energy Imbalance Price calculation impacts the derivation of the Energy Imbalance Prices. The BMRA and SAA systems and processes will be impacted.
Reporting	It is envisaged that the revised Energy Imbalance Prices will be reported within the current interface structure. It will be necessary to amend the Settlement Report (SAA-I014) to reflect the new price derivation (including the new parameters for the Potential Alternative). This will require additional reporting on the elements that make up the EPUS based prices. Specifically for the SAA-I014: • the DAOV, DABV, EBVA and/or ESVA per BM Unit and Bid-

System / Process	Impact of Proposed/Alternative Modification
	Offer number that resolves the NIV; • the DAOV, DABV, EBVA and/or ESVA per BM Unit and Bid-Offer number that have been PAR tagged; and • the DAOV and DABV per BM Unit and Bid-Offer number that have been EPUS Arbitrage tagged.

A copy of the full BSC Agent impact assessment for the Proposed Solution and the potential Alternative are attached as separate documents, Attachments 4 and 5 (respectively).

b) Impact on BSC Agent Contractual Arrangements

BSC Agent Contract	Impact of Proposed/Alternative Modification
LogicaCMG	The SAA and BMRA System will be impacted. SAA reporting is affected. The SAA and BMRA Service Descriptions will also be impacted.

c) Impact on BSC Parties and Party Agents

As this Modification is a change to the Energy Imbalance Calculation, this is a significant change to one of the main tenets of the BSC Arrangements that will impact Settlement for all BSC Parties. Recipients of SAA reports (SAA-I013) will be affected by changes to the information provided. Additionally, Parties will be impacted by the change to sub-flow 1 of the Settlement Report (SAA-I014).

There were 6 responses to the Party Impact Assessment which ranged from no impact or cost to a Party who estimated that a number of internal systems would require updating at a cost of between £50,000 and £100,000 and take 6 months to implement.

Full copies of the Party and Party Agent impact assessment responses are attached as separate documents, in Attachment's 8 and 9 respectively.

d) Impact on Transmission Company

The Transmission Company impact assessment for P211 Proposed is included as Attachment 10.

e) Impact on BSCCo

Area of Business	Impact of Proposed/Alternative Modification
BSCCo Systems	The Trading Operations Market Assurance System (TOMAS) will be impacted. Any change to the structure of SAA-I014 will impact ELEXON's Gatekeeper software.
Other (e.g. costs, staffing, etc.)	• Industry Guidance notes may require revision to reflect changes to the approach to calculation of Energy Imbalance Prices. • The Change Implementation Team will be required to manage implementation of P211. • Corporate Assurance will be required to support the implementation project. • The Design Authority team will provide Technical Assurance

Area of Business	Impact of Proposed/Alternative Modification
	during the implementation project.

f) Impact on Code

Code Section	Impact of Proposed/Alternative Modification
Section Q 'Balancing Mechanism Activities'	Section Q may require amendment if there are changes to the BM data provided by NGET.
Section T 'Settlement and Trading Charges'	Section T would require amendment to detail the changes to the Energy Imbalance Price calculation.
Section V 'Reporting'	Section V would require amendment to detail the Reporting changes.
Annex X	Annex X would require amendment to introduce new, and remove any redundant, definitions.

A copy of the draft legal text to give effect to these changes can be found in Appendix 1.

g) Impact on Code Subsidiary Documents

Document	Impact of Proposed/Alternative Modification
SAA SD	The SAA Service Description will be impacted.
BMRA SD	The BMRA Service Description will be impacted.

h) Impact on Core Industry Documents/System Operator-Transmission Owner Code

Document	Impact of Proposed/Alternative Modification
Grid Code	Note that as operational parameters MIL and MEL will now also be used as a trading parameter to create the EPUS. For the Potential Alternative, SEL, SIL RUR and RDR will also be used as trading parameters. This degree of this impact is dependent on Parties behaviour.

i) Impact on Other Configurable Items

Document	Impact of Proposed/Alternative Modification
SAA User Requirements Specification (and system documentation)	SAA documentation would require amendment to detail the amendments to the Energy Imbalance Price calculation.
BMRA User Requirements Specification (and system documentation)	BMRA documentation would require amendment to detail the amendments to the Energy Imbalance Price calculation.
BSC Business Process Model	The ELEXON BPM would require amendment to reflect the amendments to the Settlement calculations.
Interface Definition and Design	The IDD parts 1 and 2 will be impacted by the changes.

j) Impact on BSCCo Memorandum and Articles of Association

No impact.

k) Impact on Governance and Regulatory Framework

No impact.

APPENDIX 5: DESCRIPTION OF POTENTIAL ALTERNATIVE REJECTED BY THE GROUP

The potential Alternative considered and abandoned by the Group is the same as the Proposed Modification described in Section 2 above with two changes. First, rather than using Period FPN, MIL and MEL data as described in Figure 2 of Section 2, spot values for each will be used to better represent the actual volumes available. Secondly, an additional set of rules using dynamic parameters to modify the Bid and Offer volumes that are used to make up the EPUS stack. This was an attempt to better reflect what Bid and Offer volumes are actually 'available' to the System Operator, given that certain volumes cannot be accessed for energy balancing purposes, due to the dynamics of the plant (such as the time required to begin generating from a zero output position).

For the purposes of the abandoned potential Alternative, it was assumed that the SO can start instructing plant from Gate Closure and this is why Gate Closure is used as the starting point within these additional rules. The reason for choosing Gate Closure is because there is relative price and volume certainty for each BMU at this time. Additionally, it is at this point that the SO carries out its final assessment of its operating plan.

The Group analysed recalculated prices for two sets of rules. The first set included all 6 rules below and the second set included only the first 5 rules.

The dynamic parameter rules are:

1. DAOV and DABV qualifying rule when NDZ is greater than 89 minutes and FPN is equal to zero;
2. Applying RUR and Run Down Rates (RDR);
3. Where FPN is less than the Stable Export Limit (SEL) at Gate Closure (broken into minute and half hourly resolution);
4. Re-pricing Bid-Offer pairs that exist between 0MWh and SEL or between 0MWh and Stable Import Limit (SIL); and
5. The minimum of MEL and MIL at Gate Closure or at the end of the Settlement Period should be used.
6. Rejected Rule: DAOV and DABV qualifying rule when NDZ is less than or equal to 89 minutes and FPN is equal to zero with Run Up Rate (RUR) applied.

Note that the SEL, SIL, RUR and RDR data will all be sourced from data provided to the SO under the obligation in the Grid Code and, for the purposes of this potential Alternative, the BSC will use the Grid Code definitions of these parameters.

These rules are described in more detail below:

Rule 1. DAOV and DABV qualifying rule based on NDZ > 89 minutes. This rule excludes all potential DAOV or DABV for a BMU where the Notice to Deviate from Zero (NDZ) at Gate Closure is greater than 89[37] minutes and the FPN for the Settlement Period is equal to zero for the entire Settlement Period.

This rule removes from the EPUS stack volumes that would have potentially otherwise appeared but would be considered not practical for the SO to obtain without perfect foresight prior to Gate Closure.

Rule 2. RUR and run down rates.

[37] Note that currently Gate Closure is one hour prior to the start of the Settlement period and the Settlement Period is thirty minutes in duration. Hence cut–off is one minute less this total time, i.e. 89 minutes.

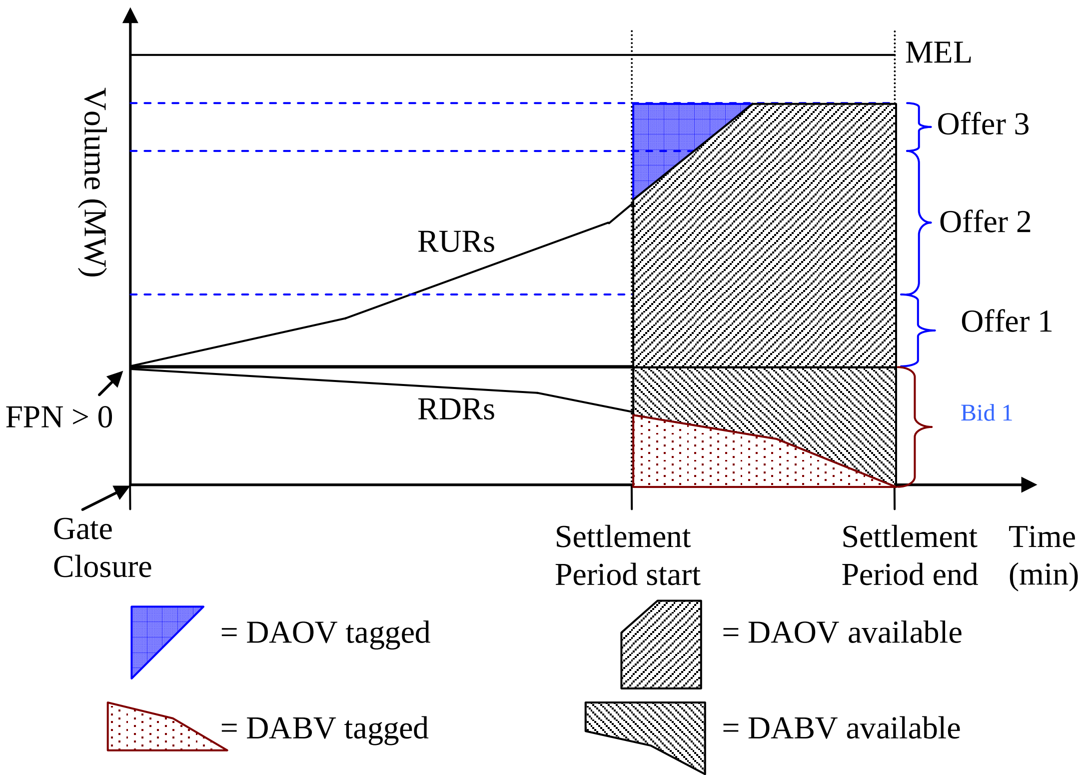
Similarly to Rule 1, this rule would remove from the EPUS stack volumes that would have potentially otherwise appeared but would be considered not possible for the SO to obtain without perfect foresight prior to Gate Closure.

The volume of DAOV and DABV that should be included for a BMU should be restricted by the RUR or Run Down Rates (RDR) of that BMU. This will be the case for a BMU with any level of FPN. If the submitted Bid/Offer pair, or a proportion of it, can be accessed from Gate Closure[38] with the submitted ramp rates applied then this volume can be included as DAOV or DABV.

Note that the BMU is considered to ramp from the FPN at Gate Closure (as opposed to any SCADA[39] snapshot of what the BMU was actually doing at Gate Closure).

The available DAOV and DABV are shown in Figure 1.

Figure 1. Rule 2 – Minute and half hourly Resolution



Similarly to Rules 1 and 2, this rule would remove from the EPUS stack any volumes that would have potentially otherwise appeared, but would be considered not possible for the SO to obtain without perfect foresight prior to Gate Closure. This rule better reflects the physical capabilities of BMUs to provide (or remove) the MWh offered (or bid).

Rule 3. Where FPN is less than SEL.

This rule seeks to exclude any volume that would not be accessible due to a generation unit desynchronising. It reflects that once a unit is below its declared SEL at Gate Closure that the unit could not be requested to increase load again (until it can re-synchronise).

If a BMU is operating at less than SEL (between 0 and SEL) at Gate Closure (for the Settlement Period in Question) indicated by the FPN[40] for that instant, and the FPN is decreasing in the SP after

[38] It is assumed that the SO has the foresight to request a BMU to start ramping from the instant of Gate Closure, if it is required to balance the system.

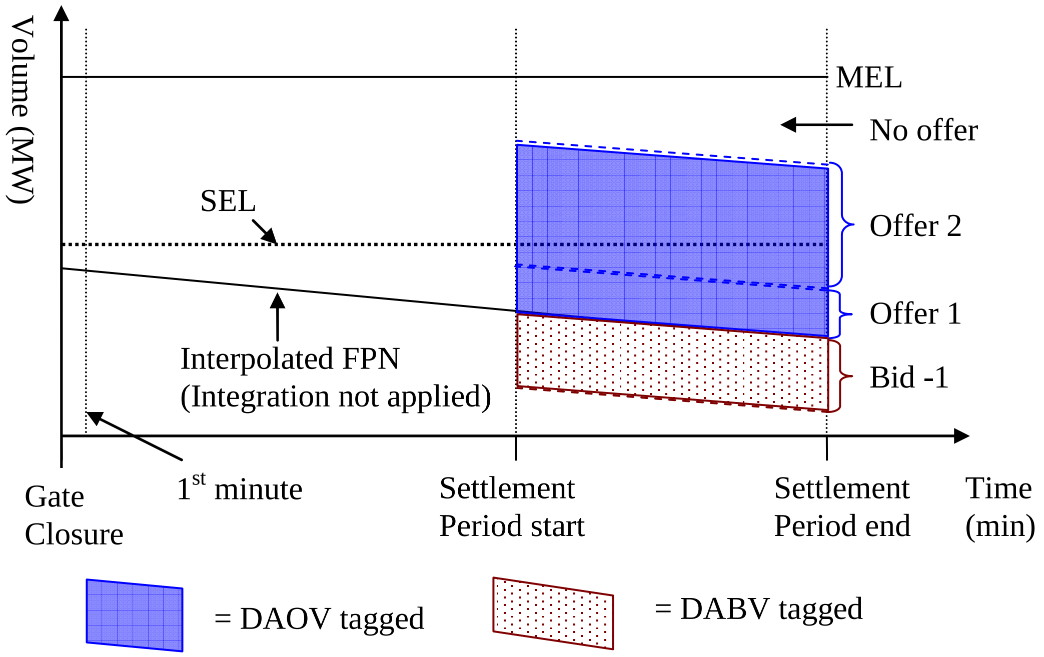
[39] Supervisory Control And Data Acquisition. SCADA systems are used for collecting real time data for what MWh a BMU is importing or exporting.

[40] Use the point variable where one exists for this minute or use the point variable discovered by linear interpolation.

Gate Closure[41] (i.e. the FPN for the Settlement Period in Question is less than the FPN for the first Settlement Period past Gate closure), then no volume can be accessed for the Settlement Period in question.

This is shown in Figure 2.

Figure 2. Rule 3 – FPN less than SEL at Gate Closure



In addition to the above three dynamic rules above there are two further rules that will be applied in each half hour. These are:

Rule 4. Re-pricing Bid-Offer pairs that exist between 0MWh and SEL or between 0MWh and SIL.

P211 Potential Alternative seeks to provide a proxy for the price of DAOV and DABV that exists between SEL and zero or between SIL and zero. This is because, once a BMU is dispatched within these ranges, the whole volume has to be taken by the SO, as the BMU in reality would have to run all the way to zero.

Therefore, for any Bid-Offer pairs that exists between 0MWh and SEL or between 0MWh and SIL, the price that the volume should appear as in the EPUS stack is the volume weighted average of the Bid-Offer bands below SEL (or above SIL)[42].

For the avoidance of doubt, the price associated with DAOV and DABV will be equivalent to the price submitted for the Bid-Offer pair number except where DAOV or DABV exists below SEL (or above SIL).

As a simplified example, consider period values for FPN and SEL as below. If:

FPN = 200MW

SEL = 100MW

Bid-Offer pair -1 (n = -1) is a 70MW band at £20/MW,

Bid-Offer pair -2 (n = - 2) is a 60MW band at £10/MW,

[41] This is to differentiate between a unit that is synchronising and desynchronising.
[42] It should be noted that when FPN is between zero and SIL (negative, therefore importing) that the average of the Bids will be the volume between FPN and SIL.

Bid-Offer pair -3 (n = - 3) is a 30MW band at £5/MW,

Then the average volume weighted cost for the DABV below SEL is £7.5/MW. (Given that the Bid Offer pairs run parallel to the FPN and therefore the volume below SEL is 30MW of Bid-Offer pair -2 and 30MW of Bid-Offer pair -3).

Conversely for the example where:

FPN = 10MW

SEL = 100MW

Bid-Offer pair 1 (n= 1) is a 70MW band at £10/MW,

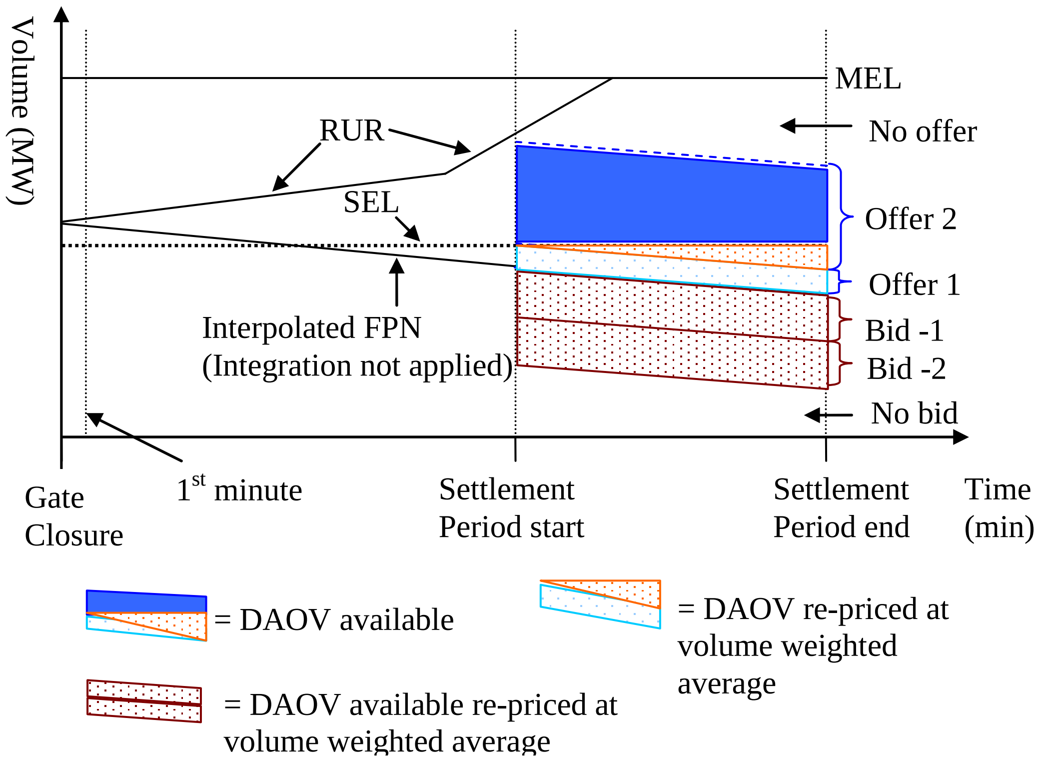
Bid-Offer pair 2 (n = 2) is a 60MW band at £20/MW,

Bid-Offer pair 3 (n = 3) is a 30MW band at £25/MW,

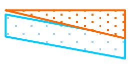
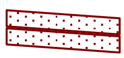
Then the average volume weighted cost for the DAOV between FPN and SEL is £12.2/MW. (Given that the Bid Offer pairs run parallel to the FPN and therefore the volume below SEL is 70MW of Bid-Offer pair 1 and 20MW of Bid-Offer pair 2).

The concept of this Rule 4 can also be shown in Figure 3 below.

Figure 3. Rule 4 – FPN greater than or equal to SEL at one minute past Gate Closure



Where:

- the DAOV below SEL represented by the area  should be priced at the volume weighted average price of the DAOV in this area; and
- the DABV below SEL represented by the area  should be priced at the volume weighted average price of the DABV in this area.

Rule 5. Minimum of MEL and MIL at Gate Closure or end of the Settlement Period.

The MEL (and MIL) used for each BMU in each Settlement Period will be the lower of the MEL (and MIL) submitted by and existing at Gate Closure or the MEL (and MIL) declared before the end of the Settlement Period.

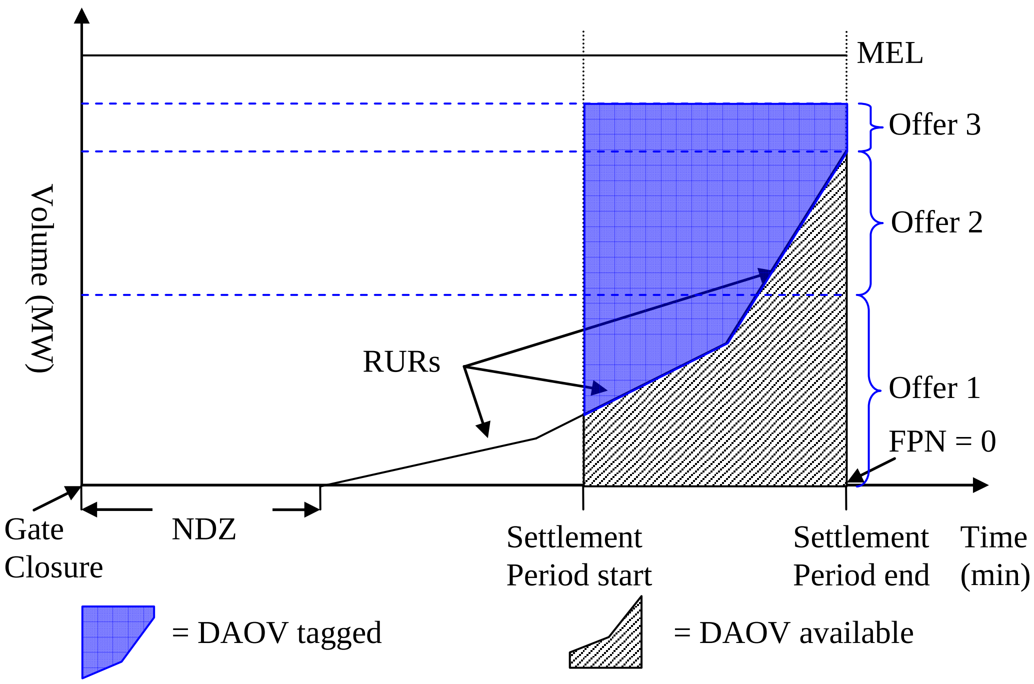
This rule will remove the possibility of Parties changing MEL (and MIL) after Gate Closure for any potential gain[43].

Rejected Rule: DAOV and DABV qualifying rule based on NDZ > 89 minutes NDZ, RUR and FPN = 0.

When an FPN is zero at the beginning of the Settlement Period in question, and NDZ is less than or equal to 89 minutes, start profiling each BMU at a time from 'Gate Closure plus NDZ' using the declared Run Up Rates (RURs)[44]. Then the available volume (for the Settlement Period in question) below this profile can be included as DAOV (providing there are existing Bid/Offer pairs submitted for that BMU in that Settlement Period).

This rejected rule will add the time notified in the NDZ from the instant of Gate Closure to represent the expected synchronisation time of the unit. It will then profile the BMUs ramp up in generation according to the RUR supplied for the BMU[45] in the Settlement Periods from Gate Closure up until the end of the Settlement Period in question. Only DAOV that lies beneath the RUR (as determined by linear interpolation from the RURs and elbow points submitted) will be included as DAOV. The available DAOV is represented in Figure 4.

Figure 4. Rejected Rule



The DAOV that would have been tagged is shown as the blue shaded area in the above Figure 4 above the RUR and will not be included in the EPUS stack of P211 Potential Alternative.

The Group initially believed that this rule would better reflect the physical capabilities of a generation unit to provide the MWh offered, i.e. NDZ and RUR.

[43] Note that Grid Code provisions BC1.4.2 (a), (c) and (e) refer to Parties obligations for submitting physical and dynamic data.
[44] This will require the RURs that are valid from Gate Closure to end of the Settlement Period in question (three Settlement Periods including the two Settlement Periods after Gate Closure but before the start of the Settlement Period in question).
[45] RUR and RDR are defined terms in the BSC. The definition is 'Has the meaning given to that term in BC1 of the Grid Code'. Note that 3 RURs or RDR can apply for any BMU within the range of 0.2-40MW per minute.

However, the analysis (presented in Figures 25 to 27 of Attachment 1) shows that for periods of system stress this could lead to extremely high prices of £1,136/MWh in Settlement Period 35 on 29 December 2005 and £20,752/MWh in Settlement Period 38 on 13 March 2006. These spurious results were not reflective of the costs faced by the SO in balancing the system in those Settlement periods. This was caused by the application of this rejected rule which excluded units (with an FPN of zero) that were on at Gate Closure and were used by the SO to resolve the market imbalance. This is because the rejected rule takes into account the minutes notified in the NDZ from Gate Closure and then applies the ramp rates (i.e. if a unit with an FPN of zero had an NDZ of 89 minutes, then it would only start ramping 1 minute before the end of the Settlement Period).

Therefore the Group determined to modify this rule for the potential Alternative considered. The modification would start a unit ramping up from 0MWh from Gate Closure and would not apply the minutes notified in the NDZ (i.e. it was assumed that the plant was effectively warmed earlier and then synchronised at gate closure). This is captured by Rule 2 above. The analysis of the potential Alternative considered is included as Attachment 2.

APPENDIX 6: IMPACT ASSESSMENT FOR THE POTENTIAL ALTERNATIVE REJECTED BY THE GROUP

Alternative MODIFICATION IMPLEMENTATION COSTS

		Stand Alone Cost Detailed reporting	Stand Alone Cost Reduced Reporting	Tolerance
Service Provider Cost				
	Change Specific Cost	£ 204,150	£ 194,800	+/- 0%
	Release Cost	£ 51,850	£ 51,850	+/- 0%
	Total Service Provider Cost	£ 256,000	£ 246,650	+/- 0%
Implementation Cost				
	External Audit	£ 0		+/- 0%
	Design Clarifications (reduced reporting)	£ 10,208	£ 9,740	+/- 0%
	Additional Resource Costs	£ 0	£ 0	+/- 0%
	Additional Testing and Audit Support Costs	£ 5,000	£ 5,000	+/- 10%
	TOMAS changes	£ 79,310	£ 79,310	+/- 5%
Total Demand Led Implementation Cost (reduced reporting)		£ 350,518	£ 340,700	+/- 10%

Port and Migrate Costs

Service Provider Cost	Port and Migrate	£ 50,000	£ 50,000	+/- 0%

ELEXON Implementation Resource Cost		Detailed Reporting 315 man days £ 69,300	Reduced Reporting: 259 man days £ 56,980	+/- 5%
Total Implementation Cost Reporting		£ 469,818	£ 447,680	+/- 10 %

APPENDIX 7: REJECTED ALTERNATIVE MODIFICATION

6.2.1 Modification Group's Initial Discussions

The Modification Group were unconvinced that the potential Alternative Modification would better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the Proposed Modification.

A number of members felt the potential Alternative went some way to addressing their concerns that the solution should seek to only include those Bids and Offers that can be 'accessed' by the SO and was therefore more accurate than the Proposed. However, this increases the complexity of the solution. Those members further commented that the potential Alternative had already had to be modified by the Group to account for anomalous results on certain stress days and there was a concern that there were other anomalies associated with the rules that would require further Modification if this potential Alternative was approved.

Further comments were made in relation to the lack of transparency of the potential Alternative in that data would be available to view, but it would be more difficult to validate how the Energy Imbalance Price was calculated. This reduces the predictability of Energy Imbalance Prices.

The Group member who believed that the Proposed Modification did better facilitate the objectives did not believe the potential Alternative better facilitates the objectives due to the complexity and noted that the prices obtained as a result of the rules being applied were (save for the stress days identified) not very different.

One Group member was undecided as to whether the potential Alternative proposal better facilitated the objectives. They recognised that this option presented a trade off between a generally less cost reflective price but one that would not be impacted by any actions taken to resolve constraints. This Group member felt that the further price analysis that is scheduled to be published later on in this consultation would enable them to take a better view on this question.

The Group therefore concluded that the Potential Alternative would not facilitate the objectives better than the current baseline.

6.2.2 Views of Respondents to Assessment Procedure Consultation

The majority view of respondents to the Assessment Procedure consultation was that the potential Alternative Modification would not better facilitate the achievement of **Applicable BSC Objectives (a), (b), (c) and (d)**.

With the exception of the concerns regarding dynamic parameters, the following arguments were expressed by respondents in support of this view in addition to the arguments for the Proposed Modification listed above:

- The dynamic rules are not sufficiently robust and can potentially result in spurious outcomes which are not reflective of the SO costs of balancing the system. This would be detrimental the achievement of **Applicable BSC Objective (c)**; and
- The increased level of complexity would deter market entry. This would be detrimental the achievement of **Applicable BSC Objective (c)**

The minority view of respondents to the Assessment Procedure consultation was that the potential Alternative Modification would better facilitate the achievement of **Applicable BSC Objectives (b), (c) and (d)**.

In addition to the arguments for the proposed Modification listed above, the following arguments were expressed by respondents in support of this view:

- A more predictable price would provide more forward certainty and would make the contracting strategies of some market Participants individually more economically beneficial. This would better facilitate the achievement of **Applicable BSC Objective (c)**.

There was a split view of respondents to the Assessment Procedure consultation as to whether the potential Alternative Modification would better facilitate the achievement of **Applicable BSC Objectives** when compared to the Proposed Modification.

The following arguments were given in support of the potential Alternative better facilitating the Applicable BSC Objectives than the Proposed Modification:

The inclusion of dynamic parameters would:

- Theoretically provide a more cost reflective price as there is a reduced chance that volumes inaccessible to the SO could enter the price calculation;
- Be an important factor to be able to reduce the potential for gaming; and
- Would allow the price to respond (albeit imperfectly) to market shocks.

The following arguments were given in against the potential Alternative better facilitating the Applicable BSC Objectives than the Proposed Modification:

The inclusion of dynamic parameters would:

- Add too much complexity without any real gain in cost reflective prices (evidenced by the small difference in prices between the Proposed Modification and potential Alternative;
- The potential to remove volume that the SO could have actually accessed and thus increase the likelihood of spurious results; and
- Not all dynamic constraints were taken into account.

6.2.3 Modification Group's Conclusions

These are captured in Section 4.2