115/05

ASSESSMENT REPORT for Modification Proposal P199

'Quantification of Demand Control in the BSC as instructed under OC.6 (c), (d) & (e) of the Grid Code'

Prepared by: P199 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 P199 seeks to make provisions for the treatment of Demand Control within the Balancing and Settlement Code. P199 proposes to treat the demand reduction for each Balancing Mechanism Unit (BM Unit) as an Offer Acceptance. The Offer Volume would be included in the Energy Imbalance Price calculations as un-priced. No payment would be made to the affected BM Units for the Offer Acceptance, but the volume would be reflected in the affected Parties' credited energy.

P199 proposes the inclusion of a process whereby Parties affected by Demand Control may query the amount of Demand Control Volume allocated to them in light of additional information.

Alternative Modification P199 seeks to make provisions that Parties affected by Demand Control would receive a payment for the associated Demand Control Volumes. The payment for the associated Demand Control Volumes would be made at the Market Price.

MODIFICATION GROUP'S RECOMMENDATIONS

The P199 Modification Group invites the Panel to:

- **AGREE that Proposed Modification P199 should not be made;**
- **AGREE that Alternative Modification P199 should not be made;**
- **AGREE that Alternative Modification P199 better facilitates the BSC Objectives when compared to Proposed Modification P199;**
- **AGREE a provisional Implementation Date for Proposed and Alternative Modifications P199 of 22 February 2007 if an Authority decision is received on or before 23 August 2006, or 28 June 2007 if the Authority decision is received after 23 August 2006 but on or before 19 December 2006;**
- **AGREE the draft legal text for Proposed and Alternative Modifications P199;**
- **AGREE that Modification Proposal P199 be submitted to the Report Phase; and**
- **AGREE that the P199 draft Modification Report be issued for consultation and submitted to the Panel for consideration at its meeting of 13 July 2006.**

[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 P199.

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	☐
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 Codes	☐
Distribution Connection Agreements	☐
Distribution Use of System Agreements	☐
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	☐

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1 EXECUTIVE SUMMARY

1.1 Overview of Key Conclusions

The key conclusions of the P199 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);
- **AGREED** by **MAJORITY** that an Alternative Modification should be developed in order to provide payment to those Parties who had been subject to Demand Control to better facilitate the achievement of Applicable BSC Objective (c), when compared to the Proposed Modification.
- **AGREED** that the Alternative Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (b), (c) and (d), compared to the current baseline.
- **NOTED** that the stand-alone implementation costs for the Proposed Modification were estimated to be £91,479 or, if implemented as part of a Release, an incremental cost of £27,262.
- **NOTED** that the stand-alone implementation costs for the Alternative Modification were estimated to be £102,239 or, if implemented as part of a Release, an incremental cost of £38,022.
- **AGREED** a provisional Implementation Date for Proposed Modification P199 of 22 February 2007 if an Authority decision is received on or before 23 August 2006, or 28 June 2007 if the Authority decision is received after 23 August 2006 but on or before 19 December 2006;
- **AGREED** a provisional Implementation Date for Alternative Modification P199 of 22 February 2007 if an Authority decision is received on or before 23 August 2006, or 28 June 2007 if the Authority decision is received after 23 August 2006 but on or before 19 December 2006; and
- **AGREED** that the draft legal text delivers the intended solution for the Proposed/Alternative Modification.

A description of the P199 solution is provided in Section 1.2. Further information regarding the Group's discussions of the areas set out in the P199 Terms of Reference is contained in Section 2. Details of the Group's recommended implementation approach and the estimated implementation costs of P199 are described in Section 3.

A summary of the Group's views regarding the merits of the Proposed Modification and Alternative Modification 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.

1.2 Description of Modifications

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

For a full description of the original Modification Proposal as submitted by The Proposer, please refer to the P199 Initial Written Assessment (IWA, Reference 1).

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1.2.1 Proposed Modification

P199 seeks to make provisions for the treatment of Demand Control[2] within the Balancing and Settlement Code. In a Demand Control scenario P199 proposes to treat the demand impact for each BM Unit as an un-priced Offer Acceptance. In summary this would mean that:

- The Total Demand Control Volume would be included in the Energy Imbalance Price calculations and the volume would be un-priced;
- The Total Demand Control Volume would be apportioned to affected Parties and reflected in their Energy Imbalance Volume calculations;
- No payment would be made to affected Parties for the Offer Acceptance; and
- There would be a claims process whereby Parties affected by Demand Control might query the amount of Demand Control Volume allocated to them in light of additional information they may possess.

1.2.2 Alternative Modification

The P199 Alternative Modification seeks to make provisions for the treatment of Demand Control within the Balancing and Settlement Code and compensate those Parties who have bought energy in good faith, but are unable to then sell this energy on to customers whose demand has been reduced through Demand Control.

P199 Alternative Modification is identical to the Proposed Modification, but payment would be made to affected BM Units for their apportioned Demand Control Offer Acceptance at the Market Price.

1.3 Key Issues

1.3.1 Preference for Current Baseline

The majority of the Group was not convinced that P199 or the P199 Alternative Modification provided further incentives on Parties to balance or gave further signals to the Market above the current baseline.

Whilst the majority of the Group was sympathetic to the principles behind P199, there was concern that the inaccuracies in the Demand Control Volume identification and allocation undermined any potential benefit of the P199 proposal.

1.3.2 Reflection of Demand Control Volumes into Settlement

The majority of the Group supported the principle of reflecting Demand Control Volumes into the Energy Imbalance Price calculation and Parties' Energy Accounts. It was felt that this targets the cost of imbalance more appropriately, during periods of Demand Control on to those Parties with Imbalance Positions.

1.3.3 Allocation of Demand Control Volume

There was substantial discussion around the Demand Control Volume allocation process and whilst it was recognised that the information available limited the feasible solutions, practicable approaches (including the preferred approach progressed as a solution to P199) were felt to be unsatisfactory in their accuracy. For further details please see Appendix 6.

Additional concerns were raised over the quality of information used in the P199 volume allocation process. It was felt that both the accuracy of the Total Demand Control Volume and the use of historic data to apportion Demand Control Volumes were questionable. It was felt that the approach to identifying Total Demand Control Volumes was unclear and appeared not to cater for a number of factors, including:

[2] With respect to P199 "Demand Control" is defined, and limited to, those matters covered by parts OC6.1.2 (c), (d) and (e) of the Grid Code.

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- Demand reduction actions taken in the same Settlement Period as the Demand Control instructed period, which are not part of Demand Control as instructed by the System Operator;
- Recognising the impact of Embedded Generation on Supplier BM Unit volumes; and
- Variations in conditions between the Demand Control Settlement Period and the historic Settlement Period utilised to derive the share of Demand Control Volumes.

1.3.4 Claims Process

The majority of the Group and respondents recognised the additional complexity that would be introduced by a claims process but felt that, in light of the concerns with Demand Control Volume identification and allocation (see 1.3.1, 1.3.2 and 1.3.3), it was essential to have some form of claims process in place. It was also noted that imbalance prices during Demand Control periods are likely to be high and the potential materiality of any error in the allocation of Demand Control Volumes would be significant to participants.

It was felt that no mechanism could cater for every possible scenario and it was also recognised that there is a lack of knowledge amongst the Industry as to how Demand Control would actually be implemented and what its potential impact would be.

There was extensive discussion over how a claim process would take place, what would be considered valid grounds on which to appeal and how the process would be implemented. The Group decided upon an Claims Process as detailed in Section 2.4.

1.3.5 Payments to Affected Parties

The majority of the Group were in support of making payment to Parties impacted by Demand Control. It was felt that this would be consistent with the principle that Parties delivering energy to the system should be paid for that energy. The absence of such a payment was seen as a negative aspect of the Proposed Modification. The Group developed an Alternative Modification to include a payment to affected Parties.

1.3.6 Concerns with Grid Code

The Group and consultation responses highlighted concerns over the transparency and explicitness of the Grid Code (with regards to the Demand Control process) and the quality of information provided to the System Operator (SO) by the Licensed Distribution System Operator as stipulated by the Grid Code.

Some Members felt that the Grid Code did not place sufficient obligations upon the SO or LDSO, to ensure that the Demand Control Volumes provided by the SO are suitable for commercial use in Settlement. However, the Group noted that this was outside the scope of P199.

2 AREAS RAISED BY THE TERMS OF REFERENCE

This section outlines the conclusions of the Modification Group regarding the areas set out in the P199 Terms of Reference.

2.1 Demand Control Triggers and Reporting

Currently, there are three system warnings available to the SO:

- Notification of Insufficient System Margin (NISM);
- High Risk Demand Reduction (HRDR); and
- Demand Reduction Imminent (DRI).

Under OC6 of the Grid Code, the SO is not required to proceed through the process of issuing the standard system warnings in order of severity, before issuing a Demand Control Instruction (DCI). The following types of Demand Control can be instructed by the SO at any time as, and when, required:

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- Demand reduction instructed by NGET (OC6.1.2(c)); and
- Emergency manual Demand Disconnection (OC6.1.2(e))

In addition to the above, the following can occur at any time:

- A Demand Control action undertaken by the SO in accordance with OC6.7.7 or OC6.7.8
- An automatic low-frequency Demand Disconnection under OC6.1.2 (d).

Currently, the Grid Code requires that, to initiate Demand Control:

- The SO should instruct the LDSOs in accordance with sections OC6.1.2 (c) and (e) of the Grid Code; or
- The SO undertakes action(s) under OC6.7.7 or OC6.7.8; or
- An automatic action is taken under OC6.1.2 (d).

P199 covers all the types of Demand Control detailed in the bullet points above. At the end of Demand Control, the Grid Code requires the SO to instruct the LDSOs to start reconnecting demand in accordance with OC6 (but only where the demand reduction was undertaken in accordance with OC6.1.2 (c), (d) or (e)).

The SO issues OC6.1.2 (c) DCIs in blocks (4-6% of the total demand) to LDSOs. However, the SO does not have any control over how LDSOs expedite Demand Control Instructions. Instead, LDSOs are required to inform the SO of the amount by which demand was reduced under any of the OC6.1.2 actions[3]. The System Operator can then decide if more OC6.1.2 (c) Demand Control Instructions need to be issued to the same LDSOs or others.

Grid Code sections, OC6.5.9 and OC6.6.8 require LDSOs to notify the SO of an estimate of the demand reduction that occurred within five minutes of the disconnection or restoration for Demand Control initiated by the SO or Automatic Low Frequency Demand Disconnection.

In addition to the obligations described in the Grid Code (and detailed above), P199 would introduce the BSC requirements to report the start and end time of Demand Control to Market Participants via the BMRS.

The Group noted that, in the Grid Code, all types of Demand Control are treated as Emergency Instructions. However, the rules in the BSC do not currently capture all Emergency Instructions. The Group discussed whether Directly Connected Sites should be included or excluded from Demand Control, as defined by the Demand Control legal text. To avoid overlap between the legal text for P199 and the existing legal text in section Q5.1.3 of the BSC and section BC2.9 of the Grid Code, the Group felt that it was necessary to explicitly state how Directly Connected Sites affected by Demand Control would be treated. The majority of the Group felt that it was not clear from section 2.9 of the Grid Code and section Q5 of the BSC if a Directly Connected Site, affected by Demand Control, would fall under the pre-existing Emergency Instructions. A Group Member felt that Directly Connected Sites are already adequately dealt with under section BC2.9 of the Grid Code ("Emergency Circumstances") and sections Q5.1.3, Q5.1.4 and Q5.3.1 of the BSC and should therefore be excluded from Demand Control. However, the majority counter view to this argument was that there should be consistency in how sites affected by Demand Control are treated, irrespective of whether they are, or are not, directly connected to the Transmission System.

Start of Demand Control

The LDSOs are instructed at the start of Demand Control

- Under Grid Code OC6.1.2 (c) and (e); or
- If the SO undertakes demand reduction under OC6.7.7 or OC6.7.8; or
- If under OC6.1.2 (d) automatic demand disconnection has occurred.

[3] Under OC6.1.2 (e), the LDSOs notify the SO of details of the amount of demand reduction or restoration achieved between 0600 and 1000 the following day.

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Once LDSOs have been instructed, the SO is required to send a system warning message as soon as possible following any of these Demand Control instruction(s) or event(s) to the BMRA notifying:

- The start time of the Demand Control Period;
- The affected LDSO(s); and
- The amount of Demand Control requested under Grid Code OC6.1.2 (c) and (e) or expected by the SO under OC6.7.7 or OC6.7.8 or under OC6.1.2 (e) (as both a MW value and percentage of Demand to be reduced in each GSP Group) per Settlement Period.

The start time of the Demand Control Period is:

- As defined by the SO in its notification to the industry that Demand Control has been instructed; or
- When the SO begins demand disconnection under OC6.7.7 or OC6.7.8; or
- The time the automatic demand disconnection has occurred.

End of Demand Control

The SO sends a system warning message to the BMRA as soon as possible following the instruction to the LDSOs to stop reducing demand (or when the SO stops demand disconnection under OC6.7.7 or OC6.7.8 or when action(s) under OC6.1.2 (e) cease), notifying:

- The time of the end of the Demand Control Period;
- The affected LDSO(s); and
- An estimate of the Demand Control achieved per Settlement Period.

The end time of the Demand Control Period is defined as the time the instruction to reconnect demand is issued by the SO.

Demand Control Settlement Periods are Settlement Periods that fall within the start and end time of Demand Control as notified by the SO. For the avoidance of doubt, Demand Control Periods are Settlement Periods that include, or fall between, the start and end time of Demand Control as notified by the SO[4].

2.1.1 Views of respondents to Assessment Procedure Consultation

A number of respondents felt that the Grid Code OC6 (the section pertaining to Demand Control) should be made more explicit and transparent with regards to the Demand Control process. OC6 details a number of potential methods that could be utilised to reduce demand.

The main concern respondents had was whether the existing Grid Code process is sufficient to accurately identify the volume of Demand Control, and participants impacted, in a manner suitable for use in Settlement.

2.1.2 Modification Group's Conclusions

The majority of the Group agreed with the concerns expressed in section 2.1.1 but felt that, whilst concerns over the explicitness of the Grid Code should be noted, they were outside of the scope of P199.

2.2 Determination of Total Demand Control Volume

P199 relies on the identification of the Total Demand Control Volume achieved in a Settlement Period; therefore the Group discussed how this value would be derived.

[4] Note: actions taken by the LDSOs under OC6.1.2 (e) may occur up to 30 minutes after the instruction, and there is no time limit on the SO actions under OC6.7.7 or OC6.7.8

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2.2.1 Modification Group's Initial Discussions

The Group recognised that the Total Demand Control Volume could only ever be an estimate and that it would be impossible to develop a methodology that would be entirely accurate for all possible circumstances.

The Group discussed how the Total Demand Control Volume could be obtained and four possible sources were identified:

- LDSO estimate;
- SO estimate (based on expected reduction in demand);
- By comparing actual National Demand (impacted by Demand Control) to a forecast of National Demand (excluding Demand Control); and
- By using profiling to estimate the demand of affected BM Units in the absence of Demand Control and comparing to the actual BM Unit demand (impacted by Demand Control).

Further details of the discussions surrounding the four approaches to Total Demand Control Volume determination can be found in Appendix 5.

The majority of the Group agreed that, in the absence of a practical alternative approach, the SO's estimate of Demand Control achieved should be used with the caveat that this should be the best possible estimate and, where extra information exists (such as affected BM Units), this should be provided.

As a minimum, the Group agreed that the following information should be provided to BSCCo by the SO, as soon as is reasonably practicable. It was noted by the SO that, due to the uncertainty surrounding the likely circumstances of a Demand Control event, it may not be possible to provide this information in one single submission. Different components of the required information would be provided to BSCCo as and when they became available:

- SO's 'Best Estimate' of Demand Control Volume(s) by LDSO area;
- Affected Settlement Day(s) and Settlement Period(s); and
- Affected LDSO area (used by BSCCo to infer GSP Group).

Additionally, any information that would enable Demand Control affected BM Units to be identified (so that the Demand Control Volume could be 'targeted' at these BM Units only) should be provided by the SO for use within Settlement.

In order to make use of SO provided data in Settlement, BSCCo would generate a mapping of LDSO areas to GSP Group. It is recognised that LDSOs do not map directly onto GSP Groups. However it is understood that, Demand Control would be issued to the incumbent LDSOs and could therefore be effectively tied to GSP Group.

The Group had significant concerns with the accuracy in the determination of the Total Demand Control Volume. The Group felt that the limited transparency of the Grid Code made it difficult to derive assurance of the accuracy of the SO provided estimate of the Total Demand Control Volume.

2.2.2 Views of respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
4a	Do you agree with the proposed methodology for the identification of Demand Control Volumes?	**5(27+1)**	**4(28)**	**1 (0+1)**

2.2.2.1 Provision of Total DC volume by SO

Most respondents recognised that the approach proposed by the Modification Group was a pragmatic solution. Several of the respondents felt that the System Operator (SO) is best placed to provide the most

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detailed estimate of Demand Control volumes. The SO can make use of a number of sources of data including their own demand forecasts and information provided to them under Grid Code OC6.5.9 and OC6.6.8 by the LDSOs. The majority of respondents supported placing an obligation on the SO to provide this information to the SAA and BSCCo as soon as is practicable, as well as making it publicly available on the BMRS.

One respondent had strong concerns over the Total Demand Control Volume being provided solely by the SO because of the lack of clarity of the processes as detailed in Grid Code OC6. Whilst several respondents felt it would be preferable to perform a check of this volume independently, they recognised that the information practically available limits the options available in the determination of Demand Control Volumes. Several respondents had concerns regarding how the SO would go about determining the Total Demand Control Volume and provide assurance that the figures presented are of the best accuracy possible. It was felt that determination of total volumes should be open to scrutiny and technical challenge in pursuit of a reasonably accurate estimate of volumes.

Respondents also had particular concerns about the terms of the Demand Control Process as detailed within Grid Code OC6. Some respondents felt that the SO was solely reliant upon the information provided to it by the LDSO (during such a time when the LDSO's principle concern would be that of system security), with no means to determine the accuracy of the data provided.

It was recognised that the derivation of the Total Demand Control Volume would not be simplistic and several potential complications were identified including:

- The treatment of different types of demand reduction (such as Automatic Low Frequency Demand Disconnection); and
- Specifically distinguishing between demand reduction resulting from the DCI in question and other demand reducing actions that have taken place outside of Demand Control as defined in P199.

It was difficult to understand how these factors would be taken into account in the SO estimate of Total Demand Control Volume.

2.2.3 Modification Group's Conclusions

The Group shared the same concerns as the respondents but agreed that, without a full understanding about how Demand Control would be implemented, the most appropriate approach to the identification of the Total Demand Control Volume is to rely on the SO's best estimate.

The Group agreed that an initial estimate should be provided by Working Day +2 wherever possible, but recognised that the primary concern during a Demand Control event would be the security of the system. Therefore, it was suggested that the SO should revise their estimate of the Total Demand Control Volume in the event of further information becoming available.

The majority of the Group agreed that a BSC obligation should be placed on the SO that, should any additional/better information become available it would enable the SO to improve their estimate of the Total Demand Control Volume. The Group decided that a revised estimate of this volume should be provided by the SO, 5 Working Days prior to the SF run (i.e. in time for the Demand Control Volume allocation to be recalculated at SF). It was felt this approach would allow for additional information to be taken into account, whilst providing a baseline against which the claims process could function (see section 2.4).

2.3 Volume Allocation

Under P199, the Total Demand Control Volume must be allocated across affected Parties and the Group discussed how this would be achieved.

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2.3.1 Modification Group's Initial Discussions

The Group recognised that the allocation of Demand Control Volumes would be an estimate and that it would be impossible to develop a methodology that would be entirely accurate for all possible circumstances.

The Group discussed how LDSOs (or, in the case of Directly Connected Demand, the SO) would select Parties and/or customers for disconnection in the event of demand reduction with the intention that this information might help better determine the Demand Control Volume and allocate it to only the BM Units affected by Demand Control. Discussions with the LDSO representatives in the Modification Group highlighted the following key points:

- Different LDSOs would probably use different approaches in disconnecting customers;
- Disconnection would be targeted in a way that would minimise impact for customers i.e. during a prolonged Demand Control scenario, the LDSO would cycle disconnection between customers;
- The level and quality of information available to the SO or ELEXON would vary between LDSOs based on their systems' capabilities; and
- In most cases the information readily available to the LDSO, SO and ELEXON would not be of a type 'translatable' to ELEXON systems (i.e. it is not held at a BM Unit level).

The Group decided that, because of the differences in the data used by the LDSOs (to implement Demand Control) and that used by the SAA (to allocate the Demand Control Volumes); a process that relied solely upon the provision of such information would not be viable.

The Group discussed how the Total Demand Control Volume could be allocated to affected BM Units and several possible approaches were identified:

- Allocating Demand Control based on Historic Demand (P138 approach); and
- Allocating Demand Control based on profiling.

2.3.1.1 Allocating Demand Control based on Historic Demand

This approach assumes that a BM Unit's share of the Total Demand Control Volume is equivalent to its share of demand in an historic reference period.

This method operates under the default assumption that all Suppliers, and therefore all BM Units in the affected GSP Group, are affected by Demand Control equally. The Group recognised that, although this is broadly true for voltage reduction, it would not necessarily be true when supply is disconnected. The Group also recognised that there would be circumstances when not all BM Units in the GSP Group are affected equally.

The Group recognised that this approach is inherently erroneous where the historic reference period does not accurately reflect the Demand Control Settlement Period. The Group investigated several different ways of deriving a BM Unit's share of the Total Demand Control Volume, and noted that the error remained significant even in the best approach.

2.3.1.2 Allocating Demand Control based on Profiling

The profiling approach required consideration of the effect of Demand Control on each affected BM Unit. Looking at each BM Unit individually, a forecast of Demand in the absence of Demand Control would be derived. This would then be compared to actual demand (which would include the impact of Demand Control) to derive an estimate of the impact of Demand Control on that BM Unit.

Any error in the forecast of demand (in the absence of Demand Control) would result in an error in the derived impact of Demand Control on that BM Unit. It was considered that these errors would be substantial.

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The derivation of the forecast of demand in the absence of Demand Control would require either a defined algorithm or a resource-intensive manual process. The majority of the Group considered this approach would not be practical.

Further details of the discussions surrounding the alternative methods can be found in Appendix 6.

The Group recognised that the allocation of Demand Control Volumes would be an estimate and that it would be impossible to develop a methodology that would be robust for all potential circumstances. It was suggested that a broad set of guidelines could be developed. The guidelines would set out the principles for the allocation of Demand Control Volumes, with a specific methodology for each occurrence of Demand Control to be agreed and developed post event to suit the particular circumstances. Whilst the Group recognised the advantage of a more flexible approach, it was agreed that a specific, clearly defined volume allocation methodology was essential (subject, where appropriate, to a claims process, see section 2.4).

Having considered several possible mechanisms, recognising that the process of volume allocation would always be subject to significant errors and that there were limitations on the information that would be available, the Group agreed the following process would provide a practical method for volume allocation. The approach detailed below makes use of historic demand and attempts to make use of additional information regarding impacted BM Units in the unlikely circumstances that it is available.

STEP 1: Identify Demand Control Group.

The GSP Demand Control Group would be defined as follows:

1. Where details of the BM Units in the relevant GSP Group are not provided by the SO in the Demand Control Report, the Demand Control Group will comprise all Supplier BM Units (i.e. those beginning 2_), in the relevant GSP Group, which were importing in the given Settlement Period (i.e. which have negative consumption in the Previous Equivalent Settlement Period used in the following volume allocation rules). Exporting BM Units and Embedded Generation are not included.

2. Where the SO has provided details of the BM Units in the relevant GSP Group impacted by Demand Control in the Demand Control Report the Demand Control Group will comprise of those BM Units in the relevant GSP Group identified by the SO in the Demand Control Report. Where information exists that would allow the targeting of the Demand Control Volume on some, but not all, of the affected BM Units, the default approach of apportioning the Demand Control Volume across the affected GSP Group should be used.

3. Where the SO has applied Demand Control to a customer with Directly Connected Demand, this customer would be treated as a separate Demand Control Group for the purposes of Demand Control Volume identification and allocation.

STEP 2: Determine each affected BM Unit's share of the Demand Control Volume

The following rules would be applied to calculate the volume:

1. The historic reference period (Previous Equivalent Settlement Period) is defined as the same Settlement Period on the same day of the week for which there had been an Initial Settlement Run (SF) performed.

2. Long and Short days would be dealt with in the same manner as the Equivalent Day as defined in section T4.2.2 (d) of the BSC;

3. Using data from the latest available Settlement Run for the Equivalent Settlement Period, the Metered Volume of all the BM Units in the relevant GSP Demand Control Group for the equivalent Settlement Period of the Day identified is summed;

4. Using data from the latest available Settlement Run for the Previous Equivalent Settlement Period, the Metered Volume of each BM Unit is divided by the total over the relevant GSP Demand Control

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Group (as calculated in step 2) to give the proportion of demand per BM Unit within the GSP Demand Control Group; and

5. For each BM Unit in the affected GSP Demand Control Group, derive the Demand Control Volume for the BM Unit by multiplying the Total Demand Control Volume for the GSP Group (as notified by the SO by Working Day + 2 in the Demand Control Report) by the proportion of each BM Unit's demand in the GSP Demand Control Group as calculated above.

STEP 3: Reconciliation of Volume Allocation

This calculation is initially carried out at Interim Information run (II) and would be reconciled at SF:

- At II the Previous Equivalent Settlement Period would be from 2-3 weeks prior to Demand Control Period, and data used in the calculation would be SF Run data; and
- At SF the Previous Equivalent Settlement Period would be from 1 week prior to the Demand Control Period, and data used in the calculation would be SF Run data (since more recent SF data would be available than at II).

Note also that no specific processing is included to account for Bank Holidays i.e. volumes for a Bank Holiday Monday would be estimated in the same way as those for a working day.

The inclusion of a claims process into P199 means that the volume allocation will not be recalculated once RF data has become available for the Previous Equivalent Period one week prior to the Demand Control Settlement Period (as specified in the P199 Requirements Specification). This is to ensure that the revised Demand Control Volume allocation resulting from a potentially upheld claim is not amended.

Appendix 2 in the P199 Requirements Specification (Reference 2) provides an example of how the calculation is implemented.

2.3.2 Views of Respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
4b	Do you agree with the proposed methodology for the allocation of Demand Control Volumes to affected Parties?	**4(20+1)**	**5(35)**	**1 (0+1)**

Several respondents recognised that any proposed solution to volume allocation is limited by the information practically available and that the allocation of Demand Control Volumes to individual Parties will always be an estimate. However, there was also a general concern that all the proposed methods of Demand Control Volume allocation are too simplified and based on too many assumptions. It was felt that the inaccuracies could lead to significant materiality, especially for smaller Parties.

The respondents recognised the need for a method that included a clear set of guidelines that show how these volumes will be calculated and were in support of P199 (if it proceeds) having this.

Several respondents highlighted reasons why the historic reference period may not be reflective of the Demand Control Settlement Period. It was suggested that if P199 utilises historic demand then there should be special arrangements in place for situations that might impact Supplier share of GSP Group Demand, resulting in an error in the allocated Demand Control Volumes.

One respondent felt that because the proposed volume allocation process is an estimation, additional incentive would be placed on Parties to avoid being subject to the mechanism and, as such, they would be encouraged to take appropriate action before a Demand Control Instruction needs to be issued.

2.3.3 Modification Group's Conclusions

The Group noted and supported the concerns raised through the consultation process. However, the Group agreed the mechanism representing the most practical approach should be progressed as the solution to

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P199. The limitations in the accuracy of the method of identifying and allocating Demand Control Volumes were a significant factor in the Group's assessment of P199 against the Applicable BSC Objectives.

In order to address the significant concerns with the accuracy and difficulty in deriving a process that would accurately reflect all possible scenarios the Group decided a claim process should be included in P199.

2.4 Error Correction (Demand Control Reallocation Claims)

P199 proposes a mechanistic approach to Demand Control Volume identification and allocation. As such it can never cater for every possible scenario that may exist during Demand Control.

2.4.1 Modification Group's Initial Discussions

The Group discussed potential ways of incorporating a claims process into P199. The Group considered the use of the Trading Disputes Process, but deemed this to be inappropriate. Participants wishing to query their Demand Control Volume allocation would be claiming against the volume assigned to them, rather than the incorrect implementation of the allocation methodology.

The Group agreed that the claims process would require Parties to present evidence that an incorrect Demand Control Volume had been allocated in their particular circumstance.

In the event of a claim being upheld Demand Control Volumes would need to be recalculated for all affected Parties. The Group had a concern that, if a claims process was included in the P199 solution, successful claims would impact all other affected Parties, potentially triggering further claims, which in turn are upheld and trigger further claims.

Additionally, the Group discussed the fact that any claims committee would have an overhead and, as such, could be seen as inefficient. The Group also expressed a concern about the Panel being used as an appeal body where Demand Control Volumes are disputed. Similar concerns have been raised previously – in both P80 and P173, where the Authority stated that it did not consider it appropriate for the BSC Panel to determine compensation claims.

A Group member felt that the Modification Process is already designed as a procedure for amending existing processes and mechanics. If the Demand Control estimate generated by the P199 mechanics is considered to be inaccurate, a new Modification should be raised. The Group also made the point that it is very difficult to raise retrospective Modifications.

Operational Implications of Reallocation Claims

The Group discussed the gate fee and how it would be applied to Parties wishing to make multiple claims. The group decided that a claim should relate to a specific BM Unit and therefore, a Party wishing to query the Demand Control Volume Allocations for several BM Units would need to submit one claim for each BM Unit. The Party would therefore be required to pay a gate fee of £5000 per BM Unit being queried.

Circumstances that would give rise to a claim would be any situation that leads to an estimate which is materially different to the actual impact of Demand Control. This difference may arise when either:

- The Party's share of the GSP Group Take was disproportionately large in the Reference Settlement Period (giving rise to an inappropriately large Demand Control Volume Allocation);
- The Party's Demand was unusually reduced (or non-existent) during the actual Demand Control Period; or
- Demand Control did not impact all BM Units equally.

An example of when the Party would be physically unable to have taken demand would be when a BM Unit is operating at a reduced level (or has no demand) because of maintenance taking place during the Demand Control Period. In such an example, the BM Unit may have had Demand during the Reference Settlement Period (giving rise to a share of the Demand Control Volume). However, because it had no demand during

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the Demand Control Settlement Period, it would not have been affected by Demand Control and to 'add' a Demand Control Volume Allocation to this BM Unit would be inappropriate and would result in the Party becoming short on that BM Unit.

Typical evidence provided by Parties might include proof of outage on a transformer, documentation showing a large change in customer numbers (i.e. after a contract round), or evidence that a Triad[5] was called in the Demand Control Reference Period. Evidence based on a Party's profiling or off-take regimes may also be included, but some Group members expressed a concern that the Panel may receive a large number of claims after a Demand Control event if this qualified as grounds for a claim.

The two main factors that the Panel would need to consider when assessing a claim are:

1. If the Claimant's evidence provides sufficient grounds for a revision of their Demand Control Volume Allocation; and
2. If the materiality of the difference between the actual Demand Control Volume (as indicated by the claimant's evidence) and the Demand Control Volume allocated to them via the Demand Control Volume Allocation Process is significant.

The Group discussed the impact of revising Demand Control Volume Allocations and noted that, should the Panel revise the Total Demand Control Volume (as the result of one, or more, upheld claims), the decision may have an impact on imbalance prices.

The Group decided that Claimants would be required to pay a £5000, non-refundable fee when lodging a claim. The Group felt that the £5000 Gate fee would help ensure that only claims where the Demand Control Volume Allocation is materially different to the Claimants evidence were submitted for claim. The Group also noted that, whilst the £5000 fee (per claim) is unlikely to cover the cost of the Demand Control Reallocation Claim process, it would contribute towards recovering some of the cost.

The Demand Control Reallocation Claims legal text is not prescriptive in how a Panel delegated committee should be organised. When seeking to delegate the reallocation claims process to a committee, the Panel would decide the structure of the committee. Typically, the committee will mainly comprise of technical members but the Panel may also wish to seek legal representation.

Similarly, when Claimants are presenting their evidence to the Panel or Panel delegated committee, they may wish to seek legal representation, but the Demand Control Reallocation Claims legal text, does not specify that they must.

2.4.2 Views of respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
9.	Do you believe that P199 should include a claims process?	**6(35+1)**	**3(20)**	**1 (0+1)**

Respondents recognised that P199 proposed a pragmatic solution to the problems of identifying and allocating Demand Control Volumes and that the availability of information limited the practical options available in both of these. However, the majority of respondents were concerned with the potential inaccuracies involved in determining Total Demand Control Volumes and then allocating this volume to impacted BM Units.

The majority of respondents felt that it would be sensible to have some form of recourse, in the form of a claims process, to cater for errors in the allocation. One respondent noted that, where a claims process has not been included, there was the potential risk of a legal challenge, which would be costly to the industry.

Several respondents expressed a concern about the additional complexity of process that a claims mechanism would introduce. It was felt that additional complexity would ultimately result in additional cost to the Modification.

[5] A Triad Period is one of the three periods of maximum demand on the national system each year.

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2.4.3 Modification Group's Conclusions

The majority of the Group agreed that it was necessary to include a claims process in both the Proposed and Alternative P199 Modifications because of the inherent problems in attempting to determine and allocate Demand Control Volumes.

Proposed Reallocation Claims Process

The Claims Process is designed to allow participants to query the Demand Control Volume that has been allocated to them through the P199 mechanistic approach. The P199 claims process does not allow participants to query the P199 process for volume identification and allocation but is a method by which participants can show that the method did not work in their particular circumstance.

The grounds for a claim would be that the estimate of the Demand Control Volume allocated to them was materially different then the actual impact of Demand Control.

1. Claimants must pay a 'Gate Fee' of £5000 per claim, to enter into the claims process. The fee will be paid up front and is non-refundable.
2. Claimants must submit their claims to BSCCo by [The Demand Control SF Run date] + 15 Working Days. They will be required to provide initial evidence with this submission so that the Panel (or a Panel-appointed Committee)[6] can decide if they will hear the cliam.
3. The evidence presented by the claimant must prove that the Demand Control Volume allocated to the claimant differs materially from the actual affect of Demand Control.
4. Once all submissions have been received, the Panel decides on how to approach the claim based on size and number of claims. The Panel will:
    a. Set the timeframe in which to consider the initial evidence and publish the details of these timescales for industry use; and
    b. Decide if it will hear a claim based on this evidence.
5. Claimants must present FULL evidence to the Panel.
6. Once all claims have been heard the Panel will make the decision to uphold or reject each claim on a case-by-case basis.
7. In the instance of any claims being upheld, the Panel will determine the revised Demand Control Volume Allocations based on the evidence presented to them by the Claimants whose claims have been upheld. In accord with the evidence presented to them, the Panel may:
    a. Reallocate the allocated Demand Control Volume(s) across Parties affected by Demand Control, thereby revising the BM Unit Period Demand Control Volume (DCVij);
    b. Revise the Total Demand Control Volume (TDCVj); or
    c. Revise the Total Demand Control Volume and the Demand Control Volume Allocations.
8. The initial revision of the Demand Control Volume Allocations will be published by the Panel and Parties will have 10 Working Days to provide additional evidence that the Panel may wish to consider, before finalising the revised Demand Control Volume Allocations.
    a. Based on this additional evidence, the Panel may decide to further revise the Demand Control Volume Allocations; and
    b. At this stage, any revision to the Demand Control Volume Allocation would pertain to only the 'additional' volume that a Party may have been allocated (above the original Demand

[6] In reference to the proposed P199 Appeals Process: when referring to "the Panel" the documented Appeals Process is also referring to any committee or body appointed by the Panel to undertake the P199 Appeals Process.

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Control Volume Allocation) as the result of a successful claim. The original Demand Control Volume Allocation may not be revised at this stage.

9. If the Panel decides to further revise the Demand Control Volume Allocations, they may:
    a. Reallocate the allocated Demand Control Volume(s) across Parties affected by Demand Control, thereby revising the Allocated BM Unit Demand Control Volume (ADCVij);
    b. Revise the Total Demand Control Volume (TDCVj); or
    c. Revise the Total Demand Control Volume and the Demand Control Volume Allocations.

    N.B. The outcome of this process will be final and no further claims will be allowed.

10. The final values as revised by the Panel will then be put into Settlement as part of the next available Settlement Run.

2.5 Interaction with Non-Delivery Rules

The Group noted that non-delivery volumes would not be calculated for Demand Control Volumes. Calculation of non-delivery requires use of the Final Physical Notifications. Since Supplier BM Units do not typically submit Final Physical Notifications, it would not be possible to account for non-delivery volumes under the P199 process.

2.6 Energy Imbalance Price Impact

The P199 Proposed Modification would treat Demand Control Volumes as un-priced in the Energy Imbalance Pricing Calculation. The addition of the deemed Demand Control Volumes to the Energy Imbalance Pricing Calculation would have an impact on Energy Imbalance Prices.

2.6.1 Modification Group's Initial Discussions

The Modification Group considered the potential impact of Demand Control on Energy Imbalance Prices.

Under the current baseline Demand Control is not reflected in the calculation of Energy Imbalance Prices and the calculation of the Net Imbalance Volume (NIV) would be impacted. As a consequence, Energy Imbalance Prices may be more favourable to Parties that are exposed to these prices than would be the case in similar conditions where Demand Control has not been utilised (e.g. if there had been additional Offer Volumes available to meet demand).

The Group discussed the appropriateness of the Demand Control Offer Acceptance being un-priced in the Energy Imbalance Price calculation. The Group recognised that including Demand Control as an un-priced volume would correct the calculation of NIV and would not dilute the Energy Imbalance Price. However, some members of the Group considered it may be more appropriate to price the Demand Control Volume where it was issued for energy balancing purposes.

The Group suggested several possible mechanisms that could be used to reflect Demand Control in the Energy Imbalance Price calculation under an Alternative Modification:

- Marginal Offer Price;
- 'Chunky' Marginal Offer Price;
- Market Price;
- Value of Lost Load (VOLL); and
- Fixed System Buy Price (SBP) for Demand Control Duration.

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Further details highlighting the specific impact of Demand Control Volumes on Energy Imbalance Prices under the considered mechanisms can be found in Appendix 7.

2.6.1.1 Marginal Offer Price

The Group suggested the use of the Marginal price as a suitable proxy.

The Group considered the impact of pricing the Demand Control Volume at the Marginal Offer Price (the price of the most expensive Offer taken by the SO) in the Energy Imbalance Pricing calculation. The Group felt that the Marginal Price reflected the fact the Demand Control would be a last resort action taken by the System Operator, once all other feasible Offers had been accepted. Therefore, in theory, the Marginal Offer Price would be a good proxy for the value of balancing energy delivered by Demand Control. However, the Group had concerns with using a potentially very small Offer volume with a high price, to determine the price of the Demand Control Volume. The Group also noted that similar concerns had been expressed in P138 and decided not to pursue this option further.

2.6.1.2 100 MWh of Most Expensive Offers ('Chunky Marginal' Price)

The Group considered the impact of pricing the Demand Control Volume at the 'Chunky Marginal' Price in the Energy Imbalance Pricing calculation. This approach proposes to take the volume weighted average of the 100 MWh of most expensive Offers to determine a Demand Control price. The Group decided that they would like to investigate this option further and that it would form a feasible approach under a potential Alternative Modification.

The Group discussed whether a Demand Control price should be derived from the Demand Control Period or the Settlement Period immediately prior to Demand Control. Most of the Group members felt that the Settlement Period prior to Demand Control should be used because of uncertainty surrounding the nature of actions that would be taken during a Demand Control Period.

2.6.1.3 Market Price

The Group considered the impact of pricing the Demand Control Volume at the Market Price in the Energy Imbalance Pricing calculation. When compared to an un-priced Demand Control Volume, the inclusion of Demand Control at the Market Price could potentially decrease SBP – although it may have no affect under the P194 pricing arrangement[7]. The Group felt that using Market Price would not be a suitable choice, as reducing SBP for a Demand Control Period would not be appropriate. The Group decided not to pursue this option further.

2.6.1.4 Value of Lost Load (VOLL)

One Group member suggested the use of VOLL as a means of pricing the Demand Control Volume in the Energy Imbalance Price calculation. The Group discussed how VOLL would be derived and several Group Members expressed concerns over how this figure could actually be calculated. The Group felt that, whilst the use of VOLL makes sense logically (VOLL is a reflection of the threshold cost of electricity at which a customer would decide they would rather be disconnected), it is not practicable. Additionally, it was felt that VOLL might act as a cap on pricing. When compared to an un-priced Demand Control Volume, the inclusion of Demand Control at the VOLL Price might increase or decrease SBP (depending on particular circumstances). The Group decided not to pursue this option further.

2.6.1.5 Fixed Imbalance Prices

The Group considered using fixed Imbalance Prices during a Demand Control Period, proposing to use the Settlement Period immediately prior to Demand Control to determine the fixed price during Demand Control. The Group had concerns that a fixed price approach would lead to the Demand Control price not following the expected profile of SBP (had Demand Control not occurred), and may introduce a discontinuity at the

[7] The pricing analysis was performed under the pre-P194 baseline and, whilst use of an offer at market price is likely to reduce SBP under the existing imbalance price baseline, under a P194 pricing method it is less likely to reduce SBP. Under P194, use of market price would only reduce SBP if it happened to fall in the bottom of the 100MWh band which would set price.

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end of Demand Control. However, the majority of the Group felt that a fixed price would ensure that pricing information could be published immediately. It was also felt that a fixed price would reduce uncertainty as the Price would remain constant throughout the duration of Demand Control irrespective of the (unknown) impact of Demand Control actions on prices. A Group Member raised the point that Demand Control would be expected to occur during a 'peak' in demand. Fixing the price, based on the Settlement Period prior to Demand Control, could potentially result in a SBP that is too low. The Group noted that the recent Gas Modification, UNC044 (dealing with Demand Control in the Gas Arrangements) had introduced a fixed price approach and decided that they would like to investigate this option further and that it would form a feasible approach under a potential Alternative Modification. The Group also noted that in the Gas Arrangements, during a period of Demand Control, the On-the-day Commodity Market (OCM) is suspended whilst in the BSC, the Balancing Mechanism remains in force.

The Group suggested that a higher SBP would provide a stronger incentive on Parties to avoid being short during a Demand Control Period, the Group deemed this to be an advantage.

2.6.2 Views of respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
5.	Do you agree with the suggested treatment of Demand Control Volumes as un-priced in the Energy Imbalance Price calculation under Proposed Modification P199?	**3(16)**	**6(39+1)**	**1 (0+1)**
6.	Do you prefer any of the alternative methods for treatment of Demand Control Volumes in the Energy Imbalance Price calculation identified by the Modification Group?	**4(37)**	**3(8+1)**	**3 (10+1)**

Some respondents were in favour of treating the Demand Control Volume as un-priced where a separate cash-out payment would be made to Parties affected by Demand Control. Those respondents not in favour of an un-priced Demand Control Volume in Settlement felt that Demand Control Volume should be priced, with a linked cash-out payment made to Parties based on the priced volume. One respondent felt that, considering the difficulties associated with calculating Demand Control Volumes, it was appropriate to treat the Demand Control Volumes as un-priced in Settlement.

One respondent had concerns over the use of a priced Demand Control Volume in the Energy Imbalance Pricing calculation, which would utilise a Previous Equivalent Settlement Period and therefore potentially have a 'random' affect on pricing. Another respondent had concerns that during a Demand Control event with duration greater than 1 hour, the forward visibility provided via the publication of system warnings may lead to participants attempting to influence prices in an undesired manner.

A respondent felt that the treatment of Demand Control Volumes as un-priced in the imbalance calculation would mean that the proposed P199 mechanism would not reflect the true cost of energy balancing within the Energy Imbalance Pricing calculation.

The consultation did not highlight a clearly preferred alternative approach for the treatment of Demand Control in the Energy Imbalance Pricing Calculation. Whilst the majority of respondents were in favour of pursuing an alternative approach (rather than the proposed approach), they differed in their preference over which of the suggested alternative approaches to pursue. Several respondents preferred the 'Chunky Marginal' approach, to price the Demand Control Volume in the Energy Imbalance Pricing calculation as they felt this would better reflect the cost of balancing the system. One respondent was in favour of the Fixed SBP approach, feeling that this would best reflect the approach adopted in the gas market and recognise the difficulty in calculating the Demand Control Volume for inclusion in the calculation of cash out prices.

One respondent suggested the treatment of Demand Control Volumes as un-priced, but applied in such a way that Parties are not brought back into their deemed position prior to Demand Control. Upon consideration of this idea, the Group decided not to pursue the approach as it was outside the scope of P199[8]

[8] P199 proposes that there is a defect in the Balancing Mechanism because after Demand Control, Parties' lengths do not appropriately reflect their position had Demand Control not happened.

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2.6.3 Modification Group's Conclusions

After consideration of the consultation responses the Group decided, by a slim majority, to treat Demand Control Volumes as un-priced in the Energy Imbalance Pricing calculation (with a separate cash-out payment), and take this approach forward as part of Alternative Modification P199.

Those members not in favour of an un-priced volume in Settlement preferred the approach whereby the Demand Control Volume would be priced at the 'Chunky Marginal' Price.

2.7 Payment to Affected Parties

Proposed Modification P199 does not propose that payments will be made to Parties affected by Demand Control.

2.7.1 Modification Group's Initial Discussions

The Group discussed payments made to Parties affected by Demand Control and considered the example of a Party that would have a balanced position in the absence of Demand Control.

A Party has contracted 100 MWh of energy (at £20.00 per MWh), to meet its customers' demand of 100MWh. A Demand Control Instruction then reduces their customer demand by 10 MWh. When there is no Demand Control the Party is perfectly balanced (no imbalance charges). The Party has contracted for 100MWh and would receive payment for this 100MWh from its customers.

Under the current baseline the Demand Control event would result in the Party appearing to be long by 10MWh. Demand Control results in the Party's customers using less than 100MWh and potentially reduces the payment from these customers to the Party. Under the current baseline, the Party could be considered to be compensated for the impact on its customers' demand via imbalance charges (i.e. the 10MWh that they were long would be paid at SSP).

Under the P199 Proposal, the above Demand Control event would result in the Party's position being adjusted from long to perfectly balanced. However, P199 doesn't provide any payment to affected Parties. A Party who had bought 100MWh of energy at £20.00 per MWh, but had only been able to charge its customers for 90 MWh (because of the 10MWh of Demand Control, that had effectively reduced customer demand), would find itself adversely impacted financially by the Proposed Modification.

The majority of the Group were uncomfortable that no payment would be made to affected Suppliers for Demand Control under the Proposed Modification and agreed that a potential Alternative Modification would be to include a payment to affected Parties for Demand Control Offer Volumes. The Group considered that, if a payment for the Demand Control Offer Acceptance was used, the price should be a neutral price for Parties. The Majority of the Group decided that, in terms of neutral pricing, the Market Price was the best 'proxy'. The Group believed that the Market Price best reflects the price of energy that a Party would have had to buy or sell to balance its position, once it had become aware of a reduction in demand.

Several of the respondents felt that the proposed use of un-priced volumes does not provide clear incentives on the SO to avoid the use of Demand Control in preference to other measures it could take to promote system security. The counter argument to this is that Demand Control is only initiated once all other options available to the SO have been utilised. As such Demand Control is driven by necessity rather than economic factors.

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2.7.2 Views of respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
7.	Do you agree with the suggested approach of not providing a payment to Parties affected by Demand Control under Proposed Modification P199?	1(1)	8(54+1)	1 (0+1)
8.	Do you prefer any of the alternative methods for providing payment to Parties affected by Demand Control identify by the Modification Group?	5(37+1)	2(8)	3 (10+1)

A number of respondents noted the Authority's original concerns with what was dubbed 'Windfall Payments' in P138 and, in particular, any undesirable incentives on Parties to which this might lead. One respondent felt that any proposal that incorporates payments to affected Parties would introduce a degree of uncertainty regarding the incentives to balance.

The majority of respondents felt that the lack of compensatory payment in the P199 Proposed Modification means Parties will lose revenue for assisting in the balancing of the system. One respondent stated that, the lack of compensation would effectively introduce a precedent into the BSC such that Parties helping to balance the system would not be paid appropriately. The majority of respondents felt that the inclusion of a cash-out payment would ensure that Parties affected by Demand Control who had purchased sufficient energy to supply their customers, would be compensated for lost customer revenue resulting from Demand Control.

Whilst most respondents felt that some form of compensation payment should be made to affected Parties, they varied in their opinions about how this payment would be derived. Those respondents in favour of using the Market Price to determine the compensation amount, believed this pricing option would provide payment to affected Parties at a 'neutral' price, whilst ensuing that there is no unwanted incentive on Parties to force Demand Control in the hope of obtaining a 'windfall gain'. One respondent was in favour of the inclusion of compensation payments in P199 at a fixed price as this would be consistent with the treatment of gas interruption that occurs in an emergency situation. Another respondent felt that the current (non-P199) baseline of imbalance cashout was preferable as they believed it effectively provided compensation to affected Parties, is simpler and more accurately reflects the impact of Demand Control.

Several respondents expressed a preference for payments made at the 'Chunky Marginal' price as it was considered this would reflect the price the Party could have achieved by offering the Energy to the Balancing Mechanism.

2.7.3 Modification Group's Conclusions

The Modification Group considered the views of the respondents and the majority of the Group decided to propose a formal Alternative Modification to P199 whereby cash-out payments are made to affected Parties for the Demand Control Offer Acceptances.

The Group agreed by a slim majority that these payments should be made at the **Market Price.** It was felt this price provides adequate compensation to affected Parties whilst remaining neutral, and thereby would be unlikely to place undesirable incentives on Parties to encourage a Demand Control event. Those members not in favour of using the Market Price, wished to see cash-out payments linked to 'Chunky Marginal' priced Demand Control Volumes in the Energy Imbalance Pricing Calculation.

2.8 Incentives on Parties

P199 seeks to increase the incentives on Parties to balance, thereby reducing the risk of entering into a Demand Control situation. Under the current baseline, a Party's imbalance position is lengthened due to reduction in that Party's Metered Volumes and Parties benefit through the Energy Imbalance charges (i.e. any Party that was short would appear less short or possibly long, and any Party that was long would appear longer). By reflecting Demand Control Volumes into affected Parties' Energy Accounts, P199 would remove any benefit in terms of Imbalance Exposure.

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P199 also seeks to address the concerns raised in P138 by not providing payment to affected Parties. Concerns were raised in P138 regarding the issue of 'windfall payments' to Parties and the risk that such payments may lead to an incentive whereby a Party attempts to force a Demand Control situation under certain circumstances.

By reflecting Demand Control Volumes into the Energy Imbalance Pricing calculation, P199 ensures that prices during a Demand Control Settlement Period are consistent with similar Settlement Periods where Demand Control had not been invoked.

2.8.1 Modification Group's Initial Discussions

The Group discussed the incentives that the Proposed Modification P199 (and any potential P199 Alternative Modification) may place on Market Participants.

The Group considered the suggestion of adjusting Parties' positions in the Energy Imbalance Pricing calculation to reflect their length had Demand Control not happened. The majority of the Group agreed that appropriately reflecting Demand Control in to Parties' Energy Accounts and in the calculation of Energy Imbalance would help to ensure that no inappropriate commercial incentive to force a Demand Control situation would exist. However, several Group members were not convinced that P199 would provide any additional incentive on Parties to ensure they are properly balanced, thereby reducing the potential need for Demand Control.

The Group considered the concern over Parties attempting to force Demand Control and felt that it was highly unlikely that a Party would attempt to force a DC situation; attempting to do so was seen as very difficult, if not impossible. However, the Group agreed that any alternative solution to P199 involving payments made to Parties should avoid the risk of leading to unwanted incentives on Parties.

2.8.2 Views of respondents to Assessment Procedure Consultation

Several respondents were not convinced that P199, nor any of its alternatives, would increase the incentives on Parties to avoid Demand Control over the current baseline.

2.8.3 Modification Group's Conclusions

The Modification Group considered the feedback from the respondents and the majority of the Group concluded that neither P199, nor the Alternative Modification, would place undesirable incentives on Parties to encourage a Demand Control situation. P199 would not place undesirable incentives on Parties as it is adjusting Party imbalance positions without making any financial payment whilst the P199 Alternative Modification would make a compensation payment to Parties at what was felt to be a 'neutral' price (the Market Price).

However, several Group Members were not convinced that the Proposed or Alternative Modification would provide any more incentive on Parties to avoid Demand Control than the current baseline.

2.9 Interaction with Other Industry Codes

P199 aims to reflect the occurrence of Demand Control in Settlement and in BSC documentation as there are no current provisions for such an event. Demand Control is carried out in accord with the Grid Code and as such, there would be interaction between BSC and Grid Code governed activities.

The Group considered whether any changes to the Grid Code would be necessary to support implementation of P199.

2.9.1 Modification Group's Initial Discussions

The Group noted that P199 would necessitate minor changes to the Grid Code in regard to the introduction of new System Warning messages. No other Industry Codes were identified as needing to be changed. Grid

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Code changes would be progressed by National Grid. BSC changes would not be dependent on changes to the Grid Code.

The Group raised the issue of the clarity of Demand Control as set out in the Grid Code and felt that changes should be made to the Grid Code to make the Demand Control process more transparent and clear. However, this is outside the scope of P199 and should be progressed separately as a change to the Grid Code.

The Group discussed the interaction between the Grid Code sections OC6, BC2.9 and BSC section Q5.1.3. One of the issues arising from these discussions was the treatment of Directly Connected Sites and whether they are currently handled under the pre-existing rules for Emergency Instructions. Further detail of this discussion can be found in section 2.1.

2.9.2 Views of respondents to Assessment Procedure Consultation

Respondents did not highlight any additional Industry codes or other areas of the Grid Code that would need to be changed.

One respondent felt that the transparency and explicitness of Grid Code should be improved with regards to the Demand Control process. The respondent expressed the view that the Grid Code should include the order of Demand Control actions (voltage reduction before disconnection) and a requirement on LDSOs to draw up Demand Control plans subject to Ofgem's approval. However, whilst these concerns should be noted as part of P199, they are out of the scope of P199 and should be raised separately as a change to the Grid Code.

2.9.3 Grid Code Observations Raised by Modification Group

Whilst the Group noted that the underlying purpose of Grid Code OC6 is to allow for efficient and flexible accomplishment of system security during a Demand Control event, they felt OC6 could be improved in certain areas.

The Group felt that there was ambiguity in OC6, particularly in reference to exactly how Demand Control would be initiated and in what order of preference the various types of Demand Control would be utilised. It was unclear from the Grid Code, what factors would drive the decision to utilise one type of Demand Control over another. The Group also felt that the procedural relationships between the SO, LDSO and Suppliers were unclear or not sufficiently defined.

The Group felt that OC6 does not seem to place specific obligations on what type of information the LDSOs would be required to provide to the SO once Demand Control had ended. The Group felt that a general lack of clarity in the Grid Code made it difficult to develop a BSC process for Demand Control that was sufficiently rigorous enough to provide industry with the required level of assurance.

The Group also felt that OC6 did not place sufficient operational obligations on the SO, or LDSO, to provide Lead Parties with advance warning notifications of disconnections and restoration of demand.

2.10 Interaction with Other Modification Proposals

P199 proposes that Demand Control Volumes are treated as un-priced in the Energy Imbalance Pricing calculation. Any other Modification that involves the Energy Imbalance Pricing calculation could potentially impact or interact with those changes proposed by P199.

The Group considered other Modifications that might interact with P199 and identified Modification Proposal P194 'Revised Derivation of the 'Main' Energy Imbalance Price'. P194 proposes that the main Energy Imbalance Price be calculated from a weighted average of the top 100MWh of the NIV. P194 was approved by the Authority on 23 March 2006 and is due to be implemented on 02 November 2006.

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The Group noted that the Energy Imbalance Price analysis performed for P199 (see Appendix 7) was against the pre-P194 baseline. However, they agreed that no further analysis needed to be performed because the available timescales restricted the option of performing any additional analysis.

2.11 Comparison with Gas Arrangements

The Group acknowledged the recent implementation of a similar Modification Proposal (Uniform Network Code modification proposal 044 'Revised Emergency Cash-out & Curtailment Arrangements') that was approved in the Gas Arrangements on 16 September 2005. The Group compared P199 and UNC044 as outlined below:

Similarities to UNC044

UNC044 Proposal	P199 Proposal
UNC044 makes use of historical data to derive one of the Emergency Curtailment Quantity (ECQ) estimates.	P199 uses historical data to derive Demand Control Volumes.
UNC044 uses a previous equivalent weekday to determine historic data i.e. same day of the week.	P199 proposes the use of a previous equivalent weekday to determine historic data i.e. same day of the week.
In UNC044 Transco National Transmission System (NTS) has included details as to how disputes in relation to the calculation of the volume of load curtailed (and hence the volume of the title trade) would be addressed, to provide clarity for shippers.	P199 includes an claims process.

Differences to UNC044

UNC044 Proposal	P199 Proposal
'Stratified' approach to disconnection/load-shedding, with the largest end-users being disconnected first.	SO decides type of Demand Control required, but actual approach to reduction and/or disconnection decided by LDSOs.
UNC044 payments are made as follows: a) The cash out price for users with a negative Daily Imbalance will be set to the SMP Buy (System Marginal Buy Price) prevailing on the day the GDE (Gas Deficit Emergency) commenced; and b) The cash out price for users with a positive Daily Imbalance will be set to the SAP (System Average Price) prevailing on the day the GDE commenced. In a curtailment situation, UNC044 proposes that the ECQ payment is made at the 30 day average SAP	P199 proposes un-priced volumes and no cash-out payment in a Demand Control situation.

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UNC044 Proposal	P199 Proposal
The ECQ calculation methodology involves the consideration of four defined estimates of an ECQ component for the relevant Gas Day. The relevant Transporter, or its representative, will select what it considers to be the most reasonable of these estimates or alternatively will manually enter an alternate estimate should the other estimates not be available or, in the relevant Transporters opinion, not conform to the obligation on the Transporter to produce its reasonable estimate of the quantity of gas that would otherwise have been offtaken by each User for the relevant Gas Day. • Estimate 1 is calculated from Historical allocations; • Estimate 2 is calculated from the relevant Shipper's Nominations; • Estimate 3 is calculated from the Supply Point Offtake Quantity (SOQ); • Estimate 4 is calculated from a scaled SOQ (Flexi-SOQ); and • Estimate 5 is a manually entered Transporter estimate based on other relevant information.	P199 proposes a single method for calculating Demand Control Volumes, based on historical share. Affected Parties are not able to 'choose' a best estimate from a variety of estimates.
Transco NTS has made clear, as part of modification proposal 044 that participants would be able to trade out imbalances throughout the emergency period.	No such proposal exists as part of P199, although this is principally due to a difference between the two Markets.

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3 IMPLEMENTATION APPROACH AND COSTS

3.1 Implementation and Cost

3.1.1 Modification Group's Initial Discussions

The Modification Group agreed that, if approved, P199 should be implemented utilising existing systems functionality. A number of options for implementation of the Proposed and potential Alternative Modifications were issued for impact assessment as follows:

Option 1:

Manipulation of Balancing Services Adjustment Data (System BSAD) by the SAA allowing the Demand Control Volume for a Settlement Period to be included as un-priced in the Energy Imbalance Price Calculation. Manipulation of the Applicable Balancing Services (QAS) flow by the SAA to include Demand Control Volumes in Parties' Energy Accounts.

Option 2:

Creation of a Dummy BM Unit allowing the Demand Control Volume for a Settlement Period to be included in the Energy Imbalance Price calculation. Manipulation of the Applicable Balancing services (QAS) flow by the SAA to include Demand Control Volumes in Parties' Energy Accounts.

A number of approaches for the treatment of Demand Control Volumes in the Energy Imbalance Price calculation were assessed as follows:

> **Pricing Approach 1:** The Total Demand Control Volume in a Settlement Period would be included in the Energy Imbalance Price Calculation as a priced volume (with the price derived from the most expensive Offers Accepted in the preceding Settlement Period).
>
> **Pricing Approach 2:** Energy Imbalance Prices would be fixed for the duration of the Demand Control Event at the value in the preceding Settlement Period.
>
> **Pricing Approach 3:** System Buy Price would be the greater of SBP in the preceding Settlement Period and most expensive Offers Accepted in that Settlement Period.

Additional Cash Flow Process:

A potential additional option for inclusion of a payment to affected Parties via manipulation of the interface between the SAA and FAA was also assessed.

Additional Claims Process:

The potential addition of an claims process was assessed.

The Modification Group agreed that the solution for the Proposed and Alternative Modifications should be derived from the options assessed as follows:

> **Proposed Modification = Option 1 + Claims Process**
>
> **Alternative Modification = Option 1 + Cash Flow Process + Claims Process**

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3.1.2 Results of Proposed Modification Impact Assessment

PROPOSED MODIFICATION IMPLEMENTATION COSTS[9]

		Stand Alone Cost	Incremental Cost	Tolerance
Service Provider[10] Cost	Change Specific Cost	£14,482	£14,482	+/-5% (£1.4k)
	Release Cost[11]	£64,217		+/-0%
	Total Service Provider Cost	£78,699	£14,482	+/-10%
Implementation Cost	External Audit[12]	£0	£0	+/-20%
	Design Clarifications	£900	£900	+/-100%
	Additional Resource Costs	£0	£0	+/-0%
	Additional Testing and Audit Support Costs	£TBC	£TBC	+/- TBC
Total Demand Led Implementation Cost		£79,599	£15,382	+/- 10%

ELEXON Implementation Resource Cost		54 Man days £11,880	54 Man days £11,880	+/- 10%
Total Implementation Cost		£91,479	£27,262	+/- 10%

PROPOSED MODIFICATION ONGOING SUPPORT AND MAINTENANCE COSTS

	Per Event Operational Cost Tolerance
Service Provider Operation Cost	Each occurrence will be different and so effort will be charged at T&M rates.
ELEXON Operational Cost	Each occurrence will be different; cost could be significant if the claim process is triggered.

[9] 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
[10] BSC Agent and non-BSC Agent Service Provider and software costs.
[11] The actual release cost incurred would be dependent on other changes delivered in Release. For example, if included with P194 (Nov 05 Release), release cost would be £21,632.
[12] ELEXON no longer uses external auditors.

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a) BSC Agent Impact

The BSC Agent cost estimates outlined above reflect the following activities:

- Development of scripts for required data manipulation;
- Documentation of new process;
- Introduction of a new manual interface from the System Operator; and
- Testing of scripts and process; and
- Project Management overhead.

The required BSC Agent lead time was three months from an Authority decision.

b) BSC Party and Party Agent Impact

A number of BSC Parties highlighted an impact on their Settlement systems. In addition, several Parties indicated an impact on their operational systems. Estimated implementation costs provided were up to £100k. Required lead times provided ranged from 10 days to 6 months after an Authority decision.

c) Transmission Company Impact

The Transmission Company impact assessment highlighted the requirement for changes to the Grid Code and the operational systems that send messages to the BMRA/BMRS. In addition, a new manual interface to the SAA for the reporting of Demand Control Information would be required. A lead time of approximately 2 months after the required Grid Code changes related to new system warning messages had been approved would be required. Grid Code changes would be progressed by National Grid and BSC changes would not be dependent on changes to the Grid Code.

d) BSCCo Impact

The BSCCo cost estimates outlined above reflect the following activities:

- Review of changes to SAA documentation;
- Review of Logica documentation;
- Operation of ELEXON testing;
- Project management and planning activities;
- Audit activities; and
- Changes to operational procedures.
- Changes to Code Subsidiary Documents

The required BSCCo lead time was three months from an Authority decision.

3.1.3 Results of Alternative Modification Impact Assessment

The impact of the Alternative Modification is identical to that of Proposed Modification with the exception of the generation of ad-hoc cashflows to realise Demand Control payments to affected participants. Inclusion of this process requires further development by the BSC Agent at an estimated additional cost of **£10,760**.

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3.1.4 Results of Alternative Modification Impact Assessment

ALTERNATIVE MODIFICATION IMPLEMENTATION COSTS[13]

		Stand Alone Cost	Incremental Cost	Tolerance
Service Provider[14] Cost	Change Specific Cost Release Cost[15]	£25,242 £64,217	£25,242	+/-5% (£1.4k) +/-0%
	Total Service Provider Cost	£89,459	£25,242	+/-10%
Implementation Cost	External Audit Design Clarifications Additional Resource Costs Additional Testing and Audit Support Costs	£0 £900 £0 £TBC	£0 £900 £0	+/-20% +/-100% +/-0% +/- TBC
Total Demand Led Implementation Cost		£90,359	£26,142	+/- 10%
ELEXON Implementation Resource Cost		54 Man days £11,880	54 Man days £11,880	+/- 10%
Total Implementation Cost		£102,239	£38,022	+/- 10%

ALTERNATIVE MODIFICATION ONGOING SUPPORT AND MAINTENANCE COSTS

	Per Event Operational Cost Tolerance
Service Provider Operation Cost	Each occurrence will be different and so effort will be charged at T&M rates.
ELEXON Operational Cost	Each occurrence will be different; cost could be significant if the claim process is triggered.

[13] 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

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

[15] The actual release cost incurred would be dependent on other changes delivered in the Release. For example, if included with P194 (Nov 06 Release), the release cost would be £46,874.

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3.1.5 Modification Group's Conclusions

The Group agreed the following recommended implementation of P199:

- An Implementation Date for the Proposed Modification of 22 February 2007 if an Authority decision is received on or before 23 August 2006, or 28 June 2007 if the Authority decision is received after 23 August 2006 but on or before 19 December 2006.
- An Implementation Date for the Alternative Modification of 22 February 2007 if an Authority decision is received on or before 23 August 2006, or 28 June 2007 if the Authority decision is received after 23 August 2006 but on or before 19 December 2006.

This approach provides sufficient lead time for participants to make the necessary amendments to their systems and processes.

If the Proposed Modification or Alternative Modification is approved, Settlement Runs and Volume allocation Runs carried out for the Settlement Days on, or after, the Implementation Date should be carried out taking the Approved Modification into account. Settlement Days prior to the Implementation Date should be performed utilising the pre-P199 baseline.

3.2 Legal Text

The Modification Group walked through the legal drafting at its final meeting and further reviewed the text via correspondence.

A copy of the draft legal text can be found in Annex 1.

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4 ASSESSMENT OF MODIFICATION AGAINST APPLICABLE BSC OBJECTIVES

This section outlines the views of consultation respondents and the Modification Group regarding the merits of P199 against the Applicable BSC Objectives. A summary table of all the Assessment Procedure consultation respondents' views can be found in Appendix 3.

4.1 Proposed Modification

4.1.1 Modification Group's Assessment

Applicable BSC Objective (b) – 'the efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System"

The following arguments were identified by the Group in support of the Proposed Modification:

- Improving the calculated size and direction of NIV, and the associated improvement in Energy Imbalance Price accuracy, would provide more appropriate incentives for participants to balance and help to avoid Demand Control occurring. This improved incentive to balance would increase efficiency of the operation of the Transmission System.
- No payment would be made to Parties affected by Demand Control and, as such, there is an increased incentive on Suppliers to submit Offers into the Balancing Mechanism prior to a Demand Control event, this would benefit operation of the Transmission System.

The following arguments were identified by the Group **NOT** in support of the Proposed Modification:

- Currently Demand Control might be viewed as a 'Free Option' for the System Operator. It could be considered that the lack of a payment to affected Parties does not discourage the use of Demand Control by the System Operator. The Proposed Modification does not resolve this issue.
- By treating the Demand Control Volume as un-priced in the Energy Imbalance Price Calculation, P199 may not provide Energy Imbalance Prices that are reflective of the true cost of energy balancing during periods of Demand Control. This may not provide an appropriate incentive to balance.

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"

The following arguments were identified by the Group in support of the Proposed Modification:

- Reflecting Demand Control in the Energy Imbalance Price calculation and Parties' Energy Accounts helps to ensure that the cost of balancing the System during periods of Demand Control is appropriately targeted at Parties with imbalance positions. Appropriate targeting of costs in this manner would promote competition.
- P199 proposes no payment to Parties affected by Demand Control and, as such, there is an increased incentive on Suppliers to submit Offers into the Balancing Mechanism prior to a Demand Control event which would facilitate competition between Suppliers in the sale of electricity to the System.

The following arguments were identified by the Group **NOT** in support of the Proposed Modification:

- The lack of payment for Demand Control Volumes under P199 could result in an affected Party that had purchased sufficient energy to supply its customers (i.e. the Party is balanced in the absence of Demand Control), being adversely affected financially by Demand Control relative to the current baseline. This could be considered detrimental for competition.

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- Inherent inaccuracies in the derivation and allocation of Demand Control Volumes could result in inaccurate Imbalance Charges for an affected Party during Demand Control periods. Inappropriate allocation of costs in this manner could be considered detrimental for competition.
- By treating the Demand Control Volume as un-priced in the Energy Imbalance Price Calculation, P199 may not provide Energy Imbalance Prices that are reflective of the true cost of energy balancing during periods of Demand Control. This may not ensure that the cost of balancing the System during periods of Demand Control is appropriately reflected on Parties with imbalance positions. This could be considered detrimental to competition.

Applicable BSC Objective (d) – "The promotion of efficiency in the implementation and administration of the balancing and settlement arrangements"

The following arguments were identified by the Modification Group in support of the Proposed Modification:

- The materiality of a Demand Control event could far outweigh the likely cost of the implementation and operation of the Demand Control Volume identification and allocation process.

The following arguments were identified by the Group **NOT** in support of the Proposed Modification:

- The process of Demand Control Volume allocation would add additional complexity to the Trading Arrangements thereby reducing efficiency in the implementation and administration of the balancing and settlement arrangements. The inclusion of an claims process adds further complexity to the Trading Arrangements.
- Demand Control should not be seen as a balancing action, but rather a change in demand that should be treated in the same manner as any other variation in demand. Changes in customer demand are already reflected in Parties' imbalance positions and consequently, the Balancing Mechanism treats Demand Control appropriately under the current baseline. Hence any change would be inefficient and unnecessary.

4.1.2 Views of respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
1.	Do you believe Proposed Modification P199 better facilitates the achievement of the Applicable BSC Objectives?	2 (11)	7 (44+1)	1 (0+1)

The **MAJORITY** view of respondents to the Assessment Procedure consultation was that the Proposed Modification **WOULD NOT** better facilitate the achievement of the **Applicable BSC Objectives**.

Applicable BSC Objective (b) – 'the efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System"

The following arguments were expressed by respondents in support of the Proposed Modification:

- The reflection of Demand Control volumes in Settlement would remove the risk of any potential distortions that may arise under current baseline and therefore, more accurately reflect the size and direction of NIV in the imbalance price calculation. The associated improvement in Energy Imbalance Price accuracy, would provide more appropriate incentives for participants to balance and help to avoid Demand Control occurring.
- The Proposed Modification would result in the more appropriate allocation of the burden of imbalance to those who contributed to that imbalance and thereby the Modification would help improve the incentives on Parties to balance. The increased incentive to balance would help avoid the need for Demand Control, benefiting efficiency in the operation of the Transmission System by the Transmission Company.

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The following arguments were expressed by respondents **NOT** in support of the Proposed Modification:

- The Proposed Modification places negligible incentives on Parties to balance their position when compared to the current baseline. Demand Control may occur for a variety of reasons including when there is insufficient generation to meet demand or when problems occur on the Transmission System and therefore Parties would not be in a position to balance.
- The absence of a payment to affected Parties for Demand Control Offer Acceptances does not provide clear incentives on the SO to avoid the use of Demand Control in preference to other measures that could be taken to promote system security.
- By treating the Demand Control Volume as un-priced in the Energy Imbalance Price Calculation, P199 may not provide Energy Imbalance Prices that are reflective of the true cost of energy balancing during periods of Demand Control. This may not provide appropriate incentives to balance and therefore be detrimental to the operation of the Transmission System.

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"

The following arguments were expressed by respondents in support of the Proposed Modification:

- The Proposed Modification would result in the more appropriate allocation of the burden of imbalance to those who contributed to that imbalance, thereby ensuring that the cost of balancing the System during periods of Demand Control is appropriately targeted at Parties with imbalance positions. This would promote competition.
- Some form of estimation (to derive and allocate Demand Control Volumes) will always be needed, irrespective of the solution chosen and the limited availability of useful and/or practically obtainable information means that the methodology detailed under the Proposed Modification is the best one available with the information currently available. The inclusion of an claims process means that it is possible for Parties to claim against the allocation of inaccurate Imbalance Charges resulting from Demand Control periods.

The following arguments were expressed by respondents **NOT** in support of the Proposed Modification:

- Concerns with the process by which Demand Control Volumes would be identified and allocated:
    - The methodology is simplified and based on assumptions leading to inaccurate Imbalance Charges during Demand Control periods. The potential impact of these errors upon Parties could be significant.
    - It is not possible to eliminate the effects of other demand reducing activities from the impact of Demand Control issued under the Grid Code.
    - It would not be possible to perform the necessary calculations in a timeframe sufficient for Parties to be informed and take action.
- Parties, who would otherwise have been balanced because they procured sufficient energy to meet their customers' demand, would suffer a financial loss as a result of having bought energy in good faith which could not then be delivered to customers. These customers cannot be billed for this lost energy and neither is it possible for the Party to sell the electricity back to the market.

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Applicable BSC Objective (d) – "The promotion of efficiency in the implementation and administration of the balancing and settlement arrangements"

The following arguments were expressed by respondents in support of the Proposed Modification:

- The materiality involved in a Demand Control event could far outweigh the likely cost of the implementation and operation of the Demand Control Volume identification and allocation process.

The following arguments were expressed by respondents **NOT** in support of the Proposed Modification:

- The process of Demand Control Volume allocation adds additional complexity to the Trading Arrangements, thereby reducing efficiency in the implementation and administration of the balancing and settlement arrangements.
- Delays in the volume reallocation process and the significant inaccuracies involved in identifying and allocating the Total Demand Control Volume would result in the increased uncertainty of Parties' imbalance positions.
- Demand Control should not be seen as a balancing action, but rather a change in demand that should be treated in the same manner as any other variation in demand. Changes in customer demand are already reflected in Parties' imbalance positions and consequently, the Balancing Mechanism treats Demand Control appropriately under the current baseline. Hence any change would be inefficient and unnecessary.

4.1.3 Modification Group's Conclusions

The Group considered the responses to the Assessment Consultation. The **MAJORITY** view of the Modification Group was that the Proposed Modification **WOULD NOT** better facilitate the achievement of **Applicable BSC Objectives (b), (c)** and **(d)** when compared to the current baseline, for the following reasons:

- In principle there would be beneficial impacts on **Applicable BSC Objectives (b)** and **(c)** in terms of reflecting Demand Control Volumes in Settlement and thereby better targeting the costs of imbalance during periods of Demand Control. However, these benefits would be outweighed by detrimental impacts on **Applicable BSC Objective (c)** due to inherent inaccuracies in the derivation and allocation of Demand Control Volumes that could result in inappropriate Imbalance Charges during Demand Control periods.
- The lack of payments to affected Parties would mean that Parties, who would otherwise have been balanced, because they procured sufficient energy to meet their customer's demand, would suffer a financial loss as a result of having bought energy in good faith which could not then be delivered to customers. This would have a detrimental impact on **Applicable BSC Objective (c).**
- The process of Demand Control Volume identification and allocation is overly complicated. As such, it adds additional complexity to the Trading Arrangements, thereby reducing efficiency in the implementation and administration of the balancing and settlement arrangements. The necessary inclusion of an claims process adds further complexity to the Trading Arrangements. Any delays in the volume reallocation process and the inaccuracies involved in identifying and allocating the Total Demand Control Volume would result in the increased uncertainty of Parties' imbalance positions. This would have a detrimental impact on **Applicable BSC Objective (d).** However, the materiality involved in a Demand Control event could far outweigh the likely cost of the implementation and operation of the Demand Control Volume identification and allocation process.
- The lack of a payment to affected Parties would mean there is no cost to the Transmission Company, should Demand Control be invoked. Subsequently, their are no incentives on the SO to ensure that Demand Control is exercised appropriately and contract ahead in order to avoid having to instruct Demand Control. This would have a detrimental impact on **Applicable BSC Objective (b).**

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- By treating the Demand Control Volume as un-priced in the Energy Imbalance Price Calculation, P199 may not provide Energy Imbalance Prices that are reflective of the true cost of energy balancing during periods of Demand Control. This may not ensure that the cost of balancing the System during periods of Demand Control is appropriately reflected on Parties with imbalance positions. This would have a detrimental impact on **Applicable BSC Objectives (b)** and **(c).**
- Demand Control should not be seen as a balancing action, but rather a change in demand that should be treated in the same manner as any other variation in demand. Changes in customer demand are already reflected in Parties' imbalance positions and consequently, the Balancing Mechanism treats Demand Control appropriately under the current baseline. Hence any change would be inefficient and unnecessary. This would have a detrimental impact on **Applicable BSC Objective (d)**.

The Group agreed that the Proposed Modification would have a neutral impact on Applicable BSC Objective (a).

4.2 Alternative Modification

P199 does not propose to price the Demand Control Volumes in the Energy Imbalance Pricing calculation or provide any means of compensation to those Parties impacted by Demand Control. In consideration of their discussions and points raised through the Assessment consultation, the Modification Group decided to develop an Alternative Modification whereby volumes would be treated as un-priced in the Energy Imbalance Pricing calculation, but a payment would be made to Parties impacted by Demand Control.

The Group discussed several potential components of an Alternative Modification and proposed the following during the consultation process, gauging respondent feedback:

- Priced Offer Acceptances in the Energy Imbalance Pricing Calculation, at either:
    1. A Demand Control Offer Price derived from the 100MWh of the most expensive Offers accepted in a previous Settlement Period;
    2. A Fixed SBP based on the Settlement Period immediately prior to Demand Control; or
    3. The greater of Option 2 or the 100MWh of the most expensive Offers accepted in a Demand Control Settlement Period.
- Payment to affected Parties at the Market Price.

The Group agreed the final scope of the Alternative Modification which would treat Demand Control Volumes as un-priced in the Energy Imbalance calculation (as per the Proposed Modification), but provide payment to Parties affected by Demand Control at the Market Price.

4.2.1 Modification Group's Assessment

Applicable BSC Objective (b) – 'the efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System"

The following arguments were identified by the Group in support of the Alternative Modification (relative to the Proposed Modification):

- The payment to affected Parties would act as a cost to the Transmission Company, should Demand Control be invoked, and would therefore help to ensure that Demand Control was exercised appropriately. Currently Demand Control might be viewed as a 'Free Option' for the System Operator. In putting a price on Demand Control, the SO would be appropriately incentivised to contract ahead in order to avoid having to instruct Demand Control. In turn this should stimulate the demand side to come forward with commercial demand reduction services to sell to the SO.

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The following arguments were identified by the Group **NOT** in support of the Alternative Modification (relative to the Proposed Modification):

- An associated payment with Demand Control would not increase the incentive on the SO to exercise Demand Control appropriately as it is a 'last resort' option and, as such, would not be exercised until all viable alternative mechanisms had first been applied; a cost implication would not drive the decision on the utilisation of Demand Control.
- The Alternative Modification still treats the Demand Control Volume as un-priced in the Energy Imbalance Price calculation and as such, the Alternative Modification may not provide Energy Imbalance Prices that are reflective of the true cost of energy balancing during periods of Demand Control. This may not provide an appropriate incentive to balance.

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"

The following arguments were identified by the Group in support of the Alternative Modification (relative to the Proposed Modification):

- The inclusion of a payment at the market price would ensure that affected Parties who had purchased sufficient energy to supply their customers (i.e. Parties who would be balanced in the absence of Demand Control), would be appropriately compensated for lost customer revenue resulting from Demand Control.
- Payment at the Market Price would provide payment to affected Parties at a 'neutral' price. The Market Price reflects the price of energy that a Party would have had to bought or sold to balance its position, once it had become aware of a reduction in Demand. This would help ensure that there is no unwanted incentive on Parties to force Demand Control in the hope of obtaining a 'windfall gain'.

The following arguments were identified by the Group **NOT** in support of the Alternative Modification (relative to the Proposed Modification):

- The Alternative Modification does not address the inherent inaccuracies in the derivation and allocation of Demand Control Volumes, which could result in inaccurate Imbalance Charges during Demand Control periods. Inappropriate allocation of costs in the manner could be considered detrimental to competition.
- The Alternative Modification still treats the Demand Control Volume as un-priced in the Energy Imbalance Price Calculation and as such, the Alternative Modification may not provide Energy Imbalance Pricesthat are reflective of the true cost of energy balancing during periods of Demand Control. This may not ensure that the cost of balancing the System during periods of Demand Control is appropriately reflected on Parties with imbalance positions. This could be considered detrimental to competition.

Applicable BSC Objective (d) – "The promotion of efficiency in the implementation and administration of the balancing and settlement arrangements"

Under the Alternative Modification, the same arguments were expressed for and against **Applicable BSC Objective (d)** as under the Proposed Modification.

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4.2.2 Views of respondents to Assessment Procedure Consultation

Q	Consultation question	Yes	No	Neutral
2.	Do you believe any Alternative Modification P199 would better facilitate the achievement of the Applicable BSC Objectives?	6(30+1)	3(25)	1 (0+1)

The **MAJORITY** view of respondents to the Assessment Procedure consultation was that, when compared to the Proposed Modification, the Alternative Modification **WOULD** better facilitate the achievement of **Applicable BSC Objectives (b)** and **(c)**.

The majority of respondents believed that Parties affected by Demand Control should be appropriately compensated for electricity bought in good faith, but which they were unable to deliver as a result of customer disconnection. However, there was a variety of preferences as to which of the Alternative methods should be used to compensate Parties affected by Demand Control.

The respondents supported the Alternative Modification (as progressed by the Group) relative to the Proposed Modification and the arguments expressed were consistent with those of the Group. However, the majority of respondents still had concerns that the Alternative Modification does not address the issue that the process of Demand Control Volume identification and allocation is one of estimation and assumption. As such, the majority of respondents did not believe that the Alternative Modification would better facilitate the Applicable BSC Objectives when compared to the current baseline.

4.2.3 Modification Group's Conclusions

The Group considered the feedback from the Assessment Procedure Consultation. The **MAJORITY** view of the Modification Group was that the Alternative Modification **WOULD** better facilitate the achievement of **Applicable BSC Objectives (b)** and **(c)** when compared to the Proposed Modification, for the following reasons:

- The Inclusion of payments means that Parties who would otherwise have been balanced, because they procured sufficient energy to meet their customer's demand, would not suffer a financial loss as a result of having bought energy in good faith which could not then be delivered to Demand Control disconnected customers. Payment at the Market Price provides a 'neutral' payment to Parties affected by Demand Control as they would receive payment for the Demand Control Volume at a price which reflected the cost of buying energy during the Demand Control Settlement Period. Hence, a payment at this price would not place any unwanted incentives on Parties to attempt to force Demand Control in the hope of obtaining a 'windfall gain'. This would better facilitate **Applicable BSC Objective (c).**
- Putting a price on Demand Control would act as a cost to the Transmission Company, should Demand Control be invoked, thereby placing appropriate incentives on the SO to:
    - Ensure that Demand Control was exercised appropriately.
    - Contract ahead in order to avoid having to instruct Demand Control.

  This would better facilitate **Applicable BSC Objective (b)**.

The **MAJORITY** of the Group agreed that, whilst P199 Alternative better facilitates the BSC Objectives, when compared to the Proposed P199 Modification, they were not convinced that it better facilitated the BSC Objectives when compared to the current baseline, for the following reasons:

- In principle there would be beneficial impacts on **Applicable BSC Objectives (b)** and **(c)** in terms of reflecting Demand Control Volumes in Settlement and thereby better targeting the costs of imbalance during periods of Demand Control. However, these benefits would be outweighed by detrimental impacts on **Applicable BSC Objective (c)** due to inherent inaccuracies in the derivation and allocation of Demand Control Volumes that could result in inappropriate Imbalance Charges during Demand Control periods.

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- The process of Demand Control Volume identification and allocation is overly complicated. As such, it adds additional complexity to the Trading Arrangements, thereby reducing efficiency in the implementation and administration of the balancing and settlement arrangements. The necessary inclusion of an claims process adds further complexity to the Trading Arrangements. Any delays in the volume reallocation process and the inaccuracies involved in identifying and allocating the Total Demand Control Volume would result in the increased uncertainty of Parties' imbalance positions. This would have a detrimental impact on **Applicable BSC Objective (d).** However, the materiality involved in a Demand Control event could far outweigh the likely cost of the implementation and operation of the Demand Control Volume identification and allocation process.

- The Alternative Modification does not address the issue that, by treating the Demand Control Volume as un-priced in the Energy Imbalance Price Calculation, P199 may not provide Energy Imbalance Prices that are reflective of the true cost of energy balancing during periods of Demand Control. This may not ensure that the cost of balancing the System during periods of Demand Control is appropriately reflected on Parties with imbalance positions. This would have a detrimental impact on **Applicable BSC Objectives (b)** and **(c).**

- Demand Control should not be seen as a balancing action, but rather a change in demand that should be treated in the same manner as any other variation in demand. Changes in customer demand are already reflected in Parties' imbalance positions and consequently, the Balancing Mechanism treats Demand Control appropriately under the current baseline. Hence any change would be inefficient and unnecessary. This would have a detrimental impact on **Applicable BSC Objective (d)**.

The **MINORITY** view of the Group was that the Alternative Modification better facilitates the Applicable BSC Objectives when compared to the current baseline, for the following reasons:

- The reflection of Demand Control volumes in Settlement would remove the risk of any potential distortions that may arise under current baseline and therefore, more accurately reflect the size and direction of NIV in the imbalance price calculation. The associated improvement in Energy Imbalance Price accuracy, would provide more appropriate incentives for participants to balance and help to avoid Demand Control occurring. This would better facilitate **Applicable BSC Objective (b)**.

- The Alternative Modification would result in the more appropriate allocation of the burden of imbalance to those who contributed to that imbalance and thereby the Modification would help improve the incentives on Parties to balance. The increased incentive to balance would help avoid the need for Demand Control, benefiting efficiency in the operation of the Transmission System by the Transmission Company. This would better facilitate **Applicable BSC Objective (b)**.

- The Alternative Modification would result in the more appropriate allocation of the burden of imbalance to those who contributed to that imbalance, thereby ensuring that the cost of balancing the System during periods of Demand Control is appropriately targeted at Parties with imbalance positions. This would promote competition. This would better facilitate **Applicable BSC Objective (c).**

- The inclusion of a payment to affected Parties would act as a cost to the Transmission Company, should Demand Control be invoked, and would therefore help to ensure that Demand Control was exercised appropriately. Currently Demand Control might be viewed as a 'Free Option' for the SO. In putting a price on Demand Control, the SO would be appropriately incentivised to contract ahead in order to avoid having to instruct Demand Control. In turn this should stimulate the demand side to come forward with commercial demand reduction services to sell to the SO. This would better facilitate **Applicable BSC Objective (b)**.

The Group agreed that the Alternative Modification would have a neutral impact on Applicable BSC Objective (a).

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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;
- The Alternative Modification **SHOULD NOT** be made; and
- The Alternative Modification **better facilitates** the Applicable BSC Objectives when compared to the Proposed Modification, but not when compared to the current baseline.

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.

Acronym/Term	Definition
BM	Balancing Mechanism
BM Unit (BMU)	Balancing Mechanism Unit
BSC	Balancing and Settlement Code
DC	Demand Control
Demand Control	Demand Control is either (i) an instructions issued in accordance with OC6.1.2 (c) or (e) to Local Distribution System Operator(s) as an instruction to reduce demand within their distribution area in the event of System stress, such as where there is insufficient generation to meet demand or a problem on the Transmission System; (ii) the automatic low frequency disconnection of demand under OC6.1.2 (d); or (iii) action undertaken by the SO in accordance with OC6.7.7 or OC6.7.8.
ECQ	Emergency Curtailment Quantity (Gas Arrangements)
GDE	Gas Deficit Emergency (Gas Arrangements)
IWA	Initial Written Assessment (see Reference 1 below)
LDSO / LDSOs	Licensed Distribution System Operator
NIV	Net Imbalance Volume
NTS	National Transmission System (Gas Arrangements)
OCM	On-the-day Commodity Market (Gas Arrangements)
SAP	System Average Price (Gas Arrangements)
SBP	System Buy Price
SMP (Buy/Sell)	System Marginal Price (post-fix identifies if price is Buy Price or Sell Price – part of Gas Arrangements)
SO	System Operator
SSP	System Sell Price

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6 DOCUMENT CONTROL

6.1 Authorities

Version	Date	Author	Reviewer	Reason for Review
0.3	28/04/06	Richard Bennett	Thomas Bowcutt	For peer review
0.4	02/05/06	Richard Bennett	P199 Mod Group	For Modification Group review
0.4	02/05/06	Richard Bennett	Sarah Jones	For technical review
0.5	05/05/06	Richard Bennett	Alex Grieve	For quality review
1.0	05/05/06	Change Delivery	BSC Panel	For Panel decision
1.1	09/05/06	Richard Bennett	Thomas Bowcutt	For peer review
2.0	09/05/06	Change Delivery	BSC Panel	For Panel decision (updated costs)
2.1	30/05/06	Richard Bennett	Thomas Bowcutt	For peer review
2.2	31/05/06	Richard Bennett	P199 Mod Group	For Modification Group review
2.3	01/06/06	Richard Bennett	Sarah Jones	For quality review
3.0	02/06/06	Change Delivery	BSC Panel	For Panel decision
4.0	13/06/06	Change Delivery	BSC Panel	Amended after Panel Discussion

6.2 References

Ref.	Document Title	Owner	Version
1	P199 Initial Written Assessment (IWA)	BSCCo	1.0
2	P199 Requirements Specification	BSCCo	1.0
3	Grid Code - Operating Code No.6 (OC6)	National Grid	1.0
4	http://www.elexon.co.uk/documents/BSC_Panel_and_Panel_Committees/ISG_Meeting_2005_-_048_-_Papers/048_013.pdf	BSCCo	1.0

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APPENDIX 1: DRAFT LEGAL TEXT

Draft legal text for the Proposed Modification is attached as a separate document, Annex 1A.

Draft legal text for the Alternative Modification is attached as a separate document, Annex 1B.

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=217

Date	Event
30/01/2006	Modification Proposal raised by NGC
09/02/2006	IWA presented to the Panel
14/02/2006	First Assessment Procedure Modification Group meeting held
07/03/2006	Second Assessment Procedure Modification Group meeting held
23/03/2006	Third Assessment Procedure Modification Group meeting held
04/04/2006	Requirements Specification issued for BSC Agent impact assessment
04/04/2006	Request for Party/Party Agent impact assessments request issued
04/04/2006	Request for Transmission Company analysis issued
04/04/2006	Request for BSCCo impact assessment issued
04/04/2006	Assessment Procedure consultation issued
18/04/2006	BSC Agent impact assessment response returned
18/04/2006	Party/Party Agent impact assessment responses returned
18/04/2006	Transmission Company analysis returned
18/04/2006	BSCCo impact assessment returned
18/04/2006	Assessment Procedure consultation responses returned
26/04/2006	Fourth Assessment Procedure Modification Group meeting held
11/05/2006	Assessment Report presented to the Panel

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ESTIMATED COSTS OF PROGRESSING MODIFICATION PROPOSAL[16]

Meeting Cost	£1500
Legal/Expert Cost	£5000
Impact Assessment Cost	£5000
ELEXON Resource	50 Man days £13,000

MODIFICATION GROUP MEMBERSHIP

Member	Organisation	14/02	07/03	23/03	26/04	24/05
Thomas Bowcutt	ELEXON (Chairman)	✓	✓	✓	✓	✓
Sakib Azam	ELEXON (Lead Analyst)	✓	X	X	X	X
Richard Bennet	ELEXON (Lead Analyst)	X	✓	✓	✓	✓
Rob Smith	National Grid (Proposer)	✓	✓	✓	✓	✓
Bill Reed	RWE npower	✓	✓	✓	✓	✓
Garth Graham	Scottish and Southern	Apologies	Apologies	Apologies	✓	✓
Paul Jones	E.ON	✓	Apologies	Apologies	✓	Apologies
Man Kwong Liu	SAIC	✓	✓	✓	✓	✓
Martin Mate	British Energy	✓	✓	✓	✓	✓
Mark Manley	Centrica	✓	✓	Apologies	Apologies	Apologies
David Lewis	EDF Energy	✓	✓	✓	✓	✓

Attendee	Organisation	14/02	07/03	23/03	26/04	24/05
John Guest	LogicaCMG	✓	✓	✓	✓	Apologies
Mark Gribble	LogicaCMG	✓	✓	✓	✓	Apologies
Chris Stewart	Ofgem	✓	✓	✓	✓	✓
Simon Bradbury	Ofgem	✓	✓	✓	Apologies	✓
Barbara Vest	GDF ESS	✓	Apologies	Apologies	Apologies	Apologies
Merel Kolfschoten	Centrica	✓	✓	✓	✓	✓

[16] 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

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Attendee	Organisation	14/02	07/03	23/03	26/04	24/05
Matthew Hayes-Stimson	EDF Energy	X	X	✓	Apologies	
Nigel Buckland	WPD	X	X	✓	Apologies	
David Briggs	Central Networks	X	X	✓	Apologies	

MODIFICATION GROUP TERMS OF REFERENCE

Modification Proposal P199 will be considered by the P199 Modification Group (formed from members of the Pricing Standing Modification Group) in accordance with the following Terms of Reference.

P199 - Quantification of Demand Control in the BSC as instructed under OC.6 (c), (d) & (e) of the Grid Code

Assessment Procedure

The Modification Group will carry out an Assessment Procedure in respect of Modification Proposal P199 pursuant to section F2.6 of the Balancing and Settlement Code.

The Modification Group will produce an Assessment Report for consideration at the BSC Panel Meeting on 11 May 2006.

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

Demand Control Triggers and Reporting

- Likelihood Demand Control occurring;
- Reporting of Start and end of Demand Control to BSCCo/Industry; and
- How Parties are selected for Demand Reductions by LDSOs

Calculation of Demand Control Offer Volume

- Appropriateness of P138 Methodology for deriving Demand Control Volumes; and
- Consider any other derivation or volume allocation methods

Pricing Impact

- Appropriateness of Offer Acceptance being un-priced in calculation;
- Impact on System Buy Price, supported by analysis; and
- Signals sent to the Market, support by analysis

Payment to affected Parties

- P199 proposes that there will be no BM Unit cashflow paid to Parties affected by Demand Control. The Group to consider whether this is appropriate or whether Parties should be paid for the deemed Offer Acceptance; and
- Consider consistency with other emergency arrangements within Code i.e. Emergency Instructions, where payment is made to Generators for being shut down

Incentives on Parties

- Consideration should be given to the incentives on Parties before, during and after periods of Demand Control under both the current baseline and that proposed by P199.

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- Group should consider financial incentives (supported by analysis) and other drivers on behaviour

P138 Areas Considered by the Authority

- Group should consider some of the areas highlighted by the Authority in the P138 decision letter

Implementation Approach

- P199 proposes that it be implemented with a manual solution;
- the Group should consider how the solution would work in practice and where potential complexities may lie.

Interaction with other Industry Codes

- The Group to highlight any impacts on other core industry documents.

Error Correction

- The Group should consider if any mechanism would need to be put into place to correct any errors in data submitted by the System Operator, or in the calculated Demand Control Volumes.

Non-Delivery Rules

- The Group to consider Interaction with Non Deliver rules.

Interaction with other Modification Proposals

- The Group to consider potential interaction with P194, if it is approved during Assessment

Comparison with Gas Arrangements

- A similar Modification Proposal (Uniform Network Code modification proposal 044 'Revised Emergency Cash-out & Curtailment Arrangements') was approved in the Gas arrangements on 16 September 2005. The Group should compare the P199 proposal with the UNC Modification 044.

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APPENDIX 3: RESULTS OF ASSESSMENT PROCEDURE CONSULTATION

10 responses (representing 55 Parties and 2 non-Parties) were received to the P199 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 believe Proposed Modification P199 better facilitates the achievement of the Applicable BSC Objectives?	2 (11)	7 (44+1)	1 (0+1)
2	Do you believe any Alternative Modification P199 would better facilitate the achievement of the Applicable BSC Objectives?	6(30+1)	3(25)	1 (0+1)
3	Do you believe there are any alternative solutions that the Modification Group has not identified and that should be considered?	2(6)	6(44+1)	2 (5+1)[17]
4a	Do you agree with the proposed methodology for the identification of Demand Control Volumes?	5(27+1)	4(28)	1 (0+1)
4b	Do you agree with the proposed methodology for the allocation of Demand Control Volumes to affected Parties?	4(20+1)	5(35)	1 (0+1)
5	Do you agree with the suggested treatment of Demand Control Volumes as un-priced in the Energy Imbalance Price calculation under Proposed Modification P199?	3(16)	6(39+1)	1 (0+1)
6	Do you prefer any of the alternative methods for treatment of Demand Control Volumes in the Energy Imbalance Price calculation identified by the Modification Group?	4(37)	3(8+1)	3 (10+1)
7	Do you agree with the suggested approach of not providing a payment to Parties affected by Demand Control under Proposed Modification P199?	1(1)	8(54+1)	1 (0+1)
8	Do you prefer any of the alternative methods for providing payment to Parties affected by Demand Control identify by the Modification Group?	5(37+1)	2(8)	3 (10+1)
9	Do you believe that P199 should include an appeals process?	6(35+1)	3(20)	1 (0+1)
10	Does P199 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure?	5(20+1)	4(35)	1 (0+1)
11	Are there any further comments on P199 that you wish to make?	3(13)	6(42+1)	1 (0+1)

Details of the arguments made by respondents can be found in Sections 2 and 4, along with the Modification Group's consideration of these arguments. Full copies of the consultation responses are attached as a separate document, Appendix 3A.

[17] One Respondent did not respond to Question 3 and has therefore been cited as a neutral response.

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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 P199.

For details of the costs associated with these impacts, please refer to Section 2.

a) Impact on BSC Systems and Processes

The impact on BSC Agents is summarised in section 3.1.2 of this report, a copy of the full BSC Agent impact assessment is attached in a separate Appendix. The Proposed Modification uses implementation option 1 as described in the BSC Agent impact assessment. The Alternative Modification also uses implementation option 1, but includes the alternative component "CF1" as described in the BSC Agent impact assessment and the P199 Requirements specification.

b) Impact on BSC Agent Contractual Arrangements

BSC Agent Contract	Impact of Proposed/Alternative Modification
LogicaCMG (BMRA, CRA, CDCA, SAA, ECVAA, TAA, FAA)	BMRA / SAA Service Descriptions amended to reflect Demand Control process.

c) Impact on BSC Parties and Party Agents

The impact on BSC Parties and Party Agents is summarised in section **3.1.2** of this report, full copies of the Party and Party Agent impact assessment responses are attached as a separate document (see separate Appendix).

d) Impact on Transmission Company

The impact on the Transmission Company is summarised in section **3.1.2** of this report.

e) Impact on BSCCo

The impact on BSCCo is summarised in section **3.1.2** of this report.

f) Impact on Code

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 Service Description	To detail the requirements on the SAA for the processing of data issued by the SO in respect of Demand Control periods.
BMRA Service Description	To detail the requirements on the BMRA to publish Demand Control Instructions using System Warnings functionality.
Reporting Catalogue	Amend Section 2.1 to include Demand Control Instructions in System Warnings.
BSCP18	New section detailing the process how the SO, SAA and BMRA will deal with Demand Control periods.

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

Document	Impact of Proposed/Alternative Modification
Grid Code	Both the Proposed and Alternative Modifications would necessitate minor changes to the Grid Code in regard to the introduction of new System Warning messages. Further details can be found in sections 2.9 and 3.1.2. BSC changes required by P199 would not be dependent on changes to the Grid Code.

i) Impact on Other Configurable Items

Document	Impact of Proposed/Alternative Modification
IDD Part 2	Changes made to the IDD Part 2 to include the new manual interface.
SAA URS	Amended to reflect Demand Control Process
BMRA URS	Changes made to the BMRA URS in accordance with the BMRA SD to state that the BMRS should publish data received in respect of Demand Control Instructions using System Warnings functionality (amend the BMRA-I003).
SAA Manual System Specification	Changes made to the SAA MSS to detail the manual processing of data issued by the SO in respect of Demand Control periods.
SAA Operations System Manual	Changes made to the SAA OSM to detail the manual processing of data issued by the SO in respect of Demand Control periods.
Business Process Model	To model the process in BSCP18 in relation to Demand Control.

j) Impact on BSCCo Memorandum and Articles of Association

No impact identified.

k) Impact on Governance and Regulatory Framework

No impact identified.

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APPENDIX 5: TOTAL DEMAND CONTROL VOLUME DETERMINATION

Under the auspices of the Grid Code, LDSOs would inform the SO of their estimates of the level demand (MW) reduction that was deemed to have achieved, as soon as possible, and in all cases by Day + 1 (as required by OC1.5.6).

Where Automatic Low Frequency Demand Disconnection has taken place, P199 requires the SO to have a method in place so that it is able to derive estimates of the level demand (MW) reduction that it deems to have achieved.

ELEXON investigated four methods of DC volume determination and invited LDSO representatives to join the Group as attendees, enabling the Group to better understand the level of detailed information that could be provided post-event, should Demand Control happen. It was suggested that the four sources of data could be compared and possibly used to provide a better estimate (through averaging), although this raises the issue as to which value(s) would take precedence should the amounts differ significantly. It was agreed that ELEXON would analyse the different mechanisms for the determination of the Demand Control Volume so that other options could be considered by the Group.

a LDSO Estimate

Several Group Members expressed an interest in attempting to obtain more detailed information from the LDSOs so that Demand Control Volumes could be calculated more accurately. After discussions involving the LDSO attendees at the Group, it became apparent that, in most cases, it would not be practicably possible to obtain information of greater detail than that provided by the SO because of a fundamental difference in the nature of the information used by LDSOs. Discussions with the LDSO representatives revealed that there was no was no way to reasonably 'translate' LDSO circuit-level data into a format useful to ELEXON (i.e. BM Unit level)

The LDSO attendees also stated that different LDSOs may apply different methods and approaches in reducing demand in the event of Demand Control and that the information obtainable might vary from LDSO to LDSO.

b SO Estimate

The majority of the Group felt that the SO best estimate of Demand Control Volumes achieved would be the most sensible and practical approach to use in the identification of total Demand Control Volume(s). The reasoning behind the Group's conclusion was:

- There is already an obligation on LDSOs to provide information on the level of Demand Control achieved to the SO under the Grid Code (Reference 3).
- P138 proposed that the SO would provide details of Demand Control Volumes, Settlement Periods affected and sufficient information to enable the SAA to identify affected GSP Groups (with reasonable accuracy).

The Group decided that an obligation should be placed on the SO to provide the 'best' and most detailed estimate of Demand Control Volumes and in giving their best estimate, the SO should consider demand forecasts. Where possible, additional information should be provided that would enable the Total Demand Control Volume to be targeted more effectively i.e. if the SO is aware that Demand Control was applied to only one BM Unit, the Demand Control Volume should be applied to this affected BM Unit only.

Several Group members expressed a concern with relying on a single, external source of data and suggested there should be a means to check that the Demand Control Volume supplied by the SO is sensible and in accord with an alternatively derived Total Demand Control Volume. The Group accepted the point, but felt that it was not practical to derive the Demand Control Volume separately.

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c Proportion of National Demand

This approach was suggested by the Group as a means of comparing actual demand to the National Demand estimate (split proportionally across GSP Groups, based on historic share) provided by the SO. The difference between the actual demand and estimated demand would provide an indication of the Total Demand Control Volume for the GSP Group.

Investigation carried out by ELEXON revealed that the GSP Group Takes used to apportion the National Demand Control Volume across GSP Groups would always be of less magnitude than the SO forecast because of Embedded Generation. The impact of Embedded Generation was further detailed in an ISG paper, "Possible CVA Issues Arising from Increased Volumes of Embedded Generation" (Reference 4). The paper highlighted the discrepancy caused by embedded generation. Embedded generation reduces the GSP Group take and so the Sum of GSP Group Takes would be expected to be less than the forecast demand.

d Profiling ('Bottom Up' approach)

This approach was suggested by a member of the Group as a means of determining a GSP Group estimate of demand in the absence of Demand Control (i.e. what the demand would have been if Demand Control had not occurred). The proposed approach would use profiling of GSP Group level data and compare this to actual demand.

The Group was aware that the use of a Profiling mechanism would require a defined approach to profiling. The lack of a defined approach would mean that any profiling would be carried out subjectively.

A Group Member pointed out that, whilst a means to verify the accuracy of the Demand Control Volume is highly desirable, the capability to produce profiles of the type requested does not currently exist within ELEXON and, as such, it would not be sensible to pursue this line of enquiry further as the approach was impractical.

Investigation of this approach by ELEXON suggested that the error margins involved in applying this method to the data would be significant and potentially on a scale comparable to the Total Demand Control Volume. The error in producing an estimate of Demand through profiling would be significant (potentially in the region of 15-25%). It was felt that the error could potentially be of a greater magnitude than the Demand Control Volume, and the process time-consuming. This approach is not considered practical.

e Conclusion

The analysis highlighted that it was not practical to derive the Total Demand Control Volume via methods (a), (c) and (d) above. In light of the problems with methods (a), (c) and (d), it was felt that the most practicable approach to identifying the Total Demand Control Volume would be to use the SO's best estimate.

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APPENDIX 6: ALTERNATIVE VOLUME ALLOCATION METHODS

ELEXON investigated several potential methods of Demand Control Volume allocation. Two main approaches in the allocation of Demand Control Volumes were suggested:

- Profiling-based approach (deemed impractical by the majority of the Group); and
- The use of Historic data to derive share of GSP Group Take.

a Volume Allocation across All BM Units

The Group considered the implications of apportioning Demand Control across all BM Units in GSP Group(s) identified as having been impacted by Demand Control.

This approach assumes all Suppliers (and therefore all BM Units) in the affected GSP Group(s) are impacted by the Demand Control equally, irrespective of the Demand Control reduction methodology applied.

The Group noted that Demand Control instructions, or events may not impact all Parties in a GSP Group. Therefore the assumption that the actions of the LDSO, SO or Automatic Demand Disconnection reduces the demand of all BM Units in a GSP Group proportionally may not be correct in all circumstances covered by P199. It was decided that the option of 'targeting' Demand Control Volume allocation to only those BM Units affected should be considered (Section b below).

b Targeted Volume Allocation

The Group discussed possible ways of targeting the apportioned Demand Control so that it is applied to only the BM Units affected by Demand Control.

One of the initial suggestions was the possibility of obtaining details of Parties impacted by Demand Control from the LDSOs.

The Group's discussions with the LDSOs revealed that the information used by LDSOs to identify appropriate entities for Demand Control was not of a form easily translatable to data that would help in the targeting of Demand Control Volumes. The Group decided that typically, it would not be possible to target specific Suppliers, BM Units or GSPs. However, there would be occasions (for example, when only one GSP has been disconnected), and so whenever possible, the System Operator should provide additional information that would enable a more focused application of Demand Control Volume allocation.

The Group considered how the Demand Control Volume would be targeted in the event of being able to identify some, but not all, of the affected BM Units. The Group considered whether it was possible for some of the Demand Control Volume could be 'targeted' at these BM Units, with the rest of the volume 'spread' across the other GSP Group BM Units and, if so, how would this be accomplished. The alternatives would be to either:

- Target the entire Demand Control Volume at only the BM Units identified as affected; or
- Spread the volume across the entire GSP Group.

Theses two approaches would be mutually exclusive and could not be combined to target elements of the Total Demand Control Volume to specific BM Units and smearing the remainder across the GSP Groups.

c Share of Historic GSP Group Take

A Group Member suggested the possible use of data from equivalent Settlement Periods either side of the Demand Control Period (i.e. the use of 'future' Settlement Periods as well as historic ones) in the determination of the volume allocation methodology. However, the Group noted that, should Demand Control happen, the industry would be aware of the mechanism used to determine a Party's Demand Control position. It was suggested that the use of data from an equivalent period post-Demand Control may provide

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the opportunity for an impacted Party to attempt to alter their Imbalance position during the Demand Control Periods.

In light of this, the Group reasoned that the 'equivalent' Settlement Periods used in volume allocation should be historic.

Some of the Group suggested the use of a 'hybrid' volume allocation approach as a means of improving accuracy. The approach would apply different methods to different Demand Control situations (one suggestion was to use the Previous Period for Demand Control events of short duration and an alternative approach for longer Demand Control events). However, it was felt that such an approach would be counter to the volume allocation requirements detailed above.

The following methodologies for volume allocation were determined, where the Equivalent Settlement Period is:

1. An average of several P138 'Previous Equivalent Periods';
2. The same Settlement Period on the previous day;
3. Settlement Period immediately prior to Demand Control; and
4. The use of HH data to split Demand Control Volumes between affected HH and NHH meters.

P138 Methodology

The Group discussed the mechanism proposed under P138 for the allocation of Demand Control Volumes to affected BM Units.

P138 proposed the use of a Previous Equivalent Settlement Period to determine what an affected BM Unit's GSP Group share of the total GSP Group Take was. This share was used to allocate the Demand Control Volume i.e. a BM Unit with a share equal to 1/50th of the GSP Group Demand would receive 1/50th of the Demand Control Volume allocation. A Previous Equivalent Settlement Period was defined as the same Settlement Period on the same day of the week for which there had been an Initial Settlement Run (SF) performed. Typically, a Previous Equivalent Settlement Period could be up to 3 weeks prior to the Demand Control Settlement Period.

The Group considered the approach proposed by P138 for the allocation of Demand Control Volumes to affected Parties and were initially concerned that the accuracy of this method may not be sufficient. In particular, the Group was concerned about the use of data up to 3 weeks prior to the Demand Control Settlement Period to estimate a BM Unit's share of GSP Group Demand.

ELEXON conducted analysis of the P138 volume allocation, considering the extent to which a BM Unit's share of GSP Group demand was consistent across Settlement Periods deemed to be equivalent under the P138 methodology. The results were presented to the Group, who noted that the difference (and hence the potential error) was significant.

In particular, the Group noted the apparent volatility for smaller BM Units (BM Units with metered volumes less than 10MWh). It was recognised that this variation could introduce a significant error into the allocation of Demand Control Volumes to affected Parties were this methodology adopted;

Because of the inaccuracy in the derived volumes calculated by this method, the Group decided to investigate alternative volume allocation methodologies.

Method 1: Average

This method took an average of the previous four weeks of equivalent P138 Settlement Periods and compared this average value to the GSP Group Share for the Demand Control Settlement Day and Period.

With this method, if Demand Control happened in Settlement Period 22 Wednesday, an average of the four preceding Wednesdays (for which there was settlement data) would be used to apportion the Demand Control Volume.

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The majority of the Group decided not to pursue this method further, preferring instead to keep the approach to volume allocation simple. It was also considered that using an average would require the use of older – and therefore potentially less relevant information. However, some of the Group Members thought that an average of Previous Equivalent Periods would help improve the accuracy of the volume allocation.

Method 2: Previous Day

The Group suggested using a forecast of the BM Unit's share of GSP Group Demand based on the Previous Equivalent Settlement Period from the day immediately prior to the Demand Control day (if Demand Control happened in Settlement Period 22 on Wednesday, Settlement Period 22 on Tuesday would be used).

The Group noted the improved accuracy with this method for certain days of the week, but were uncomfortable with using a different weekday to determine BM Unit share of the Demand Control Volume. The Group also noted the need for alternative approaches on the following days: Mondays, Bank Holidays and non-weekdays.

The Group decided not to pursue this method, preferring to use the same day of the week.

Method 3: Previous Settlement Period

The Group suggested a forecast of the BM Unit's share of GSP Group Demand based on the Settlement Period(s) immediately prior to, and on the same day as, the start of Demand Control (if a Demand Control Instruction was issued for Settlement Periods 22 and 23 on Wednesday, Settlement Period 21 on Wednesday would be used as the equivalent Settlement Period).

The Group noted the improved accuracy with this method, but were uncomfortable with using a different, non-equivalent, Settlement Period to determine BM Unit share of the Demand Control Volume.

The Group also noted the accuracy decreased as Settlement Period 'distance' from the Demand Control Periods increased, and discussed the impact should Demand Control last for a significant duration (several Settlement Periods and longer). The Group recognised that in using this method, an alternative approach would also be needed once the duration of Demand Control had exceeded a certain number of Settlement Periods.

The Group decided, by majority, not to pursue this method, preferring to use the same Settlement Period from an equivalent day of the week.

Method 4: The use of Half-Hourly (HH) Metered Data to Improve Accuracy

The Modification Group discussed the use of Half-Hourly data in the volume allocation calculation. It was thought that, because actual meter readings (rather than estimates) are available, the accuracy of the Demand Control Volume apportionment should be improved. The Group proposed a stepped approach as a possible means of incorporating Half-Hourly data into the apportionment calculation:

- Identify Affected HH Meters;
- Determine HH Demand Control Volume; then
- Allocate Remaining Demand Control Volume across NHH Sites.

A Group member suggested the use of profiling as a means of identifying and determining Demand Control Volume allocation. It was stated that during a period of Demand Control, you would expect to see reduced meter readings for the site(s) in question (because the affected site had been disconnected, for example). In a Demand profile for an affected meter, a 'dip' in Demand would be identifiable (See diagram).

The Group discussed how the profile of the deemed meter reading would be estimated. The Group considered the whether Settlement Periods immediately before and after Demand Control would be connected using a straight line (Demand Estimate 1, diagram below). The Group also considered using gradients derived from the Settlement Periods immediately before and after Demand Control to attempt to

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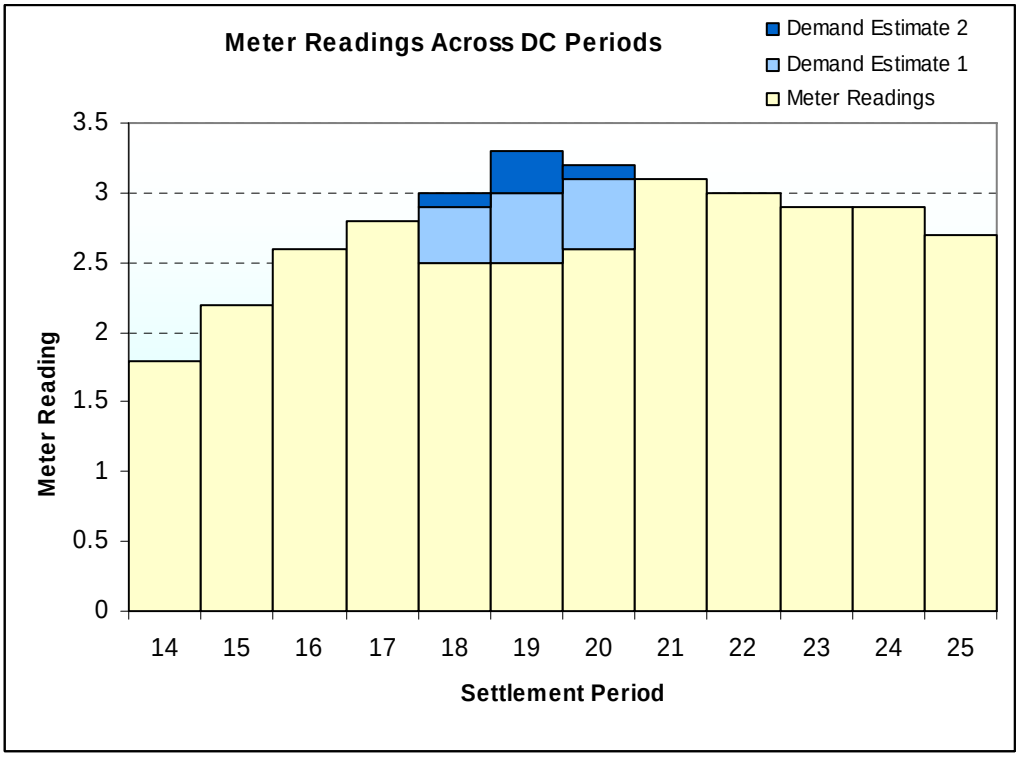
model the deemed Demand Profile (Demand Estimate 2 on diagram below). The Group also noted that there might be other methods that could be used to infer deemed demand.



Investigation by ELEXON revealed that, for allocation to be performed using the HH metered data, analysis would have to be carried out for each meter as ELEXON systems do not hold HH data by Meter ID; HH data is instead aggregated, along with Non-Half-Hourly (NHH data), at BM Unit level. To make use of Half-Hourly data, it would be necessary for sufficient information to be provided so that the Demand Control Volume could be allocated amongst individual affected meter IDs. It would also be necessary for data to be provided that would enable the affected meters to be correlated to their associated BM Units.

The Group discussed how the Demand Control Volume would be determined based on a profile of meter readings for each affected meter across the Demand Control Period(s). The readings taken during Demand Control would show the Meter IDs consumption, including the effect of Demand Control.

A group Member raised the point that, whilst obtaining the meter readings (including Demand Control) would be less problematic, to work out the Demand Control would require some form of estimate of what the meter readings should have been had a DCI not been issued. Two possible ways of determining an estimate of HH BM Unit demand in the absence of Demand Control were suggested by the Group:

- An automated algorithm (possibly based on the use of gradients) to extrapolate Demand; or
- A manual, subjective approach.

A BM Unit usually comprises both HH and NHH meter IDs and there can be a large number of HH meters per BM Unit. Hence, the above approaches would require Demand Control Volume calculation to be performed for each affected meter ID. Significant resource would be required to implement such a solution and the Group considered the potential resourcing implications involved with utilising HH data to improve the estimates of Demand Control Volumes.

The final step in an allocation process involving HH meter readings whould be the distribution of the remaining Demand Control Volume proportionally across Non-Half-Hourly BM Units affected by Demand Control using a defined methodology. The Group proposed that the total of the derived HH Demand Control Volumes should be subtracted from the total Demand Control Volume to determine the remaining Demand Control Volume that needed to be apportioned across affected NHH BM Units. In the absence of a means to

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determine which BM Units were affected, the suggestion was made that the volume should be apportioned across all BM Units in the affected GSP Group(s).

Discussions with the LDSO attendees at the Group revealed the difficulty of mapping HH data into a format useable by ELEXON. The only alternative would be the subjective analysis of each affected meter which would require significant effort. As such, the use of Half-hourly data was deemed to be impractical.

d Enhancement of Demand Control Allocation Accuracy Through the Settlement Process

The Group suggested that, whilst an initial estimate of the Demand Control position would be useful, the allocation of Demand Control Volumes should be refined during the Settlement process as further more accurate run type data became available. In addition, information from an equivalent Settlement Period from closer to the Demand Control Settlement Period could be used (i.e. 1 week prior).

e P199 Approach to Volume Allocation

The Group discussed the various methods of allocating Demand Control and the majority of the Group decided that they wanted a volume allocation method that:

- Was not overly complex to implement;
- Used an equivalent period to the DC period (i.e. the same Settlement Periods);
- Used the closest equivalent day to the DC day. (i.e. the same day of the week);
- Could be refined at a later date using settlement (i.e. re-run using R1 data, etc); and
- Used only historic data.

The above requirements were used to define the Demand Control Volume allocation approach detailed in the P199 Requirements Specification (Reference 2).

The inclusion of an claims process into P199 means that the volume allocation will not be recalculated once RF data has become available for the Previous Equivalent Period, one week prior to the Demand Control Settlement Period. This is to ensure that the revised Demand Control volume allocation resulting from a potentially upheld claim is not amended.

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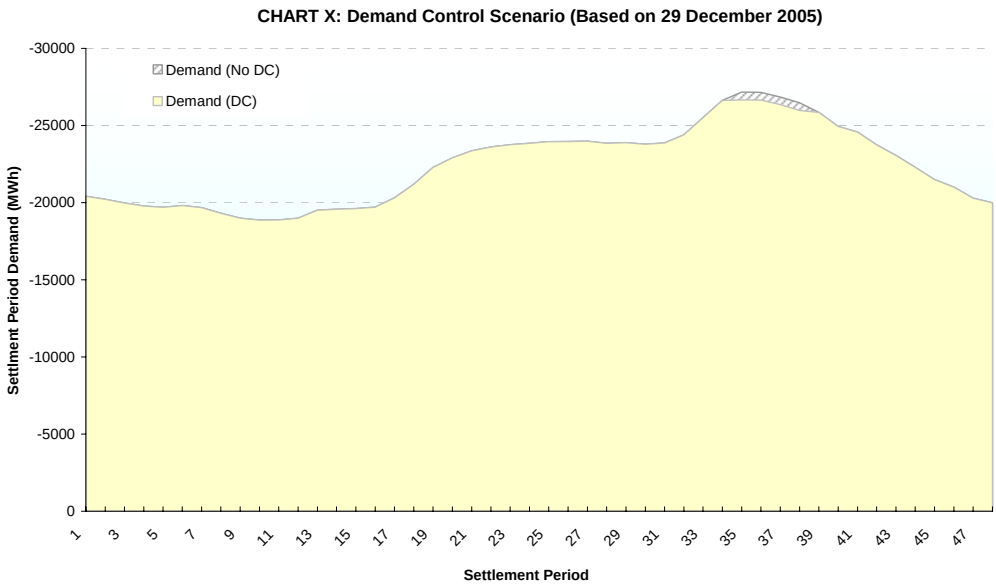
APPENDIX 7: P199 PRICING ANALYSIS (PRE-P194 BASELINE)

Approach

Historic data representing periods of Demand Control is not available; therefore the following approach was utilised to provide a scenario for the purpose of the analysis performed.

Settlement Day 29 December 2005 was chosen to create the Demand Control scenario. Notice of Insufficient System Margin (NISM) and High Risk of Demand Reduction (HRDR) messages were issued for 30 December 2005 prior to real time. On the day, sufficient generation was available and Demand Control was not required.

To create the Demand Control scenario, a BM Unit on which a significant volume of Offers were accepted on the actual Settlement Day was identified. It was then assumed that Offers from this BM Unit were not available for Settlement Periods 35 to 38 (over the demand peak). In the absence of Offers from the BM Unit identified, it was assumed that Demand Control was utilised to balance the System. 500MWh of Demand Control was considered to have been taken in each of Settlement Periods 35 to 38. In each period, an additional volume of Bid Acceptances (at a price equal to the most expensive, in terms of cost to the System, Bid actually accepted) was also introduced; such that the net volume of the Demand Control and Bid Volumes introduced was equal to the Volume of Accepted Offers removed. Chart X (below) illustrates Demand profiles for the actual Settlement Day and the Demand Control scenario created.



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Energy Imbalance Prices during the Demand Control scenario were then estimated for the following mechanisms:

- **Option 1: Demand Control not reflected in price calculation (current baseline)**
- **Option 2: Demand Control Volume reflected in price calculation as an Un-priced volume (P199 Proposed)**
- **Option 3 a/b: Demand Control Volume reflected in price calculation at marginal Offer Price / 'Chunky' Marginal Offer Price**
- **Option 4: Demand Control Volume reflected in price calculation at Market Price**
- **Option 5: Demand Control Volume reflected in price calculation at Value of Lost Load (VOLL)**
- **Option 6: SBP fixed at pre Demand Control level**

Results:

Option 1: Demand Control not reflected in Price calculation (current Baseline)

Under the current baseline Demand Control is not reflected in the calculation of Energy Imbalance Prices. As a consequence, Energy Imbalance Prices may be more favourable to Parties that are exposed to these prices than would be the case in similar conditions where Demand Control has not been utilised (e.g. if there had been additional Offer Volumes available to meet demand). This is illustrated in the simplified examples shown in Figures 1 and 2:

Figure 1: Current Baseline - Demand Control

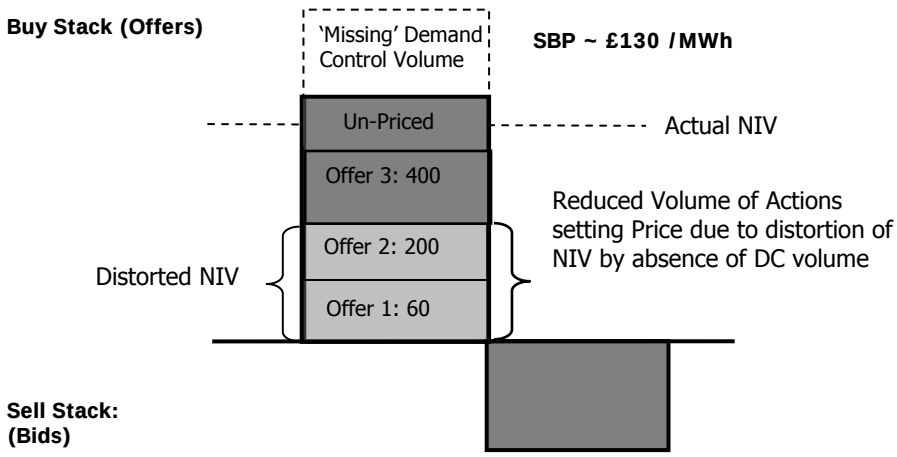

Figure 2: Current Baseline - Additional Offers

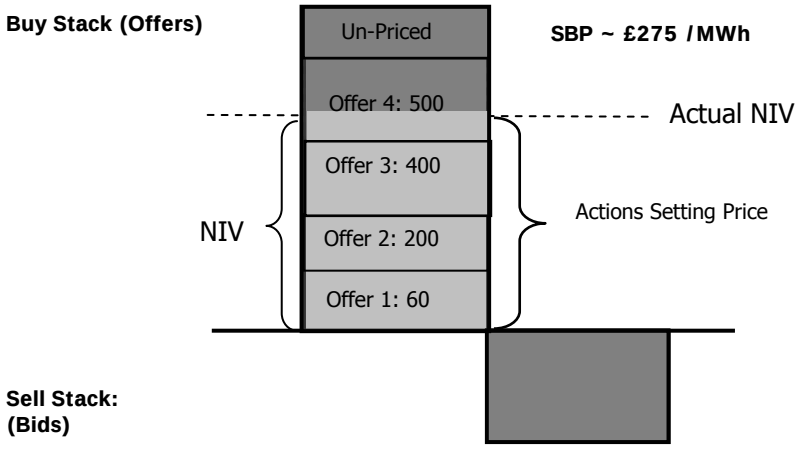

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Chart A illustrates the estimated impact of Demand Control on System Buy Price (SBP) under the current baseline in the scenario created for this analysis. SBP is lower in the Demand Control scenario than it would be had additional Offer Volumes been available to balance the System (i.e. as actually occurred on the Settlement Day in question). This impact on SBP is a consequence of the reduction of NIV resulting from not including the Demand Control Volume in the calculation.

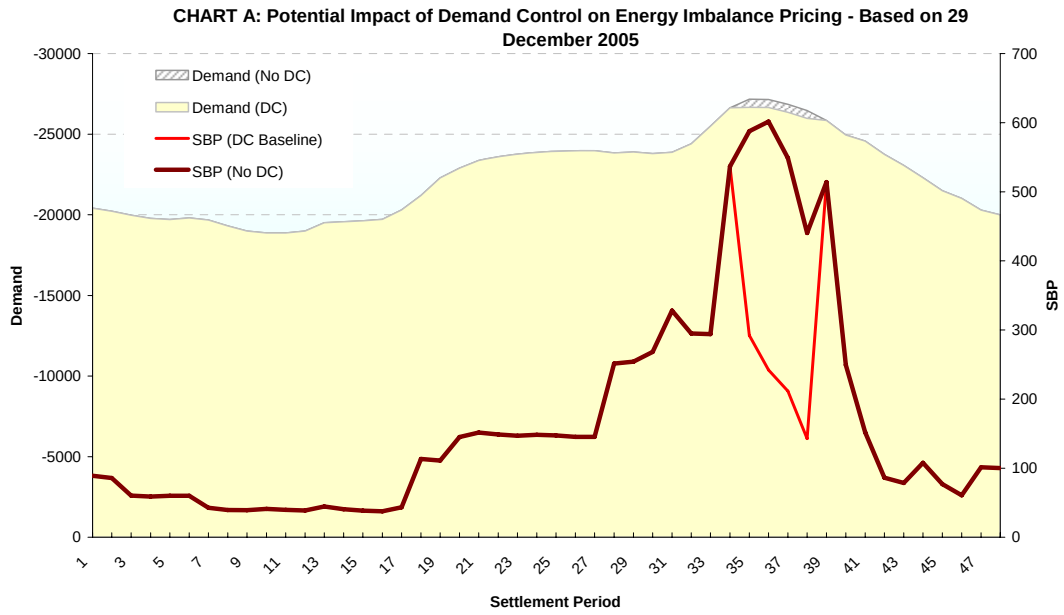
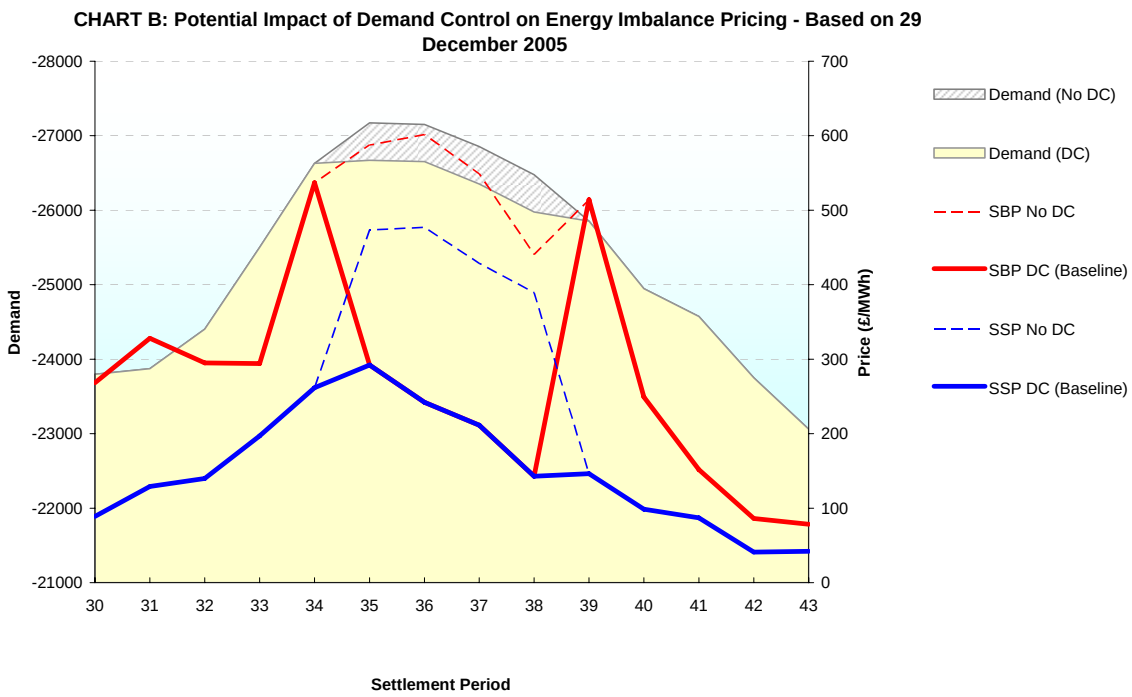


Chart B provides a closer view of the Demand Control scenario under the current baseline and illustrates the impact on System Sell Price (SSP). SSP is lower in the Demand Control scenario than it would be had additional Offer Volumes been available to balance the System (i.e. as actually occurred on the Settlement Day in question). The impact on SSP is a consequence of the defaulting rules; since SBP (main price) is lower than the market price under the Demand Control scenario, SSP is capped at SBP.



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Option 2: Demand Control un-priced (Proposed Modification P199)

Including Demand Control as an un-priced volume would correct the calculation of NIV and would not dilute the Energy Imbalance Price. However, the cost of Demand Control would not be reflected in Energy Imbalance Prices. This is illustrated in the simplified example shown in Figure 3.

Figure 3: Demand Control Un-Priced

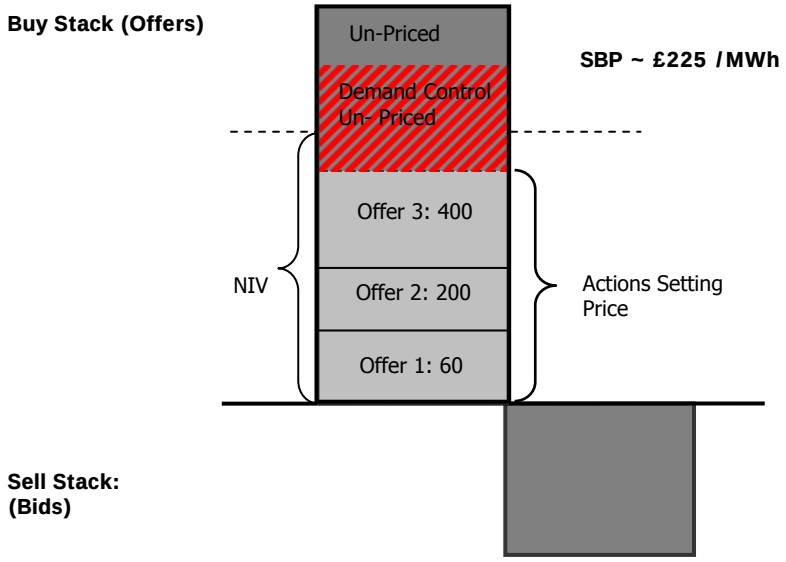

Chart C illustrates the estimated impact of Demand Control on Energy Imbalance Prices under Proposed Modification P199 in the scenario created. The results illustrates that SBP would be higher than would have been the case had additional Offer volumes been available to the System Operator to balance the System (i.e. as actually occurred on the Settlement Day in question). This is due to the impact of removing Offer Volumes at a price lower than the average cost of actions influencing SBP to create the Demand Control scenario.

CHART C: Potential Impact of Demand Control on Energy Imbalance Pricing - Based on 29 December 2005

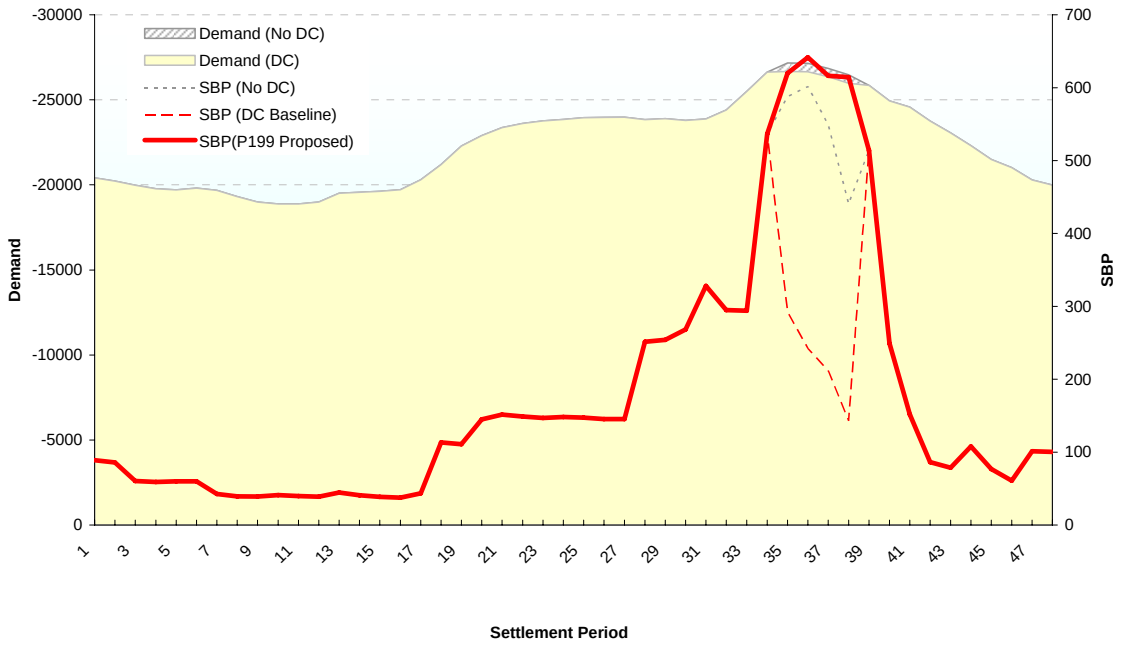

Chart D provides a closer view of the Demand Control scenario under Proposed Modification P199 and illustrates the impact on SSP. Under Proposed Modification P199, SSP in the Demand

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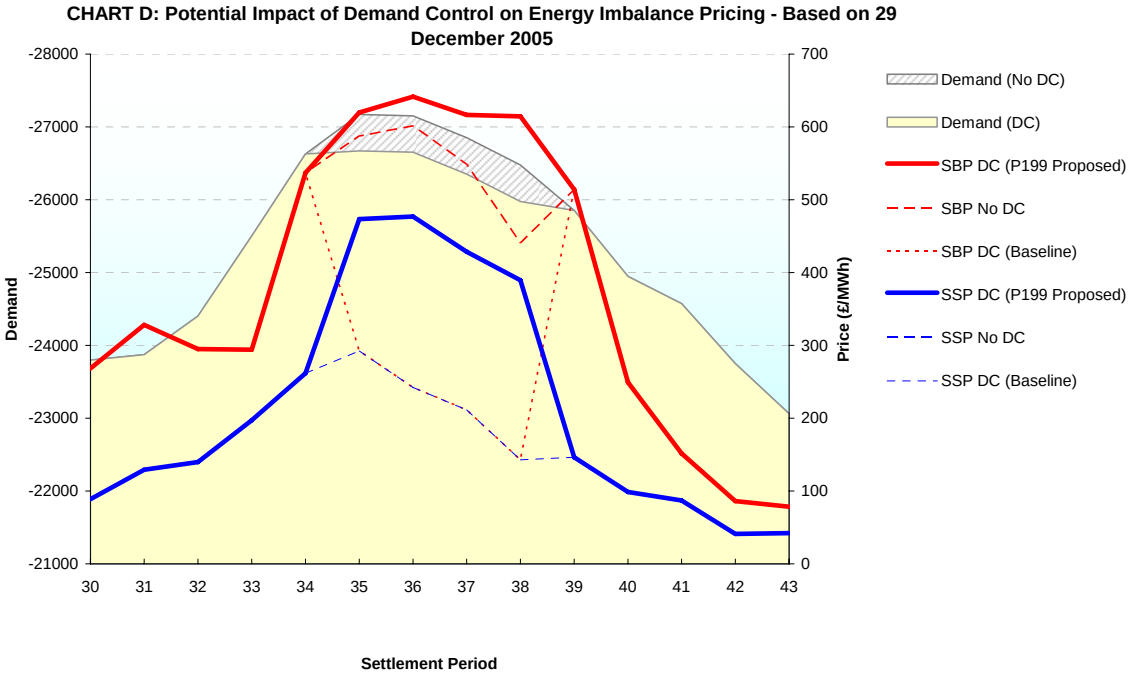
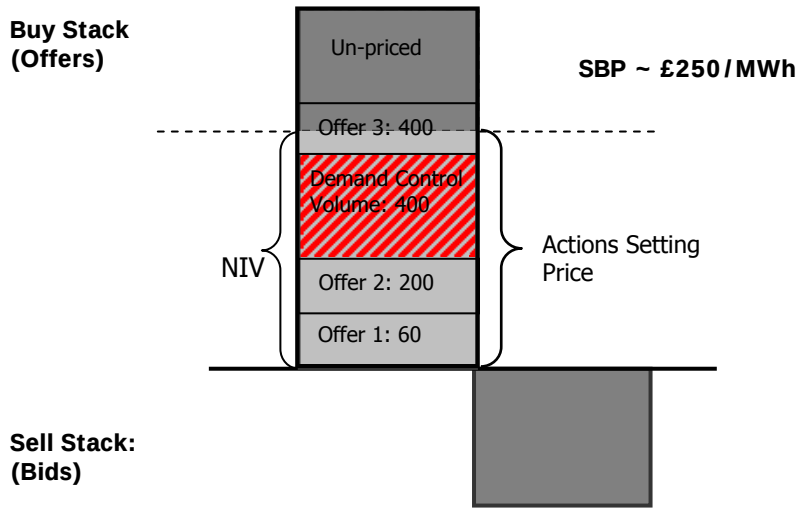
Control scenario is aligned with what it would have been had additional Offer volumes been available to the System Operator to balance the System (i.e. as actually occurred on the Settlement Day in question).



Option 3 a/b: Demand Control at marginal Offer Price / Chunky Marginal Offer Price

Including Demand Control at the marginal Offer price (i.e. the price of the most expensive Offer taken by the System Operator in the affected Settlement Period) would correct the calculation of NIV and increase the Energy Imbalance Price. This is illustrated in the simplified example shown in Figure 4.

Figure 4: Demand Control at Marginal Offer Price



A further option based on this approach would be to derive the Demand Control Offer Price from the volume weighted average of 100MWh of the most expensive accepted Offers (referred to as a 'chunky' marginal approach). This method avoids using a single small volume action to set the Demand Control Offer Price.

Chart E illustrates the estimated impact on Energy Imbalance Prices under a mechanism whereby Demand Control Volumes are included in the price calculation at the marginal or 'chunky' marginal Offer price (NB: in the situation considered these two approaches give identical prices). This approach would result in a higher SBP than under the Proposed

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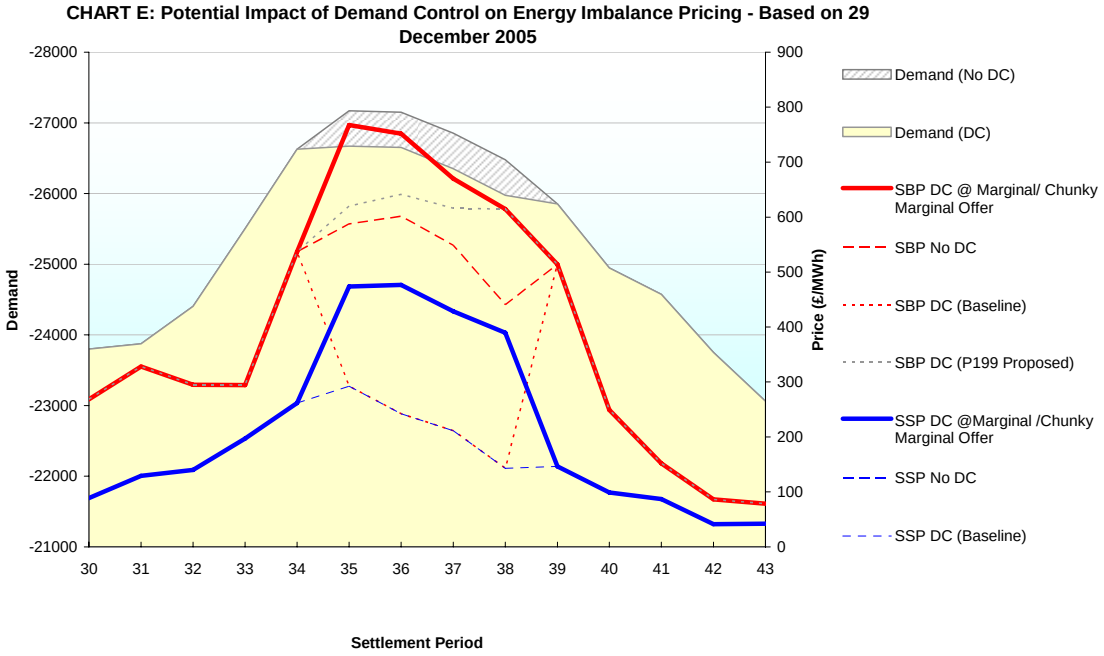
Modification in the scenario considered. Again SSP remains the reverse/market price due to the inclusion of the Demand Control Volume in the Energy Imbalance Price calculation.



Option 4: Demand Control Volume reflected in Price calculation at Market Price

Including the Demand Control Volume in the price calculation at the Market Price (derived from trades undertaken on power exchanges via information provided by Market Index Data Providers) would correct the calculation of NIV but may dilute the Energy Imbalance Price. This is illustrated in the simplified example shown in Figure 5.

Figure 5: Demand Control at Market Price

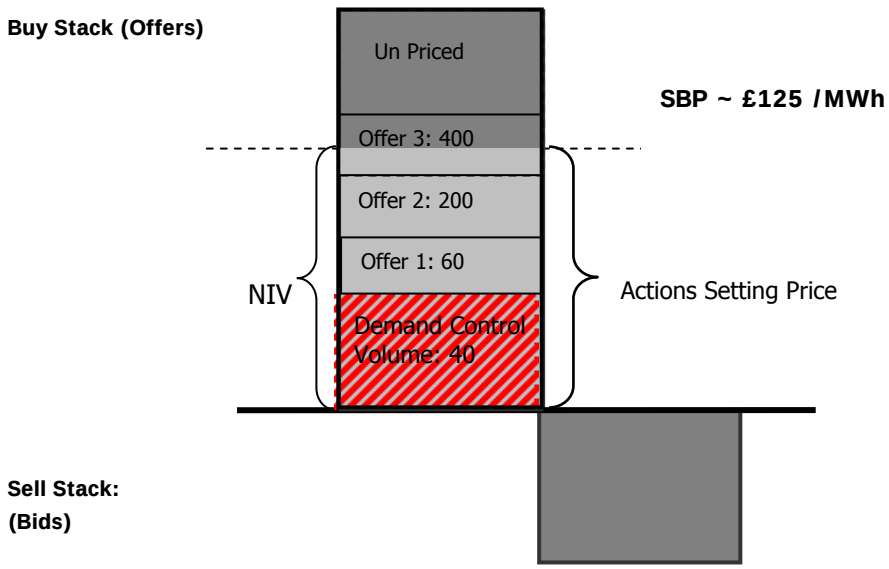


Chart F illustrates the estimated impact on Energy Imbalance Prices under an approach whereby Demand Control Volumes are included in the price calculation at the Market Price. This approach would result in a lower SBP[18] than under the Proposed Modification in the scenario considered. SSP is also lower than it would be had additional Offer Volumes been available to balance the

[18] This analysis was performed under the pre-P194 baseline and whilst use of an offer at market price is likely to reduce SBP under the existing imbalance price baseline, under a P194 pricing method it is less likely to reduce SBP. Under P194, use of market price would only reduce SBP if it happened to fall in the bottom of the 100MWh band which would set price.

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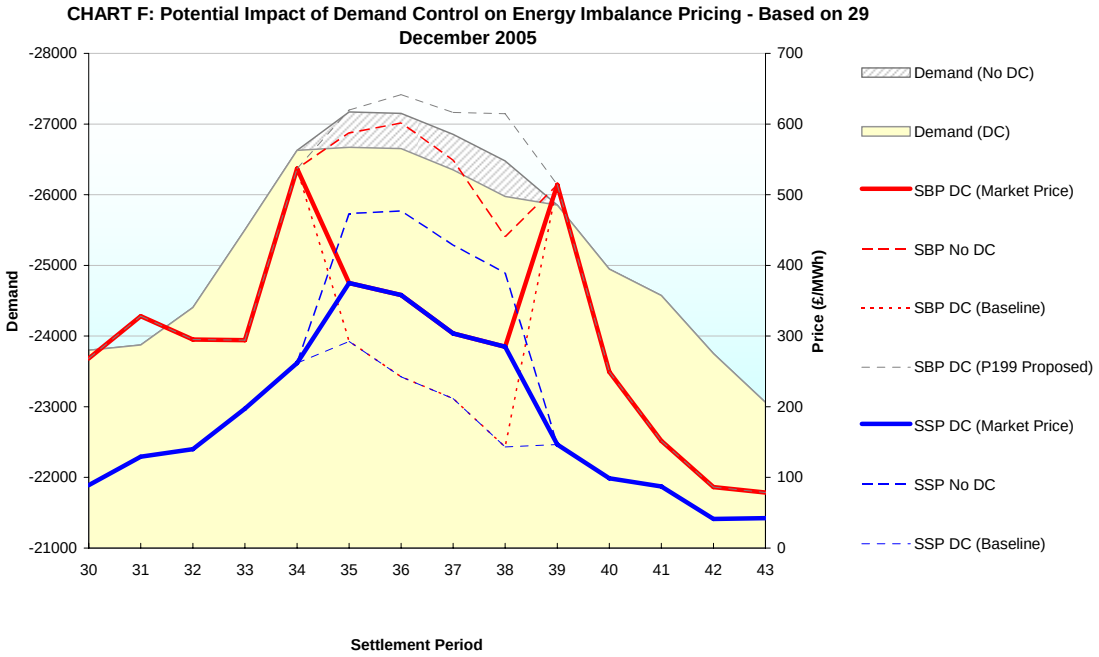
System (i.e. as actually occurred on the Settlement Day in question). The impact on SSP is a consequence of the defaulting rules; since SBP (main price) is lower than the Market Price, SSP is capped at SBP.



Option 5: Demand Control Volume reflected in Price calculation at Value of Lost Load (VOLL)

Including Demand Control at VOLL (i.e. an estimate of the price demand would be willing to pay before forgoing generation) would correct the calculation of NIV and could either increase or decrease the Energy Imbalance Price (depending on the price of other Offers accepted in the Settlement Period). This is illustrated in the simplified example shown in Figure 6 (NB: For the purpose of this analysis VOLL has been taken as £3,000/MWh).

Figure 6: Demand Control at VOLL

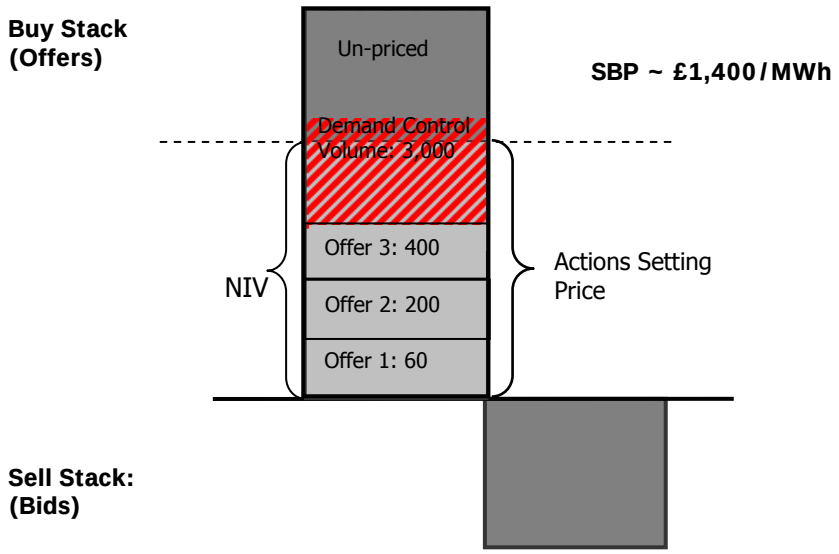


Chart G illustrates the estimated impact on Energy Imbalance Prices under an approach whereby Demand Control Volumes are included in the price calculation at an estimate of VOLL. The results illustrate that this approach would result in a higher SBP than under the Proposed Modification in the scenario considered.

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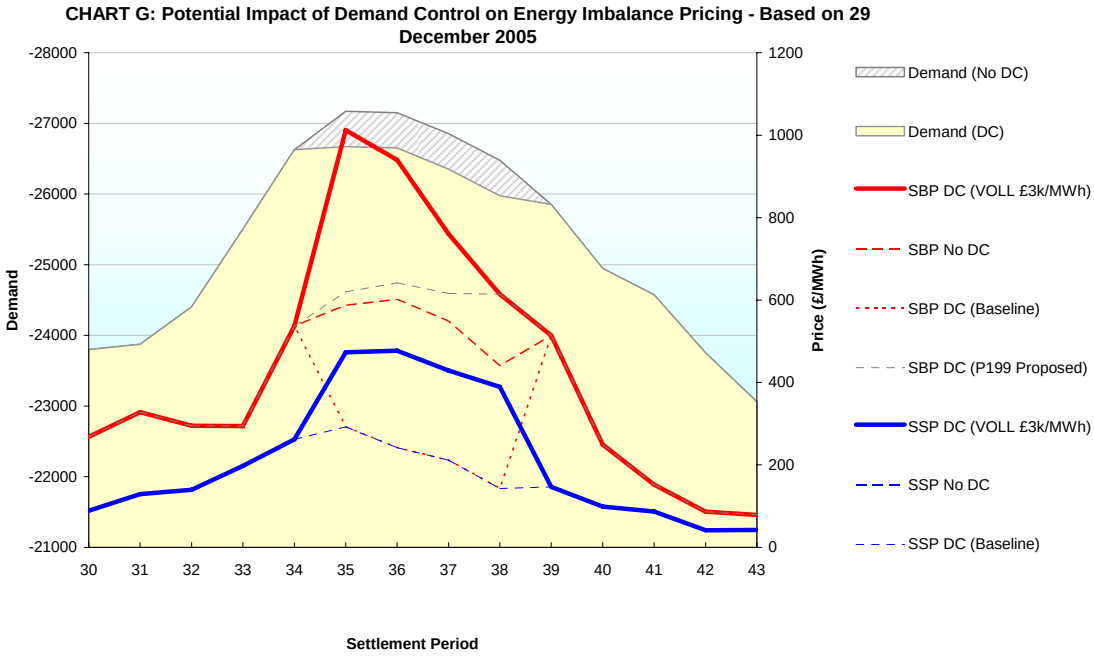
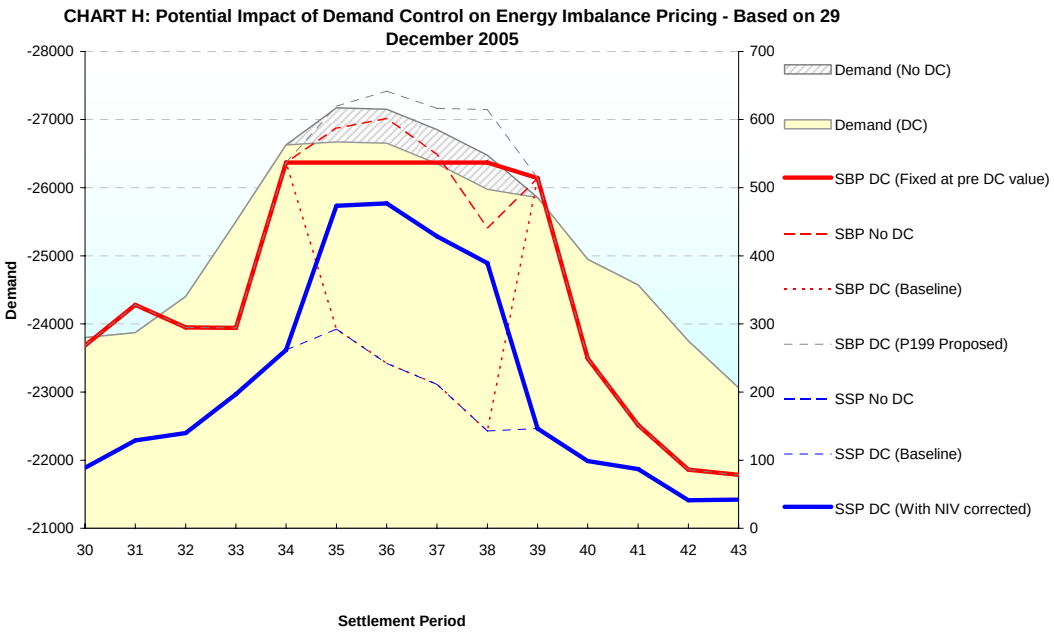


Option 6: Fixed SBP for Demand Control duration

Chart H illustrates the estimated impact on Energy Imbalance Prices under an approach whereby Demand Control Volumes would be included in the price calculation to correct the NIV (to ensure that calculation of SSP remains appropriate) and SBP is fixed at the value in the Settlement Period immediately preceding the Demand Control Period for the duration of the event. The results illustrate that this approach provides a SBP which does not follow the profile of SBP that would have occurred if Demand Control had not been required; in addition a discontinuity is potentially introduced at the end of the Demand Control period at the transition to the normal calculation (although in the example this effective is relatively minor).



It is worth noting that it is not currently possible to fix System prices within central systems. Therefore, a solution whereby System prices are fixed during the Demand Control period requires a more complex implement approach than the other options identified.

Conclusions:

It is considered the following high level conclusions were drawn form the analysis performed:

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- Under the current baseline a period of Demand Control could result in a lower SBP relative to an otherwise similar period in which Demand Control was not required. In addition, the determination of main and reverse price may be affected;
- Inclusion of Demand Control Volume at the Market Price could result in a lower System Buy Price relative to an otherwise similar period in which Demand Control was not required;
- Fixing SBP for the duration of the Demand Control Period limits the flexibility of Energy Imbalance Prices during the Demand Control period and could introduce a discontinuity at the end of the Demand Control Period. The implementation approach for this mechanism is likely to be more complex than other options identified and would need to be considered via impact assessment if this approach is progressed;
- The impact of pricing Demand Control at VOLL is dependent on the particular circumstances of the Demand Control event. The impact on Energy Imbalance Prices of the VOLL approach is potentially substantial relative to an otherwise similar period in which Demand Control was not required. Progression of the VOLL approach would require further consideration of how the value of lost load figure would be estimated;
- Under Proposed Modification P199, a period of Demand Control could result in System Buy Prices higher than that in an otherwise similar period in which Demand Control was not required; and
- Inclusion of Demand Control Volume at either the marginal or 'chucky' marginal Offer price could result in a comparable or higher System Buy Price relative to an otherwise similar period in which Demand Control was not required.

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APPENDIX 8: P138 AREAS CONSIDERED BY AUTHORITY

Area Considered in P138	Relevance to P199
The treatment of Demand Control as Offer (for the purposes of imbalance cashout) would not send signals to market in sufficient time for the market to react since such a signal would only arise once Demand Control had been instructed.	Still present under P199.
The "Windfall Payment" made by the SO to Parties affected by Demand Control could reduce incentives on Parties to balance; in the event of Demand Control, such a payment could reduce (or negate) any increase in imbalance exposure faced by Parties that are short.	P199 proposes no payment to Parties affected by Demand Control.
Some members of the industry considered the payment to Parties affected by Demand Control at the Marginal Offer Price would act as an incentive on the SO The Authority was of the opinion that Demand Control is an operationally-driven decision taken by the SO to ensure overall system stability rather than an economic option. Treating Demand Control as an Offer Acceptance would not impact the level of reserve held by the SO.	P199 proposes no payment to Parties affected by Demand Control. However, the issue is relevant under options being considered as potential Alternative Modifications.
Increased uncertainty in the market in relation to imbalance cashout prices and Residual Cashflow Reallocation Cashflow (RCRC) payments as the volume and associated price with the Demand Control Offer would not be known until after the event.	Still present under P199 as there is still a delay in the market signals and additional uncertainty introduced through the determination of Demand Control Volume allocation.
Treating Demand Control as an Offer would reduce the potential financial risks associated with Demand Control to Supply Parties.	Under P199, there is potential for greater financial risk associated with Demand Control as Parties are not being compensated for lost Customer Demand
Allocation of Demand Control Volumes to Supply Parties would reduce the potential for inconsistent imbalance cashout.	Still present under P199.
The reduced incentive on Suppliers to submit Offers into the Balancing Mechanism normally.	P199 proposes no payment to Parties affected by Demand Control. Therefore, there is a potentially increased incentive on Suppliers to provide Offers into balancing mechanism before a Demand Control event because they would receive payment for reducing demand (opposed to Demand Control with no associated payment for reduced Demand).

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Area Considered in P138	Relevance to P199
Unwanted incentive on Parties to attempt to increase the likelihood of Demand Control (when in an increasingly short position, for example) in the hope of receiving a 'Windfall Payment' via the Demand Control Offer.	P199 proposes no payment to Parties affected by Demand Control.
Additional complexity in the Trading Arrangements.	Still present in P199./
Over-reliance on Estimates to calculate Demand Control Volumes	Still Present in P199.

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