P305 'Electricity Balancing Significant Code Review Developments'

P305 proposes to progress and implement the conclusions to the Electricity Balancing Significant Code Review, which will put in place a single, marginal imbalance price, introduce Reserve Scarcity Pricing and introduce pricing for Demand Control actions.

This Report Phase Consultation for P305 closes:

5pm on **Tuesday 3 March 2015**

The Panel may not be able to consider late responses.

The BSC Panel initially recommends **rejection** of P305

This Modification is expected to impact:

- BSC Trading Parties
- Distribution System Operators (DSOs)
- Data Aggregators (HHDAs/NHHDAs)
- Data Collectors (HHDCs/NHHDCs)
- The Transmission Company
- The Balancing Mechanism Reporting Agent (BMRA)
- The Central Data Collection Agent (CDCA)
- The Settlement Administration Agent (SAA)
- The Supplier Volume Allocation Agent (SVAA)
- ELEXON

Consequential changes will be required to:

- The Data Transfer Catalogue (DTC)

ELEXON

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About This Document

This is the P305 Draft Modification Report, which ELEXON is issuing for industry consultation on the BSC Panel's behalf. It contains the Panel's provisional recommendations on P305. The Panel will consider all consultation responses at its meeting on 12 March 2015, when it will agree a final recommendation to the Authority on whether or not the change should be made.

There are six parts to this document:

- This is the main document. It provides details of the solution, impacts, costs, benefits/drawbacks and proposed implementation approach. It also summarises the Workgroup's key views on the areas set by the Panel in its Terms of Reference, and lists its membership and full Terms of Reference.
- Attachment A contains the detailed analysis and assessment undertaken by the P305 Workgroup, including the results of ELEXON's historical analysis.
- Attachments B and C contain the draft changes to the BSC to deliver the P305 Proposed and Alternative Modifications.
- Attachment D contains the full non-confidential responses received to the Workgroup's Assessment Procedure Consultation.
- Attachment E contains the specific questions on which the Panel seeks your views. Please use this form to provide your responses to these questions, and to record any further views or comments you wish the Panel to consider.

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1 Summary

Why Change?

P305 has been raised by National Grid to progress the conclusions to Ofgem's Electricity Balancing Significant Code Review (SCR) (EBSCR), which looked at addressing concerns with electricity balancing arrangements. In particular, Ofgem expressed concerns that imbalance prices are not creating the correct signals for the market to balance, which could undermine efficiency in electricity security of supply and balancing, unnecessarily increasing costs.

Solution

P305 proposes to:

- reduce the Price Average Reference (PAR) value to 50MWh and the Replacement PAR (RPAR) value to 1MWh upon implementation, and reduce the PAR value further to 1MWh on 1 November 2018;
- introduce a single imbalance price;
- improve the way Short Term Operating Reserve (STOR) actions are priced by introducing a Reserve Scarcity Price (RSP) which is determined with reference to a 'static' Loss of Load Probability (LoLP) function upon implementation before switching to a 'dynamic' function on 1 November 2018; and
- introduce pricing for Demand Control actions and a process for correcting participants' imbalance volumes following such an event.

The Workgroup has developed an Alternative Modification which will reduce the PAR value to 100MWh upon implementation with no further changes and will remove the switch to a 'dynamic' LoLP function, but is otherwise identical to the Proposed Modification.

Impacts & Costs

P305 will directly impact Distribution System Operators (DSOs), Data Aggregators, Data Collectors, the Transmission Company and BSC Agents. P305 will indirectly impact BSC Trading Parties. The central systems implementation costs are approximately £625k.

Implementation

P305 is proposed for implementation on 5 November 2015 (November 2015 BSC Systems Release).

Recommendation

The Panel believes that neither the Proposed Modification nor the Alternative Modification would overall better facilitate the Applicable BSC Objectives. It therefore initially recommends that both the Proposed and Alternative Modification should be rejected.

2 Why Change?

What is imbalance pricing?

Imbalance pricing (also known as "cash-out") is a key part of the wholesale trading arrangements in Great Britain (GB).

The wholesale electricity market is set up such that BSC Parties enter into bilateral contracts with each other in order for generators to be able to sell the energy they produce to Suppliers to supply their customers. For any given half hour Settlement Period, Parties may trade with each other up to a point one hour beforehand, known as Gate Closure. Parties will aim to balance their position for a given Settlement Period at this time such that the amount of energy they generate or buy matches the amount of energy they consume or sell. However, there are circumstances where this does not happen, such as a generator experiencing an unexpected outage that does not allow them to generate the expected amount of energy, or a Supplier over- or under-estimating the actual demand its customers use. This leaves the Party in a position of imbalance.

Following Gate Closure, National Grid, in its role as the National Electricity Transmission System Operator (NETSO) (referred to under the BSC as the Transmission Company), will assess the amount of planned generation and the amount of demand expected for the Settlement Period, and will take actions to balance the system such that the total amount generated matches the total amount consumed. It does this in the Balancing Mechanism (BM) by accepting Bids and Offers submitted by Parties, usually generators, to increase or decrease the amount of energy they will produce (or consume) to ensure the system is balanced. It can also take actions outside the Balancing Mechanism, such as the use of STOR. It will do this up to and throughout the Settlement Period to ensure the system is balanced at all times.

Following the end of a Settlement Period, ELEXON will compare the amount of energy each Party contracted with its metered volumes for the Settlement Period, accounting for any balancing actions. Any surplus or shortfall that the Party has is paid for using the relevant imbalance price:

- If the Party is **short** (it consumed or sold more energy than it generated or bought) then it pays for its shortfall at the **System Buy Price** (SBP).
- If the Party is **long** (it generated or bought more energy than it consumed or sold) then it is paid for its surplus at the **System Sell Price** (SSP).

There are two methods for calculating the imbalance price:

- The **Main Price** is based on the Bids and Offers accepted by the Transmission Company for that Settlement Period.
- The **Reverse Price** is based on the market price of electricity for that Settlement Period.

Which method (Main or Reverse) is applied to which imbalance price (SBP or SSP) is determined by whether the system as a whole was long (the Net Imbalance Volume (NIV) was zero or negative) or short (the NIV was positive) in that Settlement Period:

- If the system is long, the SSP will be the Main Price and the SBP will be the Reverse Price.
- If the system is short, the SBP will be the Main Price and the SSP will be the Reverse Price.

What are Bids and Offers?

Bids and Offers are submitted by Parties to the Transmission Company, proposing to increase or reduce generation or demand in exchange for payment. The Transmission Company will accept these as required to balance the system.

Bids are proposals to reduce generation or increase consumption.

Offers are proposals to increase generation or reduce consumption.

Imbalance Pricing Guidance Note

More detail on imbalance prices and how they are calculated can be found in our Imbalance Pricing Guidance Note.

As a result, the Main Price is applied to any Party whose imbalance contributed to the overall system imbalance, who will therefore face the costs of the Bids and Offers accepted to resolve that imbalance. Conversely, the Reverse Price is applied to any Party whose imbalance helped to reduce the overall system imbalance, who will therefore face a price that reflects what it would have incurred had it traded out its position ahead of time.

What is STOR?

National Grid has access to contracts that can either increase system supply or reduce system demand in the form of generation or demand reduction during certain periods of the day. This enables it to ensure that it can respond to scenarios such as actual demand being greater than forecast demand or unforeseen generation unavailability. These additional sources of power are referred to as 'Reserve'.

To help meet its reserve requirement, National Grid procures STOR by contracting for balancing services via a competitive tender process from a range of service providers, for example in the form of standby generation or demand reduction from parties that may or may not participate in the BM. This is a contracted Balancing Service whereby the provider is required to deliver a contracted level of energy when instructed by the Transmission Company, within pre-agreed parameters. The requirement for STOR varies depending on the time of year, week and day, and is a function of the system demand profile at that time.

STOR is contracted ahead of time, in some cases many months before it is actually used. Under STOR contracts, availability payments may be made to the balancing service provider in return for the unit being made available to National Grid. When STOR is called upon, the price National Grid pays for its use is the price agreed between it and the provider under the contract, referred to as the Utilisation Price. This may be noticeably different to the price National Grid may have paid had it called upon a BM action, and therefore may not reflect the prevailing market prices at the time of use. It is this Utilisation Price that is used when STOR information (as Balancing Services Adjustment Data) is submitted into the imbalance price calculations. Availability costs are currently allocated to Settlement Periods via the Buy Price Adjuster (BPA) according to a weighted profile; this approach does not necessarily reflect tight margins or STOR usage.

What is Demand Control?

If National Grid is unable to call upon sufficient generation to meet the current demand, then it can call upon Demand Control under Grid Code Section OC6 'Demand Control', as a last resort emergency instruction, to manage the situation. This enables it to call upon DSOs to reduce demand in their areas, either through initiating Voltage Reduction and/or disconnecting consumers through Demand Disconnection. A DSO typically may be required to reduce demand in blocks of approximately 5% of its total demand, and is required to respond to National Grid's instruction within five minutes of it being issued. It is usually left to the DSO to determine how it achieves the instructed reduction, which will often be through a combination of Demand Disconnection and Voltage Reduction.

What is the Electricity Balancing Significant Code Review?

In August 2012, Ofgem launched its Electricity Balancing Significant Code Review to look at imbalance prices, in order to address long-standing concerns that it had raised in 2010 within its Project Discovery report. In particular, Ofgem expressed concerns that imbalance prices are not creating the correct signals for the market to balance, which could undermine efficiency in balancing and security of supply.

Ofgem published its Final Policy Decision on 15 May 2014. Its final decision document lays out its conclusions and builds on the extensive analysis and stakeholder engagement it conducted during the EBSCR over the course of several years.

What is Ofgem's rationale for reform?

In its Final Policy Decision, Ofgem lays out its rationale for why reform of imbalance prices is needed. In it, it notes that the actions of the Transmission Company in balancing the system in real time are the basis for the calculation of imbalance prices, and considers that a number of factors currently dampen these prices:

- Prices are calculated using an average of the most expensive (to the Transmission Company) 500MWh of Bids or Offers taken to balance the system, rather than the most marginal action (the energy balancing action with the highest cost to the Transmission Company).
- Prices do not include the costs to consumers of involuntary Demand Disconnections and Voltage Reductions.
- The way reserve capacity is costed does not allow imbalance prices to rise to reflect tight margins (defined as the amount of surplus capacity available at any given time over the volume of expected demand at that time).

Additionally, the current dual imbalance price system creates unnecessary balancing costs, disadvantaging smaller Parties in particular.

Ofgem considers that the shortcomings with the current arrangements mean that the market does not sufficiently value flexibility (the ability to ramp generation or demand up or down quickly in response to changing market conditions). As a consequence, market participants have insufficient incentives to provide flexible capacity (such as flexible generation, demand response services and storage) to enable the Transmission Company to balance the system. Shortcomings may also make it more likely that Interconnectors export at times of system stress or import less than under more efficient arrangements. As the share of intermittent generation grows, flexibility will only become more important for efficiency in security of supply and balancing.

Ofgem believes that imbalance price arrangements and the government's planned Capacity Mechanism (CM) have distinct but complementary roles in seeking to ensure electricity security of supply. The CM is intended to address longer term capacity adequacy by providing capacity providers with a secure revenue stream for their investment. Reform of imbalance prices complements this by providing efficient signals of the value of flexibility, influencing the type of capacity coming forward. In addition, imbalance prices have the potential to reduce the cost of procuring capacity in the CM auction by allowing flexible capacity providers to recoup missing money from the wholesale market.

What is a Significant Code Review?

A Significant Code Review is an Authority-led review process on an area of work which the Authority considers:

- has a significant impact on the Authority's principal objective, statutory functions or relevant obligations imposed by European Union law; and in particular:
  - has significant impacts on consumers or competition; and/or
  - has significant impacts on the environment, security of supply or sustainable development; or
- creates significant cross code or cross licence issues.

Upon completion of a Significant Code Review, the Authority may direct the Transmission Company to raise one or more Modifications to progress the conclusions. Such a Modification cannot be refused and cannot be amalgamated or withdrawn without the Authority's consent.

The SCR's conclusions and subsequent direction shall not fetter the views of the Workgroup, its ability to raise an Alternative Modification, the voting rights of the Panel or the Panel's recommendation to the Authority.

What is the issue?

Upon completion of an SCR, the Authority may, under BSC Section F5.3, issue a direction to the Transmission Company to raise an SCR Modification Proposal to progress the outcomes.

On 15 May 2014, Ofgem, as the Authority, issued such a direction to National Grid, as the Transmission Company, to raise two such Modifications to progress the conclusions of the EBSCR. P304 'Reduction in PAR from 500MWh to 250MWh' was raised to progress an initial, standalone change to the PAR value ahead of the winter 2014/15 season, but has since been rejected. P305 'Electricity Balancing Significant Code Review Developments' has been raised to progress the EBSCR's full package of proposed changes ahead of the winter 2015/16 season.

Work under the EBSCR

The detailed and comprehensive analysis and evidence base arising from the EBSCR can be found on the EBSCR page of the Ofgem website. A full list of the relevant documents can be found in Appendix 3.

Proposed Modification

P305 proposes to progress the reforms outlined by the Authority arising from the EBSCR. These reforms have been split into four areas:

- reductions in the PAR value;
- moving to a single imbalance price;
- the introduction of Reserve Scarcity Pricing; and
- the introduction of pricing for Demand Control actions.

The full detail on each area of reform and the rationale behind them can be found in Ofgem's Final Policy Decision. A summary diagram of the changes proposed by P305 can be found in Appendix 1, and the detailed solution requirements for each area can be found in Attachment A.

Reductions in the PAR value

P305 proposes to reduce the PAR value from its current level of 500MWh to 50MWh upon implementation, before reducing further to 1MWh on 1 November 2018 ahead of the winter 2018/19 season.

P305 will also reduce the RPAR value from its current level of 100MWh to 1MWh upon implementation.

These changes will make the imbalance price more marginal, as eventually only the most expensive 1MWh of actions would be used to set the price.

Moving to a single imbalance price

A single imbalance price will be used instead of the dual imbalance prices currently in use. The calculation of the SBP and SSP will be retained, but they will be set equal to each other, with that single price being calculated using the Main Price methodology.

Market Index Data will be retained and the Market Price would be used to set the imbalance price in any Settlement Period where the NIV was zero. Market Index Data would be published for each Settlement Period on the Balancing Mechanism Reporting Service (BMRS).

Introduction of Reserve Scarcity Pricing

Both accepted BM and non-BM STOR Actions will be included in the calculation of imbalance prices as individual actions, with a price which is the greater of the Utilisation Price for that action or the RSP. The RSP function will be based on the prevailing system scarcity, and would be calculated as the product of two new values:

- the LoLP, which will be calculated by the Transmission Company at Gate Closure for each Settlement Period; and
- the Value of Lost Load (VoLL), a defined parameter as outlined below.

What is PAR and RPAR?

The **PAR** volume is a set volume of the most expensive balancing actions remaining at the end of the Main Price calculations, and is currently 500MWh. The volume-weighted average of these actions is used to produce the Main Price. This is referred to as PAR Tagging.

The **RPAR** volume is a set volume of the most expensive priced actions remaining at the end of the Main Price calculations, and is currently 100MWh. The volume-weighted average of these actions, known as the Replacement Price, is used to provide a price for any remaining unpriced actions prior to PAR Tagging.

STOR availability costs would be removed from the Buy Price Adjustment (BPA) calculation.

A 'static' function will be used to calculate LoLP values effective from the P305 Implementation Date. This will be replaced by a 'dynamic' function effective from 1 November 2018. Below are summaries of the two functions and full details of each can be found in Attachment A.

Details of the LoLP functions

The full details of each of the 'static' and 'dynamic' LoLP functions can be found in Attachment A.

'Static' function

For Settlement Periods from the P305 Implementation Date up to and including 31 October 2018, the LoLP will be determined by the Transmission Company for each Settlement Period using the 'static' function described in Attachment A. This approach relies on determining a mathematical relationship between historical values of de-rated margin and LoLP values, which allows a LoLP value to be derived based on the forecasted de-rated margin for a particular Settlement Period.

In the run-up to Gate Closure, the Transmission Company will publish its forecast of the de-rated margin on the BMRS. Forecasts will be published, as a minimum, at 24, eight, four, two and one hour(s) prior to the start of each Settlement Period. The one hour ahead (Gate Closure) value will be used to determine the Final LoLP that will be used in the calculation of the RSP for that Settlement Period, and this LoLP value would also be published on the BMRS. Participants can use the forecast information to derive their own estimate of the LoLP value in the run-up to Gate Closure.

'Dynamic' function

For Settlement Periods from 1 November 2018, a LoLP value will be calculated by the Transmission Company for each Settlement Period using the 'dynamic' function described in Attachment A. This approach relies on the calculation of specific LoLP values for each Settlement Period based on a statistical relationship in up-to-date operational data available to the Transmission Company, and would take account operational data relating to system supply and demand. Values would be calculated at the following times:

- An indicative value would be calculated at 12:00 each day for all Settlement Periods up to the end of the next Operational Day[1].
- An indicative value would be calculated for each individual Settlement Period at eight, four and two hours prior to the start of the Settlement Period (seven, three and one hour(s) prior to Gate Closure).
- The final value would be calculated for each Settlement Period at Gate Closure for that Settlement Period (one hour before the start of the Settlement Period).

All indicative and final values of LoLP would be published on the BMRS as soon as possible following calculation. If no value can be calculated for a given calculation point, the value will default to the most recently calculated indicative value for that Settlement Period at that point in time, or if no such value is available then to null. The final value would be used in the calculation of the RSP for that Settlement Period.

[1] Operational Day is defined under the Grid Code as the period starting at 05:00 on one day and ending at 05:00 on the following day.

Values would begin to be calculated and published using the 'dynamic' function no later than 1 May 2018 (six months before the switchover), and potentially earlier if agreed nearer the time. These would be for information purposes only, and would not be used in the calculation of the RSP. This will enable participants to compare the LoLP values calculated under the 'static' and 'dynamic' functions and adapt to the 'dynamic' function in a live environment before it actually takes effect.

Introduction of pricing for Demand Control actions

The volumes of any disconnections and voltage reduction instructed by the Transmission Company ("System Operator (SO) instructed Demand Control actions") would be included in the imbalance price calculation at a price referred to as the VoLL price. This price would be set to £3,000/MWh upon implementation, rising to £6,000/MWh on 1 November 2018 ahead of the winter 2018/19 season. This value would be hard-wired into the Code, and could be amended at any time via a Modification.

A VoLL review process will be introduced into the BSC to allow the Panel to initiate a review of the value at any time or upon the request of the Authority. The VoLL review process:

- would be initiated by the Panel from time to time or upon the request of the Authority, with no maximum period between reviews;
- would allow the Authority to contribute its views to the review;
- would include consultation with the industry; and
- would allow the Panel to raise a corresponding Modification if the review recommended a change be progressed, with no minimum lead time on any change.

This process would not prevent any other participant eligible to do so from raising their own Modification at any time to propose a revised VoLL value.

An estimate of the total volume of Demand Control actions would be calculated using a 'top-down' approach based on the volumes instructed of DSOs by the Transmission Company. This estimate will be included in the imbalance price calculations (including the BMRS indicative prices) as though it was an Offer, and will be priced at the VoLL price. It would be subject to the current rules for calculating the Main Price, as set out in Section T, including the usual tagging and flagging rules such as being flagged as system management actions.

A more accurate 'bottom-up' approach to calculating the total Demand Disconnection volume will be carried out in time for the Initial Settlement Run (SF), which will entail identifying the individual meter points involuntarily affected and estimating what they would have consumed had the disconnection not taken place. This estimate of consumption provides an estimate of the involuntarily disconnected volume, and participants' imbalance positions would be adjusted to add this 'bottom-up' estimate of Demand Disconnection back (minus an estimate for any voluntary actions requested by the Transmission Company) as Balancing Services. This would adjust their imbalance position back toward what it would have been had they not been subjected to the involuntary disconnections.

What is the Value of Lost Load?

The VoLL price is an assessment of the average value that electricity consumers attribute to the security of supply.

Further information on this price and how the proposed values were calculated can be found in the DECC-Ofgem study by London Economics on the Value of Lost Load for GB consumers.

Demand Control volume estimation process requirements

The detailed solution requirements for the Demand Control volume estimation processes can be found in Attachment A

The 'top-down' approach is covered by Requirements D2-D4.

The 'bottom-up' approach is covered by Requirements D5-D9.

At this stage, a method for estimating and adjusting volumes to reflect Voltage Reduction actions has not been developed, and the P305 Workgroup has agreed that this will be progressed separately to P305 through a BSC Issue.

Alternative Modification

The Workgroup has developed an Alternative Modification, which is identical to the Proposed Modification except for the following two differences:

- The PAR value would be reduced from its current level of 500MWh to 100MWh upon implementation. No further changes would be made under P305.
- The switch to the 'dynamic' LoLP function in 2018 would be removed, and the 'static' function would remain in place.

Legal text

The draft changes to the BSC to deliver P305 can be found in Attachments B (Proposed Modification) and C (Alternative Modification). Due to the complexity of these changes, the Workgroup was unable to consult upon these changes in the Assessment Procedure Consultation.

A significant number of Code Subsidiary Documents (CSDs), Configurable Items and Core Industry Documents will also require changes to implement P305, and the list of these documents can be found in Section 4. The changes to these documents will be prepared and consulted upon separately as part of implementation, should P305 be approved.

Are there any other potential Alternative Modifications?

The Workgroup considered several other potential alternative solutions to P305 in relation to the proposed reductions in the PAR value and the calculation of LoLP values, as well as discussing other areas. It concluded that there were many options it felt would better facilitate the Applicable BSC Objectives than the Proposed Modification and so could be put forward as an Alternative Modification, and ultimately elected to progress the option outlined above. The full Workgroup discussions in relation to all these areas can be found in Section 7.

Alternative PAR values

The Workgroup considered the following alternative PAR values in addition to that put forward by the Proposer when it consulted the industry as part of its Assessment Procedure Consultation:

- 250MWh upon implementation then 100MWh 12 months later;
- 100MWh upon implementation with no further change;
- 50MWh upon implementation with no further change; and
- 1MWh upon implementation with no further change.

In all cases, the RPAR value would be set to 1MWh upon implementation.

The range of values proposed reflected the differing views of both Workgroup members and consultation respondents between whether the benefits of a marginal price should be realised sooner or whether a more cautious approach should be taken. Following consultation, the Workgroup agreed that a PAR value of 100MWh would be a suitable compromise to progress under the Alternative Modification.

Alternative LoLP function

The Proposer originally put forward a 'dynamic' LoLP function developed by the Transmission Company, with the view that this should be used from the P305 Implementation Date. The Workgroup developed a 'static' LoLP function which would use historical values produced by the 'dynamic' function to derive a static function relating the de-rated margin in a given Settlement Period to a LoLP value. The details of both of these functions can be found in Attachment A.

The Proposer noted the Workgroup's majority preference for the 'static' function, and elected to adopt it into the Proposed Modification as an interim step towards implementing the 'dynamic' function at a later date. However, a majority of Workgroup members did not believe a switch to the 'dynamic' function should be mandated and elected to remove this step from the Alternative Modification.

One Workgroup member did not believe a LoLP value or the RSP was necessary, and felt that simply including non-BM STOR Actions in the imbalance price calculations at their Utilisation Prices would offer the same outcomes in a more efficient manner. However, a majority of members disagreed with this approach, and elected not to progress this option further.

The Workgroup considered whether the Final LoLP value for a given Settlement Period should be determined under the 'static' function using the forecasted de-rated margin:

- one hour ahead of the relevant Settlement Period (i.e. at Gate Closure for the Settlement Period), as put forward by the Proposer;
- two hours ahead of the Settlement Period (one hour ahead of Gate Closure);
- four hours ahead of the Settlement Period (three hours ahead of Gate Closure); or
- 24 hours ahead of the Settlement Period.

A slim majority of the Workgroup felt that calculating the Final LoLP value at Gate Closure would be the most appropriate option to progress under the Alternative Modification, and therefore elected to progress this option.

Other areas

One Workgroup member was concerned with the accuracy and implications of the 'bottom-up' calculation that had been proposed for correcting participants' imbalance volumes following a Demand Disconnection event, and considered whether such a process may be unnecessary. However, other members felt that this process, while not ideal, was necessary to avoid participants from gaining windfall gains as a result of such an event, and unintended consequences that may then arise through 'gaming'. It was also felt that removing this part of the solution may result in the Alternative Modification from being disregarded by the Authority, jeopardising the other areas of P305 that members wanted to amend under the Alternative Modification. Overall, only a minority of Workgroup members supported removing the 'bottom-up' process, and therefore this process was retained within the Alternative Modification.

A couple of Workgroup members considered whether lower VoLL values should be proposed, such as £2,000/MWh then £3,000/MWh. It was also considered whether, as all the other 2018 step-change aspects of the P305 Proposed Modification had been removed from the Alternative Modification, the planned step-change in the VoLL value to £6,000/MWh should also be removed. However, a majority of members felt that the proposed approach to introducing VoLL into the BSC was appropriate and should remain unchanged.

Participants' views on potential Alternative Modifications

Several respondents to the Assessment Procedure Consultation put forward possible alternative solutions:

- The RSP should be removed as discussed by the Workgroup above.
- Voltage Reduction should be removed from the 'top-down' estimate of the Demand Control volume, due to the difference in effects on consumers between it and Demand Disconnection.
- A 'top-down' estimate should be applied to the Demand Control volume correction process instead of the proposed 'bottom-up' approach. If this is not taken forward then the DSO should send reports to other participants rather than the proposed new DWWWW data flow.
- The DNO would produce the proposed new DXXXX and DYYYY data flows instead of Supplier Agents, removing the need for the DWWWW flow.
- A "good behaviour incentive" could be applied to participants through a new licence condition to continue contracting flexible products even if the margin tightens and a Demand Control event becomes a possibility.
- The complete removal of the 'bottom-up' Demand Control volume correction process, as discussed by the Workgroup above.
- Lower VoLL values.
- A shorter Gate Closure time, as this will allow more time to balance positions ahead of real time, and will increase the accuracy of forecasts for variable generation and demand.
- A single price would be applied only to small Parties, offering protection to those who are less able to trade and balance their position, with larger Parties retaining the current dual price mechanism.

Some respondents noted that none of the options on offer were better than the current baseline or that the existing solutions still needed further development before they could be progressed.

You can find the full responses made by Assessment Procedure Consultation respondents in Attachment D.

The Workgroup has noted all of the potential alternative solutions proposed by respondents, but elected not to progress any of them further.

Interaction with P304, P314 and P316

Interaction with P304 and P314

P304 was raised by National Grid alongside P305 to propose a reduction in the PAR value to 250MWh ahead of the winter 2014/15 season. This was intended to provide an early step-change in the PAR value ahead of the full EBSCR reforms being implemented, to assist participants in transitioning to the new arrangements. P314 'Reduction in PAR from 500MWh to 350MWh' was raised by First Utility during the progression of P304 to propose an alternative reduced PAR value of 350MWh.

It was felt that reducing the PAR value without implementing a single price could have a detrimental on some participants and that the change was proposed to come in too quickly for Parties to be able to respond to the signal. Both Modifications have since been rejected by the Authority as it was felt that the effects of the proposed changes were finely balanced and would be modest at most.

You can find more information on each Modification in their respective Final Modification Reports and the accompanying Authority Decision Letter, available on the P304 and P314 pages of our website.

Interaction with P316

P316 'Introduction of a single marginal cash-out price' has been raised by RWE Supply and Trading. It proposes to progress only the reductions in the PAR and RPAR values and the move to a single imbalance price aspects of P305, and the Proposer believes that the proposed solution to P316 should match these aspects of P305, to give the Authority a straight choice between the two solutions. For the same reason, the P305 and P316 Workgroups also agreed that, where the two Modifications overlapped, the same Alternative Modification would be put forward.

The P316 Proposer considers that P316 will increase the certainty of a single marginal price being implemented in a timely manner and ahead of winter 2015/16, and would potentially allow for the other areas proposed by P305 to be implemented at a later date.

P316 is being progressed in parallel with P305, and you can find the full details and discussions in relation to P316 in the P316 Assessment Report.

Estimated central implementation costs of P305

The total central implementation costs for P305 are approximately **£625k** to make the necessary changes to the BSC central systems and the BMRS website.

Changes are needed to the Settlement Administration Agent (SAA) and the Balancing Mechanism Reporting Agent (BMRA) systems to move to a single price and to include STOR and Demand Control actions in the imbalance price calculations. The SAA, Supplier Volume Allocation Agent (SVAA) and Central Data Collection Agent (CDCA) systems will also need amending to introduce the Demand Control volume estimation processes.

The BMRS website will be updated to publish all Indicative and Final LoLP values, all individual STOR Actions and any Demand Control notifications issued by the Transmission Company.

The Transmission Company has indicated implementation costs for P305 to be in the region of £1m to £3.5m, although it notes that changes to the solution requirements since its original assessment means costs are more likely to be at the lower end of this range.

The Transmission Company would need to calculate LoLP values for each Settlement Period and submit these to the BSC Agents. It would also need to issue Demand Control notifications. It has also noted that changes to the way it takes balancing actions may need to be made.

Indicative industry implementation costs of P305

DSOs have indicated that they would incur costs of between £20k and £100k to implement the 'bottom-up' process for calculating the total Demand Disconnection volume, while **Supplier Agents** have indicated "medium to high" costs, likely to be in the order of tens of thousands of pounds. These participants would need to amend their software to send and/or receive the new Data Transfer Catalogue (DTC) data flows that will be created by P305 and will need to put in place the new processes for the Demand Disconnection volume calculation process. These processes would need to be in place to successfully implement the P305 solution.

BSC Trading Parties have indicated costs ranging from minimal up to around £200k to implement P305, with some indicating on-going costs of up to £100k per annum. These participants will be predominantly impacted by the changes in imbalance charges and exposure, which will impact the levels of Credit Cover they consider they may need to lodge as well as their trading strategies. They may also need to amend their systems to receive any new data published on the BMRS. However, there would be no direct impacts on these participants to implement the P305 solution.

The full responses made by participants to the Impact Assessment can be found on the P305 page of our website and to the Assessment Procedure Consultation in Attachment D.

Implementation impacts and costs

This Section only considers the implementation impacts and costs of P305.

The wider impacts of P305 have been considered as part of the Workgroup's analysis in Attachment A and in Ofgem's Final Policy Decision.

P305 impacts

Impact on BSC Parties and Party Agents	
Party/Party Agent	Impact
BSC Trading Parties	BSC Trading Parties will be indirectly impacted by the reforms, as Ofgem's reform package will introduce a more marginal but potentially more volatile single imbalance price.
DSOs	DSOs, Data Aggregators and Data Collectors will be involved in the 'bottom-up' process for calculating the total Demand Disconnection volume.
Data Aggregators	
Data Collectors	

Impact on Transmission Company
The Transmission Company will be required to implement and execute the LoLP calculation functions, which would be contained in a new document on the BSC Baseline. It would then need to calculate the LoLP for each Settlement Period at Gate Closure for that Settlement Period. The Transmission Company will also be required to publish de-rated margin forecasts and, from November 2018, Indicative LoLP figures ahead of Gate Closure. The Transmission Company will notify the BMRA of the start and end of any Demand Control events and associated details of anticipated delivery from the instruction, and provide any data required for calculating the volume impacted by the event.

Impact on BSCCo	
Area of ELEXON	Impact
Imbalance price arrangements	Processes, reports and documents will need to be amended to account for the changes introduced by P305.
BSC Audit	Amendments may be required for the new processes introduced by P305, in particular the 'bottom-up' process for calculating the total Demand Disconnection volume.
EMRS	The EMRS may be required to provide information to the SAA as part of the 'bottom-up' process for calculating the total Demand Disconnection volume. This would require corresponding changes to the Electricity Market Reform (EMR) arrangements, which would be progressed separately to P305.

Impact on BSC Systems and processes	
BSC System/Process	Impact
BMRA	Changes will be required to reflect the changes to the imbalance price calculations. The BMRA will also be required to publish LoLP values and Demand Control event notifications on the BMRS.

Impact on BSC Systems and processes	
BSC System/Process	Impact
SAA	Changes will be required to reflect the changes to the imbalance price calculations. The SAA will also be impacted by the 'bottom-up' process for calculating the total Demand Disconnection volume.
CDCA	The CDCA and the SVAA will be impacted by the 'bottom-up' process for calculating the total Demand Disconnection volume.
SVAA	

Impact on Code	
Code Section	Impact
Section F	Changes would be required to implement this Modification. The proposed changes can be found in Attachments B (Proposed Modification) and C (Alternative Modification).
Section Q	
Section R	
Section S	
Section S Annex S-2	
Section T	
Section V	
Section X Annex X-1	
Section X Annex X-2	

Impact on Code Subsidiary Documents	
CSD	Impact
BSCP01	Changes may be required as a result of this Modification.
BSCP03	
BSCP18	
BSCP40/BSCPXXX	Changes will be required to detail the VoLL review process; it is currently anticipated that this process would be captured either in BSCP40 or in a new BSCP.
BSCP502	Changes will be required to detail the 'bottom-up' process for calculating the total Demand Disconnection volume; it is to be confirmed which of these documents will need amending to reflect this.
BSCP503	
BSCP504	
BSCP505	
BSCP508	
BMRA Service Description	Changes will be required to reflect changes to existing processes and/or the introduction of new processes for the relevant BSC Agents.
CDCA Service Description	
SAA Service Description	

Impact on Code Subsidiary Documents	
CSD	Impact
SVAA Service Description	
BMRA User Requirement Specification	
CDCA User Requirement Specification	
SAA User Requirement Specification	
SVAA User Requirement Specification	
NETA Interface Definition and Design	Changes will be required to reflect new data flow and any consequential updates to existing data flows.

Impact on other Configurable Items	
Configurable Item	Impact
Market Index Definition Statement	Updates to this document may be required to reflect the revised use of Market Index Data under the BSC.
Loss of Load Probability Calculation Statement	The Loss of Load Probability Calculation Statement will be established as a new item on the BSC Baseline Statement.

Impact on Core Industry Documents and other documents	
Document	Impact
Data Transfer Catalogue	Changes will be required to reflect the new DTC data flows that P305 will introduce.
BSAD Methodology	Changes will be required to these documents as a result of this Modification.
SMAF Methodology	

Other Impacts	
Item impacted	Impact
Imbalance Pricing Guidance Note	Changes would be required as a result of this Modification.
Electricity Trading Arrangements Beginners Guide	

Recommended Implementation Date

The Workgroup recommends that, should P305 be approved, it is implemented on **5 November 2015** as part of the November 2015 BSC Systems Release.

The Workgroup notes that Ofgem highlighted in its Final Policy Decision that it seeks its proposed reforms to be implemented as part of the November 2015 BSC Systems Release, which will go live on 5 November 2015, to introduce these changes ahead of the winter 2015/16 season. It therefore strongly urged the industry to facilitate this approach to the best of its ability. The Workgroup agrees that P305 should be implemented on this date, if approved.

ELEXON will be able to implement the necessary BSC central system changes for P305 in time for this date based on the anticipated date by which an Authority decision is anticipated[2]. The Transmission Company initially noted a lead time of up to 18 months, but as the solution has been further developed and clarified it has subsequently noted that it can meet a November 2015 Implementation Date for the solutions set out in this report, based on anticipated decision dates.

Participants' views on the proposed Implementation Date

Two thirds of BSC Trading Parties who responded were in support of the Workgroup's proposed Implementation Date of 5 November 2015. These respondents noted that the date was in line with the Authority's Final Policy Decision, and would allow the benefits of the EBSCR to be realised ahead of winter 2015/16. Many respondents noted lead times of around six months would be sufficient to implement P305, although longer would be better.

The remaining Trading Parties disagreed with the proposed Implementation Date. They felt that the implementation timescales that had been put forward under the EBSCR were too ambitious, and did not allow the industry enough time to fully assess and implement the necessary changes, especially given the volume of change proposed by P305. In particular, some respondents felt that areas of the solution still require further development and assessment before they can be implemented, as it is essential these processes are robust. It was also noted that participants have no certainty as to whether a change will be made or not until an Authority decision is received, which may not leave enough time to then adapt to the P305 changes before they are implemented.

All of the DSOs and Supplier Agents that responded to the Assessment Procedure Consultation disagreed with the proposed Implementation Date of 5 November 2015. In their responses, they noted that this would not leave enough time to implement the new processes that would be needed, especially given their view that the relevant parts of the solution applicable to them had not been developed sufficiently at this time. It was also noted that at least six months would be needed to progress the necessary changes to the DTC for the new data flows P305 would create.

Some of these respondents also highlighted the significant amount of other change already approved or in progress, in particular the changes relating to EMR, the introduction of smart metering and the implementation of P300 'Introduction of new Measurement Classes to support Half Hourly DCUSA Tariff Changes (DCP179)' in

[2] The P305 Final Modification Report is due to be sent to the Authority in mid-March 2015.

November 2015 and P272 'Mandatory Half Hourly Settlement for Profile Classes 5-8' in April 2016. They were unhappy that they were being asked to implement these further changes at relatively short notice and with little communication at an already busy time. It was believed a lead time of 12 months following Authority decision was needed, and that the June 2016 Release would be a more appropriate Implementation Date.

One respondent felt that any changes to the PAR value should be made at a more benign time of the year, such as just ahead of a summer period, to allow participants more time to gain experience of the change before the following winter. Another respondent felt that the changes scheduled for 2018 should not be determined this early as part of P305, and that it would be prudent to see how other changes elsewhere (for example the CM or new European requirements) impact the arrangements, as a lot could happen between now and then.

The full responses given by respondents to the Assessment Procedure Consultation can be found in Attachment D. The Workgroup has noted the views of respondents who did not agree with the proposed implementation approach, but decided not to change its proposed approach.

6 Summary of Workgroup's Discussions

This Section 6 summarises the areas discussed by the Workgroup and its conclusions in respect to those areas. A page reference has been given to each area indicating where in Section 7 you can find the detailed discussions on that area. You are advised to read this Section 6 first before turning to the relevant parts of Section 7 that you wish to follow up on. The Workgroup's views against the Applicable BSC Objectives can be found in Section 8.

Summary of the Workgroup's discussions and conclusions

The Workgroup discussed and agreed the following areas:

- Most of the Workgroup did not agree with the proposed approach to reducing the PAR value, and proposed several alternative options to be considered. From these the majority of members supported an alternative PAR value of 100MWh, which was adopted into the Alternative Modification. There was also consideration of whether the PAR values proposed by P305 and P316 need to be co-ordinated. (Page 24)
- The Workgroup agreed that there should be a single imbalance price, and considered the effect this may have on the Residual Cashflow Reallocation Cashflow (RCRC). (Page 27)
- The Workgroup agreed that Market Index Data should be used to set the imbalance price when NIV was zero, and so believed that this data should remain unchanged by P305. (Page 28)
- All STOR Actions should be published on the BMRS in disaggregated format, with both the Utilisation Price and, if applicable for that action, the RSP. These will be published after the Settlement Period has been completed. (Page 29)
- The Workgroup agreed that the RSP should only be applied to STOR Actions and should be calculated as the product of LoLP and VoLL. (Page 30)
- The Workgroup considered analysis of the 'dynamic' LoLP function developed by the Transmission Company, and made amendments to the calculation based on the results of this analysis. The amendments addressed the main issues with the 'dynamic' approach, but some Workgroup members remained concerned that the function was not sufficiently predictable, was a measure of plant availability rather than margin and was not as transparent as members would like. The Workgroup therefore developed an alternative 'static' function based on the use of historic output data produced by the 'dynamic' function, which would enable a LoLP value to be derived based on the de-rated margin in a given Settlement Period. A majority of Workgroup members preferred this alternative approach, and included it in the Alternative Modification. The Proposer adopted the 'static' function into the Proposed Modification as an interim step towards implementing the 'dynamic' function in 2018. (Page 30)
- The Workgroup agreed that the LoLP calculation should enable a signal to be provided to participants ahead of real time to allow them to react to any potential issues. The Workgroup therefore agreed that Indicative LoLP values produced by the 'dynamic' function in the run-up to a Settlement Period should be published at the times stated in Section 3 with the Final LoLP value (to be used in the RSP)

calculated and published at Gate Closure. The Workgroup considered multiple options for the lead time at which a Final LoLP value should be determined under its alternative 'static' LoLP function, ranging from Gate Closure for the Settlement Period to 24 hours ahead of the Settlement Period, but agreed that setting the Final LoLP value at Gate Closure would be the most appropriate option. It was also questioned whether the LoLP could be 'gamed'. (Page 39)

- The Workgroup agreed with the VoLL values put forward by the Proposer and the times at which each step change takes effect. (Page 44)
- The Workgroup disagreed with the original proposal that the Authority could direct a change to the VoLL value. A VoLL review process to sit under BSC governance was developed, which Ofgem agreed could be adopted into the Proposed Modification in place of allowing the Authority to direct changes (this review process would also be included in the Alternative Modification). In any event, BSC Parties would still be able to raise a Modification to propose a change to the VoLL value at any time. The Workgroup agreed the VoLL value should not increase automatically in line with inflation. (Page 45)
- Demand Disconnection and Voltage Reduction events would be treated under the BSC as types of Demand Control events that would feed into the imbalance price. However, automatic Low Frequency Demand Disconnection (LFDD) events would be treated as system balancing actions and would be tagged accordingly. Notifications of all forms of Demand Control events will be published on the BMRS, and these notifications would be used to derive the 'top-down' estimate of the total Demand Control volume for use in the imbalance price calculation. (Page 49)
- The Workgroup could not, within the timescales available, develop a method for estimating the total volume affected by a Voltage Reduction event for use in the 'bottom-up' estimate of the total Demand Control volume. It was agreed that it was not vital that this aspect be included initially and that it should be considered separately. Consequently, only Demand Disconnection events will be included in the 'bottom-up' estimate. (Page 51)
- The Workgroup has developed a process for correcting participants' imbalance positions following a Demand Disconnection event, which will require action from DSOs, Supplier Agents and BSC Agents to complete. This process needs to be as accurate as possible and therefore should account for voluntary actions where possible. The Workgroup has further developed the Non Half Hourly (NHH) Supplier correction process from the proposals issued in the Impact Assessment, and seeks views from DSOs and Supplier Agents on this. (Page 52)
- It was agreed that the 'bottom-up' estimate of the Demand Control volume should not feed into the imbalance price calculation, but that the 'top-down' approach should be used at all Settlement Runs. (Page 55)
- The Workgroup considered what impact the Continual Acceptance Duration Limit (CADL) may have on the processes under P305, but is not proposing any change to this value at this time. (Page 56)
- Members believe that there will be impacts on participants' Credit Cover as a result of P305, with the amount of Credit Cover needed expected to increase, but were unable to quantify the scale of the increase. (Page 57)

- The Workgroup considered the impact P305 may have on liquidity, but views were mixed as to whether there would be a beneficial or detrimental impact. (Page 57)

- The Workgroup sought views from Assessment Procedure Consultation respondents on the impacts that P305 may have on intermittent generators and the interactions on the CM and Contracts for Difference (CfD) arrangements. (Page 58)

- The Workgroup has discussed the substantial qualitative analysis, forward-looking modelling and historical modelling undertaken under the EBSCR, including input from Ofgem and the EBSCR modelling provider. It also requested additional analysis based on historical data from ELEXON, which is available in Attachment A. Some Workgroup members were concerned that the distributional effects of P305 had not been fully explored, but other members were content that sufficient analysis on the impacts of P305 had been undertaken. (Page 60)

- The Workgroup noted some concerns from consultation respondents that not enough time has been allowed to fully develop and assess P305, and that areas of the solution may not be robust enough to implement. Some Workgroup members agreed with these views, while others felt that sufficient time had been given to consider the impacts of P305. (Page 64)

7 Workgroup's Discussions

This Section 7 covers the detailed discussions from the Workgroup on the P305 solution and related areas. You are advised to read the high-level summary of the Workgroup's discussions in Section 6 first, which contains page references to the relevant parts of this Section 7 that cover the detailed discussions on that area. You can then use these references to turn straight to the parts of this Section 7 that you wish to follow up on.

The discussions have been generally ordered by solution area, following the order given in Section 3. Any discussions areas not relating to a specific part of the solution can be found at the end of this Section.

Responses from Assessment Procedure Consultation respondents to questions asked by the Workgroup are summarised as part of the relevant discussions in this Section 7. You can find the full responses made by these respondents in Attachment D.

What PAR value should be set?

The EBSCR proposed that P305 would reduce the PAR value to 50MWh upon implementation before making a further reduction to 1MWh in 2018. The Workgroup was generally supportive of a phased approach to lowering the PAR value, but some members had concerns over the marginal values proposed by the EBSCR, and felt a more cautious approach to reducing the PAR value should be considered, though there was minority support for accelerating the move to a marginal 1MWh PAR value.

EBSCR PAR analysis

Ofgem's proposal for the reduction in the PAR value draws on the analysis undertaken under the EBSCR, available on the EBSCR page on the Ofgem website.

For rationale and evidence underpinning Ofgem's proposals for the PAR value, please refer to:

- EBSCR Final Policy Decision 2014 p13-15
- EBSCR Final Policy Decision Impact Assessment 2014 p33-34
- EBSCR Draft Policy Decision 2013 p15-18
- EBSCR Draft Policy Decision Impact Assessment 2013 p32-35

Concerns around flagging and tagging and possible distortions

A concern was raised over the impacts that incorrect tagging of system actions by the Transmission Company could have on the imbalance price. The Transmission Company now has the ability to retrospectively correct erroneously tagged or untagged actions which should mitigate the risk of any flagging error having an enduring impact on a given Settlement Period's main imbalance price. Furthermore, it does retrospectively check all tagged actions to ensure that they were correctly tagged, although it doesn't check the actions it did not tag to check whether they should in fact have been tagged. Some members felt this created the potential for an action that should have been tagged out to go on to set the imbalance price. It was considered that the Transmission Company has a tendency to 'over-tag' actions, and so it is unlikely that an action that should have been tagged would not be. However, some members felt that a formal process for allowing participants to challenge the Transmission Company's system action tagging should be introduced to mitigate the potential impacts.

One member was concerned that the use of marginal values could amplify existing inefficiencies in the current calculation. Following on from the tagging concerns above, they noted that the Transmission Company can sometimes accept a high-priced Offer in one Settlement Period to resolve an issue at that time, but because of the dynamics of the BM Unit called upon, that Offer may have to persist for several hours, impacting future Settlement Periods where a lower-priced Offer would otherwise have been accepted. They noted that without these potential distortions they would be in favour of moving to a value of 1MWh.

Other members agreed that a cautious approach should be taken, with a value of 100MWh to 250MWh being implemented at first and subsequent changes being raised once the effects had been observed and any issues better understood. This also allows the market more time to adapt to the new arrangements. There were concerns that, with the rejection of P304/P314 (which would have introduced an intermediate PAR value) P305 is proposing to change the PAR value straight from 500MWh to 50MWh.

However, other members were in favour of moving to 50MWh, or even directly to a lower PAR value. They suggested that the Transmission Company tends to apply a particularly cautious approach to the flagging and tagging of system balancing actions, and that the marginal imbalance price is a good reflection of the expense Parties would have otherwise had to incur to address the imbalance themselves. Others felt that the PAR value is currently 500MWh, as introduced by P205 'Increase in PAR level from 100MWh to 500MWh', and not 100MWh, as originally proposed under P194 'Revised Derivation of the 'Main' Energy Imbalance Price', because previously system constraints were not being tagged and flagged. Given this issue has been addressed under P217 'Revised Tagging Process and Calculation of Cash Out Prices', the logical next step is 50MWh as a stepping stone to 1MWh. It was also considered whether setting too high a PAR value may undermine the intent of the EBSCR, and so may be rejected by the Authority.

Staggered and phased PAR reduction approaches

Workgroup members felt that a 'staggered' approach to lowering the PAR value (whereby subsequent reductions in the PAR value at later dates would be written into the BSC as part of P305) would be beneficial, and that a less marginal value than put forward under the proposed solution should be the first step, and the impacts assessed before lowering the value further. The impacts of a lower PAR are not linear, and are likely to get steeper as the PAR value gets closer to 1MWh. Some members thought that a jump from 500MWh to 250MWh, as had been proposed by P304, or possibly as far as 100MWh should have relatively little overall impact, and that it was only once the value goes below 100MWh the effects and impacts will begin to be more noticeable. However, ELEXON's analysis (see below) suggested that the jump from 500MWh to 100MWh accounted for around two thirds of the total impact of moving to 1MWh.

The Ofgem Representatives were cautious about such an approach, feeling that this could create uncertainty in the industry as to whether the next step was to take place, particularly if this was explicitly linked to the achievements of pre-set targets, and that this may delay the implementation of the most efficient solution or impede efficient changes in behaviour. Other members queried why a phased approach is necessary, arguing that if a lower value (such as 1MWh) is seen as ultimately beneficial then the industry should move directly to it.

It was noted that by placing all the steps (the subsequent value and when it would take effect) for a phased approach in the BSC at the point P305 was implemented would provide clarity and certainty that a further reduction would take place, the size of the further reduction and when it would take effect. It would also mean those steps would take place unless and until a further Modification was raised and approved to change that.

PAR review process

It was considered whether a PAR review process should be introduced, to allow for regular reviews of the PAR value, similar to the agreed VoLL review process (see below). However, members did not see the benefit of this, noting that if anyone wanted to propose a change to the PAR value then they could simply raise a Modification. All of the analysis that would be carried out under a review would be carried out under a Modification, and so there would be no benefit in introducing a new review process. The Ofgem Representatives did not raise objections to this view.

PAR value options

The Workgroup noted that a PAR value of 1MWh was deemed by Ofgem to be the best value on the basis that this reflected the conclusion of the EBSCR assessment.

In the Assessment Procedure Consultation, the Workgroup proposed several potential PAR values that members felt could be adopted. The Proposer confirmed that they did not intend to change the approach to PAR values originally put forward in the Proposed Modification, and so any alternative PAR changes would need to form an Alternative Modification. The values that were considered by the Workgroup were:

- 50MWh upon implementation then 1MWh from 1 November 2018 (as under the proposed solution);
- 250MWh upon implementation then 100MWh 12 months later;
- 100MWh upon implementation with no further change under P305;
- 50MWh upon implementation with no further change under P305; and
- 1MWh upon implementation with no further change under P305.

Respondents to the Assessment Procedure Consultation were mixed in their views as to which value would be the most appropriate. As with Workgroup members, some respondents saw the benefits in moving directly to a marginal price, questioning why the benefits should be delayed, while other respondents sought a more cautious approach to mitigate the risks of unintended and detrimental impacts arising from the more marginal price. There was no clear majority view put forward by the industry.

After considering these views, some members felt that they could not formulate a view without seeing the distributional effects that P305 would have on participants' imbalance charges. They were concerned that the distributional impacts between different types of Suppliers may be significant, creating competitive distortions, and could have adverse impacts on particular types of Parties. Other members highlighted that the EBSCR analysis coupled with the data made available by ELEXON from its historical analysis (see below) provided a wealth of data for members to draw upon, sufficient for members to assess the distributional impacts for themselves. One member felt that the analysis that had been done was not showing anything unexpected, in that P305 would produce cost-reflective prices and behaviour would be expected to match. Other members agreed, considering that any distributional impacts would likely be similar to that shown under the analysis carried out for P304, and that as that analysis had not considered the effects of single price, it could be taken as the 'worst case scenario' as a result.

Overall, although the views of different Workgroup members remained divergent, a majority of members were satisfied with the adoption of a value of 100MWh as a suitable PAR value to put forward under the Alternative Modification, feeling that this would be low enough to make prices more marginal while also mitigating concerns that had been raised with respect to a more marginal value still.

How do the PAR values proposed by P305 and P316 interact?

Both P305 and P316 have the same proposed solution regarding a single marginal imbalance price and the same proposed Implementation Date of 5 November 2015. However, the Workgroup has noted the possibility that P316 could potentially be implemented ahead of P305 to ensure delivery of the single marginal price parts of the EBSCR separate to (and possibly earlier than) the RSP and Demand Control parts. If the approaches to the reduction in the PAR value did not align between the two Modifications then there would be a possibility that the PAR value approved under P305 would then overwrite that approved under P316. The Proposer of P316 has stated that the P316 Proposed Modification will mirror the P305 Proposed Modification on all aspects where the two Modifications overlap (reduction in PAR and RPAR values and moving to a single imbalance price), and the Workgroup decided to adopted the same approach with respect to the P305 and P316 Alternative Modifications.

P305 and P316 are two separate Modifications, and neither can be dependent or reliant on the other. However, the Workgroup has co-ordinated this aspect of the solution to facilitate a possible phased implementation of the EBSCR conclusions (for example by implementing P316 first to put in place a single marginal imbalance price ahead of winter 2015/16 before implementing P305 later to bring in the remainder of the reforms in 2016).

Should there be a single imbalance price?

The Workgroup agreed with the Proposer that a single imbalance price should be applied in place of the dual imbalance prices currently in use, and agreed with the proposed approach for doing so. It was noted that a benefit of doing so would be to remove the inefficient price spread between the SBP and SSP, which would also remove the costs incurred currently by Parties who make an error in allocating volume to the correct Energy Account resulting in their Production and Consumption Energy Accounts being out of balance by an equal and opposite amount.

However, members noted that the single price could impact the amount of money that remains as RCRC with this 'pot' potentially becoming very large when prices increase. It was also highlighted that the redistribution of RCRC is based on a Party's share of the total credited energy volume in a Settlement Period, meaning larger participants receive a larger share of the RCRC than smaller participants. This could mean smaller participants suffer proportionally higher imbalance charges when prices rise but larger participants receive an increased level of RCRC, creating a competitive distortion.

One member considered whether RCRC should be broken down into smaller 'pots' based on different types of participant to reflect a fairer share of RCRC among similarly behaving Parties, otherwise there exists situations such as, for example, wind farms subsidising thermal generators as a result of their imbalance. However, this was deemed outside the scope of P305.

It was also noted by some Workgroup members that no analysis had been undertaken to understand the relationship between RCRC and Balancing Services Use of System (BSUoS) charges as a result of P305.

Should Market Index Data be retained?

The Workgroup noted that P305 would remove the Reverse Price methodology as both SBP and SSP would be calculated using the Main Price methodology. Members therefore considered whether Market Index Data would still be required, as its only use under the BSC is in the calculation of the Reverse Price.

It was highlighted that a method for producing an imbalance price would be required in the event that the NIV was equal to zero. Although this is a rare event that has happened on only a handful of occasions in the last decade, this scenario can occur and a method for resolving it would be required. Suggestions that had been put forward included setting the price to zero, setting it equal to the previous Settlement Period or using the Market Price for that Settlement Period.

It was felt that setting the price to zero would not be appropriate as, while the system may have been perfectly balanced, costs would have been incurred to achieve that position. Additionally, the price of the previous Settlement Period may not be reflective of the price in the relevant Settlement Period (for example if a STOR Action priced at a high RSP had set the price in the previous Settlement Period, but the relevant Settlement Period fell outside the STOR Window).

One member also suggested a method where, should the NIV equal zero but actions had been taken by the Transmission Company then a price could be derived from the highest priced accepted Bid and the lowest priced accepted Offer. Another member suggested using the last action taken that resulted in the NIV becoming zero. It was felt by these members that this would retain the principle of the marginal price being put forward by P305, and that if actions had been taken to balance the system then these should be used to set the imbalance price. Overall though, Workgroup members were not in favour of developing these more complex methods, given the expected frequency of them being used and also as they would not work in scenarios where no Bids or Offers had been accepted and so a further method would be required for these cases.

Workgroup members felt that the Market Price was a fair price to use in these scenarios, as no-one would be disadvantaged by this. It was also noted that, while Market Index Data is currently only used for the Reverse Price methodology under the BSC, it has many other applications elsewhere in the industry. The Workgroup noted that the total cost to ELEXON (and thus BSC Parties) per annum to maintain Market Index Data was around £330k, although a breakdown of these costs could not be made available due to commercial sensitivity with the Market Index Data Providers. While there would be cost-savings under the BSC to remove Market Index Data, some members felt these savings could be dwarfed by the costs incurred elsewhere to establish alternative methods to use in place of this. The Workgroup therefore felt that it would be prudent to leave Market Index Data untouched by P305 and to instead investigate this separately, and agreed that this data would continue to be published by ELEXON separately for each Settlement Period. It therefore also concluded to use Market Index Data to set the imbalance price when the NIV is zero.

It was noted that rules around imbalance prices are being drawn up under the forthcoming European Balancing Code, which could prevent the use of Market Index Data to set the prices. However, it was noted that this Code is still only in draft form, and that any changes required from it for imbalance prices are unlikely to need to be implemented before 2018. The Workgroup therefore elected to ignore this element under P305, noting that it should be picked up under any wider changes to implement the Code.

How should STOR Actions be reported?

P305 proposes that all STOR Actions will be included in the imbalance price calculations as actions priced at the greater of their respective Utilisation Price (the price incurred by the Transmission Company in calling upon the action) or the RSP for that Settlement Period. The Workgroup discussed how this would be reported, and agreed that it would be beneficial to see the Utilisation Price of each action even if it was subsequently replaced with the RSP.

It was therefore agreed that the Transmission Company would send the BMRA all STOR Actions taken and the Utilisation Price of each action. Both the Utilisation Price and, if applicable to that action, the RSP that replaced it would be published on the BMRS for each STOR Action. All STOR Actions would be sent from the Transmission Company to the BMRA in dis-aggregated format alongside Bids and Offers, with a flag to differentiate whether it was a STOR Action or not.

The volume of a STOR Action would also be that which the Transmission Company had instructed from the action, rather than the volume actually delivered, as this would be consistent with how similar actions such as Bid-Offer Acceptances (BOAs) are currently reported. Workgroup members felt that an 'actual' volume could take a significant amount of time to calculate, and that if the industry wants prompt pricing then it cannot wait for this volume to be calculated. Furthermore, feeding a revised volume in to the calculations at a later date could result in radically different prices being produced at later Settlement Runs.

It was noted that the RSP would only be applicable in Settlement Periods that fell within a STOR Window, as these would be the only times when STOR Actions could be called upon. The start and end of these windows will be either on the hour or the half-hour, and so align with the start and end times of Settlement Periods. Therefore, as long as the actions are provided to ELEXON with sufficient information to be able to derive Half Hourly (HH) granularity it would be able to apply RSP to the parts of an instruction within a STOR Window while ignoring the rest. Sites that hold a STOR contract with the Transmission Company can elect to operate outside the STOR Windows of their own volition, but would operate and be treated as any other participant would in those circumstances.

Some members believed that STOR Actions should be published as soon as possible when called upon, so that the industry is made aware of this and the possibility of the RSP being applied in that Settlement Period. This would be more important in summer when it is much harder to forecast periods where STOR Actions may be called upon. Such events may not be due to system scarcity but simply a result of generation sites taking periods of planned outage, resulting in times when the system demand is at an 'ordinary' or 'low' level but the margin between supply and demand is itself low due to a reduction in available generation. The Transmission Company noted that there is a degree of confidentiality around STOR contracts which would make publication of the details difficult ahead of time.

Another member noted that STOR Actions would most likely be called upon after Gate Closure, where participants would be unable to react for that Settlement Period, and so questioned the benefit of early publication of STOR Actions. They also noted that Settlement Periods where STOR is called upon are likely to be Settlement Periods where Indicative LoLP values or de-rated margin forecasts were high, and so participants would have had some visibility in advance through these values.

Overall, it was agreed that STOR Actions, their Utilisation Price and, if applicable, the replacement RSP would be published on the BMRS after the Settlement Period was complete, at the same time as the indicative imbalance prices. The Transmission Company indicated that it would require suitable wording to be introduced into the BSC to allow it to disclose the relevant new STOR information; this is reflected in the proposed redlined changes in Attachments B and C.

How and when should the RSP be applied?

One member queried why only STOR Actions had been singled out under the EBSCR, and whether other types of action could be subject to the RSP, such as Supplementary Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR). They felt that scarcity pricing should be applied more generally to all Settlement Periods, and not just those in STOR Windows, and could not see where reserve came into the equation.

Other members responded that the RSP is only being applied to STOR Actions as these are the only actions that aren't priced at the time of use, with the Utilisation Prices for STOR Actions set in advance and therefore not reflecting the prices at the time they are called upon. Furthermore, availability fees are set at a fixed level and therefore do not reflect scarcity. All other types of action are priced at the time of their use, and so would at least partly reflect the prevailing scarcity and value to the market at the time of use. The RSP is designed to better reflect the price of STOR Actions. One member noted that SBR and DSBR should not be included as these are not technically treated as Balancing Services Adjustment Data (BSAD) now, and that the concept of the RSP function is to capture the value that people would be willing to pay that had not been captured within the Utilisation Price.

The first member also queried why participants would price Offers below the expected scarcity price if they knew they could get a higher price for their action. It was noted that the prices offered by participants would not necessarily reflect scarcity if more economic options were available. Furthermore, participants may elect to submit lower prices to make it more likely they would be called upon, which is a feature of a competitive market.

The Workgroup also considered whether the proposed calculation of RSP as the product of the LoLP and VoLL values was the right function, or whether an alternative method could be applied that would 'uplift' the RSP for a given LoLP value. One proposed option discussed was that the RSP could be the lesser of the prevailing VoLL value in the BSC or the product of the LoLP value and 'true VoLL' (considered under the EBSCR to be £17,000/MWh). This would have the result of the RSP, and therefore the imbalance price, reaching the VoLL value at a LoLP value of potentially significantly less than 1 (or 100% probability), strengthening the incentive to ensure capacity was available. Workgroup members could not see the justification for this approach as P305 was predicated on the idea of RSP rising gradually to the VoLL value as the LoLP got closer to 1 (100%).

How should the LoLP be calculated?

In its Final Policy Decision, Ofgem left it open to the P305 Workgroup to develop the calculation for producing a LoLP value, within a given framework. Two calculation methods have been developed:

- A **'dynamic' function**, intended to calculate LoLP values as originally envisaged under the EBSCR, which would be used in the run-up to each Settlement Period and would be based on inputs including plant availability data and forecast demand data at that time.

- A **'static' function**, under which a mathematical relationship between the de-rated margin in a Settlement Period and a corresponding LoLP value would be calculated on an annual basis using historic data over previous years. This function would then apply to all Settlement Periods during the subsequent year.

The details of each method can be found in Attachment A.

The Proposer agreed that the 'static' function would be put in place upon implementation of P305, but would be replaced with the 'dynamic' function on 1 November 2018. The Workgroup elected to progress only the 'static' function under the Alternative Modification.

The agreed calculations for each function will be documented in a new document, the LoLP Calculation Statement, to sit on the BSC Baseline Statement. This will mean that any errors in the calculation of a LoLP value (such as use of an incorrect value) will be deemed a Settlement error and will need to be resolved through the Disputes process. This would also make the execution of the process subject to the BSC Audit. All changes to this document (including the initial version) would need to be approved by the Authority.

Consideration of the proposed 'dynamic' calculation

The 'dynamic' calculation is designed to measure the probability of the available generation being less than the amount needed to meet the expected demand in a given Settlement Period. The calculation is based in part on an expected availability or reliability factor for each fuel type. These availability factors have been calculated based on the stated availability of each BM Unit a certain amount of time before a Settlement Period compared to its actual availability in that Settlement Period. These values would be updated each year based on the results from the last three calendar years and stated within the LoLP Calculation Statement.

The Transmission Company has also proposed to produce two sets of these values, split between summer (April to September) and winter (October to March). This is designed to reflect the difference in reliability or availability between these two times, which can be more pronounced for some fuel types such as wind. Workgroup members considered whether further splits should be considered, such as between day and night or between Working Days and non-Working Days.

The Workgroup considered the scenario of a BM Unit indicating that it was available ahead of a Settlement Period, but upon commencing generation a fault occurred that prevented the BM Unit from performing. It was queried how this could be factored into the calculation, but one member noted that there is always a chance of this happening, and another noted that all information regarding availability would be provided in good faith. There is always a greater risk of failure with a BM Unit commencing generation compared to one that is already running. The Transmission Company noted that there was insufficient information on individual BM Units to break the data down to that granularity, and that fuel type is the most pragmatic grouping available.

The calculation includes a dynamic 'reserve for response' value or Largest Loss Reserve (LLR) to represent the amount of reserve that the Transmission Company will hold to use as last resort, for example for frequency response. The Transmission Company is required to hold on to this reserve to provide response, initiating a Demand Control event in part of the country rather than risking a system-wide blackout due to no reserve being left to call upon to manage the frequency. A fixed value for the largest loss (an input into the reserve for response) was selected as a more dynamic parameter would be more complicated to produce and would require more data input. It was also felt that this value should be a fixed value tied to a publicly-available value to maximise transparency and aid other participants in replicating the LoLP calculation should they wish. It was believed that the Security and Quantity of Supply Standard (SQSS) value should be used, and this Infrequent Infeed Loss Risk value is 1,800MWh.

Each BM Unit is assumed to either be fully operational or completely unavailable in a given Settlement Period, which, while not fully reflective of reality, was considered a reasonable assumption. However, gas plants can have multiple shafts under a single BM Unit, and so the assumption put forward in the calculation is that a gas BM Unit is modelled as two Units with half the capacity on each. Averaged over all gas BM Units, which can have anywhere from one up to five shafts, analysis carried out by the Transmission Company suggests this assumption to be sufficiently accurate enough when compared to reality. One Workgroup member was not certain about this, and questioned whether the assumption would affect the reliability of the calculation, and if it did then it would need to be reconsidered.

The Workgroup considered how Interconnectors should be factored into the calculation. Interconnectors can only be subjected to Demand Control in proportion to the level of Demand Control taking place within GB. Otherwise, the only actions that can influence Interconnector flows would be emergency instructions between SOs, which would effectively reduce the chance of losing demand elsewhere. It was thought that should these not be factored into the calculation, the LoLP values may be overstated as a result. It was confirmed that Interconnectors have been accounted for in the demand side of the calculation.

The Workgroup noted that the calculation should aim to be as accurate as possible. If participants begin to use the results in a serious way and issues were uncovered later on, the calculation and the data feeding into it could come under a lot of scrutiny. It was felt by one member that the LoLP value would never be totally accurate as a forecast due to the assumptions being used.

Consideration of the Transmission Company's analysis and development of the 'dynamic' function

The Transmission Company's 'dynamic' function has undergone several iterations. This section summarises the discussions and analysis of the Workgroup across previous iterations that led to the development of the current proposal detailed in Attachment A.

Analysis on the original iteration

The Transmission Company's analysis of the original version of the 'dynamic' LoLP function was focused on 2013 data, which was noted to be a year with a lot of available margin on the Total System, but was also just prior to plants that have elected not to comply with the Large Combustion Plant Directive (LCPD) beginning to close down, which will have a detrimental effect on available margin in subsequent years.

The Workgroup found the results surprising, as they suggested that the highest LoLP values were appearing at times outside the STOR Windows, with several of the more notable values occurring within an hour of midnight. Members were concerned whether the proposed LoLP function was providing the correct signals if high LoLP values were being produced at times when participants would not intuitively expect the system to be tight, such as overnight. One member noted that the overnight period would generally see

Transmission Company's LoLP analysis

The results of the Transmission Company's LoLP analysis can be found in Attachment A.

The raw LoLP data produced by the Transmission Company is available to download from the ELEXON Portal (a free login account is required to view this page).

low demand and plenty of available capacity. While the margin may be low if some generation units were unavailable overnight, the system would not expect to be 'stressed'. They intuitively felt that the proposed LoLP function was not providing the expected results.

It was noted that these overnight values all occurred over the same night, 13 November 2013, and that the Transmission Company had called upon reserve during this time, indicating this was a legitimate, albeit anomalous, event. The LoLP values for these periods would not set the imbalance price though as the RSP would only apply within a STOR Window. The Transmission Company subsequently revised the 'dynamic' function to account such anomalies by adjusting the treatment of dynamic parameters in the LoLP calculation, which had the result of capturing more typical patterns of plant availability overnight, and this revision forms part of the current proposal.

It was also highlighted that, within the STOR Windows, not one Settlement Period across 2013 had a LoLP value high enough for the RSP to replace the Utilisation Price, and only around 20 Settlement Periods[3] had a Final LoLP value in excess of 0.01 (1%). The Ofgem Representatives noted that their historical analysis had suggested the RSP could have a greater impact (between 1-3% of the time), but recognised that whilst this analysis was based on the information available at the time, the detailed LoLP calculation had not yet been developed. Workgroup members wondered if this was a sign that the STOR Windows may not be in the right places.

The Workgroup also considered modelling undertaken by the Transmission Company for 11 February 2012, which was a date on which a Demand Control event had taken place. Several calculations of the LoLP values across that day had been carried out, using availability values calculated for a range of times from the hour-ahead Maximum Export Limit (MEL) values to the winter outlook data submitted at the start of the preceding October. It was noted that the LoLP values generated from the hour-ahead data were very low values of less than 0.01 (1%), while the values arising from the winter outlook availability data were significantly higher, getting near to 1 (100%) on a couple of occasions and above 0.5 (50%) for a large amount of the day.

It was noted that this was an exceptional circumstance in which temperatures of -18°C had been recorded. On that occasion, gas BM Units had continually recorded availability up until mid-morning, when a large number of them froze at around the same time, resulting in the Transmission Company initiating Demand Control. A 'type fault' across a particular fuel type is an incredibly rare event, and this event was unforeseen by the whole industry, with even the Transmission Company being unaware of the potential for this issue until almost the moment it occurred. Consequently, it would have been unlikely this would have shown up in the Indicative LoLP values for the Settlement Period in which the event occurred, and for later Settlement Periods only upon commencement of the event, by which time the industry would have become aware anyway. The Workgroup therefore felt that this event may not be a suitable one in which to test the calculation or base conclusions on, as the LoLP would be expected to be very low when no issues are foreseen. Furthermore, it was noted that the SBPs for that day seemed to produce a clearer signal of the times when the system was tight than the LoLP values did. However, there is only one other Demand Control event to have occurred over the last few years which can be investigated, and this was for an automatic LFDD event, the actions for which would be system action flagged and so would not impact imbalance prices.

[3] There are 17,520 Settlement Periods in a non-leap year.

Analysis on the second iteration

Following the amendments made to the model following the original analysis, the Workgroup requested the Transmission Company undertake further analysis for the week beginning 13 October 2014, which had been noted as a period of low margin and high imbalance prices due to high-priced Offers being accepted. The Workgroup felt that this was the closest scenario available to it to a full Demand Control event that it could use to properly assess the proposed LoLP function. The Transmission Company Representatives noted that they had been close to issuing warnings to the wider industry during this time.

The analysis initially showed significant spikes in the Final LoLP values calculated at Gate Closure compared to the Indicative LoLP values calculated one hour previously, which some members were concerned could not have been predicted, and with LoLP values rising above 0.5 (50%) at Gate Closure when they had been below 0.1 (10%) one hour earlier, there was the potential for significantly high imbalance prices to be set that participants could not have anticipated and for which little signal had been perceived to have been available. While there had been issues during that week, the members felt they had not been severe enough to warrant an imbalance price in excess of £2,000/MWh.

Members felt that this pattern could be expected, with high LoLPs at the day-ahead point when there is greater uncertainty, then values reducing over time, then rising sharply at the last minute when a generation unit experiences a sudden outage. However, this is not what some members believed should feed into the imbalance price as such outages cannot be predicted, although one member disagreed with this idea that Parties should only be exposed to imbalance charges for events they could predict or anticipate. Furthermore, members were concerned that such high LoLP values were being produced during a fairly warm and windy October period.

The Transmission Company Representatives identified that this spike at Gate Closure may have been caused by the assumption applied to the Notice to Deviate from Zero (NDZ), which meant that the MELs of units were only counted if that unit was available at the start of the Settlement Period. The Transmission Company took an action to rerun the model applying the assumption that a unit's MEL would be accounted for if it could be synchronised by the end of the Settlement Period. When the model was rerun with this assumption accounted for, this change resulted in the spikes being removed. The Transmission Company also amended its availability factors to use the same values at all calculation lead times, which reduced the high day-ahead Indicative LoLP values that had also been observed. These amendments form part of the current proposal.

Analysis on the final iteration

Following these further amendments, the 'dynamic' function was rerun for all Settlement Periods across 2013 and up to mid-October 2014. The Workgroup noted that the results produced by this re-run indicated that the amendments made to the function had achieved the desired effects and were much closer to some members' expectations. The highest LoLP value produced at Gate Closure was a result of a combination of tight margins and a generation outage between two hours ahead and Gate Closure, although even this value would have been too low for the RSP to feature in the imbalance price. It was considered by some members that high LoLP values would only arise if there was a sudden generation outage coinciding with a period of low margin.

Members were generally satisfied that the specific concerns identified had been resolved. The Transmission Company and Ofgem Representatives noted that the analysis showed that whenever there was a high Final LoLP value, a warning had been provided by the Indicative LoLP values. Specifically, in every Settlement Period where a high Final LoLP value had been produced, this had been preceded by a series of Indicative LoLP values that were significantly different from those in 'normal' Periods. However, while some Workgroup members voiced their support for the proposed function based on this updated analysis, others were still concerned with the proposed function generally.

The results of the Transmission Company's analysis on the final iteration can be found in Attachment A, and the raw data produced by this work can be downloaded from the ELEXON Portal. It is this iteration that forms the 'dynamic' function under P305.

Is the 'dynamic' LoLP function correct?

The Workgroup considered whether the calculation would produce high LoLPs for many days at the day-ahead point, where data is less certain, and whether the values could be similar across most days. There was a feeling among members that LoLP values would likely start high and come down closer to real time as availability became clearer. If this was the case, participants may elect to ignore the LoLP values this far out. At the other extreme, they may react to the high chance of imbalance prices being set to the VoLL price, although it was noted that reaction to a high LoLP value would likely result in it subsequently falling as the signal of an initially high Indicative LoLP value could naturally lead to the Final LoLP value being much lower as participants react to the initial signal. One member noted that the way probability can work means that a Demand Control event may occur with only a 1% chance forecasted, or may not even with a 50% chance forecasted.

One Workgroup member was unclear what the values produced by the 'dynamic' LoLP function were supposed to be showing. They expected the LoLP value to be higher in periods of higher demand, when there would be fewer actions available to the Transmission Company to call upon. They also felt that the Indicative LoLP values were not providing a systematic upward trend as margins tightened but were spiking sharply at Gate Closure in reaction to last-minute events such as sudden plant outage, which participants could not anticipate. They therefore did not feel that the 'dynamic' LoLP function was delivering what was required, and could not be seen as reliable. Other members agreed that the calculation should be questioned if it was producing high LoLP values at times when they would not be expected. However, the Transmission Company Representatives cautioned against subjectively manipulating the calculation to match the Workgroup's intuition, noting that the results of doing so would affect the whole market. They noted that the 'dynamic' calculation was statistically robust, and that it is possible that the Workgroup's intuitive expectations are wrong.

It was felt by one Workgroup member that the LoLP value should measure the risk of reserve being dispatched when the Transmission Company was running out of capacity, as the Final LoLP value would then be used in pricing these reserve actions. The LoLP therefore needed to be able to measure the available capacity. Another member disagreed, noting that the LoLP was a measure of the chance of losing load. It was countered that this was why the Transmission Company procures reserve, in order to avoid this happening, and that it should be expected that the LoLP would lift prices when reserve was called upon.

It was noted that the LoLP values produced by the Transmission Company's analysis were very low generally, and that the subsequent RSP values would not impact imbalance prices. However, the analysis had focused on only the last couple of years, which had been generally benign and so low values were to be expected. One member also flagged that the country has historically held a good generation capacity, although it was questioned why reserve was needed if that was the case. The Ofgem Representatives also noted that the SCR's analysis showed RSP would usually only feature when the margin fell below around 2.5GW, and felt that the Transmission Company's analysis was consistent with the SCR's conclusions. Nevertheless, members were concerned that they could not draw firm conclusions on the function because of this, but it was felt that there was little point in re-running the analysis earlier than 2013 as there haven't been any notably tight periods in several years with which to assess the results against.

The Transmission Company Representatives queried whether the questions raised by the Workgroup suggested that LoLP was not what members wanted in the RSP calculation. They felt that the Workgroup's comments and concerns were around something more fundamental than just the LoLP itself, noting that its proposed function did what was asked of it. It was considered whether it wasn't the LoLP function that concerned members but the subsequent RSP function. Members responded that the concern was around the interaction between the LoLP value and the corresponding margin. They expected the highest LoLP values to occur when demand was rising sharply, as this would be the time when they would expect issues to occur. However, others noted that a high LoLP value should be a function of both demand and generation. It was also expected that Indicative LoLP values would start high for these times at the day-ahead point, and reduce over time as participants react to the signal.

One member felt that the 'dynamic' LoLP function seemed to be showing a 'loss of generation' probability, as it was mainly picking up plant failing close to real time. They felt that the function reflects what the Transmission Company is doing with scheduled generation units but that this did not relate to the imbalance price. They felt this LoLP function was doing a good job of showing loss of generation, but it wasn't showing demand versus capacity and it did not enable the LoLP value be predicted, and so should not be used in setting the imbalance price.

The Workgroup also had concerns with the transparency of the 'dynamic' LoLP function's calculation, with several of the input parameters not being publically available. The Transmission Company Representatives flagged that it was primarily the MEL values that could not be published prior to Gate Closure due to confidentiality agreements. However, the forthcoming regulation on submission and publication of data in electricity markets (the Transparency regulation) (Regulation (EU) No 543/2013)[4], due to be implemented at the beginning of January 2015, would require indicative MEL values to be published, but only on a prospective basis. This would remove this element of opaqueness and would facilitate participants attempting to recreate the function.

Overall, some members were concerned with the proposed 'dynamic' LoLP function, believing it should not be implemented, and felt that an alternative solution should be developed, considering a more 'static' function may be appropriate.

Development of the 'static' LoLP function

Some members noted that the Transmission Company must procure reserve based on some long-term measure of the probability of it needing to be used, and wondered if something similar could be used for producing LoLP values here. They considered that this would be a better measure of the margin than the MEL-based method under the 'dynamic'

[4] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2013:163:0001:0012:EN:PDF

LoLP function. The Transmission Company Representatives highlighted that the methods used to procure reserve long-term were very different to the methods used to balance the Total System in real time.

Members felt that the LoLP should be higher when margin was lower. Once it was understood how the margin is calculated, a function linking that to a LoLP value could be produced. This would result in a pre-agreed function published ahead of time, and participants could use this to forecast LoLP based on forecasts of demand or margin. Members agreed that, while a 'dynamic' function would be preferable ideally, a 'static' function was appealing due to the increased certainty it could provide to the market.

The Workgroup proposed an alternative 'static' LoLP function that would use the historical Final LoLP values produced from the 'dynamic' LoLP function for a given period of time to derive a relationship between de-rated margin and LoLP. It was agreed that such a curve would be calculated as an "upside down normal cumulative distribution function", and would be calculated on an annual basis, effective from 1 April in a given year, with an initial curve to be calculated as part of the implementation of P305 to go live on the P305 Implementation Date and would be effective up until the following 1 April. For the first curve to be produced, the most recent 12 months of historic data would be used. For all subsequent curves, the historic data produced since the last curve was produced would be added to the pool of existing historic data, meaning the pool of data would get gradually bigger as years go by. An updated curve would be produced and published three months before it would become effective. The full details can be found in Attachment A.

It was considered by some members whether curves should be calculated more frequently and for specific times of the year (for example summer/winter, or by BSC Season). However, the volume of useful data from the LoLP analysis carried out by the Transmission Company was too small to be able to draw a meaningful conclusion as to whether there was a material difference between different times of the year. It was agreed to leave the process as outlined above, but that the question could be revisited at a later date once more data becomes available.

Members agreed that this 'static' LoLP function would be more predictable, and would provide participants with an ex-ante signal with which to trade against. However, it was noted that it was not dynamic as it simply relates the de-rated margin to a LoLP value, whereas imbalance prices are dynamic and react to the actions taken by the Transmission Company.

Although the process for calculating the function would be captured in the LoLP Calculation Statement, for which all changes would be subject to Authority approval, some members believed that any key parameters relating to this method would need to be written into the BSC. This would mean that those values could not change without a BSC Modification being raised. However, which values these may be were not agreed by the Workgroup, and so all such information will be contained in the LoLP Calculation Statement.

The Proposer noted the Workgroup's preference for the 'static' approach, a view shared by a majority of Assessment Procedure Consultation respondents (see below). They were indifferent in the short run as to which of the 'static' or 'dynamic' function should be used, noting that the 'dynamic' approach would be more accurate whereas the 'static' function would be easier for Parties to initially adjust to. However, they believed that the 'dynamic' function would be better in the medium run once Parties have had time to understand the broad concept of the RSP. They therefore elected to adopt the 'static' LoLP function as part of the Proposed Modification, although only for an interim period up to winter

2018/19, at which point the function would switch to the 'dynamic' function. The Workgroup elected to use the 'static' function under the Alternative Modification, but without a mandated switch to the 'dynamic' function at a later date.

The Workgroup agreed that if there was to be a switch between the 'static' function and the 'dynamic' function then, in order to facilitate the switchover, information-only LoLP values using the 'dynamic' function would start being produced and published in advance. It was put forward that these would begin six months ahead of the switchover, as this would allow sufficient time for participants to adapt without placing undue strain on the Transmission Company in running two separate processes simultaneously. Some members sought a longer lead time, such as 12 months, as a six month lead time would not cover a winter period, and would not leave enough time to prevent the switchover if it was felt that the values were not appropriate. Other members noted that some of the highest LoLP values observed in the Transmission Company's analysis had come in the summer period, but noted that this lead time should not be hardwired so as to make it longer if it was felt that would be necessary in 2017.

Participants' views on the LoLP functions

A significant majority of respondents to the Assessment Procedure Consultation who expressed a view were in support of the 'static' function over the 'dynamic' function. These respondents felt that the 'static' model would be a simpler model to use, and would offer a more predictable, reliable and transparent method than the 'dynamic' approach. Respondents were also concerned about the potential for last-minute events or issues to impact the Final LoLP produced under the 'dynamic' function which participants would be neither able to predict or react to, and felt the 'static' function would be less subject to these events.

However, a few respondents were in support of the 'dynamic' approach. They agreed with the Workgroup's observations that imbalance prices are dynamic, and therefore felt that the LoLP values should also be dynamic. Similarly, it was noted that the 'dynamic' function would be more accurate than the 'static' function as it would take into account live plant data rather than historical performance over a period of time. It was also considered that the 'dynamic' function would better reflect the principles set out in the EBSCR around the LoLP values.

How do LoLP and RSP fit in to the full solution?

The intent of the RSP function is to provide a price for STOR Actions that reflects the conditions in the market at the time it is called upon. The results of the LoLP and the resultant RSP should be to provide a suitable price for these actions when they are called upon.

Some members were concerned that the whole RSP mechanism proposed by P305 was creating uncertainty for no real benefit, and queried whether it would add value to the overall arrangements. It was noted that in a liquid market prices would naturally rise to the RSP, but this is not happening. However, GB is the most liquid European market not counting those countries where participants are forced to trade. It was queried whether the imbalance prices were dampening the forward market. However, some members did believe that the move towards an RSP for STOR Actions was better than the current method of including them in the BPA. Nevertheless, the RSP cannot be assessed solely on its own merits in isolation, but on how it fits in with the rest of the full P305 solution.

Some members have queried whether the RSP is even necessary. It was noted from ELEXON's historical analysis (see below) that, with a VoLL value of £3,000/MWh, of the nearly 40,000 STOR Actions taken in 2013 only 36 would have been re-priced at the RSP (rising to 46 with a VoLL value of £6,000/MWh) and none of these went on to set the imbalance price. Instead, the only notable impact the RSP aspect of the P305 solution had on the imbalance price was from the inclusion of non-BM STOR Actions as individual actions rather than aggregated through the BPA. One member queried why such a complex and possibly misleading solution was being put forward for no apparent benefit. It was also felt that as the 'static' function is based on historical data, it would not be reflective of the prevailing conditions when it was used. They felt that the RSP should be removed from the P305 solution and that all STOR Actions should simply be priced at their Utilisation Price. This view had also been raised by several respondents to the Assessment Procedure Consultation.

Other Workgroup members disagreed with this view. They noted that it would not be expected for the RSP to feature in 2013 as it had been a benign year with no notable periods of scarcity. Additionally, although the curve used under the 'static' function would be based on historic data, the LoLP values calculated from it would be based on the de-rated margin at the time of calculation, so would reflect prevailing conditions. The absence of a link between scarcity and the pricing of reserve in imbalance prices was also noted as part of the defect identified by P305, and so the solution needs to cater for this. By removing this aspect from the Alternative Modification there was a risk that the Authority would disregard it; it was considered to come down to which aspects the Workgroup deemed more critical to amend under the Alternative Modification. Overall, the Workgroup elected not to remove the RSP requirements.

The Workgroup considered whether STOR Actions should not be priced in advance at the Utilisation Price but instead priced on demand. It was questioned how a price on demand would be calculated, and what assumptions would need to be made. It was noted that the highest priced Offer could be a reflection of the market conditions that could be used. Assumptions would also need to be made on the relevant participant's short-run costs. One member noted that the price would be the price that would have been submitted had the action been taken under the BM rather than through a STOR instruction, and it was noted that STOR can be used ahead of an Offer if it is cheaper. Overall though, this idea was ruled out as participants would be unlikely to sign up to provide STOR in this situation, which would have a serious impact on the security of supply.

When should LoLP values be produced and published?

The Workgroup considered when Indicative LoLP values should be produced under the 'dynamic' LoLP function and at what time in relation to the relevant Settlement Period the Final LoLP value should be determined under the 'static' function and published under either option.

Can participants respond to the indicative signals?

One member queried whether participants would be able to respond to any signals in advance of Gate Closure, noting that participants don't have such signals now for imbalance prices generally. The Ofgem Representatives noted that the intent of having indicative signals was to warn participants of potentially high imbalance prices as a result of STOR Actions being called upon or the initiation of a Demand Control event. They did not want such an event to be completely unpredictable, although they noted the potential for trade-offs to be made between criteria of statistical soundness, providing appropriate prices at the appropriate time, and providing a signal that Parties can react to. Signals should encourage participants to trade in the forward market to manage their positions, although it was felt that the very inclusion of RSP and VoLL in the arrangements would send a general signal to participants.

One member believed that smaller participants would usually need at least four hours to effectively respond to any signal, and that this would be dependent on there being sufficient liquidity with which to trade. They were concerned that as margin gets tighter liquidity tends to dry up, preventing participants from being able to trade out their position. They believe that participants need to be able to respond to signals, and that sufficient time needs to be given for them to react in to mitigate the risk of exposure to high imbalance prices. Otherwise, the arrangements proposed by P305 could be seen as a penalty rather than an incentive.

It was noted that the 'dynamic' LoLP function would provide a less reliable signal the further ahead of real time it was calculated, and that values produced further out would be less reflective of the situation. One member observed that this is just how markets work. Other members believe that a smooth glide-path is needed in the run-up to a Settlement Period to allow participants to be better able to trade, and it was felt the 'static' LoLP function could achieve that as participants can use their own forecasts to assess what they believe the LoLP value would be. This could be enhanced further by having the Transmission Company publish forecasts of de-rated margin on the BMRS, and the Workgroup believed this would need to be a condition of the 'static' LoLP function.

When should Indicative LoLP values be published?

Members noted that an indicative value needed to be produced sufficiently far enough in advance to incentivise participants to trade to avoid any potential Demand Control event from being needed and imbalance prices rising to at least the VoLL value. Members began by proposing that, for any given Settlement Period, an indicative value should be produced at 24, eight, four and one hour(s) prior to Gate Closure.

The Workgroup discussed how the 24 hour ahead value should be published, and whether it should be a 'rolling' calculation (i.e. carried out 24 hours prior to Gate Closure for a given Settlement Period), or calculated in a batch as part of the day-ahead information produced by the Transmission Company at 11:00 each day for all Settlement Periods up until the end of the next Operational Day. A member in favour of the latter argued that the Transmission Company would have much more information for a calculation carried out at 12:00 on a given day than it would for a calculation run at 09:00, and so values produced in this manner would be more meaningful. Other members argued that a rolling basis would be more consistent with the reporting required under the regulation on wholesale energy markets integrity and transparency (REMIT) (Regulation (EU) No 1227/2011)[5] and the Transparency regulation.

The Transmission Company Representatives noted that information is constantly received, and is processed by the systems at the point of receipt. Therefore, all information that had been received when a calculation was performed would be included in that calculation. The day-ahead calculation simply collates all this information. However, some members were not convinced that a significant amount of data would not arrive just prior to the

[5] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:EN:PDF

day-ahead calculations, and that any Indicative LoLP value calculated just prior to that would be less useful for missing this information, especially as the value may not be revised for a further 16 hours. It agreed that, in addition to the specific times of eight, four and one hour(s) prior to Gate Closure, an indicative LoLP value is produced for all applicable Settlement Periods at 12:00 each day, and that there would not be a 24 hour ahead rolling Settlement Period-specific Indicative LoLP.

Another member highlighted that day-ahead trading on the Power Exchanges ceases at 11:00. They considered whether a further set of Indicative LoLP values should be produced at 08:00 each day to inform participants of the Indicative LoLP values over the subsequent Operational Day ahead of this deadline.

One member felt that calculating indicative values at specific times is prescriptive, and believed that the industry would prefer continual updates, although they conceded that this may be a tall order for the Transmission Company. They considered whether an Indicative LoLP value could be updated whenever new information is received by the Transmission Company that could materially affect the value. It was noted that data would be constantly received, and it would be difficult to determine what would be material, and that other forecast information published under the Grid Code and BSC Section V 'Reporting' is published at set times, rather than continually updated. A member thought that, if this was not feasible, the value could be re-calculated every half-hour even if no new information had been received. However, it was felt that this could result in 'data overload'. It was ultimately elected not to progress this idea.

The Transmission Company Representatives were concerned as to how accurate an indicative value calculated 24 hours ahead could be. They noted that a day-ahead value could be produced, but its accuracy would depend on how accurate the MEL values it had received at that time were. At this time, the Transmission Company would only possess a high-level idea of the expected generation and demand, and it is not until closer to real-time that the picture becomes clear enough to produce a meaningful estimate. However, other members felt that the Indicative LoLP values were more for the industry's benefit than for the Transmission Company, and that it would be for individual participants to determine whether the 24 hour ahead value was of worth to them or not.

Following this, one Workgroup member queried whether Indicative LoLP values should be calculated for more than just the next Operational Day. They noted that some smaller participants only trade during Business Hours, and felt that these participants would want a rough idea just before a weekend what the likely LoLP would be at the start of the next week. Taking Bank Holidays into account, they considered that extending the day-ahead batch of values calculated at 12:00, and possibly 08:00, to cover the next five Operational Days would be beneficial to these smaller participants. The Transmission Company Representatives reiterated their previous concerns over whether an indicative value at five days out would show anything at all meaningful. Other members responded that any information would be better than none, and noted again the view that it would be for participants to judge whether they should respond to the value or not. The Transmission Company Representatives noted this, but queried, while little information was better than none, whether the accuracy of a value this far out could result in this being misinformation.

Following Impact Assessment, the Transmission Company noted that it did not possess the data required to be able to produce Indicative LoLP values further out than as part of the day-ahead calculations. To calculate a meaningful result further out than that would require participants submitting data such as Physical Notifications (PNs) and MEL values earlier than currently. This would impact those participants. The Transmission Company also noted that it would be easier if the times at which LoLP values were produced were linked to the start of the Settlement Period and not to Gate Closure, noting that its systems were designed around the obligations under the Grid Code, and so it would be beneficial to align with this wherever possible. It proposed that indicative values are produced at 12:00 for all Settlement Periods up to the end of the next Operational Day, then at eight, four and two hours prior to specific Settlement Period beginning (equating to seven, three and one hour(s) prior to Gate Closure), with the final value being calculated one hour before the Settlement Period (equating to Gate Closure). The Workgroup agreed with this approach.

The Workgroup agreed that if a Final LoLP value could not be produced for a given Settlement Period then the last available indicative value for that Settlement Period would be used in its place. If no such value was available then the value would be null and the RSP for that Settlement Period would be set to zero. A flag would be included with each LoLP value produced to mark how it had been calculated, and whether it was an actual value or a defaulted value. Members noted that while this approach held a risk of an incorrect value being used, it was felt that this defaulting rule would be the most appropriate in this scenario.

When should the Final LoLP value be published?

Some Workgroup members expressed concerns at whether a Final LoLP value published for a Settlement Period at Gate Closure could influence participants to deviate from the position they had declared at Gate Closure, self-balancing in order to mitigate the impacts of imbalance prices rising to the VoLL value should they end up short. It was considered whether the Final LoLP value should not be published until after the Settlement Period had finished, alongside the indicative SBP and SSP for that Settlement Period, to mitigate this potential impact. However, other members noted that deviating from the declared position at Gate Closure would be in contravention of the Grid Code, although it was considered whether the penalties for this would be severe enough when compared to an imbalance price of £6,000/MWh, and that this would not apply to non-Grid Code participants. One member also highlighted that an indicative value would be published one hour before Gate Closure, which participants could respond to, and that participants should not be deviating after Gate Closure. It was considered whether participants reacting to a stressed system would be beneficial, but it was felt that it would not be if this put the stability of the system at risk. However, the issue of self-balancing exists now, and is unlikely to go away under P305.

Members also noted that the LoLP calculation is likely to be sufficiently transparent if all the data used in it was publicly available that any participant could calculate the Final LoLP value themselves at Gate Closure. In this scenario it makes little sense not to publish the value, as that would only bias against participants without the resources to do this themselves.

Overall, it was concluded that there would be no real benefit in delaying the publication of this value, and that in the interests of transparency it should be published as soon as it becomes available. Respondents to the industry Impact Assessment who expressed a view on this matter all supported this view, for similar reasons to those put forward by the Workgroup.

When should the LoLP value be determined under the 'static' LoLP function?

The Workgroup discussed at what point a Final LoLP value should be determined for a given Settlement Period under the 'static' LoLP function, based on the forecasted de-rated margin for that Settlement Period at the time of determination. The options considered were:

- At Gate Closure, as this would be the most realistic estimate of the de-rated margin for the relevant Settlement Period.
- Two hours before the Settlement Period begins, as this would leave participants the final hour before Gate Closure to trade knowing what RSP would be applied should a STOR Action be called upon.
- Four hours before the Settlement Period begins, as this would factor in the final wind forecast for the Settlement Period, and leaves participants more time to trade in response to the confirmed RSP for the Settlement Period. It also aligns with the lead time for warnings issued under the CM.
- 24 hours before the Settlement Period begins, as this gives participants, and particularly smaller participants, significantly more notice of what the RSP for the Settlement Period will be.

These options were only considered for the 'static' LoLP function; the Final LoLP value under the 'dynamic' LoLP function would always be set at Gate Closure, as detailed above. This is because the 'static' LoLP function would be primarily dependent on the overall forecast of de-rated margin, while the 'dynamic' LoLP function would be more dependent on individual variables that will change constantly in the run-up to Gate Closure.

Under this approach, a forecast of the de-rated margin will be published on the BMRS. This will remove the need for any Indicative LoLP values to be produced, as participants could observe the forecasted de-rated margin and use the function to derive the expected LoLP themselves.

Members felt that whichever option was chosen would be based on a trade-off between early certainty of the RSP and the accuracy of the forecasted de-rated margin. It was noted that the further out the LoLP value is determined, the greater the potential becomes for inaccurate signals, as a lot can change in the intervening space of time (potentially as long as 24 hours), including Parties reacting to the signal.

Some members were concerned that the forecasted de-rated margin may change considerably between 24 hours ahead of real time and four hours ahead of real time, and that a lot of this uncertainty comes from how much the wind forecast may change during this time. The Transmission Company noted that the mean absolute error in the wind forecasts, which is measured in relation to the metered capacity, improves from 5% at 24 hours ahead to 3% at Gate Closure, based on 2013 data.

One member noted that a LoLP at any given point in time will be correct for that point in time, but that it becomes more representative closer to real time and that Gate Closure is the last point at which participants can take any action to affect the LoLP value. Another member noted that it is possible for the market to run out of options before this point, but also that the further out a participant trades, the more time there is for events to occur that makes that trade a detrimental decision. It was also considered that this discussion has been more about the signal provided by the LoLP value and not the actual LoLP value itself.

Respondents to the Assessment Procedure Consultation were split as to which approach should be taken, with near-equal numbers of respondents opting for each of the four options proposed. The rationale given by respondents was broadly in line with that given by the Workgroup for each option.

Some members believed that the Final LoLP value should be determined ahead of Gate Closure, so that participants know what the RSP would be should a STOR Action be called upon. It was noted that participants cannot react to the Final LoLP value if it was set at Gate Closure. However, other members noted that the forecasted de-rated margin would be published in the run-up to Gate Closure, which would provide sufficient signal to the industry of what the Final LoLP may be. Furthermore, the Final LoLP value should use the most accurate forecast of the de-rated margin, and fixing the value further out ran the risk that the margin could change between then and Gate Closure due to participants reacting. If the Final LoLP value was determined ahead of Gate Closure while the de-rated margin was forecast to be tight, this would result in a higher LoLP value feeding in to the RSP. However, participants could then react to that signal, resulting in the de-rated margin becoming less tight, and the LoLP decreasing as a result. However, the original, higher, LoLP value would be the one that would set the RSP, meaning the RSP, and potentially the imbalance price, would be higher than necessary.

Following consideration of all of these points, the Workgroup elected that setting the Final LoLP value, to be used in calculating the RSP, would be done at Gate Closure. This will be the case under both the Proposed and Alternative Modification.

Could the LoLP value be 'gamed'?

One member considered whether participants could 'game' their MEL values in order to increase the LoLP and potentially increase prices in the wholesale market. However, other members considered this unlikely due to the reporting obligations imposed on the industry under the REMIT and Transparency regulations, under which participants are required to promptly report any unavailability, both planned and unplanned, and the subsequent restoration of that unavailability as soon as they become aware of this information. The penalties for erroneous reporting under these regulations are severe, and participants would likely lose significantly more from this than they could gain from gaming.

The sensitivity of the 'dynamic' LoLP calculation to potential gaming of the LoLP calculation has not been considered in any detail by the Workgroup. However one member raised the issue of the potential for market participants to influence the LoLP calculation by withholding plant. This could have the effect of indicating that there is limited unavailability of plant and a correspondingly high potential for lost load, which could influence cleared prices in the day-ahead or within-day markets.

What VoLL value should be set?

The EBSCR proposed that P305 would introduce an administrative VoLL value of £3,000/MWh upon implementation before rising to £6,000/MWh in 2018. The Workgroup was generally supportive of this approach.

One member queried whether the VoLL values proposed by P305 were appropriate, or whether lower values of £1,000/MWh or £2,000/MWh should be used to begin with. They were concerned that the high values being proposed had the potential to unintentionally adversely impact smaller participants. Another member noted that single-site generators

EBSCR consideration of 'gaming'

Ofgem's consideration of 'gaming' under the EBSCR can be found on pages 36-38 of the Final Policy Decision Impact Assessment.

EBSCR VoLL analysis

Ofgem's detailed analysis outlining why the administrative VoLL price is as proposed can be found in its consultation for the Draft Policy Decision, which ran between July and October 2013. In particular, please see Section 4 (p19-23) and Appendix 6 (p55-60).

Further information can also be found in the DECC-Ofgem study by London Economics on the Value of Lost Load for GB consumers and in Ofgem's Final Policy Decision.

would be at the greatest risk of adverse impacts, as they could potentially lose their whole generation output to an unexpected outage, creating a significant imbalance position. In contrast, while Supplier positions tend to be more unpredictable due to consumers' patterns of consumption it is unlikely they would be as significantly out of balance.

It was flagged that the VoLL values put forward under P305 had been calculated based on the assumptions the CM would pick up the rest of the expected impact. One member noted that these values were designed to act as an incentive for participants to balance their positions, and though that if there was a risk of a generally reliable single-site generator suffering an unexpected outage then they should be able to secure insurance against this. Furthermore, the VoLL values put forward had been based on extensive analysis and consultation carried out under the EBSCR, and that there was clear rationale for a VoLL value of £6,000/MWh. The proposal to begin with a VoLL value of £3,000/MWh was intended as an introduction for participants. Members felt there was no justification for other values to be put forward, and were content that the values proposed by P305 were appropriate.

A majority of respondents to the Assessment Procedure Consultation agreed with the proposed values and phased approach for implementing the VoLL value, noting that the case and justification for this approach had been reasonably presented, and that the approach has been well signalled to the industry, having been announced as part of the Draft Policy Decision in mid-2013. However, a few respondents disagreed, believing that the values were disproportionate and that not enough consideration had been given to the impacts on smaller Parties. A couple of respondents suggested using values of £2,000/MWh and £3,000/MWh would be preferable, while two more believed that only the £3,000/MWh step should be introduced and the increase to £6,000/MWh dropped.

It was queried by both Workgroup members and some consultation respondents whether there should be different VoLL values for Demand Disconnection, which consumers would notice, and Voltage Reduction, which consumers likely wouldn't, noting that DSOs would likely elect to take Voltage Reduction over Demand Disconnection where possible. However, it would be very difficult to disentangle the two types of event as DSOs tend to use both in parallel to achieve a Demand Control action. In any event, it was questioned how a value for each type would be derived, and members felt there would be no advantage over the proposed approach of a single VoLL value. The Ofgem Representatives noted that the value proposed under P305 was lower than the 'true' average VoLL value of £17,000/MWh, and accounts for this value applying to both Voltage Reduction and Demand Disconnection events.

How should revisions to the VoLL value be made?

There has been significant discussion within the Workgroup as to how future changes to the VoLL value should be raised.

The Proposer originally proposed that the VoLL value would be as prescribed in the BSC (and subject to the usual Modification process), or as directed by the Authority. The Workgroup proposed an alternative where the value is subject to the BSC process, as proposed, but that the Panel could initiate a review of the VoLL level.

Following constructive discussions between the Workgroup and the Ofgem Representatives on the principles that industry and Ofgem would like to see followed for a future review process, the Proposer has adopted the alternative proposal as part of their Proposed Modification, but with explicit reference to the Authority being able to request the Panel to initiate a review of VoLL, and that any evidence or issues set out by the Authority will be duly considered.

Authority direction

The original proposal giving effect to the conclusions of Ofgem's Final Policy Decision was that the VoLL value should be prescribed in the BSC, and subject to the usual Modification process, but that the Authority should have the ability to bring about a change to the VoLL value, which would then take effect at a time to be determined, superseding the value currently in the BSC.

The Ofgem Representatives noted both the value in having this parameter 'hard-wired' into the BSC, but also that there should be an appropriate process for Authority involvement in assessing future changes to the VoLL value, noting the values proposed were derived from a study performed for the Department of Energy and Climate Change (DECC) and Ofgem. There should be an appropriate mechanism to initiate change so that the value that consumers place on electricity is appropriately reflected in the market arrangements

The Workgroup was in agreement that the VoLL value should be hard-wired into the BSC and that changes can be proposed by anyone eligible to do so via a Modification. However, the Workgroup was strongly against the idea of the Authority directing changes to the VoLL value. The Ofgem Representatives on the Workgroup noted that the ability to bring about a change to the VoLL value formed a part of the Final Policy Decision and that the Proposed Modification should be consistent with this. However, they noted the Workgroup's concerns and so worked with members to explore alternative options that could be put forward.

Workgroup members considered that, should the Authority direct a change to the VoLL value, such a change should have a minimum lead time before it could come into effect, to allow the industry time to react and prepare for the change. Members were concerned that a value could otherwise be introduced with a very short lead time. One Workgroup member considered that a period of 24 months would be preferable, but most Workgroup members felt that 12 months would be sufficient if a lead time was to be mandated for any Authority-directed change to the VoLL value.

Members were keen to ensure that a process was put in place for any changes to the VoLL value, to ensure the industry has the opportunity to respond to the proposal before a final decision is made. The Ofgem Representatives noted that in reaching any such decision the Authority would be subject to the usual public law requirements in relation to procedural unfairness, including in relation to adequate consultation. However, it was noted that there were concerns around placing obligations on the Authority in this way. Members felt that submitting all proposals through the BSC Modifications process would be the most suitable route for ensuring they could be fully assessed and consulted upon.

Following the further discussions on this area detailed below, the Proposer elected to remove the ability for the Authority to direct a change to the prevailing VoLL value from the Proposed Modification and replace it with the VoLL review process discussed below, which the Authority could feed into. The Ofgem Representatives did not object to this.

Potential amendments to the original proposal

Members considered an alternative solution where the Authority could direct the Transmission Company to raise a Modification to progress a change to the VoLL value. This would allow the Authority to direct a change to the VoLL value and ensure industry engagement and consultation through the Modification process, which one member felt would also be more transparent than an Authority-led consultation. The Ofgem Representatives noted there was a risk that this proposal could require a change to the Transmission Company's licence, which could impact the timeline for P305.

One member suggested the option where the Authority could request that the Panel raise a Modification. As the BSC sits under the licence, this could be implemented simply through suitable wording in the BSC. The Ofgem Representatives raised concerns whether it could introduce a discrepancy between the licence and the BSC.

One member considered that the Authority could raise an SCR if it felt a new VoLL value needed to be explored, which already allows it to direct a Modification be raised. They considered that a change to the VoLL value would be a significant change that would require holistic consideration of the impact across the market, which is the intent of an SCR. The Ofgem Representatives noted involvement was only suggested in the VoLL value, and considered the SCR process may not always be appropriate for this purpose.

The Workgroup considered several other parameters under the BSC where the Authority is required to approve changes. However, none of these parameters allows for the Authority to direct a change, only to approve or reject a change following a BSC-led review. Workgroup members were concerned that allowing the VoLL value to be changed by Authority direction could create precedence for Authority-directed parameter changes, and were keen to avoid this. They agreed that the VoLL value would be an important parameter which would affect forward prices, and that safeguards were required around changes to this value. A thorough review would be required on any changes due to the impacts on the imbalance price.

The Proposer noted that the Authority direction to raise P305 specified that provision must be included to allow the Authority discretion to direct a change. A Workgroup member considered that the approval of a Modification would constitute a direction to the industry, and felt that allowing the Authority to direct a Modification to be raised would therefore be in keeping with the SCR direction. They were concerned that giving the Authority the power to direct changes to a Code would undermine the independence of the Codes. They noted that the BSC was set up as an inter-Party agreement and that the SCR, while Authority-led, is required to be progressed via a Modification to allow for industry assessment and engagement. Another member also had reservations with the Authority raising Modifications without prior discussion with the industry, as it would have the ability to raise and subsequently approve a change, noting that this was the reason why the SCR Modification provisions had been introduced into the BSC. Other Workgroup members did not believe that a BSC Party couldn't be relied upon to voluntarily raise a Modification should a change to the value of VoLL become evidently required.

Overall, Workgroup members noted the points raised by the Ofgem Representatives regarding these proposed alternative options for an Authority-led change to the VoLL value, and elected not to progress them any further.

VoLL review process

The Ofgem Representatives suggested an alternative option whereby a BSC Issue or similar could be raised upon request of the Authority to look at a revised VoLL value, which would take into account any evidence presented by the Authority. Consultation with the industry would take place as part of this, and the Issue Report would form the basis of a recommendation from the Panel to the Authority on whether a change should be made. Workgroup members considered this, and considered that this could resolve some of its concerns.

Members considered that a better approach would be to put in place a review process similar to that currently undertaken for the Market Index Definition Statement (MIDS). Under this approach, the Panel could initiate a review at any time, or upon the request of the Authority. The review would include consultation with the industry, and at the end of the review, if a recommendation to change the VoLL value was made then the Panel would have the power to raise a Modification to make the change. It would be expected, though not stipulated or mandated to avoid fettering the Panel's discretion, that such a Modification would progress straight to the Report Phase with a recommendation to approve. The lead time for any change would be determined under the review and reflected in the Modification. The high-level process and the key points would be contained under the BSC, with the detail either contained in a CSD (potentially a new BSC Procedure (BSCP)) or left for the Panel to determine. It would also be able to delegate this responsibility, most likely to the Imbalance Settlement Group (ISG) or a new group formed specifically for VoLL reviews. Again, this approach would not preclude any BSC Party from raising a Modification of its own at any time to propose its own revised VoLL value.

It was noted that the Authority would be able to request the Panel to initiate a review at any time. The Ofgem Representatives requested explicit reference that the Authority could ask the Panel to initiate a review should be included for clarity, amid concerns that the Panel may refuse such a request. Workgroup members were confident that this would not happen, and could not see why it would, but agreed that this clarity should be included. Members considered that if the Authority had a particular VoLL value in mind when a review was initiated it should feed that into the review, and should not reject the outcome of a review in favour of a different value. It was highlighted that the Authority could send a representative to attend and participate at any meeting held under the BSC.

Some members queried whether there should be a maximum interval between reviews, feeling this would provide more certainty to participants, and would make it more likely that resulting changes to the value would be small and would not surprise participants. It was proposed that a review should take place at least annually, to provide visibility to participants on when a change to the VoLL value may come, and highlighted that a review could recommend that no change be made. It would also help to flag to new participants the presence of the VoLL value. However, most members could not see the benefits in this, feeling that it was very unlikely the VoLL value would be one that would change little and often, that a process could be developed that gave industry clear sight on potential changes, and that any changes would likely be more significant in response to changes in the prevailing market conditions. A significant majority of Assessment Procedure Consultation respondents agreed that no maximum interval should be set, for the same reasons.

A member also proposed that a minimum lead time should be applied to any change arising from a review, and suggested this be set to six months, a view echoed by a couple of consultation respondents. However, it was felt more appropriate to allow the review to determine the most appropriate lead time, and that this could be a barrier should an urgent reduction in the VoLL value be identified as necessary. In any event, a participant could circumnavigate a fixed minimum lead time with their own Modification Proposal, which would not be subject to any minimum lead time.

Overall, the Workgroup agreed that the VoLL review process:

- would be initiated by the Panel from time to time or upon the request of the Authority, with no maximum period between reviews;
- would allow the Authority to contribute its views to the review;
- would include consultation with the industry; and
- would allow the Panel to raise a corresponding Modification if the review recommended a change be progressed, with no minimum lead time on any change.

The Proposer noted the Workgroup's support for the VoLL review process and therefore elected to adopt this process in place of the Authority's ability to direct a change to the VoLL value. The Ofgem Representatives were content with this amendment.

Should the VoLL value increase in line with inflation?

The Workgroup also considered whether the VoLL value should be automatically increased each year in line with inflation. A proposal was made that this could increase every April in line with the Consumer Price Index (CPI) value in the preceding January, giving participants three months to prepare. However, members noted that the values were an administrative value to act as a proxy to reality and so did not need to account for inflation. Several members also expressed views that the values put forward under P305 were high enough already, and felt further increases in line with inflation were unnecessary. It was highlighted that the DECC-Ofgem study on the Value of Lost Load for GB consumers suggested an average VoLL of £17,000/MWh, notably more than the ultimate value of £6,000/MWh proposed by P305. The Workgroup agreed that if the VoLL value was deemed inappropriate or no longer right at a later date then a Modification could be raised to review this and propose a revised value, and could be progressed as an Urgent Modification if it was felt necessary. One member was adverse to the step-change in the VoLL value that was being proposed, and preferred that it be indexed on a regular basis instead. However, other members believed that the proposed values were appropriate, noting that the initial value of £3,000/MWh would allow the industry to get used to the VoLL value.

It was queried whether the VoLL value could be seen as a cap on prices. The Ofgem Representatives confirmed this was not the intent, and a Workgroup member flagged that it could be exceeded by a high-priced BOA, noting that Bids and Offers can currently go as high as £99,999/MWh.

Which type of Demand Control events should fall under P305?

The Workgroup noted that Demand Disconnection and Voltage Reduction events had been put forward as events that should be accounted for by P305, but that the EBSCR had left automatic LFDD events open for it to consider. It was noted that an action had to be deemed an energy balancing action in order to affect the imbalance price, as system balancing actions would be unpriced as part of the calculation. Members considered that

LFDD actions should be considered a type of system balancing action, as they would be undertaken by the Transmission Company, potentially automatically, to maintain the frequency of the system within the statutory limits. They believed that participants should not be penalised for actions taken by the Transmission Company to meet its statutory obligations, and which participants cannot forecast.

The Workgroup considered the notifications that would be published for Demand Control events, noting that they would contain the start and end times of the event. It was agreed that these notifications should be updated whenever further instructions were made by the Transmission Company to distributors, and that the most practical volume to report would be the volume instructed by the Transmission Company. All notifications would be published on the BMRS.

The Transmission Company noted that it would seek to provide all Demand Control notifications within 15 minutes, but due to the manual nature of instructing Demand Control and that the control room would be more focused on managing the situation, this would be met on a 'reasonable endeavours' basis. The Workgroup was content with this approach. One member was concerned that if a notification came in too late it may not be included in the indicative imbalance prices published on the BMRS 15 minutes after a Settlement Period, and queried whether an ad-hoc revision could be made to the published prices in those circumstances. This was not agreed by the Workgroup.

Members queried the shape of a Demand Control event profile that would be calculated under the 'top-down' method, which would be based on these notifications. It was highlighted that this would be a high-level estimate based on the volumes requested by the Transmission Company, and not the volume actually delivered. Although in reality there would be a 'ramp-rate' where demand is removed or subsequently returned, it would be difficult to factor this in to the calculation, but as this would be a high-level estimate this would be unlikely to have a material effect. It was also considered that in most events the Transmission Company would end all instructions close to simultaneously, and that simultaneous termination could be assumed for the purpose of profiling the disconnected volume, although for some larger events it may seek to terminate instructions in a more staggered approach for safety reasons.

One member was concerned about the impact of 'negative demand' and whether this may have unintended consequences on the estimate of the volume. The DSO may disconnect a part of its network that contains exporting Meter Point Administration Numbers (MPANs), which may reduce the total volume that is disconnected. Another member noted that if a DSO had been asked to disconnect a certain volume then it would be expected to deliver that volume, and that it should have accounted for any potential exporting MPANs when deciding which areas to disconnect. The 'top-down' estimate would be based on instructed volume and not delivered volume, using the control room's estimate of the volume delivered from the volume instructed. The first member was still concerned that any impacts of 'negative demand' could result in an over-estimate of the volume being submitted into the imbalance price calculation. Another member felt that this was a question that could never be answered as it would never be known for sure what actually happened.

Members queried how directly connected sites and Interconnectors would be used in a Demand Control event. The Grid Code obligates directly connected sites to have disconnection capability, and that it would be for the Transmission Company to determine the cost of disconnecting that site, which would essentially be equivalent to an Offer. It was agreed these sites need to be identified and included in the imbalance position correction process proposed under P305. Interconnectors are deemed part of the

Transmission System, and rules are in place at a European Union level about when and how an SO can disconnect an Interconnector connected to their Total System. One member thought that should an Interconnector be exporting at a time of high LoLP then that would suggest prices were also high in the market on the other side of the Interconnector, as a consequence of market coupling. It was noted that the Transmission Company could issue a SO-SO instruction if necessary, although this would not be captured in the imbalance price calculation.

Can Voltage Reduction events be included in the 'bottom-up' calculation?

The Workgroup noted the Authority's request to it in the direction that it consider whether the 'bottom-up' volume correction process for Demand Disconnection events can also be applied to Voltage Reduction events. This had been discussed under the SCR's Technical Working Group (TWG), but this group had not been able to develop a solution, electing to leave it to the P305 Workgroup to consider.

One member queried how a Voltage Reduction event could be measured, or what would be being measured. For a Demand Disconnection event an MPAN's volume can be assumed to be zero during the affected period. This would not be the case for an MPAN subject to a Voltage Reduction event. Members could not put forward any viable options for estimating a volume for a Voltage Reduction event, feeling that input would be required from experts such as DSOs, who were not present on the P305 Workgroup. It was noted that Grid Code Modification GC0050 'Demand Control (OC6)' had looked at areas related to Voltage Reduction, and that any output from that group should be considered. However, it was also noted that results from a Voltage Reduction event could vary wildly for the same instructed volume.

The Workgroup agreed that, given the work that it believed would be required to develop a process to produce a 'bottom-up' estimate for Voltage Reduction events, and given the timescales for P305, the question should be considered separately, most likely under a BSC Issue. Any solution that was developed would then be progressed and implemented via a separate Modification. The process required for correcting volumes developed under P305 would work for Voltage Reduction events as well as Demand Disconnection events, so once a method for estimating the volumes had been produced, the rest of the process developed under P305 could be utilised with little subsequent amendment.

Workgroup members considered whether, if a volume for Voltage Reduction events could not be calculated, it should be included under P305. It was also questioned whether Demand Disconnection and Voltage Reduction events should be treated equally, as a majority of consumers will never notice if they are affected by a Voltage Reduction event but would notice a Demand Disconnection event. One member felt it may be wrong to develop and introduce a complex and likely expensive process for an event that has hardly any impact. Such issues can be considered as part of an Issue focussed specifically on Voltage Reduction. At this stage, P305 only enables the inclusion of Voltage Reduction estimates in the 'top-down' estimate for use in the imbalance price calculation, and until a process for producing Voltage Reduction estimates is implemented they are in effect not counted as part of the 'bottom-up' calculation to adjust participants' imbalance positions.

How should the 'bottom-up' calculation work?

The Workgroup has considered the detail of the 'bottom-up' calculation for correcting participants' imbalance positions following a Demand Control event.

One Workgroup member highlighted that this area has been considered in the past, most recently under P199 'Quantification of Demand Control in the BSC as instructed under OC.6 (c),(d) & (e) of the Grid Code', which was rejected by the Authority in 2006 as it was felt that the proposed process of allocating the correct volumes to the correct participants was not sufficiently accurate. The member was concerned that the same issue could occur with the calculation proposed under P305. They could see the case for a single marginal imbalance price and for the pricing of reserve actions, but were worried that the process for correcting imbalance volumes may cause the entirety of P305 to be rejected if it was not correct. It was believed that this would be less of an issue in a fully HH settled market, as the main issues are with the correction of NHH volumes, but it will be many years before such a market can be realised.

What is the impact on DSOs and Supplier Agents?

Although not impacted by the consequences of P305, DSOs and Supplier Agents would be involved in the 'bottom-up' calculation for the Demand Control volume. DSOs would be required to identify the impacted MPANs, after which Supplier Agents would calculate the impacted volume for each of their Suppliers to allow their imbalance positions to take account of the involuntary disconnection. This is a relatively small impact in the scale of both P305 and other, wider industry changes, and so no DSO or Supplier Agent representatives elected to join the P305 Workgroup. While they had not joined Ofgem's TWG under the SCR either, Ofgem had worked closely with them in developing the EBSCR proposals. The views and impacts on these participants have also been gained through responses to the P305 Impact Assessment and with conversations with these participants directly or through other forums such as the Software Technical Advisory Group (STAG).

A key area noted by these participants was the highly automated nature of the Data Aggregator roles. Data Aggregators disagreed with the Workgroup's proposal in the Impact Assessment that the lists of impacted MPANs should be sent from DSOs to Supplier Agents via a spreadsheet. They felt this could be too unstructured, and would not easily allow for automatic loading of the MPANs into the Data Aggregator systems. They preferred that this information was submitted via a DTC flow. This will now be the case.

As part of its discussions of the proposed solution, the Workgroup also considered the other flows by which Demand Control related information would be submitted. It was believed that it would generally be easier, and likely cheaper, to create new Demand Control specific DTC flows to be sent alongside the existing flows, rather than amend the existing flows to contain new fields and information. This would also make it easier to distinguish 'actual' volumes from those affected by the imbalance position correction processes.

How should voluntary actions be accounted for?

Members noted that it is possible for some MPANs in a Demand Control area to have already reduced their consumption in response to voluntary actions. These MPANs should therefore be identified as part of the imbalance position correction process to ensure they are not 'double-counted' by the process. If these actions were not accounted for, participants' adjusted positions may result in participants being paid too little or paying too much in imbalance charges. It was felt it may be better to under-estimate the involuntarily disconnected volume than over-estimate it.

In particular, members felt that voluntary reductions called through non-BM STOR Actions, DSBR and responses to CM warnings should be calculated and taken into account when adjusting participants' imbalance volumes. It should be noted that none of these voluntary reduction actions currently have processes for estimating the volumes and accounting for them in settlement, and so these would be new processes which would only be applied in Settlement Periods where Demand Disconnection is called upon.

Accounting for non-BM STOR and DSBR actions

In its Impact Assessment response, the Transmission Company noted that it would not be able to provide the MPANs impacted by a DSBR instruction until after the SF Settlement Run, as this is how long it would take for Supplier Agents to complete the necessary processes introduced under P299 'Allow National Grid access to Metering System Metered Consumption data to support the DSBR service'. Furthermore, it would not be able to provide the details of non-BM STOR instructions at anything more granular than at BM Unit level. This is because in both cases the Transmission Company would issue its instruction against a portfolio of MPANs, and the recipient of the instruction would determine which MPANs within the portfolio would be affected to discharge the instruction. The Workgroup was surprised at this, but noted that receiving the data at a BM Unit level would be sufficient for the imbalance position correction process.

The Transmission Company Representatives have since confirmed that it would be able to work with the providers of non-BM STOR and DSBR actions to identify the specific MPANs called upon, before applying an estimate of the instructed volume to these MPANs. Where the action is applied to a portfolio of MPANs, the aggregated volume would be split across the relevant MPANs. The relevant BSC Agents could then use data from the Electricity Central Online Enquiry Service (ECOES) database to map each MPAN to the relevant Supplier. However, the Transmission Company Representatives stressed that this process would need to be done on a 'reasonable endeavours' basis, as the Transmission Company could not commit to a five Working Day turnaround for this information.

Accounting for responses to CM warnings

The Workgroup noted that estimating the volume reduction achieved in response to a CM warning would be significantly more difficult, as there is no specific instructions to the relevant sites, but instead a general warning issued to the market to which each CM Party is expected to achieve as much reduction as it is able and willing to achieve. The only way to know what was achieved is through the subsequent Meter reading, which is not possible if that reading was zero as a result off an involuntary disconnection.

In any event, it was noted that any changes to the BSC to require the relevant EMR Body to provide information on MPANs that have reduced volume under the CM for use in this process would need to be progressed through the EMR change processes, which would ultimately require approval from the Secretary of State. If the relevant changes to the BSC were made under P305, then approval of P305 would be delayed while awaiting approval from the Secretary of State, and if the Secretary of State did not agree with the EMR changes then all of the P305 changes would be rejected as a result.

The Workgroup believes that accounting for MPANs that have responded to a CM warning is a material issue but not one that can be progressed or resolved under P305. Instead, this aspect of the solution will need to be raised and progressed separately through the EMR Change processes. Consequently, the requirement to identify MPANs that have responded to a CM warning has been removed from the P305 requirements.

How should NHH Suppliers' imbalance positions be adjusted?

The Workgroup considered several options for correcting NHH Suppliers' imbalance positions as part of the 'bottom-up' process, and you can find the details of these in the industry Impact Assessment available on the P305 page of our website. These options put forward several methods of different complexity, but also different levels of accuracy for the redistribution of the estimated disconnection volume across impacted Suppliers. However, all of the options considered were designed to remove the issues around applying Grid Supply Point (GSP) Group Correction Factors within the correction process. It was also noted that one option would remove the involvement of Supplier Agents from this part of the process, although this would likely be the least accurate of the methods.

Following conversations with Supplier Agents, the Workgroup has proposed a revised method for correcting NHH Suppliers' imbalance volumes following a Demand Control event. It believes that this method would be both cheaper to implement and operate and also more accurate than any of the three options it proposed in the Impact Assessment. The requirements for this process can be found in Attachment A (specifically Requirement D8).

How accurate does the process need to be?

Members discussed whether the more complex 'bottom-up' approach was required or whether the simpler 'top-down' approach could be adapted for use in its place. However, it was noted that the 'top-down' approach does not provide sufficient granularity to allow the total volume to be adequately distributed among impacted participants, and so this was disregarded as an option.

It was highlighted that the 'bottom-up' calculation needed to be as accurate as possible, noting that the concept of accuracy with this process was in relation to the accurate allocation of the estimated Demand Control volume between the impacted participants, as it was felt the true total volume could never be known for certain. Settlement Periods in which the 'bottom-up' calculation would be used would likely be Settlement Periods where the imbalance price would be set to the VoLL value, which would have a significant impact on participants. Assuming a VoLL value of £6,000/MWh, it would only require a Demand Control event of around 170MWh for the total materiality to exceed £1m, and events, should they occur, are likely to be several times that size. If any adversely impacted participant felt that the calculation for correcting its volumes were wrong or unfair, it could cause a lot of scrutiny to be turned on the process. The industry therefore needed faith in the process, and it was felt that it would be better to under-estimate the volume and leave Parties slightly longer then they should have been, than over-estimate and leave them slightly shorter than they should have been.

One member considered whether there was a risk of developing a complex and expensive process for an event that may rarely or never take place. It was noted that there have only been two Demand Control events in the last few years, but that the Secretary of State was forecasting as many as three per year in coming years, meaning that this process could be called upon relatively frequently. Having a sufficiently accurate process with sufficient assurance around it would also set expectations of what would happen following a Demand Control event, especially for participants who may find themselves short as a result of the event. Furthermore, the complexity of the process could act as an incentive not to trigger it in the first place. It was also noted that without a correction process there could be a risk of 'gaming' should participants seek to "bust the system" in order to "chase the imbalance price". In any event, the incentive on participants should be to avoid Demand Control events occurring at all.

Should participants' positions be corrected?

One member noted the complexity involved with correcting participants' positions, and wondered if it was even necessary with the move towards Time of Use tariffs. They considered that a Demand Control event could be seen by the European Union as a form of Offer made by the consumer, and that the volume should be calculated before then being treated as an Offer. They also considered a participant who may have made an expensive trade at the day-ahead stage in reaction to a high Indicative LoLP value before perfectly balancing their position, only for their consumers to be disconnected. The participant's resultant position would therefore be a long one, which would be adjusted back by the process. However, as their customer would not have consumed, the participant would be left with the cost of their expensive trade. They believed the participant's position should be left long and the subsequent windfall from their imbalance position treated as compensation.

Other members were not convinced by this argument, noting that each participant adopts different trading strategies. In this scenario, the only 'missing money' would be a few hours of consumption being removed from the customer's bill, which would likely be a very small volume. It was also flagged that without the correction, there was a risk that participants may "chase the imbalance price" in an attempt to profit, which would exacerbate the situation.

It was also noted that payments to Suppliers and consumers as compensation for involuntary disconnections had been proposed during the consultation for the EBSCR Draft Policy Decision. Following strong push-back on this proposal and the results of a cost-benefit analysis on this area that had suggested this would not be in the interest of consumers, it had been removed from the final EBSCR scope.

Should the 'bottom-up' volume be used in the price calculation?

The EBSCR Final Policy Decision put forward the solution that the 'top-down' estimate of the volume of instructed Demand Control actions would be used for the BMRS indicative imbalance prices published 15 minutes after the end of the Settlement Period and in the Interim Information Settlement Run (II). This would be based on the volume instructed by the Transmission Company. The 'bottom-up' estimate, calculated using actual data, would be used instead from the SF Settlement Run onwards. This was proposed as it was felt this would allow a more accurate volume to be included in the calculation when it became available.

Workgroup members noted that this approach is different to that taken for other types of instructions. In particular, it was noted that BOAs are inserted into the imbalance price calculation using the volume instructed by the Transmission Company. This volume is used throughout all Settlement Runs for calculating the imbalance prices, with no attempt made to calculate the volume that was actually delivered. Members believed it would be more consistent to apply this principle to Demand Control actions too and therefore to use the 'top-down' volume at all Settlement Runs. This would also prevent the volumes from changing significantly from one Settlement Run to the next, which could cause a significant change in the imbalance price for that Settlement Period, and would create uncertainty to what the imbalance price is prior to the SF Settlement Run.

The Proposer agreed with the Workgroup's views on this area, and adopted the Workgroup's proposal into its proposed solution, meaning that the 'top-down' volume would be used at all Settlement Runs.

Members queried how the Demand Control volumes would be entered into the stacks. Instructions would be issued to DSOs in stages, with each stage being aimed at particular GSP Groups. However, as the volume would be priced into the imbalance price calculation at the VoLL value, it was deemed easier to enter a single action per Settlement Period consisting of the total instructed volume applicable to that Settlement Period, rather than split it down by GSP Group or similar. It was noted that the details of all instructions would be published on the BMRS individually, and so it would not decrease transparency to aggregate the volumes in the imbalance price calculation.

One Workgroup member queried what would happen if a Demand Control impacted Settlement Period were to form a Triad period. It was felt that such a Settlement Period was unlikely to form a Triad period, and also that the intent of the correction process is only to correct imbalance positions, with the actual volumes delivered being used elsewhere.

Should other parameters be considered?

One member noted that the CADL is currently set to 15 minutes, meaning that any action that lasts for less than 15 minutes would be CADL-tagged and subsequently unpriced as part of the imbalance price calculation as it would be deemed a form of system balancing action. This would mean that if a Demand Control event occurred for less than 15 minutes then it would not affect the imbalance price.

The member also queried whether imbalance positions should be corrected in Settlement Periods where the Demand Control volume is subject to CADL-tagging. Other Workgroup members believed positions should still be corrected in this scenario as prices would still likely be high, and not correcting in CADL-tagged Settlement Periods may cause the situation where positions are corrected for some events and not for others, which could result in an uneven playing field.

Another member also noted that an expensive action taken by the Transmission Company on account of a fast ramp-up rate could have the potential to set the price if the duration lasted for more than 15 minutes. Furthermore, it is possible that the generation unit may have been instructed for 15 minutes, and so would be CADL-tagged, but overran slightly, meaning it would not be CADL-tagged. Should this action then straddle two Settlement Periods it could end up setting the imbalance price in both Settlement Periods when in reality it should have been tagged out of the calculation. However, it was unclear how this scenario could be resolved. Other members felt that an action of this nature would likely be deemed a system action and would be flagged accordingly.

What impacts could P305 have on credit?

Members were concerned on the impacts that P305 may have under the credit arrangements. It was noted that several other Modifications have been or are being progressed, notably P306 'Expanding the definition of a 'Letter of Credit' to include regulated insurance companies', P307 'Amendments to Credit Default arrangements' P308 'Alternative security product for securing credit under the BSC', and P310 'Revised Credit Cover for Exporting Supplier BM Units', which would amend the credit arrangements in different ways. However, Modifications cannot be contingent on each other, and so P305 cannot be made contingent on the outcomes of these other changes, but it was felt that P305 would have a direct impact on credit. Members therefore felt that the implications of P305 on participants' Credit Cover needed to be highlighted.

A concern was raised that corrected imbalance volumes arising from the 'bottom-up' calculation would not be available before the SF Settlement Run, which could cause participants' positions at the II Settlement Run to be too long. This could mask a participant's true position up until this point, giving it a false sense of security as its position would be underestimated.

Assessment Procedure Consultation respondents were near-unanimous in their agreement that P305 would result in an increase in the levels of Credit Cover lodged, although there was no clear view as to whether this increase would be small or significant in magnitude. It was considered that any potential decrease in the average imbalance price would be cancelled out by the increase in volatility and the potential for a significant spike in prices to occur. There was also concern from some respondents whether smaller Parties would be able to raise the necessary funds to cover any increase in Credit Cover.

EBSCR Credit Cover analysis

Baringa's forward modelling for Ofgem carried out under the EBSCR simulated Credit Cover impacts, available as part of the Final Policy Decision, in particular:

- Baringa's Further Analysis to Support Ofgem's updated Impact Assessment 2014 p53 & p65
- EBSCR Final Policy Decision Impact Assessment 2014 Chapter 4

What impacts may P305 have on liquidity?

The Workgroup noted numerous comments from Assessment Procedure Consultation respondents on the impacts P305 would have on liquidity.

Some respondents believed that P305 would increase liquidity in the market by encouraging participants to trade to balance their positions. The increase in capacity that P305 would create will also help to increase liquidity.

However, other respondents were concerned that P305 would reduce liquidity, and especially so during times of scarcity. They were concerned that as margin gets tighter liquidity tends to dry up, preventing participants from being able to trade out their position. Furthermore, by moving to a single price, there is a potential for liquidity to be moved to just before Gate Closure as providers of generation hold onto capacity until they are more certain that their own position will not be short. One respondent highlighted the period of scarcity around 2005-2008, when liquidity became a serious issue due to little trading taking place, and price spreads exceeded £1,000/MWh on occasions.

Furthermore, physical participants may have less incentive to trade against a single imbalance price compared to dual imbalance prices, and with a lack of spread between the prices one counterparty to a trade would lose out as they could have paid less or been paid more had they remained out of balance. The price of trades made by participants through a power exchange would not be reflected in the imbalance price either, due to the removal of the Reverse Price calculation under P305. Should any changes occur to the amount of supply or demand, prices have the potential to move to the expected imbalance price, increasing volatility and Bid-Offer spreads in the run-up to Gate Closure. Any

EBSCR liquidity analysis

Ofgem's EBSCR analysis considered the impact of the reforms on liquidity, and the outcomes can be found on pages 35-36 of the Final Policy Decision Impact Assessment.

reduction in trade may also result in the products that support independent Suppliers from not being made available, impacting their ability to trade.

The Workgroup noted these comments. Some members agreed with the views that liquidity would increase as a result of P305, noting that the changes would attract traders such as commodity speculators to trade in the market. One member considered that the major factor in determining liquidity is the number of participants who are trading, rather than the volumes, and that it's whether participants have the incentives to trade that is important. Another member agreed with this, but felt that P305 would have a negative impact on liquidity as it would reduce the incentives to trade, with a further member considering this would be the case especially in the intraday market.

One member also felt that under a single imbalance price, Non Physical Traders would have more incentive to trade as, should they correctly analyse the state of the system, they could then be more confident that the single price would reflect their analysis of the system and that any positions that have not been closed prior to Gate Closure would be cashed out accordingly. Under the existing dual prices, such open positions would be cashed out at the Reverse Price based on market trades, and therefore there is little incentive to trade. They considered that this change is likely to bring more Non Physical Traders into the market.

It was noted that the ability to trade has increased since 2006 with new opportunities offered through power exchanges, and that liquidity was seen to rise during winter months. However, it was highlighted that while this may be the case in the more benign conditions experienced in recent years, this has not been proven in a time of scarcity, and that while liquidity may be seen to rise in winter generally, the peak periods (such as Settlement Period 35) could still not be considered liquid.

How might P305 impact other areas and arrangements?

The Workgroup noted that it would be very difficult to assess the potential impacts on intermittent generators, as such impacts are quite difficult to assess through analysis. The Workgroup therefore sought to obtain information on this area from respondents to the Assessment Procedure Consultation. It also sought respondents' views on the interaction that P305 may have with the CM or with CfD. The full views of respondents on these areas can be found in Attachment D.

Impact on intermittent generators

Respondents to the consultation were in general agreement that P305 would impact intermittent generators under the agreements offered through Power Purchase Agreements (PPAs). It was noted that intermittent generators will generally have less control over their output than other types of generation (for example wind farms are dependent on how the wind blows), which leaves them more exposed to potential imbalance. This risk would generally be passed on to the provider of a PPA with that generation site, which may necessitate the relevant contract being renegotiated in response to P305 to account for this.

P305 could also impact on the price offered under a PPA may be lowered to account for the potentially higher imbalance costs and the Credit Cover necessary in response to this. This could also potentially increase the discounts applied to prices offered under a PPA due to the relative inability to respond to price signals. However, one respondent felt that this

EBSCR consideration on additional areas

Ofgem's analysis under the EBSCR sought to look at these additional areas, and these can be found in the Final Policy Decision. In particular:

- Baringa's EBSCR Further Analysis to Support Ofgem's Updated Impact Assessment p51-53 & p65-67 outlines the simulated forward-looking impacts on intermittent generators (among others)
- EBSCR Final Policy Decision 2014 p38 and Ofgem's Final Policy Decision Impact Assessment p17-19 looks at the interaction with the CM

is the nature of the market, and that changes like this could present opportunities as well as risks.

In addition, there could be an interaction with negative pricing and the terms of any CfD, with P305 potentially increasing the number of Settlement Periods with negative prices. This could reduce the amount of time that an intermittent generator can export, which they may not be able to compensate for at other times due to their intermittent nature.

However, while respondents felt that intermittent generation would be affected by P305, they were uncertain of the full impacts and unable to quantify the effects, although a Workgroup member highlighted that opportunity costs for independent wind generators had been assessed under the EBSCR. Some Parties felt that this could lead to a more cautious approach being taken with the terms of PPAs.

Impact on the CM

It was considered that the CM and the EBSCR complement each other in that each is seeking to address concerns around 'missing money' in relation to the ways in which a capacity provider can recover costs. Furthermore, some respondents noted that both policies are seeking to increase the UK's generation capacity, and could offer more favourable conditions for flexible generation and Demand Side Response (DSR). It was also felt that should P305 encourage more capacity to be made available this could reduce auction prices under the CM. However, other respondents were concerned that these still may not be enough to encourage more investment in capacity.

One respondent believed there was an interaction between the LoLP and the CM. They considered that under a CM it would be expected that all generation plant would be available at the peak times of the day, or risk facing penalties for non-delivery. This could have an impact on the calculation of a LoLP value, and this potential interaction should be considered in any LoLP calculation.

There were concerns that the VoLL value has an interaction with CM penalties. Should the imbalance price have the potential to rise to the VoLL value in times of scarcity, one respondent felt this could risk creating a "race to the top" where prices rise in response to scarcity. In the event a CM warning was issued, there is a potential for prices to quickly rise to the VoLL value, which could be difficult to justify if customers do not notice the effect of a Voltage Reduction event.

It was noted that under the CM participants are obliged to self-dispatch in response to a CM warning. If those participants were unable to trade out their subsequent imbalance this could leave them long and exposed to the imbalance price. This could create a two-tier system whereby Parties who participate in the CM are able to submit lower prices into the market as a result of the payments they receive under the CM. However, it was considered that, while participants may be long, they would not be encouraged to over-generate as this may result in a long system and a payment for any spill at a marginal imbalance price.

One respondent highlighted that the CM had been given a clear indication by Ofgem that it should anticipate P305 being fully implemented by 2018. It had therefore advised bidders under the recent auction to anticipate the full implementation of P305 in 2018. The respondent felt that P305 needs to be implemented in a timely manner so as not to impact the CM auction results and the tender process, otherwise the 2015 auction may result in higher prices, increasing costs to the end consumer.

Impact on CfD

One respondent felt that P305 would result in the reassessment of balancing risks to be reflected in the strike price offered under a Feed-in Tariff (FiT) or CfD. In this scenario, a portfolio generator may be better placed to manage these risks than a single-site generator, and so single-site generators may begin to lose out to portfolio generators as a result of needing to seek a higher strike price. This may result in the costs under a CfD from rising. It could also result in participants submitting bids that are too low into an auction, and then suffer "winner's curse" if their bid is subsequently accepted.

One respondent noted that closer to real time the output of an intermittent generator becomes more accurate, which fits in to the timescales for calculating the Final LoLP value and the associated RSP. However, it is very difficult to isolate the overall impacts due to so many policies driving prices both up and down, although a fixed strike price provides a generator some certainty while still retaining an incentive to balance.

What analysis has been undertaken?

Ofgem's SCR analysis

The Ofgem Representatives urged the Workgroup and other participants to read and digest the analysis that had been undertaken by Ofgem under the EBSCR. They also presented an overview of the approach taken in developing the evidence base over the last four years, and the issue and rationale for reform, as well as responding to specific Workgroup queries. The presentation highlighted that the evidence base had been driven by qualitative analysis of proposals, stress-tested by extensive quantitative analysis (including forward modelling, historic modelling and a commissioned study) and subjected to further stress-testing through consultation with stakeholders.

EBSCR analysis

The full suite of analysis undertaken by Ofgem under the EBSCR can be found as part of the EBSCR Final Policy Decision.

One member was concerned that the analysis had not gone far enough in determining the distributional effects that the EBSCR would have, highlighting the significant effects that had been revealed under P304. However, it should be noted that the P304 analysis was based on analysis of historical data whereas the SCR analysis included both forward-looking modelling that aimed to take into account behavioural changes (the impetus for reform) as well as historical analysis.

The Ofgem Representatives noted that economic theory is the key driver for the reforms, to ensure that the incentives for Parties to manage their imbalance positions aligned with the consumer interest, and the analysis and modelling draws upon this theory. One finding had been that bigger Parties are more exposed to the risk of driving a large net imbalance volume, and so according to their imbalance performance could be more impacted by the reforms and see less benefit from a single price. Conversely, smaller Parties are less likely to drive the net imbalance volume, more likely to enjoy the more favourable single price on opposite imbalances, and on average are less impacted. Furthermore, Parties who are better able to forecast positions will benefit more. The Ofgem Representatives noted that the SCR process had been evidence-based, and had been developed and consulted upon over a number of years, providing qualitative narrative informed by the findings of the quantitative analysis that could fulfil the Workgroup's Terms of Reference. They felt that the question of whether the SCR forward modelling should be revised or expanded was a balance between the benefits of seeing the results versus the cost of extending the analysis and the time this would take. They noted that to form a view against the Applicable BSC Objectives it is not necessary to understand the precise financial implications for every BSC Party, as well as noting the risk that modelling at individual Party level presents spurious accuracy. It was noted that re-running the model to show impacts at individual Party level would cost around £50k-£75k and take around two to three months to complete. The Ofgem Representatives felt overall the costs of re-running the model would outweigh the value it would provide, and the Workgroup agreed that no further work should be undertaken with Ofgem's forward modelling analysis.

The member felt they needed to understand the economic theory more, but stressed that the Workgroup needed to be satisfied that any unintended consequences arising from it would not be of a magnitude to cause significant harm to competition, and felt that the impacts only become clear when they are broken down over sufficiently granular subsets of participants. Another member noted that historical analysis is the only factual form of analysis available, and that anything else is based on assumptions. The Ofgem Representatives responded that if the EBSCR conclusions had been implemented several years ago, the behaviour of participants today would be very different to what it currently is, meaning that historical analysis is built on an assumption that Parties do not change behaviours in response to changed incentives. It was also noted that Ofgem's historical analysis had suggested that, on average, the SBP would be about £10/MWh higher under the EBSCR arrangements than the current arrangements.

A member was concerned to understand the impact on a Party-by-Party basis, noting that some participants would be new, with little historical data available, or may have chosen to trade through another Party, and that these would be hard to model. Another member highlighted that, while many people were focused on the potentially detrimental impacts that smaller Suppliers may face, independent generators are just as much at risk should they suffer an unplanned outage at the wrong time. The Ofgem Representatives noted it was not the Workgroup's role to assess the impacts on every individual Party but to draw out the overall efficiency and competition impacts, noting behaviour change as the key impetus for reform, highlighting the importance of forecasting demand, maintaining plant, striking contracts for DSR or other flexibility capacity providers, adjusting hedging strategies and developing strategies to deal with wind forecast error correlation. They urged the Workgroup to read the EBSCR reports and analysis in detail as it goes into more detail on these themes.

A member queried the finding from the historical analysis and forward modelling that larger Parties drive the price and so smaller Parties would be less impacted. They asked to see a correlation on prices and the volumes in participants' Consumption Energy Accounts, which may challenge that assertion.

Members noted that participants would always want to know the impact of any change on their own organisation. It was also flagged that if the analysis is not done at a Party level then there could be an odd Party adversely impacted due to a very specific but perfectly valid trading or business model, and that the electricity market is one where smaller players can be quite niche. Furthermore, while the changes may make sense economically there will still be winners and losers. If this change was going to jeopardise participants, they would want as much notice of this as possible to prepare. However, it was noted that all the benefits of the EBSCR would be realised through behavioural change, and that if participants did not change their behaviour then they would likely lose out. The Ofgem Representatives also queried how the identification of impact at Party level supported an efficient process.

One member noted that the forward modelling undertaken by Ofgem had assumed rational behaviour by participants, but felt that this may not be the case in reality. They queried whether a sense-check had been undertaken by Ofgem, for example speaking to smaller participants on what they could do in a given situation compared to what they would ideally like to have done. In many situations, it may be that the options available to the participant are not the options it would ideally like to take, such as in response to a signal of high prices occurring very close to real time with little time in which to react. This situation can be exacerbated if the participant cannot access credit or be able to adequately trade its position, and the member felt that imbalance prices can be penal to these participants if the relevant tools are not available to them. The Ofgem Representatives noted that it is hard to model irrationality, but that the assumption of no behaviour change is not particularly helpful for shedding light on a policy with behaviour change as its key motivation. They also noted the combination of forward analysis (assuming rationality) and historical analysis (assuming no rational change in behaviour) helps to inform the range of potential effects. More generally, the Ofgem Representatives noted that their policy had been developed over a number of years in consultation with a broad range of Parties. This has allowed views of a variety of Parties to be represented in consultation responses and considered in development of policy.

The Workgroup considered the conclusions that prices would be much higher in the future, noting that this was largely due to the forecasted increase in intermittent generation. It was asked how high imbalance prices would have to go to sufficiently incentivise participants to invest in new technology. The Ofgem Representatives highlighted that investment effects had been very difficult to assess, and as a result the modelling had not captured all the dynamic efficiency benefits of driving a more efficient flexible generation mix. They noted however that allowing prices to better reflect the cost to the consumer of the SO’s balancing actions is key in supporting efficient investment and dispatch in flexible capacity. It was also noted by a member that data relating to carbon prices that Ofgem had used in its model had since been updated, and felt the model should be redone with this updated information. The Ofgem Representatives felt this would not support an efficient process, noting that it would be unlikely to affect the relative differences between the EBSCR and do-nothing scenarios, and that the information could change again while this was taking place. Another member noted that the key consideration was the relative difference in prices should the EBSCR conclusions be implemented compared to no change, and flagged that the model was showing that, for most participants, the costs would be lower under the former, indicating that the EBSCR conclusions would be better than doing nothing. It was also felt that, while it may not be possible to see what new innovations could be developed over the next decade at this point in time, this did not mean things would not be developed going forward. One member felt that there would always be something participants could do to avoid being in imbalance.

Members highlighted that liquidity in the electricity market is not as high as was originally envisioned when the current arrangements were introduced in 2001. There was a concern that a single price may have a negative impact on liquidity, especially in the intra-day market. Other members noted the intra-day market had not been identified as a source of concern, and that the Secure & Promote requirements drive liquidity further along the curve. The Ofgem Representatives noted that liquidity effects had been discussed in consultation and analysed over the years of EBSCR analysis, and that the TWG had discussed liquidity but had been unable to determine how this could be meaningfully modelled.

One member asked what measures had been considered if, following implementation of P305, many participants were forced to exit the market due to a significant spike in imbalance prices. Another member felt that such an event would likely cause a domino effect, as the counterparties to any exiting Party would themselves be impacted. The main concern is whether large prices can be predicted and whether Parties would be able to avoid them, and it was noted that there has been relatively little stress on the Total System over the last few years and so it is hard to foresee what may happen if such a time was experienced. The Ofgem Representatives considered that the phased approach of implementing the full EBSCR solution would help mitigate such an effect, and felt that this change had been signposted for a sufficiently long enough period of time for participants to make preparations.

ELEXON's analysis for the Workgroup

A Workgroup member noted that while Ofgem had done a significant amount of analysis under the EBSCR, the Workgroup had been charged with doing further analysis as it saw fit to assess the impacts of P305. This could include endorsing Ofgem's analysis, but did not preclude the Workgroup from doing its own. The Ofgem Representatives did not disagree with this, but emphasised that any analysis undertaken should be done on a pragmatic basis, in particular to inform assessment against the Applicable BSC Objectives.

Some Workgroup members were keen to undertake historical analysis of recent years with the P305 arrangements in place. Other members were unsure what this would show, noting that participants' behaviour would have been different in a single price regime and so whatever such analysis produced would be wrong. The Ofgem Representatives were also unsure of the merits of performing additional historical analysis, particularly given that the intent of the EBSCR is to drive behavioural changes. However, participants in favour suggested that this would show the worst-case scenario should participants not change their behaviour in response to P305. It would also allow distributional effects to be assessed, and could be used to assess the most suitable PAR value(s) to adopt. It was also felt that the data should be made available to all participants, so that they can assess the impacts on their own organisations for themselves. There was also a view that should ELEXON's analysis support Ofgem's conclusions then this may provide more comfort to participants, while if it does not then this would suggest areas that need to be considered further.

The results of ELEXON's analysis, including a high-level summary of the results, can be found in Attachment A, and the raw participant-level data is available to download from the ELEXON Portal. Although ELEXON's analysis had looked at historic scenarios and made no attempt to model behavioural changes, while Ofgem's analysis was more focused on forward-looking scenarios and did attempt to model behavioural changes, it could be concluded that the outcomes of the two independent pieces of work were broadly consistent.

One Workgroup member asked whether the analysis could show anything around market power, and whether there was the potential for one Party to consistently set the imbalance price or if there would be a sufficient depth of potential Parties. If a Party was the one consistently setting the imbalance price then there is the risk that they could increase the prices attached to their Bids and Offers to increase the resulting imbalance price.

For this, it was considered how many Bids or Offers tend to form the price under different PAR values. The Ofgem Representatives noted this had been considered under the EBSCR, and that for a PAR value of 1MWh an average of three to four actions would set the price, rising to six for a PAR value of 50MWh. This is compared to around 15 under the current PAR value of 500MWh. Even under a 1MWh PAR value, it is possible that actions from several different Parties could contribute to setting the imbalance price. ELEXON's assessment of these values largely agreed with Ofgem's results, although it was noted that it is more often than not only a single Party whose actions were setting the price under a 1MWh PAR scenario, rising to two with a PAR of 50MWh, compared to an average of four under the current arrangements. Therefore, it is generally the case that a single Party

ELEXON's historical analysis

The results of ELEXON's historical analysis can be found in Attachment A.

The raw Party-level data produced by the historical analysis is available to download from the ELEXON Portal (a free login account is required to view this page).

would be setting the price only when the PAR value is at or close to 1MWh, with one member noting that someone has to set a marginal price. Furthermore, in order to set the price, a specific Bid or Offer would have to remain after NIV-tagging had been completed.

One member felt that in order to understand this area further, a much more in-depth piece of work would need to be undertaken, which would be outside the scope of P305, but they could not see how moving to a marginal price would create an issue with respect to market power. The pricing calculations are sufficiently transparent, with full details on each Settlement Period's Bid-Offer stacks available from the BMRS. It was also considered that there is the potential under the current arrangements for only a couple of participants to have actions remaining in the stack following NIV-tagging, as well as the risk that a 'sleeper' Bid or Offer (where the Party sets an extreme price for a Bid or Offer to mitigate the chance of it being accepted) is forced to be accepted by the Transmission Company and feeds into the imbalance price.

If there was a concern in this area then the recommendation should be to monitor this situation, noting that participants are obliged under the REMIT regulation to declare anything that could be considered inside information. However, the Workgroup felt that market power as a result of a marginal price would not be an issue under P305.

A few members of the Workgroup were keen to understand the distributional impact that P305 would have on different types of participant, noting that this analysis had been carried out under P304 and which they had found very useful in assessing that Modification. They were concerned that the distributional impacts between different types of Suppliers may be significant, and that this could create competitive distortions between different types of participant, and could have adverse impacts on particular types of Parties. These members were also keen to see the effects that times of scarcity would have on the distributional effect, noting the concerns highlighted previously on the impact this may have on liquidity, and felt that further analysis still needed to be completed before a full view on the effects of P305 could be assessed.

Other members highlighted that the EBSCR analysis coupled with the raw data from this historical analysis provided a wealth of data for members to draw upon, which would be sufficient for members to assess the distributional impacts for themselves. The results of analysis on the distributional effects was not available in time for the Workgroup to consider before giving its final views on P305, but is now available in Attachment A. The raw data available on the ELEXON Portal also includes the groups that each Party was classified under for the distributional effects analysis, allowing participants to assess this area for themselves.

How have the EBSCR reforms been progressed?

Several respondents to the Assessment Procedure Consultation are in support of the proposed reforms put forward under the EBSCR to be implemented as soon as possible, to enable the benefits to be realised. However, other respondents have expressed concerns with the time that had been allowed to develop and assess the P305 solution.

Several DSOs and Supplier Agent organisations have stated that not enough time has been allowed to fully understand the detailed solution requirements and the impacts that P305 will have on them, and neither has enough time been allowed for them to implement the changes, especially given the significant amount of other changes affecting these types of participant being progressed at this time (see Section 5).

Other respondents also felt that not enough time had been allowed to assess in detail the impacts that P305 would have on participants, feeling that the analysis carried out under P305 to be incomplete. Concerns were also noted around the time allowed to develop the more complex parts of the solution, with several respondents believing that the RSP and Demand Control parts of the solution are not fully developed or assessed, and are not sufficiently robust enough to implement. One respondent had felt that P305 has been rushed in order to adhere to the EBSCR timetable, with this timetable set before it became apparent how much work needed to be carried out.

A couple of respondents expressed a preference that P305 should have been progressed as multiple Modifications, to have enabled these other areas to be more fully developed and assessed in their own right, rather than as part of a much larger package. There is also feeling among respondents that the single marginal price elements should be progressed now through P316, with the more complex RSP and Demand Control elements delayed to allow further assessment and development, perhaps through two new and separate Modification Proposals.

The Workgroup has noted these concerns, with a few Workgroup members expressing similar concerns that areas of the solution and the wider impacts of the Modification have not been fully assessed. The LoLP calculation methodology in particular was only considered at a high level under the EBSCR, with the detail of the calculation left to the Transmission Company and the Workgroup to develop and assess under P305 within an agreed framework. Members have noted that this has been a challenging area in its own right to develop over the course of P305's progression, but has not been the only such area that the Workgroup has needed to develop, with the VoLL and Demand Control areas also needing detailed consideration, along with assessing the impacts of the Modification as a whole on participants. However, other members felt that sufficient time had been allowed under P305 and that a considerable amount of additional analysis had been produced during this time. Members also noted the views from the Ofgem Representatives during the progression of P305 that the changes and the targeted implementation approach have been signposted for a sufficiently long enough period for participants to make preparations.

Workgroup's recommendation to the Panel

The Workgroup has concluded that:

- the Proposed Modification **does not** better facilitate the Applicable BSC Objectives than the current Baseline and so should be **rejected**;
- the Alternative Modification **does** better facilitate the Applicable BSC Objectives than the Proposed Modification and so should be put forward; and
- the Alternative Modification **does** better facilitate the Applicable BSC Objectives than the current Baseline and so should be **approved**.

Therefore, the Workgroup recommends to the Panel that **the P305 Alternative Modification should be approved and the P305 Proposed Modification should be rejected**.

Workgroup's Voting *(15 members were eligible to vote, including the Proposer)*	
Does the Proposed Modification better facilitate the Applicable BSC Objectives than the current Baseline?	
Votes for Proposed Modification	5
Votes for current Baseline	**10**
Does the Alternative Modification better facilitate the Applicable BSC Objectives than the Proposed Modification?	
Votes for Alternative Modification	**10**
Votes for Proposed Modification	5
Does the Alternative Modification better facilitate the Applicable BSC Objectives than the current Baseline?	
Votes for Alternative Modification	**9**
Votes for current Baseline	6

The views given by the Proposer, Workgroup members and Assessment Procedure Consultation respondents against the Applicable BSC Objectives are detailed below.

Proposer's views against the Applicable BSC Objectives

Applicable BSC Objective (b)

The Proposer believes that the changes to the main imbalance price calculation strengthen the incentive on Parties to make efficient balancing decisions, particularly during times of tight margin. This should reduce the cost of achieving balance as borne by the market and the actions taken by the Transmission Company, and support security of supply. This effect may be reinforced as improvements in cost reflectivity further encourage investment decisions and innovations that drive long run cost savings in delivery of any given level of security of supply.

What are the Applicable BSC Objectives?

(a) The efficient discharge by the Transmission Company of the obligations imposed upon it by the Transmission Licence

(b) The efficient, economic and co-ordinated operation of the National Electricity Transmission System

(c) Promoting effective competition in the generation and supply of electricity and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity

(d) Promoting efficiency in the implementation of the balancing and settlement arrangements

(e) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency [for the Co-operation of Energy Regulators]

(f) Implementing and administrating the arrangements for the operation of contracts for difference and arrangements that facilitate the operation of a capacity market pursuant to EMR legislation

This Modification will also signal the start of reforms designed to better reflect the value of flexible plant in the balancing arrangements. It may therefore contribute to deferring the decommissioning of generation with more flexible capacity and help counteract potential tightening of availability.

The Proposer considers that the phased nature of implementation should allow time for the industry to adjust to the EBSCR reforms and to change behaviours accordingly.

Applicable BSC Objective (c)

The Proposer considers that current inefficiencies could limit the potential for some Parties, in particular those offering services that facilitate flexibility and balance (such as DSR or storage) to participate in the wholesale electricity market. These reforms are intended to address these inefficiencies and thereby support effective competition (that delivers in the interest of the consumer) by:

- allowing flexible and reliable plant to gain a competitive advantage that reflects the value provided to the consumer; and
- improving the incentives for these Parties to enter the market, driving the flexibility and reliability needed to accommodate growing intermittency on the system

The inclusion of a single imbalance price removes the existing inefficient price spread and thereby reduces the net imbalance costs for many Parties, particularly smaller Parties, which would therefore encourage market participation.

The Proposer also believes that strengthening the imbalance price signal as proposed by P305 should incentivise market participants to trade in order to balance their positions ahead of Gate Closure. This should increase liquidity in the forward market and benefit competition by encouraging investment in flexible capacity.

Workgroup members' views against the Applicable BSC Objectives

Applicable BSC Objective (b)

A majority of Workgroup members felt that the Proposed Modification would be detrimental against Applicable BSC Objective (b). They believed that the proposed changes risked sending out the wrong signals to participants, with the LoLP signal potentially sending out false signals to participants and risked participants self-balancing after Gate Closure to mitigate the impact of a high Final LoLP. More volatile prices may also potentially result in participants taking a longer position to avoid the risk of being short when the price was high. These actions would make the Transmission Company's ability to co-ordinate the system more difficult.

It was also considered that the reduction in the PAR value to 50MWh and then to 1MWh increased the likelihood of amplifying existing distortions in the calculation of the imbalance price. In particular, high-priced Offers accepted in one Settlement Period could go on to set the price in later Settlement Periods when the Transmission Company couldn't end that Offer sooner due to the nature of the plant called upon despite the action no longer being needed.

A minority of members believe that the Proposed Modification would be beneficial against Applicable BSC Objective (b). Those in support generally agree with the reasons given by the Proposer above. It was also considered that P305 could increase liquidity, which would better enable participants to balance their positions ahead of Gate Closure.

However, around half of the members who felt that the Proposed Modification would be detrimental against Applicable BSC Objective (b) felt that the Alternative Modification, and in particular the higher PAR value, resolved enough of their concerns that it could instead be beneficial compared to the current Baseline. All other members' views remain unchanged. This means that a majority of Workgroup members believe the Alternative Modification would be beneficial against Applicable BSC Objective (b).

Applicable BSC Objective (c)

A majority of Workgroup members felt that the Proposed Modification would be detrimental against Applicable BSC Objective (c). In particular, members were concerned as to how the volatility in imbalance prices may affect participants, and that the potential distributional effect could harm some participants' ability to participate in the market. They noted that this information hadn't been available when they were giving their views on P305, and felt that the uncertainty would count against the case to change.

It was believed that a move to a PAR value of 50MWh, or even 100MWh, was too large a single step to take, and that a more cautious approach should be taken. This would allow time to assess the impacts of reducing the PAR value, and would allow changes to be halted if it was having too detrimental an effect.

There was also concern that the changes proposed by P305 could have a detrimental impact on liquidity in the market, which would make it harder for smaller participants to trade. In particular, a single price may result in some of the larger vertically integrated participants not trading in the market, reducing the ability for smaller participants to trade.

However, a minority of members felt that P305 would be beneficial against Applicable BSC Objective (c). Many members agreed with the reasons put forward by the Proposer above. In addition, it was felt that a single price would be beneficial to competition as it would bring more Non Physical Traders, such as commodity speculators, into the market, and that more participants is key to greater liquidity. Furthermore, there was concern that the current arrangements were dampening signals of scarcity, and that sharpening imbalance prices would send out stronger signals.

Again, around half of the members who felt that the Proposed Modification would be detrimental against Applicable BSC Objective (c) felt that the Alternative Modification resolved enough of their concerns that it could instead be beneficial compared to the current Baseline. All other members' views remain unchanged. This means that a majority of Workgroup members believe the Alternative Modification would be beneficial against Applicable BSC Objective (c).

Applicable BSC Objective (d)

A few Workgroup members felt that both solutions would be detrimental against Applicable BSC Objective (d). They believe that the new processes being introduced under P305 were complex and would be costly for ELEXON and the Transmission Company to implement and administer, but would offer little if any benefit to the arrangements.

However, the majority of the Workgroup felt that P305 had no impact on Applicable BSC Objective (d). One member agreed that the processes proposed by P305 seemed complex, but believed that this very complexity would act as an incentive for participants to never invoke them.

Summary of Workgroup members' views

Summary of Workgroup Members' Views[6]		
Obj	Proposed Modification	Alternative Modification
(a)	**Neutral** *(unanimous)*	**Neutral** *(unanimous)*
(b)	**Beneficial** *(minority)* • Strengthens incentive to balance efficiently, particularly in times of tight margin • Improvements in cost-reflectivity will encourage investment, driving long run cost savings • Better reflects the value of flexible generation, which may help defer the decommissioning of such plant • Potential increase in liquidity which will help participants balance ahead of Gate Closure **Detrimental** *(majority)* • LoLP values could send out false signals and could encourage balancing after Gate Closure if high • Volatile prices may cause participants to take longer positions to avoid the consequences of being short • More marginal prices increases the risk of balancing actions incorrectly impacting the imbalance price in subsequent Settlement Periods	**Beneficial** *(majority)* • Strengthens incentive to balance efficiently, particularly in times of tight margin • Improvements in cost-reflectivity will encourage investment, driving long run cost savings • Better reflects the value of flexible generation, which may help defer the decommissioning of such plant • Potential increase in liquidity which will help participants balance ahead of Gate Closure • A PAR value of 100MWh mitigates the risk of amplifying distortions that feed into the imbalance prices compared to the Proposed Modification • The movement toward more marginal prices is of a degree that mitigates the risk of volatility and participants taking longer positions compared to the Proposed Modification **Detrimental** *(minority)* • LoLP values could send out false signals and could encourage balancing after Gate Closure if high • Volatile prices may cause participants to take longer positions to avoid the consequences of being short
(c)	**Beneficial** *(minority)* • Allows flexible and reliable plant to gain advantage that reflect their value to consumers • Improves incentives for flexible and	**Beneficial** *(majority)* • Allows flexible and reliable plant to gain advantage that reflect their value to consumers • Improves incentives for flexible and

[6] Shows the different views expressed by Workgroup members – not all members necessarily agree with all of these views.

Summary of Workgroup Members' Views[6]		
Obj	Proposed Modification	Alternative Modification
	reliable plant to enter the market • Single price removes the inefficient price spread and the net imbalance costs that creates • Incentivises participants to balance positions, increasing liquidity and encouraging investment in flexible capacity • Sharpens the signals of scarcity to the market **Detrimental** *(majority)* • Volatile prices will have a detrimental effect on smaller participants • The distributional effects of P305 are unknown • The reduction in PAR to 50MWh is too large a step and the impacts this will have are unknown • Single price may result in less trading, reducing liquidity	reliable plant to enter the market • Single price removes the inefficient price spread and the net imbalance costs that creates • Incentivises participants to balance positions, increasing liquidity and encouraging investment in flexible capacity • Sharpens the signals of scarcity to the market • The movement toward more marginal price with no further step change is of an appropriate degree to deliver benefit for participants compared to the Proposed Modification **Detrimental** *(minority)* • Volatile prices will have a detrimental effect on smaller participants • The distributional effects of P305 are unknown • The reduction in PAR to 100MWh is still too large a step and the impacts this will have are unknown • Single price may result in less trading, reducing liquidity
(d)	**Detrimental** *(minority)* • Introduces complex processes with little proven benefit **Neutral** *(majority)*	**Detrimental** *(minority)* • Introduces complex processes with little proven benefit **Neutral** *(majority)*
(e)	**Neutral** *(unanimous)*	**Neutral** *(unanimous)*
(f)	**Neutral** *(unanimous)*	**Neutral** *(unanimous)*

Participants' views against the Applicable BSC Objectives

Views of respondents to the Assessment Procedure Consultation were mixed, with a slight majority believing P305 would not better facilitate the Applicable BSC Objectives overall. Like the Workgroup, respondents felt that the relevant Applicable BSC Objectives were (b), (c) and (d), and that there was no impact on the others.

It should be noted that respondents were consulted on only the Proposed Modification as it currently stands with the exception that the 'dynamic' LoLP function would be used from the P305 Implementation Date. No Alternative Modification had been formally put forward at that point. A high-level summary of the key points received can be found here, and the full responses can be found in Attachment D.

Respondents felt that P305 would better reflect the value to consumers of security of supply and balancing in the imbalance prices, which would provide a more efficient signal for balancing and for flexibility. This may encourage more efficient behavioural change and increase the incentives to invest in and provide flexible capacity, better facilitating Applicable BSC Objective (b). However, other respondents were not convinced that P305 would drive efficiency, and that other reforms such as the CM would be more effective.

There was also concern that sharper or more unpredictable prices may encourage participants to take a longer position to avoid the consequences of being short. It was also noted that benefits only arise if participants are able to respond to signals, but it was felt that the LoLP values and RSP could be a misleading signal while the price signal is not seen until after a Settlement Period is complete. Furthermore, participants may elect to hold capacity for themselves until close to Gate Closure, to ensure their own position was secure, before trading the spare capacity close to Gate Closure, which could reduce liquidity. These could all result in P305 being detrimental to Applicable BSC Objective (b).

Some respondents believed that P305 would benefit competition and therefore Applicable BSC Objective (c). P305 would reward those who are able to balance or provide flexibility or other balancing services. It would also align the competitive incentives on participants with consumer interests, and could alter the incentives on participants to enter the market. Furthermore, the introduction of a single price and the removal of the price spread between the SBP and SSP would reduce net imbalance costs for participants, with one respondent believing this was the most needed part of P305, although another respondent felt the benefit of this would diminish as the PAR value got smaller. Nevertheless, this could mitigate the risks of other areas of P305 on smaller participants, particularly independent participants.

However, others felt that P305 would be detrimental to Applicable BSC Objective (c). In contrast to reasons given in support, these respondents felt that P305 would result in higher and less predictable imbalance prices, and the increased complexity being added into the arrangements would make it near-impossible for participants to view the outturn prices. This could create unmanageable risk for participants and lead to unintended consequences, with the proposed VoLL values noted as a significant risk to independent participants. This would increase the levels of Credit Cover that participants would need to lodge, reducing funds available to participants to use elsewhere, such as in attracting new customers.

It was also felt that P305 would result in an asymmetric reallocation of the RCRC, the sum of which may be greater as a result of higher prices. In particular, it was felt that the better balanced Parties would be worse off from this as their RCRC payments would be subsidising participants who were short in that Settlement Period. This could impact the incentives on participants to balance. A related argument was put forward by one respondent in that P305 would have different impacts on different participants, which could create competitive distortions. Not all participants would be able to change their behaviours in response to events, with smaller Parties less able to respond to signals quickly and intermittent generators' ability to react limited by the technology available (for example the accuracy of wind forecasts would impact wind farms).

Some respondents felt that P305 would encourage participants to balance their positions more efficiently, which would lead to an increase in liquidity in the market. However, other respondents felt that P305 would be detrimental to liquidity, particularly in times of scarcity when there was concern liquidity would completely dry up as participants seek to balance their own positions. Other initiatives such as CfD are also encouraging participants to balance elsewhere, which reduces the available volume to trade within the market. It was felt that P305 is seeking to sharpen imbalance prices without ensuring there is sufficient liquidity first, and that exploration of a deeper and more liquid intraday market would be a better approach.

No respondents considered that P305 would better facilitate Applicable BSC Objective (d). However, a a minority of respondents considered that P305 would not better facilitate Applicable BSC Objective (d) due to increases in complexity for little or no apparent benefit. In particular, one respondent noted that the RSP had had no impact on the historical analysis carried out by ELEXON, and questioned the benefit of introducing a process as complex as the LoLP functions for no proven benefit. The accuracy and benefits of the Demand Control volume correction processes was also considered to be uncertain, and appeared a very complex that would rarely be called upon, with the risk of an artificial volume like this being applied at times of high prices being challenged. This increase in complexity may also increase work and costs for existing participants and may discourage new participants from entering the market.

Some respondents were unable to give a clear view on P305. One respondent felt that without an understanding of how different participants would be impacted a view could not be given, and that this analysis had not been sufficiently executed. Others felt that the solution requirements were not sufficiently developed to be able to be fully assessed, and that further work still needs to be carried out. It was considered to be risky to introduce so much change in such a short time, and that if P305 were to be implemented it should be done so at a more benign time of the year. Implementing P305 after P272 would also be of benefit as there would be a greater number of Metering Systems settled HH that would increase the accuracy of the Demand Control volume correction process.

It was also considered that the current arrangements appear to work well, and that P305 had not been sufficiently demonstrated to be better, and so there was no case for change. Another respondent felt that it had not been proven that these changes would allow participants to be able to avoid a Demand Control event occurring.

Panel's initial recommendations

The Panel initially recommends that:

- the Proposed Modification **does not** better facilitate the Applicable BSC Objectives than the current Baseline and so should be **rejected**;
- the Alternative Modification **does not** better facilitate the Applicable BSC Objectives than the current Baseline and so should be **rejected**; and
- the Alternative Modification **does** better facilitate the Applicable BSC Objectives than the Proposed Modification (although neither are better than the current Baseline).

Therefore, the Panel initially recommends that **both the P305 Proposed and Alternative Modifications should be rejected**.

The Panel's discussions on P305 and its views against the Applicable BSC Objectives are detailed below.

Panel's views on P305

Views on the PAR value options

A couple of Panel Members noted that they felt that a PAR value of 50MWh would be the most suitable, but were uncomfortable with the subsequent move to 1MWh in 2018 under the Proposed Modification, feeling this value to be too small. Equally, they felt that the value of 100MWh under the Alternative Modification was right on the cusp of being too high to deliver benefit. These Members would have liked to have seen a solution proposing 50MWh with no further reductions.

Views on the LoLP functions

One Panel Member highlighted the expected rise in flexible capacity, with up to 20GW of wind generation being available in the future, coupled with the fluctuations in demand. They sought assurance that the LoLP functions fully accounted for the variations in the output of these types of generation, for example wind generation being dependent on the weather. It was noted that a lot of work had been done on the 'dynamic' LoLP function, and that the Transmission Company was content that factors such as these had been fully accounted for in the model. The 'dynamic' function takes into account all available forecasts, including demand and wind forecasts, as well as historic performance of particular fuel types.

It was flagged that the Workgroup's main concern had been around the potential for the Final LoLP value to 'spike' at Gate Closure compared to the indicative value one hour earlier. This had the potential to give misleading signals, as the Indicative LoLP values decreased in the run-up to Gate Closure before spiking at Gate Closure when participants would not be able to react. The Workgroup had questioned if this was an appropriate signal to provide to the industry. The Workgroup had therefore agreed that the 'dynamic' LoLP function was a good model, but that it would be better to use the output from that model to create a 'look-up' function, as proposed by the 'static' LoLP function.

It was confirmed that this 'static' curve would be updated at least annually, and that this arrangement could be reviewed in the future. The processes for calculating each function would also be contained in the LoLP Calculation Statement, which could also be reviewed from time to time as necessary, allowing amendments to either function to be proposed at a later date.

Views on the VoLL value

One Panel Member queried whether more regular reporting on VoLL and related information could be published, for example through the Trading Operations Report. It was noted though that the VoLL value is not one that would be expected to change regularly, as it is based on an average value and was felt to be a sufficiently large enough number already. An annual review had been suggested by the Workgroup, but was not included for these reasons.

The Panel considered that the VoLL value would mean different things to different participants, for example providing an investment signal to participants. As such, the VoLL value could rise over time, so sufficient flexibility is needed to allow this to be reflected under the BSC. The Panel also considered that it was important that there was consistency throughout all policies that use VoLL in some way, to provide a consistent signal to the industry.

Views on the impacts of future changes

One Member flagged that the analysis that had been undertaken under P305 had all been on historic data, but that the future looks very different to the last few years. In particular, they flagged the impacts of Ofgem's Secure & Promote policy and the impact that the forthcoming European Network Codes may have. This would make it very difficult to forecast the full impacts of P305.

Another Member was uncomfortable with the proposal to include hardwired changes in 2018 as part of P305. They understood the intent by Ofgem to provide a clearer long-term signal and that this change would provide a four-to-five year signal to the industry. However, they noted that the baseline in three years' time may be different to the baseline today, and queried whether known changes due to take effect in that time, such as the expected increase in wind generation, may have an impact on the suitability of agreeing the 2018 changes now. Similar concerns among the Workgroup contributed to the development of the Alternative Modification, which does not include either a further reduction in PAR or a change from a static to a dynamic LoLP function, although the rise in the VoLL value was retained. The Panel Member was keen to get the views of Report Phase Consultation Respondents on how the baseline may change in the next three years and whether this would impact the changes proposed for 2018 and whether it is therefore appropriate to include hardwired future changes as part of P305.

Report Phase Consultation Question
Do you believe that expected changes between now and winter 2018/19 mean it would be inappropriate to include further hardwired changes in P305 proposed to go live on 1 November 2018? *Please provide your rationale.*
The Panel invites you to give your views using the response form in Attachment E

Views on the analysis and assessment of P305

One Panel Member highlighted the views of some of the Workgroup that there had been insufficient opportunity to assess some parts of the historical analysis, noting in particular that the Workgroup had been unable to consider the final parts of the analysis before it had made its recommendations. This Member felt that the Workgroup should have the opportunity to comment on the results of this work. As the Assessment Procedure is now complete, there will be no further Workgroup meetings, but the industry, including Workgroup members, will have the opportunity to assess this analysis as part of the Report Phase Consultation, and the Panel welcomes any views respondents may have on the results of this work.

A Panel Member asked what the relative impacts are between the four solution areas, and whether there was more benefit in implementing some areas sooner as a 'quick win'. While analysis had been undertaken on the solution areas in an incremental nature (see Attachment A), the solution had been developed as a single solution, and the Authority Representative confirmed that it intended for the EBSCR reforms to be delivered as a single package. However, it was noted that P316 could be progressed sooner to achieve a staggered implementation approach, facilitating the implementation of elements that would deliver benefit but had a lower implementation effort compared with the remaining elements, and had been raised partly to allow for this option.

Another Member felt that there had been insufficient work done to understand the impacts P305 may have on Credit Cover. They had concerns over the impacts that a rise in Credit Cover could have at this time. The Authority Representative noted that work had been done on this area under the EBSCR, but acknowledged that there is uncertainty in the future and it was not clear how some of these impacts could be effectively predicted.

Consequential costs under the BMRS Upgrade

The Panel noted that should P305 be implemented as part of the November 2015 Release then ELEXON would need to postpone some parts of its upgrade of the BMRS. In particular, it would need to implement P305 on the existing BMRS platform before then migrating it to the new platform around May 2016. This would incur a separate £250k cost to the project in addition to the P305 implementation costs outlined in Section 4. If P305 was to be implemented later than November 2015 this additional expenditure may not be incurred.

Panel's views against the Applicable BSC Objectives

The Panel considers that the relevant Applicable BSC Objectives are (b), (c) and (d), and unanimously considers P305 to be neutral against Applicable BSC Objectives (a), (e) and (f).

Applicable BSC Objective (b)

The Panel unanimously believes that both the Proposed Modification and the Alternative Modification would better facilitate Applicable BSC Objective (b).

All Panel Members believe that the proposed arrangements would improve efficiency for the Transmission Company. They consider that the proposed changes would mean that the imbalance prices would better value flexibility and would provide signals for investment, and one Panel Member noted that anything that would help encourage investment would be beneficial, considering the current outlook on this area. In addition, P305 is more focused on how plants dispatch, and would not on its own encourage investment, but may influence what type of generation participants invest in.

Applicable BSC Objective (c)

The Panel, by majority, believes that both the Proposed Modification and the Alternative Modification would not better facilitate Applicable BSC Objective (c), and that this detrimental impact outweighed the benefits against Objective (b).

Concern was raised over the potential distributional impacts that P305 may have, notably on intermittent generation due to their relative difficulty in managing risk and the impact P305 may have on related contracts. However, one Member disagreed, believing that all participants would benefit from the removal of the price spread arising from the dual prices currently in use.

Members were also not convinced that participants would be able to respond to the signals under the proposed arrangements, especially at lower values of PAR, and that this situation could be worse at times of scarcity should liquidity dry up. One Member felt this concern was mitigated slightly under the Alternative Modification due to the higher PAR value proposed. The complexity of the proposed solutions could also impact the ability of smaller participants to be able to respond. One Member was concerned that the complexity may not send out the right investment signals, and could result in a reduction in investment.

A couple of members felt that a PAR value of 50MWh was about the right value, but were concerned about the subsequent move to 1MWh in 2018, feeling this value was too small. They also felt that the value of 100MWh under the Alternative Modification may be too large, believing it was on the cusp of the size of reduction that they believed would have a beneficial effect. One Member noted that a more marginal price under P305 may have the potential to allow market power to the detriment of competition, should one or two participants have the ability to influence prices. They highlighted discussions on this area held by the Competition Commission, which had raised concerns over lower PAR values.

Only one Member felt that both the Proposed and Alternative Modifications would be beneficial to competition, and especially for generators, and noted that the point of P305 was to encourage investment. Another Member felt that the Alternative Modification could be slightly better for competition than the current Baseline.

Applicable BSC Objective (d)

The Panel, by majority, believes that the Proposed Modification would not better facilitate Applicable BSC Objective (d), while the majority view is that the Alternative Modification would be neutral to Applicable BSC Objective (d).

It was felt by some Members that the proposed changes were too complex and that not enough time had been allowed to implement the changes, with one Member believing that there would be issues with implementing P305 that could impact the efficiency of the arrangements. Another Panel Member felt that P305 had too many parts to it to be able to take an accurate view on its impacts, believing it could have been better progressed if split up into separate Modifications.

There was also concern with the move to the 'dynamic' LoLP function under the Proposed Modification, with one Member uncertain what the 'dynamic' model actually looked like. This concern was removed under the Alternative Modification.

Proposed Modification versus Alternative Modification

While the Panel considers that neither the Proposed Modification nor the Alternative Modification would better facilitate the Applicable BSC Objectives compared to the current Baseline, Panel Members that gave views on this matter unanimously considered that the Alternative Modification would be less detrimental than the Proposed Modification. One Member abstained, feeling that they were not able to make a judgment on this matter at this time.

Members felt that a PAR value of 100MWh under the Alternative Modification may be slightly better than the ultimate move to 1MWh under the Proposed Modification, though one Member believed the certainty of a next step was beneficial. However, there was general agreement that the removal of the move to the 'dynamic' LoLP function was beneficial.

The Panel therefore puts forward the recommendation that the Alternative Modification would be better than the Proposed Modification, although neither would be better than the current Baseline.

Report Phase Consultation Questions
Do you agree with the Panel's initial recommendation that the P305 Proposed Modification should be rejected? *Please provide your rationale with reference to the Applicable BSC Objectives.*
Do you agree with the Panel's initial recommendation that the P305 Alternative Modification should be rejected? *Please provide your rationale with reference to the Applicable BSC Objectives.*
Do you agree with the Panel's initial recommendation that the P305 Alternative Modification would be better than the P305 Proposed Modification? *Please provide your rationale with reference to the Applicable BSC Objectives.*
The Panel invites you to give your views using the response form in Attachment E

Panel's views on the Implementation Date

One Panel Member highlighted the views expressed by DSOs in the Assessment Procedure Consultation (see Section 5) that they would not be able to meet the proposed Implementation Date of 5 November 2015, and flagged that they had been contacted by other DSOs with similar concerns. A lot of work is needed by DSOs to implement P305, including necessary Master Registration Agreement (MRA) changes, and the further details within the BSCPs still need to be prepared. The Member also noted that the Supplier Meter Registration Services (SMRSs) do not hold time of day information that P305 may need, although another Panel Member felt this wasn't needed as DSOs would just be providing a list of affected MPANs and would use the times issued by the Transmission Company.

The Panel noted these concerns, but agreed to initially recommend an Implementation Date of 5 November 2015, as put forward by the Workgroup. However, it encouraged participants, and in particular DSOs, to provide as much further information as possible on the impacts of P305 and their ability to meet this date as part of the Report Phase Consultation, to allow the Panel to thoroughly consider this matter when it discusses responses to the Report Phase Consultation.

Report Phase Consultation Question
Do you agree with the Panel's recommended Implementation Date? *Please provide your rationale.*
The Panel invites you to give your views using the response form in Attachment E

Panel's views on the draft legal text

The Panel noted that some amendments were required to the P305 draft legal text, following its issue as part of the Assessment Report, to fully reflect the process for accounting for non-BM STOR and DSBR actions, as intended by the Workgroup (see Section 7). These amendments have been included in the versions of the legal text in Attachments B and C to this consultation. It had also been identified that the acronym 'RSP_j' is already used under the BSC for 'Replacement Sell Price', and so a new acronym was needed for 'Reserve Scarcity Price', with '$RSVP_j$' being chosen.

The Panel has therefore noted the draft legal text, and invites comments from respondents to the Report Phase Consultation.

Report Phase Consultation Question
Do you believe that the redlined changes to the BSC deliver the intention of P305? *Please provide your rationale.*
The Panel invites you to give your views using the response form in Attachment E

Post-meeting note: Comment from the Transmission Company on consequential Grid Code changes

Following the Panel meeting, the Transmission Company has noted that, having reviewed the proposed legal text revisions to the BSC and the new requirements on it for the provision of information in the event of a Demand Control event, it does not consider a change to Section OC6 of the Grid Code is required, as originally envisioned. The additional information requirements for P305 are detailed under the draft legal text, which captures the data requirements from the Transmission Company and does not impact any activities under Grid Code Section OC6. As a result, no consequential impacts to the Grid Code are considered to be necessary.

Respondents to the Report Phase Consultation are asked whether they agree with this view, and if they disagree to highlight what Grid Code changes they believe may be necessary. The P305 legal text is not impacted by this clarification from the Transmission Company.

Report Phase Consultation Question
Do you agree with the Transmission Company that there are no consequential changes necessary to the Grid Code in response to P305? *Please provide your rationale and, if 'No', please state which Section(s) you believe are impacted and how they should be amended.*
The Panel invites you to give your views using the response form in Attachment E

10 Recommendations

The BSC Panel initially recommends to the Authority:

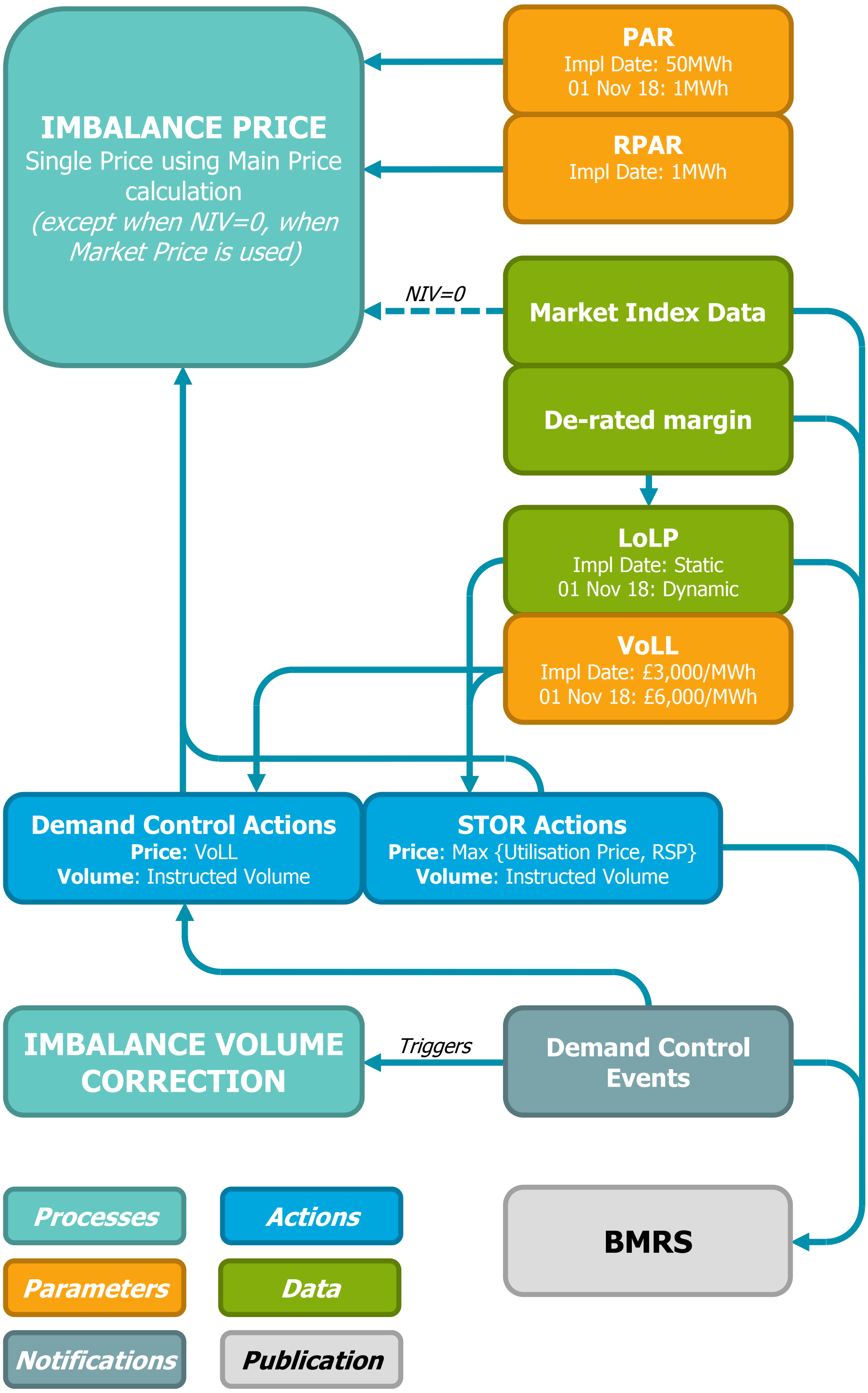
- That the P305 Proposed Modification should be **rejected**;
- That the P305 Alternative Modification should be **rejected**;
- That the P305 Alternative Modification is better than the P305 Proposed Modification;
- An Implementation Date for the P305 Proposed Modification of 5 November 2015; and
- An Implementation Date for the P305 Alternative Modification of 5 November 2015.

The BSC Panel notes the draft BSC legal text for the P305 Proposed and Alternative Modifications for consultation, subject to further consideration and agreement.

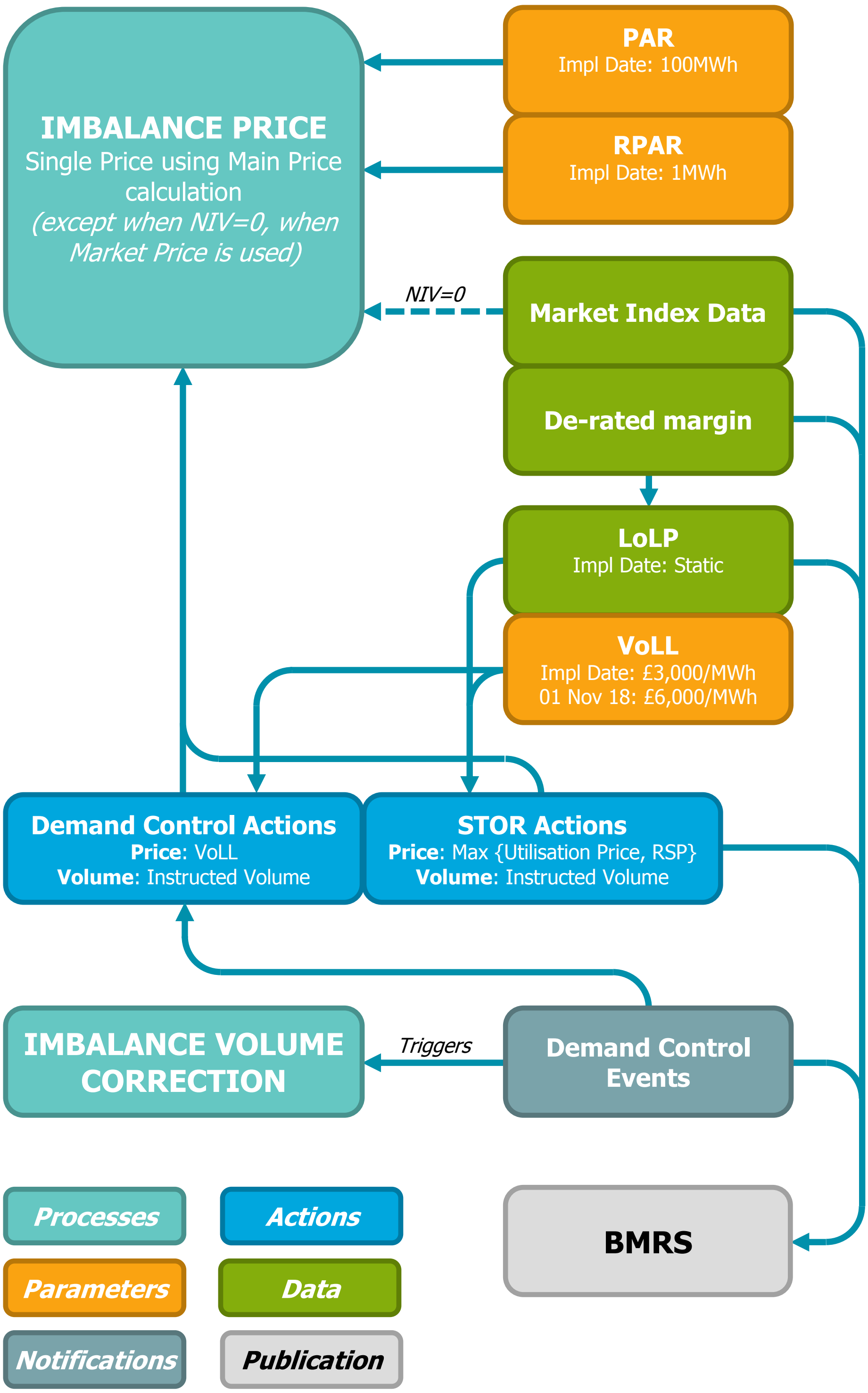
Appendix 1: P305 Solution Summary Diagrams

These diagrams summarises the impacts and interactions of P305 on the imbalance price calculations. Any part of the existing process not included will not be impacted by P305.

Proposed Modification



Alternative Modification



Appendix 2: Workgroup Details

Workgroup's Terms of Reference

Specific areas set by the BSC Panel in the P305 Terms of Reference
Are the proposed solutions the most appropriate way to implement the EBSCR conclusions?
Are the proposed step-changes to the PAR value the most appropriate values?
How should the LoLP value be calculated for each Settlement Period?
Is there a risk of market abuse or manipulation and how can this be mitigated or prevented?
Will a move towards a more marginal price reflect a more marginal cost?
What impact may P305 have on Parties' behaviour and the likely positions they may seek to take following implementation of the changes, and what issues may this cause?
What impact will each aspect of P305 have on different types of users, in particular non-portfolio generators, small Suppliers and intermittent generators?
What are the answers to the questions posed by Ofgem in its draft business rules and how should they be incorporated into the proposed P305 solution? These questions are: • How should the imbalance price be calculated when NIV is zero? • Should Market Index Data and the MIDS be removed, and would there be any wider implications in doing so? • What, if any, input metrics to the LoLP calculation should be published on the BMRS? • How frequently and far in advance of Gate Closure should indicative LoLP values be published? • Should VoLL increase in line with inflation each year? • Should automatic Low Frequency Demand Disconnections be included as a type of Demand Control event? • Is there a more accurate means to correct a Supplier's imbalance position for the II Run than proposed? • Is it feasible to calculate an accurate estimate of the volume of voltage reduction? • How should historic GSP Group Correction Factor data be used in the correction of Suppliers' imbalance positions?
What views and arguments have been expressed under previous Modifications relating to the imbalance prices and do they apply to P305?
The Workgroup should undertake any analysis required to demonstrate the impacts that P305 may have, drawing upon the analysis undertaken under the EBSCR where possible.
Do the changes proposed by P305 have the potential to simplify the imbalance price calculations?
What is the most appropriate Implementation Date for P305?
What changes are needed to BSC documents, systems and processes to support P305 and what are the related costs and lead times?
Are there any Alternative Modifications?
Does P305 better facilitate the Applicable BSC Objectives than the current baseline?

Assessment Procedure timetable

P305 Assessment Timetable	
Event	Date
Panel submits P305 to Assessment Procedure	12 Jun 14
Workgroup Meeting 1	19 Jun 14
Workgroup Meeting 2	18 Jul 14
Workgroup Meeting 3	22 Aug 14
Industry Impact Assessment	05 Sep 14 – 26 Sep 14
Workgroup Meeting 4	10 Sep 14
Workgroup Meeting 5	03 Oct 14
Workgroup Meeting 6	07 Oct 14
Workgroup Meeting 7	21 Oct 14
Workgroup Meeting 8	29 Oct 14
Panel grants two month extension	13 Nov 14
Workgroup Meeting 9 (joint with P316)	28 Nov 14
Workgroup Meeting 10 (joint with P316)	01 Dec 14
Assessment Procedure Consultation	16 Dec 14 – 14 Jan 15
Workgroup Meeting 11 (joint with P316)	21 Jan 15
Workgroup Meeting 12 (joint with P316)	23 Jan 15
Panel considers Workgroup's Assessment Report	12 Feb 15

Workgroup membership and attendance

P305 Workgroup Attendance													
Name	Organisation	1	2	3	4	5	6	7	8	9	10	11	12
Members													
Adam Lattimore	ELEXON *(Chair)*	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
Dean Riddell	ELEXON *(Chair)*	✗	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
David Kemp	ELEXON *(Lead Analyst)*	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Sally Lewis	National Grid *(Proposer)*	✓	✓	✓	✓	✓	✓	✓	✓	✗	✗	✓	✓
Alex Haffner	National Grid *(Prop's Alt.)*	✗	✗	✗	✗	✗	✗	✗	✗	✓	✓	✗	✗
Bill Reed	RWE	✓	✓	✗	✓	✓	✓	✓	✓	✓	✓	✓	✓
Esther Sutton	E.ON	✓	✓	✓	✓	✓	✗	✓	✓	✓	✓	✓	✓
Lisa Waters	Waters Wye Associates	✓	✓	✓	✓	✓	✓	✗	✗	✗	✗	✗	✗
Olaf Islei	APX	✓	✓	✗	✓	✗	✓	✗	✓	✓	✓	✓	✓
Sarah Owen	Centrica	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
James Anderson	Scottish Power	✓	✗	✓	✓	✓	✓	✓	✓	✗	✗	✓	✓
Tom Edwards	Cornwall Energy	✓	✓	✗	✗	☎	☎	✗	✗	✓	✓	✗	✓

P305 Workgroup Attendance													
Name	Organisation	1	2	3	4	5	6	7	8	9	10	11	12
Andy Colley	SSE	✓	✓	✗	✓	✓	✓	☎	✓	✓	✓	✓	✓
Libby Glazebrook	GDF Suez	✓	✗	✗	✗	✓	✓	☎	✓	☎	✓	✓	☎
Colin Prestwich	SmartestEnergy	✓	✓	✗	✓	✗	✓	✓	✓	✓	✓	✓	✓
Cem Suleyman	Drax	✓	✓	✓	✓	✗	✗	✓	✓	✗	✗	✓	✓
Martin Mate	EDF	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Christine Hough	Haven	✓	✗	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗
Alan Goodbrook	Good Energy	✗	✓	✓	✗	✗	✓	✓	✓	✓	✓	✓	✓
Keith Munday	First Utility	✗	✓	✓	✓	✗	✗	✗	✗	✓	✓	✓	✓
Stephen Mason	Hess	✗	✗	✗	✗	✓	✓	✓	✓	✗	✓	✓	✓
Attendees													
Talia Addy	ELEXON *(P316 Lead Analyst)*	✗	✗	✗	✗	✗	✗	✗	✗	✓	✓	✓	✓
Jonathan Priestley	ELEXON *(Design Authority)*	✓	✓	✓	✓	✗	✗	✗	✗	✗	✗	✗	✗
Nick Rubin	ELEXON *(Design Authority)*	✗	✗	✗	✓	✓	✓	✓	✓	✓	✓	✓	✓
Nick Brown	ELEXON *(Lead Lawyer)*	✓	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓
Stephen Casement	National Grid	✓	✓	✓	✓	✓	✗	✓	✓	✓	✗	✗	✗
Leon Walker	National Grid	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
Matthew Roberts	National Grid	✗	✗	✗	✓	✓	✗	✗	✓	✓	✗	✗	✗
Dominic Scott	Ofgem	✓	✗	✓	✓	✓	✓	✓	✗	✓	✓	✓	✓
Dipali Raniga	Ofgem	✓	✓	✓	✗	✓	✓	✓	✓	✓	✓	✗	✗
David Beaumont	Ofgem	✗	✓	✗	✓	✓	✓	✗	✓	✓	✓	✗	✗
Caroline Selman	Ofgem	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
James Soundraraju	Ofgem	✗	✗	✓	✓	✓	✗	✗	✗	✗	✗	✓	✓
Adam Gilham	Ofgem	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✓	✓
Duncan Sinclair	Baringa	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗
Richard Devenport	EDF	✓	✓	✓	✗	✓	✗	✓	☎	✓	✗	✓	✓
Mari Toda	EDF	✓	☎	✓	✗	✗	✗	✓	✗	✗	✗	✗	✗
Sam Hollister	Energy UK	✓	✗	✓	✗	✗	✗	✗	✗	✓	✗	✗	✗
Pavel Miller	Energy UK	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
Christopher Steele	Energy UK	✗	✗	✗	✓	✗	✓	✓	✗	✗	✗	✗	✓
John Lawton	ENWL	☎	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
Jeremy Guard	First Utility	✗	✓	✗	✗	✗	✗	✓	✗	✗	✓	✓	✓
Nick Haines	Good Energy	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗
Phil Hewitt	EnAppSys	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗
Peter Bolitho	Waters Wye Associates	✗	✗	✗	✗	✗	✗	✓	✗	✓	✓	✓	✗

Appendix 3: EBSCR Document References

EBSCR Final Policy Decision documents

EBSCR – Final Policy Decision Impact Assessment, May 2014

EBSCR – Business Rules, May 2014

EBSCR – Further analysis to support Ofgem's Updated Impact Assessment, Baringa, May 2014

These three documents can be accessed at:

https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision

Directions issued by GEMA to National Grid in relation to EBSCR, May 2014

https://www.ofgem.gov.uk/publications-and-updates/direction-national-grid-electricity-transmission-plc-relation-electricity-balancing-significant-code-review

EBSCR forward modelling results (2014)

https://www.ofgem.gov.uk/ofgem-publications/88744/ebscrforwardmodellingresults.xlsx

EBSCR Draft Policy Decision documents

Electricity Balancing Significant Code Review – Draft Policy Decision, July 2013

https://www.ofgem.gov.uk/ofgem-publications/82294/ebscrdraftdecision.pdf

Electricity Balancing Significant Code Review – Draft Policy Decision Impact Assessment, July 2013

https://www.ofgem.gov.uk/ofgem-publications/82295/ebscr-draft-policy-decision-impact-assessment.pdf

Electricity Balancing SCR: Quantitative Analysis, Baringa, July 2013

http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Baringa%20EBSCR%20quantitative%20analysis.pdf

The Value of Lost Load for Electricity in Great Britain, London Economics, July 2013

http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/London%20Economics%20Value%20of%20Lost%20Load%20for%20electricity%20in%20GB.pdf

Further EBSCR documents

Electricity Balancing Significant Code Review – Initial Consultation, August 2012 (Reference 108/12)

www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Electricity%20Balancing%20SCR%20initial%20consultation.pdf

Electricity cash-out issues paper, November 2011, (Reference 143/11)

www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/Electricity%20cash-out%20issues%20paper.pdf

Cash-out price data (2013)

https://www.ofgem.gov.uk/ofgem-publications/82972/cash-outpricedata.xlsx

P217A preliminary analysis (2012)

https://www.ofgem.gov.uk/ofgem-publications/40803/p217a-preliminary-analysis.pdf

P217A preliminary analysis data (2012)

https://www.ofgem.gov.uk/ofgem-publications/40784/p217a-preliminary-analysis-data.xlsx

Appendix 4: Glossary & References

Acronyms

Acronyms used in this document are listed in the table below.

Acronyms	
Acronym	Definition
BM	Balancing Mechanism
BMRA	Balancing Mechanism Reporting Agent *(BSC Agent)*
BMRS	Balancing Mechanism Reporting Service
BOA	Bid-Offer Acceptance
BPA	Buy Price Adjustment *(value)*
BSAD	Balancing Services Adjustment Data *(value)*
BSCP	BSC Procedure *(document)*
BSUoS	Balancing Services Use of System *(charge)*
CADL	Continual Acceptance Duration Limit *(parameter)*
CDCA	Central Data Collection Agent *(BSC Agent)*
CfD	Contracts for Difference
CM	Capacity Mechanism
CPI	Consumer Price Index
CSD	Code Subsidiary Document *(document)*
DECC	Department of Energy and Climate Change *(Government department)*
DSBR	Demand Side Balancing Reserve
DSO	Distribution System Operator *(BSC Party)*
DSR	Demand Side Response
DTC	Data Transfer Catalogue
EBSCR	Electricity Balancing Significant Code Review
ECOES	Electricity Central Online Enquiry Service *(industry database)*
EMR	Electricity Market Reform
FiT	Feed-in Tariff
GB	Great Britain
GSP	Grid Supply Point
HH	Half Hourly
II	Interim Information *(Settlement Run)*
ISG	Imbalance Settlement Group *(Panel Committee)*
LCPD	Large Combustion Plant Directive *(European Regulation)*
LFDD	Low Frequency Demand Disconnection
LLR	Largest Loss Reserve

Acronyms	
Acronym	Definition
LoLP	Loss of Load Probability *(value)*
MEL	Maximum Export Limit
MIDS	Market Index Definition Statement *(document)*
MPAN	Meter Point Administration Number
MRA	Master Registration Agreement *(industry Code)*
NDZ	Notice to Deviate from Zero
NETSO	National Electricity Transmission System Operator
NHH	Non Half Hourly
NIV	Net Imbalance Volume *(value)*
PAR	Price Average Reference *(parameter)*
PN	Physical Notification
PPA	Power Purchase Agreement
RCRC	Residual Cashflow Reallocation Cashflow *(volume of money)*
REMIT	Regulation on wholesale energy markets integrity and transparency *(European Regulation)*
RPAR	Replacement Price Average Reference *(parameter)*
RSP	Reserve Scarcity Price *(value)*
SAA	Settlement Administration Agent *(BSC Agent)*
SBP	System Buy Price *(value)*
SBR	Supplementary Balancing Reserve
SCR	Significant Code Review
SF	Initial Settlement *(Settlement Run)*
SMRS	Supplier Meter Registration Service
SO	System Operator
SQSS	Security and Quantity of Supply Standard *(parameter)*
SSP	System Sell Price *(value)*
STAG	Software Technical Advisory Group *(Panel Sub-group)*
STOR	Short Term Operating Reserve
SVAA	Supplier Volume Allocation Agent *(BSC Agent)*
TWG	Technical Working Group *(SCR Workgroup)*
VoLL	Value of Lost Load *(parameter)*

External links

A summary of all hyperlinks used in this document are listed in the table below.

Hyperlinks listed in Appendix 3 are not included here.

All external documents and URL links listed are correct as of the date of this document.

External Links		
Page(s)	Description	URL
3, 6, 7, 24	EBSCR page on the Ofgem website	https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review
4	Imbalance and Pricing page on the ELEXON website	https://www.elexon.co.uk/reference/credit-pricing/imbalance-pricing/
5	Grid Code page on the National Grid website	http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/
6	Project Discovery Final Report on the Ofgem website	https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinal.pdf
6, 15, 44, 57, 58, 60	EBSCR Final Policy Decision page on the Ofgem website	https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision
7	EBSCR Direction page on the Ofgem website	https://www.ofgem.gov.uk/publications-and-updates/direction-national-grid-electricity-transmission-plc-relation-electricity-balancing-significant-code-review
7, 14	P304 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p304/
7, 15, 54	P305 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p305/
10, 44, 46, 49	DECC-Ofgem VoLL Study by London Economics Report on the Ofgem website	https://www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gb.pdf
14	P314 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p314/
14	P316 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p316/
19	P300 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p300/
20	P272 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p272-mandatory-half-hourly-settlement-for-profile-classes-5-8/

External Links		
Page(s)	Description	URL
25	P205 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p205-increase-in-par-level-from-100mwh-to-500mwh/
25	P194 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p194-revised-derivation-of-the-main-energy-imbalance-price/
25	P217 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p217-revised-tagging-process-and-calculation-of-cash-out-prices/
32, 35, 63	Historic System Prices under the EBSCR Proposed Reforms page on the ELEXON Portal *(a free login account is required to view this page)*	https://www.elexonportal.co.uk/p305analysis
36	Transparency Regulation on the EUR-Lex website	http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2013:163:0001:0012:EN:PDF
40	REMIT Regulation on the EUR-Lex website	http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:EN:PDF
44, 45, 55	EBSCR Draft Policy Decision page on the Ofgem website	https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-draft-policy-decision
51	GC0050 page on the National Grid website	http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0050/
52	P199 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p199-quantification-of-demand-control-in-the-bsc-as-instructed-under-oc-6-cd-e-of-the-grid-code/
52	STAG page on the ELEXON website	https://www.elexon.co.uk/group/software-technical-advisory-group-stag/
53	P299 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p299/
57	P306 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p306/
57	P307 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p307/
57	P308 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p308/
57	P310 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p310/